PENNSYLVANIA POWER & LIGHT COMPANY

Statement 6-R TJS-2-12 5/25/95 1HG jar

Rebuttal Testimony of John J. Slivka

Docket No. R-00943271

Q. Please state your name, title, and business address.

A. John J. Slivka, Project Manager - Load Analysis and Information Systems for Pennsylvania Power & Light Company, Two North Ninth Street, Allentown, Pennsylvania 18101.

Q. Mr. Slivka, have you testified previously in this proceeding?

A. Yes. I submitted direct testimony (Statement 6).

Q. What is the purpose of your rebuttal testimony?

A. I will respond to the direct testimony of Mr. Steven Andersen on behalf of the Central Eastern Pennsylvania Fuel Oil Dealers ("CEPFOD" or "oil dealers"), in which he concluded that "PP&L's marketing of RTS was so aggressive that it not only shifted usage away from the daytime hours, it also shifted the time of the system peaks." He further concluded that "the RTS peaking problems" could not be solved by additional load management initiatives. Mr. Andersen heavily relies on an eight-year old PP&L planning study entitled Issues Associated with Nighttime Peak.

Q. Please summarize your rebuttal testimony.

A. I will show that Mr. Andersen has not substantiated his conclusions. Specifically, I will show with regard to the eight-year old planning study cited by Mr. Andersen that:

- Mr. Andersen failed to acknowledge that the recommendation of that study was to not implement aggressive residential marketing programs over the long-term because of the potential adverse impact on peak demand.

- The aggressive marketing goals assumed in the PP&L analysis were not pursued and, therefore, not achieved. In fact, following a de-emphasis of RTS promotion since 1990, the number of actual residential thermal storage (RTS) customers in 1994 (14,000) is now vastly less than the projections and goals for 1995 made in 1986 (over 52,000).

- A potential "peaking problem" stemming from thermal storage systems discussed in the study did not develop. RTS does not create an evening peak on PP&L's system. Rather, the current near-equal probability of morning or evening peaks is a result of:

    - growth in the total residential class,

- load profiles of the electric heating and non-electric heating customers,
- reduction in frequency of mid-morning peaks, and
- unpredictable weather conditions.

Q. What are your comments on the conclusions and recommendations in the planning report entitled <u>Issues Associated with Nighttime Peak</u> that Mr. Andersen relies upon to support his conclusions?

A. I believe it is important to review that report in the context of the time frame it covers and, most important, in the context of the underlying assumptions that were the basis for the planning study. It also is necessary to recognize the subsequent results, recommendations, and the change in marketing strategy. The planning study analyzed the potential impact of all marketing and economic development programs that were included in the 9/86 "Integrated" Forecast. For planning purposes, the impact of those programs was measured against the 9/86 "Base" Forecast to assess system facility requirements and system operating characteristics. The difference between the two forecasts is a scenario of aggressive marketing in the residential, industrial and commercial sectors and major economic development initiatives.

In particular, I want to address the assumptions underlying the residential marketing forecast and the impact those assumptions had on the report's conclusions. For purposes of my rebuttal testimony, I will highlight the years 1994 and 1995 from that study because those are the years relevant to the test year in this case and also are significant for one of the principal conclusions of the study. See Exhibit JJS-2. That exhibit shows that the residential marketing program had a two-fold approach. In the new construction market, it was assumed that an aggressive residential marketing effort would achieve a total of more than 17,000 thermal storage systems by 1994 and more than 20,000 by 1995. More significantly, it also was assumed that the conversion market would have achieved a total of more than 27,000 fossil systems converted to ceramic thermal storage systems by 1994; and that amount would increase to over 32,000 by 1995. Thus, a key assumption of the residential marketing program was that by 1995, 60% of the 52,000 thermal storage systems would be conversions.

Q. What effect did these assumptions have on the Company's projected customer growth rates?

A. The impact of these assumptions can be seen on Exhibit JJS-3 "9/86 Integrated Forecast Average Number of Customers by Customer Class," and Exhibit JJS-4 in a comparison of residential electric heating customers (Electrically Heated Homes) shown in the 9/86 "Integrated" Forecast and the 9/86 "Base Case" Forecast. In 1995, the 9/86 "Integrated" Forecast reflects a shift of 37,000 customers from non-electric heating to electric heating, some of which are assumed to have converted to thermal storage systems. This shift in customers produces a corresponding shift in sales as seen on Exhibits JJS-5 and JJS-6, in a comparison of projected 1995 sales between the 9/86 "Integrated" Forecast and 9/86 "Base" Case Forecast. The total residential sales level in the 9/86 "Integrated" Forecast (Exhibit JJS-5) is nearly one billion KWH higher than in the 9/86 "Base" Forecast (Exhibit JJS-6) and sales from the residential non-electric heating group (General Residential) shift to the residential electric heating group (Electrically Heated Homes) as a result of the attainment of the thermal storage systems goals.

Q. Was there also an impact upon PP&L's projected peak load?

A. Yes. The planning study analyzed customer levels and per customer hourly load impacts resulting from the residential marketing assumptions to determine the impact on hourly demands during PP&L's forecasted winter peak day. Exhibit JJS-7, pages 1 and 2, shows for the winter peak day in 1994 through 1997, the change in demand by hour between the "Base Case" Forecast and "Integrated" Forecast that would result from various marketing programs. Exhibit JJS-8, pages 1 and 2, shows the impact relative to the base case (LOADWB = Base Case vs. LOADW2 = Integrated Case). In 1996 and thereafter, the peak hour shifts to the evening. Exhibit JJS-7 demonstrates quite vividly the demand impact on the evening hours. By 1995 conversions alone were expected to add 600 megawatts to the evening hours; and by 1996, that has increased to 700 megawatts. The emphasis of the report's conclusions was that prior to 1995 the residential thermal storage systems would reduce winter peak growth as compared to the 9/86 "Base Case" Forecast. After 1995, however, the residential marketing goals, if achieved, would have created winter peak growth greater than the base case.

Q. What was the basis of these high goals?

A. The projections of 52,000 additional thermal storage systems by 1995 reflect high-end forecasts set by the Marketing Department. They assumed a much more aggressive effort to encourage the installation of thermal storage systems.

Q. What did the report recommend?

A. Because of the impact upon PP&L's peak loads, the 1987 "Nighttime Peak" report recommended that the Company de-emphasize the residential thermal storage program before the growth in peak demand would exceed the base case. Mr. Andersen's testimony quotes and relies on the study's conclusion that the assumed residential thermal storage marketing goals in the 9/86 "Integrated" Forecast would create increased peak demand after 1995. However, he neglects to acknowledge the study's recommendation to decrease the emphasis on RTS and to consider more sophisticated RTS load control strategies.

Q. Did the Company ultimately follow this recommended strategy?

A. Yes. The Company began to phase-out RTS promotional efforts in 1991, and currently offers no promotions to new RTS customers. PP&L now is encouraging more sophisticated systems such as ground source heat pumps.

Q. Has this change in emphasis affected the level of residential thermal storage marketing penetration as compared to the assumptions in the nighttime peak study?

A. Yes. As seen in Exhibit JJS-9, the total level of RTS customers ~~is~~ currently is about 20% below that which was projected for the new construction market. In total, the current RTS class size is 70% below the total residential thermal storage market projected in the study.

Q. Has the number of new customers joining the RTS class decreased sharply over the past two years?

A. Yes. In 1993, 806 customers became RTS customers. In 1994, there was an increase of 549 RTS customers; and over the first three months of this year, only 145 new RTS customers came on the system.

Q. What do you conclude?

A. The 1987 "Nighttime Peak" study upon which Mr. Andersen relies was premised upon projections that were never realized, and its predictions of peak load impact due to RTS never occurred. The study's recommendation that the Company de-emphasize the RTS rate was implemented.

Current Impact of RTS on the System Peak

Q. What has been the impact of RTS on the Company's system peak?

A. The development of a trend toward an evening peak is complex. As I will show, RTS did not and does not create the evening peak. Although RTS has incrementally increased the evening peak, its role in reducing the morning peak results in little, if any, overall effect on the Company's peak day requirements.

Q. Would you please discuss the factors affecting the hour of PP&L's winter peak?

A. Mr. Andersen indicated that the contribution of residential thermal storage system to peak demand is unpredictable. That is incorrect. The RTS contribution to the system winter peak demand is quite predictable given the controlled operation of RTS systems. What is unpredictable is the occurrence of the PP&L system peak. This unpredictability results from a number of factors interacting to determine the hour that the peak demand occurs. Currently, PP&L is a winter peaking company due to the number of residential and commercial space heating customers on its system. See Exhibit JJS-10. As demonstrated by the plots of that exhibit, the total residential (RS) profile during the winter peak day is fairly flat with morning and evening peaks of nearly equal magnitude and a mid-afternoon valley. However, the electric heating customers (EHH) have distinctly different demand profiles than the non-electric heating customers (GRS). Typically the electric heating customers peak in the morning, and the non-electric heating customers peak in the evening. Electric heating systems tend to be morning peaking because of the typical winter heating load which requires a higher morning demand coupled with early morning household water heating and cooking demand with a similar level of demand repeated in the evening. The non-electric heating customers peak in the evening because of the greater residential activity, including lighting, greater use of electric appliances, in some instances, electric cooking and electric water heating. The commercial and industrial heating customers tend to peak from mid-morning to mid-afternoon. The load profiles in Exhibit JJS-10 for the years 1985, 1986, 1987, 1989, 1990, 1991, and 1993 exhibit the typical winter peak day use patterns. Another factor affecting the time of the system winter peak is the growth in residential customers. Since

1985, PP&L has added 165,000 residential customers to the system. Exhibit JJS-11 shows the frequency of occurrence of weekday peaks during January and February since 1981. Since 1983, there has been a significant shift in the peak from mid-morning to evening. The mid-morning peaks driven by the commercial and industrial loads have been replaced by more evening peaks caused by residential customers.

Q. **What is the impact of these usage trends in recent years?**

A. In 1988, 1992, and 1994, PP&L experienced its winter peak in the evening. As the graphs indicate, the residential class (including both GRS and EHH) in those years peaked in the evening. The profile for EHH in those years is indicative of atypical weather conditions which produced extremely low daytime temperatures coupled with wind chills resulting in EHH demand build-up during the day. The resultant evening peak is the result of both EHH and GRS peaking in the evening. When PP&L's system has an evening peak, the residential class has an evening peak contributed to by the electric heating and non-electric heating customers.

Q. Has the current level of RTS customers caused the evening peak?

A. Absolutely not. As explained above, the shift in peak demand is caused by the residential class as a whole, not RTS. The Company has experienced its system peak in the evening three times -- 1988, 1992 and 1994. In each of those years, the peak would still have occurred in the evening even if all RTS load were removed from the system. There is simply no basis for Mr. Andersen's conclusion that RTS has caused a shift in the time of PP&L's peak.

Finally, the RTS systems, as a demand management option for electric heating systems, place more demand on PP&L's system in the evening and nighttime, as opposed to other systems. At the same time, they reduce the load of the morning peak, which is of equal importance in determining the Company's peak generation requirements. Therefore, RTS does not measurably increase the Company's peak needs relative to other electric heat customers.

Q. Does this conclude your testimony?

A. Yes, it does.

PENNSYLVANIA POWER & LIGHT COMPANY

5/25/95
1403 jar

Statement 7-R
+ Ex JMK-4

Rebuttal Testimony of Joseph M. Kleha

Docket No. R-00943271

I. Introduction.

Q. Please state your name and business address.

A. My name is Joseph M. Kleha. My business address is Pennsylvania Power & Light Company, Two North Ninth Street, Allentown, Pennsylvania 18101.

Q. Are you the same Joseph M. Kleha who previously testified in this proceeding on behalf of the Pennsylvania Power & Light Company?

A. Yes, I am. I submitted my direct testimony (Statement 7) on December 30, 1994, and was cross-examined on March 23 and 28, 1995.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal responds to the assertions of witnesses on behalf of the various intervenors on the following topics:

(1) the appropriate cost allocation method in this proceeding, including alternatives to PP&L's preferred 12 CP demand allocation methodology (responding to Messrs. Baron, Brubaker, Eisdorfer and Johnson);

(2) the appropriate ratemaking treatment of the value of interruptible load to PP&L's system and the proposal for a separate interruptible service rate class (responding to Messrs. Baron and Brubaker);

(3) the appropriate ratemaking treatment of the revenue requirement deficiency resulting from EDI/IDI credits (responding to Messrs. Baron, Brubaker and Johnson);

(4) the proper allocation of NUG output payments (responding to Messrs. Baron and Brubaker);

(5) the use of a minimum size system study to determine the applicable customer cost component (responding to Messrs. Andersen and Johnson);

(6) the proper allocation of intangible plant, and A&G O&M expenses (responding to Mr. Andersen);

(7) the treatment of Electric Plant Held For Future Use (responding to Mr. Metro);

(8) the proposed elimination of the Company's ECR (responding to Mr. Prisco); and

(9) the appropriateness of ECR recovery of non-energy revenue requirements associated with expiring capacity and energy agreements and the treatment of associated off-system sales revenue (responding to Messrs. Baron, Kahal and Prisco).

II. Cost Allocation Principles and the 12 CP Demand Allocation Methodology.

Q. Mr. Kleha, do you have any general comments regarding the various cost allocation methodologies proposed by the opposing parties in this proceeding?

A. Yes. When considering the appropriateness of a utility's proposed cost allocation methodology, cost allocation must be recognized for what it is -- an art, not an exact science. There is no single, absolutely correct method. Moreover, as the Commission has repeatedly recognized, a cost allocation study serves only as a guide and is but one of several important factors to be considered when designing a utility's rates.

The opposing parties in this proceeding offer a variety of criticisms of the Company's cost allocation study. The one consistency among them is that they all propose changes which, if adopted, would place their respective clients in a more advantageous position. The Company, however, lacks the incentive to favor one customer class over another when assigning costs. The Company has attempted to take a reasonable, middle-of-the-road position regarding the allocation of costs to the various customer classes. Of particular note is the fact that the Office of Trial Staff, the only other party not associated with a particular customer class, has not challenged the Company's cost of service study.

Finally, although the opposing parties have raised some interesting theoretical issues regarding cost allocation techniques, those issues have only limited relevance in this proceeding. The central issue to be considered is whether the Company's proposed allocation of the revenue increase and its rate design are reasonable.

Q. **Why does PP&L prefer the monthly peak responsibility demand allocation methodology, or 12 CP method, to allocate its generation and transmission facilities and associated operating expenses?**

A. As discussed in my direct testimony, PP&L's preference for the monthly peak responsibility or 12 CP demand allocation method is based on four primary considerations.

The first reason is long-term stability. Abrupt changes with respect to rate matters are undesirable, especially changes regarding cost allocation methods. PP&L has used the 12 CP method in every Pennsylvania and Federal rate filing in which it has submitted cost allocation studies. This Commission consistently has determined that the Company's 12 CP method is acceptable, including the Company's last base rate case. Nothing in this filing provides any compelling reason to discontinue its acceptance and use.

The second reason is PP&L's installed capacity obligation to the PJM Interconnection. The PJM's planned capacity requirement needed to meet its reliability objectives is defined as a levelized amount over a 12-month planning period, and each member is obligated to provide its share of that requirement. As explained by Mr. Sipics, the opposing witnesses fail to recognize how the determination of PP&L's obligation reflects many factors, including seasonal load diversities and average peak load shapes over the year. The 12 CP method is consistent with the determination of PP&L's PJM installed capacity obligation. The methods proposed by the other parties are not.

The third consideration is PP&L's belief that recognition of seasonal class diversities is necessary to properly reflect those benefits among rate classes. The 12 CP method provides for this consideration.

The fourth consideration is the scheduling of generation equipment maintenance throughout the year. As part of its participation in the PJM, PP&L must schedule planned generation equipment maintenance throughout the year in coordination with the other PJM member companies. Only the 12 CP method fully reflects consideration of these actual system operating conditions.

Q. Do you agree with Messrs. Baron, Brubaker and Eisdorfer that the winter peak (1 CP) demand allocation method is an appropriate way to allocate PP&L's generation facilities and costs?

A. No. For the reasons I just mentioned, the 12 CP methodology is the most appropriate for PP&L. The winter peak (1 CP) demand allocation method focuses exclusively on a single monthly peak to allocate the costs associated with PP&L's generation facilities. By focusing on only a single monthly peak, the winter peak method ignores the very real fact that customers impose demands on PP&L's system in each and every month of the year. Moreover, this method fails to recognize that the calculation of PP&L's PJM capacity obligation is based on the provisions of levelized amounts of capacity for the entire 12 months of each year and that the determination of that obligation reflects many factors, including <u>but not limited to</u>, the winter peak load.

Analysis of PP&L's actual monthly peak load and scheduled generating unit maintenance data indicates that the Company's maximum capacity requirements (monthly peak load plus scheduled maintenance requirement) do not always occur in the three-month winter period (December, January and February). Such requirements, which are equal to or greater than PP&L's annual winter peak load, can and do occur in any month of the year, except the summer months when PJM's load requirements are expected to be the most critical. For example, in recent years, the Company's maximum capacity requirements have occurred during the following months:

Year	Month(s)
1989	March
1990	March
1991	April
1992	March
1993	March, April and November
1994	March, April and November

Finally, the parties who advocate a 1 CP method focus unduly on the amount of capacity on PP&L's system and ignore the type of capacity required. If PP&L were to design a system solely to meet its single winter peak, that system would be far different than the present mix of generation capacity resources installed by PP&L to meet its customers' demands over the entire year.

Q. **Do you agree with Mr. Johnson's proposal to allocate a portion of PP&L's generation facilities on a demand**

basis and a portion of those facilities on an energy basis?

A. No, I do not. Mr. Johnson proposes to allocate a portion of PP&L's generation facilities on the basis of customers' demand in the three-month winter peak period (December, January and February) and in the two-month summer peak period (July and August) and the remaining portion of those facilities on the basis of customers' energy usage. I disagree with this peak demand and average energy allocation proposal for several reasons.

First, I would note that the Commission rejected a peak and average allocation proposal by the OCA in the Company's 1982 base rate case at Docket No. R-822169. The same conclusion is appropriate in this proceeding.

Second, Mr. Johnson's proposed allocation methodology fails to recognize that customers' load at the time of each month's peak is important in determining the amount and type of generating capacity installed on PP&L's system.

Third, Mr. Johnson's proposed methodology fails to consider seasonal class diversities for the entire 12 months of the year.

Fourth, Mr. Johnson's proposed methodology ignores the fact that PP&L must perform maintenance on its generation facilities during the other seven months of the year. As explained above, in recent years, PP&L's

maximum capacity requirements (peak load plus scheduled maintenance) have not occurred in the 5 months utilized by Mr. Johnson to allocate production costs.

Fifth, generation (and transmission) facilities are fixed capacity resources the costs of which do not vary with customers' energy usage. For example, a utility does not use energy (KWH) generation data to determine its depreciation rates for such facilities. Nor are its generating facilities assessed property taxes in proportion to the amount of energy generated during a given time period. The costs of these fixed capacity resources are related directly to a utility's peak demands, because it is the need to meet this demand instantaneously in a reliable manner that determines the mix and size of its generating and transmission facilities. Generation facilities properly are, for allocation purposes, assigned on the basis of customers' demand imposed on those facilities -- not on the basis of their energy usage.

Sixth, Mr. Johnson's proposed methodology produces unreasonable results, wherein approximately 60% of the cost of the Company's generation facilities would be allocated on an energy basis. This would impose sudden and very substantial increases in cost responsibility, particularly on large, high load factor industrial customers. Indeed, Mr. Johnson's method would assign greater production cost responsibility to those customer classes who increase their load factors and use PP&L's system more efficiently. Increased load factors provide benefits to the Company and all of its customers, and should be encouraged, not discouraged.

Finally, Mr. Johnson's proposal is incomplete. If there is to be an energy allocation of production plant costs, then there also should be a demand component in the allocation of energy costs. The Company allocates production costs on a demand basis (12 CP) and energy costs on an energy basis (class KWH usage). Mr. Johnson proposes to change the allocation of production costs without considering the corresponding effect on the allocation of energy costs. This is clearly inconsistent. Energy costs vary over time, with higher costs during on-peak periods and lower costs during off-peak periods. By failing to consider this interrelationship, Mr. Johnson has produced biased and inconsistent results.

Q. **Mr. Kleha, what is your conclusion regarding the various proposed cost allocation methodologies proposed by opp ing parties?**

A. I bel..ve that 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. The 12 CP method, which was followed in the preparation of Exhibits JMK-1 and 2, consistently has been approved by this Commission in previous PP&L base rate cases. This method also should be accepted in this proceeding.

III. Ratemaking Treatment of the Value of Interruptible Load and Proposal for a Separate Interruptible Rate Class.

Q. Do you agree with Mr. Baron's criticism of PP&L's use of a "peaking capacity" resource to determine the value to PP&L's system of interruptible load?

A. No, I do not. As discussed in my direct testimony, PP&L has calculated the value provided to its system by interruptible load on the basis of a "peaking capacity" resource. The value of this capacity-related resource was calculated by using a two-step approach. Under this approach, the Company (1) allocated the costs of its system electric generation facilities using the total forecasted system coincident peak demand contributions of all customers, and (2) provided a "peaking capacity value" credit to interruptible service customers based on their estimated non-firm coincident peak demand contributions for the future test year.

Under the Company's approach, the costs of PP&L's existing system generation facilities were allocated to each customer class in proportion to the total forecasted coincident peak demand contribution of that class for the future test year. After assigning the applicable costs to each customer class, the amount of non-firm coincident peak demand for interruptible service customers was estimated by subtracting those customers' contracted firm demand level from their total forecasted coincident demand contribution for the future test year. The non-firm demand of these customers was then multiplied by the value of a new "peaking capacity" resource. The resulting credit amount was subtracted from the costs of the existing system electric generation facilities assigned to the affected customer classes in relationship to the amount of their applicable non-firm demand. The non-participating portion of the affected customer classes and all other customer classes were then assigned their proportionate share of the value of interruptible load to PP&L's system. This approach properly assigns the cost responsibility for interruptible load consistent with basic cost allocation principles. The proposals advanced by witnesses for the opposing parties do not meet this criterion.

Q. What adjustment does Mr. Baron suggest?

A. Mr. Baron criticizes this "rate base adjustment" approach and suggests that PP&L directly credit the revenue requirements of interruptible service customers on the basis of the calculated tariff revenue credit for interruptible load. In his view, this would eliminate a perceived "mismatch" between the calculated revenue requirements and the amount of the tariff credit.

Q. Is there any merit to this proposal?

A. No. Mr. Baron incorrectly equates the level of the tariff credit established for rate design purposes with the appropriate treatment of a capacity-related resource for cost allocation purposes. The two items are not the same and involve fundamentally different considerations. Rates to customer classes may be above or below the cost of service at a particular point in time for a variety of reasons. For example, the current tariff credit for interruptible service is part of PP&L's economic development program and is well above any reasonable measure of cost to provide that service. Rates which depart from cost may be justified for a variety of reasons. However, these reasons provide no basis for revising the cost allocation study to reflect non-cost issues.

Mr. Baron's proposal also seriously overstates the actual value of interruptible load to PP&L's operating system. Under his tariff revenue credit approach, interruptible load would be valued at about $23.3 million rather than PP&L's appropriate system value of about $12.9 million. PP&L's proposed rate base treatment of the value of interruptible load for cost allocation purposes is designed to be sound technically because it values interruptible load on the basis of its resource value. It also is designed to be "middle-of-the road" because it neither understates nor over-states the value to PP&L's operating system of useful interruptible load. I would note that the OCA recommends a much lower, market-based value of interruptible load of $15/KWH. This underscores the reasonableness of the Company's approach.

Q. **Do you agree with Mr. Brubaker's criticism of PP&L's treatment of the system value of interruptible load for cost allocation purposes?**

A. No. Mr. Brubaker criticizes PP&L's use of a specific interruptible load capacity resource credit to recognize the value of interruptible load to PP&L's system for cost allocation purposes. His criticism relates to PP&L's use of the cost of a new combustion turbine (CT) unit to calculate the value of interruptible load. He instead proposes to arbitrarily exclude the demands imposed on PP&L's system by interruptible service customers in determining their cost of service. According to Mr. Brubaker, PP&L should not allocate any costs of its generation facilities to those customers who can provide interruptible load. Under his proposed approach, the demands imposed monthly on PP&L's system by interruptible service customers would be arbitrarily ignored, and these customers would not be allocated <u>any</u> of the costs of PP&L's existing generation facilities which were installed to meet their load requirements throughout each month of the year.

Q. **Does Mr. Brubaker's theory support his recommendation or the facts of this case?**

A. No. All of the Company's current interruptible service customers were, at some point in time, firm service customers. When the Company last added generation capacity in 1984, only three of its customers were classified as interruptible and those customers were assigned their applicable share of PP&L's then-installed generation facilities in the last base rate case. All of the Company's existing generation facilities were originally installed to serve the demand requirements of Mr. Brubaker's client and the Company's other industrial customers.

Q. Is Mr. Brubaker's recommendation wrong on other grounds as well?

A. Yes. As explained above, the Company does not agree with Mr. Brubaker's "causation" theory. In any event, his arguments ignore the real world conditions on PP&L's system. Customers who, under certain circumstances, can provide interruptible load do impose very real demands on the Company's system at the time of each month's system peak throughout the year. The only time that interruptible service customers do not impose demands at the time of the Company's monthly system peak is during system emergencies when, by application of its tariff, PP&L may request interruptible service customers to reduce their demands down to contract-established firm levels.

Under its tariff, the Company has only a limited right to request participating customers to reduce their demands -- only up to 20 days and up to 200 hours per year. In actual practice, interruptions, other than for testing purposes, are infrequent. Only 15 curtailments occurred from 1984 through 1994, and no curtailments occurred in 1990 or 1993. This data is presented in my Exhibit JMK-4, "Curtailment Summary."

Moreover, unlike its own installed generating capacity resources, customer-provided interruptible load is not under the direct control of PP&L. Although penalties can be imposed for a customer's failure to reduce load to the contract firm demand level, PP&L has no guarantee that interruptible load will be available at the time of the monthly system peak or that it will respond as required. It should be noted that in February 1995 when PP&L set a new all-time system peak demand level, no interruptible service customers were requested to interrupt service.

Q. **Do you agree with Mr. Brubaker's suggestion that interruptible service customers be treated differently for cost allocation purposes, by segregation into a separate rate class?**

A. No. Customers qualifying for the interruptible service options under Rate Schedules LP-4, LP-5 and LP-6 receive essentially similar service, whether they are classified as firm or interruptible. No significant character of service differences have been shown which would, in my opinion, justify establishing new rate schedules and rate classes for those customers. Mr. Brubaker's approach is, therefore, inappropriate at this time. It may have some merit if the Company were given direct control over the loads imposed by interruptible service customers at the time of its monthly system peaks. That is, if PP&L had the capability, at its discretion, to automatically reduce these customers' demand imposition at the time of its monthly system peaks and if the Company were permitted to exercise that capability, then segregating these customers into a separate rate class might be appropriate. However, no such proposal has been presented in this case.

Moreover, I would note that since the Company cannot predict its monthly peaks in advance, customers probably would have to be interrupted several times each month to ensure that they are not taking service at the time of the Company's monthly peak.

IV. Ratemaking Treatment of the EDI/IDI Credit Revenue Requirements Deficiency.

Q. For cost allocation purposes, should the revenue requirement deficiency due to EDI/IDI credits be assigned specifically to other rate classes as Messrs. Baron and Brubaker propose?

A. No. EDI/IDI credits are rate discounts provided for economic development and load retention. They are not "costs" to be allocated in a cost allocation study. Costs should be allocated based on appropriate allocation factors, and compared to available revenues (including discounts) to determine the overall revenue requirement of each rate class. EDI/IDI credits are rate discounts to customers served under Rate Schedules LP-4 and LP-5 customers and should be reflected in the revenues received from those classes.

V. Allocation of NUG Output Payments.

Q. Should PP&L's cost of NUG output payments, shown in Exhibit JMK-2 and reflected in its net cost of energy for ECR roll-in purposes, be allocated on a demand/energy basis as proposed by Mr. Brubaker and Mr. Baron?

A. No, but I do recommend an adjustment that accomplishes a similar result. As indicated in my direct testimony, payments for NUG output are made on the basis on energy-only avoided cost contract rates. This fact is not disputed by any party to this proceeding. Therefore, such costs are properly allocated on an energy-only basis. However, for cost allocation study purposes, the ECR revenue adjustment credit amount of $21,487,000, shown on Line 4 of Pages 83-84 of Exhibit JMK-2, should be revised to exclude the effect of the NUG output payment demand/energy allocation which should be reflected only in the calculation of PP&L's proposed ECR for billing purposes. This revision, which will be incorporated into the Company's final accounting exhibits, will produce the same earned revenue requirements result as that proposed by Messrs. Baron and Brubaker and will maintain the appropriate energy-only allocation of the cost of PP&L's NUG output payments.

VI. Use of a Minimum Size System Study.

Q. Have you reviewed Mr. Andersen's criticism of PP&L's use of a minimum size system study to determine those costs to be classified as customer-related?

A. Yes. Mr. Andersen criticizes PP&L because its minimum size distribution system study is based on the smallest size equipment <u>currently</u> being installed on its system, rather than the smallest size piece of equipment installed at any point in time on its system. He also criticizes PP&L's method stating that it results in higher cost attribution than would result from using a different method. However, although he apparently supports the use of a "zero intercept" method, he has not offered the results of that method or any other method to support his position.

Q. Do you agree with this criticism?

A. No. PP&L has followed the NARUC Cost Allocation Manual that defines a minimum size distribution system based on the smallest size equipment <u>currently</u> being installed by the utility. (See NARUC Cost Allocation Manual).

Mr. Andersen proposes to use the cost of the smallest size equipment that was installed <u>at any point in time</u> on PP&L's system. However, this approach (1) fails to consider the vintage and installed unit cost of that equipment; (2) ignores the fact that PP&L no longer installs such equipment; and (3) significantly understates the cost of today's minimum size operating distribution system. It also fails to consider the fact that as a utility grows and evolves over time, its customer mix changes and its customers' service requirements change. These changes also affect the equipment size and capability required to construct a minimum size operating distribution system and must be considered in determining actual minimum size system requirements.

Moreover, Mr. Andersen fails to recognize that the smallest size equipment ever installed does not necessarily result in the lowest average installed cost. For example, the smallest size overhead transformer that exists on PP&L's distribution system is a 1 KVA transformer. That transformer has an average installed cost of $425 per unit. In contrast, the minimum size overhead transformer currently being installed on PP&L's system is a 10 KVA transformer. This transformer has an average installed cost of $321 per unit.

Q. **Mr. Andersen suggests that the zero intercept method is better than the minimum size system method. Is this suggestion realistic?**

A. No, and I would note an important correction. Mr. Andersen mistakenly believes that PP&L sponsored the results of a traditional zero intercept method study in its last base rate case. This is incorrect. The Company proposed a study based on only the labor component of installing a minimum size distribution system (Tr. 613-615). This study was described as a "modified" zero intercept method, but was, in reality, merely a subset of a traditional minimum size system study.

The Company has studied the use of the zero intercept method and found this method impractical, given the available data in its accounting records. As Mr. Andersen notes, a key problem with this method is the lack of necessary data. Even if the necessary data were available, the zero intercept method is complex and inherently arbitrary. PP&L's last review of this method produced negative zero intercept cost results. Therefore, the zero intercept method obviously is not an accurate or reasonable approach for PP&L.

Q. **Have you reviewed Mr. Andersen's and Mr. Johnson's proposals regarding adjustment of the Company's demand allocators because its minimum size equipment has some load-carrying capability?**

A. Yes, I have.

Q. Do you agree with their proposals?

A. No. Both witnesses propose to adjust the Company's demand allocators because the equipment used in its minimum size system study has some load-carrying capability. Their respective proposals are flawed for several reasons.

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.

Q. Do you have any further comments on the minimum system issue?

A. My specific critique of the opposing party arguments is set forth above. More importantly, the selective criticism offered by these witnesses misses the point. <u>All</u> aspects of any cost allocation study are based on judgment. The entire purpose of a cost allocation study is to "allocate" costs which cannot be directly assigned. Reasonable people can differ as to the basis for allocating all of the costs in a cost allocation study. However, it is unfair, in my view, to focus on only one aspect of cost allocation, criticize it, and adjust it, without concurrently doing the same for all other aspects of the study.

For example, Messrs. Andersen and Johnson extensively critique PP&L's allocation of secondary distribution system costs - contending that the Company has overstated the customer component and understated the demand component. Yet, these same witnesses ignore the treatment of primary distribution system costs, which PP&L allocated 100% on a demand basis and 0% on a customer basis. Valid arguments can be made that some portion of <u>primary</u> distribution system costs should be allocated on a customer basis. In my view, any minor overstatement of the customer cost component of the <u>secondary</u> distribution system under the Company's minimum size system method would be partially offset by the allocation of <u>all primary</u> distribution system costs on a demand basis. For these reasons, it is my opinion that on an <u>overall</u> basis PP&L's allocation of its distribution system costs, both primary and secondary, is fair and reasonable.

VII. Allocation of Intangible Plant and A&G O&M Expenses.

Q. **Do you agree with Mr. Andersen's criticism of PP&L's use of a labor factor ratio to allocate intangible plant and A&G expenses?**

A. No, I do not. Mr. Andersen recommends allocating intangible plant and Administration & General (A&G) O&M expense, which he classifies as corporate overheads, on the basis of class revenue requirements, rather than by use of generally-accepted "overhead or miscellaneous" allocation factors, such as the labor ratio factor. Mr. Andersen's proposal ignores the fact that the FERC, in its cost allocation procedures, and the NARUC Cost Allocation Manual recognize the labor ratio factor as a generic allocator to be used when assigning those costs that cannot be attributed to a specific functional activity. The labor ratio factor is considered a reasonable "overhead" allocator because it is based on a comprehensive ratio of a utility's production, transmission, distribution and other functional labor costs to the amount of total labor expense. This factor blends the contribution of all labor expenditures by operating function into an allocator that more closely aligns utility overheads and/or miscellaneous costs with the actual functional activities of the Company. In fact, approximately 45% of total A&G expense, excluding employee benefits and other directly assignable costs, is labor cost associated with the supervision and management of all functional operating areas of the Company. Therefore, because it is easily calculated, the labor ratio factor provides a reasonable, generally-accepted proxy for obtaining the cost causation of overhead and miscellaneous costs that Mr. Andersen seems to be seeking. Thus, it provides a reasonable allocation of PP&L's overhead and miscellaneous costs among the Company's various functional activities.

Q. **How does Mr. Andersen propose to allocate the Company's intangible plant and A&G expense?**

A. Mr. Andersen proposes to assign PP&L's intangible plant and A&G O&M expense on the basis of class revenue requirements. However, this approach is flawed and impractical for several reasons.

First, Mr. Andersen would include depreciation as part of his "overhead/miscellaneous" allocation factor. However, depreciation is not an allocator in and of itself, rather it is an operating expense component to be assigned on the basis of the functional property investment the utility has placed in service. It does not relate to the incurrance of A&G O&M expense or the level and components of a utility's intangible plant. Second, Mr. Andersen would include all of a utility's taxes and its earned return in his allocation factor; however, neither of these items bears any relationship to A&G O&M expense. Taxes are, in the case of gross receipts tax, a function of the amount of certain types of revenue received. Real estate taxes are related to the net value of a utility's plant in service. Income taxes are related to the amount of a utility's net taxable income, not the various functional activities which may give rise to its A&G expenses or intangible plant. Third, in order to calculate a utility's taxes, return and revenue requirements by rate class, A&G expenses already must be allocated to the various rate classes. Mr. Andersen's proposal to use overall class revenue requirements to allocate a very minor portion of the costs which produce these same revenue requirements would "put the cart before the horse."

Q. Do you have any other comments regarding Mr. Andersen's criticism of PP&L's cost identification and allocation techniques?

A. Overall, Mr. Andersen suggests that cost causation is the absolute determining element in the identification and allocation of all rate base and operating expense components of a utility's revenue requirements. Yet, for those elements of the Company's cost identification and allocation that he challenges (allocation of intangible plant and A&G O&M expense, identification of customer-related distribution plant on the basis of a minimum size system study), Mr. Andersen offers no empirical evidence to support his recommendations. Rather, he substitutes his judgment (absent specific information and direct knowledge of PP&L, its customers, its service area and its accounting records) for those of the Company. He ignores the fact that PP&L, in its cost allocation studies, consistently assigns all costs on the basis of cost causation when that causation can be identified by functional activity or customer group. For those costs that cannot be specifically identified by a particular cost-causative activity, PP&L employs easily-calculated, generally-accepted, generic allocation factors traditionally found to be reasonable by both the FERC and this Commission.

VIII. Treatment of Electric Plant Held For Future Use.

Q. Mr. Kleha, have you reviewed Mr. Metro's recommendation regarding the Company's proposed treatment of Electric Plant Held For Future Use?

A. Yes, I have. Mr. Metro recommends that the Commission deny PP&L's proposal regarding the recording of a return on Electric Plant Held For Future Use property that is not reflected in its claimed rate base.

Q. Do you agree with his proposed recommendation?

A. No, I do not. As discussed in my direct testimony, PP&L has made no request in this proceeding to include Electric Plant Held For Future Use property in its future test year rate base claim. Rather, the Company has requested specific Commission approval to begin accruing a return component, equivalent to the applicable Allowance For Funds Used During Construction (AFUDC) rate, on its future use property investments and to include all accrued amounts (to be recorded as a regulatory asset) as part of its Electric Plant In Service at the time such plant actually is placed into service. Absent the inclusion of Electric Plant Held For Future Use property in its allowed rate base claim or approval of its proposal for a return on such plant, the Company will not be compensated for its investment in property (land and rights-of-way) required to meet the future load and energy requirements of its customers prior to the inclusion of that investment in Construction Work In Progress (CWIP). Without specific approval to receive or record a return on funds expended to provide reliable service to its customers, a utility's incentive to acquire land and rights-of-way in advance of the time they actually are needed (generally at a lower cost or when available) would be eliminated. Consequently, this Commission, recognizing that the public interest is served by acquiring land and rights-of-way in advance of the actual need for these investments, consistently has approved the future use property treatment requested by PP&L for other utilities.

Q. Is the Company seeking guaranteed future rate base treatment for these amounts?

A. No. When these costs become part of the Company's plant in service they will be claimed in a base rate case where all parties will have the opportunity to review the prudence and reasonableness of the Company's investment in new plant. The Commission has repeatedly approved identical requests for other utilities and should do the same for PP&L.

IX. Proposed Elimination of the Company's Energy Cost Rate. (ECR)

Q. Have you reviewed Mr. Prisco's recommendation that the Commission eliminate PP&L's ECR?

A. Yes, I have.

Q. Do you agree with Mr. Prisco's recommendation?

A. No, I do not. I believe that Mr. Prisco's recommendation that the Commission eliminate PP&L's ECR is shortsighted and contrary to the public interest. Mr. Prisco's recommendation fails to consider the fact that this Commission required its jurisdictional electric utilities to institute an ECR. It also fails to consider that continued use of the ECR is in the public interest.

As discussed in my direct testimony, this Commission established the net energy clause (predecessor to the current levelized ECR) in 1978. At that time, the Commission prescribed the specific components and parameters of a utility's energy clause by expanding its fuel adjustment clause to include amounts charged or credited to FERC Account 555 for energy purchases from and interchange energy sales to other utilities. Subsequent to the passage of the Public Utility Regulatory Policies Act of 1978 (PURPA), energy purchases from Qualifying Facilities (QFs) also were included in the calculation of a utility's ECR.

The Commission specifically designed the ECR to provide full and current recovery of all applicable energy costs and to flowback to customers all applicable energy cost credits. That is, as a utility's calculated ECR rises or falls due to current energy costs incurred and receipts from energy sales to other utilities, those energy cost changes are reflected in customers' rates on a full and current basis.

This approach provides for overall rate stability by eliminating the need for base rate filings due to the potential for volatile changes in a utility's fuel prices. In fact, the Commission added another measure of customer rate stability by requiring that the ECR be levelized over a 12-month period.

For these reasons, the Commission's prior establishment of an ECR mechanism was appropriate and its continued use clearly is in the public interest.

X. Appropriateness of ECR Recovery of Non-Energy Revenue Requirements Associated With Expiring Capacity and Energy Agreements and Treatment of Associated Off-System Sales Revenue.

Q. Have you reviewed the recommendations of Messrs. Baron, Kahal and Prisco that the Commission disallow recovery through the Company's ECR of the non-energy revenue requirements associated with its expiring bulk power capacity and energy agreements, including the JCP&L Agreement?

A. Yes, I have.

Q. Do you agree with their recommendations?

A. No, I do not. In this proceeding, the Company has made an innovative proposal designed to limit the need for future base rate proceedings and to flowback to customers on a full and current basis the revenues received from off-system capacity-related transactions. The witnesses opposing the Company's approach would eliminate these benefits simply because PP&L's proposed use of the ECR for these purposes is innovative.

The opposing parties argue that the costs of the expiring agreements currently are not reflected in retail jurisdictional rates and are not appropriately addressed in this proceeding. They claim that the Company's request would grant it authority to automatically increase retail rates whenever a wholesale power contract is terminated. This is incorrect for a number of reasons.

First, the affected facilities and associated costs of the JCP&L agreement are known and measurable, and this case is an appropriate opportunity for the Commission to establish a mechanism for the orderly treatment of these costs and revenues. Second, under the Company's proposal, all costs and <u>revenues</u> from off-system capacity-related sales will be reflected in the ECR. Under the opposing parties' recommendations, the Company and its customers will be forced into a full base rate case annually as each increment of capacity returns to the Company's system. The potentially enormous costs and regulatory burden of those proceedings can be essentially eliminated by adoption of the Company's proposal.

Q. What about the concern that the Company might earn more than its allowed return?

A. Given the cost and revenue pressures facing the Company over the next several years, I do not think this will be an issue. However, the Commission receives and reviews quarterly earnings reports from all major utilities, including PP&L. The Commission and other parties are free to act on these filings if they believe that any action is appropriate.

Q. What if the Company's proposal is rejected?

A. If the Company's proposal is rejected, two actions must occur. First, if capacity costs associated with expiring agreements are to be excluded from the ECR, then revenues from off-system capacity-related sales also should be excluded from the ECR and treated as an element of base rates only. This is the traditional ratemaking practice and would permit the Company to retain revenues from incremental off-system capacity-related sales to at least partially offset the cost of capacity returning under expiring agreements.

Second, the Company should be permitted to retain the energy savings associated with the return of capacity from the expiring agreements. For example, when the first increment of JCP&L capacity returns on July 1, 1996, the Company's capacity costs will increase by about $35 million and its energy costs will decrease by about $15 million. Under current regulatory practice in Pennsylvania, the Company's shareholders would absorb this $35 million cost increase and ratepayers would automatically receive a $15 million cost decrease through the ECR. Under the Company's proposal, both the capacity costs and energy savings would be reflected in the ECR, along with all of the revenues received from other off-system capacity-related sales. If the Company's proposal is rejected, however, at a minimum, the Company should be permitted to retain the energy savings to offset a portion of the capacity costs that produced those savings. Although this is not a complete solution to the problem, it at least avoids the fundamental mismatch of costs and savings described above and could help the Company avoid immediate rate filings to reflect the returning JCP&L capacity and energy.

Q. Does this conclude your testimony at this time?

A. Yes, it does.

EXHIBIT JMK 4

Curtailment Summary

Rebuttal Testimony of Joseph M. Kleha
Docket No. R-00943271

CURTAILMENT SUMMARY

Date	Period of Curtailment	Amount of Curtailment (MW)	Reason for Curtailment	Number of Customers
8/15/84	1100-2100	Not Available	Emergency	2
1/21/85	1025-1825	Not Available	Emergency	2
7/09/87	1400-1700	Not Available	Emergency	3
8/17/87	1435-1900	Not Available	Emergency	4
6/22/88	1506-1712	Not Available	Emergency	4
8/15/88	1314-1744	Not Available	Emergency	4
6/02/89	1227-1446	Not Available	Emergency	5
6/27/89	1334-1839	Not Available	Emergency	5
7/26/89	1356-1656	Not Available	Emergency	5
9/11/89	1415-1645	Not Available	Emergency	5
9/16/91	1434-2009	133	Emergency	5
7/14/92	1510-1631	126	Emergency	6
1/19/94	506-2230	185	Emergency	43
1/20/94	740-2400	201	Emergency	43
1/21/94	2400-1151	203	Emergency	43

DOCKETED
MAY 31 1995

RECEIVED
95 MAY 30 PM 1:20
PA. P.U.C.
INFO. CONTROL DIV.

PENNSYLVANIA POWER & LIGHT COMPANY

Statement 8-R

5/25/95
OGK-5-13

Rebuttal Testimony Of Oliver G. Kasper

Docket No. R-00943271

DOCUMENT
FOLDER

BA

Q. Please state your name, title, and business address.

A. Oliver G. Kasper, Manager-Pricing & Contract Administration for Pennsylvania Power & Light Company, Two North Ninth Street, Allentown, Pennsylvania 18101.

Q. Mr. Kasper, have you testified previously in this proceeding?

A. Yes. I submitted direct testimony (Statement 8) and was cross-examined on March 28 and 29, 1995.

Q. What are the purposes of your rebuttal testimony?

A. Witnesses representing other parties have submitted testimony in numerous areas of rate design. The purpose of my testimony is to discuss the positions taken by these various witnesses and to demonstrate that the proposals submitted by the Company represent a reasonable and equitable resolution of the issues raised. The following is a summary of the areas to be discussed in my testimony, along with the names of the witnesses and parties that have submitted testimony in these areas:

Topic	Witness	Party Represented
Allocation of Increase	Mr. Eisdorfer	UCC
	Mr. Baron	PPLICA
	Dr. Johnson	OCA
Potential Scale Back of Increase	Mr. Knecht	OSBA
	Mr. Yarolin	OTS
Residential Rate Design	Dr. Johnson	OCA
	Mr. Yarolin	OTS
	Mr. Andersen	CEPFOD
Residential Thermal Rate	Dr. Johnson	OCA
	Mr. Yarolin	OTS
	Mr. Andersen	CEPFOD
General Service Rates	Mr. Knecht	OSBA
EDI/IDI Riders	Mr. Baron	PPLICA
	Dr. Johnson	OCA
	Mr. Biewald	Sierra Club
Interruptible Rate Levels	Dr. Johnson	OCA
	Mr. Brubaker	Bethlehem Steel
	Mr. Baron	PPLICA
Competitive Pricing	Mr. Brubaker	Bethlehem Steel
	Mr. Baron	PPLICA
Streetlighting	Mr. Yarolin	OTS

ALLOCATION OF THE RATE INCREASE

Q. What are your comments on the various proposals that have been presented regarding distribution of the revenue increase among the customer classes?

A. My conclusion is that these proposals present an unreasonable assignment of the rate increase to one or more of the rate classes. The proposals of each intervenor witness benefit his client's interest at the expense of other rate classes. Also, the allocations proposed by many of the witnesses are based on their own cost of service studies or adjustments to the Company's study, which are erroneous for the reasons explained by Mr. Kleha. Table I compares PP&L's proposal to the recommendations of three intervenor witnesses.

TABLE I

% Rate Increase

Rate Class	PP&L	UCC Eisdorfer	PPLICA Baron	OCA Johnson
RS	15.29%	25.5%	17.55%	11.7%
GS-1	3.89%	-2.4%	0.0%	5.93%
GS-3	6.72%	0.2%	7.41%	11.00%
LP-4	10.16%	0.2%	6.32%	11.60%
LP-5	15.45%	4.9%	10.91%	15.56%

PP&L believes that each rate class deserves fair and just treatment in the rate increase allocation. The broad standards that PP&L developed and applied in its filing recognize the importance of an even-handed and gradual approach to rate increase allocation. The Company's proposed allocation was based upon the principles outlined below:

- Move each rate class rate of return closer to the proposed system average rate of return.

- Limit each rate class increase percentage to a maximum of 1.5 times the overall rate increase percentage.
- All rate classes will receive some rate increase.
- Correct the interruptible rate design to reduce the excessive credit in the current interruptible rate.

Application of these constraints and principles will provide a better allocation of the rate increase than any offered by the intervenor witnesses. For example, assuming that the Company's 12 CP cost allocation method is maintained, the other parties' rate design proposals will not move all customers closer to a system average return. The Company's proposed allocation remains the most reasonable of all the recommendations.

POTENTIAL SCALE BACK OF THE RATE INCREASE

Q. Please comment on the several methods of allocating the revenue increase among customer classes if the Company is not awarded the full amount of its request.

A. It is important to recognize that PP&L believes it is fully entitled to the increase that it has requested. However, if the Commission allows the Company a lesser rate increase, PP&L would allocate that amount by following the principles that guided its original proposed allocation. I summarized those principles earlier in my rebuttal testimony. The Company believes that, after correcting for the proper valuation of interruptible load, and any major adjustments made by the Commission to PP&L's claimed revenue requirements, a proportional scale back would be the most equitable method of allocating the allowed increase.

The different proposals set forth by the intervenor witnesses again, like the allocation of the increase, are designed to benefit a specific class at the expense of the other classes. For example, the Office of Small Business Advocate (OSBA) proposes a method that would reduce the increase assigned to the GS-1 and GS-3 rate classes at the expense of the residential class.

The PUC Office of Trial Staff (OTS) offer a novel proposal that the first $17 million of rate increase be assigned to Rate RTS and the Rate RS customer charge. The Company believes that this recommendation unfairly singles out the residential class and should therefore be rejected.

RESIDENTIAL RATE DESIGN - RATE SCHEDULE RS

Q. Are there any concerns raised by the OTS, Office of Consumer Advocate (OCA), and Central Eastern Pennsylvania Fuel Oil Dealers (CEPFOD) regarding the proposed design of Rate RS?

A. Yes. The OTS recommends a customer charge of $5.90; OCA recommends maintaining the Company's current $4.80 customer charge, and the CEPFOD also recommends $4.80. The Company does not agree with these proposals because none of them would provide for proper recovery of the applicable customer component costs. As indicated by reference to the Company's response to Question OTS-RS-4D of Interrogatories of the Office of Trial Staff dated January 13, 1995, total customer component costs for the residential class are $17.51 per customer per month, with $10.18 per customer per month for billing, metering and services alone. These calculations were performed in accordance with the accepted NARUC criteria for customer charges based upon a Minimum System Concept.

Q. The OCA witness, Dr. Johnson, recommended a lower Rate Schedule RS customer charge than that proposed by PP&L. Did PP&L consider other levels of customer charges prior to the filing?

A. Yes. PP&L considered both lower and higher customer charges than the charge it proposes. The use of a lower charge was rejected for several reasons:

1. Use of a lower customer charge spreads recovery of the remaining customer costs over too large an amount of customer energy use. Customer costs are generally dependent on the number of customers served, not on their usage levels. Collecting these costs in KWH charges would send the wrong price signal and would make revenue recovery less stable.
2. Since PP&L has not filed for a base rate increase in 10 years, its current customer charge is understated. PP&L's cost studies indicate that a significant portion of the proposed residential increase is associated with this component.
3. Increasing the Rate Schedule RS customer charge by $2.40/month would not cause an undue hardship on the vast majority of residential ratepayers; it should not force residential customers to ration access to the electric system. Moreover, the proposed $7..20/month customer charge would not be the highest in the state. In contrast, a $4.80 charge would be the lowest among major electric utilities in the state.

Q. If the customer charge in Rate Schedule RS is reduced from the proposed $7.20/month, how will the Company propose to adjust the RS rate design in this filing?

A. If the customer charge is adjusted as proposed by CEPFOD, OTS or OCA, the Company would propose to increase the first two blocks of the proposed Rate Schedule RS to recover these costs. This will recover the customer component early within the rate structure, minimizing the revenue instability caused by spreading the customer charge over all the steps of the rate. The number of KWHs billed in the last step of Rate Schedule RS are affected by weather conditions. A mild winter or summer would result in a revenue shortfall compared to the normalized test year; a cold winter or hot summer would have the opposite effect. Also, allocating more of the customer component over a larger portion of KWH usage creates an intra-class cross-subsidization where large usage residential customers are subsidizing low usage customers.

Q. Did the Company study any other rate structures for the residential class before settling on the proposed three step rate structure?

A. Yes. Many different designs were studied, including a customer charge that recovered the full customer component, a single flat KWH rate, two step KWH rate structures, and others. The rate design proposed by PP&L sends the proper price signals without penalizing either low users or high users of electricity. I have attached a chart, Exhibit OGK-5, illustrating the impact of adopting the OTS proposed customer charge and recovering the demand charges in the first billing block of a two block method.

Q. Several witnesses criticize the Company's proposal to establish a third block in Rate RS. Do you agree with their arguments?

A. No, I do not. These witnesses assert that the third block was established to recover customer costs and that the Company has overstated the customer component of the cost of service. They therefore contend that the third block is not necessary. First, as Mr. Kleha explains in his rebuttal testimony, the Company's cost of service study is fair and reasonable and should be approved. Second, the arguments of opposing parties are largely irrelevant. To the extent that the costs at issue are not customer-related costs, they are clearly demand-related costs. Whether customer- or demand-related, these costs should be recovered in the early blocks of the residential rate and not the trailing energy block. Higher initial blocks are appropriate to recover both customer <u>and</u> demand costs, particularly for rates without explicit demand charges.

RESIDENTIAL THERMAL STORAGE RATE DESIGN - RATE SCHEDULE RTS

Q. What proposals have been made concerning Rate Schedule RTS?

A. Parties have urged a wide range of proposals. On one hand, Mr. Andersen has recommended that Rate RTS be terminated as being unjustifiably low. At the other extreme, certain individual RTS customers are concerned that they have been too heavily burdened by the proposed rate increase. Mr. Yarolin (for OTS) recommends a Commission investigation. Taking the middle ground, Dr. Johnson has suggested that Rate RTS be frozen at its current class membership; that the rate benefits be maintained going forward for those customers; and that the Company propose a new rate in the future designed to address problems identified in this proceeding.

Q. What position does the Company take on these proposals?

A. In summary, the CEPFOD claims are simply wrong and should be rejected. The concerns of individual RTS customers, though perhaps understandable, are unfounded. Rate RTS was developed as a load management tool. It continues to benefit RTS customers through substantially lower rates. It also benefits other customers, particularly through contributions to the Company's fixed costs and some load management effects. Finally, having reviewed the issue, the Company finds merit in Mr. Johnson's proposal to close the RTS rate. Because of changes in its residential customer usage patterns, as discussed in Mr. Slivka's testimony, the Company's peaks have been shifting toward the evening. Over time, this trend will reduce the benefits of RTS unless control devices are placed on the customers' facilities. Technological advances also have shifted the optimum control strategy away from timing devices at each customer location -- the basis for Rate Schedule RTS -- and toward central controls over customer meters. As I mentioned earlier in this proceeding, the Company is planning a pilot program to implement such devices on a test basis. If that test works well, the Company expects to apply the controls to substantially improve the load management benefits provided by electric thermal storage systems customers. Given their investment in the thermal storage facilities and the history of this rate, it would be most appropriate to allow the existing customers to continue to receive the current RTS rate while the Company installs and tests the control devices for new customers. Therefore, the Company proposes to undertake the following steps:

- Applications for service under Rate Schedule RTS will be accepted only through December 31, 1995;
- After that date, customers desiring to use an electric thermal storage system will be eligible to do so under a new rate schedule incorporating the newer technology and appropriate terms, conditions and rates;
- Customer locations served under Rate Schedule RTS will continue to receive service under that rate during the life of the currently installed thermal storage system; The Company will not propose to reduce the existing 2.3 ~~2.9¢~~/KWH differential between RS and RTS customers before December 31, 1999.

This proposal is broadly similar to Mr. Johnson's recommendation and will allow the Company to continue its commitment to electric thermal storage while responding to changing technology and markets.

Q. What prompted the Company to implement thermal storage heating as a load management tool? When was this option originally explored?

A. In 1982, with the Susquehanna Steam Electric Station nearing commercial operation, the Company began exploring strategies to constrain growth in energy sales to a sustainable 3% and simultaneously decouple the growth in system peak load to 2.8% compounded annually. Previous work had indicated that these growth levels would result in the most efficient and economical use of the Company's generating, transmission, and distribution facilities and defer the need for new generating capacity until well after the year 2000.

Q. What lead to the adoption of thermal storage technology versus other options?

A. To accomplish the necessary decoupling of energy sales from peak load growth, several new customer load management technologies were investigated. The technical limitations of commercially available options at the time and load management measure reliability concerns led to the development of off-peak space conditioning and water heating systems. Moreover, these types of loads were the principal contributors to system peak demands. The European experience with stored heat technologies in the 1960's indicated that the technology was commercially available. The Company's own research showed that these technologies could be adapted to meet customer needs, were reliable, and could be energy efficient.

Q. Since the Company had no immediate need for additional generating capacity, why was the load management option implemented at that time?

A. Load management measures need a long-lead time compared to supply side options. Customers must be educated, sales, installation, and service infrastructure must be in-place in advance of any need for the additional capacity resources.

Q. Please describe the criteria used by the Company in selecting a load management technology at that time.

A. The Company needed to be assured that candidate load management options: could shift the desired amount of load coincident with projections of peak load; had the potential for participation by a sufficiently large population of customers to meet the load management objectives; would not require large capital investments; and would be long-lived. Thermal storage met these criteria. Unlike other load management options studied at that time, thermal storage in residences and commercial buildings required little capital investment. The investment was largely incremental and directly proportionate to the number of participants. In addition, the investment was shared between the Company and the participants; the participating customers recovered their additional investment in heat storage facilities through rate savings; and the measure was very long-lived. By comparison, utility dispatched load control and communications equipment did not satisfy the Company's criteria at that time.

Q. **Please discuss the rationale for the design of Rate Schedule RTS and the grant programs instituted by the Company to support the thermal storage load management option?**

A. To ensure that customers realized a payback on their investment in additional equipment over a reasonable time frame, the European experience clearly indicated that the ratio of average energy cost between conventional residential service and off-peak service needed to be 4:1 or better. Because it was not economically possible for the Company to achieve this ratio of 4:1 solely through energy rates, it was decided to provide grants in combination with Rate Schedule RTS. A demand component was added to the rate to minimize customer tendencies to add new on-peak load, thereby reducing the impact of the load shifted by thermal storage over time. As is typically true of programs of this type, it has always been the Company's intent to gradually eliminate the monetary incentive of the grants. In addition, the Company estimated that, over time, the thermal storage market would mature with more equipment and service providers. The resulting competition would eliminate the need for grants or other out-of-pocket incentives over the long-term.

Q. What factors have changed over the intervening decade since the introduction of the RTS rate that have changed the Company's load management strategy?

A. There are many reasons for the change in strategy. Shifting customer usage patterns have led the Company to pursue a much more flexible load management strategy that can accommodate changing customer energy consumption habits. New technologies make dispatchable load management more economical in part because the large capital investments once required for communications infrastructure are being made by others. The cost of load management technologies has significantly decreased. The Company recognizes a need for a broad array of load management options to provide diversity and increase customer options. Industrial customers are demanding new service options, such as real-time pricing, that offer opportunities for cost savings while providing load management benefits to electric utilities.

Q. Overall, characterize the success of the thermal storage load management option in meeting the Company's objectives.

A. The thermal storage load management option has been largely successful. Fourteen thousand residential customers have opted to install thermal storage technologies. Another 150 commercial and industrial customers have selected heating or cooling thermal storage. The vast majority of those customers would have installed conventional electric heating or cooling systems, directly contributing to the growth of system peak load.

Q. Can the load impact of thermal storage systems be further reduced?

A. Yes. When and if it becomes necessary to move this load to other times of day to avoid peak load periods, thermal storage installations can be easily adapted to permit direct utility dispatch of the load. The Company's design criteria for residential thermal storage systems specifies that they be able to meet the home's design heating requirements for fourteen hours under outside conditions that may only occur once in twenty-five years and allows that they can be fully recharged from a depleted state in ten hours or less. Those ten hours need not be contiguous. Therefore, the systems lend themselves well to utility dispatch. In addition, the timing devices on the existing thermal storage systems can be reset to move them away from the current peak, eliminating the negative return.

Q. **Why should Mr. Andersen's proposals be rejected?**

A. Much of his testimony is based on a selective review of old internal PP&L documents from 1991 and earlier. The resulting recommendations are outdated and erroneous and of dubious value in a case that deals with the justness and reasonableness of Rate Schedule RTS in 1995 and going forward.

Moreover, Mr. Andersen's historical portrait of Rate Schedule RTS is simply wrong. Rate Schedule RTS was developed in large part to meet load management goals and avoid unnecessary new generating plant construction in the future. Mr. Slivka, in his testimony, points out that the Company subsequently decided to de-emphasize Rate Schedule RTS and that only approximately 14,000 customers have selected the rate, not the projected 52,000. Mr. Andersen's focus on how the

Company viewed the future of RTS service years ago, and the Company's response, should not cloud the key issue in this case. The RTS rate is at an appropriate level based on a cost of service analysis and other accepted ratemaking techniques.

Further, the PUC staff has recently rejected very similar claims as shown by a letter dated April 3, 1995 from the Commission's Chief Counsel to counsel for Losch Boiler Sales & Service Company. I have included a copy of that letter as Exhibit OGK-6.

Q. **Has Mr. Andersen supported his claims that the RTS rate has harmed the oil dealers?**

A. No. Mr. Andersen simply makes broad claims that the RTS rate has caused a substantial loss of business for the oil dealers without any independent support. Since 1983, over 150,000 new homes have been constructed in the Company's service territory, yet the RTS customer class totals only approximately 14,000. Moreover, only a negligible percentage of the RTS customers were conversions from oil. Mr. Andersen's claims simply are unfounded.

The competitive relationship between electric heating and alternative, fossil fuel heating is far more complex than Mr. Andersen suggests. In fact, as demonstrated by CEPFOD's stipulations in response to the Company's data requests, CEPFOD has not been able to produce any studies or data that support the allegation of business loss due to Rate Schedule RTS as claimed in Mr. Andersen's testimony and cross-examination. I have included the relevant CEPFOD stipulations as Exhibit OGK-7.

Homeowners have been replacing older, inefficient oil equipment with new higher efficiency equipment, reducing usage per home. Over time, homeowners also have been adding insulation, which further reduces usage. This phenomena is not new and is present in all energy markets. The oil heating customer growth rate also likely has been affected by the lifting of the moratorium on natural gas usage for space heating and water heating in the 1980s.

Q. **Mr. Andersen claims repeatedly that the RTS rate is "below cost," "subsidized" and fails to recover the Company's incremental fuel cost. Is that true?**

A. No. The RTS customers more than cover the incremental and variable costs of service. The average per unit rate that PP&L receives from a new customer under Rate Schedule RTS is about 5.4¢/KWH at current rates. PP&L's variable cost is roughly equal to its cost to produce incremental energy. The RTS rate exceeds both:

- PP&L's average energy cost, which is about 1.8¢/KWH, and
- PP&L's marginal energy cost, which is about 2.2¢/KWH (based on PP&L's actual 1994 Energy Only Avoided Costs).

As these figures demonstrate, the RTS customers provide a substantial contribution to the system's fixed costs.

Q. **What about the fact that the Company's cost of service study shows Rate RTS providing a negative class rate of return?**

A. The negative return is caused by the fact that the Company, in recent years, has begun to experience monthly winter peaks in the evening when RTS systems are in operation. This is a relatively recent phenomenon and has produced distorted cost of service results for Rate RTS. The steps proposed for rate schedule RTS in this testimony, address this newer problem. With improved load control steps, the negative returns shown in the current cost of service are not expected to continue.

Q. **Do you agree with Mr. Andersen's other contentions, such as his claim that the RTS service shifted the system peak toward the evening?**

A. Not at all. Mr. Andersen relies upon little more than his reading of a small set of Company documents, none of which are more recent than 1991, and data responses. It is not surprising that his conclusions are mistaken. For example, apparently he was unaware that the internal 1987 projection that peak shifts would result from Rate Schedule RTS assumed that by 1995, over 52,000 customers would be on Rate Schedule RTS. In fact, only one-third that number of RTS customers materialized, due in part to the Company's de-emphasis of that option since 1991. This de-emphasis is the long-term strategy suggested in the 1987 study that Mr. Andersen relied upon for this mistaken proposition that the Company deliberately invited load shifting problems in its RTS planning. Indeed, as explained by Mr. Slivka, RTS load has <u>not</u> caused a shift in PP&L's winter peaks.

Q. Is the service level of the RTS customers different from service to other residential customers on Rate Schedule RS?

A. Yes. RTS customers must accept the inconveniences associated with living with a thermal storage rate. Rate Schedule RTS imposes substantial penalties if a customer operates appliances such as an electric range or a clothes dryer during on-peak periods. Rate

Schedule RS does not include these penalties. This substantial difference in quality of service is not reflected in the cost of service study results and further supports the RTS rate levels.

It was suggested by Mr. Andersen during his cross-examination that an RTS customer could simply "plug in" a portable space heater and purchase low cost energy. This is not true. With the demand charge and limited hours of use, this energy would be relatively expensive. This point is illustrated by example in Exhibit OGK-8; under those usage assumptions a rate schedule RTS customer would end up paying 7.32¢/KWH for the incremental electricity used by the space heater.

Q. What response do you have to RTS customer complaints and the suggestion that an investigation is needed as to whether RTS customers were fully informed?

A. In large part, this is a perception problem among the customers. It appears to arise from a letter that the Company sent to these customers in late March to explain the impact of the proposed changes in Rate Schedule RTS. That letter, a copy of which is attached as Exhibit OGK-9, unfortunately confused the customers by providing data about the increase that did not demonstrate the true overall rate effect. The Company regrets the resulting confusion, and has since sent to every RTS customer that has contacted the Company a clarifying letter properly recalculating the expected impact of the proposed rates on the customer's charges. The Company hopes to have resolved much of the confusion and annoyance among RTS customers by means of the second letter, a sample of which is also included in Exhibit OGK-9. While the Company sincerely regrets any confusion its March letter may have caused, there is no basis for any investigation of Rate Schedule RTS.

Q. **What of the more general complaint that some RTS customers may have lost the promised benefits of their investment in thermal storage facilities as a result of this rate proposal?**

A. I have not seen all of these complaints, but the Administrative Law Judge has supplied a copy of one letter, which I included in Exhibit OGK-9. I have attached an analysis showing that, despite the proposed rate increase, a typical RTS customer will continue to recoup his investment in the thermal storage facilities through rates that are substantially lower than rates available under Rate Schedule RS. <u>See</u> Exhibit OGK-8. Certainly, the Company has never undertaken to freeze the absolute level of rates under Rate Schedule RTS. All of its rates are subject to being changed either (1) in filings before this Commission as the Company's costs change, or (2) pursuant to other Commission proceedings. What the Company did undertake, and has fulfilled in this rate case, is to maintain a cost structure for the RTS rate that provides appropriate rate benefits for customers who have invested in thermal storage facilities. The proposed rate achieves this goal and provides substantial benefits to recoup that investment. The proposal that I outlined earlier would protect these RTS customers for four more years.

GENERAL SERVICE AT SECONDARY VOLTAGE - RATE SCHEDULES GS-1 AND GS-3

Q. Do you agree with the OSBA regarding the recommended adjustments over three years to Rate Schedules GS-1 and GS-3 at the expense of the residential class?

A. No. In my view, tracking adjustments such as the one suggested by Mr. Knecht are not appropriate for a select group of customers. Mr. Knecht fails to provide the needed support for his proposal.

OPTIONAL INTERRUPTIBLE POWER - RATE SCHEDULE LP-4, LP-5, AND LP-6

Q. Have you reviewed the testimony of Mr. Baron and Mr. Brubaker on behalf of the industrial customers?

A. Yes, I have.

Q. Do you agree with their recommendations?

A. No, I do not. Before I address their proposals in detail, it is important that I respond to two broad premises for the relief requested by both witnesses. Both witnesses, as well as the individual PPLICA customer witnesses, criticize the proposed rates for interruptible customers as not being "competitive." Both point to allegedly disproportionate increases in rates to the interruptible customers as a reason for recommending changes to the cost of service and rate allocation methods for the industrial customers. Neither claim withstands scrutiny. A close examination of these issues strongly supports the Company's proposed rates, and not the lower rates sought by the industrial customers.

Q. Why do you disagree with their contention that the proposed interruptible rates are "non-competitive?"

A. In assessing whether the Company's rates are competitive, all of its rate offerings must be considered, not just the interruptible rate option. In addition to the interruptible option, PP&L currently offers EDI/IDI credits, demand free days, real time pricing and, most importantly, the competitive rate rider (CRR). From this broader, and more proper, perspective, PP&L's rates are clearly competitive.

Moreover, as I will discuss later, the proposed increase in PP&L's interruptible rates merely returns those rates to the levels in effect prior to introduction of the interruptible options in the early 1990s.

Q. **Please elaborate on the rate options available to industrial customers to help them compete.**

A. There are two competitive options. The Company currently has in place an experimental Price Response Service providing "real-time" pricing for industrial customers. This option was developed in response to customer input, including a number of energy intensive industrial customers. Price Response Service gives industrial customers access to hourly energy prices which enables them to reduce production during high-cost hours and increase production during low cost periods. Early results of this pricing experiment show that customers can realize substantial savings using the Price Response Service.

Q. **What is the second option?**

A. Customers that can demonstrate that they face serious competitive challenges can request service under the CRR that I mentioned previously. This option can act as a "safety net" for customers that might be forced to choose between remaining full service customers, transferring production to another plant, producing some or all of their own requirements, or taking service from a competing energy supplier.

Q. What makes these products superior to interruptible service?

A. Under both the Price Response Service and the Competitive Rate Rider, the customer's load may be served as firm load and, therefore, can be offered at a higher level of reliability compared to interruptible service. Price Response Service is designed to allow the customer to custom tailor energy purchases to its competitive situation. Both rates are customer specific options that should better fit the needs of individual customers and their competitive environment. In addition, these rates are much more focused in their application.

Q. Why are these options superior to low interruptible class rates, from a ratemaking standpoint?

A. Using either of these riders is far preferable to the approach advocated by PPLICA, i.e., granting extremely low interruptible rates to all industrial customers as a means of retaining load. The PPLICA/Bethlehem approach may be compared to a "blunderbuss" strategy;

in contrast, the Company believes its approach is more appropriate in responding to competitive conditions on an individual customer basis.

Q. **Why is it important that the Company approach competitive problems on an individual basis?**

A. First, the circumstances of each industrial company vary widely. The testimony of the individual PPLICA members demonstrates the range of competitive differences among them. Designing a single interruptible rate to meet the competitive needs of all the customers is not practical, unless the Company follows a "least common denominator" approach to pricing for that group of customers.

Moreover, that approach could lead to a second problem; the need to avoid overreacting to competitive threats by assigning insufficient costs to the industrial class and, thereby, overburdening the residential and smaller commercial customers. As this filing demonstrates, the Company believes that it has a duty to balance the needs of the residential, commercial, and industrial customers, by establishing appropriate, cost-based interruptible (and firm) rates for large industrial customers, while preserving the option of negotiating rates under CRR to respond to individual customer circumstances.

Q. Who loses if the Company fails to provide competitive rates?

A. If load is lost, the Company's shareholders would bear the full impact of the resulting loss of revenue (and earnings) until the next general base rate filing. The Company has every incentive to provide the competitive prices needed by industrial customers.

Q. Why are the intervenors not justified in complaining of the level of rate increase allocated to the interruptible customers?

A. All of the interruptible customer witnesses ignore the full context for the interruptible rates proposed in this filing. For PP&L's non-interruptible customers, this filing represents an increase over the rates established in the Company's last general base rate case in 1984. In contrast, the interruptible customers enjoyed a major price decrease beginning (for most) in 1992, as the result of new interruptible tariff provisions filed by the Company. In the aggregate, interruptible customers experienced a 21% decrease in their cost of electricity. Earlier this year, at the Company's request, the Commission allowed PP&L to close that rate provision (Docket No. R-00943081). If the proposed increase is granted in full, nearly all of the industrial customers on the interruptible provision will be paying less than they were paying in 1991 under the base rates established in 1984. Exhibit OGK-10 graphically illustrates this point.

Q. What should the Commission conclude from these facts?

A. Relative to all of the Company's other customers, the interruptible industrial customers as a group will receive no increase at all in this proceeding, relative to rate levels established in the Company's last base rate case. To the extent that equities and principles of gradualism govern the allocation of the rate increase in this case, any class rate increase within the 150% average increase guidelines would be fully appropriate.

Q. Do you have any other comments on the significance of recent events affecting these rates?

A. Yes. The Commission allowed the Company to close its interruptible rate options, largely because of the threat of an increasing number of customers installing on-site capacity that would no longer produce the kind of benefits that had initially justified the new rates. By proposing a new, separate interruptible class under his proposed reduced cost responsibility, Mr. Baron effectively seeks to undo the Commission's recent order closing the optional interruptible power tariff.

Q. Did you review the LP-5 and LP-6 interruptible rate proposed by the PP&L Industrial Customer Alliance (PPLICA)?

A. Yes. PPLICA proposes a single interruptible provision *for LP-5 and LP-6 interruptible rates.* The interruptible rate proposed by PPLICA uses the same design as PP&L's current interruptible rates, which as noted above, were closed by the Commission earlier this year.

Q. Do you agree with the PPLICA design?

A. No. The PPLICA design does not move the credit for interruptible load closer to the value of peaking capacity. As explained in Mr. Sipic's testimony, interruptible capacity is similar to, although somewhat less reliable than, peaking capacity. In its cost of service study, PP&L has valued interruptible capacity at approximately $3.75/KW, which is the carrying charges (15%) on the cost of a combustion turbine - $300/KW. Even accepting Mr. Baron's 1.2 x adjustment for active load management the credit would be approximately $4.50/KW. Under the Company's current (closed) interruptible rate the credit is approximately $11.60/KW. Under PPLICA proposed rate the credit would be $9.90/KW. Both of these substantially exceed the $3.75/KW value of interruptible load as calculated by the Company or the $4.50/KW adjusted value offered by Mr. Baron.

Q. How does the Company's proposed interruptible credit compare to these values?

A. Assume a hypothetical customer with:

- monthly on-peak load factor of 85%;
- KWH consumption of 7,400,000 per month;,
- average on-peak demand of 13,200 KW; and
- firm load of 100 KW.

Exhibit OGK-11 shows the bill calculation for this hypothetical customer. The customer's monthly bill is approximately $437,000 under PP&L's proposed LP-6 firm rate and about $371,000 under PP&L's proposed LP-6 interruptible rate. The interruptible load credit for this customer would equal the difference between the firm and interruptible bills divided by the interruptible load (13,100 KW) or about $5.10/KW. While this exceeds the $3.75/KW value of interruptible load, it is much closer than the PP&L proposal or the Company's current (closed) rate.

Q. Do you agree with PPLICA that the optional interruptible power under LP-4, LP-5, and LP-6 should be separated into separate rate schedules?

A. No. The cost to provide service to and the use of service by an interruptible customer is very similar to a firm requirements customer. The only discernible difference is that, in an emergency, the Company can request the interruptible customers to curtail operations and reduce load. It is the customer's choice to curtail. These customers weigh the penalties for non-curtailment against the lost production costs for curtailment. An interruptible customer may choose to fully interrupt or only partially curtail its operations. If it chooses not to curtail, PP&L must supply it just as though it were a firm power customer. Exposure to interruptible occurrences is limited to 200 hours/year for a duration of 10 hours/day or less. During the remaining hours, the interruptible customer receives electric service just as any firm requirements customer. PP&L must maintain power plants, transmission facilities, billing and customer service functions, as well as all the other services that are provided to similar sized firm requirements customers. These interruptible customers are not really a separate rate class, but merely a subgroup of PP&L's standard tariff rate schedule classification; i.e., Rate Schedule LP-4, Rate Schedule LP-5, or Rate Schedule LP-6.

The appropriate way to credit a customer for the service it provides by reducing load is a credit to its firm capacity charge. It is not necessary to create a series of new tariff rate schedules and their associated administrative burdens. In fact, a separate rate class for interruptible service would only obscure the inherent customer class characteristics of these customers normally differentiated by voltage level and size.

Q. **Do you agree with PPLICA's proposal to use the same rate design as the current interruptible rate?**

A. No. The current interruptible rate design is deficient in several areas and must be changed. First, it was designed originally as an economic development initiative and also an interruptible rate. As an economic development rate it overstates the interruptible credit to participating customers. The overstatement is embedded within the rate design. Second, the present rate provides a very large incentive for customers to move load from off-peak to on-peak hours. This is also a result of crediting customers for interruptible load. Third, PP&L has evolved its rate design philosophy to recognize the market and resource value of interruptible load.

COMPETITIVE PRICING COMPARISONS

Q. In Mr. Brubaker's testimony on behalf of Bethlehem Steel Corporation, he cites exhibits that show the Company's interruptible rates as non-competitive with other electric utilities. Are these valid comparisons?

A. No. The utilities listed in Mr. Brubaker's testimony, specifically Exhibits MEB-1 Schedule 1 and MEB-2, compare the Company's current and proposed interruptible rates to a group largely consisting of midwestern utilities. Industrial customers in the Mid-West region are largely serving markets located in that region as most firms located in the Company's service area are serving markets located in the Mid-Atlantic and New England regions. The Company more appropriately should be compared to utilities in the Mid-Atlantic and New England regions. If these comparisons are made, the Company's rates compare favorably. This point is illustrated by the map in Exhibit OGK-12 which compares the Company's industrial rates to industrial rates of other PJM member utilities. Moreover, Mr. Brubaker's own schedules show that the Company's rates for interruptible service are highly competitive with Northern Indiana Public Service Company which serves Bethlehem Steel's Burns Harbor Plant.

Q. Do you have any other comments on the rate comparisons used by Mr. Brubaker?

A. Yes. He has selected comparisons at load levels and load factors which do not represent the customer base on Rate Schedule LP-5. The average monthly peak load factor for the customers on Rate Schedule LP-5 interruptible is 85% (weighted by peak demand), not the 68% as depicted in his testimony. For these reasons, Mr. Brubaker's rate comparisons are not valid.

Q. Do you believe the FERC wholesale rates currently offered by PP&L to the 18 municipal electric companies are a basis for retail market based rates as suggested by PPLICA?

A. No. The wholesale power market is fundamentally different from the retail market and, accordingly, references to wholesale rates are not relevant in a retail rate proceeding.

EDI/IDI PROGRAMS

Q. Please explain the general criteria for customers to qualify for the EDI/IDI expanded use credits program.

A. Each customer receiving the EDI/IDI program expanded use credits of 1¢/KWH and $2/KW, was required to submit data demonstrating its intent to expand physical plant or add production capability. If this demonstration was not made, a contract was not prepared, and the customer did not receive the benefits of expanded usage credits.

Q. Do you agree with Mr. Baron's and Mr. Johnson's suggestion that all customer classes share the cost of the EDI/IDI programs?

A. No. This suggested treatment does not follow the Commission's current direction for similar program costs or lost revenues produced by Demand-Side Management (DSM) programs. The Commission's current DSM order requires recovery of costs and lost revenues from the classes receiving direct benefits from the programs (Docket No. I-900005). PP&L has used an analogous approach and assigned the costs of the EDI/IDI programs to the rate classes receiving major direct benefits.

Q. Do you agree that the shareholders of PP&L should continue to bear the responsibility, or share the costs of providing these EDI/IDI credits as proposed by Mr. Johnson?

A. No. The EDI/IDI credits are important economic development programs providing substantial direct and indirect benefits to the Company's customers and its service territory. As demonstrated in Exhibit OGK-4, the EDI/IDI credit programs produced a significant savings for customers in two major rate classes, LP-4 and LP-5. These programs helped to prevent the loss of 20 major manufacturing customers. Participating customers demonstrated that the EDI programs contributed to retaining their facilities in PP&L's service territory by allowing them to produce at a lower incremental cost than competing plants. These customers have made and continue to make substantial contributions to fixed cost recovery. This benefits all of the Company's customers.

Q. Do you have any information demonstrating that non-participating customers are indirectly benefiting from these credits as referred to in Mr. Johnson's testimony?

A. Exhibit OGK 13 shows a benefit/cost analysis for the EDI/IDI program. The benefit/cost analysis essentially follows the methodology of this Commission's "all-ratepayers" DSM test. The test is a measure of the difference between the change in total revenues paid to PP&L and the change in total costs resulting from the program.

The change in total revenues for the EDI/IDI program is based on the projected loss of 20 industrial customers if the EDI/IDI program was not offered. The change in total costs is based on the marginal energy, capacity, and administrative cost required to serve the 20 industrial customers. Incidently, Mr. Johnson is simply mistaken when he contends that these savings should be discounted because the new load increase is higher than average energy costs. The study uses <u>marginal</u> energy costs.

The analysis shows that over the 10 year study period, the cumulative present value of revenues exceeds the cumulative present value of incremental costs. This result shows that the EDI/IDI program would tend to reduce PP&L's average revenue requirement.

Q. You recommended charging the rate class that benefited directly by EDI/IDI credits with the cost of those credits. Is this treatment also appropriate for the ISA rate class?

A. Yes. With this specific rate, the customer receives significant benefits including EDI credits. Unlike the other classes receiving EDI credits, rates to this class were not increased to within the target rate of return. Assigning additional EDI/IDI costs from other rate classes to the customer is unnecessary and inappropriate. Moreover, the Commission should reject Mr. Johnson's unsupported request that this rate schedule receive a substantial rate increase. This rate class was, in part, a specifically designed competitive response. While costs of the EDI/IDI program are included within the cost allocation for Rate Schedule ISA, it is not appropriate to adjust ISA at this time. The ISA rate class consists of only one customer with very unique use and industry characteristics. The unique competitive environment and end-use characteristics of the customer required PP&L to respond to the customer's need for lower rates using the rate mechanism available at the time. The Company now has available the Competitive Rate Rider--a mechanism to adjust rates for specific competitive situations.

Q. Please explain the additional retention of 300 million KWH in sales due to the EDI/IDI program.

A. Mr. Farber, in his direct testimony, referred the retention of an estimated 300 million KWH in existing sales due to the EDI/IDI credit program. The EDI/IDI riders contain a provision that the credit is not available to customers with other sources of power which can replace the Company's supply.

As customers that received EDI/IDI credits began investigating on-site cogeneration, the cost of the replacement electric from the proposed generators usually was higher than the power purchased from PP&L under the EDI/IDI program. This resulted in almost no on-site cogeneration being installed within the Company's service territory over the past 10 years. If the EDI/IDI program had not existed, the majority of EDI/IDI incremental sales would have been lost, and an additional 300 million in base KWH sales would have been lost to on-site cogeneration.

Q. Do you have any objections to requiring customers to perform extensive energy audits as a precondition to receiving a discount rate, such as EDI/IDI, as suggested by Mr. Biewald, representing the Sierra Club of Pennsylvania?

A. No. Most customers in a competitive environment are performing these types of studies regularly. However, I do not believe that implementation of the findings from such an audit should be used as a precondition for receiving the discount rate. Like any potential capital investment, conservation measures must compete on an equal footing with other projects for scarce capital resources. I also do not believe the Company should be responsible for the cost of these energy audits. The customer will benefit from the rate discount, and potentially from the findings in the energy audit. Other customers or shareholders should not be required to subsidize these audits.

Q. Do you have any other statements regarding the EDI/IDI programs?

A. Yes. PP&L believes that the EDI/IDI programs sponsored by the Company are appropriate programs that benefit all customers and the costs properly are recoverable from customers. However, if the Commission disagrees, then the programs should be terminated. Continuing the programs with shareholder funding, as proposed by Mr. Johnson, simply is not good policy or ratemaking practice and is unacceptable to the Company.

STREETLIGHTING - RATE SCHEDULE SE

Q. Do you agree with the recommended increases for Rate Schedule SE as discussed on Pages 14 and 15 of OTS Statement No. 3?

A. No. As Mr. Yarolin stated during his cross examination, the percentage increases in rates for Rate Schedule SE, cited in OTS Statement No. 3, are the changes in base rate only. The proposed changes to Rate Schedule SE include the roll-in of the State Tax Adjustment Surcharge (STAS) and partial roll-ins of the Energy Cost Rate (ECR) and the Special Base Rate Cost Adjustment (SBRCA). The proper comparison to total charges under present rates is total charges under proposed rates. Using this approach, the proposed increase to service under Rate Schedule SE is 20.49% See Exhibit Future 1, Schedule D-3, Page 5, Column 10, Line 15.

Q. Do you agree with the OTS recommendation that Rate Schedule SE should be considered an off-peak rate and should not get any increase in rates in this proceeding?

A. No. Rate Schedule SE should not be considered an off-peak rate and should receive an increase in this proceeding. The documentation that PP&L has submitted in this proceeding supports this position.

As indicated in the Company's response to Question OTS-RS-31D of Interrogatories of the Office of Trial Staff Dated January 13, 1995, the Street/Area Lighting class, of which Rate Schedule SE is a member, contributes to the Monthly System Peak in five of the 12 months. Clearly, Rate Schedule SE is not off-peak throughout the year.

Cost allocation studies presented by PP&L with the rate filing recognize the Street/Area Lighting contribution to the Monthly System Peaks. Furthermore, the cost allocation study submitted in support of the initial filing of Rate Schedule SE at Docket No. R-821927 in 1982 similarly recognized the Street/Area Lighting class contribution to the Monthly System Peaks.

The OTS states that ownership of the streetlighting equipment is a reason supporting treatment of Rate Schedule SE as an off-peak rate (OTS Statement No. 3, Page 14, Lines 9 through 18). Ownership of the streetlighting equipment is not related in any way to the operation of the equipment. Customer operation of customer-owned streetlighting equipment under Rate Schedule SE is identical to PP&L operation of PP&L-owned streetlighting equipment under other streetlighting rate schedules in its tariff. Operation of all streetlighting equipment, including the customer-owned equipment served under Rate Schedule SE, is by photoelectric control.

In addition, the OTS witness indicated that, "since streetlighting is a community service, all customer classes benefit directly or indirectly from this service." Again, this reasoning does not support his recommendation that service under Rate Schedule SE should be priced as an off-peak service. The OTS witness does not present any evidence to support his concern that the proposed increase to Rate Schedule SE could place a financial strain on a given community.

Finally, the OTS witness relies upon his opinions as to the off-peak nature of service under Rate Schedule SE and the community service benefit of streetlighting to support his recommendation that Rate Schedule SE should not get an increase in this proceeding. As I indicated earlier, his opinion regarding the off-peak nature of service under Rate Schedule SE is flawed. Establishing Rate Schedule SE as an off-peak rate and not increasing the charges in the rate schedule in this proceeding would require a subsidy from the other rate classes. This simply is not appropriate because PP&L is attempting to move each rate class closer to the system average rate of return in this proceeding. A subsidy would move the Street/Area Lighting class in the opposite direction.

Finally, it is not clear that off-peak rates would produce any material benefits for that class. Because about one-half of the year, street lighting contributes to the monthly peaks, and the other half of the year it does not, higher charges during the on-peak months would largely offset lower charges during the off-peak months. In addition, off-peak rates are generally employed for those customers who have the ability to shift load to off-peak periods.

Street lighting does not have that flexibility and therefore is not an appropriate class for off-peak rates.

OTHER RATE ISSUES

Q. Do you agree with Mr. Biewald's proposal for recovering "stranded benefits" through a system charge?

A. No. I do not believe that he has supported consideration of that proposal in this proceeding. No "stranded benefits" have been identified, and thus the plan is premature. Particularly in the absence of any actual cost support here, this type of proposal would best be considered in the Commission's generic proceeding on stranded cost recovery.

Q. Do you have any other corrections for the record?

A. Yes. The tariff has several minor errors that will be corrected in the Company's compliance filing.

Q. What are those corrections?

A. For Rate Schedule GS-1, page 24, and Rate Schedule GS-3, page No. 25, under Off-Peak Space Conditioning and Water Heating, the proposed rate is shown as 3.00 cts. per KWH for all KWH of use. That figure should be corrected to 4.10 cts. per KWH. Similarly, Rate Schedule IS-1, page 30, shows 5.50 cts. per KWH for the first 730 KWH per kilowatt of billing KW, which will be corrected to 4.70 cts. per KWH and the proposed rate of 3.60 cts. per KWH for all additional KWH, will be corrected to 4.10 cts. per KWH. Finally, for Rate Schedule LP-4, at Page No. 27A, the proposed off-peak Space Conditioning rate of 2.90 cts. per KWH for all KWH of use would be corrected to 4.00 cts. per KWH. These were computational error in the program to the rate case calculations, as a result of which, the ECR was not rolled into these components of the rate.

Q. Are there any other adjustments offering customer changes on terms of service?

A. Interruptible Service by Agreement, page No. 19D; the Competitive Rate Rider, page No. 19E; Rate Schedule LP-

4, page No. 27; Rate Schedule LP-5, page 28, Rate Schedule LP-6, page No. 28B; Rate Schedule IS-1, page No. 30; and Rate Schedule PR-2, page No. 32 will be amended to clarify that new interruptible power agreements will not be entered into if the total of all interruptible services exceeds 500 MW. This is consistent with the information previously provided to the customers, and with my testimony at the March hearing. However, this proposal would be reconsidered if the Company's rate filing were significantly changed by the Commission.

Also, under Rate Schedule LP-6, under Billing KW Credit, the sentence is changed to clarify that the $6.00 per KW credit in the Billing KW Credit formula is increased by $2.00 per KW to $8.00 per KW for customers with 10,000 KW or more of Interruptible Power who reduce their load to the Firm Power level within 30 minutes from the time the Company initially calls the customer for an interruption.

Under Rate Schedule LP-4, page No. 27A, and Rate Schedule LP-5, page No. 28A, under Industrial Development Initiatives Rider and Economic Development Initiatives Rider, the exclusion of customers served under the Interruptible Power Provision is eliminated.

This change however is contingent upon approval of the Company's proposed interruptible rates in this proceeding.

Q. Does this conclude your testimony at this time?

A. Yes.

EXHIBIT OGK 5

RS Rate Design Using OTS Customer's Charge
And Two Energy Steps

Rebuttal Testimony of Oliver G. Kasper
Docket No. R-00943271

RS Rate Redesign Using OTS
Customer Charge and Two Energy Steps

Customer Charge:	$5.90/month
First 600 KWH	$0.10073/KWH
Excess KWH	$0.07600/KWH

EXHIBIT OGK 6

Losch Boiler Sales & Service Company v. PP&L
Opinion Letter Of The PUC Staff

Rebuttal Testimony of Oliver G. Kasper
Docket No. R-00943271

COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION
P.O. BOX 3265, HARRISBURG, PA 17105-3265

IN REPLY PLEASE REFER TO OUR FILE

April 3, 1995

Catherine Panchou Cox, Esquire
Harvey, Pennington, Herting
& Renneisen, Ltd.
Eleven Penn Center, 29th Floor
1835 Market Street
Philadelphia, PA 19103

Re: Losch Boiler Sales & Service Co. v. Pennsylvania Power & Light Co., C.A. No. 92-2359, and Yeager's Fuel, Inc. v. Pennsylvania Power & Light Co., C.A. No. 91-5176, E.D. Pa. (Padova, J.)

Dear Ms. Cox:

In connection with the above-captioned civil litigation initiated against Pennsylvania Power & Light Co. (PP&L) and at your suggestion, the Law Bureau and Bureau of Conservation, Economics and Energy Planning (hereinafter "PUC Staff") have reviewed the various documents referred to in your letter dated October 25, 1994 dealing with PP&L's internal RTS rate cost studies, its electric capacity and demand forecasts and its business plans. Although covered by a Protective Order to shield commercially senstitive information from public disclosure, the PUC Staff executed a Written Assurance to abide by the Protective Order's non-disclosure terms and, thereafter, on December 5, 1994, was provided with full access to and copies of the relevant documents (including those referenced in Mr. Loper's August 25, 1994 deposition).

Based on our careful review of these documents, there appears to be no firm basis to your suggestion that PP&L misrepresented and/or omitted critical information in describing its promotional activities to the PUC. In particular, these documents indicate that the Electric Thermal Storage (ETS) Program did cover its costs (when after-tax earnings per RTS customer are compared to after-tax costs), (2) that the ETS Program did not advance the need for more electric generating capacity in the PP&L system before the turn of the century, and (3) that PP&L's present promotional practices are in compliance with the PUC's amended promotional practices regulations at 52 Pa. Code §57.61-.67. As such, the PUC Staff does not intend to initiate any formal proceedings against PP&L regarding the matters alleged in your letter of October 25, 1994.

Nevertheless, to the extent that your clients continue to believe that PP&L has violated the Public Utility Code or PUC regulations in conducting its promotional activities, you remain free to file your own Section 701 complaint against the company and to have your case heard and adjudicated by an Administrative Law Judge. See 66 Pa. C.S. §§701-03. At this juncture, however, the PUC Staff does not see any substance to your allegations.

Very truly yours,

John F. Povilaitis
Chief Counsel

JFP/der

cc: Bohdan R. Pankiw, First Deputy Chief Counsel
Z. Ahmed Kaloko, Director, Bureau of CEEP
John L. Dial, Executive Director
Paul E. Russell, Esquire
Wayne M. Thomas, Esquire
Jeffrey H. Howard, Esquire

EXHIBIT OGK 7

CEPFOD's Responses to PP&L's Data Requests

Rebuttal Testimony of Oliver G. Kasper
Docket No. R-00943271

MORGAN, LEWIS & BOCKIUS

ILADELPHIA
W YORK
IAMI
PRINCETON
BRUSSELS

COUNSELORS AT LAW
1800 M STREET, N W
WASHINGTON D C 20036
TELEPHONE (202) 467-7000
FAX (202) 467-7176

WASHINGTON
LOS ANGELES
HARRISBURG
LONDON
FRANKFURT
TOKYO

CHRISTOPHER J. BARR
DIAL DIRECT (202) 467-7142

April 14, 1995

Robert P. Haynes
Mette, Evans & Woodside
8401 North Front Street
P.O. Box 5950
Harrisburg, PA 17110

Re: Pennsylvania Public Utility Commission *et al.* v. Pennsylvania Power & Light Company, Docket No. R-00943271, et. seq.

Dear Mr. Haynes:

Enclosed please find the Interrogatories and Request for Production of Documents of Pennsylvania Power & Light Company addressed to the Central Eastern Pennsylvania Fuel Oil Dealers in the above-referenced matter. Please send the responses directly to Mr. Russell at the following address:

Paul E. Russell
Pennsylvania Power & Light Co.
Two North Ninth St.
Allentown, PA 18101

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

Yours truly,

Christopher J Barr

Christopher J. Barr

Enclosure

cc: All Parties

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

INTERROGATORIES AND REQUESTS
FOR PRODUCTION OF DOCUMENTS AND DATA
OF PENNSYLVANIA POWER & LIGHT COMPANY
TO THE CENTRAL EASTERN PENNSYLVANIA FUEL OIL DEALERS

Pennsylvania Power & Light Company hereby propounds this Set of Interrogatories and Requests for Production of Documents and Data to the Central Eastern Pennsylvania Fuel Oil Dealers to be answered by you or such other person or persons capable of responding to these Interrogatories and Requests and authorized to do so. Telephone or other contact concerning availability and timing of formal responses is encouraged. The answers should restate the question asked and indicate the person(s) supplying the information.

Introductions/Definitions

a) The answers provided should restate the questions asked and identify the person(s) supplying the information.

b) You shall divulge all information that is within your knowledge, possession, control or custody, or that may be reasonably ascertained. "Respondent", "your" and "you", as used herein, includes your agents, employees, experts and/or other representatives.

c) For any questions that request information or data for a series of years, please provide as much of the data as is available for each year, and explain why any data not provided is unavailable.

d) Whenever these Interrogatories request Respondent to identify a person or a witness, please set forth:

1. His or her name;
2. His or her business address; and
3. His or her profession, educational background and work experience.

e) Whenever these Interrogatories request Respondent to identify a model, set forth:

1. The type of model; and
2. The name of the model.

f) All references in these interrogatories to "document(s)" "analyses" and "studies" shall be construed to include, but shall not be limited to, all work papers, studies and reports, and any and all other written, recorded or graphic matter, including, but not limited to, originals and legible copies (with or without notes or changes therein), in whatever form, stored in or on whatever medium including computerized memory or magnetic media.

PENNSYLVANIA POWER & LIGHT COMPANY
Docket No. R-00943271
Interrogatories for
Central Eastern Pennsylvania Fuel Oil Dealers

---

1. For the period 1985 through 1994: (a) Please provide specific information on CEPFOD's members' home heating market share statistics within PP&L's service area versus other energy sources, specifically electric heat and gas heat. (b) Please show the number of new home heating customers served and average budgeted and/or actual oil deliveries per new home. (c) Please state CEPFOD's members' market share for new: (i) single family homes; (ii) townhouses; and (iii) mobile homes.

2. Please provide CEPFOD's documentation of the number of existing oil-heated homes within the Company's service area that were converted to RTS service, by year, for the period 1985 through 1994.

3. Please provide all documents or other evidence possessed by CEPFOD or its members on PP&L's continued direct promotion of the RTS rate and/or electric thermal storage systems to residential customers during the historic or future test years.

4. Please provide documentation of the number of new oil heated homes in PP&L's service area that include central air conditioning equipment, by year, for the period 1985 through 1994.

5. In his direct testimony, Mr. Anderson concludes that "PP&L's marketing of RTS was so aggressive that it not only shifted usage away from the daytime hours, it also shifted the time of system peak." Please provide any studies or data supporting this claim, including documentation and calculations that shows the contribution that RTS service had to the shift in the time of the Company's system peak.

6. Please provide any evidence that the Company has planned to continue the promotion of the RTS service beyond 1995.

7. In his direct testimony, Mr. Anderson concludes that "the RTS peaking problem" could not be solved by additional load management initiatives. This conclusion is supported by reference to an 8 year-old planning study. What analysis has CEPFOD or Mr. Anderson conducted to determine the benefit of load management initiatives in light of today's costs and availability of these alternatives?

8. Please document the change in average annual overall heating efficiency of installed residential oil-fired space heating equipment within the Company's service area for the period 1985 through 1994.

9. Please provide documentation of the percentage of national market share of oil heated new homes versus other energy sources by year for the period 1985 through 1994.

10. Please provide documentation of the actual number and percentage of total new oil heated residential homes installing "high efficiency" oil-fired space heating systems and the average installed cost of these systems within the service area served by the Company for the period 1985 through 1994.

11. Please provide any studies conducted or possessed by CEPFOD that compares the cost benefit of an investment in RTS service with the value of deferred generating capacity on the Company's system.

12. How many residential customers has CEPFOD serviced for each of the following years: 1990, 1991, 1992, 1993, 1994?

13. (a) What is the average CEPFOD residential price of fuel oil for the same years as requested in Question 12? (b) What has been the average fuel oil usage per customer served by CEPFOD for each of those years? (c) Also provide the data requested in (b) weather normalized for each year.

14. What is the seasonal average residential fuel efficiency of the typical CEPFOD customers': (a) space heating equipment, and (b) hot water heating equipment?

15. What is the seasonal average efficiency of new oil space heating and hot water heating systems being installed as of January 1, 1995, by CEPFOD customers?

16. Are existing fuel oil customers of CEPFOD replacing existing oil space heating and oil water heating systems with new oil systems? Please provide the number of system upgrades for each end-user for the same time frame as Question 12.

17. How many CEPFOD residential customers have replaced oil heating systems and oil hot water systems with other fuels for the same years stated in Question 12? How many have selected a gas or propane replacement? How many have selected dual fuel heat pumps? How many have selected standard heat pumps with electric resistance supplemental? Please provide this data by year from 1985 through 1994.

18. With regards to Mr. Anderson's testimony at page 8, (a) please explain the derivation of the $0.02 per kwh for the heating service under the RTS rate, and provide all work papers. (b) Please demonstrate by example the statement that the incremental charges for heating service on RTS is not sufficient to recover off-peak fuel expense. Provide all work papers to substantiate this calculation.

19. Please provide a calculation showing that the typical RTS customer is recovering their added investment within 5 years as stated in your testimony.

20. Mr. Anderson states in his testimony that CEPFOD members can only regain lost customers if RTS subsidies are eliminated. If this elimination is solely for the purpose of providing business for the CEPFOD members, please explain why PP&L shareholder should accept the cost of elimination of the rate and not the CEPFOD members?

21. In 1986, was the use of gas as a home heating fuel and hot water fuel prohibited? What year was the use of natural gas as a home heating fuel prohibited? What year was this prohibition removed?

22. Mr. Anderson states at page 8 of his testimony that an RTS home uses 2.6 times as much energy as an average RS customer. Please provide all studies or other support for this statement, including a breakdown of all energy use on which you based your statement, including fuel used for space heating and water heating regardless of fuel source. Please respond in MBTU per year.

23. Please provide support (studies and market research) for Mr. Anderson's statement that RTS customers are turning up their thermostats in response to the availability of "cheap" energy.

24. On page 3 lines 27 to 29, Mr. Anderson states that PP&L offers a discount to other electric space heating customers. Please provide a copy of the analysis and any other documents supporting this conclusion.

25. Throughout Mr. Anderson's testimony, he states that RTS does not recover the cost of providing the service. Please provide a copy of the analysis supporting that conclusion.

26. In Mr. Anderson's view, what points would a heating customer consider in choosing a heating system and fuel source?

27. Please provide a copy of the analysis supporting Mr. Anderson's conclusion that the GS-1 class would subsidize the RTS class.

28. Please provide any and all analysis that proves Mr. Anderson's recommended RTS rate design eliminates price distortion.

29. Why does Mr. Anderson recommend recovering the remainder of the increase in RTS revenues through an increase in the energy charge? Please explain the answer in detail and provide all studies or analyses underlying this recommendation.

30. Please provide the study which supports Mr. Anderson's contention at page 41 that PP&L's exposure to uncollectible expenses, depends on the size of the customer's bill.

31. If PP&L transfers customers from RTS to RS or RTD, how should the $50/month guarantee be treated in PP&L's rate case?

32. Regarding Mr. Anderson's testimony at page 41, please provide all analysis which demonstrates customer costs of $8.00 when uncollectibles and customer assistance expenses have been excluded.

33. Regarding Mr. Anderson's testimony at page 42-43, please explain in detail whether Mr. Anderson contends that a customer charge of $7.20/month rations access to the utility system, and, if so, how that charge rations capacity?

34. Please explain in detail how Mr. Anderson's proposed $1/month increase in customer charges would recover out-of-pocket customer costs when he states that they exceed $8.00/month?

35. Please explain in detail how placing customer costs into energy blocks add to pricing efficiency?

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing documents upon the participants listed below, in accordance with the requirements of Section 1.54 (relating to service by a participant).

BY FEDERAL EXPRESS

Tanya J. McCloskey, Esquire
Office of Consumer Advocate
425 Strawberry Square
Harrisburg, PA 17120

Matthew I. Kahal
Exeter Associates
12510 Prosperity Drive
Suite 350
Silver Spring, MD 20901

BY FIRST CLASS MAIL

Johnnie E. Simms, Esquire
Office of Trial Staff
Pennsylvania Public Utility
Commission
Pitnick Bldg. - 3rd Floor
901 N. 7th Street - Rear
Harrisburg, PA 17102

Karen Oill Moury, Esquire
Office of Small Business Advocate
Suite 1102, Commerce Building
300 North Second Street
Harrisburg, PA 17101

David M. Kleppinger, Esquire
McNees Wallace & Nurick
100 Pine Street
P.O. Box 1166
Harrisburg, PA 17108-1166

David A. McCormick, Esquire
General Attorney
Office of the Judge Advocate
General
901 North Stuart Street
Arlington, VA 22203-1837

James P. Melia, Esquire
Kirkpatrick & Lockhart
240 North Third Street
Harrisburg, PA 17101

Wayne M. Thomas, Esquire
Kohn, Nast & Graff, P.C.
1101 Market Street, 24th Floor
Philadelphia, PA 19107

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

* Jane Drennan, Esquire
-nnan & Associates
.15 16th Street, N.W.
Washington, D.C. 20036

Craig Kuennen
Commission on Economic Opportunity
211 S. Main Street
Wilkes-Barre, PA 18701-1596

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

Kenneth Zielonis, Esquire
Stevens & Lee
208 North 3rd Street, Suite 310
Harrisburg, PA 17101

*Robert P. Haynes, III, Esquire
Mette, Evans & Woodside
3401 N. Front Street
Harrisburg, PA 17110-0950

Stephen J. Selden, Esquire
Assistant General Counsel
Bethlehem Steel Corporation
Eighth & Eaton Avenues
Bethlehem, PA 18016

Eric J. Epstein
2308 Brandywine Drive
Harrisburg, PA 17110

Dated: April 14, 1995

Christopher J. Barr
Christopher J. Barr
Counsel for Pennsylvania Power
& Light Company

* Via Telecopy

MORGAN, LEWIS & BOCKIUS

PHILADELPHIA
NEW YORK
MIAMI
PRINCETON
BRUSSELS

COUNSELORS AT LAW
1800 M STREET N W
WASHINGTON D C 20036
TELEPHONE 202) 467-7000
FAX 202) 467-7176

WASHINGTON
LOS ANGELES
HARRISBURG
LONDON
FRANKFURT
TOKYO

CHRISTOPHER J. BARR
DIAL DIRECT 202) 467-7142

May 3, 1995

Wayne M. Thomas
Kohn, Swift & Graf, P.C.
1101 Market Street, Suite 2400
Philadelphia, PA 19107-2924

Re: PUC v. Pennsylvania Power & Light Co.; Discovery Requests to CEPFOD Dated April 14, 1995

Dear Mr. Thomas:

This letter will memorialize our agreement regarding the Central Eastern Pennsylvania Fuel Oil Dealers ("CEPFOD") objections to the Interrogatories and Requests for the Production of Documents to CEPFOD from Pennsylvania Power & Light Co. ("the Company") dated April 14, 1995. The Company agrees to withdraw or modify certain of these data requests, and CEPFOD agrees either to answer or stipulate as to certain of these data requests, as set forth below:

1. CEPFOD stipulates that it and its members lack any of the requested data, except as provided by the Company in civil litigation, and that it and its members have not prepared any independent analysis or study based on that information provided by the Company. In this proceeding, and as to the facts referenced in this data request, CEPFOD will only refer to such data supplied by the Company. This will be referred to in this letter as the "Standard Stipulation."

2. CEPFOD agrees to the Standard Stipulation.

3. The Company withdraws this data request.

4. The Company withdraws this data request.

8. CEPFOD agrees to provide a response showing the relative efficiency of installed residential oil-fired space heating equipment in 1985 versus 1994. CEPFOD stipulates that neither it nor its members will introduce more detailed information as evidence in this proceeding.

9. Standard Stipulation, but with the exception that CEPFOD has additional information solely from the Statistical Abstract of the United States, and will provide this additional data, or the specific references to this data, to the Company.

10. The Company will withdraw this data request, based upon CEPFOD's stipulation in response to No. 8.

12. CEPFOD stipulates that, with the exception noted in the next sentence, neither it nor its members currently have compiled the data requested, and that CEPFOD will not have the data compiled before the close of the record in this rate proceeding. Several individual companies have collected partially responsive data, and CEPFOD will provide that data to the Company.

13. Consistent with its offer in its April 21 Objections to this request, CEPFOD will provide approximations or estimates of the fuel oil prices and consumption for typical customers in selected geographic areas for the period beginning in 1989. CEPFOD will not offer more detailed information on this topic later in this proceeding.

14. and 15. CEPFOD stipulates that neither it nor its members possess the requested information, but will supply the information in response to Item No. 8, subject to the stipulation in 8.

16. CEPFOD stipulates that some fuel oil customers of its members are replacing existing fuel oil systems with new fuel oil systems, and that neither CEPFOD nor its members can quantify the percentage of customers so electing.

17. CEPFOD stipulates that neither it nor its members presently possess the information requested that is complete and accurate. CEPFOD stipulates that it will not introduce any such information in this proceeding, other than data obtained from the Company in discovery in the civil litigation.

21. The Company withdraws this request.

Yours very truly,

Christopher J. Barr

Christopher J. Barr

Counsel for Pennsylvania Power & Light Co.

METTE, EVANS & WOODSIDE
A PROFESSIONAL CORPORATION
ATTORNEYS AT LAW
3401 NORTH FRONT STREET
P.O. BOX 5950
HARRISBURG, PA 17110-0950

April 28, 1995

VIA FACSIMILE AND FIRST CLASS MAIL
Paul E. Russell
Pennsylvania Power & Light Co.
Two North Ninth Street
Allentown, PA 18101

RE: **Pennsylvania Public Utility Commission et al. v. Pennsylvania Power & Light Company, Docket No. R-00943271 et seq.**

Dear Mr. Russell:

Enclosed please find the responses of Central Eastern Pennsylvania Fuel Oil Dealers to Pennsylvania Power & Light Company interrogatories Nos. 5 through 7, 11, 18 through 20, and 22 through 35 in the above-referenced matter. If you have any questions, please do not hesitate to contact the undersigned.

Sincerely yours,

Robert P. Haynes

RPH/me

Enclosures

cc: All Parties per Certificate of Service
John G. Alford, Secretary (w/o enclosure)
7507.1

31804 1

CERTIFICATE OF SERVICE

RE: Pennsylvania Public Utility Commission et al. v. Pennsylvania Power & Light Company, Docket No. R-00943271 et. seq.

I hereby certify that I have this day served a true copy of the documents identified in cover letter upon the parties of record and in the manner indicated below which satisfies the requirements of §1.54:

VIA FACSIMILE AND FIRST CLASS MAIL
Paul E. Russell, Esquire
Pennsylvania Power & Light Company
Two North Ninth Street
Allentown, PA 18101

VIA FIRST CLASS MAIL

Thomas P. Gaddsden, Esquire
David B. MacGregor, Esquire
Morgan, Lewis & Bockius
2000 One Logan Street
Philadelphia, PA 19103

David A. McCormick, Esquire
Regulatory Law Office
Office of the Judge Advocate General
Department of the Army, DAJA-RL 3848
901 N Stuart Street, Room 713
Arlington, VA 22203-1837

Karen Oill Moury, Esquire
Office of Small Business Advocate
Suite 1102 Commerce Building
300 North 2nd Street
Harrisburg, PA 17101

James P. Melia, Esquire
Daniel P. Delaney, Esquire
Kirkpatrick & Lockhart
240 North 3rd Street
Harrisburg, PA 17101-1507

Stephen J. Selden, Esquire
Assistant General Counsel
Bethlehem Steel Corp.
8th & Eaton Avenues
Bethlehem, PA 18016

Joan O. Brandeis, Esquire
Schnader, Harrison, Segal & Lewis
1600 Market Street
Philadelphia, PA 19103

Eugene M. Brady, Executive Director
Commission on Economic Opportunity
211 South Main Street
Wilkes-Barre, PA 18701-1596

David M. Kleppinger, Esquire
McNees, Wallace & Nurick
100 Pine Street
P. O. Box 1166
Harrisburg, PA 17108-1166

Johnnie E. Simms, Esquire
Kenneth L. Mickens, Esquire
Stephen Gorka, Esquire
Office of Trial Staff
Pennsylvania Public Utility Commission
P. O. Box 3265
Harrisburg, PA 17105-3265

Tanya J. McCloskey, Esquire
Office of Consumer Advocate
1425 Strawberry Square
Harrisburg, PA 17120

Eric J. Epstein
2308 Brandywine Drive
Harrisburg, PA 17110

Kenneth Zielonis, Esquire
Stevens & Lee
208 North 3rd Street, Suite 310
Harrisburg, PA 17101

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

Robert D. Knecht
Industrial Economics Incorporated
2067 Massachusetts Avenue
Cambridge, Massachusetts 02140

D. Jane Drennan, Esquire
Sarah E. Tomalty, Esquire
Drennan & Associates
1216 16th Street, N.W.
Washington, DC 20036

Stephen J. Baron, President
J. Kennedy and Associates, Inc.
Suite 475 35 Glenlake Parkway
Atlanta, GA 30328

Mr. Maurice Brubaker
Drazen-Brubaker & Associates, Inc.
7730 Forsyth Boulevard, Suite 200
St. Louis, MO 63105-0840

Tom S. Catlin
Exeter Associates
12510 Prosperity Drive
Suite 350
Silver Spring, MD 20901

METTE, EVANS & WOODSIDE

By: ______________________
3401 North Front Street
P. O. Box 5950
Harrisburg, PA 17110-0950
(717) 232-5000

DATED: ~~April 28~~ May 1, 1995

5. In his direct testimony, Mr. Anderson concludes that "PP&L's marketing of RTS was so aggressive that it not only shifted usage away from the daytime hours, it also shifted the time of system peak." Please provide any studies or data supporting this claim, including documentation and calculations that shows the contribution that RTS service had to the shift in the time of the Company's system peak.

RESPONSE:

PP&L's estimate of the RTS class contribution to test year system peak is 258 MW (OTS-RS-9D). Peak demand per RTS customer is approximately six times the RS class average CP per customer. As indicated in Table 2 (Andersen direct testimony, page 15), the difference between the 1993 morning peak and the 1994 evening peak (274 MW) is not appreciably different from PP&L's estimate of the RTS class contribution to system peak. Adjustment of the 1993 peak for customer growth would further narrow the difference between morning and evening peaks. Therefore it is reasonable to conclude that the promotion of RTS service accounts for a large part if not all of the shift of PP&L's peak demand from the morning to the evening hours.

6. Please provide any evidence that the Company has planned to continue the promotion of the RTS service beyond 1995.

RESPONSE:

As long as Rate Schedule RTS exists it is logical to assume that it will be promoted. The fact that PP&L proposes to continue to offer RTS service to new customers at rates that only recover approximately 50 percent of the cost of providing RTS service constitutes continued promotion of the service. PP&L's tariff requires PP&L to offer the most favorable rate to a customer. Rate Schedule RTS is the most favorable rate available as a result of the discount provided at a rate below the cost to provide the service.

Pennsylvania Power & Light Company
Docket No. R-00943271
Witness: S. Andersen

7. In his direct testimony, Mr. Anderson concludes that "the RTS peaking problem" could not be solved by additional load management initiatives. This conclusion is supported by reference to an 8 year-old planning study. What analysis has CEPFOD or Mr. Anderson conducted to determine the benefit of load management initiatives in light of today's costs and availability of these alternatives?

RESPONSE:

The studies referenced at page 17, line 6 of Dr. Andersen's testimony were prepared by PP&L in 1987 and 1991. No additional analyses have been prepared by or reviewed by Dr. Andersen as of the date of this response.

11. Please provide any studies conducted or possessed by CEPFOD that compares the cost benefit of an investment in RTS service with the value of deferred generating capacity on the Company's system.

RESPONSE:

No such studies have been prepared by CEPFOD or by Dr. Andersen. Dr. Andersen has reviewed no information to support a conclusion that RTS has permitted PP&L to defer the addition of generating capacity, or that RTS service will result in future deferral of capacity additions. Instead, experience to date demonstrates that RTS will result in an accelerated addition of generating capacity. See response to Interrogatories 5 and 22.

18. With regards to Mr. Anderson's testimony at page 8, (a) please explain the derivation of the $0.02 per kwh for the heating service under the RTS rate, and provide all work papers. (b) Please demonstrate by example the statement that the incremental charges for heating service on RTS is not sufficient to recover off-peak fuel expense. Provide all work papers to substantiate this calculation.

RESPONSE:

Please refer to Attachment SA-18 (COSA.Wk4, Tab 12CP, Cells A24-T52). As indicated in this attachment, energy usage for RTS customers is 2.44 times average usage for non-space heating RS customers during months that lie outside the space heating season. Applying this ratio to the space heating months, normalized annual usage per RTS customer is estimated to be 17,861 kWh. When priced at the rate for RS service, the annual cost of 17,861 kWh is $1,240. Average annual revenue per RTS customer is $1,408. Dividing incremental revenue ($1,408 - $1,240 = $168) by incremental kWh (26,482 - 17,861 = 8,621) yields incremental revenue per kWh equal to $.01947. According to PP&L's response to CEPFOD 7, 1995 incremental fuel costs during the winter months are as follows:

Off peak	$.0243 per kWh
On peak	$.0290 per kWh.

Pennsylvania Power & Light Company
Docket No. R-00943271
Witness: S. Andersen

19. Please provide a calculation showing that the typical RTS customer is recovering their added investment within 5 years as stated in your testimony.

RESPONSE:

According to PP&L's response to CEPFOD 53, the RTS rate is structured to produce an annual saving for the customer equal to $500. This is reasonably consistent with the actual savings of $568 indicated in PP&L's response to CEPFOD 42. Dividing an RTS customer's incremental cost of $2,655 (CEPFOD 42) by annual savings of $568 implies a 4.67 year payback.

20. Mr. Anderson states in his testimony that CEPFOD members can only regain lost customers if RTS subsidies are eliminated. If this elimination is solely for the purpose of providing business for the CEPFOD members, please explain why PP&L shareholder should accept the cost of elimination of the rate and not the CEPFOD members?

RESPONSE:

The elimination of the rate subsidy is not to provide business for CEPFOD members. Instead, the purpose is to recommend just and reasonable rates that eliminate an unfair subsidization for a rate schedule directed to attracting heating customers away from fossil fuels. As discussed at page 5, lines 4-13 and page 22, lines 9-23 of Dr. Andersen's testimony, the primary purpose of his recommendation that the RTS shortfall either be recovered through an increase in the rate for RTS service (with PP&L providing appropriate compensation to customers for their investment in RTS qualified heating equipment) or subtracted from total revenue requirement is to prevent the shifting of this subsidy to other rate classes.

Pennsylvania Power & Light Company
Docket No. R-00943271
Witness: S. Andersen

22. Mr. Anderson states at page 8 of his testimony that an RTS home uses 2.6 times as much energy as an average RS customer. Please provide all studies or other support for this statement, including a breakdown of all energy use on which you based your statement, including fuel used for space heating and water heating regardless of fuel source. Please respond in MBTU per year.

RESPONSE:

<u>See</u> attachment to CEPFOD's response to interrogatory 18 for the data used to calculate the 2.6 ratio and the 2.4 ratio discussed at page 8 of Dr. Andersen's testimony. The term "energy" refers to kWh. Because PP&L does not have information regarding RS or RTS end-use of electricity, no analysis of end-use is possible.

Pennsylvania Power & Light Company
Docket No. R-00943271
Witness: S. Andersen

23. Please provide support (studies and market research) for Mr. Anderson's statement that RTS customers are turning up their thermostats in response to the availability of "cheap" energy.

RESPONSE:

No such studies have been prepared, nor are any required. This statement is based on the proposition that the demand for electricity is not perfectly inelastic with respect to price, and the assumption that income effects are normal.

Pennsylvania Power & Light Company
Docket No. R-00943271
Witness: S. Andersen

24. On page 3 lines 27 to 29, Mr. Anderson states that PP&L offers a discount to other electric space heating customers. Please provide a copy of the analysis and any other documents supporting this conclusion.

RESPONSE:

The referenced statement is based on the two block structure of PP&L's current RS rate, and the fact that a larger portion of usage by space heating customers is priced at the tail block rate.

25. Throughout Mr. Anderson's testimony, he states that RTS does not recover the cost of providing the service. Please provide a copy of the analysis supporting that conclusion.

RESPONSE:

Please refer to page 113 of Mr. Kleha's class cost of service study, Andersen Schedule A, and page 38, lines 9 through 28 of Dr. Andersen's direct testimony. In addition, all other cost of service studies presented in this proceeding as evidence show Rate Schedule RTS at a negative rate of return under present and proposed rates.

Pennsylvania Power & Light Company
Docket No. R-00943271
Witness: S. Andersen

26. In Mr. Anderson's view, what points would a heating customer consider in choosing a heating system and fuel source?

RESPONSE:

Dr. Andersen's expertise as an economist would have the choice be based on total overall cost to customer, including:

a. installation expense;
b. operating expense;
c. maintenance expense;
d. risk expense;

These expenses would be evaluated by the consumer under a rational economic choice over different time periods. Dr. Andersen is not able to offer an opinion on the other factors that may influence a customer's decision other than the rational economic considerations identified above.

A decision regarding heating system alternatives is frequently inseparable from the decision to purchase a residence. When heating systems and housing are purchased as a package through the purchase of an existing house, then the positive and negative attributes of a particular heating system are subject to offset by positive and negative attributes of a particular house that are unrelated to space heating.

Pennsylvania Power & Light Company
Docket No. R-00943271
Witness: S. Andersen

27. Please provide a copy of the analysis supporting Mr. Anderson's conclusion that the GS-1 class would subsidize the RTS class.

RESPONSE:

Please refer to pages 113 and 114 of Mr. Kleha's class cost of service study. According to this analysis, GS-1 is the only class for which a significant surplus would exist if the rates proposed by PP&L were to be adopted.

28. Please provide any and all analysis that proves Mr. Anderson's recommended RTS rate design eliminates price distortion.

RESPONSE:

Elimination of the RTS subsidy and a lump sum monthly payment to RTS customers would eliminate distortions directly associated with RTS pricing. However price signals may remain distorted if RTS customers migrate to a different rate that is not cost based. Dr. Andersen has not analyzed the extent to which the structure of the RTD rate is cost based. If the RTS rate is not eliminated, price distortion will remain as long as the rate fails to recover costs. However, the magnitude and impact of this distortion can be minimized by recovering any increase in RTS revenues through higher demand and energy charges.

29. Why does Mr. Anderson recommend recovering the remainder of the increase in RTS revenues through an increase in the energy charge? Please explain the answer in detail and provide all studies or analyses underlying this recommendation.

RESPONSE:

If RTS rates fail to recover costs, it makes sense to apply any increase to the demand and energy components of the rate because these are the components to which usage is sensitive.

30. Please provide the study which supports Mr. Anderson's contention at page 41 that PP&L's exposure to uncollectible expenses, depends on the size of the customer's bill.

RESPONSE:

Holding credit worthiness constant, PP&L's exposure to uncollectible expense depends on the size of a customer's bill, which depends primarily on usage.

Pennsylvania Power & Light Company
Docket No. R-00943271
Witness: S. Andersen

31. If PP&L transfers customers from RTS to RS or RTD, how should the $50/month guarantee be treated in PP&L's rate case?

RESPONSE:

Please refer to page 4, lines 17 through 19 of Dr. Andersen's testimony. The result is a transfer from PP&L's other sources of income that have been subsidizing Rate Schedule RTS' losses since its inception.

Pennsylvania Power & Light Company
Docket No. R-00943271
Witness: S. Andersen

32. Regarding Mr. Anderson's testimony at page 41, please provide all analysis which demonstrates customer costs of $8.00 when uncollectibles and customer assistance expenses have been excluded.

RESPONSE:

Please refer to Attachment SA-32 (COSA.Wk4, Tab: CCHG, Cells A1-G29). Based on PP&L's response to OTS-RS-4D, Dr. Andersen estimated RS customer costs as follows:

Out of pocket	$4.71 per customer per month
Total	$7.68 per customer per month.

Adjustment for the unreconciled $4,322,000 expense difference shown in SA-32 adds $.34 per customer per month to these estimates.

Pennsylvania Power & Light Company
Docket No. R-00943271
Witness: S. Andersen

33. Regarding Mr. Anderson's testimony at page 42-43, please explain in detail whether Mr. Anderson contends that a customer charge of $7.20/month rations access to the utility system, and, if so, how that charge rations capacity?

RESPONSE:

Please refer to page 43, lines 1 through 4 of Dr. Andersen's testimony. Because residential customers have no practical alternative to taking electric service from PP&L, it is meaningless to view the RS customer charge as a rationing mechanism.

Pennsylvania Power & Light Company
Docket No. R-00943271
Witness: S. Andersen

34. Please explain in detail how Mr. Anderson's proposed $1/month increase in customer charges would recover out-of-pocket customer costs when he states that they exceed $8.00/month?

RESPONSE:

As indicated in CEPFOD's response to interrogatory 32, out-of-pocket customer costs for the RS class are approximately $5.00 per customer per month. An RS customer charge of $5.20 per month would therefore recover these costs.

Pennsylvania Power & Light Company
Docket No. R-00943271
Witness: S. Andersen

35. Please explain in detail how placing customer costs into energy blocks add to pricing efficiency?

RESPONSE:

Because meter and service drop costs vary with usage, a portion of total "customer" costs varies with usage and should be recovered through the energy rather than the customer charge. If spread over all RS energy usage, recovery of the difference between a customer charge of $5.20 per month and total customer costs of $8.00 per month would increase the RS energy charge by approximately $.00329. The extent to which this would represent price distortion would depend on the overall relationship between RS revenues and costs, and the extent to which the $8.00 total actually varies with usage. It should also be noted that the initial RS block recovers $3.88 per customer per month. This is more than sufficient to recover the $2.80 customer charge revenue "shortfall".

	RS	RTS
Cust	1,604,650	14,946

	CP Per Customer (OBD-88-84-B)			MWh Per Customer (DCA 97-40) RS	RTS		RS	RTS	Mean RTS	Delta	RS Ex Heating (OBD-88-4ID) Cust	MWh	kWh/Cust	RTS Ratio	Mean RTS	Delta
10	1.28	1.28	0.50	605	1,386	2.34	606,000	24,500	1,386	0	732,700	388,457	534	2.43	1,296	0
11	1.65	8.97	0.10	780	1,669	2.48	797,607	28,062	1,568	422	730,641	405,177	552	1.87	1,346	424
12	2.40	16.46	6.34	1,050	2,750	2.71	1,067,348	48,289	2,461	640	730,048	481,361	651	4.22	1,306	1,346
1	2.95	17.72	6.61	1,374	3,636	2.80	1,380,697	52,484	2,497	588	730,758	501,588	700	4.80	1,486	1,882
2	2.85	3.76	1.40	1,348	3,428	3.16	1,386,486	52,782	2,376	1,282	732,380	488,680	675	3.87	1,440	1,878
3	2.85	18.48	8.50	1,360	3,360	3.35	1,338,886	61,488	2,370	1,367	730,688	487,585	635	3.46	1,385	2,086
4	1.67	2.61	1.87	966	2,465	2.55	983,886	38,088	1,792	698	731,082	480,376	688	4.19	1,488	1,088
5	1.61	1.80	1.30	787	1,488	2.80	780,045	21,379	1,488	0	731,886	387,587	527	2.87	1,483	0
6	1.67	2.47	1.40	486	1,388	2.30	670,520	16,487	1,386	0	730,884	380,720	586	2.30	1,308	0
7	2.46	8.80	2.85	780	1,681	2.18	786,896	21,480	1,494	0	731,400	460,940	641	2.20	1,494	0
8	1.56	2.80	1.40	789	1,386	1.87	786,004	20,380	1,386	0	730,888	481,884	630	2.21	1,386	0
9	0.90	1.80	1.21	694	1,480	2.08	780,481	18,285	1,488	0	732,040	480,040	487	2.30	1,480	0
ISCP	1.89	4.67	3.50	10,720	26,482	2.50	10,554,326	553,260	25,482	5,345	732,787	5,361,380	7,320	2.46	17,061	6,620
ISCP Load Factor				30.86%	57.00%											
II CP Load Factor				81.40%	65.98%											
										58						
										250						
				4,300	8,904	2.07				1,588						
										1,788						

C. Chg	58	
Heat Stack	177	
Return	988	
Total	1,280	
Actual	1,480	10,776,000
Difference	200	0.01967

Attachment SA-18

	O&M			Adjusted			
	Customer Related	Customer Related	Total	Per PPL	Andersen		
			5,818				
Ovhd	9,334	9,334	21,432				
Under	1,622	1,622	2,535				
Tlx	2,015	2,015	3,222				
Svcs	3,482	3,482	3,724	3,482	3,482		
Meters	3,367	3,367	5,018	3,867	3,367		
Misc	3,822	3,822	7,189	3,822	1,143	2,679	Prorata
Cust Inst	3,078	3,078	3,078	3,078	3,078		
MtrRd	7,969			7,965	7,963		
			51,714				
Uncoll	$\boxed{13,795}$			13,795		13,795	
Other	22,301			22,301	22,301		
CSvc	$\boxed{15,693}$			15,696		15,693	
Sales	$\boxed{2,000}$			2,000			
Direct	88,375			75,404	41,234		
Adjusted	58,887			45,916	41,234		
A&G	27,241			21,241	19,075		
Total O&M	115,618	26,720		96,545	60,309	29,488	
PPL (OTS RS 4D)	115,266			92,865			
Kiehl (p. 69)		26,871					
Difference	968	1,651		$\boxed{4,222}$			
Per customer per month				$\boxed{0.94}$			
Customers					1,066,698		
					4.71	2.80	
Monthly O&M per customer							
Total (OTS RS 4D)				130,344			
Other (Return, etc.)				36,021	2.97		
					7.66	9.99	

Attachment SA-32

EXHIBIT OGK 8

Single RTS Customer Comparison (Example)

Rebuttal Testimony of Oliver G. Kasper
Docket No. R-00943271

SINGLE RTS CUSTOMER COMPARISON
(EXAMPLE)

	Monthly at Present	Monthly at Proposed
2000 KWH/month Rate Schedule RS	153.03	168.79
2000 KWH/month at 6 KW Demand RTS	109.35	128.08
RTS Saving	43.68	40.71
RTS Annual Savings over RS	**$524.16**	**$488.52** */

---

*/ **If the RTS customer were to plug in a space heater for 5 hours a day to supplement the storage system, boosting demand to 8 KW and usage to 2300 KWH, the incremental cost of that power would be 7.32 cts. per KWH.**

EXHIBIT OGK 9

Rate Schedule RTS-Letters And Supporting Documents

Rebuttal Testimony of Oliver G. Kasper
Docket No. R-00943271

PP&L Pennsylvania Power & Light Company

Two North Ninth Street • Allentown, PA 18101-1179 • 610/774-5151

March 27, 1995

Dear Customer:

You have probably heard that PP&L has proposed to raise base electric rates for the first time in 10 years. I would like to take this opportunity to provide you with some background on the reasons for requesting this increase and to show how it might affect you.

On December 30, 1994, PP&L filed a request for an electric rate increase with the Pennsylvania Public Utility Commission (PUC). The decision to request this increase was a difficult one, but after 10 years of rising costs, it was a decision PP&L could no longer avoid. Any increase granted would take effect in October.

Over the past decade we have worked hard to keep electricity prices stable. During this 10-year period, electricity bills have lagged far behind the rate of inflation. The cost of living, as measured by the Consumer Price Index, has increased 30% in this period. We have taken many steps to avoid rate increases including refinancing high-cost securities, staff reductions, early retirements and other aggressive cost-cutting measures. However, this has not been enough to completely offset the increasing cost of providing you with high quality electric service.

We would like to assure you that, in filing this request, we have made every effort to allocate costs fairly to all classes of customers. We carefully considered the rates charged to our various classes of customers and made every effort to make sure those rates matched our cost of serving those customers.

We would also like you to know that we have stepped up our efforts to help customers on fixed incomes and those who are having a hard time paying their bills.

Regarding the Residential Thermal Storage (RTS) rate which affects you, we are proposing changes to the three main components as follows:

COMPONENT	CURRENT	PROPOSED
Monthly Charge	$10.95	$15.00
Billing Demand (In Excess of 2 KW On-Peak)	$ 5.80 per KW	$ 6.50 per KW
Cost Per Kilowatt-Hour	$ .0284 per KWH	$ .045 per KWH

The effect of these proposed changes on your electric bill will depend on your monthly kilowatt-hour (KWH) use and on-peak billing demand. For example, an RTS customer with a 6 kilowatt (KW) monthly billing demand who uses 25,000 KWH a year could expect their electric bill to increase about $20.00 a month or 16%.

You and other Residential Thermal Storage customers are important to PP&L and we appreciate your business. If you have any questions concerning this rate increase, please call us toll-free at 1-800-DIAL-PPL (1-800-342-5775).

Sincerely,

Gerald S. Farber

Manager-Sales & Account Management

Please send to main file & make copies.

RECEIVED

APR 13 1995

OFFICE OF ... PUBLIC UTILITY ...

April 11, 1995

Robert A. Christianson
Law Judge, Public Utility Commission
Box 3265
Harrisburg PA 17105-3265

RE:PP&L RATE INCREASE

I have read in the newspaper and received a letter from PP&L regarding a proposed rate increase to be effective 10/95. I'm sorry that I was unable to attend the P.U.C. meeting held in Williamsport.

Using and speaking in terms of averages PP&L has said this was a 15-20% increase for the average user with costs increasing for low demand user and having moderate increases for the higher demand residential user. <u>This rhetoric is far removed from reality and how this rate increase will effect my electric bill.</u>

My home, built in 1986, is a total electric home utilizing a heat storage system with a monitor that allows the heating of the storage units only at off-peak times. Off-peak is defined as between 5:00 P.M. and 7:00 A.M. Off-peak demand heating systems were promoted by utilities because it helped with their supply demand curve, it will help eliminate the need for additional generating facilities.

<u>According to the letter received from PP&L regarding my type of electric usage, my electric charges will increase 56% per kilowatt used. 56% is quite different from the 20% being advertised.</u>

I find it amazing that it costs 56% more to produce electricity now during off-peak times. I feel the rate is excessive for the Residential Time of Day Heat Storage customers. For many, they will have to make income allocation choices between food and paying the electric bill.

I strongly oppose a Carte-Blanche approval of this rate increase. It is being touted as minor but the rate increase is major.

MA Sennett

Michael A Sennett
1675 Oakridge Place
Williamsport PA 17701

Administrative Law Judge
Public Utilities Commission
Room G-06
North Office Building
P.O.Box 3265
Harrisburg, PA 17105-3265

Att: Judy Weaver

April 12, 1995

Dear Sir:

I am writing to you concerning the recently disclosed rate increase filed by Pennsylvania Power and Light Company for customers on the Residential Thermal Storage (RTS) Rate.

Unfortunately, the first that I became aware of this proposed rate increase was from the enclosure in my most recent monthly bill from PP&L. I apparently missed previous public notices and was not aware of the public hearings that were held in Lancaster until after they occurred. Therefore, I am submitting to you this written commentary on the proposed increase in the RTS rate schedule.

When we built a new home in 1991, we gave very careful consideration to the type of heating system that should be installed. We were particularly concerned about the economy and continued supply of the fuel source for our heating system. When a PP&L salesperson explained the concept of the Thermal Storage System, with the ability to store hot water that was heated during off-peak periods and then used to heat the house during peak periods without the use of any fuel during the peak period, we were easily convinced of the economic efficiency of such a program. The appeal of this system was the special rate that PP&L applied to all electric power consumption for homes using an RTS heat storage system.

RECEIVED

APR 14 1995

OFFICE OF ... PUBLIC UTIL...

Having witnessed the way that PP&L had previously enticed homeowners to install electric resistance heating (baseboard and ceiling) with a special low "whole house" electric rate, and then later more than doubled that rate (and the heating costs for many customers), I was especially skeptical of PP&L's commitment to maintain the special rate advantage of the thermal storage system. Since the added cost of the thermal storage system was more than $4,000 for our new home, I was very much concerned that the RTS rate would be retained long enough to pay back the investment cost and to compensate us for the inconvenience of limiting our use of electricity during the peak period.

I was personally assured by PP&L sales representatives (on several occasions) that PP&L was committed to this rate schedule. As evidence of that commitment, the sales representatives pointed out the RTS Contract, under which PP&L was obligated to pay $50.00 per month to the homeowner if they withdrew the rate within 10 years of the installation. I have enclosed a copy of the contract for your review.

The sales representatives offered this provision of the contract as proof that the heat savings projected by PP&L was guaranteed for the next ten years. It is this guarantee of no rate increases during the next ten years that convinced me to pay the additional costs to install the thermal storage system in my new home.

The notice of the rate increase that PP&L has enclosed in my monthly service bill indicates that the increased cost resulting from this proposed RTS rate increase will be "about $20.00 a month or 16%." My application of the new rates to my 1994 actual electric consumption shows that the proposed rate increase will result in a monthly increase in costs of $51.73 or 39%. This is not a minor rate increase by anyone's evaluation! I have enclosed a copy of the PP&L notice for your review.

I additionally note that PP&L's notice claims that the RTS rate has not changed during the past ten years, while PP&L's costs have increased. This would not seem to be the case, since the rates that I have been billed since early 1991 have always been higher than the rates quoted in PP&L's projection of our electric costs. I have enclosed a copy of the RTS rate schedule that was supplied to me prior to installing the thermal storage system, which you will notice indicates lower rates than those listed in the PP&L notice.

Additionally, PP&L claims that they have absorbed cost increases during the past ten years is a bit of a fantasy when you recognize that they have been permitted to pass onto their consumers all of their fuel costs and increased taxes. There have been months that the "energy charge" has been nearly one-half of the Cost Per Kilowatt-Hour rate, and during nearly every month since we began this service the add-on fees have caused a 25% increase in my bill. It certainly appears to me that PP&L has been able to pass at least some of its increased costs onto its consumers!

The proposed increase in PP&L's RTS Rate Schedule provides a $4.05 (37%) increase in the Monthly Charge; a $.70 (12%) increase in the Billing Demand; and a $.0166 (58%) increase in the Cost Per Kilowatt-Hour. For my electric power consumption, this amounts to a 39% increase in the cost of electric service.

This is an outright violation of the contract that I hold from PP&L, and is a total violation of the trust that I put in the information and promises made by several PP&L sales representatives as an inducement to have me invest in the thermal storage heating system. To allow the requested rate increase to PP&L would be an endorsement of PP&L's fraudulent business practice, and would be a violation of the trust that the public has given to the Public Utilities Commission and its professional staff.

I urge you to reject the pending request from Pennsylvania Power and Light Company for an increase in their RTS Rate Schedule.

Sincerely,

Robert G. Walton
1034 Hunters Path
Lancaster, PA 17601

cc: Mr. William F. Hecht
President
Pennsylvania Power and Light Company
2 North 9th Street
Allentown, PA 18101

PENNSYLVANIA POWER & LIGHT COMPANY

RATE SCHEDULE RTS
RESIDENTIAL SERVICE - THERMAL STORAGE

APPLICATION OF RATE SCHEDULE RTS

This rate schedule is for single phase residential service with load management capabilities in accordance with the APPLICATION PROVISIONS hereof.

NET MONTHLY RATE (Effective 1-1-89)

$10.71 per month plus

5.69 per kilowatt of on-peak billing KW in excess of 2 KW.
2.78 cts. per KWH for all KWH use.

The Energy Cost Rate applies to all KWH supplied under this rate.

The Net Monthly Rate Minimum is $10.71.

BILLING KW

The billing demand is the average kilowatts supplied during the 15 minute period of maximum use during the on-peak hours of the current billing period.

ON-PEAK HOURS

On-peak hours for billing purposes are 7 AM to 5 PM, 8 AM to 6 PM or 9 AM to 7 PM local time at the option of the customer, Mondays to Fridays inclusive except New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

LEVELIZED BUDGET BILLING

Levelized Budget Billing is available at the option of the customer.

STATE TAX ADJUSTMENT SURCHARGE (C)

The State Tax Adjustment Surcharge included in this Tariff is applied to charges under this rate except for charges made under the Energy Cost Rate.

PAYMENT

The above net rate applies when bills are paid on or before the due date specified on the bill, which is not less than 20 days from the date bill is mailed. After the due date, the Company may initiate collection procedures and a late payment charge of 1.25% per month on the then unpaid and overdue balance is applicable.

CONTRACT PERIOD

Not less than one year. In the event this rate is withdrawn from the Tariff within 10 years of the date of its application to a specific location, the Company will pay $50.00 to the ratepayer [illegible] each month after such withdrawal for the remainder of the 10 year period.

APPLICATION PROVISIONS

1. This rate schedule is applicable to service which would otherwise qualify under Rate Schedule RS except for the following:

(a) Service to two or more separate dwelling units supplied through a single meter.

(b) Seasonal service and seasonal use customers.

(c) Service with separate meter controlled water heater service.

(d) Residential service with general farm use which includes more than 2,000 watts of connected general farm load.

2. Any changes in service entrance equipment to accommodate metering under this rate are made by the customer at his own expense.

(C) Indicates Change

(Continued)

Gerald S. Farber

Manager

Sales & Account Management

FP&L

Dear Sir;

We are in receipt of your circular letter of March 27, 1985. In this letter you state that: "For example, an RTS customer with a 6 kilowatt (KW) monthly billing demand who uses 25,000 KWH a year could expect their electric bill to increase about $20.00 or 16%."

We suggest to look over the following calculation:

	Current	Per year	
Monthly charge	10.95x12	131.40	
Billing Demand	5.80x6x12	417.60	
RTS charge	25,000x0.0284	710.00	
		$ 1,259.00	

Current monthly charge $ 104.92

	Proposed		
Monthly charge	15x12	180.00	(37% increase)
Billing Demand	6.50x6x12	468.00	(12% increase)
RTS charge	25,000x0.045	1,125.00	(58% increase!)
		$ 1,773.00	

Proposed monthly charge $ 147.75.

From the above it follows that your proposed monthly increase for this customer is

about $ 43.00 or 41%

outpacing both the increase of the Consumer Price Index (30%) and the inflation over the past 10 years. Your proposed increase of the RTS rate is 58%!!!

Will you please enlighten us about the significant discrepancy between your statement and these figures.

Sincerely,

Zoltan P. Czukrasz

March 29, 1955

Zoltan Czukrasz

787 Vose Ave., Apt. C-5

Orange, N.J. 07050

Customer # 233 1686 400

PP&L Pennsylvania Power & Light Company

Two North Ninth Street • Allentown, PA 18101-1179 • 610/774-5151

April 20, 1995

Zoltan Czukrasz
787 Vose Ave., Apt. C-5
Orange, New Jersey 07050

Dear Mr. Czukrasz:

I am writing in response to your concerns about the proposed changes to the Residential Thermal Storage (RTS) rate that were explained in my letter dated March 27, 1995. That letter detailed the changes proposed for the monthly charge, the billing demand charge and the kilowatt-hour charge for the RTS rate as part of PP&L's pending rate increase request.

The information provided to you about the proposed base rate changes was correct, but, by itself, was not sufficient to accurately calculate your bill. If the rate were to go into effect as proposed, the increase for most RTS customers would be about 16 percent. If you used only what was in the letter to estimate your bill, you probably calculated a much higher increase.

To accurately estimate an electric bill, all of the separate charges on the bill must be applied in the proper manner. The letter you received included proposed base rate changes to the RTS rate, but it did not include information about the other components on the bill that we are asking to change at the same time the base rates are changed (Special Base Rate Adjustment, Surcharge for Pennsylvania Taxes and Energy Charge).

We received calls and letters from RTS customers who, like yourself, were concerned about the percentage increase they calculated using the information on base rate changes in the letter. To provide you with an accurate estimate of how the rate increase will affect your bill if it were approved as proposed, I am enclosing a complete analysis of one of your recent bills from a winter month using both existing rates and proposed rates.

If, after examining the analysis you have any further questions, please call 1-800-DIAL-PPL. I apologize for any confusion this may have caused.

Sincerely,

Gerald S. Farber
Manager-Sales & Account Management

Encl.

RESIDENTIAL THERMAL STORAGE (RTS) RATE CALCULATION
CURRENT* RATE COMPARED TO PROPOSED RATE

CUSTOMER-SPECIFIC
DATA REDACTED

CUSTOMER INFORMATION

Customer Number	233-1686-400
Customer Name	Zoltan Czukrasz
Monthly KWH Use	
Billing Demand (KW)	
Meter Reading Date	3/2/95
Days In Billing Period	30

RATE COMPONENTS	CURRENT*	PROPOSED
Customer Charge	$ 10.95	$ 15.00
Use Charge (Per KWH)	0.0284	0.0450
Billing Demand Charge (Per KW) Note: Your first 2 KW are free.	5.80	6.50
Special Base Rate Credit Adjustment (SBRCA)	-0.023000	-0.016600
Surcharge For PA Taxes	-0.002000	0.000000
Energy Cost Rate	0.010698	-0.000378

BILL COMPONENTS	CURRENT*	PROPOSED	EQUATION
Customer Charge	$ 10.95	$ 15.00	Customer Charge
Use Cost			Monthly KWH Use x Use Charge
Billing Demand Cost	5.80	6.50	Billing Demand in excess of 2 KW x Billing Demand Charge
Base Rate Cost			Customer Charge + Use Cost + Billing Demand Cost
SBRCA Amount			Base Rate Cost x SBRCA
Adjusted Base Rate Cost			Base Rate Cost + SBRCA Amount
Surcharge For PA Taxes Amount			Surcharge For PA Taxes x Adjusted Base Rate Cost
Energy Cost Rate Amount			Monthly KWH Use x Energy Cost Rate
Total Electric Bill	$	$	Adjusted Base Rate Cost + Surcharge For PA Taxes Amount + Energy Cost Rate Amount

ESTIMATED MONTHLY INCREASE : 16%

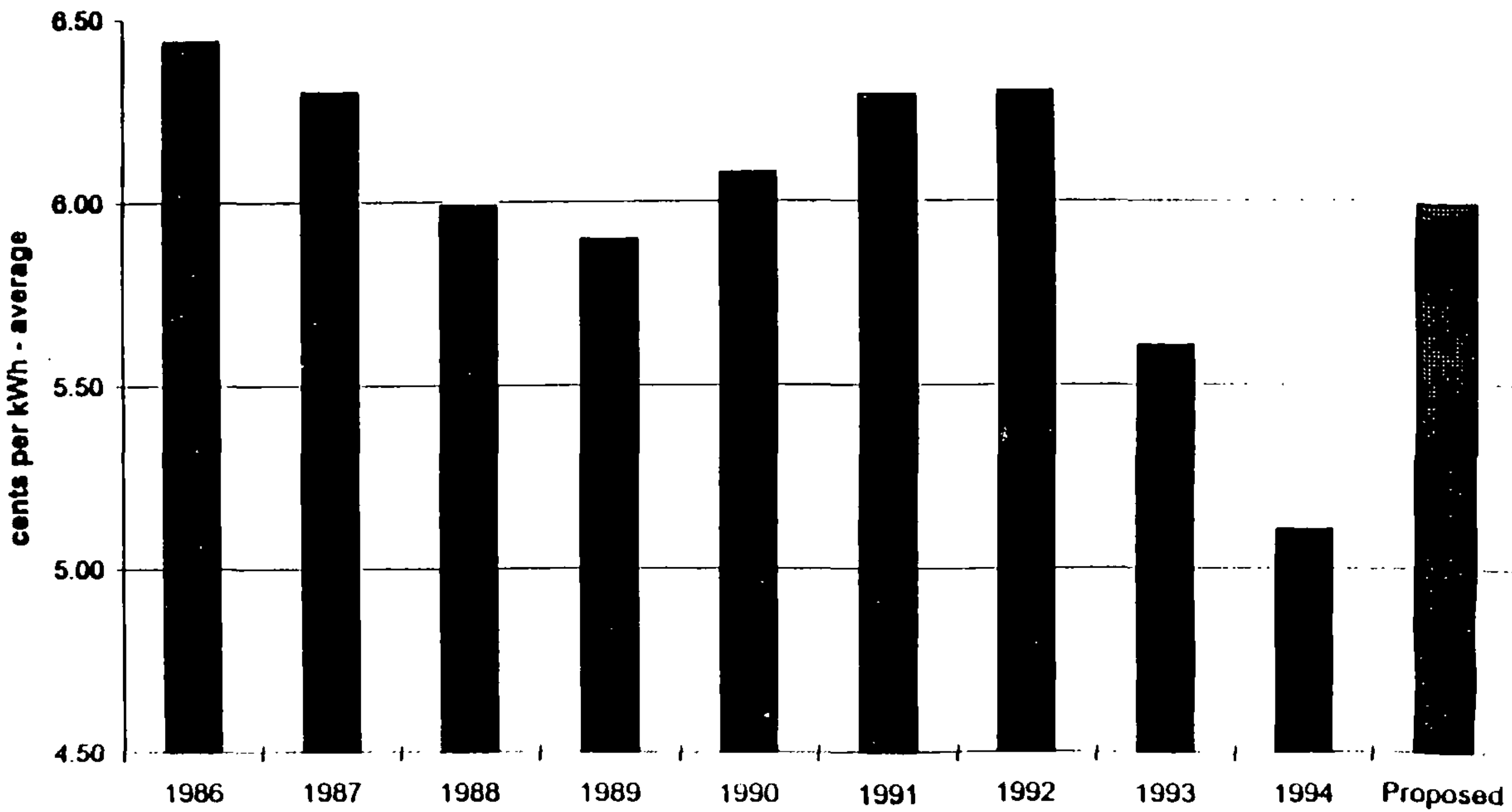
* The current rate components reflect the rates in effect on the meter reading date shown above in the Customer Information Section

EXHIBIT OGK 10

Interruptible Customers Historic And Proposed Average Cents Per KWH

Rebuttal Testimony of Oliver G. Kasper
Docket No. R-00943271

Rate Schedule LP-4 Optional Interruptible Power
Customer Average Cents per kWh



Rate Schedule LP-5 Optional Interruptible Power Customer Average Cents per kWh

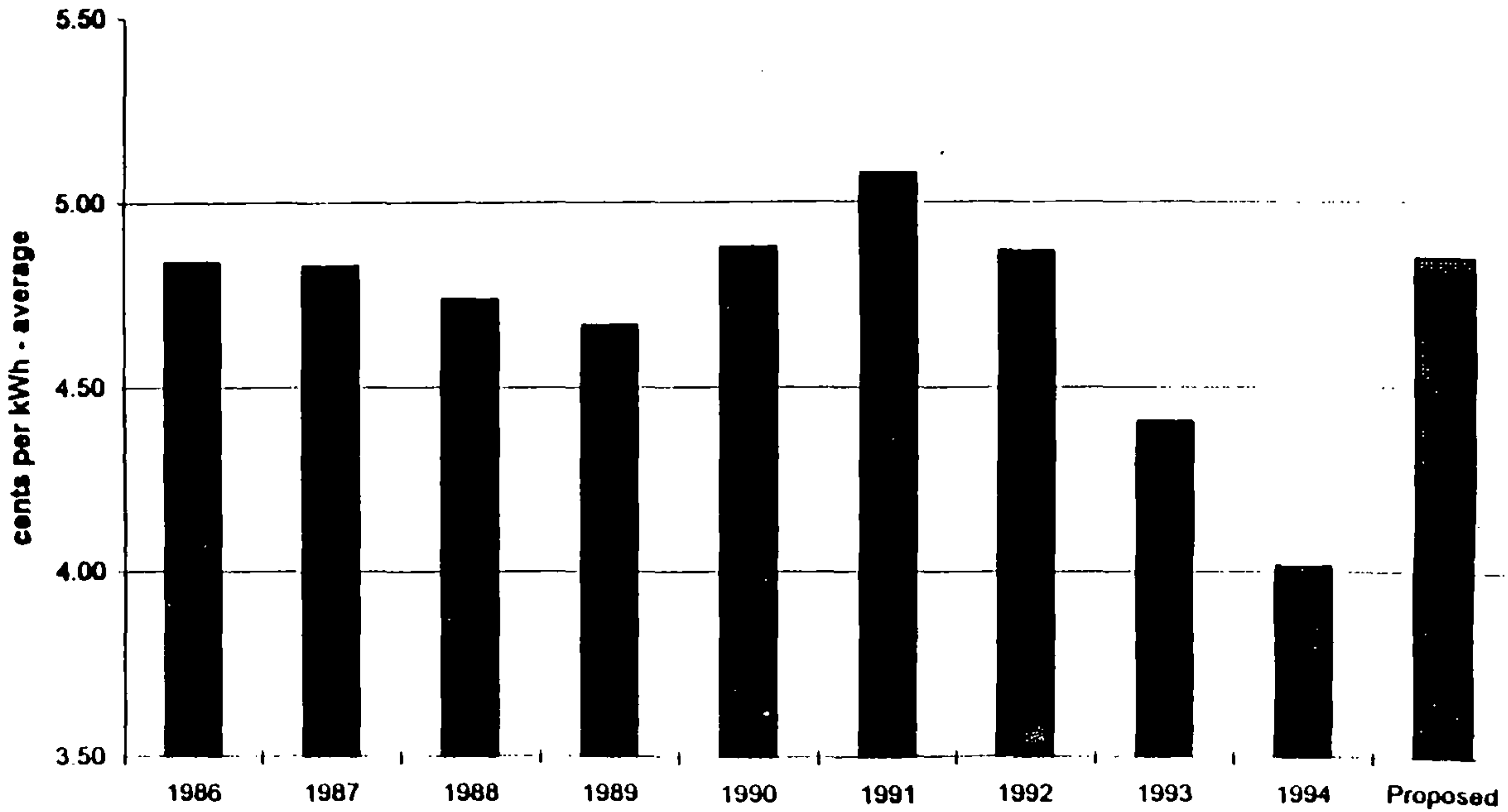


EXHIBIT OGK 11

Interruptible Bill Calculation
PP&L vs. PPLICA

Rebuttal Testimony of Oliver G. Kasper
Docket No. R-00943271

Bill Calculation Example

Hypothetical customer characteristics:

- Monthly KWH = 7,400,000
- Average On-peak Demand = 13,200 KW
- Firm Load = 100 KW
- On-peak Load Factor = 85%

PP&L Proposed Rates (ignores riders):

- LP6: 13,200 KW (6 \$/KW) = \$79,200

  $(13{,}200\ \text{KW})\ (400\ \frac{\text{KWH}}{\text{KW}})\ (.055\ \$/\text{KWH}) = \$290{,}400$

  2,120,000 KWH (.032 \$/KWH) = \$ 67,840

  Total Bill = \$437,440

- LP6 Interruptible:

  LP6 Firm = \$437,440
  Interruptible Credit = (13,200 - 100 KW) (.85) (6 \$/KW) = (66,810)

  LP6 Interruptible Bill = \$370,630

- Interruptible Credit:

  $$\frac{\$437{,}440 - \$370{,}630}{13{,}100\ \text{KW}} = 5.1\ \$/\text{KW}$$

PPLICA Proposed Rates (ignores riders):

- LP6: 13,200 KW (5.96 $/KW) = $78,672

  (13,200 KW) (400 KWH/KW) (.0546) = $288,288

  2,120,000 KWH (.0318) = $67,416

  Total Bill = $434,376

- Interruptible:

  BKW = 100 + .15 (13,100 KW) = 2,065 KW

  11.29 $/KW (2,065 KW) = $23,314

  2,065 KW $\left(\frac{\text{400 KWH}}{\text{KW}}\right)$ (.0541) = $44,687

  (6,574,000 KWH) (.0360) = $236,664

  Total = $304,665

- Interruptible Credit:

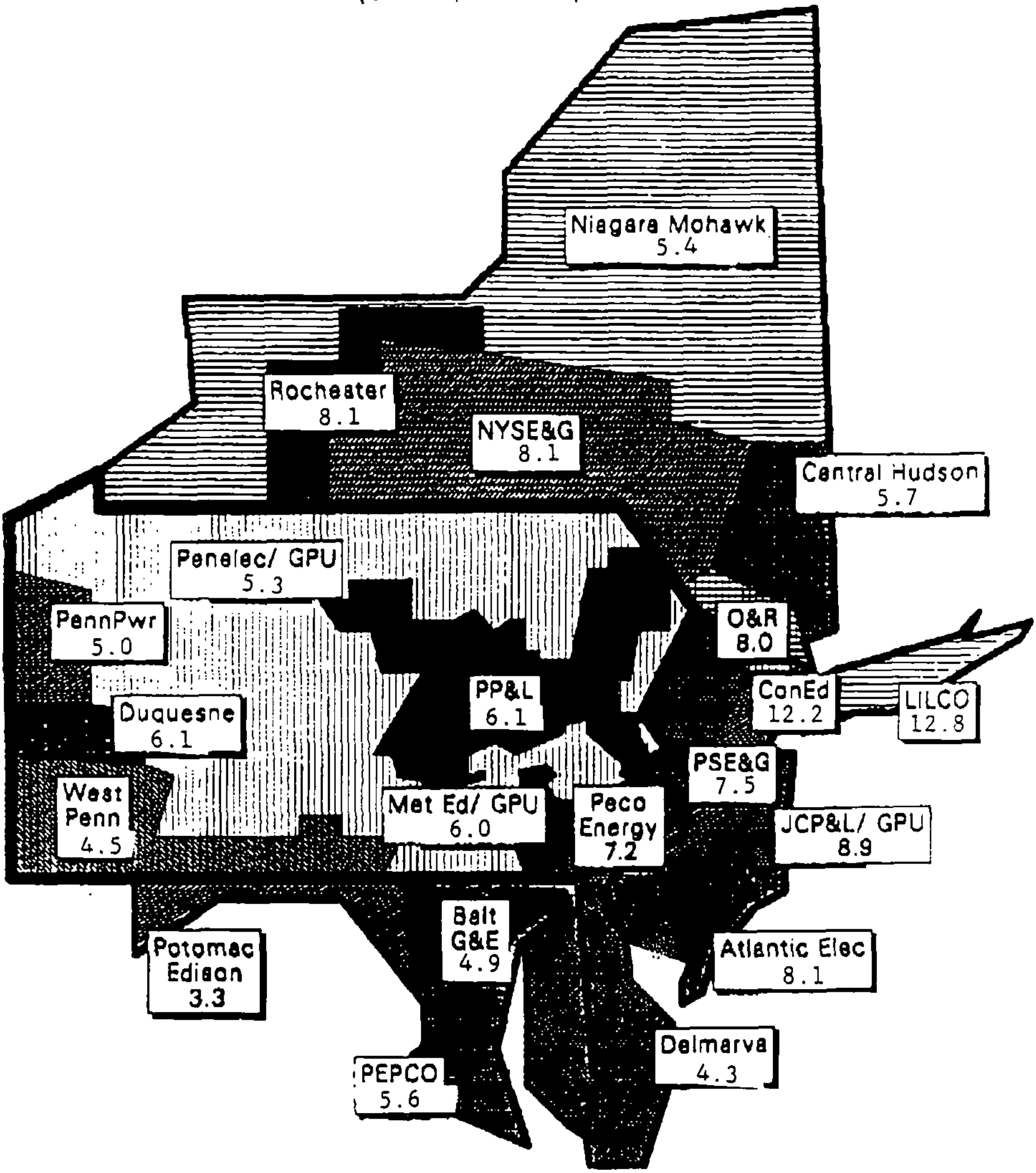
  $\frac{\$434{,}376 - \$304{,}665}{\text{13,100 KW}}$ = 9.9 $/KW

EXHIBIT OGK 12

Months Ended December 1994 Average Price
For Industrial Customers And Commercial Customers

Rebuttal Testimony of Oliver G. Kasper
Docket No. R-00943271

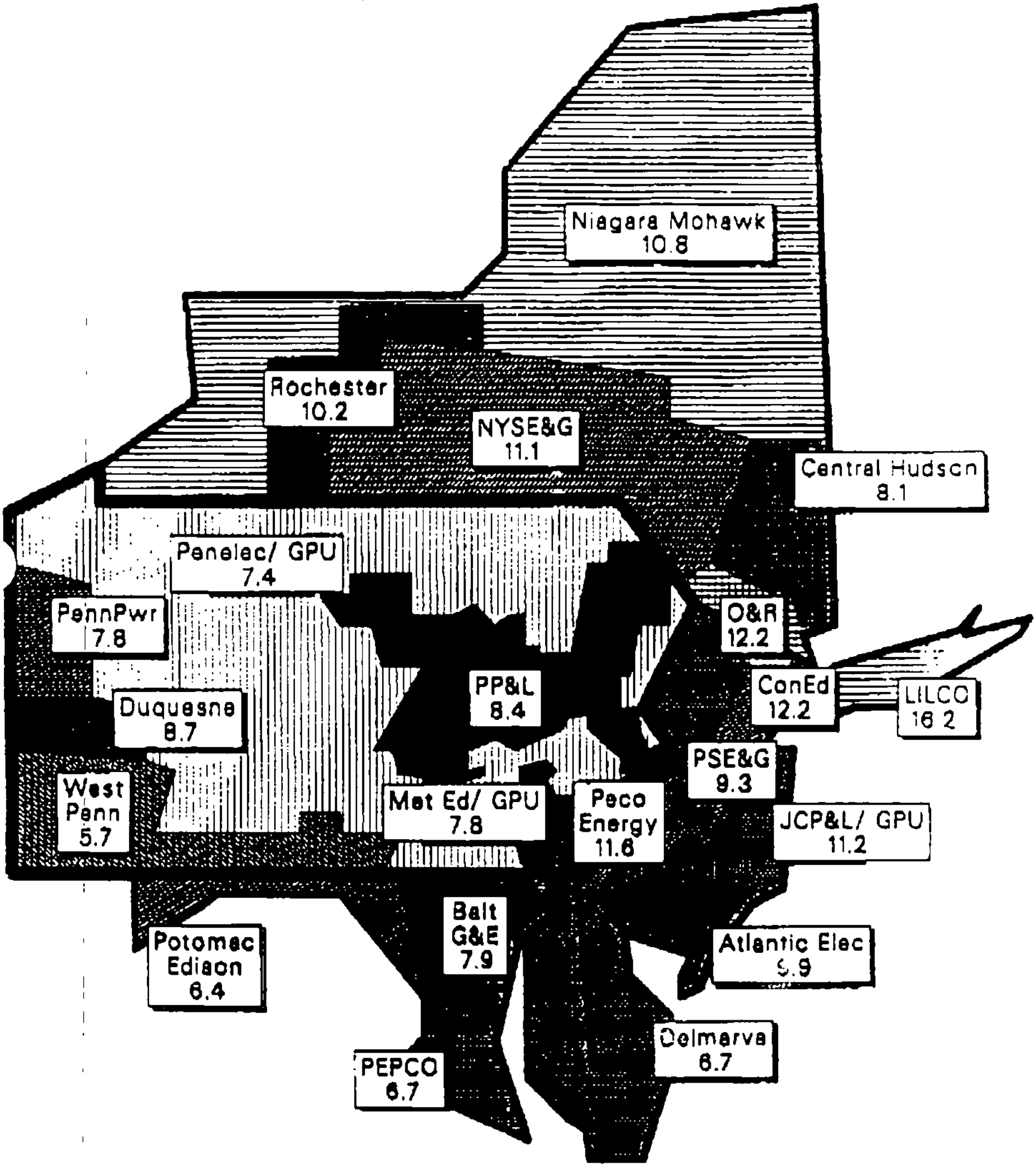
12 Months Ended December 1994 Average Price for Industrial Customers
(Cents per KWH)



PP&L Filed Rates and Met Ed New ECR Used

Pricing & Contract Admin
May 1995

12 Months Ended December 1994 Average Price for Commercial Customers
(Cents per KWH)



PP&L Filed Rates and Met Ed New ECR Used

Pricing & Contract Admin
May 1995

EXHIBIT OGK 13

Demand-Side Management (DSM)
All Ratepayers Analysis Of EDI/IDI Programs

Rebuttal Testimony of Oliver G. Kasper
Docket No. R-00943271

PENNSYLVANIA POWER AND LIGHT COMPANY

DSM ALL RATEPAYERS ANALYSIS OF EDI / IDI PROGRAM

Year	[illegible] EDI Customers				All Remaining EDI Customers			
	Without EDI		With EDI		Without EDI		With EDI	
	KWH	Revenue	KWH	Revenue	KWH	Revenue	KWH	Revenue
1995	0	$0	1,030,127,510	$49,802,798	5,040,969,563	$320,107,687	5,040,969,563	$301,802,399
1996	0	$0	1,030,127,510	$49,802,798	5,040,969,563	$320,107,687	5,040,969,563	$301,802,399
1997	0	$0	1,030,127,510	$49,802,798	5,040,969,563	$320,107,687	5,040,969,563	$301,802,399
1998	0	$0	1,030,127,510	$49,802,798	5,040,969,563	$320,107,687	5,040,969,563	$307,904,175
1999	0	$0	1,030,127,510	$49,802,798	5,040,969,563	$320,107,687	5,040,969,563	$314,005,986
2000	0	$0	1,030,127,510	$49,802,798	5,040,969,563	$320,107,687	5,040,969,563	$320,107,687

Year	Total EDI Customers					
	Without EDI		With EDI		Additional KWH	Additional Revenue
	KWH	Revenue	KWH	Revenue		
1995	5,040,969,563	$320,107,687	6,071,097,073	$351,605,195	1,030,127,510	31,497,508
1996	5,040,969,563	$320,107,687	6,071,097,073	$351,605,195	1,030,127,510	31,497,508
1997	5,040,969,563	$320,107,687	6,071,097,073	$351,605,195	1,030,127,510	31,497,508
1998	5,040,969,563	$320,107,687	6,071,097,073	$357,706,971	1,030,127,510	37,599,284
1999	5,040,969,563	$320,107,687	6,071,097,073	$363,808,782	1,030,127,510	43,701,095
2000	5,040,969,563	$320,107,687	6,071,097,073	$369,910,483	1,030,127,510	49,802,798

Pennsylvania Power and Light Company

DSM All Ratepayers Analysis of EDI / IDI Program

							Present Value			
Year	Admin cost ($)	Additional Sales (kwh)	Additional Cap Obl (kw)	Additional Revenue ($)	Energy Cost ($)	Capacity Cost ($)	Admin cost $	Additional Revenue $	Energy Cost $	Capacity Cost $
1995	5,000	1,303,127,510	89,255	31,497,508	33,099,439	1,410,234	4,587	28,898,798	30,366,458	1,293,793
1996	5,000	1,303,127,510	89,255	31,497,508	31,665,998	1,463,787	4,208	26,510,822	26,852,637	1,232,040
1997	5,000	1,303,127,510	89,255	31,497,508	31,798,311	1,528,266	3,861	24,321,855	24,552,566	1,178,557
1998	5,000	1,303,127,510	89,255	37,599,284	32,058,937	2,374,191	3,542	26,636,281	22,709,942	1,681,937
1999	5,000	1,303,127,510	89,255	43,701,096	33,490,377	3,293,521	3,250	28,402,713	21,766,447	2,140,563
2000	5,000	1,303,127,510	89,255	49,802,796	35,184,443	4,284,255	2,981	29,695,780	20,979,334	2,554,581
2001	5,000	1,303,127,510	89,255	49,802,796	36,878,509	5,346,393	2,735	27,243,835	20,173,807	2,924,660
2002	5,000	1,303,127,510	89,255	49,802,796	38,702,887	6,488,881	2,509	24,994,344	19,423,674	3,256,541
2003	5,000	1,303,127,510	89,255	49,802,796	40,787,891	7,711,659	2,302	22,930,591	18,779,878	3,550,662
2004	5,000	1,303,127,510	89,255	49,802,796	43,394,146	9,023,712	2,112	21,037,239	18,330,156	3,811,713
							32,088	260,670,257	223,734,920	23,625,027

Item	Present Value
Capacity Cost	$ 23,625,027
Energy Cost	$ 223,734,920
Admin Cost	$ 32,088
Revenue Benefit	$ 260,670,257
NPV	$ 13,278,222
Benefit/Cost	1.05

PENNSYLVANIA POWER & LIGHT COMPANY

Statement 13-R

5/25/95
1109

Rebuttal Testimony of Thomas S. LaGuardia

Docket No. R-00943271

Q. Please state your name and business address.

A. Thomas S. LaGuardia, 148 New Milford Road East, Bridgewater, Connecticut 06752.

Q. Mr. LaGuardia, have you previously submitted testimony in this proceeding?

A. Yes. My direct testimony was admitted as PP&L Statement No. 13 and I was cross-examined at the hearing held on March 30, 1995.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to adjustments proposed by OTS witness Sivulich, OCA witnesses Bridenbaugh and Catlin and PPLICA witness Kollen to Pennsylvania Power & Light Company's ("PP&L" or the "Company") claims for nuclear plant and fossil plant decommissioning expense.

NUCLEAR DECOMMISSIONING EXPENSE

Q. Please summarize the positions of the other parties regarding PP&L's claim for nuclear decommissioning expense.

A. The OCA, through Messrs. Bridenbaugh and Catlin, would reduce the Company's claim to reflect (1) the elimination of the estimated costs of dismantling and disposing of non-radiological facilities, (2) the removal of the contingency incorporated into the estimated costs of decommissioning radiological facilities, (3) the continued accrual of decommissioning trust fund earnings during the decommissioning period itself and (4) the use of a higher assumed earnings rate on the trust fund. I will address the first three issues and I understand that Mr. Chappelear will be addressing the fourth.

The OTS, through Mr. Sivulich, properly recognizes that the Commission's recent practice has been to approve claims for the decommissioning of both the radiological and non-radiological portions of nuclear facilities, but proposes to eliminate all contingency dollars. In addition, Mr. Sivulich would reject PP&L's use of the so-called "annuity" method. Mr. Bernini will be addressing this latter point.

Finally, PPLICA, through Mr. Kollen, recommends that the Company's annuity calculations be revised to incorporate a higher trust fund earnings rate. As previously noted, Mr. Chappelear responds to this proposal in his rebuttal testimony.

Q. Please first respond to Mr. Bridenbaugh's objections to the recovery of non-radiological decommissioning costs.

A In my direct testimony, I explained why, in my opinion, it will be necessary, from both an engineering and regulatory standpoint, to dismantle and dispose of certain non-radiological structures and equipment. Other than what may be regarded as somewhat of a semantic argument over whether the Building Official and Code Administrators ("BOCA") National Building Code would apply to retired nuclear generating units, Mr. Bridenbaugh does not appear to take issue with any of the specifics of my decommissioning study. Instead, his position is based on the following observations: (1) that the NRC does not require the decommissioning of non-radiological facilities and purportedly has expressed little, if any, interest in the subject; and (2) that it is reasonable to assume that the Susquehanna site will not be abandoned and that some existing facilities will continue to be used.

Q. Do either of Mr. Bridenbaugh's observations justify the disallowance of non-radiological decommissioning costs?

A. No, they do not. While Mr. Bridenbaugh is correct that NRC regulations do not require the removal of non-radiological structures and equipment, I cannot agree that the NRC has no interest in the subject. In fact, I am aware of instances where the NRC has dictated site restoration activities as part of the nuclear delicensing process. More to the point, however, this Commission has recognized that partially dismantled nuclear generating facilities can pose a serious risk to the health and safety of the public and has approved claims to recover non-radiological decommissioning costs on that basis.

Q. Could not the non-radiological facilities be made safe by fencing and guarding the Susquehanna site, as Mr. Bridenbaugh suggests?

A. In my opinion, Mr. Bridenbaugh has glossed over a very serious issue. In order to fully secure and maintain the site, PP&L would have to do much more than simply fencing and guarding the remaining facilities. Moreover, it should be obvious that PP&L would incur substantial costs in carrying out these activities.

Q. Do you agree with Mr. Bridenbaugh that reuse of the Susquehanna site is a possibility?

A. Yes, and I stated as much in my direct testimony. Significantly, however, that possibility is not inconsistent with the assumptions which I employed because my study does <u>not</u> provide for the removal of the basic structures for which it is reasonable to believe that a useful purpose will exist after decommissioning, such as the switchyard, transmission towers, culverts, head walls etc. It should also be noted that the decommissioning and removal activities that I have assumed involve only structures and equipment located within the restricted areas of the site. Stated differently, no costs have been claimed for the removal of buildings or other facilities located outside the perimeter of the restricted area.

Q. Should the collection of site restoration costs be deferred pending the submission of a detailed cost/benefit analysis of all reuse options, as Mr. Bridenbaugh suggests?

A. No. In my opinion, any attempt to quantify the costs and benefits of specific site plans thirty to forty years into the future would be a meaningless exercise, particularly in light of the technological changes that have been witnessed over the last thirty years. That does not suggest, however, that reasonably foreseeable decommissioning activities should be ignored. Rather, the proper course, and the one which I followed in my study, is to make basic assumptions about the ongoing usefulness of the facilities currently in service based on the best information available at the time.

In addition, I do not believe it would be appropriate for PP&L to wait until definitive site use plans had been formulated to collect the expenses related to the removal of non-radiological facilities. This would force future customers to bear a disproportionate burden of the costs to decommission the plant at a time when they were receiving little or no benefit from it.

Q. Mr. LaGuardia, the second major area of dispute concerns your inclusion of contingency in your nuclear decommissioning cost estimates. Why, in your view, is the inclusion of contingency appropriate and justified?

A. The basis for including contingency is set forth in my direct testimony. By way of amplification, however, I believe that TLG's experience as the largest subcontractor in the decommissioning of the Shippingport Atomic Power Station provided a unique opportunity to test and confirm the reasonableness of our cost estimating methodology, including the use of contingency factors. All work on this program was competitively bid and required the highest degree of accuracy in estimating individual activity costs. TLG relied upon this same cost estimating methodology in preparing its bids for Shippingport that it used in developing the decommissioning estimates for Susquehanna SES. Not only was TLG a successful bidder at Shippingport, but the company was the only subcontractor to complete its assigned task(s) within budget and on schedule. *This success provided field confirmation of* TLG's *empirical data* base used to produce its estimates.

The accuracy of TLG's estimates have also been confirmed in decommissioning activities undertaken at the Yankee Rowe, Shoreham, Pathfinder, and Rancho Seco Plants. Each estimate contained a level of contingency appropriate with the activities identified for the specified decommissioning program.

Q. In his testimony, Mr. Bridenbaugh cites the uncertainty over the ultimate disposal of low-level radioactive waste as a reason for disallowing recovery of any contingency. Do you agree?

A. No. Contrary to Mr. Bridenbaugh's opinion, the use of contingency within an estimate for waste disposal is not only appropriate but also consistent with both industry and government cost estimating practices. Regardless of the pricing structure assumed, there are uncertainties and risks associated with the disposal of low-level radioactive waste. Among the variables addressed by contingency are:

Waste Volume

Waste volumes projected from the decommissioning of a nuclear plant, prior to the cessation of operations, are based upon as-designed parameters. Experience in planning for the decommissioning of shutdown facilities has shown that additional volumes of material are generally identified once an intensive characterization of the immediate and surrounding facility has been completed. Additional cost is generally required to remediate and dispose of contamination located beyond the primary design boundaries as a consequence of 40 years of plant operations.

The NRC has also been considering more restrictive release criteria for cleanup of sites for unrestricted use. Lower permissible residual levels could increase the quantities of materials to be remediated and disposed. Waste quantities could also increase if the assumed packaging efficiencies are not realized, decontamination techniques fail to achieve free release limits or packaging criteria change.

Disposal Options

Low-level radioactive waste is classified in accordance with the level of stability or isolation required for disposal. Classifications range from the least restrictive Class A to the most restrictive C and Greater-than-Class C (GTCC) categories. GTCC material is not suitable for shallow land burial and, as stated by Mr. Bridenbaugh, will most likely be disposed of at DOE's geologic repository. However, even though DOE has acknowledged this eventuality, a disposal criterion or schedule has not been established. It is unlikely that GTCC material will be incorporated within the existing spent fuel queue and the potential exists for long-term interim storage at the reactor sites until such time that this non-standard waste form can be accommodated.

There is an additional uncertainty in the proposed operation of the Appalachian Compact facility. The Compact is considering the exclusion of Class C waste for regional disposal. PP&L would have no other alternative for the disposition of this material, with the possible exception of negotiating with other compacts. Exporting waste from the Compact (if permitted by both the originating and receiving states) could increase the currently projected cost for disposal.

<u>Cost</u>

The cost to site and develop regional facilities has continued to skyrocket. The unit disposal rate used in the estimate for Susquehanna SES is at the low end of the range being projected for new facilities. Furthermore, utilities have continued to work to minimize the volumes of low-level radioactive waste produced in the operation of the nuclear units. This has dramatically lowered the anticipated volumes of waste upon which new facilities are able to recover their capital and operation expenses. Decommissioning volumes have also decreased (approximately 50% in the past 10 years) as additional decontamination and volume reduction have become cost effective with the rising cost of disposal. As the volumes continue to decrease, the regional sites will have to compensate for the lost revenue. The facility in Barnwell, South Carolina significantly increased its charges in a recent attempt to offset such a declining waste stream.

Q. Mr. Bridenbaugh further implies that the $279 per cubic foot figure which you utilized for the disposal of low-level radioactive waste may be excessive. Do you have any comments?

A. Yes. The $279 figure (which included a $220 surcharge) represented the then-current cost incurred by PP&L for disposal of low-level radioactive waste. The value was also judged to be a fair <u>proxy</u> of the minimum cost that would be incurred in the disposal of low-level radioactive waste within a regional facility.

The development costs for an above-ground concrete facility, as proposed for the Pennsylvania site, are significantly higher than the costs associated with a shallow-land facility, e.g., at Barnwell, South Carolina. US Ecology, the developer for the Central States Compact facility, is estimating a cost of $403 per cubic foot in the first year of site operation for a earth-mounded above-ground concrete vault facility. Unlike the disposal facilities in operation today, which have already recovered and amortized their start-up costs, the revenue requirements for the Pennsylvania site will incur licensing costs, construction costs, perpetuity costs and, in addition, will have to provide a return to its investors/developers/operators.

I should further note that the cost projections for undeveloped regional facilities used by other utilities fully support use of the $279/cubic foot value. For example, the Nebraska Public Power District relied upon a base rate of $350 in its 1993 decommissioning cost estimate for the Cooper Nuclear Station, as did Iowa Electric Light & Power in its 1992 estimate for the Duane Arnold unit. Houston Lighting & Power Company is using a Texas Low-Level Radioactive Waste Disposal Authority projection of $290/cubic foot in estimating waste disposal costs for the decommissioning of the South Texas Project two-unit station. Michigan and Wisconsin utilities are using comparable values ranging between $300 to $400. The Wolf Creek Nuclear Operating Company relied upon a $300 value for estimating 1993 disposal costs for the Wolf Creek Plant in Kansas, while burial costs at the Callaway Plant in Missouri were estimated using $250 as a unit disposal cost in the same year.

Finally, the Arkansas Public Service Commission recently granted Arkansas Power & Light Company an increased decommissioning expense allowance to reflect the associated increase in waste disposal costs. More specifically, the Arkansas Commission approved an addition of $199 million to account for the increase in base disposal rates, from the approximately $44/cubic foot figure used in a 1992 estimate to the 1994 cost of $291.60. The Commission recognized that until a dependable projection of the rates for the Central States Compact was available, the then-current Barnwell cost represented a reasonable proxy.

In summary, PP&L's value of approximately $300, as a base disposal rate, is consistent with projections being used by other utilities for estimating the disposal of low-level radioactive waste at regional facilities.

Q. Do any of the other reasons cited by Mr. Bridenbaugh justify the removal of contingency from your decommissioning cost estimate?

A. No, they do not. For example, Mr. Bridenbaugh speculates that increases in waste burial costs might make the SAFSTOR option more attractive. However, he indicated on cross-examination that he was not advocating any particular decommissioning method. Moreover, based on analyses conducted by TLG including those performed for purposes of this proceeding, the SAFSTOR option consistently generates a higher estimate than the DECON option which was assumed for purposes of my Susquehanna study.

Q. Mr. Bridenbaugh implies that there would be a significant decrease in low-level radioactive waste and less occupational exposure if a facility is placed in SAFSTOR for 50 years. Do you agree?

A. No. While the activity declines, there is no large reduction in waste volume over the time span as implied by Mr. Bridenbaugh. Long-lived radioisotopes inhibit the reduction in contamination levels and will not permit the material's release as clean scrap or for salvage without additional remediation. This has been confirmed through discussions with operations personnel at several operating nuclear units.

In addition, decommissioning experience with large commercial reactors with established operating histories, e.g., Yankee Rowe, Rancho Seco and Trojan, has provided detailed radiological profiles which demonstrate the mitigating effects of longer-lived isotopes on the rate of dose reduction. In particular, Cesium-137, with its 30 year half-life, becomes the primary radionuclide of concern with the decay of Cobalt-60 in any long-term analysis. Decontamination, shielding and administrative controls can be used in the DECON alternative to effectively control and minimize worker exposure such that the differential between a prompt and deferred alternative can be considerably narrowed. While this level of planning is not reflected in a cost study prepared for ratemaking purposes, actual field experience supports such an observation.

Q. Mr. Bridenbaugh also suggests that technological development and experience gained will reduce decommissioning costs in the future. Please comment.

A. Unfortunately, if history is any guide, the opposite is more likely to be true. Indeed, I fully expect that nuclear decommissioning costs will continue to escalate at rates in excess of general inflation. Furthermore, I have incorporated all "lessons learned" in my study and any subsequent technological advances can and no doubt will be reflected in future decommissioning cost estimates.

Q. Mr. Sivulich's objection to the inclusion of contingency appears to be based on his perception that the Commission has been unwilling in the past to recognize this factor. Do you agree?

A. No, I do not. I am aware that an adjustment was made in PP&L's last base rate case to strip out contingency. However, it is my understanding that the Company's claim in that proceeding was based on a generic, and not a site-specific, decommissioning study. More importantly, I sponsored decommissioning cost studies in a subsequent rate proceeding involving Pennsylvania Power Company (Docket No. R-850267). Those studies included a 25% contingency to account for unanticipated difficulties and, to the best of my knowledge, were accepted in full by the Commission in approving the utility's claims.

Q. Mr. LaGuardia, the third area of dispute over PP&L's nuclear decommissioning expense claim concerns Mr. Catlin's observation that the Company's trust fund will continue to earn a return after the units are retired and while they are being decommissioned. Would you care to comment?

A. Yes. Current NRC rules require the nuclear decommissioning trust fund to be fully funded in the amount necessary to terminate the license at the time of plant shutdown. PP&L, as the licensee of the Susquehanna Plant, must abide by these requirements. For plants that have shut down prematurely, the NRC has made exceptions on a case-by-case basis.

FOSSIL DECOMISSIONING EXPENSE

Q. Turning now to the Company's claim for fossil decommissioning expense, please summarize the principal objections expressed by the opposing parties.

A. Messrs. Catlin, Sivulich and Kollen all propose that PP&L's claim for fossil decommissioning expense be rejected in its entirety. In general, each witness cites one or more of the following factors in support of his recommendation: (1) there is no legal requirement to decommission fossil-fired generating units; (2) the lives of fossil units may be extended and/or the sites and structures reused; (3) the cost of dismantling fossil units is speculative and, in any event, can be recovered through the standard ratemaking allowance for net negative salvage; and (4) idled fossil units do not present the same threat to public health and safety as nuclear units.

Q. Do you agree that the decommissioning of fossil units is not required by law?

A. Not entirely. As I pointed out in my direct testimony, the BOCA Code mandates that "[a]ll unsafe structures shall be taken down and removed or made safe and secure." In my opinion, this requirement applies to both nuclear and fossil-fueled generating units. Moreover, and apart from any absolute legal obligation, I believe that the decommissioning of fossil units represents sound environmental policy.

Q. Is it not possible that PP&L's fossil units will be life-extended and/or the sites and structures reused?

A. That may be a possibility. However, I have serious reservations over how much of the existing facilities could, in fact, be reused economically and, as I noted in my direct testimony, the fossil units in service today will likely be technologically obsolete by the time they are retired.

Q. Mr. Sivulich contends that your dismantling cost estimates are unduly speculative because they are based on 49 major assumptions and that a change in any one of those assumptions could result in a significantly lower cost estimate. Do you agree?

A. No. TLG has made it a practice to clearly identify the bases for its estimates to eliminate any chance of confusion or misinterpretation. We have attempted to identify every major assumption that can affect the cost estimates either in a positive or negative manner. By so doing, the assumptions minimize the degree of speculation as to what is, or is not, included in the estimate. In fact, upon evaluation of the 49 assumptions alluded to by Mr. Sivulich, I conclude that changes would, in most instances, likely result in significant <u>increases</u> in costs rather than decreases. For example, Assumption No. 11 states, "Acid, caustic and demineralizer tanks will be empty prior to the start of dismantling." If the acids or caustics are not consumed during the last days of plant operation, they will have to be removed as hazardous wastes at significantly greater cost. Mr. Sivulich simply missed the point of our care for accuracy in these estimates. The number of assumptions used in an estimate is an affirmation of the validity of an estimate, not a sign of weakness.

Q. Mr. Sivulich further asserts that the decommissioning of fossil units cannot be construed as "significant, relevant, and substantial when compared to normal levels of net negative salvage." Mr. Kollen also suggests as much when he discusses PP&L's prior experience in dismantling fossil units. Please comment.

A. I understand that Mr. Hoch will address this point in the context of PP&L's previous activities. However, I can offer some insights based on my own experience in the area.

Aside from nuclear plants, the decommissioning of fossil-fueled power plants represents one of the largest sources of net negative salvage. Dismantling work is highly labor intensive, and cannot be accomplished for the value of salvaged materials as perhaps was the case many years ago. The piping and components have no resale value except as scrap, as these components will have operated for many years and newer generation fossil plants will not be able to use any of the dismantled plant equipment. In fact, the value of scrap is barely enough to cover the costs to cut it into "firebox size" of 18 inches by 60 inches, the size steel mills require for remelting the steel into new products. Nor can the scrap value support the cost of transporting the steel to the scrap yard or steel mill. Accordingly, PP&L will have to pay to have the plants dismantled at the end of their useful lives. These costs are significant, relevant and substantial when compared to <u>any</u> standard of net negative salvage.

Q. Are there any other reasons why, in your view, the decommissioning of fossil units does not lend itself to the Commission's standard practice regarding the treatment of net negative salvage?

A. Yes. As I discussed earlier in this rebuttal testimony, those who have received the benefit of the power generated should pay for its removal. This is particularly important where individual older units of a multi-unit site are retired and left in dormancy until the last of the generating units is shutdown so the dismantling activities can be performed on a cost-effective basis on all the units concurrently. If recovery of dismantling costs is not allowed while the units are operating, current customers will not pay their fair share of the removal costs. This is clearly a case of intergenerational inequity, a factor considered by the NRC in its decision to require nuclear plant decommissioning funding over the life of the facility.

Q. Finally, Mr. LaGuardia, would you please describe the safety concerns presented by retired fossil units and, in the process, address Mr. Sivulich's assertion that you previously testified that such plants do not have any "*extraordinary safety problems*."

A. Mr. Sivulich has taken my response to a question posed during cross-examination (Tr. 963) out of context. What I tried to convey was that I was unaware of any specific problems associated with PP&L's fossil units that one might not encounter at facilities of similar vintage and design. I did not intend to imply, and indeed categorically reject Mr. Sivulich's contention, that "conventional generating plants do not present any compelling safety related issues."

Virtually all older fossil-fueled plants have asbestos, PCBs, lead-painted surfaces, acids and caustics. All work in abating and removing these materials is extremely hazardous for which trained professionals must be retained. Federal and state regulations require workers to have complete medical examinations including electrocardiograms, x-ray examinations, and pulmonary function tests. All workers must successfully complete 32 hours of asbestos removal traning (40 hours for supervisors, additional 8-hour courses for asbestos sampling technicians). Workers are required to wear full protective clothing (coveralls, boots, gloves, caps), and wear air purifying or supplied air masks for respiratory protection, and carry and monitor portable air samplers.

In addition, all work must be performed in double-walled tents maintained under negative pressure. Upon leaving an asbestos work area, *workers are required to remove their protective clothing (but not their* respirator), and shower to remove residual asbestos fibers. After showering, they enter a third enclosure to remove the respirator and change into street clothes. This process is repeated at least four times a day when considering the need for breaks and lunch. All materials brought out of the work area (asbestos materials, tools and equipment) and into a "cargo area," must be double bagged, stripped of the outer bag in the cargo area, and rebagged for disposal or storage.

Similarly, workers involved in cutting lead-painted surfaces by any cutting technique are required to have separate, but similar training for worker safety and lead contamination control.

In summary, this work is hazardous and "special" in the context that it should be handled from a financial planning standpoint in the same manner as nuclear power plant decomissioning; namely, the future dismantling of PP&L's fossil units should be authorized by the Commission.

Q. Does that conclude your rebuttal testimony?
A. Yes, it does.

EXHIBIT JJS 2

Rebuttal Testimony of John J. Slivka
Docket No. R-00943271

FCCXR32

15:23 THURSDAY, SEPTEMBER 4, 1986

PENNSYLVANIA POWER & LIGHT COMPANY
RESIDENTIAL CUSTOMERS ON DEMAND MANAGEMENT PROGRAMS
AND % OF NEW I&C SQ. FOOTAGE ON OFF-PEAK SYSTEMS

YEAR	SESS NEW CONSTRUCTION	CERAMIC NEW CONSTRUCTION	CERAMIC CONVERSIONS	I&C OFF PEAK HEATING
1986	684	338	120	5
1987	897	862	620	15
1988	1,410	1,623	2,120	30
1989	2,076	2,631	5,120	50
1990	2,897	3,863	9,620	75
1991	3,801	5,218	14,120	100
1992	4,800	6,716	18,620	125
1993	5,896	8,360	23,120	150
1994	7,084	10,141	27,620	175
1995	8,371	12,072	32,120	200
1996	9,741	14,128	36,620	225
1997	11,175	16,323	41,120	250
1998	12,725	18,640	45,620	275
1999	14,381	21,132	50,120	300
2000	16,124	23,747	54,620	325
2001	17,888	26,393	59,120	350
2002	19,652	29,039	63,620	375
2003	21,416	31,685	68,120	400
2004	23,201	34,363	72,620	425
2005	25,012	37,079	77,120	450
2006	26,823	39,795	81,620	475

EXHIBIT JJS 3

Rebuttal Testimony of John J. Slivka
Docket No. R-00943271

FCBXR62

9/86 INTEGRATED FORECAST

PENNSYLVANIA POWER AND LIGHT COMPANY
AVERAGE NUMBER OF CUSTOMERS BY CUSTOMER CLASS

YEAR	ELECTRICALLY HEATED HOMES	GENERAL RESIDENTIAL	TOTAL COMMERCIAL	TOTAL INDUSTRIAL	TOTAL OTHER	TOTAL SYSTEM
1985	215,923	708,754	115,518	5,617	1,387	1,047,199
1986	229,991	708,537	118,500	4,317	1,406	1,062,751
1987	242,511	708,967	119,650	4,290	1,411	1,076,829
1988	257,011	707,417	120,800	4,265	1,408	1,090,901
1989	273,011	704,367	121,950	4,240	1,405	1,104,973
1990	290,661	699,667	123,120	4,215	1,402	1,119,065
1991	308,101	694,427	124,290	4,195	1,399	1,132,412
1992	325,381	689,147	125,460	4,175	1,396	1,145,559
1993	342,661	683,867	126,630	4,155	1,393	1,158,706
1994	359,861	678,567	127,800	4,135	1,390	1,171,753
1995	376,901	673,227	128,970	4,115	1,387	1,184,600
1996	393,872	667,206	130,150	4,100	1,384	1,196,712
1997	410,902	661,026	131,330	4,085	1,381	1,208,724
1998	427,932	654,846	132,510	4,070	1,378	1,220,736
1999	445,102	648,526	133,690	4,055	1,375	1,232,748
2000	462,272	642,206	134,870	4,040	1,372	1,244,760
2001	479,532	635,246	136,050	4,025	1,369	1,256,222
2002	496,792	628,286	137,230	4,010	1,366	1,267,684
2003	514,052	621,326	138,410	3,995	1,363	1,279,146
2004	531,452	614,226	139,590	3,980	1,360	1,290,608
2005	549,022	607,156	140,780	3,965	1,357	1,302,280
2006	566,592	600,086	141,970	3,950	1,354	1,313,952

EXHIBIT JJS 4

Rebuttal Testimony of John J. Slivka
Docket No. R-00943271

FCBXR62

9/84 BASE CASE FORECAST

PENNSYLVANIA POWER AND LIGHT COMPANY
AVERAGE NUMBER OF CUSTOMERS BY CUSTOMER CLASS

YEAR	ELECTRICALLY HEATED HOMES	GENERAL RESIDENTIAL	TOTAL COMMERCIAL	TOTAL INDUSTRIAL	TOTAL OTHER	TOTAL SYSTEM
1985	215,923	708,754	115,518	5,617	1,387	1,047,199
1986	229,991	708,537	118,500	4,317	1,406	1,062,751
1987	242,511	708,967	119,650	4,290	1,411	1,076,829
1988	254,761	709,667	120,800	4,265	1,408	1,090,901
1989	266,811	710,567	121,950	4,240	1,405	1,104,973
1990	278,711	711,617	123,120	4,215	1,402	1,119,065
1991	290,563	711,965	124,290	4,195	1,399	1,132,412
1992	302,559	711,969	125,460	4,175	1,396	1,145,559
1993	314,701	711,827	126,630	4,155	1,393	1,158,706
1994	326,911	711,517	127,800	4,135	1,390	1,171,753
1995	339,251	710,877	128,970	4,115	1,387	1,184,600
1996	351,522	709,556	130,150	4,100	1,384	1,196,712
1997	363,852	708,076	131,330	4,085	1,381	1,208,724
1998	376,182	706,596	132,510	4,070	1,378	1,220,736
1999	388,652	704,976	133,690	4,055	1,375	1,232,748
2000	401,122	703,356	134,870	4,040	1,372	1,244,760
2001	413,682	701,096	136,050	4,025	1,369	1,256,222
2002	426,242	698,836	137,230	4,010	1,366	1,267,684
2003	438,802	696,576	138,410	3,995	1,363	1,279,146
2004	451,502	694,176	139,590	3,980	1,360	1,290,608
2005	464,372	691,806	140,780	3,965	1,357	1,302,280
2006	477,242	689,436	141,970	3,950	1,354	1,313,952

EXHIBIT JJS 5

Rebuttal Testimony of John J. Slivka
Docket No. R-00943271

FCBXR61

9/86 INTEGRATED FORECAST

PENNSYLVANIA POWER AND LIGHT COMPANY
ANNUAL SALES BY CUSTOMER CLASS
INCLUDING SUPPLY TO UGI

(MILLIONS OF KWH)

YEAR	ELECTRICALLY HEATED HOMES	GENERAL RESIDENTIAL	TOTAL COMMERCIAL	TOTAL INDUSTRIAL	TOTAL OTHER	TOTAL SYSTEM
1985	3,833	4,814	6,836	7,906	1,091	24,480
1986	3,900	4,800	7,140	7,790	1,145	24,855
1987	4,100	4,820	7,400	7,945	1,170	25,435
1988	4,296	4,835	7,700	7,969	1,190	25,990
1989	4,530	4,828	8,010	8,002	1,225	26,595
1990	4,817	4,818	8,290	8,000	1,270	27,195
1991	5,103	4,809	8,570	8,140	1,310	27,932
1992	5,396	4,792	8,840	8,380	1,350	28,728
1993	5,689	4,776	9,100	8,570	1,390	29,525
1994	6,002	4,762	9,360	8,790	1,430	30,344
1995	6,323	4,738	9,620	8,990	1,370	31,041
1996	6,637	4,725	9,880	9,210	1,400	31,852
1997	6,904	4,701	10,140	9,460	1,440	32,725
1998	7,300	4,678	10,400	9,710	1,475	33,563
1999	7,642	4,655	10,660	9,960	1,510	34,427
2000	7,905	4,621	10,930	10,220	1,550	35,306
2001	8,339	4,587	11,210	10,470	1,585	36,191
2002	8,604	4,553	11,490	10,710	1,620	37,057
2003	9,036	4,510	11,770	10,960	1,660	37,936
2004	9,301	4,478	12,050	11,200	1,700	38,806
2005	9,738	4,441	12,330	11,420	1,735	39,664
2006	10,094	4,396	12,610	11,650	1,770	40,520

NOTE: SALES TO ATLANTIC ELECTRIC AND JCP&L ARE NOT INCLUDED.
1985 VALUES ARE WEATHER-NORMALIZED.

EXHIBIT JJS 6

Rebuttal Testimony of John J. Slivka
Docket No. R-00943271

FCBXR61

9/86 BASE CASE FORECAST

PENNSYLVANIA POWER AND LIGHT COMPANY
ANNUAL SALES BY CUSTOMER CLASS
INCLUDING SUPPLY TO UGI

(MILLIONS OF KWH)

YEAR	ELECTRICALLY HEATED HOMES	GENERAL RESIDENTIAL	TOTAL COMMERCIAL	TOTAL INDUSTRIAL	TOTAL OTHER	TOTAL SYSTEM
1985	3,833	4,814	6,836	7,906	1,091	24,480
1986	3,980	4,800	7,140	7,790	1,145	24,855
1987	4,100	4,820	7,400	7,945	1,170	25,435
1988	4,230	4,850	7,640	7,869	1,190	25,779
1989	4,350	4,870	7,880	7,802	1,225	26,127
1990	4,470	4,900	8,100	7,700	1,270	26,440
1991	4,590	4,930	8,320	7,730	1,310	26,880
1992	4,720	4,950	8,530	7,840	1,350	27,390
1993	4,850	4,970	8,740	7,960	1,390	27,910
1994	5,000	4,990	8,950	8,060	1,430	28,450
1995	5,160	5,000	9,160	8,200	1,370	28,890
1996	5,310	5,020	9,370	8,330	1,400	29,430
1997	5,480	5,030	9,580	8,480	1,440	30,010
1998	5,640	5,040	9,790	8,640	1,475	30,585
1999	5,810	5,050	10,000	8,800	1,510	31,170
2000	5,980	5,050	10,220	8,970	1,550	31,770
2001	6,160	5,050	10,450	9,130	1,585	32,375
2002	6,330	5,050	10,680	9,280	1,620	32,960
2003	6,510	5,040	10,910	9,430	1,660	33,550
2004	6,680	5,040	11,140	9,580	1,700	34,140
2005	6,860	5,040	11,370	9,720	1,735	34,725
2006	7,040	5,030	11,600	9,860	1,770	35,300

NOTE: SALES TO ATLANTIC ELECTRIC AND JCP&L ARE NOT INCLUDED.
1985 VALUES ARE WEATHER-NORMALIZED.

EXHIBIT JJS 7

Rebuttal Testimony of John J. Slivka
Docket No. R-00943271

FCCXR34

15:23 THURSDAY, SEPTEMBER 4, 1986

PENNSYLVANIA POWER & LIGHT COMPANY
DEMAND CHANGES DUE TO COGENERATION,
OFF-PEAK SYSTEMS, AND MARKETING

WINTER IMPACTS

YEAR=1994

HOUR	COGENERATION	SESS NEW	CERAMIC NEW	CERAMIC CONV	I&C OFF PEAK	I&C MARKETING	RES. MARKETING	TOTAL
1	0	32	86	518	70	117	24	847
2	0	32	86	494	70	117	25	824
3	0	32	86	458	70	115	26	787
4	0	32	86	457	70	117	26	788
5	0	16	58	305	70	116	28	593
6	0	0	28	153	0	119	29	329
7	0	-4	-6	7	0	129	33	159
8	0	-21	-76	-6	-35	153	36	51
9	0	-16	-71	-6	-35	167	33	72
10	0	-14	-67	-11	-35	169	29	71
11	0	-13	-64	-9	-35	172	27	78
12	0	-13	-63	-8	-35	168	25	74
13	0	-13	-60	-6	-35	166	24	76
14	0	-13	-59	-4	-35	169	24	82
15	0	-13	-59	-4	-35	164	24	77
16	0	-13	-56	-5	-35	156	23	70
17	0	[illegible]	-61	-4	-35	144	26	54
18	0	-16	-61	-4	-35	143	27	54
19	0	0	0	-8	-35	140	27	124
20	0	40	62	60	-35	136	28	291
21	0	57	123	214	0	136	29	559
22	0	57	123	355	35	129	28	727
23	0	46	106	513	70	124	27	886
24	0	32	86	515	70	119	26	848

YEAR=1995

HOUR	COGENERATION	SESS NEW	CERAMIC NEW	CERAMIC CONV	I&C OFF PEAK	I&C MARKETING	RES. MARKETING	TOTAL
1	0	38	103	603	80	132	25	981
2	0	38	103	574	80	131	26	952
3	0	38	103	533	80	130	27	911
4	0	38	103	531	80	131	27	910
5	0	19	69	355	80	130	29	682
6	0	0	34	178	0	134	30	376
7	0	-5	-7	8	0	145	34	175
8	0	-25	-91	-7	-40	171	37	45
9	0	-18	-85	-7	-40	188	34	72
10	0	-17	-80	-13	-40	190	29	69
11	0	-16	-76	-11	-40	193	28	78
12	0	-15	-75	-9	-40	189	26	76
13	0	-16	-71	-7	-40	186	25	77
14	0	-15	-70	-5	-40	189	25	84
15	0	-15	-70	-5	-40	185	24	79
16	0	-16	-69	-3	-40	176	24	72
17	0	-18	-72	-5	-40	161	27	53
18	0	-18	-72	-5	-40	161	28	54
19	0	0	0	-9	-40	158	28	137
20	0	48	74	69	-40	152	29	332
21	0	68	146	249	0	152	30	645
22	0	68	146	413	40	144	29	840
23	0	54	127	597	80	139	28	1025
24	0	38	103	599	80	134	27	981

FCCXR34

15:23 THURSDAY, SEPTEMBER 4, 1986

PENNSYLVANIA POWER & LIGHT COMPANY
DEMAND CHANGES DUE TO COGENERATION,
OFF-PEAK SYSTEMS, AND MARKETING

WINTER IMPACTS

YEAR=1996

HOUR	COGENERATION	SESS NEW	CERAMIC NEW	CERAMIC CONV	I&C OFF PEAK	I&C MARKETING	RES. MARKETING	TOTAL
1	0	44	120	687	90	147	26	1114
2	0	44	120	655	90	147	27	1083
3	0	[illegible]	120	607	90	144	28	1033
4	0	[illegible]	[illegible]	606	90	146	28	1034
5	0	[illegible]	[illegible]	404	90	145	30	772
6	0	0	40	203	0	149	31	423
7	0	-6	-8	9	0	162	35	192
8	0	-29	-106	-8	-45	191	38	41
9	0	[illegible]	[illegible]	-8	[illegible]	209	35	71
10	0	[illegible]	[illegible]	-16	-45	212	30	70
11	0	[illegible]	[illegible]	-12	[illegible]	215	29	79
12	0	-18	-88	-10	-45	210	26	75
13	0	-19	-83	-8	-45	207	25	77
14	0	-18	-82	-6	-45	211	26	86
15	0	[illegible]	[illegible]	[illegible]	-45	206	25	80
16	0	[illegible]	[illegible]	[illegible]	-45	196	24	71
17	0	[illegible]	[illegible]	[illegible]	-45	180	28	51
18	0	-21	-85	-6	-45	179	29	51
19	0	0	0	-10	-45	176	29	160
20	0	56	86	79	-45	169	30	375
21	0	79	171	204	0	170	31	736
22	0	79	171	471	45	161	30	957
23	0	65	148	680	90	158	28	1164
24	0	44	120	683	90	149	28	1114

YEAR=1997

HOUR	COGENERATION	SESS NEW	CERAMIC NEW	CERAMIC CONV	I&C OFF PEAK	I&C MARKETING	RES. MARKETING	TOTAL
1	0	50	139	771	100	162	26	1248
2	0	50	139	735	100	162	27	1213
3	0	50	139	682	100	159	29	1169
4	0	50	139	680	100	161	29	1169
5	0	[illegible]	[illegible]	454	100	160	31	864
6	0	0	46	228	0	164	32	470
7	0	-7	-10	10	0	178	36	207
8	0	-34	-122	-9	-50	210	39	34
9	0	[illegible]	-114	-9	-50	230	34	68
10	0	[illegible]	-108	-16	-50	233	31	68
11	0	[illegible]	-103	-16	-50	237	30	79
12	0	-20	-101	-12	-50	232	27	76
13	0	-21	-96	-9	-50	229	26	79
14	0	-20	-95	-7	-50	233	27	88
15	0	-20	-95	-7	-50	227	26	81
16	0	-21	-93	-4	-50	216	25	73
17	0	-25	-98	-7	-50	198	28	46
18	0	-25	-98	-7	-50	198	30	48
19	0	0	0	-12	-50	194	29	161
20	0	64	100	89	-50	187	31	421
21	0	91	198	319	0	187	32	827
22	0	91	198	529	50	177	31	1076
23	0	73	171	764	100	171	29	1308
24	0	50	139	766	100	165	28	1248

EXHIBIT JJS 8

Rebuttal Testimony of John J. Slivka
Docket No. R-00943271

FCCXR38

16:23 THURSDAY, SEPTEMBER 4, 1986

PENNSYLVANIA POWER & LIGHT COMPANY
HOURLY LOADS UNDER SCENARIOS AND DIFFERENCE FROM BASE

YEAR=1994

HOUR	LOADHB	LOADH1	DIFH1	LOADH2	DIFH2	LOADSB	LOADS1	DIFS1	LOADS2	DIFS2
1	4314	4455	141	5161	847	2983	3090	107	3093	110
2	4249	4391	142	5073	824	2895	3005	110	3006	111
3	4230	4371	141	5017	787	2776	2883	107	2884	108
4	4295	4438	143	5083	788	2654	2756	102	2757	103
5	4362	4506	144	4955	593	2653	2755	102	2756	103
6	4623	4771	148	4952	329	2801	2910	109	2911	110
7	5334	[illegible]	162	5493	159	3290	3413	123	3416	126
8	[illegible]	[illegible]	189	6031	51	3922	4074	152	4044	122
9	6060	6260	200	6132	72	4325	4497	172	4470	145
10	5921	6119	198	5992	71	4523	4698	175	4671	148
11	5842	6041	199	5920	78	4707	4890	183	4866	159
12	5686	5877	193	5758	74	4817	5005	188	4985	168
13	5846	5736	190	5628	76	4857	5044	187	5024	167
14	5522	5715	193	5604	82	4890	5078	188	5064	174
15	5440	5628	188	5517	77	4793	4977	184	4963	170
16	5326	5505	179	5396	70	4682	4857	175	4843	161
17	5397	5567	170	5451	54	4703	4869	166	4855	152
18	5699	5869	170	5753	54	4593	4745	152	4728	135
19	5705	5872	167	5829	124	4484	4632	148	4615	131
20	5521	5606	164	5813	291	4360	4509	149	4604	244
21	5432	5597	165	5991	559	4189	4330	141	4428	239
22	5206	5363	157	5933	727	4310	4453	143	4551	241
23	4950	5101	151	5836	886	3925	4057	132	4155	230
24	4668	4813	145	5516	848	3478	3600	128	3653	181

YEAR=1995

HOUR	LOADHB	LOADH1	DIFH1	LOADH2	DIFH2	LOADSB	LOADS1	DIFS1	LOADS2	DIFS2
1	4378	4535	157	5359	981	3025	3145	120	3149	124
2	4312	4469	157	5264	952	2937	3061	124	3062	125
3	4293	4450	157	5204	911	2816	2937	121	2938	122
4	4359	4517	158	5269	910	2692	2807	115	2808	116
5	4427	4586	159	5109	682	2691	2806	115	2807	116
6	4691	4855	164	5067	376	2841	2964	123	2965	124
7	5413	5592	179	5588	175	3337	3476	139	3480	143
8	6069	6277	208	6114	45	3978	4150	172	4114	136
9	6150	6372	222	6222	72	4387	4580	193	4548	161
10	6009	6228	219	6078	69	4587	4785	198	4753	166
11	5929	6150	221	6007	78	4774	4981	207	4954	180
12	5768	5983	215	5844	76	4885	5097	212	5073	188
13	5628	5839	211	5705	77	4927	5138	211	5114	187
14	5604	5818	214	5688	84	4960	5172	212	5156	196
15	5521	5730	209	5600	79	4862	5070	208	5054	192
16	5405	5605	200	5477	72	4749	4946	197	4930	181
17	5477	5665	188	5530	53	4771	4958	187	4942	171
18	5783	5972	189	5837	54	4658	4829	171	4809	151
19	5790	5976	186	5927	137	4548	4715	167	4695	147
20	5604	5785	181	5936	332	4423	4591	168	4703	280
21	5512	5694	182	6157	645	4249	4408	159	4524	275
22	5283	5456	173	6123	840	4372	4533	161	4649	277
23	5024	5191	167	6049	1025	3981	4130	149	4246	265
24	4737	4898	161	5718	981	3521	3665	144	3726	205

PCCX0150 PENNSYLVANIA POWER & LIGHT COMPANY 15:23 THURSDAY, SEPTEMBER 4, 1986

HOURLY LOADS UNDER SCENARIOS AND [illegible]

[illegible]

YEAR=1996

HOUR	LOADHB	LOADM1	DIFM1	LOADM2	DIFM2	LOADSB	LOADS1	DIFS1	LOADS2	DIFS2
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
3	4384	4556	172	5417	1033	2867	3001	134	3002	135
4	4451	4625	174	5485	1034	2741	2869	128	2870	129
5	4520	4695	175	5292	772	2739	2866	127	2867	128
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
9	6280	[illegible]	244	6351	71	4467	4681	214	4644	177
10	6136	6378	242	6206	70	4671	4890	219	4853	182
11	6054	6298	244	6133	79	4861	5090	229	5058	197
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
15	5638	5869	231	5718	80	4950	5180	230	5161	211
16	5520	5740	220	5591	71	4836	5055	219	5036	200
17	5592	5800	208	5643	51	4857	5065	208	5046	189
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
21	5629	5830	201	6364	735	4326	4503	177	4636	310
22	5395	5586	191	6352	957	4451	4630	179	4765	312
23	5130	5313	183	6294	1164	4054	4219	165	4352	298
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

YEAR=1997

HOUR	LOADHB	LOADM1	DIFM1	LOADM2	DIFM2	LOADSB	LOADS1	DIFS1	LOADS2	DIFS2
[illegible]	4554	4744	188	5804	1248	3135	3283	148	3288	153
[illegible]	[illegible]	[illegible]	189	5708	1213	3043	3196	153	3198	155
3	4468	4656	188	5627	1159	2918	3067	149	3069	151
4	4536	4726	190	5695	1159	2789	2931	142	2933	144
5	4607	4798	191	5471	864	2788	2929	141	2931	143
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	470	[illegible]	[illegible]	[illegible]	3097	153
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	176
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
9	6400	6666	266	6468	68	4547	4785	238	4743	196
10	6253	6517	264	6321	68	4754	4997	243	4955	201
11	6170	6437	267	6249	79	4947	5201	254	5165	218
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	5291	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	5354	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	5379	[illegible]
15	5746	5999	253	5827	81	5038	5294	256	5273	235
16	5625	5866	241	5698	73	4922	5165	243	5144	222
17	5699	5925	226	5745	46	4944	5175	231	5154	210
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	5037	[illegible]	5011	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	4918	[illegible]	4892	179
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	4790	207	4935	[illegible]
21	5736	5955	219	6563	827	4403	4599	196	4749	346
22	5498	5706	208	6574	1076	4631	4729	198	4879	348
23	5228	5428	200	6536	1308	4126	4309	183	4459	333
[illegible]	[illegible]	[illegible]	193	6178	1248	3649	3826	177	3907	258

EXHIBIT JJS 9

Rebuttal Testimony of John J. Slivka
Docket No. R-00943271

TABLES3.TES

PENNSYLVANIA POWER & LIGHT COMPANY Customers With Residential Thermal Storage Heating				
	Actual	9/86 Integrated Forecast		
		New Construction	Conversions	Totals
1986	1,095	1,021	120	1,141
1987	2,411	1,759	620	2,379
1988	4,668	3,033	2,120	5,153
1989	6,919	4,707	5,120	9,827
1990	9,021	6,760	9,620	16,380
1991	10,842	9,019	14,120	23,139
1992	12,280	11,516	18,620	30,136
1993	13,347	14,256	23,120	37,376
1994	14,028	17,225	27,620	44,845

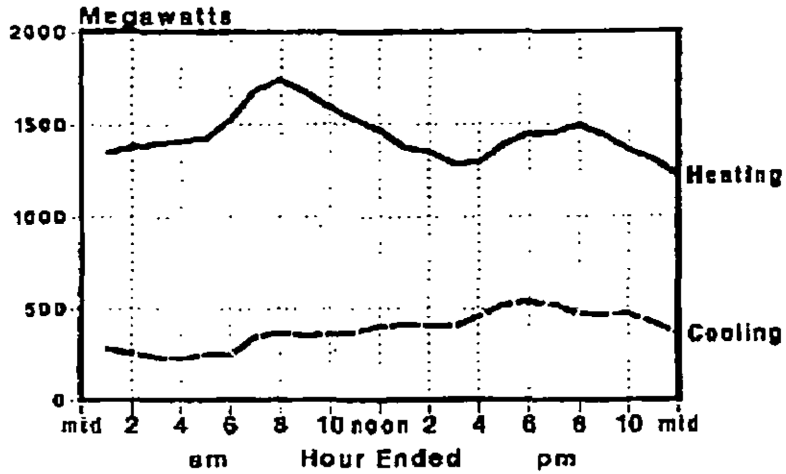
EXHIBIT JJS 10

Rebuttal Testimony of John J. Slivka
Docket No. R-00943271

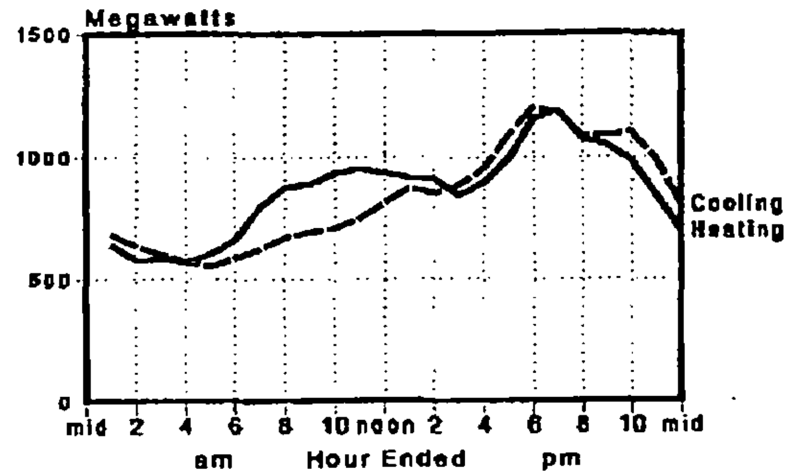
Customer Class Heating and Cooling Season System Peaks

Heating: January 21, 1985   Cooling: August 15, 1985

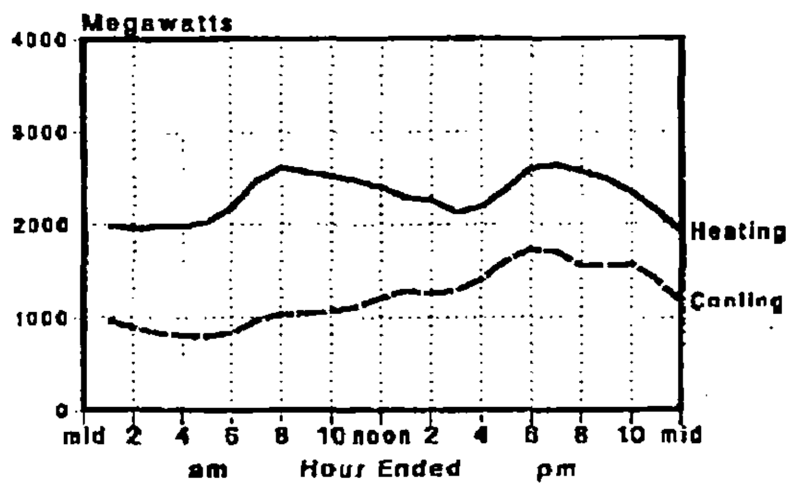
Electric Heat (EHH)



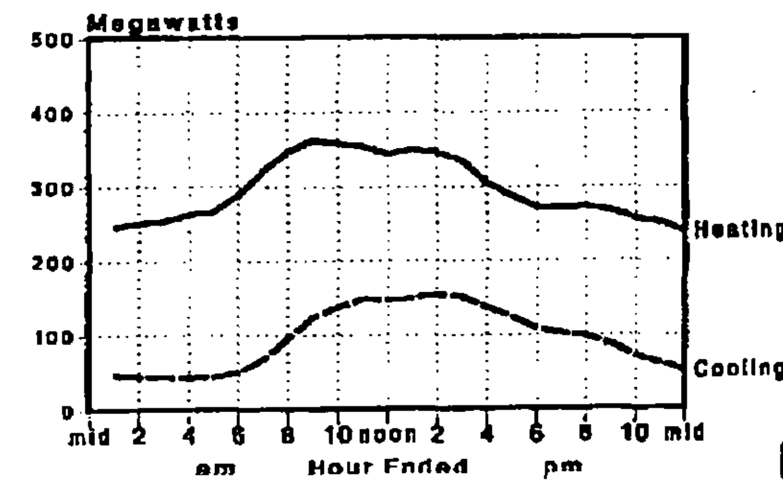
General Residential (GRS)



Residential Service (RS)



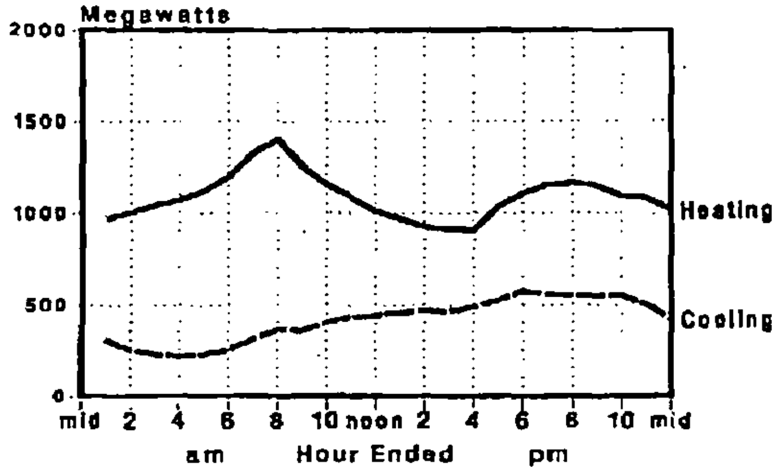
Commercial & Industrial (GH)



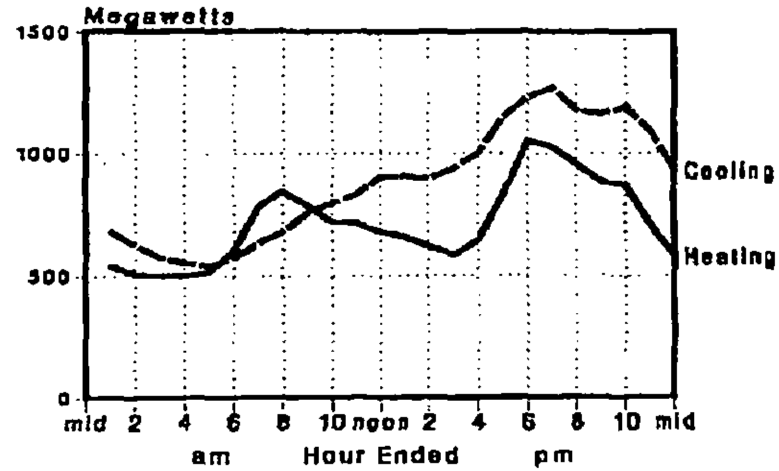
Customer Class Heating and Cooling Season System Peaks

Heating: January 15, 1986 Cooling: July 7, 1986

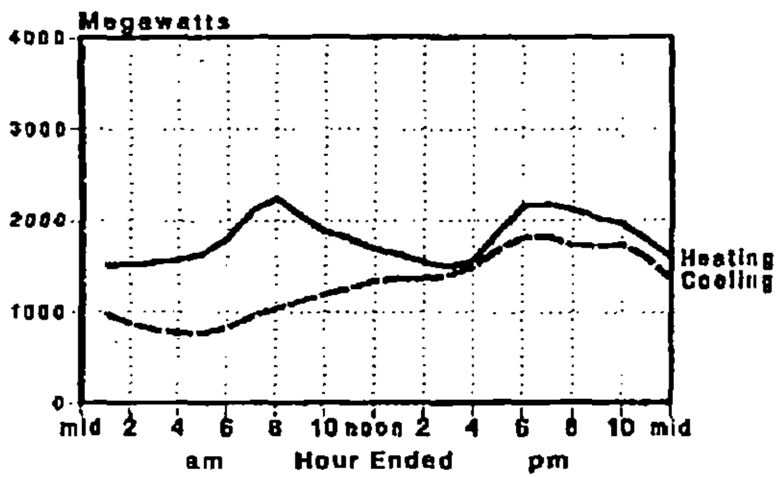
Electric Heat (EHH)



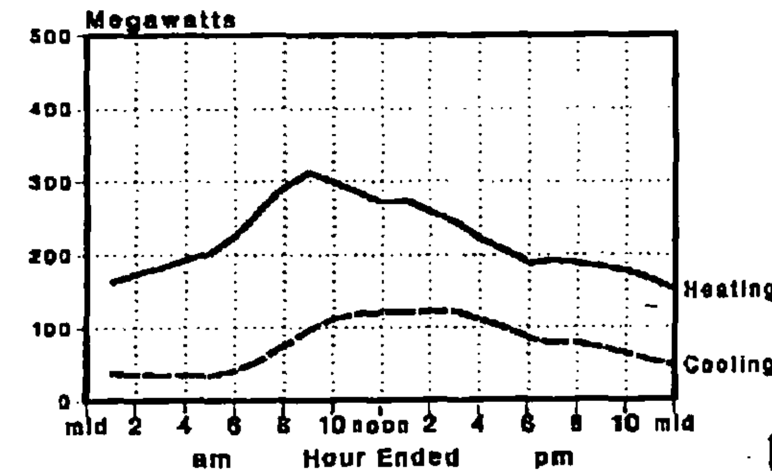
General Residential (GRS)



Residential Service (RS)



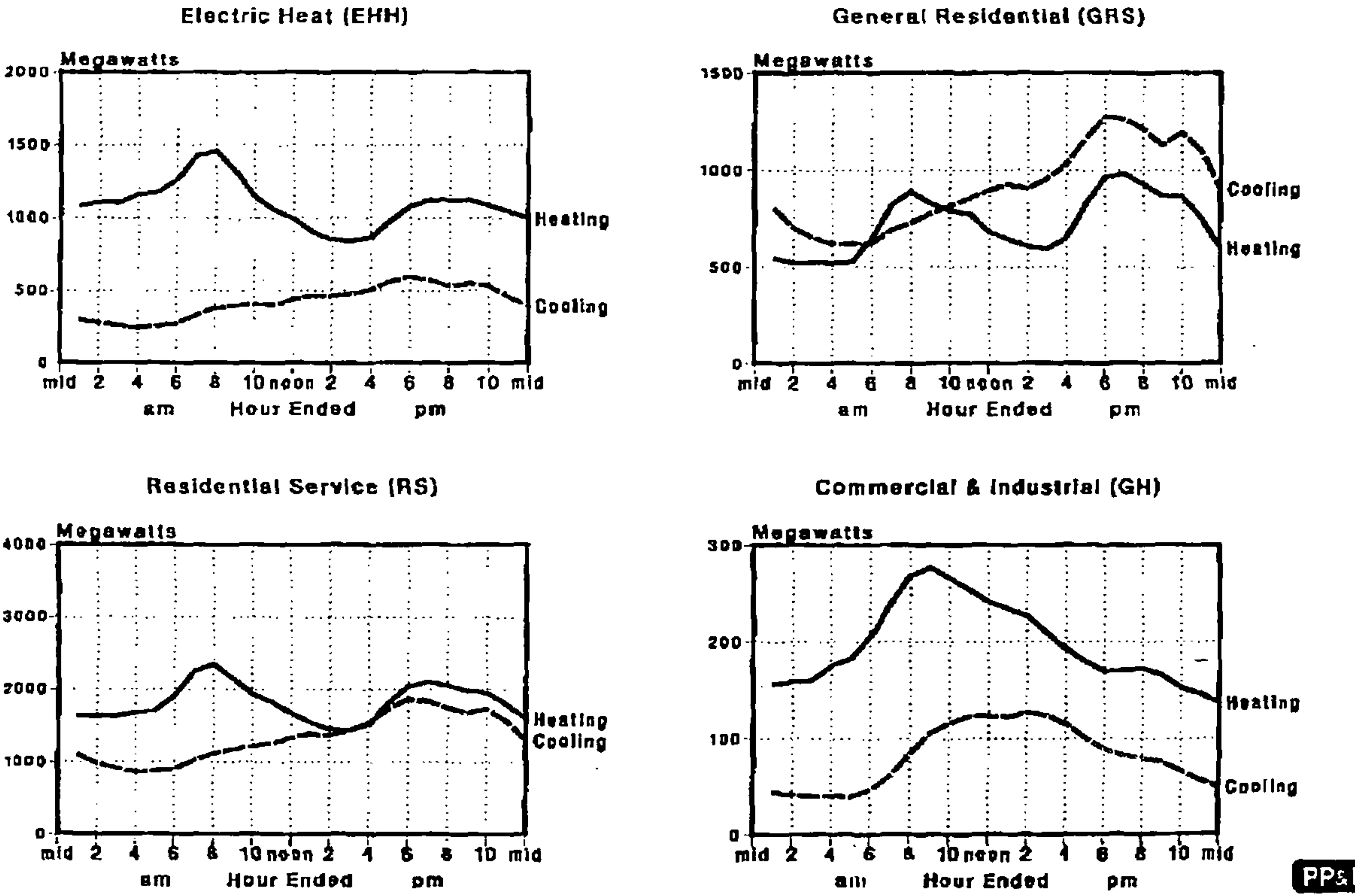
Commercial & Industrial (GH)



PP&L

Customer Class Heating and Cooling Season System Peaks

Heating: January 28, 1987 Cooling: July 22, 1987

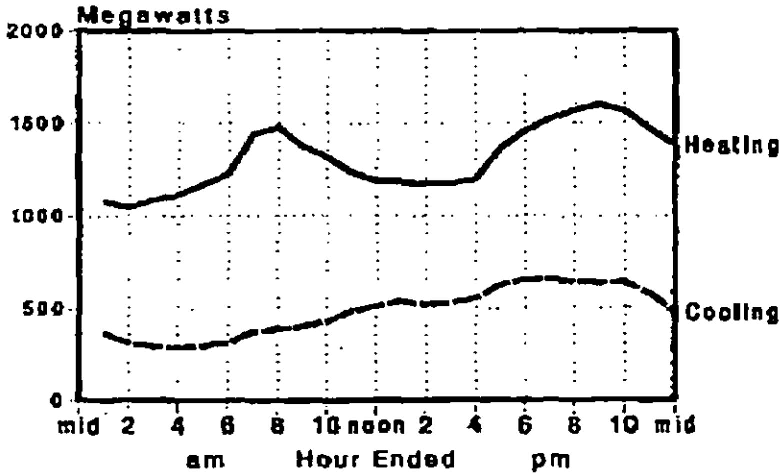


PP&L

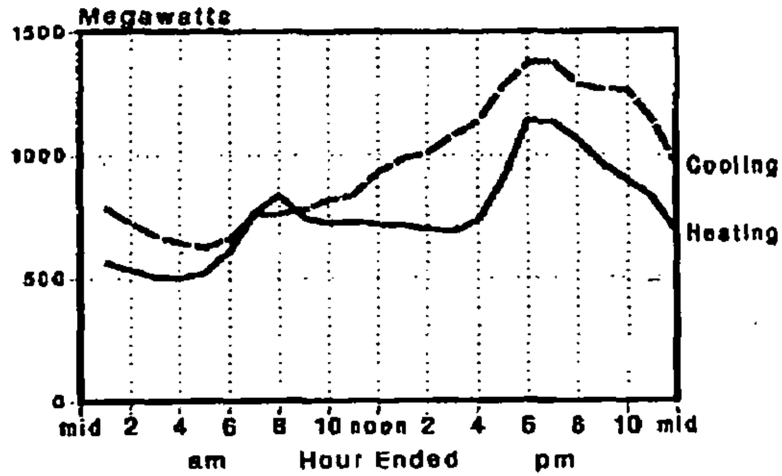
Customer Class Heating and Cooling Season System Peaks

Heating: January 5, 1988 Cooling: August 11, 1988

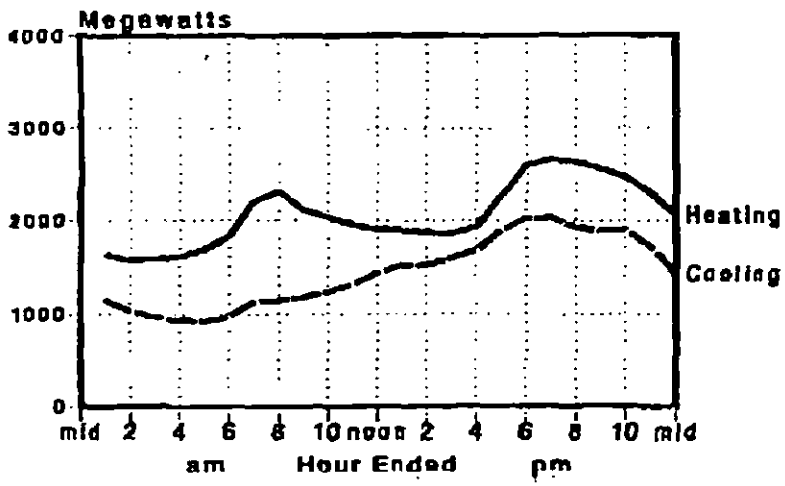
Electric Heat (EHH)



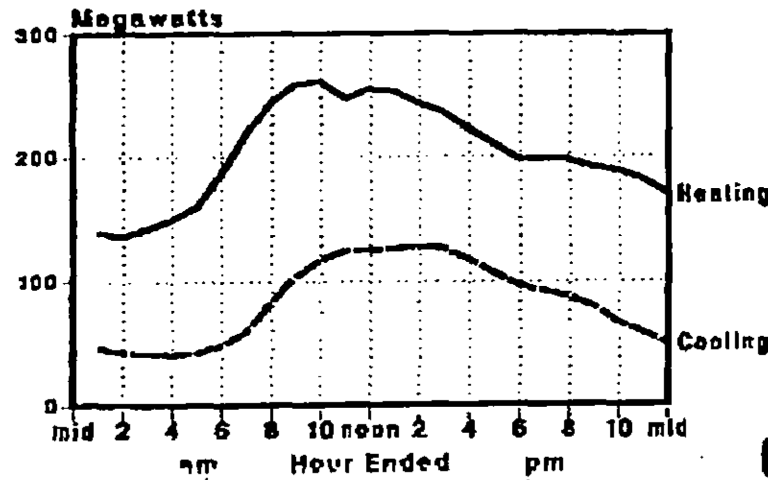
General Residential (GRS)



Residential Service (RS)



Commercial & Industrial (GH)

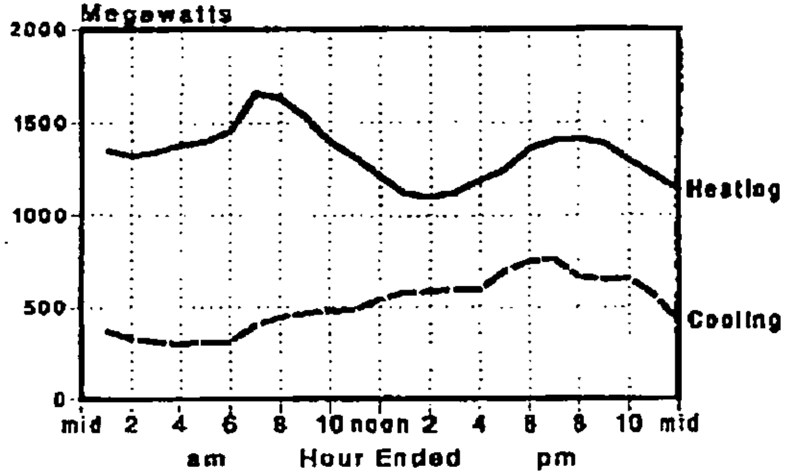


PP&L

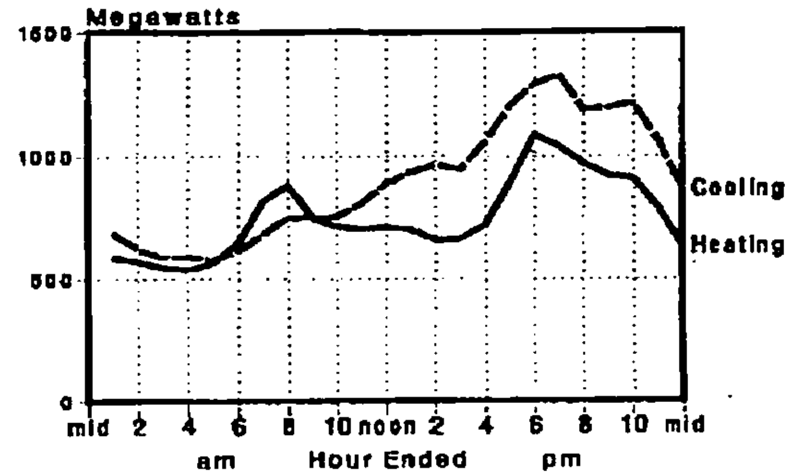
Customer Class Heating and Cooling Season System Peaks

Heating: January 5, 1989 Cooling: July 26, 1989

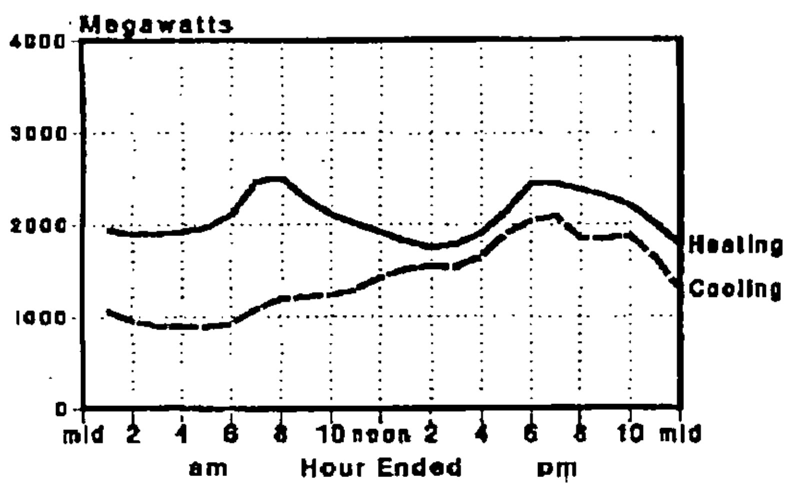
Electric Heat (EHH)



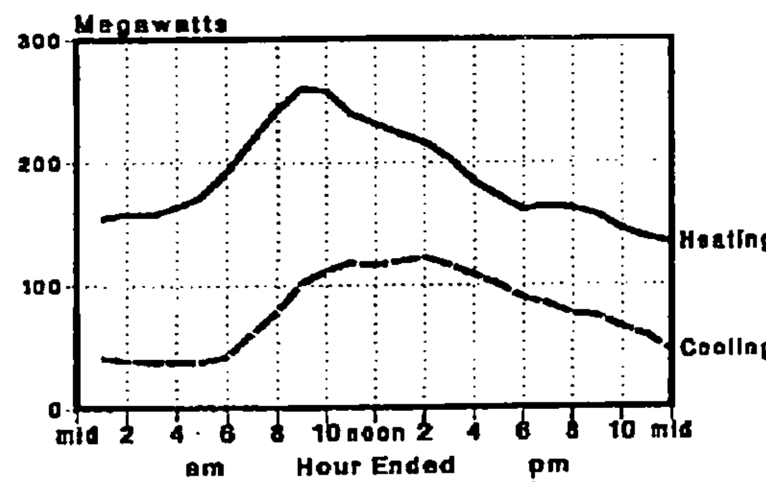
General Residential (GRS)



Residential Service (RS)



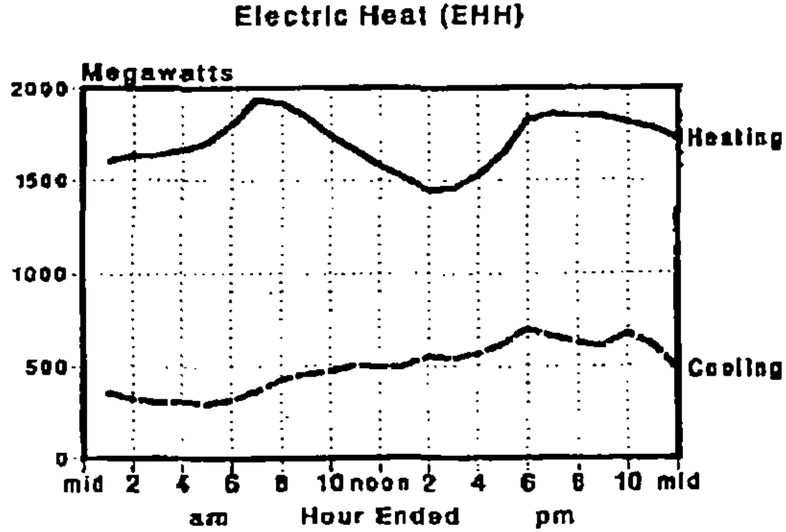
Commercial & Industrial (GH)

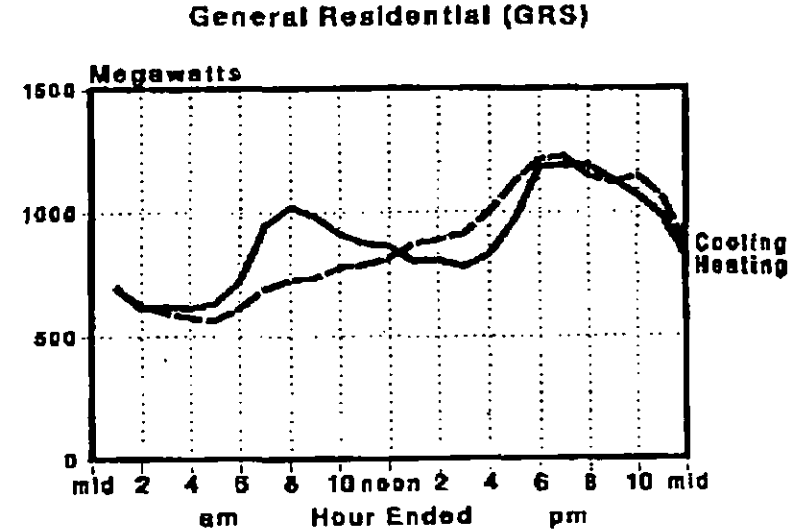


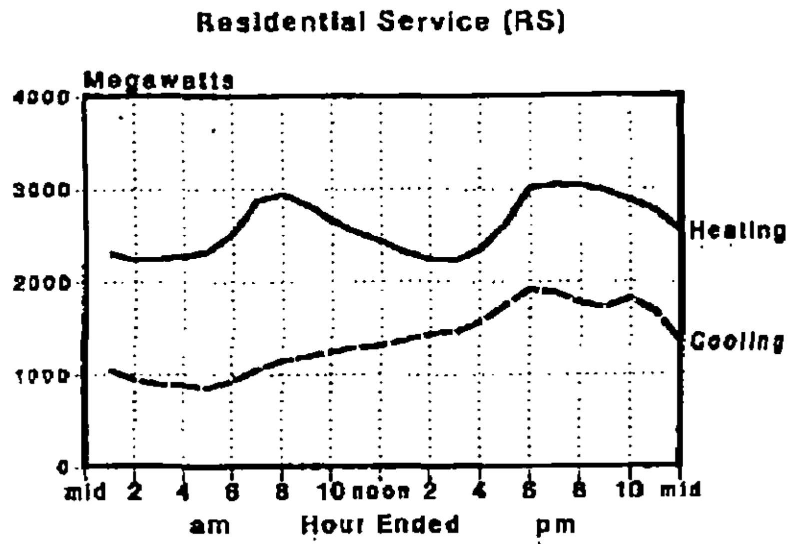
PP&L

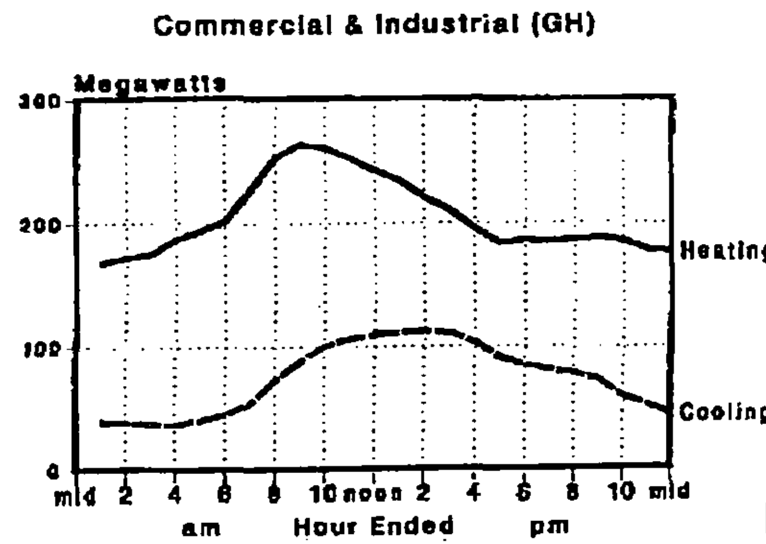
Customer Class Heating and Cooling Season System Peaks

Heating: December 22, 1989   Cooling: July 19, 1990







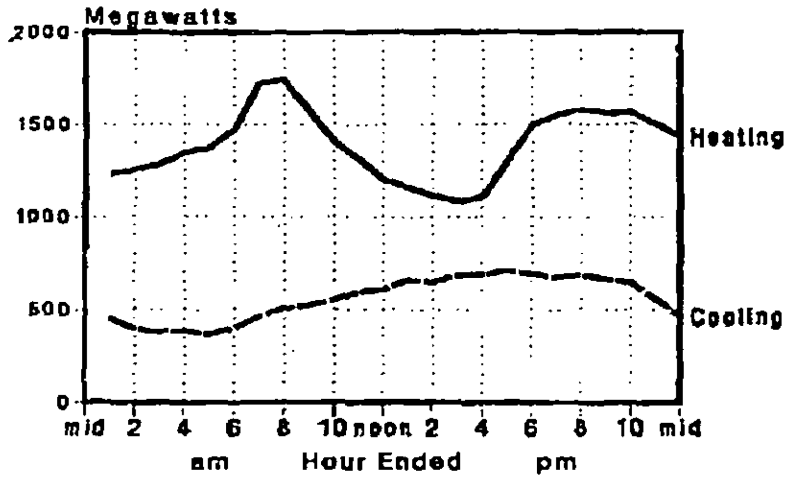


PP&L

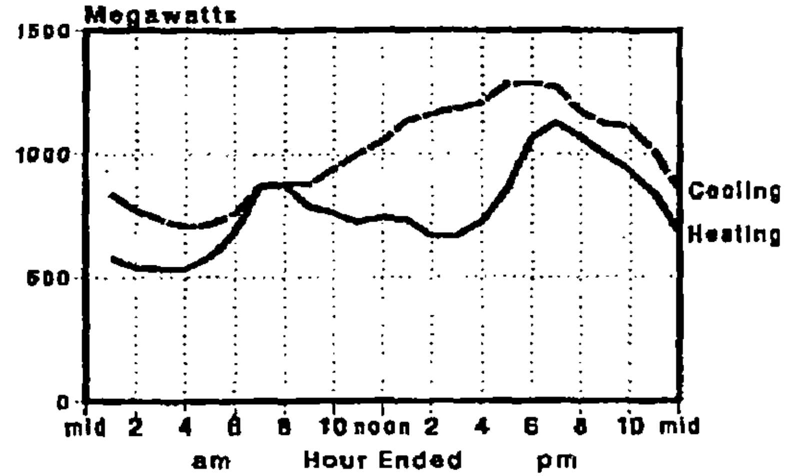
Customer Class Heating and Cooling Season System Peaks

Heating: January 22, 1991   Cooling: July 23, 1991

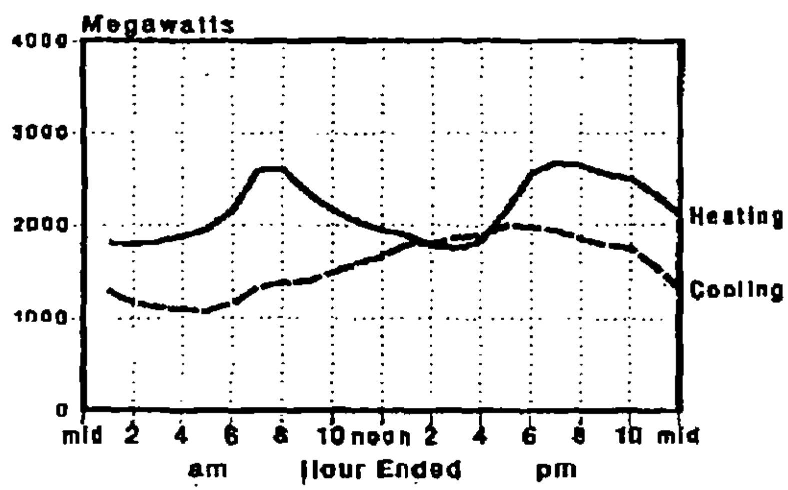
Electric Heat (EHH)



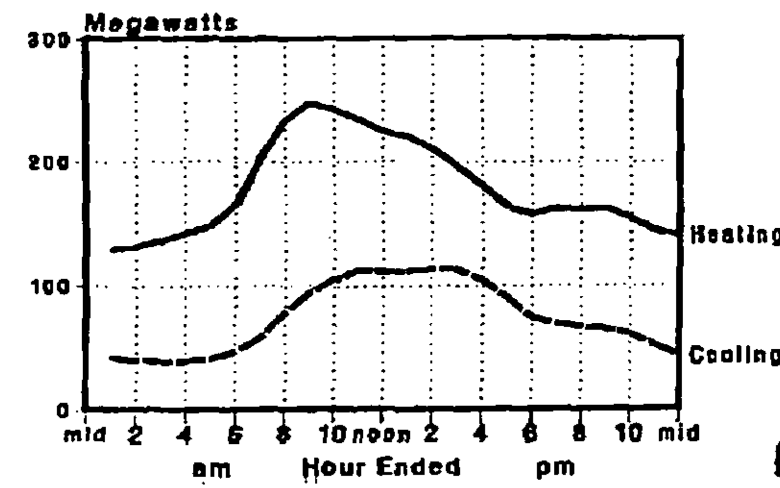
General Residential (GRS)



Residential Service (RS)



Commercial & Industrial (GH)

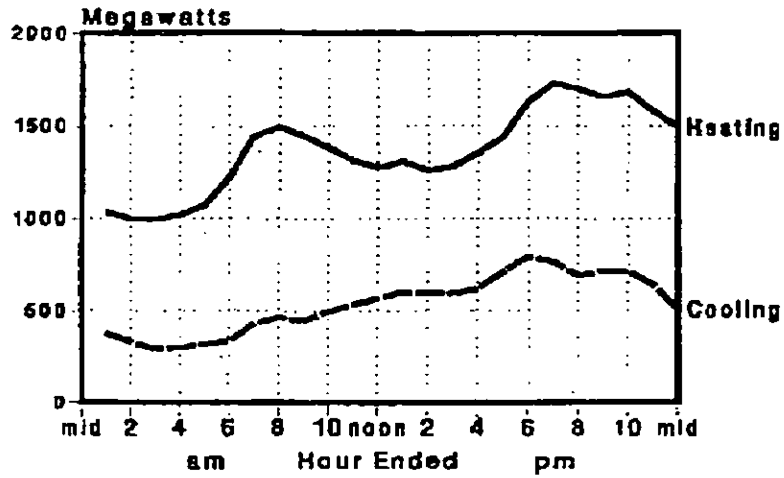


PP&L

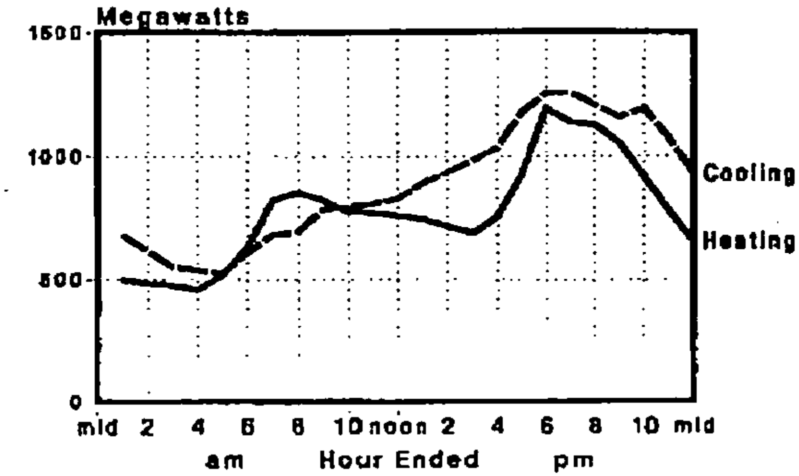
Customer Class Heating and Cooling Season System Peaks

Heating: January 16, 1992 Cooling: July 14, 1992

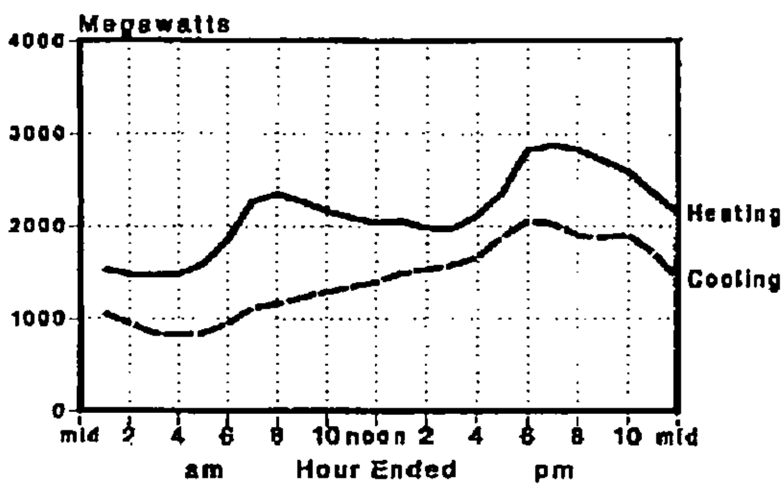
Electric Heat (EHH)



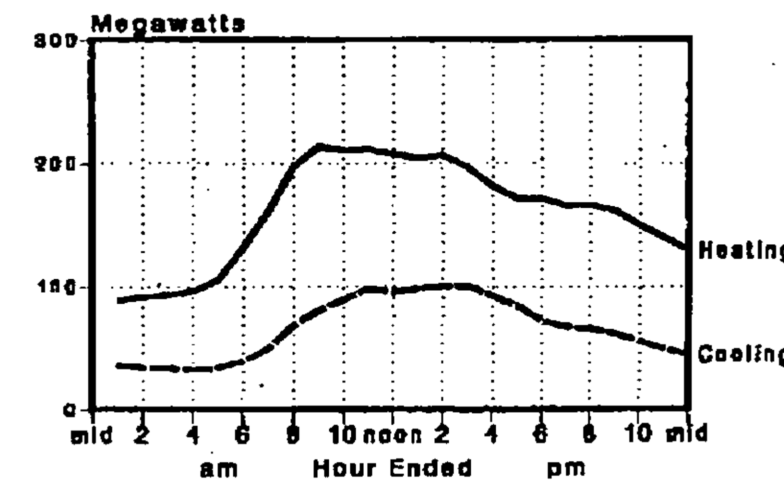
General Residential (GRS)



Residential Service (RS)



Commercial & Industrial (GH)

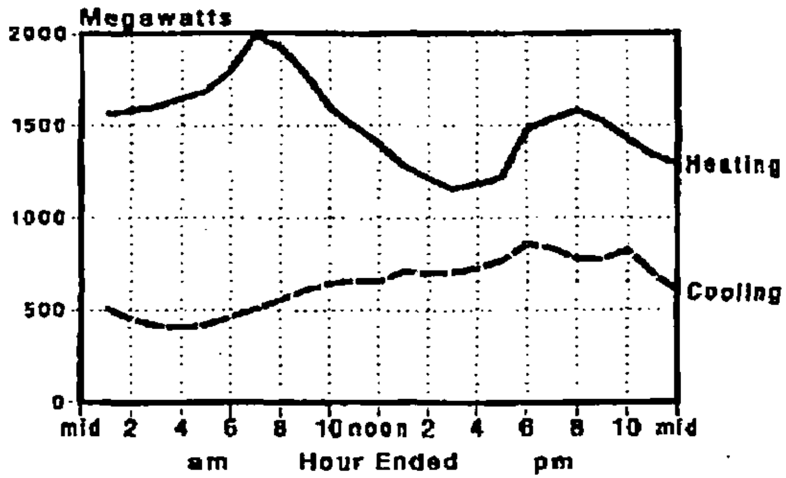


PP&L

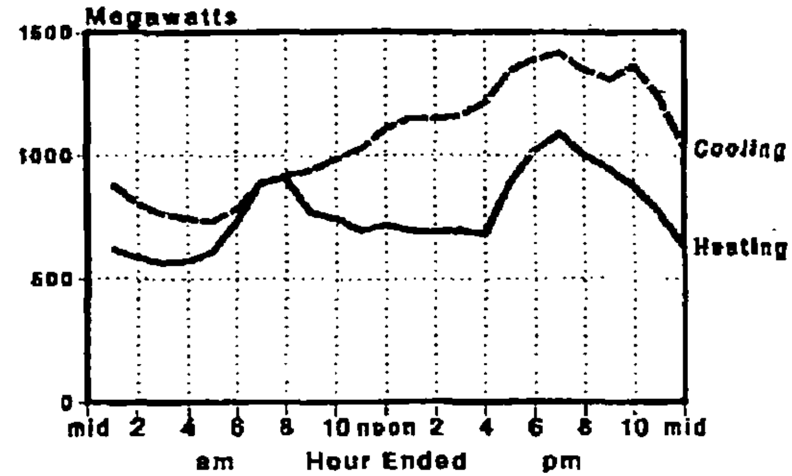
Customer Class Heating and Cooling Season System Peaks

Heating: February 2, 1993   Cooling: July 8, 1993

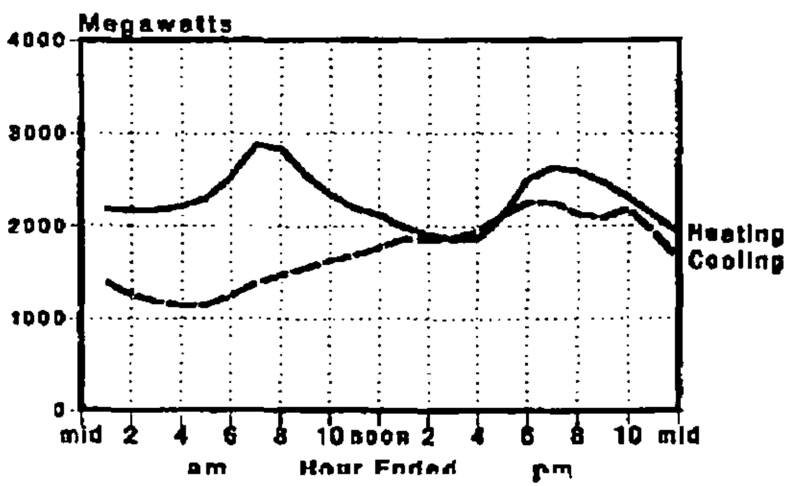
Electric Heat (EHH)



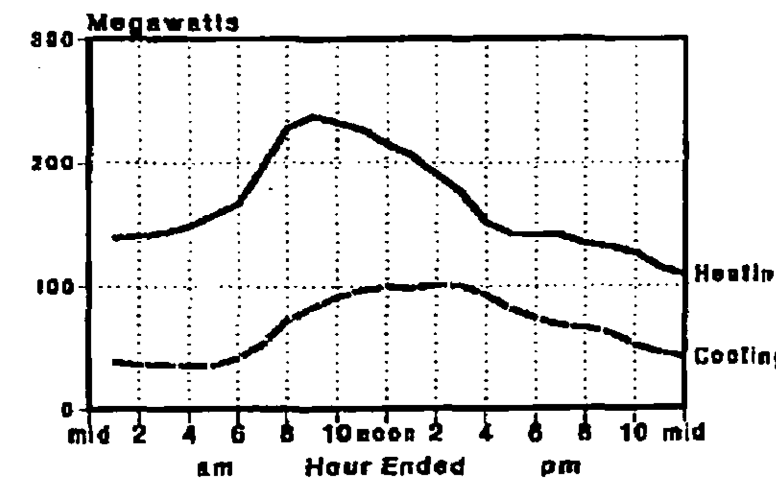
General Residential (GRS)



Residential Service (RS)



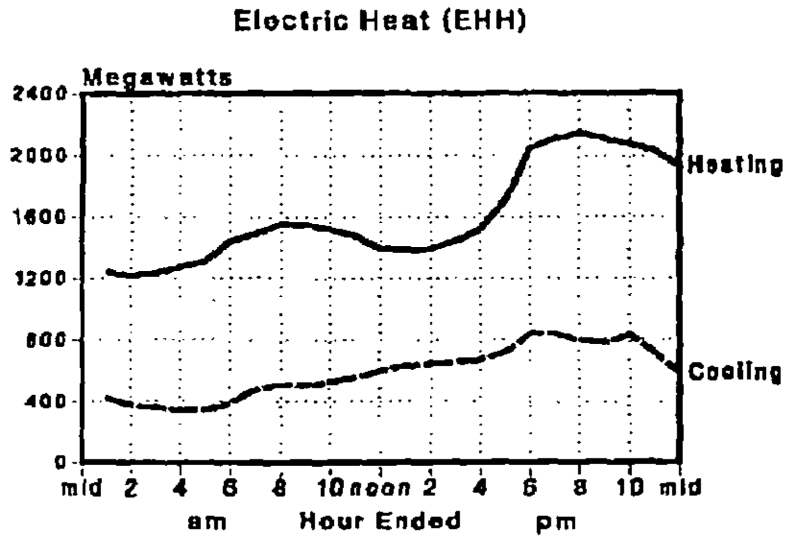
Commercial & Industrial (GH)

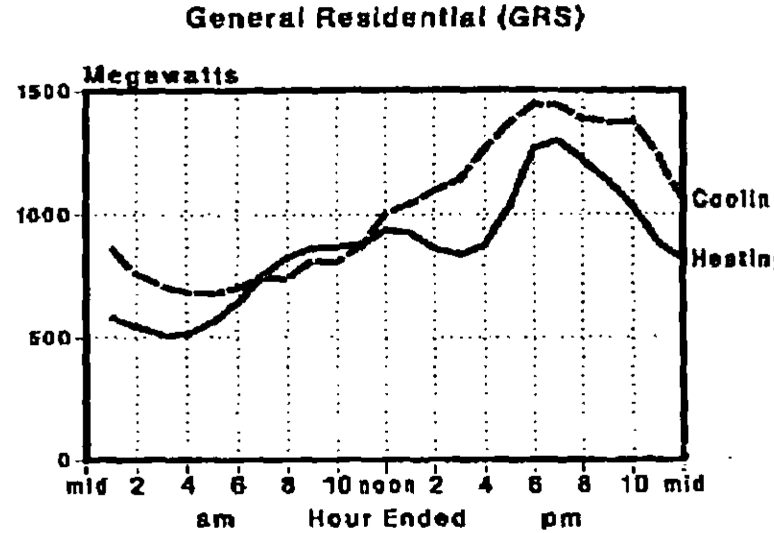


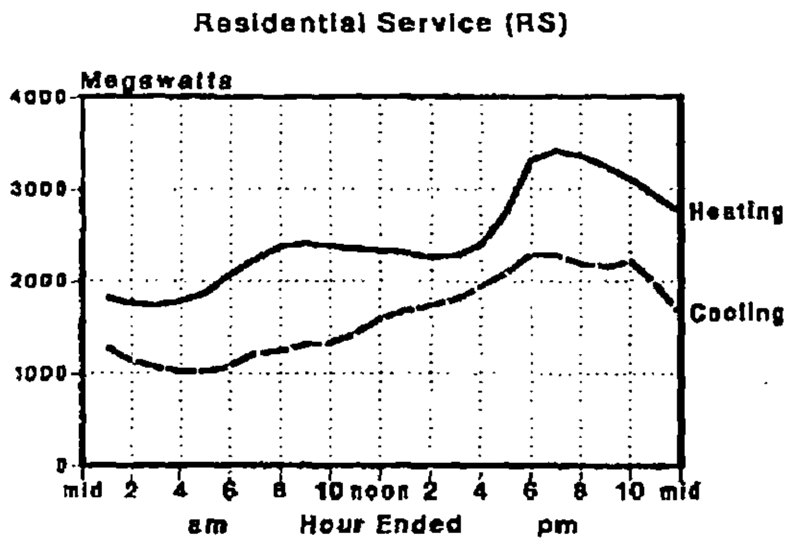
PP&L

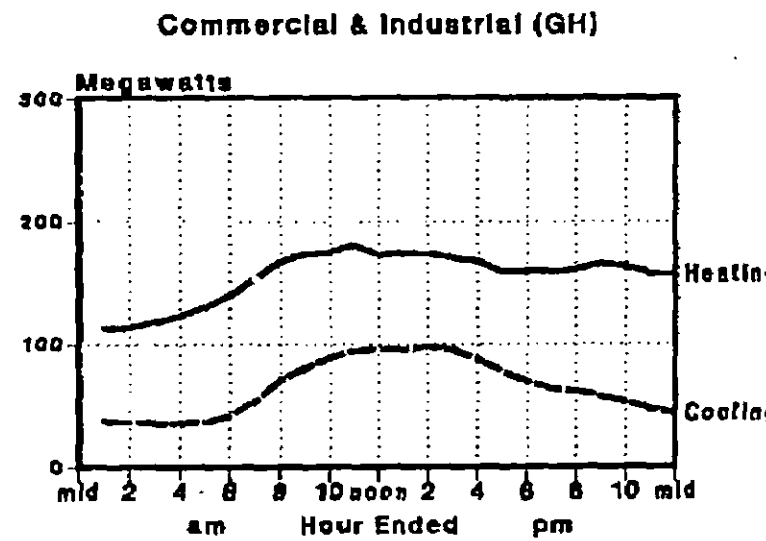
Customer Class Heating and Cooling Season System Pea...

Heating: January 18, 1994 Cooling: July 20, 1994









PP&L

EXHIBIT JJS 11

Rebuttal Testimony of John J. Slivka
Docket No. R-00943271

January and February Weekday Peaks Occurring during Particular Hours

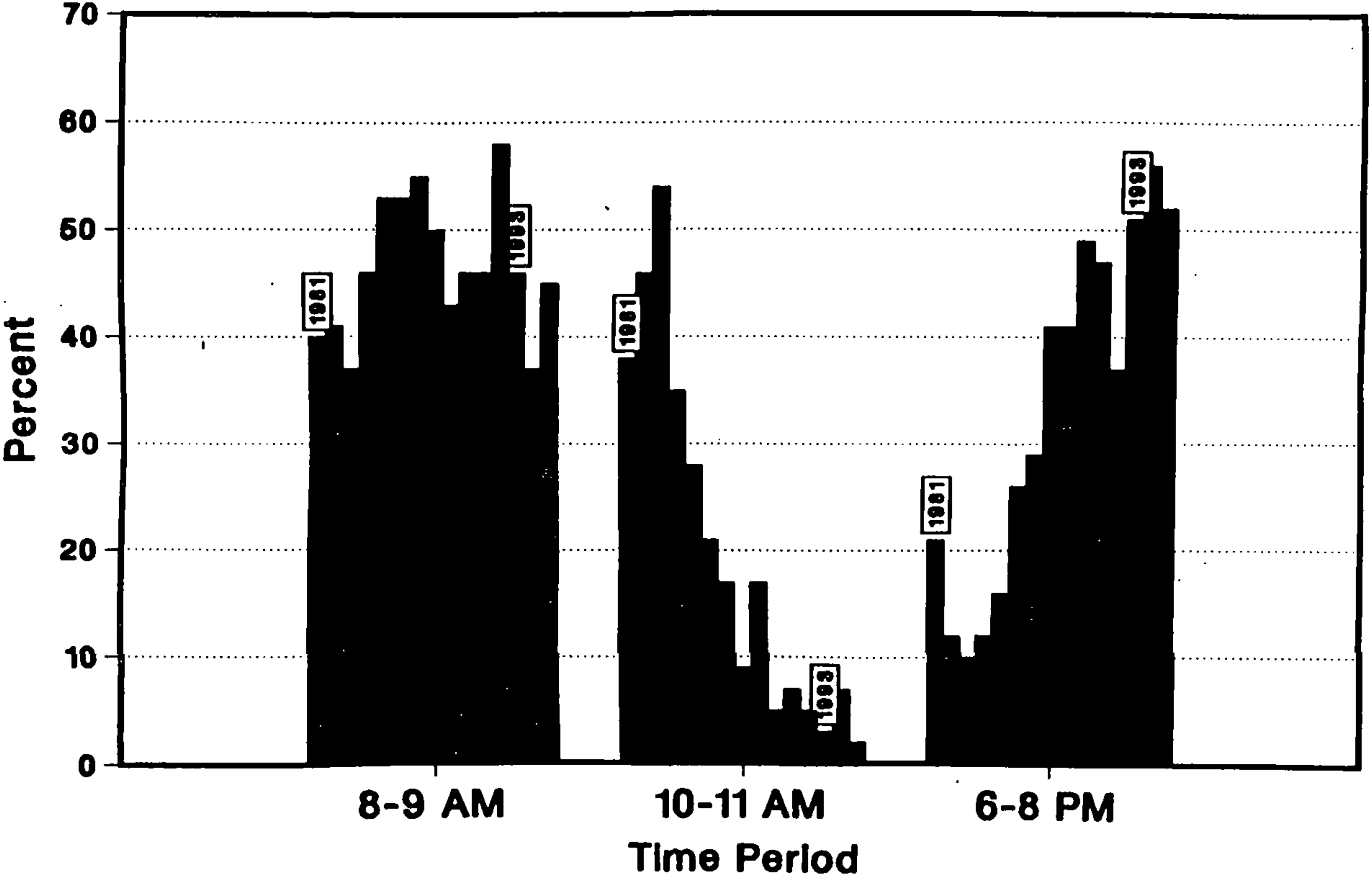


EXHIBIT JJS 12

Rebuttal Testimony of John J. Slivka
Docket No. R-00943271

Bethlehem Steel
Ex 1R
gv
5-25-95
KG
R-943271

Before the

Pennsylvania Public Utility Commission

Docket No. R-00943271

PENNSYLVANIA POWER & LIGHT COMPANY

Rebuttal Testimony and Exhibit

of

MAURICE BRUBAKER

On Behalf of

Bethlehem Steel Corporation

Project 6308
May 1995

Brubaker & Associates, Inc.
St. Louis, Missouri 63105-0840

PENNSYLVANIA POWER & LIGHT COMPANY

Before the

Pennsylvania Public Utility Commission

Docket No. R-00943271

Rebuttal Testimony of Maurice Brubaker

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Maurice Brubaker, 7730 Forsyth Boulevard, St. Louis, Missouri.

Q ARE YOU THE SAME MAURICE BRUBAKER WHO HAS PREVIOUSLY SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A Yes.

Q WHAT IS THE SUBJECT OF YOUR REBUTTAL TESTIMONY?

A I am addressing certain portions of the direct testimony of Dr. Charles Johnson, a witness appearing on behalf of the Office of Consumer Advocate (OCA). In particular, I address Dr. Johnson's proposed demand allocation methodology. The fact that I do not address other aspects of Dr. Johnson's testimony (including his comments concerning interruptible power) or the testimony of other witnesses, should not be interpreted as an endorsement of opinions or recommendations expressed elsewhere by Dr. Johnson or by the other witnesses.

Q WHAT DEMAND ALLOCATION METHODOLOGY HAS DR. JOHNSON PROPOSED TO USE IN THIS CASE?

A Dr. Johnson has proposed to use what he describes as the "peak and average" (P&A) method.

Q DO YOU AGREE WITH DR. JOHNSON THAT THE P&A METHOD IS APPROPRIATE?

A No, I do not. The P&A method is seriously flawed and should not be used.

Q WHAT ARE THE FLAWS WITH THE P&A METHOD?

A The P&A method is based on the theory of capital substitution (CAPSUB). Under this theory, it is assumed that an electric utility will invest in more expensive types of generating capacity in order to achieve the lower fuel cost associated with that capacity as compared with the fuel costs of peaking units. Given this assumed substitution of capital investment for fuel cost, the proponents argue that a substantial portion of the plant-related costs associated with generating units should be classified and allocated relative to <u>annual</u> <u>energy</u> <u>usage</u>. In this case, Dr. Johnson argues in favor of using the system load factor, which he calculates to be 61.05%, to define the proportion of capital costs to be allocated on energy.

CAPSUB-based allocation methods, like P&A, have four principal flaws. They are:

(1) The CAPSUB postulate is an oversimplification of the system planning process.

(2) CAPSUB-based allocation methods fail to appropriately recognize the trade-offs between capital and operating costs, a flaw which is often referred to as the "Fuel Symmetry" problem.

(3) Energy consumption (or average demand) is double-counted.

(4) The assumption that capital investment decisions are related to annual kWh sales is unfounded.

OVERSIMPLIFICATION OF THE PLANNING PROCESS

Q DO UTILITY PLANNERS CHOOSE TO CONSTRUCT MORE CAPITAL INTENSIVE (I.E., BASE LOAD AND INTERMEDIATE) CAPACITY FOR THE PURPOSE OF ACHIEVING REDUCED FUEL COSTS?

A No. The CAPSUB postulate is an oversimplification of the planning process. In reality, planners are faced with the dual dimensions of (1) providing reliable service and (2) minimizing total cost. Because electric energy cannot be stored in large quantities for any significant length of time, providing reliable service requires construction of generating capacity sufficient to meet the projected system peak demands and to provide an adequate reserve margin. This will ensure that whenever a consumer flips the switch an electric light or other appliance will operate. Firm customers often take it for granted that electricity will be instantaneously available whenever and at whatever rate of usage and quantity they demand.

Cost minimization is the requirement that the utility provide the service at the lowest overall cost. The utility strives to install the mix of generating capacity (i.e., base, intermediate and peaking) that, along with the existing generation, yields the lowest total cost. **In other words, the economic choice between a base load unit and a peaking unit must consider both capital costs and operating costs, and therefore is a function of average *total* costs.**

The capital cost of peaking units is lower than the capital cost of base load units, but the operating costs of peaking units are higher than the operating costs of base load units. Moreover, when the hours of use are considered, the capital cost of the base load unit is usually less than the capital cost of the peaking unit, when expressed on a per kilowatthour basis. Of course, since the fuel costs of base load units are generally lower than the fuel costs of peaking units, the overall cost per kilowatthour for base load units is also less than the overall cost per kilowatthour for peaking units.

System planners, therefore, must consider both capital costs and operating costs in light of the expected capacity factor of a new unit. **The fact that base load units typically have lower fuel costs than peaking units does not mean that the investment in base load units is made to achieve lower fuel costs.** Investment in a base load unit would be made to achieve lower <u>total</u> costs, of which capital costs and operating costs are the primary ingredients.

Q **ARE THERE ANY OTHER FACTORS, BESIDES THE ECONOMIC TRADE-OFFS, THAT CAN AFFECT UTILITY INVESTMENT DECISIONS?**

A Yes. For example, the decision can be affected by the existing generation mix, the availability of a suitable site for the unit, environmental restrictions, access to an ample supply of cooling water, the ability to obtain transmission rights of way, system stability, licensing, government and other regulatory restrictions, fuel supply, fuel diversification, access to facilities to transport fuel to the plant, political priorities, etc.

FUEL SYMMETRY

Q TURNING TO YOUR SECOND CRITICISM, IN WHAT WAY DO CAPSUB ALLOCATION METHODS FAIL TO SYMMETRICALLY ALLOCATE BOTH CAPITAL AND OPERATING COSTS?

A Typical CAPSUB methods focus on the allocation of the investment in production units. For example, Dr. Johnson's P&A method allocates more production investment costs to high load factor classes than does either a coincident peak method or an average and excess method. This result is claimed to be fair by CAPSUB proponents, on the theory that the high load factor customers require relatively more base load capacity and because the capital costs of base load units tend to be higher than either intermediate or peaking units.

CAPSUB advocates, however, usually make no attempt to recognize the other side of the capital cost/operating cost trade-off; that is, base load units may have above-average capital costs, but they usually have below-average operating costs relative to either intermediate or peaking units. Dr. Johnson is no exception. Ignoring the fuel cost differentials creates a fundamental mismatch between theory and application.

Q PLEASE ELABORATE.

A Under the P&A allocation, all customer classes, regardless of load factor, are allocated the same average fuel cost per kilowatthour. Except for line losses, there is no fuel cost distinction among classes. In contrast, the effect of the P&A method is to allocate more capacity cost per kilowatt of peak load to high load factor customer classes than to low load factor customer classes. Thus, the P&A method "de-averages" capital costs for purposes of class cost allocation, but completely ignores theory and allocates fuel costs on a uniform basis to all customer classes regardless of load factor.

Q **CAN YOU DEMONSTRATE THIS LACK OF SYMMETRY IN DR. JOHNSON'S ALLOCATION?**

A Yes. I calculated the generation plant net investment per kilowatt, and the fuel costs per kilowatthour, for selected classes from Dr. Johnson's workpapers. The information appears in the following table:

P&A Allocation of Generation Plant Net Investment and Fuel Cost to Selected Classes

	Generation Plant Net Investment		Fuel Cost	
Class	Per kW (1)	Index (2)	Per kWh (3)	Index (4)
RS	$569	90	1.29¢	100
GS-1	618	98	1.29¢	100
LP-5	763	121	1.29¢	100
Total PA Jurisdiction	$631	100	1.29¢	100

Note that while the generation plant net investment per kilowatt of demand varies substantially across customer classes, the fuel cost per kilowatthour is identical! If Dr. Johnson were consistent in the application of his theory, customers receiving an above-average allocation of generation plant investment (such as LP-5) would receive a below-average fuel cost.

Q WHY SHOULD THE FUEL COST ALLOCATION BE DE-AVERAGED IF A P&A ALLOCATION METHOD IS USED FOR CAPACITY?

A As discussed above, the basic premise of the P&A theory is that higher load factor customers require or receive a disproportionate benefit from base load units. Since base load units have below-average fuel costs, those customer classes (high load factor) that receive an above-average allocation of the capital costs should correspondingly receive fuel costs that are below the average. Similarly, a low load factor class, that is allocated a below-average plant investment per kilowatt of demand, should be allocated an above-average fuel cost. The P&A method looks only at the capital cost side and completely fails to come to grips with the resulting distortions in the allocation of fuel costs.

To use an analogy, suppose that two different customers need to rent a fleet of cars and that there are two types of cars. One type has a high fixed charge per day and gets many miles to the gallon (which is analogous to a base load unit), while the other type has a low fixed charge per day and gets poor mileage (which is analogous to a peaking unit). The P&A method argues that a customer who drives a car only a few miles per day (i.e., a low load factor customer) should be allocated more gas guzzlers and fewer of the more efficient cars, with the opposite type of allocation for the customer that will put in many miles per day (i.e., a high load factor customer). While arguing that the lower load factor customer should pay a lower daily charge for the car than the higher load factor customer, the P&A method fails to recognize that the lower load factor customer should accordingly pay a higher mileage charge than the higher load factor customer in order to recognize the higher fuel costs of the gas guzzler.

Q HAS THE FUEL SYMMETRY PROBLEM BEEN CITED BY ANY OTHER REGULATORY COMMISSIONS AS A REASON FOR REJECTING CAPSUB-BASED ALLOCATION METHODS?

A Yes. The fuel symmetry problem was one of the primary reasons cited by the Public Utility Commission of Texas in rejecting every type of CAPSUB-based allocation method proposed in rate cases throughout the 1980s and 1990s (see for example Docket No. 5560; Docket No. 5700; Docket Nos. 7460 and 7172; Docket No. 8032).

For instance, in Docket No. 7460, the Texas Commission adopted the Hearing Examiner's Report, which cited the lack of "fuel symmetry" in rejecting capital substitution.

> "The Examiner's find that the most important flaw in Dr. Johnson's capital substitution methodology is the lack of symmetry, both as to fuel and as to operations and maintenance expense. To the extent that relative class energy consumption becomes the primary factor in apportioning capacity costs as between customer classes, as is the case with Dr. Johnson's proposal, the high load factor classes, which will bear higher cost responsibility for base load units will not also receive the benefit of the lower operating costs and lower fuel costs associated with those units." (El Paso Electric Company, <u>Examiner's Report</u>, Docket Nos. 7460 and 7172, Pages 355-356; emphasis added)

Q THE ABOVE CITATION REFERS TO A DR. JOHNSON. IS THIS THE SAME DR. JOHNSON WHO IS TESTIFYING ON BEHALF OF THE OCA IN THIS DOCKET?

A No, but the theory is the same.

DOUBLE-COUNTING

Q TURNING TO YOUR THIRD CRITICISM, WHAT IS THE DOUBLE-COUNTING PROBLEM INHERENT IN A CAPSUB-BASED ALLOCATION METHOD?

A Double-counting occurs because average demand (which is the equivalent of year-round energy consumption divided by 8,760 hours) is also a component of the coincident peak demand. This is illustrated in Exhibit MEB-4 (   ).

Average demand is equivalent to the area at the bottom of each bar. Coincident demand is represented by the total bar height, consisting of the yellow (or black) area at the bottom plus the red (or blue) area at the top of each bar. The double-counting occurs where average demand and the coincident demand used for cost allocation overlap as shown in the dark (black) shaded portion of the chart for the five months used in Mr. Johnson's allocation.

By allocating some capital costs relative to average demand and some relative to coincident demand, energy is counted twice: Once by itself and a second time as a subset of the coincident peak demand.

Q AT PAGE 10 OF HIS DIRECT TESTIMONY DR. JOHNSON ATTEMPTS TO JUSTIFY HIS USE OF THE SYSTEM LOAD FACTOR IN THE P&A METHOD BY DESCRIBING THE AVERAGE AND EXCESS (A&E) METHOD. ARE THE TWO METHODS SIMILAR?

A No. They are not even close. In the P&A method, as previously discussed, the average demand or energy is weighted by the system load factor, and the coincident peak is weighted by the quantity one minus the system load factor.

Hence, the double-counting because average demand is a component of coincident peak demand.

In the A&E method, on the other hand, while average demand is weighted at the system load factor, the demand used in the second half of the equation, and which receives a weight equal to the quantity one minus the system load factor, is not the coincident peak demand. The demand used in this portion of the A&E factor development is the excess demand, which is the difference between class peak demand and the class average demand. Hence, the method avoids the double-counting inherent in the P&A method.

Q DOES DR. JOHNSON ADDRESS THIS CONCEPT OF DOUBLE-COUNTING AT ANY PLACE IN HIS TESTIMONY?

A Yes. Dr. Johnson addresses this concept at Pages 15-17 of his direct testimony, when he criticizes the minimum system method which is used for the allocation of distribution system facilities. He specifically points out on Line 12 of Page 16 that there is a double-counting in this method because the customer portion has a load carrying capability—and goes on to argue that the balance of the investment should not be allocated on the total demand, but rather the total demand minus the demand that can be served by the minimum system. The criticism which Dr. Johnson expresses of the minimum system applies equally to his own proposed P&A method.

Q HAS THE DOUBLE-COUNTING PROBLEM BEEN CITED AS A CRITICAL FLAW IN THE P&A AND OTHER CAPSUB METHODOLOGIES?

A Yes. The Public Utility Commission of Texas cited the double-counting problem in numerous cases. For example:

> "As to double-counting energy, the flaw in Dr. Johnson's proposal is the fact that the allocator being used to allocate peak demand, and 50% of the intermediate demand, includes with it an energy component. Dr. Johnson has elected to use a 4CP demand allocator, but such an allocator, because it looks at peak usage, necessarily includes within that peak usage average usage, or energy."
>
> * * *
>
> "A substantial portion of average demand is being utilized in two different allocators, and thus "double dipping" is taking place." (El Paso Electric Company, Examiner's Report, Docket No. 7460, Page 352)

CAPITAL INVESTMENT DECISIONS ARE NOT RELATED TO ANNUAL KWH SALES

Q **DO ANNUAL KWH SALES AFFECT THE DECISION TO INVEST IN A PARTICULAR TYPE OF GENERATING CAPACITY?**

A No. The break-even point—that is, the hours of use at which the total cost of base load and peaking units are equivalent—will occur at an hours' use less than the total number of hours in a year. Below the break-even point, a peaking unit would be more economical than a base load unit. Beyond the break-even point, a base load unit would be the more economical choice. Whether additional capacity would be operated 1,000, 2,000, 4,000 or even 100 hours beyond the break-even point would, therefore, be irrelevant. **In other words, once the break-even threshold is reached, additional energy use (and the fuel cost differential resulting therefrom) has no impact on the investment decision.** Therefore, load duration may influence capital investment decisions, but only up to a point. It would be logically incorrect to jump from this conclusion to a method in which production capital costs are allocated to all 8,760 hours per year—such as P&A.

Consider again the rental car analogy. Assuming that the fuel efficient car costs $60 per day and 30¢ per mile, while the gas guzzler costs $30 per day and 60¢ per mile, a customer who would drive more than 100 miles per day would always choose the more fuel efficient car (i.e., $60 + $.30 x 100 = $90; $30 + $.60 x 100 = $90). In other words, the break-even point between the fuel efficient car and the gas guzzler would occur at 100 miles. If one customer were to drive the car 200 miles and the second were to drive it 400 miles, both customers would choose the same car—the more efficient one. Thus, the total distance driven would have no effect on the decision. The P&A method, however, would assign about twice as much of the extra daily charge of the more fuel efficient car to the 400-mile per day customer.

Q **HAS ANY OTHER REGULATORY AUTHORITY REJECTED A CAPSUB-BASED METHODOLOGY BECAUSE IT WOULD EFFECTIVELY ALLOCATE THE "EXTRA" CAPITAL COSTS TO THOSE HOURS BEYOND THE ECONOMIC BREAK-EVEN THRESHOLD?**

A Yes. For example, the Florida Public Service Commission agreed with this logic in rejecting a CAPSUB-based methodology (Gulf Power Company, Docket No. 891345-EI, Order No. 23573, October 3, 1990, Page 48).

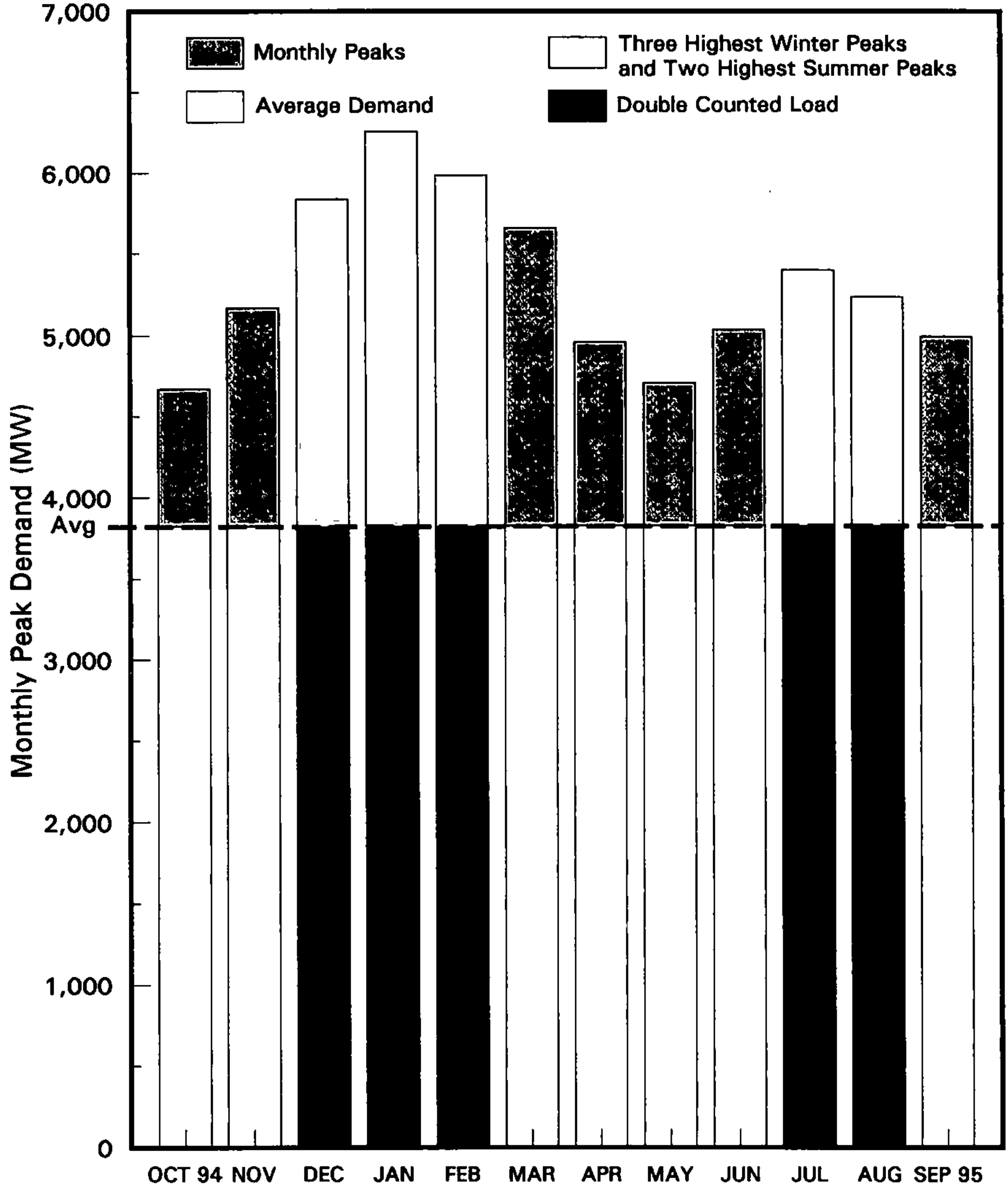
Q **DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

A Yes, it does.

Exhibit MEB-4 (   )

PENNSYLVANIA POWER & LIGHT COMPANY

Double Counting Illustration



PPLICA Stmt 7-R

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY

DOCKET NO. R-00943271

5/25/95

REBUTTAL TESTIMONY

OF

STEPHEN J. BARON

ON BEHALF OF THE

PP&L INDUSTRIAL CUSTOMER ALLIANCE

Air Products and Chemicals, Inc.
Alumax Mill Products, Inc.
Appleton Papers Inc.
Armstrong World Industries, Inc.
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 Industrial Gases
Magee Carpet Company
M&M/Mars, Inc.
Praxair, Inc.
R. R. Donnelley & Sons
The Stroh Brewery Company
Thomson Consumer Electronics, Inc.
Victaulic Company of America

J. KENNEDY AND ASSOCIATES, INC.
ATLANTA, GEORGIA

MAY 1995

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA POWER & LIGHT COMPANY

DOCKET NO. R-00943271

REBUTTAL TESTIMONY OF STEPHEN J. BARON

Q. Please state your name and business address.

A. My name is Stephen J. Baron, President of J. Kennedy and Associates, Inc. ("Kennedy and Associates"). My business address is 35 Glenlake Parkway, Suite 475, Atlanta, Georgia 30328.

Q. Have you previously submitted direct testimony in this proceeding?

A. Yes, I have.

Q. What is the purpose of your rebuttal testimony?

A. I am responding to the direct testimony submitted by Dr. Charles Johnson on behalf of the Office of Consumer Advocate ("OCA"). Among other issues, Dr. Johnson has presented testimony regarding the appropriate cost-of-service methodology to be used by the Commission in this proceeding. I will address Dr. Johnson's recommendation with respect to the peak and average allocation method, as well as other aspects of his proposed cost-of-service study.

Finally, I will also respond to the proposal of Sierra Club of Pennsylvania witness Bruce Biewald regarding his proposal to require energy audits of customers receiving "discounts."

Q. Would you please briefly describe OCA witness Johnson's proposed peak and average cost-of-service methodology ?

A. As in the most recent West Penn Power Company rate case, Dr. Johnson is recommending a peak and average production demand allocation methodology in this case. The peak and average methodology relies predominantly on the annual energy use of each customer class (both on-peak and off-peak energy use) to compute the demand allocation factor used to assign the cost of fixed generating station investment to customer classes.

Dr. Johnson bases his recommendation for the use of a peak and average method to allocate production demand costs on his opinion that the type of capacity installed on the PP&L system is determined by energy use.

Q. What specific computations has OCA witness Johnson made to implement his proposed peak and average methodology?

A. Based on his testimony, Dr. Johnson has assigned 61% of PP&L's production investment on the basis of annual energy use (average demand) by each customer class and 39% on the basis of class demands during the three winter and two summer months system peaks.

Q. Do you believe that Dr. Johnson's recommended peak and average method is a reasonable approach to assign production demand costs to PP&L's retail rate classes?

A. No. As I indicated in my direct testimony, I have utilized PP&L's 12 CP methodology in this proceeding to assign production demand costs to rate classes. Dr. Johnson's recommendation to shift away from demand responsibility by customer class and towards energy responsibility is a radical change from the methodology recommended by PP&L and previously adopted by the Commission for the Company. I do not believe that the Commission should adopt the energy-oriented peak and average methodology recommended by Dr. Johnson.

Q. What are some of the concerns you have with Dr. Johnson's proposal?

A. There are a number of problems with the proposed peak and average methodology recommended by Dr. Johnson.

First, it is premised on <u>a simplistic notion that the system load factor determines the amount of PP&L investment</u> which is due to energy use by PP&L's customers, with the remainder due to peak demand usage.

Under Dr. Johnson's proposed cost allocation methodology, <u>there is no factor</u> implicit in his approach that considers, in any manner, the actual composition (e.g., peaking, baseload) of generating plants on the PP&L system. Dr. Johnson's method would produce the same allocation results if all of PP&L's generating capacity were comprised of 20-year-old simple cycle combustion turbines <u>or</u> were all 10-year-old nuclear units identical to Susquehanna. Despite his "theoretical" underpinning on generation planning economics, <u>there is nothing in his method that actually considers such economic tradeoffs, or even considers the actual system in place</u>.

Q. **Is Dr. Johnson's proposed peak and average methodology in this case consistent with the peak and average methodology that he proposed in the recent West Penn Power Company case (Docket No. R-00942986, July 1994)?**

A. No. 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 his 1994 West Penn testimony, he stated as follows:

> **Q. How do you calculate the peak and average demand allocator?**
>
> **A. I have based the peak and average demand allocator on the weighted average of the six months demand and the average annual demand. <u>This is arithmetically equivalent to the calculations used for the single CP and average and the 12 CP and average in the NARUC manual.</u>** (Direct Testimony of Dr. Charles E. Johnson, page 45, lines 9-14, emphasis added)

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."[1]

Q. What would be the impact of using the NARUC peak and average method (which Dr. Johnson used in West Penn) in this case?

A. For the <u>residential class</u>, the production demand allocator would be calculated as follows:

[1] 1992 NARUC <u>Electric Utility Cost Allocation Manual</u>, page 57.

TABLE 1

Calculation of Peak and Average Factor Using NARUC Method

Residential:	
a) Avg. 5 CP Demands	2,430,189
b) Avg. Annual Demand	1,356,891
c) Sum (1)	3,787,080
Total PPUC:	
a) Avg. 5 CP Demands	5,743,161
b) Avg. Annual Demand	3,820,155
c) Sum (2)	9,563,316
Residential P&A Factor: [sum (1)/sum (2)]	39.60%
Residential 12 CP Factor: (per PP&L cost study)	38.39%

If Dr. Johnson had used the NARUC peak and average approach, which he adopted ten months ago in the West Penn case, he would have allocated 3.2% more production and transmission investment to residential customers than PP&L's 12 CP method allocates.

Q. Could you discuss some of the additional problems inherent in a peak and average methodology?

A. The peak and average methodology is essentially a production demand allocation approach that relies on the capital substitution concept, which argues that costs should be allocated to a customer class in recognition of the fact that baseload units cost more in terms of capital but provide lower lifetime operating costs. The general theory advocated by capital substitution or energy allocation proponents such as Dr. Johnson is that this economic trade-off dictates that a substantial part of production investment and associated expenses should be assigned to customer classes based on annual energy use. This energy use, under the peak and average methodology advocated by Dr. Johnson, <u>includes energy use during peak periods as well as energy use during the lowest load periods on the system (off-peak periods)</u>.

The method is premised on the assumption that utilities expend additional capital costs over and above the costs of a simple cycle combustion turbine (or other peaking capacity) in order <u>to achieve fuel savings</u>, i.e., lower fuel costs relative to the fuel costs associated with the combustion turbine. The problem with this theory is that it assumes that the entire excess capital and fixed O&M costs of a baseload unit (e.g., the Susquehanna unit), over and above a combustion turbine unit, are solely related to fuel savings. The facts do not comport with this theoretical assumption. As is clearly pointed out by OCA witness Kahal, the Susquehanna capacity is <u>uneconomic</u>, implying that a portion of its high capital cost is <u>not</u> related to fuel savings.

Under Dr. Johnson's methodology, these uneconomic Susquehanna costs are assigned to customer classes on the basis of energy under the erroneous assumption that they provide energy-related fuel savings. There is no justification for allocating "mistakes" on the basis of energy, which assumes that customer classes with higher off-peak usage (relative to on-peak usage) are more responsible for these mistakes. There is simply no basis for arguing, as Dr. Johnson does, that 61% of the production demands costs on the PP&L system are related to annual energy use (average demand over <u>all</u> hours).

Q. What does the peak and average allocation methodology imply with respect to the cost of off-peak energy on the PP&L system?

A. Since 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, <u>Dr. Johnson's methodology has the perverse effect of providing a price signal to customers to refrain from increased off-peak energy usage on the PP&L system</u>.

Dr. Johnson would presumably argue that increased off-peak usage by industrial customers (due to instituting a third shift in its production process, for example) imposes costs on the PP&L system by increasing the amount of baseload capacity. This is simply an incorrect price signal for current PP&L rates and is <u>inefficient</u> for cost allocation purposes. With excess baseload capacity on the PP&L system, this price signal makes no sense. Customers should not be irrationally penalized for increasing consumption in PP&L's <u>off-peak periods</u>.

Q. Does Dr. Johnson address the economic trade-offs between baseload and peaking capacity in his testimony?

A. Yes. Though he does not actually recognize the economic trade-offs in his methodology, he relies on economics as a foundation for his method. On page 8, at lines 11 to 22 of his testimony, he states:

> **If it were only necessary to meet the maximum demand (even the 12 monthly maximum demands) for a short duration, PP&L could do so at lowest cost by installing combustion turbine peaking units and would not need to install baseload generating capacity. In order to supply energy year around and meet the maximum demands, the Company installs a mix of generation facilities -- baseload, intermediate and peaking. The baseload units have relatively higher fixed costs and relatively lower variable costs so that if they run a large number of hours of the year, the total cost is lower than for the other two types. The peaking units have relatively lower fixed costs and relatively higher variable costs, enabling loads of short duration to be met at the lowest total cost. Intermediate units have both fixed costs and variable costs between those of baseload and peaking units.**

Dr. Johnson is actually identifying a generation planning "break-even" analysis. The break-even point is simply the number of hours at which the cost of serving the load is the same for both baseload and peaking capacity.

In fact, as I will show subsequently, based on the current embedded cost of peaking and baseload capacity on the PP&L system (including Susquehanna), the break-even capacity factor on the PP&L system is <u>29%</u>. Above this level, which equates to 2,531 hours during the year, PP&L baseload capacity, in the aggregate, has a lower total cost. During the first 2,531 hours of highest demand on the PP&L system, peaking capacity has the lowest total cost (capital, O&M, fuel). Most significantly, <u>hours-use of demand in excess of 2,531 hours does not affect the economic trade-off between a peaking unit and a baseload unit</u>. As such, kWh use in the first 2,531 hours of highest PP&L load is the only appropriate measure of class responsibility associated with the economic choice between peaking and baseload capacity. Kilowatt-hour use in the remaining 6,229 hours during the year do <u>not</u> impact the economic choice between baseload capacity and peaking capacity. Dr. Johnson's overly-simplified assertion as to the premises underlying the PP&L system provides an incorrect basis to allocate costs.

Q. Would you please briefly describe the "break-even" economic analysis that you previously referenced?

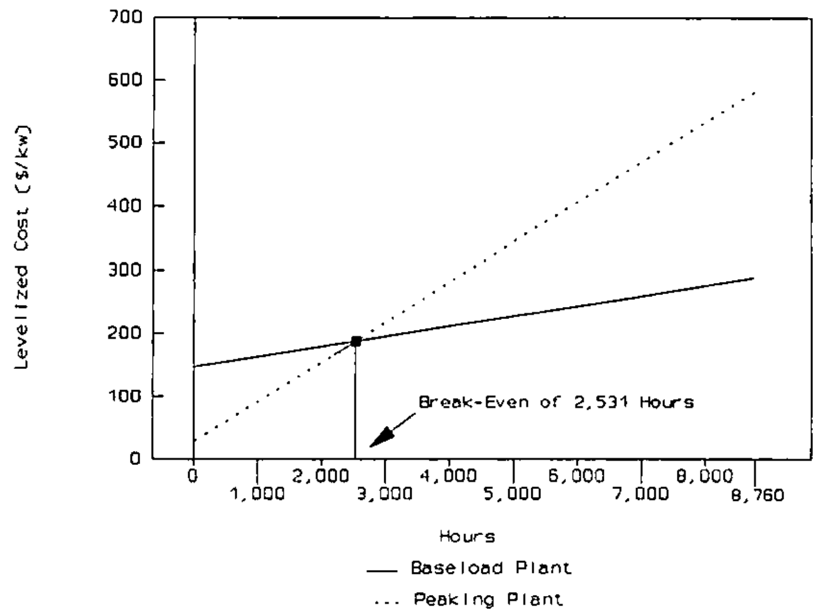
A. Yes. Using the current embedded cost of PP&L peaking and baseload capacity, and expected fuel costs on the PP&L system, I developed a screening curve analysis which shows the economic trade-off between peaking and baseload plant on the PP&L system, using the investment costs which are at issue in this case, i.e., embedded costs of plant.

Figure 1 shows the results of this analysis. The "dotted line" shows the total cost curve associated with PP&L peaking plant, while the solid line shows the cost curve associated with baseload plant.[2] These two cost curves cross at 2,531 hours, which means that at this point, a kW of either peaking or baseload plant has the same total cost. For hours-use of a kW of capacity in excess of 2,531 hours, a baseload plant is cheaper (again using PP&L's current embedded cost of baseload facilities, including Susquehanna), while for usage below 2,531 hours, peaking facilities are the least cost.

2 These cost curves represent the total cost (capital, O&M, fuel) associated with 1 kW of each type of capacity at various hours of operation.

FIGURE 1

PENNSYLVANIA POWER & LIGHT
Screening Curve Analysis



Once it is determined that a kW of demand will be "used" for 2,531 hours during the year, a baseload unit is less expensive than a peaking unit. Figures 2 and 3 illustrate this point. Figure 2 is a graph of PP&L's 1994 load duration curve ("LDC"), showing the "break-even" point of 2,531 hours. Once the break-even point is reached, the higher capital cost of PP&L's baseload capacity has already been recovered via fuel savings. Thus, the break-even point does not change, even if the LDC is changed (the rectangular portion of the LDC representing additional off-peak kWh) by adding kWh during the off-peak period. These additional off-peak kWh are not responsible for the choice of baseload capacity over the less expensive peaking capacity. It is the kWh usage in the top 2,531 hours that influences the economic decision.

FIGURE 2

PENNSYLVANIA POWER & LIGHT
Load Duration Curve

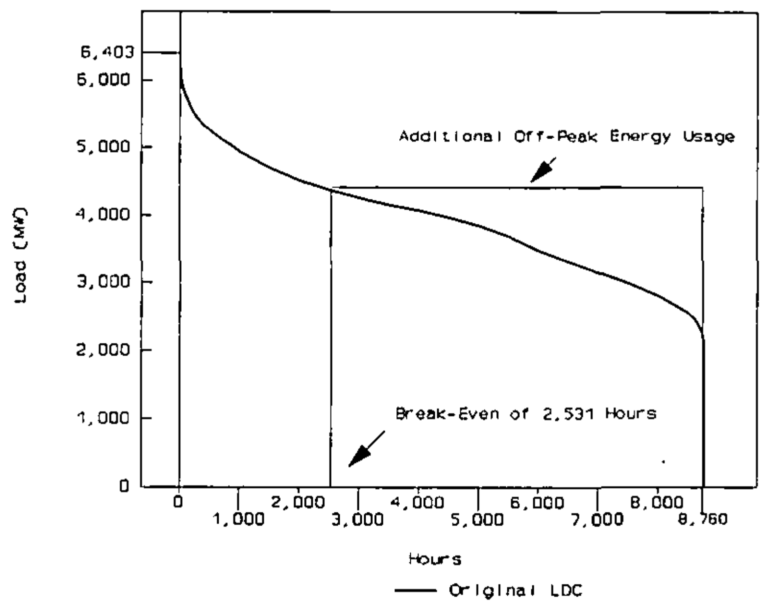
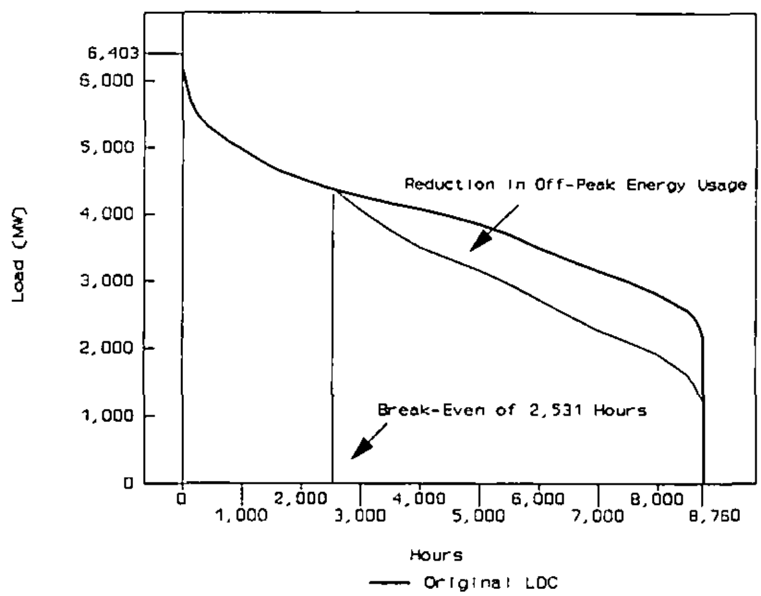


Figure 3 is a similar graphic depiction except that the LDC is changed by reducing kWh use in the off-peak period. Again, this reduction in off-peak kWh does not affect the break-even analysis and <u>thus does not impact the economic choice between peaking and baseload capacity</u>. Dr. Johnson's use of annual total energy in his analysis is inappropriate, since it allocates cost based on off-peak kWh usage, which is not responsible for the economic choice between peaking plant and baseload plant.[3]

<u>FIGURE 3</u>

PENNSYLVANIA POWER & LIGHT
Load Duration Curve



As a result, even if one were to accept Dr. Johnson's general capital substitution theory for cost allocation, <u>the energy which is relevant to the economic choice between peaking capacity and baseload capacity occurs in the first 2,531 hours on the</u>

---

[3] In this context, off-peak is defined as the hours during the year when system load is <u>below</u> the top 2,531 hours of load.

load duration curve, not the entire 8,760 hours (annual energy) utilized by Dr. Johnson. The energy component of Dr. Johnson's peak and average analysis should reflect the class contribution to energy in the first 2,531 highest demand hours on the PP&L system.

Q. **Have you calculated such an allocation factor?**

A. I have not been able to calculate such a factor, since this would require hourly class load research data for the entire year to develop class energy use during the "highest" 2,531 hours of system load. This would be the proper "energy" to use in a peak and average allocation. However, I have developed a proxy allocator by using the system load duration curve.

Q. **Would you please explain your approach in developing a proxy for class contribution to energy during the highest 2,531 hours of demand on the PP&L system?**

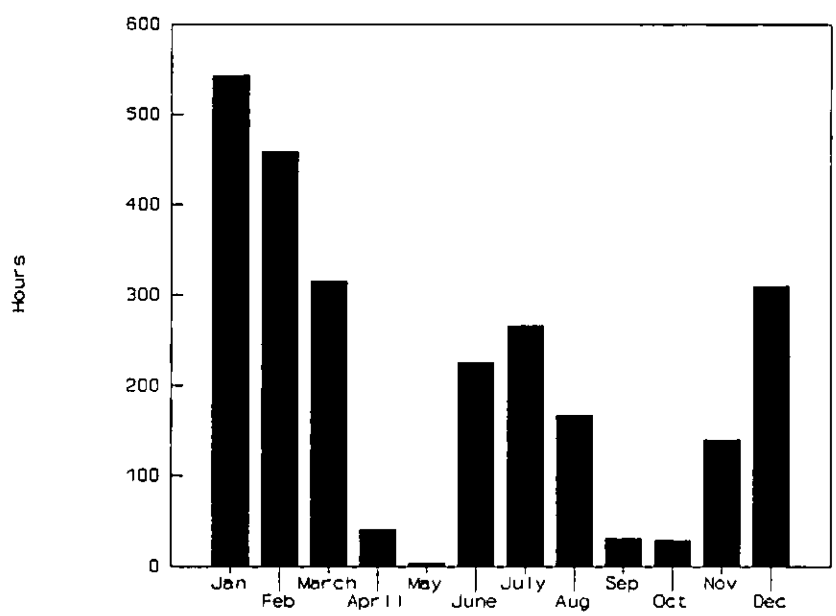
A. To estimate class contributions to the highest 2,531 hours of demand, I examined the distribution of these hours by month for each month of 1994.[4] Figure 4 shows the number of hours each month associated with the first 2,531 highest hours on the PP&L load duration curve. As can be seen, most of the 2,531 hours are concentrated

[4] A 1994 system load duration curve was used for this purpose.

in January, February, March, June, July, August, and December, while the remaining months have very few hours. This means that kWh usage in these seven months is the primary determinant as to the optimal mix of baseload capacity and peaking capacity for PP&L, using current embedded costs.

FIGURE 4

MONTHLY DISTRIBUTION OF THE HIGHEST 2,531 HOURS OF DEMAND ON THE PP&L SYSTEM



I then used the relative share of these hours in each month to weight the monthly energy, by customer class, to arrive at an overall weighted average demand allocation factor for use in a corrected "average" factor in the peak and average analysis.

Q. What are the results of this analysis?

A. Table 2 below compares, for each rate class, the <u>annual</u> energy allocation factor (utilized by Dr. Johnson in his analysis), to the "weighted average demand allocation factor" that I previously described.

<u>TABLE 2</u>

Comparison of "Annual Average Demand" Factor to "2,531 Hour Average Demand" Factor

Rate Schedule	Dr. Johnson's "Annual Avg. Demand" Factor	"Top 2,531 Hours Avg. Demand" Factor
RS	35.52%	38.81%
RTS	1.27%	1.48%
GS-1	4.96%	4.88%
GS-3	21.90%	21.00%
LP-4	14.51%	13.47%
LP-5	17.58%	15.92%
LPEP	0.46%	0.03%
ISA	1.66%	0.43%
GH	1.76%	1.60%
SL/AL	0.34%	2.04%
Standby	0.04%	0.35%

Q. Have you calculated the residential class "P&A" allocation factor with a corrected "average" component, using the results of the weighted average demand analysis that you previously described?

A. Yes. Though I believe that the peak and average methodology Dr. Johnson recommends, regardless of the refinements which I am discussing, should be rejected by the Commission as inappropriate, if one were to accept this methodology, it is clear that the energy component should reflect the actual contribution of each class to demand during the highest 2,531 load hours on the system, which, conservatively, can be represented by the weighted average demand factor that I previously discussed.[5]

Utilizing this weighted average demand factor, together with all of the other assumptions made by Dr. Johnson (e.g., 61%/39% energy/demand weighting), produces a production demand allocation factor for the residential class of 40.17%, which allocates 5% <u>more</u> investment to residential customers than the 12 CP method recommended by PP&L and utilized in my own analysis. Though I have not developed a cost-of-service analysis based on this methodology, <u>it should be clear</u>

---

[5] Since the weighted average demand factor, which I used as a proxy for the average demand in the highest 2,531 hours, continues to include off-peak energy use in its computation, it understates cost responsibility for low load factor classes (e.g., residential) and overstates cost responsibility for higher load factor classes, though not as severely as Dr. Johnson's method.

that residential customers would be worse off (compared to 12 CP) under the peak and average theory, if it is applied properly.

Additional Cost-of-Service Issues

Q. Do you have any additional comments on Dr. Johnson's proposed cost-of-service methodology?

A. Yes. The final comment I have concerns Dr. Johnson's proposed use of his peak and average allocation factor to assign the cost responsibility associated with transmission facilities on the PP&L system. Essentially, Dr. Johnson's methodology assumes that the same capital substitution economics, which he asserts applies to production facilities, also applies to transmission facilities. There is simply no basis for making this assumption. Even if one were to accept the underlying rationale behind Dr. Johnson's allocation of 61% of production demand costs on an energy basis, and 39% on a demand basis (due to his alleged economic trade-offs between peaking capacity and baseload generation), there is no such rationale to support the use of the same assignment factors to transmission plant.

Nonetheless, Dr. Johnson's cost-of-service analysis allocates transmission plant on the same basis as generation plant. Dr. Johnson's methodology is thus flawed, since it inappropriately assigns transmission costs, which are demand-related, on an energy basis. Dr. Johnson has not performed any capital substitution analysis to support his allocation factors for transmission plant, nor does he even reveal in his direct testimony that he has made such an allocation.

Treatment of Interruptible Load in Dr. Johnson's Cost-of-Service Analysis

Q. Would you please discuss the concerns you have with the treatment of interruptible load in Dr. Johnson's analysis?

A. Dr. Johnson has adopted the Company's basic framework for the treatment of interruptible load within the cost-of-service study. In this regard, he accepts the "resource value" approach, which the Company attempted to model in its study, except that Dr. Johnson moves much further than the Company by incorporating a "market-based" adjustment to the resource value associated with interruptible load. As I discussed in my direct testimony, I think it is entirely inappropriate to use such a resource value approach. I have recommended that a cost-of-service based methodology be employed to develop an appropriate interruptible rate.

In my analysis, I rejected the Company's use of a $300 per kW credit to plant-in-service, and substituted the actual revenue credits associated with the Company's proposed interruptible rates. As I discussed in my direct testimony, this is a more equitable and consistent methodology to treat interruptible load, if one adopts the Company's resource value framework (which I do not).

Dr. Johnson has moved in the opposite direction. He has accepted the Company's basic framework but has argued, in his direct testimony, that the value of interruptible load should be based on the market value, rather than the cost of a combustion turbine (the approach taken by PP&L) or based on the interruptible credits being provided to customers under the Company's proposed rates (the approach that I employed in my cost-of-service analysis), which approximately equates to the PJM capacity deficiency rate.

For comparative purposes, the Company's $300 per kW plant-in-service (rate base) credit equates, in terms of revenue requirements at present rates, to approximately $3.00 per kW per month of interruptible load under contract.[6]

Dr. Johnson, on the other hand, has moved to what I consider to be an extreme position and is basing his analysis, supposedly, on an interruptible credit of $1.25 per kW month for the purposes of cost-of-service analysis. This is based on his assessment of the current "market value" of peaking capacity on the PJM system. Dr. Johnson cites the Company's testimony that certain capacity credit sales have been

---

[6] In PP&L's cost-of-service study, at present rates, $1.00 of rate base is approximately equivalent to $0.12 of revenue requirements for LP-5. This includes the return component, taxes, and indirect costs associated with rate base. Thus, a $300 per kW rate base credit produces an annual revenue requirement of $36 per KW, or $3.00 per kW per month.

made for <u>as low as 10% to 15%</u> of the official PJM capacity deficiency rate.[7] Dr. Johnson has utilized this information to arrive at his proposed $15.00 per kW value credit, which he then states that he used to calculate "the equivalent rate base offset" (page 18, line 11 of his testimony).

Q. Has Dr. Johnson, in fact, utilized an "equivalent rate base offset" to his recommended $15.00 per kW year ($1.25 per kW month) estimate of the "current value" of interruptible load in his cost-of-service study?

A. No. As shown in Dr. Johnson's workpapers, he has used a "rate base offset" of $61.64 per kW to value interruptible load in terms of <u>investment</u> or rate base. In his cost study, this equates to an annual revenue requirement effect (at present rates) of $7.40 per kW year, or <u>$0.62 per KW month</u>. This $0.62 per kW credit is only one-half the "value" which Dr. Johnson says is appropriate for use in the cost-of-service study. As a result, the reported cost-of-service results shown in Dr. Johnson's testimony are not correct, even based on his own misguided market-based "value" method.

Q. Do you think that it is reasonable to rely on a market-based valuation for interruptible rates on the PP&L system?

---

[7] The mere fact that some transactions have occurred at rates this low is a far cry from asserting that <u>all</u> transactions occur at this price, <u>which they do not</u>.

A. Absolutely not. Dr. Johnson's approach is totally unreasonable and violates what I consider to be a basic tenet of regulation: protecting customers from monopoly or, in this case, monopsony power. Since interruptible customers, under both the Company's and Dr. Johnson's resource value framework, are required to sell their peaking capacity to PP&L and only to PP&L, the Company is a monopsonist with respect to this type of transaction. It is the <u>only</u> purchaser of peaking capacity from interruptible customers. No market exists other than PP&L's purchase of such capacity. It is entirely unreasonable for Dr. Johnson to impute a market-based valuation for peaking capacity, when interruptible customers are not permitted to sell their peaking capacity (in the form of interruptible load under the resource value framework) to all PJM or other utilities.

If a competitive market did exist for the sale of "interruptible load" peaking resources to PJM and other utilities, a market-based approach <u>might</u> be a reasonable methodology. No such recommendations have been made by either the Company or Dr. Johnson in this case, and I therefore strongly oppose the use of such a market-based valuation methodology. It is simply unfair and violates the basic protections that regulatory commissions provide to captive customers.

As I discussed in my direct testimony, I believe that interruptible customers should be afforded the same rights as other retail customers on the PP&L system. These customers are, in reality, <u>purchasing</u> low-quality power, for which they should receive a lower price, in recognition of the cost of such low-quality power. To force these customers to sell capacity to PP&L at an assumed "market" price where no such market exists for their capacity is simply unreasonable. Dr. Johnson's methodology should be rejected.

<u>**Response to Sierra Club of Pennsylvania Witness Biewald**</u>

Q. Have you reviewed Mr. Biewald's recommendation to require a "certified comprehensive energy audit" of a large business customer prior to receiving a discount?

A. Yes. Mr. Biewald is recommending such audits for all customers "before they are given a discount rate" (Biewald direct, page 29, line 20). I believe that it is inappropriate to single out such customers for energy audits. There is no more rationale to require energy audits for these industrial customers than for any other customers. This recommendation should be rejected and, at the most, be considered in a case related to DSM issues, not a rate case.

Q. Does that complete your testimony?

A. Yes.