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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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SECRETARY'S OFFICE
Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY COMMISSION, et al.,

v.

PHILADELPHIA ELECTRIC COMPANY

Docket No. R-850152

TESTIMONY AND EXHIBITS
OF
RANDALL J. FALKENBERG

ON BEHALF OF
PHILADELPHIA AREA INDUSTRIAL ENERGY USERS GROUP*

*Allied Corporation, Fibers Division
Boeing-Vertol Company
BP Oil, Inc.
The Budd Company, Inc.
Liquid Air Corporation
Lukens Steel Company
Nabisco Brands, Inc.
SDC/A Burroughs Corporation
Smithkline Beckman Corporation
Sun Refining and Marketing Company
3M Company
United States Steel Corporation

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Kennedy and Associates
January, 1986

PHILADELPHIA ELECTRIC COMPANY

DOCKET NO. R-850152 (LIMERICK 1)

TESTIMONY OF RANDALL J. FALKENBERG

Q. **Please state your name and business address.**

A. Randall J. Falkenberg, Suite A-1220, 1150 Hammond Drive, Atlanta, Georgia 30328.

Q. **What is your occupation and by whom are you employed?**

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm Kennedy and Associates.

Q. **Please summarize your educational background.**

A. I received my Bachelor of Science degree with Honors in Physics and a minor in mathematics from Indiana University. I received a Master of Science degree in Physics from the University of Minnesota. My thesis research was in nuclear theory. At Minnesota I also did graduate work in engineering economics and econometrics.

Q. **Please summarize your professional experience and qualifications.**

A. After graduating from the University of Minnesota in 1977, I was employed by Minnesota Power as a Rate Engineer. I designed and coordinated the Company's first load research program. I also performed load studies used in cost-of-service studies and assisted in rate design activities.

In 1978, I accepted the position of Research Analyst in the Marketing and Rates department of Puget Sound Power and Light Company. In that position I prepared the two year sales and revenue forecasts used in the Company's budgeting activities and developed methods to perform both near and long-term load forecasting studies.

In 1979, I accepted the position of Consultant in the Utility Rate Department of Ebasco Service Inc. In 1980, I was promoted to Senior Consultant in the Energy Management Services Department. At Ebasco I performed and assisted in numerous studies in the areas of cost-of-service, load research and utility planning. In particular I was involved in studies concerning analysis of excess capacity, evaluation of the planning activities of a major utility on behalf of its public service commission, development of a methodology for computing avoided costs and cogeneration rates, long-term electricity price forecasts and cost allocation studies.

I was the principal author of production costing software used by 18 utility clients and public service commissions for evaluation of marginal costs, avoided costs and production costing analysis. I assisted over a dozen utilities in the performance of marginal and avoided cost studies related to the PURPA of 1978 and cogeneration rate design. In this capacity I worked with utility planners and rate specialists in quantifying the rate and cost impact of generation expansion alternatives. This activity included estimating carrying costs, O&M expenses and capital cost estimates for future generation.

In 1982 I accepted the position of Senior Consultant with Energy Management Associates, Inc. and was promoted to Lead Consultant in June 1983. At EMA I trained and consulted with planners and financial analysts at several utilities in applications of the PROMOD and PROSCREEN planning models. I assisted planners in applications of these models to the preparation of studies evaluating the revenue requirements and financial impact of generation expansion alternatives, alternate load growth patterns, alternate regulatory treatments such as CWIP in rate base, and the phase-in of new baseload generation. I also assisted in EMA's educational seminars where we trained utility personnel in aspects of production cost modeling and other modern techniques of generation planning.

I became a Principal in Kennedy and Associates in 1984. Since then I have performed studies of future industrial electric rates and performed analyses of the impact of alternate planning decisions on industrial consumers. I have testified before the regulatory commissions in Arkansas, Florida, Kentucky, Connecticut, Pennsylvania, North Carolina, Georgia and West Virginia as an expert witness on utility planning, addressing issues of CWIP in rate base, generation expansion alternatives, excess capacity and phase-in. In previous testimony I have testified that the Susquehanna and Millstone nuclear units, along with the Crystal River 5 coal unit were economically beneficial to customers. I have testified regarding the economic and reliability advantages of alternatives to the Limerick 2 nuclear unit. Kennedy and Associates performed an independent investigation for the Georgia Public Service Commission regarding Georgia Power Company's Construction Program. In that study, we recommended completion of GPC's Vogtle nuclear plants and the Scherer coal units. We recommended cancellation of the Rocky Mountain pumped storage unit.

Also, in June of 1984, I was asked to speak before the Mid-America Regulatory Commissioners' convention on the topic "Nuclear Rate Shock - Is Phase-In the Answer"

Q. **On whose behalf are you appearing and what is the purpose of your testimony?**

A. I have been asked by the Philadelphia Area Industrial Energy Users' Group ("PAIEUG") to analyze the phase-in proposal developed by the Philadelphia Electric Company ("PECO") in this case, and to study the possibility of an alternative phase-in for the Limerick Nuclear Plant. In particular, in my testimony, I will discuss the following points:

1. PECO's Phase-in Proposal has a serious flaw, which must be corrected in order for it to be useful in this case.

2. PECO has incorrectly included 100% of Limerick common plant in rate base.

Thus, the rate increase it proposes is overstated.

3. The Commission should adopt an alternative depreciation method, the sinking fund depreciation technique, for use on the Limerick plant.

4. I will discuss the economics of the Limerick 1 nuclear plant, and its reliability impact. I will show the plant is now excess capacity and will not benefit consumers over the long run.

5. I will discuss the logical errors in Dr. Hieronymus' testimony concerning the proper regulatory principles the Commission should consider in determining the proper rate treatment for the Limerick plant.

6. I will establish that in deciding to construct the Limerick nuclear unit, PECO was engaging in a course of action it should have known would carry substantial risks that the plant would prove to be too expensive or unneeded. Now that some of these risks have materialized, PECO should bear some of the consequences.

PECO'S PHASE-IN PROPOSAL

Q. Mr. Falkenberg have you had an opportunity to review PECO's phase-in proposal?

A. Yes, I have. This proposal contains a serious flaw which must be corrected to render it useful in this case.

Q. Mr. Falkenberg what is the problem with the PECO phase-in proposal?

A. PECO's phase-in proposal does not follow sound regulatory ratemaking principles. PECO has determined a revenue requirement for the test year based on its costs of providing service (not to be confused with an allocated class cost-of-service study). However, the collection of these revenue requirements occurs over a six year period. Thus, PECO proposes to collect revenue requirements for the current test year, several years beyond the test year.

The theory of the test year is that it will represent the future level of the costs of service of the utility company. Until the utility proves that the rates from the prior test year are insufficient (in a rate case) it is assumed that the test year based rates are sufficient to provide investors an opportunity to earn a reasonable profit. In cases where a known and measurable change in costs from the test year can be shown to exist beyond the test year, the test year cost-of-service may be modified to reflect those changes. From time to time utilities have requested attrition allowances to adjust for the possibility of future inflation. As a general principle I do not recommend attrition allowances since they could remove some of the incentive of management to control costs, particularly when inflation is low.

In the case at hand, PECO is proposing to develop a rate structure which will collect test year revenue requirements automatically over a period of the next six years. The flaw in the approach is that known and measurable changes will exist in PECO's cost-of-service over this period of time. In particular the cost of power from the Limerick plant will decline during the phase-in period because Limerick ratebase will decline through depreciation and increases in deferred income taxes. Based on my analysis, the base rate revenue requirement of Limerick Unit 1 will be $950 million for the test year. During the second year of operation this amount will decrease to $918 million. By year six, the revenue requirement will reduce to $807 million. In total, Limerick 1 revenue requirements will decrease by over $400 million dollars during the Phase-In period.

Q. **Are you suggesting that PECO may overcollect Limerick revenue requirements as a result of this phase-in proposal?**

A. Yes that is a possibility. In effect, the Company is building an attrition allowance into its cost and rate structure. The Company would propose to be granted automatic rate increases over the next several years to collect the initial increase in cost due to Limerick. However, the Company is ignoring the fact that the cost of Limerick will be declining during this time. Thus, the money needed to completely cover Limerick revenue requirements in the years following the test year, is actually less than the Company will be collecting through its rates, unless an annual true-up of rates and costs occurs through a base rate case. PECO has announced its intention to avoid base rate cases as long a possible and has made a promise of sorts to stay out until September of 1987. A skeptic might suggest that this is not simply a charitable gesture by the Company.

Q. **Hasn't it always been the case that power plant costs decrease through time and yet inflation has caused utilities to need rate increases?**

A. Yes that is true. Historically, however, utilities built plants more often and built lower cost plants. In this case, Limerick is adding $3.8 billion dollars to PECO's rate base. Limerick alone is over 50% of PECO's rate base. Thus, the declining cost pressure from this one plant is significant. At the same time, the rate of inflation is currently quite low.

Q. **Isn't it true that other costs may go up, and the overcollection may not materialize?**

A. PECO's other plant in service will depreciate, inflation may drive up O&M expenses, interest rates and PECO's cost of money may go up or down., and class revenue requirements may change from the test year. In any event other than depreciation, it would not be safe to say that the future changes in costs are known and measurable at this time. Reduction in carrying costs is something that can be computed mechanically, however.

Q. **Mr. Falkenberg you seem to be suggesting that the problem with the PECO phase-in is that it applies test year rate base and expense figures to a rate** structure which is expected to persist over the next six years. Do you believe it would be more appropriate to develop a phase-in proposal which reflects cost-of-service for the Limerick plant reflecting the next six years of operation?

A. This would be a method to correct for the flaws in PECO's phase-in. Essentially all that is required is to redesign PECO's phase in plan to reflect considerations beyond the test year.

Q. Has PECO filed for any rate base adjustments in this case which reflect cost-of-service beyond the test year?

A. Yes. Mr. Hill has prepared a rate base adjustment for nuclear fuel assemblies contained within the Limerick reactor which are based on a two year average of the cost of the assemblies. Mr. Hill states, and correctly so, that it is necessary to use a two year average cost for these fuel assemblies or these cost will be overstated.

In another instance the Company has estimated fuel cost savings attributable to the Limerick plant as being $207 million. This figure also is not a test year figure. It is actually an estimate of the average fuel savings over the next two years. Once again, PECO has adjusted its cost-of-service to reflect considerations beyond the test year. I believe that to correct PECO's phase-in, it must contain a reflection of this same approach, i.e., consideration of the cost and rate base characteristics of the Limerick plant beyond the single test year if the phase-in of the cost of the unit is to extend beyond the test year.

Q. Please discuss your correction to the PECO phase-in proposal.

A. Please turn to Falkenberg Exhibit-1. This exhibit shows the Limerick fixed charges through the period 1986 to 1991 as well the PECO proposed phase-in. The Limerick rate increase is composed of fixed charges and credits to operating expenses. For the 1986 test year for retail jurisdictional customers the base rate increases, i.e., fixed charges, amount to $950 million. As a result of changes in fuel cost, reduced operating expenses from retirement and life extension of older plants, and a reduction in the return requirement, PECO proposes to reduce the $950 million base increase by $279 million during the test year. The result is the $671 million rate increase. The reductions in cost are primarily related to changes in fuel cost which are trued-up periodically by the Company in the ECR adjustment cases. These costs do not substantially affect PECO's ability to properly collect its revenue requirements. For purposes of this illustration only the $279 million is held constant. The fourth column of the exhibit shows the total revenue requirement associated with Limerick over the next six years computed on the same basis as the test year. The first year revenue requirement is $671 million. By the fifth year the rate impact of Limerick has been reduced to $528 million. This is due to a reduction in fixed charges from $950 million to $807 million. The fifth column of the exhibit shows the increased revenues PECO proposes to collect over the next six years. These amount to about $4.0 billion. However, returning to the previous column we see that the full increase in cost-of-service resulting from the Limerick plant amounts to about $3.6 billion. Thus, the Company phase-in proposal could result in an overcollection of over $400 million over the next six years. The exhibit shows that even after imputing interest on the deferred rate increase, an overcollection of PECO's revenue requirements of over $200 million could exist. Thus, it is misleading for PECO to state that the deferred revenue requirements are collected without interest. In fact if the maximum potential overcollection occurs, PECO would actually be collecting interest at a rate of 16%! It is no surprise that PECO's auditor, Coopers and Lybrand partner Mr. David Farling, was able to accept the PECO phase-in without reservations when one considers these facts.

Q. How do you propose to correct this error?

A. Many approaches are possible. One possibility is to simply use the average of Limerick 1 revenue requirements over the six year phase-in period. This is analogous to Mr. Hill's treatment of nuclear fuel assemblies. The result is a $875 million base rate increase, or a total rate increase of $596 million. This amount is phased-in as $199 million in year one, $397 million in year two, $596 million in year three, and $795 million in years four, five and six. This adjustment alone would reduce first year revenue requirements by $25 million.

Q. Please summarize the advantages of this correction to PECO's phase-in.

A. With this adjustment to PECO's phase-in, the Company will have the opportunity to collect all of the Limerick 1 revenue requirements over the phase-in period, but only that amount. No disguised attrition allowance is built into PECO's rates. Thus management will have to continuously strive to control expenses and will not reap an unjustified reward from building Limerick. If during the phase-in period, PECO fears it will earn an insufficient return, it will always have the opportunity to file for base rate increases. Thus there is no undue risk placed upon PECO that it will fail to earn a reasonable return.

Q. Mr. Falkenberg, have any other regulatory commissions recognized ratemaking considerations beyond the test year under similar circumstances?

A. In Duke Power Co. Docket E7-Sub 391, the North Carolina Public Service Commission required the utility to recover purchased power costs from the Catawba 1 nuclear plant by levelizing those costs over the life of the contracts (10 to 15 years). The levelization approach required in the Duke case is analogous to the averaging process suggested here, except that a return is imputed to the deferred costs. Given the shorter time period of this phase-in, and PECO's stated desire not to earn interest on the deferred amount, I have imputed no interest in this calculation. Finally, I will establish later that PECO must bear some of the risks associated with the Limerick plant, and for this reason it is appropriate to at least award the company with no interest on the phase-in deferral.

LIMERICK COMMON PLANT

Q. **Has PECO included 100% of Limerick common plant into its rate request?**

A. Yes, it has. I recommend that the Commission allow only 50% of Limerick common plant into rate base for a number of reasons: minimization of costs to customers, past PUC precedent, and to require PECO to live up to prior commitments concerning Limerick common plant.

Q. **Please elaborate.**

A. First of all, it is easy to show that if the AFUDC rate is the discount rate, the present value of revenue requirements to consumers is equal whether AFUDC accumulates on half of Limerick common plant, or the cost of common plant is currently included in ratebase. Currently, PECO's AFUDC rate is about 9.7%. However, customers have higher discount rates than this. Credit cards charge customers 15-18%. Home mortgages cost customers about 11% now. Many consumers obtained mortgages in the past few years at much higher interest rates. The prime lending rate is now about 9.5%, but this is the rate banks charge their most credit worthy borrowers. Many commercial and industrial firms face much higher rates. If consumers wish to make a long term investment in PECO, they could buy its bonds. Currently, these securities are considered investment grade and some currently yield over 15%. Thus, consumers of all financial circumstances can find opportunities to invest, (or cut interest cost by paying off debts early) at rates substantially above PECO's 9.7% AFUDC rate. Clearly, investing in Limerick common plant through higher rates is not an attractive investment for PECO's customers.

Secondly, the Pennsylvania PUC has consistently required that common plant be split between the units at a generating station. This was done in the case of Peach Bottom 2 and 3 in the 1970's, and reaffirmed in the case of Susquehanna Units 1 and 2 recently. Past commissions have recognized the wisdom of this approach.

Finally, and most significantly, PECO implied in the recent Limerick 2 investigation that the company would include only 50% of common plant into ratebase, if it was given permission to complete Limerick Unit 2. In the economic studies presented by PECO, it was assumed that only if Limerick 2 were cancelled, would 100% of common plant be requested in rate base when Unit 1 entered service. In cases where Unit 2 was completed it was assumed that common plant would be split equally between the units.

Our testimony in that case showed that Limerick 2 was not the most economic alternative for PECO. The Administrative Law Judges order found that to be a fact as well. The PUC has granted PECO a conditional permission to complete

Unit 2, in an order with a strong dissent from one of the Commissioners. At present PECO still intends to complete Unit 2 and the Company has accepted the Commission plan. Given this situation, I believe PECO should live up to its prior commitment to ratebase only one half of Limerick common plant, until Unit 2 is completed or cancelled. At that time examination of the proper rate treatment of the remaining common plant could take place.

I believe that Limerick Unit 2 is not the most economical alternative for PECO. This view is widely shared by PAIEUG members, other intervening parties and the ALJ in Docket No.I-840381. I do not believe it would be a sound regulatory policy to provide PECO with unnecessary financial rewards at consumers expense, for pursuing an uneconomic course of action. The denial of one half of Limerick common plant from rate base is perhaps an effective means to encourage PECO to pursue the prudent and economically sensible alternatives to completing Unit 2. Certainly PECO needs no further encouragement to complete the unit.

Q. **What is the implication of including only 50% of Limerick common plant into ratebase for the PECO phase-in?**

A. Falkenberg Exhibit 2 shows the corrected phase-in assuming that only 50% of common plant is currently included in ratebase. The exhibit shows that the test year revenue requirement of $671 million would be reduced to $523 million. The six year average revenue requirement is $466 million. Applying the same correction as shown in Falkenberg Exhibit 1 yields a phase-in schedule where a $155 million increase is allowed in year one, $310 million in year two, $466 million in year three, and $621 million is allowed in years four, five and six. This implies a first year rate increase of 6.3%.

SINKING FUND DEPRECIATION

Q. Do you have any recommendations concerning the appropriate depreciation technique for use on the Limerick Unit?

A. Yes. In Dockets No. R-822169 and No. R-842651 the PUC allowed Pennsylvania Power and Light Co. to use a modified sinking fund technique for depreciation of the Susquehanna nuclear plant. I would like to recommend that sinking fund depreciation be used on the Limerick unit as well.

Q. Explain sinking fund depreciation.

A. In this technique, the amount of annual depreciation on an asset increases by a constant percentage each year of its life. The first year depreciation expense is computed so that over the life of the asset it is fully depreciated. The rate of annual increase is called the sinking fund rate, and conceptually corresponds to the rate of interest which might be earned on the depreciation reserve, were it actually invested to provide for the ultimate replacement of the asset. In reality this is not done, of course.

One of the problems with a capital intensive investment like a nuclear plant, is that it takes a long time for the investment to benefit consumers. This is exacerbated by the fact that traditional utility ratemaking (using straight line depreciation and tax normalization) makes the carrying costs on a unit highest during its first years of operation. Thus consumers have to wait a long time to benefit from the unit (if they ever do). Years later, the cost of the unit is heavily depreciated and consumers at that time have lower rates than would otherwise be the case.

An additional factor to consider is that when PECO finishes its nuclear construction program (presuming both Units 1 and 2 are built) it will enter a period of time where little construction is needed. Eventually new plant will be needed and financing that construction will be quite costly.

Under the sinking fund depreciation technique, depreciation expense is deferred into the future. This reduces the large rate increases required in the test year and will ultimately improve cash generation from depreciation in the future, when it will be needed more.

It is interesting to note that sinking fund depreciation techniques are closely related to the concept of levelization. Without tax normalization, under sinking fund depreciation the annual carrying costs of a generating unit would be levelized through time. Customers in each year would pay the same revenue requirement for return and depreciation on the plant. Levelization techniques were commonly used by PECO and other utilities when studying the economics of nuclear plants compared to other options in the mid to late 1970's. For this reason, the short-term rate impact of the nuclear unit may not have been fully recognized in those studies. While there is nothing wrong with this approach to performing life cycle economic studies, it would seem appropriate now to adopt this concept for the actual rate treatment of the Limerick unit. In this manner the economic considerations involved in the early Limerick decisions may be reflected in current rates, and the large first year rate increase will be mitigated.

Q. **What is the sinking fund rate you would propose to use and why?**

A. First of all, I would point out that straight line depreciation is really a sinking fund at a 0% sinking fund rate. I would propose to use a 6% sinking fund rate. The 6% approximates PECO's projections of the <u>long-term</u> rate of inflation. Thus, customers will pay the same amount of depreciation expense each year in real dollars. This seems to be an equitable result. PECO's cost of money of 12.7% could be used as the sinking fund rate, as I proposed in the PP&L case. However, I recognize the fact that the commission was concerned this would lead to too great of a deferral in the collection of depreciation. Using 6% will reduce that problem considerably. The final result will be a test year depreciation expense of about $25 million dollars, a level reasonably close to that used in the PP&L case.

Q. What are some of the other advantages of the sinking fund depreciation approach you propose?

A. The use of sinking fund partially levelizes the carrying costs of Limerick 1 over the phase-in period. Thus the potential for overcollecting built into the phase-in is reduced.

Another advantage of sinking fund is that it may immediately be switched to straightline by the PUC in the event that PECO's financial requirements necessitate it. In the event PECO requires more internal fund generation to construct new plant in the future, the remaining plant balance can be straight lined. This would allow flexibility in the future.

Finally, it is important to remember that use of sinking fund depreciation has no impact on PECO's earnings and will increase the amount of deferred taxes from the difference between liberalized tax and book depreciation. PECO's own witness Dr. Lewis J. Perl testified in the Limerick 2 investigation that sinking fund depreciation was a useful approach to use to improve the economic impact of a nuclear plant on consumers.

Q. Can the sinking fund approach you propose be integrated into the phase-in plan?

A. Yes, in fact PP&L proposed to do just that in the last Susquehanna case.

There is no reason PECO's phase-in could not accommodate such a plan.

Falkenberg Exhibit 3 shows the modified and corrected phase-in plan assuming sinking fund depreciation computed at 6%, and only 50% of common plant included in rate base. The test year revenue requirement is reduced to $439 million, the six year average revenue requirement is reduced to $404 million. Thus, the modified phase-in proposal I recommend allows a $135 million increase in year one, $269 million in year two, $404 million in year three, and $539 million in years four, five, and six.

GUARANTEE OF LIMERICK FUEL SAVINGS

Q. **Should PECO guarantee the $207 million fuel savings**

A. Yes. The Company should be required to live up to that estimate. PECO has made much of the fact that Limerick will produce these savings. Unfortunately, if oil prices fall, or Limerick doesn't operate at 65% capacity factor, the rate impact of the unit will be even more severe.

Q. **Is this consistent with PUC precedent?**

A. Yes, in the Salem rate case, the PUC required the Company to guarantee the fuel savings. PECO agreed to this approach in that case.

Q. Should PECO also guarantee the 65% capacity factor assumed in the development of the $207 million fuel cost credit?

A. I believe this should be required of the Company as well. PECO estimates Limerick will operate at a 65% capacity factor for the purpose of computing the $207 million figure. PECO contends Limerick will operate at this level. I believe it should be required to live up to this estimate. To the present time, the Salem and Peach Bottom units have not achieved a 65% lifetime capacity factor. In addition, it is necessary to guarantee the capacity factor, as well as the total fuel savings, because a rapid (though perhaps unlikely) increase in oil prices could allow PECO to achieve the $207 million with a much lower capacity factor.

IMPLICATIONS OF PP&L ORDER

Q. Please describe Falkenberg Exhibit 4.

A. This exhibit shows the implications of the recent Commission order in the PP&L SSES-2 case. In that case the PUC found that a reserve margin of 22% for installed capacity was reasonable for a determination of excess capacity. Since PP&L installed reserves exceed that level, it was found that the SSES-2 nuclear plant was excess capacity. No equity return was allowed for the unit, and according to the PUC order, none will be allowed until the unit is needed or beneficial to consumers. In addition the PUC adopted the sinking fund depreciation technique for the unit. Finally, in the PP&L order the procedure of spliting common plant equally between units was continued by the PUC. Falkenberg Exhibit 4 shows the implications of the PP&L order if it were applied to the Limerick unit, in this case. The exhibit shows that if the PP&L order were applied to this rate case, PECO's total rate request would be reduced by $609 million. Thus, instead of a $671 million increase, PECO would be allowed, at most, a $61 million dollar increase. Furthermore, based on PECO's own analysis of the economic benefits of Limerick, no equity return would be allowed until 1994.

Q. **Would the PP&L precedent be applicable to PECO's current situation?**

A. Yes. Falkenberg Exhibit 5 shows that PECO's current installed reserve margin is 2660 MW, or 43.2%. Without Limerick Unit 1, PECO would have an installed reserve of 1605 MW, or 26.1%. Staff witness Gruber recommended calculation of reserves based on a five year average of peak demand in the PP&L case. Applying the installed capacity to the five year average peak demand of 6200 MW, produces a reserve margin of 42% with Limerick 1 or 25% without the unit. Removing the excess capacity on the PP&L system, based on the Gruber method, produced a 24% reserve margin. Clearly PECO's installed reserves without Limerick 1 are sufficient to meet either the PUC's 22% reserve level, or the PJM reserve requirement of 25%. Thus the situation here is entirely analogous to the PP&L case, where the last unit added to the system (SSES-2) was found to be the excess capacity on the system.

Q. **Do you recommend the PP&L precedent be applied in this case?**

A. No. However, I do believe the PP&L precedent is a more reasonable alternative than PECO's filed request. In the PP&L case, Kennedy and Associates did not propose action as drastic as the PUC took, and we do not recommend complete adoption of the PP&L precedent in this case either. However, it is clear that the PUC needs to recognize the excess capacity nature of Limerick 1, and should also be cognizant of the fact that Limerick 1 costs substantially more per KW than Susquehanna. There are important economic implications of the PP&L order, that go beyond regulatory philosophies or precedents. For example, businesses and industries in the PECO service territory may have competitors in PP&L's service area. Considering that PP&L's rates are already lower than PECO's, the drastic increase in PECO's rates as a result of Limerick could have substantial impact on the competitiveness of industry in the area. Clearly, the PUC needs to be cognizant of its treatment of PP&L, while considering this case.

ANALYSIS OF THE RELIABILITY AND ECONOMIC BENEFITS OF LIMERICK

Q. **Have you performed any analysis of the reliability and life cycle economic impact of Limerick Unit 1?**

A. Yes I have. I conclude that Limerick Unit 1 will reduce PECO's operational reliability from previous levels, though reliability will remain more than adequate for the system. Secondly Limerick Unit 1 will not produce economic benefits to consumers over the life of the plant, based on PECO's own economic study, as would be interpreted by the majority of executives in the electric utility industry in the United States. My alternative economic analysis shows Limerick to produce even greater losses to consumers than the corrected PECO study shows.

Q. **Regarding the subject of reliability, I am somewhat confused by the fact that PECO contends its reserve is only 28% with Limerick Unit 1. You contend PECO has a 43% reserve margin. Also, explain how adding the Limerick unit will reduce reliability on the PECO system.**

A. The answer lies in the fact that PECO intends to remove several older oil steam plants, and a number of combustion turbines from service. In total PECO will remove some 1585 MW of capacity from service over the next 9 years. In 1985 and 1986 PECO will remove 962 MW of oil fired capacity. Clearly, one large nuclear plant which is expected to be available only 65% of the time, cannot provide the same level of reliability as several smaller units. In addition the nuclear plant cannot provide the quick start capability of the combustion turbines. Thus, Limerick Unit 1 will degrade PECO's reliability. However, owing to the interconnections with the PJM pool, the reliability of the PECO system will still be more than adequate at the 28% active capacity level. Thus, the removal of several hundred megwatts of capacity from the PECO system, is proof of the fact that Limerick Unit 1 is not needed for reliable service. Based on PECO's load forecast and the 25% PJM reserve requirement, PECO does not begin to need the capacity of Limerick Unit 1 until 1989. With PECO's load growing less than 60 MW per year at that time, it would be a long time before the capacity of Limerick Unit 1 is fully needed.

Q. Isn't it true that by removing the older units, PECO is making economic retirements?

A. Yes, that is quite correct. Limerick 1 is an unavoidable fact of life. Given that the unit is on line, there is no longer any need for the older oil fired units. However, in the Limerick 2 investigation, it was made quite clear, that it was possible to extend the lives of the older units, for many years at a very low cost per KW of capacity. I showed that life extension of these units was economically preferable to completion of Limerick Unit 2. In the case of Limerick Unit 1, it appears that the recognition of the viability of the life extension option came too late, or was simply rejected by PECO, as the Company has done in the case of Limerick 2. In any event, given that Limerick Unit 1 is now completed and in service, it arguably makes economic sense to retire some of the older units. However, it is a quantum leap of logic to suggest, that on the basis of these retirements Limerick Unit 1 is now needed capacity. Clearly the unit is not needed, because ample, lower cost capacity is available without the new plant.

Q. Has the economic retirement phenomenon become commonplace in the utility

industry?

A. Yes, the so called economic retirement of generating plants and Extended Cold Shutdown (ECS) plans have become a common practice in recent years when large new plants have entered service. While this is an economic response to an excess capacity situation, I am disturbed that many utilities (PECO included) seem to believe this approach eliminates the problem rather than just slightly reduces the economic burden of excess capacity. The financial community is aware of this situation, as well. Quoting Merrill Lynch's Leonard S. Hyman

> "Now consider the utility that was going to explain its 90% reserve margin to the regulators. All it has to do is take a lot of plants out of service, for long term maintenance, or even because they aren't as economical to run as the new station, and down goes the reserve margin and along comes a low operating margin. At least that's how we would see it.....".

I do not believe the PUC should fall victim to this sort of reasoning.

Q. Dr. Hieronymus discusses at great length the prudence standard, and its role in utility ratemaking. He concludes that prospective lifecycle economic studies such as the one he performed have no relevance as regards prudence. Is that your view as well?

A. Yes. How attractive or unattractive a plant looks today is no <u>proof</u> of the prudence or imprudence of past decisions. However, that does not mean such analyses have no proper role in the ratemaking treatment of a new plant. First of all, if a current life cycle economic study shows the project to be a cost effective capacity addition over its life, prudence is not an issue as concerns planning decisions. Obviously, engineering construction management and operational areas such as fuel procurement might still be areas for a prudence review. In the case at hand, Dr. Hieronymus contends that Limerick Unit 1 will produce lifetime savings of $2.0 to $2.8 billion dollars for PECO's customers. If that is true then Dr. Hieronymus analysis of the prudence of past PECO decisions and studies is irrelevant. Likewise the testimony of NERA witnesses Perl, Wile and Guth should simply be ignored.

Q. **Why is that?**

A. Based on Dr. Hieronymus study, PECO would be prudent today to acquire Limerick Unit 1 if it had been built by someone else. Since the plant would ultimately lower rates for consumers, (even with todays knowledge of load forecasts and the actual cost of the Limerick unit) there would be no damages from any possible past imprudence in PECO's planning or forecasting activities. If we believe Dr. Hieronymus calculations, Limerick is ultimately a benefit to consumers. Thus, there is no serious long term consequence of past imprudence. This interpretation is verified in Dr. Hieronymus testimony and his response to our data request, attached as Falkenberg Exhibit 6. My interpretation of Dr. Hieronymus testimony is that he believes PECO was prudent at every step along the way, as regards Limerick Unit 1 planning decisions. More importantly, even knowing how things have turned out in 1986, and if PECO had the opportunity to do it all over, they shouldn't change a thing according to Dr. Hieronymus.

Somehow, I am skeptical of this conclusion.

Q. What role do you think lifecycle economic studies should have in determining the prudence and ratemaking treatment of a new plant?

A. As regards prudence, all the lifecycle studies do is identify whether a potential problem exists. In a case where a unit fails to produce economic benefits, one may wish to examine the prudence of past decisions. In a case where a project is known to be the result of imprudence, the analysis quantifies the damages to consumers. However, prudence alone, is not sufficient for full rate treatment of an investment. As I will discuss later, the project must also be used and useful. Lifecycle economic studies, done prospectively provide information concerning whether a project is used and useful or will ever be so.

Q. How do you interpret the lifecycle economic study performed by Dr. Hieronymus?

A. I have some serious differences of opinion concerning some of Dr. Hieronymus' assumptions. However, I believe it would be enlightening to accept his study for a moment, and ask how the rest of the electric utility industry might interpret the results of the Limerick 1 cost benefit study over the life of the plant.

Q. How can that be done?

A. Falkenberg Exhibit 7 is a survey of the EEI Finance Committee which discusses the discount rate used in economic studies within the utility industry. The survey covers 106 electric utilities owning 76% of the investor-owned electric utility assets in 1983.

Based on the EEI survey 75% of Investor Owned Utilities in the United States used the incremental cost of capital (with no adjustment for tax deductibility of debt interest) for internal economic evaluations. For the utilities responding to the survey this cost of capital figure averaged 14.3%. Dr. Hieronymus has used a net of tax discount rate of 9.7%. According to the EEI survey only 8 percent of the survey respondents used the net of tax discount rate for their economic studies. By using the 14.3% discount rate it is possible to interpret Dr. Hieronymus study as it would be viewed by others in the industry.

Q. What is the result of the analysis using the 14.3% discount rate?

A. Falkenberg Exhibit 8 shows that rather than producing a benefit of $2.0 billion dollars, as computed by Dr. Hieronymus, the Limerick plant produces a penalty of over $600 million dollars in the next 40 years. From this I conclude that the view of executives within the electric utility industry would be that Limerick is not a cost effective addition for PECO. Though I have not actually surveyed utility executives to validate this contention, it would appear to be the conclusion one would draw based on the responses to the EEI study. Considering that 14.3% is actually an average figure for the industry, and that PECO's cost of capital may exceed the industry average, Limerick Unit 1 is even less cost effective for PECO.

Q. What is the conclusion you would draw from this interpretation of the Hieronymus study?

A. First of all, it would now appear that the testimony concerning prudence is of some relevance, because at least in hindsight we can see that Limerick is a mistake for PECO. Thus it is important to consider whether this mistake was due to bad luck or bad management. Second, and more importantly, regardless of the prudence of past PECO decisions, which led to the current situation, the question is raised as to whether PECO should profit from its mistakes. None of the members of PAIEUG profit from mistakes they make. At a minimum I would suggest that the PUC should simply take note of the economic disadvantages of Limerick Unit 1, in weighing the factors which influence the ultimate rate treatment of the project.

Q. Have you performed an independent lifecycle analysis of Limerick Unit 1?

A. Yes, though many of my assumptions were developed from Dr. Hieronymus study. The main difference between my study and PECO's is that I used my own computer models to compute carrying costs, I included my own estimates of Limerick 1 O&M

expenses, and I included 100% of common plant with Limerick 1 in ratebase. I ignore the "acid rain" costs PECO uses and employ the 14.3% discount rate. Since my computer models only differ in some minor accounting details from Dr. Hieronymus calculation, the major differences concern O&M expenses and the treatment of common plant.

Q. **Why do you include 100% of common plant in ratebase with Limerick 1 when you recommend the PUC disallow current recovery on 50% of common plant?**

A. First of all, that is the rate treatment PECO is requesting in this case. Second, and most important, I have already demonstrated in the Limerick 2 Show Cause Investigation that Unit 2 is not cost effective for PECO without any common facilities. My conclusion is that the alternatives to unit 2 are more economic, and that if PECO follows the most economic course of action, 100% of common plant will ultimately be associated with Unit 1.

Q. **Why are your O&M expense assumptions different from PECO's?**

A. Once again, PECO is largely ignoring the observed trend of real increases in nuclear O&M expenses. In this case PECO assumes a 3% real growth in nuclear O&M expenses until 1990, and 0% real growth thereafter. Historically, nuclear plant O&M expenses have grown at a real rate of escalation in excess of 10%. For Peach Bottom, O&M expenses grew at a real rate of 11% from 1976 to 1983. Falkenberg Exhibit 9 shows a summary of Peach Bottom O&M expenses in the period

1976 to 1983. I have developed a regression equation to predict the level of O&M expenses as a function of time. This model implies a very conservative real growth in O&M expenses of $2.3 million dollars annually which is only about 3% real growth at current levels slowing down to .3% in the future.

Q. **What is the result of your lifecycle economic analysis of Limerick Unit 1?**

A. My analysis shows that Limerick Unit 1 is not a cost effective addition for PECO and that it results in $1.2 billion dollars in higher rates over the life of the plant.

RISK SHARING AND REGULATORY PRINCIPLES

Q. **What is the implication of the economic analysis you have performed as regards the rate treatment of Limerick Unit 1?**

A. The study shows that Limerick is not cost effective for PECO for two simple reasons: Limerick Unit 1 costs too much compared to alternatives and the plant is currently not needed to provide reliable service. By allowing full and immediate ratebase treatment for the unit, the PUC would be in a position of allowing PECO to profit from its mistakes at the ultimate expense of consumers. I do not believe this to be a sound regulatory policy. The PUC should strike a balance between the interests of consumers and shareholders. I recommend that the PUC require PECO shareholders to bear some of the adverse consequences of the investment decisions of management. As I will show later on, PECO should have been aware for some time that there was a substantial risk that Limerick could cost more than it expected, and that the demand for its power would not be as great as PECO anticipated. First I will discuss our recommendation as to the proper approach for PECO to share in the adverse consequences of the Limerick unit.

Q. **Please elaborate.**

A. PECO has proposed a phase-in plan to fully collect Limerick revenue requirements in a period of six years. I believe a longer phase-in could easily be justified on reliability or economic grounds. Based on a reliability criteria the phase-in would not begin until 1989. However, in the interest of moderation of the financial impact on the Company, I will accept the PECO phase-in period. PAIEUG clients wish to support a responsible phase-in plan that doesn't jeopardize PECO's financial capability over the long run. At the same time, I propose that any reductions in PECO's request made by the PUC should be taken off proportionately from each years phase-in revenue requirements, as opposed to being taken off the last years as suggested by PECO. I also recommend that no interest be allowed on the deferred revenue requirements, so that PECO does absorb some of the excess costs of the Limerick plant. This approach, I believe will provide an acceptable compromise between the interests of PECO's owners and customers.

Q. **Why do you believe this is a sound approach?**

A. The PUC should determine the proper level of test year revenue requirements, and any anticipated future adjustments. Costs found to be incorrectly included in ratebase (such as the additional 50% of common plant) or found to be imprudently incurred (such as possible excess costs due to delays) would not be granted rate recognition. The resulting reasonable costs are then phased-in using the same six year schedule as proposed by PECO. The ultimate financial impact on PECO is no greater than would be the case under traditional ratemaking and the lost interest on the deferred revenues is less as the total ratebase adjustments diminish the rate increases. Thus, the lost interest tends to be mitigated by other disallowances.

Q. **Please elaborate on your previous contention that PECO should bear some of the risks of its decision to build Limerick.**

A. Dr. Hieronymus has discussed at length the prudence standard. I believe it is important to understand some of the limitations in this ratemaking standard. It is often suggested in proceedings such as this, that unforeseen events such as the 1973 oil embargo or the 1979 accident at Three Mile Island, changed the world to such a degree that utilities could not accurately predict the future need for nuclear plants or their final costs. Testimony of PECO witnesses and Dr. Hieronymus and Mr. Guth seem to support these types of propositions. Based on this type of reasoning, it is suggested that the managers of utilities were pursuing sound and prudent expansion plans designed to minimize customer costs. Due to unforeseen events, it is argued that utilities could not have avoided the mistakes that they may have made. Having made only prudent mistakes, so the story goes, the utility should fully recover the costs of the project. Dr. Hieronymus cites a Wall Street Journal article by Alfred Kahn, that suggests customers should pay for "power plant duds", which were prudently planned and built.

The problem with this approach is that it seeks to completely eliminate the risk of mistakes from the owners and managers of utilities. In effect the utilities are requesting the regulators to use their ratemaking authority to guarantee the profitability of the utility companies, much the same as the U.S. Government uses its taxing authority to guarantee the interest and principal of treasury securities. The utilities who promote this prudence standard as the only important ratemaking consideration would see the regulator act as a taxing agent to back the utilities investments. Under Dr. Hieronymus prudence standard, it is virtually impossible for consumers as a whole to reduce their contributions to the profits of the utility company. Reductions in consumption, ultimately are rewarded only by a small reduction in fuel costs and variable O&M expenses. Based on this prudence principle, reduction in consumption, due to the economic self interest of consumers, conservation, or innovation is destined to fail in substantially reducing consumers payments to utilities.

It is important to realize that not even the Federal government can insure that all those who purchase long term treasury securities will be able to sell those securities at any time for their full purchase price, due to interest rate risk. If the prudence standard is the only factor considered, it should be possible for equity investors to fully recover their investment in utilities, because the equity return could be adjusted once or twice a year to eliminate interest rate risk. The Federal Government does issue securities which have their interest rate adjusted twice a year, series EE savings bonds. They pay an interest rate of 85% that of longer term securities (currently 8.36%). PECO seeks a much higher return on Limerick. However, PECO's discount rate used to evaluate the value of Limerick is close to the current return on treasury bonds.

Q. What is the basis for the regulatory principles espoused by Dr. Hieronymus, and do you see any flaws in his reasoning.

A. Dr. Hieronymus discusses, at great length, the unwritten contract between consumers and shareholders. In my view, Dr. Hieronymus has misinterpreted this "implicit bargain" between consumers and investors, at least as it has been interpreted in the Commonwealth of Pennsylvania.

In Pennsylvania, the utilities have received protection for competition in a limited sense, and have received in exchange a return on investments in prudently constructed assets which are useful to consumers. In cases where assets were not used and useful during the test year, investors received no return.

Despite the fact that Three Mile Island may have been a prudent investment originally, it was removed from ratebase when it could no longer operate. When TMI-1 returned to service, it began to earn a return once more. A number of years ago the Commission found that a number of PECO's combustion turbines were excess capacity and disallowed rate recognition. The PUC did not find that PP&L was imprudent in constructing SSES, but on two separate occasions disallowed return on the excess capacity created by the unit. In many instances, the PUC has upheld the used and useful principle as the most important element in determining the revenue requirements of a particular utility. For this reason, the cost of capital of PECO and other utilities in Pennsylvania reflects the level of risk shareholders have become accustomed to. In removing the used and useful criteria and relying on the prudence standard alone, Dr. Hieronymus seeks to "opportunistically change the rules of the game" now that the result is an unfavorable outcome for investors. I would suggest that if the Commission wishes to adopt a prudence only requirement, that proper notice be given, and return levels gradually be adjusted or reflect the risk level of that situation.

Q. **What do you mean by the comment that electric utilities are protected from competition in a limited sense.**

A. The utility franchise provides that PECO be the <u>only electric company</u> that can sell power in its service territory. However, individual consumers always have the option to find other sources of power, alternative fuels or ways to simply use less electricity.

If the Commission were to drop the possibility of excess capacity penalties, in effect, it is severly limiting the ability of consumers to make economic choices between electricity and competing products. If a "prudence only" standard is applied, shareholders profits are protected from <u>all</u> forms of competition -- alternative fuels or even the customers prerogative to turn off his lights. In effect, the prudence only standard advocated by Dr. Hieronymus would seem to require that customer contributions to shareholder profits be based <u>solely</u> on the level of consumption which may have been reasonably expected (but not actually achieved) in the past. Clearly, it is unreasonable to expect such a regulatory policy to result in efficient investment in utility plant or energy consuming equipment.

Applying the technique of "reductio ad absurdium" one would find a situation where only one consumer remains on the electric system, and is expected to pay <u>all</u> of the revenue requirements. Under the prudence standard his only possible escape would be to disconnect from the system (and that might not even work). Clearly, even Dr. Hieronymus would agree that <u>some</u> limit must exist on the application of the prudence standard. The real question is then, when does one begin to look beyond prudence. In this case, I suggest that the limits of the prudence standard have been exceeded and the Commission should require PECO to share in the adverse consequences of Limerick Unit 1.

Q **What are the implications of Dr. Hieronymus's framework regarding the prudence standard?**

A. In effect, Dr. Hieronymus is suggesting that an electric utility company is entitled to a full return on all of its investments unless imprudence can be established. In other words, unless it can be proven that the decision making by the utility was totally unreasonable, regardless of the outcome.

The implication is that the utility's owners will receive their desired return on investment even if their appointed management has badly managed the enterprise, as long as it can't be shown that these managers were any worse than others in similar businesses. As a result of this standard, the stockholders face no business risk on their investments. As long as the management of the utility performs in a similar manner to other utility management, it does not matter whether a reasonable or sufficient performance level is acheived, only that it is not significantly worse than comparable management.

Q **What do you perceive the risk to be for the investors under Dr. Hieronymus's prudence standard?**

A. Given his definition and framework for evaluating prudence, I believe that the risk to investors is only the risk associated with interest rate fluctuation and not business risk. The appropriate cost of debt under this framework is the cost of long term U.S. treasury bonds. These bonds provide a business risk free return yet incorporate a premium over and above short term rates to reflect interest rate risk over a long period (20 to 30 years).

Q What is a representative long term credit risk free rate in today's market?

A. U.S. treasury bonds maturing in 2015 are currently yielding 9.28% to maturity.

Q What would be the impact on PECO's requested rate increase if Dr. Heironymus was correct in his interpretation of the prudence standard?

A. Using the business risk free cost of debt of 9.28% for PECO's interest costs and 8.36% for the cost of equity, I have computed PECO's revenue requirements using their claimed test year costs for all other (except capital cost) components of cost of service. In essence, I simply substituted a 9.28% value for PECO's debt return and the savings bond rate of 8.36% for the return on equity. The results of this analysis are presented in Falkenberg Exhibit 11.

This exhibit shows that under Dr. Heironysus's proposed definition of prudence, PECO should only receive a $193 million increase or 8%. This includes a return on 100% of Limerick I common plant, as requested by Dr. Heironymus.

Q. Why would there be only a 8.36% return on equity under the approach proposed by Dr. Heironymus?

A. If his philosophy were adopted it appears that since management was presumed to be prudent, some sort of cost-of-service indexing approach would be in effect to grant automatic rate increases once or twice a year. Since the equity return could be adjusted to reflect changes in the cost of funds, interest rate risk would be substantially reduced. Thus, I presume that the rate on savings bonds would be a proxy for the risk free equity return.

PECO LOAD FORECASTS FROM 1972 TO 1985

Q. You contend that Limerick Unit 1 is not needed for reliable service. NERA witness Guth, has testified that PECO's load forecasts were reasonable during the period from 1972 to the present. Dr. Hieronymus also testified that PECO's load forecasts were sound. What is your view of the reasonableness of PECO's load forecasts?

A. I have not concluded that PECO's load forecasts were imprudent, when developed. However, I can show that other analysts within the utility industry could have developed much different and more reasonable forecasts using very simple techniques available during this period. From this I conclude that PECO should have been aware that there was some risk that the capacity from Limerick would not be needed when completed. This supports my conclusion that PECO should bear some of the adverse consequences of the Limerick decision.

Q. **Please discuss your analysis of PECO's load forecasts.**

A. Mr. Guth has suggested that a reasonable test of the PECO load forecasts is to compare them to those which might have been developed through statistical analysis of historical trends. In general, I believe this is a reasonable approach, for it allows one to determine if PECO's forecasts were consistent with the trends occurring at the time.

Q. **Was trend-line analysis common in the utility industry in the 1970's?**

A. Yes, in fact this approach was the basis for the load forecasts of many utilities. West Penn Power used this method until 1980. Historically, the approach had proven a successful forecasting tool. It is often suggested that unforeseen events such as the oil embargoes and the recessions of the 1970's led to a situation where past trends no longer continued. Utility forecasts based on historic trends could no longer accurately predict the future. From this scenario, it is often concluded that load forecasts errors were not the result of imprudence, but rather simply bad luck.

I believe that analysis of PECO's historic load growth patterns is a useful exercise, to test the hypothesis that unforeseen events made it <u>impossible</u> for PECO to produce reasonable load forecasts. At the same time this analysis will show whether PECO's load forecasts were at least consistent with historic trends. If PECO's forecast were not consistent with historic trends, one may wonder why.

Q. **How was this analysis performed?**

A. The approach used was to study the growth patterns in PECO's loads for ten year periods. For example to analyze the 1972 load forecast, the load growth over the period 1961 to 1971 was studied. This would have been the most recent 10 year period of data available prior to preparation of the 1972 load forecast. Likewise the 1973 forecast analysis was based on the peak demand data for the period 1962 to 1972.

Q. **Why use a ten year period as the basis for the forecast?**

A. PECO typically projected ten years ahead, thus a ten year historic period seems reasonable. Also PECO was not a summer peaking utility until 1959 or 1960, so the data prior to that time may have been influenced by other trends.

Q. **Please discuss the analytic procedures you employed.**

A. The summer peak demand data was examined using regression analysis. Exponential and linear growth models were examined. The model exhibiting the best statistical results was used as the basis for the forecast, until 1978.

After that the linear trend model was used.

Q. What are the results of this analysis?

A. Falkenberg Exhibit 12, shows the results of the trend based forecasts compared to PECO's actual forecasts. Every year from 1972 to 1977 PECO's own peak demand forecasts significantly exceeded the trend based forecasts. In all cases PECO's peak demand forecasts in the terminal year exceed the trend analysis result by 900 MW. In some cases the PECO forecasts exceeded the trend prediction by 2000-3000 MW. From 1978 to the present time, PECO's load forecasts are quite close to the trend line model predictions. Thus the immediate conclusion from this analysis is that during a period of time critical to Limerick decision making, PECO's load forecasts were consistently higher than historic trends would have suggested. The implication is that PECO expected future load growth to differ from that in the past in a consistent fashion. From 1972 to 1977 PECO expected future load growth to consistently exceed that of the past ten years.

For whatever reasons PECO expected load growth to depart from historical experience, it appears that they were consistently disappointed with the actual result. It is instructive to examine the load growth expected in the first year of each forecast. In 1972 PECO predicted load would grow by 818 MW over 1971. The 1972 forecasts predicted the annual load growth in all subsequent years would be much lower, and would only average 568 MW from 1973 to 1981.

In the 1973 PECO load forecast a similar situation emerges. In that year PECO predicted peak demand would grow by 707 Mw over the 1972 peak. In the period that followed, load was expected to grow by 571 mw per year (the average growth from 1974 to 1982). It is interesting to note that during the period 1962 to 1972 PECO's peak demand grew at a rate of only 262 MW on average. What is more significant is that during the ten year period preceding the 1973 load forecast there is no significant trend of increase in the annual peak demand growth. By the time the 1973 forecast was prepared PECO's summer peak demand was exhibiting a pattern of linear growth. Thus PECO's forecast of 707 Mw growth in PEAK demand in 1973 was 2.7 times greater than the level actually experienced during the previous ten years.

The 1974 and 1975 forecasts exhibit a similar pattern. In the 1974 forecast first year load growth of 640 Mw was expected compared to actual experience of 276 Mw for the preceding ten years. In 1975 first year load growth of 849 Mw was expected as opposed to historical growth of 261 Mw. In both cases the growth expected in the first year was higher than the level expected in subsequent years.

It is unclear, what PECO expected to drive such large increases in load growth. However, it is clear that PECO expected it to occur quickly, and to have its greatest influence on the first year of the forecast. Each year this expectation was not realized.

Q. Discuss the implications of the linear pattern of load growth?

A. In the 1970's many utilities expected that the historic pattern of exponential growth in electric demand would continue. Such a growth pattern implies that the annual increase in peak demand grows through time. In essence, it is a pattern of a constant percentage growth. In the linear trend model it is expected that the peak demand would increase by the same number of megawatts each year. PECO's forecasts were much closer to the linear growth model, except for the fact that higher growth was usually expected in the first year of the forecast. In general it appears PECO correctly anticipated the <u>pattern</u> of load growth, however, the <u>level</u> of load growth expected far exceeded experienced trends.

Q. What are the implications of the trend model predictions for the 1973 and 1974 load forecasts?

A. The 1973 and 1974 trend forecasts predicted future demand levels 2000 to 3000 MW less than PECO's forecasts did at the time. The data from these forecasts would have been available by mid 1973, <u>before</u> the first oil embargo. By comparing the trend model predictions to actual load growth during the period 1974 to 1985 it is possible to discern the impact of the oil embargo and subsequent unforeseen events on PECO's load growth. The difference between trend model predictions and actual load growth might reasonably be attributed to the events that led to the discontinuation of the historic trends. Thus the difference between the trend model prediction and actual loads is the unavoidable forecast error. A positive value suggests the forecasts were worse than necessary. A negative value for the unavoidable forecast error suggests better forecasts than could normally be expected.

The difference between the PECO forecast and the trend model prediction, would arguably be forecast errors that could have been anticipated. In the testimony of Dr. Hieronymus and Mr. Guth, it seems to be implied that all of the variances in the forecasts could be attributed to unavoidable errors. In fact as Falkenberg Exhibit 12 shows, avoidable forecast errors account for a substantial portion of the variation between actual load and PECO's predictions in the period 1972 to 1977. In the pre-embargo 1973 and 1974 forecasts, over half of the error in PECO's forecasts was avoidable. This is arguably a low standard of comparison, because it presumes that the reasonable analyst could have done no better than simply extrapolate observed trends. It seems that PECO's management would have had the advantage of much more knowledge of their load growth prospects than a few observations of peak demand.

Q. **What is your conclusion from this analysis?**

A. First of all it is apparent that the Commission should not be impressed by the argument that PECO's forecasts proved wrong because they did not foresee events such as the oil embargo. PECO's forecasts would have been too high even without these events had past trends continued. Second, it is clear that PECO could or should have known that its projections of peak demand growth (and therefore the need for Limerick) vastly exceeded previous experience. For whatever reasons PECO expected this growth, there should have been an awareness that this level of growth was unprecedented. Clearly, this suggests PECO's management should have considered this forecast carried a substantial downside risk. Finally, I think it is interesting to note that even when PECO's forecasts dramatically declined and improved in 1978 and afterwards, they still are quite close to simple trend line results. Thus it would appear that the improvement on PECO's load forecasts came when it was finally recognized that future growth would approximate (not exceed) past trends.

PECO'S EARLY LIMERICK COST ESTIMATES

Q. **Your economic studies indicate that Limerick costs too much to be a cost effective addition for PECO. PECO's earlier cost estimates for Limerick were much lower than the actual final cost of the plant. Have you analyzed PECO's early cost estimates?**

A. Yes. I have focused on the pre-1979 (TMI) period cost estimates, for two reasons. First of all, by 1980, the PUC investigated completion of the unit, and found it reasonable (at that time) to complete Unit 1. It appears that by that time PECO had crossed the point of no return on Unit 1. Thus the question is whether the company might have acted differently before 1980 if it had perceived the possibility of Limerick costing more to build. Secondly, I wished to see what level of cost might have been expected for Limerick, based on information available before the TMI accident. This allows one to examine whether the unforeseen TMI incident might have made it impossible to accurately predict the cost of the nuclear plant.

Q. **What is the conclusion of your analysis?**

A. I have concluded PECO could have been aware that their was considerable risk that their forecast of the cost of Limerick would be much too low, based on data available by 1978. My analysis shows that PECO could have expected the cost of the Limerick plant to be more than 60% greater than the 1978 forecast predicted.

Q. **What is the basis for this conclusion?**

A. I have based this conclusion on statistical data. First of all, the phenomenon of rapidly escalating nuclear plants is not new. Since the late 1960's nuclear plant costs have escalated rapidly. Falkenberg Exhibit 13 shows generic nuclear plant cost estimates published by the Federal Power Commission in the "1964 National Power Survey". This document projected nuclear plant costs would be in the range of $107 to $125 per KW for a mid to late 1970's vintage plant. This cost was expected to be quite close to the cost of new coal fired plant. At that time nuclear units were expected to be more reliable, have greater operational flexibility, offer the potential to avoid expensive air pollution control equipment, and cost less to operate than conventional plants. With all these advantages it is not surprising that many utilities like PECO, embraced nuclear power.

By 1970 the outlook for nuclear power was becoming less favorable. The estimated costs of new reactors had more than doubled in just 4 years. According to the 1970 FPC "National Power Survey" in March 1967 large nuclear plants were expected to cost $135/KW. By 1969 the expected cost of a new unit rose to $220/KW and by 1971 the cost jumped to $300/KW. PECO's 1971 cost estimate for Limerick was $339/KW. This cost was the first "order of magnitude" estimate, according to the Theodore Barry testimony. Unfortunately, in this case "order of magnitude" carries the scientific connotation : the estimate is within a factor of 10 of the correct value.

Q. **Why did nuclear plant cost rise so much?**

A. There are probably many reasons. Turning to Falkenberg Exhibit 14, we see comparisons of the original estimated costs to actual for nuclear plants of different vintages (Source Power Engineering: The data base for U.S. Power Plants). Plants coming on line in the period 1969 to 1974 exceeded original estimates by 57%, on average. Plants coming on line from 1975 to 1979 exceeded original expectations by 178%. As we now know the situation has only gotten worse since that time.

In this rate case it has been suggested that changing regulatory requirements have been partly responsible for the increase in nuclear plant costs. This is not new in the utility industry either. For example, in the 1972 Florida Power Corporation Annual Report we find the following statement:

> "A major concern in our efforts to meet the increasing need for electricity is being able to build new plants on schedule and at the planned cost. A key factor is the delay caused by the red tape of regulatory bodies."
>
> "Sometimes, as was the case this year, the tangle of delay is just too much. In July, we cancelled plans to build a second nuclear plant at Crystal River.....Our first nuclear unit was originally scheduled to be in operation by April 1972. This plant is now delayed to late 1974, over 2 1/2 years behind schedule."

Q. Did PECO's early cost estimates reflect the trend towards increasing costs for nuclear plants?

A. Yes, in the July 1972 estimate the cost of Limerick had increased by 69% to $573/KW. By 1975 the estimated cost had jumped another 66% to $949/KW.

Q. What was the observed trend nuclear plant costs for units entering service in the period 1968 to 1978?

A. Falkenberg Exhibit 15 shows a summary of the installed cost per KW of nuclear plants entering service during this time period. The source of data for this exhibit are surveys performed by TVA and the Alabama Power Co. The exhibit shows the plants entering service each year, and the size of these plants and their installed cost per KW (including AFUDC). On the same exhibit is PECO's estimated cost for Limerick during each year.

The figures show that installed cost of nuclear plants actually dropped slightly after the first plants entered service from 1968 to 1971. Possible explanations would be that new plant were getting larger, and that a learning curve effect was taking place. In 1970 and 1971 the average cost of a plant coming on line was about $164/KW. As we know the estimated cost for new plants ordered in that year was $300-$339/KW. Thus in 1971, it was expected that new plant costs would escalate at a rate of 16% per year (or 11 % in real terms) over the most recently completed units.

During the period 1971 to 1978 the cost of new plants entering service showed a remarkable upward trend. By 1974 the average plant entering service cost $331/KW, twice as much as plants completed in 1971. In 1975 the average cost rose again to $457/KW nearly triple the cost of plants finished in 1971. By 1977 the cost of nuclear plants reached $638/KW, nearly quadruple the cost of plants completed 6 years earlier. This was an annual rate of escalation of over 25%, or a real escalation rate of about 20%!

Q. **How did PECO's cost estimates for Limerick compare to the cost of plant completed during the 1971 to 1978 time frame?**

A. In the early years (1971 to 1974) PECO was expecting a substantial level of escalation in the cost of Limerick compared to recently completed plants. During this time frame PECO expected the cost of Limerick would escalate over recently completed plants at an annual rate of almost 10% over inflation. It would seem clear that PECO's management recognized there were forces at work which would cause the cost of nuclear power to dramatically increase in real terms.

As years passed, the cost of new plants entering service continued to rise. However, PECO's estimates for Limerick rose at a much slower rate. The implied real level of escalation in Limerick's cost began to drop substantially in the period 1975 to 1978. In 1977 and 1978, PECO's expected cost of Limerick, implied only a 2% real annual rate of escalation over the cost of the most recently completed units. From this it would appear that PECO expected, for some reason, that the trend of substantial real escalation in the cost of nuclear plants would be substantially reduced. In light of the observed trends this seems to have been a rather optimistic point of view.

Q **What kind of cost estimate might PECO have developed for Limerick in 1978 looking only at statistical data?**

A. I have developed a regression equation of the installed cost of the nuclear plants completed before 1979. In developing this equation, I decided to simply examine the implications of the observed trends in nuclear plant cost circa 1978. Thus the model I develop simply identifies and measures the magnitude of cost increases for nuclear plants that occurred during 1968 to 1978. It makes no attempt to explain why these cost increases occurred. The model does attempt to measure the impact of economies of scale on nuclear plant costs, as well as the differences in costs between initial and add-on units, and extra costs incurred in plants built in the Northeast. The model identifies and measures these factors with no attempt to explain why they occur. Falkenberg Exhibit 16 summarizes the results of the best fit regression model. All of the explanatory variables are statistically significant, and the model successfully explained 85% of the variation in the cost of nuclear plants in the sample.

Q. **What would the regression model have predicted as the final installed cost for the Limerick plant, based on the in-service dates expected in 1978?**

A. The model would have predicted a final installed cost of $2454/KW for the station. In 1978 PECO was predicting Limerick would cost $1508/KW, some 60% less.

Q. **What is your interpretation of this result?**

A. The forecast of the regression model is based on the assumption that past trends would continue to the future. By 1978 it was fairly clear that a temporal trend towards rapidly escalating nuclear plant cost had persisted for a number of years. The reasons for this trend may have been inflation, rising interest rates, lengthening construction times, and perhaps even "regulatory red tape". The model tells what kind of cost could be expected if these trends did not get any better or worse. The fact that PECO's 1978 estimate is $900/KW less that the regression prediction, implies that the Company was optimistic that the trends experienced prior to 1979 would for some reason abate in the future. While that may not have been an imprudent expectation, on its own, it was at least a risky proposition. Certainly by 1979 when the TMI accident occured, there should have been cause for concern that the previous trends in cost would not improve.

The second conclusion one might draw from this statistical analysis is that if PECO's estimates for nuclear plants were reasonable compared to the rest of the industry in 1978, then the industry as a whole, was either ignoring or discounting the experienced trend towards increasing nuclear plant costs.

Finally, it is interesting to note that even before the TMI accident, there was ample evidence that nuclear plant costs were going to be much more expensive than predicted. Just as in the case of the impact of the oil embargo on load growth, the impact of unforeseen events (i.e., TMI) on the economics of nuclear power may have been exagerated.

CONCLUSION

Q. **Please summarize the conclusions of your testimony?**

A. It is clear that in deciding to build Limerick, PECO was pursuing a risky course of action. Whether the company evaluated these risks or not, reasonable analysts could have suggested that PECO's load forecasts were optimistic on the high side, and that PECO's Limerick cost forecast was optimistic on the low side. Now PECO has ended up with a plant that is not needed and costs too much to be an economical capacity addition. It is not simply hindsight to say that PECO should have been aware of the risks it was taking. Others within the utility industry recognized the problems with nuclear power much earlier. Turning to Florida Power Corporation's 1975 Annual Report we find:

> "While the cost of producing energy from nuclear fuel is now lower, the outlook is changing rapidly. The cost of constructing nuclear generating plants is increasing faster than the cost of fossil-fueled plants. <u>An extension of this trend in relative costs could make nuclear power plants economically impractical within the near future</u>." (emphasis added)

Had PECO adopted this position in 1975, the $1.2 billion dollar penalty to rates Limerick creates would have been avoided.

Q. **Please summarize your conclusions.**

A. PECO must bear some of the adverse consequences of the Limerick plant. It does not appear that PECO can absorb all of the costs of Limerick and remain financially viable. The proposal I suggest would equitably distribute the Limerick burden between consumers and investors. This phase-in plan allows PECO a $404 million rate increase to be collected over six years, starting with $135 million in 1986. PECO should also bear the risk of operating Limerick at a 65% capacity factor, or better and guarantee the $207 million in fuel savings. Most importantly, any reductions in PECO's rate request must be removed proportionately from each years rate increase, not taken off the last years as proposed by the Company.

Q. **Does this complete your testimony?**

A. Yes.

Randall J. Falkenberg

Randall J. Falkenberg

State of Georgia
County of Fulton

Subscribed and sworn to before me, a notary public in and for the State and County aforesaid.

My commission expires

MY COMMISSION EXPIRES SEPT. 12, 1988

This 10th day of January 1986

Barbara J. Trojanowski

Notary Public

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION, et al.,

v.

PHILADELPHIA ELECTRIC COMPANY

Docket No. R-850152

EXHIBITS
OF
RANDALL J. FALKENBERG

ON BEHALF OF
PHILADELPHIA AREA INDUSTRIAL ENERGY USERS GROUP

Kennedy and Associates
January, 1986

Falkenberg Exhibit 1a
Corrected PECO Phase-In
$Millions

Year	Limerick Fix Charge	Other Change	Total Revenue Reqmt.	Peco Phase-In	Actual Deferal	With Int. at 9.7	Corrected Phase-In
							875
1986	950	279	671	224	-447	-469	199
1987	918	279	639	447	-191	-715	397
1988	885	279	606	671	65	-717	596
1989	859	279	585	895	315	-456	795
1990	832	279	553	895	341	-143	795
1991	807	279	526	895	366	228	795
Total 1986:1991	5250	1673	3577	4025	448		3577
Six Year Average	875	279	596	671			596

Falkenberg Exhibit 1b
Corrected PECO Phase-In
$Millions

Year	Limerick Fix Charge	Other Change	Total Revenue Reqmt.	Peco Phase-In	Actual Deferal	With Int. at 16	Corrected Phase-In
							875
1986	950	279	671	224	-447	-483	199
1987	918	279	639	447	-191	-767	397
1988	885	279	606	671	65	-820	596
1989	859	279	560	695	315	-611	795
1990	832	279	553	895	341	-340	795
1991	807	279	528	895	366	1	795
Total 1986:1991	5250	1673	3577	4025	448		3577
Six Year Average	875	279	596	671			596

Falkenberg Exhibit 2
Modified and Corrected Phase-In with 50% Common Plant
$Millions

Year	Limerick Fix Charge	Other Change	Total Revenue Reqmt.	Peco Phase-In	Corrected Phase-In
					744
1986	802	279	523	174	155
1987	777	279	498	349	310
1988	752	279	473	523	466
1989	731	279	453	698	621
1990	712	279	433	698	621
1991	693	279	414	698	621
Total 1986:1991	4467	1673	2793	3139	2793
Six Year Average	744	279	466	523	466

Falkenberg Exhibit 3
Modified and Corrected Phase-In with 50% Common Plant
With Sinking Fund Depreciation
$Millions

Year	Limerick Fix Charge	Other Change	Total Revenue Reqmt.	Peco Phase-In	Corrected Phase-In
					683
1986	718	279	439	146	135
1987	699	279	420	293	269
1988	684	279	405	439	404
1989	674	279	395	586	539
1990	665	279	386	586	539
1991	656	279	377	586	539
Total 1986:1991	4097	1673	2423	2636	2423
Six Year Average	683	279	404	439	404

FALKENBERG EXHIBIT 4

IMPACT OF SSES-2 ORDER ON LIMERICK UNIT 1

RATE REQUEST ($ millions)

Rate Base with 100% Common Plant	3,700
Rate Base with 50% Common Plant	3,100
Depreciation Expense	25
Preferred Equity	35
Normalized Income Tax	31
ITC Amortization	(13)
O&M and Other	101
Debt Return	170
Limerick Revenue Requirement	349
Non-Jurisdicational	(9)
Change in Fuel and O&M Costs	(279)
Total Rate Increase	61

FALKENBERG EXHIBIT 5
DEMAND/CAPACITY BALANCE
1984-1994

YEAR	PEAK (MW)	INSTALLED CAPACITY	RESERVE (MW)	RESERVE (%)	RESERVE (%) w/o Limerick
1984*	5925	7282	1357	22.9	22.9
1985*	6034	7765	1731	28.7	28.7
1986	6160	8820	2660	43.2	26.1
1987	6180	8820	2640	42.7	25.6
1988	6200	8820	2620	42.3	25.2
1989	6220	8820	2600	41.8	24.8
1990	6240	8820	2580	41.3	24.4
1991	6260	9875	3615	57.7	24.0
1992	6320	9875	3555	56.3	22.9
1993	6380	9875	3495	54.8	21.7
1994	6440	9875	3435	53.3	20.6

* ACTUAL PEAKS

FALKENBERG EXHIBIT 6

IR-PAIEUG-2-65

Q. IR-PAIEUG-2-65 Is it correct to infer from the testimony on page 56 of PECo Statement No. 15 that PECo would consider it prudent to buy today the Limerick Unit No. 1 nuclear plant from an outside party in the hypothetical event that someone else had built it?

A. IR-PAIEUG-2-65 As discussed at length at pages 16 to 55 of PECo Statement No. 15, Dr. Hieronymus is of the opinion that these calculations are not relevant to any prudence issue in this proceeding. Nevertheless, it does follow from the conclusion on page 56 that Limerick Unit No. 1 is a cost effective addition to the PECO system that the acquisition of the hypothetical plant with like characteristics would be prudent if Limerick Unit No. 1 were not already available to PECo. While he cannot speak directly for it, Dr. Hieronymus presumes that this same conclusion would be reached by PECo management.

Responsible Witness: W. H. Hieronymus, Putnam, Hayes & Bartlett

FALKENBERG EXHIBIT 7

EDISON ELECTRIC INSTITUTE

FINANCE COMMITTEE

COST OF CAPITAL USED FOR INTERNAL ECONOMIC EVALUATIONS
1984 SURVEY OF EEI MEMBERS

PREPARED BY THE FINANCE DIVISION
OF
EDISON ELECTRIC INSTITUTE

MAY 1985

Contents

Tables

Figures

1984 Cost of Capital Survey

Background

The intent of this study was to analyze the average costs of capital used by the investor-owned electric utility industry for the purpose of evaluating economic alternatives. Surveys were received from 106 electric utility companies. Those companies accounted for approximately 76 percent of the investor-owned electric utility industry assets in 1983.

The survey was conducted during the second half of 1984. During that period, interest rates and bond and dividend yields declined about 200 basis points. Nevertheless, the average yield on a public utility bond was 50 basis points higher during the period of the 1984 survey than during the 1983 survey. The result was an increase in the composite weighted average cost of capital from 13.9 percent in 1983 to 14.3 percent in 1984.

Respondents were asked to provide financial, regulatory, and accounting data. In addition to cost of capital components and weighted average costs of capital, respondents provided information pertaining to regulatory (i.e. allowed) costs of capital, accounting returns, bond ratings, construction work in progress in rate base, and plant and revenue statistics. EEI appreciates the efforts made by the companies to complete this survey.

Cost of Capital

Respondents to the 1984 survey used a composite weighted average cost of capital of 14.3 percent for the internal evaluation of economic alternatives. This rate was up slightly from 13.9 percent in 1983 and can be attributed to a number of factors including higher market interest rates and, to some degree, higher degrees of risk for some utilities as perceived by investors. The increased perception of risk stemmed primarily from the trouble experienced by many companies which are still involved in the construction of large generating plants.

Respondents were not asked to differentiate between capital costs for varying types of facilities such as generation versus transmission or nuclear versus coal. However, those companies with an interest in a nuclear generating plant reported a 14.8 percent composite weighted average cost of capital, 50 basis points higher than the cost of capital for the entire industry, and 90 to 100 basis points over the composite weighted average cost of capital for companies with no participation in nuclear generating plants.

The 14.3 percent weighted average cost of capital is based on companies which use the <u>incremental</u> cost of debt for internal economic evaluations. For the 1984 survey, those companies accounted for 75 percent of the companies responding. Fourteen percent of the respondents reported using historical or embedded cost of debt in determining their cost of capital, the average of which was 11.6 percent. The remaining companies used net-of-tax costs and other methods of costing debt in determining their cost of capital.

Table 1 presents the average cost of capital for investor-owned electric utilities using incremental and historical costs of debt.

Table 1

Average Cost of Capital, 1975-1984

Year	Average Cost of Capital for Users of Historical Cost of Debt [(a)]	Average Cost of Capital for Users of Incremental Cost of Debt
1984	11.6	14.3
1983	12.4	13.9
1982	12.0	15.4
1981	11.9	15.2
1980	10.1	12.7
1979	9.9	11.5
1978	9.3	11.0
1977	9.8	11.0
1976	9.9	11.4
1975	9.4	11.4

Cost of Debt

The average cost of incremental debt reported by respondents to the 1984 survey increased to 13.2 percent from 12.4 percent as reported in the 1983 survey. A summary of the cost of debt using various methods of measurement previously discussed is presented in Table 2.

[(a)] 1984 is based on a fewer number of reporting companies and conseqently is not strictly comparable to earlier years.

Table 2

Determination of the Cost of Debt
Used for Internal Economic Evaluations

Method of Determination of Cost of Debt	Number of Companies	Percent of Total Respondents	Average Cost of Debt
Incremental	80	75	13.2
Embedded	15	14	9.6
Net of Tax	8	8	7.4
Other	3	3	

During the period the survey was conducted (third and fourth quarter, 1984), yields on public utility bonds declined more than 200 basis points. The average public utility bond (gas and electric) yield as measured by Moody's Investors Service fell from 15.2 percent in the beginning of July to 12.9 percent at the end of December.

The average yields on public utility bonds with various bond ratings as reported by Moody's during the period of the 1984 survey are shown in Table 3.

Table 3

Average Yields on Public Utility Bonds
July 1984 through December 1984
(Percent)

	Aaa	Aa	A	Baa	Average
Average	12.62	13.45	13.93	14.37	13.86
Range	12.35-12.92	12.64-14.77	12.94-15.12	13.38-15.66	12.83-15.18

Source: Moody's Investor Service - Manual.

On average, however, bond public utility yields were 50 basis points higher during the period covered by the 1984 survey than they had been one year earlier during the 1983 survey. This was in part due to higher market interest rates and in part due to increased risk as perceived by investors. Continuing financial problems and the association with nuclear generating plants may have inflicted an additional risk premium on some utilities at certain times during the survey periods which in turn affected the higher bond yields.

Inflation, high interest rates, and the massive construction financing requirements since 1975 have had severe impacts on electric utility bond ratings. In turn, declining bond ratings have contributed to generally increasing debt costs since 1975. Table 4 presents the distribution of bond ratings of the same 95 companies in each of the years 1984, 1982, 1980, and 1975. Eleven respondents whose debt was either privately placed or for some other reason not rated by Moody's were excluded from the distributions. The same data are presented graphically in Figure 1.

Table 4

Distribution of 1984 Survey Respondents by Bond Ratings
1984, 1982, 1980, 1975

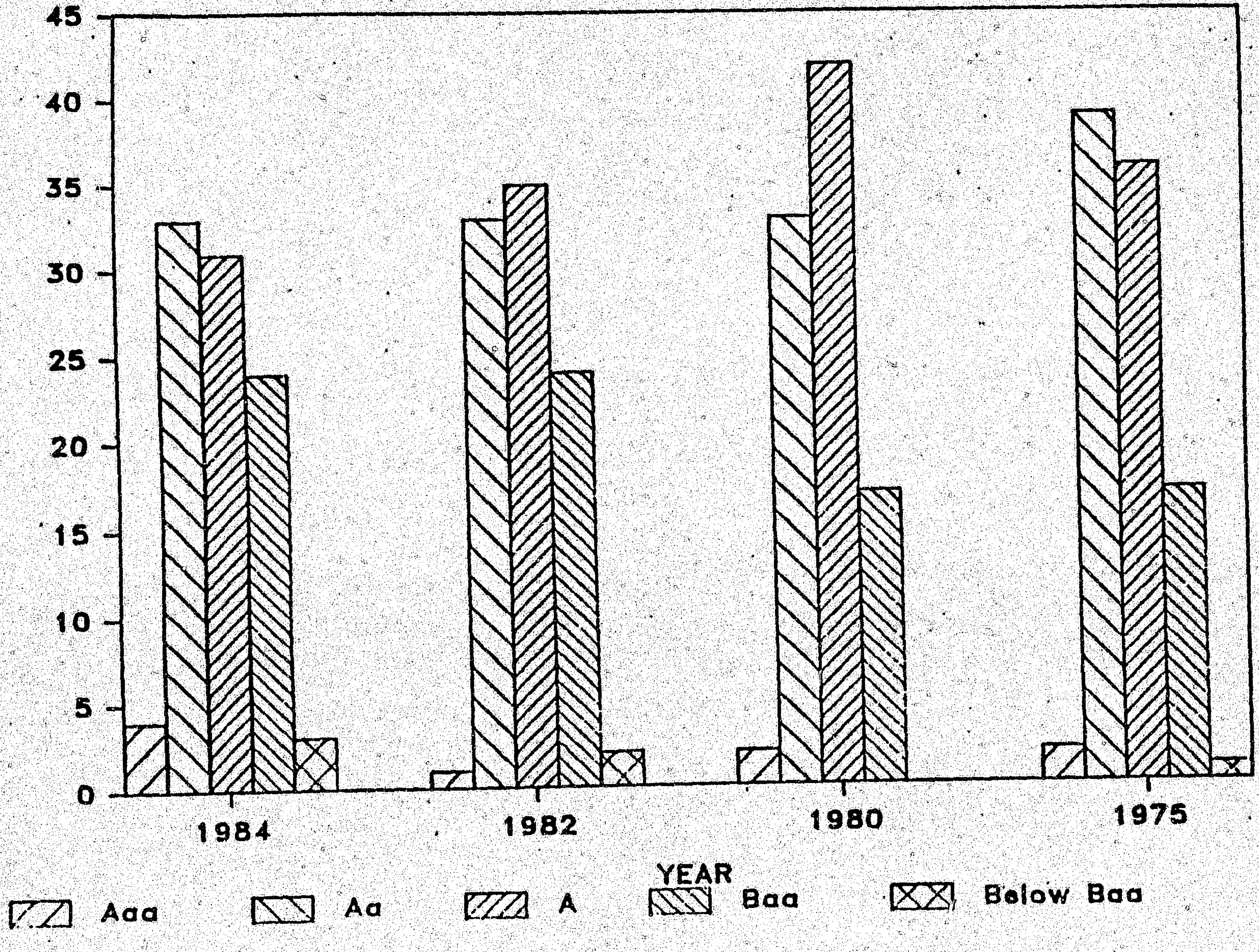
Year	Aaa	Aa	A	Baa	Below Baa
1984	4	33	31	24	3
1982	1	33	35	24	2
1980	2	33	42	17	0
1975	2	39	36	17	1

Table 4 and Figure 1 demonstrate the shift that occurred in the industry's financial well being in the late seventies and early eighties. During the mid-seventies, the industry was predominately rated A to Aa. As the decade progressed and construction programs, interest rates, and inflation escalated, bond ratings began to fall. By the beginning of the eighties, the industry had shifted closer to an A rating on average. Finally, the ratings from 1984 reflect the increased financial hetrogeneity of the industry.

Cost of Equity

The average cost of equity used by respondents to the 1984 survey was 16.3 percent, the same rate reported in the 1983 survey. For purposes of determining their cost of equity, the majority of the respondents relied primarily on the discounted cash flow (DCF) methodology. Fifty-seven of the 103 companies responding to this question (55 percent) reported using the DCF methodology as the primary means of determining their cost of

ELECTRIC UTILITY BOND RATINGS



Falkenberg Exhibit 7

equity. Thirty-three of the 48 companies reporting alternative or corroborating means of determining cost of equity (69 percent) used a risk premium-based methodology.

Regulatory Cost of Capital

The average regulatory cost of equity (most recently approved) cited by respondents to the 1984 survey was 16.1 percent -- about 20 basis points below the average cost of equity used for internal economic evaluations. The regulatory cost of debt averaged 9.3 percent, compared to the 9.6 percent average cost of debt for companies using embedded or historical debt costs in determining their weighted average cost of capital.

Construction Work In Progress

Fifty of the 106 respondents (47 percent) reported some percentage of construction work in progress (CWIP) in rate base. Percentages of construction work in progress allowed in rate base ranged from less than 1 percent to 100 percent with the mean allowance equalling about 59 percent.

The presence of CWIP in rate base was found to have an impact on the composite weighted average cost of capital reported in the 1984 survey. Companies reporting some percentage of CWIP in rate base had a composite weighted average cost of capital of 13.9 percent. Companies reporting no CWIP in rate base had a composite weighted average cost of capital of 14.7 percent. Table 5 presents a comparison of the average costs of capital components reported by companies with and without CWIP in rate base.

Table 5

Average Costs of Capital Components

	Companies With CWIP In Rate Base	Companies Without CWIP In Rate Base
Debt	12.8	13.5
Preferred	11.7	12.6
Common Equity	15.8	16.4
Weighted Average	13.9	14.7

Falkenberg Exhibit 8a
Hieronymus Limerick Unit 1 Cost Benefit Study
$Millions

Year	Total Costs	Capacity Charges Avoided	Total Benefits	Benefits Less Costs
1986	$857.52	$80.57	$231.39	($626.13)
1987	$830.85	$88.78	$274.82	($556.03)
1988	$811.59	$97.23	$306.68	($504.91)
1989	$801.44	$144.03	$466.39	($335.05)
1990	$779.64	$152.68	$435.14	($344.50)
1991	$764.54	$161.84	$482.64	($281.90)
1992	$750.82	$171.54	$651.57	($99.25)
1993	$736.01	$181.84	$607.75	($128.26)
1994	$716.51	$192.75	$756.43	$39.92
1995	$716.86	$204.31	$1,050.35	$333.49
1996	$709.57	$216.57	$954.38	$244.81
1997	$712.97	$229.57	$1,032.10	$319.13
1998	$727.63	$243.35	$1,319.21	$591.58
1999	$718.95	$257.95	$1,095.76	$376.81
2000	$728.22	$273.43	$1,255.89	$527.67
2001	$745.46	$289.85	$1,549.16	$803.70
2002	$739.33	$307.24	$1,486.61	$747.28
2003	$749.14	$325.68	$1,487.76	$738.62
2004	$774.30	$345.22	$2,033.79	$1,259.49
2005	$769.39	$365.94	$1,747.58	$978.19
2006	$783.48	$387.90	$1,894.61	$1,111.13
2007	$813.77	$411.18	$2,501.36	$1,687.59
2008	$812.16	$435.84	$2,268.23	$1,456.07
2009	$830.51	$461.98	$2,290.95	$1,460.44
2010	$870.32	$489.71	$3,180.50	$2,310.18
2011	$870.03	$519.10	$2,752.38	$1,882.35
2012	$895.08	$550.25	$2,943.48	$2,048.40
2013	$944.22	$583.27	$3,983.85	$3,039.63
2014	$946.89	$618.27	$3,572.35	$2,625.46
2015	$979.79	$655.37	$3,674.63	$2,694.84
2016	$1,036.60	$694.70	$5,214.07	$4,177.47
2017	$1,039.54	$736.37	$4,471.32	$3,431.78
2018	$1,081.12	$780.55	$4,587.13	$3,506.01
2019	$1,158.69	$827.39	$6,325.73	$5,167.04
2020	$1,178.20	$877.04	$5,545.68	$4,367.48
2021	$1,245.30	$929.67	$5,889.83	$4,644.53
2022	$1,366.46	$985.45	$8,314.74	$6,948.28
2023	$1,438.96	$1,044.58	$7,331.79	$5,892.83
2024	$1,645.45	$1,107.24	$7,908.12	$6,262.67
Total	$35,077.31	$17,426.23	$103,876.15	$68,798.84
		2,312		

Gross Recpt. Tax	4.5	
Discount Rate	9.7%	
Net present Value of Benefits with 100% Increase in Capacity Charges		3,166
Net present Value of Benefits with 50% Increase in Capacity Charges		2,561
Net present Value of Benefits with 0% Increase in Capacity Charges		1,956

Falkenberg Exhibit 8b
Hieronymus Limerick Unit 1 Cost Benefit Study
$Millions

Year	Total Costs	Capacity Charges Avoided	Total Benefits	Benefits Less Costs
1986	$857.52	$80.57	$231.39	($626.13)
1987	$830.85	$88.78	$274.82	($556.03)
1988	$811.59	$97.23	$306.68	($504.91)
1989	$801.44	$144.03	$466.39	($335.05)
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1995	$716.86	$204.31	$1,050.35	$333.49
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2000	$728.22	$273.43	$1,255.89	$527.67
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2002	$739.33	$307.24	$1,486.61	$747.28
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2019	$1,158.69	$827.39	$6,325.73	$5,167.04
2020	$1,178.20	$877.04	$5,545.68	$4,367.48
2021	$1,245.30	$929.67	$5,889.83	$4,644.53
2022	$1,366.46	$985.45	$8,314.74	$6,948.28
2023	$1,438.96	$1,044.58	$7,331.79	$5,892.83
2024	$1,645.45	$1,107.24	$7,908.12	$6,262.67
Total	$35,077.31	$17,426.23	$103,876.15	$68,798.84
		1,289		

Gross Recpt. Tax	4.5	
Discount Rate	14.3%	
Net present Value of Benefits with 100% Increase in Capacity Charges		30
Net present Value of Benefits with 50% Increase in Capacity Charges		-308
Net present Value of Benefits with 0% Increase in Capacity Charges		-645

Falkenberg Exhibit 9a

Trend in Nuclear O&M Costs

	Peach Bottom O&M		Gross National Product Implicit Price Deflator		Peach Bottom O&M	
Year	Nominal $	% Increase	Base 1972	Base 1983	Real $	% Increase
1976	$11,902		1.3234	0.61374	$19,393	
1977	$18,499	55.4%	1.4005	0.64949	$28,482	46.9%
1978	$16,701	-9.7%	1.5042	0.69758	$23,941	-15.9%
1979	$16,998	1.8%	1.6342	0.75787	$22,429	-6.3%
1980	$24,167	42.2%	1.7842	0.82744	$29,207	30.2%
1981	$27,822	15.1%	1.9514	0.90498	$30,743	5.3%
1982	$31,269	12.4%	2.0688	0.95942	$32,592	6.0%
1983	$40,700	30.2%	2.1563	1.00000	$40,700	24.9%
1976-1983		19.2%				11.2%
1978-1983		19.5%				11.2%

Falkenberg Exhibit 9b

Regression Results
For Equation of the Form
$ O&M = A + B*Year
(Million of 1983 $)

Period	R^2	T	A	B
1979 - 1983	88.6	5.56	-6523.8	3.309
1976 - 1983	74	4.14	-4611.2	2.343

FALKENBERG EXHIBIT 10
ACCUMULATED PRESENT WORTH OF LIMMERICK UNIT 1 COST BENEFIT

Year	Total Benefits	Total Costs	Benefits-Costs	Accum PW *
1986	191	999	-808	-707
1987	230	963	-733	-1268
1988	258	926	-668	-1715
1989	394	899	-505	-2011
1990	359	862	-503	-2269
1991	402	835	-433	-2463
1992	566	812	-246	-2560
1993	514	787	-273	-2653
1994	657	758	-101	-2684
1995	945	749	196	-2632
1996	843	736	107	-2608
1997	914	737	177	-2572
1998	1194	748	446	-2494
1999	963	736	227	-2459
2000	1116	742	374	-2408
2001	1401	756	645	-2332
2002	1330	747	583	-2272
2003	1321	753	568	-2221
2004	1857	775	1082	-2136
2005	1560	767	793	-2081
2006	1696	778	918	-2025
2007	2291	805	1486	-1947
2008	2045	800	1245	-1889
2009	2054	815	1239	-1839
2010	2929	851	2078	-1766
2011	2486	847	1639	-1715
2012	2661	869	1792	-1666
2013	3685	914	2771	-1601
2014	3256	912	2344	-1552
2015	3339	941	2398	-1509
2016	4859	998	3861	-1447
2017	4095	998	3097	-1404
2018	4188	1035	3153	-1366
2019	5903	1104	4799	-1315
2020	5097	1110	3987	-1278
2021	5415	1156	4259	-1243
2022	7811	1242	6569	-1197

* A negative value indicates that Limerick results in higher rates over the plant life. A positive value indicates lower rates.

Falkenberg Exhibit 11

PHILADELPHIA ELECTRIC COMPANY
REVENUE REQUIREMENTS ANALYSIS
USING RISK FREE COST OF CAPITAL

O & M EXPENSES	1441
DEPRECIATION	265
OTHER TAXES	36
ITC (NET)	3
RATE BASE	6964
PRE-TAX RETURN ON RATE BASE (a)	913
REVENUE REQUIREMENTS	2652
TOTAL REV REQ INCLD GRT	2706
CURRENT REVENUES	2502
RATE INCREASE	204
INCREASE LESS GROWTH ADJUSTMENT	193
PERCENT	8%

(a) RATE OF RETURN COMPONENTS

	CAPITALIZATION	COST	WTD COST	TAX EFFECT	PRE-TAX REV REQ
DEBT	50.7%	9.28%	0.0470	1	4.70%
PREFERRED	10.8%	9.28%	0.0100	1.9907629	2.00%
COMMON EQ	38.5%	8.36%	0.0322	1.9907629	6.41%
TOTAL			8.93%		13.11%

WSJ 1/3/86
US TREAS NOV 2015, 9 7/8S
YIELD 9.28%

FALKENBERG EXHIBIT 12-A
1972 FORECAST

YEAR	HISTORIC LOAD	PECO FORECAST	PECO FORECAST ERROR % DIFFERENCE	EXPONENTIAL REGRESSION FORECAST	UNAVOIDABLE FORECAST ERROR % DIFFERENCE	AVOIDABLE FORECAST ERROR % DIFFERENCE
1962	2721					
1963	2926					
1964	3134					
1965	3366					
1966	3673					
1967	3727					
1968	4375					
1969	4592					
1970	4712					
1971	4922					
1972	5313	5740	8.04	5412	1.87	6.17
1973	5760	6300	9.38	5785	0.43	8.95
1974	5431	6850	26.13	6182	13.83	12.29
1975	5530	7480	35.26	6608	19.49	15.78
1976	5346	8110	51.70	7062	32.10	19.60
1977	5888	8630	46.57	7548	28.19	18.38
1978	5667	9240	63.05	8067	42.34	20.70
1979	5641	9770	73.20	8621	52.84	20.36
1980	6095	10300	68.99	9214	51.18	17.81
1981	5731	10840	89.15	9848	71.84	17.31

FALKENBERG EXHIBIT 12-B
1973 FORECAST

YEAR	HISTORIC LOAD	PECO FORECAST	PECO FORECAST ERROR % DIFFERENCE	LINEAR REG FORECAST	UNAVOIDABLE FORECAST ERROR % DIFFERENCE	AVOIDABLE FORECAST ERROR % DIFFERENCE
1962	2721					
1963	2926					
1964	3134					
1965	3366					
1966	3673					
1967	3727					
1968	4375					
1969	4592					
1970	4712					
1971	4922					
1972	5313					
1973	5760	6020	4.51	5523	-4.11	8.62
1974	5431	6670	22.81	5786	6.53	16.28
1975	5530	7240	30.92	6048	9.36	21.56
1976	5346	7850	46.84	6310	18.03	28.81
1977	5888	8400	42.66	6572	11.62	31.05
1978	5667	8950	57.93	6834	20.59	37.34
1979	5641	9750	72.84	7096	25.80	47.05
1980	6095	10110	65.87	7358	20.73	45.15
1981	5731	10680	86.35	7620	32.97	53.39
1982	5691	11240	97.50	7882	38.51	59.00

FALKENBERG EXHIBIT 12-C
1974 FORECAST

YEAR	HISTORIC LOAD	PECO FORECAST	PECO FORECAST ERROR % DIFFERENCE	LINEAR REG FORECAST	UNAVOIDABLE FORECAST ERROR % DIFFERENCE	AVOIDABLE FORECAST ERROR % DIFFERENCE
1962	2721					
1963	2926					
1964	3134					
1965	3366					
1966	3673					
1967	3727					
1968	4375					
1969	4592					
1970	4712					
1971	4922					
1972	5313					
1973	5760					
1974	[illegible]	6400	17.84	5891	8.47	9.38
1975	5530	6960	25.86	6168	11.54	14.32
1976	5346	7490	40.10	6445	20.56	19.54
1977	5888	8020	36.21	6723	14.17	22.04
1978	5667	8530	50.52	7000	23.52	27.00
1979	5641	9010	59.72	7277	29.00	30.72
1980	6095	9480	55.54	7554	23.94	31.59
1981	5731	9960	73.79	7832	36.65	37.14
1982	5691	10460	83.80	8109	42.48	41.31
1983	5879	10950	86.26	8386	42.64	43.61

FALKENBERG EXHIBIT 12-D
1975 FORECAST

YEAR	HISTORIC LOAD	PECO FORECAST	% DIFFERENCE	LINEAR REG FORECAST	% DIFFERENCE	AVOIDABLE FORECAST ERROR % DIFFERENCE
1962	2721					
1963	2926					
1964	3134					
1965	3366					
1966	3673					
1967	3727					
1968	4375					
1969	4592					
1970	4712					
1971	4922					
1972	5313					
1973	5760					
1974	5431					
1975	5530	6280	13.56	6021	8.88	4.69
1976	5346	6690	25.14	6282	17.51	7.63
1977	5888	7130	21.09	6543	11.12	9.97
1978	5667	7600	34.11	6804	20.06	14.05
1979	5641	8040	42.53	7065	25.24	17.29
1980	6095	8490	39.29	7326	20.19	19.10
1981	5731	8950	56.17	7587	32.38	23.79
1982	5691	9430	65.70	7848	37.90	27.80
1983	5879	9900	68.40	8109	37.93	30.47
1984	5925	10380	75.19	8370	41.26	33.93

FALKENBERG EXHIBIT 12-E
1976 FORECAST

YEAR	HISTORIC LOAD	PECO FORECAST	PECO FORECAST ERROR % DIFFERENCE	LINEAR REG FORECAST	UNAVOIDABLE FORECAST ERROR % DIFFERENCE	AVOIDABLE FORECAST ERROR % DIFFERENCE
1962	2721					
1963	2926					
1964	3134					
1965	3366					
1966	3673					
1967	3727					
1968	4375					
1969	4592					
1970	4712					
1971	4922					
1972	5313					
1973	5760					
1974	5431					
1975	5530					
1976	5346	5820	8.87	6100	14.10	-5.23
1977	5888	6320	7.34	6337	7.63	-0.29
1978	5667	6660	17.52	6575	16.02	1.50
1979	5641	7020	24.45	6813	20.78	3.67
1980	6095	7390	21.25	7051	15.68	5.57
1981	5731	7780	35.75	7289	27.18	8.58
1982	5691	8180	43.74	7526	32.25	11.49
1983	5879	8580	45.94	7764	32.06	13.88
1984	5925	8990	51.73	8002	35.05	16.68
1985	6035	9390	55.59	8240	36.53	19.06

B1

FALKENBERG EXHIBIT 12-F
1977 FORECAST

YEAR	HISTORIC LOAD	PECO FORECAST	PECO FORECAST ERROR % DIFFERENCE	LINEAR REG FORECAST	UNAVOIDABLE FORECAST ERROR % DIFFERENCE	AVOIDABLE FORECAST ERROR % DIFFERENCE
1962	2721					
1963	2926					
1964	3134					
1965	3366					
1966	3673					
1967	3727					
1968	4375					
1969	4592					
1970	4712					
1971	4922					
1972	5313					
1973	5760					
1974	5431					
1975	5530					
1976	5346					
1977	5888	6000	1.90	6035	2.50	-0.60
1978	5667	6300	11.17	6233	9.98	1.19
1979	5641	6600	17.00	6430	13.98	3.02
1980	6095	6900	13.21	6627	8.73	4.48
1981	5731	7200	25.63	6824	19.07	6.56
1982	5691	7500	31.79	7021	23.37	8.42
1983	5879	7800	32.68	7218	22.78	9.90
1984	5925	8100	36.71	7415	25.15	11.56
1985	6035	8400	39.19	7612	26.14	13.05
1986		8700		7809		0.00

BS

FALKENBERG EXHIBIT 12-G
1978 FORECAST

YEAR	HISTORIC LOAD	PECO FORECAST	PECO FORECAST ERROR % DIFFERENCE	LINEAR REG FORECAST	UNAVOIDABLE FORECAST ERROR % DIFFERENCE	AVOIDABLE FORECAST ERROR % DIFFERENCE
1962	2721					
1963	2926					
1964	3134					
1965	3366					
1966	3673					
1967	3727					
1968	4375					
1969	4592					
1970	4712					
1971	4922					
1972	5313					
1973	5760					
1974	5431					
1975	5530					
1976	5346					
1977	5888					
1978	5667	5700	0.58	6133	8.22	-7.64
1979	5641	5850	3.71	6313	11.91	-8.21
1980	6095	6050	-0.74	6493	6.52	-7.26
1981	5731	6250	9.06	6672	16.43	-7.37
1982	5691	6480	13.86	6852	20.41	-6.54
1983	5879	6710	14.14	7032	19.61	-5.48
1984	5925	6940	17.13	7212	21.72	-4.59
1985	6035	7150	18.48	7392	22.48	-4.01
1986		7350		7572		
1987		7550		7751		

FALKENBERG EXHIBIT 12-H
1979 FORECAST

YEAR	HISTORIC LOAD	PECO FORECAST	PECO FORECAST ERROR % DIFFERENCE	LINEAR REG FORECAST	UNAVOIDABLE FORECAST ERROR % DIFFERENCE	AVOIDABLE FORECAST ERROR % DIFFERENCE
1962	2721					
1963	2926					
1964	3134					
1965	3366					
1966	3673					
1967	3727					
1968	4375					
1969	4592					
1970	4712					
1971	4922					
1972	5313					
1973	5760					
1974	5431					
1975	5530					
1976	5346					
1977	5888					
1978	5667					
1979	5641	5700	1.05	6042	7.11	-6.07
1980	6095	5850	-4.02	6177	1.35	-5.37
1981	5731	6000	4.69	6313	10.15	-5.46
1982	5691	6150	8.07	6448	13.30	-5.24
1983	5879	6300	7.16	6583	11.98	-4.82
1984	5925	6450	8.86	6718	13.39	-4.53
1985	6035	6600	9.36	6854	13.57	-4.20
1986		6800		6989		
1987		7000		7124		
1988		7200		7260		

FALKENBERG EXHIBIT 12-1
1980 FORECAST

YEAR	HISTORIC LOAD	PECO FORECAST	PECO FORECAST ERROR % DIFFERENCE	LINEAR REG FORECAST	UNAVOIDABLE FORECAST ERROR % DIFFERENCE	AVOIDABLE FORECAST ERROR % DIFFERENCE
1962	2721					
1963	2926					
1964	3134					
1965	3366					
1966	3673					
1967	3727					
1968	4375					
1969	4592					
1970	4712					
1971	4922					
1972	5313					
1973	5760					
1974	5431					
1975	5530					
1976	5346					
1977	5888					
1978	5667					
1979	5641					
1980	6095	5800	-4.84	5989	-1.74	-3.10
1981	5731	5900	2.95	6096	6.38	-3.43
1982	5691	6000	5.43	6204	9.01	-3.58
1983	5879	6100	3.76	6311	7.35	-3.59
1984	5925	6200	4.64	6418	8.32	-3.68
1985	6035	6300	4.39	6525	8.13	-3.74
1986		6400		6633		
1987		6500		6740		
1988		6600		6847		
1989		6700		6955		

FALKENBERG EXHIBIT 12-J
1981 FORECAST

YEAR	HISTORIC LOAD	PECO FORECAST	PECO FORECAST ERROR % DIFFERENCE	LINEAR REG FORECAST	UNAVOIDABLE FORECAST ERROR % DIFFERENCE	AVOIDABLE FORECAST ERROR % DIFFERENCE
1962	2721					
1963	2926					
1964	3134					
1965	3366					
1966	3673					
1967	3727					
1968	4375					
1969	4592					
1970	4712					
1971	4922					
1972	5313					
1973	5760					
1974	5431					
1975	5530					
1976	5346					
1977	5888					
1978	5667					
1979	5641					
1980	6095					
1981	5731	5900	2.95	6084	6.15	-3.20
1982	5691	6000	5.43	6184	8.66	-3.23
1983	5879	6100	3.76	6284	6.89	-3.13
1984	5925	6200	4.64	6384	7.75	-3.11
1985	6035	6300	4.39	6484	7.45	-3.06
1986		6400		6585		
1987		6500		6685		
1988		6600		6785		
1989		6700		6885		
1990		6800		6986		

FALKENBERG EXHIBIT 12-K
1982 FORECAST

YEAR	HISTORIC LOAD	PECO FORECAST	% DIFFERENCE	LINEAR REG FORECAST	% DIFFERENCE	AVOIDABLE FORECAST ERROR % DIFFERENCE
1962	2721					
1963	2926					
1964	3134					
1965	3366					
1966	3673					
1967	3727					
1968	4375					
1969	4592					
1970	4712					
1971	4922					
1972	5313					
1973	5760					
1974	5431					
1975	5530					
1976	5346					
1977	5888					
1978	5667					
1979	5641					
1980	6095					
1981	5731					
1982	5691	5800	1.92	5992	5.29	-3.37
1983	5879	5850	-0.49	6061	3.10	-3.60
1984	5925	5900	-0.42	6131	3.48	-3.90
1985	6035	5950	-1.41	6201	2.74	-4.15
1986		6000		6270		
1987		6050		6340		
1988		6100		6409		
1989		6150		6479		
1990		6210		6548		
1991		6270		6618		

FALKENBERG EXHIBIT 12-L
1983 FORECAST

YEAR	HISTORIC LOAD	PECO FORECAST	PECO FORECAST ERROR % DIFFERENCE	LINEAR REG FORECAST	UNAVOIDABLE FORECAST ERROR % DIFFERENCE	AVOIDABLE FORECAST ERROR % DIFFERENCE
1962	2721					
1963	2926					
1964	3134					
1965	3366					
1966	3673					
1967	3727					
1968	4375					
1969	4592					
1970	4712					
1971	4922					
1972	5313					
1973	5760					
1974	5431					
1975	5530					
1976	5346					
1977	5888					
1978	5667					
1979	5641					
1980	6095					
1981	5731					
1982	5691					
1983	5879	5600	-4.75	5880	0.01	-4.76
1984	5925	5650	-4.64	5919	-0.10	-4.54
1985	6035	5700	-5.55	5958	-1.27	-4.28
1986		5750		5997		
1987		5800		6036		
1988		5850		6076		
1989		5900		6115		
1990		5950		6154		
1991		5980		6193		
1992		6010		6232		

FALKENBERG EXHIBIT 12-M
1984 FORECAST

YEAR	HISTORIC LOAD	PECO FORECAST	PECO FORECAST ERROR % DIFFERENCE	LINEAR REG FORECAST	UNAVOIDABLE FORECAST ERROR % DIFFERENCE	AVOIDABLE FORECAST ERROR % DIFFERENCE
1962	2721					
1963	2926					
1964	3134					
1965	3366					
1966	3673					
1967	3727					
1968	4375					
1969	4592					
1970	4712					
1971	4922					
1972	5313					
1973	5760					
1974	5431					
1975	5530					
1976	5346					
1977	5888					
1978	5667					
1979	5641					
1980	6095					
1981	5731					
1982	5691					
1983	5879					
1984	5925	5900	-0.42	5887	-0.65	0.23
1985	6035	5930	-1.74	5918	-1.93	0.19
1986		5960		5950		
1987		5990		5982		
1988		6020		6013		
1989		6050		6045		
1990		6080		6077		
1991		6110		6109		
1992		6150		6140		
1993		6190		6172		

FALKENBERG EXHIBIT 12-N
1985 FORECAST

YEAR	HISTORIC LOAD	PECO FORECAST	% DIFFERENCE	LINEAR REG FORECAST	% DIFFERENCE	AVOIDABLE FORECAST ERROR % DIFFERENCE
1962	2721					
1963	2926					
1964	3134					
1965	3366					
1966	3673					
1967	3727					
1968	4375					
1969	4592					
1970	4712					
1971	4922					
1972	5313					
1973	5760					
1974	5431					
1975	5530					
1976	5346					
1977	5888					
1978	5667					
1979	5641					
1980	6095					
1981	5731					
1982	5691					
1983	5879					
1984	5925					
1985	6035	6140	1.74	5985	-0.83	2.57
1986		6160		6030		
1987		6180		6076		
1988		6200		6122		
1989		6220		6167		
1990		6240		6213		
1991		6260		6258		
1992		6320		6304		
1993		6380		6350		
		6440				

FALKENBERG EXHIBIT 13

1964 Estimates of Future Nuclear Power Plant Costs Compared to Conventional Plants

TABLE 31

Approximate General Range of Competition Between Nuclear and Coal Fired Generation

1. Year plant placed in service	1967	1970	1975	1980
2. Nominal plant output—kilowatts	300,000	500,000	1,000,000	1,200,000
3. Projected investment cost of alternative conventional plant (reference base for line 4)—$/kw	130	122	110	107
4. Approximate additional investment cost of nuclear plant compared to alternative fossil fuel plant. Dollars per kw of capacity	40–60	10–30	0–15	0–12
5. Effect of additional investment in nuclear plant on energy cost—mills per kwh	0.7–1.1	0.2–0.5	0–0.3	0–0.2
6. Effect of additional operation and maintenance of nuclear plant on energy cost—mills per kwh	0.3	0.2	0.1	0.1
7. Nuclear fuel cost—mills per kwh	1.8–2.1	1.5–1.9	1.2–1.6	1.0–1.4
8. Cost of fossil fuel—in mills per kwh (total of items 5, 6, 7) at which total power cost of nuclear generation or fossil fuel generation would be about equal under generalized conditions assumed herein. (Referred to as "break even" cost.)	2.8–3.5	1.9–2.6	1.3–2.0	1.1–1.7
9. Break-even fossil fuel cost in item 8 converted to cents per million Btu of fossil fuel cost	31–39	21–29	15–22	12–19

88

Source: Federal Power Commission 1964 National Power Survey

FALKENBERG EXHIBIT 14

OVERRUN IN NUCLEAR PLANT COST ESTIMATES 1969-1989

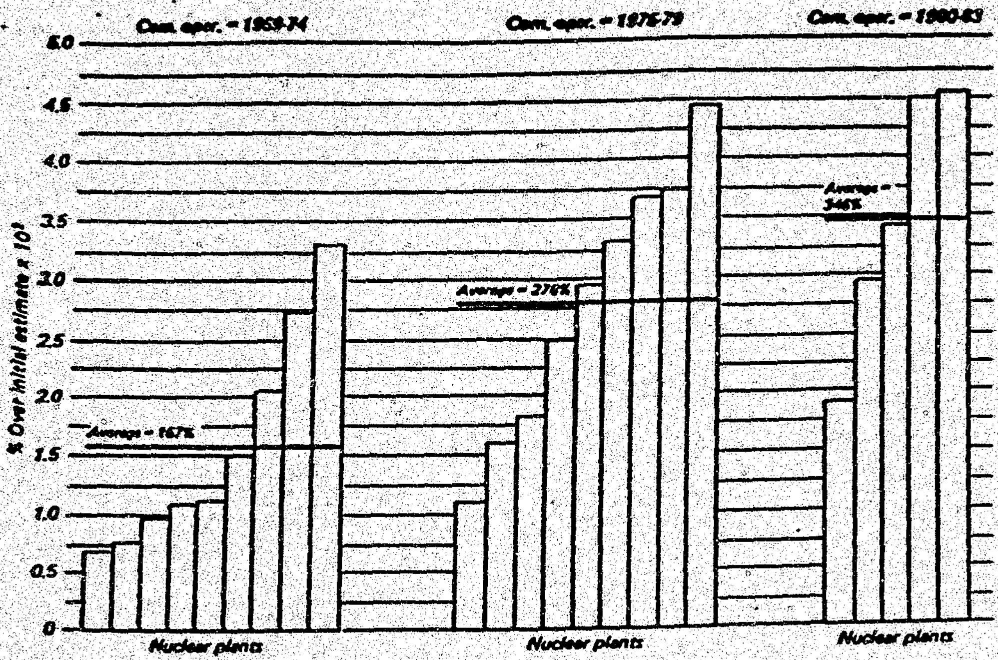

Figure 24. Actual percent increase in capital costs over initial estimates for completed nuclear plants.

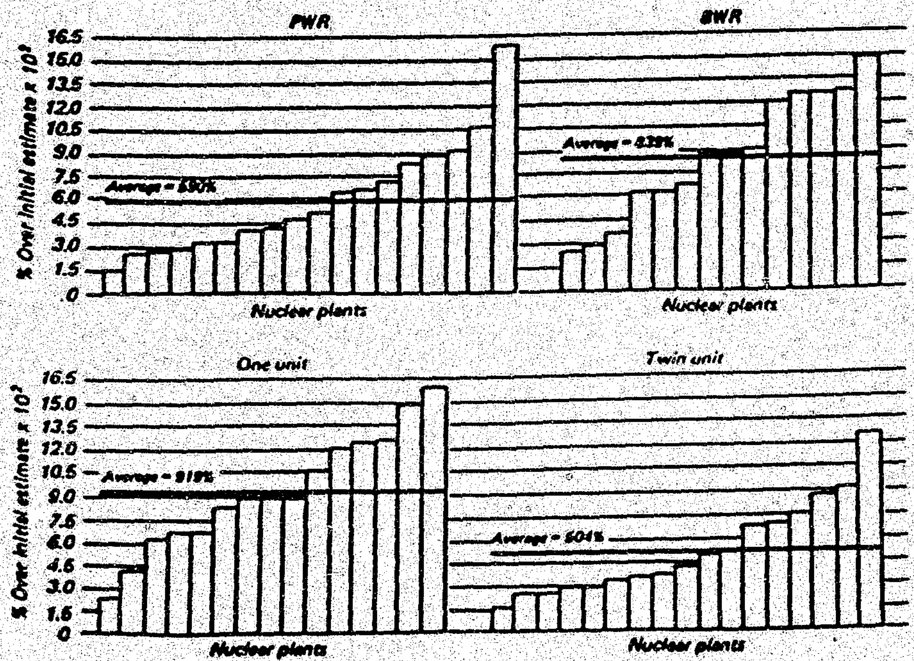

Figure 25. Percent increase in capital costs over initial estimates for nuclear plants scheduled for commercial operation between 1984 and 1988. The data base for Figures 24 and 25 consists of 65 plants designed by nine A/Es and two utilities.

Source: Power Engineering - The Data Base for U.S. Power Plants

Falkenberg Exhibit 15

Comparison of PECO Limerick Cost Estimates to Plants Completed from 1968-1978

Plant	COD	Total Cost ($Millions)	Gross Capacity MW	$/kw	Annual Average $/kw	Source	Peco Est. Limerick $/kw	Limerick Station Avg. COD	Escalation Recent Plants	Expected Inflation	Real Esc Implied in PECO Est.
San Onofre 1	68	88	436	202	202	TVA					
Oyster Creek	69	93	620	150		TVA					
Nine Mile Pt 1	69	164	620	265	207	TVA					
Ginna 1	70	87	470	185		TVA					
Dresden 2	70	115	794	145		TVA					
Pt Beach 1	70	86	519	166	165	APCO					
Millstone 1	71	101	660	153		TVA					
Robinson 2	71	84	700	120		TVA					
Monticello	71	119	545	218		TVA					
Dresden 3	71	117	794	147		TVA					
Palidase 5	71	143	805	178	163	TVA	339	76	15.7%	5.0%	10.8%
Pilgrim 1	72	238	670	355		APCO					
Pt Beach 2	72	75	519	145		APCO					
Vermont Yankee	72	180	537	335		APCO					
Maine Yankee 1	72	217	863	251		APCO					
Turky Pt 3	72	104	760	137	245	APCO	573	79	12.9%	4.9%	8.0%
Quad City 1	73	140	789	177		TVA					
Quad City 2	73	120	789	152		TVA					
Oconee 1	73	156	887	176		TVA					
Indian Pt 2	73	216	1013	213		APCO					
Ft. Calhoun	73	163	481	339		APCO					
Turky Pt 4	73	94	760	124		APCO					
Zion 1	73	284	1080	263	206	APCO	573	79	18.6%	5.1%	13.5%
Prairie Island 1	74	234	560	418		APCO					
Cooper 1	74	380	801	474		APCO					
Peach Bottom 2	74	497	1098	453		APCO					
TMI 1	74	402	840	479		APCO					
Zion 2	74	286	1080	265		APCO					
Oconee 2	74	160	887	180		TVA					
Arkansas 1	74	260	903	288		APCO					
Peach Bottom 3	74	263	1098	240		APCO					
Prairie Island 2	74	181	560	323		APCO					
Oconee 3	74	166	887	187	331	TVA	824	82	12.1%	5.9%	6.2%
Rancho Seco 1	75	340	966	352		APCO					
Calvert Cliffs 1	75	429	880	488		APCO					
Fitzpatrick	75	319	821	389		TVA					
BSEP 2	75	412	821	502		APCO					
Hatch 1	75	414	813	511		APCO					
Millstone 2	75	434	870	499	457	APCO	949	82	11.0%	7.0%	4.0%
Trojan 1	76	470	1178	399		APCO					
Indian Pt 3	76	527	965	546		TVA					
St. Lucie 1	76	486	890	546	497	APCO	949	82	11.4%	7.3%	4.1%
Crystal River 3	77	417	855	488		APCO					
BSEP 1	77	344	821	419		APCO					
Beaver Valley 1	77	679	852	797		APCO					
Calvert Cliffs 2	77	310	880	352		APCO					
Salem 1	77	963	1136	848		APCO					
Davis Besse	77	668	906	737		APCO					
Farley 1	77	741	898	825	638	APCO	1222	84	9.7%	7.3%	2.5%
North Anna 1	78	784	947	828		APCO					
TMI 2	78	675	905	746	787	APCO	1508	86	8.5%	6.9%	1.5%

FALKENBERG EXHIBIT 16

Regression Equation Relating Total Cost Per KW of Nuclear Plants Completed from 1968 to 1978 to Commercial Operation Date and other Factors

Variable	Variable Mean	Regression Coefficient	t-Statictic
Installed Cost $/KW (1)	356.3725	-	-
Constant	-	41191.26	-
C.O.D.(2)	74.1973	-1185.2391	-4.955
INITIAL/ADD-ON (3)	0.7059	132.4998	5.365
MW (4)	808.3529	-0.1267	-1.595
(C.O.D.) (2)	5511.2378	8.5439	5.298
Northeast (5)	0.3725	75.071	3.298
Number of Observations	51		
Adjusted R^2	0.8604		
Standard Error	77.57		

Sources and Notes

1. Installed cost per KW is measured in total installed cost (including AFUDC) per KW of capacity. Source is Alabama Power Co.'Power Plant Cost Trends' -January 1984 and 1983 TVA Survey of Nuclear Plant Costs.

2. C.O.D. is year and month of commercial operation; source TVA and APCO surveys.

3. Initial Add-On Indicator = 1 for First Unit at Site, 0 for subsequent units.

4. Gross Capacity in Megawatts for the unit.

5. Northeast Indicator = 1 for Utilities in FERC region 1, 0 otherwise.

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February 18, 1986

Re: Pennsylvania Public Utility Commission, et al., v. Philadelphia Electric Company
Docket No. R-850152

RECEIVED
FEB 19 1986
SECRETARY'S OFFICE
Public Utility Commission

Administrative Law Judge
Joseph P. Matuschak
Pennsylvania Public Utility Commission
97 East Main Street
Uniontown, PA 15401

Dear Judge Matuschak:

At the hearing on February 14, 1986, PAIEUG identified and moved PAIEUG Exhibit No. 12 which consisted of the entire response of PAIEUG to PECo interrogatory Set II, No. 14. PECo had previously identified and moved as PECo Exhibit No. 33 a portion of this interrogatory response, namely, 14(f).

After reviewing our records, we have found that PAIEUG had not previously utilized Exhibit No. 11. Therefore, we respectfully request that the complete response of PAIEUG to PECo interrogatory Set II, No. 14 be renumbered as PAIEUG Exhibit No. 11.

Copies of this renumbered PAIEUG Exhibit No. 11 are being provided to all parties of record as well as the court reporter.

We apologize for any confusion created as a result of our initial mis-numbering of this Exhibit.

DOCUMENT FOLDER

Very truly yours,

McNEES, WALLACE & NURICK

By David M. Kleppinger
David M. Kleppinger

DMK/jf
Enclosure
cc: All Parties of Record (w/encl.)

Ex 11
SOM 2-14-86 H129

RECEIVED R-850152

FEB 24 1986

SECRETARY'S OFFICE
Public Utility Commission

PAIEUG - EXHIBIT No. 11

DOCUMENT
FOLDER

DOCKETED

MAR 5 - 1986

<u>Responses to Data Request of the</u>

<u>Philadelphia Electric Company Set 2 Addressed to the</u>

<u>Philadelphia Area Industrial Energy Users' Group</u>

Q. 14. On page 41 you state that "other analysts within the utility industry could have developed much different and more reasonable forecasts using very simple techniques".

a. Who are the analysts you are referring to and for whom do they work?

b. Were these forecasts indeed developed?

c. What is the magnitude of the difference between these forecasts and PECO forecasts?

d. On what do you base the statement that these forecasts would have been more reasonable?

e. What are the simple techniques used to make these forecasts? Who was using these techniques at the time?

f. Had these forecasting techniques been proven to be accurate? Please support your answer with evidence.

A. 14. Part a - The other analysts to whom Mr. Falkenberg was referring on page 41 were the planners and forecasters employed by electric utilities throughout the United States. Attachment 1 is a report to the Federal Power Commission (part of the 1970 National Power Survey) entitled "The Methodology of Load Forecasting". This was prepared by the Technical Advisory Committee on Load Forecasting Methodology for the National Power Survey in 1969. Page 2 of that attachment shows a list of the members of the Committee. These analysts reported on page IV-4-35 that "Extrapolation often produces acceptable results because electric loads exhibit stable patterns of growth of rather long periods". In effect, these reasonable analysts, the executives of the electric utility industry, reported in 1969 that extrapolation, i.e., trending produced acceptable results.

Part b - Yes indeed other utility companies utilized trending methods as part of the arsenal of tools to forecast electric load in 1960's, 1970's and 1980's.

Part c - Falkenberg Exhibit 12 shows the magnitude of the differences between the types of forecasts which other analysts might have produced and those produced by PECO.

Part d - The statement that the forecasts based on trend data would have been more reasonable to PECO is based on the observation that the trending technique was developed to be the <u>most</u> reasonable forecast vis-a-vis the historic data. Thus, the fact that the forecast was more reasonable than PECO is because it reflected the historic data and the historic pattern of growth experienced by the Company. As pointed out in the testimony of Mr. Falkenberg the ten year average load growth of Philadelphia Electric was on the order of 260 MW at the time the

1973 PECO load forecast was produced. PECO forecast predicted an annual load growth of more than 500 over the next ten year period. Clearly, this establishes that the trend based model was more reasonable vis-a-vis historic data. Subsequently, we have learned that the historic trend model would have produced more accurate forecasts as well.

Part e - The simple techniques used to make these forecasts was single variable linear regression analysis. Referring again to the Federal Power Commission report it is apparent that forecasters within the electric utility industry were using these techniques in the 1970's.

Part f - Attachment 2 is a recently published article entitled "Can Electric Utilities Improve Their Load Forecast Accuracy A Historical Prospective". This article appeared in the December 26, 1985 of Public Utilities Fortnightly. Mr. Falkenberg would suggest that PECO read this article for it establishes that the forecasting techniques utilized by electric utilities have not improved substantially over the past ten years. To the extent that there was a greater reliance on trending in the past, this suggest trending techniques may be just as valid and accurate today as they were in the early 1970's. In addition, the analysis performed in this article clearly suggests that trending models have proven as accurate as econometric models over the historical time period from 1972 to the present.

THE METHODOLOGY

OF

LOAD FORECASTING

PREPARED BY

THE TECHNICAL ADVISORY COMMITTEE
ON LOAD FORECASTING METHODOLOGY
FOR THE NATIONAL POWER SURVEY

1969

PREFACE

e need for a comprehensive study of the odology of electric utility load forecasting oeen recognized by many in the electric y industry and government. No basic reference e has existed covering the data requirements current methods and techniques used in this of utility operations. The Federal Power Com-ion, cognizant of this need, established the d Forecasting Methodology Committee as one our technical advisory committees formed to t the Commission in updating the National ver Survey of 1964. The assignment given this nmittee was to determine the state of the art of d forecasting, to assess the need for improved thods and techniques and to suggest means of eting such need.

The Committee's study of which this report is e result was conducted in cooperation with many gments of the electric power industry. The Com-ittee wishes to express its appreciation to all ntributors who have given time and assistance preparation of this study. There are too many 5 name here individually, but thanks are due articularly to members of the Commission staff vho worked with the Committee, to the Regional dvisory Committees who helped obtain data rom utilities and to the many electric utilities who ubmitted statistical data and other information regarding their operations and load forecasting procedures.

Committee Members:

William R. Brownlee, Chairman	Southern Services, Inc.
Dr. Clopper J. Almon, Jr.	University of Maryland
*Donald N. Anderson	Southern California Edison Company
Andrew J. Baldwin	Pennsylvania Power & Light Company
Walter M. Bowers	Southwestern Power Administration
*John R. Dunigan	Public Service Company of Indiana, Inc.
Edward L. Hoffman	Niagara Mohawk Power Corporation
*Hans H. Landsberg	Resources for the Future, Inc.
Frank W. Linder	Dairyland Power Cooperative
*René H. Malès	Commonwealth Edison Company
William R. New	Tennessee Valley Authority

Assisting the Chairman:

Carl E. Asbury	Southern Services, Inc.

Federal Power Commission Staff:

Phyllis H. Kline	Office of Economics
William W. Lindsay	Liaison to the Committee
Jerry R. Milbourn	Committee Secretary

* Member of Editing Subcommittee

CHAPTER V—CURRENT FORECASTING METHODS

Forecasting techniques are tools. No single method or group of techniques in itself assures success in forecasting. Knowledge and judgment of the forecaster in applying selected techniques in a given utility load situation are essential. So is final judgment of the elements used in arriving at the ultimate load forecast.

The number and kinds of forecasting methods used vary considerably from utility to utility. Use of several methods is common. Differences in methods result in part from variations in economic and geographic conditions, system characteristics and mix of loads in the utility areas.[1] For example, population may change rapidly in one utility area and be stable in another. Utilities with large cooling loads have an interest in developing estimates of historical cooling loads and load weather relationships and use these in forecasting cooling loads. Utilities serving industrial loads which are highly responsive to the business cycle and which constitute a large proportion of total load usually put more emphasis upon analysis of industrial loads than do utilities serving a stable and small industrial load.

A. Basic Forecasting Methods

Forecasting methods can be grouped into two categories: extrapolation and correlation.

1. Extrapolation

Extrapolation is based upon the assumption that future growth will be a continuation of a discernible pattern of past growth. Specific methods include compound rates of growth, annual increments, fitting of mathematical growth curves and use of graphs of treated or untreated historical data.

Extrapolation often produces acceptable results because electric loads exhibit stable growth over rather long periods. Residential, outdoor lighting and service loads appear to be largely insulated from the business cycle. However, forecasters relying predominantly upon this method may fail to recognize underlying changes which eventually will affect future growth. For example, a succession of very hot summers might mask declining growth in non-air conditioning loads.

2. Correlation

Correlation relates electric power loads to selected associated factors. Correlation methods include scatter diagrams, simple correlation, multiple correlation and simple or complex models. While results from these techniques, especially the more sophisticated methods, cannot be accepted at face value but must be evaluated in terms of the theories underlying the techniques, including their limitations, they provide insight into the causes of past growth and its variation and quantify relationships between load and factors which affect load. This leads to a clearer understanding of the factors which cause growth and of their relative importance. Further, when forecasts deviate from actual loads, the correlation approach is helpful in identifying causes of deviation.

One problem associated with correlation methods is the need to obtain and select forecasts of these associated factors, i.e., independent variables, such as population, income, appliance saturation, etc. There is no assurance that this can be done with any greater accuracy than forecasting electric loads directly. Despite this difficulty, correlation is useful because it forces the forecaster to consider and analyze future load in a context of other factors rather than as a completely independent phenomenon.

It is important, however, that the analyst/forecaster avoid the mistake of drawing conclusions from spurious correlations which have a high degree of statistical significance but no logical relationship.

B. Special Information and Judgment

Although extrapolation and correlation are fundamental to the art of load forecasting, they

[1] Specific forecasting methods employed by four electric systems are detailed in Appendix A.

are not generally sufficient to assure the best results. Two additional ingredients that are often important to the development of a sound load forecast are the use of special information and the exercise of informed judgment.

1. Special Information

Special information is used to modify or reinforce the forecast. Examples include opinions of industrial plant managers as to probable future loads, planned utility promotion programs, the results of appliance surveys to determine present saturations and buying intentions, predictions of business activity and area and national electric power forecasts. Such information is not only an important indication of definite future planning for electric consumption by others, but also it is a stimulant to the forecaster in thinking about the possibility of new trends.

2. Informed Judgment

In forecasting, informed judgment is necessary in the selection of the factors to be analyzed and in the selection of the forecasting methods to be employed. It is also essential in determining the weight to be given to differing forecasts derived from use of several techniques. In uncertain situations when information is incomplete or when forces affecting load are not quantified, the informed judgment of the analyst is of particular importance. For example, he must decide whether forces favorable and unfavorable to growth of a new type of load are such that the new load is likely to become significant over the relevant planning period.

Finally, informed judgment plays a major if not decisive role in identifying likely future changes in trends, in selecting among competing forecasts of external forces such as economic activity and housing starts, in evaluating market penetration in such areas as air conditioning and heating and in identifying areas and degree of competition from alternate energy sources.

C. Survey of Industry Forecasting Methods

In order to determine the present state of the art of load forecasting in the industry, a survey was made of the current practices. Survey respondents were selected with the objective of including all types of systems, all areas of the country and all types of forecasting methodology rather than on a random basis. The survey-questionnaire was prepared and distributed through the FPC Regional Advisory Committees. Appendix E shows the format used. Thirty organizations responded. The techniques used by the respondents for short-term, intermediate-term and long-term load forecasting are discussed below.

The survey results reflect the dynamic nature of forecasting methodology in use during the period 1961–1967. Forecasting methods have evolved to meet the particular needs and individual characteristics of the various electric utility systems. Several respondents adopted changes in methods during the seven-year period; others mentioned changes that are being considered. This evolutionary process is found to be common in systems represented on the Committee as well as in the experience of those responding to the survey.

The wider daily and seasonal swings in loads experienced in the last few years and growth of new kinds of loads or changing patterns of growth of existing loads have been among the reasons for the search for new forecasting techniques. Another reason has been the increasing need for improved accuracy and more detailed forecasts to enable economic planning for greater use of energy interchange and larger generating units. Finally, improved forecasting methodology developed outside the industry along with the development and availability of greater computational capability also have been responsible for changes in load forecasting methodology.

1. Short-Term

Most utilities reported that hour-to-hour and day-to-day load forecasts are prepared by adding expected load changes to current or recent past loads. Nearly all reporting utilities indicated that expected weather conditions are considered in preparing forecasts 24 hours in advance. Half specifically report use of temperatures while only five refer to humidity or wind velocity. Nearly all indicated that historical hourly load patterns and day-of-week patterns are considered. Ten utilities report that changes in large industrial loads, strikes and other abnormal events are recognized in making the forecast.

Few of the reporting utilities use complex forecasting methods for short-term forecasting. However, a small number report developmental work to computerize hour-to-hour and day-to-day load forecasting, presumably to permit analysis of more variables. One utility reports it is engaged in developing empirical formulae to automate short-term forecasting of hourly loads based on expected temperatures, previous temperatures and previous loads.

2. Intermediate-Term

In the survey questionnaire, intermediate-term forecasting is defined as covering a period of four to six years. The survey indicates that the most intensive use of statistical techniques is in intermediate-term forecasting.

a. Adjustment of Data

All utilities report adjusting historical data in some manner, i.e., making some form of preliminary analysis to eliminate the effects of cyclical, seasonal, or irregular factors prior to analysis of trend factor. More than half specifically report adjusting for the effect of weather, while others take weather into account through judgment or historical relationships. Five report adjusting for specific events such as plant shutdowns.

A quarter of the utilities specifically report use of formal statistical treatment. These include time series analysis, correlation analysis, analysis of variance and other such techniques. The remaining three-quarters report calculations based upon historical relationships; it is not clear from the survey responses whether these systems determine the historical relationships through formal statistical analysis.

b. Approaches

In the forecasting of loads, utility systems are using a variety of approaches. Four sets of approaches to various phases of load forecasting are set forth below.

(1) *Energy vs. Peak Demand*

About half of the reporting utilities prepare an energy forecast as the primary forecast, with a peak demand obtained by use of load factor relationships. The other half prepare peak demand forecasts directly. Several report less detailed forecasting of the secondary data to serve as a check on other methods. For example, one utility prepares energy forecasts in detail by classes of service and geographic areas and calculates peaks by use of load factor projections. As a check on these figures, weather-adjusted peaks are extrapolated on the basis of past trends.

Advantages claimed for emphasizing peak forecasts are that it is the most direct way to obtain what most systems consider the most important forecast; that load factors are frequently erratic and difficult to project; and that demand data can be related more directly to such variables as temperature.

Advantages claimed for emphasizing energy forecasts are that energy data are usually less erratic over time than peak data and are therefore a better indicator of underlying growth trends; that load factors are no more erratic than peaks in the short run and in many cases tend to be rather stable over long periods despite year-to-year variation; and that detailed data are available by classes of services, areas, or other sub-divisions and can be readily related to appropriate variables, such as weather, national economic indicators and population.

(2) *Total Load vs. Components*

About one-third of the reporting utilities prepare forecasts of system loads in total. The other two-thirds assemble peak forecasts either by geographic areas, by types of customers or by some other subdivision of load. Forecasts of the individual parts are combined and adjusted for losses and diversity to obtain a total system load forecast. Loss and diversity adjustments are based on historical relationships.

Proponents of the total load approach argue that it is difficult to perceive changes in trends in each load component, e.g., the sudden surge in residential air conditioning, the rebuilding of one area, a new industrial development. In addition, their experience has shown that the overall growth of demand and energy has been smooth in the past, rapid growth in one component offset by slower growth in another. Rather than trying to foresee each new application or change in use of existing applications for each component, they feel more confident in predicting the overall continuing rate of growth of their system.

Proponents of the components approach argue that one part, e.g., a portion of the service area, a class of service, or a type of load, may be growing much more rapidly than the remainder. If this part is substantial and its rate of growth differs significantly from that of the total, failure to segregate it can result in misleading conclusions. Further, they argue that a great deal more detailed information can be more meaningfully correlated to the parts than the total.

(3) *Average Weather vs. Extremes*

Most utilities prepare forecasts designed to reflect normal weather conditions. Historical

Can Electric Utilities Improve Their Forecast Accuracy? The Historical Perspective

By WILLIAM R. HUSS

This is the second of two articles describing the results of a study to assess what makes a good electric utility load forecast and what has been the historical record of the various techniques used by the industry. Accuracy of forecast as measured by mean absolute percentage error and median absolute percentage error was analyzed from a variety of perspectives including (1) forecast horizon, (2) forecast vintage, (3) person-months devoted to forecasting, (4) customer sector, (5) technique, and (6) type of forecast (sales-energy or peak).

Although utilities, consultants, and academicians have spent millions of dollars to develop more sophisticated and (they hoped) more accurate forecasting techniques, very little has been done to look back and assess the relative success or failure of these efforts. By knowing which techniques have previously worked best, given a certain customer sector, level of effort, and forecast horizon, recommendations can be made concerning the selection of a technique and insights gained as to the cost of obtaining additional accuracy.

This article describes the results of a study which looked at historical accuracy of utility load forecasts from a variety of perspectives including forecast horizon (two, four, six, and eleven years), forecast vintage (1972, 1976, 1978, 1980, and 1982), person-months devoted to forecasting, sector (residential, commercial, industrial), technique (trending, econometric, end use, customer survey, advanced time series, et cetera), and type of forecast (sales-energy or peak). Fifty of the 75 largest utilities in the United States chose to participate by submitting historical forecasts and actual sales and peak data. In addition, a random sample of 25 smaller utilities (between 700 and 5,000 gigawatt-hours in 1982 sales) were contacted and ten chose to participate. A list of participating utilities appears with this article.

William R. Huss is the manager of forecasting and planning at Battelle Laboratories Columbus Division where he has led projects in planning and forecasting for the electric and gas utility industries. He is currently involved in developing a forecasting and simulating methodology for the Electric Power Research Institute. **Mr. Huss** holds a BA degree in mathematics and physics from Gettysburg College and an MA degree in public administration and an MS degree in industrial and systems engineering from Ohio State University.

Analysis of Total Energy Forecasts

Tables 1 and 2 present the historical accuracy data for total energy forecasts. The results are disaggregated by utility size and technique as well as by vintage and horizon. The mean absolute percentage error and its standard deviation along with the median absolute percentage error and the number of responses are also presented. These tables also show the results pooled by horizon (two-, four-, and six-year ahead forecasts, respectively).

Large utilities seem to perform marginally better than small utilities for all horizons, with mean absolute percentage errors (MAPES) of 4.15 compared to 5.18 for the two-year horizon, 11.16 compared to 12.96 for the four-year horizon, and 20.86 compared to 21.79 for the six-year horizon. The t-test statistical significance levels are fairly small at roughly .75 for the two- and four-year horizons and .55 for the six-year horizon. When looking at the median absolute percentage errors (MedAPE), however, the small utilities were able to outperform the large utilities by a small amount for both the four- and six-year horizons. One must conclude from these data that the size of the utility has little to do with the accuracy of its forecasts of total energy.

Tests were also made on total energy forecasts comparing forecasts made using (1) a combination of trend extrapolation and judgement, (2) econometrics, and (3) end-use models. Since most total energy forecasts are calculated as the sum of the residential, commercial, industrial, and miscellaneous sector forecasts, one must be careful in placing a forecast in one of the three categories. Whichever technique predominated tended to define the category. Only large utility forecasts are considered at this point.

Complex econometric models (those having multiple equations for each sector) seem to outperform simple models in the short term (two-year horizon) with 90 to 95 per cent significance, but do only slightly better (60 to 65 per cent significance) for four-year horizons. Simple econometric models, on the other hand do better in the longer six-year horizons at an 85 to 90 per cent significance level. These results tend to be consistent with the philosophy that complicated techniques provide a better fit to the data and therefore do better in the short term, while simple techniques tend to capture the long-term trend and miss short-term fluctuations.

End-use models seem to be the big winner, outperforming econometric techniques for all horizons at a minimum 90 per cent confidence level. End-use techniques also do better than trending approaches although the difference is insignificant for the two-year horizon. Since the trending approaches include judgement gained as a result of considerable customer contact, perhaps that can explain the strong performance of trending-judgement techniques in the short term. In the long term, however, these techniques rely less on judgement and more on identifying the long-term trend through extrapolation.

Finally, trending-judgement techniques were compared with econometrics with the results showing the trending

TABLE 1

Mean Absolute Percentage Errors, Median Absolute Percentage Errors for Energy Forecasts

		Vintage: Horizon												
		72:73	76:77	78:79	80:81	82:83	72:75	76:79	78:81	80:83	72:77	76:81	78:83	72:82
All Large Utilities	Mean	2.72	4.54	3.73	4.82	5.60	16.75	8.14	10.65	11.70	22.24	17.35	23.55	65.34
	Std. Dev	3.048	7.807	4.167	5.594	5.144	7.518	5.362	7.405	10.397	11.183	10.783	23.001	20.378
	Median	1.37	3.28	2.72	3.48	4.49	17.50	7.08	9.725	8.54	22.47	16.99	19.70	63.52
	No. of Resps.	21	42	44	47	49	22	42	44	48	21	42	44	17
Small Utilities	Mean	3.84	6.29	4.60	5.46	4.50	42.57	8.04	10.40	14.53	30.07	16.07	25.85	25.55
	Std. Dev.	–	5.670	4.981	3.265	3.192	35.843	8.649	10.751	18.068	18.491	12.528	24.297	35.143
	Median	3.84	4.41	2.80	4.03	3.28	42.57	4.51	5.16	10.18	30.07	15.09	17.18	25.55
	No. of Resps.	1	10	10	10	10	2	10	10	10	2	10	10	2
Trending (Large Utilities)	Mean	2.48	4.93	3.96	3.07	3.75	15.92	8.07	10.69	9.27	20.68	16.50	29.16	62.90
	Std. Dev.	2.854	8.983	5.249	1.721	1.308	6.890	5.204	7.198	6.741	10.561	10.903	31.984	21.426
	Median	1.37	3.37	2.53	2.84	4.49	17.51	7.22	9.72	6.50	22.42	15.57	23.96	60.625
	No. of Resps.	18	31	19	8	3	18	31	19	8	18	31	19	14
Simple Econometric (Large Utilities)	Mean	9.18	3.55	3.53	8.80	10.71	32.94	6.94	10.60	16.88	44.17	16.24	16.51	73.91
	Std. Dev	–	2.387	4.361	9.839	9.125	–	4.622	6.170	15.617	–	9.186	7.248	–
	Median	9.18	2.50	1.03	5.94	6.13	32.94	5.96	12.20	10.14	44.17	15.97	18.01	73.91
	No. of Resps.	1	5	8	8	6	1	5	8	9	1	5	8	1
Complex Econometric (Large Utilities)	Mean	2.65	3.17	4.12	5.12	5.27	16.37	11.15	11.51	13.03	30.85	22.26	22.66	68.43
	Std. Dev		3.469	2.903	4.941	3.996	10.239	8.549	9.088	10.016	-	13.92	13.777	-
	Median	2.65	0.63	3.83	3.85	5.34	16.37	8.23	8.96	9.20	30.85	22.89	18.38	68.43
	No. of Resps.	1	4	12	19	25	2	4	12	20	1	4	12	1
All Econometric (Large Utilities)	Mean	5.91	3.38	3.89	6.21	6.32	21.89	8.81	11.14	14.23	37.51	18.91	20.20	71.17
	Std. Dev	4.617	2.721	3.460	6.775	5.606	11.997	6.559	7.877	11.876	9.419	11.179	11.782	3.875
	Median	5.91	2.50	3.65	5.56	5.34	23.61	6.93	10.09	10.14	37.51	20.23	18.38	71.17
	No. of Resps.	2	9	20	27	31	3	9	20	29	2	9	20	2
End Use (Large Utilities)	Mean		3.20	2.10	2.85	5.08		8.65	5.86	6.81	–	17.08	12.66	–
	Std. Dev	–	–	1.838	3.210	4.516		–	4.965	5.637		–	11.336	–
	Median	–	3.20	0.93	1.27	3.28	–	8.65	3.67	5.52	–	17.08	11.51	–
	No. of Resps.	–	1	4	11	13	–	1	4	11	–	1	4	–

Table 2

Mean Absolute Percentage Errors and Median Absolute Percentage Errors for Two, Four, and Six Years Ahead for Energy Forecasts

		Horizon: Two Years	Four Years	Six Years
Large Utilities	Mean	4.50	11.16	20.86
	Std. Dev.	5.569	8.031	16.989
	Avg. Med.	3.30	9.74	19.18
	No. of Resps.	203	156	107
Small Utilities	Mean	5.18	12.96	21.79
	Std. Dev.	4.412	14.561	19.287
	Avg. Med.	3.64	8.86	17.40
	No. of Resps.	41	32	22
Trending (Large Utilities)	Mean	3.91	10.71	21.14
	Std. Dev.	6.451	6.314	19.166
	Avg. Med.	2.70	10.21	19.73
	No. of Resps.	79	76	68
Econometric (Large Utilities)	Mean	5.43	12.79	20.94
	Std. Dev.	5.394	10.053	11.536
	Avg. Med.	4.75	10.31	20.15
	No. of Resps.	89	61	31
End Use (Large Utilities)	Mean	3.76	6.69	13.54
	Std. Dev.	3.945	5.489	11.336
	Avg. Med.	2.19	5.25	12.62
	No. of Resps	29	16	5
Simple Econ (Large Utilities)	Mean	6.78	13.23	18.39
	Std. Dev.	7.217	11.010	8.007
	Avg. Med.	4.08	10.94	19.15
	No. of Resps.	28	23	14
Complex Econ (Large Utilities)	Mean	4.82	12.53	23.05
	Std. Dev.	4.086	9.608	13.808
	Avg. Med.	4.23	9.40	20.17
	No. of Resps.	61	38	17

approach to be better in the short term with little or no difference apparent for the six-year horizon.

The superiority of the end-use approach also seems to be confirmed when comparing the median absolute percentage errors. Since one conclusion of this study is that end-use techniques seem to provide improved accuracy, the key issue becomes how much this additional accuracy is worth to the utility in the way of increased development and data collection costs.

Analysis of Residential Sector Forecasts: For the residential sector, statistical analysis was performed comparing end-use, econometric, and trending-judgement techniques for two-, four-, and six-year forecast horizons. Data are also presented for the eleven-year horizon, but the sample size is too small for much in the way of statistical analysis. Data for the residential analysis are presented in Table 3.

Again, the end-use methodology shows considerably lower mean absolute percentage errors with respect to all techniques for all horizons. For the two-year horizon, end-use MAPE (MedAPE) was 3.11 (2.36) compared to 3.84 (3.53) for trending-judgement and 4.22 (3.68) for econometrics. These differences were significant at the 95 per cent level in all cases. For the six-year horizon, end use also was the strongest performer with MAPE (MedAPE) of 16.80 (15.54) compared to 18.31 (16.61) for trending-judgement and 20.72 (19.35) for econometrics. These differences were only significant at the 65 per cent level.

No significant differences above the 65 per cent level were shown between trending-judgement and econometrics for any forecast horizon.

Analysis of Commercial Sector Forecasts: For the commercial sector, large utility forecasts employing trending-judgement and econometrics were compared. Since end-use models are just beginning to be used by the electric utility industry, there were not enough data to compare

Utility Participants

Large Utilities

Alabama Power
Allegheny Power
American Electric Power
Arizona Public Service
Arkansas Power and Light
Baltimore Gas and Electric
Boston Edison
Carolina Power and Light
Central Power and Light
Central Illinois Power and Light
Commonwealth Edison
Consolidated Edison
Consumers Power
Dayton Power and Light
Delmarva Power and Light
Detroit Edison
Duke Power
Duquesne Light
Florida Power Corp.
Georgia Power
Gulf States Utilities
Houston Lighting
Illinois Power
Kansas Gas and Electric
Long Island Lighting
Los Angeles DWP
Louisiana Power and Light
Middle South Services
Minnesota Power and Light
Mississippi Power and Light
Montana Power
NEPOOL
New York State Electric
Niagara Mohawk
Northern States Power
Ohio Edison
Oklahoma Gas and Electric
Pacific Power and Light
Pennsylvania Electric
Philadelphia Electric
Public Service Colorado
Public Service Oklahoma
San Diego Gas and Electric
Southern California Edison
Southwest Electric
Tampa Electric
Toledo Edison
Union Electric
Virginia Electric
Washington Water Power

Small Utilities

Bangor Hydro-Electric
Arizona Electric
Buckeye Power
Empire District Electric
Iowa Power and Light
Lakeland
Otter Tail Power
Pennsylvania Power
St. Joseph Light and Power
Sierra Pacific

Table 3

Mean Absolute Percentage Errors and Median Absolute Percentage Errors for Two-, Four-, Six-, and Eleven-Year Ahead Residential Forecasts (Large Utilities)

		Horizon			
		Two Years	Four Years	Six Years	Eleven Years
Trending	Mean	3.84	11.74	18.31	62.72
	Std. Dev.	2.318	6.187	11.099	11.135
	Avg. Med.	3.53	9.87	16.61	58.37
	Number	27	24	23	4
Econometric	Mean	4.22	10.87	20.72	47.23
	Std. Dev.	3.433	7.706	11.066	–
	Avg. Med.	3.68	10.64	19.35	47.23
	Number	37	27	17	1
End Use	Mean	3.11	6.45	16.80	62.42
	Std. Dev.	2.468	4.911	8.860	–
	Avg. Med.	2.36	4.48	15.54	62.42
	Number	44	27	12	1
Overall	Mean	3.75	9.81	18.75	62.64
	Std. Dev.	2.845	6.519	10.399	11.853
	Avg. Med.	3.21	8.95	18.34	61.38
	Number	111	80	52	7

end-use models. Data for the commercial analysis are presented in Table 4.

Although all of the resulting differences were significant in the range of only 60 to 80 per cent, the trending-judgement techniques did better in the two- and six-year horizons while econometrics was slightly more accurate for the four-year horizons. The virtually identical result occurred for the residential sector. These results may lend some support to the philosophy mentioned earlier that trending-judgement is strong in the short term because it relies on judgement gained from close association between the utilities and their customers; and, that trending-judgement is strong in the long term because it captures the long-term trend and is not affected by sudden changes as more adaptive techniques might be. Its weakness may be in the middle range; namely, for forecasts with three-to-five-year horizons. Obviously, however, the evidence is inconclusive.

Analysis of the Industrial Sector Forecasts: For the industrial sector (Table 5) comparisons were made between large utility forecasts using either trending-judgement, econometrics, or customer surveys. Since the industrial sector tends to be dominated by a few large customers, utilities often rely on inputs from these customers to estimate electricity consumption. Often these customers are better able to evaluate the economic conditions affecting their industry and may also have insights concerning plant additions or shutdowns and the introduction of new technologies. End-use techniques are used only by a few utilities because obtaining the necessary inventory of equipment and their associated use patterns is prohibitively expensive and often not available from customers who might be sensitive about releasing such information.

Table 4

Mean Absolute Percentage Errors and Median Absolute Percentage Errors for Two-, Four-, Six-, and Eleven-Year Ahead Commercial Forecasts (Large Utilities)

		Horizon			
		Two Years	Four Years	Six Years	Eleven Years
Trending	Mean	3.16	9.60	17.12	61.29
	Std. Dev.	2.368	5.289	9.448	20.040
	Avg. Med.	3.13	9.77	14.52	53.34
	No. of Resps.	35	31	26	5
Econometric	Mean	3.31	8.62	18.45	81.58
	Std. Dev.	2.708	6.013	11.302	–
	Avg. Med.	2.93	7.54	18.05	81.58
	No. of Resps.	57	39	21	1
Overall	Mean	3.34	8.83	17.64	66.56
	Std. Dev.	2.666	6.110	10.421	18.709
	Avg. Med.	3.04	8.43	17.13	68.24
	No. of Resps.	103	73	48	7

Table 5

Mean Absolute Percentage Errors and Median Absolute Percentage Errors for Two-, Four-, Six-, and Eleven-Year Ahead Peak Forecasts (Large Utilities)

		Horizon			
		Two Years	Four Years	Six Years	Eleven Years
Trending	Mean	6.43	12.51	18.92	59.63
	Std. Dev.	5.343	7.646	10.199	21.680
	Avg. Med.	5.09	11.68	18.60	63.18
	No. of Resps.	50	46	39	9
Econometric	Mean	5.81	11.58	21.55	69.74
	Std. Dev.	4.093	7.252	14.312	-
	Avg. Med.	5.13	10.98	21.39	69.74
	No. of Resps.	61	44	24	1
Load Factor	Mean	5.38	11.56	19.21	58.47
	Std. Dev.	6.115	9.317	13.240	29.874
	Avg. Med.	3.36	8.27	18.51	53.06
	No. of Resps.	66	52	39	7
Overall	Mean	5.85	11.62	19.59	59.75
	Std. Dev.	5.196	8.125	12.266	24.014
	Avg. Med.	4.43	10.27	17.85	63.18
	No. of Resps.	189	148	103	17

The results show that customer surveys do extremely well in the short term (two-year horizons) with a MAPE (MedAPE) of 2.32 (1.55) compared to 4.50 (3.68) for trending-judgement and 7.44 (3.90) for econometrics. These results are significant at the 90 per cent level or above. For the longer forecast horizons, there is no significant difference between any of the three approaches. For the same reasons stated earlier, it is not surprising that in the short term, customer surveys seem to produce good industrial sector forecasts. Plant managers usually have a fairly good idea at least two years ahead of what plant additions (and sometimes closings) will occur as well as what new equipment purchases are planned. Their forecasts, however, become no better than other models when the forecast horizon is extended.

Trending-judgement techniques seem to perform better than econometrics for the two- and four-year forecast horizons. Trending-judgement shows a MAPE (MedAPE) of 4.50 (3.68) for the two-year horizon compared to 7.44 (3.90) for econometric methods. For the four-year horizon, trending-judgement shows a MAPE (MedAPE) of 13.26 (12.71) compared to 22.73 (20.37) for econometrics. The fact that judgement results from knowledge of customer plans for electricity use may explain the short-term superiority of trending-judgement over econometrics. Econometric models in the utility industry are for the most part calibrated using data from the 1950-75 time frame (some more recent data for the recent forecasts). In general this time frame does not show the volatility currently experienced in the economy as shown by the recessions of 1974-75, 1979-80, and 1982-83. Therefore, these models are apparently unable to capture downturns in the economy as well as forecasters using expert judgement and trending approaches. In addition, these models may not capture today's emphasis on conservation.

Analysis of Peak-load Forecasts

Peak-load forecasts were compared for trending-judgement, econometric, and load factor techniques (see Table 6). Again, not enough utilities are using end-use techniques for these to be included in the analysis. Load factor analysis is somewhat different from the other approaches in that it is driven off of the energy forecast. In fact, for the most part the forecast is obtained by estimating a multiplier called a "load factor" which is then applied to the energy forecast.

Although no differences between the three techniques were significant above the 80 per cent level, load factor analysis held a slight edge in MAPE for the two- and four-year horizons and a slight edge in the weighted average median percentage error (MedAPE) for all horizons. For the two-year horizon, load factor analysis showed a MAPE (MedAPE) of 5.38 (3.36) compared to 5.81 (5.13) for econometrics and 6.43 (5.09) for trending-judgement. For the four-year horizon, load factor analysis showed a MAPE (MedAPE) of 11.56 (8.27) compared to 11.58 (10.98) for econometrics and 12.51 (11.68) for trending-judgement. For the six-year horizon, load factor analysis showed a MAPE (MedAPE) of 19.21 (18.51) compared to 21.55 (21.39) for econometrics and 18.92 (18.60) for trending-extrapolation.

Again there is some evidence that trending-judgement seems to improve its performance over longer horizons. Unlike its performance in the commercial and industrial sectors, however, trending-judgement failed to perform well for the two-year horizon peak forecasts.

Table 6

Mean Absolute Percentage Errors and Weighted Average Median Absolute Percentage Errors For Two-, Four-, and Six-Year Ahead Peak Forecasts (Large Utilities)

		Horizon		
		Two Years	Four Years	Six Years
Trending	Mean	6.43	12.51	18.92
	Std. Dev.	5.343	7.646	10.199
	Avg. Med.	5.09	11.68	18.60
	No. of Resps.	50	46	39
Econometric	Mean	5.81	11.58	21.55
	Std. Dev.	4.093	7.252	14.312
	Avg. Med.	5.13	10.98	21.39
	No. of Resps.	61	44	24
Load Factor	Mean	5.38	11.56	19.21
	Std. Dev.	6.115	9.317	13.240
	Avg. Med.	3.36	8.27	18.51
	No. of Resps.	66	52	39
Overall	Mean	5.85	11.62	19.59
	Std. Dev.	5.196	8.125	12.266
	Avg. Med.	4.43	10.27	17.85
	No. of Resps.	189	148	103

Comparison of Sector Forecasts

Tables 3-5 can be used to compare large utility forecasts of the residential, commercial, and industrial sectors. Commercial sector forecasts seem to be slightly more accurate than residential forecasts for the two-, four-, and six-year horizons; however, the difference is insignificant except perhaps for the two-year horizon where the significance level (using the standard paired t-test) is between 85 and 90 per cent. Residential forecasts do slightly better for the 11-year horizon although the sample size is small and the significance low at 65 to 70 per cent.

Both the residential and commercial sector forecasts do *considerably* better than industrial sector forecasts with significance levels well in excess of 99 per cent for the two-, four-, and six-year horizons. Even for the 11-year horizon with its small sample size, the significance level was greater than 95 per cent. Since the residential, commercial, and industrial sectors each comprise roughly one-third of electricity consumption, there seems to be room for improvement in the industrial sector. This observation may justify utilities spending more time and money to improve performance of industrial sector models than for residential and commercial sector approaches.

Analysis of Vintage

Although no statistical analysis was conducted, direct observation shows little or no evidence that utility forecasting is improving over time. The one-year horizon MAPEs for 1972, 1976, 1978, 1980, and 1982 forecasts respectively are 2.72, 4.54, 3.73, 4.82, and 5.60. Except for the 1978 forecast of 1979 increasing rather than decreasing errors are observed. Although the 1972 three-year forecast shows the highest MAPE with a drop to 8.14 in 1976, errors begin to grow again with a three-year MAPE of 10.65 from the 1978 forecast and 11.70 from the 1980 forecast. The five-year forecasts show a MAPE of 22.24 from the 1972 forecast, falling to 17.35 for the 1976 forecast, but rising again to 23.55 for the 1978 forecast. From these data, no improvement in utility forecasting accuracy over time is apparent.

Conclusions and Recommendations

The results described in this article support a number of conclusions.

1. The accuracy of utility forecasting has apparently not improved over time. New techniques are being developed all the time and many recently developed techniques have not been around long enough to be tested especially over the longer term. But, utilities should be somewhat skeptical of spending tremendous amounts of time and money on new techniques and data collection in the hopes of improving forecast accuracy. The detailed models should be justified by their ability to provide special insights into relationships between variables and into the behavior of specific customer segments.

2. In the residential sector, end-use techniques clearly outperform all other techniques. Utilities possessing end-use analysis capabilities also seem to do better when forecasting overall energy as well. Although each utility must decide for itself if an end-use residential model is worth the additional cost of data collection, it is recommended that the decision be evaluated carefully in the light of the improved accuracy demonstrated in this study.

3. In all sectors, econometric techniques fail to outperform trend extrapolation-judgemental techniques. Unless econometric modeling can provide needed insights, sensitivities, or a level of disaggregation unavailable from other methods, its use in utility forecasting must be questioned.

4. Although large utilities tend to develop more sophisticated models and spend more time and money on forecasting, this study was unable to verify that improved forecast accuracy is achieved.

5. Very little difference is apparent between the forecast accuracy of the residential sector and that of the commercial sector; however, forecasts for both of these sectors have been considerably more accurate than those made for the industrial sector.

6. Customer survey forecasts seem to be by far the best technique for forecasting the industrial sector up to about a two-to-four-year forecast horizon.

EDITOR'S NOTE: The first article in this series, "What Makes a Good Load Forecast?" by William R. Huss, describing the results of a survey of utility analysts, utility senior managers, and utility commissions to identified forecast evaluation criteria and uses and the evolution of forecasting techniques, appeared in PUBLIC UTILITIES FORTNIGHTLY, November 28, 1985.

Utility's Oil-to-Coal Conversion Program Recognized

For his role in helping to direct a massive oil-to-coal conversion program at Virginia Power, Tyndall L. Baucom, the company's vice president for fossil and hydro operations, has been selected "coal technology person of the year." Baucom, who joined Virginia Power in 1965, directs the company's coal, oil, and hydro operations and was an early architect of the coal conversion program. He received the award recently at an international coal convention in Pittsburgh.

Coal Technology '85, the international organization that sponsors the convention of electric utility industry groups, presented the award in recognition of Baucom's contribution to the expanded use of coal. Virginia Power expects to burn about 10 million tons of coal next year.

Virginia Power has converted 2.3 million kilowatts of generating capacity from oil to coal since 1975, the largest such program in the country.

OCA Statement No. 5

50~ 2-14-86 HDG R-850152

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

RECEIVED

FEB 18 1986

SECRETARY'S OFFICE
Public Utility Commission

IN RE:	)	
	)	
PENNSYLVANIA PUBLIC UTILITY COMMISSION	)	Docket No. R-850152
	)	
v.	)	
	)	
PHILADELPHIA ELECTRIC COMPANY	)	

DOCKETED

FEB 2 1986

TESTIMONY AND EXHIBITS

OF

PETER J. LANZALOTTA

CONCERNING

SYSTEM RELIABILITY

AND

EXCESS CAPACITY

January, 1986

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

IN RE:	)	
	)	
PENNSYLVANIA PUBLIC UTILITY COMMISSION	)	Docket No. R-850152
	)	
	)	
v.	)	
	)	
PHILADELPHIA ELECTRIC COMPANY	)	

TESTIMONY AND EXHIBITS
OF
PETER J. LANZALOTTA

Q. Please state your name and business address.

A. Peter J. Lanzalotta, Suite 350, 1301 Pennsylvania Avenue, N.W., Washington, D.C., 20004.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of the Pennsylvania Office of Consumer Advocate.

Q. Please describe your experience and qualification.

A. I am a graduate of Rensselaer Polytechnic Institute, where I received a Bachelor of Science degree in Electric Power Engineering. In addition, I also hold a Masters degree in Business Administration with a concentration in Finance from Loyola College in Baltimore.

Q. Please describe your professional experience.

A. I am a partner with Whitfield Russell Associates with whom I have been associated since March, 1982. My major areas of expertise include cost of service, rates, bulk power sales, system operation, and utility computer applications. Prior to joining Whitfield Russell Associates, I was employed by the Connecticut Municipal Electric Energy Cooperative ("CMEEC") as System Engineer. I was responsible for providing operational, financial, and rate expertise to budgeting, ratemaking and project evaluation processes, the management of CMEEC's participation in the Hydro-Quebec/New England Power Pool Interconnection project, and the development of a data base structure to support CMEEC's operational and financial data needs. I also provided expertise in the preparation of testimony for use before the Federal Energy Regulatory Commission.

Prior to this, I served as Chief Engineer at the South Norwalk (Connecticut) Electric Works, with responsibility for data processing, engineering, rates and tariffs, generation, bulk power sales, and distribution operations. While at South Norwalk, I designed and implemented cogeneration and small power production tariff provisions, as well as programs for toxic substance storage and reporting. I developed and implemented improvements in the utilization of wholesale purchases and generation resources which decreased the total cost of power. I also designed, programmed, and implemented a computer system which handled billing systems, customer accounting, financial reporting, system security and data management.

From 1977 to 1979 I worked as a utility consultant in a variety of positions. During this time, I developed cost of service, rate base valuation, and rate design impact data to support direct testimony and exhibits in a variety of utility proceedings, including antitrust, gas pipeline, and electric rate increase cases.

I worked for approximately 2 years as a Service Tariffs Analyst for the Finance Division of the Baltimore Gas & Electric Company ("BG&E") where I developed cost and revenue studies, evaluated alternative rate structures, and studied the rate structures of other utilities for a variety of applications. I was also employed by BG&E in Electric System Operations for approximately 3 years, where my duties included providing statistical expertise for operating reports, analyzing distribution operations, and developing an "on-line" analysis of system disturbances.

Q. Are you a member of any professional organization?

A. Yes. I am a member of the Institute of Electrical & Electronic Engineers, the National Society of Professional Engineers, the American Solar Energy Society, and the Financial Management Association. I am also a registered Professional Engineer in the states of Maryland and Connecticut.

Q. Have you previously testified before a regulatory Commission?

A. Yes. I have presented testimony in FERC Docket Numbers ER78-337 and ER78-338, <u>in re: Public Service Company of New Mexico</u>, in Maryland Public Service Commission Case No. 7238-V <u>in re: Baltimore Gas and Electric Company</u>, in Texas Public Utility Commission Docket No. 4712 <u>in re: Houston Lighting and Power Company</u>, in Virginia State Corporation Commission, Case No. PUE820091 <u>in re:</u>

Virginia Electric and Power Company, in Nevada Public Service Commission, Docket No. 83-707 in re: Nevada Power Company, in New Jersey Board of Public Utilities, Docket No. 831-25 in re: Public Service Electric and Gas Company, in Pennsylvania Public Utility Commission, Docket No. P-830453 in re: Philadelphia Electric Company, in the Public Utilities Commission of Ohio, Case No. 84-13-EL-EFC in re: Cincinnati Gas & Electric Company, and in the State Corporation Commission of Kansas, Docket Nos. 142,099-U and 120,924-U in re: Kansas City Power & Light Company.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present my analysis of Philadelphia Electric Company's ("PECO") need for the Limerick 1 generating capacity from the point of view of system reliability.

I will also address some other arguments by PECO for recovering the costs of Limerick 1 through PECO's rates.

Q. Is Limerick 1 excess to the needs of PECO for generating capacity to insure system reliability?

A. Yes. All of Limerick 1 is excess to the needs of PECO in 1986 and 1987 and a substantial portion of Limerick 1 remains excess capacity through 1990. Specifically, I would conclude that at least 450 MW of Limerick 1 represents excess capacity at least through 1990.

Q. How much capacity does PECO need?

A. PECO's needs for capacity are based upon PECO's forecast of annual probable peak demand and the reserve margin which PECO is required to maintain as a result of its membership in the PJM Pool.

Q. Why are reserve margins necessary?

A. The purpose of providing a reserve margin is to allow PECO to provide reliable service regardless of unscheduled generating unit outages during peak load periods and to allow for potentially higher than expected peak demands. The PJM Pool determines the reserve margin level which each member utility is required to supply. These reserve margin targets are designed to maintain a minimum acceptable level of system reliability.

Q. What happens if a PJM member's capacity is below that required by PJM?

A. If a PJM member falls short of its required reserve margin level, it is subject to a deficiency charge based on the costs of a combustion turbine ("CT").

Q. What is the PJM charge for capacity deficiencies?

A. The present PJM charge for capacity deficiencies of PJM members is $52.93 per KW per year. By way of comparison, this is considerably higher per KW than PECO's estimated net total cost of keeping its existing CT generating capacity on-line. The total net cost of keeping this CT capacity on-line, rather than prematurely retiring it, was estimated by PECO to be approximately $14.00 per KW per year through 1996.

The function of the PJM capacity deficiency charge is to provide capacity at a price as a means of serving capacity deficiencies resulting from unexpectedly high levels of load growth, as well as capacity deficiencies resulting from delays or timing difficulties in the in-service dates of planned generating facilities.

Q. Is PECO facing the possibility of having a capacity deficiency?

A. No. PECO is not facing any imminent capacity shortages for which it would be required to pay the PJM capacity deficiency rate. Indeed, PECO will have so much excess capacity available when Limerick 1 is commercially available for service that PECO has advanced the scheduled retirement dates of a number of generating units so as to reduce the apparent amount of excess capacity which results from Limerick 1.

Q. You indicate that PECO is speeding up the planned retirement of some of its existing generation units because of the excess capacity resulting from Limerick 1. Please explain.

A. PECO has accelerated the retirement of still-useful generating facilities by up to ten years and has attempted to sell, on a long-term firm basis, substantial portions of its present and proposed nuclear base load generating capacity. The acceleration in the retirement dates of existing PECO generation involves 458 MW of CT generating capacity at the Plymouth Meeting and Richmond generating stations, as well as about 336 MW of oil-fired steam generation at the Southwark generating station. The proposed long-term firm sales involve generating capacity from the Salem 2 nuclear generating unit as well as from the Limerick nuclear generating station.

Q. Please describe the early retirement of the CT capacity.

A. PECO originally planned that the 458 MW of CT generating capacity in question would be in service until 1996.

When PECO examined the question of whether CT capacity should be leased or purchased, PECO made this decision based upon a 25 year service life. PECO decided to lease this CT capacity. The 25 year lease expires on September 30, 1996. Now, as shown on PECO's response to IR-GSA-2-11, this 458 MW of CT capacity will have been in service, for the most part, for only 14 years as of mid-December 1985. Thus, these units are being retired more than 10 years before the end of their useful lives.

Q. Why is PECO retiring 458 MW of CT capacity before the end of its useful service life?

A. PECO's position is that the availability of the Limerick 1 capacity allows PECO to retire 458 MW of combustion turbine ("CT") generating capacity which otherwise could be useful and usable at nominal cost at least through 1996.

In its response to IR-GSA-2-10, PECO states that:

> "The addition of Limerick 1 is allowing PECO to retire 458 MW of CT capacity before the end of their nominal lives."

Q. What is the nominal cost of keeping the CT capacity in-service through 1996?

A. Based on PECO's response to IR-OCA-15-5, the total net cost of keeping the 458 MW of CT capacity would, on average, be about $6.45 million per year, or about $1.17 per KW per month. PECO has already collected more than $40 million from its ratepayers towards expected lease termination charges, thus lowering the incremental cost of keeping, rather than retiring, the CT capacity.

Q. Has PECO also advanced the proposed retirement date for Southwark 1 and 2?

A. Yes. As recently as June 30, 1982, PECO had planned on the Southwark 1 and 2 generating units being available through 1987, as indicated in item 22 of PECO's Cost of Service Information, which was enclosed as an attachment in response to IR-OCA-6-32. PECO now plans on retiring Southwark 1 and 2 when Limerick 1 is commercially available.

In response to IR-GSA-2-10, PECO comments on the retirements of Southwark 1 and 2:

> "These units are inefficient, oil-fired, obsolete, and 38 years old. The addition of Limerick does allow PECO to retire these units without enduring a capacity shortage."

Q. What effect do the early retirements have on the physical need for capacity from Limerick 1?

A. The change in the amount of excess capacity caused by the acceleration of the retirement dates of Southwark 1 and 2 is not long-lived. Originally, these units would have been available through 1987. Now their retirement is accelerated so that they will be unavailable for use in helping to serve the 1986 and 1987 summer peaks. The accelerated retirement of Southwark 1 and 2 results in 336 fewer MW of apparent excess capacity during the years 1986 and 1987 than would otherwise be the case.

If PECO's available capacity is adjusted to reflect the fact that, except for the presence of excess capacity in the form of Limerick 1, PECO would, at nominal cost, have 458 MW of additional CT generating capacity through at least 1996 and 336 MW of additional oil-fired steam generating capacity through at least 1987 available to it, the amount of excess capacity resulting from Limerick 1 is quite large.

As shown in Schedule 1, when the 458 MW of CT generating capacity is deemed available through at least 1993 and Southwark's 336 MW of capacity is deemed available through 1987, the amount of excess capacity which results from Limerick 1 increases dramatically. In 1986, the first annual peak load period for which Limerick 1 is commercially available, PECO experiences more than 1100 MW of excess generating capacity over and above its PJM reserve requirement. The same is true in 1987. In addition, the excess capacity resulting from Limerick 1 is more than 500 MW or larger through 1990.

Q. Your Schedule 1 shows no excess capacity after 1990. Why?

A. I have assumed that the retirements of Delaware 7 and 8 and Cromby 2 take place as presently scheduled by PECO and that there will be no life extension of these units. However, PECO has conducted studies which show that these plants, as well as a Schuylkill unit, could be life extended for 15 years. I also did not include any capacity from Limerick 2 in this analysis.

Q. Are you using the annual reserve margin required of PECO by PJM to determine the amount of excess capacity?

A. Yes.

Q. Does PECO use the PJM reserve requirement for system planning purposes?

A. No. PECO uses a general reserve margin planning target of 25 percent. PECO's actual PJM reserve requirement, as shown on page 15 of PECO Statement No. 14, varies from 21.9 percent to 25.8 percent from 1986 to 1991.

Q. Why do you use the PJM reserve margin requirement as the means of checking for excess capacity?

A. I use the PJM reserve requirement for PECO because that is the level of reserve margin which is actually required for PJM's selected level of system reliability. The use of a higher reserve margin can unnecessarily increase the cost of service.

The average PJM requirement for PECO for the 16 years ending in 1985 was less than 20 percent. On the other hand, in 1991, when PJM's reserve requirement for PECO is 25.8 percent, PECO's target level of 25 percent would be insufficient to avoid PECO's paying a capacity deficiency charge to PJM. It makes more sense to use the year-by-year PJM requirements for the years in which they are available. For the long-range future for which there are no forecast PJM requirements, the use of a rough planning target level seems more acceptable.

PECO's capacity requirements needed to maintain system reliability in 1986 are based on a PJM-required level of 22.5 percent reserves. From a reliability standpoint, anything above 22.5 percent reserves is excess capacity.

Q. What is the effect on the level of excess capacity if 25 percent is used rather than the PJM-required reserve margins?

A. The amount of excess capacity will decrease slightly as shown below:

	Excess Capacity Over Reserve Requirement	
Year	PJM Reserve	25% Reserves
1986	1106 MW	952 MW
1987	1119	927
1988	752	566
1989	597	529
1990	554	504

Q. Would any of your recommendations change if the Commission were to use a 25 percent reserve margin rather than the PJM reserve margin requirement as the basis for determining excess capacity?

A. No. In either case, PECO has substantial excess capacity in each year through at least 1990.

Q. You said earlier that PECO's forecast need for generating capacity is based upon PECO's forecast of its probable annual peak demands. How reasonable does PECO's forecast of probable annual peak demands appear in light of actual historical experience?

A. PECO's actual 1985 demand was 6034 MW as compared with a PECO forecast probable demand for the summer of 1985 of 6140 MW. PECO claims that the fact that its actual 1985 peak fell below its forecast 1985 probable peak demand is accounted for by the fact that PECO's 1985 peak occurred on a day of "below standard weather factor". In order to estimate what its peak load would have been had it occurred on a day which was not of below standard weather factor, PECO takes the position that the actual peak of 6034 MW should be adjusted upwards to account for the effects of weather on the actually experienced PECO peak demand during the summer of 1985. When so adjusted for weather, PECO's 1985 peak was 6139 MW.

However, it turns out that PECO's method of determining what is a day of below standard weather factor is such that <u>all</u> of the summer period of 1985 was considered to be of below standard weather factor. In IR-OCA-9-1, PECO said that <u>no</u> days in 1985 had weather factors equal to or greater than its standard weather factor.

While PECO's weather factor indicated less than optimal conditions for having a record peak load, every company in PJM, other than PECO, experienced record levels of peak demand during the summer of 1985. PJM, as a whole, also experienced an all-time record level of demand during the summer of 1985. It is also my understanding that PECO's standard weather factor was questioned by a number of parties and was rejected by the administrative law judge in the recent Limerick 2 Investigation.

If PECO's load forecast was to be adjusted to reflect PECO's <u>actual</u> 1985 peak demand experience, PECO's need for capacity would be reduced by about 125 MW. This reduction includes 105 MW of weather adjustment plus the associated reserve margin.

However, this adjustment is not reflected in my determination of the excess capacity resulting from Limerick 1 as shown on Schedule 1. My determinations are based upon PECO's own forecast probable peak demands without adjustment.

Q. Other than the premature retirement of the CT capacity, what other indications are there that Limerick 1 represents excess capacity?

A. PECO has offered and/or has indicated an interest in selling substantial portions of its nuclear base load generating capacity. PECO actually did sell its entire share of the output from 471 MW of net dependable capacity from Salem No. 2 to Jersey Central Power & Light for a period which ended on December 31, 1984. PECO attempted to sell this Salem No. 2 capacity for periods continuing through 1996 but was unsuccessful.

PECO has also indicated an interest in selling substantial portions of its capacity at the Limerick generating station. As recently as 1982, PECO indicated its willingness to sell 250 MW of Limerick 1 and 250 MW of Limerick 2 for a 10 year period beginning in 1985 and 1988 respectively.

Q. What are the implications of this willingness in 1982 of PECO to sell up to 500 MW from the Limerick generating station through the mid-1990's?

A. As shown in OCA Exhibit 63, in the July 7, 1982 memo from J.S. Kemper to R.F. Holman, the sale of 500 MW from the Limerick generating station for a 10 year period would have resulted in the need for PECO to delay some of its planned retirements in order to meet PECO's 25 percent target reserve margin to the year 2000.

The attachment to that memo indicates that PECO considered delaying the retirement of 473 MW of its CT's in order to accommodate the 500 MW long term sale from Limerick. Under various scenarios considered by PECO in 1982, the possibility of temporarily mothballing these CT's and then subsequently reactivating them at some future time (when their capacity was needed) was considered a possibility to help facilitate the hoped-for long term firm sale of capacity from Limerick. This attachment also shows that with or without the proposed sale, PECO planned on the availability of Southwark 1 and 2 through the end of 1987. The attachment also indicates that PECO considered it possible to delay the retirement of Delaware 7 and 8 until 1995 in the event that PECO found it possible to sell base load capacity from the Limerick station.

In addition to the delays in retirements which PECO has indicated were possible if chunks of Limerick could be sold on a long term firm basis, PECO also indicates in its attachment to the July 7, 1982 Kemper memo that the reactivation in 1991 or 1995 of more than 470 MW of CT generating capacity was also possible if required to meet PECO's reserve margin targets.

Q. Are there any other indications that the 1055 MW of Limerick 1 are excess to PECO's needs?

A. Yes. In its response to IR-PAIEUG-1-2, PECO indicates that PECO had sufficient capacity available to allow the scheduling of planned maintenance on more than 1200 MW of generating capacity during the summer peak load months of 1984 and 1985. Even before the availability of Limerick 1, PECO had sufficient capacity to allow the scheduling of more than 1200 MW average of planned maintenance per month for the summer peak months of June, July, and August.

During the month of August 1985, when the PJM pool experienced an all-time record demand for power, PECO was able to schedule maintenance of 1043 MW of generating capacity.

Q. Have you reviewed those portions of the testimony of Mr. Rush which deal with the need for more base load generating capacity by PECO?

A. Yes, I have.

Q. Does Mr. Rush take the position that Limerick 1 is needed to maintain system reliability?

A. Yes, Mr. Rush appears to be taking that position on page 19 of his testimony where he says: "Without Limerick 1, the 1986 reserve margin would be 10 percent." This position is misleading.

Q. Why is that?

A. Mr. Rush ignores the fact that the 10 percent reserve margin, which he forecasts in the absence of Limerick 1, is arrived at by assuming the accelerated retirement of 458 MW of CT generating capacity and more. PECO itself takes the position that these premature retirements are made possible because of the presence of capacity represented by Limerick 1. If Limerick 1 is not available, PECO can delay the premature retirement of these combustion turbine units and also that of the Southwark units, thereby achieving a reserve margin far higher than the 10 percent supported by Mr. Rush.

Q. Mr. Rush attempts to justify Limerick 1 on the basis of the theory of optimal generation unit mix. How important is the theory of the optimal generation mix to the question of whether PECO needs 1055 MW of nuclear base load capacity now?

A. The optimal generation mix is that mix which will allow PECO to provide reliable service at the lowest cost. It is this combination of reliable service at minimum cost which makes a particular mix of generation optimal. If Limerick 1 is not needed for reliability reasons <u>or</u> if it causes an increase in costs over some equally reliable alternative, then including Limerick 1 in PECO's generation mix cannot result in the optimal mix.

Mr. Rush's testimony on optimal generation mix does not address whether PECO needs Limerick 1 for reliability reasons or if the addition of Limerick 1 is the least cost alternative to PECO's system needs.

Q. Mr. Rush, on page 21 of his direct testimony, takes the position that PECO should theoretically have more than 4700 MW of base load capacity. What is your analysis of Mr. Rush's position?

A. Mr. Rush's position on PECO's need for base load capacity is difficult to reconcile with PECO's own actions and its operating environment.

PECO has attempted to sell substantial amounts of base load capacity from Salem 2 and Limerick. It is difficult to accept that Limerick 1 is desirable because of an imbalance (too little base load capacity) in PECO's resource mix while PECO is selling or trying to sell base load capacity and, thereby, worsen the supposed imbalance. Mr. Rush's theory of optimal resource mix obviously was not important to PECO in determining whether or not it has base load capacity available to sell. In 1984 when PECO attempted to continue to sell 471 MW from Salem 2, there was no mention of the effect of such a sale on PECO's theoretical optimal resource mix.

Further, Mr. Rush's determination that 4737 MW of base load capacity is ideal does not accurately reflect the realities of PECO's loads. During the month in which PECO experienced its 1985 peak load of 6034 MW, there were only 96 hours, out of a monthly total of 744 hours, when PECO's loads were as high as 4732 MW or higher. This is less than 13 percent of the hours in the peak month. Mr. Rush would have PECO build so much base load generation that, if it all ran during PECO's peak load month, the output from this generation would be in excess of PECO's needs during 85 percent of the whole month. This is the same base load generation, according to Mr. Rush, for which the utility is willing to pay a high fixed cost, because such generation will run as much of the time as possible, in order to reap the benefit of a very low variable cost.

However, Limerick 1 won't provide Mr. Rush's theoretical ideal of 4737 MW of base load generation, but rather the lesser amount of only 4359 MW. During August 1985, the annual peak load month, PECO's loads were at this level or higher for about 187 hours or 25 percent of the month. It seems inconsistent for PECO to build so much base load generation that, if it all runs during the month of the annual peak load, it would exceed PECO's system needs during 75 percent of the hours in the month unless it is cost-justified. During these hours, part of the low-fuel cost benefit for which the utility has paid such a high fixed-cost premium will be lost due to unit backdowns or will flow off the PECO system in the form of interchange sales. The only conceivable reasons to build base load capacity would be to provide needed reliability or to lower system cost.

Q. Mr. Rush, in his determination of the optimal amount of base load capacity, provides enough base load capacity, in addition to allowances for 25 percent system reserve and 65 percent base load unit availability factor, to have base load capacity available to provide power to pump water at PECO's Muddy Run pumped storage facility. Is this appropriate?

A. While it is a benefit to PECO to have a pumped storage facility with which to absorb base load generation which, during off-peak periods, may be excess to PECO's needs, this hardly seems to be justification by itself for adding additional base load generation to PECO's resource mix. By providing base load generation in amounts sufficient to guarantee the availability of PECO's own base load generation for use in operating a pumped storage facility, PECO is incurring very high fixed costs and, in the process, is limiting its opportunities to be able to take advantage of economically priced interchange generation which may exist on the PJM system for use in operating the pumped storage facility. It is usually excessively costly to build dedicated base load generating facilities on the justification that the output from these facilities will be used to operate a pumped storage facility when the utility is a member of a Pool such as PJM which typically has opportunities to purchase substantial amounts of economically priced off-peak interchange generation.

Q. Please discuss Mr. Rush's position that without Limerick 1 and the accelerated retirement of 458 MW of CT capacity, PECO will have too much peaking capacity available as compared to an optimal generating resource mix.

A. It is true that, if PECO were not part of the PJM Pool and the PECO system were to be designed from scratch, then, based on optimal generating mix theory, PECO's mix would probably be different from what is presently the case. This seems to be little justification for deciding to replace CT capacity which will cost PECO approximately $14.00 per KW per year with nuclear capacity which will cost several orders of magnitude more unless the total cost comparison favors such actions.

The optimal PECO resource mix, in the final analysis, is that resource mix which minimizes the total cost of supplying reliable service to its system. The optimal mix determination should take into account PECO's existing mix of available generation and the supplies of interchange energy available from and through PJM. If PECO were not in PJM, but rather operated as an isolated utility, its ideal mix requirements would be different from that needed as a result of such membership.

PECO's generation mix should not be reviewed in isolation as Mr. Rush does because that is not how PECO's generation is operated. Rather, PECO's generation is operated along with the generation of the other PJM members as if all the PJM members were one big company. PECO's generation is not operated in isolation against PECO's loads. The operation of PECO's generation and the amount of capacity needed by PJM to produce the lowest total system costs are both directly affected by the generating capacity, and the load shapes, of PJM members other than PECO, too.

PECO's membership in the PJM Pool changes the need for certain types of capacity needed to achieve the optimal resource mix because PJM frequently will have economically priced interchange power available to help offset the effects of PJM members having less than what would be an optimal amount of base load capacity if there were no pool.

PECO's central location in the PJM Pool area allows PECO to have strong access to generation available within the Pool. This access reduces the importance of achieving what would be the ideal mix of resources for reliability purposes for a non-pool utility.

Q. Are there any other indications that PECO does not presently need Limerick 1 for reliability purposes?

A. Yes. PECO's proposed early retirement of 458 MW of CT capacity and its replacement with an equivalent amount of Limerick 1 moves PECO's system from being more reliable towards being less reliable. If all of the PJM companies were to replace 458 MW of CT capacity spread-out over 18 generating units with a similar amount of capacity on one generating unit, the result would be an increase in the PJM reserve margin required to meet PJM's 1-day-in-10-years Loss-Of-Load Probability target for system reliability.

The 458 MW of CT capacity which PECO proposes to prematurely retire is spread out over a large number of units, 18 in all. PECO proposes replacing this capacity with nuclear-fired capacity which is concentrated on a single generator shaft. In the case of the CT capacity, it would take 18 simultaneous forced outages to deprive PECO ratepayers of the 458 MW of generation from these units. In the case of Limerick, it would take one forced outage to deprive the system of more than twice this amount of capacity.

This can be demonstrated simply. Let's suppose that a utility can serve a 100 MW block of load either with one 100 MW unit with a forced outage probability of 20 percent <u>or</u> with five 20 MW units each with a forced outage probability of 40 percent. Even though the smaller 20 MW units have twice the probability of suffering a forced outage on a per-unit basis, the chance that the full 100 MW will be forced out is only about 1 percent with the smaller units while it is 20 percent with the single big unit.

It is a basic rule of system reliability that, all other things being equal, concentrating your generating capacity on a smaller number of shafts requires a higher reserve margin to maintain a given level of reliability than does spreading your generating capacity out over a larger number of generator shafts. PECO apparently does not need additional system reliability, nor does it even need to maintain the present level of reliability inherent in its own system. PECO tells us this by prematurely retiring 18 combustion turbines and replacing this generation and more with one nuclear-fired base load generating unit. If system reliability were at all an issue in the need for Limerick, such actions on the part of PECO would be completely illogical. Such is not the case. If the reliability of PECO's system were hanging in the balance, PECO would not be retiring 458 MW of CT capacity before the end of its service life.

Q. What other advantages do the CT's offer?

A. The CT's, as presently situated, are fueled with oil. Because of the recent decline in oil prices, the variable operating cost of these CT's to meet peak loads could be more attractive than PECO may have anticipated just a few years ago.

Also, these combustion turbines have the ability to use natural gas as a generating fuel. The availability of natural gas for use as a utility fuel is presently at high levels while the prices at which such natural gas is available are at relatively low levels.

Q. Why consider the availability of this CT generating capacity in determining how much of Limerick 1 represents excess capacity.

A. The only reason that the 458 MW of CT generating capacity is being retired at this time is that the availability of capacity from Limerick 1 makes these CT's excess to PECO's needs 10 years ahead of schedule. If PECO does not bring Limerick 1 on-line, these CT's will not be retired prior to the 1986 summer peak.

Therefore, because the only reason for retiring these CT's is the presence of Limerick 1, it is not proper to