disregard the 458 MW of capacity from these CT's when studying the portion of Limerick 1 which represents excess capacity.

It is, after all, the capacity of Limerick 1 which led PECO to decide to prematurely retire this generating capacity. Therefore, it is only proper to include this 458 MW of generating capacity as being available to PECO (which it is, on a discretionary basis) when determining how much of Limerick 1 is needed by PECO.

Q. For the period ending in 1996, how do the projected costs of Limerick 1 compare with the projected costs of keeping the 458 MW of CT capacity on-line?

A. PECO has provided, in IR-OCA-2-25, the net cost of Limerick 1 by year and, in IR-OCA-15-5, the net cost of retaining the 458 MW of CT capacity.

For the years 1986 through 1996, PECO has projected that Limerick 1 will have a net cost, as developed on Attachment IR-OCA-2-25b, Item 1, page 2, of $169.90 per KW per year. I would note that I am <u>not</u> agreeing with all of PECO's assumptions. I am only using these assumptions for purposes of this analysis. If OCA witness Komanoff's assumptions were used, it would show an even greater difference in cost between the CT capacity and Limerick 1.

For the same period, the CT capacity would have a net <u>negative</u> cost, or a net benefit, of $132.71 per KW per year. This assumes that the CT capacity allows PECO to avoid the same capacity charges, on a per-KW basis, as Limerick 1.

If PECO had been able to sell, at cost, 458 MW of Limerick 1 through 1996 and replaced this capacity with the CT capacity, the total benefit, as shown in Schedule 2, would be more than $1.5 billion in total net cost over this 11 year period.

Q. What capacity charges does PECO claim to avoid as a result of Limerick 1?

A. PECO takes the position that, without Limerick 1, it would have had to pay capacity deficiency charges to PJM. PECO assumes, because of this reliance by PECO on the PJM Pool for capacity, that PJM would double the capacity deficiency charge. This doubling of the charge makes Limerick 1 look more attractive as a long term resource than it would otherwise be.

Q. Is it reasonable to assume that PECO would pay PJM a deficiency charge which is twice as high as it would have been in the absence of Limerick 1?

A. No. It is illogical.

Q. Why?

A. The present level of the PJM capacity deficiency charge is based on the price of CT capacity. If PJM were to double the level of the charge as suggested by PECO, then PECO could add CT capacity at costs equivalent to one-half the PJM capacity deficiency charge. It is not logical to think PECO would pay twice as much to PJM for capacity it could add at one-half the cost on its own.

Of course, PECO wouldn't even have to add CT capacity for a while. PECO could simply delay its premature retirement of 458 MW of CT capacity at a cost which would be less than 15 percent of what PECO says the PJM deficiency charge could be. The 458 MW of CT capacity would cost about $14.00 per KW per year through 1996 whereas the present PJM deficiency charge doubled is more than $100.00 per KW per year.

Q. Please summarize your testimony.

A. My testimony concludes that at least 450 MW of Limerick 1 is excess to PECO's reliability needs through 1990 and that all of Limerick 1 exceeds PECO's reliability needs until 1988.

Q. Does this complete your direct testimony?

A. Yes, at this time.

PHILADELPHIA ELECTRIC COMPANY

LOADS AND RESOURCES

ADJUSTED TO REMOVE EARLY RETIREMENTS OF

SOUTHWARK 1 & 2 and 458 MW OF COMBUSTION TURBINES

	YEAR	FORECAST PROBABLE PEAK DEMAND (MW)	ADJUSTED TO REMOVE EARLY RETIRMENTS: CAPACITY START (MW)	CAPACITY CHANGES (MW)	CAPACITY AVAILABLE (MW)	RESERVE MARGIN (%)	REQUIRED PECO PJM RESERVES (%)	EXCESS CAPACITY (MW)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	1985	6140	7294	305	7599	23.8	22	108
2	1986	6160	7599	1053	8652	40.5	22.5	1106
3	1987	6180	8652	0	8652	40.0	21.9	1119
4	1988	6200	8652	-336	8316	34.1	22	752
5	1989	6220	8316	-12	8304	33.5	23.8	~~597~~ 604
6	1990	6240	8304	0	8304	33.1	24.2	554
7	1991	6260	8304	-454	7850	25.4	25.8	-25
8	1992	6320	7850	0	7850	24.2	23.8	26
9	1993	6380	7850	0	7850	23.0	24.6	-99

OTE: The available capacity does not include Limerick 2 and assumes that all future retirements of PECO capacity will be carried out as scheduled. The retirements shown include 336 MW from Southwark 1 and 2 after the 1987 peak, 12 MW from Schuylkill 3 after the 1988 peak, and 454 MW, made up of 253 MW from Delaware 7 and 8 and 201 MW from Cromby 2, after the 1990 peak.

PHILADELPHIA ELECTRIC COMPANY
COMPARISON OF 458 MW OF COMBUSTION TURBINES ("CT")
WITH 458 MW OF LIMERICK

SUMMARY TABLE
($1,000,000)

	YEAR	NET BENEFIT 458 MW OF LIMERICK 1	NET BENEFIT 458 MW OF CT	ADVANTAGE OF CT'S OVER LIMERICK 1
	(1)	(2)	(3)	(4)
1	1986	$(271.82)	$31.98	$303.79
2	1987	(241.39)	32.54	273.93
3	1988	(219.19)	38.21	257.40
4	1989	(145.45)	56.53	201.98
5	1990	(149.56)	59.28	208.84
6	1991	(122.38)	64.25	186.64
7	1992	(43.09)	68.47	111.56
8	1993	(55.68)	72.14	127.82
9	1994	52.81	76.90	24.09
10	1995	187.28	80.96	(106.32)
11	1996	152.52	87.35	(65.17)
TOTAL		$(855.94)	$668.60	$1,524.55

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Set II

Q. 8. Refer to p. 15. What is your basis for concluding that placing more than one-half of Limerick common plant into the rate base would "provide PECO with unnecessary financial rewards at consumers' expense"?

A. 8. To the extent that the Limerick generating unit with common plant produces net economic losses to consumers over the life of the plant and to the extent that that generating plant is not needed now to provide reliable service it is clear that Limerick Unit 1 and common plant is not used and useful capacity. Inasmuch as this capacity is not used and useful application of the PP&L precident would allow no equity return or profit on this investment. Thus, any return on Limerick Unit 1 and common plant might well be considered an unnecessary financial reward which is being made at customers expense. Clearly, by increasing the amount of common plant included in rate base the amount of plant which is not used and useful and which is earning an equity return is thereby increased and therefore increases the unnecessary financial reward.

Q. 9. Refer to p. 22 and Falkenberg Exhibit 5. Please defin the phrase "installed capacity."

A. 9. The definition of the phrase "installed capacity" utilized on page 22 of Falkenberg Exhibit 5 includes capacity which was installed and capable of operation prior to the retirements of the combustion turbines and oil fired generating capacity taken out of service by PECO in 1985 and 1986. As noted in detail in the testimony this capacity did not need to be removed from service and was in fact only removed because the addition of the Limerick generating plant resulted in PECO having excess levels of reserves. By removing this capacity from service PECO has reduced its reserve margins computed on the basis of active capacity. However, the amount of capacity which the Company could have made available to serve load, had it so desired, includes the capacity which was retired by the Company in order to reduce the excess level of capacity reserves accompanying the Limerick Unit 1 generating unit into service. Clearly the fact that PECO was able to take out of service over 900 MW of capacity when the Limerick 1 unit entered service indicates that little (if any) of the Limerick Unit capacity was needed to serve customer load.

Set II

Q. 12. Refer to p. 24, lines 16-18. What is the basis for you statement that "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."? What factors did you consider in reaching this conclusion?

A. 12. The answer to this question is obvious to anyone with an understanding of simple mathematics. Limerick Unit 1 is expected to operate 65% of the time. Thus, the unit is only available to serve load 65% of the time due to maintenance requirements and random forced outages. Clearly, the loss of 1000 MW of capacity is a situation which will adversely impact the Company's operating reliability at any particular point in time. However, PECO intends to remove much more capacity from several smaller units. The probability of loosing 1000 MW from ten small units, all at the same time, is equal to the forced outage rates of those ten units to the tenth power. For virtually any reasonable forced outage rate this probability is much smaller than the 65% presumed for Limerick. For example, if it is assumed that the smaller units also have a 35% forced outage rate the probability of loosing all ten of these smaller units simultaneously is less than 1%. Thus, it would be virtually impossible for the many smaller units to be as unreliable as one large unit.

Q. 21. On page 30, at line 14, Mr. Falkenberg states "whether PECO should profit from its mistakes." Please explain what Mr. Falkenberg means by PECO profiting from its mistakes.

A. 21. The question is raised as to whether PECO should profit from its mistakes. The economic analysis performed by Mr. Falkenberg shows that Limerick is clearly a mistake for PECO. The plant is not needed capacity and will result in much higher rates for customers over time than alternatives would have. On this basis "profiting from its mistakes" would mean earning a return on an asset that is not used and useful. It would not mean "having learned from their mistakes."

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Q. 24. On page 34, at lines 7 and 8, Mr. Falkenberg states, "the resulting reasonable costs are then phased-in using the same six-year schedule as proposed by PECO".

a. Please explain precisely what is meant by this statement.

b. Is this treatment proposed in place of or in addition to, the exclusion of interest cost on deferred revenues?

A. 24. Part a - By stating that "the resulting reasonable costs are then phased-in using the same six-year schedule as proposed by PECO" Mr. Falkenberg implies that should the Commission adopt other disallowances or other adjustments to PECO's rate increase, then it would be appropriate for these to be included in the test year revenue requirement. Once this test year requirement has been determined, Mr. Falkenberg proposes that these dollars would be phased-in using the same six year schedule as proposed by PECO. This would mean that one third of the test year revenue requirement would be recovered the first year, two thirds the second, the full amount in year three, and four thirds of the test year amount in years four, five and six. It would also be necessary to make the corresponding overcollection adjustment proposed by Mr. Falkenberg. Obvioulsly, this proposal of Mr. Falkenberg's must be tempered by a recognition of the level of the total revenue requirement allowed. For example, if the Commission were to adopt the PP&L precident in this case, it would not appear necessary to phase-in the $61 million revenue increase shown in Falkenberg Exhibit 4 over the six year period.

Part b - The treatment proposed is in addition to the exclusion of interest costs on deferred revenues.

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Q. 13. Refer to p. 26, lines 7-8. What is the basis for you conclusion that economic retirement of generating plants "just slightly reduces the economic burden of excess capacity."? Please provide all studies upon which you relied in making this statement.

A. 13. The observation that the economic retirement of generating plants "just slightly reduces the economic burden of excess capacity" has been vividly proven in this case. In this case the Company is requesting a rate increase of over $670 million to account for the increase cost of service associated with the Limerick Unit 1 generating unit. The Company is also crediting its rate increase with the savings attributable to the economic retirement and life extention of older units. However, the magnitude of this rate increase is such that it clearly overwhelmes any minute benefits which may have occured as a result of these early retirements of the unneeded generating plants.

This experience has been quite common in the utility industry in the last few years. In 1984 for example, Florida Power Company requested a rate increase on the order of $100 million to include a new base load coal fired plant into rate base. However, at the same time the Company was shutting down several hundred megwatts of older units. The cold shutdown of these older units did reduce the size of Florida Power Corporation's rate increase by a small amount but not nearly enough to offset the $100 million total request the Company desired.

In late 1985, West Penn Power Company sought a substantial rate increase (on the order of $80 million) to include into its cost of service the Bath County pump storage generating plant. Once again there was a economic retirement or extended cold shutdown of older oil-fired plants. Once again the savings attributable to these early retirements or economic cold shutdown was much less than the overall rate increase requested.

In mid 1985 Duke Power Company requested a $340 million rate increase to include into its cost of service Catawba 1 nuclear plant. At the same time the Company announced an extended cold shutdown program of 997 MW of old oil fired plants. Once again the savings attributable to the cold shutdown of the older plants was not anywhere near the rate increase requested to reflect the cost of the new nuclear powered generating station. Incidentially, the cost of the Catawba 1 nuclear generating plant was substantially less than the cost of the Limerick 1 generating plant.

Just recently in November of 1986 Northeast Utilities filed for a large rate increase (ultimately over $400 million) to reflect the cost of service of the Millstone 3 nuclear generating plant. In this case the Company is proposing to put into early retirement some 360 MW of older oil fired generating plants. Once again the savings attributable to the older oil fired generating plants - on the order of $12 million over the next ten years - is substantially less than even the first year rate increase sought under the Northeast utilities phase-in plan.

It is clear from all of the examples that the phenomena of early retirement of economic cold shutdown of now unneeded generating plants is wide spread in the utility industry. At the same time it is clear that in none of the examples cited was the reduction in cost created by the savings attributable to the economic retirement program anywhere near the increase in rates attributable to the new generating plants which were entered into service.

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Q. 14. Please explain the use on page 22, at line 7, of the phrase "at most."

A. 14. On page 22, line 7 of Mr. Falkenberg's testimony it is stated that Falkenberg Exhibit 3 shows that if the PP&L order were applied to this 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 increase. The meaning of the term at most in this phrase means "no more than." In the case of Pennsylvania Power and Light Company, the Company identified several millions of dollars worth of rate claims that the Company could have made but which it did not make in order to reduce its rate request. If any or all of these were applied in this case, it is possible that PECO might in fact have a lower rate increase granted than PP&L. The second implication of the term "at most" is that the assumption that Falkenberg Exhibit 4 was that all other PECO claims in this case would be acted upon positively by the Commission. Thus, it would be assumed that PECO's requested rate of return as well as all other expense adjustments would be accepted. In the event that any of these other cliams or adjustments are not accepted by the Commission then the fact PECO would receive less than the $61 million implied in Falkenberg Exhibit 4.

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Q. 19. Please explain in full the relationship, in Mr. Falkenberg's opinion, between the used and useful standard for rate treatment of a utility investment and life cycle studies. Please provide any studies or other documentation which supports this opinion.

A. 19. In Mr. Falkenberg's view the use and useful standard is the most appropriate standard for determining the rate treament of a utility investment. The life cycle cost study is an important tool which would allow for a more realistic determination of whether an asset is used or useful over its life.

For example take the case of an investment in a large plant, such as a nuclear plant, which is not needed for reliability purposes in a given test year. Suppose also the plant produces higher rates, in that year. Such an investment would fail to be used and useful to customers. However, provided the same investment produced lifetime economic savings to customers in a present worth sense, then that plant could be said to pass a cost benefit tests. In this case the investment is used and useful when considered over the entire life of the asset. In the case when a unit fails to produce a positive cost benefit over its life, and it fails to produce a positive cost benefit during the test year, then the asset is clearly not used and useful during the test year. It would also not be used or useful over its life. In this case a departure from the ordinary full rate base recognition of the investment would normally be considered an appropriate course of action for the regulator to examine. With regards to documentation relied upon to support this opinion please see attached summary of Utility Commissions and Appeals Court Decision involving excess capacity claims. This document establishes that the used and useful principal has been utilized in numerous excess capacity cases, and the cost benefit analysis has been used as a basis for the determination of an excess capacity claim. In fact, as the document shows it has often been the case that excess capacity claims have been rejected on the basis of a positive showing of a cost benefit of particular generating plant. This clearly establishes in Mr. Falkenberg's opinion the fact that other regulatory commissions have in fact looked at economic considerations as a basis for determining used and useful nature of a generating plant.

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Q. 29. What standard, in Mr. Falkenberg's opinion, should apply in determining when one should "begin to look beyond prudence" as stated, on page 38 of his testimony?

A. 29. There is no single specifics standard which in Mr. Falkenberg's opinion should apply in determining when one should "begin to look beyond prudence" as stated, on page 38 of his testimony. However, Mr. Falkenberg would note that a number of factors might be considered:

1. In the case of excessive high reserve margins, it would appear that the Commission should look beyond the simple application of the prudence standard in determining if full revenue recovery should be allowed on excess capacity. In the case of Pennsylvania Power & Light Company in the SSES-2 rate case the Commission found no imprudence on the part of PP&L. Yet, at the same time, the Commission disallowed a return on the Susquehanna nuclear plant. This was an example of the Commission looking beyond prudence, or at least not relying soley on the prudence standard.

2. Another case where the Commission may wish to look beyond prudence is in the determination of the rate treatment for a plant that is extremely costly when compared to other sources of power. For example, the Limerick Unit 1 cost $3.8 billion an amount much higher per KW than Pennsylvania Power & Light's investment in the Susquehanna nuclear plant. Clearly, in the case of a competitive market it would be impossible for a firm to stay in business if its cost of production were substantially higher than those of his competitors. For this reason, the Commission may wish to adopt the position that regulation is to serve as a proxy for competition. Therefore, it might pursue a rate treatment for the Limerick nuclear plant that recognizes the adverse consequences of the high cost of this plant.

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Q. 2. On page 12 of the tstimony, at line 22, Mr. Falkenberg refers to "PECO's stated desire not to earn interst on the deferred amount." Please indicate where PECO has so stated this desire. Please also provide any other support that Mr. Falkenberg has for this statement.

A. 2. Please see PECO statement No. 17, page 5 lines 8 through 12. While this passage does not specifically state that PECO desires to earn no interest on the deferred amount, it does indicate that PECO has implied that it is not earning any interest on the deferred amount.

Q. 26. On page 35, at lines 20 through 23, Mr. Falkenberg states, "Based on this prudence principle, reduction in consumption, due to economic self-interest of customers, conservation, or innovation, is destined to fail in substantially reducing consumers' payments to facilities."

a. Does Mr. Falkenberg mean to imply that if a customer reduces his consumption of electricity by 30%, the customer will not see a similar reduction in his electric bill?

b. Is Mr. Falkenberg's comment at the cited passage in the testimony related only to the capital recovery portion of revenue requirements rather than the total revenue requirements.

A. 26. On page 35 of his testimony Mr. Falkenberg points out that if prudence were the only concern of the regulator then, in fact, the fixed portion of revenue requirements (including shareholders profits, fixed operating and maintenance expenses and administrative and general expenses) of the utility company would not be affected by changes in sales. This simply means the utility would over a long period of years recover all of their required fixed costs of providing service. Only variable costs such as fuel costs or variable O&M expenses would change as a result of changes in consumption. The result of this "prudence only" approach would be that if a individual customer reduced his consumption of electricity by 30%, he might see in the short term a reduction in his electric bill. However, over the period of time required for the utility to seek an increase in electric rates (to cover the decline in profitability accompanying this customer's reduction in consumption) one of two events would occur. Either other consumers would have likewise reduced their consumption in which case, overall revenue requirements for each customer would not change substantially, or the allocation of revenue requirements between customers would have changed. In either case, the consumers in total would contribute the same number of dollars to cover the fixed costs (including profits) of the utility.

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Q. 35. At the bottom of page 43 and the top of page 44, Mr. Falkenberg describes the analytic procedures he employed for producing his trend forecasts.

a. On page 43, at line 24, he states that until 1978, he used the model "exhibiting the best statistical results." Please explain in detail what is meant by best statistical results.

b. After 1978, he states that the linear trend model was used. Please explain why different selection procedures were used for the period until 1978 and the period after 1978.

A. 35. Part a - Mr. Falkenberg developed an analytic procedure for producing retrospective trend line forecasts. These forecasts were then compared to the actual forecast developed by Philadelphia Electric Company at various points in time. Mr. Falkenberg's testimony concluded that the simple trend base forecasts would have produced more reasonable forecasts than the ones employed by Philadelphia Electric Company from the period 1972 to 1977. This was a critical time period in the decision making regarding the Limerick Unit. Mr. Falkenberg's trend models were developed by examining exponential and linear trend models from the period 1972 to 1977. By the best statistical results, Mr. Falkenberg means that a variety of statistics for the linear and exponential trend models considered. The key variable examined was generally the R-squared statistic. However, Mr. Falkenberg also examined the T-statistics, the Durbin-Watson statistic, and the standard error of the estimate in certain cases. In instances where the R-squared variable was too close between the two models to make a definitive recommendation as to whether an exponential or linear model should be applied, Mr. Falkenberg pursued further analysis. Even though as the original desire was to project peak demand, it was felt that it would also be necessary to examine the trends in energy sales growth. Thus, in a case when the models for the peak demand forecast were approximately equal, Mr. Falkenberg examined the implications of the energy sales growth models. In a number of these cases Mr. Falkenberg found that the linear sales growth models were a much better representation of the historic data. Thus, Mr. Falkenberg selected on this basis the linear peak demand growth models. The reason for this is that it would not be logical for peak demand to follow an exponential growth pattern while sales grew in the linear fashion. Finally, Mr. Falkenberg also examined in certain instances the trend of the annual increases in peak demand growth to determine if in fact there was any significant evidence of an increase in the annual amount of increase in peak demand.

Part b - Mr. Falkenberg notes that use of a linear trend model is designed to determine if the types of load forecast techniques applied by other analysts within the utility industry in the early 70's would have produced substantially different forecasts than those developed by Philadelphia Electric Company. It is to be noted that judgment of the forecaster has always been an important variable in determining the appropriateness of any particular forecast. In the period of 1978 and beyond it was Mr. Falkenberg's judgment that a linear growth model would

Response to Data Request of the
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be a more appropriate model for predicting future electric demand. These models also closely track the results obtained by Philadelphia Electric Company and its load forecasting models. In effect, the analysis shows that a reasonable forecaster tempering the analysis of time series data by judgment could have projected approximately the same load growth that Philadelphia Electric Company has projected since 1978.

Q. 39. Relative to your regression analysis in Exhibit 12, at what R squared value or other statistical measurement would you question the ability of the regression equation to yield a reliable forecast?

A. 39. Mr. Falkenberg points out that when the regression equation itself is not statistically significant, i.e., the R-squared variable is not statistically significant then it would be inappropriate to use the regression equation (or at least unnecessary to use the regression equation) as the basis for forecasting. In the event that the regression equation failed to determine any significant trend of growth over time, then the appropriate forecast for the data in question would simply be the simple average value of the data set over the period of history examined.

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Attach. 2 Set 16 - 19(+1)

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

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

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.

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.

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PECO EXHIBIT NO. 34

1984 SURVEY OF THE COST OF CAPITAL USED FOR ECONOMIC EVALUATIONS BY INVESTOR-OWNED ELECTRIC UTILITIES

CONFIDENTIAL*

Please return one completed copy by November 2, 1984

Theodore I. Gradin
Director of Finance
EDISON ELECTRIC INSTITUTE
1111 19th Street, N. W.
Washington, D. C. 20036-3691

A. GENERAL INFORMATION ABOUT PARTICIPANT IN SURVEY

1. Name of Company ______________________

2. Name of Correspondent ______________________

3. Name and telephone number of individual for follow-up of details of information ______________________

____

4. Line of Business (check space)

   a. Only electricity ________

   b. Combination company (e.g., electricity and gas) ________

*No individual company data will be shown or divulged. Only aggregated data will be presented.

B. CAPITAL STRUCTURE

1. INCREMENTAL cost of capital currently used for INTERNAL ECONOMIC EVALUATIONS of plans for new electric facilities.

	I Capital Structure %	II Cost %	III (= I x II) Weighted Cost %
Debt			
Pfd. & Pfd. Conv.			
Common Equity			
Other			

2. If your company uses NON-INCREMENTAL capital cost for INTERNAL ECONOMIC EVALUATIONS, please provide those costs below and indicate whether they are:

_________ Embedded

_________ Net of Tax

_________ Other (Please specify) ____________________

	I Capital Structure %	II Cost %	III (= I x II) Weighted Cost %
Debt			
Pfd. & Pfd. Conv.			
Common Equity			
Other			

3. Please indicate the method(s) of determining the current cost of common equity:

Primary Method: ______________________________

Alternative Method(s): ______________________________

____

____

C. REGULATORY DATA

1. Please provide details of the most recently APPROVED regulatory rate of return. If company operates in more than one jurisdiction, please provide data from the largest jurisdiction (in terms of revenue).

	I Capital Structure %	II Cost %	III (= I x II) Weighted Cost %
Debt			
Pfd. & Pfd. Conv.			
Common Equity			
Other			
Total			

2. Is construction work in progress (CWIP) included in rate base:

_________ Yes _________ % CWIP included in rate base.

_________ No

If company operates in more than one jurisdiction, please provide percentage of CWIP allowed by each:

Jurisdiction	Percent of CWIP in Rate Base

3. Does the return on CWIP represent a real revenue flow (Yes/No); or

Does the regulatory commission require that AFUDC in the test year be netted against the authorized return for ratemaking purposes (Yes/No)?

D. FINANCIAL/ACCOUNTING

1. 1983 accounting rate of return for 12 months ending December 31, 1983 (Operating income ÷ net plant without CWIP)

   ________ %

2. Bond rating:

Moody's	________
Standard & Poor's	________
Other (specify)	________

3. Statistical data (12 months ending December 31, 1983)*

Utility plant, original cost (without CWIP)	($ millions)	________
Utility plant, less depreciation (without CWIP)	($ millions)	________
Total operating revenues	($ millions)	________
Total electric operating revenues	($ millions)	________

*Please indicate whether or not these data correspond with data submitted in the 1983 Uniform Statistical Report:

____ Yes

____ No

PECO Ex 35
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PECO EXHIBIT NO. 35

Request No. 7

Refer to p. 6. Define what Mr. Lanzalotta means by "still-useful generating facilities." On what basis would he determine that a generating facility is "still useful"?

Response No. 7

By "still-useful generating facilities" Mr. Lanzalotta refers to generating facilities which are capable of operating in their originally intended fashion. Mr. Lanzalotta would conclude that a generating facility is "still-useful" on the basis of its age, its operability and its operating economics and its susceptibility to repair, repowering, and/or rehabilitation.

Response prepared by: Peter J. Lanzalotta
Whitfield Russell Associates
Suite 350
1301 Pennsylvania Avenue, N.W.
Washington, D.C. 20004

Request No. 8

On page 6 of Mr. Lanzalotta's testimony at lines 6-11, he states in part "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." Please provide any and all support for this statement, especially in regard to the intent of PECO.

Response No. 8

The retirement of 458 MW of CT capacity by PECO reduces the capacity available to PECO by 458 MW. A reduction in the capacity available to PECO by 458 MW means that, if there are X MW of excess capacity with Limerick 1 and without the CT's, then there would be X + 458 MW of excess capacity with Limerick 1 and with the CT's. In this respect, the advancement of the scheduled retirement dates of a number of PECO's generating units reduces the amount of excess capacity apparent on the face of a load-resource comparison.

Mr. Lanzalotta does not assume that the reduction of apparent excess capacity was the sole purpose of PECO in its advancement of these retirement dates. But the reduction of apparent excess capacity is the unavoidable effect of the early retirement.

Response prepared by: Peter J. Lanzalotta
Whitfield Russell Associates
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1301 Pennsylvania Avenue, N.W.
Washington, D.C. 20004

Request No. 11

On page 11 of Mr. Lanzalotta's testimony at line 20, the phrase "'below standard weather factor'" appears.

a) From what source does the quotation come?

b) Please provide a description of Mr. Lanzalotta's understanding of the meaning of this phrase.

c) Does Mr. Lanzalotta understand a standard weather factor day to be normal weather for any day of the summer or normal weather for the day on which the annual peak is reached?

Response No. 11

a) PECO's Statement No. 14, page 11.

b) PECO has developed a quantitative representation for what it considers to be standard weather. This numerical representation is known as the "standard weather factor". Mr. Lanzalotta understands that "below standard weather factor" refers to these quantitative representations of PECO's weather factor which fall below those representations which PECO has determined represent standard weather.

c) Mr. Lanzalotta understands that it is PECO's representation that the "standard weather factor" represents a standardization process by which PECO "corrects" historical peak load to reflect what PECO feels is the effect of weather on peak demand.

Response prepared by: Peter J. Lanzalotta
Whitfield Russell Associates
Suite 350
1301 Pennsylvania Avenue, N.W.
Washington, D.C. 20004

Request No. 13a

a) Has Mr. Lanzalotta made a determination as to whether the addition of Limerick 1 is the least cost alternative to PECO's system's needs? If so, what has he concluded and how did he arrive at his conclusions?

Response No. 13a

a) No.

Response prepared by: Peter J. Lanzalotta
Whitfield Russell Associates
Suite 350
1301 Pennsylvania Avenue, N.W.
Washington, D.C. 20004

Request No. 14

On page 16 at lines 21-24, there is a discussion of 96 hours out of 744 hours when PECO loads were as high as 4732 MW or higher. If the weather had been any warmer, would the 4732 MW level likely have been reached in more than 96 hours. Please explain Mr. Lanzalotta's answer.

Response No. 14

If PECO's load had been higher than historical levels in response to this warmer weather, then the 4732 MW level would likely be reached in more than 96 hours. If PECO's loads are not higher in response to this warmer weather then the opposite is true.

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Washington, D.C. 20004

Request No. 15

On page 17 at lines 3-6, there is a discussion of 187 hours or 25%. If the weather had been warmer during August 1985, would the number of hours and the percentage likely have been larger? Please explain Mr. Lanzalotta's answer.

Response No. 15

Please see Mr. Lanzalotta's response to the preceding interrogatory item 14.

Response prepared by: Peter J. Lanzalotta
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SCM 2-14-86 #69 R-880652

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Q.IR-GSA-2-10. Please provide a list of all plants, including Southwark 1 and 2, whose retirement was precipitated by the completion of Limerick 1.

A.IR-GSA-2-10. We do not agree that the retirements of Southwark 1 and 2 units have been precipitated by the addition of Limerick. 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. The addition of Limerick 1 is allowing PECo to retire 458 MW of CT capacity before the end of their nominal lives. The following units are being retired near the service date of Limerick 1:

Southwark 1
Southwark 2
Southwark diesel
Plymouth Meeting 9
Plymouth Meeting 15
Richmond 21
Richmond 22
Richmond 31
Richmond 32
Richmond 41
Richmond 42
Richmond 43
Richmond 44
Richmond 51
Richmond 52
Richmond 61
Richmond 62
Richmond 71
Richmond 72
Richmond 73
Richmond 74

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Responsible Witness: C.H. Rush, Chief Engineer - Research and Planning Division