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PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

DIRECT TESTIMONY OF DR. LEWIS J. PERL

LIMERICK 1 AND COMMON PLANT INDEPENDENT ASSESSMENT OF LIMERICK COST AND SCHEDULE AND PRUDENCY OF PAST DECISIONS

September 27, 1985

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Q. Please state your name and business address.

A. My name is Lewis J. Perl. My business address is 123 Main Street, White Plains, New York.

Q. By whom are you employed and in what capacity?

A. I am Senior Vice President of National Economic Research Associates, Inc., an economic consulting firm specializing in the economics of energy, the environment, antitrust and labor.

Q. Please describe briefly your educational and employment background prior to your association with National Economic Research Associates, Inc.

A. I received my B.S. degree in industrial and labor relations from Cornell University in 1963. I received my M.A. degree in 1968 and my Ph.D. degree in 1970, both in economics from the University of California at Berkeley. From 1968 to 1972, I taught economics at the New York State School of Industrial and Labor Relations at Cornell University.

Q. Please describe the nature of National Economic Research Associates, Inc.

A. National Economic Research Associates, Inc. (NERA) is an economic consulting firm established in 1961. We offer consulting services in the economics of energy, regulatory policy, labor markets and antitrust practices.

Q. What is your area of specialization at NERA?

Since joining NERA in 1972, I have been responsible for a variety of studies relating to the economics of energy and the environment. These include numerous analyses of the comparative

costs of coal and nuclear generation for presentation in licensing and other regulatory proceedings. In particular, I have presented testimony on comparative costs at Nuclear Regulatory Commission and Federal Energy Regulatory Commission hearings and in hearings held by state commissions in Arkansas, California, Idaho, Indiana, Louisiana, Maine, Mississippi, New York, Ohio, Oregon, Pennsylvania, Virginia, Washington and Wisconsin.

In addition, I have done analyses of the costs of air and water pollution control for the electric utility industry, as well as various comparisons of the costs and benefits of specific environmental programs. I have directed a number of econometric studies of the elasticity of demand for electricity, the elasticity of demand for telephone service and the price of uranium. I have been involved in the development of a model for projecting coal prices and a variety of studies evaluating the economics of alternative energy sources. In the course of these analyses, I have become very familiar with utility accounting practices and with the implications of those practices for the cost of electricity to consumers. A copy of my vita listing testimonies, publications and speeches on these matters is attached.

Q. Have any of your writings been published?

A. Yes. I am the author of numerous economic papers which have appeared in such professional journals as The American Economic Review, the Quarterly Journal of Economics and the Journal of Human Resources, and such publications as Nuclear News, Nation's Business, The Wall Street Journal, The New York Times and The Los

Angeles Times. In addition, I have given speeches on energy and environmental-related topics before the Atomic Industrial Forum and the World Energy Conference.

Q. Of what professional and honorary societies and industry groups are you a member?

A. I am a member of the American Economic Association and the International Association of Energy Economists.

Q. Dr. Perl, what is the purpose of your testimony?

A. The purpose of my testimony is twofold. First, I have evaluated the reasonableness of Limerick 1's construction costs and schedule by comparison with other nuclear units and my testimony presents the results of those reviews. Second, I have evaluated the economic soundness of PECO's decisions regarding the Limerick nuclear project in the 1975 to 1980 period. Specifically, I have evaluated the economic soundness of the decisions to continue construction on the project in each year from 1975 to 1980 and the decisions taken in 1976 and 1978 to impose financial constraints in construction expenditures for Limerick and thereby risk delays in the on-line date for the plant. This testimony also presents the results of each of these prudency analyses.

Q. Why have you limited your analysis to the 1975 to 1980 period?

A. For several reasons. First, it is my understanding that the decisions made prior to this period had been previously held to be prudent by the Pennsylvania Commission. Second, in testimony before this Commission in 1981 I evaluated the economics of

Limerick as of that date. Since that analysis clearly reflected my assessment of Limerick's economics given the facts available in 1981, there is no need to repeat it here. Third, on the basis of that analysis and others submitted at the same time, I understand that the Commission concluded that continuation of the project was the only prudent course of action open to the company. Since the Commission affirmed the prudence of completing Limerick as of 1981, the prudence of expenditures made after that date are presumably not an issue in this proceeding.

Q. Dr. Perl, can you briefly summarize your conclusions?

A. Yes. First, on the basis of a comparison with other nuclear units constructed in the same time frame Limerick 1's cost and schedule are clearly reasonable. In 1984 dollars, the cost for Limerick 1 is $2,868 per kilowatt. When standardized to Limerick's characteristics, the estimated cost of other units built in the same time frame is $2,751 per kilowatt. Thus, Limerick 1's costs are only 4 percent above the average of other units built in the same period.

Second, Limerick's schedule is also typical of other units built during this period. For Limerick 1 the elapsed time from construction permit to commercial operation is 11.68 years. The average for other units sampled (adjusted for Limerick's characteristics) is 11.69 years.

Third, the decisions to continue the Limerick project during the 1975 to 1980 period were economically sound. While the expected costs of Limerick rose markedly over this period, the

incremental cost of energy from Limerick was always substantially cheaper than any available alternative. Moreover, the conclusion that completion was economic during the 1975 to 1980 period is very robust. Thus, the project was economic throughout this period even if evaluated on a total cost basis. And, the soundness of the decision to complete the project is quite insensitive to alterations in assumptions about load growth and the cost of the Limerick project. Even if expected load growth in 1980 had been zero and the incremental cost forecast for the period had increased more than threefold, it still then would have been economic to complete the Limerick project.

Finally, given the information available in 1976 and in 1978, there did not appear to be any losses to consumers from a one to two year delay in scheduled completion in 1976 and 1978. And, if as seemed reasonable, the delays would ease the company's financial constraint, such delays would be expected to benefit consumers.

Q. Dr. Perl, please describe your analyses of Limerick's construction costs.

A. In order to evaluate Limerick 1's construction costs, I have compared it to the actual or estimated completed cost of all other nuclear units which were constructed in the U.S. and which received construction permits after 1971. The comparison group consisted of 34 plants and 59 units. I have focused on this group because a careful analysis of cost data indicates that the units licensed earlier were built under much less stringent regulatory conditions and the costs of these units are both lower and influenced by

different factors than those built after 1971.

Costs for Limerick 1 and other plants in this sample are compared in Schedule 1. Before making this comparison, however, the costs for other units were adjusted for any differences in plant characteristics between those units and Limerick. For example, construction wages for Limerick were different from those for other units in the sample so costs for each unit were adjusted to reflect what they would have been if they had been constructed at the wage rate for Limerick. Once these adjustments are made, the average costs for other units in the group average $2,751 per kilowatt which is only 4 percent above Limerick's cost of $2,868 per kW. In order to abstract from differences in the timing of constructions, these comparisons exclude the AFDC and have been expressed in constant 1984 dollars per kilowatt.

Q. You indicate that you have adjusted the costs for other units to reflect Limerick's characteristics. Please explain in more detail the nature of these adjustments.

A. In order to adjust for differences in unit characteristics, I first ran a regression relating costs to unit characteristics for all the units in the comparison group. The results of this regression are summarized in page 3 of Schedule 1. It indicates that

nuclear construction costs are positivcly related to construction wages;

subsequent units at a site are much cheaper than the first unit;

units built in the Northeast are more expensive than

those built in other regions;

units built on soil sites are more expensive than those built on rock sites;

single unit boiling water reactors are more expensive than other units;

units built by utilities simultaneously constructing several plants and operating as their own A/E or constructor (TVA, Duke and Commonwealth) are cheaper than other units.

With this regression I can adjust other units for any differences between their characteristics and those of Limerick. For example, the equation indicates that each 10 percent increase in construction wages result in a 3.7 percent increase in nuclear construction costs. When I compared Limerick with another unit which had been built at 10 percent lower wages, I adjusted its costs upward by 3.7 percent to reflect this wage differential. To take another example, the second unit of a two-unit plant appears to cost 34 percent less than the first unit. Thus, the cost per kilowatt for two-unit plants would be expected to be 17 percent less than Limerick 1 which is the first unit of a multiple unit project. When comparing Limerick's costs with those of two-unit plants, I adjusted for this differential.

Q. Do you believe this statistical analysis provides an appropriate basis for comparing costs for nuclear units?

A. Since each nuclear plant has some features which are unique, there may be no ideal way to make these comparisons. But, I believe that in making such comparisons one must at a minimum adjust for factors which are known to influence costs. Of course,

as other witnesses in this proceeding argue, there may be a number of regulatory constraints which have resulted in higher costs for Limerick than for other projects and my comparison takes no account of such factors.

Q. What is the basis for the data used in making this comparison?

A. In making this comparison I have relied primarily on data from a March 1985 TVA survey of nuclear construction costs. In some cases, where data were omitted from the TVA survey, I obtained information directly from the utility. For each case, the costs used are nominal construction expenditures exclusive of AFDC. These were converted to 1984 dollars using the Handy Whitman Index of Public Utility Construction Costs.

Q. Dr. Perl, what have you done to evaluate the effect of expenditure constraints on the construction schedule for Limerick?

A. I have compared construction time for the Limerick 1 nuclear unit with those for other units being built during the same time period. This comparison is summarized in Schedule 2. On the basis of this comparison, construction time for Limerick appears to be about average for units constructed during this period.

When standardized to reflect the characteristics of Limerick, the average first or single unit plant built during this period had a construction time of 11.69 years. Limerick's construction time is 11.68 years or about the same. This result indicates that the Limerick 1 nuclear unit took no longer to complete than other projects built during the same period.

This result is quite important in evaluating PECO's decision in 1976 and 1978 to slow construction expenditures on the project. Since Limerick's construction time is about average, it does not appear that these decisions actually had the effect of delaying its completion by comparison with other units built during the same period.

Q. How is it possible that a decision to slow construction expenditures on Limerick would not have the effect of delaying the unit or increasing its costs?

A. First, by slowing the pace of construction expenditures, PECO allowed engineering to keep pace with construction and this probably ultimately speeded rather than slowed construction. Some of the most troubled projects are those for which construction did proceed ahead of engineering which often resulted in expensive and time-consuming retrofits. Second, financial constraints on construction expenditures, similar to those experienced by PECO, appear to have been endemic in the nuclear industry and to have lengthened construction schedules for all plants. If this is the case, the problem is clearly no more significant for Limerick than for other units built during the same period.

Q. In making these schedule comparisons, you indicate that you have standardized construction time for other units to match the characteristics of Limerick. What do you mean by "standardized"?

A. The time taken to complete individual nuclear plants is influenced by a number of factors clearly outside of a utility's control. In particular, regulatory change has caused construction

times to lengthen substantially over time. Consequently, I have limited the comparison to other units receiving construction permits in 1972 or later. Second, subsequent units at a site obviously have longer schedules than first units. So, in evaluating the construction schedule for Limerick 1 I considered only other first units and single unit plants. Finally, as indicated in page 3 of Schedule 2, construction times are systematically longer in the Northeast than other regions of the country. This may reflect the effect of weather factors, or the more restrictive work rules prevailing in this area of the country. In either case, since virtually all plants in the Northeast exhibit relatively long construction time, it is presumably outside of utility control. Consequently, in making schedule comparisons between Limerick and other units I adjusted schedules for all non-Northeast plants upward to reflect the effect of the Northeast differential.

Q. Dr. Perl, what have you done to examine the prudency of past decisions to construct the Limerick project?

A. First, I attempted to determine whether Limerick was part of the least cost expansion plan for PJM. For this purpose I used a linear programming model to evaluate the least cost mix of capacity addition for PJM as of 1973, 1976, 1978 and 1980. Using this model, I was able to determine whether Limerick was part of the least cost plan and whether its inclusion in that plan was sensitive to alternative assumptions as to growth in demand and construction costs.

Second, I evaluated the economic benefits to consumers from completing Limerick as of each year from 1975 to 1980. To do this I compared the incremental cost of electricity from Limerick with the cost of two alternatives--a contemporaneous coal plant or continued use of oil and gas. I examined the benefits from the Limerick project as a whole and from Unit 1 viewed in isolation.

Q. What are the results of your analysis of the least cost expansion plan?

A. In each of the years analyzed--1973, 1976, 1978 and 1980--the Limerick plant is part of the least cost plan. Moreover, in each of these years, even at costs much higher than were anticipated it was still economic to finish the project. This result is described in Schedule 3. For example, in 1973 the anticipated total cost of the Limerick plant was $771 per kW and its incremental cost was $594 per kW. At those costs Limerick was part of the least cost plan and even at total capital costs of $2,440 per kW and incremental costs of $2,263 per kW, Limerick was still part of the least cost plan. This was also true in 1980. At that time the total cost of the plant was estimated at $1,515 per kW and the incremental cost was $596 per kW. But even at incremental costs of $1,903 (more than three times those expected) or total costs of $2,822 (nearly twice the expected level), the plant was part of the least cost plan.

The results also demonstrate that the soundness of the decision to complete Limerick was not particularly sensitive to forecasts of load growth in the region. Even if zero load growth

were forecast for PJM, completion of Limerick was still part of the least cost plan in each of the years 1973, 1976, 1978 and 1980. And, even in this zero growth case Limerick's expected costs would have to increase markedly to eliminate the plant from the optimal plan. Thus, in 1980 with a zero growth forecast Limerick's incremental cost could rise to $1,845 per kW and its total cost to $2,764 per kW and the unit would still be part of the least cost plan.

Not only does this analysis support the decision to complete Limerick on an incremental cost basis, it indicates that even if the decision were based to total cost, Limerick would still be part of the least cost plan. Thus, in each year of the analysis, the maximum cost at which Limerick is economic exceeds the total capital cost of the project.

We should also note one important conservatism in the analysis. In evaluating the least cost expansion plan, I only considered demands and fuel prices as of the date Limerick was expected to come on line. But since demands were expected to grow and real fossil fuel prices were expected to rise in the years following Limerick's on-line date, the analysis understates the economics of the unit. Thus, even if Limerick had not proved to be part of the least cost plan based on initial demands and fuel prices, its completion might well be justified because of future growth in demands and fossil fuel prices.

Q. How did you derive the optimal capacity expansion plan?

A. We used a linear programming model to determine the least

cost mix of capacity additions with which to meet loads in PJM. In meeting demands this model, which is explained in detail in Dr. Wile's testimony, takes into account the operating cost of existing plants, the cost of planned additions, the cost of Limerick and various generic coal additions.

Q. What were the results of your analysis of the benefits from completing Limerick?

A. These benefits are summarized in Schedule 4. In 1975, the benefits are $9.7 billion by comparison with a coal plant and $10.8 billion by comparison with continued use of existing oil. Over the next five years the benefits from completion fell somewhat by comparison with coal, but nevertheless remained high throughout the period. Thus, even in 1980 the incremental cost of electricity from Limerick has a 1984 present value which is $6.9 billion less than that from a contemporaneous coal plant.

During this same period the benefits from completing Limerick by comparison with continued use of oil increase markedly. They rise from $10.8 billion in 1975 to nearly $19.5 billion in 1980. This reflects the marked rise in oil prices and expected oil price escalation which occurred over this period. Consequently, despite rising construction and operating costs, there were very large benefits to consumers from completing the project throughout this period.

Q. You indicate that the Limerick plant was economic. Was it also economic to build Limerick 1 as a stand-alone unit?

A. Yes. While the economic benefits from Limerick are substan-

tially enhanced as a two-unit project, completion of Limerick 1 as a stand-alone unit was justified throughout this period. This is also illustrated in Schedule 4. In it, I examine the present value of the gains from Limerick 1 alone. As is clear from this table, had Limerick 1 been built as a single unit plant, the expected benefit to consumers as of 1975 would have been $4.8 billion by comparison with coal and $5.3 billion when compared to oil. In 1980 the benefits against coal had declined to $3.5 billion but when compared to oil, the benefits rose to $9.7 billion.

While the benefits from completing Unit 1 are always large, they are never as large as those from completing the entire plant. This result leads to two important conclusions. First, it would never have been economic to abandon Unit 2 and complete the project as a single-unit plant. On the other hand, if cancellation or delay of Unit 2 were imposed on Philadelphia Electric, it would still be economic to complete unit 1 as a stand-alone project.

Q. What do you mean by the incremental cost of Limerick and why have you based your analysis on the incremental rather than the total cost of electricity from Limerick?

A. The incremental costs of Limerick include all fuel and operating costs, but only those capital-related costs which remain to be spent as of the year of analysis. Thus, construction costs made prior to the date of the analysis have been excluded from the analysis.

The analysis focuses on the incremental cost of Limerick

because this is the only way to determine whether, at each stage of construction, the project should have been continued. Had the project been cancelled at any point after its inception, this would save the remaining capital expenditures, but not those made previously. Consequently, in deciding whether or not to cancel the project, past investments in construction should be ignored. If the incremental cost of electricity from Limerick (including fuel, O&M and all remaining capital investments) is less than the cost of the next best alternative, the project should be continued; otherwise, it should be cancelled.

Q. There is a general perception that the economic advantages of nuclear power eroded markedly over the period 1975 to 1980, but your analysis shows only a modest decline in the incremental benefits from completing the Limerick plant. What explains the difference?

A. There are two factors. First, the general perception of the decline is generally overstated. As indicated in Schedule 5, while the nuclear cost advantage over coal did decline over this period, even at the end of the period the total cost of electricity from Limerick was still expected to be markedly less than coal. And, relative to oil, the total nuclear cost advantage actually improved during this period. Second, PECO made substantial investments in the completion of Limerick over this period and, consequently, despite marked increases in the total capital cost of the project, the incremental cost was about the same in 1980 as in 1975. As a consequence, despite rises in projected nuclear operating costs,

the incremental advantages of completing the project remained quite stable.

Q. Recognizing that incremental costs provide the appropriate basis for decision making, how did the total cost of Limerick compare with the costs of coal or oil during the period?

A. Even when viewed on a total cost basis, Limerick had substantial advantages over either a contemporaneous coal plant or continued use of oil and gas. This is illustrated in Schedule 5 where I compare the discounted present value of <u>total</u> revenue requirements for Limerick and the equivalent energy derived from a new coal plant or continued use of existing oil capacity. When compared to coal Limerick's total cost advantage ranged from $8.2 billion at the outset of the period to $3.0 billion at the end. By comparison with oil, the Limerick cost advantage started at $9.3 billion, fell to $5.7 billion by 1977, but rose again to $15.5 billion by the end of the period.

Q. If the increases in construction and operating costs occurring over this period had been anticipated earlier, would this have altered the results of your analysis?

A. No. Even on a total cost basis the Limerick nuclear plant remained an economic investment in 1980. Consequently, if in 1975 analysts generally had foreseen accurately the costs of coal and nuclear power which were apparent in 1980, they would still have advocated the construction of Limerick in lieu of coal or continued use of existing oil plants.

Q. What, in your judgement accounts for the rises in total cost

which erode the economic advantages of Limerick over this period?

A. For nuclear, there are three principal factors which account for the rise in costs over time. First, changes in the NRC regulations under which nuclear plants are built and operated have dramatically increased the capital costs of constructing nuclear plants and the length of the construction period. My statistical analysis of construction costs over the period 1975 to 1980 suggests that these changes have caused the estimated cost of constructing Limerick 1 (excluding AFDC) to increase by 43 percent. Second, these same regulatory changes also appear to have resulted in increases in the extent of post-commercial capital additions and non-fuel operating and maintenance costs. Annual fixed O&M expenses more than doubled and the annual cost of post-commercial capital additions increased fourfold.

Third, there was a decline in the projected nuclear plant capacity factor over this period. As of 1973, typical projections of mature nuclear capacity factors were 75 percent or higher and, even allowing for the lead time to maturity, a levelized lifetime capacity factor of 70 percent seemed plausible. But actual performance in the U.S. has not generally been at this level, and based upon poorer than expected performance, projected nuclear capacity factors were revised downward to about 63 percent by 1980. As a result of these changes in my forecast, the cost per kilowatt hour of output for Limerick 1 has risen more than the cost per kilowatt. While the effect has been less dramatic, there have also been marked increases over this period in the cost of the coal

alternative. Thus, regulatory changes (particularly tighter sulfur and particulate emissions limits) have resulted in about a 36 percent increase in the constant dollar capital cost of constructing coal plants. The effect has been to increase the levelized cost of the coal alternative from 42.2 to 49.1 mills per kWh over this period.

Q. Do you believe that these increases could have been anticipated earlier?

A. No, I do not for several reasons. First, as suggested above, most of the cost increase for nuclear plants is attributable to regulatory change. But the effect of these changes could not be predicted before they occurred. At each point in time, the regulations in place were believed to take account of the major safety problems associated with nuclear plants and there was no reason to believe that there would be major changes in regulations or that such changes would have a major cost impact.

Moreover, even after regulatory changes were imposed, their cost impacts were often not apparent for many years. This is true for several reasons. First, the direct cost consequences of regulatory changes have in general proven to be a small part of their total cost impact. Changes in the regulatory system often caused unanticipated design changes in other systems. These synergisms have often resulted in the total cost of a specific design change being far greater than the direct effects anticipated when the change was made.

Second, in many cases regulatory changes did not consist of

additional hardware components but of changes in the very process by which plants were built. For example, this was certainly true of the stricter quality assurance and quality control regulations imposed in the later 1970's. The effect of these regulations, which ultimately resulted in dramatic increases in the manhours required to construct nuclear plants, was not generally anticipated when the changes occurred.

Third, as described more fully in Dr. Mattson's testimony, there was no single source at the NRC which produced regulatory changes. Changes emerged through alterations in regulatory guides 1.108, 1.09, 1.133, 1.136, 1.127, 1.21, 1.29, 1.36, 1.60, 1.68, 1.70, 1.75, 1.81 and 1.97. The multitude of sources for regulatory change made it very difficult to anticipate the changes in cost.

Q. What is included in the discounted present value of revenue requirements for Limerick and its alternative?

A. These include the revenues which must be collected from customers of Philadelphia Electric in order to cover the fuel costs, operating costs and all capital-related costs associated with the project. Capital-related costs include the cost of amortizing the initial investment in the project and any subsequent investments needed to maintain the performance and safety of the unit. These costs include allowances for interest on debt, return on equity, depreciation and applicable income and property taxes. For Limerick (but not the coal alternative) capital-related expenses also include allowances for the ultimate cost of decommissioning.

In calculating the present value of revenue requirements for Limerick and its alternative, I first projected revenue requirements in each year of the operating life of the Limerick project. Annual revenue requirements were then discounted to 1984 at the after-tax cost of money for PECO.[1] The present value of revenue requirements is the sum of these discounted annual revenue requirements. It is necessary to make the comparison in this way because revenue requirements per kilowatt hour of output vary widely from year to year. Given these variations, choices among generating options can best be made by comparing the economics of these projects over their lives. Since such comparisons involve costs incurred over a 30-year period, valid comparisons require that all costs be discounted to a common year of analysis.

Q. Is it possible to compare Limerick and its alternatives on the basis of cost per kWh of output rather than the present value of revenue requirements?

A. Yes, the analysis of the economics of Limerick and its alternative may also be understood in terms of the levelized cost of electricity from Limerick and its alternative. Levelized cost is a constant annual charge for electricity which, over the life of a project, will cover all project costs. This comparison for the entire plant and for Limerick 1 alone is described in Schedule 6. For the rest of this discussion, however, I have focused on the

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[1]Costs were first discounted to the year of analysis at the expected after-tax cost of money. Then they were future worthed from the analysis date to 1984 at the actual cost of money.

expected benefits from the Limerick project. The details on the benefits from Limerick 1 alone are also described in the schedule. As of 1975, the incremental levelized cost of electricity from Limerick was expected to be 2.1 cents per kilowatt hour. By comparison the cost of a coal alternative was 4.2 cents per kWh and the cost of oil was 4.5 cents per kWh. Thus, the incremental cost of energy from Limerick is half the cost of coal and less than half the cost of oil. In the face of such numbers, it clearly would have been imprudent not to complete the unit.

Q. What is the after-tax cost of money and why have you used this rate to discount revenue requirements for Limerick and its alternative?

A. The after-tax cost of money for PECO is a weighted average of the costs of debt and equity capital, where debt costs have been adjusted to reflect the tax deductibility of interest payments. The formula for the after-tax cost of money is:

$$CER * CES + PER * PES + DR * DS * (1-TR)$$

where:

CER = the expected rate of return on common equity over the life of the project;

CES = common equity as a share of total capital;

PER = the expected yield on preferred equity capital;

PES = preferred equity as a share of total capital;

DR = the expected interest rate on debt over the life of the project;

DS = debt as a share of total capital; and

TR = the composite Federal and state income tax rate.

Since the objective of the analysis is to find the option which is lowest cost to consumers, the choice of the after-tax cost of money to the utility may seem peculiar. But, the after-tax cost of money (ATCOM) is the correct rate to use for the analysis. This is because the ATCOM is the rate at which the utility borrows and lends funds on behalf of consumers. In this context, the ATCOM functions like a market interest rate at which consumers can borrow and lend. And, as most texts on investment decision point out, if there is an interest rate at which consumers can borrow and lend, this, rather than the consumers' discount rate, should be used to evaluate alternative investments.

The reason for this can be seen from a simple example. Suppose a consumer has the option of buying a fuel efficient car for $15,000 or a less efficient car for $12,500. Further, suppose the consumer's discount rate is 15 percent, the investment in fuel efficiency earns a return (in the form of fuel savings) of 12.5 percent per year and that the consumer can borrow the purchase price of the car at an interest rate of 10 percent. If the consumer evaluates the decision at his own discount rate (15 percent), he would not purchase the fuel efficient car, since its return is lower than his discount rate. But this is the wrong decision. Since the investment earns a return which is higher than the rate at which the consumer can borrow, it is economic to purchase the fuel efficient car regardless of his own discount rate.

Q. Why does the ATCOM function like a market interest rate at which consumers can borrow and lend?

A. The timing of charges for any generating plant can be adjusted by altering the book depreciation schedule. For example, current straight-line depreciation methods tend to make capital charges high in the early years of plant operation and low later on. Sinking fund depreciation or economic depreciation would defer more of the capital charges to later years. The effect of such deferrals is to borrow funds on behalf of consumers at the utility's ATCOM. For example, if the utility defers $1.00 of depreciation one year, the consumer pays the depreciation charge one year later plus an interest charge equal to the after-tax cost of money. Thus, by setting the depreciation schedule for a plant, a commission can act as a financial intermediary for consumers. When they do so, they lend funds to the consumer at the ATCOM.

Q. PECO decided to slow construction expenditures on Limerick in 1976 and in 1978. Assuming, arguendo, that this slowdown did delay Limerick's on-line date, were the decisions economically sound?

A. Yes. Based upon reasonable assessments of financial markets in 1976 and 1978, PECO believed that attempting to raise sufficient funds to build the project on the fastest possible track would adversely affect its bond rating and thereby its ability to attract capital at reasonable interest rates. If this were the case, my analysis suggests that it was clearly economic to delay the project because it would result in lower costs to consumers. Moreover, even if the company's assessment was wrong and the more rapid

construction schedules could have been achieved without any interest rate effect, the delay had no significant impact on consumer costs.

Q. What evidence do you have to demonstrate this point?

A. I have examined the anticipated effect on system revenue requirements of a one-year delay in Limerick's on-line date and the results are summarized in Schedule 7. I examined the effect of delay both in 1976 and in 1978 under two assumptions about financing cost--first, that the accelerated schedules could be accomplished only at a 1.0 percentage point increase in the cost of money and, second, that it had no effect on the cost of money. In 1976 I considered the effect of delaying the unit from 1982 to 1983 and in 1978 I examined the effect of delaying the unit from 1984 to 1985. The analysis was done using both a 30 and a 35-year life for Limerick. Assuming that rapid completion of the unit did increase borrowing costs, delaying the unit reduced the present value of system requirements by $99 to $140 million. However, even if the delay had no effect on borrowing cost, its effect was de minimus ranging from a decrease in revenue requirements of $4 million to an increase of $8 million.

Q. Please explain the relationship between delay and system revenue requirements.

A. Delaying Limerick at either of these dates does result in an increase in project capital costs. These cost increases, which amounted to $90 million in 1976 and $106 million in 1978 occur because the delay adds to the direct cost of the project and

increases the extent of interest during construction. The delay also increases the present value of fuel costs because the real cost of nuclear fuel escalates over time. In addition, the delay also increases system fuel cost in the year the delay occurs. These added fuel costs amounted to $198 million in 1976 and $177 million in 1978. However, the increased capital and fuel costs in the year of delay are offset by a number of factors. First, the delay causes an increase in fuel savings later in the life of the project. With the delay, each operating year for Limerick occurs at a later point in time. Since the replacement costs were expected to rise over time, the delay increases the value of these fuel savings. These added savings, amount to $191-194 million in the 1976 analysis and $180 to $182 million in 1978. Moreover, the delay also produces an offsetting capital cost savings which occurs because the delay defers by one year the investment which will be needed to replace Limerick when it retires. This deferral of capital expenditures has a present value of $65 - $67 million in the 1976 analysis and $68 to $71 million in the 1978 analysis. There is also a savings on O&M costs from the deferral and this amounts to $29 to $34 million.

In total these effects are virtually offsetting, but there is still another key effect of delay. In 1976 and again in 1978 the company was finding it difficult to raise the capital needed to finance the Limerick project. Other witnesses in this proceeding have testified that raising additional funds would have eroded coverage and adversely affected the company's bond rate and

required increases in borrowing costs. By delaying the on-line date, PECO reduced its cash flow requirements in the 1976 to 1980 period and may thereby have reduced expected borrowing costs. Assuming for illustrative purposes delay reduced interest costs and required return on equity by 1.0 percentage point adds about $105 million to the benefits from delay in 1976 and $136 million in 1978. Moreover, this may understate the effect of such a delay since I have only considered the effect of higher interest costs on Limerick's capital costs not the effect on the company's other construction expenditures.

Q. Are these estimated savings from delay something that might be expected to occur generally or are they specific to the factual situation prevailing in 1976 and in 1978?

A. The results are very specific to the actual facts in 1976 and 1978. Specifically, three circumstances result in the gains from delay. First, as of 1976 and 1978, the prevailing cost of money was low by today's standards. Because of this low cost of money, the discount rate used to evaluate this decision was low and, hence, the gains from delay, which occur later in the life of the project, have a high value when compared with the shorter term costs. Second, viewed from the perspective of 1976 or 1978, Limerick was not actually needed to meet load in the 1983 to 1984 time frame. Consequently, delaying the unit, while entailing higher fuel charges, did not impose any higher capital charges for added capacity. Finally, as of 1976 and 1978, oil prices projected for the 1983-85 period were still, by today's standards, relatively

low. But these prices were expected to rise markedly over time. Hence, the fuel savings from bringing Limerick on line in those years are low relative to those anticipated later in the life of the unit.

Q. Please explain in somewhat more detail how you derived these estimates of the savings from a one year delay in Limerick's on-line date.

A. First, I developed estimates for the direct capital cost of Limerick in 1976 and in 1978 given the then expected schedule for the project. The company then supplied me with an estimate of the anticipated increase in capital costs of a one year increase in the construction time for the unit. This estimate, for both 1976 and 1978, came to about $30 million in 1984 dollars (for Limerick 1 and common). Using these estimates of direct costs and a financial accounting model, I developed estimates of the booked cost of Limerick for its scheduled completion date and for a one year delay. This same program also gave an estimate of the annual capital-related revenue requirements for each of these alternatives. These were then combined with estimates of annual fuel and O&M costs for each on line date to provide the total present value of Limerick's revenue requirements after each scheduled completion date. The differences between these costs for the one year delay in schedule are reported in Schedule 7. I also examined the effect of delay on the value of the energy displaced by Limerick. This calculation can be simplified because the value of the fuel displaced in the first operating year of the delayed

unit corresponds to the savings in the second operating year for the on-time unit, the second year of the delayed unit corresponds to the third year for the on-time unit and so on. These savings cancel out. The two units, however, do not overlap in the first year for the on-time unit and the last year for the delayed unit. By comparing the difference in present value of displaced energy in the first year for the on line unit and the last year of the delayed unit, I can compute the overall difference in fuel savings between these alternatives. For the first operating year of the on time unit, I obtained data from PECO comparing the difference in PECO fuel costs with and without Limerick in 1982 and in 1984. For the value of the energy displaced by Limerick in the last operating year for the delayed unit, I used the levelized annual cost of a new coal-fired plant evaluated as of that date. I did the analysis assuming two alternative operating lives for Limerick--30 years and 35 years.

Q. How is your analysis different from that done by the company to analyze the effect of expenditure constraints in the 1976 to 1978 time frame?

A. They differ in two respects. First, the company's analysis gave substantial weight to on the effects of delay on system costs over the first ten years after Limerick came on line. Delay clearly reduces cost in this time frame. Second, in looking at the long-term effect of the delay, the company appears to have considered the adverse effect of delay on system fuel costs during the delay period but ignored the beneficial effects of delay

in system fuel costs at the end of the project life. For this reason the company's long-term analysis overstates the adverse consequences of delaying Limerick.

Q. Returning to your analysis of the prudence of past decisions, please describe briefly how you have developed estimates of Limerick's expected cost and the cost of the alternative in each year from 1975 to 1980.

A. Using data available in each of the years of the analysis, I developed estimates of components of costs for Limerick and a coal alternative. The components of cost included the capital cost of construction, an allowance for some continuing capital expenditures after the beginning of commercial operation, non-fuel O&M costs and fuel costs. In order to determine the energy output and fuel efficiency of these alternatives, I also made forecasts, based on data then available, of capacity factors and several other measures of unit performance (heat rates for coal units and specific power, burnup and thermal efficiency for nuclear units). In addition, I determined the expected future cost of debt and equity capital, the projected future capital structure and anticipated tax rates for PECO. Finally, I determined the total sunk expenditures on Limerick as of each date and the costs of debt and equity capital at which these historical expenditures had been financed. Using this information and a utility financial accounting model, I projected the year-by-year revenue requirements for Limerick on both an incremental and a total cost basis and then developed a similar forecast of revenue requirements for the

alternative to Limerick.

I should emphasize that in deriving these estimates, I relied only on information which was available to PECO as of the year of analysis. Thus, in 1975 I used an estimate of construction costs for Limerick based on what was then known about the costs of nuclear construction. Similarly, forecasts of future interest rates in 1976 reflected projections which were current at that time. In subsequent years, as new information developed, I modified the estimates. In deriving these retrospective analyses of historical costs, I generally did not rely on PECO's own past forecasts. Rather, I made a comprehensive analysis of data available in the past and used these to make what in my view were the best possible projections of costs using the available data.

The basic alternative to Limerick used throughout this analysis consisted of a coal-fired alternative capable of replacing the expected energy from Limerick. I based the cost of the alternative on the need to replace the energy and not the capacity of Limerick. Thus, for Limerick 1 net electrical capacity is 1,055 MW. In years where the projected capacity factor of Limerick was 63 percent, the project would be expected to provide annual energy output to PECO of 5.8 billion kWh. If the projected capacity factor for the coal plant was 65 percent, I based the analysis on a coal plant consisting of 1,023 MW of capacity.[2] Had I replaced

[2]The actual size of the coal plant was 400 MW per unit, but PECO was only charged for the capacity needed to replace Limerick 1. This assumes that the remainder of the plant would be sold at cost to another participant.

the capacity of Limerick 1, the cost of the alternative would have been higher and, hence, the results would have been more favorable to Limerick.

Once construction started for Limerick, it was probably not possible to cancel the unit and replace it with a contemporaneous coal alternative. Planning and construction time for the coal option would simply require too much time. Nevertheless, for simplicity, I have assumed throughout this analysis that the alternative to Limerick was a contemporaneous coal alternative. This was accomplished by using an admittedly overoptimistic five year schedule for constructing the coal plant. As a consequence, the analysis undoubtedly understates the benefits of completing Limerick. In practice, in the early years of operation, Limerick's energy and capacity would have been replaced by purchased power at prices well above the levelized cost of the coal option.

We also compared the cost of Limerick with the cost of continued use of existing oil-fired plants. In this case, the costs of the oil-fired alternative included energy and O&M costs but no capital costs. I have compared Limerick's costs with oil because in the late 1970's reduced oil dependence was one of the key reasons for constructing Limerick. This comparison enables us to calculate the benefits to consumers from substituting Limerick for existing oil-fired units in the PECO system.

Q. Please summarize the components of costs for Limerick and the coal alternative.

A. These are both summarized in Schedule 8. This schedule describes the components of cost in each analysis year. While Schedule 8 describes the components of costs separately for the Limerick plant and Limerick 1 as a stand-alone unit, in this discussion I will focus entirely on the Limerick plant. For illustrative purposes, let's review the cost components in 1979. As indicated in column 1, my estimate of the incremental booked costs for Limerick as of 1979 was $646 per kW. When expressed in 1984 dollars, this comes to $584 per kW. (As discussed later, this estimate assumes total direct costs of $1,350 kW for the Limerick plant of which $800 per kW had already been spent through 1979. The remaining directs of $550 per kW plus interest during construction result in incremental booked costs of $646 per kW.) Given the costs of debt and equity capital anticipated in 1979, these capital costs would have resulted in levelized annual capital charges of $40 per kilowatt per year (in 1984 dollars). These capital costs are fixed, that is, they do not vary with the output of the plant. There are two other fixed cost components for nuclear plant costs: continuing capital expense (betterments) and annual non-fuel O&M expense. As of 1979, I would have projected these at $7.35 per kW for continuing capital expense and $22.81 per kW for O&M expense. (In each case, these are levelized annual expenses and they have been expressed in 1984 dollars.) When these are added to capital costs, I obtain a total fixed expense of

$70.16 per kW for Limerick 1. To express these costs per kWh of output, they must be divided by the expected annual hours of output for Limerick 1. Using the capacity factor I would have projected for Limerick 1 in 1979, 64 percent, annual fixed expenses come to 12.51 mills per kWh. To these I add an estimate of nuclear fuel cost of 13.37 mills to come to an incremental cost of 25.88 mills per kWh.

A similar analysis for coal is also contained in Schedule 8. Once again, let's consider the derivation of costs for the coal alternative in 1979. As of that year, I would have projected booked costs of a coal plant at $1,396 per kW. When expressed in 1984 dollars, this comes to $1,345 per kW. These construction costs for the coal plant generate levelized annual fixed and continuing capital charges of $98.83 per kW. Combined with fixed O&M charges of $16.31 per kW, this results in total fixed charges of $115.14 per kW, which is, of course, much greater than the incremental capital cost of Limerick. In 1979, my projection of the capacity factor for the coal unit would have been 64.9 percent and, consequently, when fixed charges are expressed per unit of output, they come to 20.26 mills per kWh. In addition, the variable O&M costs of the coal plant come to 3.38 mills per kWh and fuel costs come to 24.70 mills per kWh. The sum of these costs is 48.34 mills per kWh, which is significantly above the 25.88 mills then projected for Limerick.

Q. Please explain in more detail the approach you used to forecast the cost of Limerick and its alternative.

A. This description is perhaps best done on a component by component basis. Let's consider first the capital cost of the Limerick project. In attempting to project these costs in each year from 1975 to 1980, I made use of three sources of data--the PECO/Bechtel estimate of Limerick's cost at each of these dates, the actual costs of other units completed as of each date and, in 1979 and 1980, the estimated cost of other units then under construction. Using data on the actual costs of units completed in each analysis year and the estimated costs of units then under construction, I made an independent forecast of what one would then have expected the Limerick project to cost. This was done by adjusting the average cost of completed units for any difference between Limerick and those units. If these estimates of the expected cost of Limerick exceeded the PECO/Bechtel estimate for a particular year, I used that value. Otherwise I used the PECO/Bechtel estimate. The PECO/Bechtel estimate in each year and a range of estimates for the project based on units completed that year or units then under construction are summarized in Schedule 9. These estimates are exclusive of interest during construction and have been expressed in constant 1984 dollars. For the years 1978 and 1979, my estimates are higher than those developed by PECO/Bechtel and, hence, I used those values. In all other years, I have used the PECO/Bechtel estimates which were at or above the levels I would have projected based upon either completed units or units under construction. Once I had settled on an estimate of total costs, incremental costs were determined by subtracting

expenditures made through the analysis year. The computation of incremental costs is also summarized in Schedule 9.

Q. Please explain in more detail how you derived estimates of the cost for Limerick based on costs for other units.

A. I obtained data on the average costs of nuclear units completed in each year from 1975 to 1980. For 1979 and 1980, I also obtained data on the average estimated costs of units under construction. To derive costs for Limerick, I then made use of two statistical equations which enable us to adjust nuclear plant costs for the effect of plant characteristics. These equations were used to adjust the average costs of completed units and units under construction to reflect the effect of Limerick's characteristics and the resultant estimates were used to infer the cost of Limerick. In years where I had estimates based both on completed units and units under construction, both were used to estimate the costs of Limerick. I use the higher of these values to project Limerick's costs. Moreover, if in any year the Bechtel estimate was higher than our own it was used to estimate the economics of the project.

The derivation of these cost estimates is described in Schedule 9. Page 1 of this schedule summarizes the average costs of units completed (or under construction) in each year from 1975 to 1980. This table also indicates NERA's estimate of Limerick costs in each of these years as derived from these average costs and the Bechtel estimate of Limerick in each year. In 1978 and 1979 I used the NERA estimate since it exceeded Bechtel; in the

remaining years I used the Bechtel estimate.

The regression equations used to adjust the cost of completed units to the cost of Limerick are summarized in pages 5 through 9 of Schedule 9. The first of these equations is based on data on the actual costs of nuclear units receiving construction permits prior to 1972. The second equation is based on the actual or currently estimated costs of units licensed in 1972 or later. I have used these two separate equations because there appears to be a marked shift in the determinants of cost between these two periods. Both equations were used to adjust the average cost of other units to the cost of Limerick and the higher of the two estimates was used in the analysis.

The actual method by which these equations were used to derive costs for Limerick is described in an example in Schedule 9. This example describes the derivation of costs in 1980. As described in page 3 of Schedule 9, I determined the average characteristics and the characteristics of Limerick. The parameters of each of the equations were multiplied by the differences in characteristics to determine the difference, if any, between the costs of completed units and the expected costs of Limerick. This difference was added to or subtracted from the cost of the average unit to obtain the cost of Limerick.

I should point out that by using these regression equations to adjust costs, I am making use of data which was not available at the time each of these estimates were made. Nevertheless, I believe the technique is appropriate for the limited purpose to

which it is applied. Utilities building nuclear plants could not actually have used these regression equations (since they are based on cost data which was unavailable). But I am using the equation only to adjust costs for such specific plant factors as wage and size. Utilities clearly had engineering models which indicated the effect of such factors.

In one respect the analysis is actually quite conservative. Most engineering models of nuclear costs suggest substantial economies of scale in nuclear construction cost. And, statistical analysis of data on the actual costs of units completed through 1980 and the estimated costs of units under construction in that year support this view. But, the statistical analysis of the current cost estimates for units licensed after 1972 units indicates no economies of scale and in forecasting the costs of Limerick, I made use of this equation. This has resulted in higher estimates of Limerick costs than would have emerged from strict reliance on contemporaneous data.

Q. Did you use the same approach in estimating the capital cost of a coal-fired alternative to Limerick?

A. The approach for the coal plant was different only in that I did not have an engineering estimate with which to compare my projection. I used an equation which related coal construction costs to the characteristics of coal plants based upon units constructed in the United States over the period 1965 through 1983. This equation contains a vintage term which enables us to forecast costs for coal units completed in each year. This equation was

used to forecast the cost of an alternative to Limerick 1 in each year from 1975 through 1980. As with Limerick, my estimates of costs in each year were based upon the actual costs of units completed in that year. Thus, the estimate for 1975 is based upon units completed in 1975, the estimate in 1976 for units completed in that year and so on.

The coal plant forecast is actually based on three equations. The first equation projects plant costs, the second projects the costs of associated scrubber equipment and the third projects the costs of particulate removal equipment. The parameters of these equations and the actual characteristics assumed for the Limerick alternative are described in Schedule 10. In selecting the characteristics of this coal-fired alternative to Limerick, I attempted to choose a plant which would meet applicable environmental standards, provide electricity at lowest cost and conform to characteristics of other units built in the region. For this reason, I selected a plant consisting of two, 400 megawatt subcritical units. The plant was designed to burn medium sulfur Pennsylvania coal, was assumed to be located at the Chester site in Eastern Pennsylvania, had fully indoor construction and had a cooling tower. The assumed construction wages for this project were those prevailing in the Philadelphia area. In all other respects, the characteristics of the unit were based upon the average characteristics of subcritical coal-fired units built over this period in the U.S. (The specific characteristics assumed are summarized in Schedule 10.) In order to assure compliance with New

Source Performance Standards limits, in analyses done prior to 1978 the plant was designed to achieve a sulfur emissions limit of 1.2 lbs. per MMBtu and a particulate emissions limit of 0.1 lbs. per MMBtu. For analyses done after 1978, the plant was designed to achieve an 89 percent reduction in sulfur emissions and to limit particulate emissions to 0.03 lbs. per MMBtu. The particulate and sulfur limits assure compliance with Federal New Source Performance Standards.

Q. Based upon these estimates of the capital costs of construction, how did you estimate annual capital-related revenue requirements?

A. In order to estimate annual capital costs, I made use of a utility financial accounting model. Given an estimate of direct construction expenditures and an assumed construction period, this model first calculates the booked capital cost of a project. The booked cost includes direct costs and allowances for both interest and escalation during construction. For Limerick, the capital costs considered included only those remaining to be spent and not those previously expended as of the end of the analysis year. Using these booked costs, the model then calculates the annual revenue requirements needed to amortize the investment, provide a return to equity holders, pay interest on debt and pay all applicable income and property taxes.

In order to estimate the expected future costs of debt and equity capital in each year of my analysis, I also made use of historical data. These expected future debt and equity rates were

a geometric average of actual rates prevailing over the current and the previous four years. Thus, for the expected rate at the end of 1976, I averaged the rates for 1972 through 1976.

In deriving the historic debt costs, I used actual debt rates for PECO in each year. The rates used are summarized in Schedule 11. The preferred dividend was estimated by calculating the difference in yields between debt and preferred for all A rated utilities and assuming that differential applied for PECO as well. For common equity, I estimated the required return by observing the average differential between the required rates and the debt rate for all U.S. electric utilities in each year of the analysis. The equity premium was added to the debt rate for PECO to provide an estimate of the required rate of return in each year.

Estimates of the debt and equity rates as described above are used to calculate the AFDC rate during construction and annual capital-related revenue requirements once the plant comes on line. They are also used to calculate the after-tax cost of money which is used as a discount rate in this analysis.

In deriving annual revenue requirements the financial accounting model attempts to duplicate the accounting conventions employed by PECO in each year of the analysis. These accounting conventions and the applicable tax rates used in the analysis are also summarized in Schedule 11.

Q. Dr. Perl, how did you estimate non-fuel operating and maintenance costs and the costs of post-commercial capital additions for Limerick?

A. For both of these components of cost, I used a similar approach. Using data on currently operating nuclear units in the United States, I developed an equation relating the annual operating and maintenance costs to unit characteristics: size, prevailing wages, unit age, location, etc.--and to the year in which costs were experienced. This equation was used to project O&M costs for Limerick 1 in each year of the analysis. The projected costs for the analysis year 1975 were based upon the actual experience of units operating in that year. The projected costs for the analysis year 1976 were made on the basis of units operating in that year and so on. A similar equation was also developed relating annual post-commercial capital additions to unit characteristics and this equation was used to forecast post-commercial capital additions for Limerick 1 in each analysis year. The capital additions equation is described in Schedule 12 and the non-fuel O&M equation is described in Schedule 13. Each of these schedules also describes the characteristics assumed for Limerick. It should be noted that projected O&M costs are higher in each subsequent year of analysis. This is because these costs have risen markedly over time and the cost for each analysis year is based upon data as of that year. The historical data also imply a systematic relationship between unit age and both O&M costs and capital additions. Operating and maintenance costs appear to rise with age, while capital additions costs appear to fall with age. These age trends have been taken into account in forecasting annual operating and maintenance costs and capital additions for Lim-

erick. As a consequence, the levelized O&M cost for Limerick is somewhat above the first year cost, whereas the levelized cost of capital additions is below the first year cost.

Q. How did you evaluate O&M costs and capital additions for the coal project?

A. With respect to post-commercial capital additions, I did not have a similar data base to that described above for nuclear. I did analyze a small number of plants and these data suggested that annual post-commercial capital additions were approximately 0.5 percent of initial booked capital cost. Consequently, I used this percentage in projecting post-commercial capital additions for the coal project.

With respect to coal O&M costs, I developed separate estimates for two components of these costs. For plant O&M costs (exclusive of scrubber costs) the approach was identical to that used for nuclear plants. A data base consisting of a sample of existing coal-fired units was used to relate O&M costs to key plant characteristics and to the year in which the cost was experienced. This equation was then used to project fixed O&M costs for the coal plant as of each analysis year. This equation contains a parameter indicating the effect of a scrubber on O&M costs and, consequently, enables us to estimate separately the O&M cost of the plant alone and that attributable to the addition of a scrubber. However, because this equation did not permit us to estimate the effect of scrubber characteristics on scrubber costs, I used it only to project plant O&M exclusive of scrubber costs. In order to project

the additional operating and maintenance costs of the scrubber I made use of the O&M equation described above supplemented by data on O&M costs for a sample of scrubbers examined by DOE. These sample data were used to develop an equation relating scrubber O&M cost and to percent and pounds of inlet sulfur removed by the scrubber. While this latter equation indicated quite plausible relationships between cost and scrubber characteristics, it forecasted overall scrubber costs which were much higher than the overall level implied by the plant O&M equation. Consequently, the parameters of the scrubber cost equation were scaled downward to produce an overall scrubber cost consistent with that implied by the total plant O&M equation. The prediction of scrubber O&M costs and the original scrubber cost equation are described in Schedule 15.

Q. Dr. Perl, please describe how you estimated the capacity factor for the nuclear plant.

A. The projected capacity factor for Limerick is based upon a combination of engineering forecasts and statistical analyses of actual performance in the U.S. Using data on actual capacity factors of nuclear units operating in the U.S. over the last 24 years, I determined that the expected performance of a unit like Limerick would be approximately 60 percent. However, it is clear that, as of 1975, forecasted capacity factors were much higher. This was because at that time there was limited operating experience and such experience as had been accumulated was based on smaller nuclear units. Data for these small units suggested that

forecasts of capacity factors in the 70 percent range were quite reasonable. As more data accumulated, it became apparent that capacity factors for larger units have been lower than this. Consequently, as of 1975, I assumed 68 percent capacity factor for Limerick 1, but I reduced the capacity factor by 1 percentage point per year over the period analyzed to reflect the gradual accumulation of experience. By 1980 the projected capacity factor was 63 percent.

While this estimate is well below the level currently projected by PECO, this does not mean that I would necessarily reject the PECO value. Engineering studies have generally suggested that nuclear plants can achieve capacity factors above 70 percent. Such levels of performance have been achieved by individual units in the U.S. and are even more common in Western Europe. Moreover, many nuclear engineers would testify that the factors which have in the past prevented most nuclear plants from achieving this level of performance have been corrected in the units now under construction. For example, the pipe cracking problems which have plagued many BWR plants have resulted in modifications in water chemistry and in the composition of the metal used in piping for current BWRs. Thus, it is entirely possible that the company's estimate will be achieved. However, throughout this analysis, I have chosen to rely on historical expectations rather than projected future measures of performance and to be consistent I have used historical values in projecting future nuclear capacity factors.

Q. Was a similar approach used in forecasting capacity factors for coal?

A. Yes. For coal, however, I have relied exclusively on historical data. This is because there is an extensive track record on the performance of coal-fired units and it would have been reasonable in the period 1975 to 1980 to rely on this track record in forecasting future capacity.

In order to forecast the capacity factors of coal units, I first made a statistical analysis of equivalent availability for a very large sample of subcritical coal-fired units. The equivalent availability of a unit measures the average percentage of the unit's capacity which is available for load over the course of a year. The statistical analysis of these data related equivalent availability to the characteristics of the units. This equation, which was used to project equivalent availability for the coal alternative to Limerick, is described in Schedule 16. This schedule also includes the assumed characteristics of the alternative to Limerick and the projected first year equivalent availability of the unit. As of 1980, the projected first year equivalent availability for the coal alternative to Limerick was 70 percent. The first year capacity factor was projected to be 65 percent or 93 percent of equivalent availability. The disparity between capacity factor and equivalent availability reflects the observed fact that even baseloaded units do not in general achieve capacity factors equal to equivalent availability. For nuclear units (which are clearly baseloaded), the capacity factor is 91

percent of equivalent availability and for supercritical coal-fired units with low heat rates (which are likely to be baseloaded), the capacity factor is 93 percent of equivalent availability.

We should also note that this equation suggests that equivalent availability for coal units rises during the first few years of operating life, remains level for a period of time and then tends to fall off. As a consequence, the levelized capacity factor is very close to the forecast of the capacity factor in the first year. In general the forecasted capacity factor for the coal-fired alternative to Limerick 1 was in the range of 64.5 percent throughout the period of analysis.

Q. Dr. Perl, please describe how you estimated fuel costs for the Limerick units.

A. Fuel costs for nuclear units consist of five basic components--the cost of U_3O_8, conversion, enrichment, fuel fabrication and waste disposal. With respect to U_3O_8, I used the published NUEXCO market price for uranium as of the year of the analysis. In projecting future U_3O_8 prices, I assumed that the prices prevailing as of the analysis year would escalate at the general rate of inflation plus 2.0 percent.

With respect to the enrichment charges, I used data supplied by Colorado Nuclear Corporation on actual U.S. Department of Energy charges for 1975 to 1980. For conversion fabrication and waste disposal, I used the estimates developed by NUS in a 1976 study.

In calculating actual nuclear fuel costs, some components of nuclear fuel were assumed to be purchased before actual use in

order to allow time for processing. U_3O_8 and conversion services were purchased three years prior to use; enrichment services were purchased one and one-half years prior to use; and fabrication services were purchased six months prior to use. On the other hand, disposal costs were assumed to occur five years after use. Items purchased prior to use were assumed to accumulate capitalized interest at the after-tax cost of money. Thus, the revenue requirements for these fuel components exceed the actual purchase price. By the same token, for waste disposal, where the actual expenditures will not occur until after use, revenues collected at the time of use were assumed to accumulate interest at the after-tax cost of money. Consequently, the revenues actually collected for waste disposal are less than the cost.

In calculating nuclear fuel costs per kWh, I assumed that the fuel for the plant would have an enrichment percentage of 3.05 percent, a specific power of 23.3 MW thermal per metric ton and a burnup of 27,550 MW days thermal per metric ton. These data were supplied to us by PECO. Nuclear fuel charges include both the cost of fuel used and interest on the in-core inventory of the fuel. These inventory charges are calculated using the estimates of the cost of money to PECO, which have been described above. The components of the nuclear fuel price are summarized in Schedule 17.

Q. Dr. Perl, please describe how you estimated the cost of fuel for the coal alternative to Limerick.

A. In estimating the fuel costs for this alternative, I made use of data from FERC Form 423 which describes delivered prices of fuel

to electric utilities. For each analysis year from 1975 to 1980, I used the actual prices of fuels delivered to utilities in Eastern Pennsylvania. I limited consideration to fuels with a sulfur content of 1.5 percent and higher. These prices were then assumed to escalate at a rate which was 1 percent above the general rate of inflation. This escalation premium reflects modeling runs done by NERA using a model which predicts the future price of coal fuels by region and sulfur content.

Q. How did you estimate fuel costs on a mills per kWh basis?

A. In order to estimate the cost of coal fuel on a mills per kWh basis, it is necessary to determine the net heat rate of the projected coal alternative. The estimate of the heat rate for this plant was once again based upon a statistical analysis of existing coal-fired power plants in the U.S. These data were used to derive an equation relating the heat rate to unit characteristics. The equation used is described in Schedule 19. Thus, for the 1980 analysis, the equation suggests a first year heat rate for the alternative to Limerick 1 of 10,175 Btus per kWh. However, the equation also suggests that heat rates improve in the first few years of analysis and then deteriorate somewhat thereafter. As a consequence, in the same 1980 analysis the levelized heat rate over the life of the plant is 10,446 Btus per kWh.

Q. Dr. Perl, how did you estimate the present value of revenue requirements for the oil alternative to Limerick?

A. To do this I estimated the year by year energy plus O&M costs for a typical oil burning plant. For the fuel costs we

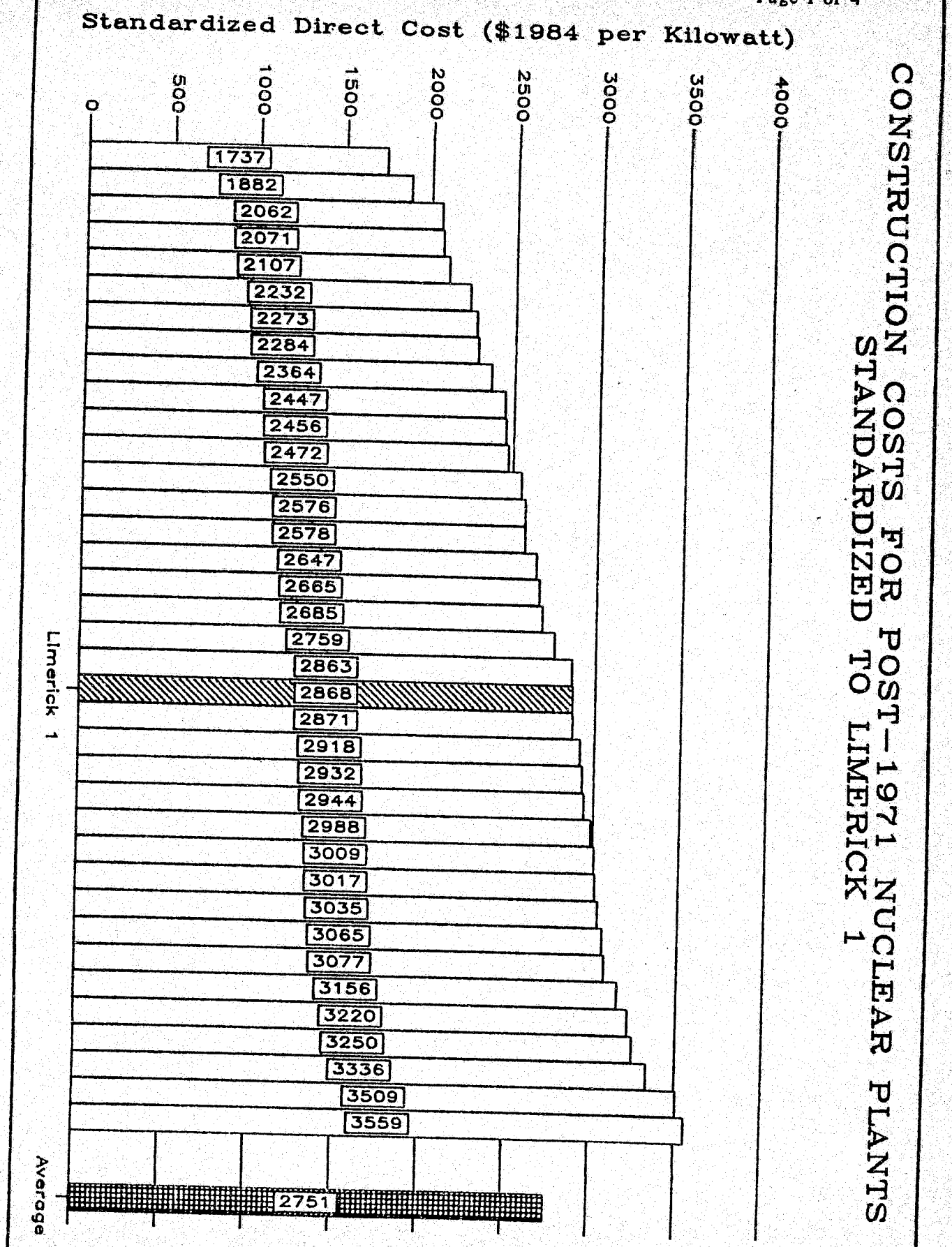
determined the delivered cost of oil to Pennsylvania for each year of analysis. The delivered oil prices were from DOE, Cost and Quality of Fuels for Electric Utility Plants. These prices are described in Schedule 18. I then escalated these base year prices at 1 percent per year above the general inflation rate for the 1975 through 1979 analyses and at 2 percent per year for the 1980 analysis. To convert these fuel prices to mills per kilowatt-hour I assumed an average heat rate of 10,000 Btus per kilowatt-hour.

The non-fuel O&M expenses for the oil alternative were assumed to be 90 percent of the non-scrubber O&M costs for the coal alternative to Limerick. The components of levelized cost for the oil alternative are summarized in page 7 of Schedule 8.

Q. Dr. Perl, does this conclude your testimony?

A. Yes, it does.

CONSTRUCTION COSTS FOR POST-1971 NUCLEAR PLANTS STANDARDIZED TO LIMERICK 1



NUCLEAR CAPITAL COSTS FOR POST-1971 PLANTS STANDARDIZED TO LIMERICK 1

Unit	Actual Direct Cost (1984 $/kW)	Standardized Direct Cost (1984 $/kW)
	(1)	(2)
Hatch 2	$ 952	1,737
Arkansas Nuclear One 2	922	1,882
McGuire	867	2,062
St. Lucie 2	1,747	2,071
Susquehanna	1,702	2,107
Farley	1,312	2,232
Hope Creek	3,215	2,273
LaSalle	1,335	2,284
Summer	1,557	2,364
Perry	1,727	2,447
Clinton 1	2,707	2,456
WPPSS 2	3,029	2,472
San Onofre	2,022	2,550
Palo Verde	1,852	2,576
Callaway	2,062	2,578
Marble Hill	1,700	2,647
Braidwood 1	1,966	2,665
Wolf Creek	1,992	2,685
Limerick 1	2,868	2,868
Fermi 2	3,027	2,759
Shoreham	4,102	2,863
Nine Mile Point 2	3,583	2,871
Beaver Valley	3,356	2,918
Millstone 3	2,714	2,932
Byron	1,565	2,944
Comanche Peak	1,814	2,988
Watts Bar	1,447	3,009
Midland	2,454	3,017
Waterford 3	2,524	3,035
Catawaba 1	1,404	3,065
River Bend	3,424	3,077
Grand Gulf	1,975	3,156
Seabrook	2,539	3,220
Bellefonte	1,559	3,250
South Texas	2,449	3,336
Harris	2,128	3,509
Vogtle	2,433	3,559
Average, Excluding Limerick 1	2,001	2,751

REGRESSION RELATING CAPITAL COST FOR NUCLEAR UNITS WHICH RECEIVED A CONSTRUCTION PERMIT IN 1972 OR LATER TO SELECTED CHARACTERISTICS[1]

BASED ON 1985 DATA

	Variable Mean[2] (1)	Regression Coefficient[3] (2)	t-Statistic[4] (3)
Log of Construction Cost	7.5358	-	-
Constant	1.0000	7.7808	-
Log of Wage Index[5]	-0.1040	0.3708	2.262
Subsequent Unit Indicator[6]	0.4068	-0.4183	7.607
Single Unit BWR Indicator[7]	0.1186	0.2289	2.538
Rock Foundation Indicator[8]	0.6271	-0.1245	1.975
Cooling Tower Indicator[9]	0.6102	0.0579	1.027
Utility is Constructor Indicator[10]	0.2373	-0.2490	3.783
Northeast Indicator[11]	0.1864	0.2119	2.943
Number of Observations		59	
Adjusted R^2		0.7551	
Standard Error		0.1951	

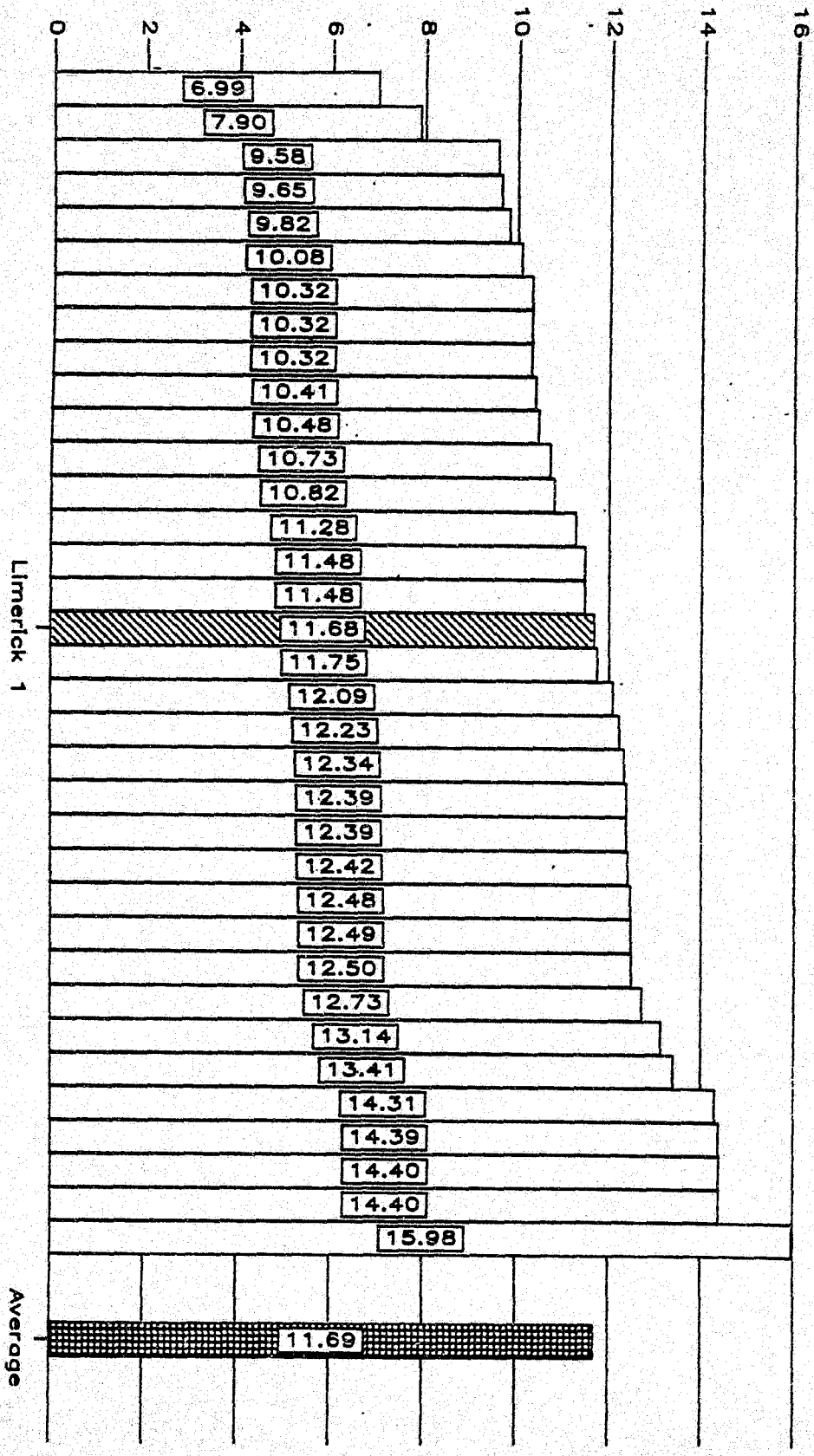
REGRESSION RELATING CAPITAL COST FOR NUCLEAR UNITS WHICH RECEIVED A CONSTRUCTION PERMIT IN 1972 OR LATER TO SELECTED CHARACTERISTICS[1]

BASED ON 1985 DATA

Sources and Notes

[1]The dependent variable in the regression is the natural log of capital cost per kilowatt. Actual costs have been adjusted to reflect the cost of constructing the plants at labor and materials costs prevailing in 1984 with no allowance for funds used during construction. The data are from a March 1985 TVA survey, or from a
[2]NERA survey of individual utilities if TVA did not report costs for a unit.
[3]The variable mean is the average value of each of the variables in the analysis for the sample used to estimate the regression equation.
[4]The regression coefficient describes the effect of a one-unit change in the independent variable on the dependent variable.
[5]A t-statistic is the ratio of the mean of the coefficient to its standard error. It measures the reliability with which the coefficient is measured. A t-statistic of 2.01 or higher indicates that the coefficient is significantly different from zero at the 5 percent level. A t-statistic of 1.68 or higher indicates significance at the 10 percent level.
[6]The wage rate is a composite of 1981 wages plus fringe benefits for crafts used in constructing nuclear power plants. The composite consists of the following crafts: steamfitters (30 percent), electricians (19 percent), common laborers (18 percent), carpenters (12 percent), steelworkers (10 percent), operating engineers (7 percent), boilermakers (2 percent) and millwrights (2 percent). The wage is expressed as an index relative to the national average. Wages for these crafts were obtained from R.S. Means Co., Inc., 1978 Labor Rates for the Construction Industry for the communities from which construction labor was hired.
[7]The indicator is equal to 1 if the unit is a subsequent unit of a series built at a site and 0 otherwise.
[8]The indicator is equal to 1 if the unit is a single unit plant with a boiling water reactor and 0 otherwise. BWR classification is taken from U.S. Department of Energy, U.S. Central Station Nuclear Electric Generating Units; Significant Milestones (Status as of July 1, 1983), DOE/NE-0030/9, October 1983.
[9]The indicator is equal to 1 if the unit is built on a rock foundation and 0 otherwise. Rock or soil site classification was provided to NERA from Burns & Roe in March 1984.
[10]The indicator is equal to 1 if the unit has a cooling tower and 0 otherwise. Cooling tower data are from NUS Corporation, Commercial Nuclear Power Plants, Edition No. 16, February 1984.
[11]The indicator is equal to 1 if the utility is the construction manager and either TVA, Duke Power Company, or Commonwealth Edison Company. Otherwise, the indicator is equal to 0. Construction manager data are from NUS Corporation, Commercial Nuclear Power Plants, Edition No. 16, February 1984.
The indicator is equal to 1 if the unit is in Connecticut, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont or Washington, D.C. and 0 otherwise. Locations are from U.S. Department of Energy, U.S. Central Station Nuclear Electric Generating Units; Significant Milestones (Status as of July 1, 1983), DOE/NE-0030/9, October 1983.

CONSTRUCTION TIME FOR POST-1971 NUCLEAR PLANTS
STANDARDIZED TO LIMERICK 1
FIRST AND SINGLE UNITS ONLY



CONSTRUCTION TIME FOR POST-1971 NUCLEAR PLANTS STANDARDIZED TO LIMERICK 1

First and Single Units Only

Unit Name	Construction Time (Years)	
	Actual	Standardized
Farley 1	5.34	6.99
St. Lucie 2	6.25	7.90
Susquehanna 1	9.58	9.58
Perry 1	8.00	9.65
Wolf Creek	8.17	9.82
Seabrook 1	10.08	10.08
Harris 1	8.67	10.32
Callaway 1	8.67	10.32
Marble Hill 1	8.67	10.32
River Bend	8.76	10.41
McGuire 1	8.83	10.48
La Salle 1	9.08	10.73
Byron 1	9.17	10.82
Palo Verde 1	9.63	11.28
San Onofre 2	9.83	11.48
Catawba 1	9.83	11.48
Limerick 1	11.68	11.68
Millstone 3	11.75	11.75
Hope Creek	12.09	12.09
Waterford 3	10.58	12.23
Nine Mile Point 2	12.34	12.34
Grand Gulf 1	10.74	12.39
Clinton 1	10.74	12.39
Beaver Valley	12.42	12.42
Braidwood 1	10.83	12.48
Summer	10.84	12.49
Shoreham	12.50	12.50
Comanche Peak 1	11.08	12.73
South Texas 1	11.49	13.14
WPPSS 2	11.76	13.41
Midland 1	12.66	14.31
Enrico Fermi 2	12.74	14.39
Watts Bar 1	12.75	14.40
Vogtle 1	12.75	14.40
Bellefonte 1	14.33	15.98
Average, excluding Limerick 1	10.38	11.69

REGRESSION RELATING CONSTRUCTION TIME FOR NUCLEAR UNITS WHICH RECEIVED A CONSTRUCTION PERMIT IN 1972 OR LATER TO SELECTED CHARACTERISTICS[1]

	Variable Mean[2] (1)	Regression Coefficient[3] (2)	t-Statistic[4] (3)
Construction Time	11.0763	-	-
Constant	1.0000	10.0821	-
Subsequent Unit Indicator[5]	0.4035	1.6767	2.867
Northeast Indicator[6]	0.1930	1.6461	2.264
Number of Observations		57	
Adjusted R^2		0.1497	
Standard Error		2.1476	

Sources and Notes

[1]The dependent variable in the regression is the construction time in years for each unit. Construction time is calculated as the difference between the commercial operation date and the date the unit received its construction permit.

[2]The variable mean is the average value of each of the variables in the analysis for the sample used to estimate the regression equation.

[3]The regression coefficient describes the effect of a one-unit change in the independent variable on the dependent variable.

[4]A t-statistic is the ratio of the mean of the coefficient to its standard error. It measures the reliability with which the coefficient is measured. A t-statistic of 2.01 or higher indicates that the coefficient is significantly different from zero at the 5 percent level. A t-statistic of 1.68 or higher indicates significance at the 10 percent level.

[5]The indicator is equal to 1 if the unit is a subsequent unit of a series built at a site and 0 otherwise.

[6]The indicator is equal to 1 if the unit is in Connecticut, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont or Washington, D.C. and 0 otherwise. Locations are from U.S. Department of Energy, U.S. Central Station Nuclear Electric Generating Units; Significant Milestones (Status as of July 1, 1983), DOE/NE-0030/9, October 1983.

EVALUATION OF THE LIMERICK SYSTEM AS PART OF THE LEAST COST EXPANSION PLAN FOR PJM

Year	Expected Capital Cost		Maximum Cost at Which Limerick System is Economic as of On-Line Date			
			Expected Growth		Zero Growth	
	Incremental	Total	Incremental Cost[1]	Total Cost[2]	Incremental Cost[1]	Total Cost[2]
	(1984 $/kW)					
	(1)	(2)	(3)	(4)	(5)	(6)
1973	$594	$ 771	$2,263	$2,440	$1,487	$1,664
1976	702	1,184	1,909	2,391	1,038	1,520
1978	602	1,309	1,818	2,525	1,056	1,763
1980	596	1,515	1,903	2,822	1,845	2,764

Sources and Notes

[1]The maximum incremental costs are those at which it is no longer economic to complete Limerick. These projections are from the NERA Utility System Planning Model.

[2]The maximum total cost is the sum of the maximum incremental cost and the sunk cost, which is column (2) - column (1).

EVALUATION OF LIMERICK 1 AS PART OF THE LEAST COST EXPANSION PLAN FOR PJM

Year	Expected Capital Cost		Maximum Cost at Which Limerick 1 is Economic as of On-Line Date			
			Expected Growth		Zero Growth	
	Incremental	Total	Incremental Cost[1]	Total Cost[2]	Incremental Cost[1]	Total Cost[2]
	(1984 $/kW)					
	(1)	(2)	(3)	(4)	(5)	(6)
1973	$647	$ 930	$2,208	$2,491	$1,431	$1,714
1976	640	1,376	1,838	2,574	1,120	1,856
1978	541	1,579	1,703	2,741	1,100	2,138
1980	385	1,755	1,759	3,129	1,731	3,101

Sources and Notes

[1]The maximum incremental costs are those at which it is no longer economic to complete Limerick 1. These projections are from the NERA Utility System
[2]Planning Model.
[2]The maximum total cost is the sum of the maximum incremental cost and the sunk cost, which is column (2) - column (1).

PRESENT VALUE OF ADVANTAGE FROM COMPLETING LIMERICK SYSTEM BY YEAR OF ANALYSIS[1]

Year of Analysis	Present Value of Revenue Requirements: Incremental Cost of Limerick[2]	Total Cost of Alternative[3]: Coal	Total Cost of Alternative[3]: Oil	Advantage of Limerick Over: Coal	Advantage of Limerick Over: Oil
	(Millions of 1984 Dollars)				
	(1)	(2)	(3)	(2)-(1) (4)	(3)-(1) (5)
1975	$ 9,507	$19,209	$20,327	$ 9,702	$10,820
1976	10,163	17,335	18,678	7,172	8,515
1977	10,018	17,437	18,471	7,419	8,453
1978	9,701	17,053	19,344	7,352	9,643
1979	7,570	14,212	23,336	6,642	15,766
1980	7,921	14,863	27,435	6,942	19,514

Sources and Notes

[1]The present value as of mid-1984 of the projected costs of Limerick 1 & 2 and an oil or coal alternative. The projections are based upon a retrospective analysis of the information available through the end of each year for which the analysis was done. Thus, the 1976 analysis reflects data available through 1976.

[2]The present value as of mid-1984 of the incremental revenue requirements associated with completing Limerick 1 & 2. This is defined as the total present value of revenue requirements associated with Limerick 1 & 2 minus the present value of the revenue requirements associated with expenditures incurred through the end of the year for which the analysis was done (sunk expenditures). The present value of the revenue requirements associated with incremental expenditures includes the interest on debt, returns on common and preferred equity, depreciation and taxes necessary to amortize these expenditures over the operating life of Limerick 1 & 2.

[3]The present value as of mid-1984 of the revenue requirements associated with the projected cost of replacing the power generated by Limerick 1 & 2 with an oil plant or a new subcritical coal plant entering commercial operation at the same time as Limerick 1 & 2.

PRESENT VALUE OF ADVANTAGE FROM COMPLETING LIMERICK 1 BY YEAR OF ANALYSIS[1]

Year of Analysis	Present Value of Revenue Requirements: Incremental Cost of Limerick 1[2]	Total Cost of Alternative[3]: Coal	Total Cost of Alternative[3]: Oil	Advantage of Limerick 1 Over: Coal	Advantage of Limerick 1 Over: Oil
	(Millions of 1984 Dollars)				
	(1)	(2)	(3)	(2)-(1) (4)	(3)-(1) (5)
1975	$ 4,817	$ 9,575	$10,117	$ 4,758	$ 5,300
1976	5,157	8,662	9,318	3,505	4,161
1977	5,049	8,701	9,202	3,652	4,153
1978	5,011	8,547	9,657	3,536	4,646
1979	3,895	7,210	11,674	3,315	7,779
1980	3,987	7,513	13,694	3,526	9,707

Sources and Notes

[1]The present value as of mid-1984 of the projected costs of Limerick 1 and an oil or coal alternative. The projections are based upon a retrospective analysis of the information available through the end of each year for which the analysis was done. Thus, the 1976 analysis reflects data available through 1976.

[2]The present value as of mid-1984 of the incremental revenue requirements associated with completing Limerick 1. This is defined as the total present value of revenue requirements associated with Limerick 1 minus the present value of the revenue requirements associated with expenditures incurred through the end of the year for which the analysis was done (sunk expenditures). The present value of the revenue requirements associated with incremental expenditures includes the interest on debt, returns on common and preferred equity, depreciation and taxes necessary to amortize these expenditures over the operating life of Limerick 1.

[3]The present value as of mid-1984 of the revenue requirements associated with the projected cost of replacing the power generated by Limerick 1 with an oil plant or a new subcritical coal plant entering commercial operation at the same time as Limerick 1.

PRESENT VALUE OF TOTAL ADVANTAGE FROM COMPLETING LIMERICK SYSTEM BY YEAR OF ANALYSIS[1]

Year of Analysis	Present Value of Revenue Requirements: Total Cost of Limerick[2]	Present Value of Revenue Requirements: Total Cost of Alternative[3]: Coal	Present Value of Revenue Requirements: Total Cost of Alternative[3]: Oil	Advantage of Limerick Over: Coal	Advantage of Limerick Over: Oil
	(Millions of 1984 Dollars)				
	(1)	(2)	(3)	(2)-(1) (4)	(3)-(1) (5)
1975	$11,050	$19,209	$20,327	$ 8,159	$ 9,277
1976	12,302	17,335	18,678	5,033	6,376
1977	12,734	17,437	18,471	4,703	5,737
1978	12,884	17,053	19,344	4,169	6,460
1979	10,972	14,212	23,336	3,240	12,364
1980	11,894	14,863	27,435	2,969	15,541

Sources and Notes

[1]The present value as of mid-1984 of the projected costs of Limerick 1 and 2 on a total cost basis and an oil or coal alternative. The projections are based upon a retrospective analysis of the information available through the end of each year for which the analysis was done. Thus, the 1976 analysis reflects data available through 1976.

[2]The present value as of mid-1984 of the total revenue requirements associated with completing Limerick 1 and 2.

[3]The present value as of mid-1984 of the revenue requirements associated with the projected cost of replacing the power generated by Limerick 1 and 2 with an oil plant or a new subcritical coal plant entering commercial operation at the same time as Limerick 1 and 2.

PRESENT VALUE OF TOTAL ADVANTAGE FROM COMPLETING LIMERICK 1 BY YEAR OF ANALYSIS[1]

Year of Analysis	Present Value of Revenue Requirements: Total Cost of Limerick 1[2]	Present Value of Revenue Requirements: Total Cost of Alternative[3]: Coal	Present Value of Revenue Requirements: Total Cost of Alternative[3]: Oil	Advantage of Limerick 1 Over: Coal	Advantage of Limerick 1 Over: Oil
	(Millions of 1984 Dollars)				
	(1)	(2)	(3)	(2)-(1) (4)	(3)-(1) (5)
1975	$ 5,990	$ 9,575	$10,117	$ 3,585	$ 4,127
1976	6,746	8,662	9,318	1,916	2,572
1977	7,021	8,701	9,202	1,680	2,181
1978	7,287	8,547	9,657	1,260	2,370
1979	6,337	7,210	11,674	873	5,337
1980	6,850	7,513	13,694	663	6,844

Sources and Notes

[1]The present value as of mid-1984 of the projected costs of Limerick 1 on a total cost basis and an oil or coal alternative. The projections are based upon a retrospective analysis of the information available through the end of each year for which the analysis was done. Thus, the 1976 analysis reflects data available through 1976.

[2]The present value as of mid-1984 of the total revenue requirements associated with completing Limerick 1.

[3]The present value as of mid-1984 of the revenue requirements associated with the projected cost of replacing the power generated by Limerick 1 with an oil plant or new subcritical coal plant entering commercial operation at the same time as Limerick 1.

LEVELIZED COST ADVANTAGE FROM COMPLETING LIMERICK SYSTEM BY YEAR OF ANALYSIS[1]

Year of Analysis	Levelized Cost: Incremental Cost of Limerick	Levelized Cost: Total Cost of Alternative: Coal	Levelized Cost: Total Cost of Alternative: Oil	Advantage of Limerick Over: Coal	Advantage of Limerick Over: Oil
	(1984 Mills/kWh)				
	(1)	(2)	(3)	(2)-(1) (4)	(3)-(1) (5)
1975	21.07	42.58	45.06	21.51	23.99
1976	24.95	42.55	45.85	17.60	20.90
1977	24.49	42.64	45.16	18.15	20.67
1978	25.46	44.75	50.76	19.29	25.30
1979	25.88	48.59	79.78	22.71	53.90
1980	26.57	49.86	92.03	23.29	65.46

Sources and Notes

[1]Each of the values in the schedule reflects the present values presented in Schedule 4 divided by the discounted present value of expected generation from Limerick 1 and 2. Generation is first discounted to the analysis year at the expected real discount rate as of each analysis year. The present value of generation as of the analysis year is then future worthed to mid-1984 at the actual real discount rate. The real discount rate is the nominal discount rate divided by the rate of inflation. The present value of generation (in GWh) for Limerick 1 and 2 by year of analysis is:

Year	Present Value of Generation
1975	451,126
1976	407,373
1977	408,973
1978	381,109
1979	292,506
1980	298,110

LEVELIZED COST ADVANTAGE FROM COMPLETING LIMERICK 1 BY YEAR OF ANALYSIS[1]

Year of Analysis	Levelized Cost: Incremental Cost of Limerick 1	Levelized Cost: Total Cost of Alternative: Coal	Levelized Cost: Total Cost of Alternative: Oil	Advantage of Limerick 1 Over: Coal	Advantage of Limerick 1 Over: Oil
	(1984 Mills/kWh)				
	(1)	(2)	(3)	(2)-(1) (4)	(3)-(1) (5)
1975	21.25	42.24	44.64	20.99	23.39
1976	25.14	42.22	45.42	17.08	20.28
1977	24.55	42.31	44.74	17.76	20.19
1978	26.09	44.50	50.28	18.41	24.19
1979	26.11	48.34	78.27	22.23	52.16
1980	26.04	49.06	89.42	23.02	63.38

Sources and Notes

[1]Each of the values in the schedule reflects the present values presented in Schedule 4 divided by the discounted present value of expected generation from Limerick 1. Generation is first discounted to the analysis year at the expected real discount rate as of each analysis year. The present value of generation as of the analysis year is then future worthed to mid-1984 at the actual real discount rate. The real discount rate is the nominal discount rate divided by the rate of inflation. The present value of generation (in GWh) for Limerick 1 by year of analysis is:

Year	Present Value of Generation
1975	226,667
1976	205,158
1977	205,676
1978	192,058
1979	149,150
1980	153,144

SAVINGS AND COSTS FROM A ONE YEAR DELAY IN LIMERICK 1 USING A COAL PLANT TO VALUE THE ENERGY DISPLACED BY LIMERICK

EXPECTED COST OF MONEY[1]

	Present Value of Revenue Requirements			
	1976 Analysis[2]		1978 Analysis[3]	
	30-Year Life	35-Year Life	30-Year Life	35-Year Life
	(Millions of 1984 Dollars)			
	(1)	(2)	(3)	(4)
Effect of Delay on Cost of Limerick 1:[4]				
Capital	90	90	106	107
O&M	-7	-8	-10	-11
Fuel	12	15	8	10
Total	96	98	104	105
Effect of Delay on Other System Costs:				
Capital[5]	-67	-65	-71	-68
O&M[5]	-30	-29	-34	-33
Fuel:				
First Year[6]	198	198	177	177
Other Years[5]	-191	-194	-180	-182
Total	-91	-90	-108	-106
Net Savings from Delay	-5	-8	4	1

SAVINGS AND COSTS FROM A ONE YEAR DELAY IN LIMERICK 1 USING A COAL PLANT TO VALUE THE ENERGY DISPLACED BY LIMERICK

EXPECTED COST OF MONEY[1]

Sources and Notes

[1]The expected cost of money case was based on the same financial assumptions used to estimate the net benefits from completing the Limerick project.
[2]For the 1976 delay analysis the in-service date for Limerick 1 was assumed to be deferred for one year, from 1982 to 1983.
[3]For the 1978 delay analysis the in-service date for Limerick 1 was assumed to be deferred for one year, from 1984 to 1985.
[4]The delay of Limerick 1 was assumed to raise the direct capital cost by $28.5 per kilowatt expressed in mid-1984 dollars. This cost estimate was developed by Bechtel in August 1976. This estimate was used in assessing the effects of both the 1976 and 1978 delays.
[5]These reflect the generating costs for replacement energy for the year after Limerick retires in the no delay case. These costs are based on the levelized costs of a coal plant.
[6]The first year fuel costs are the additional system fuel costs that would have been incurred if Limerick 1 was delayed for one year. These estimates were developed by Philadelphia Electric Company in 1977.

SAVINGS AND COSTS FROM A ONE YEAR DELAY IN LIMERICK 1 USING A COAL PLANT TO VALUE THE ENERGY DISPLACED BY LIMERICK

HIGH COST OF MONEY[1]

	Present Value of Revenue Requirements			
	1976 Analysis[2]		1978 Analysis[3]	
	30-Year Life	35-Year Life	30-Year Life	35-Year Life
	(Millions of 1984 Dollars)			
	(1)	(2)	(3)	(4)
Effect of Delay on Cost of Limerick 1:[4]				
Capital	-12	-12	-28	-28
O&M	-7	-8	-10	-11
Fuel	11	14	6	8
Total	-8	-7	-32	-32
Effect of Delay on Other System Costs:				
Capital[5]	-67	-65	-71	-68
O&M[5]	-30	-29	-34	-33
Fuel:				
First Year[6]	198	198	177	177
Other Years[5]	-191	-194	-180	-182
Total	-91	-90	-108	-106
Net Savings from Delay	99	97	140	137

SAVINGS AND COSTS FROM A ONE YEAR DELAY IN LIMERICK 1 USING A COAL PLANT TO VALUE THE ENERGY DISPLACED BY LIMERICK

EXPECTED COST OF MONEY[1]

Sources and Notes

[1]For the high cost of money case the interest rate and the returns to common and preferred equity were assumed to be one percentage point above the rates for the expected cost of money. These higher rates were assumed to apply only through the construction period for Limerick.
[2]For the 1976 delay analysis the in-service date for Limerick 1 was assumed to be deferred for one year, from 1982 to 1983.
[3]For the 1978 delay analysis the in-service date for Limerick 1 was assumed to be deferred for one year, from 1984 to 1985.
[4]The delay of Limerick 1 was assumed to raise the direct capital cost by $28.5 per kilowatt expressed in mid-1984 dollars. This cost estimate was developed by Bechtel in August 1976. This estimate was used in assessing the effects of both the 1976 and 1978 delays.
[5]These reflect the generating costs for replacement energy for the year after Limerick retires in the no delay case. These costs are based on the levelized costs of a coal plant.
[6]The first year fuel costs are the additional system fuel costs that would have been incurred if Limerick 1 was delayed for one year. These estimates were developed by Philadelphia Electric Company in 1977.

COMPONENTS OF PROJECTED GENERATING COST FOR LIMERICK SYSTEM BY YEAR OF ANALYSIS

Year of Analysis	Incremental Booked Capital Cost: On-line Date $/kW[1]	Incremental Booked Capital Cost: 1984 $/kW[2]	Annual Capital Cost[3]	Annual Capital Additions[4]	Annual Fixed O&M Cost[5]	Levelized Capacity Factor[6]	Annual Levelized Cost: Capital and Fixed O&M[7]	Annual Levelized Cost: Fuel[8]	Annual Levelized Cost: Total[9]
			(1984 $/kW)			(Percent)	(1984 Mills/kWh)		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1975	$584	$679	$37.33	$ 3.43	$12.46	68%	8.94	12.14	21.07
1976	688	705	41.56	4.05	16.01	67	10.50	14.45	24.95
1977	574	574	33.22	7.14	18.17	66	10.12	14.37	24.49
1978	709	606	36.34	6.72	20.23	65	11.11	14.34	25.46
1979	646	584	40.00	7.35	22.81	64	12.51	13.37	25.88
1980	752	623	41.65	13.95	27.75	63	15.10	11.47	26.57

Sources and Notes

[1]The nominal incremental booked cost per kilowatt of Limerick 1 & 2 as of the projected on-line date. This estimate includes only construction costs from the year of analysis through commercial operation plus capitalized property taxes and allowance for funds used during construction (AFDC). The estimate of AFDC assumes that construction work in progress is excluded from the rate base. The rates used to estimate AFDC in each year are described in Schedule 11. For the derivation of construction costs, see Schedule 9.
The projected commercial operation dates by year of analysis for Limerick 1 & 2 are as follows:

Year	Commercial Operation Date
1975	1982.0
1976	1984.0
1977	1984.0
1978	1986.0
1979	1986.0
1980	1986.5

COMPONENTS OF PROJECTED GENERATING COST FOR LIMERICK SYSTEM BY YEAR OF ANALYSIS

Sources and Notes

[2]Column (1) converted to mid-1984 dollars per kilowatt. To estimate booked costs in 1984 dollars, costs as of the date of commercial operation were brought back to year of analysis dollars by removing expected inflation and brought forward to 1984 dollars using actual inflation rates. The GNP implicit price deflator was used to measure price changes and is given in Schedule 11. Expected inflation is also shown in Schedule 11.

[3]The levelized annual capital cost expressed in mid-1984 dollars per kilowatt. This includes allowances for returns on common and preferred equity, interest on debt, depreciation and taxes associated with amortizing the initial construction cost of the project.

[4]The levelized annual cost of capital additions occurring over the plant's operating lifetime, in mid-1984 dollars per kilowatt. The derivation is described in Schedule 12.

[5]The levelized annual non-fuel operating and maintenance cost in mid-1984 dollars per kilowatt. The derivation is described in Schedule 13.

[6]The projected levelized capacity factor for Limerick. The estimate was derived, as discussed in the text, from a combination of engineering and statistical data.

[7]The sum of columns (3), (4) and (5) divided by the product of column (6) and 0.0876. The last constant is the number of hours in the year (8,760) divided by 1,000 (to convert from dollars to mills) and divided by 100 (to convert the capacity factor to a proportion).

[8]The levelized annual cost of fuel for Limerick in mid-1984 mills per kilowatt hour. The prices assumed for each nuclear fuel cycle component as of each analysis year are reported in Schedule 17.

[9]Column (9) equals the sum of columns (7) and (8).

COMPONENTS OF PROJECTED GENERATING COST FOR LIMERICK 1 NUCLEAR UNIT BY YEAR OF ANALYSIS

Year of Analysis	Incremental Booked Capital Cost: On-line Date $/kW[1]	Incremental Booked Capital Cost: 1984 $/kW[2]	Annual Capital Cost[3]	Annual Capital Additions[4]	Annual Fixed O&M Cost[5]	Levelized Capacity Factor[6]	Annual Levelized Cost: Capital and Fixed O&M[7]	Annual Levelized Cost: Fuel[8]	Annual Levelized Cost: Total[9]
			(1984 $/kW)			(Percent)	(1984 Mills/kWh)		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1975	$509	$632	$33.94	$ 4.50	$16.62	68%	9.24	12.01	21.25
1976	585	640	37.03	5.31	21.35	67	10.85	14.28	25.14
1977	430	462	26.16	9.37	24.23	66	10.34	14.21	24.55
1978	590	542	31.98	8.82	26.98	65	11.90	14.19	26.09
1979	495	477	32.10	9.64	30.43	64	12.87	13.24	26.11
1980	432	397	25.78	18.31	37.02	63	14.70	11.34	26.04

Sources and Notes

[1]The nominal incremental booked cost per kilowatt of Limerick 1 as of the projected on-line date. This estimate includes only construction costs from the year of analysis through commercial operation plus capitalized property taxes and allowance for funds used during construction (AFDC). The estimate of AFDC assumes that construction work in progress is excluded from the rate base. The rates used to estimate AFDC in each year are described in Schedule 11. For the derivation of construction costs, see Schedule 9. The projected commercial operation dates by year of analysis for Limerick 1 are as follows:

Year	Commercial Operation Date
1975	1980.0
1976	1983.0
1977	1983.0
1978	1985.0
1979	1985.0
1980	1985.0

COMPONENTS OF PROJECTED GENERATING COST FOR LIMERICK 1 NUCLEAR UNIT BY YEAR OF ANALYSIS

Sources and Notes

[2]Column (1) converted to mid-1984 dollars per kilowatt. To estimate booked costs in 1984 dollars, costs as of the date of commercial operation were brought back to year of analysis dollars by removing expected inflation and brought forward to 1984 dollars using actual inflation rates. The GNP implicit price deflator was used to measure price changes and is given in Schedule 11. Expected inflation is also shown in Schedule 11.

[3]The levelized annual capital cost expressed in mid-1984 dollars per kilowatt. This includes allowances for returns on common and preferred equity, interest on debt, depreciation and taxes associated with amortizing the initial construction cost of the project.

[4]The levelized annual cost of capital additions occurring over the plant's operating lifetime, in mid-1984 dollars per kilowatt. The derivation is described in Schedule 12.

[5]The levelized annual non-fuel operating and maintenance cost in mid-1984 dollars per kilowatt. The derivation is described in Schedule 13.

[6]The projected levelized capacity factor for Limerick 1. The estimate was derived, as discussed in the text, from a combination of engineering and statistical data.

[7]The sum of columns (3), (4) and (5) divided by the product of column (6) and 0.0876. The last constant is the number of hours in the year (8,760) divided by 1,000 (to convert from dollars to mills) and divided by 100 (to convert the capacity factor to a proportion).

[8]The levelized annual cost of fuel for Limerick 1 in mid-1984 mills per kilowatt hour. The prices assumed for each nuclear fuel cycle component as of each analysis year are reported in Schedule 17.

[9]Column (9) equals the sum of columns (7) and (8).

COMPONENTS OF PROJECTED GENERATING COST FOR A SUBCRITICAL COAL ALTERNATIVE TO LIMERICK BY YEAR OF ANALYSIS

Year of Analysis	Booked Capital Cost: On-line Date $/kW[1]	Booked Capital Cost: 1984 $/kW[2]	Annual Capital Cost[3]	Annual Fixed O&M Cost[4]	Annual Levelized Cost: Levelized Capacity Factor[5]	Annual Levelized Cost: Capital and Fixed O&M[6]	Annual Levelized Cost: Variable O&M[7]	Annual Levelized Cost: Fuel[8]	Annual Levelized Cost: Total[9]
			---(1984 $/kW)---		(Percent)	----------(1984 Mills/kWh)----------			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1975	$ 823	$1,021	$60.84	$14.93	64.49%	13.41	2.53	26.30	42.24
1976	1,002	1,097	69.17	15.31	64.55	14.94	2.53	24.75	42.22
1977	1,076	1,156	72.69	15.80	64.51	15.66	2.53	24.12	42.31
1978	1,304	1,198	76.91	16.19	64.57	16.46	3.38	24.66	44.50
1979	1,396	1,345	98.83	16.31	64.87	20.26	3.38	24.70	48.34
1980	1,515	1,392	99.48	16.84	64.83	20.48	3.38	25.20	49.06

Sources and Notes

[1]The nominal booked cost per kilowatt of the coal alternative as of the projected on-line date. This estimate includes all construction costs through commercial operation plus capitalized property taxes and allowance for funds used during construction (AFDC). The estimate of AFDC assumes that construction work in progress is excluded from the rate base. The rates used to estimate AFDC in each year are described in Schedule 11 and construction costs are derived in Schedule 10. The projected commercial operation dates for the coal alternative to Limerick 1 by year of analysis are as follows:

Year	Commercial Operation Date
1975	1981
1976	1983
1977	1983
1978	1985
1979	1985
1980	1985

COMPONENTS OF PROJECTED GENERATING COST FOR A SUBCRITICAL COAL ALTERNATIVE TO LIMERICK 1 BY YEAR OF ANALYSIS

Sources and Notes

[2]Column (1) converted to mid-1984 dollars per kilowatt. To estimate booked costs in 1984 dollars, costs as of the date of commercial operation were brought back to year of analysis dollars by removing expected inflation and brought forward to 1984 dollars using actual inflation rates. The GNP implicit price deflator was used to measure price changes and is given in Schedule 11. Expected inflation is also shown in Schedule 11.

[3]The levelized annual capital cost expressed in mid-1984 dollars per kilowatt. This includes allowances for returns on common and preferred equity, interest on debt, depreciation and taxes associated with amortizing the initial construction cost of the project. Capital additions for coal plants are estimated at 0.5 percent of initial construction cost annually.

[4]The levelized annual revenue requirements associated with fixed non-fuel operating and maintenance costs, expressed in mid-1984 dollars per kilowatt. The derivation of O&M cost is described in Schedule 14.

[5]The levelized capacity factor is 93 percent of the projected equivalent availability. This derivation is described in Schedule 16. The forecast for each analysis year was based only on units operating in that year.

[6]The sum of columns (3) and (4) divided by column (5) times 0.08760. This last constant is the number of hours in the year (8,760) divided by 1,000 (to convert from dollars to mills) and divided by 100 (to convert the capacity factor to a proportion).

[8]The levelized annual variable O&M cost in mid-1984 mills per kilowatt hour. The derivation is described in Schedule 15.

[9]Column (9) equals the sum of columns (6), (7) and (8).

COMPONENTS OF PROJECTED GENERATING COST FOR AN OIL ALTERNATIVE TO LIMERICK BY YEAR OF ANALYSIS

Year of Analysis	Annual Fixed O&M Cost[1] (1984 $/kW) (1)	Levelized Capacity Factor[2] (Percent) (2)	Annual Levelized Cost: Fixed O&M[3] (1984 Mills/kWh) (3)	Fuel[4] (1984 Mills/kWh) (4)	Total[5] (1984 Mills/kWh) (5)
1975	$13.44	68%	2.26	42.38	44.64
1976	13.78	67	2.35	43.07	45.42
1977	14.22	66	2.46	42.28	44.74
1978	14.57	65	2.56	47.72	50.28
1979	14.68	64	2.62	75.65	78.27
1980	15.15	63	2.75	86.67	89.42

Sources and Notes

[1]The levelized annual non-fuel operation and maintenance cost in mid-1984 dollars per killowatt.

[2]The levelized capacity factor for the oil alternative is assumed to equal that of Limerick so that the replacement generation of the oil alternative equals Limerick's generation.

[3]Column (1) divided by the product of column (2) times 0.0876. The last constant is the number of hours in a year (8,760) divided by 1,000 (to convert from dollars to mills) and divided by 100 (to convert the capacity factor to a proportion).

[4]The levelized anual cost of fuel in mid-1984 mills per kilowatt hour. Fuel cost in dollars per MMBtu is described in Schedule 18.

[5]Column (5) equals the sum of columns (3) and (4). The oil alternative is assumed to be an existing plant and therefore does not incur capital costs.

DERIVATION OF CAPITAL COST FOR LIMERICK SYSTEM

COMPARISON OF AVERAGE ANNUAL CONSTRUCTION COST FOR LIMERICK 1&2 AND OTHER NUCLEAR UNITS

Year of Analysis	Average Cost[1] of Other Units	Estimate[2] Based on Industry Data	PECO[3] Estimate
	(1984 $/kW)		
	(1)	(2)	(3)
1975	$ 944	$ 914-972	$1,059
1976	1,063	1,012-1,042	1,184
1977	875	1,051-1,112	1,184
1978	1,070	1,232-1,309	1,103
1979	912-966	1,115-1,350	1,182
1980	828-1,147	1,221-1,463	1,515

CONSTRUCTION COST ESTIMATES USED IN LIMERICK ANALYSIS

Year of Analysis	Total[4] Cost	Sunk[5] Cost	Incremental[6] Cost
	(1984 $/kW)		
	(1)	(2)	(3)
1975	$1,059	$362	$697
1976	1,184	483	701
1977	1,184	605	579
1978	1,309	707	602
1979	1,350	800	551
1980	1,515	919	596

DERIVATION OF CAPITAL COST FOR LIMERICK SYSTEM

Sources and Notes

[1]For 1975 through 1978, the average cost is for units completed in those years. For 1979 and 1980, the lower end of the range is the average cost of units completed in those years and the upper end of the range is the average of the projected completed cost of units under construction in those years.

[2]These ranges are estimates of the expected construction cost of Limerick based on an analysis of actual and estimated construction costs for other nuclear units. The estimates include all direct construction expenses but exclude interest during construction. They have adjusted to labor and materials prices prevailing in mid-1984 using the Handy-Whitman Index of nuclear construction expenses. Estimates from 1975 through 1978 are based on the average costs of completed units adjusted to Limerick's characteristics. The lower bound estimates for 1977 and 1978 and the higher bound estimates for 1975 and 1976 are based on the regression equation for pre-1972 units described on page 5 of this schedule. The other estimates for these years are based on the regression equation for post-1971 units described on page 8 of this schedule. For 1979 and 1980, the range includes data on average projected completed costs for units under construction in these years standardized to Limerick's characteristics. The lower bound estimate in 1979 is based on average projected completion cost using the pre-1972 units regression. The lower bound in 1980 is based on completed construction costs using the pre-1972 units regression equation. The higher bound estimates in 1979 and 1980 are based on completed costs using the post-1971 units equation.

[3]PECO's estimate of construction costs for units 1 and 2 of Limerick. This estimate includes all construction expenditures including pre-operation and start-up expenses as well as other owners' costs and capitalized property taxes, but excludes any AFDC. The estimates of cost have been adjusted to reflect labor and materials prices as of mid-1984. Adjustment to 1984 dollars is based on the Handy-Whitman Index of nuclear construction expenses.

[4]The total cost estimate used in each year is the highest value of the estimate based on industry data or the PECO estimate.

[5]Sunk costs are the actual direct cost expenditures through the end of the year of analysis.

[6]Incremental cost is equal to the total cost reported in Column (1) minus the sunk cost in Column (2).

DERIVATION OF CAPITAL COST FOR LIMERICK IN 1980 BASED ON THE PRE-1972 UNITS REGRESSION EQUATION

Average Capital Cost For Units in 1980:[1]

1984 $/kW	$828
Log	6.719

	Limerick[2] Characteristic	Average Annual[3] Characteristic	Regression[4] Coefficient	Adjustment[5] Factor ((1)-(2))*(3)
	(1)	(2)	(3)	(4)
Adjustments for Limerick's Characteristics				
Log of Size	6.961	6.813	-0.2277	-0.034
Log of Wage Index	-0.0496	-0.28	0.6531	0.150
Subsequent Unit Indicator	0.5	1	-0.1792	0.099
First Unit Indicator	0.5	0	0.0726	0.035
Turnkey Unit Indicator	0	0	-0.4050	0.000
Northeast Indicator	1	0	0.1382	0.138
Total Adjustment Factor:				0.388
Log of Limerick Cost in 1980:				7.1073
Limerick Cost in 1980: (1984 $/kW)				$1,221

DERIVATION OF CAPITAL COST FOR LIMERICK IN 1980 BASED ON THE POST-1971 UNITS REGRESSION EQUATION

Average Capital Cost For Units in 1980:[1]

1984 $/kW	$828
Log	6.719

	Limerick[2] Characteristic	Average Annual[3] Characteristic	Regression[6] Coefficient	Adjustment[5] Factor ((1)-(2))*(3)
	(1)	(2)	(3)	(4)
Adjustments for Limerick's Characteristics				
Log of Wage Index	-0.0496	-0.28	0.3708	0.085
Subsequent Unit Indicator	0.5	1	-0.4186	0.230
Single Unit BWR Indicator	0	0	0.2020	0.000
Rock Foundation Indicator	1	0	0.2191	0.219
Northeast Unit Indicator	1	0	0.2191	0.219
Cooling Tower Indicator	1	0.5	0.0678	0.034
Utility is Constructor	0	0.00	-0.2560	0.000
Total Adjustment Factor:				0.569
Log of Limerick Capital Cost in 1980:				7.2881
Limerick Capital Cost in 1980: (1984 $/kW)				$1,463

DERIVATION OF CAPITAL COST FOR LIMERICK SYSTEM

Sources and Notes

[1]The average capital cost (exclusive of AFDC, in 1984 $/kW) for units completed in 1980 is adjusted to reflect Limerick's characteristics using the nuclear capital cost regression equation. Since the dependent variable in the regression is the natural log of cost the adjustments are made to the log of average cost.

[2]This column describes the characteristics of Limerick as they are used in this equation. Limerick's size is 1,055 MW and the wage index used is for Philadelphia, PA and is equal to 0.952. To derive an average cost for units 1 and 2 a weight of 0.5 is given to both the subsequent unit and first unit indicators.

[3]This column describes the average unit characteristics for all nuclear units completed in 1980.

[4]The regression coefficients are taken from the regression reported at page 5 of this schedule. This regression relates costs to unit characteristics for a sample of 66 nuclear units which received a construction permit piror to 1972. The footnotes to that table contain a detailed description of each of the variables in the equation.

[5]Limerick's capital cost is derived by multiplying the regression coefficient for each variable by the difference between Limerick's characteristic and the corresponding characteristic of the units completed in 1980. The sum of these adjustment factors added to the log of the average capital cost for the completed units in 1980 is equal to the natural log of the capital cost for Limerick. The antilog of this value is the capital cost in 1984 dollars per kilowatt.

[6]In this example the nuclear capital cost regression based on post-1971 units is used to adjust the average cost to Limerick's characteristics. This regression equation is described in detail at pages 8 and 9 of this schedule.

REGRESSION RELATING CAPITAL COSTS FOR NUCLEAR UNITS WHICH RECEIVED A CONSTRUCTION PERMIT PRIOR TO 1972 TO SELECTED CHARACTERISTICS

	Variable Mean[2]	Regression Coefficient[3]	t-Statistic[4]
	(1)	(2)	(3)
Log of Construction Cost	6.5613	-	-
Constant	1.0000	8.2695	-
Log of Size[5]	6.6889	-0.2277	1.689
Log of Wage Index[6]	-0.1114	0.6531	3.479
Subsequent Unit Indicator[7]	0.3182	-0.1792	2.384
First Unit Indicator[8]	0.3182	0.0726	0.983
Turnkey Unit Indicator[9]	0.1818	-0.4050	4.358
Northeast Indicator[10]	0.3182	0.1382	2.205
Vintage Indicators:[11]			
1966 or earlier	0.1364	-0.4202	3.958
1967	0.2121	-0.3469	4.261
1969 or later	0.3182	0.2578	3.854
Number of Observations		66	
Adjusted R^2		0.7872	
Standard Error		0.2124	

REGRESSION RELATING CAPITAL COSTS FOR NUCLEAR UNITS WHICH RECEIVED A CONSTRUCTION PERMIT PRIOR TO 1972 TO SELECTED CHARACTERISTICS

Sources and Notes

[1]The dependent variable in the regression is the natural log of capital cost per kilowatt. Actual costs have been adjusted to reflect the costs of constructing the plants at labor and materials costs prevailing in 1984 with no allowance for funds used during construction. Results are based on all nuclear units, including demo and turnkey units, which received
[2]construction permits prior to 1972.
[2]The variable mean is the average value of each of the variables in the
[3]analysis for the sample used to estimate the regression equation.
[3]The regression coefficient describes the effect of a one-unit change in the
[4]independent variable on the dependent variable.
[4]The t-statistic is the ratio of the mean of the coefficient to its standard error. It measures the reliability with which the coefficient is measured. A t-statistic of 1.96 or higher indicates that the coefficient is significantly different from zero at the 5 percent level. A t-statistic of 1.64 or
[5]higher indicates significance at the 10 percent level.
[5]Size is the natural log of the net design electric rating as reported in U.S. NRC, Licensed Operating Reactors, at the time the unit received its
[6]operating permit.
[6]The wage rate is a composite of 1981 wages plus fringe benefits for crafts used in constructing nuclear power plants. The composite consists of the following crafts: pipefitters (30 percent), electricians (19 percent), common laborers (18 percent), carpenters (12 percent), steelworkers (10 percent), operating engineers (7 percent), boilermakers (2 percent) and millwrights (2 percent). Wages for these crafts were obtained from R. S. Means Co., Inc., 1978 Labor Rates for the Construction Industry, for the communities from which construction labor was hired. The wage is expressed as an index relative to the national
[7]average.
[7]The indicator is equal to 1 if the unit is a subsequent unit built of a multi-
[8]unit plant and 0 otherwise.
[8]The indicator is equal to 1 if the unit is the first of a multi-unit plant and
[9]0 otherwise.
[9]The indicator is equal to 1 if the unit is a turnkey or demo unit and 0 otherwise. Unit status is taken from N.U.S. Corporation, Commercial Nuclear Power Plants, Edition No. 16, February 1984.

REGRESSION RELATING CAPITAL COSTS FOR NUCLEAR UNITS WHICH RECEIVED A CONSTRUCTION PERMIT PRIOR TO 1972 TO SELECTED CHARACTERISTICS

Sources and Notes

[10] The indicator is equal to 1 if the unit is in Connecticut, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont or Washington, D.C. and 0 otherwise. Locations are from U.S. Department of Energy, U.S. Central Station Nuclear Electric Generating Units; Significant Milestones (Status as of July 1, 1983), DOE/NE-0030/9, October 1983.

[11] The indicator is equal to 1 if unit received its construction permit in the year or years indicated and 0 otherwise. Yearle 66 equals 1 if unit received permit in 1967. Construction permit date is taken from U.S. Department of Energy, U.S. Central Station Nuclear Electric Generating Units; Significant Milestones (Status as of July 1, 1983), DOE/NE-0030/9, October 1983.

REGRESSION RELATING CAPITAL COST FOR NUCLEAR UNITS WHICH RECEIVED A CONSTRUCTION PERMIT IN 1972 OR LATER TO SELECTED CHARACTERISTICS[1]

	Variable Mean[2] (1)	Regression Coefficient[3] (2)	t-Statistic[4] (3)
Log of Construction Cost	7.4925	-	-
Constant	1.0000	7.7510	-
Log of Wage Index[5]	-0.1040	0.3708	2.421
Subsequent Unit Indicator[6]	0.4068	-0.4186	8.368
Single Unit BWR Indicator[7]	0.1186	0.2020	2.462
Rock Foundation Indicator[8]	0.6271	-0.1516	2.642
Cooling Tower Indicator[9]	0.6102	0.0678	1.322
Utility is Constructor Indicator[10]	0.2373	-0.2560	4.275
Northeast Indicator[11]	0.1864	0.2191	3.344
Number of Observations		59	
Adjusted R^2		0.7915	
Standard Error		0.1775	

REGRESSION RELATING CAPITAL COST FOR NUCLEAR UNITS WHICH RECEIVED A CONSTRUCTION PERMIT IN 1972 OR LATER TO SELECTED CHARACTERISTICS[1]

Sources and Notes

[1]The dependent variable in the regression is the natural log of capital cost per kilowatt. Actual costs have been adjusted to reflect the cost of constructing the plants at labor and materials costs prevailing in 1984 with no allowance for funds used during construction. The data are from a September 1984 TVA survey, or from
[2]a NERA survey of individual utilities if TVA did not report costs for a unit.
[2]The variable mean is the average value of each of the variables in the analysis for
[3]the sample used to estimate the regression equation.
[3]The regression coefficient describes the effect of a one-unit change in the
[4]independent variable on the dependent variable.
[4]A t-statistic is the ratio of the mean of the coefficient to its standard error. It measures the reliability with which the coefficient is measured. A t-statistic of 2.01 or higher indicates that the coefficient is significantly different from zero at the 5 percent level. A t-statistic of 1.68 or higher indicates significance at the
[5]10 percent level.
[5]The wage rate is a composite of 1981 wages plus fringe benefits for crafts used in constructing nuclear power plants. The composite consists of the following crafts: steamfitters (30 percent), electricians (19 percent), common laborers (18 percent), carpenters (12 percent), steelworkers (10 percent), operating engineers (7 percent), boilermakers (2 percent) and millwrights (2 percent). The wage is expressed as an index relative to the national average. Wages for these crafts were obtained from R.S. Means Co., Inc., 1978 Labor Rates for the Construction Industry for the
[6]communities from which construction labor was hired.
[6]The indicator is equal to 1 if the unit is a subsequent unit of a series built at a site
[7]and 0 otherwise.
[7]The indicator is equal to 1 if the unit is a single unit plant with a boiling water reactor and 0 otherwise. BWR classification is taken from U.S. Department of Energy, U.S. Central Station Nuclear Electric Generating Units; Significant Mile-
[8]stones (Status as of July 1, 1983), DOE/NE-0030/9, October 1983.
[8]The indicator is equal to 1 if the unit is built on a rock foundation and 0 otherwise. Rock or soil site classification was provided to NERA from Burns & Roe in March
[9]1984.
[9]The indicator is equal to 1 if the unit has a cooling tower and 0 otherwise. Cooling tower data are from NUS Corporation, Commercial Nuclear Power Plants, Edition
[10]No. 16, February 1984.
[10]The indicator is equal to 1 if the utility is the construction manager and either TVA, Duke Power Company, or Commonwealth Edison Company. Otherwise, the indicator is equal to 0. Construction manager data are from NUS Corporation, Commercial
[11]Nuclear Power Plants, Edition No. 16, February 1984.
[11]The indicator is equal to 1 if the unit is in Connecticut, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont or Washington, D.C. and 0 otherwise. Locations are from U.S. Department of Energy, U.S. Central Station Nuclear Electric Generating Units; Significant Milestones (Status as of July 1, 1983), DOE/NE-0030/9, October 1983.

DERIVATION OF CAPITAL COST FOR A SUBCRITICAL COAL ALTERNATIVE TO LIMERICK 1 IN 1980

Variable	Regression Coefficient[1] (1)	Plant Characteristic[2] (2)	Cross Product[3] (3)
Constant	4.3978	1	4.3978
First Unit Indicator	0.2934	0.5	0.1467
Lagged First Unit Indicator	0.1392	0	0
Log of Net Size in Megawatts	-0.2081	5.9915	-1.2467
Log of Wage Index	0.5671	0.0446	0.0253
Operation Date	0.0401	80	3.2064
Supercritical Indicator	0.8501	0	0
Supercritical Size Trend	-0.1263	0	0
Low Sulfur Indicator	0.0786	0	0
Outdoor Boiler Indicator	-0.0664	0	0
Cooling Tower Indicator	0.0575	1	0.0575
Mountain Indicator	-0.8529	0	0
Mountain Time Trend	0.0124	0	0
Southwest Indicator	-2.2217	0	0
Southwest Time Trend	0.0270	0	0
Northeast Indicator	-1.8695	1	-1.8695
Northeast Time Trend	0.0279	80	2.2281
Architect/Engineer Indicator:			
A/E-B	0.1362	0.0949	0.0129
A/E-S	0.2324	0.0678	0.0158
Utility-A	0.0802	0.0271	0.0022
Utility-T	0.3830	0.0169	0.0065
Log of Plant Capital Cost in 1980:			6.9828
Scrubber Capital Cost			
Constant	4.1752	1	4.1752
Subsequent Unit Indicator	-0.2093	0.5	-0.1047
Lime/Limestone Scrubber Indicator	-0.3396	1	-0.3396
Percent Sulfur Removal	0.0158	89.39	1.4124
1972-1977 On-Line Year Indicator	0.5990	0	0
Log of Scrubber Capital Cost in 1980:			5.1433
Particulate Capital Cost			
Constant	5.6399	1	5.6399
Log of Size (MW)	-0.2000	5.9915	-1.1983
Log of Wage Index	0.5000	0.0446	0.0223
Percent Sulfur in Coal	-0.0660	2.7	-0.1782
Particulate Emission Limit	-5.0950	0.03	-0.1529
Log of Particulate Capital Cost in 1980:			4.1329
Coal Capital Cost in 1980 (1984 $/kW):[4]			
Plant Cost:			$1,077.97
Scrubber Cost:			171.28
Particulate Cost:			62.36
Total Plant Cost:			$1,311.60

DERIVATION OF CAPITAL COST FOR A SUBCRITICAL COAL ALTERNATIVE TO LIMERICK 1 IN 1980

Sources and Notes

[1]The regression coefficients for the plant capital cost equation are taken from the regression equation shown at page 3 of this schedule. The regression equation for the scrubber capital cost is shown at page 6. The footnotes to those tables contain a detailed description of the definition of each variable included in the regression equations. The constant for the plant capital cost equation shown here has been adjusted downward by 3 percent to remove the cost of simple particulate control systems included in the plant cost data. The parameters of the particulate cost equation are based upon estimates presented in "Impact of Particulate Emission Regulations on the Economics of Power Production for New, Large, Coal-Fired Power Plants" prepared by Stearns-Roger for EPRI, October 1977.

[2]The coal alternative is assumed to consist of two 400 MW subcritical units with indoor boilers, cooling towers and lime/limestone scrubbers burning coal with 2.7 percent sulfur content. The journeymen's wage index is for Philadelphia, PA and is equal to 1.0456. For architect/engineer the average values for subcritical coal plants in the U.S. which began commercial operation between 1965 and 1983 are used.

[3]The capital cost is derived by multiplying the regression coefficient for each variable by the corresponding characteristic of the coal alternative. The sum of these cross products is equal to the natural log of the capital cost; the antilog of this sum yields the capital cost in mid-1984 dollars per kilowatt.

[4]The total plant capital cost for the coal alternative is equal to the sum of the plant, scrubber and particulate capital cost.

REGRESSION RELATING CAPITAL COSTS FOR COAL PLANTS TO SELECTED CHARACTERISTICS[1]

	Variable Mean[2]	Regression Coefficient[3]	t-Statistic[4]
	(1)	(2)	(3)
Log of Capital Cost	6.2862	-	-
Constant	1.0000	4.4278	-
First Unit Indicator[5]	0.3322	0.2934	9.728
Lagged First Unit Indicator[6]	0.2305	0.1392	4.079
Log of Net Size in Megawatts[7]	6.1271	-0.2081	6.406
Log of Wage Index[8]	-0.0738	0.5671	3.984
Operation Date[9]	-73.5390	0.0401	11.082
Supercritical Indicator[10]	0.3254	0.8501	1.486
Supercritical Size Trend[11]	2.1162	-0.1263	1.420
Scrubber Indicator[12]	0.1492	0.1762	4.217
Low Sulfur Indicator[13]	0.4203	0.0786	2.501
Outdoor Boiler Indicator[14]	0.3763	-0.0664	2.084
Cooling Tower Indicator[15]	0.4508	0.0575	1.877
Mountain Indicator[16]	0.1220	-0.8529	1.260
Mountain Time Trend[16]	9.2339	0.0124	1.395
Southwest Indicator[17]	0.0847	-2.2217	1.223
Southwest Time Trend[17]	6.7322	0.0270	1.181
Northeast Indicator[18]	0.0814	-1.8695	2.171
Northeast Time Trend[18]	5.7254	0.0279	2.284
Architect/Engineer Indicator[19]			
A/E - B	0.0949	0.1362	2.950
A/E - S	0.0678	0.2324	4.375
Utility - A	0.0271	0.0802	0.907
Utility - T	0.0169	0.3830	3.740
Number of Observations		295	
Adjusted R^2		0.6931	
Standard Error		0.2078	

REGRESSION RELATING CAPITAL COSTS FOR COAL PLANTS TO SELECTED CHARACTERISTICS[1]

Sources and Notes

[1]The dependent variable in the regression is the natural log of capital cost per kilowatt. Actual costs have been adjusted to reflect the costs of constructing the plants at labor and materials costs prevailing in 1984 with no allowance for funds used during construction. Cost data are taken from FERC (FPC) Form 1 for the year in which the unit first came on-line. Unless otherwise noted, all other data are from USFPC, Steam Electric Plant Construction Cost and Annual Production Expenses, annually.

[2]The variable mean is the average value of each of the variables in the analysis for the sample used to estimate the regression equation.

[3]The regression coefficient describes the effect of a one-unit change in the independent variable on the dependent variable.

[4]A t-statistic is the ratio of the mean of the coefficient to its standard error. It measures the reliability with which the coefficient is measured. A t-statistic of 1.96 or higher indicates that the coefficient is significantly different from zero at the 5 percent level. A t-statistic of 1.64 or higher indicates significance at the 10 percent level.

[5]The indicator is equal to 1 if the unit is the first unit of a series built at a site and 0 otherwise.

[6]The indicator is equal to 1 if the unit is not the first unit of a series at site but came on-line 3 or more years later or differs in size by 10 percent or more than the previous unit at that size and 0 otherwise.

[7]Size is the natural log of the net electrical rating. To derive a net rating data reflecting the gross generator nameplate rating as reported to the FPC were multiplied by 0.9 if the unit had a scrubber and 0.93 otherwise.

[8]The wage rate represents the average wage plus employer contributions to funds for journeymen in the construction industry of the SMSA nearest to the plant. The wage is expressed as an index relative to the U.S. average. Wages are taken from U.S. Bureau of Labor Statistics, Union Wages and Benefits: Building Trades, July 3, 1978, Bulletin 2038, Table 16.

[9]The operation date is the year the plant came on-line minus 1900.

[10]The indicator is equal to 1 if the unit is a supercritical unit and 0 otherwise.

[11]The supercritical size trend is the product of the supercritical indicator and the natural log of the net size of the unit.

[12]The indicator is equal to 1 if the unit has a scrubber and 0 otherwise. Scrubber data are taken from U.S. Department of Energy, Cost and Quality of Fuels for Utility Plants, annually.

[13]This indicator is equal to 1 if the coal sulfur content is less than 1 percent and 0 otherwise.

[14]The indicator is equal to 1 if the unit is built with an outdoor boiler and 0 otherwise.

REGRESSION RELATING CAPITAL COSTS FOR COAL PLANTS TO SELECTED CHARACTERISTICS[1]

Sources and Notes

[15]The indicator is equal to 1 if the unit has a cooling tower and 0 otherwise.
[16]The indicator is equal to 1 if the unit located in Arizona, Colorado, Montana, Nevada, New Mexico or Wyoming and 0 otherwise. The Mountain time trend variable is the product of the mountain indicator and the operation date.
[17]The indicator is equal to 1 if the unit is located in Arkansas, Oklahoma or Texas and 0 otherwise. The southwest time trend is the product of the southwest indicator and the operation date.
[18]The indicator is equal to 1 if the unit is located in Connecticut, Maine, Massachussetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island or Vermont and 0 otherwise. The northeast time trend is the product of the northeast indicator and the operation date.
[19]This indicator is equal to 1 if the plant was built by this particular architect or utility and 0 otherwise. Codes beginning with utility indicate that the utility was its own A/E. A/E data are taken from Power Engineering, New Generating Plants (annually) or from Kidder Peabody, Status Report on Engineers and Construction Managers for Electric Utility Nuclear Reactors and Fossil Boilers.

REGRESSION RELATING SCRUBBER CAPITAL COSTS FOR COAL PLANTS TO SELECTED CHARACTERISTICS[1]

	Variable Mean[2] (1)	Regression Coefficient[3] (2)	t-statistic[4] (3)
Log of Scrubber Capital Cost	5.3182	-	-
Constant	1.0000	4.1752	-
Subsequent Unit Indicator[5]	0.3077	-0.2093	1.774
Lime/Limestone Scrubber Indicator[6]	0.7231	-0.3396	2.823
Percent Sulfur Removal[7]	75.7831	0.0158	4.708
1972-1977 On-line Year Indicator[8]	0.4308	0.5990	5.428
Number of Observations		65	
Adjusted R^2		0.4999	
Standard Error		0.4316	

Sources and Notes

[1]The dependent variable in the regression is the natural log of scrubber capital cost per kilowatt. Actual costs have been adjusted to reflect the costs of constructing the plants at labor and materials costs prevailing in 1984 with no allowance for funds used during construction. Data are taken from U.S. Department of Energy, Cost and Quality of Fuels for Electric Utility Plants, 1981 Annual, September 1982.

[2]The variable mean is the average value of each of the variables in the analysis for the sample used to estimate the regression equation.

[3]The regression coefficient describes the effect of a one-unit change in the independent variable on the dependent variable.

[4]A t-statistic is the ratio of the mean of the coefficient to its standard error. It measures the reliability with which the coefficient is measured. A t-statistic of 1.96 or higher indicates that the coefficient is significantly different from zero at the 5 percent level. A t-statistic of 1.64 or higher indicates significance at the 10 percent level.

[5]The indicator is equal to 1 if the unit is a subsequent unit at a site and 0 otherwise.

[6]The indicator is equal to 1 if the unit uses lime/limestone with the sulfur removal system and 0 otherwise.

[7]Indicates the percentage sulfur removed by the sulfur removal system.

[8]The indicator is equal to one for units which began commercial operation in the particular years indicated and 0 otherwise.

ACTUAL YIELDS ON LONG-TERM DEBT AND ACTUAL INFLATION RATES

Year	Yield on Long-Term Debt[1] (Percent) (1)	Inflation Rate[2] (Percent) (2)
1971	7.70%	3.48%
1972	7.65	3.56
1973	8.08	7.65
1974	9.72	11.41
1975	10.74	7.18
1976	9.54	4.75
1977	9.08	6.21
1978	10.25	8.19
1979	11.44	6.89
1980	14.23	9.76

Sources and Notes

[1]This is the actual yield to maturity on selected Philadelphia Electric Company unsubordinated debt outstanding in each year as reported in Moody's Public Utility Manual, annual issues.

[2]This is the annual percent change from 4th quarter to 4th quarter in the GNP implicit price deflator. See the Economic Report of the President, February 1985 (Washington, D.C.: U.S. Government Printing Office, 1985): Table B-3, p. 236.

CAPITAL STRUCTURE BY YEAR[1]

Year	Common Equity	Preferred Equity	Long-Term Debt
	(Percent)		
	(1)	(2)	(3)
1971	35.07%	11.74%	53.19%
1972	35.32	13.32	51.35
1973	37.06	14.42	48.52
1974	33.13	14.95	51.92
1975	34.48	13.70	51.82
1976	34.58	13.96	51.47
1977	35.24	13.86	51.66
1978	34.43	13.61	51.95
1979	34.89	12.79	53.32
1980	35.50	13.25	51.25

Sources and Notes

[1] Year-end book values as reported for Philadelphia Electric Company in Moody's Public Utility Manual, annual issues.

ACTUAL FEDERAL AND STATE INCOME TAX RATES

Year	Income Tax Rates	
	Federal	State
	(Percent)	
	(1)	(2)
1975	48.0%	9.50%
1976	48.0	9.50
1977	48.0	10.50
1978	48.0	10.50
1979	46.0	10.50
1980	46.0	10.50

EXPECTED COST OF MONEY, DISCOUNT RATE AND INFLATION RATE BY YEAR OF ANALYSIS

Year of Analysis	Expected Cost of Money: Long-Term Debt[1]	Expected Cost of Money: Common Equity[2]	Expected Cost of Money: Preferred Equity[3]	Expected Discount Rate[4]	Expected Inflation Rate[5]
	(Percent)				
	(1)	(2)	(3)	(4)	(5)
1975	8.77%	11.03%	8.72%	7.14%	6.62%
1976	9.14	11.98	9.24	7.65	6.88
1977	9.43	12.83	9.58	8.04	7.42
1978	9.86	13.45	9.98	8.37	7.52
1979	10.21	13.95	10.18	8.75	6.64
1980	10.89	14.06	10.63	9.10	7.15

Sources and Notes

[1]This is the five-year geometric mean of the actual yields on long-term debt given on page 1 of this schedule. The average includes the yield in the year of analysis plus the previous four years.

[2]A discounted cash flow method was used to estimate the required rate of return for a large number of U.S. electric utilities. For those utilities we calculated the differential between the long-term debt rate and the required rate of return. This premium was added to the expected debt rate in column (1) to obtain the required return on common equity.

[3]A procedure similar to that outlined in footnote 2 was used for preferred equity.

[4]The expected discount rate is the weighted average after-tax cost of money. This rate is also used as the AFDC rate in calculating the booked capital cost for Limerick and the coal alternative.

[5]The expected inflation rate for each year of analysis is the geometric mean of the actual inflation rate in that year and the preceding four years. Actual annual inflation rates are on page 1 of this schedule.

OTHER FINANCIAL ASSUMPTIONS

	Limerick	Coal & Oil Alternative
Book Life (years)	30	30
Tax Life (years)	10	15
Decommissioning Charge as Percent of Booked Cost	0.5%	-
Property Tax Rate During Operating Period as Percent of Net Plant	0.48%	0.48%
Accounting Treatment[1]		
Liberalized Depreciation	Normalized	Normalized
Treatment of ITC	Ratable	Ratable

Sources and Notes

[1]Based on the actual accounting treatment applied by PECO.

INVESTMENT TAX CREDIT RATE BY YEAR OF ANALYSIS

	Expected ITC Rates			
	Limerick		Coal Alternative	
	Plant	Unit 1	Plant	Unit 1
	(Percent)			
	(1)	(2)	(3)	(4)
1975	10.0%	9.0%	10.%	8.8%
1976	8.0	7.4	8.0	6.0
1977	7.6	7.0	8.0	6.0
1978	10.0	10.0	10.0	10.0
1979	10.0	10.0	10.0	10.0
1980	10.0	10.0	10.0	10.0

Sources and Notes

[1]The ITC rates for each year of analysis are the average rates expected to prevail through the construction period.

DERIVATION OF CAPITAL ADDITIONS FOR LIMERICK SYSTEM

AVERAGE ANNUAL CAPITAL ADDITIONS FOR LIMERICK 1 & 2 AND OTHER NUCLEAR PLANTS

Year of Analysis	Average Annual[1] Capital Additions	Limerick Plant[2] Capital Additions
	(1984 $/kW)	
	(1)	(2)
1975	$ 6.51	$ 3.43
1976	6.76	4.05
1977	10.93	7.14
1978	10.20	6.72
1979	9.89	7.35
1980	17.34	13.95

DERIVATION OF CAPITAL ADDITIONS FOR LIMERICK 1 & 2 IN 1980

Average Capital Additions Cost For Units in 1980:

1984 $/kW	$17.34
Log	2.853

	Limerick[3] Characteristic	Average Annual[4] Characteristic	Regression[5] Coefficient	Adjustment[6] Factor ((1)-(2)*(3))
	(1)	(2)	(3)	(4)
Adjusted for Limerick's Characteristics:				
Log of Number of Units	0.693	0.290	-0.3925	-0.158
Log of Average Size	6.961	6.633	-0.6461	-0.213
Reciprocal of Unit Age	1	0.190	1.2747	1.033
Log of Wage Index	-0.050	-0.102	1.0962	0.056
Northeast Indicator	1	0.293	0.2132	0.151
South Indicator	0	0.317	-0.0512	0.016
Saltwater Indicator	0	0.317	0.2198	-0.070
Total Adjustment Factor:				0.814
Log of Limerick Capital Additions in 1980:				3.667
Limerick Capital Additions in 1980: (1984 $/kW)				$39.15

CAPITAL ADDITIONS BY YEAR OF OPERATION

Year	Capital Additions (1984 $/kW)
1	$39.15
5	14.11
10	12.42
30	11.41
Levelized Capital Additions	$13.95

DERIVATION OF CAPITAL ADDITIONS COST FOR LIMERICK

Sources and Notes

[1]To derive the capital additions cost for Limerick for each year of analysis the average cost of plants operating in each year is adjusted to reflect Limerick's characteristics.

[2]This column represents the capital additions for Limerick, levelized over a 30 year life, in each year of analysis.

[3]Limerick is a two unit plant with an average unit size of 1,055 MW. The utility wage index is for Philadelphia, PA and is equal to 0.952.

[4]This column describes the average characteristics of plants operating in 1980.

[5]The regression coefficients are taken from the regression equation shown at page 3 of this schedule. The footnotes to that table contain a detailed description of the definition of each of the variables in the equation.

[6]The capital additions for Limerick is derived by multiplying the regression coefficient for each variable by the difference between Limerick's characteristic and the corresponding characteristic of plants operating in 1980. The sum of these adjustment factors added to the log of the average capital additions of plants operating in 1980 is equal to the log of capital additions for Limerick; the antilog of this value yields the first year capital additions in mid-1984 dollars per kilowatt.

REGRESSION RELATING CAPITAL ADDITIONS FOR NUCLEAR PLANTS TO SELECTED CHARACTERISTICS[1]

	Variable Mean[2] (1)	Regression Coefficient[3] (2)	t-Statistic[4] (3)
Log of Capital Additions	2.5173	-	-
Constant	1.0000	4.5023	-
Log of Number of Units	0.2690	-0.3925	2.117
Log of Average Size[5]	6.5646	-0.6461	2.412
Reciprocal of Unit Age[6]	0.2393	1.2747	4.014
Log of Wage Index[7]	-0.1047	1.0962	1.722
Northeast Indicator[8]	0.3289	0.2132	1.210
South Indicator[8]	0.2763	-0.0512	0.201
Saltwater Cooling Indicator[9]	0.3237	0.2198	1.520
Year Indicators:[10]			
1971	0.0105	0.1666	0.219
1972	0.0184	0.1252	0.188
1973	0.0342	0.5559	0.921
1974	0.0368	1.0314	1.724
1975	0.0632	1.1232	1.971
1976	0.0763	1.2850	2.273
1977	0.0737	1.8547	3.256
1978	0.0974	1.7906	3.197
1979	0.0921	1.8574	3.281
1980	0.0974	2.5016	4.409
1981	0.1000	2.7032	4.765
1982	0.1132	2.5357	4.493
1983	0.0921	2.8812	5.023
1984	0.0816	3.2657	5.649
Number of Observations		380	
Adjusted R^2		0.2590	
Standard Error		1.1259	

REGRESSION RELATING CAPITAL ADDITIONS FOR NUCLEAR PLANTS TO SELECTED CHARACTERISTICS[1]

Sources and Notes

[1]The dependent variable in the regression is the natural log of capital additions (capital costs that occur after the plant has come on-line) in 1984 dollars per kilowatt. With the exception of the wage indices, the 1965-1978 data are from the Federal Power Commission (now Federal Energy Regulatory Commission), Steam-Electric Plant Construction Cost and Annual Production Expenses, and the 1979-1984 data are from Schedule 432 of Federal Power Commission, Form 1, "Annual Report of Privately Owned Electric Utilities, Classes A and B."

[2]The variable mean is the average value of each of the variables in the analysis for the sample used to estimate the regression equation.

[3]The regression coefficient describes the effect of a one-unit change in the independent variable on the dependent variable.

[4]The t-statistic is the ratio of the mean of the coefficient to its standard error. It measures the reliability with which the coefficient is measured. A t-statistic of 1.96 or higher indicates that the coefficient is significantly different from zero at the 5 percent level. A t-statistic of 1.64 or higher indicates significance at the 10 percent level.

[5]Size is the natural log of the net design electric rating as reported in U.S. NRC, Licensed Operating Reactors, at the time the unit received its operating permit.

[6]Age is defined as the average age of units operating at the site and is entered as the reciprocal of age. Unit age is equal to the year of observation minus the commercial operation date.

[7]The wage rate is a composite of 1981 wages plus fringe benefits for crafts used in constructing nuclear power plants. The composite consists of the following crafts: pipefitters (30 percent), electricians (19 percent), common laborers (18 percent), carpenters (12 percent), steelworkers (10 percent), operating engineers (7 percent), boilermakers (2 percent) and millwrights (2 percent). Wages for these crafts were obtained from R.S. Means Co., Inc., 1978 Labor Rates for the Construction Industry, for the communities from which construction labor was hired. The wage is expressed as an index relative to the national average.

[8]The indicator is equal to 1 if the plant is located in the region and 0 otherwise. The regions are defined as follows:

Northeast:	Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont.
South:	Alabama, Arkansas, Florida, Georgia, Kentucky, Louisiana, Maryland, Mississippi, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, Virginia, West Virginia.

[9]The indicator is equal to 1 if saltwater is used as cooling water and 0 otherwise.

[10]The indicator is equal to 1 if the observation is for that particular operating year and 0 otherwise.

DERIVATION OF FIXED O&M COST FOR LIMERICK SYSTEM

AVERAGE ANNUAL O&M COST FOR LIMERICK 1 & 2 AND OTHER NUCLEAR UNITS

Year of Analysis	Average Annual[1] Fixed O&M (1984 $/kW)	Limerick[2] Fixed O&M (1984 $/kW)
	(1)	(2)
1975	$14.32	$12.46
1976	19.11	16.01
1977	21.50	18.17
1978	24.16	20.23
1979	27.68	22.81
1980	33.19	27.75

DERIVATION OF FIXED O&M COST FOR LIMERICK 1 & 2 IN 1980

Average Fixed O&M Cost in 1980:

1984 $/kW	$33.19
Log	3.502

	Limerick[3] Characteristic (1)	Average Annual[4] Characteristic (2)	Regression[5] Coefficient (3)	Adjustment[6] Factor ((1)-(2)*(3)) (4)
Adjusted for Limerick's Characteristics:				
Log of Number of Units	0.693	0.290	-0.4156	-0.167
Log of Average Size	6.961	6.633	-0.4707	-0.155
Log of Plant Age	0	1.794	0.0868	-0.156
Log of Wage Index	-0.050	-0.102	0.6263	0.033
Northeast Indicator	1	0.293	0.2263	0.160
South Indicator	0	0.317	0.1838	-0.058
Saltwater Indicator	0	0.317	0.1396	-0.044
Total Adjustment Factor:				-0.387
Log of Limerick Fixed O&M Cost in 1980:				3.115
Limerick Fixed O&M Cost in 1980: (1984 $/kW)				$22.54

FIXED O&M COST BY YEAR OF OPERATION

Year	Fixed O&M Cost (1984 $/kW)
1	$22.54
5	25.91
10	27.52
30	30.27
Levelized O&M Cost	$27.75

DERIVATION OF FIXED O&M COST FOR LIMERICK

Sources and Notes

[1]To derive the fixed O&M cost for Limerick for each year of analysis the average cost of plants operating in each year is adjusted to reflect Limerick's characteristics.

[2]This column represents the fixed O&M cost for Limerick, levelized over a 30 year life, in each year of analysis.

[3]Limerick is a two unit plant with an average unit size of 1,055 MW. The utility wage index is for Philadelphia, PA and is equal to 0.952.

[4]This column describes the average characteristics of plants operating in 1980.

[5]The regression coefficients are taken from the regression equation shown at page 3 of this schedule. The footnotes to that table contain a detailed description of the definition of each of the variables in the equation.

[6]The fixed O&M cost for Limerick is derived by multiplying the regression coefficient for each variable by the difference between Limerick's characteristic and the corresponding characteristic of plants operating in 1980. The sum of these adjustment factors added to the log of the average O&M cost of plants operating in 1980 is equal to the log of O&M cost for Limerick; the antilog of this value yields the first year O&M cost in mid-1984 dollars per kilowatt.

REGRESSION RELATING FIXED OPERATING AND MAINTENANCE COSTS FOR NUCLEAR PLANTS TO SELECTED CHARACTERISTICS[1]

	Variable Mean[2]	Regression Coefficient[3]	t-Statistic[4]
	(1)	(2)	(3)
Log of O&M Cost	3.2936	-	-
Constant	1.0000	5.0628	-
Log of Number of Units	0.2810	-0.4156	7.560
Log of Average Size[5]	6.5797	-0.4707	5.235
Log of Average Age[6]	1.5789	0.0868	2.299
Log of Wage Index[7]	-0.1041	0.6263	3.373
Northeast Indicator[8]	0.3326	0.2263	4.371
South Indicator[8]	0.2764	0.1838	2.445
Saltwater Cooling Indicator[9]	0.3191	0.1396	3.236
Year Indicators:[10]			
1971	0.0180	0.0572	0.301
1972	0.0247	0.1465	0.820
1973	0.0382	0.4407	2.639
1974	0.0472	0.6172	3.787
1975	0.0562	0.6135	3.801
1976	0.0742	0.8654	5.444
1977	0.0831	0.9911	6.227
1978	0.0944	1.0997	6.910
1979	0.0966	1.2267	7.600
1980	0.0921	1.4219	8.673
1981	0.0944	1.5532	9.403
1982	0.1011	1.6101	9.712
1983	0.0831	1.7820	10.486
1984	0.0809	1.9718	11.490
Number of Observations		445	
Adjusted R^2		0.7001	
Standard Error		0.3658	

REGRESSION RELATING FIXED OPERATING AND MAINTENANCE COSTS FOR NUCLEAR PLANTS TO SELECTED CHARACTERISTICS

Sources and Notes

[1]The dependent variable in the regression is the natural log of expensed non-fuel operating and maintenance cost, in 1984 dollars per kilowatt. With the exception of the wage indices, the 1965-1978 data are from the Federal Power Commission (now Federal Energy Regulatory Commission), Steam-Electric Plant Construction Cost and Annual Production Expenses, and the 1979-1984 data are from Schedule 432 of Federal Power Commission, Form 1, "Annual Report of Privately Owned Electric Utilities, Classes A and B."

[2]The variable mean is the average value of each of the variables in the analysis for the sample used to estimate the regression equation.

[3]The regression coefficient describes the effect of a one-unit change in the independent variable on the dependent variable.

[4]The t-statistic is the ratio of the mean of the coefficient to its standard error. It measures the reliability with which the coefficient is measured. A t-statistic of 1.96 or higher indicates that the coefficient is significantly different from zero at the 5 percent level. A t-statistic of 1.64 or higher indicates significance at the 10 percent level.

[5]Size is the natural log of the net design electric rating as reported in U.S. NRC, Licensed Operating Reactors, at the time the unit received its operating permit.

[6]Age is defined as the average age, of units operating at the site and is entered as the natural log of age. Unit age is equal to the year of observation minus the commerical operating date.

[7]The wage rate is a composite of 1981 wages plus fringe benefits for crafts used in constructing nuclear power plants. The composite consists of the following crafts: pipefitters (30 percent), electricians (19 percent), common laborers (18 percent), carpenters (12 percent), steelworkers (10 percent), operating engineers (7 percent), boilermakers (2 percent) and millwrights (2 percent). Wages for these crafts were obtained from R.S. means Co., Inc., 1978 Labor Rates for the Construction Industry, for the communities from which construction labor was hired. The wage is expressed as an index relative to the national average.

[8]The indicator is equal to 1 if the plant is located in the region and 0 otherwise. The regions are defined as follows:

Northeast:	Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont.
South:	Alabama, Arkansas, Florida, Georgia, Kentucky, Louisiana, Maryland, Mississippi, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, Virginia, West Virginia.

[9]The indicator is equal to 1 if saltwater is used as cooling water and 0 otherwise.

[10]The indicator is equal to 1 if the observation is for that particular operating year and 0 otherwise.

DERIVATION OF FIXED O&M COST FOR A SUBCRITICAL COAL ALTERNATIVE TO LIMERICK 1 IN 1980

Variable	Regression Coefficient[1] (1)	Plant Characteristic[2] (2)	Cross Product[3] (3)
Constant	6.4976	1	6.498
Log of Number of Units	-0.0922	0.693	-0.064
Log of Average Size	-1.8934	5.992	-11.344
Log of Average Size, Squared	0.1731	35.898	6.213
Log of Plant Age	0.3397	0	0
Reciprocal of Plant Age	0.3299	1	0.330
Time	0.0289	16	0.462
Log of Wage Index	0.8881	0.045	0.040
Northeast Indicator	0.1383	1	0.138
South Indicator	0.0552	0	0
West Indicator	0.2323	0	0
		Log of Coal O&M Cost:	2.272
		First Year Coal O&M Cost: (1984 $/kW)	$ 9.70

Coal Fixed O&M By Year of Operation

Year	O&M Cost (1984 $/kW)
1	$ 9.70
5	12.87
10	15.76
30	22.39

Levelized Fixed O&M Cost: (1984 $/kW) $16.84

DERIVATION OF FIXED O&M COST FOR A SUBCRITICAL COAL ALTERNATIVE TO LIMERICK 1 IN 1980

Sources and Notes

[1]The regression coefficients are taken from the regression equation shown at page 3 of this schedule. The sources and notes to that table contain a detailed description of the definition of each of the variables in the equation. Since a separate equation is used to estimate scrubber O&M costs the scrubber indicator in this equation is not used.

[2]The coal alternative to Limerick is assumed to consist of two 400 MW units. The time variable is expressed as the year minus 1964, which for the year 1980 is equal to 16. The wage index used is for Philadelphia, PA and is equal to 1.0456.

[3]The predicted O&M cost is derived by multiplying the regression coefficient for each variable by the corresponding characteristic of the coal alternative. The sum of these cross products is equal to the natural log of the first year O&M cost; the antilog of this sum yields the first year O&M cost in mid-1984 dollars per kilowatt.

REGRESSION RELATING FIXED OPERATING AND MAINTENANCE COSTS FOR COAL PLANTS TO SELECTED CHARACTERISTICS[1]

	Variable Mean[2]	Regression Coefficient[3]	t-Statistic[4]
	(1)	(2)	(3)
Log of O&M Cost	2.4150	-	-
Constant	1.0000	6.4976	-
Log of Number of Units	0.6220	-0.0922	2.340
Log of Average Size[5]	6.0238	-1.8934	3.920
Log of Average Size, Squared	36.5808	0.1731	4.138
Log of Plant Age[6]	1.7430	0.3397	5.283
Reciprocal of Plant Age[6]	0.2514	0.3299	1.969
Time[7]	12.0166	0.0289	5.767
Log of Wage Index[8]	-0.0775	0.8881	3.103
Proportion of Plant Scrubbed[9]	0.0310	0.5679	5.223
Northeast Indicator[10]	0.2118	0.1383	2.756
South Indicator[10]	0.3661	0.0552	0.843
West Indicator[10]	0.1210	0.2323	4.024
Number of Observations		661	
Adjusted R^2		0.4429	
Standard Error		0.4012	

REGRESSION RELATING FIXED OPERATING AND MAINTENANCE COSTS FOR COAL PLANTS TO SELECTED CHARACTERISTICS

Sources and Notes

[1]The dependent variable in the regression is the natural log of expensed non-f -l operating and maintenance costs, in 1984 dollars per kilowatt. With the exception of the wage indices, the 1965-1978 data are from the Federal Power Commission (now Federal Energy Regulatory Commission), Steam-Electric Plant Construction Cost and Annual Production Expenses, and the 1979-1981 data are from Schedule 432 of Federal Power Commission, Form 1, "Annual Report of Privately Owned Electric Utilities, Classes A and B."

[2]The variable mean is the average value of each of the variables in the analysis for the sample used to estimate the regression equation.

[3]The regression coefficient describes the effect of a one-unit change in the independent variable on the dependent variable.

[4]The t-statistic is the ratio of the mean of the coefficient to its standard error. It measures the reliability with which the coefficient is measured. A t-statistic of 1.96 or higher indicates that the coefficient is significantly different from zero at the 5 percent level. A t-statistic of 1.64 or higher indicates significance at the 10 percent level.

[5]Average size is the average unit size at the plant based on the gross nameplate capacity as reported to the FPC. Net size is derived by multiplying gross size by 0.9 for scrubber units and 0.93 otherwise.

[6]Age is measured as full calendar years of operation. The age variables are constructed as the reciprocal of age and the natural log of age.

[7]Time is measured as the year of the observation minus 1964.

[8]The wage rate represents the average wage plus employer contributions to funds for journeymen in the construction industry for the SMSA nearest to the plant. The wage is expressed as an index relative to the U.S. average. Wages are taken from U.S. Bureau of Labor Statistics, Union Wages and Benefits: Building Trades, July 3, 1978, Bulletin 2038, Table 16.

[9]Proportion of plant scrubbed is derived as the ratio of the portion of the plant with scrubber to the total plant (in megawatts) in each year.

[10]The indicator is equal to 1 if the plant is located in the region and 0 otherwise. The regions are defined as follows:

Northeast:	Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont.
South:	Alabama, Arkansas, Florida, Georgia, Kentucky, Louisiana, Maryland, Mississippi, North Carolina, Oklahoma, South Carolina, Tennessee, Texas, Virginia, West Virginia.
West:	Arizona, California, Colorado, Idaho, Montana, Utah, Washington, Wyoming.

DERIVATION OF SCRUBBER O&M COST FOR A SUBCRITICAL COAL ALTERNATIVE TO LIMERICK IN 1989

Variable	Regression Coefficient[1] (1)	Plant Characteristic[2] (2)	Cross Product[3] (3)
Constant	0.0644	1	0.064
Design Percent Removal	0.0429	89.39	3.835
Lime/Limestone Indicator	-0.9740	1	-0.974
Quantity of Sulfur Removed	0.1136	4.0	0.454
Scrubber O&M Cost in 1984 mills/kWh			3.38

Sources and Notes

[1]The regression coefficients are based on the regression equation shown at page 2 of this schedule. The values shown here have been adjusted downward by 61 percent to reflect the observed difference in scrubber O&M cost between plants with and without a scrubber and to convert to 1984 dollars. The sources and notes to that table contain a detailed
[2]description of the definition of each of the variables in the equation.
The coal alternative to Limerick is assumed to burn bituminous coal with a sulfur content of 2.7 percent and a heat content of 12,064 Btu/lb. The quantity of sulfur removed, based on a design percent removal of 89.39
[3]percent, is 4.0 lbs./MMBtu.
The predicted scrubber O&M cost is derived by multiplying the regression coefficient for each variable by the corresponding characteristic of the coal alternative. The sum of these cross products is equal to scrubber O&M cost in 1984 mills per kilowatt hour.

REGRESSION RELATING SCRUBBER O&M COST FOR COAL PLANTS TO SELECTED CHARACTERISTICS[1]

	Variable Mean[2] (1)	Regression Coefficient[3] (2)	t-Statistic[4] (3)
Scrubber O&M Cost	7.3986	-	-
Constant	1.0000	0.1650	-
Design Percent Removal[5]	75.3317	0.1100	3.128
Lime/Limestone Scrubber Indicator[6]	0.7143	-2.4974	2.462
Quantity of Sulfur Removed[7]	2.5213	0.2912	1.136
Number of Observations		63	
Adjusted R^2		0.2990	
Standard Error		3.5295	

Sources and Notes

[1]The dependent variable in the regression is scrubber operating and maintenance cost in 1979 mills/kWh. Data are taken from U.S. Department of Energy, Cost and Quality of Fuels for Electric Utility Plants, 1981, September 1982.

[2]The variable mean is the average value of each of the variables in the analysis for the sample used to estimate the regression equation.

[3]The regression coefficient describes the effect of a one-unit change in the independent variable on the dependent variable.

[4]The t-statistic is the ratio of the mean of the coefficient to its standard error. It measures the reliability with which the coefficient is measured. A t-statistic of 1.96 or higher indicates that the coefficient is significantly different from zero at the 5 percent level. A t-statistic of 1.64 or higher indicates significance at the 10 percent level.

[5]Design percent removal is the sulfur percent removal the scrubber was designed to achieve.

[6]The indicator is equal to 1 if the unit uses lime or limestone in the scrubber and 0 otherwise.

[7]The quantity of sulfur removed is equal to the sulfur content of the coal, expressed as pounds of SO_2 per MMBtu, multiplied by the design percent removal (expressed as a proportion).

DERIVATION OF CAPACITY FACTOR FOR A SUBCRITICAL COAL ALTERNATIVE TO LIMERICK 1 IN 1980

Variable	Regression Coefficient[1] (1)	Plant Characteristic[2] (2)	Cross Product[3] (3)
Constant	176.1880	1	176.188
Log of Net Size	-12.6082	5.992	-75.542
Reciprocal of Age	-20.2009	1	-20.201
Log of Age	-7.3757	0	0
Vintage Indicators:			
1961 or Earlier	-	-	-
1962-1971	-4.3260	0	0
1972 or Later	-2.5554	1	-2.555
Post-1974 Operating Year Indicator	-5.5160	1	-5.516
Log of Sulfur Content	-1.1788	0.993	-1.711
Cyclone Indicator	-4.5902	0	0
Balanced Draft Indicator	3.0564	1	3.056
Boiler Manufacturer Indicator:			
Combustion Engineering	-2.7526	0.532	-1.466
Foster Wheeler	-10.4096	0.087	-0.907
Riley	-5.3342	0.056	-0.301
Architect/Engineer Indicator:			
A/E-B	-2.0778	0.071	-0.148
A/E-S	-4.6569	0.081	-0.377
A/E Utility-S	0.5539	0.068	0.038
A/E Utility-D	3.8561	0.039	0.149
A/E Utility-A	0.1323	0.094	0.012
A/E Utiltiy-T	-3.4080	0.156	-0.530
A/E Utility-C	-14.3542	0.075	-1.071
A/E Utility Other or Unknown	1.0019	0.391	0.392
First Year Equivalent Availability:			70.05%
First Year Capacity Factor:[4]			65.15%

Capacity Factor By Year of Operation

Year	Equivalent Availability	Capacity Factor
1	70.05%	65.15%
5	74.34	69.14
10	71.25	66.26
30	64.49	59.98
Levelized Capacity Factor:		64.83

DERIVATION OF CAPACITY FACTOR FOR A SUBCRITICAL COAL ALTERNATIVE TO LIMERICK 1 IN 1980

Sources and Notes

[1]The regression coefficients are taken from the regression equation reported at page 3 of this schedule. The footnotes to that table contain a detailed description of the definition of each of the variables in the equation.

[2]The characteristics assumed for the coal alternative to Limerick. The coal plant is assumed to consist of two 400 MW balanced draft units, burning coal with a 2.7 percent sulfur content. For the boiler manufacturer and architect/engineer variables, the value used in the average for all subcritical coal plants located in the United States, which began commercial operation between 1965 and 1989.

[3]Equivalent availability for the Limerick coal alternative is derived by multiplying the regression coefficient for each variable by the corresponding characteristic of the coal alternative. The sum of these cross products is equal to the first year equivalent availability.

[4]The first year capacity factor is derived by multiplying the first year equivalent availability by 0.93, the observed ratio of capacity factor to equivalent availability for large baseload coal units.

REGRESSION RELATING EQUIVALENT AVAILABILITY FOR SUBCRITICAL COAL UNITS TO SELECTED CHARACTERISTICS[1]

	Variable Mean[2] (1)	Regression Coefficient[3] (2)	t-Statistic[4] (3)
Equivalent Availability	75.0977	-	-
Constant	1.0000	176.1880	-
Log of Net Size[5]	5.6794	-12.6082	10.294
Reciprocal of Age[6]	0.1715	-20.2009	4.671
Log of Age[6]	2.1968	-7.3757	4.409
Vintage Indicators:[7]			
1961 or earlier	0.4334	-	-
1962-1971	0.3969	-4.3260	3.240
1972 or later	0.1697	-2.5554	1.244
Post-1974 Operating Year Indicator[8]	0.6868	-5.5160	5.915
Log of Sulfur Content[9]	0.5648	-1.1788	2.142
Cyclone Indicator[10]	0.1515	-4.5902	4.285
Balanced Draft Indicator[11]	0.5530	3.0564	3.683
Boiler Manufacturer Indicators:[12]			
Combustion Engineering	0.5319	-2.7526	2.993
Foster Wheeler	0.0871	-10.4096	7.519
Riley	0.0564	-5.3342	3.356
Architect/Engineer Indicators:[13]			
A/E - B	0.0712	-2.0778	1.562
A/E - S	0.0809	-4.6569	3.643
A/E Utility - S	0.0683	0.5539	0.412
A/E Utility - D	0.0387	3.8561	2.214
A/E Utility - A	0.0940	0.1323	0.089
A/E Utility - T	0.1555	-3.4080	2.967
A/E Utility - C	0.0746	-14.3542	10.161
A/E Utility Other or Unknown	0.3912	1.0019	0.856
Number of Observations		1,756	
Adjusted R^2		0.3023	
Standard Error		12.9920	

REGRESSION RELATING EQUIVALENT AVAILABILITY FOR SUBCRITICAL COAL UNITS TO SELECTED CHARACTERISTICS[1]

Sources and Notes

[1]The dependent variable in the regression is coal equivalent availability (expressed as a percent) for a large sample of subcritical coal units operating from 1969 to 1980. Initial partial years of operation were excluded as were years in which equivalent availability was less than or equal to 0.10 percent and years when a fuel other than coal was burned. Data are from NERC, Generating Availability Data System, Report on Equipment Availability, 1982, unless
[2]otherwise indicated.
[2]The variable mean is the average value of each of the variables in the analysis
[3]for the sample used to estimate the regression equation.
[3]The regression coefficient describes the effect of a one-unit change in the
[4]independent variable on the dependent variable.
[4]The t-statistic is the ratio of the mean of the coefficient to its standard error. It measures the reliability with which the coefficient is measured. A t-statistic of 1.96 or higher indicates that the coefficient is significantly different from zero at the 5 percent level. A t-statistic of 1.64 or higher indicates significance
[5]at the 10 percent level.
[5]Size is based on gross generator nameplate rating in megawatts as reported to the FPC, and is entered as the natural log of size. To convert to net it is
[6]multiplied by 0.9 for scrubber units and 0.93 otherwise.
[6]Age is measured as full calendar years of operation. The age variables are
[7]constructed as the reciprocal of age and the natural log of age.
[7]The indicator is equal to 1 if the unit began commercial operation in the particular years indicated and 0 otherwise. Units which came on-line prior to 1962 are treated as the reference group and are not explicitly included in the
[8]regression equation.
[8]The indicator is equal to 1 for 1974 and later operating years and 0 otherwise.
[9]Sulfur content is measured as percent by weight and is entered as the natural log
[10]of sulfur content. Coal sulfur content data are taken from FERC Form 67.
[10]The indicator is equal to 1 if the unit has a cyclone boiler and 0 otherwise. Cyclone boiler data are from S.M. Stoller Corporation, SMSC Pedigree Data for
[11]Fossil Units.
[11]The indicator is equal to 1 if the unit was built with a balanced draft boiler and 0 otherwise. This data was obtained from Electric World, Steam Station Design
[12]Survey, annually.
[12]The indicator is equal to 1 if the boiler was manufactured by the particular manufacturer indicated and 0 otherwise. Boiler manufacturer data were obtained from Kidder, Peabody & Co., Electric Utility Generating Equipment
[13]Data Base, or from Power Engineering, New Generating Plant, annually.
[13]The indicator is equal to 1 if the unit was built by the particular architect/engineer represented and 0 otherwise. Codes beginning with utility indicate that the utility was its own A/E for the unit. (Unknown indicates that A/E data for that unit were not available.) A/E data were obtained from the same sources as boiler manufacturer, which are listed in footnote 12.

ASSUMED PRICES FOR NUCLEAR FUEL CYCLE COMPONENTS BY YEAR OF ANALYSIS[1]

Year of Analysis	U_3O_8[2] (1984 $/lb) (1)	Conversion[3] (1984 $/Kg) (2)	Enrichment[4] (1984 $/SWU) (3)	Fuel Fabrication[5] (1984 $/Kg) (4)	Waste Disposal & Transportation[6] (1984 $/Kg) (5)
1975	$53.85	$8.85	$ 95.18	$212.37	$336.25
1976	67.12	8.85	107.00	212.37	336.25
1977	65.81	8.85	113.01	212.37	336.25
1978	61.35	8.85	119.90	212.37	336.25
1979	49.49	8.85	128.76	212.37	336.25
1980	33.75	8.85	135.19	212.37	336.25

Sources and Notes

[1]In deriving the fuel cost for Limerick the following assumptions were made. Assumed characteristics for nuclear fuel:

Enrichment Percentage	3.05%
Tails Assay Percentage	0.20%
Specific Power	23.30 MW/MT
Burnup	27,550 MWD (thermal)/MT

In calculating the cost for specific nuclear fuel components the following leads or lags between purchase and use were assumed:

Component	Lead or (Lag)
U_3O_8	3 years
Conversion	3 years
Enrichment	1.5 years
Fuel Fabrication	0.5 years
Waste Disposal	(5) years

ASSUMED PRICES FOR NUCLEAR FUEL CYCLE COMPONENTS BY YEAR OF ANALYSIS

Sources and Notes

We also assumed the following losses of fuel at each stage of processing:

Mining and milling	1.5%
Conversion and enrichment	0.5%
Fabrication	1.0%

[2]The nominal price per pound of U_3O_8 adjusted to mid-1984 dollars at actual general inflation rates. The prices are the average market prices as of the end of each analysis year published in NUEXCO, "Monthly Report on the Nuclear Fuel Market," No. 197 (January 1985): p. 22. In the analysis, U_3O_8 was assumed to escalate at 2.0 percent above the anticipated rate of general inflation.

[3]The nominal price per kilogram for conversion of U_3O_8 to UF_6 or uranium hexafloride, adjusted to mid-1984 dollars at actual general inflation rates. Prices are based on an estimate prepared by NUS Corporation. See NUS Corporation, "Draft Testimony of the NUS Corporation in the Matter of Generic and Environment Statement on Mixed Oxide Fuel" (November 1976): Exhibit 1.

[4]The nominal price per SWU for enrichment services adjusted to mid-1984 dollars at actual general inflation rates. The prices are the volume weighted averages of U.S. Department of Energy charges for enrichment services in each analysis year. The data were supplied to NERA by the Colorado Nuclear Corporation.

[5]The nominal price per kilogram for fuel fabrication adjusted to mid-1984 dollars at actual general inflation rates. The prices were obtained from the NUS Corporation (see footnote 3, ibid).

[6]The projected nominal price for nuclear waste transportation and disposal adjusted to mid-1984 dollars at actual general inflation rates. See NUS Corporation, ibid.

ASSUMED FUEL PRICES FOR COAL AND OIL ALTERNATIVES TO LIMERICK[1]

Analysis Year	Delivered Cost of Coal (1984 $/MMBtu) (1)	Delivered Cost of Coal (1984 $/ton) (2)	Delivered Cost of Oil (1984 $/MMBtu) (3)
1975	$ 2.14	$51.67	$ 3.47
1976	1.93	46.50	3.50
1977	1.89	45.71	3.46
1978	1.92	46.36	3.88
1979	1.96	47.37	5.16
1980	2.02	48.74	6.01

Sources and Notes

[1]Coal price data reflect the average cost of coal with a sulfur content greater than 1.5 percent delivered to the Eastern PJM region in each year. Cost data are taken from FERC Form 423. The coal price is converted to dollars per ton using a heat content of 12,064 BTU/lb.

[2]Oil prices are the average price of oil delivered to utilities in each analysis year, taken from U.S. Department of Energy, Cost and Quality of Fuels For Electic Utilities in the United States, annually.

DERIVATION OF HEAT RATE FOR A SUBCRITICAL COAL ALTERNATIVE TO LIMERICK 1 IN 1980

Variable	Regression Coefficient[1] (1)	Plant Characteristic[2] (2)	Cross Product[3] (3)
Constant	5,988.872	1	5,988.872
Log of Net Size	1,240.123	5.992	7,430.153
Reciprocal of Size	402,141	0.003	1,005.353
Log of Age	208.881	0	0
Reciprocal of Age	278.459	1	278.459
Vintage Indicators:			
1963 or Earlier	-		
1964-1970	303.626	0	0
1971-1975	442.311	0	0
1969 or Later	795.808	1	795.808
Log of Output Factor	-895.783	4.533	-4,060.226
Equivalent Availability	-6.282	70.054	-440.079
Log of Heat Content	-649.955	2.490	-1,618.535
Cyclone Indicator	130.175	0	0
Boiler Manufacturer Indicator:			
Combustion Engineering	80.807	0.544	43.943
Foster Wheeler	800.200	0.079	23.596
Riley	116.159	0.044	5.053
Turbine Manufacturer Indicator:			
Westinghouse	78.540	0.331	26.005
Allis-Chalmers	-31.244	0.033	-1.044
Architect/Engineer Indicator:			
A/E-B	26.009	0.068	1.766
A/E-S	-33.340	0.069	-2.304
A/E Utility-S	95.047	0.071	6.739
A/E Utility-D	-282.061	0.040	-11.254
A/E Utility-A	-52.228	0.098	-5.103
A/E Utiltiy-T	-106.702	0.163	-17.350
A/E Utility-C	-56.620	0.078	-4.416
A/E Utility Other or Unknown	42.440	0.408	17.316
First Year Gross Heat Rate: (Btu/kWh)			9,463
First Year Net Heat Rate[4]: (Btu/kWh)			10,175

Heat Rate By Year of Operation

Year	Gross Heat Rate	Net Heat Rate
	--------(Btu/kWh)--------	
1	9,463	10,175
5	9,576	10,297
10	9,693	10,423
30	9,904	10,649
Levelized Heat Rate:		10,446

DERIVATION OF HEAT RATE FOR A SUBCRITICAL COAL ALTERNATIVE TO LIMERICK 1 IN 1980

Sources and Notes

[1]The regression coefficients are taken from the regression equation reported at page 3 of this schedule. The footnotes to that table contain a detailed description of the definition of each of the variables in the equation.

[2]The characteristics assumed for the coal alternative to Limerick. The coal plant is assumed to consist of two 400 MW units burning coal with a heat content of 12,064 Btu/lb. Equivalent availability is derived as shown in page 1 of Schedule 16. For the boiler manufacturer, turbine manufacturer and the architect/engineer variables the values used are the averages for all subcritical coal plants located in the U.S. which began commercial operation from 1965 through 1979.

[3]The gross heat rate for the Limerick coal alternative is derived by multiplying the regression coefficient for each variable by the corresponding characteristic of the coal alternative. The sum of these cross products is equal to the first year gross heat rate.

[4]First year net heat rate is the gross heat rate divided by 0.93. Ninety-three percent is the average ratio of gross to net for coal-fired plants.

REGRESSION RELATING GROSS HEAT RATE FOR SUBCRITICAL COAL UNITS TO SELECTED CHARACTERISTICS[1]

	Variable Mean[2] (1)	Regression Coefficient[3] (2)	t-Statistic[4] (3)
Gross Heat Rate	9,355.70	-	-
Constant	1.0000	5,988.872	-
Log of Net Size[5]	5.6788	1240.123	6.119
Reciprocal of Size[5]	0.0037	402,141	6.305
Log of Age[6]	2.2230	208.881	3.993
Reciprocal of Age[6]	0.1659	278.459	1.844
Vintage Indicators:[7]			
1963 or earlier	0.5474	-	-
1964-1970	0.2752	303.626	6.952
1971-1975	0.1298	442.311	6.960
1976 or later	0.0476	795.808	9.250
Log of Output Factor[8]	4.3628	-895.783	9.675
Equivalent Availability[9]	75.2976	-6.282	6.962
Log of Heat Content[10]	2.3979	-649.955	4.755
Cyclone Indicator[11]	0.1549	130.175	3.384
Boiler Manufacturer Indicators:[12]			
Combustion Engineering	0.5438	80.807	2.365
Foster Wheeler	0.0786	300.200	5.337
Riley	0.0435	116.159	1.770
Turbine Manufacturer Indicators:[13]			
Westinghouse	0.3311	78.540	2.802
Allis-Chalmers	0.0334	-31.244	0.435
Architect/Engineer Indicators:[14]			
A/E - B	0.0679	26.009	0.504
A/E - S	0.0691	-33.340	0.647
A/E Utility - S	0.0709	95.047	1.894
A/E Utility - D	0.0399	-282.061	4.289
A/E Utility - A	0.0977	-52.228	1.001
A/E Utility - T	0.1626	-106.702	2.468
A/E Utility - C	0.0780	-56.620	1.015
A/E Utility-Other or Unknown	0.4080	42.440	1.125
Number of Observations		1679	
Adjusted R^2		0.3419	
Standard Error		467.560	

REGRESSION RELATING GROSS HEAT RATE FOR SUBCRITICAL COAL UNITS TO SELECTED CHARACTERISTICS

Sources and Notes

[1]The dependent variable in the regression is gross heat rate (Btu per kilowatt-hour) and was calculated using boiler-specific fuel consumption data from FERC Form 67. The data for the independent variables were obtained from NERC, Generating Availability Data System, Report on Equipment Availability, 1981, unless otherwise noted. The regression is based on a sample of subcritical coal units operating from 1969 through 1980. Initial partial years of operation were excluded as were years in which equivalent availability was less than or equal to 0.10 percent. Observations for which the coal heat, ash or moisture content was not available were also excluded.

[2]The variable mean is the average value of each of the variables in the analysis for the sample used to estimate the regression equation.

[3]The regression coefficient describes the effect of a one-unit change in the independent variable on the dependent variable.

[4]The t-statistic is the ratio of the mean of the coefficient to its standard error. It measures the reliability with which the coefficient is measured. A t-statistic of 1.96 or higher indicates that the coefficient is statistically different from zero at the 5 percent level. A t-statistic of 1.64 or higher indicates significance at the 10 percent level.

[5]Size is based on gross generator nameplate rating in megawatts as reported to the FPC, and is entered as the natural log of size and the reciprocal of size. To convert to net it is multiplied by 0.9 for scrubber units and 0.93 otherwise.

[6]Age is measured as full calendar years of operation. The age variables are constructed as the reciprocal of age and the natural log of age.

[7]The indicator is equal to 1 if the unit began commercial operation in the particular years indicated and 0 otherwise. Units which came on-line prior to 1964 are treated as the reference group and are not explicitly included in the regression equation.

[8]The output factor is defined as (Capacity Factor)/(Service Hours/Period Hours) and is entered as the natural log of the output factor.

[9]Equivalent availability is measured as a percent.

[10]Heat content is the average heat content of coal expressed as MBTU/lb and is entered as the natural log of heat content. Heat content data are obtained from FERC Form 67.

[11]The indicator is equal to 1 if the unit has a cyclone boiler and 0 otherwise. Cyclone boiler data are from S.M. Stoller Corporation, SMSC Pedigree Data for Fossil Units.

[12]The indicator is equal to 1 if the boiler was built by the particular manufacturer indicated and 0 otherwise. Boiler manufacturer data were obtained from Kidder, Peabody & Co., Electric Utility Generating Equipment Data Base, or from Power Engineering, New Generating Plant, annual.

[13]The indicator is equal to 1 if the turbine was built by the particular manufacturer indicated and 0 otherwise. Turbine manufacturer data are from the same sources as boiler manufacturer data which are listed in footnote 12.

REGRESSION RELATING GROSS HEAT RATE FOR SUBCRITICAL COAL UNITS TO SELECTED CHARACTERISTICS

Sources and Notes

[14]The indicator is equal to 1 if the unit was built by the particular architect/engineer represented and 0 otherwise. Codes beginning with utility indicate that the utility was its own architect/engineer for the unit. A/E data were obtained from the same sources as boiler manufacturer data listed in footnote 12.

VITA

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PROFESSIONAL BACKGROUND:

9/72-Present — NATIONAL ECONOMIC RESEARCH ASSOCIATES, INC.
Senior Vice President

Dr. Perl has been responsible for a variety of studies relating to the economics of energy and the environment. These include analyses of the costs of air and water pollution control for the electric utility industry and for the copper, lead, and zinc industry, as well as various comparisons of the costs and benefits of specific environmental programs. He has also directed a number of econometric studies of the elasticity of demand for electricity, the elasticity of demand for telephone service, and the price of uranium. He has also been involved in the development of a model for projecting coal prices and a variety of studies evaluating the economics of alternative energy sources.

Dr. Perl has also been extensively involved in research on the economics of the labor market and particularly on the economic analysis of employee discrimination problems. He has assisted clients in evaluating their labor market practices, in developing constructive responses to charges of labor market discrimination brought by the EEOC and in developing Affirmative Action Programs.

1968-1972 — CORNELL UNIVERSITY--Ithaca, New York

Dr. Perl taught economics at the New York School of Industrial and Labor Relations. His fields of specialization were labor economics, econometrics and economic history.

EDUCATIONAL BACKGROUND:

UNIVERSITY OF CALIFORNIA AT BERKELEY
Ph.D., Economics, 1970
Dissertation Title: "The Role of Educational Investment and Family Background in the Production and Distribution of Educational Services"

UNIVERSITY OF CALIFORNIA AT BERKELEY
M.A., Economics, 1968

CORNELL UNIVERSITY
B.S., Industrial and Labor Relations, 1963

NUCLEAR-COAL

Publications:

with Frederick C. Dunbar, "Indexing Coal and Other Mineral Contracts," Eastern Mineral Law Foundation, Proceedings of the Third Annual Institute, (New York, New York: Matthew Bender, 1982), pp. 1-1 to 1-18.

Workshop on Concepts of Uranium Resources and Producibility, a report prepared by the Panel on Concepts of Uranium Resources (Washington, D.C.: National Academy of Sciences, 1978), pp. 126-147.

"Nuclear Power: Let's Not Pull the Plug," The Los Angeles Times, January 17, 1978.

"The Future of Nuclear Power in the Electric Utility Industry," Nuclear News, Vol. 17, No. 15, December 1974.

Speeches:

"The Economics of Nuclear Power," presented at the 1982 Annual Conference sponsored by the Atomic Industrial Forum, Washington, D.C., November 15, 1982.

"The Current Economics of Electric Generation from Coal in the U.S. and Western Europe," presented before the International Scientific Forum on 'Reassessing the World's Energy Prospects: The Critical Questions,' Paris, France, October 26, 1982.

"The Economics of Nuclear Power," presented at 'The Economics of Nuclear Power: Should Construction Proceed?' Seminar sponsored by National Economic Research Associates, Inc., New York, New York, June 3, 1982.

"Cost Comparisons Among Nuclear Plants Under Construction," presented at 'The Economics of Nuclear Power: Should Construction Proceed?' Seminar

sponsored by National Economic Research Associates, Inc., New York, New York, June 3, 1982.

"The Economics of Canceling Nuclear Construction Projects," presented at 'The Economics of Nuclear Power: Should Construction Proceed?' Seminar sponsored by National Economic Research Associates, Inc., New York, New York, June 3, 1982.

"Planning to Meet Needs in An Optimal Way: Nuclear vs. Coal vs. the Other Sources," summary of remarks before 'Utility Planning and Management in An Era of Increasing Constraints,' a seminar sponsored by National Economic Research Associates, Inc. and Kidder, Peabody & Co., Inc., The Wigwam, Litchfield Park, Arizona, November 5-7, 1979.

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"Estimated Costs of Coal and Nuclear Generation," presented at a seminar sponsored by The New York Society of Security Analysts on 'Energy--The Next Steps: Policy, Pricing and Future Supply,' Downtown Athletic Club, New York, New York, December 12, 1978.

Exhibits on the economic considerations in energy production prepared for a seminar for the Atomic Safety and Licensing Board Panel Members, U.S. Nuclear Regulatory Commission, sponsored by the National Center for Administrative Justice, Bethesda, Maryland, December 1, 1978.

"The Impact of Nuclear Constraints on the Costs of Electric Generation," presented at The American Nuclear Society Executive Conference on the 'The Economic Viability of the Nuclear Industry,' Del Webb's Towne House, Phoenix, Arizona, October 17, 1978.

"Nuclear, Coal, or Both? An Economic-Environmental Evaluation," before an Energy Seminar sponsored by the Louisiana Press Association, Baton Rouge, Louisiana, September 23-24, 1977.

"The Cost of Regulatory Uncertainties to the Nuclear Industry," before a Conference on Nuclear Power Financial Considerations sponsored by the Atomic Industrial Forum, Seattle, Washington, July 27, 1977.

"The Economic Viability of Nuclear Energy," before a Seminar for Members of Congress and Their Staffs sponsored by The Scientists' Institute for Public Information, Washington, D.C., June 7, 1976.

Testimonies:

Rebuttal testimony, commenting on the testimonies of Messrs. Charles Komanoff, Randall Falkenberg, Rudolph Yanuck and C. Hoff Stauffer, on behalf of Philadelphia Electric Company, Docket No. I-840381, March 18, 1985.

Testimony, with John H. Wile, estimating the cost of electric generation to CMP consumers using a market rule to determine the price of electricity from all

units on the CMP system, on behalf of Central Maine Power Company, February 4, 1985.

Testimony, with John H. Wile, evaluating the economics of completing the Limerick 2 nuclear unit on behalf of the Philadelphia Electric Company, December 3, 1984.

Rejoinder testimony examining the responses in surrebuttal testimony of Mr. Rudolph Bertschi and Staff and responding to criticisms of Mr. Charles Komanoff on behalf of Long Island Lighting Company, October 29, 1984.

Rebuttal testimony describing changes in the analysis of Seabrook 1 completion to reflect Seabrook sales option discussed in the hearings, responding to inquiries about the savings from completing Seabrook and discussing methodological errors in the testimonies of Messrs. Rosen and Chernick on behalf of Central Maine Power Company, Bangor Hydro-Electric Company and Maine Public Service Company, October 5, 1984.

Rebuttal testimony examining the appropriateness of the method proposed by Charles Komanoff for establishing a cap on capital cost for Palo Verde on behalf of Arizona Public Service, ACC Docket No. U-1345-83-155, Part II, October, 1984.

Testimony discussing the appropriate methodology for evaluating the economic viability of the Seabrook 1 nuclear plant on behalf of United Illuminating, Docket No. DPUC 84-06-17, September 20, 1984.

Rebuttal testimony reviewing estimates of costs for Grand Gulf and a coal alternative presented by Mr. Thomas Flaherty and Mr. Thomas Weiss, on behalf of Mississippi Power and Light Company and Middle South Energy, Inc., September 10, 1984.

Testimony summarizing the results of Central Maine Power Company's capacity expansion plan based on their new modifications and projections, on behalf of the Central Maine Power Company, August 31, 1984.

Testimony, with John H. Wile, summarizing the results of our evaluation of the benefits of Seabrook 1 to Bangor Hydro-Electric Company's customers, on behalf of the Bangor Hydro-Electric Company, August 31, 1984.

Testimony, with John H. Wile, summarizing the results of our evaluation of the benefits of Seabrook 1 to Maine Public Service Company's customers, on behalf of the Maine Public Service Company, Docket No. 84-80 and the Maine Public Utilities Commission, Docket No. 84-113, August 31, 1984.

Testimony examining the economic benefits to consumers from past decisions to build the Seabrook 2 nuclear unit and from subsequent decisions to continue construction on that unit, on behalf of the owners of the Seabrook 1 project, August 27, 1984.

Rebuttal testimony reviewing testimony presented by Charles Komanoff before the Washington Utilities and Transportation Commission, on behalf of Puget Sound Power & Light Company, June 29, 1984.

Rebuttal testimony comparing the results of our statistical review of the costs of Shoreham to statistical reviews of such costs contained in the quantification testimony previously submitted by the New York State Public Service Commission Staff and Suffolk County, on behalf of the Long Island Lighting Company, May 25, 1984.

Testimony regarding a determination of whether the cost of the Schahfer 17 is in line with the costs of other coal-fired power plants and compariing the levelized costs for different size units to see if lower per kilowatt-hour costs could have been achieved by building a larger facility, on behalf of the Northern Indiana Public Service Company, May 1, 1984.

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Testimony examining the prudence of past decisions to continue the construction of Grand Gulf 2 and regarding the current economics of completing Grand Gulf 2, on behalf of Mississippi Power and Light Company and Middle South Energy, Inc., February 27, 1984.

Testimony regarding the economics of the Skagit/Hanford nuclear plant before the Washington Utilities and Transportation Commission, on behalf of Puget Sound Power & Light Company, November 3, 1983.

Testimony regarding the basis for the conclusions of NERA's 1980 study concerning the continued operation of VEPCO's North Anna Nuclear Plant Unit #3 and the cancellation of Unit #4, before the State Corporation Commission of Virginia, Case No. PUE830041, on behalf of the Virginia Electric and Power Co., July 25, 1983.

Testimony regarding the savings to consumers from the operation of the Grand Gulf nuclear project and an evaluation of the prudency of the original decision to build the plant, before the Mississippi Public Service Commission, on behalf of Mississippi Power & Light Co. and Middle South Energy, Inc., Docket No. U-4285, April 29, 1983.

Testimony regarding the future cost of oil and, based on that forecast, an evaluation of the proposal to trend revenue requirements for the Grand Gulf nuclear project, before the Louisiana Public Service Commission, on behalf of the Louisiana Power & Light Co., January 17, 1983.

Testimony regarding the future cost of oil and, based on that forecast, an evaluation of the proposal to trend revenue requirements for the Grand Gulf nuclear project, before the Louisiana Public Service Commission, on behalf of New Orleans Public Service, Inc., January 17, 1983.

Testimony to evaluate the economic impact on electric customers in Pennsylvania of allowing Lukens Steel to switch electricity suppliers, before the Pennsylvania Public Utility Commission, on behalf of Philadelphia Electric Co., Docket No. P-810310, December 22, 1982.

Testimony regarding an estimation of savings to consumers from the operation of the Grand Gulf nuclear project and an evaluation of the prudency of the original decision to build this unit, before the Federal Energy Regulatory Commission, on behalf of Middle South Energy, Inc., Docket No. ER 82-616, October 15, 1982.

Testimony regarding the cost of the proposed Limerick nuclear project vs. the cost of abandoning Limerick and meeting electricity needs from alternative sources, before the Pennsylvania Public Utility Commission, Docket No. 1-80100341, on behalf of Philadelphia Electric Company, Revised April 9, 1981.

Testimony examining the need for and desirability of the Allens Creek nuclear plant as a component of Houston Lighting & Power Company's generation expansion plan in the next decade, before the Nuclear Regulatory Commission Docket No. 50-466, on behalf of Houston Lighting & Power Company, December 18, 1980.

Oversight hearing on nuclear economics before the Ninety-Sixth Congress, Congress of the United States, United States House of Representatives, Subcommittee on Energy and the Environment of the Committee on Interior and Insular Affairs, July 12, 1979.

Testimony regarding the prospective cost of electricity from coal and nuclear plants in Ohio, before the Power Siting Commission, State of Ohio, in the matter of Ohio Edison Company, Erie Nuclear Power Plant Units 1 and 2, Case No. 01-00003, June 26, 1978.

Testimony regarding nuclear and coal capacity factors and their influence on the cost of electricity, before the Ninety-Fifth Congress, Congress of the United States, United States House of Representatives, Environment, Energy and Natural Resources Subcommittee of the Committee on Government Operations, September 15, 1977.

Testimony regarding assessment of the costs of electric generation for alternative unit sizes at the Sundesert Nuclear site in the matter of San Diego Gas & Electric Company, Docket No. 76-NOI-2, July 27, 1977.

Testimony regarding a general methodology for evaluating the economics of coal and nuclear-fired generating plants in New York in the matter of proceeding on motion of the Commission as to the comparative economics of nuclear and fossil fueled generating facilities before the State of New York Public Service Commission, Case No. 26974, June 17, 1977.

Testimony evaluating the comparison of nuclear and coal-fired alternatives in the matter of San Diego Gas & Electric Company, Docket No. 76-NOI-2, November 1, 1976.

Consulting Reports:

"An Evaluation of Capacity Planning and Load Forecasting for Central Maine Power Company," prepared for Central Maine Power Company, February 17, 1984.

"An Evaluation of the Economics of the Skagit/Hanford Nuclear Project," prepared for Puget Sound Power & Light Company, Pacific Power & Light Company, Portland General Electric Company, and Washington Water Power Company, September 15, 1983.

"An Analysis of the Grand Gulf Nuclear Project," prepared for Mississippi Power & Light Company, January 11, 1983.

"An Economic Evaluation of the Marble Hill Nuclear Project," prepared for the Staff of the Public Service Commission, State of Indiana in Commission Cause No. 36818, October 4, 1982.

"Estimated Market Prices of Coal Alternatives to Production from the Quarto Mine, 1980-2000," prepared for Ohio Edison Company, July 1980.

"A Comparison of the Projected Cost of Electricity from the Palo Verde Nuclear Plant and Selected Coal-Fired Alternatives, Part II: A Review and Critique of 'Energy Options for the Southwest: Part 1, Nuclear and Coal Power' (A Study Endorsed by Arizonans for Safe Energy)," prepared for Arizona Public Service Company, July 11, 1979.

"A Comparison of the Projected Costs of Electricity from the Palo Verde Nuclear Plant and Selected Coal-Fired Alternatives: Final Report," prepared for Arizona Public Service Company, April 30, 1979.

"An Analysis of the Economic Comparability of Alternatives to the Sundesert Nuclear Facility," prepared for San Diego Gas & Electric Company, March 1, 1978.

"Projected Construction Costs and Capacity Factors for the Sundesert Plant," prepared for San Diego Gas & Electric Company, December 20, 1977.

with Alan J. Fishbein, "The National Energy Plan and the Demand for and Economics of Electric Utility Coal Conversion," August 1977.

ELECTRICITY DEMAND

Publications:

"Why Utilities Can't Build the Power Plants We Need," Nation's Business, September 1975.

with Irwin M. Stelzer, "Energy Use and Population Growth," position paper prepared for Division 1, Ninth World Energy Conference, Detroit, Michigan, September 22-27, 1974.

Speeches:

"Planning in a World of Uncertainty," presented at Edison Electric Institute's Seventeenth Financial Conference, Coronado, California, October 19, 1982.

"Electric Utility Fuel Consumption in 1980," presented before 'Energy Outlook: The Next Two Years'; a conference sponsored by The Conference Board, New York, New York, December 7, 1977.

Testimonies:

Testimony examining the need for and desirability of the Allens Creek nuclear plant as a component of Houston Lighting & Power Company's generation expansion plan in the next decade, before the Nuclear Regulatory Commission Docket No. 50-466, on behalf of Houston Lighting & Power Company, December 18, 1980.

Testimony regarding the appropriate criteria for evaluating the need for the economic desirability of the Big Bend generating unit, before the Florida Public Service Commission, Docket No. 800595-EW, on behalf of Tampa Electric Company, December 4, 1980.

Testimony regarding load forecasting and capacity planning in California, before the Joint Committee on the State's Economy, San Diego, California, October 22, 1979.

Need for power testimony in the matter of Houston Lighting & Power Company (South Texas Project, Units 1 and 2), Docket Nos. 50-498, 50-499, April 1975.

Need for power testimony in the matter of Houston Lighting & Power Company (Allens Creek Nuclear Generating Station, Units 1 and 2), Docket Nos. 50-466, 50-467, March 1975.

Need for power testimony in the matter of Public Service Company of New Hampshire (Seabrook Station, Units 1 and 2), Docket Nos. 50-443, 50-444, January 1975.

Consulting Reports:

with Kent P. Anderson, "The Costs of Electricity Shortages and the Determination of Optimal System Reliability," January 17, 1980.

with Kent P. Anderson, "The Reliability of Electricity Generation, Reserve Margins and the Costs of Capacity Shortages Circa 1990," October 1, 1979.

OTHER ELECTRIC

Speeches:

"Incentive Effects of Utility Rate Trending," presented at the Workshop on "Alternative Electric Power Plant Financing and Cost Recovery Methods," National Science Foundation, Washington, D.C., May 7, 1984.

"Building to Minimize Generating Cost: Can We Afford It?", presented at a Workshop on the Electric Imperative, sponsored by Atomic Industrial Forum, Monterey, California, June 16, 1981.

Exhibits on the economic considerations in energy production prepared for a seminar for the Atomic Safety and Licensing Board Panel Members, U.S. Nuclear Regulatory Commission, sponsored by the National Center for Administrative Justice, Bethesda, Maryland, December 1, 1978.

"The Impact of Nuclear Constraints on the Costs of Electric Generation," presented at The American Nuclear Society Executive Conference on the 'The Economic Viability of the Nuclear Industry,' Del Webb's Towne House, Phoenix, Arizona, October 17, 1978.

"The Impact of Environmental Standards on the Financial Viability of the Electric Utility Industry," presented at the Edison Electric Institute's Financial Division Annual Meeting, New York, New York, May 19, 1978.

"Cost of Alternative Air Pollution Strategies for the Electric Utility Industry," before the Annual Meeting of the Air Pollution Control Association, Portland, Oregon, June 29, 1976.

"Growth of the Electric Utility Industry in the Decade of the 1970s," before the Financial Analysts Federation Fall Conference, Detroit, Michigan, October 8, 1974.

Testimonies:

Testimony regarding the inclusion of construction work in progress (CWIP) in rate base, before the Pennsylvania Public Utility Commission, on behalf of Philadelphia Electric Company, Docket No. R-811626, Revised December 22, 1981.

Testimony concerning the regulation of the fuel cost adjustment clause contained within the rate schedules of the Ohio Edison Company, before the State of Ohio, Public Utilities Commission, Case No. 80-235-EL-FAC, on behalf of Ohio Edison Company, July 1980.

Testimony regarding the determination of appropriate rentals to be paid for the Pelton hydroelectric site during the period 1978 to 1987, before the Federal Energy Regulatory Commission, Project No. 2030, on behalf of Portland General Electric Company, January 30, 1980.

Testimony evaluating costs of alternative sources of electrical generation before the Wisconsin Public Service Commission, October 28, 1977.

Testimony on the costs and environmental benefits of closed cycle cooling systems in the matter of Carolina Power & Light Company (Brunswick Steam Electric Plants, Units 1 and 2), June 1976.

Consulting Reports

with David M. Blitzer, "An Examination of the Economic Issues Raised by Interim Regulations Issued by the Economic Regulatory Administration Under the Powerplant and Industrial Fuel Use Act of 1978," prepared for Edison Electric Institute, October 31, 1979.

with Kent P. Anderson, "The Reliability of Electricity Generation, Reserve Margins and the Costs of Capacity Shortages Circa 1990," October 1, 1979.

with John H. Wile, "Further Comments on the Economic Impacts of EPA's September 19, 1978 Proposed Revision to New Source Performance Standards for Electric Utility Steam Generating Units", prepared for the Utility Air Regulatory Group, January 15, 1979.

with John H. Wile, "Comments on the Economic Impacts of EPA's September 19, 1978 Proposed Revision to New Source Performance Standards for Electric Utility Steam Generating Units," prepared for the Utility Air Regulatory Group, January 12, 1979.

with John H. Wile, "Analysis of the Economic Impacts of Alternative Proposed Revisions to New Source Performance Standards," prepared for the Utility Air Regulatory Group of Edison Electric Institute, September 5, 1978.

with Kent P. Anderson, "An Evaluation of Electricity Supply Alternatives for California," prepared for The California Council for Environmental and Economic Balance, July 16, 1978.

with David M. Blitzer, "Status of Present and Planned Intake and Discharge Systems for the Electric Utility Industry: The Results of a Survey," prepared for the Utility Water Act Group, May 15, 1978.

with David M. Blitzer, "Costs and Economic Impacts of Steam Electric Pretreatment Standards," prepared for the Utility Water Act Group Task Force, August 11, 1977.

"An Analysis of the Economic and Environmental Costs of Alternative SO_2 Control Systems for Public Service Indiana," prepared for Public Service Company of Indiana, September 22, 1976.

"Estimated Costs for the Electric Utility Industry of Non-Significant Deterioration Amendments Currently Considered by the United States House of Representatives," prepared for the Clean Air Coordinating Committee of the Electric Utility Industry, July 15, 1976.

"Estimated Costs for the Electric Utility Industry of Non-Significant Deterioration Amendments Currently Considered by the United States Senate," prepared for the Clean Air Coordinating Committee of the Electric Utility Industry, April 16, 1976.

"An Analysis of the Costs to the Electric Utility Industry of House and Senate Significant Deterioration Proposals," prepared for the Clean Air Coordinating Committee of the Electric Utility Industry, December 12, 1975.

"The Costs of Reducing SO_2 Emissions from Electric Generating Plants," prepared for the Clean Air Coordinating Committee of the Electric Utility Industry, June 1975.

"Comments on the Economic Impact of the Environmental Protection Agency's Proposed Effluent Guidelines," prepared for Edison Electric Institute Ad Hoc Water Quality Group and Utility Water Act Group, June 26, 1974.

"Estimates of the Value of Changes in Aquatic Life Resulting from Reductions in Thermal Effluent," prepared for Edison Electric Institute Ad Hoc Water Quality Group and Utility Water Act Group, June 26, 1974.

"Costs and Benefits of Thermal Effluent Reduction," prepared for Edison Electric Institute Ad Hoc Water Quality Group and Utility Water Act Group, June 26, 1974.

n/e/r/a

NATIONAL ECONOMIC RESEARCH ASSOCIATES, INC.
CONSULTING ECONOMISTS

ORIGINAL

PECO STATEMENT NO. 12

PENNSYLVANIA PUBLIC UTILITY COMMISSION v.
PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

RECEIVED
SEP 27 1985
SECRETARY'S OFFICE
Public Utility Commission

DIRECT TESTIMONY
of
MR. LOUIS A. GUTH

LIMERICK 1 AND COMMON PLANT INDEPENDENT ASSESSMENT OF LIMERICK COST AND SCHEDULE AND PRUDENCY OF PAST DECISIONS

September 27, 1985

RECEIVED
SEP 27 1985

TESTIMONY
of
LOUIS A. GUTH
on Behalf of
PHILADELPHIA ELECTRIC COMPANY

Q. Would you please state your name and address.

A. My name is Louis A. Guth. My business address is 123 Main Street, White Plains, New York.

Q. What is your present employment?

A. I am a Senior Vice President of National Economic Research Associates, Inc., a firm of consulting economists.

Q. Would you briefly describe your educational and employment background prior to your association with National Economic Research Associates, Inc.

A. I received a B.A. degree, magna cum laude, in economics from Harvard University and a M.A. degree in economics from the University of Pennsylvania. I have completed all requirements for a Ph.D. degree in economics from the University of Pennsylvania except completing my dissertation. The major emphasis of my graduate study has been economic theory with particular emphasis on industrial organization and econometric and statistical methods.

While at the University of Pennsylvania, I held an appointment as Instructor and taught courses in the principles of economics and courses in industrial organization. Prior to joining NERA in February 1968, I was Assistant Professor of Economics at the Graduate School of Business Administration, New York University. While at NYU, I taught and did research in the application of economic theory and quantitative analysis to managerial problems and antitrust matters. Courses which I taught included

industrial organization, managerial economics, national income theory and economic principles. A copy of my personal vita is attached as Exhibit _____ (LAG-1).

Q. Would you describe the nature of your work with National Economic Research Associates, Inc.

A. National Economic Research Associates, Inc. was established in 1961 to offer economic consulting services in a number of fields, with particular emphasis on regulated industries and their problems.

With NERA, I have prepared reports and testimony dealing with antitrust matters concerning reciprocity, market structure and mergers, particularly the effects of conglomerate mergers. I have also done substantial work in regulatory matters. This includes a study of the role and quantifications of economic cost concepts in regulation of communications and other companies, a detailed statistical analysis of costs in the brokerage industry and participation in a study of the future demand for fuels by utilities. I have prepared a lengthy critique of studies dealing with the residential demand for electricity. That report was submitted to the U.S. Senate Committee on Interior and Insular Affairs. I have also prepared a detailed statistical analysis of the residential demand for electricity in the United States.

In addition, I have participated in a number of studies concerning competition between regulated companies, including the preparation of testimony on competitive rates and practices by electric utilities for submission before a Congressional committee.

Q. Mr. Guth, have you testified as an expert witness?

A. I have testified before the Securities and Exchange Commission, the

Civil Aeronautics Board, the U.S. District Court for the Eastern District of Wisconsin, and numerous state public service commissions in matters concerning electric, gas and telephone utilities.

Q. Mr. Guth, in connection with the work you have done with NERA on the demand for electricity in the United States, have you testified as an expert witness?

A. I have testified on this subject before the Atomic Safety Licensing Board, state power facilities siting boards, and state public service commissions. In this connection, I have consulted with over fifty private and publicly owned electric utilities on load forecasting issues.

Q. Have any of your writings been published?

A. I am the author of an article "Advertising and Market Structure Revisited" and co-author of an article "Buyer Concentration Ratios," which appeared in The Journal of Industrial Economics, April 1971 and June 1977, respectively. I am co-author of an article entitled "The Use of Buyer Concentration Ratios in Tests of Oligopoly Models," which appeared in the November 1976 issue of The Review of Economics and Statistics. This article was published as a working paper by the Graduate School of Business Administration, New York University in 1973. I am also the author of reports listed in Exhibit ____ (LAG-1).

Q. What is the purpose of your testimony?

A. I have been asked by the Philadelphia Electric Company (PECO) to review and comment on the reasonableness of PECO's sales and peak load forecasting methodologies and resulting forecasts since the Arab oil embargo, i.e., from 1973 to date.

Q. Have you previously provided consulting services to PECO regarding

load forecasting issues and/or testified on behalf of PECO in these matters?

A. I have not previously testified on behalf of PECO. In 1984, in connection with some analysis undertaken by my associate, Dr. Perl, regarding the economics of Limerick, I did supervise the preparation of a sales forecast for PECO using NERA's load forecasting methodology. This provided a check on PECO's own sales outlook. Depending on the assumptions chosen, my own forecast was consistent with, or somewhat higher than, PECO's contemporaneous forecast.

Q. Describe the general nature of the research you undertook in connection with your current assignment.

A. I have reviewed the actual sales experience of PECO going back to the early 1950s. I have also looked at the forecasts prepared by the Company since 1973, particularly with respect to how these forecasts changed in response to developments in regional, national, and world markets. And I have reviewed the general methodology used by PECO to prepare its forecasts in the late 1970s.

In order to evaluate the reasonableness of the forecasts emerging from this process, I have compared what PECO was saying about prospective load growth during the 1970s with other generally available forecasts. I have analyzed reasons why those forecasts proved to be erroneous. And I have considered how PECO forecasts adapted to changes taking place following the second disruption of oil supply in the Spring of 1979. Finally, I have estimated what kinds of forecasts PECO might have developed based on past sales trends and compared these with actual PECO forecasts. This provided some indication of whether PECO could/should have been more aggressive in responding to changing growth in demand for electricity during

the 1970s and 1980s.

Q. What is your conclusion as to the reasonableness of PECO's load forecasting efforts?

A. I believe PECO forecasts were reasonable and prudent given the information available to the Company at the time the forecasts were adopted. Throughout the decade following the Arab oil embargo in 1973, electric utility companies struggled to adjust their load forecasts to a continuing wave of developments: economic recessions, energy price jolts, high inflation and interest rates, and the like. PECO was no exception; the Company's forecasts of the late 1970s have been at least as accurate as the rest of the industry.

Q. What, in your opinion, are the relevant questions to raise in evaluating the prudence of load forecasting efforts?

A. I believe the relevant questions include:

a. Did PECO make adequate use of available information on past trends in such load growth-causing factors as economic activity, energy prices, competing fuel availabilities, and conservation practices?

b. Were the forecasted growth rates projected for electricity sales and the factors explaining those sales consistent with what other experts were saying at that time?

c. With perfect foresight of what actually happened to the economy after 1978, would the forecasts of the Company have come closer to the mark?

In a nutshell, these questions ask: did Company forecasters do an adequate job in the 1970s and were they eventually proved wrong <u>for the right reasons</u>, i.e., economic growth slumped and energy prices soared well

beyond what a prudent observer would have guessed?

Q. To begin, what has been the history of PECO electricity requirements (kilowatt-hours) and peak demand (kilowatts) during the relevant time period?

A. I have set forth the data on sales in Exhibit ____ (LAG-2). As the charts indicate, PECO sales in virtually all categories grew fairly smoothly and rapidly through 1973. The first major disruption to this trend occurred in 1974. Growth subsequently resumed, albeit at lower annual rates; 1979 brought about a second major disruption. Subsequent to that event, there was very little system growth in sales (excluding sales for resale) until the last few years. System peak demand has a similar pattern since that time.

Q. What generally accounts for the major disruptions in the early and late 1970s?

A. There were, of course, many factors at work. But the disruptions are certainly associated with events flowing from the Arab oil embargoes, including supply disruptions, in 1973 and again in 1979. The direct effect of these embargoes was, of course, to raise very abruptly the real price of oil. But there were many additional effects, of which four are particularly noteworthy. First, the prices of all forms of energy, including electricity, rose following oil price increases. More expensive energy led consumers and industries to cut back consumption. Second, public conservation policies were encouraged or mandated by local, state, and federal authorities. Third, fairly major recessions followed, and perhaps resulted from, the oil embargoes. Less economic activity means reductions in the use of energy and other goods and services. Fourth, inflation accelerated with a major impact on interest rates. These higher rates also led to higher electricity

prices than would otherwise have been the case.

Q. Let's focus for the moment on the period between the two Arab oil embargoes. Did electric utility companies modify their forecasts in response to these changes?

A. They certainly did. My associate at NERA, Robert Uhler, has depicted these changes in a report to the Electric Power Research Institute entitled: "The NERC Summary Load Forecasts: A Retrospective Appraisal and Technical Analysis." (Co-authored with C. R. Nelson, University of Washington, RP1153-10, May 31, 1985.) The analysis is based on the compiled national forecasts assembled each year by the regional member councils of the North American Electric Reliability Council (NERC) from the reports of individual utilities. From 1974 to 1978 the sales and peak forecasts decreased each year. These changes accounted for a reduction in projected electricity requirements by 1985 of roughly 850,000 GWh, or 21 percent.

Q. Did PECO modify its forecasts during this period in a similar fashion?

A. Yes. PECO revised its forecast each year during this time period. Again looking forward to 1985, changes between the 1974 and 1978 PECO sales forecasts amount to reductions of approximately 18,000 GWh, or 35 percent. The reduction in the peak forecast for 1985 over this period was over 5,000 MW, or more than 40 percent. Thus, the question is not whether PECO did respond to changing conditions by modifying its load forecasts; rather it is whether the response was reasonable. In my opinion, all of the evidence indicates that PECO's response was reasonable.

Q. As of 1979, prior to the second oil supply disruption, what was the

outlook for electricity growth in PECO's service area?

A. As of PECO's forecast dated December 1978, projected average annual growth in total sales, excluding sales for resale, for the ten year period 1978 to 1988 was 2.9 percent. Forecasted average annual growth in peak load for the same period was 2.4 percent. This compares with actual growth in sales and peak load for the previous ten years of 2.9 and 2.6 percent respectively.

Q. As of this time period, how did these forecasts compare with electric utility industry forecasts generally?

A. The load growth outlook of PECO was very much consistent with forecasts on the regional and national level. This is depicted in Exhibit _____ (LAG-3).

Q. Let's look at the NERC industry numbers first. How do the NERC national numbers compare with those of PECO and the Mid-Atlantic Area Council (MAAC) generally as of 1979, prior to the second disruption of supply oil?

A. Tables 1 and 2 of Exhibit _____ (LAG-3) show regional and national numbers for forecasted energy requirements as of Spring 1978 and Spring 1979. Tables 3 and 4 of Exhibit _____ (LAG-3) show the same information for regional peak demands. At the time that PECO was forecasting energy growth of 2.9 percent and peak growth of 2.4 percent, the regional and national numbers of the reliability councils were somewhat higher. MAAC compiled forecasts were in the range of 3 to 4 percent, while projected national growth was in the range of 4 to 5 percent.

Table 5 of Exhibit _____ (LAG-3) then compares the 10-year energy growth forecasts of MAAC, including PECO, with the compiled national

forecasts. From Spring 1974 through Spring 1979, the MAAC forecasts declined as fast, or faster, than the NERC national compiled forecast, consistent with the decline in MAAC energy requirements as a percent of national by about one-half percentage point.

Q. Were there other forecasts of national electricity growth available as of 1979, prior to the second disruption of oil supply, in addition to the industry projections?

A. Yes. Forecasts were available from the government, industry trade press and information/data services such as Predicasts.

Q. What did they show?

A. Tables 1-3 of Exhibit _____ (LAG-4) show the forecasts of the Department of Energy (DOE). Their projections reported in the 1977 Annual Report were for annual growth around 4.6 percent, roughly one-half percentage point below the industry forecasts. By the next year, the DOE figure dropped only slightly to 4.4 percent. It was not until after the oil supply disruption, that is by the Spring of 1980 when the DOE issued its Annual Report for 1979, that their estimated growth fell substantially to just below 3 percent.

Tables 4-6 of Exhibit _____ (LAG-4) show the projections of Edison Electric Institute at roughly the same time. Their figures in the Springs of 1978 and 1979 were approximately 5 percent. After the oil supply disruption, their estimates fell to 4 percent.

Finally, Table 7 of Exhibit _____ (LAG-4) includes a variety of forecasts as cited in the trade press and reported by the Predicasts organization during 1978 and 1979. Predicasts is an information/data service which publishes forecasts compiled from various industry

publications. While the specific growth figures vary in composition and detailed definition, there is a specific recurrence of figures around 5 percent. Thus, the generally available forecasts of government and industry were all pretty much consistent with the context in which PECO forecasts fit, i.e. the compiled MAAC and NERC forecasts. These forecasts by no means indicate that there were no other forecasts at much lower growth rates. They do mean, however, that the judgments on load growth expressed by PECO during this time period were consistent with the judgments of most other informed companies and agencies, given the information then available. Indeed, the forecasts called for significantly lower growth than nationally or regionally, reflecting the economic outlook for PECO's service area.

Q. Describe the methodology used by PECO at this point in preparing its forecasts?

A. PECO has relied upon a methodology which combines detailed analysis of end uses of electricity and economics. The methodology has been refined year-by-year as additional information is acquired. But, in structure it is essentially the same approach used by PECO in the last 10 years.

The PECO methodology is described in detail in annual reports, and the Electric Budget Forecasts. Essentially, for each customer class, PECO breaks down kilowatt-hour sales into type of customer, type of use, and pattern of usage. The residential class has the greatest detail, dealing with specific types of housing units — houses, townhouses, and apartments — numerous appliances and uses, and a detailed analysis of factors which account for change in usage rates. Similarly, the analysis of small and large commercial and industrial customers breaks down total usage into specific

industry categories and identifies the key factors accounting for changes in consumption within those categories. In the case of PECO's eight to ten largest manufacturing customers, direct contact with each customer is relied upon as the basis for projecting individual requirements.

Of course, PECO's approach is one of several different methodologies in use, including a variety of statistical techniques. In its detail and analysis of available data, PECO's methodology is, I believe, a state-of-the-art representative of the end-use approach.

Q. What are the key factors that account for changing levels of electricity requirements, as you have identified them?

A. These key factors include growth in economic activity -- expressed in an appropriate way for each class, i.e., residential (housing construction), commercial (nonmanufacturing employment and general construction) and industrial (manufacturing employment and regional industrial production) -- growth in population and households and changes in electricity and energy prices.

Q. Taking each of these in turn, would you please describe how actual growth did happen from 1979 forward compared with recent historic growth at both the national and PECO service area level?

A. At the national level, the analysis of Mr. Uhler, to which I referred earlier, provides a nice summary of what happened. Several of his charts are reproduced in Exhibit _____ (LAG-5). The first three charts show measures of overall economic activity: (a) per capita income, (b) industrial production, and (c) gross national product. Each series shows sharply lower growth in the 1970s compared with the 1960s. And, after 1979, there is very little growth at all shown for per capita income and GNP, while industrial

production actually declined consistently through 1982.

The next four charts in the exhibit show the trends for energy and electricity prices. Prices of oil, coal, and natural gas accelerated after 1973 following the Arab oil embargo. And these prices surged again after the oil supply disruption of 1979.

Q. Why did electricity prices rise in the way you described in this exhibit?

A. Of course, specific factors differ for each electric utility company. However, as a general matter, the principal constituent parts of electricity costs are fuel and capital-related costs. Thus, rising fuel prices and interest rates were bound to drive up electricity prices quickly.

Q. Should an electric utility forecaster in 1978 have anticipated the increases in fuel costs and in interest rates of the magnitude that occurred?

A. Clearly not. The price of fuels and interest rates are both determined in markets where there is trading in futures and foresight could enable you to make considerable profits. To the best of my knowledge, however, there were no major price movements in these markets in advance of the oil supply disruption of 1979. Thus, an expectation of only moderate changes in these factors as of that time was certainly consistent with what the general market seemed to be expecting.

Q. Please return to your discussion of changes in key economic factors in the PECO service area after 1979.

A. I have prepared several charts, included in Exhibit _____ (LAG-6), for the PECO service area that are similar to the national charts in Exhibit _____ (LAG-5). The overall picture is basically the same. Of course, the Philadelphia area suffered through the same economic slowdown

in the early 1980s that affected the rest of the country. The first two charts of this exhibit illustrate this slowdown in terms of major drops in housing starts. Similarly, manufacturing employment in the Philadelphia area has declined steadily since 1979. Overall, these factors are associated with a slowing in growth of the number of residential customers served. Finally, the real price of electricity jumped sharply in 1980 as a result of much higher fuel costs, leaving rates in real terms well above 1974-1979 levels.

Q. What happened to sales and peak load growth as a result of these changes?

A. Largely as a result of these changes in economic activity and energy prices, electricity sales and peak growth were further curtailed; indeed, on a national basis, electricity consumption actually dropped in 1982. Exhibit _____ (LAG-7) shows that the "fanning downward" of load growth projections continued after 1979 because of these factors. And Exhibit _____ (LAG-8) shows the same effect for PECO forecasts. Between Spring 1979 and Spring 1984, national load growth projections for 1988 dropped by 24 percent, MAAC projections by 19 percent, and PECO projections by 18 percent. (See Exhibit _____ (LAG-9)).

Q. Assume that the forecasters at PECO as of 1979 had perfect foresight of coming changes in energy prices and economic activity. Would they have forecast emerging sales and peak requirements correctly using their methodology?

A. I believe they would have been quite accurate.

Q. On what do you base this opinion?

A. It is virtually impossible for me to reconstruct PECO's own forecast

of December 1978 as it would have appeared with perfect knowledge of what would happen to economic growth in PECO's service area and to the price of electricity. However, I have prepared Exhibit ____ (LAG-10) in which I compare the forecasting assumptions used by PECO at that time for the period out to 1983 with subsequent actual trends.

Note first that from a base of actual 1977 sales and normalized peak loads, PECO forecast average annual growth through 1983 of 2.28 percent in sales and 2.04 percent in peak. Sales were almost flat and peak grew only 1.30 percent. These differences seem entirely consistent with the shortfalls in economic performance and rising energy costs of the period. For example, Gross National Product grew over one and one-half percentage points slower than had been forecast (1.91 percent versus 3.62 percent). The effect of this slowdown is also reflected in slower new construction and customer growth. Although the PECO forecast does not use GNP directly as a key factor in forecasting sales growth, there is a general proportionality between economic activity and electricity requirements in the model, all else equal. So this slowdown should account for a reduction in the sales forecast of at least one, and probably more like one and one-half, percentage points. That would reduce the sales growth forecast to a range of approximately 0.75 to 1.25 percent.

In addition, electricity price (constant dollars) rose 0.71 percent annually, above the forecasting assumption of no real increase. In PECO's forecast, the effect of rising energy costs is measured directly through conservation and adjustments in use of equipment rather than through an explicit price elasticity. For a reasonable conservative range of values for price elasticity, however, that level of price increase would, in my opinion,

reduce the sales growth rate by 0.2 to 0.35 percentage points. That further reduces the range for the sales forecast to 0.4 up to 1.1 percent, roughly consistent with the actual trend. But there were also other factors at work. First, sharply rising oil prices signalled all consumers about the rising cost of energy and the need for conservation. And second, changing national policy and gas market conditions resulted in an end to restrictions on gas use and new connections. And, of course, other factors would have modified the complete forecast. But I believe the general point is already illustrated: if, in the late 1970s, PECO forecasters had had perfect foresight of future energy and market conditions, they, and other forecasters using similar methodologies, would have produced projections that were reasonably consistent with subsequent actual sales and peak requirements.

Q. Please summarize, in your opinion, how the changes in market conditions brought about by the second Arab oil embargo changed the electricity sales outlook.

A. As is generally recognized, economic forecasting is a risky and uncertain business. Yet it is precisely the difficult-to-anticipate changes in economic factors that play a prominent role in determining customer demand for electricity. The changes brought on by the second oil supply disruption -- in economic activity and in energy price levels -- had a major impact on the demand for electricity in succeeding years. Had forecasters in early 1979 been sufficiently prescient to anticipate these changes, I believe their product would have been very much consistent with what actually did happen to electricity sales, in PECO's service area and throughout the nation. But their lack of this degree of foresight hardly suggests imprudence; indeed, it would require reaching a conclusion that

pretty much all of the forecasts then available were imprudent, either in outlook for electricity requirements, or in projections for other variables such as economic growth and energy prices.

Q. Did PECO forecasting respond to these changes?

A. Quite clearly it did, as indicated in Exhibit _____ (LAG-8).

Q. Based on your findings, in your opinion did PECO forecasts reflect reasonable practices?

A. Yes. Since the time of the Arab oil embargo, PECO has developed a state-of-the-art forecasting methodology stressing detailed examination of end uses of electricity. During this time, PECO's forecasts have been responsive to changing underlying economic conditions as they were recognized. As a result, by 1979 PECO had cut earlier forecasts of requirements by roughly 40 percent. Following the second oil supply disruption, PECO continued to adjust downward its forecasts in response to sluggish economic growth and rising energy costs. As a result, the PECO forecasts have tracked reasonably well with those prepared by most other forecasters, given the information available at the time they were prepared. By 1979, with perfect foresight, the PECO forecasting methodology would likely have produced projections that squared well with subsequent sales and peaks.

Q. What additional analysis have you performed to check this?

A. I have duplicated, using PECO data, a portion of the technical analysis performed by Professor Nelson and detailed in the report to EPRI that I cited earlier.

Q. Please describe the general nature of this analysis.

A. Professor Nelson posed the following questions:

> Were the NERC summary forecasts farther off target than they needed to be? Could NERC, using standard statistical techniques and data available at the time, have made more accurate aggregate forecasts? Were the individual utilities' forecasters too timid in responding to the slowdown in demand for electricity in the mid-1970s?

He then considered answers to these questions using statistical analysis of time series data. For example, he considered what available information about future growth could be extracted from past growth in electricity sales by forecasters using exponential smoothing and other time series statistical methodologies.

Q. What conclusions did Professor Nelson reach as a result of his investigation of the national data?

A. His basic result for a first-cut exponential smoothing analysis are set forth in Exhibit _____ (LAG-11). In the analysis, forecasts of 10-year sales growth rates are based solely on evaluating past sales data with the criterion of minimizing errors in trend forecasts. Columns (4) and (5) of Table 1 of Exhibit _____ (LAG-11) compare the forecast Nelson gets using this approach with the actual NERC compiled forecasts from 1973 through 1982. The results suggest that the NERC forecasts compiled from individual company analyses produce forecasts "much like" the results of Professor Nelson's first-cut statistical analysis of past growth trends.

More generally, and on the basis of more sophisticated investigation introducing the effects of income and prices into his analysis, Nelson concludes:

> Analysts must accept part of the blame [for overly optimistic forecasts]. The individual utility forecasts and the NERC summary forecasts, in retrospect, were optimistic in terms of electricity sales growth.
>
> Yet, it is easy to see with hindsight why those forecasters were optimistic. They (and NERC) probably could not have done much better, as this retrospective analysis shows. More broadly, the forecasters and

much more senior utility executives, in 1974, could look back on dozens of years of robust growth in electricity sales. Ever concerned with providing reliable and adequate service, those executives' professional sense of responsibility towards the industry's customers, coupled with an optimistic view of future rapid GNP growth and stable real electricity prices, probably drove too many expansionist decisions forward.

Q. How did you use this analysis for the PECO service area?

A. I employed the same methodology, using PECO energy sales data (excluding sales for resale) instead of national data.

Q. Do the PECO data generally "look" the same as the national data for purposes of this analysis?

A. Yes they do. I have prepared a chart (Exhibit ____ (LAG-12)) in which I have plotted the annual percent changes in PECO sales and in national sales data. The two series correspond quite closely, although PECO changes are frequently below national figures. And vagaries of weather, activity in individual industries, and the like make the data for a single service area somewhat more volatile. Nevertheless, the analysis used by Professor Nelson should apply for the PECO data.

Q. Describe your findings based on the supposition that PECO simply made best use of emerging sales trends for forecasting future growth.

A. My findings based on PECO data only are set forth in Exhibit _____ (LAG-13). Each set parallels the equivalent table and chart prepared by Professor Nelson and reproduced in Exhibit _____ (LAG-11). Thus, column (4) of the table in Exhibit _____ (LAG-13) shows the estimated 10-year growth rate forecasted using exponential smoothing techniques on past sales trends. And column (5) has the corresponding PECO forecast for the relevant period. These data are plotted on the chart in this Exhibit.

Of interest first is that the PECO data yield a so-called "smoothing coefficient" (column (3)) of 1.0 for each year through 1977. This means that

the best exponential smoothing forecast for PECO using data starting in 1952 and ranging through 1972 up to 1977 is simply the average of past growth. In subsequent years — that is beginning with the availability of 1978 data — the smoothing coefficient is less than 1.0. This indicates that more weight should be given to most recent sales growth trends and less weight to historic trends.

The results of Table 1, Exhibit ____ (LAG-13) indicate to me that PECO may have been initially cautious about new growth trends, but quickly adapted their forecasts. Thus, by 1976 — that is, with 1975 sales results available — the PECO forecasts were very much in line with those based solely on past sales trends. Indeed, the Company forecasts have been consistently below the simple trended forecasts since that time.

Comparing the ES/BJ forecast with the PECO forecast shows how rapidly and to what magnitude PECO forecasters revised their projections. The ES forecast is based on a "signal plus noise" model. That is, the change in the variable (growth of electricity sales) can be described as a trend (the signal) and transitory fluctuations that affect the variable (the noise). PECO, likewise, forecasted based on the trend in growth rates and analysis of independent economic factors which affect electricity demand. Under the circumstances of the mid-1970s, the PECO forecasters had the advantage of being able to recognize the effect of these economic factors on the trend in electricity sales as more than mere "noise". This meant downgrading their projections based on the worsening economic situation, rather than relying solely on smoothing trends.

Since (a) the PECO data did not indicate weighting more recent sales data more heavily until the 1978 data; and (b) PECO forecasts did

seem to respond to emerging trends around this time, I considered, as an alternative, using the national smoothing coefficients with PECO sales data. These results are contained in Exhibit ____ (LAG-14). PECO forecasts and the exponential smoothing forecasts using this approach match up somewhat more closely, suggesting that PECO did begin to weigh in more recent sales growth information by the mid-1970s.

Q. Mr. Guth, do the results set forth in Exhibit _____ (LAG-13) modify in any way your conclusion that PECO's load forecasting efforts during the 1970s and early 1980s were reasonable and prudent?

A. No they do not. As I have already stated, the problem posed by load forecasting was particularly difficult during the decade starting with the oil embargo in late 1973. PECO grappled with this problem, which was especially formidable given that the preceding period had been one of very rapid growth and concommitant concern with meeting loads. However, by the latter 1970s, PECO had clearly adapted its forecasts to the new emerging trends consistent with the best information available at the time.

Q. Does that conclude your testimony?

A. Yes.

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Mr. Guth has prepared studies on the interrelationships of market structure, advertising behavior, risk and rate of return. He has prepared numerous reports and testimony dealing with antitrust matters concerning reciprocity, market structure and mergers, particularly the effects of conglomerate mergers. He has also prepared analyses and testimony dealing with economic and antitrust issues in professional sports.

Mr. Guth has also done substantial work in regulatory matters, including the quantification of economic demand and cost concepts, and the development of policies to balance competitive and regulatory objectives. His studies include detailed statistical analysis of costs in the stock brokerage industry and a review of proposals to modify the extent of competition between scheduled and nonscheduled air passenger services. He has performed an extensive analysis of the elasticity of demand for electric power of the major customer classes. Based on this analysis, he has prepared reports and testimony developing forecasts of growth in energy and peak demand for electric utilities. Mr. Guth has also developed NERA's regional gas demand model, RGD and NERA's energy forecasting model, NERAGEM. He has participated in and prepared numerous analyses

concerning national and regional natural gas policy. He supervises NERA efforts in forecasting state-specific, regional and national projections of gas, electricity and oil requirements and gas wellhead and burner-tip prices. He has appeared as an expert witness before the SEC, the FPC, the FERC, the CAB, the NRC, and state regulatory commissions, as well as Federal District Courts.

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ARTICLES:

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"Impact on Natural Gas Prices and Annual Requirements of Proposed Legislation: A Comparative Analysis," Oil and Gas Analyst, December 1983.

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Before the Nuclear Regulatory Commission, In the Matter of Kansas Gas & Electric Company and Kansas City Power & Light Company (Wolf Creek Generating Station, Unit 1), Docket No. 50-482, 1976.

Before the New York State Department of Public Service and the New York State Board on Electric Generation Siting and the Environment on behalf of Rochester Gas and Electric, et al., In the Matter of the Rochester Gas and Electric Corporation Sterling Power Project, Nuclear Unit No. 1, 1975.

Before the Virginia State Corporation Commission on behalf of Virginia Electric and Power Company, In the Matter of Virginia Electric and Power Company, Case No. 19426, 1975, also before the FPC in Project No. 2716.

Before the Atomic Safety and Licensing Board of the Atomic Energy Commission on behalf of Boston Edison, In the Matter of Boston Edison Company, et al., (Pilgrim Nuclear Generating Station Unit 2), Docket No. 50-471, 1975.

Before the Atomic Safety and Licensing Board of the Atomic Energy Commission on behalf of Union Electric Company, In the Matter of Union Electric Company (Callaway Plant, Units 1 and 2), Docket Nos. 50-483 and 50-486, 1975.

Before the New York Public Service Commission, on behalf of Rochester Telephone Corporation, In the Matter of the Rochester Telephone Corporation, Case No. 26215, 1974.

Before the Public Utilities Commission of Ohio on behalf of Dayton Power and Light Company, In the Matter of Dayton Power and Light Company, Case No. 74-283-4, 1974.

Before the Arizona Corporation Commission, on behalf of Duval Corporation, American Smelting and Refining Co., Cyprus Pima Mining Company and Arizona Portland Cement Co., In the Matter of the Tucson Gas & Electric Company Rate Case, Docket No. U-1933, 1974.

Before the Atomic Safety and Licensing Board of the Atomic Energy Commission, on behalf of Florida Power & Light Company, In the Matter of Florida Power & Light Company (St. Lucie Unit 2), Docket No. 50-389, 1974 and in June 1975, before the State of Florida Public Utilities Commission, Department of Pollution Control hearing, dealing with the same matter.

Before the Atomic Safety and Licensing Board of the Atomic Energy Commission on behalf of Cleveland Electric Illuminating Company, In the Matter of Cleveland Electric Illuminating Company (Perry Units 1 and 2), Docket Nos. 50-440 and 50-441, 1974.

Before the South Carolina Public Service Commission on behalf of Duke Power Company, Docket No. 17057, 1974.

Before the North Carolina Utilities Commission on behalf of Duke Power Company, in NCUC Docket E-7, Sub 159, 1974.

Before the United States District Court, Eastern District of Wisconsin on behalf of New York Stock Exchange in Thill Securities Corp., et al. v. New York Stock Exchange, Civil Action No. 63-C-264, May 1973.

Before the Missouri Public Service Commission on behalf of Union Electric Company, Case No. 17140, 1971.

Before the Civil Aeronautics Board, Testimony on behalf of Trans World Airlines, Docket No. 21866-9, 1970.

Before the Securities and Exchange Commission, In the Matter of S.E.C. Rate Structure Investigation of National Securities Exchange, August 1968 and May 1969.

ACTUAL PHILADELPHIA ELECTRIC COMPANY (PECO) ELECTRICITY SALES
1950-1984

Year	Customer Class							
	Residential	Small Commercial and Industrial	Large Commercial and Industrial	Govt. and Municipal	Resale	Railroads and Railways	Interdepartmental	Total Sales less Sales for Resale & Interdept.
	(Kilowatt Hours)							
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1950	1,340,111,068	1,057,578,251	3,879,358,459	97,454,572	545,078,034	1,153,676,708	39,100,723	7528179058
1951	1,477,439,045	1,114,380,148	4,351,739,354	101,742,590	230,820,349	1,166,017,715	39,145,053	8211318852
1952	1,629,986,401	1,183,791,357	4,547,538,894	108,961,324	45,260	1,144,741,440	27,612,537	8615019416
1953	1,794,839,702	1,260,110,170	4,903,025,366	115,050,686	7,662,123	1,092,129,580	24,807,069	9165155504
1954	1,952,999,427	1,312,990,029	4,897,180,619	123,071,856	8,468,006	1,035,639,630	25,495,345	9321881561
1955	2,159,747,504	1,398,144,632	5,501,675,723	133,904,905	9,922,263	1,041,997,640	27,426,070	10235470404
1956	2,402,817,221	1,473,956,006	5,791,428,881	143,217,792	11,007,149	987,506,930	26,545,971	10798926830
1957	2,577,695,914	1,530,019,207	6,029,503,755	149,946,068	21,357,929	923,067,740	27,641,807	11210232684
1958	2,732,177,203	1,542,157,186	5,921,793,881	157,412,130	28,023,544	854,273,140	30,492,068	11207813540
1959	2,965,101,313	1,670,137,015	6,565,071,701	168,925,206	30,697,948	836,247,520	27,910,350	12205482755
1960	3,056,608,112	1,683,662,411	6,881,737,380	180,026,275	20,656,849	815,472,150	28,140,950	12617506328
1961	3,298,458,928	1,751,456,497	7,235,036,223	191,172,362	17,782,372	810,918,130	27,018,566	13287042140
1962	3,405,298,471	1,780,711,036	7,635,357,021	201,788,413	21,996,040	829,100,670	27,384,371	13852255611
1963	3,612,622,968	1,822,865,755	8,143,032,277	204,423,979	26,593,322	808,563,100	28,469,026	14591508079
1964	3,847,322,933	1,911,863,504	8,749,383,236	210,312,349	24,297,633	825,535,220	26,519,609	15544417242
1965	4,167,574,000	2,003,082,000	9,469,512,000	219,124,000	22,737,000	830,723,000	24,909,000	16690015000
1966	4,456,554,000	2,086,560,000	10,267,444,000	230,989,000	25,204,000	822,917,000	34,701,000	17864464000
1967	4,762,716,000	2,125,184,000	10,724,098,000	245,487,000	29,822,000	780,452,000	35,494,000	18637937000
1968	5,329,575,000	2,256,311,000	11,960,803,000	259,747,000	32,293,000	746,015,000	37,536,000	20552451000
1969	5,812,139,000	2,292,579,000	12,662,784,000	267,720,000	35,238,000	758,808,000	43,821,000	21794030000
1970	6,380,973,000	2,365,033,000	12,969,656,000	270,260,000	37,575,000	741,669,000	47,829,000	22727591000
1971	6,648,886,000	2,427,874,000	13,296,527,000	285,817,000	39,262,000	713,941,000	45,532,000	23373045000
1972	6,855,782,000	2,503,484,000	14,010,947,000	282,747,000	55,524,000	727,321,000	70,317,000	24380281000
1973	7,493,526,000	2,663,317,000	14,952,786,000	288,195,000	109,671,000	715,839,000	77,391,000	26113663000
1974	7,159,012,000	2,558,043,000	14,621,442,000	289,200,000	105,722,000	756,398,000	66,271,000	25384095000
1975	7,424,017,000	2,623,868,000	14,059,946,000	295,852,000	106,635,000	758,311,000	66,866,000	25161992000
1976	7,584,895,000	2,754,933,000	14,661,642,000	300,454,000	106,443,000	806,322,000	58,605,000	26108246000
1977	8,110,432,000	2,825,124,000	14,912,141,000	303,610,000	107,709,000	877,997,000	60,278,000	27029304000
1978	7,875,376,000	2,888,274,000	15,302,342,000	311,227,000	109,527,000	847,983,000	59,573,000	27225202000
1979	7,967,522,000	2,927,754,000	15,428,191,000	308,566,000	111,067,000	798,529,000	59,056,000	27430562000
1980	8,341,313,000	3,064,582,000	15,056,280,000	248,093,000	113,159,000	740,219,000	57,214,000	27650487000
1981	8,013,558,000	3,115,239,000	14,916,155,000	193,442,000	1,332,501,000	636,612,000	60,582,000	26875006000
1982	7,877,028,000	3,141,611,000	14,177,602,000	194,469,000	3,458,475,000	651,356,000	60,827,000	26042066000
1983	8,467,240,000	3,283,906,000	14,478,093,000	195,415,000	456,789,000	635,828,000	60,914,000	27060482000
1984	8,515,491,000	3,543,423,000	14,880,555,000	196,058,000	1,510,287,000	685,541,000	64,001,000	27821068000

Source: Philadelphia Electric Company System Quantity Sales and Customers: Electric Gas and Steam, 1950-1984

Exhibit (LAG-2)
Table 1 of 3

PECO ACTUAL AND FORECASTED PEAK LOADS

YEAR	Net Peaks		1972 Forecast	1973 Forecast	1974 Forecast	1975 Forecast	1976 Forecast	1977 Forecast
	Summer	Winter						
	Megawatts							
1955	1847	2116						
1956	1993	2095						
1957	2239	2155						
1958	2125	2222						
1959	2452	2359						
1960	2511	2353						
1961	2702	2464						
1962	2721	2575						
1963	2926	2683						
1964	3134	2822						
1965	3366	2972						
1966	3673	3234						
1967	3727	3351						
1968	4375	3509						
1969	4592	3771						
1970	4712	3797						
1971	4922	3886						
1972	5313	4186	5740					
1973	5760	4189	6300	6020				
1974	5431	4160	6850	6670	6400			
1975	5530	4255	7480	7240	6960	6280		
1976	5346	4457	8110	7850	7490	6690	5820	
1977	5888	4525	8630	8400	8020	7130	6320	6000
1978	5667	4627	9240	8950	8530	7600	6660	6300
1979	5641	4702	9770	9570	9010	8040	7020	6600
1980	6095	4537	10300	10110	9480	8490	7390	6900
1981	5731	4804	10840	10680	9960	8950	7780	7200
1982	5691	4846		11240	10460	9430	8180	7500
1983	5879	4730			10950	9900	8580	7800
1984	5925	4678				10380	8990	8100
1985	6034	5238					9390	8400
1986								8700
1987								
1988								
1989								
1990								
1991								

Exhibit ____ (LAG-2)
Table 2 of 3

Exhibit ____ (LAG-2)

Table 3 of 3

YEAR	1978 Forecast	1979 Forecast	1980 Forecast	1981 Forecast	1982 Forecast	1983 Forecast	1984 Forecast
1979	5700						
1980	5850	5800					
1981	6000	5900	5900				
1982	6150	6000	6000	5800			
1983	6300	6100	6100	5850	5600		
1984	6450	6200	6200	5900	5650	5900	
1985	6600	6300	6300	5950	5700	5930	6140
1986	6800	6400	6400	6000	5750	5960	6160
1987	7000	6500	6500	6050	5800	5990	6180
1988	7200	6600	6600	6100	5850	6020	6200
1989		6700	6700	6150	5900	6050	6220
1990			6800	6210	5950	6080	6240
1991				6270	5980	6110	6260
1992					6010	6150	6320
1993						6190	6380
1994							6440

Source: PECo Budget Forecasts 1978-1984, and PECo Technical Services.

Note: Forecasts from 1978-1984 project peak load for ten years beginning in the next year.

PECO RESIDENTIAL SALES OF ELECTRICITY

1960–1984

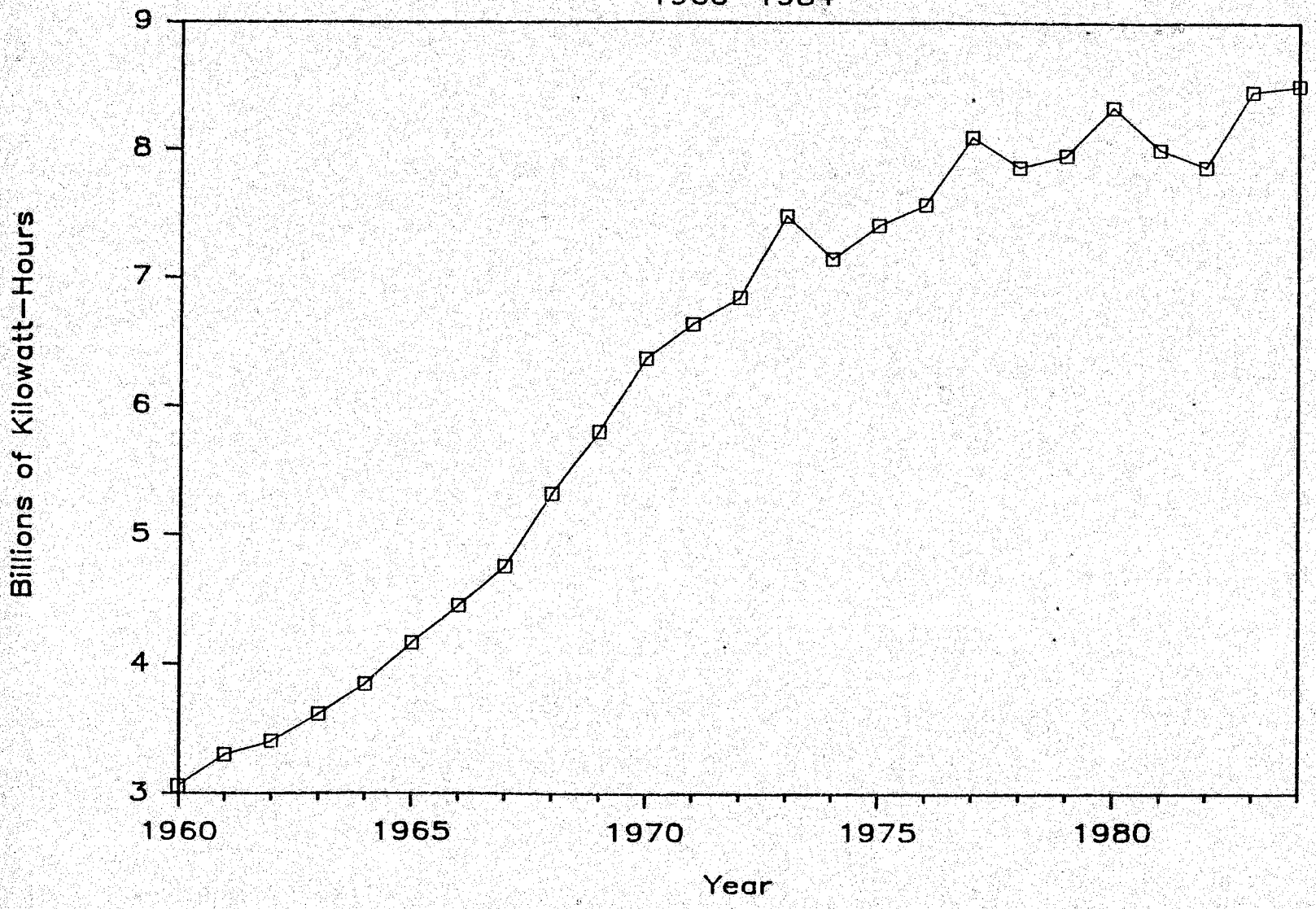


Exhibit ___ (LAG-2)
Chart 1 of 5

PECO SMALL COMMERCIAL & INDUSTRIAL

SALES OF ELECTRICITY, 1960–1984

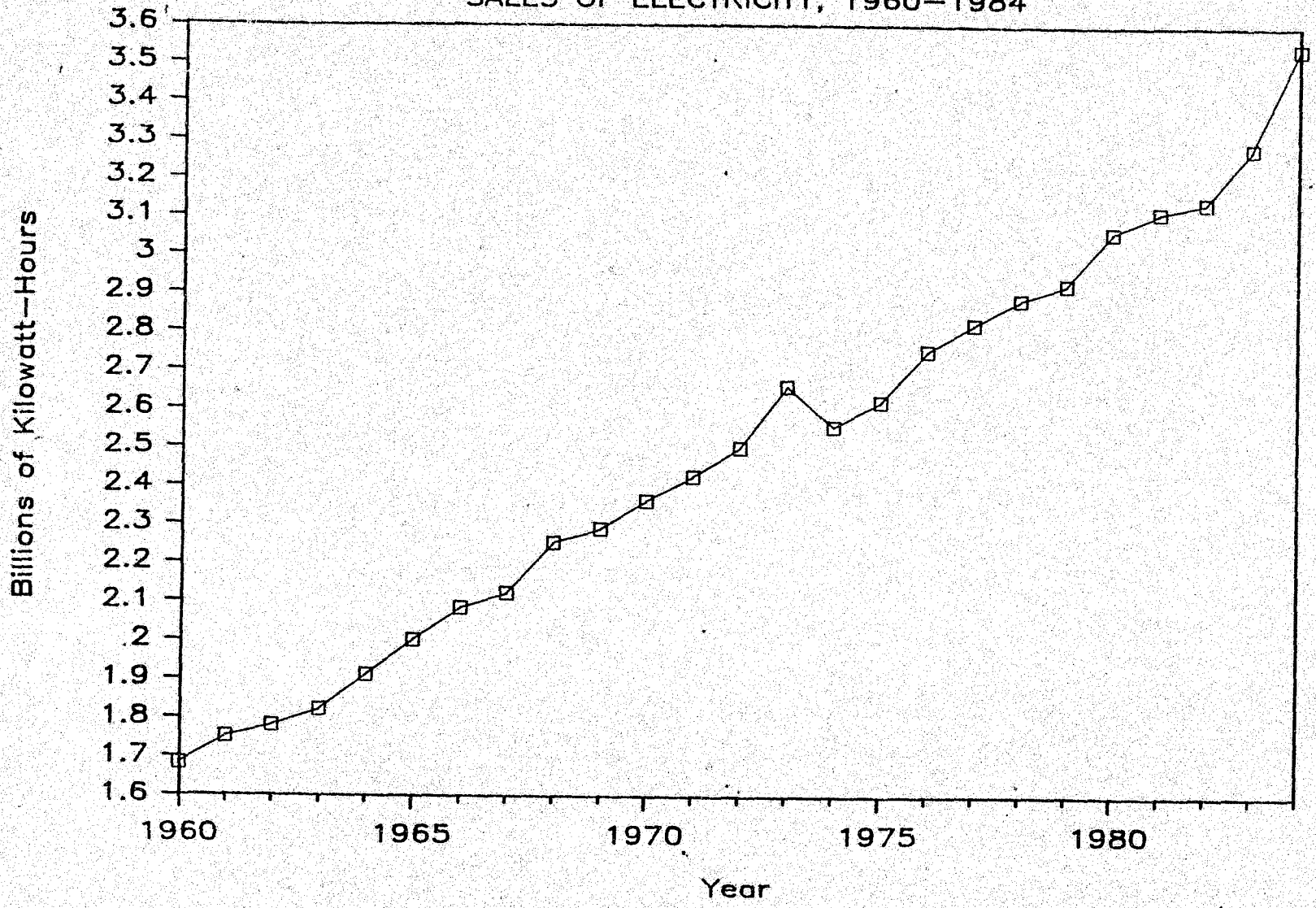


Exhibit ___ (LAG-2)
Chart 2 of 5

PECO LARGE COMMERCIAL & INDUSTRIAL

SALES OF ELECTRICITY, 1960–1984

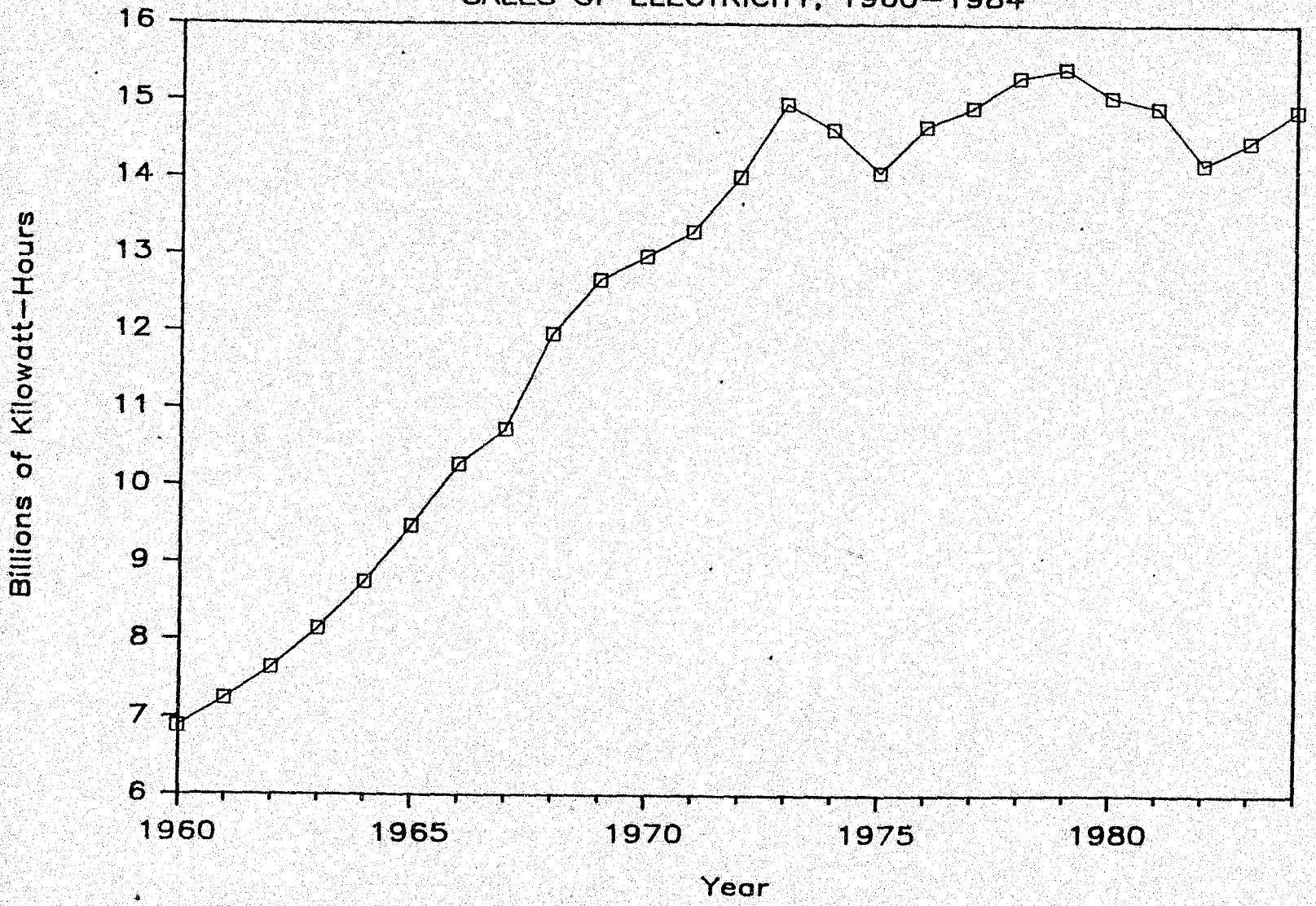


Exhibit ___ (LAG-2)
Chart 3 of 5

PECO Total Sales less Sales for Resale

and Interdepartmental Sales 1960–1984

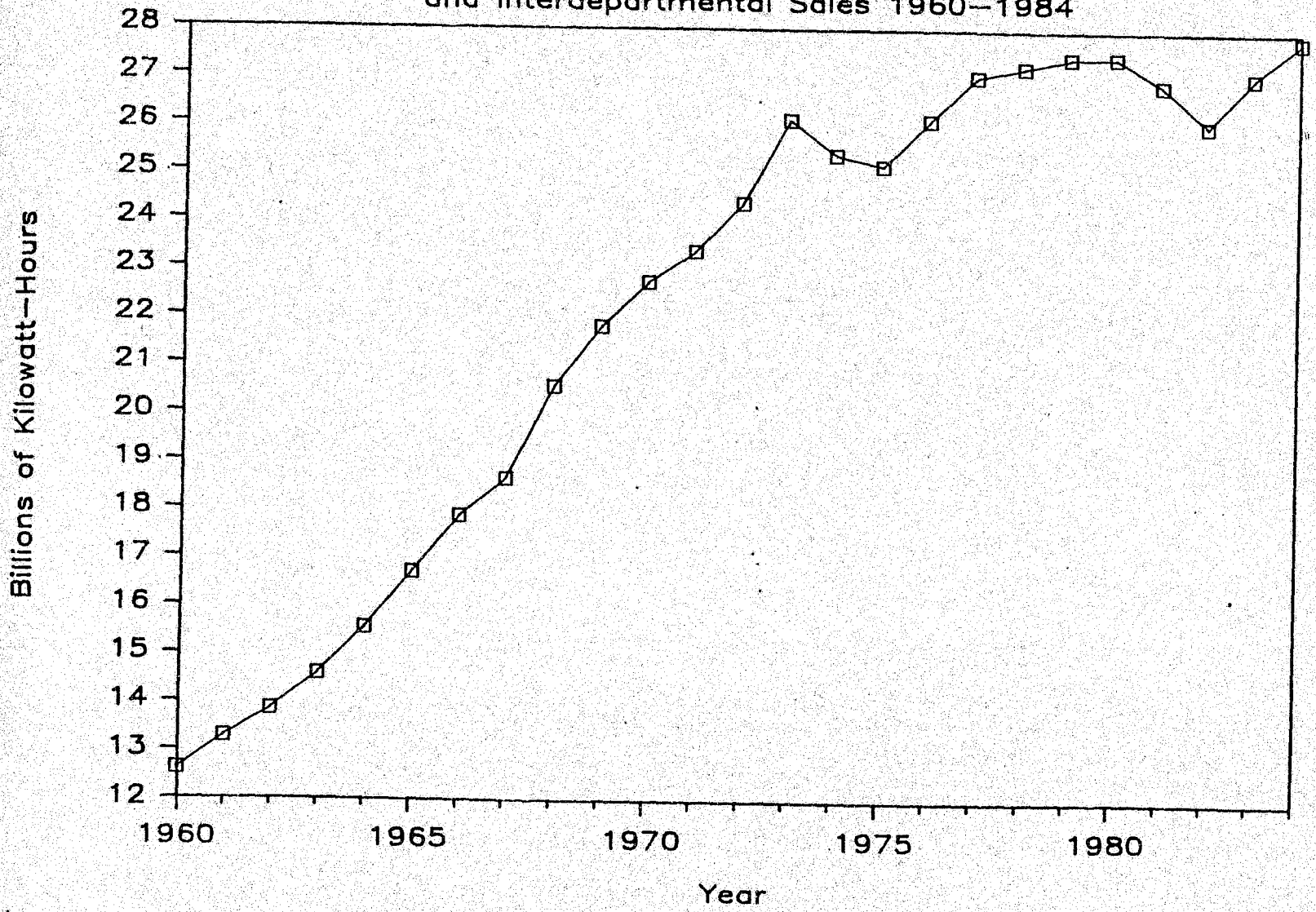


Exhibit (LAG-2)
Chart 4 of 5

PECO ANNUAL PEAK DEMAND
1955 – 1985

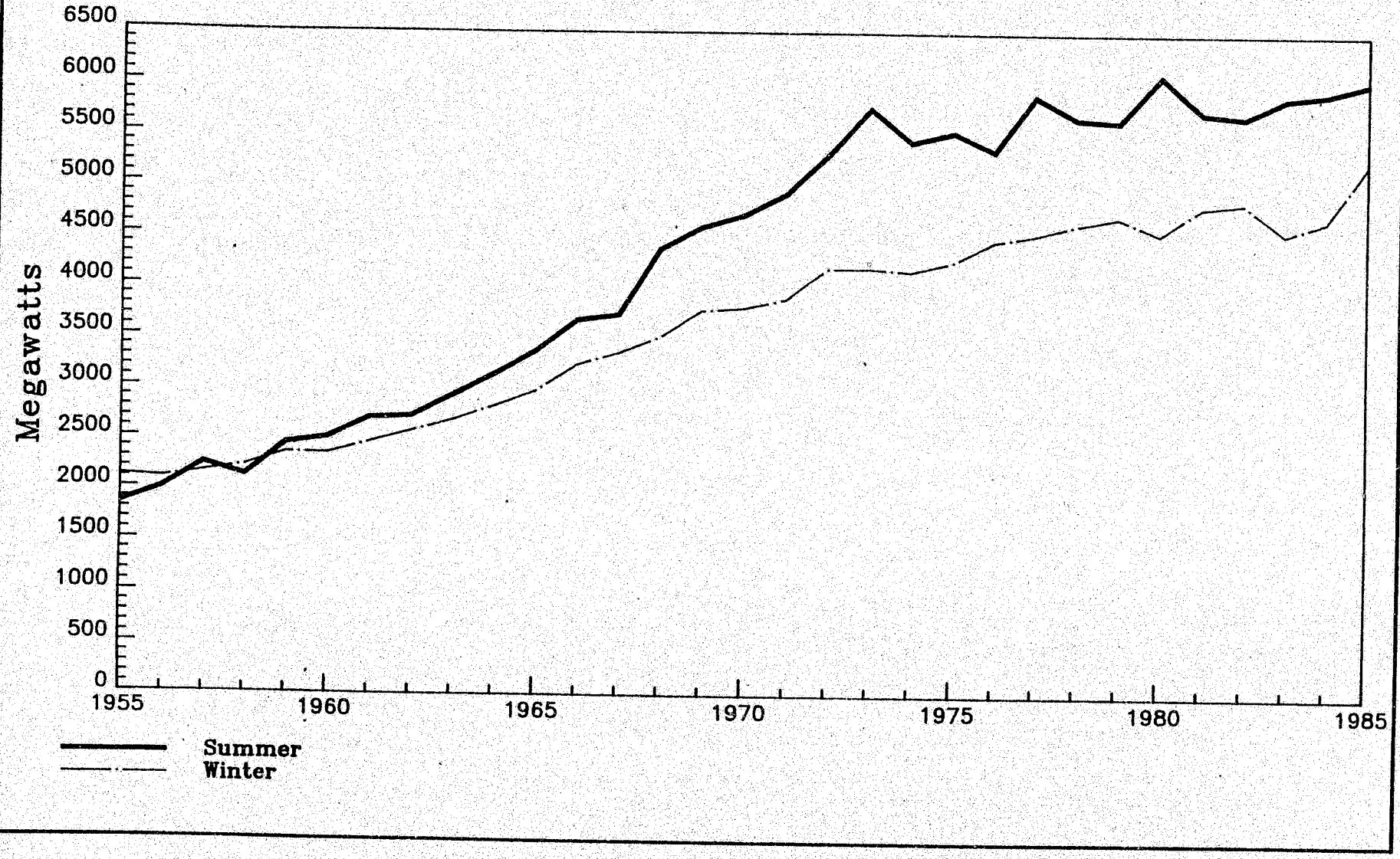


Exhibit (LAG-2)
Chart 5 of 5

NET ANNUAL ENERGY REQUIREMENTS AS COMPILED BY NERC
FOR THE MAAC AND THE CONTIGUOUS UNITED STATES
1978 - 1987

Year	MAAC		Contiguous United States	
	Energy Requirements (GWh) (1)	Percentage Change (Percent) (2)	Energy Requirements (GWh) (3)	Percentage Change (Percent) (4)
1978	170,781	--	2,263,500	--
1979	178,893	4.75%	2,386,900	5.45%
1980	186,641	4.33	2,524,200	5.75
1981	195,505	4.75	2,661,800	5.45
1982	203,999	4.34	2,804,300	5.35
1983	212,810	4.32	2,946,000	5.05
1984	221,428	4.05	3,100,700	5.25
1985	230,114	3.92	3,257,300	5.05
1986	238,810	3.78	3,418,600	4.95
1987	247,271	3.54	3,577,600	4.65
Average Annual Growth Rate				
1978 - 1985		4.35%		5.34%
1978 - 1987		4.20%		5.22%

Source: Col. (1): Economic Regulatory Administration, Division of Power Supply and Reliability U.S. Department of Energy, Electric Power Supply and Demand 1978-1987 for the Contiguous United States (Washington DC: U.S. Govt. Printing Office), June 15, 1978, Table 4.

Col. (3): Edison Electric Institute, 1978 Annual Electric Power Survey, April 1978.

Exhibit ___ (LAG-3)
Table 1 of 5

EDISON ELECTRIC INSTITUTE
PROJECTED NET ANNUAL ENERGY REQUIREMENTS
FOR THE MAAC AND THE CONTIGUOUS UNITED STATES
1978 - 1988

Year	MAAC		Contiguous United States	
	Energy Requirements (GWh) (1)	Percentage Change (Percent) (2)	Energy Requirements (GWh) (3)	Percentage Change (Percent) (4)
1978 <1	169,766	--	2,218,700	--
1979	175,386	3.31%	2,339,700	5.45%
1980	182,155	3.86	2,460,200	5.15
1981	188,816	3.66	2,589,400	5.25
1982	196,091	3.85	2,715,000	4.85
1983	203,286	3.67	2,838,600	4.55
1984	210,608	3.60	2,976,300	4.85
1985	217,782	3.41	3,114,700	4.65
1986	224,991	3.31	3,250,200	4.35
1987	232,248	3.23	3,391,600	4.35
1988	239,579	3.16	3,542,600	4.45
Average Annual Growth Rate				
1978 - 1985		3.62%		4.97%
1978 - 1988		3.50%		4.79%

1> Actual.

Source: Edison Electric Institute, 1979 Annual Electric Power Survey, April 1979, pp. 14-15.

Exhibit ____ (LAG-3)
Table 2 of 5

PEAK DEMANDS FOR THE MAAC AS COMPILED BY NERC
1978 - 1987

Year	Peak Demand		Growth in Peak Demand	
	Summer	Winter	Summer	Winter
	(Megawatts)		(Percent)	
	(1)	(2)	(3)	(4)
1978	32,713	28,866	--	--
1979	34,097	30,114	4.23%	4.32%
1980	35,382	31,489	3.77	4.57
1981	36,887	33,063	4.25	5.00
1982	38,362	34,528	4.00	4.43
1983	39,859	36,102	3.90	4.56
1984	41,274	37,626	3.55	4.22
1985	42,759	39,141	3.60	4.03
1986	44,191	40,715	3.35	4.02
1987	45,651	42,274	3.30	3.83
Average Annual Growth Rate				
1978 - 1985			3.90%	4.45%
1978 - 1987			3.77%	4.33%

Note: The demands include interruptible load and exclude inter-regional purchases and sales of capacity.

Source: Economic Regulatory Administration, Division of Power Supply and Reliability, U.S. Department of Energy, Electric Power Supply and Demand 1978-1987 for the Contiguous United States (Washington DC: U.S. Govt. Printing Office), June 15, 1978, Table 2.

Exhibit ____ (LAG-3)
Table 3 of 5

EDISON ELECTRIC INSTITUTE
PROJECTED PEAK DEMANDS FOR THE MAAC
1978 - 1988

Year	Peak Demand		Growth in Peak Demand	
	Summer	Winter	Summer	Winter
	(Megawatts)		(Percent)	
	(1)	(2)	(3)	(4)
1978 <1	31,812	28,655	--	--
1979	33,446	29,686	5.14%	3.60%
1980	34,436	30,776	2.96	3.67
1981	35,586	32,036	3.34	4.09
1982	36,876	33,286	3.63	3.90
1983	38,066	34,566	3.23	3.85
1984	39,196	35,806	2.97	3.59
1985	40,426	37,036	3.14	3.44
1986	41,566	38,306	2.82	3.43
1987	42,756	39,576	2.86	3.32
1988	44,066	40,856	3.06	3.23
Average Annual Growth Rate				
1978 - 1985			3.48%	3.73%
1978 - 1988			3.31%	3.61%

1> Actual.

Source: Edison Electric Institute, 1979 Annual Electric Power Survey, April 1979, pp. 6-9.

Exhibit ____ (LAG-3)
Table 4 of 5

EDISON ELECTRIC INSTITUTE
FORECASTS OF ANNUAL KILOWATT-HOUR REQUIREMENTS
1974 - 1982

Year		MAAC			All NERC Regions			MAAC as % of All Regions	
		Actual Electricity Requirements	10-Year Forecasted Requirements	Annual Growth Rate	Actual Electricity Requirements	10-Year Forecasted Requirements	Annual Growth Rate	Actual Electricity Requirements	Annual Growth Rate
		(GWh)		(Percent)	(GWh)		(Percent)	(Percent)	
		(1)	(2)	(3)	(4)	(5)	(6)	[(1)/(4)] (7)	[(3)/(6)] (8)
1973		155,362	--	--	1,847,862	--	--	8.41%	--
1974	<1	151,274	210,713	5.68%	1,851,727	2,791,756	7.08%	8.17	80.19%
1975		151,439	260,976	5.59	1,900,670	3,510,302	6.33	7.97	88.40
1976		159,679	254,136	4.76	2,021,266	3,579,464	5.88	7.90	80.88
1977		164,135	247,271	4.18	2,115,089	3,561,179	5.35	7.76	78.22
1978		169,766	239,579	3.50	2,202,166	3,527,611	4.82	7.71	72.64
1979		172,540	236,938	3.22	2,246,927	3,380,530	4.17	7.68	77.29
1980		175,622	230,713	2.77	2,292,718	3,236,073	3.51	7.66	78.89
1981		174,668	222,013	2.43	2,311,006	3,180,947	3.25	7.56	74.77
1982		171,662	212,779	2.17	2,258,744	3,123,464	3.29	7.60	65.88

-- Not Available.

Note: The 1975 Electric Power Survey is the first survey with data on the Reliability Councils as they are currently defined.

1> These forecasts are for six years.

Source: Edison Electric Institute, Annual Electric Power Survey, annual editions, 1975-1983.

Exhibit ____ (LAG-3)
Table 5 of 5

ENERGY INFORMATION ADMINISTRATION
PROJECTED GROWTH IN NATIONAL ELECTRICITY CONSUMPTION
1976 - 1985

Sector	1976 Actual	1985 Mid Demand Mid Supply	1985 High Demand High Supply	1985 High Demand Low Supply	1985 Low Demand High Supply	1985 Low Demand Low Supply	1985 Mid Demand Mid Supply
	(Billion kWh)						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Residential	613	841	847	825	845	825	838
Commercial	501	696	698	697	678	678	690
Industrial	725	1,225	1,256	1,182	1,260	1,187	1,263
Transportation	4	4	4	4	4	4	4
Total Consumption	1,843	2,766	2,805	2,708 <2	2,787 <2	2,694	2,795
Average Annual Growth Rate		4.61%	4.78%	4.37%	4.70%	4.31%	4.74%

1> Increasing world oil prices.
2> Differs from sum given in source.

Source: Energy Information Administration, U.S. Department of Energy, Annual Report to Congress, 1977, Volume II: Projections of Energy Supply and Demand and Their Impacts (Washington, DC: U.S. Govt. Printing Office), p. 211.

Exhibit ___ (LAG-4)
Table 1 of 7

ENERGY INFORMATION ADMINISTRATION
PROJECTED GROWTH IN NATIONAL ELECTRICITY SALES
1977 - 1990

Sector	1977	1985	1990				
	Actual	Mid Demand Mid Supply	Mid Demand Mid Supply	High Demand High Supply	High Demand Low Supply	Low Demand High Supply	Low Demand Low Supply
	(Quadrillion Btu per Year)						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Residential	2.23	2.83	3.34	3.37	3.32	3.38	3.25
Commercial	1.83	2.61	3.09	3.45	2.85	3.16	2.80
Industrial	2.58	3.96	5.02	5.47	5.21	4.90	4.67
Transportation	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Total Sales	6.66	9.41	11.46	12.30	11.39	11.45	10.73
Average Annual Growth Rate		4.42%	4.26%	4.83%	4.21%	4.26%	3.74%

Source: Energy Information Administration, U.S. Department of Energy, Annual Report to Congress, 1978, Volume III: Forecasts (Washington DC: U.S. Govt. Printing Office), pp. 266-269.

Exhibit ___ (LAG-4)
Table 2 of 7

Exhibit ____ (LAG-4)
Table 3 of 7

GROWTH IN NATIONAL ELECTRICITY CONSUMPTION PROJECTED BY THE ENERGY INFORMATION ADMINISTRATION 1978 - 1985

	1978	1985		
World Oil Price ($1979 per Barrel):	Actual	Low 27.00	Mid 32.00	High 39.00
	(Quadrillion Btu)			
	(1)	(2)	(3)	(4)
Residential	2.4	2.8	2.8	2.8
Commercial	1.7	1.9	1.9	1.9
Industrial	2.7	3.6	3.6	3.6
Total Consumption	6.8	8.3	8.3	8.3
Average Annual Growth Rate		2.9%	2.9%	2.9%

Source: Energy Information Administration, U.S. Department of Energy, Annual Report to Congress, 1979, Volume III: Forecasts (Washington DC: U.S. Govt. Printing Printing Office, April 1980), pp. 83 & 108. Prepared April 1980.

EDISON ELECTRIC INSTITUTE
1978 PROJECTIONS OF PEAK DEMAND FOR THE CONTIGUOUS UNITED STATES
1978 - 1987

Year	Peak Demand (Megawatts)		Growth in Peak Demand (Percent)	
	Summer	Winter	Summer	Winter
	(1)	(2)	(3)	(4)
1978	421,100	390,300	--	--
1979	444,900	412,000	5.65%	5.56%
1980	469,250	436,150	5.47	5.86
1981	494,400	459,950	5.36	5.46
1982	520,400	484,100	5.26	5.25
1983	545,400	509,550	4.80	5.26
1984	573,500	537,350	5.15	5.46
1985	601,900	564,800	4.95	5.11
1986	631,700	593,350	4.95	5.05
1987	660,600	623,350	4.57	5.06
Average Annual Growth Rate				
1978 - 1985			5.24%	5.42%
1978 - 1987			5.13%	5.34%

Source: Edison Electric Institute, 1978 Annual Electric Power Survey, April 1978, pp. 6-9.

Exhibit ____ (LAG-4)
Table 4 of 7

EDISON ELECTRIC INSTITUTE
1979 PROJECTIONS OF PEAK DEMAND FOR THE CONTIGUOUS UNITED STATES
1978 - 1988

Year	Peak Demand		Growth in Peak Demand	
	Summer	Winter	Summer	Winter
	(Megawatts)		(Percent)	
	(1)	(2)	(3)	(4)
1978 <1	408,050	383,100	--	--
1979	436,600	405,250	7.00%	5.78%
1980	458,250	426,950	4.96	5.35
1981	481,400	448,950	5.05	5.15
1982	505,250	470,300	4.95	4.76
1983	526,750	493,150	4.26	4.86
1984	551,800	517,100	4.76	4.86
1985	576,950	540,650	4.56	4.55
1986	602,050	564,750	4.35	4.46
1987	628,250	589,900	4.35	4.45
1988	655,600	615,600	4.35	4.36
Average Annual Growth Rate				
1978 - 1985			5.07%	5.04%
1978 - 1988			4.86%	4.86%

1> Actual.

Source: Edison Electric Institute, 1979 Annual Electric Power Survey, April 1979, pp. 6-9.

Exhibit ___ (LAG-4)
Table 5 of 7

EDISON ELECTRIC INSTITUTE
1980 PROJECTIONS OF PEAK DEMAND FOR THE CONTIGUOUS UNITED STATES
1978 - 1989

Year	Peak Demand		Growth in Peak Demand	
	Summer	Winter	Summer	Winter
	(Megawatts)		(Percent)	
	(1)	(2)	(3)	(4)
1978 <1	408,050	383,100	--	--
1979 <1	411,550	380,700	0.86%	-0.63%
1980	438,150	411,350	6.46	8.05
1981	457,250	430,900	4.36	4.75
1982	478,550	449,100	4.66	4.22
1983	497,950	468,200	4.05	4.25
1984	518,650	488,600	4.16	4.36
1985	539,150	508,400	3.95	4.05
1986	559,400	529,000	3.76	4.05
1987	580,400	549,900	3.75	3.95
1988	601,600	570,900	3.65	3.82
1989	623,600	591,150	3.66	3.55
Average Annual Growth Rate				
1978 - 1985			4.06%	4.13%
1978 - 1989			3.59%	3.34%

1> Actual.

Source: Edison Electric Institute, 1980 Annual Electric Power Survey, 1980, pp. 6-9.

Exhibit ___ (LAG-4)
Table 6 of 7

Exhibit ____ (LAG-4)
Table 7 of 7
Page 1 of 2

FORECASTED GROWTH RATES FOR ELECTRIC POWER AS REPORTED IN PREDICASTS ANNUAL CUMULATIVE EDITIONS

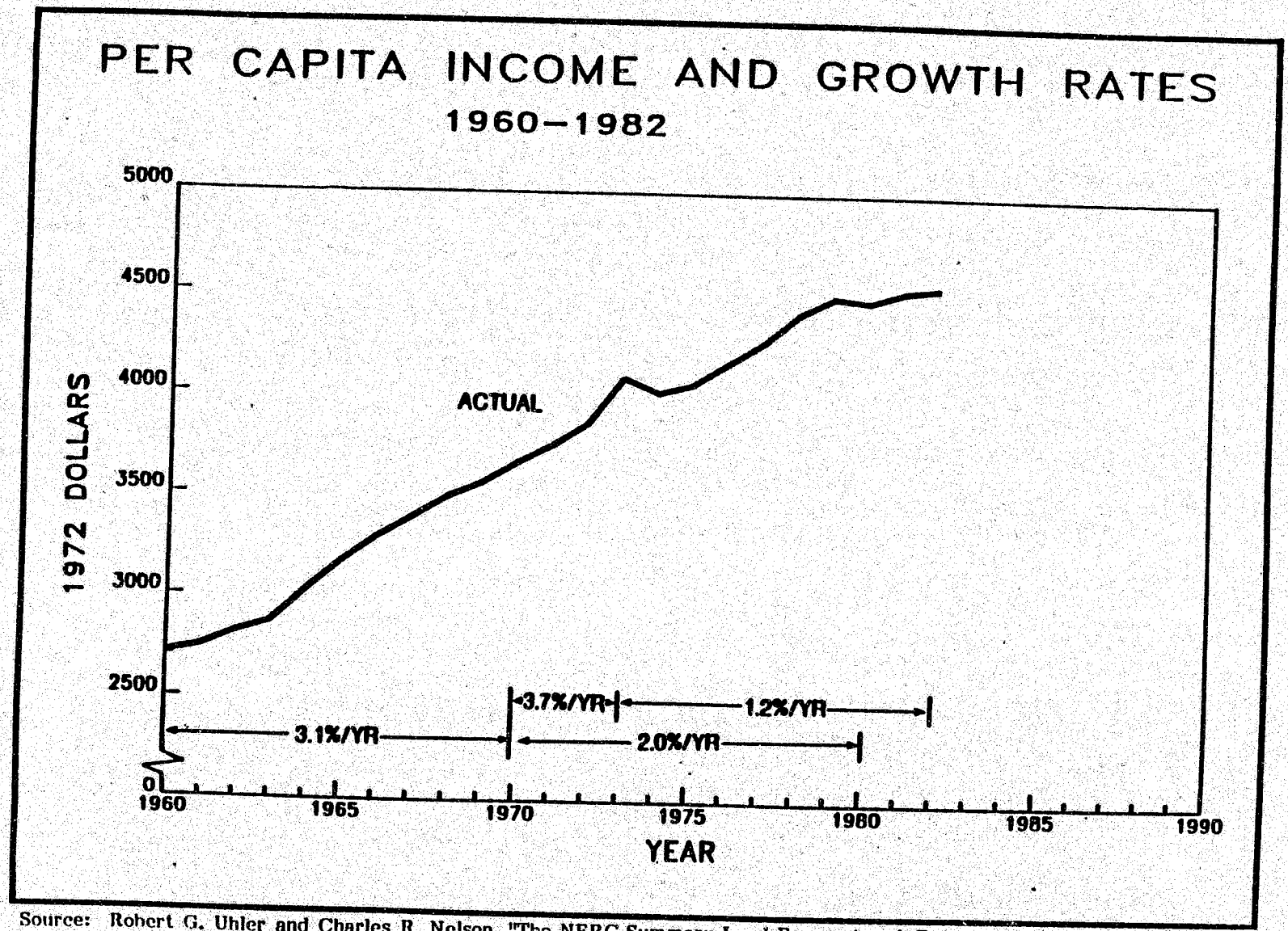
Electric Power Category	Additional Descriptor	Source: Journal	Source: Date	Forecast Period	Annual Growth Rate
		(1)	(2)	(3)	(Percent) (4)
1978 Predicasts					
Peak Load	(annual non-coin)	Electrical World	9/15/77	1977 - 1995	5.3%
Peak Load		Business Week	11/7/77	1978 - 1987	5.7
Consumption	primary energy	American Gas Association	10/ /77	1976 - 1985	4.4
Consumption	primary energy	U.S. International Trade Commission, Publication #832	9/ /77	1975 - 1985	5.1
Consumption	primary energy	Congressional Research Service, 93-856	7/ /77	1976 - 1985	4.4
Consumption	primary energy	Congressional Research Service, 93-856	7/ /77	1975 - 1985	5.8
Consumption		Commerce America	5/9/77	1976 - 1985	2.4
Consumption		U.S. Coal Developments -- Promises, Uncertainties	9/22/77	1975 - 1985	5.4
Consumption		U.S. Coal Developments -- Promises, Uncertainties	9/22/77	1975 - 1985	7.7
Consumption		Iron Age	4/10/78	1975 - 1990	4.7
Consumption		Oil & Gas Journal	8/1/77	1977 - 1990	5.5
Consumption		Wall Street Transcript	1/2/78	1978 - 198?	4.5
Consumption		Wall Street Transcript	12/5/77	1978 - 198?	5.5
Consumption		Modern Casting	1/ /78	1978 - 1990	6.5
Sales	by sector	Energy Information Administration, Annual Report to Congress	4/ /78	1976 - 1985	4.6
Sales		Electrical World	9/15/77	1977 - 1995	4.5
Sales		Electrical World	1/1/78	1977 - 1981	5.9
1979 Predicasts					
Peak Load	(winter)	Survey of Power Equipment Requirements of the U.S. Electric Utility Industry, 1973 - 1982	3/ /78	1978 - 1986	5.6
Peak Load	(summer)	Same as above	3/ /78	1978 - 1986	5.4
Peak Load		Industrial Research	3/ /79	1977 - 1987	5.3
Peak Load		Chemical Week	11/15/78	1978 - 1987	5.5
Peak Load		Energy User News	1/1/79	1978 - 1985	5.0
Peak Load		Power Engineering	1/ /79	1978 - 1987	5.0

FORECASTED GROWTH RATES FOR ELECTRIC POWER AS REPORTED IN PREDICASTS ANNUAL CUMULATIVE EDITIONS

Electric Power Category	Additional Descriptor	Source: Journal	Source: Date	Forecast Period	Annual Growth Rate
		(1)	(2)	(3)	(Percent) (4)
Consumption	(per capita)	Energy User News	12/4/78	1978 - 1990	4.3
Consumption		Energy User News	8/21/78	1977 - 1985	4.3
Consumption		Economic Bulletin (Metropolitan Life)	3/ /79	1979 - 1983	4.7
Consumption		Chain Store Age	1/ /79	1976 - 1985	5.9
Consumption		Turbo Machinery International	4/ /79	1977 - 1985	4.6
Consumption		Science	9/15/78	1978 - 1987	4.4
Consumption		Science	9/15/78	1978 - 1987	5.2
Consumption		Wall Street Transcript	1/22/79	1980 - 1990	4.3
Consumption		Chemical & Engineering News	6/11/79	1978 - 1990	4.5
Consumption		Power Engineering	4/ /79	1978 - 1990	4.6
Consumption		Chemical Marketing Reporter	7/17/78	1973 - 1990	5.0
Consumption		Energy User News	12/4/78	1978 - 1990	5.0
Sales		Industry	1/ /79	1978 - 1990	4.3
Sales		Power Engineering	1/ /79	1978 - 1987	5.0

Source: Predicasts Annual Cumulative Edition (Cleveland, Ohio: Predicasts, Inc.), 1978 & 1979 editions.

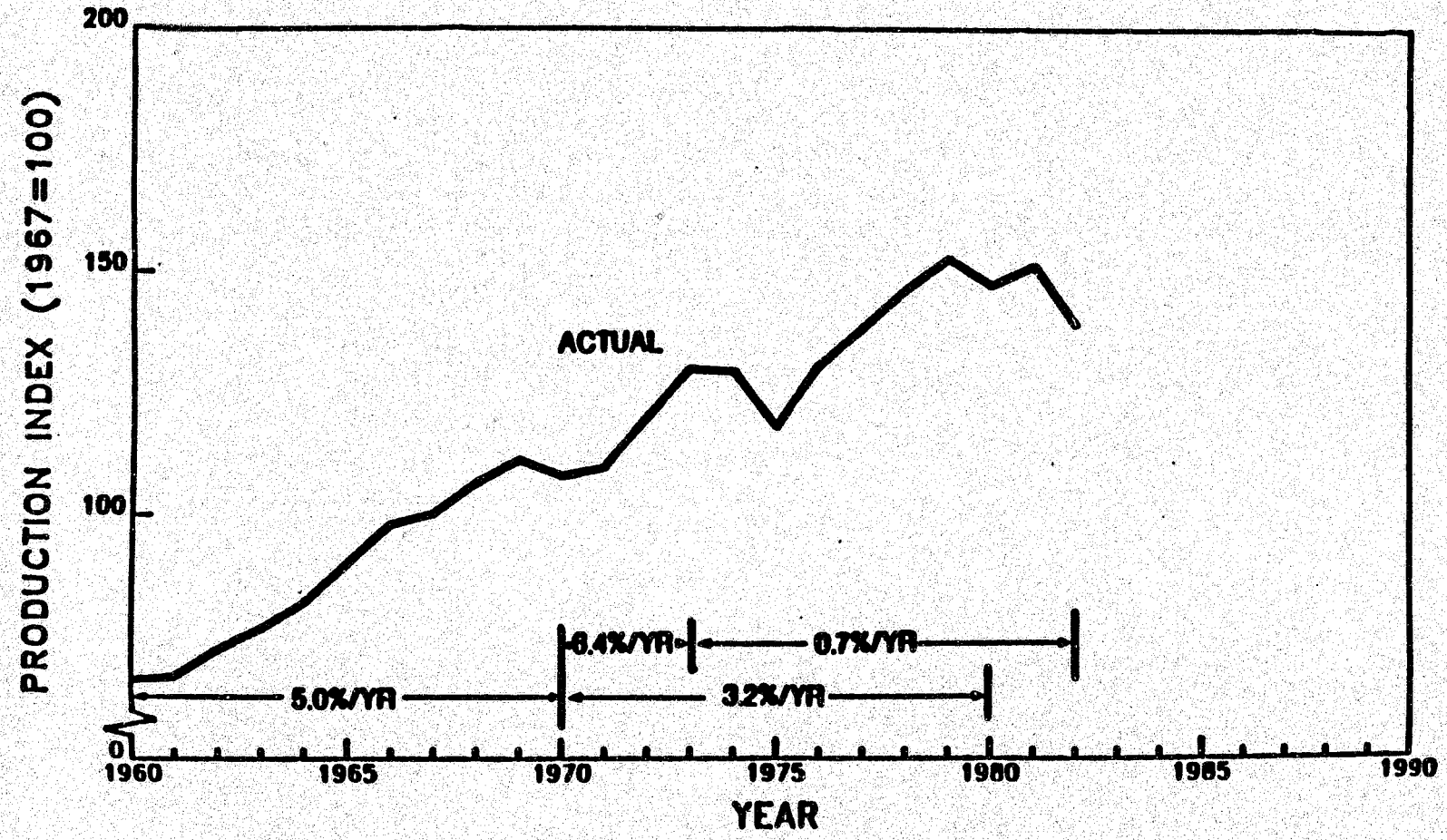
PER CAPITA INCOME AND GROWTH RATES
1960–1982



Source: Robert G. Uhler and Charles R. Nelson, "The NERC Summary Load Forecasts: A Retrospective Appraisal and Technical Analysis," May 31, 1985.

Exhibit ___ (LAG-5)
Chart 1 of 7

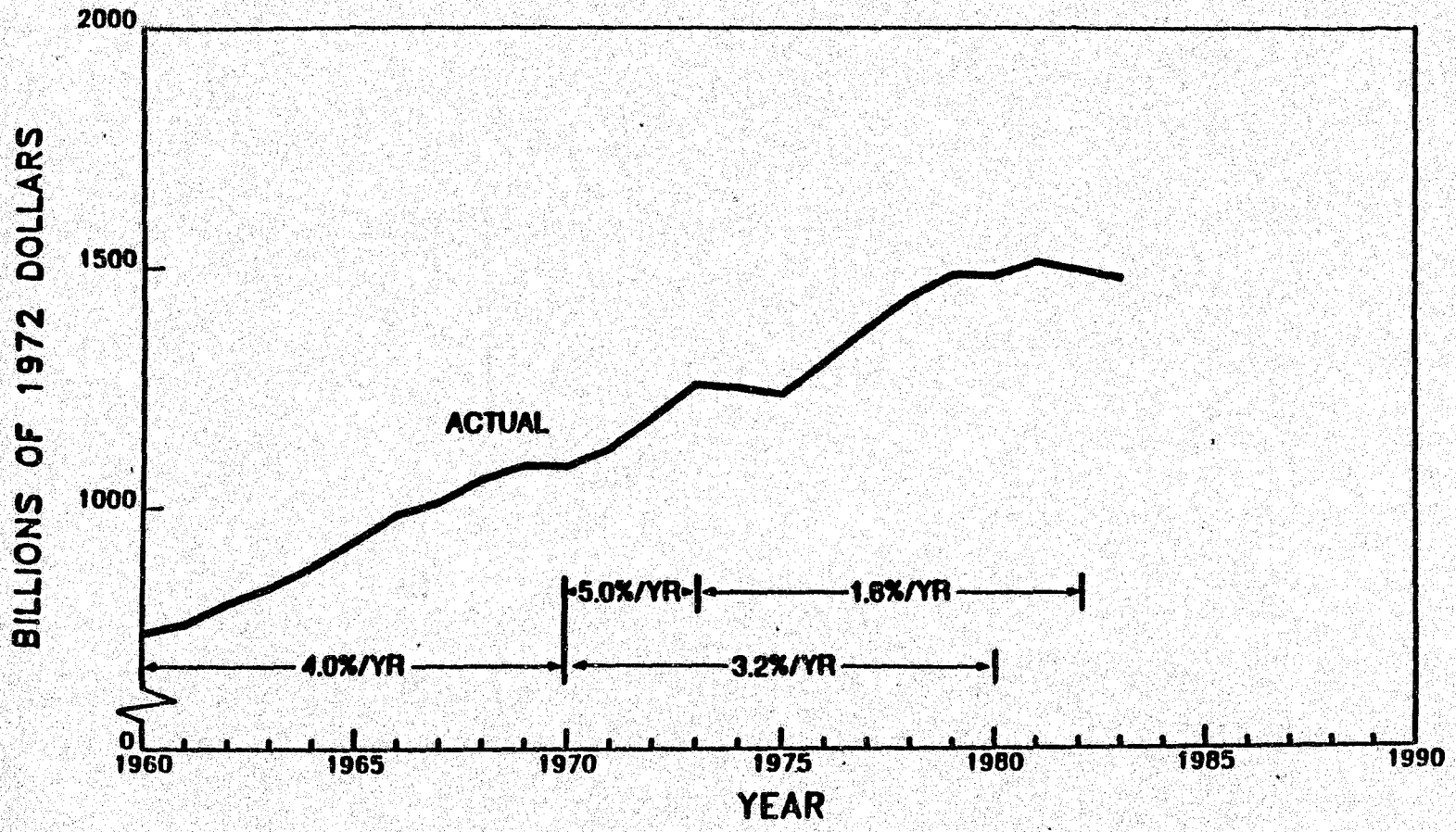
INDUSTRIAL PRODUCTION INDEX AND GROWTH RATES
1960–1982



Source: Robert G. Uhler and Charles R. Nelson, "The NERC Summary Load Forecasts: A Retrospective Appraisal and Technical Analysis," May 31, 1985.

Exhibit ___ (LAG-5)
Chart 2 of 7

GROSS NATIONAL PRODUCT AND GROWTH RATES
1960–1982

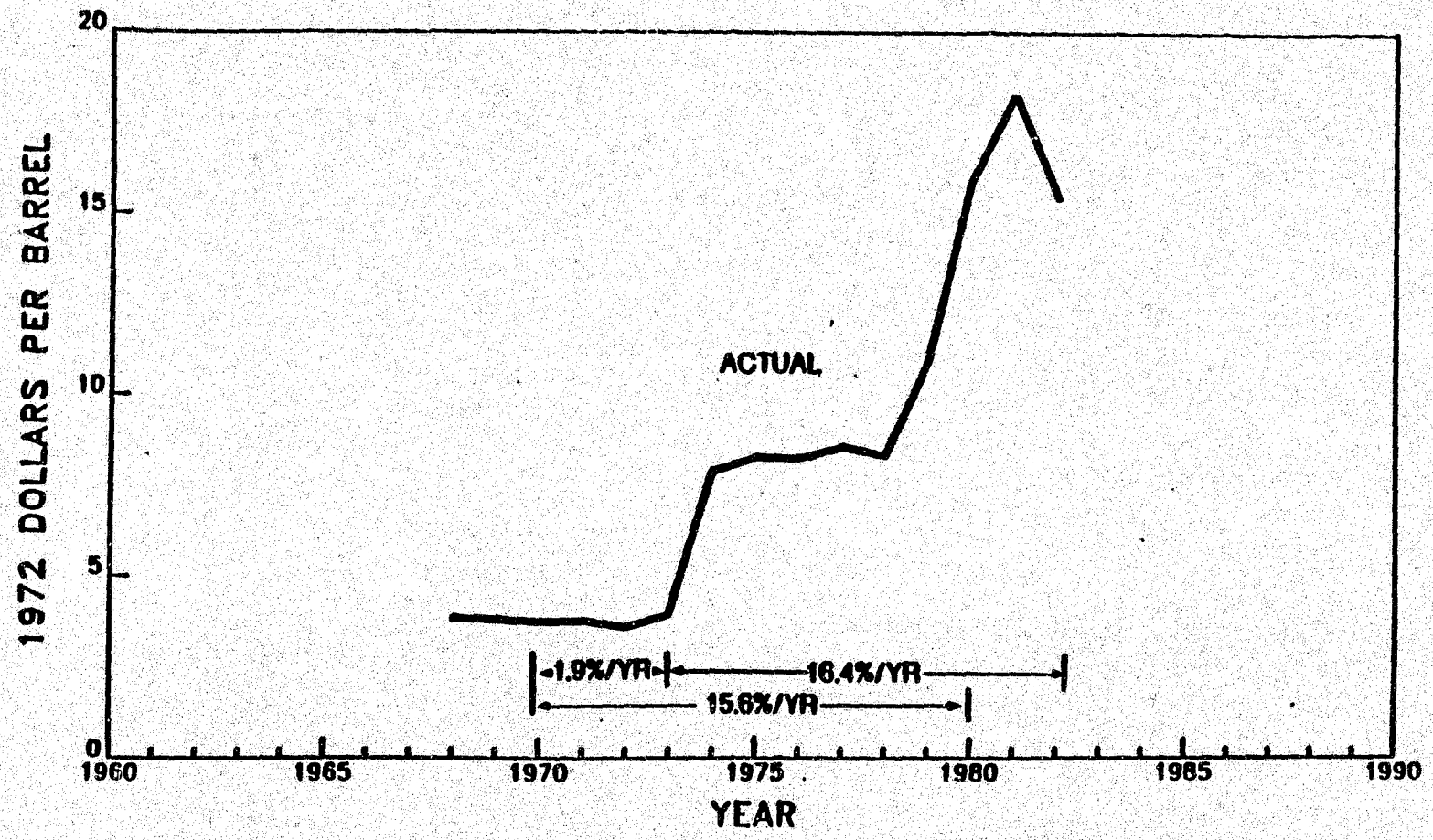


Source: Robert G. Uhler and Charles R. Nelson, "The NERC Summary Load Forecasts: A Retrospective Appraisal and Technical Analysis," May 31, 1985.

Exhibit ___ (LAG-5)
Chart 3 of 7

CRUDE OIL COST AND GROWTH RATES

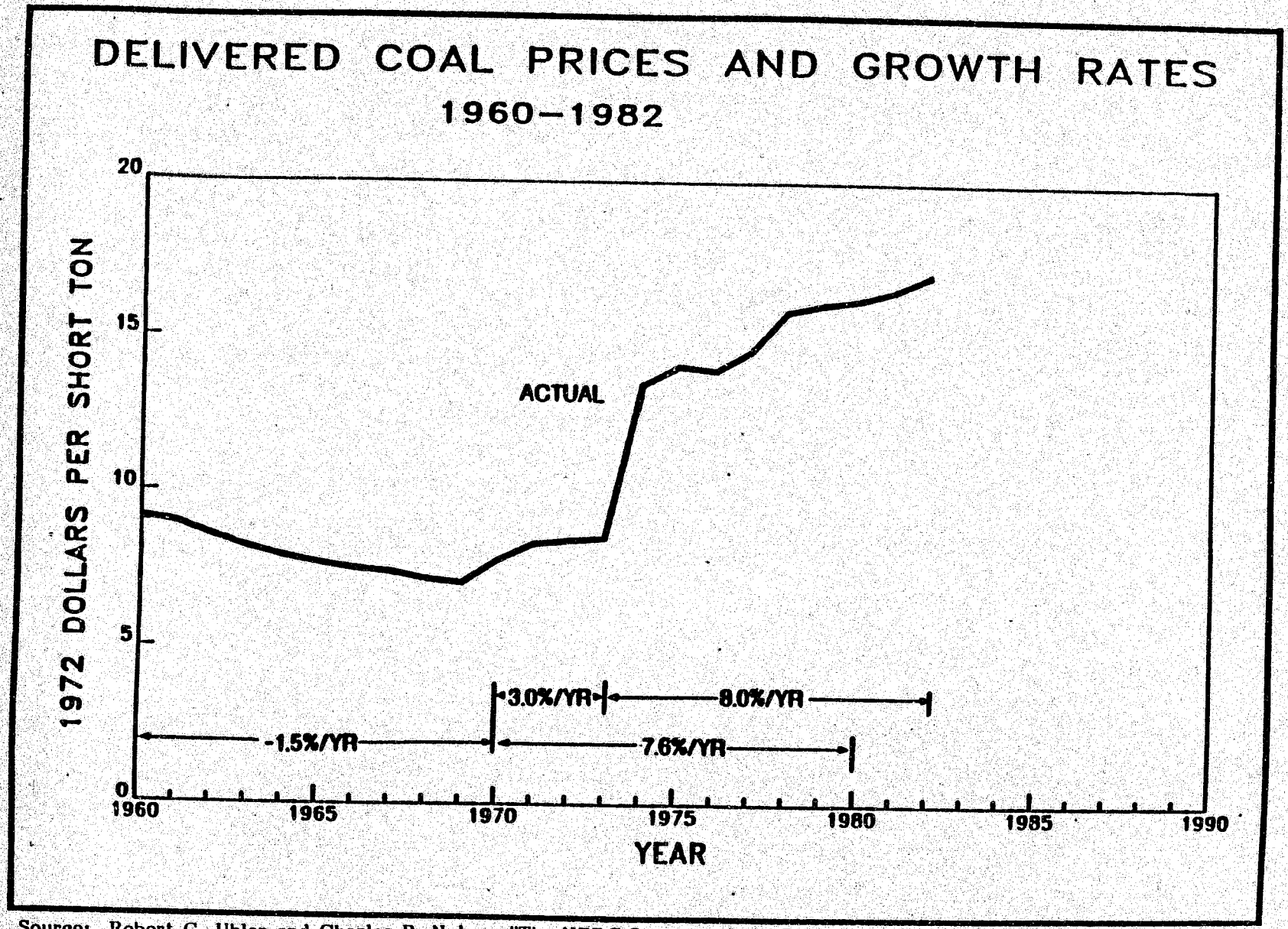
1968–1982



Source: Robert G. Uhler and Charles R. Nelson, "The NERC Summary Load Forecasts: A Retrospective Appraisal and Technical Analysis," May 31, 1985.

Exhibit ___ (LAG-5)
Chart 4 of 7

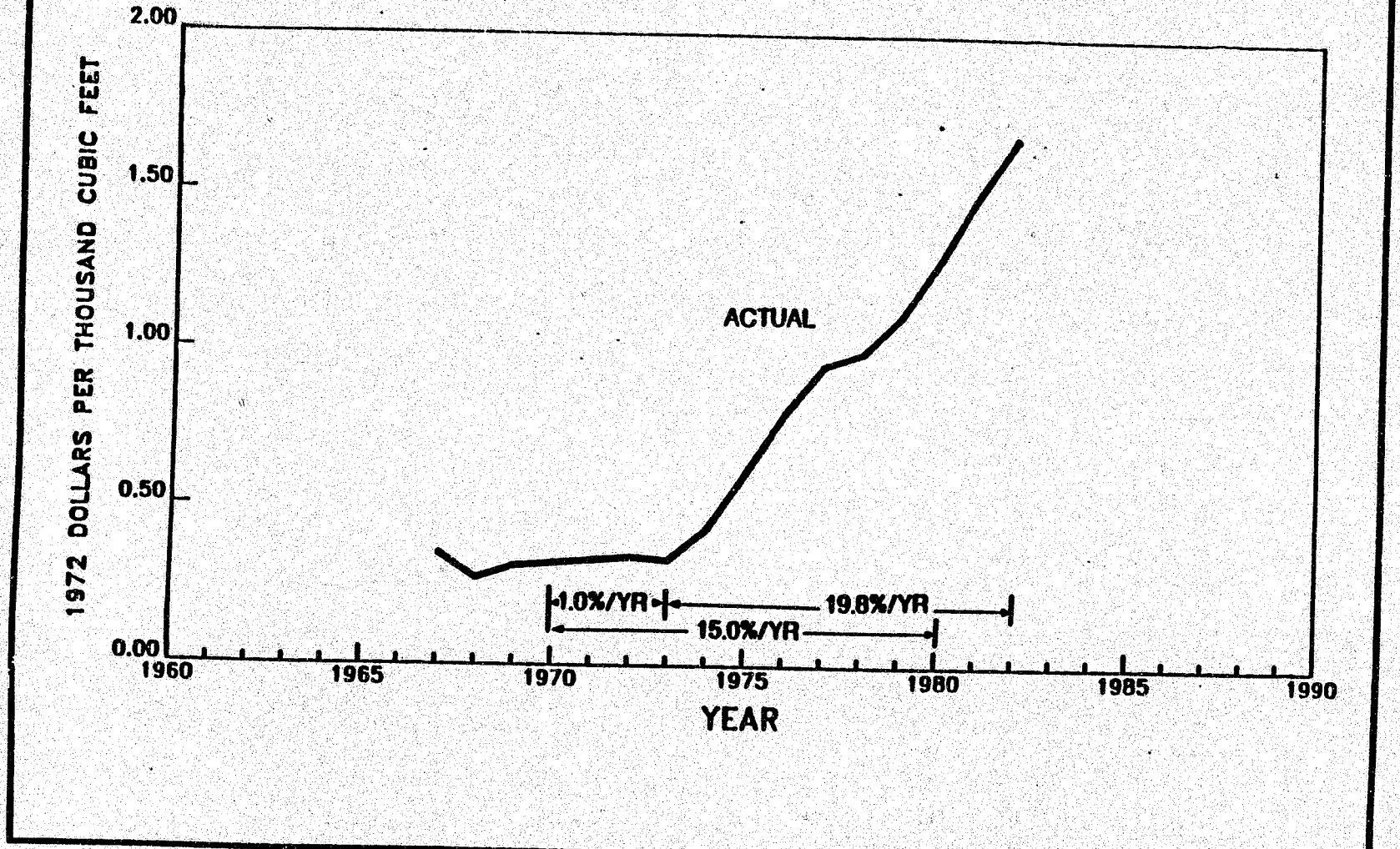
DELIVERED COAL PRICES AND GROWTH RATES
1960–1982



Source: Robert G. Uhler and Charles R. Nelson, "The NERC Summary Load Forecasts: A Retrospective Appraisal and Technical Analysis," May 31, 1985.

Exhibit ___ (LAG-5)
Chart 5 of 7

DELIVERED PRICE OF NATURAL GAS AND GROWTH RATES
1967–1982

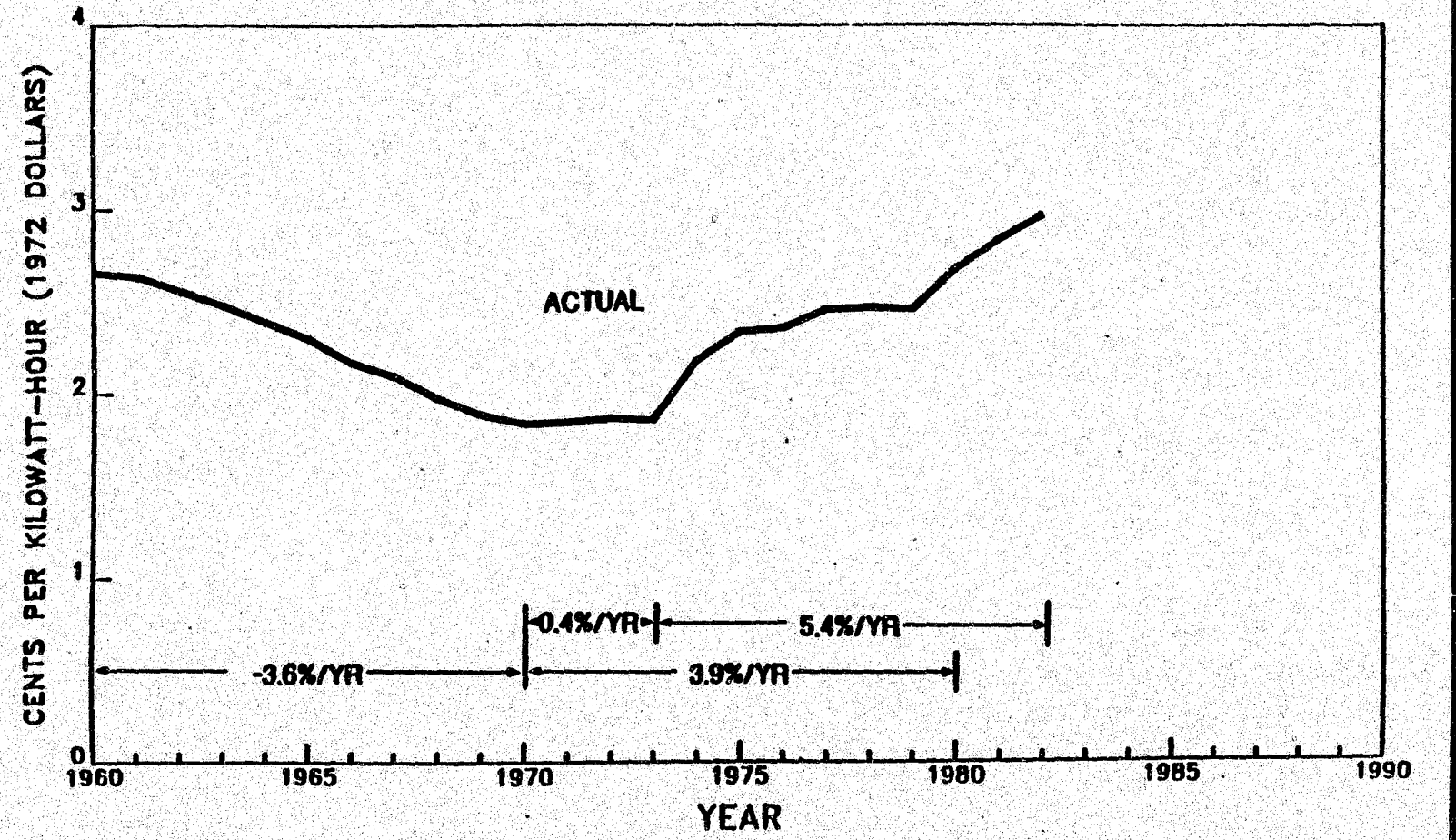


Source: Robert G. Uhler and Charles R. Nelson, "The NERC Summary Load Forecasts: A Retrospective Appraisal and Technical Analysis," May 31, 1985.

Exhibit ___ (LAG-5)
Chart 6 of 7

PRICE OF ELECTRICITY: WEIGHTED AVERAGE

1960–1982



Source: Robert G. Uhler and Charles R. Nelson, "The NERC Summary Load Forecasts: A Retrospective Appraisal and Technical Analysis," May 31, 1985.

Exhibit ___ (LAG-5)
Chart 7 of 7

Exhibit (LAG-6)

Chart 1 of 4

Residential New Construction

PECo System Service Area

Manufacturing Employment

of Philadelphia SMSA

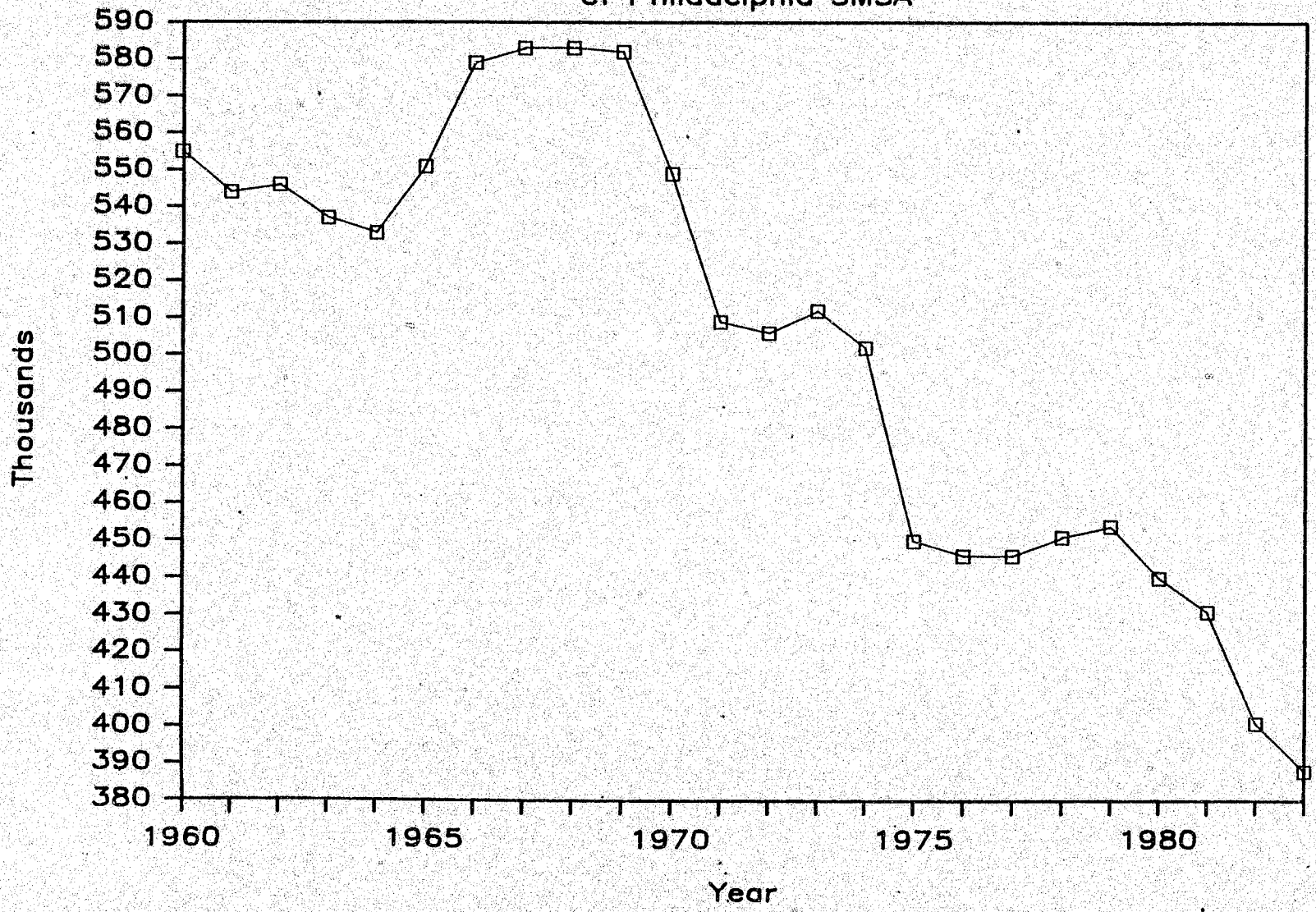


Exhibit ___ (LAG-6)
Chart 2 of 4

Exhibit (LAG-6)

Chart 3 of 4

PECO Total Residential Customers

1970–1983

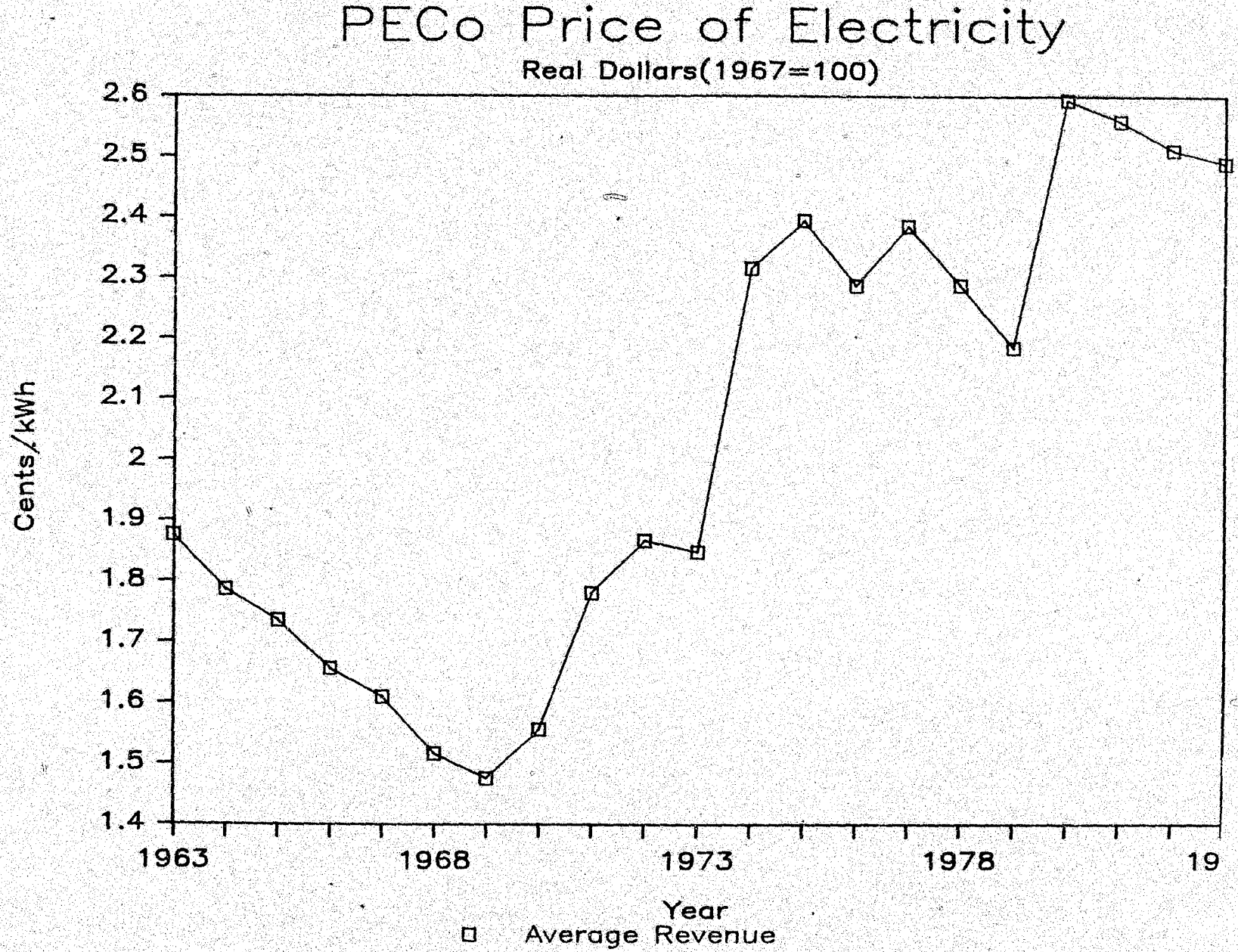
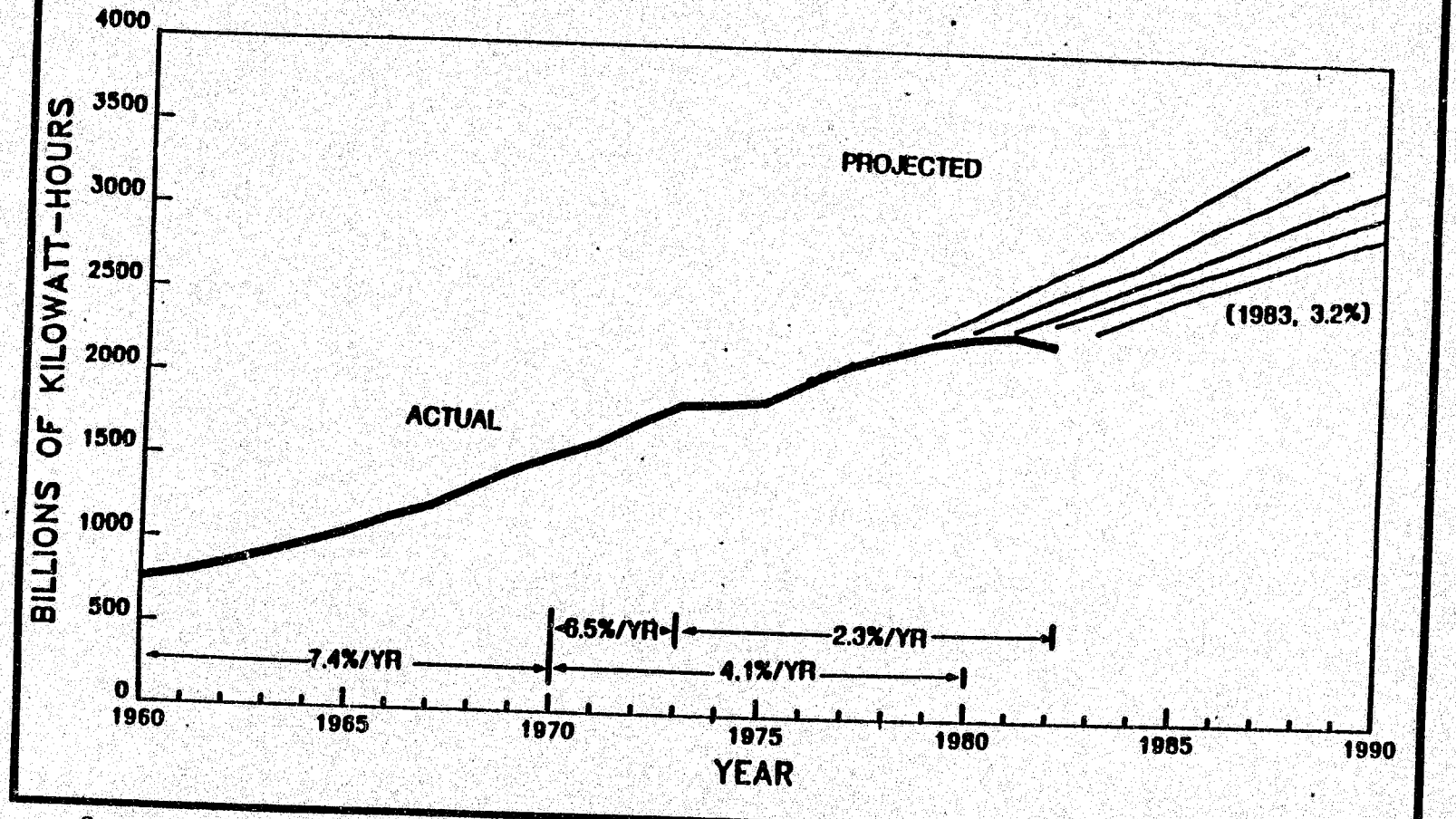


Exhibit ___ (LAG-6)
Chart 4 of 4

NET ENERGY REQUIREMENTS AND GROWTH RATES

1960–1982: ACTUAL
1983–1990: PROJECTED



Source: Robert G. Uhler and Charles R. Nelson, "The NERC Summary Load Forecasts: A Retrospective Appraisal and Technical Analysis," May 31, 1985.

Exhibit ___ (LAG-7)
Chart 1 of 1

PECO ACTUAL AND FORECASTED PEAKS
1970 – 2004

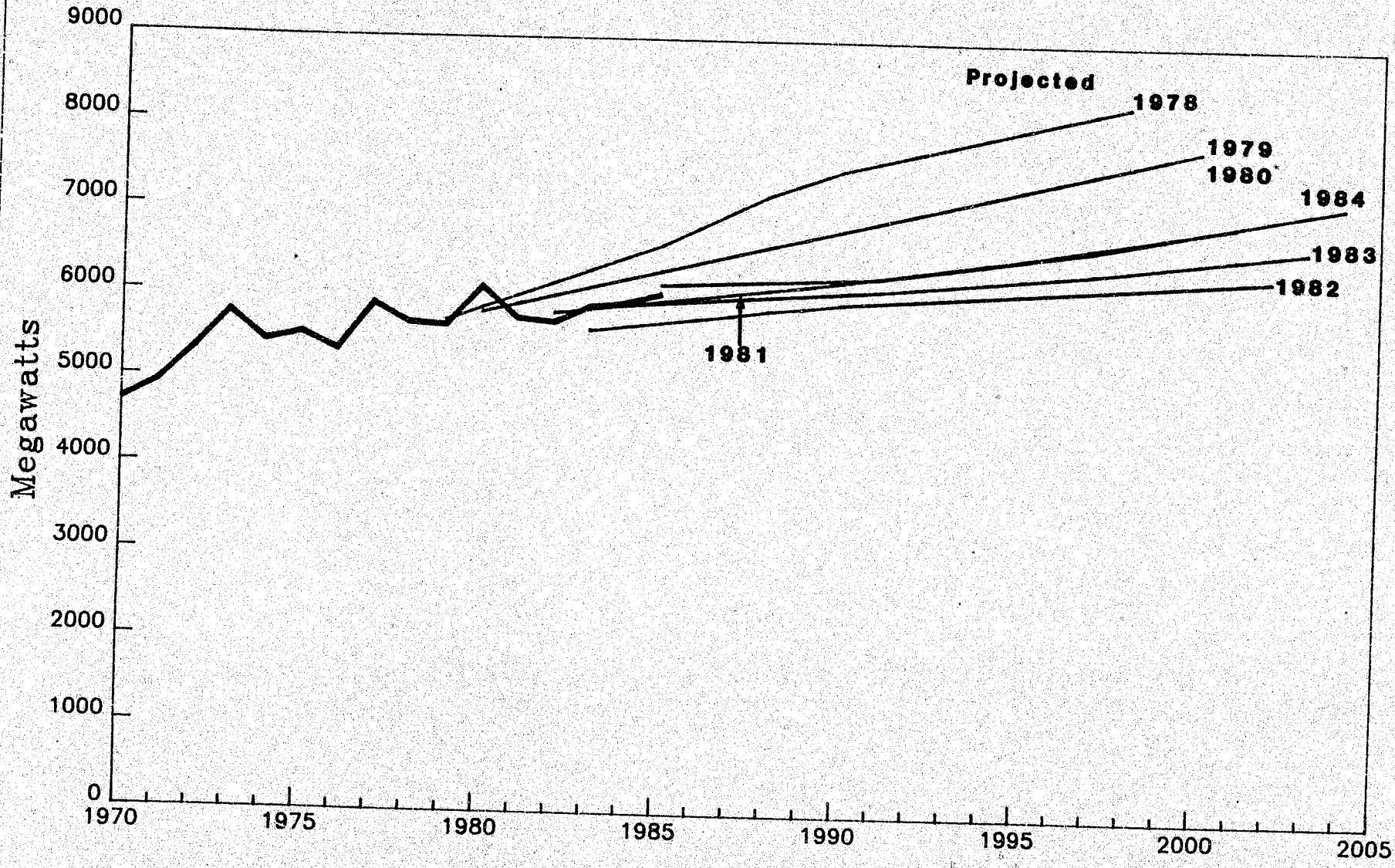


Exhibit ___ (LAG-8)

CHANGE IN FORECASTS OF ENERGY SALES REQUIREMENTS FOR PECO, MAAC AND THE UNITED STATES

Region		1979 Forecast for 1988	1984 Forecast for 1988	Percent Change in Forecasts
		(Gigawatt-hours)		(Percent)
		(1)	(2)	(3)
PECo	<1	34622	28389	-18.0030%
MAAC	<2	239579	194020	-19.0162
USA	<2	3542600	2684998	-24.2082

1> Forecast of Energy Sales.
2> Forecast of Net Annual Energy Requirements.

Source: Column (1): PECo Forecast, table 1, and Edison Electric Institute, 1979 Annual Electric Power Survey, April 1979, pp.14-15.

Column (2): PECo Forecast, table 1, and U.S. Department of Energy, Electric Power Supply and Demand for the Contiguous United States 1984-1993, June 1984, p.6.

Exhibit ___ (LAG-9).

Exhibit ___ (LAG-10)
Table 1 of 1
Page 1 of 2

Comparison of PECO Forecast Assumptions and Realized Changes in Selected Demographic and Economic Statistics

Average Annual Rates of Growth, 1978-1983
PECO System Service Area

		As Projected by PECO, December 1978	Actual
		(1)	(2)
		Base Case	
		Percent	
		Economic Statistics	
(1)	GNP	3.62	1.91
(2)	GRP 1)	2.28	na
		Philadelphia Area Statistics	
(3)	Residential Customers	1.09	0.98
(4)	Cumulative New Construction 2)	1.22	0.81
(5)	Dwelling Units	1.01	0.86
(6)	Manufacturing & Non-Manufacturing	1.73	0.40
(7)	Manufacturing	-0.76	-2.96
(8)	Non-Manufacturing	2.48	1.37
		Energy Statistics	
(9)	Price of Electricity	0.00	0.71 3)
(10)	Oil - No. 2	1.50	7.26 4)
(11)	Total Sales of Electricity Less Interdept. and Resale 5)	2.28	0.02
(12)	Peak(Standard)	2.04	1.30

NOTE:

1) Estimated.
2) As compared with total units in 1977.
3) Average cent per kilowatt-hour.
4) In 1967 Dollars.
5) Not normalized.

SOURCE:

Row 1, Column 1: PECo 1978-1988 Electric Budget Forecast, December 1978, p. 8.
Row 1, Column 2: Economic Report of the President, February 1984, p.222.
Row 2, Column 1: PECo 1978-1988 Electric Budget Forecast, December 1978, p. 8.
Row 2, Column 2: -------
Row 3, Column 1: PECo 1978-1988 Electric Budget Forecast, December 1978, p. 150.
Row 3, Column 2: PECo Annual Reports 1975-1984.
Row 4, Column 1: PECo 1978-1988 Electric Budget Forecast, December 1978, p. 170.
Row 4, Column 2: PECo 1984-1994 Electric Budget Forecast, December 1984, p. 149.
Row 5, Column 1: PECo 1978-1988 Electric Budget Forecast, December 1978, p. 175.
Row 5, Column 2: PECo 1978-1988 Electric Budget Forecast, December 1978, p. 175.
Row 6, Column 1: 1980 Bureau of the Census Data provided by PECo.
Row 6, Column 2: 1980 Bureau of the Census Data provided by PECo.
Row 7, Column 1: 1980 Bureau of the Census Data provided by PECo.
Row 7, Column 2: 1980 Bureau of the Census Data provided by PECo.
Row 8, Column 1: 1980 Bureau of the Census Data provided by PECo.
Row 8, Column 2: 1980 Bureau of the Census Data provided by PECo.
Row 9, Column 1: PECo 1978-1988 Electric Budget Forecast, December 1978, p. 9.
Row 9, Column 2: 1980 Bureau of the Census Data provided by PECo.
Row 10, Column 1 PECo 1978-1988 Electric Budget Forecast, December 1978, p. 9.
Row 10, Column 2 Monthly Energy Review, Energy Information Administration, April 1985, p.98.
Row 11, Column 1 PECo 1978-1988 Electric Budget Forecast, December 1978, p. 13.
Row 11, Column 2 PECo System, Quantity Sales and Customers: Electric, Gas and Steam, 1950-1984.
Row 12, Column 1 PECo 1978-1988 Electric Budget Forecast, December 1978, p. 283.
Row 12, Column 2 PECo System Actual Peak Load Data, October 22, 1975, provided by PECo System Planning Division.

Exhibit ___ (LAG-10)
Table 1 of 1
Page 2 of 2

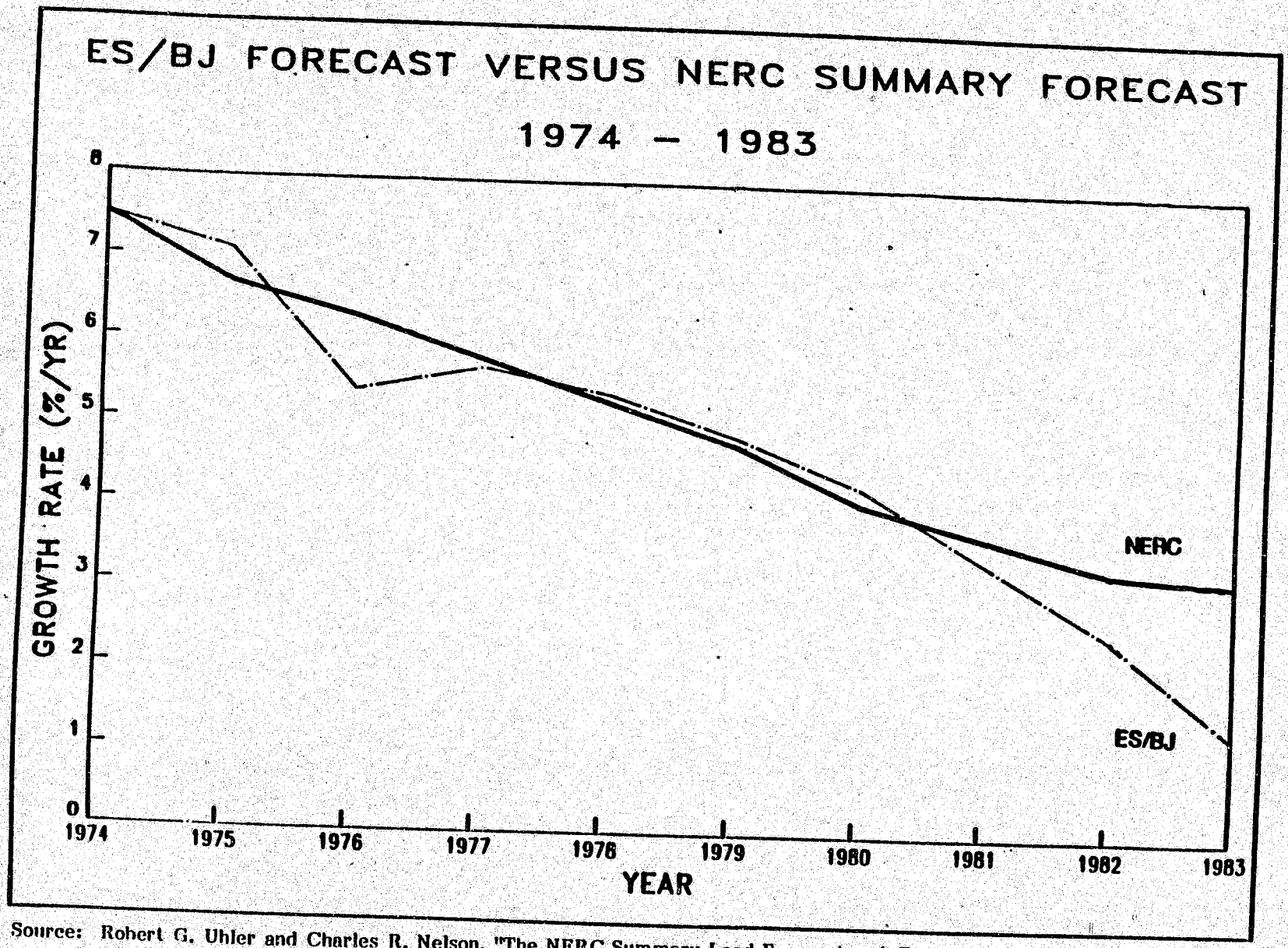
Exhibit ____ (LAG-11)

EXPONENTIAL SMOOTHING/BOX-JENKINS FORECAST VERSUS NERC SUMMARY FORECAST

Using Data Through	10-Year Forecast Period	Smoothing Coefficient(θ)	Exponential Smoothing/ Box-Jenkins Forecast	NERC Summary Forecast
			(Percent)	
(1)	(2)	(3)	(4)	(5)
1973	1974-1983	0.971 ≈ 1.0[1]	7.5%	7.5%
1974	1975-1984	1.0	7.1	6.7
1975	1976-1985	0.84	5.4	6.3
1976	1977-1986	0.86	5.7	5.8
1977	1978-1987	0.85	5.4	5.3
1978	1979-1988	0.82	4.9	4.8
1979	1980-1989	0.79	4.3	4.1
1980	1981-1990	0.76	3.4	3.7
1981	1982-1991	0.73	2.5	3.3
1982	1983-1992	0.69	1.2	3.2

[1] For 1973 and 1974, the least squares value of the smoothing coefficient was at or near the upper boundary of unity. In this situation, the projected growth rate is the actual average growth rate since 1951.

Source: Robert G. Uhler and Charles R. Nelson, "The NERC Summary Load Forecasts: A Retrospective Appraisal and Technical Analysis," May 31, 1985.



Source: Robert G. Uhler and Charles R. Nelson, "The NERC Summary Load Forecasts: A Retrospective Appraisal and Technical Analysis," May 31, 1985.

Exhibit ___ (LAG-11)
Chart 1 of 1

PECo Sales vs. National Sales

Comparison of % Change in Total Sales

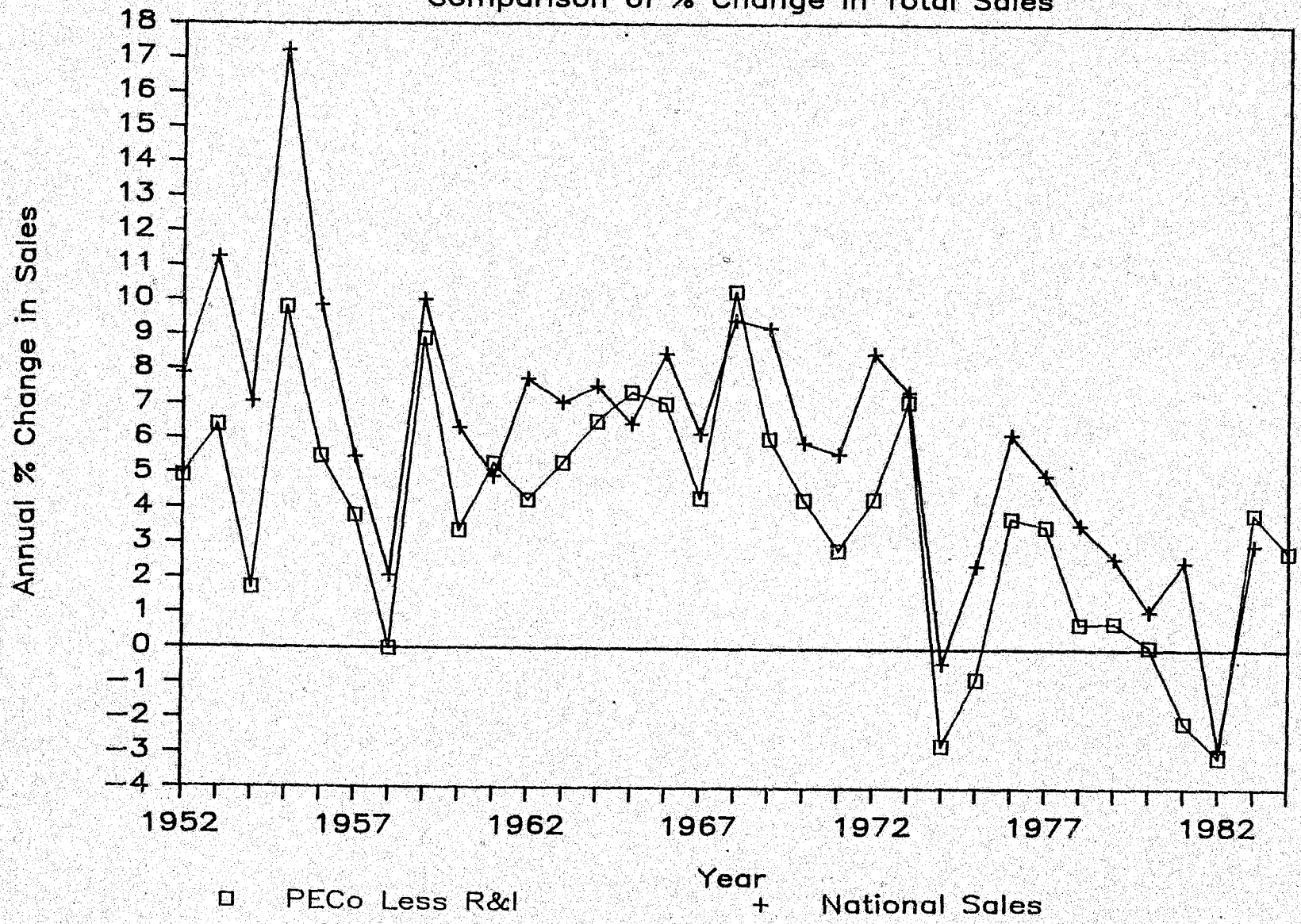


Exhibit ___ (LAG-12)

COMPARISON OF FORECASTS OF GROWTH IN PECO SALES USING
EXPONENTIAL SMOOTHING/BOX-JENKINS TECHIQUES VERSUS
PECO FORECASTS

Using Data Through	10-Year Forecast Period	Smoothing Coefficient	Exponential Smoothing/ Box-Jenkins Forecast	PECo Forecast
(1)	(2)	(3)	(4)	(5)
1972	1973-1983	1.00	5.34	6.75
1973	1974-1984	1.00	5.42	6.41
1974	1975-1985	1.00	5.03	5.38
1975	1976-1986	1.00	4.77	4.90
1976	1977-1987	1.00	4.73	3.48
1977	1978-1988	1.00	4.68	2.93
1978	1979-1989	0.84	4.03	2.57
1979	1980-1990	0.80	3.38	2.24
1980	1981-1991	0.78	2.68	1.52
1981	1982-1992	0.74	1.46	1.18
1982	1983-1993	0.70	0.11	0.66
1983	1984-1994	0.76	1.14	0.85
1984	1985-1995	0.67	1.34	

Note: Smoothing Coefficients Based on PECO Data.

Exhibit ___ (LAG-13)

ES/BJ Forecast vs. PECo Forecast

Smoothing Coefficients Based on PECo

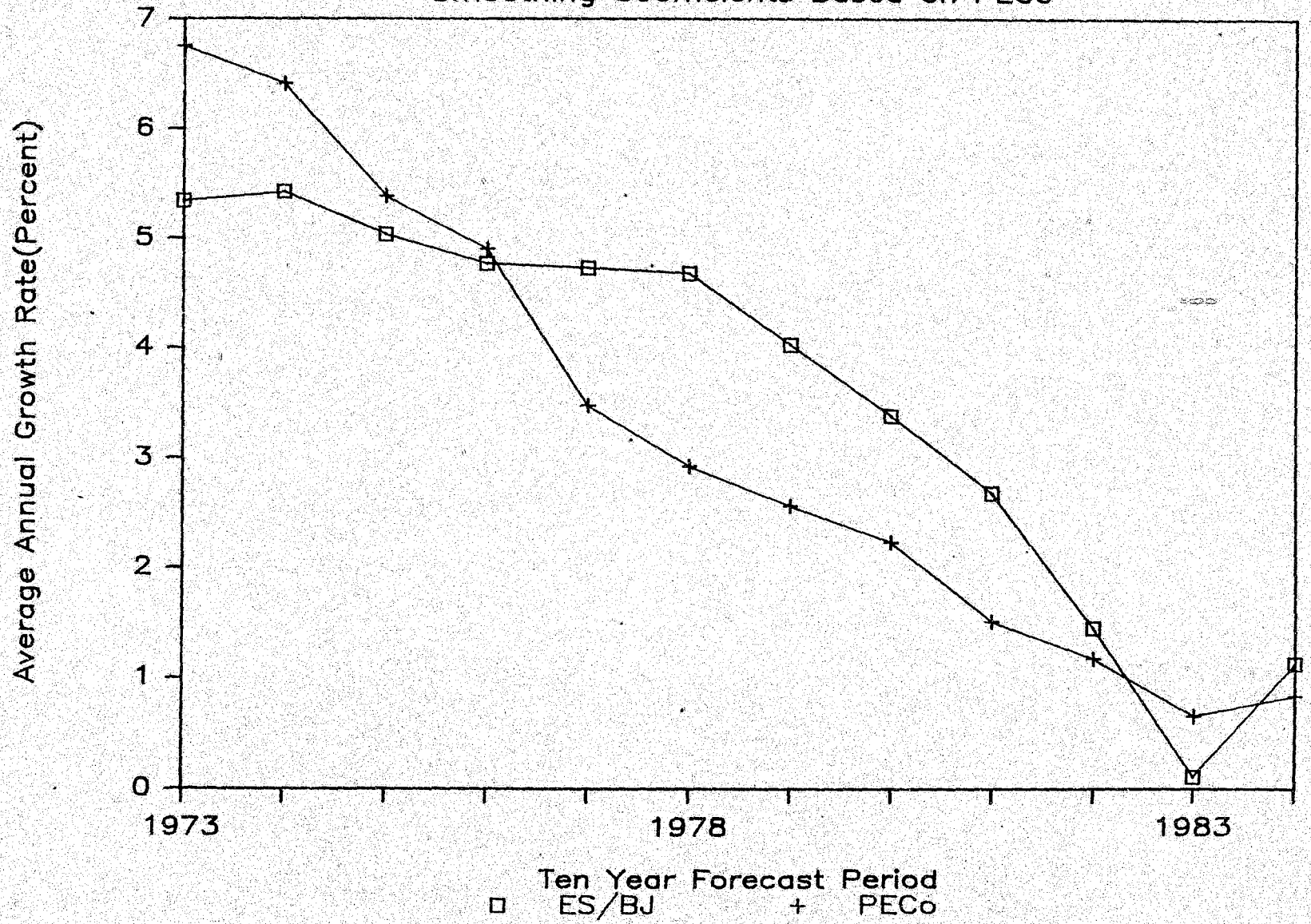


Exhibit ___ (LAG-13)

COMPARISON OF FORECASTS OF GROWTH IN PECO SALES USING EXPONENTIAL SMOOTHING/BOX-JENKINS TECHNIQUES VERSUS PECO FORECASTS

Using Data Through	10-Year Forecast Period	Smoothing Coefficient	Exponential Smoothing/ Box-Jenkins Forecast	PECo Forecast
(1)	(2)	(3)	(4)	(5)
1972	1973-1983	1.00	5.34%	6.75%
1973	1974-1984	1.00	5.42%	6.41
1974	1975-1985	1.00	5.03%	5.38
1975	1976-1986	0.84	4.09%	4.90
1976	1977-1987	0.86	4.04%	3.48
1977	1978-1988	0.85	3.97%	2.93
1978	1979-1989	0.82	3.38%	2.57
1979	1980-1990	0.79	2.83%	2.24
1980	1981-1991	0.76	2.17%	1.52
1981	1982-1992	0.73	1.02%	1.18
1982	1983-1993	0.69	-0.26%	0.66
1983	1984-1994	0.73	0.87%	0.85
1984	1985-1995	0.67	1.34%	

Note: Smoothing Coefficients Based on National Data.

Exhibit ___ (LAG-14)

ES/BJ Forecast vs. PECo Forecast

Smoothing Coefficients = National

Exhibit ___ (LAG-14)

ORIGINAL

PECO STATEMENT NO. 13

RECEIVED
SEP 27 1985
SECRETARY'S OFFICE
Public Utility Commission

PENNSYLVANIA PUBLIC UTILITY COMMISSION v.
PHILADELPHIA ELECTRIC COMPANY
Docket No. R-850152

DIRECT TESTIMONY OF WILLIAM C. HOCH, JR.

DESCRIPTION OF 1974-1981 ENERGY FORECASTS

September 27, 1985

RECEIVED

TESTIMONY OF WILLIAM C. HOCH, JR.

Q. Please state your name and business address for the record.

A. My name is William C. Hoch, Jr., 2301 Market Street, Philadelphia, Pennsylvania.

Q. What is your present position?

A. I am Manager, Marketing Department, a department within Commercial Operations, of Philadelphia Electric Company (PECO or the Company).

Q. Will you please state your employment history with PECO?

A. I joined the Company in 1944 after a term in the Merchant Marine and have been with the Company ever since, except for two years in the U. S. Army. I started as an Applications Engineer. In 1953, I was transferred to the Industrial Sales Department as an Industrial Sales Engineer. In 1962, I advanced from Senior Sales Engineer to Supervisor, Governmental Sales. In 1965, I moved to Supervisor, Lighting and Space Conditioning Section. In 1967, I advanced to Assistant Manager, Marketing Services. In 1972, I was appointed Manager, Research and Forecasting. In 1979, the Research and Forecasting Department and the Applications Department were combined into the Technical Services Department and I was appointed Manager. In 1983, the Technical Services Department was combined with the Business Services Department to form the Marketing Department and I was appointed Manager.

Q. What is your educational background?

A. I have a B.S. in Mechanical Engineering from Drexel University and am a

Registered Professional Engineer in Pennsylvania. Among other courses, I have completed the summer program known as The Executive Program (TEP) at the Darden Graduate School of Business Administration, University of Virginia.

Q. Would you briefly describe your experience in the field of utility forecasting?

A. Under the direction of Mr. William B. Morlok, Vice-President of Commercial Operations, I have had administrative responsibility for preparing the Company's energy forecasts since 1973. Also, I have served as Company liaison in our participation in and joint-sponsorship of the regional model developed by Wharton Econometric Forecasting Associates (WEFA).

I have attended many Electric Power Research Institute (EPRI) conferences and seminars on forecasting and participated actively in several meetings and seminars. Eight years ago, I initiated a Customers Research Group made up of forecasting personnel from member companies of the Pennsylvania-New Jersey-Maryland (PJM) Interconnection group which meets several times a year for an exchange of information. I regularly review material of the Electric Utility Market Research Council (EUMRC), of which our Market Research Supervisor is an elected member and past-President.

I am an active member (past-Secretary) of the Citizens Advisory Committee of the Delaware Valley Regional Planning Commission (DVRPC), a member of the Board of Governors of the Electrical Association of Philadelphia, a past-President of the Philadelphia Chapter of Construction Products Manufacturers Council (CPMC), and a member of the International Association of Energy Economists, among other affiliations.

Q. Have you previously testified before the Pennsylvania PUC on behalf of Philadelphia Electric Company?

A. Yes. I have testified concerning PECO's energy forecast in the Company's 1977 rate case (RID 438), 1979 rate case (Docket No. R-79060865), 1980 rate case (Docket No. R-80061225), and in the Limerick Nuclear Generating Station Investigations (Docket Nos. I-80100341 and I-840381).

Q. What is the purpose of your testimony?

A. I will describe the Company energy forecasts which were issued during the 1970s and early 1980s.

Q. Could you briefly provide an historical review of the forecasts of kilowatthour sales?

A. The forecasts can be divided into four basic periods to provide an overview of changes to the forecasts over time: the high-growth period prior to the first Arab oil embargo late in 1973; the post-embargo period from 1974 to 1978; the two or three years following the second major oil shock in 1979; and the current period from 1982 to the present which finds the forecasts on a plateau reflecting a projected growth rate of about 1% per year, consistent with the experience of the 1974-84 low-growth decade overall.

Q. What were the economic and regulatory conditions surrounding the forecast prior to 1974?

A. That period was the exact opposite of the current period in terms of general expectations and media and regulatory commission perceptions and pressures.

In the 1960s growth in demand for electricity exceeded forecasts, leading to a decline in the reserve margins of Pennsylvania's electric utilities. This rapid growth quickly reduced reserve capacity of the companies from an adequate 22.5% in 1962 to a low point of 0.2% in 1966, despite the addition of new capacity by the companies during this period.

In November of 1965, the widespread blackout in the northeastern portion of the United States dramatized the potential consequences of insufficient reserve capacity. Soon thereafter, the Pennsylvania PUC, other state commissions and the Federal Power Commission began to pressure utilities to accelerate their plans for increasing generating capacity. At a March 1966 meeting in Philadelphia, utilities were warned by the commissions of Pennsylvania, Delaware, Washington, D.C., Maryland and New Jersey that "[a] desperate situation is developing that within the near future could result in possible blackouts and customer load curtailment." After another power interruption in June 1967, member companies of the PJM Interconnection, along with the same state utility commissions, met again in Philadelphia. The electric companies were told that "excuses [for inadequate reserve capacity] are unacceptable." A headline in the Philadelphia Bulletin in December 1969, read: "Philadelphia area faces 'critical' shortage of electric power, head of PUC says."

In 1970, the Chairman of the Pennsylvania PUC suggested that a 10% growth rate should be used by utilities in forecasting load growth. Although reserve capacity of electric utilities had grown to a more encouraging 14.7% level by 1971,

the PUC nevertheless expressed concern in a March 13, 1972 Order to all electric utilities. The Order questioned "whether current plans are satisfactory to meet projected future needs for electric power." In the late 1960s, as part of the effort to hike reserve capacity to 20%, Pennsylvania's electric companies were urged to install 2000 MW of combustion turbines. In I.D. No. 138 (March 13, 1972), the Commission ordered that each company file with the Commission each May a ten-year forecast and a schedule of generating plant additions necessary for each utility to meet forecasted load requirements during the 10-year period. In December 1972, the Chairman of the PUC wrote to all members of the General Assembly stating:

> "Unless prompt and intelligent steps are taken to avert it, Pennsylvanians will shortly encounter a very serious energy crisis. People in their homes will suffer from inadequate heat, light and other vital necessities. Employers will be unable to energize their equipment, and unemployment will be widespread. Some areas have already been affected."

Similarly, many newspaper and magazine articles carried dire warnings of looming power shortages. It was in this heated environment that most utility forecasters of that time were inclined to risk erring on the high or conservative side, having been castigated for low forecasts for so long.

The Company forecast prepared in 1971 -- the first ten year forecast, prior to which projections were only for five years -- projected an annual growth rate from 1971-81 of 7.6%. In June 1972, this was reduced to 7.3% and in May 1973, still prior to the oil embargo, this was again reduced to 6.7% for 1973-83. In April 1974, the forecast for the same period (1973-83) was dropped to 5.7%. While the latter forecast was issued five months after the embargo struck, preparation of

forecasts usually began about six months before issuance and the numbers were set about two months before the book was ready for distribution.

In the documents containing the 1971-74 forecasts, the growth rate reductions were largely attributed to an early recognition of conservation inspired by rising costs, an awareness of energy shortages, and our "use energy wisely" programs.

Q. How were the forecasts changed in the mid-1970s?

A. By 1975, it had become evident that the severe recession induced by the oil embargo as well as growing awareness of the need to conserve energy would have a lasting impact. In every year going back to 1971, the projected 10-year growth rate was reduced. The forecasted annual rates of growth are shown below and can also be traced over a set of varying periods in Appendix A, Table I, which shows PECO forecast growth rates compared to 45 forecasts made by other forecasters between 1975 and 1985. Note that the forecasts listed for comparison purposes are concentrated in the 1970s. Tables 2 and 3 in Appendix A show more sets of forecasts made in the 1980s confirming that our forecasts were consistently conservative.

Date Issued	Years	Annual Growth in kWh-%	20 Year* Forecast
4/71	1971-81	7.6	
6/72	1972-82	7.3	
5/73	1973-83	6.7	
4/74	1974-84	6.4	
4/75	1975-85	5.4	
12/76	1976-86	4.9	3.9
12/77	1977-87	3.5	2.9
12/78	1978-88	2.9	2.5
2/80	1979-89	2.6	2.3
2/81	1980-90	2.2	2.1
7/82	1981-91	1.5	1.5
6/83	1982-92	1.2	1.1
5/84	1983-93	0.6	0.8
11/84	1984-94	0.8	1.1

*20 year forecasts first prepared in 1976.

The Table shows that due to greater effects expected from conservation and the deteriorating economy of the City of Philadelphia, the growth rate was halved from the 1975-76 period to 1980 after the second oil price shock. After 1980-81, in the current period, the forecast has centered around a 1% growth rate in line with recent experience, although it appears to be conservative now in view of our most recent experience and growing expectations for the local economy relative to the rest of the country, including the Sunbelt and Southwest.

Q. How would you describe the series of changes in the forecasts?

A. By estimating the effects of the current projections of GNP, population, housing, appliance sales, etc., each forecast was separately calculated. As more conservative economic forecasts were issued and more data on equipment sales, population and other inputs were collected, the series of forecasts provided an orderly reduction enabling the Company to adjust its planned capacity accordingly.

Each forecast made since 1973 was put out in book form so that anyone - Company personnel, critics or government representatives alike -- could fully understand its assumptions and methodology.

Q. Did you compare your forecasts with others, and did this ever give you reason to suspect your forecasts were too high or low by comparison?

A. As I pointed out earlier, Appendix A, Table 1 gives a comparison with 45 forecasts, mostly made by governmental agencies. It also shows our relative position in PJM and with all Pennsylvania utilities. In general, the Table shows that our forecasts were low or conservative by comparision. Our growth as forecast is about 80% of the forecasted national growth until about 1977, after which, reflecting the poor local economy, it is 60%. Currently, most forecasters are projecting long-term national growth at 2.5%, while we expect about 1% locally (See Appendix A, Tables 2 and 3).

Because our forecasts were continuously reduced as new data became available and because we constantly checked our forecasts against others, we continued to believe ours were conservative.

Q. What are the principal factors which determine the level of forecast growth in kilowatthour sales?

A. The forecast depends on the expected outlook for the national and regional economy, which determines growth in manufacturing sales. For these projections, we rely on a broad group of government and academic economists, accumulating as many economic forecasts as we can.

Population is also important as it relates to housing, housing starts and employment. We again gather as much data as we can from government sources, using the U. S. Bureau of Census, Delaware Valley Regional Planning Commission and State-generated data.

Price of electricity and cost and availability of competitive fuels enters the forecast indirectly, particularly in estimates for electric space heating. Price data is also obtained from a variety of sources, including gas and oil industry associations and Department of Energy-sponsored publications.

Many other factors impact the forecast, including industry material on appliance improvements.

Q. Please describe how your forecasts were prepared during the period 1974 to 1981?

A. As I stated above, each forecast book since the early 1970s contained detailed descriptions of factors affecting the results. These details became more explicit over time as the forecasts were put to greater use as reference sources in presentations to various audiences, were referenced in rate hearings and were used as customer information resources by other Company departments. Descriptions of

our forecast methodology were provided in my testimony in both Limerick Investigations. This methodology was also described in my direct testimony in the 1979 rate proceeding, which is attached as Appendix B. Although it is not one of our latest descriptions -- these can be found in the Limerick Investigation testimony and in our recent forecast books -- it is resubmitted here to outline our methodology applicable to the 1978-88 forecast.

Q. What type of information do you provide to the System Planning Division which is used by them to forecast peak loads?

A. In addition to the material in the annual forecast book, we provide an estimate of kWh sales by class of service for the months of January, April and October for each year of the forecast. Sales for those three months are developed based on historic data and the long-term forecast of future kWh sales. Also provided, for the same months, are estimated demands for the eight customers supplied at 66 kV or higher. This data is based on historic energy use plus information obtained from the customers themselves. Also furnished to System Planning are connected air conditioning loads for the Residential, Small Commercial and Industrial and Large Commercial and Industrial classes for future years. Future air conditioning loads are based on housing characteristics and estimated square footage for the Industrial and Commercial classes, the expected level of air conditioning saturation in each, and the efficiency and size of present and future air conditioning systems.

Q. In your 1978 forecast, you indicated that you compared your forecast with one derived from an econometric model. Why did you engage WEFA to prepare an econometric forecast?

A. As our forecasting method is mainly an end-use and technological type of analysis, we decided that an econometric model would be valuable as a check.

In 1977, we analyzed proposals from several econometric consultants. Having met several times with Dr. Lawrence Klein and others of his firm, we selected WEFA because of Dr. Klein's reputation as the "father of econometrics" (for which he won a Nobel prize in economics), because WEFA was part of the University of Pennsylvania which offered us close proximity in developing the model and data base, and because PECO and the City of Philadelphia had been participating with WEFA in developing a model of regional economics which gave WEFA a head start on developing a regional energy model. In 1978, the City had contracted to pay WEFA $40,000 for specific forecasts for the City.

Q. Did WEFA's econometric model support your forecasts?

A. Yes. Their results generally projected a slightly higher growth rate than ours for the same time spans, so they increased our confidence in our own methodology. WEFA results are also included in Appendix A, Table I.

Q. Were any other steps taken or did anything else occur to lend support to your forecast methodology?

A. Yes. We kept in frequent touch with PJM forecasting procedures through meetings of the PJM Conservation and Load Management Committee and Customer Research Group. I initiated the Customer Research Group, composed of market research and forecasting personnel, in 1977. In addition, our Company has been represented on the Electric Utility Market Research Council (EUMRC) since 1970. The Council holds two national meetings a year to exchange market research and customer

information. The supervisor of our Market Research Section, which has a primary responsibility of preparing energy forecasts, was Chairman of the EUMRC in 1980-81.

On February 28, 1979, the New Jersey Board of Public Utilities in Docket No. 762-194 found that the forecasting methodologies of New Jersey utilities were appropriate: "Based on the aforementioned forecasting testimony, cross-examination and an extensive record, the parties to the proceeding have agreed no controversy currently exists regarding the electric utilities current forecasts and forecast methodologies." The New Jersey utilities, of course, are part of PJM and we were satisfied that our methodologies were comparable.

In 1977-78, the Maryland PSC, in Case No. 6807, investigated forecasting methodologies. Our subsidiary, Conowingo Power Company, operates in Maryland. The State of Maryland recommended no standard forecasting methodology as a result of these hearings, although econometric modeling was recommended. The Maryland Peoples Counsel recommended that "at least two alternate forecasting methodologies" be used. At this time we were in preparation of the WEFA model which, as stated previously, provided verification for our end-use and economics methods.

From time to time, the Pennsylvania PUC showed interest in forecasting and forecasts but never specified any methodologies. In 1979, the Bureau of Conservation, Economics and Energy Planning (CEEP) looked into the costs and resources employed for forecasting. A copy of the PECO reply is attached as Appendix C. This briefly describes the procedures and personnel engaged in preparing forecasts.

Q. Has the Pennsylvania PUC ever expressed an opinion of the Company's load forecasting during this period?

A. Yes. In RID 438 (Order entered February 5, 1979), the Commission, while pointing out the historical errors in the Company's forecast, found that such errors had been "the general situation in the electric industry throughout the nation since the oil embargo." The Commission refused to find any imprudency in the Company's load forecasting.

Q. What were the overall results of the application of your forecast methodology?

A. As previously stated our forecasts prior to 1970 were too low, resulting in pressure from the Commission to increase forecasts and move as quickly as possible to improve reserves. Through the 1960s our load grew at an annual levelized rate of 5.8%. This was true in both the 1962-67 and 1967-73 time spans.

The forecasts had been raised in the early 1970s because of higher expected air conditioning and electric space heating growth. The forecast issued in May 1973 projected a ten-year growth rate of 6.7%.

As noted earlier, following the oil embargo shock in October 1973 each forecast was gradually lowered. By 1976, the growth rate compared with 1973 was reduced by 27% and by 1977 was reduced by 48%, almost half, as the after-effects of the embargo and ensuing severe recession were better understood. Each forecast explained the differences from the earlier forecast. The effects of the weak local and state economies, with high labor costs and taxes and older industrial plant stock, were also more evident. Erroneous forecasts by economists and government agencies greatly impacted our forecasts of energy sales.

In July 1975, a 25-year forecast to 2000 was attempted. This indicated a probable long-term growth of 5.0%, showing that growth was expected to taper off. Further indicating the weakening local economy, our projection showed sales in 2000 at 3.33 times 1975 whereas the 1976 EPRI forecast showed national sales at 3.5 times. From 1977 to 1981, the 20-year growth rate was dropped from 2.9% to 1.5%, almost a 50% reduction, following the severe recession and oil price shock in 1979. In summary, our forecasts were gradually lowered each year in a fairly uniform way as less optimistic forecasts were issued concerning the population and the economy.

Q. How did and do these economic predictions, such as Gross National Product (GNP), influence the PECO forecasts?

A. While GNP forecast figures were not directly used in PECO's forecasts, various components closely tied to GNP such as manhours, the Industrial Production Index, and non-manufacturing employment were used.

Table VI of the 1973-83 forecast, which is reproduced as Table 1 of Appendix D, shows GNP forecasts made by various economics consultants prior to the oil embargo. These indicate annual growth rates from 1972 to 1980 of 4.1% to 4.8% and from 1972 to 1985 of 3.7% to 4.3%.

Actual growth from 1972 to 1980 was 2.8%, 32% below the lowest forecast, and from 1972 to 1985 (preliminary) actual GNP growth was 2.7%, 32% below the average forecast. The average growth for the ten-year post-embargo period -- 1973 to 1983 -- was only 2.0%, reflecting a decade which saw three recessions and two oil-price shocks with high inflation. Previously, the worst consecutive ten

years of growth in the post-war period was 2.6% from 1965-1975. Because the Department of Commerce revised its system of calculating GNP in 1980, GNP values in the tables are not applicable, only growth rates.

Economists had coped with the lasting impact of the oil embargo and associated recession by 1978 and lowered economic forecasts each year. Page 238 of the 1978-88 forecast, which is shown as Appendix D, Table 2, shows GNP growth projections for both 1977 and 1978. Again, GNP values were revised by the government so only growth rates are comparable.

Projected growth for 1976 to 1985 in the 1977 forecast ranged from 3.7% to 3.9%, while actual growth was 2.9%. For 1977 to 1985, in the 1978 forecast, economists' projections ranged from 3.4% to 3.9%, and actual growth was 2.6%. Economists' forecasts have been lowered over time. In 1978, however, as just pointed out, they were predicting a growth rate 40% greater than was realized. The forecasts of relatively high real GNP growth in the 1976-78 period followed by a trend to more pessimistic rates in the following years are analogous to the changes in projected kWh growth.

Our forecast for 1978-98 projected a growth rate of 2.5%, substantially below the 3.3% GNP growth projected from 1977-95 by Wharton EFA and McGraw-Hill Economics in 1977 (Appendix D, Table 2) and that of the EEI Task Group 20 (a group of twenty economists) of 3.5%. While electric energy growth grew at about twice the GNP rate and energy growth grew at about the GNP rate until 1973, forecasters generally felt in the late 1970s that energy and GNP growth were becoming "uncoupled". But most forecasters still expected kWh growth to parallel growth in GNP.

Q. You previously mentioned that population is an important factor in the forecast since it has a direct relationship to the number of living units on line. How have the results of the component-cohort method you have been using for making projections of area population compared with projections made by other groups?

A. Our in-house model for population was developed and first used in our 1976 Budget forecast. Prior to that, we had relied on projections made by the Delaware Valley Regional Planning Commission (DVRPC). In 1976, we based our projections on the DVRPC's slow growth scenario. It was becoming more apparent about this time that the DVRPC's projections were affected by political considerations, as noted in a contemporaneous Inquirer article from which I quote:

> "Planners and politicians on the Del-Commission were....forced to choose between a 'no growth' population policy and federal dollars.
>
> They chose the policy that would mean more government spending in the nine-county Philadelphia region by predicting a 13 percent population growth on both sides of the Delaware River by the year 2000."

As a result, in 1977, PECO's population projection began to diverge from the DVRPC's. There were other population projections being made in the 1975-1978 period for the area. (See Appendix D, Table 3) As can be seen, PECO's 1976 projection closely aligned with that of the DVRPC. This was still well below that made by the Pennsylvania Department of Education. PECO's 1978 projection for 1980 was well below the 1980 figures for the others of that vintage. In addition, PECO's population forecasts for 1985 made in 1976 and 1978 were, in all cases, lower than those made by others in the same years. By the year 2000, only one projection is below that of PECO. If PECO had used any of the other sources for

its population projections, the forecast would have been between 0.3 and 2.1 billion kWh above the 1978 forecast figure for 1980, based on 1980 average per capita usage figures.

In 1980, after more data became available showing a continuation of net out-migrations and lower birth rates, PECO lowered its projections. These changes assumed a higher level of continued net out-migrations and use of the Bureau of Census low fertility series. This last projection, in our opinion, remains valid today. The November 1984 projection of population is essentially the same as the 1980 Forecast except that it was aligned with the 1980 Census of Population figures.

Q. Why did the population forecasts miss the mark?

A. You have to look at the sources of data available to everyone at the time the projections were made. Basically, the major source is the Census of Population which is conducted only once every ten years. The Current Population Reports from the Bureau of the Census is the main source for the intervening years. These reports indicated a reduction in the trend of declining population in the 1974-1977 period. The figures show the following changes in area population: 1974-1975, -24,000; 1975-1976, -15,000; 1976-1977, -13,000. Everyone believed that the population loss was ebbing, as reflected in this quote from an article in U.S. News & World Report during this period:

> "Now there are signs that some big metro areas may be pulling out of their slumps. Los Angeles - Long Beach, St. Louis and Philadelphia had slight population gains in 1976. But losses continued in New York, Pittsburgh, Detroit, Newark and Cleveland."

Q. Since the oil embargo of 1973 there have been three severe recessions which had a very negative impact on the use of electricity. Were these recessions foreseen by most economists?

A. No. Because the nation and the world had never experienced an oil embargo, the full economic effects of the embargo in late 1973 and early 1974 could not have been predicted. The recession that followed was severe and lengthy. The two succeeding recessions that occurred in the three-year period from 1980 to 1982 also produced experiences that had never before occurred. The recovery period between the two recessions, July 1980 to July 1981, was only twelve-months long and was the shortest recovery since 1920. The average post-war peacetime expansion has lasted thirty-four months. Further, the economic contraction from July 1981 to November 1982 was sixteen months in duration, compared to the eleven-month average for post-war peacetime contractions. Moreover, prior to 1974 the non-recession unemployment rate remained at less than 6%. Since 1974, the unemployment rate has almost always been over 6%. In the present recovery, the unemployment rate has fallen or to only 7.0%. In each of the past four recessions, the unemployment rate was higher in recessions and decreased less in recoveries.

Q. What were the unemployment rates and the manufacturing capacity utilization rates during this period?

A. The unemployment rates are tabulated below:

Recession	Peak	Trough
1969-70	3.4%	6.1%
1973-75	4.6%	9.0%
1980	5.6%	7.8%
1981-82	7.2%	10.7%
Last Actual 1985 (Aug.)	7.0%	-

The manufacturing capacity utilization rate has indicated the same type of pattern. The peaks are becoming lower and the troughs deeper, as indicated below:

MFG. UTILIZATION RATE

Recession	Peak	Trough
1969-70	91.6%	75.9%
1973-75	87.9%	69.0%
1980	87.5%	75.5%
1981-82	81.0%	68.8%
Last Actual 1985 (Aug.)	80.5%	-

Considering the abnormality of the above described events, they were and could not have been reasonably anticipated.

Q. Is there any other unforeseen economic development which has had a depressing effect on electric use?

A. Yes. Until 1970, the United States had never experienced a negative merchandise trade balance. Foreign trade tended to raise the level of economic activity and kilowatthour sales. In the period since 1970, the United States has experienced a

positive trade balance in only 2 of 14 years. In the period since 1975, this balance has become more negative until by 1984 approximately 1.4 million manufacturing jobs had been lost in the United States and 28,000 in Philadelphia. Using a multiplier of 2, about 2.8 million total jobs have been lost in the United States and about 56,000 in Philadelphia. Most if not all of the loss in manufacturing jobs, in recent years, can be accounted for by this "trade problem". Neither PECO nor any other forecasters could have foreseen this problem at the time forecasts were prepared in the mid-1970's and before.

In a recent study of the import problem, the U.S. House Committee on Energy and Commerce reached the following conclusions:

1. Changes in the value of the dollar since 1980 have effectively raised U.S. export prices by 70% and lowered import prices by 40%.

2. The import shock impact is more pervasive than even the OPEC oil price shocks of the 1970s.

3. From early 1981 through the third quarter of 1984, two-thirds of the growth in real final demand for durable goods was met by foreign suppliers.

4. The most severely affected sector is capital goods, for decades the mainstay of U.S. trade. Between 1980 and 1984, the real U.S. trade balance in capital goods plummeted from a record $19.3 billion net export balance to a $3.5 billion deficit.

5. Ninety-five percent of the net increase in demand for capital goods

since the last business cycle peak has been met with imported capital goods, with import penetration highest in "high-tech" capital goods. U S. production of capital goods has barely increased, if at all.

6. The balance-of-trade effects of this recent deterioration in U.S. industrial trade already exceed almost half again the combined impacts of the energy shocks of the 1970's.

7. Since the overvalued dollar has played a key role, the deterioration in the U.S. non-energy balance since 1980 has occurred across all broad industrial categories.

It was impossible for any forecaster or economist to have foreseen 10 years ago the present import "shock problem" and its impact on manufacturing activity throughout the United States and resulting reductions in energy use, including electricity.

Q. Can you illustrate any results of these unforeseen economic shocks?

A. Results of the strong dollar/trade imbalance problem and economic downturns stand out clearly in the performance of the largest ten customers, analyzed in 1978. The two steel companies used 1,587 million kWh in 1978 and were expected to increase usage modestly to 2.7% per year, about in line with the GNP. In fact, in 1979 usage increased to 1,701 million kWh (up 7%), but their combined load dropped in 1980 and continued to decrease to 962 million kWh in 1984.

The three oil companies were impacted to a lesser degree but suffered from a declining oil market and imports of refined product. Consumption by the local

refineries dropped from 1,205 million kWh in 1978 to 1,087 in 1984, whereas the forecast for 1984 was for 1,355, a 2.0% growth rate due to plans for modernization at one of the refineries which did not materialize. Two of the largest ten customers -- Linde Air Products and Firestone -- unexpectedly shut down operations in our area after 1978. The loss in 1984 versus the forecast for 1984 made in 1978 amounted to 1.6 billion kWh.

Q. Were there other areas of uncertainty which affected the forecasts in the mid-1970s?

A. One important factor was the cost and availability of competitive fuels -- oil and gas -- which affects not only space heating but also process heating and possibly prospects for cogeneration.

In the mid-1970s, it was widely anticipated that the real price of oil and gas would increase dramatically while supplies remained uncertain. In 1978, it was projected that gas prices in real dollars in 1988 would be 1.3 times higher than 1978 levels, while electric costs in real terms would remain constant.

PECO had a PUC-imposed moratorium on new gas connections from February 1972 to May 1979, which indicates the severity of the expected gas scarcity. The National Energy Act, which included PURPA and the Fuel Use Act (FUA), adopted in November 1978, prohibited the use of oil and gas in new electric plants or major fuel burning installations. In fact, in 1974 the Federal Energy Administration (FEA) had recommended a ban on oil or gas heat in new housing.

Q. What was the outlook for cogenerators?

A. A potential cogenerator could apply for an exemption under the Act, but he had to show that he needed to buy oil or gas in order to obtain the economic benefits of cogeneration and to prove that less oil or gas would be burned originally as a result of each project. In 1980, FERC issued regulations temporarily excluding diesel cogeneration from being a qualifying facility.

The restrictions on cogeneration have changed as gas and oil availability has gone from scarce to plentiful. This further indicates how the outlook for competitive fuel has changed from the mid-1970s to 1984. The national situation has changed from one of trying to lower the use of imported oil and finite supplies of natural gas by encouraging the use of coal and nuclear energy, to one of permissiveness in oil and gas consumption.

Q. Will you summarize the reasons why the 1978-98 forecast of a growth rate of 2.5% per year has not materialized?

A. Yes. Recapitulating, there was the extremely severe recession in 1981-82 following the unexpected OPEC oil-price shock to the economy in 1979. This was largely responsible for the large errors in economists' expectations for the GNP. The weak local economy resulted in continued loss of jobs and population to the Sunbelt and Southwest.

The unusually strong dollar has resulted in a drastic trade imbalance, causing a loss of our capital goods and steel markets to overseas producers. The unforeseen low price and temporary "glut" of gas and oil have slowed the trend to electrification. These conditions have caused the growth rate from 1976 to 1984 to average only 0.8 percent per year, which matches our ten-year forecast.

Q. Does this conclude your testimony?

A. Yes, it does.

FORECAST COMPARISONS

	When Issued	Period	Area	% Annual Growth	PECO Forecast Same Period
1. IEEE - Elec. Energy Forecast Committee	2/75	1973-85	U.S.	6.2	4.7
2. Electrical World	9/75	1975-85	U.S.	6.25	5.4
3. N.E.R.A.	11/75	1973-80	U.S.	5.25-6.5	4.6
4. U.S. Dept of Interior, Bureau of Mines	12/75	1974-2000	U.S.	6.1	5.0
5. F.E.A. - Project Independence	2/76	1975-85	U.S.	5.7	5.2
6. A. D. Little	3/76	1975-85	U.S.	5.9	4.9
7. Edison Elec. Inst. (EEI)	3/76	1975-85	U.S.	6.4	4.9
8. Elec. Pow. Res. Inst. (EPRI)	3/76	1975-85	U.S.	6.3	4.9
9. PJM	4/76	1975-85	PJM	5.2	4.9
10. Nat'l Elec. Mfrs. Assn. (NEMA)	5/76	1975-84	U.S.	6.0	4.8
11. EPRI Journal	6/76	1975-2000	U.S.	5.7	4.1 (1976-96)
12. G.E. Company	6/76	1975-85	U.S.	6.1	4.9
13. FPC	8/76	1976-85	U.S.	6.15 (6.3 peak)	4.9
14. F.E.A/ERDA	3/77	1976-85	U.S.	5.5/6.2	4.9
15. EPRI-Task Group 20	6/77	1975-90	U.S.	5.6	3.3
16. PJM	6/77	1975-85	PJM	5.0	4.8
17. NERC	7/77	1976-86	U.S. MAAC	6.1 peak 5.0	3.4 3.4
18. Nat'l Energy Plan (Carter)	8/77	1975-85	U.S.	4.5	3.5
19. Wharton Econometric Forecasting Assocs. (WEFA)	1977	1977-89	U.S.	4.3	3.5
20. GEC "Energy Parks"	1977	1977-2000	PA	3.5	3.3
21. G.E. (Center for Energy Systems)	12/77	1977-81	U.S.	5.7	2.8
22. EPRI	12/77	1975-90	U.S.	6.0 peak	3.3
23. NEMA	3/78	1977-86	U.S.	5.6 peak	3.5
24. GE	3/78	1977-90	U.S.	5.0	3.5
25. PJM	6/78	1978-92	PJM	3.7	3.4
26. The Penna. Economy-1978 Mid-year Update Albert Smigel, Ed. Milton J. Shapp, Gov.	6/78	1975-2000	PA	4.14	2.6

FORECAST COMPARISONS

	When Issued	Period	Area	% Annual Growth	PECO Forecast Same Period
27. DOE	7/78	1978-85	U.S.	4.8	2.8
28. NERC	8/78	1978-87	U.S. peak	5.2	3.4
29. Int'l Congress on Large HV Elec.Sys.	9/78	1976-85	U.S.	5.7	2.6
30. WEFA	10/78	1978-87	PECO	3.8	2.9
31. A.D. Little	11/78	1978-90	U.S.	4.1	2.8
32. Chern & Just -ORNL U of Cal for DOE (ORNL SLED MODEL)	12/78	1974-90	N.Y.	4.3	2.6
33. E.I.A. Annual Report to Congress	7/79	1977-85 1985-90 1990-95	U.S.	4.4 4.0 3.7	2.5 2.9 2.2
34. Electrical World	9/79	1978-88	U.S.	3.9	3.0
35. N.Y. Energy Office N.Y. Power Pool	7/79	1978-94 1978-94	N.Y. N.Y.	2.1 2.5	2.3 2.3
36. WEFA	10/79	1979-88	PECO	2.6	2.6
37. Compiled by SRC for G.E.C.	4/80	1978-90	PA	3.1	2.8
38. Cal. Utilities	11/80	1979-92	CAL	2.1	2.0
39. WEFA	4/81	1981-90	PECO	2.9	2.5
40. EPRI - Model Forecasts of Energy Consumption to 2000	10/81	1979-2000	U.S.	2.7	2.0
41. DOE	6/82	1981-91	U.S.	3.25	1.5
42. DOE - Office of Policy Planning & Annalysis (Low Oil Price Scenario)	4/83	1981-2000	U.S.	2.6	0.9
43. PEA	3/84	1983-2000	PA	1.7	0.7
44. E.I.A. -DOE Annual Energy Outlook	1/85	1985-95	U.S.	3.2	0.8
45. Gas Research Inst.	7/85	1985-2000	U.S.	2.4	1.1

COMPARISON OF ELECTRICAL ENERGY GROWTH RATES (ANNUAL AVERAGE %)

SOURCE	1982-1990	1982-2000
North American Electric Reliability Council (NERC), *Electric Power Supply & Demand*, 1984-1993, May 1984	2.8	2.7§
Siegel, John and John Sillin, "The Coming Power Boom: An Assessment of Electric Load Growth in the 1980's," July 1984	4.5	4.5
Starr, Chauncy and Milton F. Searl, "U.S. Generating Capacity Requirements for Economic Growth, 1990-2000," *Public Utilities Fortnightly*, April 29, 1982	3.7	3.7
Westinghouse, *1984 Overview*, February 1984	3.6	3.6
Wharton Econometric Forecasting Associates, *Long-Term Forecast*, March 1984	2.3	2.4
U.S. Dept. of Energy, Office of Policy, Planning and Analysis, *Energy Projections to the Year 2010*, (DOE/PE-0029/2), October 1983	3.5	2.9
U.S. Energy Information Administration, *1983 Annual Energy Outlook* (DOE/EIA-0383(82), May 1984	3.5	3.1†
Average	3.1	2.9

• Medium or base case forecasts where more than one case
† Growth rate for 1995-2000 extrapolated from 1990-1995
‡ Forecast to 1995
§ Growth rate for 1993-2000 extrapolated from 1988-1993 (2.7%/yr)

TABLE 2

App. A

LONG-RANGE ENERGY FORECASTS

Several long-range energy forecasts have been published over the past two years. They have been prepared by diverse organizations using a variety of methodologies. In some cases they reflect policy inclinations while in others they represent efforts to identify a "most-likely" energy future. As a group, they encompass the range of forecasts widely viewed as plausible for policy and planning purposes.

The range of projected growth rates has narrowed considerably over the past few years. Only "least cost" studies such as those of the Audubon Society and Roger Sant's *Creating Abundance* indicate substantially lower growth rates for energy consumption than the consensus. Siegel and Sillin, the mavericks among analysts, project both higher economic growth and electricity consumption.

A review of projected growth rates computed from the base year cited in the individual reports and ranked by electricity/GNP growth ratios is provided in Tables I and II. The mid-case or base scenario was chosen when possible. Table I shows average annual growth rates through the year 2000. For comparison purposes, Table II presents the same forecasts (when available) divided into time periods, pre- and post-1990. The differences in growth rates for the two time periods are noteworthy.

TABLE 3

Table II
Average Annual Growth Rates

	From Beginning Year to 1990				From 1990 to End Year			
	Real GNP	Avg. Imp. Oil Pr.	Primary Energy	Elec.	Real GNP	Avg. Imp. Oil Pr.	Primary Energy	Elec.
AEO (1983-1995)	3.3	3.2	2.1	3.5	2.2	6.6	1.1	2.8
DRI (1983-2000)	3.6	−1.0	2.2	4.0	2.3	4.0	1.2	2.5
DOE (1982-2000)	3.3	−0.6	2.0	3.7	2.4	6.1	0.8	2.1
EL. WORLD (1983-2000)	3.5	n/a	n/a	3.2	2.6	n/a	n/a	2.5
NCA (1982-1995)	2.6	0.5	1.5	2.4	2.3	3.7	1.3	2.2
WHARTON (1983-1994)	3.3	−0.7	2.0	3.2	3.0	2.4	1.9	2.6
GRI (1983-2000)	3.4	0.7	2.2	3.7	2.4	2.5	1.2	1.6
CON (1982-2000)	3.2	n/a	1.5	2.9	2.5	n/a	0.8	1.5
NERC (1984-1993)	n/a	n/a	n/a	2.8	n/a	n/a	n/a	2.5
BANK (1982-2000)	n/a	n/a	n/a	3.5	n/a	n/a	n/a	2.5

Source: Topics in Electricity and the Economy, Volume II, No. 1 (Spring 1985)

EXCERPT FROM THE TESTIMONY OF WILLIAM C. HOCH
IN DOCKET NO. R-79060865

Q. What is the purpose of your testimony?

A. I will describe the Electric 1978-88 Budget Forecast with 1988-98 Projections and discuss various aspects of that forecast. The budget Forecast has been written in a tutorial fashion with explanations as to how the results were derived.

Q. Have you prepared or had prepared under your direction and supervision an exhibit to support your testimony?

A. Yes, I have.

Counsel:

I ask that the following document be marked for identification: Exhibit WCH-1 Electric 1978-88 Budget Forecast with 1988-98 Projections.

Q. Describe the energy sales forecasting methodology.

A. Most of the known forecasting methods are used to some degree in deriving the ten-year forecast. These include trend analysis, correlation analysis with regressions, economic projections, technological forecasting of changes in energy-using equipment, and data derived from a regional econometric model. Models of sensitive parts of the forecast such as air conditioning loads and population analysis have been programmed for a computer and a fully

computerized econometric model has recently been programmed. The econometric model was developed by Wharton Econometric Forecasting Associates (WEFA), at our request, as a separate method of establishing future forecasts.

The forecast is produced by estimating energy sales for individual years for each rate class - Residential, House Heating, Small Commercial and Industrial, Large Commercial and Industrial, Other Public Authorities, Railroads & Railways, Street Lighting, Resale, and Interdepartmental. In order to satisfy the needs for special data to compute revenue, peaks, etc., energy sales for key months are forecasted for each year along with numbers of customers and selected data on special uses such as air conditioning and electric heat.

The forecast is estimated by classes and then aggregated. Each class in turn is made up of parts. Because of the substantial amount of data collected from field forces as well as trade associations and government agencies, we believe that establishing each component with its own correlations and data - based on uniform assumptions concerning the region and economy - leads to a more precise forecast than deriving a general forecast from a national econometric model. This is especially true of local large manufacturing customers whose use and plans often bear little resemblance to the performance of the national industry. This forecast is also more useful as a future reference source when fore-

casts for separate applications and appliances are determined.

Q. Describe how residential sales are forecast.

A. The residential energy sales forecast is based on two main determinants; the number of living units and the average use per living unit.

Using Bureau of Census materials including the Census of Population and the Census of Housing, as well as local data, population and housing units are determined for the service area and the relationship between dwelling units and population is established. A component-cohort method is used to advance the population through the year 2000, analyzing the effects of different fertility, mortality and migration rates. Correlations are determined between various segments of the population (e.g., females over nineteen and total population) and dwelling units. In addition, sociological data is reviewed to determine the effects of change in life style and marriage and divorce rates on the size of household and the mix of dwelling units (e.g., apartment, single dwellings, etc.)

New Construction must be estimated because of its large effect on electric space heating and electric water heating sales as well as other applications. Construction data collected from our field representatives, as part of the continuing reporting program, and correlations to various demographic housing and economic factors are used to determine the long term trend in new construction. Short

term new construction units are based on information from construction reports, local builders and builder's associations.

The new construction units are forecast by detached houses, townhouses, individually metered apartments and single point-metered-apartments. Single-point-metered apartments are forecast along with the other residential units, although their consumption is included in the Large Commercial and Industrial class.

Demolitions and abandonments are included in a "net losses" category. Demolition numbers are obtained from figures compiled by the Bureau of Census, county planning agencies and Philadelphia Electric Company.

Space heating for new construction is based on historical penetrations in the new housing market, availability of fuels and present and future fuel costs. Space heating conversions are estimated based on past and current trends, projected fuel prices and the size of the potential market. Electric space heating in both the new construction and conversion markets are divided into resistance and heat pumps, with consideration given to the anticipated improvements in the latter's efficiency. Residential air conditioning has been tracked since 1947. Data on size, type of unit and energy efficiency ratio, whenever available, are collected on a continuing basis from distributors and manufacturers through the Electrical Association. Annual residential surveys, conducted since 1972, are used to update the air conditioning data base. Forecast consumption

for air conditioning is based on the level of market saturation, the replacement rate and the expected continuation of strong success in our high efficiency air conditioning program.

Other appliances are forecasted separately. The annual residential surveys provide saturation data and the acquisition rate. Monthly sales statistics are also received from the Electrical Association, but these must be adjusted for anticipated replacements. Annual use of appliances is obtained from test data and industry average data (EEI and other utilities).

The consumption for each appliance and application is then summed to obtain the class totals for Residential, House Heating and the single-point-metered apartment component of Large Commercial and Industrial Sales.

Q. Describe how the large commercial and industrial sales are forecast.

A. This class is broken down into the largest ten manufacturing customers, all other manufacturing, single-point-metered apartments, and other non-manufacturing (commercial, education, government, utilities).

The big ten manufacturer's sales forecasts - which are 40% of the total manufacturing sales - are based on frequent interviews with these customers concerning their plans.

Forecasts of other manufacturing sales were made using three

different methods:

Manhours - This method used historic and forecasted manhours and kWh per manhour for the various industrial SIC's. Using actual kWh sales plus manhours per SIC from the Wharton (WEFA) Regional Model, the growth rates in kWh per manhour were calculated for the 1969-77 period. These growth rates were then applied to WEFA's forecasted manhours for the two digit SIC's for the period through 1988. Adjustments were made to SIC's 29 and 33 because the three major oil companies and the two major steel companies in these classes are in the big ten and are forecasted individually.

Relationship of Population and Employment - the ratios of population to employment by two digit industrial SIC's were determined as was the kWh per employee by SIC, by year, for the period 1965 to 1976. Through the use of linear regression, the kWh per employee was projected by year through 1988. Regressions were then run to estimate future employment by SIC using both State of Pa. Dept. of Commerce population forecasts and PE Company's population model. Using the kWh per employee and the estimates of future employment resulting from the two different population models, two slightly different kWh projections were obtained for the 1978-88 period. The average of the two was used as the base case.

Regression Analysis - A total of 30 different models were run and the three which were statistically significant and reasonable in terms of functional form and dependency were selected. The three models

used have the following independent variables: (1) Industrial Production Index, (2) the personal consumption expenditures for durable and nondurable goods and the fixed nonresidential investment components of the Gross National Product 1972 %; and (3) the third model augments the first with a lagged dependent variable of kWh sales to the manufacturing sector which assumes that the stock of electric using equipment in industry does not instantaneously adjust to changes in the economy.

The results of the three methods just described produced 1978/88 growth rates for other manufacturing sales of 2.7%, 2.8% and 2.8% respectively. The manhour method with its 2.7% growth rate was selected for the base case. Value added was also investigated as a possible forecasting technique but was found to have a number of serious deficiencies which precluded its use.

Large commercial sales were forecast using four different methods:

Manhours - The method is the same as described for other manufacturing sales.

Relationship of Population and Employment - This method is also the same as described for other manufacturing sales.

Regression Analysis - 30 different models were run and three were selected because of their reasonableness of structure, their statistical properties and their observed behavior over the estimation period. The three models used have the following independent variables: (1)

the services component of Gross National Product 1972 $ (2) Real Disposable Income 1967 $ and the lagged value of kWh sales to the nonmanufacturing sector and (3) the third model uses the services component of Real GNP 1972 $ and the lagged value of Real Disposable Income 1967 $.

Commercial Square Footage - An analysis of various data resulted in the assumption that there are 465 square feet of floor space per commercial employee. Using WEFA's regional projection of commercial employment, an estimated 121 million square feet of new commercial construction in the 1978/88 period was obtained. This figure was multiplied by 34 kWh per square foot, which was the average for new construction in PECO's service area for the 1974-77 period. The resultant figure was adjusted for known specific "non-commercial" type loads included in this class such as water and sewer plants, the Navy Yard, oil pumping stations, etc. Existing weather corrected loads were increased 1% for additional equipment, mainly data processing equipment. However, existing weather corrected loads, less the "non-commercial" segment, were also reduced by 7% to allow for additional conservation by existing customers over the 1978-88 period. Conservation in new construction was forecast to lower consumption somewhat less than the maximum impact of ASHRAE 90-75, which is based on pre-1973 construction. The new construction kWh, less conservation, were combined with the adjusted existing kWh sales to produce the final result.

The results of the four methods produced 1978/88 growth rates for large commercial sales of 5.1%, 3.7%, 4.8% and 3.7% respectively. The lower figure was selected as the base case.

Q. How are small commercial and industrial sales forecast?

A. This class was forecast by a method very similar to that just described in the Large Commercial Square Footage method. The customers in this class are not broken down into SIC's. The forecasted sales for 1988 are 3,520 million kWh which is a 1978/88 growth rate of 2.0%.

Q. How were the other classes forecast?

A. The forecasts for the other classes are made based on discussions with the limited number of customers involved and on time-series analysis and the technological changes expected (as in street lighting sources).

Q. Are high and low ranges of the forecast prepared?

A. The forecast is prepared as a base forecast based on assumptions considered most likely to occur, with high and low ranges based on variations of these assumptions. The basic assumptions which apply to all classes of service are listed in Appendix A. Many other assumptions are included with the individual discussions of the various classes of service in the Budget Forecast. Ranges are developed because outcomes will vary from forecasts for many reasons. Deviations based on business cycles and errors from the mean

economic forecast based on a band of predictions will occur. It is inevitable that the economy will be influenced by factors not now considered probable by most economists. Such things as the effects of government policy changes; OPEC actions; unanticipated technological changes or lack of improvements in appliance efficiencies; and behavorial changes affecting consumer spending, migration, jobs or life style, which, taken together, could greatly influence the growth of regional output and population away from the projected probable trend.

In addition, seldom can the future be counted on to reflect the past. In this century, there was World War I, the boom of the roaring twenties, the crash and Great Depression, World War II, the sustained postwar boom, the wide swings in birth rates, Korea and Vietnam. Since 1970, the economy has been influenced by the oil embargo, the severe recession, and the job and population outflow from the Northeast. None of these major events was foreseeable a few years in advance by the economists of the time. The base case growth rate for 1978/88 is 2.9% while the high range is 4.4% and the low range is 1.3%. In all three scenarios normal weather is assumed.

Q. How do the results of the WEFA econometric forecast model compare with the Budget Forecast results?

A. The WEFA model in 1978 forecasted consistently higher kilowatt-hour sales growth than our in-house forecasting methodology. WEFA forecasts prepared in the fall of 1978 projected total electric

consumption to grow at 3.8% annually compared to PE Company's forecast of 2.9%. Under the present circumstances, a higher forecast could be expected from the econometric model because it is based on history and might not take into consideration the full impact of government regulation on appliance efficiency and building standards.

Q. How do you factor into the forecast future fuel prices and technological improvements?

A. Projections of energy prices are prepared by PE personnel. These are applied to various heating system types as a basis for estimating saturation percentages for each fuel. The assumptions in Appendix A show the ratios currently expected. The cost of electricity and salaries and wages are expected to increase at approximately the same rate as the consumer price index over the next ten years. Therefore, with the cost of electricity taking a relatively constant percentage of the consumers' income, no special coefficient of elasticity is used. Past studies here and elsewhere were inconclusive as to values for price elasticity of electricity. However, the forecast does assume that energy conservation will continue because the high price of electricity and the optimum efficiency of energy use will remain facts of life. When forecasting energy sales for each component, whatever is applicable in optimizing energy use, such as full insulation, ASHRAE-90 standards, high efficiency (high EER) air conditioning, accelerating acceptance of heat pumps with continually

approving COP's, solid-state appliances, microwave cooking, high efficiency light sources, and others is assumed. A strong restrictive effect is thus derived which reflects the high value of electricity without relying on a fixed coefficient of elasticity with its necessary estimate of future prices. Forecasts of technological changes and data on future improvements are obtained from following a large number of publications such as Futurist, Technology Review, Spectrum, Electrical World, Electrical Week, Business Week, Energy Review, and the U.S. Information Service energy materials.

Q. How are weather and business cycle effects taken into consideration?

A. The energy sales forecasts for the base case and high and low ranges are based on normal weather (see Appendix A for description of weather-corrected sales) and normal, average economic conditions. Whether the economy is in a recession or at a peak will cause energy sales to swing considerably from the probable forecast trend line.

Q. What steps do you take to keep up with changes in forecasting techniques?

A. Meetings with other forecasters from PJM utilities are held several times per year and forecast data and techniques are interchanged. Members of the group also participate in the Electric Utility Market Research Council, Wharton Regional Model meetings, and special conferences, meetings and seminars on energy forecasting as available.

Q. Is PE Company's forecast of electric sales for the 1978/88 period compared with forecasts made by other electric utilities and industry forecasts?

A. A file is maintained on forecasts of national forecasters (such as McGraw-Hill, EPRI, FEA, FPC, A. D. Little) and of utilities all over the country as a check on the positioning of our forecast, though these are not a direct input in making projections. With the ten PJM companies, the individual forecasts range from 2.5% to 5.4%, with PE Company's forecast being 2.9%. The average for the ten companies is 3.7% and the median is 3.4%. At the time the Budget Forecast was prepared, the national forecasts of electric consumption growth were in the 4% - 5% range (e.g., McGraw-Hill 4.1%, NERC 5.2%, General Electric 5%, DOE 4.8%).

PHILADELPHIA ELECTRIC COMPANY

Energy Sales Forecast Assumptions For 1978 Forecast

The following assumptions apply to all classes of service in the ten year forecast and cover the base, high, and low cases.

1. GROSS NATIONAL PRODUCT - Real GNP and real Gross Regional Product (GRP) for the Philadelphia SMSA (Pennsylvania portion) are projected to grow at the following indicated average annual rates

	1978-79	1977-82	1982-87	1977-87
GNP - Base	2.0%	3.7%	3.2%	3.4%
GRP - Base	1.5%	2.3%	1.8%	2.1%
GNP - Low	1.5%	3.4%	3.0%	3.2%
GRP - Low	1.0%	2.2%	1.3%	1.8%
GNP - High	4.1%	4.2%	3.2%	3.7%
GRP - High	4.7%	2.5%	2.2%	2.3%

2. POPULATION - Service area population, derived from the 1970 Census, was the base upon which the computerized population model, using the cohort-component method, constructed estimates and projections through the year 2000. Calculations were based on the Census Bureau's Series II fertility rates and current survival rate tables. Estimates from 1970-76 include the 156,000 net out-migration estimate made by the Bureau of Census for the Pennsylvania portion of the Philadelphia Standard Metropolitan Statistical Area. All estimates and projections for the Conowingo Power Company's service area assume a neutral net migration over the entire period from 1970-2000.

Base case projections for the Philadelphia Electric Company service area decrease net out-migration, over a ten year period, from the 0.7% annual rate seen in the 1970-76 period, to the 0.1% experienced from 1965-70. This rate is continued through the year 2000. The low forecast's projections maintain a constant net migration rate at the 1970-76 level for the entire period. The high forecast assumes neutral net-migration after the initial 1970-76 period.

3. FERTILITY RATES - The Census Bureau's Series II fertility rates were used for all forecast scenarios. This schedule ultimately leads to replacement level fertility, which is equivalent to 2.1 births per female.

4. COSTS OF ENERGY - The following annual average rates of growth were assumed for fuel costs for the ten-year forecast period. The percentage figures apply to constant 1972 dollars so that the changes indicate a relationship to the Consumer Price Index (CPI) which is expected to increase at an inflation rate of about 5.5% per year during the period.

	Real Annual Increase	1988/1978 Costs - 1972 $
Electricity	0	1.
Oil - No. 2	1.5%	1.15
Gas - Rate GR	2.7%	1.30

Electricity projections are taken from the corporate financial model based on the current outlook for generation costs and mix. Coal and oil prices are based on data provided to Purchasing by their fuel suppliers and two studies prepared for EPRI. (1) (2)

The gas price projection is developed by Gas Operations and agrees generally with the AGA forecast for Mid-Atlantic region dated July 3, 1978 and conforms with an EPRI staff study (3) which also reinforces the electric assumptions.

The many unresolved policy decisions and the instability of the Middle-East situation make forecasts of energy prices an inexact process at best.

The fuel price projections in PECO's corporate assumptions are based on the best available studies, but in light of the great uncertainties should only be considered as relative indicators of competitive relationships.

For the low case, it was assumed the cost of oil will maintain its present relationship to electric costs and that oil will be in adequate supply.

For the high case, it was assumed oil and gas will be in tight supply, contributing to increased penetration of electric space heat.

5. CONSERVATION - In all three scenarios, government agencies and private organizations including PECO will continue to encourage energy conservation through the use of high efficiency appliances and applications and energy-efficient construction. Government regulations will play a growing role. Assumed efficiency improvements, which are attributed to both the high cost of energy and the desire to conserve, are covered in later sections.

6. PRICE ELASTICITY will continue to lead to the purchase of high efficiency appliances and energy-efficient buildings and systems as mentioned in 5. above and in the later discussion on Price Elasticity. Efficiencies are based on technology and expected government policy rather than an estimated coefficient of elasticity because of inexactness to be expected in projecting relative energy prices and elasticity coefficient values for each class.

7. OFF-PEAK APPLICATIONS - PECO will continue to promote off-peak applications -- electric space heating (particularly heat pumps) and night lighting for safety -- which improve load factor, for the base and high forecasts. A neutral stance is implied in the low forecast.

8. GAS - For the base and low cases, the improved gas supply outlook is expected to enable gas sales to resume in 1979. As a result, the penetration of electric space heating for new construction might be restricted.

For the high range, additional gas supplies would be limited to additional residential customers only to match gas service removals.

9. BUSINESS CYCLES - The three forecasts assume the currently expected economy in 1979 and are based on a normal peacetime economy through 1988.

Based on an analysis of sales for the 20 years from 1952 to 1972, whether the economy is in a recession or at the peak of a boom can cause a +5% to -7% deviation from the base trend which is based on a smooth growth rate.

In addition, recognized economists offer different projections of national economic growth, some of which are given in Table

If the high and low projections shown are imposed on the business-cycle effect described in the above paragraph, deviations from these two causes could cause an increase in sales of 8% or a decrease of 13% from trend in the later years of this forecast while most of the listed assumptions would still be applicable. Projections by class based on these high and low factors are given in Table II.

10. Average weather conditions are projected, affecting heating and cooling loads.

Normal weather for each calendar day of the year is determined by averaging actual weather data over a historic period. For the heating season, this average is computed over a 45 year period from 1930 to 1974. For the summer cooling season, the historic data covers a 30 year period from 1946 to 1975. Monthly and seasonal normal weather are the sum of normal weather for individual days. A new normal is calculated every five years.

To correct actual sales for normal weather conditions in any given year, the difference between actual weather and normal weather for the heating and cooling season is computed. These differences are then multiplied by either a summer or winter weather electric usage factor. These factors were developed using linear and multiple regression techniques and are a measure of the relationship between the changes in electrical usage and changes in weather. The resulting product, when subtracted or added from actual sales, gives kWh usage on a normal weather basis.

Other assumptions, the impact of which is concentrated on specific classes of customers or uses, appear later in the appropriate sections.

Response To Conrad J. Six Letter of December 14, 1979
Regarding Generating Capacity Planning

1. Organizational Responsibilities and Staffing Request

PE's Forecasts are prepared in 2 separate Steps

Step 1 - kWh Energy Forecast

A forecast is prepared annually by the Market Research Section of our Commercial Operations Department, providing ten and twenty year projections of electric energy. This forms the basis for projecting peaks and capacity requirements by the Energineering Department.

The resources devoted to the kWh Energy Forecast are as follows. Note that these are calculated equivalent manpower inputs; no individual spends full time on the forecast.

1. Personnel - The long-term electric sales budget is prepared by the Market Research Section which applied about five person-years to the project in 1978 at a cost of $180,000. The personnel working on the forecast are Supervisor, Market Research and the others are titled Market Analyst. These all have college degrees including 3 MBA's and one M.S.E.E. Salaries range from about $26,000 to $35,600 per year for the top non-supervisory analysts.

Step 2 - Generation Planning

We do not have any engineers whose sole job is the planning of new generation. A new generation study will involve a number of engineers who are also performing other functions; e.g. an engineer involved in the engineering for the Eddystone station flue gas scrubbing system may provide the cost estimate for new coal unit scrubbing systems. By evaluating all the various engineering contributions to a generator study we can estimate an equivalent engineering staff requirement.

We interpret generation planning to include all studies which concern decisions on generation additions, retirements, or conversions; e.g. an existing unit being converted from oil fired to coal fired. This would not include the actual engineering for any generation changes nor the development of any of the regulatory filings for state and federal agencies. As best we can estimate, an equivalent engineering staff for generation planning would consist of about 8 people including:

a) Reliability Analysis: (1 Engineer)

Determining need of capacity to meet Loss-of-Load Probability (L.O.L.P.) requirements. Developing generation outage data and load for L.O.L.P. modeling. Participating in joint studies with other utilities. Maintaining state-of-the-art capability in L.O.L.P. techniques including sensitivity studies of existing models.

b) Operating Cost Analysis: (1 Engineer)

Calculating annual operating costs on a bi-hourly basis using computer models. Providing generation and load data for models. Extracting and comparing operating data from output of models for cost, fuel consumption, capacity factors interchange, etc. Maintaining state-of-the-art capability in production cost modeling.

c) Generation Installed Cost Estimates: (2 Engineers)

Developing installed cost estimates for new units including special requirements; e.g. flue gas scrubbers, cooling towers, etc. Maintaining state-of-the-art capability for evaluating new generation types such as fuel cells, wind powered generators, etc. Developing cost estimates for retrofitting equipment on old units; e.g. flue gas scrubbers, etc.

d) Generation Economic Comparisons: (1 Engineer)

Performing overall economic comparisons for generation additions, retirements or conversions considering reliability requirements, operating costs and carrying charges on installed costs. Developing alternate generation plans for consideration including location, size and types of generations to be considered.

e) Transmission Analysis (2 Engineers)

(Every change in generation has an effect on transmission requirements and must be evaluated to get true cost comparisons). Performing load flow calculations to develop new transmission requirements for every generation change. Performing transient stability analyses to evaluate new generation. Performing short circuit analyses to evaluate new generation. Estimating cost of new transmission and substation facilities required by generation changes.

f) Computer Program Maintenance: (1/2 Engineer)

Maintaining and updating L.O.L.P. reliability, production cost, load flow, transient stability short circuit and subsidiary computer programs.

2. Computer Services

Energy Forecasts

Data Processing is done on the IBM System/34 computer which also processes other Commercial Operations reports. Cost of data processing is about $7,000 per year.

Generation Planning

The computer programs which we use in generation planning were either developed by PECO or obtained from other PJM members. We, therefore, have no program rental costs. These computer programs require IBM series 270 or compatible type computers. We do not normally segregate computer costs for generic generation planning studies, but an estimated annual cost would be about $25,000.

3. Consulting Services

Energy Forecasts

There are no consultants employed in the official energy forecast. Wharton Econometric Forecasting Associates (WEFA) was engaged to prepare an independent econometric-based forecast in 1978. Based on current proposals from WEFA, the annual cost of preparing an econometric forecast in the future with the model in place would be about $45,000. No decision has been reached by PECO at present on whether to pursue this method further.

Generation Planning

External consulting services have been hired in the past to evaluate the suitability of new sites for major generation expansions. Such evaluations have been very detailed and cover special areas of expertise such as ground strata, probability of earthquakes, wind dispersions, topographical features, etc. Such studies are very much dependant of the number of sites and the features of those sites themselves.

Appendix D

TABLE 1

GROSS NATIONAL PRODUCT PROJECTIONS
1958$

Actual 1971 - $742-
Actual 1972 - $790-

	Year Made	1975	1980	1985	1990	1995
Wharton Model	1971	906	1,109	X	X	X
National Planning Assoc.	1971	922	1,149	X	X	X
Council of Economic Advisors	1971	936	X	X	X	X
Lionel D. Edie	1971	894	1,145	X	X	X
McGraw-Hill	1971	X	X	1,274	X	X
American Gas Assoc.	1971	894	1,103	1,361	1,681	2,075
The Conference Board	1972	X	X	X	1,695	X
King - P.E.Co.	1972	927	1,145	X	X	X
McGraw-Hill	1972	905	1,101	1,303	1,509	X
National Planning Assoc.	1972	894	1,086	X	X	X
King - P.E.Co.	1973-	906	1,109	1,332	X	X

X - No Projection made.

Research and Forecasting Department
May 3, 1973

Table 2

GROSS PRODUCT PROJECTIONS

1972 Billion $

Actual 1976 GNP $1271.0 Actual 1976 GRP $26.7
Actual 1977 GNP 1332.7 Actual 1977 GRP 27.4

Previous Forecast:	Year Made	1980	1985	1990	1995	2000
NATIONAL PRODUCT						
Wharton EFA	1977	1,518	1,788	2,088	2,413	X
EEI Task Group 20	1976	X	X	2,200	X	2,925
Merrill Lynch Economics	1976	1,496	1,782	X	X	X
Council of Economic Advisors	1977	1,562	X	X	X	X
Data Resources, Inc.	1976	1,534	1,796	2,073	X	X
Mc Graw-Hill	1977	1,508	1,761	2,061	2,388	X
P. E. Co. (D. F. King)	1977	1,530	1,789	2,080	2,388	X
REGIONAL PRODUCT						
Wharton EFA	1977	34.7	X	X	X	X
Present Forecast:						
NATIONAL PRODUCT						
Council of Economic Advisors.	1978	1,537	X	X	X	X
Joint Economic Committee	1978	1,532	X	X	X	X
Wharton EFA	1978	1,509	1,744	1,985	2,288	2,662
Data Resources	1978	1,517	1,815	2,105	X	X
McGraw-Hill	1978	1,498	1,794	2,099	2,458	X
Bell Telephone	1978	1,442	X	X	X	X
P. E. Co. (D. F. King)	1978	1,505	1,761	2,061	2,338	2,662
REGIONAL PRODUCT						
Wharton EFA	1978	30.0	32.3	X	X	X

R&F Dept.
October 1978

Appendix D

TABLE 3

PROJECTIONS OF 5 COUNTY POPULATION (THOUSANDS)

SOURCES	1980 PROJECTION	1985 PROJECTION	2000 PROJECTION
PA. Dept. of Education (9/75)	4043	4123	4385
Office of State Planning & Development (6/78)	3867	3876	3965
WEFA/ABRI (10/78)	3798	3874 *	4131
DVRPC (11/76)	3878 *	3963 *	4238
DVRPC (6/78)	3810 *	3907 *	4292
PECo (9/76)	3851	3931	NA
PECo (9/78)	3761	3843	4104
Bureau of Census Reported	3683	3700 (1984)	---

* estimates based on growth rates

ORIGINAL

PECO STATEMENT NO. 14

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PHILADELPHIA ELECTRIC COMPANY
DOCKET NO. R-850152

RECEIVED
SEP 27 1985
SECRETARY'S OFFICE
Public Utility Commission

DIRECT TESTIMONY OF
CARY H. RUSH

SALIENT FEATURES OF PECO/PJM SYSTEM; PEAK LOAD FORECAST; GENERATION CAPACITY PLANNING AND RETIREMENT DATES

September 27, 1985

ACCEPTED
SEP 27 1985

TESTIMONY OF CARY H. RUSH

Q. Please state your name and business address for the record.

A. Cary H. Rush, 2301 Market Street, Philadelphia, Pennsylvania.

Q. Please state your employer and present position.

A. I am employed by Philadelphia Electric Company as the Chief Engineer, Research and Planning Division, Engineering and Research Department. I have held this position since March 1985.

Q. What is your educational background?

A. As set forth in my Curriculum Vitae, which is attached as Schedule 1 to my testimony, I received a B.S. in Electrical Engineering from the University of Pennsylvania in 1957 and an M.S. in Engineering in 1967.

Q. Are you a registered professional engineer?

A. Yes. My registration number in Pennsylvania is PE 020206-E.

Q. Are you a member of any professional societies?

A. As Schedule 1 indicates, I am a senior member of the Institute of Electrical and Electronic Engineers, and a member of Tau Beta Pi, Eta Kappa Nu and Sigma Tau. I am also a member and Vice-Chairman of the Electric Power Research Institute (EPRI) Power System Planning and Operations Task Force.

Q. Please describe the structure and functions of the Research and Planning Division.

A. The Research and Planning Division has two primary responsibilities, research and system planning, and is divided into four sections. As Chief Engineer, I oversee all aspects of the Division's activities.

The Energy Conversion Research Section and the Distribution Research Section carry out the research function, which is to coordinate research work done by EPRI and others as well as provide research assistance for PECO and other organizations.

The Planning Section and Services Section carry out the Division's system planning function. The Planning Section has a Generation and Transmission Branch, a Distribution Branch and a System Reliability Branch. This section plans the timing, location, type and size of new electric facilities, determines reserve requirements, evaluates the economics of alternative facilities and performs joint studies with other members of the PJM Interconnection to coordinate interconnection planning. The Services Section has a Forecast Branch, a Computer Branch and a Cost Control Branch. This section prepares peak demand forecasts, develops needed computer applications for the Engineering and Research Department and prepares capital budgets and forecasts.

Q. Please describe your system planning experience with the Company.

A. I have over twelve years experience in system planning with PECO. I have had engineering and supervisory experience in all aspects of PECO's system planning. Among the major activities in which I have participated are the determination of generation reserves by probability analysis; planning the timing, location, type and size of new electrical facilities; preparation of capital budgets and forecasts; and economic evaluation of alternative plans for generation and transmission of electricity. Starting as a Junior Engineer in the Research Division, I progressed to the level of Engineer before transferring to the System Planning Division in 1967. In System Planning, I

advanced to Senior Engineer while in the then Steam, Gas and Environmental Branch, and then moved to the former Long Range Generation and Transmission Branch. I was transferred to the Mechanical Engineering Division in 1976 and worked for five and one-half years in their Environmental Engineering Section and Nuclear and Environmental Section before becoming Engineer-in-Charge of the Planning Section of the System Planning Division in 1982. From there I became Chief Engineer of the recently combined Research and Planning Division in March of 1985.

Q. Have you previously given testimony before this Commission on behalf of Philadelphia Electric Company?

A. No, I have not. However, I have given brief testimony for the Company before the Federal Energy Regulatory Commission (FERC) as indicated in Schedule 1.

Q. What is the purpose of your testimony?

A. My testimony will address the following areas:

(1) the salient features of PECO's system and the Pennsylvania-New Jersey-Maryland Interconnection (PJM);

(2) the PECO peak load forecast;

(3) the PECO generation planning process;

(4) PECO's generating capacity planning program;

(5) PECO's generating capacity planning studies during the 1976 to 1982 period; and

(6) the generating unit retirement dates.

SALIENT FEATURES OF PECO AND PJM

Q. Please describe the salient features of PECO's system.

A. PECO is a public utility company supplying electricity, gas and steam to the public in southeastern Pennsylvania and northeastern Maryland. PECO's Pennsylvania electric service territory includes all or substantially all of Philadelphia, Montgomery, Bucks, Delaware and Chester Counties, and a portion of York County.

Schedule 2 contains several maps and a table concerning PECO as follows:

Page 1 is a map of the electric service territory of Philadelphia Electric Company and its Maryland electric distribution subsidiary. Each numbered area is an operating division. The total area served by PECO and its subsidiaries covers 2475 sq. miles. Electric service is supplied in an area of 2340 sq. miles of which 1972 sq. miles are in Pennsylvania. The electric service area contains about 3,700,000 people and includes over 200 cities, townships and boroughs.

Page 2 is a schematic diagram of the electric transmission system of Philadelphia Electric and its subsidiaries. It shows all of the Company's generating stations, transmission substations and transmission lines. It also shows overhead circuit mileage from 66 kV to 500 kV and underground circuit mileage from 66 kV to 220 kV. Electrically, the system consists of 12 generating stations, of which 8 are wholly owned, plus combustion turbines; about 1100 miles of transmission lines at 69 kV volts or higher; and about 27,000 miles of distribution lines of 33 kV volts or lower. The system also

includes many substations and general facilities necessary for the supply of electric service.

Page 3 is a table showing the PECO system generating capacity in service as of January 1, 1985. Summer ratings totaling 7765 MW are shown in the last column. PECO, in addition to operating its own system, is a member of the Pennsylvania-New Jersey-Maryland (PJM) Interconnection.

Page 4 of Schedule 2 is a map of the major transmission systems of the PJM Interconnection and the interconnections with neighboring systems. The dark lines show the principal 500 kV lines which are the backbone of the transmission system. The major mine-mouth generating stations, Conemaugh, Keystone, and Homer City, are located at the western end of the 500 kV system. PECO has approximately a 20% ownership share in the Conemaugh and Keystone stations. PECO's Peach Bottom (approximately 42% ownership) and Muddy Run plants, near the Maryland border, are also tied into the 500 kV system by one line to Conastone Substation in the west, one line going east to Keeney Substation in Delaware, another line going northwest to Three Mile Island (TMI) Substation, and a fourth 500 kV line heading northeast to PECO's Limerick station. The Salem plant, in which PECO has approximately a 42% ownership share, is located on the Delaware River. This plant is connected to the system by two 500 kV lines going northeast to New Freedom Substation and a 500 kV line going west to Keeney Substation. The Company's Limerick Generating Station is located on the Peach Bottom-Whitpain 500 kV line right-of-way near the point where the line crosses the Schuylkill River.

The major PJM interconnections with neighboring systems also are shown on this map. For example, there are 500 kV connections to Allegheny Power System in the eastern and western part of PJM, 230 kV connections to Virginia Electric & Power Co. to the south, and a 500 kV. connection to the New York Power Pool in the northeast.

PECO PEAK LOAD FORECAST

Q. Please describe PECO's peak load forecast.

A. A more extended discussion of this process and the data which we used in our analysis, which discussion is taken from the official corporate sales and peak load forecast, is attached as Schedule 3.

The Company's peak load forecast is derived from a sales forecast developed by the Commercial Operations Department and is given on Schedule 3, Exhibit J. Our base load estimate is for a 0.54% annual increase in the summer peak load from 1984 to 1994 with a corresponding 0.8% annual sales growth. Recent actual experience has shown a peak load growth from 1982 to 1985 of about 2% per year. Moreover, the historic long-term peak growth rate (i.e. 1973-84, the period following the watershed Arab oil embargo) has been 0.7%. Therefore, it would appear that the present peak load forecast may be conservative. If the economy continues to be healthy, actual future loads may well be closer to the high load estimates, also presented in Schedule 3, Exhibit J. This would correlate to a peak load growth of 2.3% per year from 1984 to 1994.

Q. Please summarize your methodology for peak load forecasting.

A. Our peak load forecast is developed from analysis of the relationships between various historical data and application of those relationships to

forecasted data. The forecasted data is obtained from our Commercial Operations Department and is consistent with the corporate sales forecast.

The forecast consists of two components: base load and weather sensitive load. To obtain the base load forecast, we first take the historic average April and October monthly output (i.e. sales plus losses) in gigawatthours for the previous sixteen years. This output is then compared with the associated historic April and October base demand in megawatts. Employing judgment, a factor relationship is developed of monthly base load to base demand which is believed to be representative of the future. In developing this relationship for the current forecast, a rounded value of 1.66 was used, which is consistent with the recent experience (i.e. 1979-84, Schedule 3, Exhibits F and G). April and October monthly sales and demand are used since these months are least affected by temperature conditions and thus most indicative of base (i.e. non-weather sensitive) demand. This established relationship between base demand and April/October monthly energy use is then applied to estimated future April/October monthly sales taken from the Company's sales forecast to produce our estimate of future base demand.

The second step in determining the peak load forecast is computation of the weather sensitive demand, which is the difference between regression demand and base demand. Because weather sensitive demand has been found to have a good correlation with the estimation of actual MW's of connected air conditioning, we compare the estimated connected air conditioning load for the previous sixteen years to the coincident weather sensitive demand in those years. The resulting historical ratio is applied to the forecasted

connected air conditioning load supplied to us by Commercial Operations. The result is the coincident weather sensitive forecast for that particular year. Again, this ratio or "multiplier" is determined with judgment and is intended to reflect expected future conditions. The recent data exhibits a slightly rising trend; however, we have conservatively used the most recently experienced factor (i.e. 1984 value of .478) as most representative of the likely future (Schedule 3, Exhibits H and I).

The sum of the base demand and the weather sensitive demand is the total or regression demand.

Q. Please explain what you mean by "regression demand" and what its purpose is?

A. A two-part analysis of 1984 peak load data is provided on Schedule 3, Exhibit A. This analysis has three purposes. First, it is employed in the development of historic base demand. Second, the regression analysis is used in developing estimated weather sensitive load as described above. Third, the regression analysis is used to correct historical peak loads for standard weather conditions. This is done to determine actual peak load growth and to verify that the growth pattern of future estimates is reasonable. This standardization is performed with the use of a daily weather factor (DWF), a parameter which is indicative of the weather effect on peak demand. At a given weather factor, the regression line indicates the average daily peak load.

Examination of the correlation between peak loads and daily weather factors, as shown on Schedule 3, Exhibit A, indicates a relatively constant demand value between daily weather factors of 64 and 77 (i.e. the flat

portion of the data plot) and a sloping line for all daily weather factors above 86. The running average of the DWF on the day of the annual peak over the last sixteen years provides the most probable peak daily weather factor, which for forecasting purposes has been established at 102.7 and is indicated by the dotted vertical line. This DWF factor is used to adjust the historical peak loads for standard weather and also, as described, in the development of estimated, weather-sensitive future peak demand. On Schedule 3, Exhibit A, the intersection of the sloping line and the vertical dotted line is the regression demand.

Q. Does this regression demand then constitute the estimate of future peak demand?

A. No, it does not. An examination of the historical relationship between regression-produced demands and actual peak demands reveals that the regression demands have consistently understated the peak demands. This is due to the fact that the regression is only used to arrive at the average day peak load in the year being analyzed. Inasmuch as the regression is developed based upon all days with a DWF of 86 or more, its daily peak load is tempered by the conditions present on all such days in the year being analyzed. In essence, the regression equation is based upon the average of all such conditions. The conditions present on the peak day of the year being analyzed, however, are never average, but are uniquely extreme. It is for that reason that the peak occurred on that day. The forecasted peak load for the year will never be an average peak load, and thus will always be somewhat above the regression line. The forecast of the most probable peak

load for the year must thus be an upward adjustment of the regression demand at the standard weather factor.

In order to recognize this inherent characteristic of the regression equation, the forecasted regression demand must be adjusted to obtain the most accurate prediction of future probable peak load. This correction is performed by computing the running average of the ratios of actual maximum demand for the past sixteen years to the average demand for the same years. The result is termed the standard demand factor, i.e. an adjustment factor of 1.036 (Schedule 3, Exhibit C). The regression demand in the forecast year is then multiplied by this factor to provide the most probable estimate of future peak demand.

Q. Mr. Rush, the ALJ in the Limerick 2 Show Cause Order rejected use of the standard demand factor adjustment which you have just described. Please state the reasons for your disagreement with the ALJ's reasoning.

A. The ALJ termed our adjustment "mechanical" and stated that it "does not provide a good adjustment". The ALJ further stated that our regression products were "under-predicted" and that the standard demand factor provided high results in 1983 and 1984. While it is true that our regression does not predict the most probable future peak load, and that this is the reason for the standard demand factor adjustment, this is no indictment of the regression analysis, since it is not intended by itself to forecast annual peak demand, but only the average relationship between DWF and daily peak load. The fact that use of the standard demand factor produced high results in 1983 and 1984 is no basis for rejecting it; it produced similarly and even more substantially low results in 1977, 1980 and 1982. The standard demand

factor is itself an average of historical experience.

Q. Please state what your 1985 peak load was compared to your forecast.

A. Our 1985 actual peak load equalled 6034 MW, and occurred on a day of below standard weather factor. When normalized to standard weather conditions, i.e. the basis upon which we forecast peak load, the 1985 peak load using data available as of mid-September is 6145 MW. Thus, our forecast of 1985 peak was slightly less than our actual peak adjusted to reflect the forecast normal weather conditions. As compared to the peak loads adopted as most probable by the ALJ, our actual 1985 peak load was approximately 60 MW higher and our weather-normalized peak load was approximately 170 MW higher. Thus, I believe that our late 1984 peak load estimates remain appropriate for use at the present time.

Q. Is cogeneration considered in your peak load forecast?

A. Yes. As I explained above, our peak forecast is a derivative of our energy forecast. Since our energy forecast reflects the effect of expected cogeneration to the extent that such cogeneration is used to serve the cogenerator's own load, the peak forecast also reflects this element.

Q. Is cogeneration included in your capacity planning process?

A. As described above, internal use cogeneration is subtracted from the cogenerating customer's load, and thus a capacity value is effectively assigned for this energy production. This de facto credit is justified since, if the particular customer goes out of business, his load is also lost and there is no effect on PECO capacity requirements.

However, no formal capacity credit is given for cogeneration energy sold to PECO. There are several reasons for this:

1. There is currently no cogeneration above 1 MW being sold to PECO.

2. We have a very limited data base with respect to the long-term reliability of cogeneration sales to PECO. For example, if a cogenerator goes out of business five years from now, we have little practical protection from a capacity standpoint.

3. Without an existing contract for cogeneration capacity, PECO must consider such capacity as speculative. The fortunes of the local heavy industries, such as oil and steel, who would be considered candidates for the larger cogenerator installations are good examples of the uncertainties surrounding proposed but not contracted cogeneration.

4. From 1977 to 1984 the amount of cogeneration capacity supplying internal load has declined from 205 MW to 110 MW.

5. Each proposed sale must be reviewed on a case-by-case basis. The reliability, in each case, is a function of a customer's actual operations.

PECO GENERATION PLANNING PROCESS

Q. What is the objective of the Philadelphia Electric Company generation planning process?

A. The objective of the Philadelphia Electric Company planning process is to plan an electric system that will reliably supply our customers at a minimum cost. Electric utilities are required by law to provide reliable service. Sufficient generation, therefore, must be installed to supply the forecasted annual peak demands in a reliable manner. To achieve this goal, additional generating capacity above the anticipated annual peak demands is needed to

provide a margin of reserve capacity to insure that the probability of the demand exceeding available generating capacity is at an acceptable level. This margin is necessary to allow for the day-to-day variations in the operating condition of the installed generation (such as maintenance and forced outages), and for the deviations of the annual peak demand from its estimate due to weather and business conditions.

Generation may become unavailable due to unexpected forced outages or scheduled outages for preventive maintenance. With an adequate reserve capacity, the system can be operated without disruption to customers during periods of either planned or unanticipated generation outages. If there is inadequate generating capacity or the annual peak demand is higher than can be supplied by available generation, there is nothing to be done but reduce or eliminate service to customers in order to reduce the demand.

Another dominant factor in evaluating required reserve requirements is the regional economic health. Since generation must be planned for and installed in advance of need, the same generation capacity that is adequate during periods of maximum business activity will result in higher reserves during periods of business depression. However, sufficient capacity must be kept in place during a business recession to ensure an adequate supply of electricity to be prepared to support a healthier economy.

In addition, the long lead times required to construct large economic base load generating units impose a severe restriction on the flexible planning needed to supply sudden, drastic changes in customers' demands. Moreover, because load grows incrementally over time and because generating units come in discrete sizes, the installed and planned generation

will rarely exactly match the required generation at a particular point in time. However, generating capacity is matched as close to the total generating requirement as can be economically justified.

Q. How does PECO determine the level of generation reserve required to provide reliable service?

A. As explained above, additional generation over anticipated peak load is required to allow for forced and maintenance outages of generating units and for load variations. Our customers expect and depend on highly reliable electric service. However, electric utilities can only supply service as reliable as can be justified economically. The PJM Interconnection reliability criterion, which governs PECO and is similar to that used by many other utilities, is that curtailments in electric service should not occur more often than one day every ten years because of an inadequate supply of generation. This criterion has been employed for many years, and in my view satisfies the customers' needs for reliable service without imposing excessive costs.

Applying this one day in ten year criterion, reserve requirements are calculated for PJM as a whole on the basis of expected weekly load peaks, expected generating capacity forced outage rates, expected maintenance requirements, and expected tie line support from power pools outside of PJM. This results in an overall PJM reserve requirement, assuming no maintenance during peak summer periods, ranging from 22% to 25%. PECO's specific obligations, which are set forth later, are then calculated by applying two main adjustments to the overall PJM requirements. The first adjustment is based on the comparison of PECO and PJM average forced

outage rates. The second adjustment is based on PECO's margin for doing generator maintenance in low load periods as compared with the margin for maintenance in all of PJM.

Q. Please describe the specific reserve requirements for PJM and PECO.

A. Actual calculated PJM reserve requirements, derived by a PJM committee in the spring of 1984, are as follows:

Year	%	Year	%
1986	22.0	1990	24.4
1987	22.5	1991	26.2
1988	24.3	1992	25.2
1989	24.0	1993	24.9

Based on the above values, a PJM contract obligation of 22% through 1988 and 25% thereafter was established. Inherent in these analyses is that the benefit of ties to companies outside PJM ranges between 11% to 12%. Without help from companies outside PJM, PJM reserve requirements would be approximately 35%.

PECO's actual and forecasted obligation to PJM was then calculated at the following values:

Year	%	Year	%
1986	22.5	1990	24.2
1987	21.9	1991	25.8
1988	22.0	1992	23.8
1989	23.8	1993	24.6

Based on these results, PECO employs a 25% reserve margin as its minimum planning objective. If PECO had no ties to PJM or other systems, its reserve requirement would probably be in the 40% to 50% range.

Q. Is a reserve greater than 25% used and useful in serving customer load?

A. Most assuredly. In 1984, the PJM Interconnection had a reserve approximately 35% over the experienced peak load. However, as shown in Schedule 4, this reserve, particularly during the summer period, was fully utilized. The top line shows total capacity installed as a percent of peak load. Each week of a 20-month period is shown. The top shaded area represents forced outages and generation which unexpectedly failed in service. The next area shows planned outages. Note that because of the high reserve, some maintenance could be scheduled during summer periods, thus spreading the work load and minimizing costs. Where available generation was less than the load, reliance had to be made on companies outside of PJM. Had the reserve been only 25%, maintenance costs would have been greater due to shifting this work to the spring and fall periods, and there would have been greater reliance on more expensive high cost peaking power from outside of PJM.

Q. Do you have other comments on the 25% reserve objective?

A. Yes. The 25% reserve objective, for planning purposes, is the objective. Generating units are built in discrete sizes. Thus, reserves, in a given year, may vary somewhat above and below 25%.

In addition, the percent reserve requirement as normally calculated assumes relatively accurate knowledge of future peak loads with allowance for weather variations. However, since actual future loads may be significantly different from forecasts for a variety of reasons beyond the control of the Company, it is necessary to estimate a range of expected loads, apply this reserve requirement to each set of loads, and determine

how capacity could be provided for the various load conditions. Thus, the single statement that reserves in a future year may be above or below the reserve requirement may not meaningfully assess the adequacy of future plans. Low future reserves might be deemed adequate if load estimates are thought to be on the high side and new, long-term cost effective generation is of short lead time. Conversely, high future reserves may be entirely inadequate if there is a real possibility of higher than estimated load growth and if the cost effective new generation is of long lead time.

Q. What role does economics play in the generation capacity planning process?

A. As set forth above, the Company's principal generation planning objective is to provide reliable service at minimum cost. Rational generation planning, therefore, must consider both reliability and economics. The Company considers these economic factors both in the amount and type of capacity to be utilized on its system. If it can be shown that the construction of a new unit, or extension of the life of an old unit, will reduce long-term revenue requirements and yield lower rates, it will be planned, even if the resulting reserve margin would exceed 25%.

Similarly, we carefully consider economics in the type of capacity which is installed, i.e. base load generation, intermediate (cycling) generation, and peaking generation. In order to satisfy the requirement of varying loads on an electric power system in the most economic manner, the available generation must have different load carrying functions (i.e. must be able to satisfy different portions of the demand for electricity). To minimize the revenue requirements associated with capital charges and production costs, the optimum mix of generation must include base load

generation, intermediate generation, and peaking generation.

The higher capital costs of base load units are justified by their low production costs. As a result, these units will operate at a high annual capacity factor. (A capacity factor of 100% would refer to a unit operated at its full capacity for every hour of the year.) The situation is somewhat analogous to a high mileage car owner, such as a traveling salesman, who will properly spend more for an automobile to get improved gas mileage. The intermediate generating units have lower capital but higher production costs. Thus, these units are the most economic units for cycling duty. Units designated for peaking generation are characterized by low capital costs and high production costs. They may also be units which have a limited energy generating capability. Since they are called on to operate for only short periods of time and are used to provide required operating reserves, their capacity factors are low.

Each of the above types of generating capacity has qualities which make it a necessary part of the proper mix of generating units which comprise PECO's generation. This is evident if we examine a typical peak day load cycle (Schedule 5). Base load exists at all times. Some load exists for perhaps half the time. The remaining load occurs only for a brief period. Economically, these three types of load are best served by generating capacity designed to fit these differing system requirements. In general, the base generating capacity is best supplied by nuclear or coal-fired steam units which have relatively high capital costs and low fuel costs. The intermediate generating capacity is best supplied by fossil-fired steam units which have the ability to cycle (shut down and return to service

over a short time interval, e.g. daily). These units have relatively moderate capital costs and higher fuel costs. They are often the older generating units which were previously base generating units. The peaking generating capacity is most economically supplied by either generating units which have low capital costs and high operating costs, such as combustion turbines, or units which have limited energy generating capability such as hydroelectric generation on the PECO system.

Schedule 6 shows a composite daily load cycle with the role of the differing types of generation indicated in their usual application.

PECO GENERATING CAPACITY PLANNING PROGRAM

Q. Please describe the specific generating capacity planning program PECO has developed to implement the Company's generation capacity planning goals.

A. Schedule 7 summarizes the capacity additions and retirements which we have planned for the 1984-94 period.

In 1984, PECO's reserve margin had fallen to 19%. The addition of PECO's 471 MW share of Salem 2, which was previously sold to Jersey Central Power & Light Company, and the proposed retirement of the 35-year old oil-fired Richmond 9 Unit, which was addressed in PECO's last rate proceeding, produce a 1985 reserve margin of 24%. The addition of Limerick 1 (1055 MW) in 1986, and the economic retirement of various combustion turbines totaling 458 MW, and Southwark 1 and 2 (338 MW) produce a 1986 reserve margin of 28%. Without Limerick 1, the 1986 reserve margin would be 10%.

In late 1988, the 35 year old Delaware 7 and 8 steam station (253 MW) and 50 year old Schuylkill 3 unit (12 MW) are planned for retirement. These

are economic retirements at the end of the units' useful lives. The anticipated system reserve will drop to 22% in 1989.

In the 1990-99 period, following the operation of Limerick 2 in 1990, 479 MW of dispersed combustion turbines and 325 MW of centrally-located, higher efficiency combustion turbines will reach the end of their expected lives. We expect to either life-extend or replace in kind this capacity to retain quick-start dispersed generation and localized capacity with cycling capability. The coal burning units of Eddystone 1 and 2 and Cromby 1 will have their lives extended from 35 years to 50 years. During this period, the Schuylkill 1 (166 MW) and Cromby 2 (201 MW) oil burning units will reach the end of their expected lives and be retired.

Q. Please explain how the retirements of Southwark 1 and 2 and 458 MW of combustion turbines, and the addition of Limerick 1 will affect the PECO mix of generating units.

A. The Company currently has too little base load capacity and too much peaking capacity. The retirement of Southwark 1 and 2 and the 458 MW of combustion turbines, and the addition of Limerick 1, will permit the Company to improve this currently suboptimal generating mix.

As explained previously, to provide economic service, an electric utility must have an appropriate mix of base generation, intermediate generation and peaking generation. The minimum base generation which is typically required is the amount necessary to supply the minimum continuous load. For PECO, the minimum load consists of the minimum system load equal to 35% of peak load plus the pumping load of the Muddy Run pumped hydro units equal to 15% of peak load. Altogether, the minimum PECO

continuous load is equal to about 50% of peak load. Based on an average 65% availability factor for base load units and a 25% reserve requirement, a nominal level of about 60% of PECO capacity should be base type units. This is shown in the following equation:

$$\% \text{ Base Capacity} = \frac{(\text{Min. load} = 0.5 \text{ peak load})\,(100)}{(\text{base cap. avail. factor} = 0.65)\,(\text{total capacity} = 1.25 \text{ peak load})} = 61.5\%$$

Schedule 8 compares the PECO 1986 capacity and energy projections with and without the addition of Limerick 1 and the scheduled retirements of generating units. As shown, in 1986, without the addition of Limerick 1 and scheduled retirements, PECO's generation mix would have only 43.5% of its capacity in the base category.

In 1986, PECO's forecasted peak load is 6160 MW. Allowing 25% for reserve, the capacity required is 7700 MW; 61.5% of this capacity is 4737 MW. PECO's base load units (coal and nuclear) with Limerick 1 are as follows:

Peach Bottom 2 & 3	-	886 MW
Salem 1 & 2	-	930 MW
Keystone 1 & 2	-	357 MW
Conemaugh 1 & 2	-	352 MW
Eddystone 1 & 2	-	635 MW
Cromby 1	-	144 MW
Limerick 1	-	1055 MW
		4359 MW

Thus, prior to the addition of Limerick 1, PECO has but 3304 MW of base load capacity, or 1433 MW less than the optimal level. With Limerick 1, the base load capacity will equal 55.5%, which brings the Company's base capacity within a more reasonable range.

PECO has been forced to supply a large part of its energy requirements by large purchases from other companies and by use of its oil-fired generation. Specifically, for over the past five years, PECO has had to supply about 50% of its total energy requirements from either imports or oil-fired generating units. Fortunately, in the short-term, other PJM companies have had sufficient base load energy to sell to PECO, but this cannot be expected to continue indefinitely and certainly does not provide a reasonable basis for future generation planning, particularly given the large number of planned PJM units which have been cancelled in recent years and the increased load growth projections of a number of PJM companies.

The use of oil is no longer an appropriate fuel for providing a major share of electric energy. The unnecessary use of oil is certainly against national interests.

The addition of Salem 2 energy (1985) and the completion of improvements on other PECO base load plants is expected to increase PECO base load generation over that available in recent years. However, without Limerick 1, PECO in 1986 would still have to supply over 35% of its energy requirements from oil-fired units and imports. With the addition of Limerick 1, the PECO dependency on oil-fired generation and imports will be cut in half to 17% (Schedule 8).

Similarly, the Company currently has too much peaking capacity. Without the retirements of the non-reheat oil steam units and the 458 MW of combustion turbines, 32.8% of capacity would be in the peaking category. In the summer peak load season, a period of low river flow, the hydro generation is also peaking, and the percent peaking would be about 40%.

The retirements of the non-reheat oil steam units and the 458 MW of CTs will bring the peaking capacity down to a more reasonable range of 21.6% of total capacity.

Q. Are there other reasons supporting the Company's decision to retire Southwark 1 and 2 and 458 MW of combustion turbines in 1985?

A. Yes. The Southwark units and the CTs are inefficient, high-operating cost, oil-fired units, which operate at very low capacity factors. For example, for the last three years (1982-84), the average annual capacity factors were less than 4% for the Southwark units and less than 2% for the 458 MW of CTs. Thus, while this peaking capacity is technically "available capacity," it is so uneconomic as to preclude its operation to any significant extent.

With respect to Southwark 1 and 2, these units are a pre-World War II design, are inefficient, non-reheat, oil-fired units, and will be about 38-years old when retired in 1985. Large capital expenditures, estimated to be about $85 million, would be required to extend the life of the Southwark units. The high operating cost, low efficiency and advanced age of these units do not justify this investment. In addition, the retirement of the Southwark units will save an estimated O&M expense of $6 million per year.

The 458 MW of combustion turbines were installed during 1970 and 1971 as a short lead time stop gap solution to relieve severe capacity shortages being experienced by PECO in the early 1970s. These PECO capacity shortages, along with similar shortages for other PJM members, were causing frequent operating emergencies, including load shedding by voltage reduction and other means. While not the most economic choice, combustion turbines were the only type of units which could be rapidly

installed to relieve the capacity emergency until economic base load steam units could be brought into service. These combustion turbines were never intended as a long-term solution to PECO's generating capacity requirements. With the completion of Limerick 1, these units can now be retired. In addition, the retirement of these CTs will produce annual savings in operating costs of $3.2 million.

Q. Mr. Rush, has the Company performed any studies confirming on a revenue requirements basis that Southwark 1 and 2, Richmond 9 and the miscellaneous CTs should be retired?

A. Yes. Since 1980, the Company has performed such studies to determine the most economic retirement date for these generating facilities. These analyses have consistently demonstrated that Southwark 1 and 2, Richmond 9 and the CTs should be retired at or shortly after the in-service date of Limerick 1. The Company's current retirement analysis shows that economic savings will be achieved immediately upon retirement of the facilities, and that these savings will continue beyond their anticipated lives. The current analysis reaches this conclusion despite the fact that it contains two conservative assumptions. First, and solely as a conservatism, the analysis assumes that Limerick 2 will not be built. PECO strongly supports continued construction of this unit and believes that it will be completed. Second, the present study assumes that Southwark 1 and 2, Richmond 9 and the CTs can continue to operate without any expenditures for capital improvements. However, this is extremely unlikely given the age and condition of these facilities. Thus, even with these conservative assumptions, the economic benefit of retiring these facilities is apparent.

1976-1982 CAPACITY PLANNING STUDIES

Q. What types of generation studies are done?

A. Initial studies concentrate on multiple sites and fuel types. Once a project is underway, other studies are done to assist in the review of the initial decision.

Q. Please describe the nature of the 1976 to 1981 planning studies of Limerick.

A. Schedule 9 lists the planning studies done during this time frame by the System Planning Division. These studies compare Limerick to fossil alternatives on an incremental revenue requirements basis. Generally, a levelized carrying charge rate was applied to capital cost estimates for Limerick and other base load alternatives to obtain the annual revenue requirements for each alternative. To this cost was added an estimate of annual expenses for fuel, operation and maintenance. Annual fuel costs were derived by using the expected heat rate, or efficiency, of the alternative to supply the energy requirements. In addition to the studies listed on Schedule 9, in 1979 the System Planning Division and other Company Divisions prepared a computerized revenue requirements analysis comparing Limerick to various alternatives.

Q. What was the source of the data?

A. Various sources were used. The Limerick capital costs generally used as their basis the most recent estimates of the project. Fossil plant capital costs generally were derived from generic estimates either from published data or from sources within the Company. Fuel costs were typically derived from the same sources.

Q. What were the conclusions of these studies?

A. The conclusions were that the Limerick project continued to be the economic choice for base load capacity. The results of these studies were discussed with PECO management.

GENERATING UNIT RETIREMENT DATES

Q. Are you responsible for planning the retirement of generating units?

A. Yes. The lives of all generating units are periodically reviewed. Opinions are obtained from the Mechanical Engineering Division and the Electric Production Department on the probable life of each unit. An estimate of the life of each generating unit is then agreed upon and given to the Rate Division for use in determining its depreciation life.

As explained above, the life spans recommended reflect a combination of judgment as to the physical life of the indicated generating units and of economic analyses as to when their retirement would be most economic based on expected loads and new capacity additions. To a very large extent, the life-spans recommended are identical to those accepted by the Commission at Docket R-842590. The exceptions are the reduction of the lives of the Limerick nuclear units from 40 years to 39 years to match the expected length of NRC licenses and the life extensions of the Cromby 1 and Eddystone 1 and 2 coal units and all the remaining combustion turbine units. The potential for these life extensions had been noted in the PECO testimony for Docket R-842590.

Q. Does this conclude your testimony?

A. Yes, it does.

Schedule -1

Cary H. Rush

Curriculum Vitae

Education

B.S.E.E. University of Pennsylvania, 1957
M.S.E. University of Pennsylvania, 1967

Experience (at PECO)

Chief Engineer, Research & Planning Division - Since March 1985
Engineer-in-Charge, Planning Section - 3 years
Supervising Engineer, Environmental Section and Nuclear & Environmental Section - 6 years
Senior Eng. - Long Range Generation and Transmission Branch - 1 1/2 years
Senior Eng. - Steam, Gas and Environmental Branch - 2 years
Engineer - System Planning Division - 5 1/2 years
Engineer - Apparatus and Regulator Test Branch, Research Div. - 2 years
Jr. Engineer - Research Division - 3 1/2 years
Military Leave of Absence-U.S. Navy - 3 years
Jr. Engineer-in-Training - 1 year

Testimony

Agency	Case or Docket No.	Date	Topic
FERC	EL80-30-00	Sept. 30, 1983	Economic penalties for release of water at Conowingo Dam.

Activities

Institute of Electrical and Electronics Engineers (IEEE) Power Society (1972-1973 Chairman Power System Engineering Committee, Phila. Section)

Atomic Industrial Forum (AIF) Member of Probabilistic Risk Assessment Subcommittee (1981-1982)

Electric Power Research Institute (EPRI) Member of Power System Planning & Operations Task Force (PSPO) (1984 to present)

IEEE - Member of Energy Committee (1984-1985)

IEEE - Senior Member

Tau-Beta Pi - Engineering Honor Society

Eta Kappa Nu - Electrical Engineering Honor Society

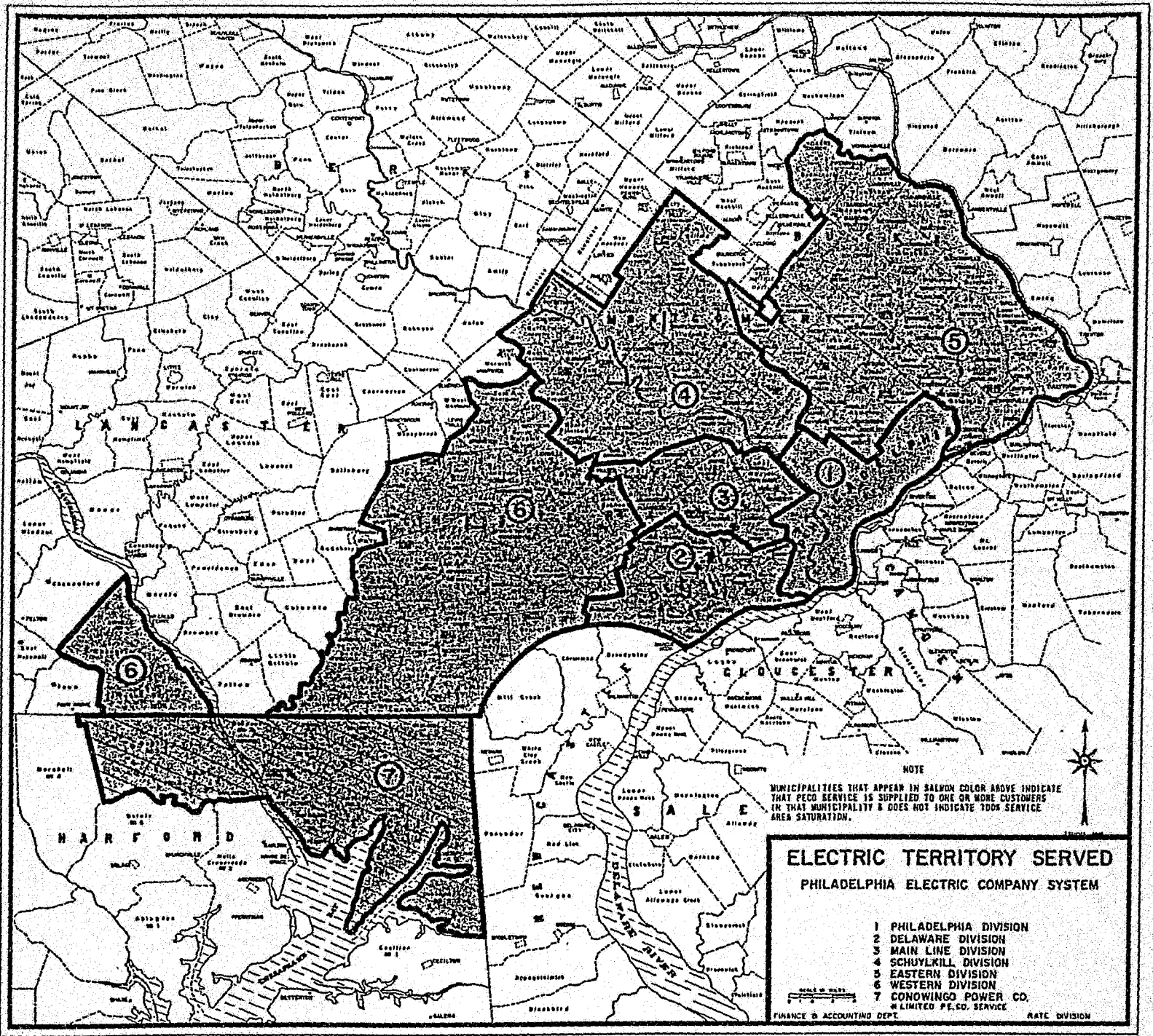
Sigma Tau - National Engineering Honor Society

SCHEDULE - 2

PHILADELPHIA ELECTRIC COMPANY

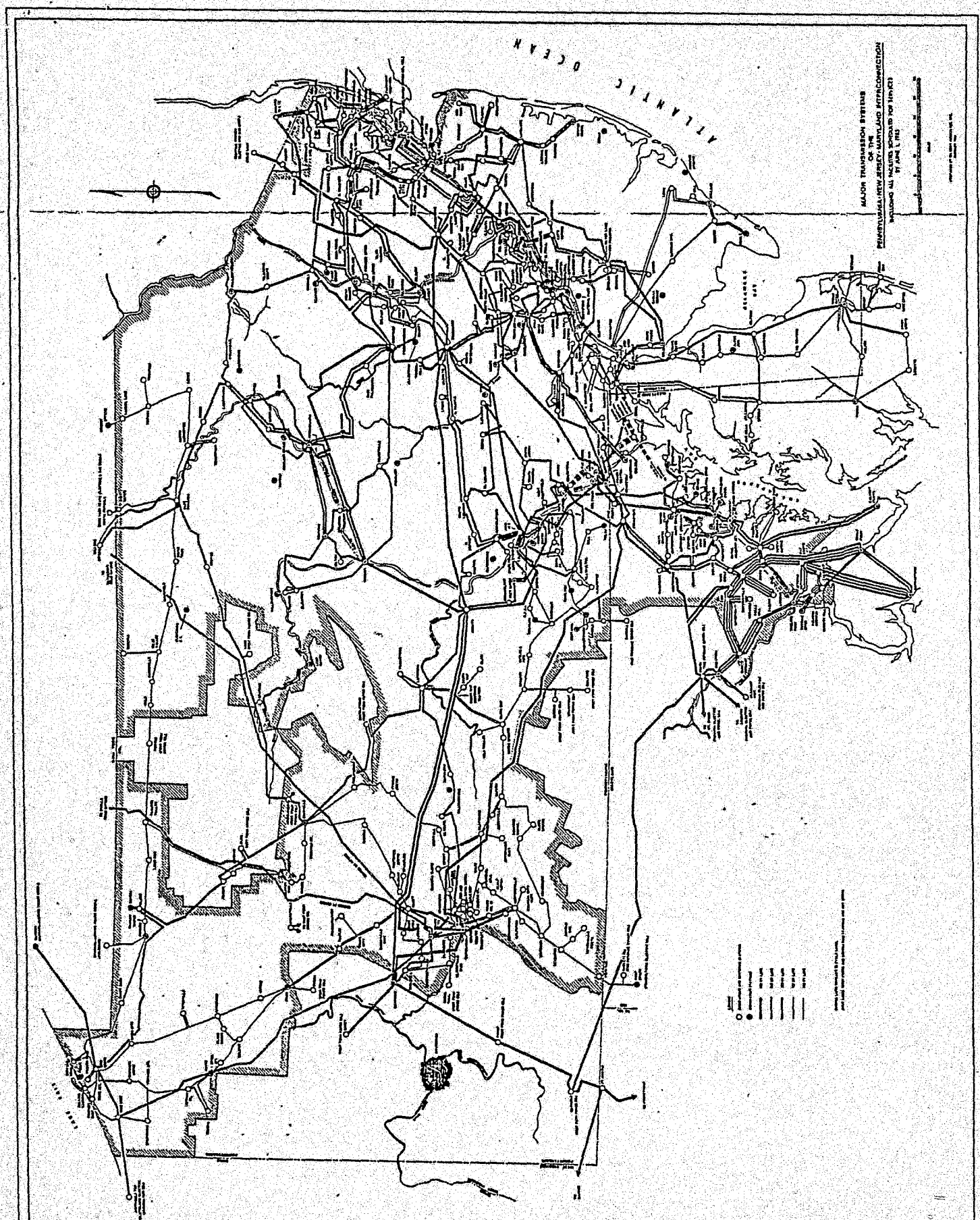
ELECTRIC OPERATIONS

SALIENT FEATURES OF THE
COMPANY'S ELECTRIC SYSTEM


BERKS
LANCASTER
CHESTER
DELAWARE
MONTGOMERY
PHILA.
GLOUCESTER
SALEM
HARFORD
1
2
3
4
5
6
7
NOTE
MUNICIPALITIES THAT APPEAR IN SALMON COLOR ABOVE INDICATE THAT PECO SERVICE IS SUPPLIED TO ONE OR MORE CUSTOMERS IN THAT MUNICIPALITY & DOES NOT INDICATE TOTAL SERVICE AREA SATURATION.
ELECTRIC TERRITORY SERVED
PHILADELPHIA ELECTRIC COMPANY SYSTEM
1 PHILADELPHIA DIVISION
2 DELAWARE DIVISION
3 MAIN LINE DIVISION
4 SCHUYLKILL DIVISION
5 EASTERN DIVISION
6 WESTERN DIVISION
7 CONOWINGO POWER CO.
* LIMITED PE.CO. SERVICE
FINANCE & ACCOUNTING DEPT.
RATE DIVISION

PHILADELPHIA ELECTRIC COMPANY - GENERATING CAPABILITY (MW)

STEAM STA.-PHILA.AREA		MAX NAME PLATE KW OF GENERATORS		WINTER RATINGS		SUMMER RATINGS	
Schuylkill	1	190,400		175		166	
	3	50,000	240,400	54	229	12	178
Eddystone	1	353,600		319		311	
	2	353,600		333		324	
	3	391,000		380		380	
	4	391,000	1,489,200	380	1,412	380	1,395
Cromby	1	187,500		147		144	
	2	230,000	417,500	211	358	201	345
Delaware	7	156,250		128		126	
	8	156,250	312,500	128	256	124	250
Richmond	9	189,750	189,750	175	175	166	166
Southwark	1	172,500		173		163	
	2	172,500	345,000	183	356	173	336
subtotal			2,994,350		2,786		2,670
STEAM STATIONS-MINE MOUTH & SHARED							
Keystone	1&2	392,932		357		357	
Conemaugh	1&2	387,878		352		352	
subtotal			780,810		709		709
NUCLEAR STATIONS							
Peach Bottom	2	489,485		449		447	
	3	489,485	978,970	439	888	439	886
Salem	1	498,303		468		459	
	2	498,303	996,606	477	945	471	930
subtotal			1,975,576		1,833		1,816
INTERNAL COMBUSTION STATIONS							
Diesels#5	Miscellaneous	13,750		13.6		13.6	
	Keystone	2,300		2.6		2.3	
	Conemaugh	2,300		2.3		2.3	
Gas Turbine	Schuylkill	39,850		38		28	
	Eddystone	79,700		76		56	
	Chester	55,800		54		39	
	Delaware	77,050		74		54	
	Richmond	729,700		742		544	
	Southwark	74,400		72		52	
	Falls	63,750		60		45	
	Moser	63,750		60		45	
	Plymouth Meeting	85,850		78		58	
	Salem	17,825		20		16	
	Croydon	546,400		437		325	
subtotal			1,852,425		1,729.2		1,280.1
HYDRO STATIONS							
Conowingo		474,480		512		410	
Muddy Run (Pump Storage)		800,000		880		880	
subtotal			1,274,480		1,392		1,290
TOTAL SYSTEM			8,877,641		8,449.2		7,765.1


ATLANTIC OCEAN
MAJOR TRANSMISSION SYSTEMS
OF THE
PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION
INCLUDING ALL FACILITIES SCHEDULED FOR SERVICE
BY JAN. 1, 1970

TEN YEAR PEAK DEMAND FORECAST

The peak demand (maximum annual MW hourly load) is derived from the energy and connected air conditioning forecast developed by the Commercial Operations Department.

Historical and projected demands, annual output (sales plus losses) and load factors are given in Exhibit 1.

Plots of summer peak demand and base (Average April and October) demands are shown in Exhibit 2. Compound annual growth rates (percent) over specified periods of years are as follows:

	Percent Compound Growth Rate		
	Demand Megawatts		Kilowatthours
	Standard Summer Peak	Base	Output
1960-68	7.5		6.3
1968-73	4.8	4.1	4.9
1973-84 (1)	0.7	0.3	0.6 (est)
1985-95 Projected	0.6	0.6	0.8

Projected growths reflect the affect of cogeneration, inflation, conservation and changing economic conditions. The 0.6% growth for PECO annual peak load is less than the 2.9%(2) generally predicted for U.S. utilities overall.

Winter peak loads are not expected to exceed the previous summer peak within the next 20 year period. Following is a comparison of this year's forecast with last year's, a description of the method used in its preparation and the 20 year maximum, minimum and probable forecast.

(1) Actual growth rate 1982-1984 = 4%/year

(2) Electrical World, September 1984

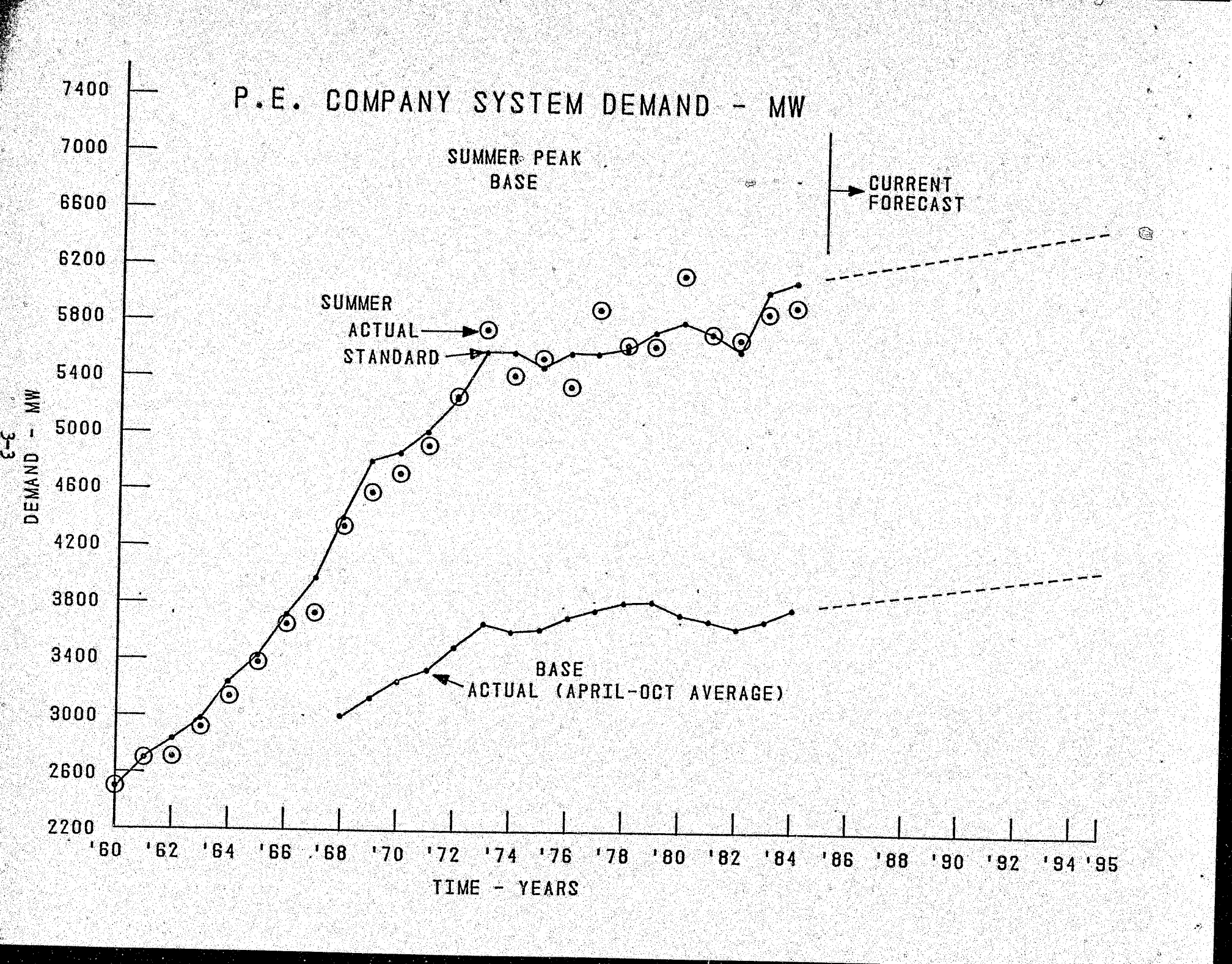
PHILADELPHIA ELECTRIC CO. SYSTEM

	Standard Demand-MW	Annual Output-GWH (1)	Annual Load Factor
1968	4460	22109	56.4
1969	4820	23469	55.6
1970	4910	24441	56.8
1971	5040	25045	56.7
1972	5340	26351	56.2
1973	5630	28095	57.0
1974	5620	27408	55.7
1975	5530	27243	56.2
1976	5650	28437	57.3
1977	5580	28845	59.0
1978	5630	29487	59.8
1979	5740	29595	58.9
1980	5810	29726	58.2
1981	5730	29035	57.8
1982	5610	28330	57.6
1983	6030	29584	56.0
1984	6100 (est.)	30000 (est.)	56.1 (est.)

FORECAST DATA

1985	6140	30369	56.5
1986	6160	30304	56.2
1987	6180	30177	55.7
1988	6200	30518	56.2
1989	6220	30841	56.6
1990	6240	31143	57.0
1991	6260	31497	57.4
1992	6320	31857	57.3
1993	6380	32228	57.7
1994	6440	32619	57.8
1995	6500	33023	58.0

(1) Actual output 1968 through 1983.
Estimated sales plus 7.5% for losses 1984-1995.
Output values do not include Salem sales which started in 1981.


P.E. COMPANY SYSTEM DEMAND - MW
SUMMER PEAK
BASE
CURRENT
FORECAST
SUMMER
ACTUAL
STANDARD
BASE
ACTUAL (APRIL-OCT AVERAGE)
DEMAND - MW
7400
7000
6600
6200
5800
5400
5000
4600
4200
3800
3400
3000
2600
2200
'60 '62 '64 '66 '68 '70 '72 '74 '76 '78 '80 '82 '84 '86 '88 '90 '92 '94 '95
TIME - YEARS

COMPARISON WITH PREVIOUS FORECAST

PHILADELPHIA ELECTRIC CO. ANNUAL DEMAND FORECAST - MW

	Estimate Prepared January 1984			Estimate Prepared October 1984			Difference Oct.-Jan.		
	Peak	Base	WS	Peak	Base	WS	Peak	Base	WS
1984	6100*	3700	2400						
1985	5930	3760	2170	6140	3829	2311	210	69	141
1986	5960	3780	2180	6160	3821	2339	200	41	159
1987	5990	3810	2180	6180	3781	2399	190	-29	219
1988	6020	3830	2190	6200	3822	2378	180	-8	188
1989	6050	3840	2210	6220	3837	2383	170	-3	173
1990	6080	3850	3850	6240	3876	2364	160	26	134
1991	6110	3890	2220	6260	3919	2341	150	29	121
1992	6150	3920	2230	6320	3965	2355	170	45	125
1993	6190	3960	2230	6380	3983	2397	190	23	167
1994	6230	3990	2240	6440	4032	2408	210	43	167
1995				6500	4081	2419			

* Weather adjusted peak demand. Actual peak was 5925 MW.

WS Weather Sensitive Demand

DESCRIPTION OF DAILY WEATHER FACTOR (DWF) FORMULA

Prior to estimating future peak loads, it is necessary to adjust actual historical peak loads to a standard weather condition. This aids in determining what actual growths have been and in checking if the growth pattern of future estimates is reasonable.

Analyses to date indicate that the weather variable most highly correlated with daily peak demands consists of 29 hours of weighted dry bulb temperatures and one hour of weighted wet bulb temperature. The formula for this weather variable referred to as DWF (daily weather factor) follows:

$$DWF = \left[\frac{1}{29} \sum_{n=1}^{29} T_{(n)\,DB} \; \frac{n+27}{56} \right] + 0.5 \; T_{(29)\,WB}$$

$T_{(29)\,DB}$ = Dry Bulb Temp. @ hour of peak weather

$T_{(1)\,DB}$ = Dry Bulb Temp. 28 hours prior

$T_{(29)\,WB}$ = Wet Bulb Temp. @ hour of peak weather

Daily peaks have a high correlation with this DWF. Generally, during hot weather, the higher the DWF, the higher will be the daily peak load.

USE OF DAILY WEATHER FACTOR (DWF) FORMULA IN ANALYZING HISTORICAL PEAKS

Exhibit A is a plot of peak load vs. daily weather factor for all weekdays, excluding holidays, of April through October 1984. Examination of similar plots for past years indicated a constant demand value for daily weather factors between 64 and 77 and a uniformly rising trend for all daily weather factors above 86. The sloping line of Exhibit A is the linear regression for all points above 86 DWF. A vertical dashed line is drawn at the most probable peak weather value (standard weather) as determined from analysis of past weather records. The intersection of the sloping line and the vertical dashed line is defined as the regression demand. The most probable peak demand (standard demand) for a year has been determined to be a value slightly above the regression demand. Data for calculating standard weather is given in Exhibit B.

Exhibit C is a tabulation of the historical relationships between the regression demands and actual peak demands. The next to the last column shows the difference in percent between the actual peak demand that occurred in each year and the regression demand at standard weather. The "running average" difference is given in the last column. The standard demand for a year is determined by increasing the regression demand by the standard demand (running average) factor.

The inter-relationships of the above discussed factors are shown in Exhibit D. The solid sloping line is the linear regression line for 1984. Its intersection with the standard weather line gives a regression demand of 5885 MW. The standard demand for 1984 is 3.6% above this, or 6097 MW. The actual peak demand for 1984 was 5925 MW.

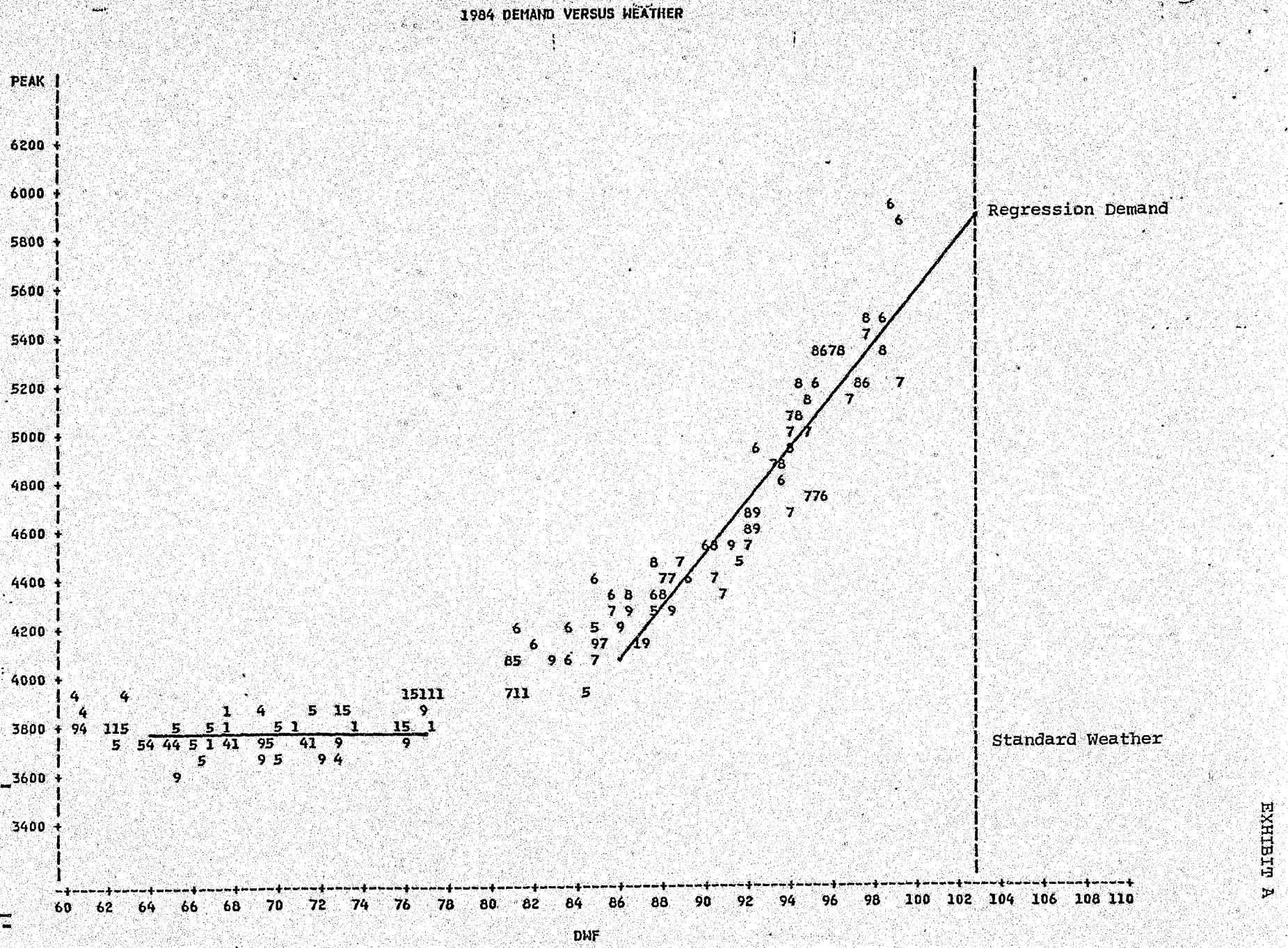

1984 DEMAND VERSUS WEATHER
PEAK
6200
6000
5800
5600
5400
5200
5000
4800
4600
4400
4200
4000
3800
3600
3400
60 62 64 66 68 70 72 74 76 78 80 82 84 86 88 90 92 94 96 98 100 102 104 106 108 110
DWF
Regression Demand
Standard Weather

EXHIBIT A

MAXIMUM DWF BETWEEN 10 AM AND TIME OF PEAK DEMAND

	DWF	Date	Standard Weather (Running Average)
1968	102.7	7/18	
1969	104.0	7/17	
1970	102.8	9/23	
1971	100.7	7/1	
1972	104.3	7/20	
1973	104.7	8/30	
1974	101.6	7/9	
1975	104.5	8/4	
1976	96.9	6/28	
1977	106.3	7/21	
1978	101.6	8/17	102.7
1979	101.7	8/1	102.7
1980	105.4	7/21	102.9
1981	104.3	7/9	103.0
1982	103.4	7/19	103.0
1983	100.4	9/6	102.8
1984	98.7	6/13	102.6

NOTE: 102.7 has been established as the standard weather to be used for forecasting purposes.

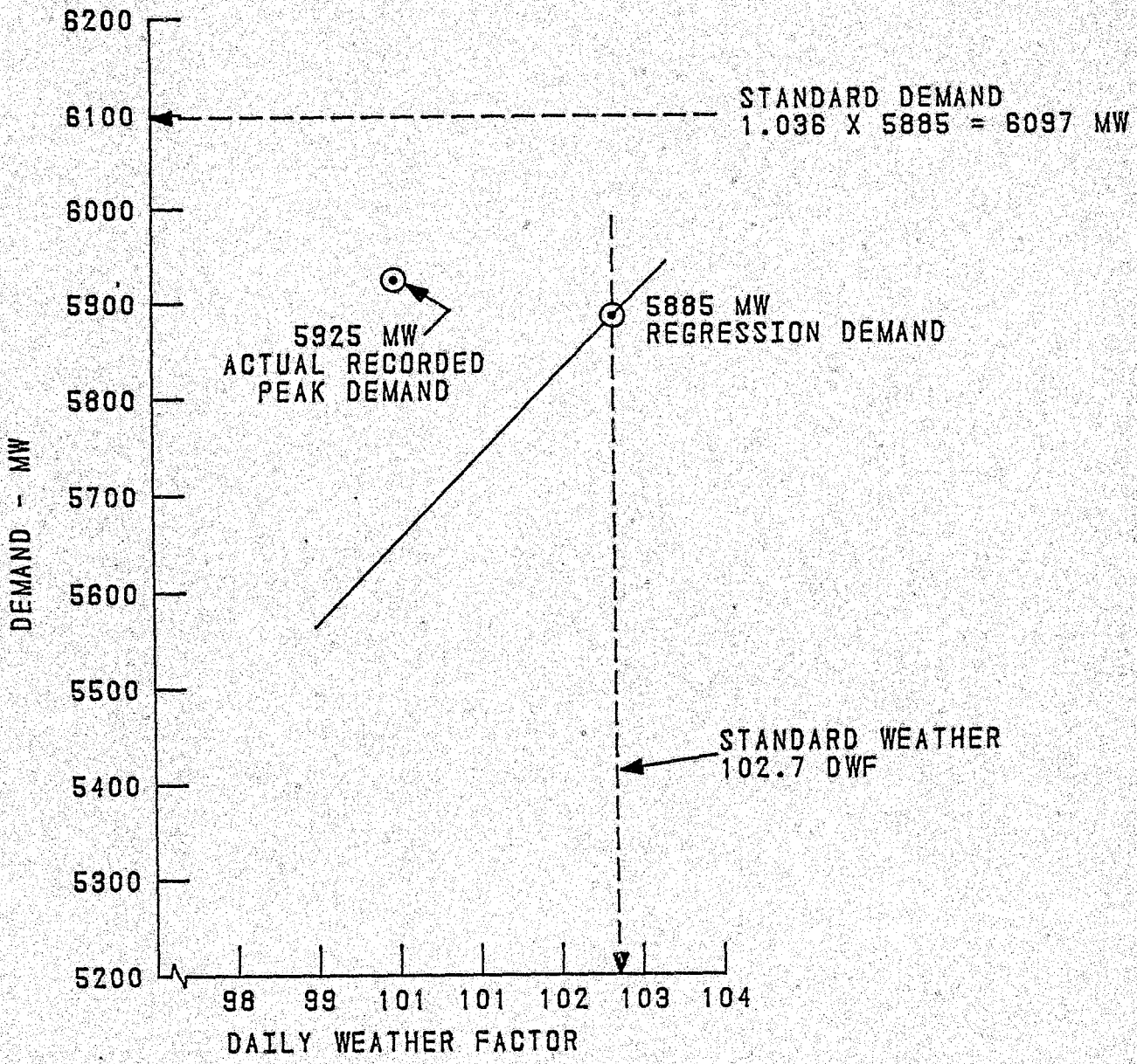
STANDARD DEMAND FACTOR

	Regression Demand @ 102.7 DWF	Net Actual Peak Demand	Corrected Peak Demand	Corrected Demand ÷ Demand @ 102.7 DWF	Standard Demand Factor (Running) (Average)
1968	4316	4375	(4445)	1.030	
1969	4661	4592	(4746)	1.018	
1970	4750	4712	(4954)	1.043	
1971	4878	4922	(5034)	1.032	
1972	5162	5313	5313	1.029	
1973	5448	5760	5760	1.057	
1974	5434	5431	(5492)	1.011	
1975	5344	5530	(5545)	1.038	
1976	5462	5346	5346	.979	
1977	5397	5888	5888	1.091	
1978	5445	5667	5667	1.041	1.034
1979	5562	5641	5641	1.014	1.032
1980	5598	6095	(6145)	1.098	1.037
1981	5522	5731	5731	1.038	1.037
1982	5407	5691	5691	1.053	1.038
1983	5821	5879	5879	1.010	1.036
1984	5885	5925	5925	1.007	1.034*

( ) Corrected for voltage reduction and load curtailment.

NOTE: Latest Running average standard Demand Factor used for determining current year's standard demand and for forecasting future demands.

* Because of unresolved meter error during summer regression period, it was decided to retain 1.036 as the standard demand factor for this forecast.


6200
6100
6000
5900
5800
5700
5600
5500
5400
5300
5200
DEMAND - MW
STANDARD DEMAND
1.036 X 5885 = 6097 MW
5925 MW
ACTUAL RECORDED
PEAK DEMAND
5885 MW
REGRESSION DEMAND
STANDARD WEATHER
102.7 DWF
98
99
101
101
102
103
104
DAILY WEATHER FACTOR

USE OF DWF APPROACH IN ESTIMATING FUTURE PEAKS

The demand weather characteristic line for 1983 (Exhibit E) illustrates the foundation for the development of the demand forecast procedure. The horizontal segment is defined as base demand. The sloping segment is a function of weather sensitive demand. Coincident weather sensitive demand is derived by subtracting base demand from the regression demand.

The base demand as defined above has been found to have a high correlation with the average April and October output.

The coincident weather sensitive demand has been found to have reasonably good correlation with the estimates of actual MW's of connected air conditioning.

Exhibit F is a tabulation of historical average total monthly outputs of April and October. Also shown in Exhibit F in the last column is a historical tabulation of the ratio of base demand to base output. These historical ratios and extrapolation into the future are plotted in Exhibit G. A flat projection is used because of economic uncertainties. The extrapolated base demand factors are applied to the forecast of base output to compute the base demand forecast. The base output forecasts do not include any off-peak sales which result from new, non-typical loads such as off-peak electric car charging.

Exhibit H shows how the coincident weather sensitive demand as developed for the years 1968 through 1984. The last column shows estimates of connected air conditioning load for all years. These estimates of connected load are year-end values and are obtained from the Commercial Operations Department.

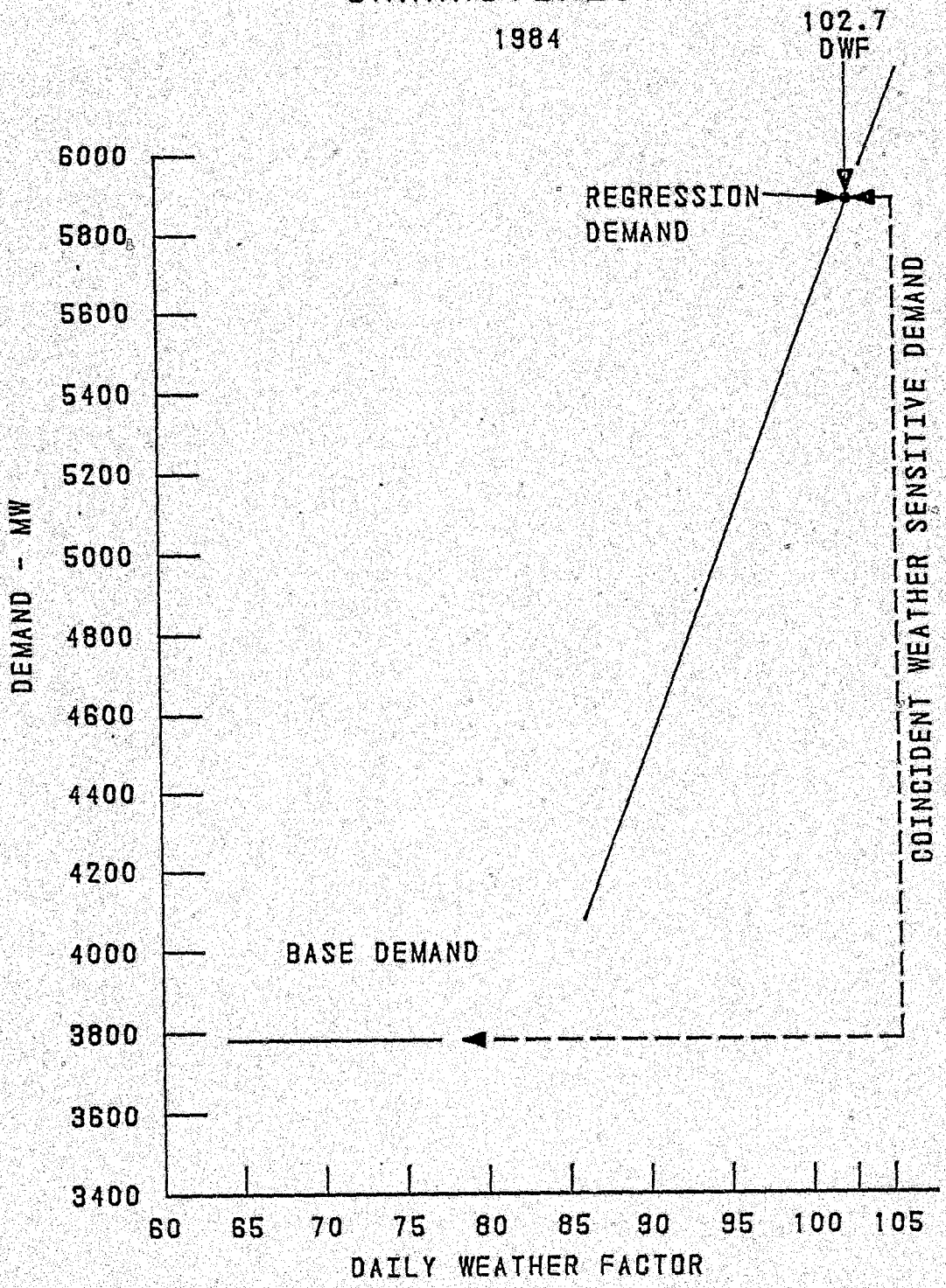
Exhibit I is a plot of a multiplier showing the relationship between coincident weather sensitive demand and connected air conditioning load for the years 1968-1984. The multiplier is determined by dividing the coincident weather sensitive demand by the connected air conditioning each year. During the 1969-78 period this multiplier has decreased and then shown a tendency to increase from 1978 to 1984. For forecast purposes the current value of .478 was used throughout.

This multiplier is applied to the forecast of connected air conditioning load to compute the coincident weather sensitive demand forecast.

The sum of the base demand and coincident weather sensitive demand produced a forecast of the regression demand (value of demand on the regression line at standard weather). As noted earlier, the regression demand must be increased by 3.6% (Standard Demand Factor) to obtain a forecast of most probable (standard) demand.

DEMAND - WEATHER CHARACTERISTIC

1984



PHILADELPHIA ELECTRIC COMPANY SYSTEM

ACTUAL AVERAGE OF APRIL AND OCTOBER OUTPUT

	Base Output-GWH	Base Demand-MW	Demand / Output
1968	1734.2	2998	1.729
1969	1840.1	3142	1.708
1970	1906.3	3255	1.707
1971	1938.5	3326	1.716
1972	2059.6	3493	1.696
1973	2168.8	3668	1.691
1974	2138.4	3612	1.689
1975	2126.7	3632	1.708
1976	2209.9	3723	1.685
1977	2196.2	3763	1.713
1978	2246.2	3813	1.698
1979	2311.5	3830	1.657
1980	2246.0	3739	1.665
1981	2210.2	3696	1.672
1982	2190.0	3644	1.664
1983	2242.0	3697	1.649
1984	2290.0 (est.)	3781 (est.)	1.651

BASE DEMAND FACTOR

BASE DEMAND = BASE DEMAND FACTOR x MONTHLY OUTPUT
MW GWHR

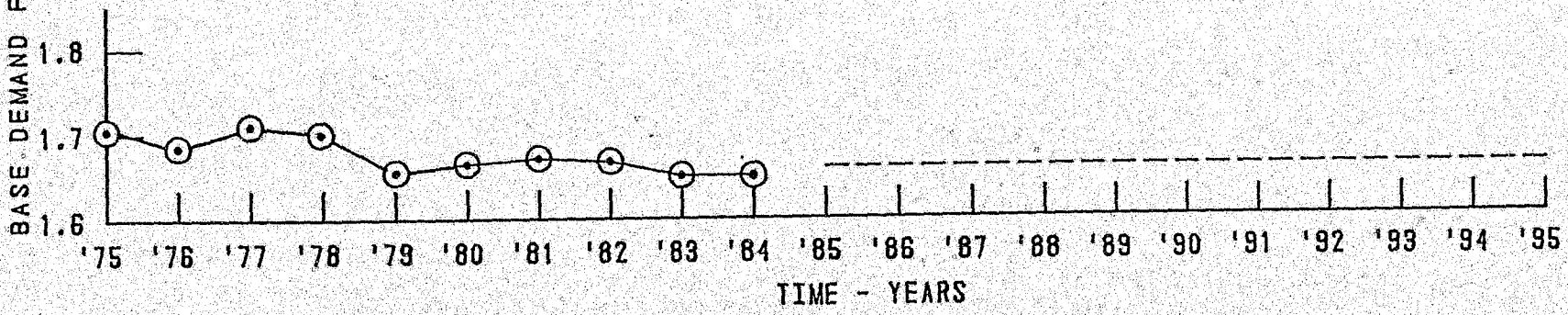


EXHIBIT G

WEATHER SENSITIVE DEMAND - MW

	Regression Demand	- Base Demand	= Coincident Weather Sensitive Demand	Connected Air Cond.	Multiplier
1968	4316	2998	1318	2470	.534
1969	4661	3142	1519	2755	.551
1970	4750	3255	1495	3041	.492
1971	4878	3326	1552	3298	.471
1972	5162	3493	1669	3524	.474
1973	5448	3668	1780	3758	.473
1974	5434	3612	1822	3966	.459
1975	5344	3632	1712	4050	.428
1976	5462	3723	1738	4085	.426
1977	5397	3763	1634	4124	.395
1978	5445	3813	1632	4200	.388
1979	5562	3830	1732	4289	.405
1980	5598	3739	1859	4352	.429
1981	5522	3696	1826	4387	.416
1982	5407	3644	1763	4351	.405
1983	5821	3697	2124	4400	.483
1984	5885	3781 (est.)	2104	4393	.478

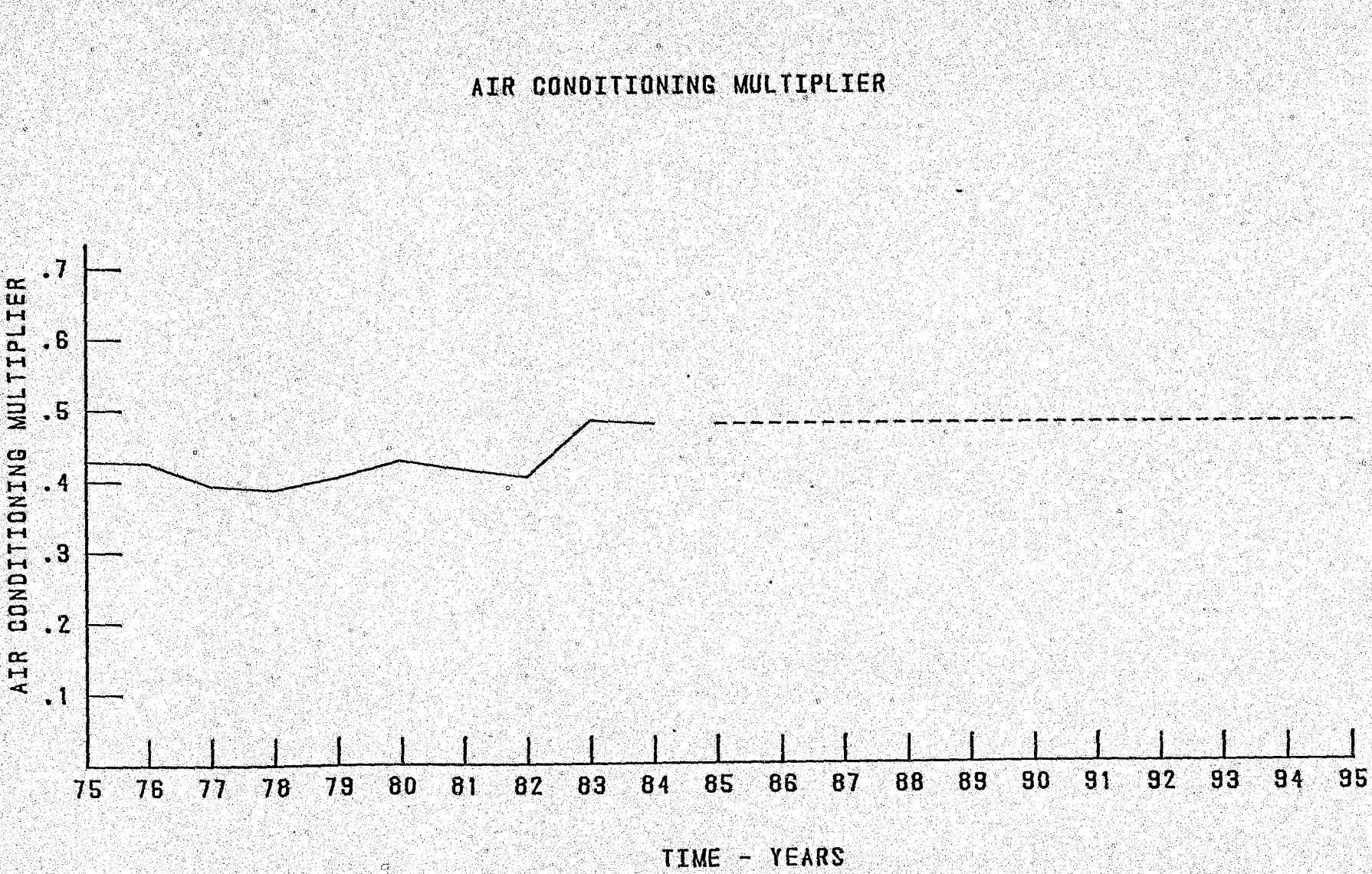

AIR CONDITIONING MULTIPLIER
AIR CONDITIONING MULTIPLIER
.7
.6
.5
.4
.3
.2
.1
75 76 77 78 79 80 81 82 83 84 85 86 87 88 89 90 91 92 93 94 95
TIME - YEARS

EXHIBIT I

SAMPLE CALCULATION OF 1985 PEAK DEMAND FORECAST

Base Demand

Base Monthly Output	2307 GWHRS
Base Demand Factor	x 1.66
Base Demand	3829 MW

Coincident Weather Sensitive Demand

Connected Air Conditioning Load	= 4381 MW
Coincident Weather Sensitive Demand obtained from Exhibit I (.478 x 4381)	= 2094 MW

Base Demand + Weather Sensitive Demand = Regression Demand

3829 + 2094 = 5923 MW

Regression Demand x Standard Demand Factor = Standard Demand

5923 x 1.036 = 6136 MW

6140 MW (rounded)

MAXIMUM, MINIMUM AND PROBABLE TWENTY YEAR DEMAND FORECAST

The twenty year probable forecast in Exhibit J was computed using the same procedure as described for the ten year forecast.

The maximum and minimum demand forecasts were computed by observing the ratios of maximum and minimum annual energy forecasts to the probable annual energy forecast and applying these ratios to the probable demand forecast.

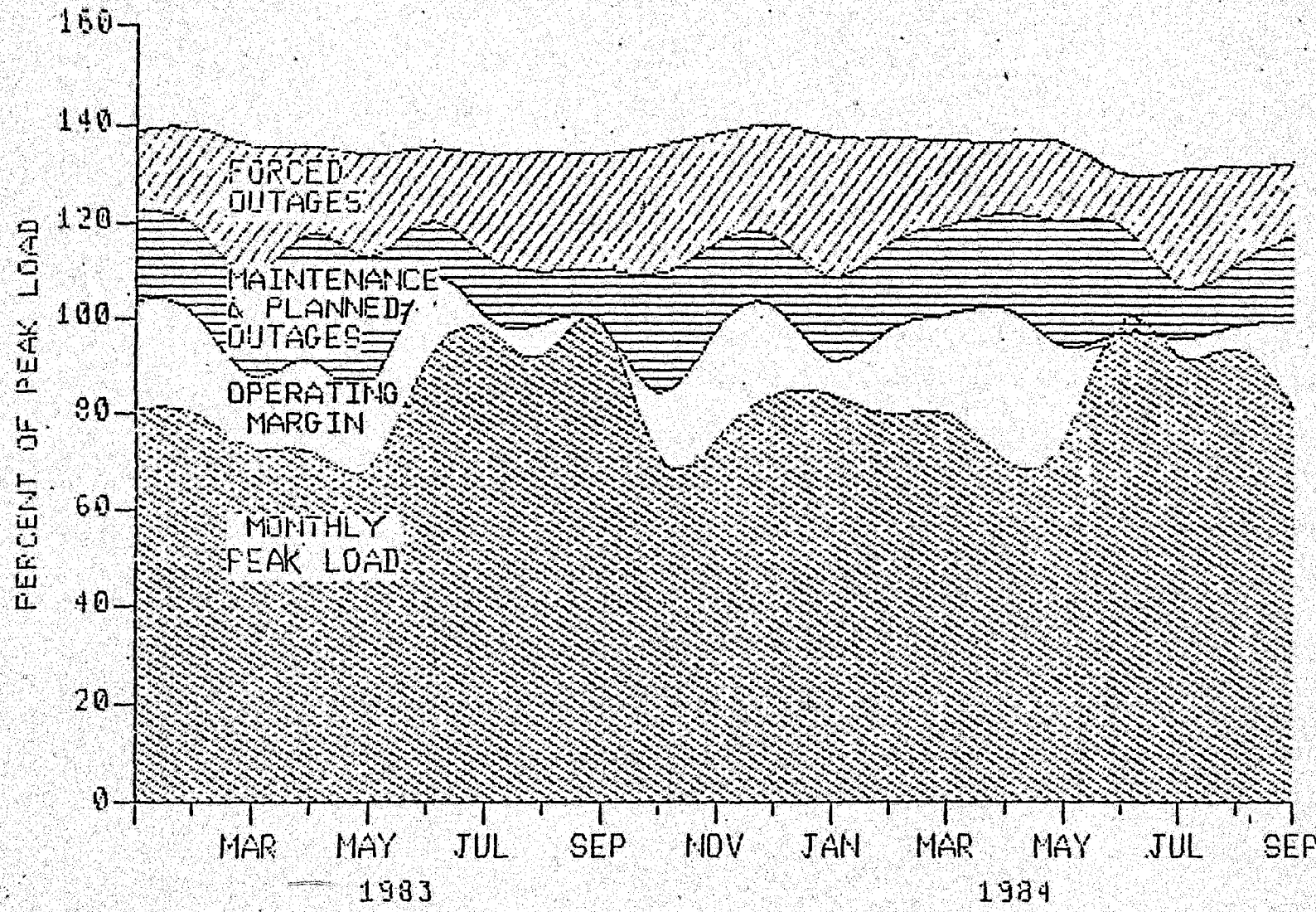
The twenty year projections are more approximate than the ten year and are presented merely to indicate present thinking as to the range in load demand that could occur in the nineteen nineties.

PHILADELPHIA ELECTRIC COMPANY SYSTEM
ANNUAL PEAK DEMAND
20 YEAR FORECAST - MW

	Probable	Maximum	Minimum
1985	6140	6310	5970
1986	6160	6450	5910
1987	6180	6590	5850
1988	6200	6730	5790
1989	6220	6870	5730
1990	6240	7010	5670
1991	6260	7150	5610
1992	6320	7330	5580
1993	6380	7510	5550
1994	6440	7690	5520
1995	6500	7870	5490
1996	6560	8050	5460
1997	6620	8230	5430
1998	6700	8440	5430
1999	6780	8650	5430
2000	6860	8860	5430
2001	6940	9070	5430
2002	7020	9280	5430
2003	7100	9490	5430
2004	7180	9700	5430

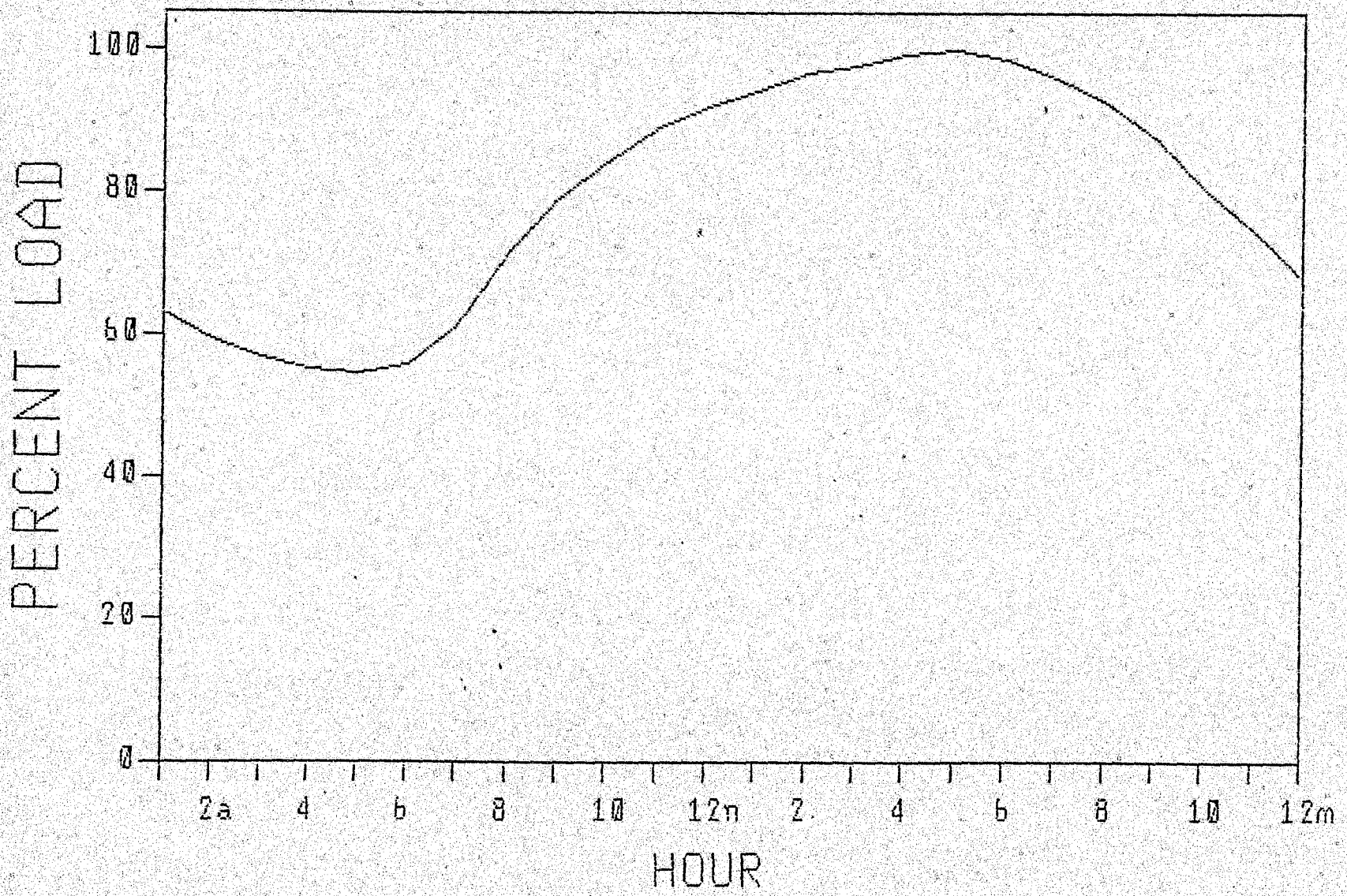
1983-84 MONTHLY PJM CAPACITY PROFILE

Total Capacity = System Capacity - Misc. Capacity



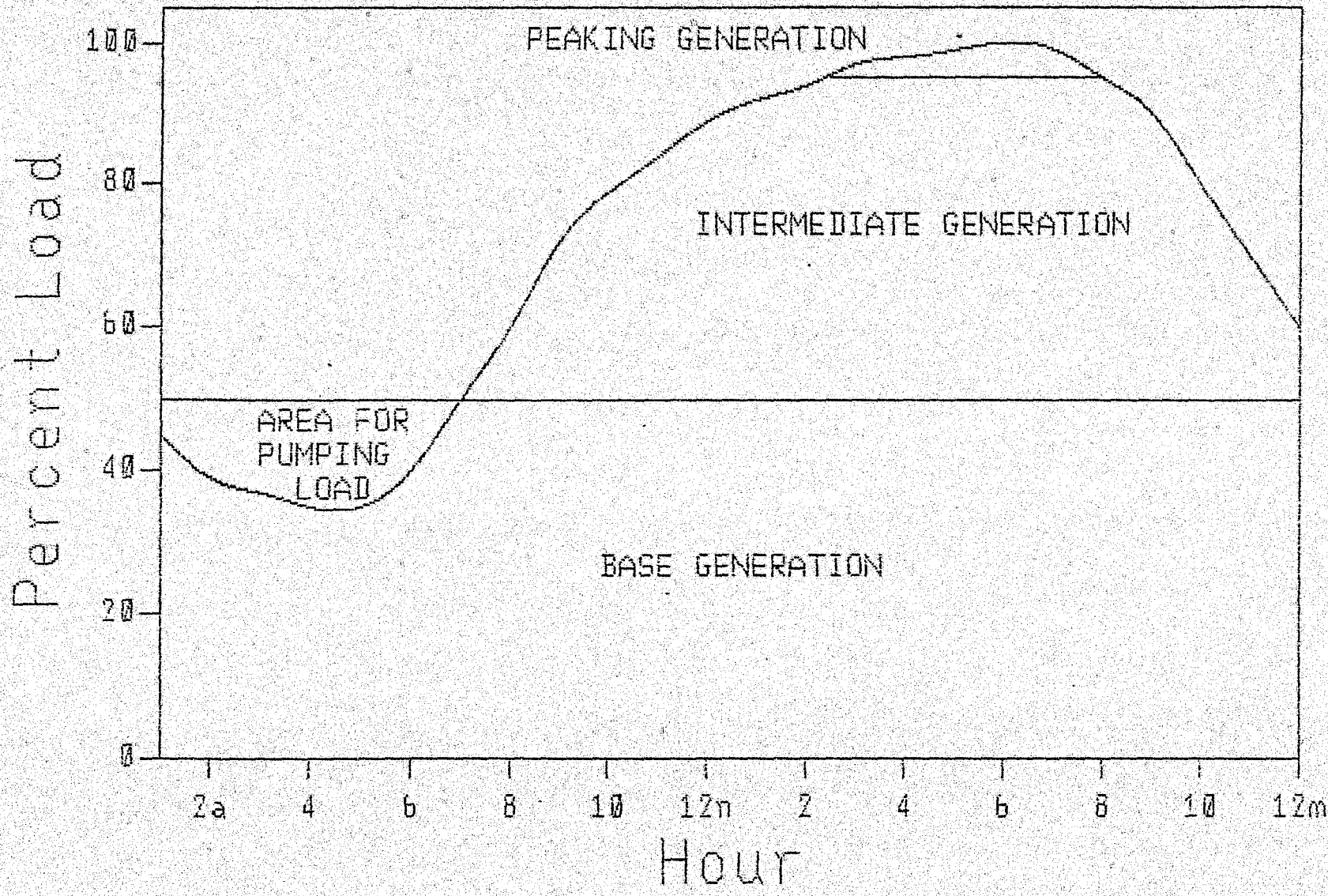
SCHEDULE - 4

PECO - DAILY LOAD CYCLE



SCHEDULE - 5

PECO Composite Daily Load Cycle With Generation Type



SCHEDULE - 6

SCHEDULE - 7

PECO LOAD & CAPACITY PROGRAM

LIMERICK 2 (7-90)

1984-1994 (Year ending June 1)

YEAR	MW	DATE	CHANGES	REASON	CAPACITY	LOAD	PERCENT RESERVE	MW EXCESS OR DEFICIT OVER 25%
1984					7282	6100	19	-343
	12	9-84	Eddy. 1	Rerate				
	471	1-85	Salem 2	End of Sale to GPU				
1985	-166	5-85	Retire Richmond 9	Econ Retirement	7599	6140	24	-76
	-338	12-85	Retire Swk. 1,2&D	Econ Ret. 38 Yr				
	1055	2-86	Limerick 1	Service Date				
1986	-458	4-86	Retire Misc CT's	Econ Retirement	7858	6160	28	158
1987					7858	6180	27	133
1988					7858	6200	27	108
	-253	12-88	Retire Del. 7,8&D	End of 35 Yr Life				
1989	-12	12-88	Retire Sch. 3	End of 50 Yr Life	7593	6220	22	-182
1990					7593	6240	22	-207
	1055	7-90	Limerick 2	Service Date				
1991	-201	12-90	Retire Cromby 2	End of 35 Yr Life	8447	6260	35	622
1992					8447	6320	34	547
1993					8447	6380	32	472
1994	-169	12-93	Retire Sch. 1&D	End of 35 Yr Life	8278	6440	29	228

PECO 1986 Capacity & Energy Projections With and Without Limerick #1

	No Limerick #1 Unit and No 1985/86 Retirements*				Limerick #1 Unit In Service with Scheduled Retirements			
	Capacity		Energy		Capacity		Energy	
	MW	%	GWh	%	MW	%	GWh	%
IMPORTS	-	-	7937	26.2	-	-	3275	10.8
Peaking Units								
Non reheat oil steam	336		137	0.4	0		0	
Internal Combustion	1280		425	1.4	820		88	0.3
Pumped Hydro Gen.	880		1111	3.7	880		1147	3.8
	2496	32.8	1673	5.5	1700	21.6	1235	4.1
Pumped Hydro Load	-	-	(1620)	(5.3)	-	-	(1672)	(5.5)
Hydro**	410	5.4	1785	5.9	410	5.2	1785	5.9
Intermediate Units								
Reheat oil steam	1389	18.3	2309	7.6	1389	17.7	1873	6.2
Base Units								
Coal	1488		7709		1488		7569	
Nuclear	1816		10512		2871		16240	
	3304	43.5	18221	60.1	4359	55.5	23809	78.5
Total	7599	100	30305	100	7858	100	30305	100

* Southwark 1&2, Combustion Turbines

** The hydro (Conowingo) will vary from base to peaking depending on the time of the year. For most of the summer peak load season, the hydro will be peaking.

Schedule-9

Economic Comparisons

Date	Study Description
7-19-76	Limerick Economic Comparison 2-1055 MW Units Service Dates 1984-86
10-21-76	Limerick Economic Comparison 2-1055 MW Units Service Dates 1983-85
6-2-77	Pencil Update of 10-21-76 Comparison. Uses Peach Bottom Actual Fuel and O&M Costs
7-3-78	Fossil-Nuclear Economic Comparison 2400 MW Station 1232(C) Service Dates 1983-85 2-1200 MW Nuclear Units 3-800 MW Fossil Units
5-27-80	V.S.B. statement to U.S. House of Representative Committee of Interior & Insular Affairs
5-28-80	PECO Annual Review (Part 2) (Presentation of Limerick history costs and savings as part of a 4 part presentation to PUC)
9-5-80	Comparison of the Limerick Nuclear Station compared with other alternatives updated to September 1980
10-9-80	35 Year Life Cycle Cost Limerick 2-1055 MW Nuclear Units 1985-87 Service Dates vs. 3-703 MW Generic Coal-Fired Units 1985-86 87 Service Dates
11-17-80	Economic Comparison 1083(A) - Limerick 2-1055 BWR's vs. Generic Coal 3-703 MW With Limestone Scrubbing

Date	Study Description
1-27-81	Comparison of the Limerick Nuclear Station with other alternatives updated to January 1981
1-29-81	Limerick Briefing Book
3-9-81	Outline of Need for Limerick 4 Plans