PECO STATEMENT NO. 11B

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PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

DOCKET NO. R-850152

SUR-SURREBUTTAL TESTIMONY

OF

DR. LEWIS J. PERL

RATE TREATMENT STANDARDS, QUANTIFICATION OF DELAY DECISIONS, DISCOUNT RATE, CAPITAL CONSTRUCTION COST RISKS, ECONOMIC IMPACT OF RATE INCREASE

March 7, 1986

SUR-SURREBUTTAL TESTIMONY OF DR. LEWIS J. PERL

Q. Please state your name and business address.

A. My name is Lewis J. Perl. My business address is National Economic Research Associates, Inc., 123 Main Street, White Plains, New York.

Q. Have you testified previously in this proceeding?

A. Yes, my direct and rebuttal testimonies were PECO Statements 11 and 11A respectively.

Q. Dr. Perl what is the purpose of this sur-surrebuttal testimony?

A. I would like to respond to a limited number of issues raised in the surrebuttal testimonies of Paul Chernick, Randall Falkenberg, Stephen Feldman and Arie Schinnar. Specifically, Mr. Chernick's surrebuttal testimony contains serious misconceptions regarding the appropriate discount rate to be used in evaluating investments of regulated utilities. Mr. Chernick also presents an illogical argument regarding the implications of my delay analysis. Mr. Falkenberg's surrebuttal testimony criticizes my use of the after-tax discount rate as being disingenuous and inconsistent with positions taken elsewhere by PECO witnesses and I will respond to this criticism. Mr. Falkenberg also misinterprets my criticisms of his capital cost analysis and I will try to correct his misinterpretations. Finally, Dr. Schinnar once again, and Dr. Feldman, attempt to argue that my Lukens analysis of employment effects is supportive of their positions. I believe this comparison is invalid and misleading.

Q. Please describe your criticisms of Mr. Chernick's analysis of the appropriate discount rate for regulated utilities.

A. Mr. Chernick criticizes the use of the after-tax cost of money as the discount rate in this analysis. He argues that while this rate would be appropriate for competitive industries it is incorrect in regulated industries because in such industries consumers must not only pay interest and equity costs but taxes as well. Thus, Mr. Chernick seems to feel that the appropriate discount rate in the regulated case would be the pre-tax rather than the after-tax cost of money. Mr. Chernick is confusing the calculation of capital related revenue requirements with the calculation of the discount rate. In calculating capital related revenue requirements (the annual cost to consumers of a dollar of additional capital expenditures), all parties to this proceeding would agree that one must include taxes as well as interest and equity charges. Consequently, the annual carrying charge associated with a dollar of capital expenditures would be the pre-tax cost of money, which in this context is about twice the after-tax cost of money. But while the pre-tax cost of money is appropriate in calculating annual revenue requirements, it is not the correct concept for calculating the discount rate.

Q. Please explain why the pre-tax cost of money is appropriate in calculating annual revenue requirements, but not for calculating a discount rate.

A. As the example presented in my rebuttal testimony illustrates (PECO St. No. 11A pp. 8 through 12), when a utility defers consumer charges from one period to the next, it is effectively lending money to consumers at the after-tax cost of money, which in this case is not 20 percent but approximately 10 percent. Since a utility can effectively borrow and lend funds to defer or accelerate revenue requirements at the after-tax cost of money, this is the appropriate discount rate to be used in evaluating alternative generating options.

Q. Mr. Chernick believes that a utility's after-tax cost of money is the appropriate rate for calculating Allowance For Funds Used During Construction (AFUDC), but not for calculating the discount rate. Please comment.

A. It is interesting that Mr. Chernick recognizes that the utility's after-tax cost of money is the appropriate rate to use in calculating AFUDC, but then denies its appropriateness as a discount rate. This is obviously inconsistent. The AFUDC rate is precisely what the consumer pays to defer annual capital charges from the construction period to the operating period. This illustrates that the after-tax rate is the rate at which utilities borrow on behalf of consumers, and should be sufficient to convince Mr. Chernick that it is the appropriate discount rate for use in this analysis.

Q. In what way do you feel that Mr. Chernick has mis-characterized your delay analysis?

A. First, Mr. Chernick argues that in evaluating delay one is simply choosing between fuel savings now and fuel savings thirty years from now. In addition, he argues fuel savings now are relatively certain and fuel savings 30 years from now are highly speculative (and for many consumers irrelevant since they will not be around to enjoy such benefits). However, in characterizing the problem in this way, Mr. Chernick confuses the mathematical steps involved in calculating delay costs with the actual consequences of delay to consumers. When deciding to delay an investment decision, a consumer is choosing between getting the benefits from that investment now (and starting to pay for it now) and deferring the benefits for one or more years. If, when correctly calculated, the annual capital cost of the investment is less than the first year fuel savings the investment should be made now; if the annual capital cost exceeds the first year fuel savings the investment should be deferred. Thus, deferral decisions are not principally choices between things happening now and things happening 30 years from now, but are choices between things happening this year and next year.

The calculation of the costs and benefits of delay does involve calculating costs over a 30 year period because annual capital charges in a regulated environment are not set by the market but by accounting conventions. Consequently, one must calculate charges over the full lives of both the current and the delayed investment in order to calculate annual capital charges accurately. In 1976 and 1978, delay appeared to be economic because Limerick was not expected to be needed to meet loads in 1981-1982, and therefore its sole benefits in those years would be fuel displacement. Subsequently, the unit would not only produce larger fuel savings but would be needed to meet growing loads and, consequently, the benefits from the unit would include the avoided costs of capacity as well. Thus, the mathematical requirements of the deferral calculation should not be allowed to obscure the essence of this calculation, which is essentially the choice between the costs and benefits of having Limerick a year earlier or a year later. This calculation principally involves a comparison of values which are equally certain or speculative in both the delay and the deferral cases.

Q. Mr. Chernick uses an example involving a consumer's investment in storm windows to suggest that your delay analysis is somehow unbounded--that if one year of delay is good, two years of delay is somehow better and that there is no end to the calculation. Do you agree?

A. No. And, in fact, Mr. Chernick's example is useful for illustrating that my delay analysis is neither a highly speculative calculation nor unbounded. If, in the storm window case, the first year fuel savings from installing the storm windows exceeds the levelized annual capital cost of the storm windows, the consumer should invest now. Otherwise, he should wait until fuel costs rise sufficiently to cover levelized annual capital cost. This is neither a highly speculative calculation nor an unbounded one. But, to calculate the levelized annual cost of storm windows correctly the consumer must calculate the true first year cost of the storm windows, which involves calculating the present value of the costs of these windows over their fifteen year life. The fact that this calculation involves present values over the lives of the assets does not make the analysis of the benefits from delay (the capital savings from deferring the investment decision) any more speculative than the cost of the delay (the annual fuel savings from the storm windows). And, nothing about the calculation implies that if one year of delay is good that indefinite delay is also desirable.

Q. Please respond to Mr. Falkenberg's criticism of your use of the after-tax cost of money.

A. Mr. Falkenberg contends that in arguing for the after-tax cost of money I am taking a position which is inconsistent with that taken by other company witnesses. He argues that the use of the after-tax cost of money as a discount rate implies that the company is willing and able to undertake deferrals of revenue requirements into the future. Since various company witnesses--Mr. Farling and Mr. Wroblewski--are critical of the proposed use of sinking fund depreciation, Mr. Falkenberg argues that the Company is either unwilling or unable to make such deferrals. But this is clearly an unreasonable position on his part. The Company's own proposal calls for a substantial deferral of revenues over the first six years of Limerick's life. So, the company is clearly willing to undertake the types of deferrals which are contemplated in using the after-tax cost of money as a discount rate. And, the Company's proposal significantly mitigates the high front end cost of Limerick.

If it is true, as Mr. Farling and Mr. Wroblewski point out, that when deferral is carried beyond some limit it is likely to make investors skeptical about the ultimate recovery of their investment. Consequently, in the current institutional environment, there are practical limits to the extent of deferrals. But this should not preclude the use of the after-tax cost of money as long as the amount of deferral which is practical is sufficient to meet the interest of both consumers and investors. Since, as a practical matter, deferrals sufficient to accommodate those interests do appear to be feasible and have been proposed by PECO, the after-tax cost of money is the appropriate discount rate to use. I do not see any inconsistency between my use of this rate and the position taken by Mr. Farling and Mr. Wroblewski.

Q. Please comment on Mr. Falkenberg's response to your criticism of his capital cost estimate.

A. Mr. Falkenberg seems to have entirely misunderstood my criticism. He interprets my criticism to be of his inclusion of two highly correlated time variables (time and time squared) in his regression. My criticism is not related to the high correlation between these two variables but simply to the implausibility of projecting the time trend implied by these variables. As Mr. Falkenberg himself has pointed out under cross-examination, good statistical analysis requires the use of judgment in determining whether a function is plausible. The function he uses, which admittedly "fits" the historical data, implies an ever accelerating trend in construction costs. I do not believe that viewed from the perspective of 1978 this would represent a plausible extrapolation of past trends, and I can find no contemporary analyst who projected trends that accelerated in this fashion. In fact, most analysts, even those like Mr. Komanoff who believed that nuclear economics were unfavorable, were projecting a decelerating trend in construction costs. Consequently, even though his model fits the data, I believe it would not have been appropriate to use this model to project future nuclear capital costs during the 1978 time frame. Moreover, I surely do not think it was inappropriate for PECO to have taken a less pessimistic view of the trends.

Q. Does Mr. Falkenberg respond to your main criticism of his capital cost estimate model?

A. No. Mr. Falkenberg entirely ignores my central criticism of his model, which is his use of a time variable (commercial operation date) which is not exogenous. By using this variable he is employing biased estimates of the time effects. My rebuttal testimony showed that a more appropriate trend variable (construction permit date) produces a cost projection which is half the level he proposes.

Mr. Falkenberg presented a forecast of Limerick's costs as of 1978 which is neither plausible nor reliable, and would not have implied cancellation as of that time even if correct. Moreover, the Company's capital cost forecast for Limerick as of that date is consistent with historic data even if one were to accept his postulate that forecasts in this time frame should include a significant allowance for continuation of past trends.

Q. Please explain how Dr. Schinnar has misused your "Lukens" model in his surrebuttal testimony.

A. In my rebuttal testimony I argued that my results for Pennsylvania of a projection done in connection with the Lukens proceeding could not be used to derive employment effects for Philadelphia because several aspects of the methodology which were applicable at the state-wide level were not applicable for the City. Dr. Schinnar responds in his surrebuttal testimony by attempting to "correct" those methodological problems and then to continue to apply the model. The adjustments he made, however, do not solve the problem and consequently do not make the model useful for this proceeding. In particular, Dr. Schinnar ostensibly uses my model to predict Philadelphia job losses of 6,921 jobs in the manufacturing sector and 13,843 jobs in the service sector. But, in my model there are no predicted losses of jobs in the service sector (with the exception of multiplier effects which Dr. Schinnar agrees we should ignore in Philadelphia). Specifically, Dr. Schinnar derives this effect by simply assuming an employment elasticity in the service sector of about half the level I derived for the manufacturing sector. But such an employment elasticity is not to be found anywhere in my model and seems entirely implausible to me. In particular, only seven manufacturing industries exhibit an employment effect in response to changes in electricity price and all of these industries have relatively high intensities of electricity use. For these industries, the ratio of electricity consumption to employment is 82 megawatt-hours per employee, whereas the average ratio of electricity consumption to employment in the service sector is 8 megawatt-hours per employee, or one tenth as large. Thus the idea that the service sector would exhibit employment elasticities which are one half as large as those in the manufacturing sector, or that there would be any significant employment effects in these sectors, does not seem at all plausible and certainly cannot be inferred from my model.

I should also point out that my criticisms of Dr. Schinnar's attempt to use my model to confirm his results apply with equal force to Dr. Feldman who uses a similarly incorrect application of the model to derive roughly the same conclusion.

Q. Dr. Perl, does this conclude your sur-surrebuttal testimony?

A. Yes, it does.

EX Attached

to Statements

PECO STATEMENT NO. 14A 4

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PENNSYLVANIA PUBLIC UTILITY COMMISSION

V.

PHILADELPHIA ELECTRIC COMPANY

DOCKET NO. R-850152

REBUTTAL TESTIMONY

OF

CARY H. RUSH

CAPACITY PLANNING, RELIABILITY,
FORCED OUTAGE RATES AND
PEAK LOAD FORECASTING

FEBRUARY 19, 1986

REBUTTAL TESTIMONY OF CARY H. RUSH

Q. Please state your name and business address for the record.

A. My name is Cary H. Rush. My business address is 2301 Market Street, Philadelphia, Pennsylvania.

Q. Mr. Rush, have you submitted prior testimony in this proceeding?

A. Yes. My direct testimony is marked as PECO Statement No. 14. My testimony addressed the salient features of the PECO/PJM system; PECO's load forecast; generation capacity planning; and retirement dates, as well as other matters.

Q. What is the purpose of your rebuttal testimony?

A. I will respond to the testimony of witnesses sponsored by various intervenors relating to the following topics:

- Capacity Planning
- Reliability
- Forced Outage Rates
- Peak Load Forecasting

CAPACITY PLANNING

Q. Mr. Lanzalotta (OCA Statement No. 5, p.10) states that for PECO in 1986, "[f]rom a reliability standpoint, anything above 22.5% reserves is excess capacity." Do you agree with this statement?

A. No. I explained in my direct testimony that PECO uses a 25% reserve planning objective. PECO's reserve objective is based on engineering judgement of the PECO requirements needed to meet the PJM reliability objective. In recent years, the calculated required reserves to meet PJM's aggregate reliability objective for 1986 have been:

Year of Calculation	Required Reserve
1981	24.6%
1982	24.6%
1983	23.6%
1984	22.0%
1985	23.13 (still under review)

The 22% reserve obligation in current use by the PJM Interconnection has not always met the reliability objective, but has been a pragmatic expedient to avoid the variations in the annual calculations and an abrupt increase in requirements. PECO, in using a 25% reserve objective, recognizes that the planned PECO generation reserve should be greater than the current 22% PJM reserve obligation, because:

1. The 22% PJM reserve obligation would eventually be raised to the value needed to meet reliability standards. This is now projected for 1989 when the PJM requirement is planned to go to 25%.
2. There would be variations from forecasted load and capacity values that could cause PECO to be below its forecasted reserves. For example, the PECO load forecast for 1986 has increased almost 200 MW in the last two years.
3. The PJM reserve requirement is calculated on the basis that the interconnection is one system without internal transmission limits. The reserve requirement for each of the member PJM companies would be much higher than the PJM value for the same reliability. The sharing of reserves by the member companies in order to reduce reserve requirements, requires the transmission of shared reserves to the company in need. The

transmission into the PECO system from other PJM companies is frequently at its maximum limit. That is, PECO could not import any more capacity into its system regardless of need.

Q. Do you have other support for your stated 25% reserve requirement for PECO?

A. Yes. In the Limerick Unit No. 2 Investigation at Docket No. I-840381, Dr. Ahmed Kaloko testified on behalf of the Commission Trial Staff and stated unequivocally in an interrogatory response (PECO Exhibit 1 in the Limerick Unit No. 2 Investigation, I-840381) that PECO's "[o]ptimal required reserve" was 25%.

Q. Mr. Falkenberg (PAIEUG Statement No. 1, Exhibit 5), Mr. Chernick (UUC/UP Statement No. 1, Table 2.1) and Mr. Lanzalotta (OCA Statement No. 5, Schedule 1) suggest capacity plans for PECO that they apparently consider more suitable than the PECO addition of Limerick Unit No. 1. Do you have any comments on these plans?

A. All of these plans rely on resurrecting retired units and postponing future PECO retirements in order to meet PECO capacity requirements. I consider these plans shortsighted and risky. A utility with its continuing obligation to serve its customers must plan a long-term economical and reliable system. The proposed plans rely basically on: (a) various oil-fired units, which are uneconomical to run, to meet PECO's capacity obligation, and (b) the hourly spot market, to provide a large part of PECO's energy requirements. In a given year a utility can meet its obligations this way. Indeed, before Limerick Unit No. 1, PECO had purchased in the 1982-85 period about one third of its energy requirements. In the long term, however, PECO has no claim on these economical energy sources. These sources are now available only because other utilities have short-term excess base load capacity, which PECO lacks. The price that on average PECO pays for this energy ($33/MWhr in 1985) is little more than the direct cost for this energy. This price is only a fraction of its total cost if the selling company's fixed costs were added. No utility would ever deliberately build a new unit to sell energy at that price. PECO, moreover, has no control over the availability of this energy. For example, acid rain legislation requiring retrofitting of pollution equipment could rapidly retire a lot of the older coal fired units now producing this energy. Similarly, a recovery of the heavy industry in the midwest could dry up the availability of low priced energy through load growth. Certainly with time it will disappear. The addition of Limerick Unit No. 1 only reduces the PECO need to purchase energy, but does not eliminate the need. PECO, despite all the arguments on alleged excess capacity, will still be a net importer of energy with the addition of Limerick Unit No. 1. Ironically, if PECO had not been doing its best to reduce its customers' costs by importing the cheapest possible energy available, the arguments supporting Limerick Unit No. 1 would be completely self-evident.

Q. What are the long-term consequences of PECO following the cited capacity plans of the interveners?

A. There are a number of long-term risks in following the intervenors' suggested capacity plans:

1. The PECO system would remain oil dependent. Almost 40% of PECO's generating units as of 1985 were oil-fired. Despite the recent down-turn of oil prices, almost no one is projecting the availability of permanent low priced oil. Any incremental use of oil is supplied by imported oil, because our Country is not self-sufficient in oil production. The continued reliance on oil would make PECO and its customers vulnerable to Mideast politics.

When the disappearance of imported low priced coal energy occurs, PECO will have to supply its energy needs by increased consumption of oil.

2. The importation of energy from long distances rather than the production of energy near the load areas always leaves the energy short area vulnerable to disruption of service. Even if properly planned and operated, a long transmission system can be disrupted by storms, accidents and sabotage. Such a disruption could lead to blackouts which can be a disaster in urban areas.

3. The PECO generating capacity would become increasingly old and would have to be replaced. At some point in time, any generating unit even with life extensions, will become completely worn out. The intervenors' suggested plans would aggravate an already massive generating capacity replacement challenge by adding approximately 1500 MW to PECO's needs to replace well in excess of 4000 MW in generating capacity in the decade beginning in the year 2000.

In the year 2000, PECO will enter a decade of massive generation retirement. During this period, generation reaching the end of its expected life totals 4399 MW. A summary of this capacity is as follows:

Retirement 2000-2011

Unit	Capacity, MW	Year
Peach Bottom 2,3 (nuclear)	886*	2008 (end of NRC License)
Salem 1,2 (nuclear)	930*	2008 (end of NRC License)
Keystone 1,2 (coal)	357*	2003 (end of 35 year life)
Conemaugh 1,2 (coal)	352*	2006 (end of 35 year life)
Eddystone 1,2 (coal)	635	2010 (end of 50 year life**)
Cromby 1 (coal)	144	2004 (end of 50 year life**)
Eddystone 3,4 (oil)	760	2010 (end of 35 year life)
Misc. Comb. Turbines	335	2007-2011 (end of 40 year life**)
	4399	

*PECO share of jointly owned units

**Assuming life extensions

This estimate is based solely on the need for replacement of existing units, without consideration of meeting any load growth needs. These retirements, assuming completion of Limerick Unit No. 2 and no other construction, will leave PECO with only 3869 MW of generating capacity by 2011. The two Limerick units will be the only base load capacity on the PECO system at that time. We believe that other utilities will also have large replacement requirements in the same period. There have been almost no new orders from American utilities for major generation facilities for sometime. We have quite a concern that the manufacturing capability to build all of this capacity will not exist when needed. This situation highlights PECO's need for long range capacity planning as opposed to stop gap approaches to system planning problems.

Q. Do you agree with Mr. Lanzalotta (OCA Statement No. 5, p. 9) and Mr. Falkenberg (PAIEUG Statement No. 1, p. 22) in their claims that the entire 1055 MW capacity of Limerick Unit No. 1 is not necessary to meet PECO's capacity requirements?

A. No. The basis of their argument is the inclusion in PECO's capacity of the Southwark 1&2 units with diesel (338 MW) and the 458 MW of combustion turbines (CT's). Mr. Falkenberg goes one step farther and adds in the Richmond 9 unit (166

MW). As part of our normal capacity planning process, these units have been retired from service with the approval of this Commission. Without the addition of these retired units, PECO is projected to have only 158 MW in 1986 above its 25% planning objective (see PECO Statement No. 14, Schedule 7). In pages 13 and 14 of my direct testimony, I discuss that such a nominal variation from the planning objective is the expected result of meeting incremental load growth with finite, economically sized units.

Q. Mr. Lanzalotta (OCA Statement No. 5, p.8) and Mr. Chernick (UUC/UP Statement No. 1, p.11) discuss the alleged acceleration of PECO generation retirements being made because of Limerick Unit No. 1. What is your opinion on this subject?

A. PECO has been using a 35-year nominal life for most of its fossil-fueled steam units. These units do not spontaneously collapse on that date, but they are worn out. It is like a car with 150,000 miles of use. You may be able to nurse a few more miles out of it or you may not. With the nominal retirement date in mind, PECO will adjust a few years around it, if it can, in order to meet capacity requirements. For example, in the last few months, PECO has decided to delay the retirements of the Delaware 7 & 8 units for two years past their nominal life of 35 years. Indeed, the decision to delay the retirements of Delaware 7 & 8 units was precisely because Limerick Unit No. 1 does not by itself totally satisfy even our short term capacity requirements. The Richmond 9 unit was 35 years old and the Southwark 1 & 2 units were about 38 years old when retired. This is not accelerated retirement.

Q. Are the 458 MW of CT's being retired before the end of their nominal life?

A. Yes, the 458 MW of CT's are being retired before the end of their nominal 25-year life, but nevertheless I consider them as being retired at the end of their useful life.

Q. Please explain.

A. CT's are used in the PECO system for the following purposes:

- to provide back-up supply for the shutdown or black start of fossil fuel steam units;
- to provide emergency service for local load; and
- to provide transmission relief.

The 458 MW of CT's were not installed for any of these purposes and they are no longer needed for peaking capacity. As I mentioned in my direct testimony, peaking capacity in 1985 approached 40% of the total PECO capacity.

Q. Why were the 458 MW of CT's installed on the PECO system?

A. These CT's were added to provide temporary short lead time capacity during a period of capacity shortages. These units were ordered in the late 1960's when the PECO installed reserve was averaging about 10% and load shedding by voltage reduction was a common occurrence in the peak season. The load growth was very high in this period and CT's were the only capacity that could quickly fill the capacity gap before the fossil steam and nuclear units under construction reached completion. In 1973, the year before the Peach Bottom nuclear units came into service, the PECO installed reserves would have been only 3% without the 458 MW of CT's. These units have served their original objective and are now infrequently operated. In the 1982-85 period these units had an average operating rate of less than 1% of the time.

RELIABILITY

Q. Mr. Chernick claims on page 22 of his testimony (UUC/UP Statement No. 1) that "[n]uclear plants contribute relatively little to reliability." His focus is on the large size of nuclear plants and their need for sufficient reserves. Will Limerick's size adversely affect PJM's reliability?

A. The effects of a 1000 MW unit such as Limerick must be evaluated in the context of the size of the system in which it operates and the number of other large units that are already a part of that system.

The first consideration is that PJM has over 45,000 MW of installed capacity. In addition, its ability to provide reliable generation is due in part to PJM's many interconnections to the surrounding power pools that have in excess of 280,000 MW of capacity. If the reliability impact of Limerick together with the retirement of smaller units was evaluated in the context of the total interconnected system, it would show essentially no change to the reliability of the PJM system.

The second consideration is that PJM already has 14 units that are 800 MW or greater. It is true that when the first large unit is added to a system that has had mostly smaller generating units, the increase in the reliability requirements is not insignificant, especially the if system itself is small. Each additional large unit added to the system, however, has a progressively decreasing effect on system reliability. Since Limerick will be the 15th large unit installed on the PJM system, it will not have the negative impact that Mr. Chernick suggests.

Q. Mr. Chernick has claimed that "the existing units would have done a better job than Limerick 1 of keeping the lights on in Philadelphia." Has he shown this to be true?

A. No. Indeed, Mr. Chernick has made incorrect assumptions concerning Limerick Unit No. 1's reliability benefits. He has made some reliability sensitivity calculations on the NEPOOL system and has arbitrarily changed them to represent the reliability sensitivity for PJM. In addition, he has overestimated a forced outage factor for Limerick, which also impacts on Limerick's reliability benefits.

Q. What relevance does Mr. Chernick's calculations for NEPOOL have to PECO or PJM?

A. Very little. All of PECO's reliability calculations are done on the basis of PJM. However, no simple comparisons can be made between PJM and NEPOOL, because the two systems are very different in size and mix of generation. For example, PJM's capacity is approximately twice as large as that of NEPOOL. These and other factors significantly influence the reliability impact of any newly added generator.

Q. What assumptions has Mr. Chernick made about forced outage rates in his comparison of Limerick and smaller unit reliability benefits?

A. Using PECO sources, Mr. Chernick has determined outage rates for all the smaller units in his Table 2.7. In some cases he has shown a range of values but the mid-range values for all smaller units were based on PECO data. However, for Limerick Unit No. 1, the number 20%, which he says is based on PECO projections, is at the <u>bottom</u> of his range of values. The value he used instead for Limerick is 27.5%.

Q. So, Mr. Chernick has used PECO outage data for all the smaller units, but has used an outage value higher than PECO's projection for Limerick Unit No. 1. What is the effect of this assumption?

A. The reliability benefit of Limerick's capacity relative to the smaller units has been computed by Mr. Chernick to be much lower than if PECO's outage projections were used.

Q. Then what is your estimate of changes in PJM's reliability with Limerick coming on line and the other units being retired?

A. In the short term, Limerick will somewhat improve the PJM reliability as Mr. Chernick states in his testimony, on page 22, because there is a net increase of capacity on the PJM system. In addition, our estimation is that the reliability benefit per MW of generation is about the same for Limerick as the average benefit of all the smaller generating units scheduled for retirement. Thus Limerick will not result in increased reserve requirements or lower reliability as Mr. Chernick has suggested.

FORCED OUTAGE RATES

Q. Mr. Gruber (Staff Statement No. MJG-1) argues that PECO should be penalized for its 3.21% extra reserve requirement due to higher than average forced outage rates, supposedly due to poor management of operations and maintenance. Such a penalty would be applied against 3.21% of the PECO installed generating plant. Do you agree with his arguments?

A. No, I do not agree with his arguments for several reasons. First I want to clarify that the 3.21% extra reserve requirement is not a percent of the installed generation but a percent of the load. Referencing this 3.21% requirement to generation with an assumed system 25% reserve requirement will result in a figure of 2.57% (3.21/1.25). That is, the 3.21% penalty really means about 2.57% of the PECO capacity.

Q. Will this requirement cause PECO's ratepayers to have higher charges due to this PJM obligation?

A. No. PECO will have sufficient capacity to meet its PJM 1986-87 reserve requirement. Therefore, there will be no extra capacity charges payable to PJM due to this higher reserve requirement.

Q. Does this 3.21% reserve requirement for 1986 impact PECO's long-term planning objectives?

A. No. In the long term, because PECO's reserve objective has been 25% as compared with PJM's minimum 22% requirement, PECO has allowed for the year-to-year fluctuations in loads as well as fluctuations in PECO's forced outage rates. In the long term PECO can expect its forced outage rates to be lower since the 3.21% requirement for 1986 was based on a period in which several extraordinary outages occurred that have previously been ruled by the Commission to be prudent.

Q. For what period was the PECO average forced outage rate calculated?

A. It covered the years 1981 to 1983 inclusive. PECO's company average was 18.78% as compared with the PJM average of 16.64%.

Q. Do you agree with the concept that a company's forced outage rate compared to some average could indicate imprudence on the part of the company?

A. No. A company's forced outage rate can be higher or lower than average for a variety of reasons outside the control of the company. A specific analysis of all the outages and reasons for them would have to be performed in order to determine whether such outages were warranted.

Q. Was the extended outage of Eddystone 1 in 1983 a significant contributor to this high forced outage rate?

A. Yes, Eddystone 1 had the highest equivalent forced outage rate of all PECO units (46.56% for the 3 year period). Because it is a fairly large unit, 311 MW, Eddystone 1 contributed significantly to the high company average.

Q. What other PECO units contributed significantly to the PECO average forced outage rate?

A. Peach Bottom 2 had an extended forced outage in 1983 complying with an NRC order to repair reactor coolant piping.

Q. Have these outages been previously reviewed by the Commission?

A. Yes, in case ECR#8, P-830453, et al, the commission ruled that all but two days of the Eddystone 1 outage (March 6, 1983--December 31, 1983) and all of the

Peach Bottom 2 outage (July 4, 1983--December 3, 1983) were prudent.

Q. Are there any other items that would warrant special consideration with regard to PECO's average forced outage rate?

A. Yes. Salem 2 also contributed substantially to the Company's average forced outage rate even though it was not included in PECO's rate base until January 1, 1985. Up to that point, all expense and capital costs were covered under sales agreements with other utilities at no cost to PECO ratepayers.

PEAK LOAD FORECASTING

Q. On pages 11 and 12 of his testimony, Mr. Lanzalotta comments on PECO's forecast of peak demands. Do you agree with his statements on this topic?

A. No, I do not. Mr. Lanzalotta appears to believe that PECO took the actual peak of 6034 MW in 1985 and arbitrarily adjusted it upward to 6139 ~~NW.~~ MW This is not the case. In my direct testimony (PECO Statement No. 14, Schedule 3), I described in depth just how we employ weather-adjustments to obtain a standard peak for a given year. There is nothing arbitrary about this approach. We take all the daily weekday summer peaks into account with their associated weather, and not just the one peak day of any given year. We do it using a regression method that we have used continuously since the late 1970's, and the resultant peak of 6139 is consistent with peak demands derived for other years.

Q. Does Mr. Lanzalotta understand the methodology and purpose of PECO's established procedures for weather normalizing historical peak loads?

A. On the basis of his direct testimony and his responses to interrogatories, I conclude that he does not. He seems to find it surprising (OCA Statement No. 5, p. 11, lines 29-34) that no day in 1985 had a weather factor equal to or greater than the standard weather factor. The standard weather factor is by definition the average over many years of data of the weather factor for the peak day of each year. By virtue of being the average over many years, the weather factor on the peak day will be above standard in some years and below standard in other years. Exhibit B of Schedule 3 of my direct testimony shows that this has been the case over the years. Because a large portion of PECO's summer loads is weather sensitive, the annual peak generally coincides with the hottest day of the summer. Hence it is simple logic that, if the peak day had a weather factor below the standard weather factor, then all other days would have been below as well. This situation is far from unusual. On the contrary, it will happen roughly half of the years of a historical sample, as it has since 1968 (see PECO Statement No. 14, Schedule 3 Exhibit B).

PECO Exhibit 35 (IR-PECO-OCA-7-11) is an interrogatory response prepared by Mr. Lanzalotta that further demonstrates his apparent lack of understanding of PECO's use of the standard weather factor. When asked if the standard weather factor should correspond to normal weather for any day of the summer or for the day on which the annual peak is reached, he apparently is unable to say to which type of day it corresponds.

Q. Does Mr. Lanzalotta seem confused about any other aspects of PECO's peak loads?

A. Yes, he seems to be confused about the weather sensitivity of PECO's summer loads. On the one hand, as shown in an interrogatory response prepared by Mr. Lanzalotta (IR-PECO-OCA-7-12), which is attached hereto as Exhibit CHR-1, he would generally expect PECO's annual peak to occur on the hottest day of the year. On the other hand, as shown in two other of Mr. Lanzalotta's interrogatory responses, PECO Exhibit 35 (IR-PECO-OCA-7-14 and 15), he seems uncertain as to whether warmer weather would increase or decrease loads. These two positions appear to be contradictory.

Historical data clearly indicate that a large portion of PECO's summer loads are weather sensitive, as my direct testimony shows. All other things being equal, if the weather is warmer, our loads will be higher. Accordingly, if we had experienced warmer weather during August of 1985, the figures of 96 hours and 187 hours cited by Mr. Lanzalotta on pages 16 and 17, respectively, of his direct testimony would have been larger. What he is doing is using the cooler than normal weather of August 1985 to construct an improper evaluation of the need for additional baseload capacity.

Mr. Lanzalotta also casts suspicion on our method because our weather factor indicated less than typical conditions for peak load while other PJM companies were experiencing higher levels of demand. We still say that our weather factor was less than optimal during 1985 based on what the weather factor has been at the time of the peak on every peak day since 1968. In determining the weather factor, we use 29 hours of dry bulb temperatures taken at the Philadelphia International Airport, which would not reflect what may be happening over other PJM company territories in five states and the District of Columbia. Mr. Lanzalotta neglects to mention that the 6034 MW actual peak that we experienced in 1985 was the second highest ever recorded for PECO. It occurred at 3 p.m. and might easily have exceeded the record peak of 6095 in 1980 if the humidity on the peak day in our area had not started dropping off at 2 p.m. Since 1976, in seven out of ten years the yearly peak has occurred at 5 p.m. I believe we would have had a new record actual peak if the weather in our area had held throughout the afternoon on August 15, 1985.

Q. Staff witness Rosenthal states on page 6 of his testimony (Staff Statement No. RAR-1), that the Company's historic peak demand has not changed since 1980. Do you agree?

A. Yes and no. If you mean by historic peak demand, that which is actually recorded by our meters, then the answer is yes. Our peak in 1980 was 6095 MW. This was curtailed by various means because of limited generating capacity and it is estimated that the 1980 peak might have been 6145 MW, if not held back. Since then our highest actual peak has been 6034 MW in 1985.

We do not, however, rely completely on actual peaks for decisions or analysis. Rather, we convert the actual peak to a standard value by taking out the extremes of weather. Thus standard peaks are lower than actual values when the weather that creates the peak is extremely hot and they are higher than actual peaks when the weather on the peak day is cooler than normal. The peak day in 1980 was one for which the weather was one of the hottest in the last decade. Therefore our standardized peak for that year was 5810 MW. In 1985, our actual peak of 6034 occurred on a day with cooler than normal weather and so our standardized peak for last year became 6140 MW. This resulted in the highest weather normalized or standardized peak in PECO's history.

Q. Are there any difficulties with Mr. Lanzalotta's use of load data from the month of August, 1985, to assess the proper level of baseload generation?

A. Yes, to look at only a single month gives a very incomplete picture of the need for baseload capacity. While in that month the loads are the highest, other months can be as important or more important in evaluating the need for baseload capacity. All generating units will require scheduled maintenance. Most of these maintenance outages are scheduled during low load months. Generally speaking, the maintenance is scheduled so as to equalize the risk of outage across all 12 months. As a result, the ratio of capacity available (i.e., not scheduled for maintenance) to anticipated load is approximately equal in all months of the year. This means that the need for and value of the available baseload capacity will come not just from the peak month but from all months. Thus a proper evaluation will consider all months.

The most important evaluation concerns the fraction of the required energy that can be generated from baseload units as I discussed in my direct testimony. Mr. Lanzalotta, without any study of what the optimal mix should be, advocates a generation mix that would continue to require that more than 35 percent of PECO's energy be supplied by oil-fired generation and purchases.

Q. Do you have any comments regarding Mr. Lanzalotta's position that PECO need not build its own baseload generation but can instead rely on the baseload generation of other PJM companies?

A. Yes. To the extent that load diversity among the members of PJM, after taking into account scheduled maintenance, makes available at certain times of the year some additional baseload capacity for generating energy to be sold through PJM, Mr. Lanzalotta may have a partial point. However, such capacity must be available on an ongoing basis. Temporary surpluses of baseload capacity by some PJM members do not represent sufficient justification for changing the capacity mix of other PJM members. In the long run, each member must plan its system to provide for its own needs including an appropriate mix of capacity. If every member were to rely on the others to provide needed baseload capacity, before long the pool as a whole would be deficient in baseload capacity. Even putting aside this argument, PJM was not created and does not continue to exist for the purpose of providing subsidies from one member utility's ratepayers to the ratepayers of another member. It exists only to share equitably the mutual benefits of the cooperative activities of its members.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Request No. 12

Based on his understanding of PECO loads, would Mr. Lanzalotta expect PECO to achieve its annual peak on (a) the hottest or one of the hottest days of the summer, or (b) some other day? If some other day, please state what conditions Mr. Lanzalotta would expect to exist, and why those conditions would coincide with the occurrence of annual peak.

Response No. 12

Mr. Lanzalotta would expect PECO, like PJM, to achieve its annual peak on the hottest or one of the hottest days of the summer.

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

PECO STATEMENT NO. 14B

R-850152
3-11-86

PENNSYLVANIA PUBLIC UTILITY COMMISSION

V.

PHILADELPHIA ELECTRIC COMPANY

DOCKET NO. R-850152

SUR-SURREBUTTAL TESTIMONY

OF

CARY H. RUSH

RESPONSE TO THE SURREBUTTAL
TESTIMONY OF PAUL CHERNICK
AND OF PETER LANZALOTTA

MARCH 7, 1986

Sur-surrebuttal Testimony

Q. Please state your name and business address for the record.

A. My name is Cary H. Rush. My business address is 2301 Market Street, Philadelphia, Pennsylvania.

Q. Mr. Rush, have you submitted prior testimony in this proceeding?

A. Yes. My direct testimony is marked as PECO Statement No. 14. My direct testimony addressed the salient features of the PECO/PJM system; PECO's load forecast; generation capacity planning; and retirement dates, as well as other matters.

My rebuttal testimony is marked as PECO Statement No. 14B. My rebuttal testimony addressed the topics of capacity planning, reliability, forced outage rates, and peak load forecasting.

Q. Have any of the statements in the surrebuttal testimonies of Mr. Lanzalotta or Mr. Chernick caused you to change any of your positions?

A. No.

Q. What is the purpose of your sur-surrebuttal testimony?

A. I will respond to what I believe are misinterpretations of my position by Mr. Lanzalotta and Mr. Chernick in portions of their surrebuttal testimonies.

Q. Mr. Lanzalotta, on page 2, line 35 of his surrebuttal testimony, states in part that "...PECO has much more discretionary capacity than Mr. Rush calculates, but PECO is advancing the retirement dates of a substantial amount of capacity because of Limerick 1". He further states that it is "circular and fallacious" to use Limerick 1 as a basis for retiring Southwark and the old CT's and then use their absence as a basis for requiring Limerick. Do you agree with Mr. Lanzolotta's characterization of your position?

A. No. My position is that capacity planning is done on a coordinated basis which begins with a recognition of service date and load growth uncertainties in long range planning. As both load and service date uncertainties diminish, capacity planning can have more precise coordination. Both Southwark and the old CT's have been scheduled for retirement in the 1980's for some time. As stated previously, the CT's were a short lead time, stop gap capacity addition until our long lead time capacity additions could come into service. The Southwark units were reviewed on the basis of their age, condition and annual costs. We concluded that they should be retired as soon as load and capacity factors made this feasible. We are now at that point in time. I believe from Mr. Lanzalotta's statements that we disagree only on the specific near term year of retirement, not the general position that all generation has a finite life.

Q. Mr. Chernick states on page 16 of his surrebuttal testimony that since "PECO did not perform production costing runs for an optimized alternative expansion plan, it is not possible for me to compare Limerick 1 to an efficient program". Did Mr. Chernick request such production cost runs?

A. No. Moreover, we made available to him copies of our production cost runs which contained sufficient base case data to perform this analysis himself if he thought it had some relevance to his position.

Q. On page 17 of his surrebuttal testimony, Mr. Chernick states that "the oil steam plants do produce fuel savings, even with Limerick 1 on line". Do you have any comments?

A. Yes. His statement is incomplete with respect to the requirements for maintaining this plant (Southwark) in service. "Fuel savings" are only one part of the requirement. To produce these "fuel savings", the plant must be maintained in a fully operational status. In 1984, the last full year prior to Limerick operation, Southwark had a capacity factor of less than 5%. However, approximately 80 employees were assigned to and required at the plant to maintain its ability to operate even at that reduced level.

Q. Mr. Chernick states on page 17 of his surrebuttal testimony that you have not explained why you believe that "Keystone, Conemaugh, or Eddystone 3 and 4 will have to be retired at age 35, when Eddystone 1 and 2 and Cromby 1 are to be extended to age 50", and "why the process of rebuilding boilers and turbines can not continue indefinitely". Do you have any comments?

A. Yes. Mr. Chernick fails to cite any major steam electric generating units in the United States which have operated significantly in excess of 50 years. I am personally aware of none. PECO is planning to obtain actual experience in our proposed extensions of the three coal-fired units (Eddystone 1 and 2 and Cromby 1). The two coal plants referenced by Mr. Chernick--Keystone and Conemaugh--are plants in which PECO has a minority ownership and cannot commit unilateraly to life extension. The Eddystone 3 and 4 units are oil fired. I cannot speculate on the economics of oil fired capacity in the 2011 time frame.

Finally, Mr. Chernick is probably aware that the "process of rebuilding boilers and turbines ... indefinitely" is an incomplete consideration. "Boilers and turbines" are but one part of the problem. Piping, switch gear, motors, cables, fuel handling facilities with finite lives and retrofits for regulatory concerns are additional considerations, as are safety concerns for personnel working near aging equipment. I am not aware of any actual experience in significant indefinite extensions to support his assertions. Therefore, to base long range plans on such speculation is not consistent with sound capacity planning practice.

Q. Mr. Chernick also states on page 17 of his surrebuttal testimony that "historically power plant retirements usually have resulted from technical obsolesence (e.g., high heat rates) rather than the physical deterioration". Do you agree?

A. No. Since Mr. Chernick has not provided any support for his assertion, and indeed appears to soften the statement in his footnote 17, I can only cite PECO's experience. Our past retirements of Barbados 1, 2, 3, 4, Chester 1, 2, 3, 4, 5, 6, Delaware 1, 2, 3, 4, 5, 6 and Richmond 9, 10, 11, 12 were all based on physical deterioration and unit size which led to high operating and maintenance costs relative to newer capacity additions.

Q. Is Mr. Chernick's assumption correct on page 18 of his surrebuttal testimony that "had Limerick 1 not been under construction, Richmond and Southwark would not have been retired"?

A. No. First, it was possible to retire the remaining unit at Richmond, Unit 9, with the addition of Salem 2. The addition of Salem 2 and the retirement of Richmond 9 were reviewed and approved by the Commission in PECO's last rate case. Therefore, the timing of the retirement of Richmond 9 is unrelated to Limerick. Second, the retirement of Southwark would have taken place during the 1980's when sufficient base load capacity was available to permit doing so even if Limerick were not around.

Q. On page 19, Mr. Chernick takes issue with your response to his "demonstration that Limerick 1 is a poor source of reliability". In his footnote 19, he further states that you are "confusing the effect of the first large unit on <u>operating</u> reserve requirements, which is very important, to the effect of that first large unit on <u>installed</u> reserve requirements (which is the measure of reserve relevant to this case), for which it is much less important". What are your comments?

A. My rebuttal testimony, at page 9, clearly states that Limerick is the fifteenth large unit to be installed on PJM, not the first as suggested in footnote 19. I also note from this footnote that Mr. Chernick agrees that even the effect of the first large unit "is much less important" on installed reserve requirements, which is the "reserve relevant to this case".

Q. In footnote 21, Mr. Chernick states that you criticize him "for using PECO data for the oil fired plants". Do you have any comments?

A. My rebuttal testimony, at page 10, clearly states my "criticism" was directed not at using PECO data for the oil-fired units, but at the selective use of PECO data. I do not differ with him in the use of our data for the oil-fired units. My ~~objective~~ objection was to his use of our data for all units <u>except</u> Limerick.

Q. On page 20 of his surrebuttal testimony, Mr. Chernick states that his "reliability sensitivity calculations [of Limerick 1 and proposed alternatives] were performed for a PJM-sized system, not for NEPOOL, and no arbitrary changes were necessary." Is this true?

A. Yes and no. In attempting to analyze the PJM system it was not arbitrary to revise the m-factor from the 425 MW value, which Mr. Chernick had previously estimated for the NEPOOL system, to some other value, since the two systems have significantly different characteristics. However, his procedure for arriving at the estimated m-factor value of 800 MW for the PJM system is unsupported. Although he has given vague descriptions of his procedure in statements such as "I scaled up the NEPOOL size parameter [m-factor] to reflect PJM's larger system" and "the value of m, which was adjusted for PJM conditions" (UUC/UP Statement 1A, page 20), he has offered no detailed description in support of his procedure.

Nor has he provided any theoretical support for his procedure.

It is also interesting to note that he has incorrectly labeled the m-factor as a "size-sensitivity" parameter (UUC/UP Statement 1A, pages 19 and 20). In actuality, the m-factor describes the sensitivity of a system's reliability versus its installed generating capacity reserves. The size of a system (e.g. the total peak demand of the system) is only one of many system characteristics which affect this sensitivity. Other characteristics such as weekly and seasonal load patterns, and the type and mix of existing generating units, can have a significant impact on the value of the m-factor. Thus if relative system size is the only "PJM condition" considered in his estimation procedure, then his estimate is subject to substantial error.

Q. Mr. Chernick indicates that his estimation of the m-factor for the PJM system was hampered due to a lack of detailed information on the PJM system (UCC/UP Statement 1A, page 21). Are there any alternative methods or techniques for estimating this parameter for which data was available to him?

A. Yes, Mr. Chernick's calculations of effective load carrying capability, which are the bases of his Table 2.7 and Table R-2 (UCC/UP Statements 1 and 1A) are based on a 1966 paper by L. L. Garver which is referenced on page 23 of UCC/UP Statement 1. Appendix III of the Garver paper, entitled "Estimating The Value of m", presents a method for roughly approximating the value of the m-factor for a system by summing, over all generating units, the product of each unit's capacity and forced outage rate. My Exhibit CHR-2 illustrates that applying Garver's approximation to PJM data provided, in response to IR-Staff-LIM-10 (PAEIUG Exhibit 1), results in an estimated m-factor for the PJM system of about 8000 MW.

Q. Table R-2 (UCC/UP Statement 1A) presents the results of an additional analysis by Mr. Chernick. Do these results offer any support for your contention that there is no substantial difference in the reliability effects of Limerick Unit No. 1 versus CT's and refurbished oil-fired units?

A. Yes. In Table R-2 Mr. Chernick presents the results of an analysis in which he consistently uses PECO estimates of outage rates for Limerick Unit No. 1 as well as the existing CT's and refurbished oil-fired units. In comparison to the results shown in Table 2.7, the approximately 17% increase in the effective load carrying capability of Limerick Unit No. 1 yields a substantial reduction in his estimate of the reliability disadvantage of Limerick.

My Exhibit CHR-3(a) reproduces the salient results of Table R-2, but also includes the weighted average of the ELCC/MW-to-Lim.-ELCC/MW ratios for 458 MW of existing CT's plus the seven oil-fired units. The value of this weighted average, 1.101, indicates that on a per MW basis this group of units has about a 10% capacity advantage over Limerick Unit No. 1. However, this is based on Mr. Chernick's estimated m-factor of 800 MW. When the Garver-derived estimate of 8000 MW is used, as shown in my Exhibit CHR-3(b), there is about a 5% reliability advantage in favor of Limerick Unit No. 1.

Q. Have you determined the sensitivity of the reliability value of Limerick Unit No. 1 to an assumption that the m-factor of 8000 MW is too high?

A. Yes. As shown in my Exhibit CHR-3(c), even if the Garver approximation is reduced by 80%, there is no substantial reliability disadvantage to Limerick Unit No. 1 over the proposed alternatives. That is, the effective load carrying capability per MW of installed capacity would be essentially the same for Limerick and the proposed alternatives.

Q. How would you summarize your assessment of the reliability benefits of Limerick Unit No. 1 relative to the proposed alternatives?

A. Considering the significant potential for error in Mr. Chernick's estimate of the m-factor for the PJM system, the broad range in reasonable alternative estimates of the m-factor, the small differences in relative reliability benefits over a large portion of the possible range of m-factor values and my knowledge of the PJM system, it is reasonable to conclude that there is no significant difference in the reliability benefits of Limerick Unit No. 1 and the alternatives proposed by Mr. Chernick.

Q. Does this conclude your sur-surrebuttal testimony?

A. Yes, it does.

Exhibit CHR-2

System	Average Forced Outage Rate (1)	System Capacity (2)	Average Capacity Outaged (3)
PS	17.97%	8999	1617.1
PE	18.78%	7845	1473.3
PL	13.76%	7399	1018.1
BC	14.28%	5872	838.5
GPU	19.45%	8749	1701.7
PEP	16.06%	5368	862.1
AE	12.02%	1746	209.9
DPL	12.86%	2442	314.0
	Estimated value of "m"		~~8037.7~~ 8037.7

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Notes:

(1) Source: IR-Staff-LIM-10 (PAEIUG Exhibit 1), Enclosure 1, Schedule 2.212, Line 4

(2) Source: IR-Staff-LIM-10 (PAEIUG Exhibit 1), Enclosure 1, Schedule 2.01 and 2.21, Line 12

(3) Product of forced outage rate and capacity summed over all units for use in estimating the value of "m" as given in Appendix III of the 1966 paper by L.L. Garver (see reference on page 23 of UUC/UP Statement 1).

EFFECTIVE LOAD CARRYING CAPABILITY
(M = 800)

	MW	m	EFOR	AVE MW	ELCC	ELCC/MW	Ratio of ELCC/MW to Lim. ELCC/MW	Weighted Averages of Ratios
Limerick 1	1055	800	20.0%	844.00	705.56	66.9%	1.000	
Existing CT's	30	800	28.4%	21.48	21.37	71.2%	1.065	
New CT's	75	800	8.0%	69.00	68.73	91.6%	1.370	
Richmond 9	166	800	28.7%	118.36	114.73	69.1%	1.033	
Southwark 1	163	800	28.4%	116.71	113.24	69.5%	1.039	1.054
Southwark 2	173	800	25.2%	129.40	125.75	72.7%	1.087	
Delaware 7	126	800	17.7%	103.70	102.20	81.1%	1.213	1.170
Delaware 8	124	800	23.3%	95.11	93.34	75.3%	1.126	
Cromby 2	201	800	16.8%	167.23	163.50	81.3%	1.216	
Schuylkill 1	166	800	24.2%	125.83	122.56	73.8%	1.104	
Total of 458 MW of existing CT's plus the 7 oil-fired units	1577				1161.50	73.7%		1.101

Exhibit CHR-3(a)

EFFECTIVE LOAD CARRYING CAPABILITY
(M = 8000)

	MW	m	EFOR	AVE MW	ELCC	ELCC/MW	Ratio of ELCC/MW to Lim. ELCC/MW	Weighted Averages of Ratios
Limerick 1	1055	8000	20.0%	844.00	832.58	78.9%	1.000	
Existing CT's	30	8000	28.4%	21.48	21.47	71.6%	0.907	
New CT's	75	8000	8.0%	69.00	68.97	92.0%	1.165	
Richmond 9	166	8000	28.7%	118.36	118.00	71.1%	0.901	
Southwark 1	163	8000	28.4%	116.71	116.37	71.4%	0.905	0.917
Southwark 2	173	8000	25.2%	129.40	129.05	74.6%	0.945	
Delaware 7	126	8000	17.7%	103.70	103.55	82.2%	1.041	1.006
Delaware 8	124	8000	23.3%	95.11	94.94	76.6%	0.970	
Cromby 2	201	8000	16.8%	167.23	166.88	83.0%	1.052	
Schuylkill 1	166	8000	24.2%	125.83	125.51	75.6%	0.958	
Total of 458 MW of existing CT's plus the 7 oil-fired units	1577				1182.05	75.0%		0.950

Exhibit CHR-3(b)

EFFECTIVE LOAD CARRYING CAPABILITY
(M = 1600)

	MW	m	EFOR	AVE MW	ELCC	ELCC/MW	Ratio of ELCC/MW to Lim. ELCC/MW	Weighted Averages of Ratios
Limerick 1	1055	1600	20.0%	844.00	781.10	74.0%	1.000	
Existing CT's	30	1600	28.4%	21.48	21.42	71.4%	0.964	
New CT's	75	1600	8.0%	69.00	68.87	91.8%	1.240	
Richmond 9	166	1600	28.7%	118.36	116.57	70.2%	0.948	
Southwark 1	163	1600	28.4%	116.71	115.00	70.5%	0.953	0.966
Southwark 2	173	1600	25.2%	129.40	127.61	73.8%	0.996	
Delaware 7	126	1600	17.7%	103.70	102.96	81.7%	1.104	1.065
Delaware 8	124	1600	23.3%	95.11	94.24	76.0%	1.026	
Cromby 2	201	1600	16.8%	167.23	165.42	82.3%	1.112	
Schuylkill 1	166	1600	24.2%	125.83	124.22	74.8%	1.011	
Total of 458 MW of existing CT's plus the 7 oil-fired units	1577				1173.07	74.4%		1.005

Exhibit CHR-3(c)

MAR 12 1986

SECRETARY'S OFFICE
Public Utility Commission

PECO STATEMENT No. 32 + Exh

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PXE-1
PXE-2
PXE-3

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PHILADELPHIA ELECTRIC COMPANY

DOCKET NO. R-850152

REBUTTAL
TESTIMONY OF
PAUL X. ENGLISH

PECO's FOSSIL FUELS PRICE FORECAST

FEBRUARY 19, 1986

DOCKETED
MAR 17 1986

DOCUMENT
FOLDER

<u>REBUTTAL TESTIMONY OF PAUL X. ENGLISH</u>

Q. Would you please state your name and business address for the record?

A. Paul X. English, 2301 Market Street, Philadelphia, Pennsylvania.

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

A. I am employed by the Philadelphia Electric Company as the Manager of the Fuel Procurement Department.

Q. Have you testified previously in this proceeding?

A. No. However, I did testify in the Limerick Unit No. 2 Investigation at Docket No. I-840381 ("Limerick Unit No. 2 Investigation").

Q. Please give us a brief description of your professional background and experience, with specific reference to your experience in connection with fossil fuels.

A. I have worked for PECO in various capacities since 1949. From 1975 to 1977 I was the Superintendent of the Generation Division of the Electric Production Department, where I was responsible for the operation of all of PECO's fossil fuel and hydro power stations. Following that, from 1977 to 1981, I was Superintendent of the Fuel Division of the Electric Production Department. As Superintendent of the Fuel Division I oversaw the purchase and transportation of the fossil fuels used in the PECO system. Since 1981 I have served as Manager of the Fuel Procurement Department. Further information on my professional qualifications is contained in my biographical sketch, which is attached to this rebuttal testimony as Exhibit PXE-1.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond both to the criticism of PECO's fossil fuels price projections contained in the direct testimonies of Messrs.

Komanoff and Chernick and to the fossil fuel price forecasts presented by Mr. Komanoff, and relied on by Mr. Chernick.

Q. Would you briefly summarize the conclusions presented in your testimony?

A. My major concerns and conclusions with respect to Mr. Komanoff's fuel forecasts are:

1. Mr. Komanoff's judgment about coal price escalation rates is based upon an inappropriate review of historical data which is not consistent with an in-depth knowledge of the coal and transportation markets.

2. Mr. Komanoff fails to take into account the depletion of surface-mineable coal reserves in northern West Virginia and western Pennsylvania in determining his coal price escalation.

3. Mr. Komanoff fails to recognize that coal prices will escalate significantly between now and the early 1990's.

4. With respect to his oil price forecast, Mr. Komanoff incorrectly uses price escalation estimates substantially below the escalation rates projected by PECO. Moreover, as the rebuttal testimony of PECO's witness Dr. William J. Hogan demonstrates, Mr. Komanoff's oil price forecast has a very low probability of occurring (PECO St. No. 37).

5. Mr. Komanoff greatly exaggerates the importance of DRI's forecasts of coal and oil prices which are only one of many tools used by PECO in reaching its independent fossil fuel price forecast.

In summary, when all of the above points are properly taken into account, Mr. Komanoff's forecasts -- for both coal and oil -- are unrealistically low.

My conclusion regarding Mr. Chernick is that he lacks any informed basis for his conclusion that the OCA assumptions are more realistic than PECO's fuel forecasts. Like Mr. Komanoff, Mr. Chernick misunderstands the role that DRI's forecasts play in PECO's fossil fuel price projections.

PECO'S COAL AND OIL PRICE FORECASTING METHODOLOGY

Q. What does the Fuel Procurement Department do?

A. We primarily procure all fossil and nuclear fuel for the Company, with the exception of natural gas.

Q. Do you do any forecasting as part of your Department's functions?

A. Yes. Because of the fact that my Department is the most intimately acquainted with the fuel markets, we do the forecasting, both short and long term, for the Company on fuel costs.

Q. Please describe briefly how you and your Department forecast coal prices?

A. PECO basically operates in a rather narrow coal producing area. Since transportation amounts to about a third of our total coal cost, most of our coal is procured from either the western part of Pennsylvania or northern West Virginia. Therefore, we are intimately acquainted with the vendors and people in that area that sell coal to meet our requirements. We stay in constant touch with them in order to stay on top of the market. We regularly solicit the views of vendors on where coal markets are going, and where they perceive the industry is going, to inform our own forecasts.

Q. Please describe briefly how you and your Department develop an oil price forecast?

A. PECO has a very peculiar marketplace in that we are located in the Philadelphia Harbor, which has a large number of refining facilities and major terminal facilities. So again, our market is narrow. While PECO is affected by world oil prices, our primary contact is the people with whom we deal in our market area. We stay in close touch with our vendors and follow essentially the same procedure that I discussed for coal.

Q. What other means does PECO employ to stay apprised of what others in the coal and oil markets anticipate and project with respect to future fuel prices?

A. We are involved with numerous other utilities through such forums as the Edison Electric Institute and the Electric Power Research Institute. We also attend any meetings with other utilities that we think will help us in determining how our marketplace is developing. In addition, we use the coal and oil price forecasts developed by DRI as a general check on price trends.

FUEL PRICES - COAL

Q. What escalation in future delivered coal prices are assumed in the forecasts of PECO and OCA witness Komanoff?

A. The projected coal prices to PECO over the 1985 to 2005 period, and the corresponding escalation rates, are summarized in Exhibit PXE-2.

Q. What factors will determine the rate of escalation of delivered coal prices to PECO over the lifetime of Limerick Unit No. 1?

A. The following factors will determine, to a large extent, the escalation of delivered coal prices to PECO: (a) the supply-demand balance; (b) the depletion of reserves; (c) mining industry productivity gains or declines; (d) the timing and mix of contract/spot purchases; and (e) railroad freight rates.

Q. In your answer to the previous question, you state that the supply-demand balance affects delivered coal price escalation. Would you please elaborate on this statement?

A. With respect to the supply-demand balance, the Northern Appalachian (i.e., Pennsylvania and northern West Virginia) coal market, which supplies over 90% of the coal to PECO's Cromby and Eddystone Stations, has been totally out of balance since 1983 due to: (a) very low demand for domestic metallurgical coal; and (b) low demand for both steam and metallurgical export coal. In 1984, the coal market for Northern Appalachian coal improved in anticipation of a United Mine Workers' strike, then fell off when the strike did not materialize. The depressed market of 1984 continued in 1985. Based on my long experience working with the coal industry, however, the depressed coal market will not continue. Without price increases, large numbers of coal producers will be forced to curtail production or shut down. As a result, the market in the areas which produce coal to PECO (i.e. northern West Virginia and western Pennsylvania) should proceed towards equilibrium through the late 1980's. This trend toward market equilibrium will result in a real escalation of mine-mouth prices between 1985 and 1990 well in excess of the zero percent real escalation assumed by Mr. Komanoff.

PECO's projection of a fairly rapid escalation of coal prices between 1985 and 1990 was substantiated by the Governor's Energy Council's witness C. Hoff Stauffer in the Limerick Unit No. 2 Investigation. Mr. Stauffer stated during his cross-examination in that proceeding that spot prices will rise from approximately $3O per ton in 1985 to approximately $36 to $38 per ton in 1990 in constant dollars (Tr. 2729; relevant portions attached hereto as Exhibit PXE-3). This implies a real escalation rate of at least 3.7% per year between 1985 and 199O.

Q. You also identified "depletion of reserves" as a factor affecting delivered coal price escalation. Would you please elaborate on this effect?

A. Strip miners have mined: (a) the reserves with the thickest seams; (b) the reserves nearest the surface; and (c) the reserves nearest the railroad tipple or preparation plant. In the future, as the strip miners have to go deeper to uncover thinner seams which are farther from the railroad tipples, their cost per-ton-recovered will increase greatly. These facts, which have been verified by numerous conversations with strip mine producers, will produce sizeable increases in the strip miner's total cost to produce a ton of coal. The aforementioned reasons, along with stricter interpretation and enforcement of reclamation requirements, and limited productivity gains, which are not expected to match deep mining gains, lead me to conclude that strip-mined coal will not provide the level of competition to deep-mined coal that it did in the late 1970s and early 1980s. The resulting reduction in competition will allow deep miners to raise the price of their coal to match the expected increase in strip mine prices. This will produce real price growth even if productivity gains are forthcoming to the extent assumed by Mr. Komanoff.

Q. You identified "mining industry productivity gains or declines" as a third factor affecting delivered coal price escalation. Would you please expand on the effect of this factor?

A. I believe that the productivity gains in recent years were a result of the deep miners' determination to stay alive in a poor demand market at a time when strip miners were providing severe competition. In addition, the closing of a substantial number of both strip-mined and deep-mined coal mines, many of which had poor productivity, increased overall industry productivity. As fewer mines close, and as the supply-demand balance moves toward equilibrium, such industry productivity gains will diminish.

Mr. Komanoff has failed to recognize adequately the cyclical nature of the coal mining industry productivity changes over the past four decades. Technological changes have improved productivity time after time, but these gains invariably are eroded by other factors such as environmental and safety regulations and miner attitudes which are quick to sense and adjust to changes in market conditions, i.e. good production when the market is highly competitive and declining productivity in times of stronger market demand.

Because of these factors, and the expected reduction of competition from strip miners previously discussed, I feel that Mr. Komanoff overstates future productivity gains, and, in doing so, understates real growth in prices, especially in the 1985 to 1995 period.

Q. You identified "contract/spot purchases - timing and mix" as another factor affecting delivered coal price escalation. Would you expand on this please?

A. With respect to coal purchases, PECO, for example, has purchased from approximately ten to ninety percent of its coal on contract in any given year. The reasons for this wide variation include: (a) spot market prices; (b) contract bid prices; (c) railroad car shortages; (d) UMW (or other) strikes; (e) expected coal specification changes; and (f) PECO's average burn of 1.2 million tons per year. With respect to coal contracts, PECO's coal contracts have ranged in term from one year to five years.

I do not know of any recently signed coal contracts for utilities in the Northeast having a term of more than ten years without "reopener clauses", which have the effect of allowing the utility and coal companies to adjust the contract price to be in line with the current market price.

Q. What is your conclusion with respect to the future rate of mine-mouth coal price escalation for coal purchased by PECO?

A. Based on my experience, on historical data on mine prices in Pennsylvania and West Virginia, on historic escalation in coal miners' wages, and projected increases in the cost of surface-mined coal, I believe the long-term real escalation in mine-mouth coal prices (F.O.B. mine) will be about two percent per year.

Q. You identified "railroad rates" as a final factor affecting delivered coal price escalation. Would you please comment on how your assumptions differ from those of Mr. Komanoff?

A. Mr. Komanoff assumes that transportation rates will escalate at the rate of inflation between 1985 and 1990, 0.5% above the rate of inflation between 1990 and 2000, and 1.0% per year above the rate of inflation after 2000. I have assumed that transportation rates will increase at 2% per year above the rate of inflation.

Q. Why do you believe that the escalation rates of transportation proposed by Mr. Komanoff are understated?

A. With respect to railroad rates, the Staggers Rail Act of 1980 ("Staggers Act"), 49 U.S.C. § 10101 et seq., which was originally designed and expected to protect captive shippers (such as utilities), has not produced such protection. Cromby and Eddystone, for example, are serviced only by Conrail, and are therefore captive. In PECO's situation, we can expect railroad coal rate increases under 49 U.S.C. §10705(b) of the Staggers Act, which allows rate increases for rail carriers not earning "adequate revenues". The pending disposition of Conrail magnifies the above uncertainties in rail rates and leads to the conclusion that there is a high probability that long range real growth in rail rates will equal or exceed the historic trend in the eastern railroad industry's operations cost, which has averaged increases of approximately two percent per year above the rate of inflation over the past thirty years.

Additionally, the current high productivity of Conrail employees could decline if the railroad is sold to an "unfavorable" carrier. Thus, I believe that it is reasonable to assume that transportation rates from mines in Pennsylvania and northern West Virginia will increase at a real rate of two percent per year over the life of the Limerick Unit No. 1 plant. As mentioned above, this increase is consistent with the real escalation in the operating costs of railroads operating in the east over the past three decades. This history is fully discussed and summarized in the rebuttal testimony of Dr. William H. Hieronymus (PECO St. No. 15B).

FUEL PRICES - OIL

Q. Why do you feel that Mr. Komanoff's oil price projections are incorrect?

A. Mr. Komanoff makes a mistake common to many people who seem to feel that oil markets will remain soft for many years. This erroneous view fails to recognize the behavior of the oil market since 1973. After the 1973-1974 oil embargo, prices declined in real terms for a number of years, but then prices more than doubled in the 1979-1981 period. Since the early 1980s it is true that markets have been soft and we have seen a recent drop in the price of crude oil. However, it would be a mistake to assume that the market will remain soft for much longer. Based on our industry contacts and experience, we believe prices will rebound quickly as demand increases and the current depressed market stabilizes.

Q. Are there any other studies which support your view of the oil market?

A. Yes. Dr. William W. Hogan's rebuttal testimony in this proceeding (PECO St. No. 37), and Dr. Hogan's recently co-authored article with Paul N. Leiby entitled "Oil Market Risk Analysis", (Harvard University Energy Security Discussion Paper Series, H-85-03 (December, 1985)), demonstrate the probability that my view that future oil prices will significantly increase is far more likely than the view presented by Mr. Komanoff.

PECO's USE OF DRI FORECASTS

Q. Please elaborate on your assertion that Messrs. Komanoff and Chernick incorrectly assume that PECO's fuel forecast should conform to the DRI forecasts.

A. As summarized earlier, DRI is only one of a number of sources used by PECO in forecasting fossil fuel prices. DRI is used only as a benchmark to see how a major forecasting organization is looking at various aspects of the economy. PECO's primary forecasting sources are its daily contacts with coal producers, fuel marketing companies, brokers, and barge, rail, and trucking companies. These contacts are supplemented by first hand experience over the past two decades in contracting for the purchase of coal, oil and transportation. I believe that "real-world" experience is the most reliable basis for developing fuel price forecasts.

Q. Would you elaborate on your assertion that Mr. Chernick lacks an informed basis for his assumption that DRI's forecasts are more reliable than PECO's forecasts?

A. Mr. Chernick apparently has had little or no experience in preparing fuel forecasts, nor has he had any practical experience in negotiating for the purchase of coal or oil. Indeed, in his cross-examination testimony he conceded that he has had no such practical experience (Tr. 2904-05). Also, he has no basis for assuming that professional forecasters such as DRI are more likely to produce accurate forecasts than individuals having years of experience in the fuel business. Mr. Chernick, in fact, acknowledged that DRI's oil price projections have not proven accurate over time (Tr. 2905).

Q. Does that conclude your rebuttal testimony?

A. Yes.

BIOGRAPHICAL INFORMATION

Paul X. English, Jr.
Manager
Fuel Procurement Department

Education

Bachelor of Science Degree in Civil Engineering
Virginia Military Institute - 1949

Nuclear Fuel and Core Management Courses
MIT and Georgia Tech - 1974 and 1975

Executive Development Program
Graduate School of Management, Cornell University - 1984

Registered Professional Engineer in Virginia

Employment

Philadelphia Electric Company - July 5, 1949 -

1949 - Cadet Engineer (Executive Training Program)

1950 - Engineer in Training - Station Economy Division

1950 - 1953 -
U.S. Army Officer
Radio Officer and Company Commander

1953 - 1959 -
Engineer Plant Test - Generating Station

1959 - 1962 -
Plant Engineer - Generating Station

1962 - 1966 -
Assistant Superintendent - Generating Station

1966 - 1972 -
Superintendent - Generating Station

1972 - 1975 -
Superintendent, Services Division
Electric Production Department

1975 - 1977 -
Superintendent - Generation Division
Electric Production Department

1977 - 1981 -
Superintendent, Fuel Division
Electric Production Department

1981 - Present -
Manager of Fuel Procurement Department

EXHIBIT PXE-2

Projected Coal Prices to PECO
($/ton in current dollars)

Year	PECO[1/] Current $	PECO[1/] Real Annual Increase	O.C.A.[2/] (Komanoff) Current $	O.C.A.[2/] (Komanoff) Real Annual Increase
1985	45.50		45.50	
		2%		0%
1990	65.30		59.46	
		2%		.5%
1995	95.95		81.47	
		2%		.5%
2000	141.00		111.62	
		2%		1.0%
2005	207.20		156.55	

1/ Prices used by PECO to conduct Limerick's life-cycle analysis.

2/ Based on escalation rates set forth on page 30 of OCA St. No. 6.

EXHIBIT PXE-3

RELEVANT PORTION OF LIMERICK UNIT NO. 2
INVESTIGATION CROSS-EXAMINATION OF
GEC WITNESS C. HOFF STAUFFER

(TR. 2728-2730)

assumption, namely that you would be entering into a contract of significant length each year?

A I understand the question. No, I don't have an estimate. I could do an estimate, but I don't have one.

Q In your estimate would it be higher or lower than the 1.1 percent escalation rate for the later period?

A I don't know. There's offsets. The long term contract in '85 that nobody would sign, would be a little bit less than the full costs of production, because it would be trying to compete in a market where the first one, at least, if not five years, would be lower than full costs.

On the other hand, what drives the escalation rate is the market demands, which causes people to open up new reserves. And those market demands don't start hitting the market for this coal until the mid '90's. So there would be very few of these kinds of mines opened up before 1985, so the real escalation rate on those mines appear to be very low. And they offset, and therefore, I don't know.

Q All right.

A I could figure it out, but I don't know.

Q What about on a spot basis, 1985 through 1990, do you have any --

A The spot prices will be going up rather smartly.

Q What kind of escalation rate in real terms would you say that would be?

A Well, for that kind of coal over that period, they will go up from -- I could tell you precisely, but I think, not following this closely, go about $30.00 a ton to $36.00 a ton. Maybe $38.00 a ton.

Q Total or annually?

A Total over that period.

Q Between 1985 and 1990?

A That's correct. And that's because the prices will be going from a variable cost level to a full cost level without even opening up any kind of reserves. It is a different kind of escalation. It is not a kind of escalation associated with opening up more difficult reserves. It is the consequences of the market coming in balance. The market demands catching up to the production capacity.

Q Which you believe is going to be happening in the late '80's and early '90's?

A Yes.

JUDGE TURNER: You are saying the total increase that you anticipate now within the next five years was somewhere between $30.00 and $38.00?

THE WITNESS: Not the increase. It would increase from $30.00 a ton, which is approximately the spot market price --

JUDGE TURNER: Right now?

THE WITNESS: Right now.

JUDGE TURNER: You are talking about a six to eight dollar increase a ton?

THE WITNESS: And $38.00 a ton is approximately the full cost price for those mines in the Pittsburgh seam.

BY MR. CALVERT:

Q All right. Now, we have covered the period from '93 to 2030 and from '94 to '90. That leaves the '90 to '93 period. Do you have any estimate of what the escalation would be in a contract price with the kind of coal we needed at the Chester plant, long term contract, between 1990 and '93?

A 30 year contract?

Q Yes.

A You can get that contract with no real escalation whatsoever.

Q But take this assumption, that in 1990 you would enter into that contract. And then now look at 1991. Assuming you enter into that same or a similar type contract in '91, you didn't do it in '90, did it in '91. You did that through '93. What I want to do is compare the 1990, starting at a 1993 starting figure, and see what kind of escalation there would be in the coal.

MS. FERKIN: Your Honor, before we go on, I'm not sure if Mr. Calvert is doing anything beyond would could have been done in discovery.

OCA Statement No. 5-A

R-850152
3-11-86

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

SURREBUTTAL TESTIMONY

OF

PETER J. LANZALOTTA

CONCERNING

SYSTEM RELIABILITY

AND

EXCESS CAPACITY

February, 1986

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

SURREBUTTAL TESTIMONY
OF
PETER J. LANZALOTTA

Q. Please state your name and business address.

A. My name is Peter J. Lanzalotta. My business address is Suite 350, 1301 Pennsylvania Avenue, N.W., Washington, D.C., 20004.

Q. Mr. Lanzalotta, have you previously submitted testimony on behalf of the Pennsylvania Office of Consumer Advocate in this proceeding?

A. Yes, my direct testimony, submitted as OCA Statement No. 5, dealt with system reliability and the need for Limerick 1.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my testimony here is to respond to certain portions of the rebuttal testimony of Mr. Cary H. Rush and Dr. William H. Hieronymus.

Q. Mr. Rush, on page 1 of his rebuttal testimony (PECO Statement No. 14-A), takes exception to the statement in your direct testimony (OCA Statement No. 5) that from a reliability standpoint in 1986, anything above 22.5% reserves is excess capacity. Do you agree with Mr. Rush's rebuttal?

A. No, I do not. Mr. Rush argues that, because PECO uses a 25% long range planning reserve margin target, this is the proper basis from which to determine in the short-term, how much capacity is needed by PECO from a reliability point of view. In truth, the amount of capacity needed by PECO is determined by PJM in its calculations of how much capacity is needed to meet PJM's one day in ten years loss-of-load probability reliability target. Mr. Rush represented in his direct testimony that, in 1984, PJM determined that PECO would need to supply a 22.5% reserve margin in 1986 in order to allow PJM to operate in a reliable fashion.

Q. Does the use of different reserve margin requirements within the range from 22.5%-25% make any difference regarding your recommendation as to the amount of excess capacity?

A. No, as my direct testimony points out, if a 25% planning reserve margin is used, then PECO's discretionary capacity is still in excess of PECO's load plus 25%, by more than twice the OCA's recommended capacity adjustment of 450 MW.

Q. On pages 6 and 7 of PECO's Statement 14-A, Mr. Rush states that, with Limerick 1, PECO will have only 158 MW of capacity in 1986 above its 25% planning objective. Do you agree?

A. No, I do not. PECO has much more discretionary capacity than Mr. Rush calculates, but PECO is advancing the retirement dates of a substantial amount of generating capacity because of Limerick 1. The advancement of the retirement dates for Southwark 1 and 2 and for the 458 MW of CT capacity is made possible by and is based upon the presence of the Limerick 1 capacity. It is circular and fallacious to, first, use the presence of Limerick 1 as justification for advancing the retirement dates of this generating capacity and then to turn around and use the capacity lost due to the advanced retirement dates for these units as justification of the need for Limerick 1's capacity. Using this type of reasoning, almost any new additional generating capacity could be justified regardless of a utility's existing reserve margin.

If Limerick allows the advancement of retirement dates of generating units, this capacity which is retired ahead of time would be available to serve load, but for the presence of the Limerick generating capacity and should be so recognized. It is illogical to use the presence of Limerick to justify these accelerated retirements and then to turn around and use these accelerated retirements as justification of the need for Limerick.

Q. On page 17 of PECO's Statement No. 14-A, Mr. Rush characterizes your position as being that PECO need not build its own base-load generation, but can instead rely upon the base-load generation of other PJM companies. Is this a correct characterization?

A. Definitely not. My position in my direct testimony is that additional base-load generation is not presently justified by PECO's reliability situation and is certainly not justified by Mr. Rush's optimal mix arguments as presented in his direct testimony (PECO Statement No. 14). It appears that even PECO did not consider these optimal mix arguments as evidenced by their repeated attempts to sell substantial amounts of base-load capacity. I am not taking the position that a utility should never build base-load generating capacity. Rather, my position is that such capacity should be built only when it is cost-justified. Mr. Rush's optimal mix theory arguments in his direct testimony do not address the issue of cost at all. My direct testimony was intended to point out these shortcomings of Mr. Rush's support for the addition of Limerick to PECO's generating mix regardless of the resulting reserve margin or cost consequences.

Q. On page 18 of his rebuttal testimony (PECO Statement No. 15A), Dr. Hieronymus testifies that PECO has reached a point where it believes it can safely retire the CT generating capacity. Is this relevant to your system reliability and excess capacity arguments?

A. No, it is not. If a utility has excess capacity, it will always have the ability to mothball or prematurely retire certain generating units. The fact that such retirements are possible does not prove the need for a new generating unit. For example, the addition of Limerick allows PECO to retire a large amount of generating capacity before the end of its normal service life simply indicates the excess nature of much of the Limerick 1 capacity. The addition of Limerick 1 is not justified on the basis of replacing relatively serviceable generating capacity, that is largely paid for, with very expensive generating capacity which requires a large increase in rates.

I question the line of reasoning wherein the presence of Limerick is used to justify the advancement of generating unit retirements and then the capacity supply situation which results from these same generating unit retirement advancements is used as justification of the need for the Limerick 1 capacity.

Q. Does this conclude your surrebuttal testimony?

A. Yes, at the present time.

OCA Statement 6A
R-850152
3-11-86

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

SURREBUTTAL TESTIMONY

OF

CHARLES KOMANOFF

CONCERNING

ECONOMICS OF LIMERICK UNIT 1

ON BEHALF OF

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

March, 1986

Q. Please state your name and business address.

A. My name is Charles Komanoff. My address is Komanoff Energy Associates, 270 Lafayette Street, Suite 902, New York, NY 10012.

Q. Have you testified previously in this proceeding?

A. Yes. I presented direct testimony on behalf of the Pennsylvania Office of Consumer Advocate (OCA). My prefiled direct testimony is marked OCA Statement 6.

Q. What is the purpose of your surrebuttal testimony?

A. My testimony addresses criticisms put forth by PECO rebuttal witnesses regarding my estimates of future Limerick 1 capacity factor, capital additions expenditures, and fuel savings.

<u>Limerick Capacity Factor</u>

Q. Please summarize your direct testimony concerning Limerick 1 capacity factor.

A. I have projected a 60% capacity factor for Limerick 1, based on my testimony a year ago in the Limerick 2 investigation (I-840381). In that testimony, I derived levelized capacity factor averages of 54% for a new plant's first 12 years of operating life and 50% for the first 20 years of life, based on boiling water reactor (BWR) operating data through 1984. I averaged these results and added 8 percentage points for Limerick 2 to reflect design improvements and a possible diminution in the effect of the TMI accident on nuclear plant performance -- resulting in a 60% projection. I deemed this result applicable to Limerick 1 as well.

Q. Did you take note of 1985 performance data in developing your Limerick 1 capacity factor estimate?

A. Yes. I observed that preliminary data indicated an average 54% capacity factor for BWRs in 1985. Although older BWRs performed quite well last year, thus weakening the correlation I had observed between advanced age and lower performance in data through 1984, I regarded the 54% average for 1985 as generally confirming my 60% projection for Limerick 1.

Q. What is PECO's major criticism of your estimate of Limerick 1 capacity factors in its rebuttal testimony?

A. PECO rebuttal witness Hieronymus has updated my statistical treatment of BWR capacity factor data by incorporating 1985 capacity factors. The result, he argues, is a 5 percentage point increase in my projected 20-year average capacity factor. From this he concludes that I should add 5 percentage points to my estimate of Limerick 1's capacity factor, changing it from 60% to 65%.

Q. Do you think Dr. Hieronymus's revision to your capacity factor projection is justified?

A. No. Dr. Hieronymus's bid to revise my capacity factor projection suffers from several important errors. First, he has calculated capacity factors as simple arithmetic averages rather than as levelized (present-worth) averages. More importantly, though he makes much of the fact that my variable relating lower capacity factors to advanced age is no longer statistically significant with 1985 data, he has neglected to reflect this in his own calculations.

Q. Please explain.

A. I'll begin with my second point, involving the aging factor, since that is the more significant.

Dr. Hieronymus appears to have misconstrued the purpose of the aging variable in my statistical analysis. Using data available a year ago, through 1984, it was apparent that BWR capacity factors generally improved with rising age, <u>but only through age 12</u>. After age 12, on very limited data, BWR capacity factors dropped sharply — by almost 30 percentage points.

Q. How did you treat this dichotomy in the relationship between age and BWR capacity factors in your Limerick 2 testimony last year, which you applied in your direct testimony on Limerick 1 here?

A. I devised two separate variables to measure BWR aging effects. One variable measured the year-to-year increase in capacity factors through age 12. This gain averaged 1.2 percentage points per year. The other measured the drop-off in performance after age 12, which came to roughly 30 percentage points.

Q. Why did you devise two age variables, rather than simply correlating capacity factor to plant age?

A. Had I done so, I would have found no statistically significant relationship between capacity factor and age. The sharp decline in capacity factors after age 12 would have offset enough of the improvement in performance before age 12 to render it statistically insignificant. While it would have been correct to conclude that, on the whole, performance wasn't related to age, that conclusion would have masked two underlying, opposing trends, one indicating improvements through age 12, the other indicating declines thereafter.

In effect, my purpose in devising the "Over-12" variable was to control for the capacity factor declines after age 12 so that the real gains through age 12 would show up statistically significant.

Q. How has Dr. Hieronymus misconstrued this?

A. According to Dr. Hieronymus, the over-12 factor loses statistical significance when 1985 data are added. That would indicate that BWR performance after age 12 isn't different from performance before age

12. In that event, the over-12 variable no longer has a role in the analysis, since there is no decline past age 12 to isolate from the remainder of the data. Thus, the over-12 variable must be discarded, and capacity factors must be correlated with plant age alone. Dr. Hieronymus failed to do this, however. By retaining the over-12 factor, he derived an artificially inflated relationship between age and improved capacity factors. The result is a flawed projection of aging trends and, therefore, of Limerick's lifetime capacity factor.

Q. What happens to the statistical projection of Limerick's capacity factor when the over-12 variable is discarded and capacity factor is correlated only to one variable representing age?

A. Although time constraints precluded my performing the complete analysis, I offer an educated guess that the age variable loses its statistical significance when performance at all ages is treated uniformly. This would result partly from data for older reactors (which still underperform the BWR average, though no longer as strongly as before 1985), and partly from the very poor performance of "middle-aged" BWRs last year. (BWRs aged 10 and 11, including Peach Bottom 2 and 3, averaged 32% capacity factor in 1985, as I pointed out in my direct testimony at p 29.) If that hunch is correct, the trajectory of projected capacity factors would be flat with respect to age, rather than increasing as in Dr. Hieronymus's projections. Needless to say, this would result in a very different set of capacity factor projections than those offered by Dr. Hieronymus.

Q. Why is Dr. Hieronymus's use of simple averages inappropriate for projecting Limerick 1 lifetime capacity factors?

A. Simple arithmetic averages of expected annual lifetime capacity factors mask the expected present-worth value of Limerick generation. Consider two hypothetical capacity factor streams, both averaging 60% but one beginning at 70% and running down to 50%, while the other runs in reverse. The former is worth more on a present-value basis since it produces more generation in the early years. Thus in calculating a single lifetime average value to reflect the anticipated trajectory of annual capacity factors, it is customary to "levelize" the stream -- to discount future capacity factors and take the resulting average. I did so in deriving 12- and 20-year average capacity factors in the Limerick 2 investigation and in my direct testimony in this proceeding.

Q. What is the effect of using arithmetic vs. levelized averages to cull an average value from Dr. Hieronymus's annual projection of capacity factors in Exh. WHH-45?

A. The effect can be seen in this table:

Lifetime Average Capacity Factor for Limerick 1

Calculated by Dr. Hieronymus using KEA Regression Equation
(Updated by Dr. Hieronymus with 1985 Data)

PLANT LIFE (years)	LEVELIZED CF	ARITHMETIC CF
12	52.01	52.83
20	52.33	53.27
39	53.65	58.60

As the table shows, Dr. Hieronymus gains 5 percentage points by employing an arithmetic rather than correct levelized average in his 39-year average calculation. Interestingly, none of the averages calculated from his capacity factor trajectory reaches my capacity factor projection of 60%, not to mention PECO's assumed 65%. In fact, his 12- and 20-year forecasts average out to the same 52% figure that I derived (to which I added 8 percentage points to arrive at the 60% forecast).

Limerick Capital Additions Costs

Q. Have Dr. Hieronymus and Mr. Helwig correctly characterized your predictions of Limerick 1 capital additions costs?

A. No. On page 5 and in Exhibit WHH-41 of his testimony, Dr. Hieronymus has fashioned a misleading representation of both historic nuclear capital additions data and my method to predict such costs for Limerick 1. Likewise, Mr. Helwig expresses unwarranted faith that "big-ticket" capital additions have become a thing of the past due to the "advanced technology" employed in newer reactors such as Limerick (p 36). Both witnesses ignore the fact that my predictions of Limerick's lifetime capital additions capture the major factors which have consistently been associated with higher capital additions throughout the industry's experience with nuclear power.

Q. What is wrong with Dr. Hieronymus's comparing your Limerick 1 predictions with average experience for the rest of the industry?

A. In using broad industry averages as a basis for comparing my Limerick predictions, Dr. Hieronymus disregards factors strongly associated with the sharp runup in nuclear capital additions over time. Essentially, he compares my predictions for a single-unit plant recently built in a relatively high-wage area -- all of which contribute to higher costs -- with a larger group of plants dominated by early-vintage plants which also include multiple units and considerable data accumulated prior to Three Mile Island -- factors which account for lower capital additions. It is therefore no surprise that my Limerick predictions exceed the industry averages Dr. Hieronymus lists in Exh. WHH-41.

Q. As you note, Dr. Hieronymus is disturbed that your predictions exceed average nuclear capital additions costs to date. Is his concern valid?

A. No. An historical example can put this into context. Through 1978, U.S. nuclear capital additions costs had averaged $14.5 per kW per year (adjusted to 1984 dollars). Using Dr. Hieronymus's logic, one would have been hard-pressed in 1978 to justify a higher projection for future capital additions at PECO's Peach Bottom 2 and 3 units, particularly since Peach Bottom benefits from being a twin-unit station. Yet Peach Bottom capital additions since 1978 have averaged $24.9/kW per year (also in 1984 dollars), or 72 percent more than the average of data available at that time.

Similarly, the fact that my Limerick capital additions projection exceeds the industry average to date (though it doesn't exceed the 1984 average until 1992 -- a conservative feature Dr. Hieronymus ignores) isn't a concern. The projection is fully consistent with historical experience, provided the experience is distilled not into a simple average but into the more explanatory series of relationships captured in my regression equation.

Q. But aren't witnesses Hieronymus and Helwig correct to credit Limerick's newer vintage with reduced expectations of future capital additions?

A. Not at all. On the contrary, data through 1984 continue to show associations of <u>higher</u> capital additions costs with more <u>recent</u> plants, even after controlling for such factors as size, age, and the TMI accident (the effects of which I halved in predicting Limerick's future costs).

Q. Have you performed an analysis that substantiates your prediction of higher capital additions for newer reactors such as Limerick?

A. Yes. In Exhibit CK-11 I have broken down annual capital additions by plant vintage and age. It shows that the newest group of plants -- those completed roughly in 1976 and thereafter -- have required substantially higher capital additions <u>at each age of their operating lives</u> than their predecessors. Over their first eight years of operation, capital additions at the later-built plants have averaged more than double those at plants completed prior to 1976 ($29/kW versus $14/kW in 1984 dollars). Without controlling for the other contributors to overall variation in nuclear capital additions, it is clear that newer means higher, not lower cost (a conclusion also evident in my analysis of nuclear O&M costs).

Q. Please explain how you perfomed this breakdown of capital additions by vintage and age.

A. Using the same database underlying the Limerick predictions in my direct testimony, I categorized the observations to achieve a more or less even concentration of operating experience within three vintage groups. This produced groupings with commercial operation beginning roughly (1) before 1973, (2) between 1973 and 1976, and (3) 1976 and thereafter. (Exhibit CK-11 shows that the three vintage groups created by this categorization have comparable amounts of operating years.) While there is little difference between capital additions between Group 1 and Group 2, the higher costs for Group 3 are unmistakable.

Q. How does the difference in capital additions costs between Group 3 and Groups 1/2 bear on Dr. Hieronymus's rebuttal testimony?

A. Dr. Hieronymus considers it significant that my predictions of Limerick 1 capital additions costs exceed the U.S. average over the 1970-84 period. The excess is far less pronounced, however, when my predictions are compared to the average for recently built plants.

Q. What about the rest of the difference between your predictions for Limerick and the average costs Dr. Hieronymus lists in his Exh. WHH-41?

A. As I said earlier, broad and simple averages do not provide the most accurate estimates of the expected costs. Much greater accuracy is gained by controlling statistically for the factors that clearly account for variations in capital additions costs between and within the experience of operating reactors. Adjusting for such characteristics as Limerick's single-unit status would shrink the disparity between my predictions and Dr. Hieronymus's averages even further; so would adjusting for differences in plants' ages. Of course, one should adjust for <u>all</u> such differences -- vintage, single vs. multiple unit plants, age, not to mention saltwater vs. freshwater cooling and pre- vs. post-TMI operation. This is precisely what I have done via multiple regression analysis in projecting Limerick 1 capital additions (and O&M) costs in my direct testimony.

Q. Dr. Hieronymus suggests (PECO St. 15A, p 32) that the median is more suited than the mean for projecting future capital additions costs from empirical data. Do you agree?

A. Emphatically not. Statistical inference is based on mean or expected (average) values of observations, not on medians. Regression analysis, which Dr. Hieronymus and I employ (as does PECO witness Dr. Perl) is simply a technique for calculating means after adjusting for causal factors. In the real world of utility economics, costs and benefits depend on means as well. Rare but expensive outages or capital additions are billed (via fuel adjustments or rate base charges) on a full-cost basis, so that ratepayers experience the sum total of all charges (or their mean on an annual basis) rather than "typical" median costs. Of course, if PECO agreed to cap outage or betterment expenses to their annual medians, Dr. Hieronymus's preference for medians over means for calculating Limerick costs might have merit. I am aware of no such offer, however.

Q. Dr. Hieronymus asserts that your capital additions regression equation "fits the data quite poorly," indicating "that we have learned little even about the historic data from [your] model." (PECO St. 15A, p 34) Is this a fair criticism?

A. The relatively poor fit of the capital additions equation to the data might be a problem if I were using it to forecast Limerick capital additions <u>in a given year</u>. But for purpose of calculating Limerick life-cycle costs I am using the equation to generate expected capital additions <u>over many years</u>. As I pointed out in surrebuttal testimony in I-840381, the prediction for any single year may be subject to wide variation, reflecting the episodic nature of capital additions expenditures; but it gives an unbiased estimate of capital additions averaged over Limerick 1's life.

Nor is it true that the equation conveys little about capital additions experience. It indicates that capital additions costs are higher for aging plants, for recently completed plants, for single-unit plants, and so forth. These statistically significant associations help make sense of the wide variation in utility capital additions expenditures at nuclear plants — a variation that, unfortunately, appears to be a fact of life for nuclear units.

Q. Dr. Hieronymus notes (p 34) that the wage variable in your capital additions equation isn't statistically significant. Why did you retain it in your analysis?

A. The wage factor, which seeks to tie variations in capital additions costs to varying wage rates in plant vicinities, was statistically significant in data through 1983, which I presented in the Limerick 2 case. Although it ceased to be significant with addition of 1984 data, I retained it for consistency with last year's approach, as I explained in my direct testimony. In any event, I did test a form of the equation that omits the wage variable. This equation, which was made available to PECO in workpapers, projects noticeably <u>higher</u> capital additions costs for Limerick 1 than the equation I employed to derive capital additions for my net benefit calculations. Thus, retaining the wage variable was conservative (it led to lower Limerick costs).

Q. Mr. Helwig takes issue with you for not basing your forecast of Limerick capital additions upon Peach Bottom, which he characterizes as "very similar" to Limerick. Are the two stations similar enough to warrant extrapolating directly from one to the other?

A. I don't believe so. Although both employ the same basic BWR concept, Limerick cost twice as much per kW to build as Peach Bottom (after adjusting for inflation and removing interest charges). This suggests that there are considerable differences in the underlying equipment, materials and components -- differences that will likely be reflected in varying requirements for upgrading and replacement. U.S. nuclear power experience is replete with instances in which a utility's second or third reactor differed greatly in cost and performance from its first. Until proven otherwise, I believe that industry-wide experience provides the better basis for extrapolating from past to future costs.

<u>Limerick Fuel Savings</u>

Q. Do you wish to comment on PECO rebuttal testimony regarding your assumptions pertaining to Limerick 1 fuel savings?

A. Yes. I will rebut assertions by PECO rebuttal witnesses Hieronymus, Hogan and English.

Q. Do you wish to comment on Dr. Hieronymus's assertions regarding future coal prices?

A. Yes. Dr. Hieronymus took issue with my statistic that the average price per ton of coal delivered to electric utilities had increased by only 0.7% per year in real terms since 1950 -- a relatively low rate for a turbulent era in the coal industry that I take as a harbinger of slow growth in future prices. Dr. Hieronymus believes the appropriate measure is the price per million Btu, since that more directly determines coal's fuel costs and, hence, nuclear fuel savings when Limerick displaces coal.

Q. Why do you disagree with that criticism?

A. Dr. Hieronymus's proposed adjustment is selective. As coal Btu contents have been dropping, making a ton of coal less valuable, coal sulfur contents have also been dropping, making a ton of coal more valuable, or at least more expensive. Many utility plants have been forced to switch to low-sulfur coal in the past 15 years. Whether utilities have responded by buying local or long-haul low-sulfur coal, the move to low-sulfur coal has raised average delivered coal prices. Accordingly, if not for the drop in sulfur contents, coal prices would have increased more slowly in past decades, whether measured by ton or by million Btu. Since PECO will be buying a constant grade of coal at its fossil stations, the historical reduction in sulfur contents that has lifted U.S. coal prices shouldn't be applied to future escalation in PECO's case. Thus, Dr. Hieronymus's estimate of the historical rate of growth in per-million Btu coal prices overstates the relevant trend for PECO.

Q. Do you take issue with Dr. Hieronymus's and Mr. English's rebuttal assertions concerning coal transportation costs?

A. Yes. Neither Dr. Hieronymus nor Mr. English makes reference to new long-term trends toward increased competition in the transportation sector. The recent wave of cost-cutting in trucking and air travel and transport, primarily in response to deregulation, will inevitably reach the railroads as well. Indeed, the first evidence of this may be in the negative real growth in railroad charge-out rates for the Eastern district in the past several years, as Exh. WHH-51 shows. The railroads, like coal mining, have begun rationalizing work rules, modernizing track and rolling stock, and installing computerized schedule and flow controls. These trends should be expected to continue, with concomitant savings.

Q. Do you share Mr. English's concern that depletion of coal reserves will lead to inexorably rising coal prices?

A. I think his concern is vastly overstated. From 1983 to 1984 (the last years for which data are available), the demonstrated coal reserve base declined by only 0.5% in both Pennsylvania and West Virginia, implying a 200-year reserve base. That, in turn, is only a subset of the larger coal "resource" base. (Source, DOE/EIA-0118 (84), "Coal Production 1984," Table A2.) This hardly supports the spectre of "great" or "sizeable" increases in mining costs conveyed to Mr. English by producers (PECO St. 32, p 6).

Q. What are your comments on Dr. Hogan's forecast that oil prices will climb higher and faster than you projected in your input assumptions for PECO's SOBIG run?

First, none of the fuel savings estimates offered in this proceeding — not OCA's and certainly not PECO's — reflect the current world oil price of roughly $15 per barrel. (While I don't have current data on PECO's or other utility's prices paid for power plant residual oil, it is a safe assumption that residual oil and crude oil will remain in rough parity, leading shortly to $15/bbl residual oil.) OCA's and PECO's assumptions of the cost of residual oil in 1986 are 75 to 85 percent above the current crude cost. As a result, both OCA's and PECO's calculations of the cost of oil in valuing Limerick 1 fuel savings are considerably overstated for 1986.

Q. Granted that 1986 oil prices will be far less than your and PECO's assumptions, isn't it possible that lower oil prices imply higher prices later on, which would offset the error from the current period of low prices?

A. Although lower oil prices may set the stage for higher prices in the future (which in turn would pave the way for supply increases and demand contraction leading to low prices, and so forth), the offset is likely to be only partial, due to the time value of money. In a present-worth calculation, future dollar savings matter less than present ones, dollar for dollar. Limerick 1 is being brought on line at the very moment when oil prices have plunged to their lowest levels in roughly a decade. Prices will have to swing upward more than proportionately in future decades to make up for the lost fuel savings in these critical early years. Thus, even if I have underpredicted average oil prices (which I raise only arguendo), I may not have underpredicted Limerick's oil savings.

Q. Do you wish to comment on the HOMS model on which Dr. Hogan's rebuttal trajectory of oil prices is based?

A. Yes. HOMS assumes that world oil demand is equally sensitive to decreases as to increases in price -- a feature that Dr. Hogan acknowledges has prompted criticism (Hogan & Leiby, "Oil Market Risk Analysis," p V-22). This appears highly questionable. Much of the decline in oil intensity (oil use per unit of economic product) since the early 1970s has resulted from major long-term capital investments to save or switch from oil. These range from home insulation to fuel-efficient aircraft, from catalytic-driven petrochemical processes to long-distance gas pipelines. Investments such as these will hardly be forsaken at lower oil prices (except in relatively marginal ways, such as reduced maintenance of some oil-displacing investments). Yet HOMS and Dr. Hogan's projections appear to assume that they will.

Q. If the assumption of symmetric oil price elasticity is incorrect, what is the effect on Dr. Hogan's oil price forecasts?

A. It would cause Dr. Hogan to overstate future oil prices. That is because HOMS derives oil prices on the basis of the level of utilization of OPEC production capacity, which is strongly affected by world oil demand. While I endorse that framework, oil demand inputs emanating from unrealistic specification of demand's sensitivity to price could lead to large forecast errors.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BREAKDOWN OF NUCLEAR CAPITAL-ADDITIONS COSTS BY AGE AND VINTAGE

1984 $/kW, Number of Plants in Group

(Page 2 shows the progression of each group's cost by age, in graph form)

AGE	VINTAGE GROUP 1	GROUP 2	GROUP 3	ALL VINTAGES
1	$16.42 15	$8.89 19	$29.93 19	$18.56 53
2	$9.44 12	$9.12 13	$25.08 16	$15.44 41
3	$9.32 13	$7.81 13	$23.59 15	$14.06 41
4	$9.96 14	$7.21 13	$21.27 14	$12.95 41
5	$9.72 14	$8.35 12	$33.76 12	$16.88 38
6	$11.58 14	$15.76 12	$44.11 11	$22.61 37
7	$24.41 14	$26.23 14	$29.29 8	$26.20 36
8	$23.67 15	$29.33 14	$29.31 4	$26.76 33
ALL AGES (1 - 8)	$14.55 111	$14.09 110	$28.92 99	$18.84 320
Group 1/2 overall avg:				14.32

Sources and Notes

Group means calculated from KEA database of nuclear capital-additions costs, through 1984.

Vintages were defined to achieve approximately even distribution across groups, as follows: GROUP 1 includes all plants entering commercial operation in or before January 1973. GROUP 2 includes plants entering service between February 1973 and November 1975. GROUP 3 contains all plants entering service after November 1975, and before 1984.

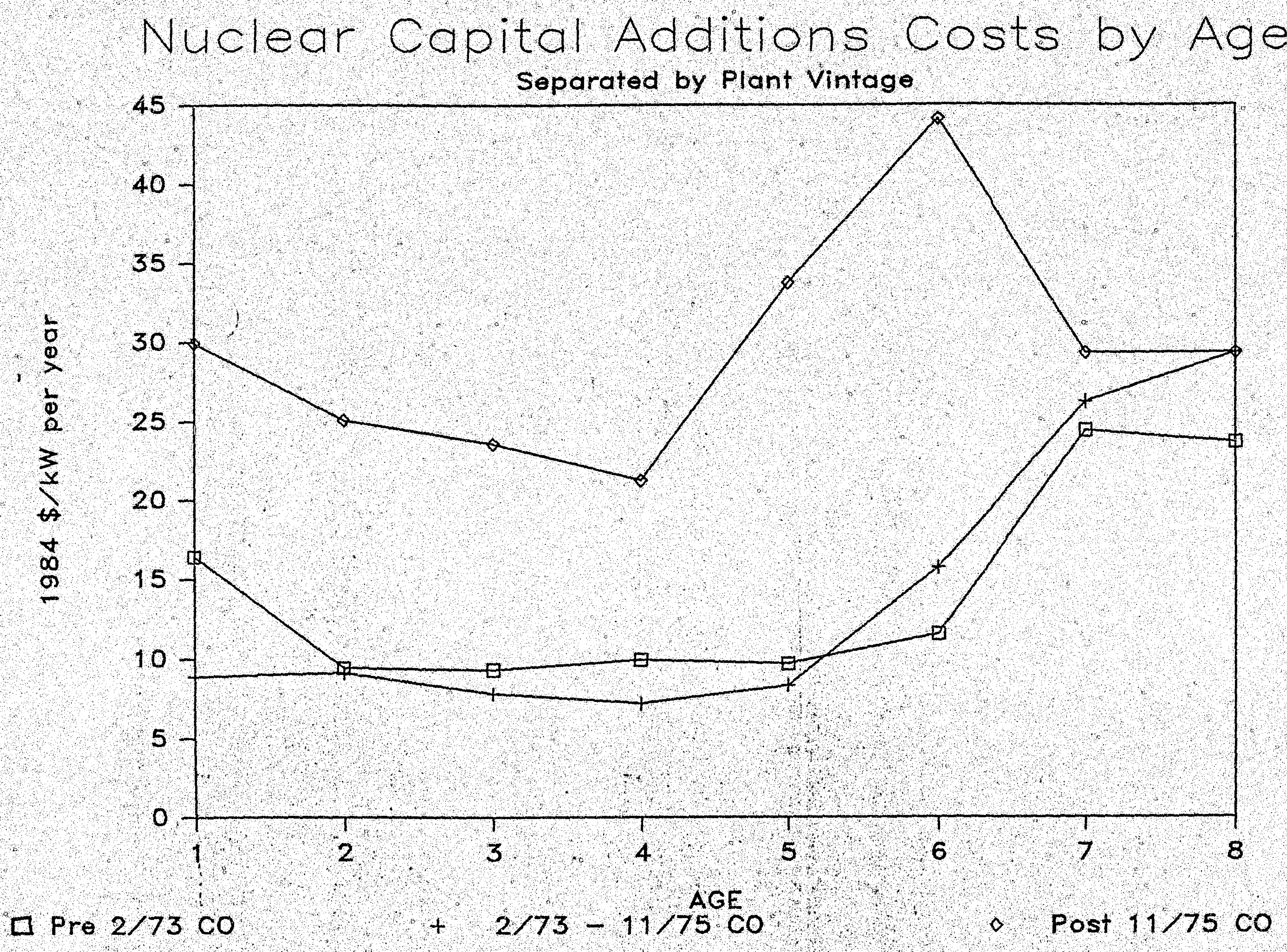

Exhibit CK-11
Page 2 of 2

OCA Statement 7A
R-850152

3-11-86
/HS

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PHILADELPHIA ELECTRIC COMPANY

SURREBUTTAL TESTIMONY

OF

THOMAS E. KNUDSEN

CONCERNING

FINAL REVENUE REQUIREMENTS RECOMMENDATION

ON BEHALF OF

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

March, 1986

Q. Are you the same Thomas E. Knudsen who previously filed direct testimony in this proceeding?

A. Yes, I have previously submitted direct testimony identified as OCA Statement 7.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my testimony is to present the OCA's final revenue requirements recommendation. This recommendation is that the Philadelphia Electric Company should be permitted to increase its rates to obtain an increase in its overall revenue requirement of no more than $136,088,000, as shown on Revised Schedule TEK-1. This revised recommendation is based upon the revised positions of OCA witnesses Bleiweis and O'Brien.

Q. Have you prepared schedules which reflect the OCA's final position?

A. Yes. Attached to this Statement are Revised Schedules TEK-1 through TEK-14.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

PHILADELPHIA ELECTRIC CO.
REVENUE REQUIREMENT
TEST YEAR AT JUNE 30, 1986
($000)

REV. SCHEDULE TEK-1

	REVISED COMPANY (1)	ADJ (2)	REVISED O.C.A. (3)	SCHEDULE
MEASURE OF VALUE	$6,943,888	($1,365,149)	$5,578,739	TEK-2
COST OF CAPITAL	12.77%	-0.74%	12.03%	ST.4,SCH. 1
P.F. OP INC-PROP RATES	$886,923	($215,801)	$671,122	
P.F. OP INC-PRES RATES	$447,335	$52,819	$500,154	TEK-3
INCOME DEFICIENCY	$439,588	($268,620)	$170,968	
CONVERSION FACTOR			2.031388	
REVENUE REQUIREMENT	$892,974	($545,672)	$347,302	
FUEL ROLL-OUT	$211,214	$0	$211,214	
NET REV REQUIREMENT	$681,760	($545,672)	$136,088	

REV. SCHEDULE TEK-2

PHILADELPHIA ELECTRIC CO.
MEASURE OF VALUE
TEST YEAR AT JUNE 30, 1986
($000)

	COMPANY (1)	ADJ (2)	O.C.A. (3)	SCHEDULE
UTILITY PLANT IN SERVICE				
ELECTRIC	$8,732,973	0	$8,732,973	ST.4,SCH.2
ALLOCATED COMMON	122,807	0	122,807	
LIMERICK #1 & 50% COMMON	=	(1,443,912)	(1,443,912)	TEK-4
TOTAL	8,855,780	(1,443,912)	7,411,868	
LESS:DEPRECIATION RESERVE	1,656,500	0	1,656,500	ST.4,SCH.2
LIM#1 DEP RESERVE		(14,641)	(14,641)	TEK-5
DEP UTILITY PLANT	7,199,280	(1,429,271)	5,770,009	
PLUS: NON-REV PROD CWIP	4,616	(1,442)	3,174	ST.4,SCH.3
LAND HELD FF USE	8,651	(8,651)	0	
M&S	94,168	(1,411)	92,757	ST.4,SCH.4
NUCLEAR FUEL	76,488	0	76,488	
CASH WORKING CAP'L	96,451	2,686	99,137	TEK-9
TOTAL ADDITIONS	280,374	(8,818)	271,556	
LESS: ACCUM DEF INC TAX				
ACCEL AMORT	2,323	0	2,323	
LIB DEPREC	525,327	(23,375)	501,952	ST.4,S.5&6
LIMERICK #1		(60,043)	(60,043)	TEK-6
CUSTOMER DEP	7,682	0	7,682	
CUSTOMER ADV	434	0	434	
SALEM UNIT #1	0	4,380	4,380	
SALEM #2 TAX BENEFITS	0	6,098	6,098	ST.4,SCH.7
TOTAL DEDUCTS	535,766	(72,940)	462,826	
TOTAL MEASURE OF VALUE	$6,943,888	($1,365,149)	$5,578,739	

PHILADELPHIA ELECTRIC CO.
INCOME ADJUSTMENTS
TEST YEAR ENDED JUNE 30, 1986
($000)

		SCHEDULE
P.F. OPERATING INCOME- COMPANY	$447,335	
ADJUSTMENTS:		
ANNUALIZATION FOR GROWTH AND CUSTOMERS	3,607	ST.4,SCH.11
BOOK DEPRECIATION	0	ST.4,SCH.2
TAX DEPRECIATION	0	ST.4,SCH.6
NORMALIZATION OF TAX DEFERRALS	0	ST.4,SCH.6
PRO FORMA INTEREST	(37,493)	TEK-14
NUCLEAR & STEAM PRODUCTION O&M	2,154	ST.4,SCH.12
KEYSTONE ALLIANCE	2,068	ST.4,SCH.13
MISC ADJUSTMENTS & AMORTIZATIONS (INCL SALEM MGT)	642	ST.4,SCH.10
DECOMMISSIONING	347	ST.4,SCH.14
SPENT FUEL DISPOSAL	0	ST.4,SCH.9
SALEM UNIT #2-TAX BENEFIT TRANSFER	115	ST.4,SCH.7
ACCUM DEFERRED STATE INCOME TAXES	3,055	ST.4,SCH.5
CAP'D PENSIONS, TAXES & BENEFITS	8,097	ST.4,SCH.15
CONSOLIDATED INCOME TAX SAVINGS	342	ST.4,SCH.8
SEQUOYAH & LEE MINES	1,532	TPH-2A,D-24
DEPRECIATION-LIMERICK	39,294	TEK-5
TAX DEPRECIATION-LIMERICK	(83,430)	TEK-6
EXCESS TAX DEPRECIATION-LIMERICK	60,043	TEK-6
I.T.C.-LIMERICK	(1,889)	TEK-7
EXCESS CAPACITY	54,335	TEK-8
TOTAL ADJUSTMENTS TO INCOME	52,819	
P.F. OPERATING INCOME- O.C.A.	$500,154	

REV. SCHEDULE TEK-4

PHILADELPHIA ELECTRIC CO.
LIMERICK UNIT #1 ADJUSTMENTS
TEST YEAR AT JUNE 30, 1986
($000)

UTILITY PLANT IN SERVICE	BALANCE	SOURCE
LIMERICK #1	$2,532,627	
LIMERICK 100%		
COMMON FACILITIES		
NON-DEPRECIABLE	7,349	
DEPRECIABLE	1,271,675	
LIMERICK TRANSMISSION	8,349	
LIMERICK #1&100% COMMON	3,820,000	TPH-2, C-2
ADJUSTMENTS:		
MARK II	(194,000)	ST.1A,JJO'B-23.3
DELAY-DIRECT(LIM#1&50% COMMON)	(386,800)	ST.1B,JJO'B-30.3
DELAY-INDIRECT-PECO(LIM#1&50% COMMON)	(83,000)	ST.1A,JJO'B-25
DELAY-INDIRECT-BECHTEL(LIM#1&50% COMMON)	(140,600)	ST.1A,JJO'B-26
50% COMMON FACILITIES	(639,512)	
TOTAL ADJUSTMENTS	(1,443,912)	
LIMERICK #1&50% COMMON	$2,376,088	

REV. SCHEDULE TEK-5

PHILADELPHIA ELECTRIC CO.
LIMERICK UNIT #1 ADJUSTMENTS
TEST YEAR AT JUNE 30, 1986
($000)

DEPRECIATION & DEPRECIATION RESERVE	BALANCE	SCHEDULE
LIMERICK #1 & 50% COMMON ADJUSTMENTS TO PLANT	($1,443,912)	TEK-4
DEPRECIATION RATE-COMPOSITE	2.72%	TPH-2,C-5c
ADJUSTMENT TO DEPRECIATION EXPENSE	($39,294)	
ADJUSTMENT TO INCOME	$39,294	
% OF TEST PERIOD TO BE IN SERVICE (FEB. 15- JUNE 30, 1986)	37.26%	
ADJUSTMENT TO DEPRECIATION RESERVE	($14,641)	

PHILADELPHIA ELECTRIC CO.
LIMERICK UNIT #1 ADJUSTMENTS
TEST YEAR AT JUNE 30, 1986
($000)

		DEPREC'N BASE FOR TAXES (1)	DEPREC'N RATE FOR TAXES (2)	DEPREC'N (3)	SOURCE
TAX DEPRECIATION					
LIB. PLANT INSTALLED 1986		($1,443,912)	11.61%	($167,638)	TPH-2,D-7a
INCOME TAX @49.768%				$83,430	
ADJUSTMENT TO INCOME				($83,430)	
TAX DEFERRAL					
DEPRECIATION-	LIBERALIZED	1,443,912	11.61%	$167,638	TPH-2,D-7a
	STRAIGHT LINE	1,443,912	2.57%	37,109	TPH-2,D-8a
EXCESS DEPRECIATION				$130,529	
TAX DEFERRAL @46%				($60,043)	
ADJUSTMENT TO INCOME				$60,043	
ADJUSTMENT TO RATE BASE				($60,043)	

PHILADELPHIA ELECTRIC CO.
LIMERICK UNIT #1 ADJUSTMENTS
TEST YEAR AT JUNE 30, 1986
($000)

REV. SCHEDULE TEK-7

I.T.C. AMORTIZATION	AMOUNT	SOURCE
LIMERICK #1 & 100% COMMON PLANT	$3,820,000	
LIMERICK #1 & 50% COMMON PLANT ADJ.	1,443,912	
RATIO:PLANT ADJ/PLANT	37.80%	
I.T.C AMORT-LIMERICK #1 & 100% COMMON	$4,997	TPH-2,D-20
ALLOCATION OF I.T.C. AMORTIZATION	$1,889	
ADJUSTMENT TO INCOME	($1,889)	

PHILADELPHIA ELECTRIC CO.
LIMERICK UNIT #1 ADJUSTMENTS
TEST YEAR AT JUNE 30, 1986
($000)

REV. SCHEDULE TEK-8

EXCESS CAPACITY

LINE NO.		BALANCE	SOURCE
1	LIMERICK #1 & 50% COMMON	$2,376,088	TEK-4
2	LESS:LIMERICK TRANSMISSION	8,349	TPH-2,C-2
3	LIMERICK NET OF TRANSMISSION	2,367,739	
4	EXCESS CAPACITY	450 MW	
5	LIMERICK #1 CAPACITY	1,055 MW	
6	WEIGHTED COST OF COMMON EQUITY	5.38%	ST.4,SCH.1
7	ADJUSTMENT TO INCOME (LINE 3x(LINE 4/LINE 5)*LINE 6)	$54,335	

PHILADELPHIA ELECTRIC CO.
CASH WORKING CAPITAL- SUMMARY
TEST YEAR AT JUNE 30, 1986
($000)

REV. SCHEDULE TEK-9

	COMPANY (1)	ADJ (2)	O.C.A. (3)	SCHEDULE
O&M EXPENSE	$91,954	($647)	$91,307	TEK-10
TAXES	33,201	(4,217)	28,984	TEK-11
INTEREST PAYMENTS	(38,489)	7,566	(30,923)	TEK-12
PREFERRED DIVIDEND PAYMENT	85	(16)	69	TEK-13
AVERAGE BANK BALANCES	9,700	0	9,700	
TOTAL	$96,451	$2,686	$99,137	

PHILADELPHIA ELECTRIC CO.
CASH WORKING CAPITAL- O&M
TEST YEAR AT JUNE 30, 1986
($000)

REV. SCHEDULE TEK-10

WAGES & BENEFITS

D-5	WAGES	5,695
D-18	LIM O&M	6,408
		12,103

NET INTERCHANGE

D-3	OP.EXP	17,406
D-19	FUEL	(3,775)
D-21	FUEL-R.O.	(206,990)
		(193,359)

OTHER INVOICES

D-10	PROD O&M	6,326
D-11	O&M RETIR	(10,556
D-12	RATE CASE	(4,300
D-15	DECOMM'G	7,335
D-16	SP FUEL	3,803
D-18	LIM O&M	69,332
B-13	UNCOLL	(16,472
	KEYSTONE	(4,117
		51,351

	ACTUAL	PRO FORMA ADJ	PRO FORMA EXP	LAG DAYS	LAG DOLLARS
PAYROLL	275,564	5,270	280,834	10.5	2,948,757
NET INTER	421,472	(193,359)	228,113	35.0	7,983,955
NUC FUEL	136,823		136,823	46.5	6,362,270
COAL	84,660		84,660	31.2	2,641,392
COAL FRT	16,766		16,766	15.0	251,490
OIL	120,360		120,360	19.3	2,322,948
BENEFITS	19,276	6,194	25,470	1.8	45,846
PENSIONS	29,009	639	29,648	15.0	444,720
OTH INV	315,051	51,351	366,402	15.4	5,642,591
A&G	87,912		87,912	15.4	1,353,845
TOTAL	1,506,893	(129,905)	1,376,988	21.8	29,997,814

RESIDENTIAL	928,292	47.7	44,279,528
SMALL C&I	359,462	47.6	17,110,391
LARGE C&I	1,174,680	43.5	51,098,580
TOTAL	2,462,434	46.0	112,488,499

AVE LAG IN RECEIPT OF REVENUE	46.0
AVE LAG IN PAYMENT OF EXP	21.8
NET LAG	24.2
PRO FORMA TEST YEAR O&M	$1,376,988
PER DAY	$3,773
REQUIREMENT	$91,307

PHILADELPHIA ELECTRIC CO. REV. SCHEDULE TEK-
CASH WORKING CAPITAL- TAXES
TEST YEAR AT JUNE 30, 1986
($000)

TAXES OTHER			INCOME TAXES		STATE	F.I.T.
A-4	GRT @4.5%	15,629	A-4	REV-PROP	(10,321)	(63,302)
D-3	GRT @4.5%	2,240	D-3	REV	2,189	13,425
D-14	FICA	741	D-5	WAGES	(397)	(2,437)
D-21	GRT @4.5%	(9,753)	D-7	TAX DEP	5,418	33,226
			D-9	INT	(8,436)	(51,738)
		8,857	D-10	PROD O&M	(441)	(2,707)
			D-11	O&M RETIR	736	4,518
			D-12	RATE CASE	(187)	(1,153)
			D-14	FICA	(52)	(317)
			D-15	DECOMM'G	(512)	(3,138)
			D-16	SPENT FUEL	(265)	(1,628)
			D-18	LIM O&M	(5,284)	(32,410)
			D-19	NON-JURIS	767	4,707
				CONSOL TAX		(342)
				KEYSTONE	287	1,762
				ACC DEF ST		2,603
				SALEM #2 TAX	16	98
				CAP'D ITEMS	1,131	6,936
				LIM#1 TAX DP	11,696	71,734
					(3,655)	(20,163)

	ACTUAL (1)	PRO FORMA ADJ (2)	PRO FORMA TAXES (3)	LAG DAYS (4)	LAG DOLLARS (5)
AD VALORUM	69,124	1,212	70,336	26.2	1,842,803
TAXES OTHER	130,713	8,857	139,570	-30.8	(4,298,756)
STATE INC	26,900	(3,655)	23,245	63.6	1,478,382
F.I.T.	105,773	(20,163)	85,610	59.0	5,050,990
TOTAL	332,510	(13,749)	318,761	12.8	4,073,419

AVERAGE LAG IN RECEIPT OF REVS	46.0
AVE LAG IN PAYMENT OF TAXES	12.8
NET LAG	33.2
PRO FORMA TEST YEAR TAXES	$318,761
PER DAY(/365)	$873
REQUIREMENT	$28,984

PHILADELPHIA ELECTRIC CO   REV. SCHEDULE TEK-12

CASH WORKING CAPITAL- INTEREST OFFSET

TEST YEAR AT JUNE 30, 1986

($000)

RATE BASE	$5,578,739
% FINANCED BY DEBT	50.90%
RATE BASE FINANCED BY DEBT	$2,839,578
COST OF DEBT	10.86%
INTEREST ALLOCATED TO RATE BASE	$308,378
AVERAGE DAILY INTEREST	$844.9
NET LAG DAYS	36.6
DECREASE IN CASH WORKING CAPITAL	$30,923

PHILADELPHIA ELECTRIC CO. REV. SCHEDULE TEK-13

CASH WORKING CAPITAL– PREFERRED DIVIDEND OFFSET

TEST YEAR AT JUNE 30, 1986

($000)

RATE BASE	$5,578,739
% FINANCED BY PREFERRED	10.70%
RATE BASE FINANCED BY PREFERRED	$596,925
COST OF PREFERRED	10.50%
DIVIDENDS ALLOCATED TO RATE BASE	$62,677
AVERAGE DAILY DIVIDENDS	$171.7
NET LAG DAYS	-0.4
INCREASE IN CASH WORKING CAPITAL	$69

REV. SCHEDULE TEK-14

PHILADELPHIA ELECTRIC CO.
PRO FORMA INTEREST
TEST YEAR ENDED JUNE 30, 1986
($000)

	COMPANY (1)	ADJUSTMENT (2)	O.C.A. (3)
ACTUAL TEST YEAR INTEREST CHARGES	$187,595	$0	$187,595
MEASURE OF VALUE	$6,943,888	($1,365,149)	$5,578,739
WEIGHTED COST OF DEBT	5.53%	0.00%	5.53%
PRO FORMA INTEREST CHARGES	$383,840	($75,336)	$308,504
ADJUSTMENT TO INTEREST	$196,245	($75,336)	$120,909
INCOME TAXES @49.768%	($97,667)	$37,493	($60,174)
ADJUSTMENT TO INCOME	$97,667	($37,493)	$60,174

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IR-STAFF-LIM-07

Refer to PECO Statement No. 11, Page 2 of Schedule 2. What criteria was used for selecting the units listed on page 2 of Schedule 2. List all criteria and the basis for using it.

Answer

The criteria used in selection were:

1. Construction permit date issued in 1972 or later;
2. Single unit or first unit of multiunit plant; and
3. Availability of data.

The basis for criterion one is that (1) empirically over the entire database there was a marked increase in nuclear capital costs for units with a construction permit date in 1972 or later vis-a-vis units with a construction permit date prior to 1972; (2) regressions run splitting the database at this date indicate much different coefficients; and (3) a study by EPRI argues that regulatory climate changed markedly since 1972.

The basis of criterion two is that the standardization was calculated for Limerick 1, thus units with similar characteristics (either first of a multiunit plant or single units) are the appropriate sample with which to compare construction times.

Criterion three is so stated.

Responsible Witness: Dr. Lewis J. Perl
National Economic Research Associates, Inc.

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IR-STAFF-LIM-18

In the Addendum to Statement No. 11 the variable "Construction Permit Received in 1972-1973 Indicator" was added to the regression equation. The variable was added because as stated on p. 2, line 7, "... the data now clearly indicates that units with post-1973 CP dates have higher costs."

a. What is the source of this new data? Please give complete bibliography with date of publication.

b. Why was it not available when you originally submitted your testimony? Please submit a table that shows "old data" by each unit and the "new data" by each unit."

Answer to a

See response to IR-STAFF-LIM-17-a.

Answer to b

NERA was not able to incorporate the data from the September TVA survey into its data base, or construct regressions for nuclear capital cost comparisons based on the data, until after the testimony was filed on September 27. See Attachment to IR-STAFF-LIM-18.

Responsible Witness: Dr. Lewis J. Perl
National Economic Research Associates, Inc.

NERCID	UNITNAME	UTILITY	Old Data COST84	Old Data COD	New Data COST84	New Data COD
360204	SANONO2	SOUTHERN CALIF EDISON CO	$2,454	83.62	$2,454	83.62
360304	SANONO3	SOUTHERN CALIF EDISON CO	$1,589	84.29	$1,589	84.29
566304	MILLSTN3	NORTHEAST NUC ENERGY CO	$2,714	86.37	$2,714	86.37
1729204	FERMI2	DETROIT EDISON CO	$3,027	85.45	$3,076	85.79
18104	SHORHAM	LONG ISLAND LIGHTING CO	$4,102	85.79	$4,378	85.79
09204	NINEMPT2	NIAGARA MOHAWK POWER CORP	$3,583	86.79	$3,804	86.79
0104	WATTSBR	TENNESSEE VALLEY AUTH	$1,655	85.79	$1,655	85.79
20204	WATTSBR	TENNESSEE VALLEY AUTH	$1,239	88.29	$1,239	88.29
8204	WPPSS2	WASHINGTON PUB PWR SUPPLY	$3,029	84.96	$3,029	84.96
01104	FARLEY1	ALABAMA POWER CO	$1,376	77.96	$1,376	77.96
6001204	FARLEY2	ALABAMA POWER CO	$1,249	81.54	$1,249	81.54
3008104	PALOV1	ARIZONA PUBLIC SERVICE CO	$2,103	86	$2,103	86
5008204	PALOV2	ARIZONA PUBLIC SERVICE CO	$1,725	86.33	$1,725	86.33
008304	PALOV3	ARIZONA PUBLIC SERVICE CO	$1,729	87.5	$1,729	87.5
2015104	HARRIS1	CAROLINA POWER & LIGHT CO	$2,865	86.71	$2,865	86.71
6015204	HARRIS2	CAROLINA POWER & LIGHT CO	$1,391	90.2	$1,391	90.2
020104	PERRY1	CLEVELAND ELEC ILLUM CO	$2,119	85.37	$2,119	85.37
020204	PERRY2	CLEVELAND ELEC ILLUM CO	$1,335	88.37	$1,335	88.37
022104	BRAIDWD	COMMONWEALTH EDISON CO	$1,632	86.79	$1,632	86.79
022204	BRAIDWD	COMMONWEALTH EDISON CO	$1,099	87.96	$1,099	87.96
023104	BYRON1	COMMONWEALTH EDISON CO	$1,908	85.13	$1,899	85.29
023204	BYRON2	COMMONWEALTH EDISON CO	$1,223	86.79	$1,223	86.79
026104	LASALL1	COMMONWEALTH EDISON CO	$1,636	82.79	$1,636	82.79
026204	LASALL2	COMMONWEALTH EDISON CO	$1,033	84.45	$1,020	84.79
028104	MIDLAND1	CONSUMERS POWER CO	$2,874	85.62	$2,874	85.62
028204	MIDLAND2	CONSUMERS POWER CO	$2,034	85.13	$2,034	85.13
029104	MARBHIL	PUBLIC SERVICE INDIANA	$2,157	.	$2,157	86.96
029204	MARBHIL	PUBLIC SERVICE INDIANA	$1,244	.	$1,244	88.45
036104	CATAWBA	DUKE POWER CO	$1,700	85.45	$1,700	85.45
036204	CATAWBA	DUKE POWER CO	$1,108	87.45	$1,108	87.45
38104	MCGUIRE1	DUKE POWER CO	$935	81.96	$935	81.96
38204	MCGUIR2	DUKE POWER CO	$798	84.2	$857	84.2
40204	BEAVRVL2	DUQUESNE LIGHT CO	$3,356	86.79	$3,457	87.96
45204	STLUCIE2	FLORIDA POWER & LIGHT CO	$1,747	83.62	$1,778	83.62
51204	HATCH2	GEORGIA POWER CO	$952	79.71	$952	79.71
59104	CLINTON1	ILLINOIS POWER CO	$3,072	86.87	$3,071	86.87
66104	WOLFCRK	KANSAS GAS & ELEC CO	$1,992	85.54	$2,020	85.62
72104	GRAGULF1	MISSISSIPPI POWER & LIGHT	$2,100	85.45	$2,155	85.54
72204	GRAGULF2	MISSISSIPPI POWER & LIGHT	$1,850	90.29	$1,642	94.04
03104	SUSQUE1	PENNSYLVANIA POWER & LT	$2,091	83.45	$2,184	83.45
03204	SUSQU2	PENNSYLVANIA POWER & LT	$1,313	85.13	$1,364	85.13
05104	LIMERIK	PHILADELPHIA ELEC CO	$2,834	86.13	$2,868	86.13
05204	LIMERIK	PHILADELPHIA ELEC CO	$1,885	90.29	$1,774	90.29
15104	SEABRK1	PUBLIC SER NEW HAMPSHIRE	$2,924	86.62	$2,754	86.62
15204	SEABRK2	PUBLIC SER NEW HAMPSHIRE	$2,155	91.04	$2,155	91.04
18104	HOPECRK	PUBLIC SERVICE ELEC & GAS	$3,215	86.96	$3,254	86.96
27104	SUMMER	SOUTH CAROLINA ELEC & GAS	$1,557	84.04	$1,557	84.04
45104	COMANCH	TEXAS UTILITIES GEN CO	$2,306	86.04	$2,306	86.04
45204	COMANCH	TEXAS UTILITIES GEN CO	$1,321	87.54	$1,321	87.54

NERAID	UNITNAME	UTILITY	Old Data COST84	Old Data COD	New Data COST84	New Data COD
6150104	BELLAF1	TENNESSEE VALLEY AUTH	$1,772	89.29	$1,772	89.29
6150204	BELLAF2	TENNESSEE VALLEY AUTH	$1,347	91.29	$1,347	91.29
6153104	CALLAWY	UNION ELECTRIC CO	$2,062	84.96	$2,062	84.96
6251104	SOTEX1	HOUSTON LIGHTING & POWER	$3,260	87.45	$3,260	87.45
6251204	SOTEX2	HOUSTON LIGHTING & POWER	$1,638	89.45	$1,638	89.45
6258104	VOGTLE1	GEORGIA POWER CO	$2,903	87.2	$3,467	87.45
6258204	VOGTLE2	GEORGIA POWER CO	$1,962	88.71	$2,363	88.71
6462104	RIVRBND	GULF STATES UTILITIES	$3,424	85.96	$3,424	85.96
8055204	ARKONE2	ARKANSAS POWER & LIGHT CO	$922	80.2	$922	80.2
8056304	WATERFD3	LOUISIANA POWER & LIGHT	$2,524	85.45	$2,524	85.45

Data marked old are from March 1985 TVA Survey. Data marked new are from September 1985 TVA Survey.

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IR-LIM-STAFF-20

If post-1973 time frame is the better period to use, why not just use units with construction permits after 1983 and eliminate the "Construction Permit" variable, similar to what you did in your original testimony when you used only plants post-1971?

Answer

We do not necessarily believe that the determinants of cost have changed after 1972, only the level. Between 1971 and 1972 there actually appears to be a marked shift in cost determinants.

Responsible Witness: Dr. Lewis J. Perl
National Economic Research Associates, Inc.

IR-LIM-STAFF-23

Please provide the results of the regression on page 3, of Schedule 20 of the Addendum to PECO Statement No. 11 for the sample excluding Limerick 1 from the data base and the independent variable "Construction Permit Received in 1972-73 Indicator." Please answer all the questions asked in IR-OCA-16-5 with the appropriate attachments as it relates to page 3 of Schedule 20.

Answer

See answer to IR-OCA-23-4.

Responsible Witness: Dr. Lewis J. Perl
National Economic Research Associates, Inc.

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IR-OCA-23-4

Concerning Schedule 20, please provide the results of the regression shown on page 3 of 4 without the Construction Permit received in 1972-1973 Indicator. If such a run has not been done, please do so. In answering this question, please provide the results of all statistical tests performed, including a listing of the predicted values and/or residuals from the regression for each unit in the sample. Please calculate the excess cost percentage for Limerick from this run (i.e. Limerick's actual cost/predicted cost and actual cost/standardized cost).

Answer

Attachment IR-OCA-23-4 contains the results of the regression equation without the Construction Permit received in 1972-1973 variable. This attachment also contains a listing of the actual value, the predicted value and the residual for each unit included in the regression. Based on this regression the predicted cost is $2,626 and the ratio of Limerick's actual cost to the predicted cost is 1.092. The average standardized cost based on this regression is $2,675 and the ratio of Limerick's actual cost to the average standardized cost is 1.072.

Responsible Witness: Dr. Lewis J. Perl
National Economic Research Associates, Inc.

ARIABLE: LNCOST84 LOG OF COST PER KW IN 1984 DOLLARS

E	DF	SUM OF SQUARES	MEAN SQUARE	F VALUE	PROB>F
	6	7.066529	1.177755	27.735	0.0001
	50	2.123238	0.042465		
AL	56	9.189767			

OOT MSE	0.206070	R-SQUARE	0.7690
EP MEAN	7.538263	ADJ R-SQ	0.7412
.V.	2.733651		

BLE	DF	PARAMETER ESTIMATE	STANDARD ERROR	T FOR H0: PARAMETER=0	PROB > |T|	STANDARDIZED ESTIMATE	VARIABLE LABEL
CEP	1	7.817352	0.056981	137.192	0.0001	0.000000	INTERCEPT
	1	-0.413051	0.058711	-7.035	0.0001	-0.504681	SUBSEQUENT UNIT INDICATOR
OCK	1	-0.145564	0.065204	-2.232	0.0301	-0.176485	COMPOSITE ROCK FOUND. INDICATOR
WR	1	0.262430	0.094346	2.782	0.0076	0.214515	SINGLE UNIT BWR INDICATOR
ND	1	0.248318	0.174578	1.422	0.1611	0.108683	LOG OF MEANS WAGE INDEX
	1	0.213848	0.081878	2.612	0.0119	0.194203	NORTHEAST INDICATOR
MX	1	-0.255366	0.069042	-3.699	0.0005	-0.273761	UTILCON VAR ONLY FOR TVA,DUKE,COMM UNITS

ID	ACTUAL	PREDICT VALUE	RESIDUAL
SANONO2	7.806	7.870	-.064004
SANONO3	7.371	7.457	-.085576
MILLSTN3	7.906	7.861	0.045432
FERMI2	8.031	7.971	0.059971
SHORHAM	8.384	8.323	0.061205
NINEMPT2	8.244	8.131	0.112667
WATTSHR	7.412	7.358	0.053364
WATTSBR	7.122	6.945	0.176914
WPPSS2	8.016	8.108	-.091613
FARLEY1	7.227	7.595	-.368365
FARLEY2	7.130	7.182	-.052347
PALOV1	7.651	7.829	-.178249
PALOV2	7.453	7.416	0.036595
PALOV3	7.455	7.416	0.038966
HARRIS1	7.960	7.574	0.386667
HARRIS2	7.238	7.161	0.077251
PERRY1	7.659	7.690	-.030524
PERRY2	7.197	7.277	-.080004
BRAIDWD	7.398	7.430	-.032640
BRAIDWD	7.002	7.017	-.014968
BYRON1	7.549	7.413	0.135964
BYRON2	7.109	7.000	0.109296
LASALL1	7.400	7.576	-.175865
LASALL2	6.928	7.163	-.235341
[illegible]	[illegible]	[illegible]	[illegible]

ID	ACTUAL	PREDICT VALUE	RESIDUAL
IDLAND2	7.618	7.441	0.176250
ARBHIL	7.676	7.660	0.016206
ARBHIL	7.126	7.247	-.121292
ATAWBA	7.438	7.317	0.121165
ATAWBA	7.010	6.904	0.106235
CGUIRE1	6.841	7.317	-.476273
CGUIR2	6.753	6.904	-.150730
EAVRVL2	8.148	8.029	0.115166
TLUCIE2	7.483	7.789	-.305671
ATCH2	6.858	7.329	-.470543
LINTON1	8.030	8.077	-.046698
OLFCRK	7.611	7.641	-.030258
RAGULF1	7.676	7.634	0.041580
RAGULF2	7.404	7.221	0.182725
USQUE1	7.689	7.853	-.164298
USQU2	7.218	7.440	-.222368
EARRK1	7.921	7.886	0.034795
EARRK2	7.676	7.473	0.202616
OPECRK	8.088	8.277	-.189213
UMMER	7.351	7.563	-.212481
DMANCH	7.743	7.623	0.120442
DMANCH	7.186	7.210	-.023392
ELLAF1	7.480	7.358	0.122157
ELLAF2	7.205	6.945	0.260734
ALLAWY	7.632	7.652	-.020510
OTEX1	8.089	7.803	0.286745
OTEX2	7.401	7.390	0.011838
OGTLE1	8.151	7.738	0.412943
OGTLE2	7.768	7.325	0.442860
IVRBND	8.138	8.045	0.053677
RKONE2	6.827	7.192	-.365314
ATERFD3	7.834	7.779	0.054074

RESIDUALS 7.86038E-13
SQUARED RESIDUALS 2.123238

AVERAGE COSTS BY PLANT
SORTED BY STANDARDIZED DIRECT COST

OBS	UNITNAME	PLANTID	_TYPE_	_FREQ_	BOOKCOST	LNCOST84	COST84	LNSTDCST	STDCOST	LNPRECST	PREDCOST	NETDER	AVGSTD
1	HATCH2	6051	1	1	460128	6.85841	951.85	7.40238	1639.88	7.32935	1524.39	786.00	1639.88
2	ARKONE2	8055	1	1	548150	6.82707	922.48	7.50801	1822.58	7.19238	1329.27	912.00	1822.58
3	STLUCIE2	6045	1	1	1420000	7.48297	1777.52	7.56765	1934.59	7.78864	2413.04	804.00	1934.59
4	MCGUIR2	6038	1	2	1103095	6.79717	896.17	7.55982	1944.98	7.11067	1251.19	1180.00	1919.50
5	SUMMER	6127	1	1	1306000	7.35072	1557.32	7.66084	2123.54	7.56320	1926.00	900.00	2123.54
6	LASALL2	6026	1	2	1247000	7.16393	1328.21	7.66772	2139.14	7.36953	1620.86	1078.00	2138.19
7	FARLEY2	6001	1	2	754039	7.17828	1312.19	7.66296	2154.67	7.38864	1652.12	829.00	2128.05
8	SUSQU2	6103	1	2	0	7.45341	1773.84	7.67999	2165.50	7.64674	2138.63	1057.50	2164.59
9	HOPECRK	6118	1	1	3795000	8.08769	3254.17	7.68411	2173.53	8.27690	3932.00	1067.00	2173.53
10	WPPSS2	3928	1	1	3234000	8.01597	3028.96	7.78171	2396.36	8.10755	3319.56	1100.00	2396.36
11	SANONO3	360	1	2	2250000	7.58835	2021.87	7.79853	2437.16	7.66314	2173.98	1093.50	2437.02
12	PERRY2	6020	1	2	2615500	7.42777	1727.16	7.81786	2485.32	7.48224	1816.04	1205.00	2484.57
13	MARBHIL	6029	1	2	0	7.40105	1700.15	7.82078	2497.73	7.45359	1763.00	1130.00	2491.84
14	CLINTON1	6059	1	1	3148000	8.02983	3071.21	7.82662	2506.45	8.07653	3218.03	933.00	2506.45
15	WOLFCRK	6066	1	1	3030000	7.61074	2019.77	7.84306	2547.99	7.64106	2081.81	1150.00	2547.99
16	PALOV3	6008	1	3	3122566	7.51578	1852.31	7.83909	2550.76	7.55401	1946.40	1270.00	2537.90
17	BRAIDWD	6022	1	2	2053500	7.20017	1365.92	7.84952	2564.59	7.22397	1401.29	1120.00	2564.49
18	CALLAWY	6153	1	1	3000000	7.63157	2062.28	7.85281	2572.96	7.65208	2105.02	1120.00	2572.96
19	WPPSS2	.	0	57	2066641	7.53826	2035.05	7.87332	2674.89	7.53826	2000.78	1081.82	2626.27
20	MILLSTN3	566	1	1	3825000	7.90613	2713.88	7.91875	2748.34	7.86070	2593.34	1156.00	2748.34
21	COMANCH	6145	1	2	2282000	7.46491	1813.82	7.92184	2763.99	7.41639	1698.61	1111.00	2756.85
22	WATERFD3	6056	1	1	2733000	7.83356	2523.89	7.92739	2772.19	7.77948	2391.04	1104.00	2772.19
23	FERMI2	1729	1	1	3575000	8.03132	3075.80	7.93329	2788.59	7.97135	2896.76	1093.00	2788.59
24	SHORHAM	2510	1	1	4266000	8.38429	4377.76	7.93453	2792.04	8.32308	4117.84	820.00	2792.04
25	RIVRBND	6462	1	1	0	8.13845	3423.59	7.96700	2884.18	8.04477	3117.44	934.00	2884.18
26	NINEMPT2	2589	1	1	5350000	8.24368	3803.50	7.98599	2939.48	8.13101	3398.23	1100.00	2939.48
27	CATAWBA	6036	1	2	1550000	7.22437	1404.02	7.98702	2942.60	7.11067	1251.19	1145.00	2942.51
28	GRAGULF2	6072	1	2	1812500	7.53955	1898.39	7.98547	2545.28	7.42739	1717.41	1250.00	2937.97
29	WATTSBR	3420	1	2	1942500	7.26699	1447.27	7.98846	2952.38	7.15185	1303.79	1177.00	2946.75
30	BEAVRVL2	6040	1	1	3559000	8.14804	3456.59	7.99248	2958.62	8.02888	3068.30	833.00	2958.62
31	SEABRK2	6115	1	2	4447650	7.79828	2454.74	7.99202	2567.70	7.67957	2210.00	1150.00	2957.28
32	BYRON2	6023	1	2	2173000	7.32927	1561.26	7.99595	2569.17	7.20664	1377.21	1120.00	2968.90
33	MIDLAND2	6028	1	2	2215000	7.79051	2453.74	8.01587	3030.36	7.64796	2141.23	852.00	3028.64
34	SOTEX2	6251	1	2	0	7.74536	2448.90	8.02261	3077.98	7.59607	2032.96	1250.00	3049.13
35	BELLAF2	6150	1	2	2820000	7.34271	1559.47	8.06476	3188.04	7.15127	1303.03	1213.00	3180.40
36	HARRIS2	6015	1	2	2725000	7.59514	2128.17	8.10528	3351.62	7.36718	1617.05	900.00	3311.91
37	VOGTLE2	6250	1	2	0	7.95936	2914.92	8.30122	4029.24	7.53146	1905.76	1160.00	4028.79

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IR-OCA-23-5

Please provide the results of the regression in Schedule 20 using a cutoff date of June 30, 1973, rather than December 31, 1973 for the new Construction Permit Received indicator. If such a run has not been done, please do so. In answering this question, please provide the results of all statistical tests performed, including a listing of the predicted values and/or residuals from the regression for each unit in the sample. Please calculate the excess cost percentage for Limerick from this run (i.e. Limerick's actual cost/predicted cost and actual cost/standardized cost).

Answer

Attachment IR-OCA-23-5 contains the results of the regression equation with the Construction Permit Received variable redefined with a cut-off date of June 30, 1973 rather than December 31, 1973. This attachment also contains a listing of the actual value, the predicted value and the residual for each of the units included in the regression equation. Based on this regression, the predicted cost is $2,618 and the ratio of Limerick's actual cost to predicted cost is 1.095. The average standardized cost based on this regression is $2,662 and the ratio of Limerick's actual cost to the standardized average cost is 1.077.

Responsible Witness: Dr. Lewis J. Perl
National Economic Research Associates, Inc.

DEP VARIABLE: LNCOST84 LOG OF COST PER KW IN 1984 DOLLARS

SOURCE	DF	SUM OF SQUARES	MEAN SQUARE	F VALUE	PROB>F
MODEL	7	7.321413	1.045916	27.430	0.0001
ERROR	49	1.868354	0.038130		
C TOTAL	56	9.189767			

ROOT MSE	0.195268	R-SQUARE	0.7967
DEP MEAN	7.538263	ADJ R-SQ	0.7676
C.V.	2.590361		

VARIABLE	DF	PARAMETER ESTIMATE	STANDARD ERROR	T FOR H0: PARAMETER=0	PROB > |T|	STANDARDIZED ESTIMATE	VARIABLE LABEL
INTERCEP	1	7.839775	0.054686	143.359	0.0001	0.000000	INTERCEPT
SUBSQ	1	-0.402696	0.055778	-7.220	0.0001	-0.492029	SUBSEQUENT UNIT INDICATOR
BABRROCK	1	-0.141946	0.061803	-2.297	0.0259	-0.172100	COMPOSITE ROCK FOUND. INDICATOR
SINGHWR	1	0.324508	0.092568	3.506	0.0010	0.265258	SINGLE UNIT BWR INDICATOR
LNWAIND	1	0.169542	0.168210	1.008	0.3184	0.074204	LOG OF MEANS WAGE INDEX
NEAST	1	0.180910	0.078626	2.301	0.0257	0.164292	NORTHEAST INDICATOR
UTILCMX	1	-0.252283	0.065434	-3.856	0.0003	-0.270456	UTILCON VAR ONLY FOR TVA,DUKE,COMM UNITS
CPD7273	1	-0.164280	0.063540	-2.585	0.0128	-0.176114	

OBS	ID	ACTUAL	PREDICT VALUE	RESIDUAL
1	SANONO2	7.806	7.875	-.069832
2	SANONO3	7.371	7.473	-.101759
3	MILLSTN3	7.906	7.862	0.044419
4	FERMI2	8.031	7.883	0.147917
5	SHORHAM	8.384	8.201	0.183265
6	NINEMPT2	8.244	8.192	0.052076
7	WATTSBR	7.412	7.242	0.170107
8	WATTSBR	7.122	6.839	0.283303
9	WPPSS2	8.016	8.019	-.003012
10	FARLEY1	7.227	7.481	-.254438
11	FARLEY2	7.130	7.079	0.051225
12	PALOV1	7.651	7.848	-.196857
13	PALOV2	7.453	7.445	0.007637
14	PALOV3	7.455	7.445	0.010003
15	HARRIS1	7.960	7.631	0.329512
16	HARRIS2	7.238	7.228	0.009741
17	PERRY1	7.659	7.710	-.051262
18	PERRY2	7.197	7.307	-.110698
19	BRAIDWD	7.398	7.455	-.057298
20	BRAIDWD	7.002	7.052	-.049982
21	BYRON1	7.549	7.443	0.105808
22	BYRON2	7.109	7.041	0.068778
23	LASALL1	7.400	7.597	-.196907
24	LASALL2	6.928	7.194	-.266778

UPDATED NUCLEAR CAPITAL COST REGRESSION BASED ON TVA 85 DATA
BASED ON POST-71 CPD UNITS W/OUT LIM PLANT
WITH CPD7273 SET AT JUNE 30 1973 NOT DECEMBER 31

13:50 TUESDAY, DECEMBER 24, 1985

OBS	ID	ACTUAL	PREDICT VALUE	RESIDUAL
25	MIDLAND1	7.963	7.701	0.262486
26	MIDLAND2	7.618	7.298	0.319532
27	MARBHIL	7.676	7.690	-.013536
28	MARBHIL	7.126	7.287	-.161389
29	CATAWBA	7.438	7.378	0.060563
30	CATAWBA	7.010	6.975	0.035278
31	MCGUIRE1	6.841	7.214	-.372594
32	MCGUIR2	6.753	6.811	-.057407
33	BEAVRVL2	8.148	8.019	0.128938
34	STLUCIE2	7.483	7.820	-.337201
35	HATCH2	6.858	7.222	-.363219
36	CLINTON1	8.030	8.162	-.132232
37	WOLFCRK	7.611	7.677	-.066067
38	GRAGULF1	7.676	7.672	0.003527
39	GRAGULF2	7.404	7.269	0.134316
40	SUSQUE1	7.689	7.857	-.167669
41	SUSQU2	7.218	7.454	-.236054
42	SEABRK1	7.921	7.879	0.041838
43	SEABRK2	7.676	7.476	0.159304
44	HOPECRK	8.088	8.334	-.246082
45	SUMMER	7.351	7.459	-.108685
46	COMANCH	7.743	7.664	0.078898
47	COMANCH	7.186	7.262	-.075293
48	BELLAF1	7.480	7.406	0.074430
49	BELLAF2	7.205	7.003	0.202656
50	CALLAWY	7.632	7.684	-.052802
51	SOTEX1	8.089	7.830	0.259645
52	SOTEX2	7.401	7.427	-.025622
53	VOGTLE1	8.151	7.786	0.365342
54	VOGTLE2	7.768	7.383	0.384903
55	RIVRBND	8.138	8.140	-.001931
56	ARKONE2	6.827	7.086	-.258480
57	WATERFD3	7.834	7.814	0.019638

SUM OF RESIDUALS 7.96252E-13
SUM OF SQUARED RESIDUALS 1.868354

AVERAGE COSTS BY PLANT
SORTED BY STANDARDIZED DIRECT COST

OBS	UNITNAME	PLANTID	_TYPE_	_FREQ_	BOOKCOST	LNCOST84	COST84	LNSTDCST	STDCOST	LAPRECST	PREDCOST	NETDER	AVGSTD
1	HATCH2	6051	1	1	460128	6.85841	951.85	7.50711	1820.95	7.22162	1368.71	786.00	1820.95
2	STLUCIE2	6045	1	1	1420000	7.48297	1777.52	7.53313	1868.94	7.82017	2490.34	804.00	1868.94
3	ARKONE2	8055	1	1	548150	6.82707	922.48	7.61185	2022.01	7.08555	1194.58	912.00	2022.01
4	HOPECRK	6118	1	1	3795000	8.08769	3254.17	7.62425	2047.24	8.33377	4162.09	1067.00	2047.24
5	LASALL2	6026	1	2	1247000	7.16393	1328.21	7.63851	2077.91	7.39575	1662.18	1078.00	2076.64
6	MCGUIR2	6038	1	2	1103095	6.79717	896.17	7.65533	2138.15	7.01217	1132.64	1180.00	2111.87
7	SUSQU2	6103	1	2	0	7.45341	1773.84	7.66845	2141.01	7.65529	2154.74	1057.50	2139.76
8	CLINTON1	6059	1	1	3148000	8.02983	3071.21	7.73810	2294.10	8.16206	3505.40	933.00	2294.10
9	SUMMER	6127	1	1	1306000	7.35072	1557.32	7.76164	2348.75	7.45941	1736.12	900.00	2348.75
10	FARLEY2	6001	1	2	754039	7.17828	1312.19	7.76873	2393.13	7.29788	1480.33	829.00	2365.45
11	SANONO3	360	1	2	2250000	7.58835	2021.87	7.78453	2403.45	7.67414	2195.75	1093.50	2403.15
12	MARBHIL	6029	1	2	0	7.40105	1700.15	7.78287	2405.70	7.48851	1823.75	1130.00	2399.14
13	PERRY2	6020	1	2	2615500	7.42777	1727.16	7.78935	2415.81	7.50875	1861.03	1205.00	2414.75
14	WOLFCRK	6066	1	1	3030000	7.61074	2019.77	7.80426	2451.03	7.67680	2157.71	1150.00	2451.03
15	PALOV3	6008	1	3	3122566	7.51978	1852.31	7.81059	2477.93	7.57952	1994.71	1270.00	2466.59
16	BRAIDWD	6022	1	2	2052500	7.20017	1365.92	7.81669	2481.69	7.25381	1442.22	1120.00	2481.68
17	CALLAWY	6153	1	1	3000000	7.63157	2062.28	7.81753	2483.76	7.68437	2174.10	1120.00	2483.76
18	WPPSS2	3928	1	1	3234000	8.01597	3028.96	7.86732	2610.55	8.01895	3038.10	1100.00	2610.55
19	RIVBIND	6462	1	1	0	8.13845	3423.59	7.86840	2613.38	8.14038	3430.21	934.00	2613.38
20	COMANCH	6145	1	2	2282000	7.46491	1813.82	7.87213	2630.95	7.46311	1778.00	1111.00	2623.15
21	WPPSS2	.	0	57	2066641	7.53826	2035.05	7.87033	2661.80	7.53826	2004.21	1081.82	2618.43
22	WATERFD3	8056	1	1	2733000	7.83356	2523.89	7.88997	2670.36	7.81392	2474.81	1104.00	2670.36
23	MILLSTN3	566	1	1	3825000	7.90613	2713.88	7.91475	2737.36	7.86172	2595.97	1156.00	2737.36
24	CATAWBA	6036	1	2	1550000	7.22437	1404.02	7.91825	2747.18	7.17645	1334.87	1145.00	2746.96
25	NINEMPT2	2589	1	1	5350000	8.24368	3803.50	7.92241	2758.40	8.19160	3610.50	1100.00	2758.40
26	GRAGULF2	6072	1	2	1812500	7.53955	1898.39	7.93925	2811.26	7.47063	1791.47	1250.00	2805.26
27	BYRON2	6023	1	2	2173000	7.32927	1561.26	7.95762	2857.76	7.24197	1425.26	1120.00	2857.27
28	SEABRK2	6115	1	2	4447650	7.79828	2454.74	7.99090	2963.12	7.67771	2203.59	1150.00	2953.96
29	SOTEX2	6251	1	2	0	7.74536	2448.90	7.98734	2973.45	7.62835	2097.47	1250.00	2547.46
30	BEAVRVL2	6040	1	1	3555000	8.14804	3456.59	7.99927	2978.78	8.01510	3038.44	833.00	2578.78
31	BELLAF2	6150	1	2	2820000	7.34271	1559.47	8.00887	3013.71	7.20417	1372.38	1213.00	3007.53
32	FERMI2	1729	1	1	3575000	8.03132	3075.80	8.01824	3035.83	7.88341	2652.90	1093.00	3035.83
33	HARRIS2	6015	1	2	2725000	7.59914	2128.17	8.03996	3142.22	7.42952	1719.26	900.00	3102.48
34	SHORHAM	2518	1	1	4266000	8.38429	4377.76	8.05360	3145.09	8.20102	3644.67	820.00	3145.09
35	WATTSBR	3420	1	2	1542500	7.26699	1447.27	8.09703	3289.97	7.04029	1164.94	1177.00	3284.71
36	MIDLAND2	6028	1	2	2215000	7.79051	2453.74	8.16134	3504.30	7.49950	1843.89	852.00	3502.87
37	VOGTLE2	6258	1	2	0	7.95936	2914.92	8.24545	3810.44	7.58424	2006.95	1160.00	3810.26

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IR-OCA-23-11

Please state what new data became available since the filing of the direct testimony.

Answer

No data that has become available since the filing of the direct testimony on September 27 has been utilized by NERA. However, a TVA survey published in September 1985 was added by NERA to its data base and provides the basis for the regressions used in the addendum for the nuclear capital cost comparison. The direct testimony was based on a March 1985 TVA survey.

Responsible Witness: Dr. Lewis J. Perl
National Economic Research Associates, Inc.

IR-OCA-16-2

Concerning the response to IR-OCA-2-8, please provide the results of the regression shown in Exhibit 1, p.3, without the Cooling Tower Indicator variable. If such a run has not been done, please do so. In answering this question, please provide the results of all statistical tests performed, including a listing of the predicted values and/or residuals from the regression for each unit in the sample, both with and without the Cooling Tower variable. Please calculate the excess cost percentage for Limerick from this run (i.e. Limerick's actual cost/predicted cost).

Answer

The ratio of the predicted cost to the actual cost based on the regression equation without the cooling tower indicator variable for Limerick is 1.08. The ratio to the average of the standardized costs is 1.065. The results of the regression equation, including a listing of the predicted values and residuals is shown in Attachment IR-OCA-16-2.

Responsible Witness: Dr. Lewis J. Perl
National Economic Research Associates, Inc.

NUCLEAR CAPITAL COSTS FOR POST-1971 PLANTS
STANDARDIZED TO LIMERICK 1
(With no Complex Cooling System Variable)

Plant	Standardized Direct Cost
Hatch 2	1733
Arkansas Nuclear One 2	1852
McGuire	1929
St. Lucie 2	1977
Susquehanna	2093
Summer	2199
Farley	2200
LaSalle	2204
Hope Creek	2263
Clinton 1	2620
Perry	2445
San Onofre	2451
WPPSS 2	2474
Marble Hill	2487
Wolf Creek	2524
Braidwood	2533
Callaway	2573
Palo Verde	2606
Shoreham	2708
Fermi 2	2724
Millstone 3	2762
Commanche	2793
Nine Mile Point 2	2817
Limerick 1	2868
Waterford 3	2893
Byron	2959
Beaver Valley 2	2966
Watts Bar	3001
Seabrook	3032
Catawba	3040
Riverbend	3053
Midland	3066
Grand Gulf	3128
South Texas	3180
Bellafonte	3241
Harris	3453
Vogtle	3561
Average, Excluding Limerick 1	2694

DEP VARIABLE: LNCOST84 LOG OF COST PER KW IN 1984 DOLLARS

SOURCE	DF	SUM OF SQUARES	MEAN SQUARE	F VALUE	PROB>F
MODEL	6	7.039946	1.173324	30.766	0.0001
ERROR	52	1.983155	0.038138		
C TOTAL	58	9.023101			
ROOT MSE		0.195289	R-SQUARE	0.7802	
DEP MEAN		7.536017	ADJ R-SQ	0.7549	
C.V.		2.591402			

VARIABLE	DF	PARAMETER ESTIMATE	STANDARD ERROR	T FOR H0: PARAMETER=0	PROB > |T|	STANDARDIZED ESTIMATE	VARIABLE LABEL
INTERCEP	1	7.800564	0.053729	145.184	0.0001	0.000000	INTERCEPT
SUBSQ	1	-0.410622	0.054479	-7.537	0.0001	-0.515796	SUBSEQUENT UNIT INDICATOR
BABRROCK	1	-0.109825	0.061507	-1.786	0.0800	-0.135803	COMPOSITE ROCK FOUND. INDICATOR
SINGBWR	1	0.247238	0.088356	2.797	0.0072	0.204438	SINGLE UNIT BWR INDICATOR
LNWAIND	1	0.346795	0.165131	2.100	0.0406	0.153446	LOG OF MEANS WAGE INDEX
NEI	1	0.210767	0.072039	2.926	0.0051	0.209901	NORTHEAST INDICATOR
UTILCMX	1	-0.257859	0.065353	-[illegible].946	0.0002	-0.280510	UTILCON VAR ONLY FOR TVA,DUKE,COMM UNITS

OBS	ID	ACTUAL	PREDICT VALUE	RESIDUAL
1	SANONO2	7.806	7.874	-.067961
2	SANONO3	7.371	7.463	-.091961
3	MILLSTN3	7.906	7.867	0.039451
4	FERMI2	8.015	7.990	0.025547
5	SHORHAM	8.319	8.300	0.019517
6	NINEMPT2	8.184	8.125	[illegible]
7	WATTSBR	7.412	7.352	0.059925
8	WATTSBR	7.122	6.941	0.181047
9	WPPSS2	8.016	8.087	-.070660
10	FARLEY1	7.227	7.584	-.356932
11	FARLEY2	7.130	7.173	-.043339
12	PALOV1	7.651	7.817	-.166231
13	PALOV2	7.453	7.407	0.046190
14	PALOV3	7.455	7.407	0.048556
15	HARRIS1	7.960	7.554	0.406612
16	HARRIS2	7.238	7.143	0.094768
17	PERRY1	7.659	7.716	-.057001
18	PERRY2	7.197	7.305	-.108511
19	BRAIDWD	7.398	7.453	-.054677
20	BRAIDWD	7.002	7.042	-.039435
21	BYRON1	7.554	7.428	0.125341
22	BYRON2	7.109	7.018	0.090998
23	LASALL1	7.400	7.562	-.162165
24	LASALL2	6.941	7.152	-.211180
25	MIDLAND1	7.963	7.852	0.110912
26	MIDLAND2	7.618	7.442	0.175885

OBS	ID	ACTUAL	PREDICT VALUE	RESIDUAL
27	MARBHIL	7.676	7.674	0.001884
28	MARBHIL	7.126	7.264	-.138043
29	CATAWBA	7.438	7.294	0.144058
30	CATAWBA	7.010	6.884	0.126659
31	MCGUIRE1	6.841	7.294	-.453380
32	MCGUIR2	6.682	6.884	-.201276
33	BEAVRVL2	8.119	8.008	0.110458
34	STLUCIE2	7.465	7.760	-.294980
35	HATCH2	6.858	7.285	-.426858
36	CLINTON1	8.030	8.043	-.013427
37	WOLFCRK	7.597	7.648	-.050609
38	GRAGULF1	7.650	7.638	0.011845
39	GRAGULF2	7.523	7.227	0.295652
40	SUSQUE1	7.645	7.856	-.210994
41	SUSQU2	7.180	7.446	-.265585
42	LIMERIK	7.961	7.884	0.077064
43	LIMERIK	7.542	7.474	0.068010
44	SEABRK1	7.981	7.902	0.078424
45	SEABRK2	7.676	7.492	0.184135
46	HOPECRK	8.076	8.235	-.159661
47	SUMMER	7.351	7.539	-.188368
48	COMANCH	7.743	7.622	0.120874
49	COMANCH	7.186	7.212	-.025389
50	BELLAF1	7.480	7.351	0.128546
51	BELLAF2	7.205	6.940	0.265095
52	CALLAWY	7.632	7.663	-.031644
53	SOTEX1	8.089	7.780	0.309385
54	SOTEX2	7.401	7.369	0.032045
55	VOGTLE1	7.974	7.690	0.283836
56	VOGTLE2	7.582	7.279	0.302828
57	RIVRBND	8.138	7.999	0.139543
58	ARKONE2	6.827	7.187	-.360379
59	WATERFD3	7.834	7.748	0.085880

SUM OF RESIDUALS 8.42437E-13
SUM OF SQUARED RESIDUALS 1.983155

R-850152
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IR-OCA-16-7

Concerning the response to IR-OCA-2-6, please explain why NERA chose to include Limerick in the dataset from which the regression in Exhibit 1, p. 3, was estimated. Please reconcile this decision with the approach NERA used in the Shoreham proceeding mentioned in the preceding question, wherein the unit under study was excluded from the underlying dataset.

Answer

Limerick was included in the data base because the exclusion of any one plant, in a 59 unit data base, is unlikely to have any significant effect on the result. In my response to IR-OCA-16-5 I have provided the results when Limerick has been excluded from the data base, and these results substantially confirm this conclusion. In general, however, I think it is preferable to exclude the unit which is the subject of the comparison from the data base.

Responsible Witness: Dr. Lewis J. Perl
National Economic Research Associates, Inc.

R-890152
3-11-86
H65 jol

PECO STATEMENT 11
LEWIS J. PERL

Q. IR-OCA-2-8.

With regard to the comparison between Limerick 1 and "nuclear units constructed in the same time frame," please explain the decision to include the variable Cooling Tower Indicator to estimate standardized costs, even though the t-statistic is 1.027, i.e., less than the threshold value of 1.68 for significance at the 10 percent level indicated in Note 4 on p. 4 of Sch. 1.

A. IR-OCA-2-8.

The cooling tower indicator variable, while not statistically significant at the 10 percent level, was included in the regression equation and used in the standardization analysis for several reasons. The coefficient has the expected sign, i.e., units built with cooling towers are expected to have higher costs than those without, and is of a reasonable magnitude. In analyses done by NERA in the past, this coefficient has been statistically significant and other analysts believe there should be a positive relationship between cooling towers and construction costs. It seems reasonable to continue to include the variable until it is shown conclusively to be a factor that does not influence construction cost.

3-11-86
1165 gt

IR-OCA-23-3

With regard to Schedule 20 of the Addendum, please explain the decision to exclude the variable Cooling Tower Indicator to estimate standardized costs.

Answer

The cooling tower indicator variable was excluded from the regression shown in Schedule 20 of the Addendum in response to the criticism by the OCA that the variable should not be included since it was not statistically significant at the 10 percent level. We believe that the question of whether or not to include this variable is a debatable issue but we wish to illustrate that our conclusion does not depend on its inclusion.

Responsible Witness: Dr. Lewis J. Perl
National Economic Research Associates, Inc.

R-830132
3-11-86
HGS jat

IR-OCA-23-8

Has Dr. Perl ever used a construction permit received indicator for 1972-1973 in prior testimonies or analyses or test regressions? If yes, please state where and when. If no, please state why not.

Answer

A construction permit received indicator for 1972-1973 variable was used in rebuttal testimony filed by Dr. Perl on behalf of Central Vermont Public Service Corporation on December 4, 1985 (Docket No. 5030).

Responsible Witness: Dr. Lewis J. Perl
National Economic Research Associates, Inc.

PECO STATEMENT 11
LEWIS J. PERL

Q. IR-OCA-2-10.

Please list all proceedings within the last three years in which the witness used the "standardized" methodology to compare a nuclear unit's construction cost with its contemporaries, as distinguished from the witness's methodology in the Shoreham prudence proceeding (NY PSC Case 27563) where that unit's predicted cost from the regression was compared with its actual cost.

A. IR-OCA-2-10.

Dr. Perl has used the "standardized" methodology to compare a nuclear unit's construction cost with its contemporaries in the following proceedings:

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.

Testimony on the economics of the Palo Verde nuclear plant on behalf of Arizona Public Service Company, May 22, 1985.

Testimony on the evaluation of Seabrook 1 on behalf of Central Maine Power Company, August 31, 1984.

Testimony on the economics of Grand Gulf 2 on behalf of Mississippi Power and Light Company and Middle South Energy, Inc., February 27, 1984.

Testimony on the economics of the Skagit/Hanford nuclear plant on behalf of Washington Water Power, May 1, 1984.

Testimony on the economics of the Skagit/Hanford nuclear plant on behalf of Puget Sound Power & Light, November 3, 1983.

Testimony on the economics of the Grand Gulf plant on behalf of Mississippi Power & Light and Middle South Energy, Inc. on April 29, 1983.

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SECRETARY'S OFFICE
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COMMONWEALTH OF PENNSYLVANIA
BEFORE THE PUBLIC UTILITIES COMMISSION

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SECRETARY'S OFFICE
Public Utility Commission

THE PENNSYLVANIA
PUBLIC UTILITIES COMMISSION
V. PHILADELPHIA ELECTRIC
COMPANY

DOCKET NO. R-850152

UUC/UP STATEMENT #1A

SURREBUTTAL TESTIMONY OF PAUL CHERNICK
ON BEHALF OF THE
UTILITY USERS COMMITTEE/
UNIVERSITY OF PENNSYLVANIA

February 27, 1986

DOCKETED
MAR 17 1986

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SURREBUTTAL TESTIMONY OF PAUL CHERNICK

OF BEHALF OF

UNIVERSITY OF PENNSYLVANIA/UTILITY USERS COMMITTEE

Q: Are you the same Paul Chernick who presented direct testimony in this proceeding?

A: Yes.

Q: What topics will you cover in your surrebuttal testimony?

A: I will discuss the following issues raised by PECo's rebuttal testimony:

1. projections of Limerick 1 operating costs and performance,
2. the measurement of Limerick 1 capacity value,
3. projections of oil prices,
4. discount rates,
5. the cost and benefits of the Limerick 1 construction delays, and
6. miscellaneous issues.

Due to the limited time available, my comments on these topics will be very brief.[1]

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1. The testimony indicates that it was filed on Wednesday, February 19. PECo did not serve a copy on me until Saturday, February 22.

1 Projections of Limerick 1 Operating Costs and Performance

Q: What PECo rebuttal witness addresses the issues of Limerick 1 operating costs and performance?

A: Dr. Hieronymus addresses these issues at pages 28 - 40 of his testimony. He disagrees with the various projections of Limerick 1 O&M, capital additions, and capacity factor offered by Mr. Komanoff, Mr. Falkenburg, and me. He makes some interesting technical arguments: it is unfortunate that PECo did not present these arguments in its original justification for its projections,[2] which would have allowed for a full and fair review of these points. Unfortunately, it is not possible to fully evaluate Dr. Hieronymus's arguments in the time available for surrebuttal. Most of these technical issues are relatively unimportant, since Limerick 1 will be an economic disaster for current customers, regardless of whether PECo's projections, or those based on historical experience, turn out to be correct.

Dr. Hieronymus also touches on similar issues on pages 20-22. The only interesting point I see in that discussion is the claim that the difference in utility-claimed economics for Limerick 1 and Susquehanna 2 is the avoided fuel savings.

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2. PECo generally offered only very limited, arbitrary computations to support its projections, or offered no data at all.

Dr. Hieronymus appears to use the total claimed Susquehanna 2 benefits, including capacity credits, as if they were all energy savings. He also ignores the fact that Susquehanna 2 (and the entire plant) was only about half as expensive as Limerick 1 and common.

Q: Do you wish to respond to any of Dr. Hieronymus's specific points?

A: Yes, there are seven such points. First, Dr. Hieronymus states that "Mr. Chernick simply assumes that O&M will grow at the geometric rate he derives. . . " (PECo Statement 15B, page 29). This is incorrect, as Dr. Hieronymus acknowledges later in his testimony: I assume linear growth, not geometric growth. Much of Dr. Hieronymus's criticism of my projection is directed to the geometric projection which I present for comparison purposes, and which is not used in any of my cost-effectiveness analyses. The geometric projection is a straw man.

Second, Dr. Hieronymus incorrectly suggests that introducing Mr. Komanoff's TMI dummy would have a dramatic effect on my O&M projections.[3] The linear projection, which I actually use in my analyses, changes rather modestly when the TMI variable is introduced: Dr. Hieronymus's calculations in Exhibit WHH 40B, page 2, indicate that the present value of

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3. The modeling tradeoff between time trends, individual year dummies, and period dummies (such as the TMI variable) deserves more study than is possible in this time frame.

the O&M costs, at his preferred discount rate, decreases only 19% from my specification to the TMI-dummy specification, while the present value of the PECo projection is 61% less than mine. For a higher, more reasonable discount rate, the present value difference due to the TMI dummy would be smaller.

Third, Dr. Hieronymus proposes a very major change to my model, while implying that such a change would be consistent with my approach (ibid., page 31, lines 1-9). In my model, O&M is assumed to display constant economies of scale (increasing unit size by a fixed percentage reduces $/kW by a fixed percentage), constant economies of duplication (adding a second unit causes a fixed percentage reduction in $/kW), and a constant percentage cost differential for northeastern plants. The specification I selected is the standard one used in situations in which economies of scale are important, and most importantly, it makes sense.

Dr. Hieronymus's model has none of these features, since he assumes that the effect of unit size, year, and unit number are additive. He assumes, for example, that O&M is $8.164 million higher for each northeastern plant in each year, regardless of whether the plant is a single 500 MW unit in 1973, or a twin 1100 MW plant in 1984. Similarly, he assumes that a second twin unit costs $18.894 million extra (27260*ln(2)), regardless of whether that unit is a 500 MW Midwestern unit in 1970, or an 1100 MW Northeastern unit in

1984. Dr. Hieronymus's proposed model design is clearly inferior to my design, on its face, and he provides no evidence to indicate that it represents a better model of nuclear O&M.[4]

Fourth, Dr. Hieronymus observes that a significant portion of capital additions occur during major outages for major repairs and upgrades. His analysis covers only the last two years of the five years which form the basis of my projection of Limerick 1 capital additions, and is thus primarily anecdotal.[5] Nonetheless, his basic point is probably true, even though his quantification of this effect is suspect: major capital additions are often due to major repairs and refits, or are accomplished during the same outages required by the repairs and refits. Dr. Hieronymus appears to suggest that it is proper to assume that Limerick 1 will have many fewer repairs and retrofits than existing plants, simply because he and I do not know what problems Limerick 1 will have. Of course, when the units listed on page 32 of PECo Statement 15B entered service, their owners did not anticipate the problems which have resulted in their capital additions.

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4. Dr. Hieronymus has simply demonstrated that arbitrary regressions, such as his, can yield arbitrary results. Since my specification is not arbitrary, he has said very little about my projections.

5. No justification is offered for this limited review of the data.

The nuclear utilities have repeatedly presented Pollyanna projections of nuclear construction costs, and of operating parameters, which have turned out to be incorrect. For example, Dr. Perl (a PECo witness in this case) repeatedly projected in the late 1970's and early 1980's that nuclear construction cost overruns and schedule slippages were over, and that costs would stabilize. He was repeatedly wrong. In 1983, Dr. Hieronymus filed testimony on behalf for the Public Service Company of New Hampshire, supporting the company's $5.2 billion cost estimate for the two-unit seabrook plant and rejecting estimates by intervenor witnesses (including me) in the $7-$10 billion range. Before Unit 2 was canceled in 1984, the cost estimates for the plant had reached the $9-$10 billion range. Current utility estimates for Unit 1 alone are $4.5 billion or more. The nuclear utilities, and their witnesses in regulatory proceedings, have generally been wrong in projecting that the bad news is over. I that hope Dr. Hieronymus is correct, and that the bad news in capital additions (at least as it affects Limerick 1) is over. I believe the Commission would not be well advised to accept the assurances of PECo or Dr. Hieronymus in this regard.[6]

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6. As I noted above, the appropriate ratemaking treatment for Limerick 1 in this decade is probably not very sensitive to the operating cost projections, since Limerick 1 is uneconomical even with PECo's cost projections.

Fifth, Dr. Hieronymus criticizes Mr. Komanoff's capital additions regressions for explaining only a small portion of the variation. As I explained on redirect, it is unrealistic to expect regression analyses to accurately predict individual annual results for such highly variable parameters as capital additions and capacity factor. The timing of outages and additions will cause large swings from year to year for individual units, which have no relationship to underlying conditions and which have little significance in projecting average values for the lifetime of Limerick 1.

Sixth, Dr. Hieronymus misstates the significance of the "confidence interval" around my best estimates of Limerick 1 capacity factors. The ranges displayed in his Exhibit WHH-43 are prediction intervals for individual annual capacity factors, and in that sense, Dr. Hieronymus is correct: Limerick 1 will probably have annual mature capacity factors which range from the 20% range to near 90%. However, these variations will tend to average out, so that units similar to Limerick 1 (the Susquehanna units, for example) will have life-time average capacity factors which are much more closely clustered. If the annual variation not explained by my model are independent (e.g., there are no inherently good or bad plants), the variability decreases with the square root of the number of years in the average: for 25 mature years, 95% of the <u>unit averages</u> would be expected to fall in the 50% - 63% range, even while 95% of the <u>annual data</u> was spread over the 26% - 88% range Dr. Hieronymus displays.[7] I have not tested the independence hypothesis, but Easterling (1981)[8] did sort out plant-related and random variations, and found that the 95% prediction interval for years 2-10 of a BWR's life was a range of 13% around his best estimate.[9] For 25 years, the range would decrease further, to 9%-10%.

Seventh and finally, from page 36, line 37 to page 39, line 3, in PECo Statement 15B, Dr. Hieronymus alleges that some unspecified data for newer reactors "suggest at a minimum that Limerick is likely to outperform Mr. Chernick's forecast in the short term." Since the data is not provided, I can not determine what Dr. Hieronymus thinks he is talking about, but he appears to be suggesting that since someone else used historical data and underprojected a year or two of performance at new units, the same will be true for my projections. Due to the lack of data, the absence of any connection with my model, and his admission that his putative data is "less clear for BWRs," Dr. Hieronymus's allegations must be dismissed as being without substantial basis.[10]

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7. Actually, the spread would be greater, since my projections already average out the effects of refuelings.

8. The full cite is listed in the bibliography to my direct testimony.

9. Since Easterling did not include as much unit-specific detail as I did (he used no size variable, where I have two), my formulation would be expected to leave less unexplained unit-specific variability.

10. At the end of this rambling and contradictory discussion, Dr. Hieronymus refers to "the perhaps premature declaration of LaSalle in commercial operation" as a partial explanation for

the poor performance of new BWRs. Since LaSalle 1 took 20.5 months from first operating license to COD, and Unit 2 took 10 months, compared to an average of 13 months, a median of 11 months and a minimum of 4 months for post-TMI units, this concern does not appear to be supported by the data. See Table R-4.

2 The Measurement of Limerick 1 Capacity Value

Q: Which PECo rebuttal witnesses discuss the capacity value of Limerick 1?

A: This topic is addressed in various ways by Dr. Hieronymus and Mr. Rush.

Q: How does Dr. Hieronymus address the issue of the capacity value of Limerick 1?

A: He discusses capacity-related issues in two sections of his testimony. The first section is entitled "Excess Capacity" (PECo Statement 15B, pages 16-18) and the second is entitled "Capacity Payments" (ibid., pages 22-26).

Q: Please comment on Dr. Hieronymus's "Excess Capacity" discussion.

A: For the most part, Dr. Hieronymus appears to have established another straw man. He spends a couple of pages defining and arguing with a position which he attributes to me, but which I did not take.[11] I do not argue that PECo should retain capacity which will be uneconomical with Limerick 1 in service. I <u>do</u> express some concern that PECo not retire existing units simply to make Limerick 1 appear to be more

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11. Dr. Hieronymus even notes that a plain reading of my testimony indicates that I am simply advocating that PECo make economic decisions, but he is apparently having too much fun beating on the straw man to stop.

necessary: the CTs, in particular, are so inexpensive that it is difficult to believe that PECo and its customers will not be better off with the capacity than without it. Nevertheless, it is possible that even the minimal cost of the CT capacity exceeds its value to PECo for internal purposes, or for sale to other systems,[12] in which case the plants should be retired.

My concern about the merits of PECo's planned retirements is really peripheral to the major topics of my testimony. For the most part, I accept PECo's assertions that the existing capacity will be retired as Limerick 1 enters service, but that it could have been retained to meet PJM obligations in the absence of Limerick 1. Dr. Hieronymus pauses in his denunciation of a non-existent ratemaking proposal to endorse the only substantive use I made of the existing capacity (PECo Statement 15B, page 17, lines 39-47).

Q: Please comment on Dr. Hieronymus's discussion of "Capacity Payments".

A: Dr. Hieronymus starts by basically restating earlier arguments for his hypothesized increase in the PJM capacity

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12. Remember that PECo, and Dr. Hieronymus, are predicting that were it not for Limerick 1, the cost of peaking capacity purchases within PJM would be about $200/kW in 1995. If PJM is that close to a severe capacity crisis, it is likely that the CT capacity could be sold for more than its cost of less than $15/kW. If PJM is not on the verge of a capacity crunch, then Dr. Hieronymus's capacity charge projections are not only unrealistic and inefficient, but also fanciful.

charge. He then acknowledges that these original arguments for the higher capacity charge are irrelevant, since PECo could build its own peakers, rather than paying PJM the price of new peakers every year. He therefore introduces an entirely new argument: that if PECo had not built Limerick 1 (or some other baseload plant), PJM would change its split-savings calculation for economy energy to require splitting capacity costs as well.[13]

Dr. Hieronymus does not provide any evidence that PJM, or any power pool, has ever considered, let alone implemented, such a scheme. The GPU system has been a major buyer from PJM since the TMI accident, has no plan for base-load additions, and appears likely to continue buying large amounts of economy energy for some time: Dr. Hieronymus offers no PJM document suggesting a revision of the split-savings formula for GPU. Many NEPOOL members are projecting capacity deficiencies throughout the 1990's, and many of those members already have (and will continue to have) relatively small

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13. Dr. Hieronymus assumes that the capacity costs to split would be based on new capacity every year, rather than on the costs of actual PECo peakers, which would be much less expensive, and the cost of the sellers' actual plants, which would usually be less expensive than the most recent unit in the pool. Under economic dispatch, the most recent and most efficient plants would be used first by their owners, and the sales to PECo would tend to be from older plants. Under Dr. Hieronymus's proposal, the seller of economy power from a new 1985 coal plant, for example, would recover <u>more than the cost of the capacity</u>, and more than would be paid for a unit capacity sale, <u>in addition</u> to receiving split energy savings. This is illustrated in Table R-1. Dr. Hieronymus's fixation with the cost of new plant in the capacity savings calculation simply leads to absurd results.

baseload entitlements: I know of no NEPOOL proposal comparable to Dr. Hieronymus's hypothesized response, and again Dr. Hieronymus offers no evidence that other NEPOOL utilities are acting the way he predicts the PJM utilities would act toward PECo.

In fact, Dr. Hieronymus's hypothesized split-capacity charge for economy energy is quite unlikely to be adopted by any pool. Utilities generally charge for capacity only when they guarantee the buyer access to the plant's power.[14] Under economy sales arrangements, the buyer gets only the power for which the seller has no other use, including serving its own load and making short-term and long-term sales. The buyer has no claim on any particular unit, and always pays more than the seller's incremental cost of production. Since the seller gives up nothing, and always gains, the split energy savings arrangement should be more than adequate to compensate sellers of economy energy. And since the buyer receives no guarantees at all, a payment of half the difference in capacity costs between the two units would be rather extravagant.

Dr. Hieronymus does not address other major flaws in his projection of replacement capacity costs, which I identified in my direct testimony. For example, he yet to explain why

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14. That guarantee may be conditioned by allowing some limited interruptions of delivery, but the buyer is at least getting first call on the capacity most of the time.

the massive hypothetical increases in the PJM capacity charge, which he attributes to a prolonged shortage of capacity, would in 1986, before any prolonged PECo capacity deficiency.[15] Similarly, Dr. Hieronymus has failed to reconcile the very high avoided energy and avoided costs PECo projects in the absence of Limerick 1, with PECo's failure to include economic capacity (particularly cogeneration) which would be built by PECo or other parties, for less than those costs.

Q: What are Mr. Rush's comments on the capacity value of Limerick 1, and are they valid?

A: Mr. Rush makes eight points relevant to my direct testimony. First, he claims that I "apparently consider [retention of existing units and construction of new CTs] more suitable than the PECo addition of Limerick Unit No. 1" (PECo Statement 14A, page 3). This is hardly a fair statement of my position, and blames me for PECo's actions. PECo chose to compare Limerick 1 to a case in which existing peaking plants were retired, no new capacity was built, and capacity deficiencies were made up by very expensive PJM charges. As I noted on direct, the proper alternative to which Limerick 1 should be compared would be an efficient program of capacity additions, upgrades, and purchases (especially from

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15. Indeed, it is hardly realistic to assume that PECo would have retired the existing units, if that would have triggered a capacity deficiency.

cogenerators): since PECo did not perform production costing runs for an optimized alternative expansion plan, it was not possible for me to compare Limerick 1 to an efficient program.

Since I was forced to use PECo's energy savings figures -- which included no fuel-saving investments -- I simply found the least-cost capacity sources which would be consistent with those energy sources. Mr. Rush does not dispute my observation that it would be foolish (in the absence of Limerick 1) for PECo to throw away the existing capacity and instead purchase capacity at costs higher than the cost of PECo-owned turbines. Yet this is the alternative to Limerick 1 which PECo proposes. I propose a slightly more efficient expansion plan to compare with Limerick 1, which substitutes inexpensive PECo-owned peaking capacity for expensive PJM capacity purchases.[16] Since my expansion plan eliminates the limited and belated benefits PECo claims for Limerick 1, comparison to a truly efficient expansion plan would reveal that Limerick 1 is even less economical than my modification to PECo's non-Limerick expansion plan would indicate.

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16. The oil-fired steam plants which are being retired as Limerick 1 enters service do have some fuel savings, even with Limerick on line, and would have greater fuel savings without Limerick. I subtracted PECo estimates of their fuel savings (with Limerick) from their O&M, to produce a slightly overstated but reasonable estimate of their net capacity costs.

Second, Mr. Rush claims that the existing oil-fired plants "are uneconomical to run" (ibid.). In fact, the oil steam plants do produce fuel savings, even with Limerick 1 on line. More important, using PECo's assumptions regarding interchange energy, it would be less expensive for the customers to use the existing plants and interchange, rather than to pay for Limerick 1, for many years and probably for the unit's life as a whole.

Third, Mr. Rush points out that excessive reliance on oil has its risks. The same is true for PECo's very heavy reliance on nuclear power for its energy requirements: both the cost and availability of that power has been difficult to predict, highly variable over time, and much more expensive than PECo expected.

Fourth, Mr. Rush raises the specter of massive capacity retirements in the first decade of the next century. He does not explain why he believes that Keystone, Conemaugh, or Eddystone 3 and 4 will have to be retired at age 35, when Eddystone 1 and 2 and Cromby 1 are to be extended to age 50, or indeed why the process of rebuilding boilers and turbines can not continue indefinitely. Historically, power plant retirements usually have resulted from technical obsolescence (e.g., high heat rates) rather than physical deterioration.[17]

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17. Of course, units which are marginally efficient are often retired at the point when major repairs would otherwise be needed. A more efficient unit which required even more extensive repairs might well be kept on line: if the state

It is perfectly possible that the fossil units Mr. Rush lists (ibid., page 6) will be retired by 2010, if a superior technology (e.g., modular fluidized bed units, fuel cells, a new generation of nuclear plants, photovoltaics) is available to replace them.[18] If the new technology, or the industrial capacity for delivering it, do not exist, then relatively few fossil plants will be retired. In any case, I agree with Mr. Rush that PECo's hypothetical alternative non-Limerick expansion plan is inefficient, and that in the absence of Limerick PECo would have invested in (or purchased) new capacity which used less oil than the PECo hypothetical alternative. Once again, Mr. Rush is blaming the intervenors for PECo's alternative supply plan.

Sixth, Mr. Rush claims that my alternative expansion plan relies "on resurrecting retired units" (page 3). This is not correct. I assume that, had Limerick 1 not been under construction, Richmond and Southwark would not have been retired: no resurrection would have been necessary.

Seventh, Mr. Rush garbles the entire retirement issue (page 6, line 47, to page 8, line 41). He focuses on semantic issues, such as whether PECo assumes early retirements or the intervenors assume late retirements, whether the retirement

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of the art has not progressed much, it will almost always be cheaper to fix an old plant than to build a new one.

18. If such superior technologies become available, they will tend to decrease the benefits of Limerick 1.

is justified with Limerick 1 nearing operation, and whether the plants have "served their original objective," rather than the real economic issues. He also makes various vague statements about units wearing out. The fact is that I have relied PECo assumptions and conclusions about the cost and effectiveness of extending the lives of these units, primarily drawn from PECo studies used to justify the retirement of the units. Mr. Rush does not dispute those studies, or my use of them. Given those PECo assumptions, it would be cheaper to replace Limerick 1 with retained capacity (including some life extensions) than with the PJM purchases PECo assumes in its cost-benefit studies.

Eighth and last, I would like to discuss Mr. Rush's response to my demonstration that Limerick 1 is a poor source of reliability. The lack of substance in his response presents a sad picture of PECo's capacity planning ability. Mr. Rush criticizes me for estimating the size-sensitivity of the PJM system (the m factor in my Table 2.7), but he offers no estimate of his own, nor does he demonstrate that any reasonable variation in the m factor would change my basic conclusions. Instead, he makes vague claims about effects of the size of PJM's system and the size of certain other units,[19] and then simply asserts -- without any analysis or

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19. Mr. Rush appears to be confusing the effect of the first large unit on operating reserve requirements, which is very important, to the effect of that first large unit on installed reserve requirements (which is the measure of

calculation -- that my observations about the Limerick 1 contribution to PJM reliability are incorrect.[20] I scaled up the NEPOOL size parameter to reflect PJM's larger system, so Mr. Rush's arguments about the differences between NEPOOL and PJM are irrelevant: the central point is that I have a reasonable estimate of the reliability benefits of Limerick 1, and he has only bald assertions.

Contrary to Mr. Rush's assertion, my reliability sensitivity calculations were performed for a PJM-sized system, not for NEPOOL, and no arbitrary changes were necessary. Other than the value of m, which was adjusted for PJM conditions, no inputs to my calculation relied on NEPOOL figures. Indeed, most of my inputs came from PECo.[21]

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reserve relevant to this case), for which it is much less important.

20. Actually, he is rather vague on his bottom line. He couches the "reliability impact of Limerick 1" in terms of the retirement of an unspecified amount of smaller units, and asserts that there would be "essentially no change in the reliability of the PJM system". If he means that retiring 458 MW of gas turbines, and bringing on 1055 MW of Limerick 1 will cause only a small increase in the frequency of blackouts, spread over all of PJM, he is probably correct. My point is not that Limerick 1 will cause massive reliability problems, but only that it does not replace the reliability value of 1055 MW in smaller, more reliable units.

Similarly, Mr. Rush says that "Limerick . . . will not have the negative impact that Mr. Chernick suggests," he may either be referring to his error, in believing that I have suggested that Limerick 1 will cause blackouts, or he may be suggesting that the "negative effect" will be slightly smaller than I suggest, which is always possible.

21. Mr. Rush even criticizes me for using PECo data for the oil-fired plants. I relied on PECo estimates of forced outage rates for refurbished steam units at Delaware, Cromby, and Schuylkill, given PECo's familiarity with the specific units

Mr. Rush does not mention the reason I was forced to estimate the size-sensitivity of PJM. PECo refused to provide PJM-specific studies of the relationship between capacity, load and reliability, on the grounds that such studies are proprietary (IR-UCC/UP-2-6 and 2-7). This is perhaps the most extraordinary claim I have ever seen a utility make on discovery. I can not imagine how any PJM member could be harmed by the release of such studies, unless they demonstrate that PJM reserve requirements are excessive, in which case this Commission should certainly know their contents. NEPOOL has suffered no apparent harm from releasing estimates of the relationship between reserves and reliability.

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when they were in good repair, and for new CTs, since there was no data readily available for the type of plants PECo says it would build. For the other steam units and the existing CTs, I use the average experience in the last 5 years. For Limerick 1, I use a forced outage rate intermediate between PECo's optimistic estimate and my own historically-based projection. Table R-2 presents the relative reliability value of a MW in each of the various units, compared to a MW of Limerick 1, if the latter achieves PECo's 20% outage rate. Even if Mr. Rush were right about Limerick's forced outage rate, he is incorrect in asserting (again without evidentiary support) that it provides the same reliability as an equal rated capacity in smaller units.

3 Projections of Fuel Prices

Q: Which PECo rebuttal witnesses address fuel cost projections?

A: Various aspects of this issue are discussed by Dr. Hieronymus, Dr. Hogan, and Mr. English.

Q: Do you have any comments on their testimony?

A: Yes, I have two comments. First, the extensive discussion of coal prices by Mr. English and Dr. Hieronymus is largely irrelevant to this proceeding. As I demonstrate in Table 2.5 of my direct testimony, PECo's replacement fuel costs are at the level of oil-fired steam or combustion turbines: coal prices clearly have little effect on the economics of Limerick 1, as PECo has constrained this case. If PECo had provided comparisons of the cost of Limerick 1 to that of a contemporaneous coal plant, coal prices would be very important. Since PECo has chosen to compare Limerick 1 to existing oil-fired capacity and largely oil-based purchases, coal prices do not matter very much.

Second, PECo's rebuttal on oil prices simply indicates that PECo does not believe their usual oil price consultant, DRI, and that PECo has found one part-time forecaster, Dr. Hogan, who agrees. No oil price forecasts are offered from other independent commercial forecasters (comparable to DRI), whose incentives are oriented to correct predictions, or even from corporate forecasters (such as for the oil companies) who may have axes to grind. In the absence of such alternative forecasts (which PECo could certainly have found and presented, had any agreed with its positions), we must assume that the DRI forecasts represent the consensus in the industry, at least before the current downturn in prices.[22]

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22. Dr. Hogan's description of the reasons for rising prices contains an apparent inconsistency. He correctly observes that "expensive tertiary recovery projects" will be delayed by falling prices: this is undoubtedly correct. However, both he and PECo project rising real prices from 1985 to 1990, and the OCA price projections show real prices returning to 1985 levels by about 1995, so the tertiary recovery projects which are delayed in the short term will be developed a few years later, or perhaps a decade later. Unlike exploration for new supplies, refitting existing fields for more efficient extraction does not involve long time lags or high risks. Actually, the rising interest in cogeneration development in such oil-producing areas as California, Texas, and Oklahoma, may accelerate tertiary recovery with steam-injection cogeneration systems.

4 Discount Rates

Q: What PECo rebuttal witnesses address the issue of discount rates?

A: Dr. Hieronymus, Mr. Hill, and Dr. Perl all touch on this issue.

Q: What response would you like to make to their comments?

A: I will avoid getting any deeper into complex theoretical issues, and will only mention a few points. At the end of the next section, I propose a regulatory solution which cuts through the tangle of detailed arguments, by letting PECo demonstrate its faith in its claimed discount rate, to the benefit of consumers. The specific points I would like to make include:

1. No PECo witness has disputed the fact that utility carrying costs (return and taxes) for investments are about 20%, once depreciation and investment-related tax credits are accounted for.

2. PECo witnesses correctly state that tax effects must be considered in establishing a discount rate. In applying this rule, they err in including only the tax deduction for debt expense, and ignore the tax multiplier which must be applied to pay the income taxes on funds collected from ratepayers to pay for

financing costs ... uity funds, as well as debt for which the tax effect has already been taken, as in net-of-tax AFUDC).

3. The after-tax discount rate is generally correct in competitive industries. Tax effects are generally subtracted from projected revenue streams, and there is in any case no connection between the cost of the investment and the resulting revenues streams. Therefore, paying a dollar in interest costs only about 50 cents, since income taxes go down by 50 cents, all other things being equal. For rate-regulated utilities, all other things are not equal: paying $1 in interest generally creates a $1 in allowed revenues, which neutralizes the tax benefit. For equity funds, which generate no tax benefits, earning $1 requires a charge to customers of $2. Thus, the net effect of taxes is to reduce the financing costs of competitive industries, and increase the financing costs of regulated utilities.

4. Dr. Hieronymus agrees that the issue is whether "ratepayers would prefer to pay the cost of Limerick sooner or later,"[23] but then uses the utility's cost of capital for comparing costs over time. This is inconsistent and contradictory. The figures we are

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23. Alternatively, the cost may that required by some alternative to Limerick.

discounting are charges to ratepayers, not the utility's cash expenditures.

5. Dr. Hieronymus quotes EPRI on the after-tax discount rate, which simply demonstrates that utilities (and their captive organizations, such as EPRI) have preferred low discount rates to justify their questionable capital investments.

6. Dr. Hieronymus argues that the utility cost of capital should be used as the discount rate, because "it is used to build the plant." This is an argument for using the utility net-of-tax cost of capital as the AFUDC rate, which no one appears to dispute. Dr. Hieronymus has created yet another straw man.

7. Dr. Hieronymus correctly observes that the discount rate for a project should be based on "the market cost of capital for a project with its risk characteristics." PECo has not attempted to find a market price for taking the risks of operating Limerick 1,[24] but we do know that when corporations, institutions, or individuals are given the opportunity to invest in much less risky projects which reduce future energy costs, they require projected returns in excess of 20%.

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24. For example, an insurer might guarantee PECo's projections of Limerick 1 operating costs and capacity factor, but only at a very high premium.

8. Dr. Hieronymus's observation that the discount rate for a project should be based on "the market cost of capital for a project with its risk characteristics" contradicts Mr. Hill's first two points (PECo Statement 18D, pages 9-11), in which he argues that the appropriate discount rate is determined only by ratemaking, and is independent of Limerick 1 characteristics.

9. Mr. Hill generally appears to confuse cost recovery issues with discount rate issues. Whether PECo recovers its investments, whether shareholders are compensated for the risk of their total investment in PECo (not just Limerick 1), whether rates are set using embedded or incremental costs of capital, and whether AFUDC rates are net or gross of tax rates, has little relevance for determining the discount rate to be applied to Limerick 1. Mr. Hill is also mistaken in his impression that I "seek to remove" tax benefits: I accept PECo's projections of Limerick 1 carrying charges (except for the treatment of common plant), which are lower due to the deductibility of interest, or higher due to taxation on equity return, depending on how one views the situation.

10. Dr. Hieronymus notes that "[h]igh hurdle rates are used to counter optimism in forecasting project cash flows." The same high hurdle rates can be applied to PECo's

optimistic projections of Limerick 1 cash flows: Limerick 1 is uneconomical at the 25%+ hurdle rates Dr. Hieronymus endorses, or even at 15% rates. Thus, if we apply to PECo's projections only a small part of the skepticism which industries and institutions apply to their own projections, Limerick 1 would not be expected to break even in discounted terms.

5 The Costs and Benefits of the Limerick 1 Construction Delays

Q: Which PECo rebuttal witness addresses the costs and benefits of the Limerick 1 construction delays?

A: Dr. Perl discusses this issue, in connection with discount rates.

Q: What is his position, and what is your response?

A: Basically, he asserts that PECo can finance costs over time at less than consumer discount rates, and that the alleged benefits of the delayed plant in the third decade of the next century were fully comparable to the increased costs of delay in the 1980's. Dr. Perl has distorted the argument somewhat on pages 12 and 13: he suggests that the critical issue is the credibility of projected savings in the 30th year of the plants operation (regardless of when it enters service) or the comparative credibility of savings in the 30th year, versus the 31st year. The only substantial difference between the delayed plant and the non-delayed plant is that the delayed plant is not available in the early years (say, 1984 and 1985) but is operating in the years after retirement of the undelayed plant (say, 2023 and 2024). Thus, we must compare savings in 2024 to costs in 1984: for most of the customers who paid the extra costs in 1984, the benefits in 2024 are irrelevant, since they will not be on the system.

The costs in 1984 are quite real and known, while the benefits in 2024 are speculative and highly uncertain.

Presumably, Dr. Perl's logic would also suggest that homeowners delay installing storm windows with a 15 year useful life, since the present value of the savings due to having the windows in year 16 will exceed the costs of not having the windows in year 1. It is not clear where Dr. Perl's rationalization for delay would end: if two years of delay are good, then would not ten years be better? Why would Dr. Perl ever bring a plant on line, install storm windows, or do anything which had a limited useful life?

Q: How would you suggest that the Commission resolve the disputes regarding the cost of delay and of the appropriate discount rate?

A: PECo asserts that 9.7% is the effective annual cost at which it can finance projects for the benefit of ratepayers. PECo further insists that the benefits it projects in 2024 are just as real as the costs in 1986. The Commission can simply take the Company at its word, and let it recover its investment,[25] including 9.7% financing, from the benefits it expects Limerick 1 to produce late in this century and into the next. To be generous, the Commission could allow PECo to

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25. Net of any penalties imposed, such as for construction imprudence.

retain its projected energy savings per kWh,[26] as forecasted in this case, plus the capacity benefits I have quantified. The real benefits of Limerick 1, compared to an efficient expansion plan, would be lower than the combined energy and capacity value calculated in this way. If Dr. Perl, Dr. Hieronymus, and the other PECo witnesses are correct about the operating costs, capacity factor, and discount rate for Limerick 1, the Company would be fully compensated.

Q: Would this approach cause major financial problems for PECo?

A: It should not do so, if investors believe PECo's projections of the costs, performance, and risks of Limerick 1. An investor who agrees with Dr. Perl would have no reluctance to invest in Limerick 1 at an expected after-tax return of 9.7%, with the time pattern of costs and benefits PECo projects. Whether the FASB considers PECo's deferrals to be earnings should be irrelevant to an investor who believes PECo's projections. The value of securities is determined by the investor's expectations of future cash returns, not by accounting reports.

Q: Why would PECo not embrace your approach?

A: I can only speculate on that point, since I obviously have not discussed this issue with top PECo management. One

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26. Note that this approach would protect PECo from variation in fuel costs or power availability, and would lock in recovery based on fuel costs higher than current consensus projections.

possibility is that PECo does not expect to be able to convince investors of the economic viability of Limerick 1, which it has asked the Commission to accept. In that case, PECo's projections would fail the market test Dr. Hieronymus proposes: the discount rate for an investment as risky as Limerick 1 is higher than 9.7%. The other possibility is that PECo does not believe its own projections, and anticipates that it would never recover the cost of Limerick 1 if cost recovery was tied to plant performance and operating costs.

5.1 Miscellaneous Issues

Q; Do you have any other response to PECo rebuttal testimony?

A: Yes. Mr. Wroblewski (PECo Statement 21A) asserts that sinking-fund depreciation (and hence presumably other deferred cost recovery mechanisms) can not represent "the loss in service value," which is the FERC definition of depreciation.[27] As measured by its projected benefits, the value of Limerick 1 <u>rises</u> for the first twenty-odd years of its life, so its economic depreciation would be negative in that period. This is demonstrated in Table R-3, which displays the present value over time of the future benefits, both for PECo assumptions and for one of my estimates of Limerick 1 benefits. The results are essentially unchanged if net operating benefits are used as the definition of "service value," rather than the gross benefits displayed in Table R-3. To avoid any extraneous dispute, Table R-3 uses PECo's preferred 9.7% discount rate.

Q: Does this conclude your surrebuttal testimony?

A: Yes.

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27. Most of Mr. Wroblewski's testimony involves such <u>non sequiturs</u> as whether banks charge transaction cost ("points") to small borrowers, and whether PECo has a claim against individual customers for cost recovery.

TABLE R-1: COMPARISON OF HIERONYMUS' HYPOTHETICAL SPLIT-CAPACITY-COST CHANGES TO THE COST OF A NEW 1986 COAL PLANT

YEAR	PJM CAP CHARGE $/KW-YR [1]	YEARLY REV REQ COAL-$/KW [2]	AVERAGE OF COLUMNS [1] + [2] [3]	ANNUAL COST 1986 COAL PLANT
1985				
1986	$52.93	$229.94	$141.44	$229.94
1987	$56.58	$241.44	$149.01	$229.94
1988	$60.23	$255.92	$158.08	$229.94
1989	$63.88	$271.28	$167.58	$229.94
1990	$68.26	$287.56	$177.91	$229.94
1991	$72.36	$304.81	$188.58	$229.94
1992	$76.70	$323.10	$199.90	$229.94
1993	$81.30	$342.48	$211.89	$229.94
1994	$86.18	$363.03	$224.61	$229.94
1995	$91.35	$384.81	$238.08	$229.94
1996	$96.83	$407.90	$252.37	$229.94
1997	$102.64	$432.38	$267.51	$229.94
1998	$108.80	$458.32	$283.56	$229.94
1999	$115.33	$485.82	$300.57	$229.94
2000	$122.25	$514.97	$318.61	$229.94
2001	$129.59	$545.87	$337.73	$229.94
2002	$137.37	$578.62	$357.99	$229.94
2003	$145.61	$613.33	$379.47	$229.94
2004	$154.35	$650.13	$402.24	$229.94
2005	$163.61	$689.14	$426.38	$229.94
2006	$173.43	$730.49	$451.96	$229.94
2007	$183.84	$774.32	$479.08	$229.94
2008	$194.87	$820.78	$507.83	$229.94
2009	$206.56	$870.03	$538.29	$229.94
2010	$218.95	$922.23	$570.59	$229.94
2011	$232.09	$977.56	$604.83	$229.94
2012	$246.02	$1,036.22	$641.12	$229.94
2013	$260.78	$1,098.39	$679.58	$229.94
2014	$276.43	$1,164.29	$720.36	$229.94
2015	$293.02	$1,234.15	$763.59	$229.94
2016	$310.60	$1,308.20	$809.40	$229.94
2017	$329.24	$1,386.69	$857.97	$229.94
2018	$348.99	$1,469.89	$909.44	$229.94
2019	$369.93	$1,558.09	$964.01	$229.94
2020	$392.13	$1,651.57	$1,021.85	$229.94
2021	$415.66	$1,750.67	$1,083.16	$229.94
2022	$440.60	$1,855.71	$1,148.15	$229.94
2023	$467.04	$1,967.05	$1,217.04	$229.94
2024	$495.06	$2,085.07	$1,290.07	$229.94
NPV AT 9.70%			$2,809.30	$2,306.43

TABLE R-2: EFFECTIVE LOAD CARRYING CAPABILITY
Linerick at 20% EFOR

	INPUTS: MW	m	EFOR	AVE MW	ELCC	ELCC/MW	ELCC/ AVE MW	Ratio of ELCC/MW to Lim. ELCC/MW	WEIGHTED AVERAGES USED IN TABLE 2.8
Limerick 1	1055	800	20.0% [1]	844.00	705.56	66.9%	83.6%	1.000	
	1055	800	25.0%	791.25	637.74	60.4%	80.6%		
	1055	800	27.5%	764.88	605.87	57.4%	79.2%		
	1055	800	30.0%	738.50	575.22	54.5%	77.9%		
	1055	800	35.0% [2]	685.75	517.23	49.0%	75.4%		
Existing Combustion Turbines	30	800	18.4% [3]	24.48	24.39	81.3%	99.7%		
	30	800	28.4%	21.48	21.37	71.2%	99.5%	1.065	
	30	800	38.4%	18.48	18.35	61.2%	99.3%		
New Combustion Turbines	75	800	8.0% [6]	69.00	68.73	91.6%	99.6%	1.370	
Richmond 9	166	800	18.7% [4]	134.96	132.23	79.7%	98.0%		
	166	800	28.7%	118.36	114.73	69.1%	96.9%	1.033	
	166	800	38.7%	101.76	97.61	58.8%	95.9%		
Southwark 1	163	800	18.9% [4]	132.19	129.54	79.5%	98.0%		
	163	800	28.4%	116.71	113.24	69.5%	97.0%	1.039	1.054
	163	800	38.4%	100.41	96.42	59.2%	96.0%		
Southwark 2	173	800	15.2% [4]	146.70	144.17	83.3%	98.3%		
	173	800	25.2%	129.40	125.75	72.7%	97.2%	1.087	
	173	800	35.2%	112.10	107.75	62.3%	96.1%		
Delaware 7	126	800	17.7% [5]	103.70	102.20	81.1%	98.6%	1.213	1.170
Delaware 8	124	800	23.3% [5]	95.11	93.34	75.3%	98.1%	1.126	
Cromby 2	201	800	16.8% [5]	167.23	163.50	81.3%	97.8%	1.216	
Schuylkill 1	166	800	24.2% [5]	125.83	122.56	73.8%	97.4%	1.104	

Notes: MW Ratings are summer ratings (from PECo Statement No.14).

1. Consistent with PECo Capacity Factor projection in non-refueling years.
2. Consistent with my Capacity Factor projection in non-refueling years.
3. From Appendix E: Overall average, best annual average and worst annual average. Assumes FOR = 1 - EAF.
4. From Appendix E, no improvement assumed from life extension. Assumes FOR = (1-EAF), for average EAF, plus or minus 10%.
5. From PECo Statement 15, I-840381, page 1-6.
6. From IR-OCA-19-11.
7. Middle value used for units with more than one value presented.

TABLE R-3: PRESENT VALUE OF LIME[illegible]1 GROSS BENEFITS,
AS FUNCTION OF AGE

YEAR	TOTAL BENEFITS [1]	PRESENT VALUE OF REMAINING BENEFITS [2]	ECONOMIC DEPRECIATION -d(P.V.)	GROSS REALISTIC BENEFITS [3]	PRESENT VALUE OF REMAINING BENEFITS [2]	ECONOMIC DEPRECIATION -d(P.V.)
1986	$231	$11,013		$168	$8,101	
1987	$275	$11,850	($837)	$163	$8,719	($618)
1988	$307	$12,725	($875)	$187	$9,402	($683)
1989	$466	$13,652	($928)	$274	$10,127	($725)
1990	$435	$14,510	($858)	$285	$10,835	($709)
1991	$483	$15,483	($972)	$353	$11,601	($766)
1992	$652	$16,502	($1,019)	$461	$12,374	($773)
1993	$608	$17,451	($949)	$457	$13,113	($739)
1994	$755	$18,536	($1,085)	$575	$13,928	($815)
1995	$1,050	$19,577	($1,042)	$765	$14,704	($776)
1996	$954	$20,425	($849)	$746	$15,366	($661)
1997	$1,032	$21,453	($1,027)	$847	$16,110	($744)
1998	$1,319	$22,502	($1,049)	$1,012	$16,826	($716)
1999	$1,096	$23,365	($863)	$892	$17,447	($621)
2000	$1,256	$24,536	($1,171)	$945	$18,247	($801)
2001	$1,549	$25,660	($1,124)	$1,143	$19,072	($825)
2002	$1,487	$26,600	($940)	$1,159	$19,779	($707)
2003	$1,488	$27,693	($1,094)	$1,113	$20,539	($760)
2004	$2,034	$28,892	($1,199)	$1,490	$21,419	($880)
2005	$1,748	$29,661	($769)	$1,322	$22,006	($588)
2006	$1,895	$30,790	($1,130)	$1,399	$22,819	($813)
2007	$2,501	$31,882	($1,092)	$1,812	$23,634	($815)
2008	$2,268	$32,473	($591)	$1,714	$24,115	($481)
2009	$2,291	$33,355	($882)	$1,673	$24,740	($625)
2010	$3,181	$34,300	($944)	$2,304	$25,467	($727)
2011	$2,752	$34,446	($147)	$2,069	$25,633	($166)
2012	$2,943	$35,035	($589)	$2,158	$26,050	($417)
2013	$3,984	$35,490	($455)	$2,887	$26,420	($369)
2014	$3,572	$34,949	$541	$2,710	$26,095	$325
2015	$3,675	$34,766	$182	$2,703	$25,916	$179
2016	$5,214	$34,464	$302	$3,807	$25,727	$189
2017	$4,471	$32,593	$1,871	$3,401	$24,416	$1,311
2018	$4,587	$31,283	$1,310	$3,385	$23,383	$1,033
2019	$6,326	$29,730	$1,553	$4,615	$22,266	$1,117
2020	$5,546	$26,289	$3,442	$4,224	$19,811	$2,455
2021	$5,890	$23,293	$2,996	$4,388	$17,508	$2,303
2022	$8,315	$19,662	$3,630	$6,119	$14,818	$2,690
2023	$7,332	$13,255	$6,407	$5,665	$10,136	$4,682
2024	$7,908	$7,209	$6,046	$5,983	$5,454	$4,682

Notes: 1. See Attachment IR-OCA-2-25b, Item 1, page 1, column 4.
2. Present Value at 9.7%
3. See Chernick Testimony, Table 3.4, Column 5.

TABLE R-4: RECENT EXPERIENCE IN START-UP INTERVALS

Unit	Date of Issuance, First Operating License [1]	Commercial Operation Date[2]	Start-up Interval [3]
	(OLIS)	(COD)	(months)
Three Mile Island 2	08-Feb-78 (F)	30-Dec-78	10.7
Hatch 2	13-Jun-78 (F)	05-Sep-79	14.8
Arkansas 2	01-Sep-78 (L)	26-Mar-80	18.8
Sequoyah 1	29-Feb-80 (L)	01-Jul-81	16.0
North Anna 2	11-Apr-80 (L)	14-Dec-80	8.1
Salem 2	18-Apr-80 (L)	13-Oct-81	17.9
Farley 2	23-Oct-80 (L)	30-Jul-81	9.2
McGuire 1	23-Jan-81 (Z)	01-Dec-81	10.3
Sequoyah 2	25-Jun-81 (L)	01-Jun-82	11.2
San Onofre 2	16-Feb-82 (L)	08-Aug-83	17.7
LaSalle 1	17-Apr-82 (Z)	01-Jan-84	20.5
Susquehanna 1	17-Jul-82 (L)	08-Jun-83	10.7
Summer 1	06-Aug-82 (L)	01-Jan-84	16.9
San Onofre 3	15-Nov-82 (L)	01-Apr-84	16.5
McGuire 2	03-Mar-83 (L)	01-Mar-84	11.9
St Lucie 2	06-Apr-83 (L)	08-Aug-83	4.1
WPPSS 2	20-Dec-83 (L)	13-Dec-84	11.8
Diablo Canyon 1	19-Apr-84 (L)	07-May-85	12.6
LaSalle 2	16-Dec-83 (L)	19-Oct-84	10.1
Susquehannna 2	23-Mar-84 (L)	12-Feb-85	10.7
Grand Gulf 1	16-Jun-82 (L)	15-Jul-85	37.0
Callaway 1	11-Jun-84 (L)	19-Dec-84	6.3
Catawba 1	06-Dec-84 (L)	15-Jun-85	6.3
Byron 1	31-Oct-84 (L)	15-Sep-85	10.5
Waterford 3	18-Dec-84 (L)	15-Sep-85	8.9
Wolf Creek	11-Mar-85 (L)	15-Sep-85	6.2

STITR4/26-Feb-86

AVERAGE: 12.91

MEDIAN: 10.96

Notes: [1] From NRC Gray Books, NRC Summary Information Report, 10/85, and "Historical Profile of U.S. Nuclear Power Development", Atomic Industrial Forum, 12/31/81 and 1/1/83. Full licenses are indicated by (F), low power licenses by (L), and zero-power licenses by (Z).

[2] Same sources as for OLIS. Updated in 11/85.

[3] All months are treated as having 30.5 days.