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COMMONWEALTH OF PENNSYLVANIA
BEFORE THE PUBLIC UTILITIES COMMISSION

THE PENNSYLVANIA PUBL~~IC~~ UTILITIES COMMISSION V. PHILADELPHIA ELECTRIC COMPANY	Docket No. R-850152

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

January 14, 1986

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TESTIMONY OF PAUL CHERNICK

1 - INTRODUCTION AND QUALIFICATIONS

Q: Mr. Chernick, would you state your name, occupation and business address?

A: My name is Paul L. Chernick. I am employed as a research associate by Analysis and Inference, Inc., 10 Post Office Square, Suite 970, Boston, Massachusetts.

Q: Mr. Chernick, would you please briefly summarize your professional education and experience?

A: I received a S.B. degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and a S.M. degree from the Massachusetts Institute of Technology in February, 1978 in Technology and Policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a Utility Analyst for the Massachusetts Attorney General for over three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and evaluation of power supply options. My work has considered, among other things, the effects of rate design and cost allocations on conservation, efficiency, and equity.

In my current position, I have advised a variety of clients on utility matters. My resume is attached to this testimony as Appendix A.

Q: Mr. Chernick, have you testified previously in utility proceedings?

A: Yes. I have testified approximately thirty times on utility issues before such agencies as the Massachusetts Department of Public Utilities, the Massachusetts Energy Facilities Siting Council, the Texas Public Utilities Commission, the Illinois Commerce Commission, the New Mexico Public Service Commission, the District of Columbia Public Service Commission, the New Hampshire Public Utilities Commission, the Connecticut Department of Public Utility Control, the Michigan Public Service Commission, the Maine Public Utilities Commission, the Vermont Public Service Board, the Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. A detailed list of my previous testimony is contained in my resume. Subjects I have testified on include cost allocation, rate design, long range energy and demand forecasts, costs of nuclear power, conservation costs and potential effectiveness, generation system reliability, fuel efficiency standards, and ratemaking for utility production investments and conservation programs.

Q: Have you testified previously before this Commission?

A: Yes. I presented testimony on behalf of the Office of Consumer Advocate in the last Pennsylvania Power and Light rate case, Docket R-842651, concerning the economics of Susquehanna Unit 2.

Q: Do you have a track record of accurate predictions in capacity planning?

A: Several of my criticisms of utility projections have been confirmed by subsequent events or by the utilities themselves. In the late 1970's, I pointed out numerous errors in the load forecasts of several New England utilities, and of the New England Power Pool (NEPOOL), and predicted that growth rates would be lower than the utilities expected. Many of my criticisms have been incorporated in subsequent forecasts, load growth has almost universally been lower than the utility forecast, and the utility forecasts have been revised downward repeatedly.

My projections of nuclear power costs have been more recent, and have yet to be fully confirmed. However, as time goes by, utility projections have tended to confirm my analyses. For example, in the Pilgrim 2 construction permit proceeding (NRC 50-471), Boston Edison was projecting a cost of $1.895 billion.[1] I projected a cost between $3.40 and $4.93 billion in my testimony of June, 1979. Boston Edison's final cost

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1. See Appendix A for full citations.

estimate (issued when Pilgrim 2 was canceled in September 1981) stood at $4.0 billion.

In MDPU 20055, Public Service of New Hampshire (PSNH) projected in-service dates for Seabrook of about 4/83 and 2/85, at a total cost of $2.8 billion. I predicted in-service dates of 10/85 and 10/87, with a cost around $5.3-$5.8 billion on PSNH's schedule or $7.8 billion on a more realistic schedule. At the time I filed my testimony in NHPUC DE 81-312, PSNH was projecting in-service dates of 2/84 and 5/86, with a total cost of $3.6 billion, while I projected dates of about 3/86 and 6/89, and a cost of about $9.6 billion. Within two months of my filing, PSNH had revised its estimates to values of 12/84, 7/87, and $5.2 billion. On March 1, 1984, PSNH released a new semi-official cost estimate of $9.0 billion, with in-service dates of 7/85 and 12/90, while PSNH's consultants released an estimate of $10.1 billion. Thus, PSNH has moved its in-service date estimates, and increased its cost estimates, substantially towards my projections.

In MDPU 20055 and again in MDPU 20248, I criticized PSNH's failure to recognize Seabrook capital additions, its error in ignoring real escalation in O&M, and its wildly unrealistic estimate of an 80% mature capacity factor.[2] I suggested

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2. So far as I know, I was the first analyst to propose explicit allowances for nuclear capital additions. Utilities had

capital additions of $9.48/kW-year, annual O&M increases of $1.5 million/unit (both in 1977 $) and 60% capacity factors for large PWR's. PSNH now includes capital additions, escalates real O & M slightly faster than inflation, and projects a mature capacity factor of 72%. Thus, PSNH has implicitly accepted my criticisms, even though its O&M escalation and capacity factor projections are still very optimistic. While my original analyses (and the studies I relied on) were based on data only through 1978, experience in 1979-84 confirms the patterns of large capital additions, rapid O&M escalation, and low capacity factors. The 60% PWR capacity factor figure, in particular, has been widely accepted by regulators (such as the California Energy Commission) and even utilities (such as Commonwealth Edison and Central Maine Power).

Critiquing and improving on utility load forecasts and nuclear power cost projections has not been very difficult over the last few years. Many other analysts have also noticed that various of these utility expectations were inconsistent with reality. While PECO'S projections are more realistic than was typical in the late 1970's, its estimates for Limerick 1 cost components continue to be quite optimistic.

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previously recognized capital additions only as an element of the fixed charge rate, if at all.

Q: Have you authored any publications on utility ratemaking issues?

A: Yes. I authored Report 77-1 for the Technology and Policy Program of the Massachusetts Institute of Technology, Optimal Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions. I also authored a paper with Michael B. Meyer "An Improved Methodology for Making Capacity/Energy Allocation for Generation and Transmission Plant", which won an Institute Award from the Institute for Public Utilities. My paper "Revenue Stability Target Ratemaking" was published in Public Utilities Fortnightly, and another article "Opening the Utility Market to Conservation: A Competitive Approach" was presented at the 1984 national conference of the International Association of Energy Economists, and was published in the conference proceedings. These publications are listed in my resume.

Q: What is the subject of your testimony?

A: I have been asked to review the propriety of placing Limerick 1 in ratebase, or of otherwise reflecting the cost of that unit in current rates. I have specifically been asked to review the need for Limerick 1 to provide reliable service, and the likely benefits of the unit to PECo ratepayers, when it enters service, and to suggest an appropriate ratemaking approach in light of that analysis.

Q: How is your testimony structured?

A: The following two sections discuss the two possible justifications for Limerick 1: the reliability benefits and the reductions in fuel costs. Section 2 discusses the magnitude and timing of the reliability benefit~~s~~ of Limerick 1, which may also be thought of as the "need for power" or the requirement that adequate capacity be available to meet peak loads with an adequate reserve margin. In the third section, I consider the unit's cost-effectiveness, which primarily results from the replacement of more expensive fossil fuels, in the near term and over the course of its useful life. The fourth portion of this testimony provides the derivation of my estimates of Limerick 1's likely operating costs and capacity factor, which are required to assess its effect on fuel costs. Section 5 discusses the range of options available to the Commission in phasing in those costs of Limerick 1 which are to be borne by ratepayers. In the final section, I will summarize my conclusions regarding the need for, and economic benefits of, Limerick 1, and make recommendations regarding the disposition of PECO'S rate increase request, including a specific phase-in proposal.

This testimony is similar in structure and content to that which I presented in Docket R-842651. This is no accident: Susquehanna 2 and Limerick 1 share many similarities. Both are boiling water reactors (BWRs) of about 1050 MW(e), located in the same power pool and the same regulatory jurisdiction, entering service only about a year apart, and with limited reliability value or fuel savings, especially in the short term. The differences between the two units -- Limerick 1 is almost twice as expensive as Susquehanna 2; Limerick 1 has quantifiable (if small) short-run capacity benefits, while Susquehanna had none; and so on -- are reflected in the specific topics covered below, and in the numerical results.

2 - THE RELIABILITY BENEFITS OF LIMERICK 1

Q: You indicated that reliability is one possible justification for constructing generating plants. What determines whether a plant is needed for reliability?

A: Utilities attempt to have sufficient capacity available to provide power whenever customers wish to use it, on-peak and off-peak, throughout the year. Forced outages of generating facilities require that the utility have more capacity than the anticipated demand (a reserve margin) available at all times, and even with a reserve, generating reliability can never be 100% certain. For utilities which are members of power pools (as PECo is a member of the PJM pool), the required reserve is determined by the utility's own load and supply characteristics, the load and supply characteristics of the pool, interconnections with other utilities and pools, and the contractual obligations under which the pool's total reserve requirements are allocated to the member utilities.

As a result, the reliability value of Limerick 1 will be determined by three considerations:

1. If PECo's projections of power demand and supply on its system are correct, the reliability value of Limerick 1 to PECo will be determined by the cost of the plants which otherwise would be required to meet PJM reserve standards.

2. The reliability value of Limerick 1 to PECo will depend on the accuracy of PECo's demand and supply projections.

3. The reliability value of Limerick 1 to the PJM pool as a whole (and thus to the Commonwealth of Pennsylvania) will vary from the unit's value to PECo.

I will discuss each of these topics in turn.

Q: What do you conclude from your analysis of the reliability value of Limerick 1?

A: The reliability value of the unit to PECo is a tiny fraction of its cost. Until 1991, there would be no need for new capacity to meet PJM requirements, even under PECo's load and supply forecast, except to allow the retirement of existing units. After 1991, Limerick 1 would eliminate the need for inexpensive combustion turbines. PECo's demand forecast, and especially its supply forecast, may overstate the (already small) value of Limerick 1. Finally, the reliability value of Limerick to PJM is even smaller than it is to PECo.

2.1 - The Value of Limerick 1 to PECo

Q: What are the reliability benefits of Limerick 1 to PECo?

A: Limerick 1 will contribute to meeting PECo's reserve requirements in the PJM power pool. Within the PJM system, each individual utility has a responsibility to maintain a share of the generating capacity required by the pool.[3] PECo does not need the capacity of Limerick 1 to meet its capability responsibilities for at least the rest of the decade, but the unit will allow PECo to accelerate the retirement of other units and to defer new investments.

Q: Since Limerick 1 is not needed to meet PJM requirements in the short term, what is it worth to PECo for reliability purposes?

A: In the short run, Limerick 1 will allow PECo to achieve some savings by retiring existing plants.[4] In the longer run,

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3. Unfortunately, the PJM agreement does not reflect well the relative reliability value of various kinds of capacity, which varies with the size and maintenance requirements, as well as the forced outage rates of each unit, so a member utility may meet its capacity requirement without really providing its share of reliability support for the pool as a whole.

4. PECo indicates some ambivalence as to whether all of the retirements are related to the commercial operation of Limerick 1 (see IR-GSA-2-10). Given the very low cost of the life extensions, and the relative youth of the units, it is clear that they would have remained in service, if not for the completion of Limerick 1.

Limerick 1 will allow PECo to avoid buying and building new capacity. The minimum fixed cost of enhanced reliability from new construction is probably the cost of new combustion turbine (CT) capacity.

At a first approximation, the PJM capability measurement rules insure that a megawatt of any plant is equally valuable to a participant.[5] Thus, we can estimate the value of Limerick 1 for meeting PJM reliability requirements by determining:

1. how many megawatts PECo would be short of its PJM obligation without Limerick and with the avoidable retirements scheduled for the 1985-2000 period, and

2. the cost of retaining and building sufficient capacity to meet the PJM reserve target, without Limerick.

Q: What would PECo's reserve deficiency be under the PJM rules?

A: Table 2.1 displays PECo's projection of its peak demand, PECo's projection of its PJM reserve requirement, and PECo's projection of its generation capability. I have included the effects of PECo's scheduled retirements, and eliminated Limerick capacity (for both units) from this Table. Table 2.1 also shows the capacity which would be provided by

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5. This approximation somewhat overstates the value of Limerick 1 to PECo, since large nuclear units tend to drive up the reserve requirement for the pool, and hence the reserves allocated to each of the members. Limerick 1 is also likely to increase PECo's average forced outage rate.

fifteen year life extensions of seven steam units (Richmond 9, Southwark 1 and 2, Delaware 7 and 8, Schuylkill 1, and Cromby 2), and retention of the leased combustion turbines to the end of the original leases.[6]

Table 2.1 also presents my calculations of the PECo reserve shortfall without the life extensions, and with the life extensions. I have assumed that all life extensions occur at the time of projected retirement;[7] in the first few years, when PECo has more capacity than it needs, delay of some life extensions would allow the units to continue operating into the period in which PECo projects a shortage of capacity without Limerick or new construction. From the capacity shortfall with the life extensions, I calculate the number of megawatts of new CTs which would have to be constructed to meet the capacity target, and then compute the share of the life extensions which can be attributed to Limerick 1.[8] In years for which the total shortfall exceeds the capacity of the life extensions, requiring the addition of new CT capacity, I have assigned the more expensive new CT capacity

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6. I have assumed that Schuylkill 3 would not be a candidate for life extension or economic replacement. I have also excluded PECo's hypothetical purchase of the leased CTs in 1996 (IR-OCA-2-22), since PECo's projection of the purchase price would make them more expensive than new CTs.

7. The exception to this rule is the Delaware capacity, which PECo expects to be able to operate to 1990 without any major investments.

8. The sum of the life extension capacity and the new CT capacity attributed to Limerick 1 in any year can not be greater than the 1055 MW capacity of Limerick 1 itself.

to Limerick 1, thereby maximizing the cost of avoided capacity attributed to Limerick 1.

Q: What would it have cost to make up the reserve deficiency without Limerick 1?

A: Table 2.2 displays my calculations of the cost of each of the life extensions. For each steam unit, I have taken the capital cost estimated by PECo, distributed the recovery of that cost over the life extension period at the capital recovery rates PECo projects for capital additions to Limerick 1 with the same 15 year life,[9] and added PECo's projection of O&M costs. The sources of the data are indicated in the notes to the Table.

The lease payments and O&M for the combustion turbines are from IR-OCA-2-22.[10] The treatment of the lease payments may overstate the cost of this capacity. It appears that the cost of the leases does not depend on when they are terminated, and thus that the avoidable lease cost is zero through 1996. IR-OCA-15-5 indicates that virtually all of the lease charges will have been collected from ratepayers by the end of this proceeding. The lease charges in Table 2.2 are small enough that I did not correct PECo's treatment. However, I did omit PECo's projected increase in fuel costs

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9. The time pattern of cost recovery is from IR-OCA-2-25.

10. Note that no capacity is included for the purchase of the leased turbines. As noted above, this purchase would not be economical.

due to the retention of the CTs. It is difficult to see how the addition of any plant to an economically dispatched system would increase fuel costs. Under economic dispatch, a unit only operates if it is less expensive than alternatives available on the system, so the CTs, if they ran at all, should reduce fuel costs (however marginally), rather than increase them.

For comparison purposes, Table 2.2 displays PECo's projections of the \$/kW capacity deficiency charge from PJM, and the doubled deficiency charge which PECo expects PJM to charge it for protracted shortfalls.[11] The life extensions are all much less expensive than PECo's projections of PJM capacity charges.

If new capacity were necessary, that capacity also could be obtained inexpensively. PECo estimates that new combustion turbines would cost about \$303/kw in 1985 dollars (IR-OCA-19-11), or only about 8.4% of the cost of Limerick 1, with much lower fixed O&M, capital additions, insurance, and retirement costs. Gas turbines can also be brought on line

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11. PECo's projection that these doubled charges will start in 1986 is quite curious, as that is the <u>first</u> year of its projected reserve shortfall without Limerick 1 and with all scheduled retirements. It is also not clear why PECo would ever expect to have to pay more than the PJM capacity rate, which "is based on the levelized carrying charge for an average new 50 MW combustion turbine in PJM" (IR-OCA-9-12). PECo (or any other utility) could build a CT for less than the continually escalating PJM rate (which is calculated from the cost of a <u>new</u> CT in each year): it would never pay even the PJM rate for more than a few years.

with only a year or two lead time, so they are unlikely to be excess capacity when they are installed.

Table 2.3 calculates the annual carrying costs and non-fuel O&M for the new CTs which would be required to make up the reserve shortfalls indicated in Table 2.1. I have not included the cost of replacing the CTs after 25 years, for several reasons. First, the life PECo projects for Limerick 1 is highly speculative, as discussed in Section 4. Second, any replacement capacity added in 2016-2023 would be very young at the end of the analysis period, and a credit for its remaining service life would be necessary. Third, PECo has assumed that it would be possible to extend the life of the leased CT's to 40 years (IR-OCA-2-22): 60% of the CT's in Table 2.3 would require only two or three years of extended life to reach PECo's projected Limerick 1 retirement date. Referring back to Table 2.2, it is clear that new CTs would be much less expensive than PECo's projection of PJM capacity charges, although they are more expensive than the life extensions.

Table 2.4 adds up the cost of the replacement capacity for Limerick 1 which would have been required by PJM reserve targets. I have not included other inexpensive options, such as purchases of peaking capacity from other utilities,[12] life

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12. As long as PJM has excess capacity, inexpensive peaking capacity should be available at costs below those of new construction.

extension of the Richmond and Plymouth Meeting leased CTs,[13] and additions of new economic plants (e.g., cogeneration facilities), which could have negative net reliability costs, once credit is taken for their fuel savings. Figure 2.1 plots the value in each year for the costs of economical replacement capacity, PECo's projection of the PJM capacity charge for the shortfall avoided by Limerick 1,[14] PECo's projection of the PJM capacity charges with doubled rates, and PECo's projection of the non-fuel costs of Limerick 1.

It is clear from Table 2.4 and Figure 2.1 that most of the cost of Limerick 1 was not required, and would never have been incurred, for system reliability.

Q: Is the capacity of Limerick 1 required to meet PECo's reserve target anytime in the 1980's?

A: No. Limerick 1 is only needed for capacity purposes in the 1980's if the units listed in Table 2.1 are retired. Those retirements are planned (or in the case of Richmond 9, have already occurred) because Limerick 1 is nearing commercial

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13. As I noted above, this extension is not cost effective at the purchase price PECo assumes. At that purchase price, it is unlikely that the owners of the turbines would find any buyers. In fact, other purchasers should not be willing to pay as much as PECo would, since they would have to transport and install the CTs at their sites. Thus, PECo should be able to purchase these CTs for less than the cost of new construction, not more.

14. For consistency, I have used my projections of the shortfall, which differ from PECo's in the first few years, apparently due to PECo's rounding algorithm.

operation. Thus, the net reliability-related benefit of Limerick 1 is not that it will keep the lights on in Philadelphia (the existing units would have done a better job of that), nor that it will allow PECo to fulfill its obligations to PJM (which the retired plants would have done), but only that it allows the retirement of capacity which costs very little to maintain.

The mere fact that PECo chooses to replace one type of plant with another does not imply that the basic function could not have been performed by the original plant, nor that the replacement was necessary. PECo could, for example, purchase a fleet of Cadillacs for its meter readers, and sell off its existing cars. It could hardly be argued that the investment in the Cadillacs was required to allow for orderly billing, or that they avoid the cost of taxicabs to transport the meter readers. Even though the Cadillacs perform both those functions (probably quite well), the old fleet served those same ends, at lower costs. The transportation benefit of the Cadillacs is the sale price of the existing cars: the cost of the new fleet above that transportation benefit is either justified by a completely different kind of benefit (e.g., improved labor relations), or not at all.

2.2 - PECo Demand and Supply Projections

Q: Have PECo's forecasts been reliable over the last decade?

A: Figure 2.2 displays PECo peak demand forecasts from every second year from 1976 (already two years past the oil embargo) to 1984, and the actual peak loads in each of those years. PECo has repeatedly had to adjust its load forecast downward over the last decade. Recent forecasts have been slightly higher than those in 1982 and 1983. This record suggests that PECo has had significant difficulty in foreseeing trends in its customers' demands. There is no reason to suppose that PECo's current projections do not contain comparable errors.

Q: Are there any particular reasons for believing that PECo's current forecast will prove to be overstated?

A: Yes. The cost of Limerick 1 itself, if passed along to customers in anything like the traditional manner, will depress sales and reduce the need for the plant. This is true whether or not the unit eventually proves to be less expensive than the fossil fuels it is backing out. If it turns out that Limerick 1 is economical, the cost of the remaining fuel which PECo burns will be even higher than the impressive cost of Limerick 1, further depressing demand.

Q: Is it appropriate to assume that no new generation, other than Limerick, will be added in PECo's service territory in the rest of the century?

A: No. PECo's capacity projections exclude any new economic capacity from cogeneration, trash-burning, small power production, or any other source, whether owned by PECo or by others, other than the two Limerick units. PECo incorrectly considers these power sources to be less "real" or useful capacity than such plants as Limerick 1 (Rush Testimony, pages 11-12).[15] It is therefore difficult to determine whether PECo's exclusion of cogeneration and small power production from its supply plan is motivated by the belief that such resources will not be developed, or by the belief that their development is irrelevant. In any case, to the extent that such facilities are developed, the reliability need for Limerick 1 is reduced.

Q: Is there any reason to believe that such capacity will be added?

A: Yes. PECo projects very high avoided energy costs. By the year 2000, PECo projects avoided costs of 18 cents/kWh, or 8 cents in 1986 dollars, as compared to less than 4 cents

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15. As we shall see below, Limerick provides relatively little reliability per kW of installed capacity. Few small power producers (except for wind- and solar-powered generators and an occasional low capacity-factor hydro development) would do worse than Limerick in this regard. The concerns about cogeneration expressed on page 12 of Mr. Rush's testimony are either irrelevant, or equally applicable to Limerick.

projected for 1986.[16] These figures are from Table 3.1. If rates for power purchased under PURPA are based on the same avoided costs PECo uses in evaluating the economics of Limerick, the incentives for independent power-production will increase substantially in the next couple of decades.

Even with PECo's fuel cost projections (which are much higher than DRI's projections), cogeneration would be much more economically viable in the future than at present. The 1986 avoided energy cost is equivalent to 1% sulfur #6 oil at a 9022 BTU/kWh heat rate: a good cogenerator would operate at a heat rate around 5000 BTU/kWh, which leaves only a relatively small margin (about 1.7 cents per kWh) to pay off fixed costs. PECo's projection for avoided energy cost in the year 2000 is equivalent to 1% sulfur #6 oil at a heat rate of almost 14000 BTU/kWh : almost two thirds of the avoided cost payment (about 11.5 cents/kWh, or 5.1 cents in 1986 dollars) would be available to pay for the cogenerator's non-fuel costs. These results are calculated in Table 2.5.

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16. In addition, PECo's projected capacity charge of $259.18/kW-year would be worth another 5 cents/kWh to a power producer with a 60% capacity factor.

2.3 - The Value of Limerick 1 Capacity to PJM

Q: ~~When~~ would Limerick 1 be required for reliability by PJM?

A: Limerick 1 would not be needed for the next few years to meet PJM's reliability targets. When Limerick 1 enters service, it will to some marginal extent increase the reliability of the PJM generation system. This reliability is expected to be more than adequate for many years to come, although there is certainly <u>some</u> benefit from increased reliability in the interim.[17] Once PJM reserve margins shrink to the merely adequate range, the presence of Limerick 1 on the system would allow the deferral of other measures to increase reliability, such as construction of new capacity, purchase of power from outside the region, or continued maintenance of existing capacity.

Q: What is the reliability value of Limerick 1 to PJM?

A: The value of Limerick 1 (or any other large nuclear unit) to PJM is considerably less than its value, under PJM capability responsibility formulas, to the individual PJM members which own that plant. Nuclear plants contribute relatively little to reliability for two reasons. First, due to their large

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17. Mr. Rush discusses some of these benefits, such as the facilitation of maintenance.

maintenance requirements, nuclear units are often not available when needed.[18] Second, due to the large size of new nuclear units, sufficient reserves must be provided to back up the simultaneous loss of a thousand megawatts or more. As a result, even with the same forced outage rates, large plants require more reserve capacity than small plants.

Analyses performed by the New England Power Pool (NEPOOL) indicate that nuclear units only support load of about 50% of their rated capacity, and therefore require an incremental reserve margin of close to 100%. This is demonstrated in Table 2.6. The size effect would be less pronounced on the larger PJM system, but the reliability of large nuclear units is less than NEPOOL assumed.

Table 2.7 presents my own analysis of the reliability of Limerick 1 and the reliability alternatives I discussed above. The Table estimates for each type of plant the amount of additional load it allows PJM to support. This additional load, technically called the Effective Load Carrying Capability (ELCC) of the unit, is calculated from the formula developed by Garver (1966). Garver's formula does not recognize any reliability effects of maintenance requirements, and therefore probably overstates the ELCC of nuclear plants, with their large (and inflexible) refueling

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18. For the same reason, forced outage rates, which are included in the PJM responsibility formula, make nuclear units less reliable.

outages. I have used PECo's projection of performance, where it is available, or a range of forced outage rates (FORs) for each plant type based on recent experience.[19] Other than the size of the unit and its FOR, Garver's formula requires a measure of system size (which he calls **m**): I have estimated this parameter as 800 MW, by scaling up my estimate of 425 MW for the smaller NEPOOL system.[20] The result of Table 2.7 is that one megawatt of capacity in the smaller units will replace 1.2 to 1.6 MW of Limerick 1.

Tables 2.8(a), 2.8(b), and 2.8(c) reproduce portions of Tables 2.1, 2.3, and 2.4, respectively, but with the capacity of each unit stated in terms of Limerick 1 megawatts with the same ELCC, using the ELCC values for the middle of each FOR range presented above.[21] Recognizing the real reliability benefits of the smaller plants, we see that much less of their capacity would have been required to replace Limerick 1. The PECo life extensions would provide enough reliability to replace Limerick 1 until 1997,[22] when the retirement of

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19. For CTs and other units which are on reserve status for many hours of the year, reported FOR's (which compare outage hours to service hours) are not very useful. In these cases, I have calculated FOR as (1-availability).

20. PECo has refused to supply the sensitivity analyses necessary to estimate the value of **m** from PJM-specific studies (IR-UUC/UP-2-6 and 2-7).

21. For the older steam units, this is probably conservative, since the life extensions would probably improve both unit reliability and rated capacity.

22. Other capacity on the PJM system might push this date back further.

the leased CTs would require the addition of 402 MW of new CTs. By 2002, a total of about 660 MW of new CTs would be required to replace all 1055 MW of Limerick 1. Therefore, Limerick 1 has a much smaller reliability benefit for PJM than it does for PECo. The apparent value of the unit to PECo is the result of a subsidy from other PJM members, who will have to support higher reserve margins due to Limerick 1.

2.4 - Summary of Limerick 1 Reliability Benefits

Q: Do the reliability benefits of Limerick 1, as you have estimated them above, justify charging ratepayers $800 million for Limerick 1 in 1986?

A: No. Reliability considerations, standing alone, would justify 1986 cost recovery for Limerick 1 of no more than about $30 million, based on the value of the unit to PJM, and certainly no more than $37 million, even based on its inflated value to PECo under the PJM agreement.

Q: Does this conclusion indicate that PECo has erred in deciding to build Limerick 1, rather than extending the lives of existing steam plants, and building new CTs?

A: Not necessarily. In the next section, I will consider the fuel savings of Limerick 1. In principle, the lower fuel costs of a new base-load plant can justify its higher cost, compared to existing units or new peakers.

Q: Does your analysis indicate that PECo should not retire the plants presently scheduled for retirement?

A: Not necessarily. Now that Limerick 1 has been built, the reliability value of existing units may be surplus to the needs of PECo or PJM. However, the units (especially the CTs) represent very inexpensive sources of reliability support, and should not be hastily discarded. Before any irreversible decisions are made regarding the retirement of _any_ of the existing units, PECo should be _very_ sure that it will not need the capacity over the next 15-20 years, and should attempt to market this very inexpensive capacity to other utilities.[23]

Q: Has PECo retired economical capacity as a way of avoiding an excess capacity adjustment?

A: It is possible that PECo's decisions to retire the existing units were motivated by the belief that more Limerick 1 costs would be allowed if inexpensive old plants were retired. I would strongly urge the Commission to make it clear to PECo, and other Pennsylvania utilities, that uneconomical capacity planning decisions will not be considered to justify the recovery of expensive new plants. To this end, I would suggest that the Commission

- measure the reliability need for new plant (including Limerick 1) in terms of the costs of other capacity sources it displaces rather than solely in terms of megawatts of capacity,
- analyze the reliability benefits of Limerick 1 by comparison to the most economical alternatives, including life extensions, as I have done above, and

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23. It is not clear whether the retirement of Richmond 9 is physically reversible at this point.

- warn PECo that it is at risk for premature retirements, and will not be expected to make up the difference between the costs of the retired units and those of replacement capacity sources, if it experiences a shortage in reserve capacity.

3 - THE BENEFITS OF LIMERICK 1 FOR FUEL DISPLACEMENT

Q: You have explained why Limerick 1 will have very limited reliability benefits. What is the unit's major benefit to PECo and the PJM system?

A: In the light of its much higher cost per kW than other capacity, it is clear that Limerick 1 is being built almost exclusively for fuel displacement purposes. Like all nuclear units, it will provide lower fuel costs than the fossil-fueled plants which PJM currently has in abundance.

Q: Have you analyzed the cost-effectiveness of Limerick 1 for fuel displacement?

A: I have compared the cost of Limerick 1 under traditional ratemaking, and under PECo's phase-in proposal, to the value of power it would displace, under a variety of assumptions regarding Limerick 1 cost and reliability, and regarding the value of the capacity and energy it provides. I have not attempted to address the larger issue of whether Limerick 1 is (or ever was, or ever appeared to be) the most economical option for reducing fuel cost.

Q: How much lower than oil and coal costs will the fuel cost of Limerick 1 be?

A: Table 3.1 lists, and Figure 3.1 displays, the differences PECo projects between Limerick 1 fuel costs and the fuel costs of the fossil (primarily coal-burning) plants it would be backing out. The projected differential starts in 1986 at about 2.9 cents per kWh, and rises to 16.9 cents per kWh by 2000, and to $1.21/kWh in 2024. These savings are substantial, if they occur, but they come at the even greater cost of building and operating Limerick 1.

Q: Are PECo's projections for Limerick 1 energy cost savings plausible?

A: No: they appear to be overstated, compared to PECo's fuel price projections. Over the first 10 years of the life of Limerick 1, PECo projects that the savings value of a kWh of Limerick power will increase at 16.7% annually, or about 10% annually in real terms. It is difficult to understand why this would be so.

PECo is only projecting a cost of $62.8/barrel for 1% sulfur residual oil in 1996; at 6.287 million BTU/barrel and 10,000 BTU/kWh, the cost of power generated from that oil would only be 10 cents/kWh. PECo projects that Limerick 1 will avoid fuel and interchange power costing 14.4 cents/kWh in 1996. Of course, some Limerick power would replace coal, and most interchange sales would involve split savings of some sort, so the operating savings would be expected to be less than the price of oil-fired power, not greater. PECo's fuel savings projections appear to be inconsistent with its fuel price projections, unless PECo is projecting that it would not have built new fuel-saving capacity (not even base-load oil plants) in the absence of Limerick 1.

Q: How cost-effective is Limerick 1 under PECo's current assumptions?

A: It is clear from the information presented in PECo's responses to information requests that even PECo expects that the costs of Limerick 1 will exceed the benefits of the unit for much of its useful life.

Q: How do PECo's data support the conclusion that Limerick 1 will not pay for itself soon?

A: In Table 3.2, I provide projections of the rate impact of Limerick 1 over its life, based on PECo assumptions of cost, benefits, useful life, and load growth. Table 3.2 also provides a running simple total of the rate impact, and running discounted totals.[24] The discounted totals are computed at discount rates of 10%, 15%, and 20%. As explained in Section 4, this range of discount rates covers much of the low end of customer discount rates, PECo's estimate of its discount rate, and my estimate of PECo's discount rate. I will generally refer to the results for the 10% discount rate, even though the 20% rate is more

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24. I refer to these statistics as the "cumulative net cost" and the "discounted net costs", respectively. Discounting is necessary to make the costs and benefits in various years comparable: a dollar in 1995 is worth less than one in 1986.

representative of the discount rate my clients apply to their own investments.

Even without discounting the cash flow, Limerick 1 would increase rates for PECo customers as a whole until 2001. By 1994, the first year the plant would cost less than it saved, consumers would have paid out almost $3 billion extra. Discounting the costs and benefits, even at just 10%, makes the situation much worse, pushing discounted breakeven to 2009. Thus, based on PECo's own assumptions, Limerick 1 does not have positive present value benefits until well into the next century.

After PECo's speculatively long unit life of 39 years, the discounted net savings are roughly $2.7 billion dollars (in 1985 terms) at 10%: this is a large value, but still smaller than the initial investment. For customers with higher discount rates, Limerick 1 never breaks even. At a 15% discount rate, the net value of Limerick 1 is slightly negative through 2024, while at 20%, the unit's costs exceed its benefits by almost $1 billion. The annual net benefits, the cumulative total, and the discounted totals are plotted in Figure 3.2.

Q: Are Table 3.2 and Figure 3.2 entirely the work of PECo?

A: Almost. The only differences between Table 3.2 and PECo's response to IR-OCA-2-25b, Item 1, page 1, is the fact that I have added running simple and discounted totals.

Q: Does Table 3.2 (or IR-OCA-2-25b) present a reasonable projection of the costs and benefits of Limerick 1?

A: No. PECo's assumptions are biased in favor of Limerick 1 in several ways:

1. Only half of the cost of common plant is included, even though PECo seeks recovery of 100% of common plant starting in 1986.

2. The projection of avoided capacity costs assumes that PECo would take extremely inefficient actions in the absence of Limerick 1.

3. PECo's projections of avoided energy costs appear to be inconsistent with its fuel price projections, unless PECo is suggesting that it would never have built additional fuel-saving capacity in the absence of Limerick 1.

4. PECo's fuel price projections are much higher than those of its fuel price consultant, Data Resources, Inc. (DRI).

5. PECo's assumptions regarding Limerick 1 capacity factors imply considerably better performance than would be indicated by recent experience.

6. PECo assumes that Limerick 1 non-fuel O&M expenses and capital additions will be considerably lower than would be indicated by recent experience and trends.

7. PECo assumes that Limerick 1 will experience a very long life, and that current estimates of decommissioning costs will prove correct 40 years in the future.

Table 3.2 also does not include the costs and benefits to ratepayers from PECo's proposed phase-in.

Q: Have you performed any other total-cost analyses?

A: I have modeled the annual costs of Limerick 1 to ratepayers for several sets of alternative cost and benefit assumptions. The inputs on which these analyses are based are the PECo projections listed in Table 3.2, which I have labeled Case 1. In the other cases, which are based on PECo's alternative fuel cost run and on the results of my review of PECo's projections for Limerick 1 (described in Section 4 of this testimony), I have adjusted PECo's projections to reflect more realistic assumptions, or at least assumptions more consistent with experience to date.

Q: What other cases have you analyzed?

A: I have repeated the previous calculations for five other cases:

- Case 2, which uses PECo's assumptions, except for the inclusion of 100% of common costs;

- Case 3a, which estimates more likely benefits for Limerick 1 by replacing PECo's fancifully high avoided capacity charges with my estimates from Section 2, and by replacing PECo's optimistic capacity factor estimates with my estimates from Section 4.1 (representing actual BWR performance in the 1980's);

- Case 3b, which is identical to Case 3a, except for the use of the fuel savings calculated in PECo's response to a request from the Consumer Advocate;
- Case 3c, which is identical to Case 3b, except for the use of my capacity factor estimates; and
- Case 4, which uses the savings assumptions from Case 3c, and also partially corrects for PECo's optimism in the cost of running Limerick 1, by replacing PECo's assumptions regarding certain operating costs with my estimates from Sections 4.2 and 4.3, resulting in annual capital additions about three times as large as PECo assumes, and station O&M expenses which continue to escalate at something like historical rates.

The results are shown in Tables 3.3 through 3.7, and in Figures 3.3 through 3.7.

It is important to recognize that all of these cases use PECo's very optimistic assumptions that Limerick 1 will last 39 years, and that the present estimate of the cost of decommissioning will prove correct 40 years hence. The recovery of depreciation and decommissioning costs, even under traditional ratemaking, is determined by the Commission based on projections of conditions far in the future, generally based on utility requests for cost recovery. I expect that PECo will eventually ask the Commission for higher decommissioning allowances and higher depreciation rates, but I do not know when these requests will occur. Nor am ~~I~~ prepared to project the Commission's response to such requests. Therefore, I have used PECo's projections of depreciation and decommissioning expenses, which are likely to be the booked expenses for the immediate future.

Also, even with the more realistic (or at least more widely accepted) fuel price projections of Cases 3b, 3c, and 4, I have relied on PECo's production costing runs, which produce avoided energy costs that grow much faster than fuel prices. As discussed above in connection with PECo's own projections, this inconsistency apparently results from an assumption that no additional fuel-saving capacity would be added (or even purchased), regardless of how high PECo's avoided costs rose.

Finally, it should be recalled that my analyses do not include PECo's proposed phase-in. The rate effects of the phase-in depend on the exact implementation, and on the period of time which elapses prior to PECo's next rate case. Under some circumstances, the phase-in could actually increase costs to ratepayers, in both nominal and discounted terms (especially at PECo's preferred discount rate), and make Limerick 1 even less advantageous. The effect arises from the failure to reduce Limerick 1 cost recovery to reflect the depreciation of its original cost.

Q: Please describe the results of Case 2.

A: Simply increasing carrying charges to reflect the other 50% of common plant, for which PECo has requested cost recovery, has a surprisingly strong effect on the cost-effectiveness of the plant. The crossover point (the first year in which ratepayers save money from Limerick 1) is delayed another year to 1995, by which time cumulative net costs approach $4 billion. Simple breakeven is reached in 2004, three years later than in Case 1. Discounted breakeven at 10% is pushed back six years to 2015. The discounted net cost through 2024 is only a $1.6 billion benefit (less than half the initial investment) at 10%, a cost of $1 billion at 15%, and a cost of $1.6 billion at 20%.

Q: Please describe the results of Cases 3a to 3c.

A: These Cases all present more realistic projections of the benefits of Limerick 1. All three Cases use realistic avoided capacity charges, as estimated in Section 2.1 of this testimony, and capacity factors more consistent with historical experience: Case 3b uses a 60% average capacity factor, while the other two use my projections of Limerick capacity factors, from Section 4.1 of this testimony. Finally, Cases 3b and 3c replace PECo's estimated avoided energy costs with the results of PECo's production costing run using OCA's fuel cost projections. In these Cases, the first year in which Limerick 1 would save customers more than it would cost them would be 1997 or 1998.[25] In those crossover years, the cumulative net cost of the plant to PECo's customers would have exceeded $5 billion. Simple breakeven would not be reached until 2009 or 2010. Discounted benefits would never exceed costs, even at a discount rate of just 10%. The final discounted cost would range from $1.1 to $2.5 billion in 1985 dollars, depending on the Case assumptions and discount rate.

Q: Your Cases 3b and 3c rely on the results of a production costing run performed by PECo for the Consumer Advocate. Have you confirmed that the OCA inputs are reasonable?

A: Yes. As discussed in Subsection 4.1.2, the Limerick 1 capacity factors assumed in the OCA run (averaging 60%) are somewhat better than would be indicated by recent historical experience, but they are much more realistic than PECo's capacity factors, which average 65%. The OCA, PECo, and DRI fuel price forecasts are compared in Appendix E: while the OCA projections exceed those of DRI for the rest of the century, they are much closer to DRI than are the prices forecast by PECo. While all fuel price forecasts are subject to considerable uncertainty, DRI's projections are produced

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25. In Case 3c, since I did not know the capacity factors which PECo assumed for individual years, I have treated all the PECo capacity factors as if they were the 60% average. As a result, the adjusted fuel savings figures vary considerably from year to year, and Table 3.6 shows small positive net benefits in 1995, with small negative net benefits in 1999 and 2000.

by professional forecasters, who have no axe to grind in this proceeding, no known biases, and no interest in their projections (so far as I know) other than not being embarrassed by an erroneous forecast. Thus, I consider the OCA runs to be based on inputs which are closer to the best available data than are the inputs to PECo's own runs. In other words, given the opportunity, I would use different assumptions, but OCA's assumptions are clearly more realistic than PECo's, and if anything, biased towards Limerick 1.

Q: Do the cost-effectiveness results change substantially in Case 4, when the operating costs are adjusted to more realistic values?

A: Yes. With realistic operating cost estimates, combined with the savings estimates of Case 3c, Limerick 1 would cost ratepayers more than it would save them annually for essentially its entire life.[26] As a result, the plant would never even reach simple breakeven, let alone discounted breakeven. If the plant remained in service until 2024, the present value of the net cost to customers would rise into the $3 to $5 billion range.

Table 3.8 summarizes some measures of cost-effectiveness for each of the six Cases: the years of crossover, simple

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26. As noted previously, the approximation I made in adjusting capacity factors causes some years to look much better than average, and every third year after 2004 shows positive net benefits. These benefits are almost always swamped by the negative benefits in surrounding years.

breakeven, and discounted breakeven (at each of the three discount rates), the cumulative net benefit to ratepayers at crossover, and the net present benefit through 2024 (at each discount rate).

Q: Are the breakeven points applicable to individual customers or only to ratepayers as a whole?

A: The dates I calculated may be meaningful for all ratepayers collectively, but not individually. Due to load growth (if PECo is correct that loads will grow, even rather slowly), the later benefits of Limerick 1 will be diluted more than the early costs, and only customers whose loads grow at the same rate as the system as a whole will break even at these dates. New customers and those with rapidly increasing energy consumption will realize positive cumulative benefits faster than I calculated, while customers who conserve in response to the high rates caused by Limerick 1 will break even later, if at all. Customers who leave the system before their breakeven date end up with a net loss, regardless of what happens to ratepayers as a group.[27]

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27. The elderly and economically tenuous businesses are particularly likely to pay for Limerick 1 without receiving commensurate benefits. In the case of industrial or commercial customers which are already under financial pressures, the rate increases from Limerick 1 might be the last straw, ensuring that they will not survive to reap whatever benefits the system receives late in the unit's life.

Q: Do these results indicate whether Limerick 1 is likely to be a good investment under conventional ratemaking treatment for the customers who pay for its early years?

A: The particular cases I presented above were selected from a wide range of possible outcomes. It is clear from the analysis that Limerick 1 will be very expensive in its early years, as compared to its benefits, and that plausible projections of plant performance, of operating cost levels and trends, and of operating benefits would prevent Limerick 1 from ever saving money for PECo's customers.

PECo's projections (implausible as they are) represent about the most favorable case which can be made for Limerick 1 economics. Most of PECo's assumptions can be attributed (if one wishes to be highly generous) to extreme optimism: the long useful life, the high capacity factor, the low capital additions, and the slow growth in O&M could be excused in this fashion. It is very difficult to envision any reasoned basis for such PECo assumptions as excluding half of the common costs from the analysis (since they will be part of the rate impact); assuming that the capacity alternative to Limerick 1 is a hypothetical PJM penalty charge, instead of the inexpensive units PECo proposes to retire; or projecting replacement energy costs based largely on peakers. Even under PECo's assumptions, present ratepayers carry a very heavy burden for a very long time before they start to see any net reward from Limerick 1. The investment in Limerick 1 might pay off for the system (as an abstract entity) over 35 years, but it is virtually certain to be highly uneconomic for real customers over the next 15 to 20 years.

PECo's assumptions could be considered a "best case" for Limerick 1 economics: they are so skewed toward justifying Limerick 1 that they might more accurately be described as a "better-than-best case". It is hard to say what a comparable "worst case" would look like, but a continuation of historical trends in operating characteristics,[28] combined with current fuel price forecasts and a relatively intelligent strategy for minimizing capacity charges, indicates that Limerick 1 is likely to be a complete economic disaster, under conditions which are much better than the "worst case".

Q: What can be concluded from these analyses?

A: First, even using PECo's own assumptions and projections, Limerick 1 will not save money for PECo customers who pay for the plant's early, uneconomic years, unless they remain customers for over twenty years. Second, given PECo's own projections, many customers would be better off if Limerick 1 had never been started, or had been canceled or sold off long ago. Third, if Limerick 1's cost and performance are

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28. Recall that my projections incorporate improvements over recent experience: capacity factors are assumed to improve considerably from 1984 levels, and the compund growth in real O&M costs is assumed to become linear.

consistent with past experience and trends, it is virtually certain to be a poor investment for essentially all the ratepayers, and for customers as a whole.

Q: Dr. Perl (PECo Statement 11) has suggested that the delays in Limerick construction in the 1970's were advantageous to ratepayers, since the increased cost of the plant will be more than recouped in higher fuel savings in the last years of the plant's life. Do you have any comment on this position?

A: Yes. There are two major flaws in this argument. First, the economic benefits of the unit near the end of its life are quite uncertain. If Limerick 1 is in operation in the second and third decades of the twenty-first century, its operating costs may not be much less than the savings it creates. We simply have no way of knowing whether Limerick 1 would be backing out expensive fossil fuels, very inexpensive fluidized-bed coal cogeneration, or some power source now scarcely imagined. It is difficult to believe that rational decision-makers would voluntarily incur the enormous current costs of the delayed Limerick 1, and have sacrificed the benefits of having Limerick 1 in service some years earlier, simply to have a chance at some highly speculative benefits which the unit might deliver after the year 2010.

Second, any comparison of costs and benefits over time must recognize the time preferences of the customers who are paying the costs and receiving the benefits. As I discuss in

Section 4.6, the discount rate PECo uses in its analyses is simply too low to reflect the preferences of most of its customers, nor does it accurately represent the cost to the company of deferring revenues. All of the major benefits Dr. Perl perceives as flowing from the delay (the non-Limerick capital cost, O&M, and "other years" fuel costs in Dr. Perl's Schedule 7) occur in the far future, 30 to 35 years after the costs. Applying a more reasonable discount rate to these remote benefits would reduce them drastically, resulting in a large net indicated loss from the delay. In other words, Dr. Perl's conclusion is highly sensitive to his assumption that consumers do not much care whether benefits are greatly delayed.

In this situation, discount rates can only address part of the timing problem raised by Dr. Perl's approach. The difference in timing between the costs and benefits of the Limerick delay (under anything like traditional ratemaking) takes this issue far beyond the normal realm of discount rates. Many of the customers who would bear the largest burden for Limerick 1 capital costs (including the cost of the delay) in its early years simply will not be around to receive any benefits it may generate in 2024. If anything, Dr. Perl's analysis strengthens the case for delaying cost recovery for Limerick 1, so as to coincide better with the benefits of the unit, which will occur late in its life, if at all.

Q: Are large rate increases such as those required by conventional ratemaking for Limerick 1 a normal and necessary result of commercial operation of large units?

A: No. According to PECo, Peach Bottom saved more than it cost from its first year of operation (IR-OCA-2-24, Attachment (a)). As recently as 1981, PECo expected that Limerick 1 would decrease rates in its first year of operation, and raise rates less than $200 million in the second year. The plant as a whole was expected to break even by the third year of operation of each unit (IR-OCA-2-24, Attachment (b)). Even with a billion dollar cost increase for the plant and a 60% capacity factor, PECo projected that the maximum rate increase from Limerick 1 would be less than $300 million. Excerpts from PECo's 1980 and 1981 Limerick studies are provided in Appendix I.

Q: How do the economics of Limerick 1 compare with those of Susquehanna 2?

A: Limerick 1 is much less cost-effective. Table 3.9 compares the cost and benefit streams of the two plants as projected by their owners. To improve the comparability of the results, all figures are stated in $/kW-year. Susquehanna 2 appears to be more cost-effective than Limerick 1 for two reasons: it was much less expensive ($2027/kW, as opposed to $3011/kW for Limerick 1 and 50% of common), even though it entered commercial operation only about one year before Limerick 1 is expected to go commercial, and its avoided cost projections were performed when fuel price projections were much higher than at present.[29] It should be noted that the Susquehanna 2 avoided cost projections, unlike those for Limerick 1, represented the entire cost of plant for which rate base treatment was sought.[30]

Q: If the Commission applies the same standard of review to Limerick 1 that it applied to Susquehanna 2, what would be the outcome?

A: The Commission found that my testimony on Susquehanna (OCA Statement 3) established

> that there is reason to believe that the Company's present value estimates for SSES 2 are overstated or, at least, uncertain (R-842651, page 18).

The results of similar analyses for Limerick 1 indicate that it is a much worse deal for the ratepayers, and that its total benefits are likely to be a much smaller fraction of its total cost (under traditional ratemaking) than was true for Susquehanna 2. The Commission continued

> Second, and more important, we hold that even on the Company's best case, future economic benefits will not accrue until the next decade. The sheer magnitude of the delay combined with the uncertainty of the projections render the net present value approach meaningless on the record before us. (ibid.)

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29. PP&L was also projecting very high avoided costs, even given its fuel price forecast.

30. Recall that PECo's cost figures for Limerick 1 include only half of the common costs, although recovery of all common costs has been requested.

The "sheer magnitude of the delay" of benefits and "the uncertainty of the projections" of eventual benefits for Limerick 1 far exceed the comparable problems for Susquehanna 2. *If* anything, the facts in this case would suggest that the ratemaking treatment for Limerick 1 should be more sympathetic to ratepayers than was the treatment in R-842651.

4 - THE COST OF POWER FROM LIMERICK 1

Q: What cost parameters have you estimated for Limerick 1?

A: I have attempted to determine realistic estimates for the capacity factor of Limerick 1; for the various costs of running the unit, including non-fuel O&M, capital additions, insurance, and decommissioning; and for its useful life. Based upon analyses of historical performance and trends:

1. Capacity factors (based on design rating) for Limerick 1 will probably average about 49% in the first four years and 57% thereafter, as compared to PECo's projected average of 65%.

2. Non-fuel O&M has been escalating much faster than general inflation, at about 12-14% in real terms, while PECo is projecting only 3% real increases through 1990, with no real increases after that date. This trend has persisted for many years and may well continue.

3. The capital cost of the plant will also increase significantly during its lifetime; if historical rates of additions apply to Limerick 1, they will be about three times as large as PECo projects.

4. Decommissioning also must be expected to cost more than PECo currently estimates.

5. PECo is projecting that Limerick 1 will operate for more than twice as long as any large (that is, over one fifth of the size of Limerick 1) domestic nuclear unit has to date, and nearly twice the median life of the small units commissioned in the early 1960's.

This section also discusses choices of discount rates used in evaluating the costs and benefits of Limerick 1 to ratepayers. Detailed analyses of these cost components are presented below, including comparisons of my estimates to those of PECo.

4.1 - Capacity Factor

4.1.1 - Measuring and Comparing Capacity Factors

Q: How can the annual kilowatt-hours output of electricity from each kilowatt of Limerick 1 capacity be estimated?

A: The average output of a nuclear plant is less than its capacity for several reasons, including refueling, other scheduled outages, unscheduled outages, and power reductions. Predictions of annual output are generally based on estimates of capacity factors. Since the capacity factor projections used by PECo are rather optimistic, it may be helpful to consider the role of capacity factors in determining the cost of Limerick 1 power, before estimating those factors.[31]

The <u>capacity factor</u> of a plant is the ratio of its average output to its rated capacity. In other words

$$CF = \text{Output}/(RC \times \text{hours})$$

where CF = capacity factor, and

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31. This portion of my testimony will also discuss some common errors in utility treatment of nuclear capacity factors, and some of the justifications utilities have offered in previous proceedings for projecting capacity factors which exceed historical experience. Including this material in my direct testimony may simplify surrebuttal on capacity factors, if that is required.

RC = rated capacity.

In this case, it is necessary to estimate Limerick 1's capacity factor, so that annual output, and hence cost per kWh, can be estimated.

On the other hand, an <u>availability</u> <u>factor</u> is the ratio of the number of hours in which some power could be produced to the total number of hours.

The difference between capacity factor and availability factor is illustrated in Figure 4.1. The capacity factor is the ratio of the shaded area in regions A and B to the area of the rectangle, while the availability factor is the sum of the width of regions A, B, and C. Clearly, if the rated capacity is actually the maximum capacity of the unit, the availability factor will always be at least as large as the capacity factor and will generally be larger. Specifically, the availability factor includes the unshaded portion of region B, and all of region C, which are not included in the capacity factor.

Capacity factors are also often compared with equivalent availability factors (EAFs). EAF is a subjective measure, reported by the operating utility and representing only the utility's opinion of what the unit might have done, if not for factors which the utility may wish to consider to be "economic". These "economic" factors include, for example, reductions in output to delay a refueling outage until other nuclear units have completed maintenance or repair procedures. Furthermore, the calculation of EAF assumes that the unit would have run perfectly if not for the "economic" limitation. Utilities frequently assume that new units will have capacity factor similar to historical EAFs, rather than historical CFs. Under the best of conditions, EAF is a performance measure of limited usefulness, due to its subjective nature.

Even if EAF were not such a flawed measure, there is little reason to believe that historical EAFs would provide better (or even as accurate) predictors of Limerick 1 CF than would historical CFs. While utility terminology often suggests that EAFs differ from CFs only because of "load following" and "load leveling", essentially all nuclear units in the US are base-loaded, and the difference between EAF and CF is rarely due to load following, per se.

Perhaps the differences between CF and EAF can best be illustrated by examining the EAFs and CFs reported for existing PJM nuclear units. These units operate under conditions similar to those Limerick 1 will face. The available data for CF and EAF (taken from an EPRI report) are listed in Table 4.1: there are sizable differences between EAF and CF for existing nuclear units in the pool, despite baseload operation and a much less nuclear-rich mix of capacity than will exist with Limerick, Hope Creek, and Susquehanna in service. It is clear from Table 4.1 that EAFs are useless for predicting capacity factors for PJM nuclear units: it appears likely that Limerick 1 will report EAFs higher than its CFs, at least in some years.

Q: What is the appropriate measure of "rated capacity" for determining historical capacity factors to be used in forecasting Limerick 1 power costs?

A: The three most common measures of capacity are

Maximum Dependable Capacity (MDC);

Design Electric Rating (DER); and

Installed or Maximum Generator Nameplate rating (IGN or MGN).

The first two ratings are used by the NRC, and the third by FERC.

The MDC is the utility's statement of the unit's "dependable" capacity (however that is defined) at a particular time. Early in a plant's life, its MDC tends to be low until technical and regulatory constraints are relaxed, as "bugs" are worked out and systems are tested at higher and higher power levels. During this period, the MDC capacity factor will generally be larger than the capacity factor calculated on the basis of DER or MGN, which are fixed at the time the plant is designed and built. Furthermore, many plants' MDCs have never reached their DERs or MGNs.

Humboldt Bay has been retired after fourteen years, and Dresden 1 after 18 years, without getting their MDCs up to their DERs. Connecticut Yankee has not done it in 16 years; nor Big Rock Point in 19 years; nor many other units which have operated for more than a decade, including Dresden units 2 and 3, and Oyster Creek. For only about one nuclear plant in five does MDC equal DER, and in only one case (Pilgrim) does the MDC exceed the DER. Therefore, capacity factors based on MDC will generally continue to be greater than those based on DERs, throughout the unit's life.

The use of MDC capacity factors in forecasting Limerick 1 power cost would present no problem if the MDCs for Limerick 1 were known for each year of its life. Unfortunately, these capacities will not be known until Limerick 1 actually operates and its various problems and limitations appear. All that is known now is an initial estimate of the DER, which is 1055 MW.[32] Since it is impossible to project output without consistent definitions of Capacity Factor and Rated Capacity, only DER and MGN capacity factors are useful for planning purposes. I use DER capacity factors in my analysis.

Actually, DER designations have also changed for some plants. The new, and often lower, DERs will produce different observed capacity factors than the original DERs. For

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32. PECo may also have published an estimate of the MGN capacity of the unit, but I have not seen it.

example, Komanoff (1978) reports that Pilgrim's original DER was 670 MW, equal to its current MDC, not the 655 MW value now reported for DER. Therefore, in studying historical capacity factors for forecasting the performance of new reactors, it is appropriate to use the original DER ratings, which would seem to be the capacity measure most consistent with the 1055 MW expectation for Limerick 1. This problem can also be avoided through the use of the MGN ratings, although MGN ratings tend to be nominal, with limited relation to actual capability.

4.1.2 - Projecting Limerick 1 Capacity Factors

Q: Are PECo's projections of Limerick 1 capacity factors appropriate for use in cost-benefit analyses, such as that in IR-OCA-2-25?

A: No. While achievement of the capacity factors PECo has projected is not completely inconceivable, those projections are significantly optimistic. PECo assumes that Limerick 1 will exceed previous performance for similar reactors.

Q: How have you determined the expected capacity factor performance of Limerick 1?

A: I have conducted a series of regression analyses of actual BWR capacity factors. The data is listed in Appendix B, and the results of my regressions are given in Table 4.2.

Projections for Limerick 1 performance, based on those results, are presented in Table 4.3. As shown in Table 4.2, I incorporated the following variables:

1. unit size, in original DER,

2. unit age, with maturation assumed at 5 years,

3. the portion of a refueling outage which occurred in the year, usually taking the values of 0 or 1,

4. an indicator for units of more than 1000 MW, and

5. indicators for various recent years.

Data were available for 216 full calendar years of operation at BWRs of more than 300 MW from 1974 to 1984. A small amount of pre-1974 operating experience could not be used for lack of refueling data.

Equation 1 demonstrates that BWR performance in 1979 was somewhat better than in previous years (although not significantly so), and that each of the following years has been progressively worse. Capacity factors have been falling by almost 4 percentage points per annum for the last five years: the largest drop occurred in 1984 (7.3%). Despite the steady downward trend in recent years, I grouped the post-1979 data in Equation 3, which shows that performance in the 1980's has been 11.3 percentage points below 1970's performance. Equation 2 repeats Equation 1, omitting Browns Ferry in 1975 and 1976, when the units were out of service due to the cable fire. Equation 4 repeats Equation 3, similarly omitting Browns Ferry in 1975 and 1976. Table 4.3 provides the projections of Equations 1, 2, 3, and 4 for Limerick 1, assuming that it enters service January 1, 1986; that it operates under the conditions which have prevailed recently; and that it shares in whatever benefits have allowed large BWR's (mostly Browns Ferry and Peach Bottom) to escape the size trend that affects PWRs and smaller BWRs. Depending on the Equation, the mature capacity factor ranges from 47% to 57%.

Q: What capacity factor value should be used in estimating Limerick 1 power cost?

A: Many reasonable regression lines can be drawn through any data set. Average life-time capacity-factor estimates for units like Limerick 1 would seem to lie in the range of 45% to 65% based on regression analyses of the historical record. There is a great deal of variation from the average, however; the regressions typically explain less than a third of the variation in the data, and Easterling (1979) derived 95% prediction intervals of about 10% for years 2 to 10 at 1100 MW BWRs. Actually, the variation would be somewhat larger, due to the greater variation in the first partial year and the first full year.[33]

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33. On the other hand, some of the apparent variation may result from the timing of refuelings, which would tend to average out for any individual unit.

Predicting the future effects of regulation, of safety issues, and of aging is difficult at best. Projecting Limerick performance based on the variables used in my equations raises such difficult questions as:

- Is performance really stable after year five, as AGE5 assumes, or is there a deterioration with further age?

- Is the better performance of units over 1000 MW related to their size or design, or is it an artifact of conditions at Browns Ferry and Peach Bottom?

- Will the deterioration in performance over the last five years continue, stabilize at 1984 levels, reverse slightly to average 1980's levels, or return to the capacity factors of the 1970's?

A year ago, based on data through 1983, I selected the functional form corresponding to Equation 4 in Table 4.2 (see my testimony in R-842651), and assumed that

- There was no adverse aging effect.

- The GT1000 variable was revealing a real characteristic of the large plants.

- Performance would rise to average 1980's levels (the average was better then).

Two events have made me less optimistic this year. First, the good performance of the large BWR's since the Browns

Ferry fire has been marred by the lengthy shutdown of all three Browns Ferry units due to the TVA's professed inability to operate them safely. This shutdown, which began in March 1985 and continues,[34] raises some question as to whether the high capacity factors of these units (and hence the value of the GT1000 variable) may have resulted from inadequate attention to safety. Peach Bottom performance has also been poor this year. The GT1000 variable will tend to be smaller and less significant when 1985 data is added to the regression.

Second, the remarkably strong downward trend detected by last year's regressions has become worse, not better, with the inclusion of 1984 data. Therefore, it is more difficult to imagine a rapid return to earlier levels of performance.

Considering all of these factors, I have based my projections on an average of the results of Equations 2 and 4, both evaluated at average 1980's conditions, some 9 percentage points above 1984 results. Further improvements in these conditions could be postulated, but given the persistence of sub-average conditions and the downward trend in every year since 1979, deterioration seems more likely than improvement. Thus, I believe the best current estimates for Limerick 1 are

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34. Unit 2 has been shut down since September 1984, originally for refueling. The various units are scheduled to return to service between September 1986 and September 1989, which assures that large BWR capacity factors will remain depressed for some time to come.

49%, 41%, 45%, 60% and 52% in years one to five, respectively (averaging 49%), and an average of 57% thereafter.

Q: Are PECo's projections for Limerick 1 capacity factor reasonable?

A: No. To compare the accuracy of the capacity factors I derived above, and PECo's projections, to actual results, I have performed the calculations presented in Table 4.4. For the five BWRs over 1000 MW which had entered service by 1979, the average capacity factor as of August 1985 was 54.5%. The capacity factor estimates which I derived in Table 4.3 (Equation 4) predict an average of 53.4%, while PECo would predict an average of 64.6%. Clearly, PECo's expectations are highly optimistic. The lifetime performance of these five units is raised (relative to recent experience) by their performance in the 1970's, when BWR capacity factors were consistently higher than they are today; the Browns Ferry 1 and 2 results reflect the effects of the fire at that plant. The actual five-unit average will vary with refueling schedules, is based on only two plants and two utilities, and has much less data than I used. At the very least, the actual data supports the conclusion that PECo's projections significantly overstate the capacity factors of large BWR's. On the other hand, my results closely approximate actual capacity factors, based on average historical conditions.

Q: Have you performed any analyses on the data from these large BWRs, on an annual basis?

A: Yes. Table 4.5 presents the annual capacity factors for the units used in the previous analysis, through December 1984. I have also added data for Susquehanna 1. No other large (over 1000 MW, or even over 825 MW) BWRs have completed a full year of commercial operation. I have assumed that the very low capacity factors for Browns Ferry in 1975 and in 1976, resulting from the fire at that plant, are not generated by the same sort of random process which accounts for the other variation in nuclear capacity factor. However, there is no reason to believe that some comparable (if not exactly identical) problem can not occur for Limerick 1. Hence, I delete these three observations from the individual year calculations, and instead reflect the probability of a major problem by computing the average effect. Compared to the results for all the other plants, this event reduced capacity factors by a total of 86.7 percentage points from average first year performance, and 48.5 points from second year performance, in 47 unit-years of experience, for a 2.9% reduction in all capacity factors. This calculation is also shown in Table 4.5. The average capacity factor which results from this analysis is about 60% for the first four years, with a mature capacity factor (from year five) of 55%. The immature average is somewhat overstated because it includes data from the 1970's, before the period of consistently depressed capacity factors in the 1980's. Even so, this analysis indicates that PECo's projections for Limerick 1 capacity factor are much higher than the actual performance of large BWRs.

Q: Is it appropriate to include the period since 1979, when the TMI accident and subsequent regulatory actions affected nuclear plant operation, in the analysis of nuclear capacity factors?

A: I believe that it is, for two reasons. First, the regulatory effects of Three Mile Island (and related developments) have depressed PWR capacity factors since 1979, and BWR capacity factors since 1980, with no sign of recovery to previous levels. Second, several more major nuclear accidents or near-misses are likely to occur before the scheduled end of Limerick 1 operation. Various recent estimates of major accident probabilities range from 1/200 to 1/1000 per reactor year (See Chernick, et al., 1981; Minarick and Kukielka, 1982). These estimates are based both on the implicit probability assessments of nuclear insurers, who must actually bet their own money on being correct, and on engineering models of actual reactor performance. Thus, major accidents can be expected every two to ten years once 100 reactors are operating. If anything, the 1968-84 period has been relatively favorable for nuclear operations, and BWR performance appears to be deteriorating steadily in the 1980's.

4.2 - Non-Fuel Station O&M

Q: How have you estimated non-fuel O&M expense for Limerick 1?

A: I have examined the available historical data on nuclear O&M for domestic nuclear plants. Appendix C lists the non-fuel O&M for each U.S. nuclear plant for each full operating year from 1968 to the most recent available data. Plants were excluded from the analysis in years in which new nuclear units were added to them, so each observation represents a full year's O&M for a clearly defined number of units and of megawatts.

Table 4.6 presents the results of five regressions on all of the data in Appendix C for light water reactors, a total of 535 observations. Table 4.7 presents the results of the same five regressions using only the data for plants of more than 300 MW, from Appendix C. All costs are stated in 1983 dollars, deflated at the GNP deflator. A total of 457 observations were available for Table 4.7.

The equations in Table 4.6 indicate that real O&M costs for all plants have increased at about 12% annually, and that the economies-of-scale factor for nuclear O&M is about 0.50, so doubling the size of a plant (in Equations 1 and 2) or of a unit (in Equations 3 - 5) increases the O&M cost by about 40%. Equations 1 and 2 indicate that, once total plant size has been accounted for, the number of units is inconsequential, and the effect on O&M expense is statistically insignificant. Equations 3 and 4 both measure size as MW per unit, and they both find that the effect of adding a second identical unit is about the same as the effect of doubling the size of the first unit: 47% for Equation 3 and 35% for Equation 4.[35] Equation 5 tests for extra costs in the Northeast, which are commonly found in studies of nuclear plant construction and operating costs, but is otherwise identical to Equation 3. Indeed, there is a highly significant differential: Northeast plants cost 32% more to operate than other plants (using the definition of North Atlantic from the Handy-Whitman index). I will use this Equation as the basis of my projection.

The results with the data set which excludes the smaller plants (Table 4.7) are quite similar: the most important difference is that the annual growth rate in large plant O&M is significantly higher than that of the overall data set. This effect would produce much larger O&M projections, if it were extrapolated out into the next century. There is no clear basis for choosing between the two data sets.

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35. The two equations do treat extra units differently after the second: a third unit increases costs by another 35% in Equation 4, but only by 26% in Equation 3. The treatment of additional units in Equation 3 seems more plausible, in that each succeeding unit should be progressively less expensive to run.

Q: What O&M projections would your regression results predict for Limerick 1?

A: Table 4.8 extrapolates the results for Equation 5 for a first unit of 1101 MW MGN, and displays the annual nominal O&M cost implied for Limerick 1 over the period 1986 - 2024, which is PECo's projection of the unit's useful life. Results are shown for both datasets. The same Table presents alternative projections from the historical data, assuming that the annual O&M expense increases linearly in real terms, at the real increment projected by Equation 5 between 1986 and 1987. Finally, Table 4.8 compares these results with PECo's projections.

Q: Are PECo's station O&M projections reasonable?

A: Based on the historical, PECo's projections for Limerick 1 O&M are fairly reasonable for the first few years: the 1986 value of $79.01 million is very close to the projection from Table 4.6, and while the assumption that real escalation will slow to 3% through 1990 is highly optimistic, it is not totally implausible. After 1990, however, PECo assumes that the persistent real escalation in nuclear O&M will abruptly end. Even the most favorable projection I present (linear escalation, based on all plants) is 2.5 times as large as PECo's projection by the year 2000, and five times as large by 2024. Thus, PECo's long-term projection of Limerick 1 station O&M costs is inconsistent with historical experience, and is extremely optimistic.

Protracted geometric growth in real O&M cost at historical rates would probably lead to retirement of this plant (and most nuclear plants) fairly early in the century, as it would then be prohibitively expensive to operate (unless the alternatives were even more expensive than PECo predicts). High costs of O&M and necessary capital additions were responsible for the retirement (formal or de facto) of Indian Point 1, Humboldt Bay, and Dresden 1, after only 12, 13, and 18 years of operation, respectively. Thus, rising costs caught up to most of the small pre-1965 reactors during the 1970's: only Big Rock Point and Yankee Rowe remain from that cohort. The operator of LaCrosse, a small reactor of 1969 vintage, has announced plans to retire it in the late 1980's.

On the other hand, our experience with nuclear O&M escalation stretches over only 17 years (1968-1984), so projecting continued real escalation past the year 2000 (another 16 years into the future) is rather speculative. On the whole, I believe that my compound growth projections of $73-85 million in 1986, with 18.5 to 20% annual escalation is at least as likely as PECo's projection of $79.01 million in 1986, with only 6.3% annual escalation. It is still more likely that the actual outcome will fall somewhere in the middle of the wide range between these two projections, such as my linear projections.

4.3 - Capital Additions

Q: Is PECo's estimate of capital additions to Limerick 1 reasonable?

A: No. PECo projects annual capital additions (or interim replacements) which are considerably lower than experience would indicate.

Q: How did you estimate capital additions?

A: Appendix C lists annual capital additions for all plants for which cost data was available from FERC and DOE compilations of FERC Form 1 data (now reported on p. 403), through 1984. Each plant is included for all years in which no units were added or deleted, and for which the data were not clearly in error. The available experience totaled 534 plant-years of operation, and the average annual capital addition in the database was $21.2/kw expressed in MGN terms, or about $23.3 million annually for Limerick 1 (at 1101 MW, MGN) in 1983 dollars. The capital additions are deflated by the appropriate regional Handy-Whitman index for nuclear construction, which has itself increased at 1.4% above the GNP inflation rate.[36] The July 1984 Handy-Whitman index was

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36. From 1970 to 1983, the GNP deflator rose from 91.45 to 215.63, for an annual rate of 6.8%. In the same period, the

estimated by escalating the July 1983 index at the growth rate of the January index from 1983 to 1984.

Capital additions vary with a number of factors, and vary greatly from year to year, complicating statistical analyses. Review of the data indicates that:

- large plants have lower capital additions per kilowatt-year than do small plants,

- multi-unit plants have lower capital additions per kilowatt-year than do single-unit plants,

- Northeastern plants have higher capital additions than those in other parts of the country, and

- capital additions per kilowatt-year have generally been rising over time, despite the greater prevalence of large and multi-unit plants in the later data.

Figure 4.2 and Table 4.9 show the average capital additions for each year since 1972, for all plants, and for single units. Levels of capital additions for both groups have increased over time, at least since the mid-1970's.[37] Over the last seven years, the average for all plants was \$27.7/kW-yr: over the last five years, the average has been

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July Handy-Whitman nuclear index for Region 1 rose from 81 to 227, an annual increase of 8.2%.

37. The data for large single units in the early 1970's is from a very small sample.

\$32.3/kW-yr. The rate of capital additions may have stabilized in the 1980's, or it may be increasing at about \$4/kw-yr^2. For the large single units, the corresponding averages are \$26.4 and \$28.8/kW-yr, with no real sign of an upward trend since 1980 (other than a jump in 1984). If capital additions continue at \$28/kw-yr in 1983 Handy-Whitman dollars, and if the nuclear Handy-Whitman index continues to run 1.4 points above the GNP deflation (for which I use PECo's projections of 4.5% in 1985, 5% in 1986, and 6% thereafter), the annual capital additions for Limerick 1 would be as shown in Table 4.10, which also shows PECo's projections of capital additions.

Some of the trend in the data may result from plant aging, and another portion is undoubtedly related to TMI-inspired regulatory charges, so extrapolating the trend out is somewhat speculative. However, there is some evidence of an overall upward trend in the period 1972-78, as well, so any TMI-related effect constitutes a continuation of the trend, rather than a unique event.

I believe that it is prudent to assume that capital additions at Limerick 1 will continue at recent levels, starting at \$36 million in 1987 and rising at 7.4% annually. By contrast, PECo assumes capital additions of only \$4.189 million in 1987,[38] jumping to \$12.781 million in 1988, and rising at

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38. Since my cost data comes primarily from FERC returns, additions in the first partial year of commercial operation

6.8% through 1995 and at 6% from 1996 to 2024.

(which will be 1986 for Limerick 1) are usually counted as part of the plant construction cost.

4.4 - Other O&M

Q: What costs are included in PECo's "other O&M" category?

A: PECo includes four expense items which are required by the operation of the plant, but are not generally included in station O&M:

- interest on the fuel inventory in the reactor,
- spent fuel disposal,
- insurance, and
- decommissioning.

Q: Are these costs projected reasonably?

A: I have not reviewed the basis for the fuel-related costs. However, both of these costs vary with capacity factor: the interest varies inversely with the capacity factor, while spent fuel disposal varies directly with capacity factor. Interest is by far the more important of the two, as it starts at three times the size of the spent fuel disposal charge in 1986, and reaches 30 times the spent fuel charge in 2024. Hence, the fuel-related portion of Other O&M will tend to be higher than PECo predicts, to the extent that PECo's capacity factor projections prove to be overstated (which is very likely).

Insurance and the allowance for decommissioning are discussed in more detail below. None of these costs is likely to have any major influence on the overall economics of Limerick 1, at least in the first few years of its life. In the longer term, decommissioning may have a significant effect on costs.

4.4.1 - Insurance

Q: Are PECo's estimates of the cost of insuring Limerick 1 reasonable?

A: PECo's initial estimates of the cost of existing insurance policies appear reasonable. However, existing coverages do not yet provide anywhere near adequate protection in the event of the total loss of a unit like Limerick 1. Some provision for future coverages (for premature decommissioning, for example) would be appropriate.

Also, despite the fact that PECo is projecting very high escalation in replacement power costs, it assumes no increase in the premium for replacement power insurance. This combination of assumptions seems rather unlikely.

4.4.2 - Decommissioning

Q: What allowance for decommissioning should be included in the cost of Limerick 1 power?

A: Chernick, et al. (1981) estimated that non-accidental decommissioning of a large reactor will cost about $250 million in 1981 dollars. This is equivalent to about $295 million in 1984 dollars, using the Handy-Whitman deflator. Assuming that the decommissioning fund accumulates uniformly (in constant dollars) over the life of the plant, and that it is invested in risk-free assets (such as Treasury securities) which have historically averaged a real return close to zero, the annual contribution (in 1984 dollars) would be about $11.8 million per year over a 25 year life, or $7.4 million annually for a 40 year life. The annual decommissioning charge would have to escalate at the rate of inflation.

Q: How does this compare to PECo's assumed decommissioning cost?

A: PECo uses a traditional engineering estimate of decommissioning costs for Limerick 1 and common plant of $146.2 million in 1984 dollars. Decommissioning cost estimates have been subject to the same sort of errors and escalation as have estimates of nuclear construction and O&M costs. Experience with decommissioning has been limited to small units with little operating history. It is rather presumptuous to assume that the current engineering cost estimates will prove to be correct 40 years hence.

PECo also assumes fairly high real interest rates on its decommissioning fund balance, resulting in a projected decommissioning charge of only $3.16 million annually. This is ultimately a ratemaking issue for the Commission, but I would question whether ratepayers should be assuming these investment risks, along with all the other risks imposed by Limerick 1.

4.5 - Limerick 1 Useful Life

Q: Is it reasonable to expect Limerick 1 to operate for 39 years?

A: No. There is simply no basis for this assumption. As I discussed above (page 66), three out of the five small commercial reactors which entered service in the early 1960's were retired by the time they reached age 18. The older and larger of the survivors, Yankee Rowe, has been in service since 1961, and is thus only 25.[39] The first units of more than 300 MW went commercial in January 1968: they have just reached age 18.

PECo is projecting that Limerick 1 will survive more than twice as long as has the oldest domestic unit over 300 MW, and over 50% longer than the oldest domestic power reactor of any size. PECo expects the unit to operate throughout this unprecedented life, at peak capacity factors, without any major life extension investments,[40] and without any real increases in O&M costs. This expectation contrasts strongly with PECo's assumption that fossil-fired plants (which do not share Limerick's exposure to safety issues, structural

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39. It is also only a 175 MW unit.

40. Indeed, PECo's projections of capital additions are lower than actual costs for relatively youthful plants.

degradation through irradiation, or radioactive accumulation interference with maintenance) require major investments to operate past 35 years of age, even if they have been operated only sporadically for several years.

While we may all hope that Limerick 1, and other nuclear units, will stay in operation for 40 years or more, at high availability levels and without need for major expenditures to prolong their lives, we must also accept the possibility that they will not survive for more than 25 or 30 years. Early retirement of Limerick 1 would deprive PECo's customers of the years in which the plant is projected to be most cost-effective (if it ever pays its way), and leave them (or PECo's shareholders) with a large liability for the undepreciated portion of the plant cost, and for the portion of the decommissioning cost not yet covered by the decommissioning fund.

4.6 - Discount Rates

Q: Why are discount rates generally used in economic cost-benefit analyses?

A: In general, costs (or benefits) are more important if they occur sooner, rather than later. Individuals and other economic entities would usually prefer to receive benefits early, and pay the costs late.[41] The discount rate is intended to approximate this time preference: if the consumer considers $1 this year to be as valuable as $1.15 next year, the appropriate discount rate is 15%.

Q: Is the appropriate discount rate the same for all investment decisions?

A: No, for two reasons. First, different entities have different discount rates, since the short-term sacrifices they would have to make for long-term benefits will differ. A rich person, a poor person, a non-profit organization, a start-up high-tech firm, the local branch of an international conglomerate, and the Commonwealth of Pennsylvania will find different ways of raising funds to pay an additional cost,

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41. Hence the attraction of "Fly now, pay later." Unfortunately, Limerick 1 (and many other investments) require us to "Pay now, fly later." In the case of Limerick 1, the situation may be "Pay now, and someone else will get to fly in twenty years."

such as increased electric bills to pay for Limerick 1. The rich person may put less in his mutual fund, the poor person may do without dinner, and the start-up firm may cut back on the research program which would have made it a market leader. Thus, the discount rate chosen for an evaluation should reflect the time preferences of the entities which will be paying the bills and receiving the benefits.[42]

Second, not all investments carry the same risks. Investors require a higher expected return from equity holdings in high-risk startup ventures than from risk-free Treasury securities, for example. The discount rate used should therefore reflect the degree of risk involved in the projected stream of costs and benefits.

Q: Is PECo's use of a 9.7% discount rate in IR-OCA-2-25 appropriate?

A: No, for three reasons. First, PECo is erroneously using an estimate of its own discount rate, instead of customer discount rates. This discount rate is being used to discount cash costs and benefits to customers, not PECo's cash outlays, and should therefore reflect the time and risk preferences of the customers, rather then of PECo itself, or of its shareholders.

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42. It is meaningless to apply discount rates to anything other than cash, such as depreciation, AFUDC, or other non-cash accounting concepts.

Q: Is PECo's discount rate a reasonable approximation of its customers' discount rates?

A: No. If Limerick 1 just broke even for the customers (had a 0 net present value) at 10%, for example, it would be equivalent to a return of 10%, roughly equivalent to a ten-year payback.[43] When electric ratepayers have the opportunity to make conservation investments, even ones much less risky than Limerick 1, they generally appear to require returns well in excess of 10%.

Appendix F tabulates the results of a telephone survey of some of my clients, who report required paybacks on the order of 2 to 5 years: none of the enterprises surveyed indicated a discount rate of less than 20%. Industrial firms will also rarely make non-productive investments with expected paybacks of more than four years, and for some firms (especially those in the least secure financial situations) this target is less than one year. Similarly, Hausman (1979) found that residential consumers used real discount rates of 15-25% in comparing appliances of differing efficiencies. These high discount rates indicate that most consumers would not be willing to pay the costs of Limerick 1, if they could expect a return of only 10%, even if Limerick 1 were only as risky as typical investments.

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43. This simplification would be correct if the benefits to the ratepayers were very long-lived and constant, which they are not. Since traditional ratemaking front-loads the costs of new plants, and since the benefits of Limerick 1 grow over its lifetime, the payback would be later than ten years.

Q: What is the second problem with PECo's use of the 9.7% discount rate?

A: The second problem is that Limerick 1 is not a typical investment in terms of risk. The risky aspects of Limerick 1 include its capacity factor, operating costs, capital additions, decommissioning costs, useful life, and the chance of an accident at the plant. Limerick 1 must be much riskier than PECo's average business risk, for its distribution, transmission, and even fossil generation.

For an investment with the risk characteristics of Limerick 1, 9.7% is an implausibly low target return. This is roughly the return one would expect from an investment in risk-free Treasury securities. I do not believe that any reasonable person would suggest that Limerick 1 is as safe an investment as government bonds.

Q: What is the third problem with PECo's use of the 9.7% discount rate?

A: The third problem is that 9.7% is not even PECo's own time value of money. PECo calculates its discount rate by using the "after tax cost of money" computation, which subtracts the tax benefits from the debt portion of the capital structure. This is an appropriate calculation of <u>corporate</u> discount rates only if either (a) revenues do not vary with financial costs (which is true for most corporations, but not for utilities), or (b) the utility requires no return on deferred recovery of investments. If the return on investment is to be covered by increased revenues, taxes must be added to the cost of money, not subtracted, to establish a discount rate at which the utility would be indifferent between expensing an expenditure (that is, getting paid for it immediately) and capitalizing that expenditure. This point is illustrated in Table 4.11, which compares a $1000 cash expenditure with the same cost rate-based and depreciated over 10 years, under traditional rate-base treatment, and shows that the present value of the annual revenue requirements is equal to the initial investment only for a discount rate equal to the average return, plus taxes on the equity portion. Since the utility is paid a cash return on its investment, it must pay additional taxes if it finances expenditures by capitalizing rather than expensing them. Hence, the discount rate at which the utility is equally satisfied with the cash flows resulting from expensing or capitalizing an investment is the overall rate of return, plus income taxes.

Q: What discount rate would you recommend using in cost-benefit analyses of Limerick 1?

A: Given the considerations outlined above, 15% is probably a minimum reasonable discount rate, and a value of 20% or more may be appropriate. My analyses in Section 3 calculate present values at discount rates of 10%, 15%, and 20%.

5 - PHASE-IN OPTIONS

Q: If the Commission does not disallow all or most of the costs PECo has claimed for Limerick 1 in this case, how should the remaining costs be reflected in rates?

A: I would strongly urge the Commission to phase the costs into rates over an extended period, so that the costs were recovered in a time pattern which reflects the time pattern of benefits from the plant.

Q: Is the PECo phase-in proposal adequate?

A: No. PECo's proposal would require three successive annual increases of at least 9.4%, if the entire expenditure is allowed into rates and Limerick 1 performs as PECo projects, with correspondingly larger increases if Limerick 1 is more expensive to operate or less reliable. As I showed in Section 3, Limerick 1 would impose large costs on ratepayers in the rest of this century, for benefits to be provided in the next century (if at all), under either traditional ratemaking or PECo's proposed phase-in. The PECo phase-in does not adequately synchronize costs and benefits over time.

Q: Is it necessary to synchronize the costs and benefits of <u>all</u> utility investments, in the manner you propose for Limerick 1?

A: No, for several reasons. First, it is difficult to define the benefits of any particular investment, except as compared to the cost of operating the rest of the system, without that one investment. Therefore, while the fuel savings of Limerick 1 (or any other generator, or any reasonably small group of generators) can be calculated with reference to the costs of the system without Limerick 1 (or whatever plant is under discussion), the fuel savings of the entire PECo generation plant is probably undefinable. Second, some plant investments are immediate cost-savers, so the problems of rate shock and intertemporal equity associated with Limerick 1 -- raising rates for customers in the short term, with a promise of long-run savings -- simply do not arise. If the simple, traditional ratemaking approach works for all parties, there is no reason to deal with phase-in issues. Third, many investments involve small costs, so the administrative overhead involved in a phase-in would not be justified, even though the time pattern of costs and benefits is a miniature version of those of Limerick 1. Fourth, some investments (a few generation projects, many transmission projects, and a large proportion of distribution investments) perform functions which simply could not be served otherwise: there is often no basis for comparison of the project's costs and benefits.

Q: What principles might be applied in designing a phase-in for the portion of an expensive new plant which the utility will eventually be allowed to recover from ratepayers?

A: The central goal is the alignment of costs with benefits. There is simply no compelling reason for Limerick 1 to make customers much worse off in one time period, so that customers in another time period may be much better off. If the plant is beneficial overall, in present value terms, it should be possible to ensure that rates will not be higher in any year with Limerick 1 than they would have been without the unit. If the allowed cost of the plant exceeds its lifetime benefits, the net burden can be shared fairly over time.

Q: Does the objective of aligning costs and benefits lead to a unique phase-in pattern or mechanism?

A: No. There are many time patterns of costs which might be generally described as "synchronizing" costs and benefits, and for each such pattern, there are several ratemaking mechanisms which would be expected to produce the expected result.

Q: How might the time pattern of the phase-in be varied, within the general objective of matching costs to benefits?

A: The net lifetime difference between costs and benefits (whether that difference is positive or negative) can be distributed in several ways. Rates can be set so that the net cost (or net benefit) per kWh of generation from the plant is constant in nominal terms over the years, or so that it is constant in real (inflation-adjusted) terms over time, or so that the ratio of the net cost to the gross benefits is constant from year to year. In another dimension, the differential between costs and benefits may be levelized per kWh of Limerick 1 generation (which would be expected to rise over the first few years of the unit's life), per kWh of PECo retail sales (which PECo projects to rise slowly throughout the life of Limerick 1), or per year. Phase-in structures can also be very detailed, with cost recovery calculated on an annual basis to match benefits, or they can be simplified for administrative convenience and predictability: for example, simplified recovery can be set at 7 cents/kWh over the first five years, or at $250 million annually in 1986, escalating at 6% annually until 1995.[44]

Q: How can the phase-in pattern be modified, if the benefits of Limerick 1 exceed its costs?

A: There are two basic options. First, PECo may be allowed to collect the full benefits of the unit until benefits exceed cost recovery under standard ratebase ratemaking, at which time the phase-in may be ended and the plant may be treated like any other PECo investment. Alternatively, annual cost recovery may be set at a fraction of the costs avoided by the

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44. These approaches can also be combined with other considerations, such as smoothing out annual rate increases over time.

unit, with the fraction chosen so that PECo will recover all of its allowed costs over the life of the unit.[45]

Q: How can the phase-in pattern be modified, if the costs of Limerick 1 exceed its benefits?

A: If the Commission wishes to assign PECo shareholders some of the costs of planning and building a plant which is not worth what it costs, no modification is necessary. If the Commission wishes to make the Company entirely whole for its investment, rate recovery may be set at a multiple (say, 110%) of the plant's benefits, so that life-time cost recovery will equal life-time costs. If PECo is correct about the benefits of Limerick 1, this situation will not arise, since Limerick 1 will pay for itself.

Q: What kinds of variation in ratemaking mechanisms are appropriate within the general objective of matching costs to benefits?

A: The first type of variation is in the form of the cost recovery, which may take place through base rates, through the fuel adjustment mechanism, or through a separate adjustment. Base rates may be increased to reflect the expected savings of the plant in the rate year (or future test year). Alternatively, fuel cost recovery may be calculated as if Limerick 1 did not exist, which would allow

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45. This treatment could be combined with some form of credit to PECo for its deferred cost recovery.

PECo to keep the actual fuel savings the unit produces. If the automatic adjustment mechanism (which reduces the frequency of base rate cases) is desirable, but the Commission does not wish to interfere with the original purposes of the ECR mechanism, a separate adjustment mechanism for Limerick 1 costs may be appropriate.

The second type of variation is in the measure of benefits utilized in the matching process. The benefits may be measured in the short run or the long run. In the short run, the benefits are the fuel costs, the cost of meeting PJM reserve targets, and other costs which would have been experienced in the individual rate year if Limerick 1 suddenly disappeared. Short-run benefits may be estimated in 1986 for the entire life of the plant, or estimated annually for the next year, or determined retrospectively at the end of each year (or other period). In the long run, the benefits of Limerick 1 are the cost of the system adjustments which would have been made in the absence of Limerick 1, perhaps including some of the short-run costs, but also including construction of new plants and implementation of conservation and load-management programs. Long-run benefits can generally be estimated in advance: the real question is when the hypothetical decision to replace Limerick 1 would have been made, which determines when replacement capacity would have been ready, and what mix and timing of investments PECo would reasonably have pursued.[46]

The third dimension of variation in ratemaking mechanisms concerns the extent to which PECo's cost recovery is subject to outcomes, rather than projections. At one extreme, cost recovery may be set at the level of projected benefits, regardless of actual Limerick 1 power production, the performance of other PECo plants, fuel cost differentials, or purchased power availability. A second possibility is to set recovery on a projected cents/kWh basis, so that PECo's cost recovery is dependent on Limerick 1 power production, but not on fuel or purchased power conditions. Finally, cost recovery may be tied directly to after-the-fact results, so that PECo receives only the actual value of Limerick 1 in each year.[47]

Finally, the process of matching costs to benefits may be designed to make PECo whole for its Limerick 1 investment,

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46. For example, in 1980 the replacement of oil generation with coal seemed far more important (and viable) economically than it does today.

47. These options tend to interact with the other choices made in setting up the cost-recovery mechanism. For example, it makes little sense to discuss "actual" savings if the measure of benefits is the long-run cost of a hypothetical alternative plant. Similarly, the choice between base-rate and ECR recovery for Limerick 1 costs is partially dependent on whether the Commission wishes to allow PECo to recover projected benefits (in which case base rate treatment is appropriate) or whether it prefers to use actual after-the-fact benefits (which would favor an automatic adjustment mechanism, perhaps tied to the ECR).

regardless of the actual benefits of the unit; to require PECo to share the burden arising from a limited set of parameters, such as Limerick 1 capacity factor, while immunizing PECo from all other risks (especially the economic risks of varying fuel prices); or to expose PECo to a share of the full range of risks associated with Limerick 1.

Q: Would a benefit-matching phase-in have to change if it would impose financial constraints on PECo, such as triggering bond indenture limits on interest coverage?

A: Financial constraints may prompt the Commission to modify the phase-in, but could hardly invalidate the basic approach. Since a benefit-matching phase-in will generate more cash for PECo than Limerick 1 did while it was still under construction, the utility's cash financial condition should improve, rather than deteriorate, once the phase-in takes effect. The Commission may determine that it is in the interests of ratepayers for PECo to receive even more cash, or for the quality of some of the non-cash earnings to be improved, as by providing a reasonable assurance of later recovery.[48] Either of these actions may be taken as a part of fine-tuning a phase-in, consistent with the basic goals of matching benefits to costs as well as is feasible, and

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48. I have not examined the financial condition of PECo, or the cost to ratepayers of various financial constraints, and therefore have not analyzed the financial implications of alternative phase-in treatments.

sheltering current customers from large rate increases to pay for a plant which is of little value to them.

6 - CONCLUSIONS AND RECOMMENDATIONS

Q: What do you conclude from your examination of the need for, and economics of, Limerick 1?

A: First, I conclude that Limerick 1 would not have been required for system reliability in the rest of this decade, and will have very limited reliability benefits throughout its life. Second, I conclude that, if PECo recovers the entire cost of Limerick 1 under normal ratemaking treatment, it will not provide an economic benefit to ratepayers, and it will represent a net loss to PECo's ratepayers, in 1986 and well beyond the year 2000. Even under PECo's biased assumptions, rates would be higher for the rest of the century to pay for Limerick 1, and the present value of the unit's rate effect will be a net cost for almost another decade further.

The economics of Limerick 1 will be much worse, compared to realistic and efficient capacity and energy benefits, or if historical patterns in operating cost and reliability continue. The cost burdens for individual customers who pay for the unit's early years will be even more severe, than those on the system as a whole. Under traditional ratemaking, customers would be heavily taxed throughout the rest of this century, and well into the next, to reduce the cost of power to customers in the second and third decades of the twenty-first century, if ever.

Q: What implications do your observations have for ratemaking?

A: There are three major implications. First, it is doubtful that the entire cost of Limerick 1 will ever be justified by its operating savings for customers, and the reliability value of Limerick 1 will never be more than a tiny fraction of its cost. Thus, the portion of the Limerick 1 investment which is useful to the ratepayers is significantly smaller than the entire booked cost.

Second, most of the justifiable costs of Limerick 1 are justified, either prospectively or retrospectively, by the expectation that Limerick 1 will provide many kWh annually at a low incremental fuel cost. The Limerick 1 investment which is eventually charged to ratepayers would never have been incurred simply to meet peak demand. Most of the cost of building and running Limerick 1 is related to its energy-serving function, rather than its demand-serving (that is, reliability-related) function. Therefore, most of the cost of the unit should be treated as an energy cost, for both inter-class cost allocations and intra-class rate design. My award-winning Institute of Public Utilities paper on the allocation generating plant costs (Chernick and Meyer, 1982), attached as Appendix G to this testimony, discusses this point in greater detail.

Third, because the benefits and costs under traditional ratemaking would be so out of line, and would tend to fall on very different groups of ratepayers, the cost of the plant should be recovered in a manner which more closely follows the benefits over time. In other words, a substantial phase-in of plant costs is absolutely necessary to produce any semblance of equity.

Q: Do you have any suggestions regarding the application of the "used and useful" test which the Commission applied to Susquehanna Unit 1 and Unit 2?

A: Yes. The "used and useful" concept was applied in different ways to the two Susquehanna units. For Unit 1, it was applied solely as an excess capacity adjustment, through exclusion of a "slice of the system" from rate base.

For Unit 2, the equity return on the unit was denied, due to the remoteness of either a reliability need or a direct economic benefit to ratepayers.

The adjustments made by this Commission in the Susquehanna I and Susquehanna 2 cases were fully justified by the economics of the Susquehanna units and did significantly reduce the burden on ratepayers. Even these approaches would not really solve the inter-temporal equity problems posed by Limerick 1. The equity problems would not be solved because Limerick 1 would still sharply increase rates to customers in the short run without commensurate benefits, and regardless of whether the unit is beneficial in the long run. In part, the Susquehanna ratemaking treatments are less effective in the case of Limerick 1, because that unit is almost twice as expensive as either of the Susquehanna units. The slice-of-the-system approach is the less effective of the two, since the average PECo capacity is much less expensive than Limerick 1. Applying the Susquehanna 2 treatment to Limerick 1 would address the short-term problem better, but does not fully protect ratepayers in this decade from substantial rate increases for a plant which will provide most of its benefits in the next century.

Just as significant as the immediate rate effect for PECo customers, this case gives the Commission the opportunity to establish that the cost to the utilities of excess capacity will be greater when that capacity is excessively expensive. The slice-of-the-system approach puts utilities at risk for excess MW's of capacity, but not for excessively expensive and uneconomical capacity. The Susquehanna 2 treatment is again superior, in that the costs it assigns to shareholders are at least proportional to the construction cost of the unit, but it also has shortcomings. The denial of equity returns places the burden for an essentially constant portion of the plant's cost on the shareholders. For a very expensive plant like Limerick 1, the denial of equity return would relieve the ratepayers of a smaller portion of the net rate increase from the plant.[49] Power plant economics are also affected by operating costs, capacity factor, and the value of the power they displace: ratemaking treatments which respond only to capital costs can not reflect these factors.

In the Susquehanna cases, the Commission has started the process of defining and refining the concepts of "useful" and "excess" capacity. The Susquehanna 1 decision focused exclusively on excess megawatts, while the Susquehanna 2 decision was directed specifically toward the cost of that unit. However, the Commission's decision in R-842651 indicated that PP&L could apply again for full ratebase treatment of Susquehanna 2 when the unit's capacity was required, leaving open the question of whether the economics of the unit are at all relevant for ratemaking purposes, so long as the capacity is needed.

The problems with Limerick 1 or with Susquehanna, or with Beaver Valley 2, have less to do with capacity than they have to do with cost. One of the central points which arise from Sections 2 and 3 of this testimony (and even

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49. On the other hand, if the same rule were applied to a less expensive plant, it might result in an immediate rate decrease.

from PECo's analyses, as in IR-OCA-2-25) is that the capacity value of a large nuclear is only a small part of its total value: the investment in expensive nuclear capacity is primarily justified by its fuel savings (if it is justified at all). This point is made in various forms by such PECo witnesses as Mr. Rush (PECo Statement 14, page 18) and Mr. Carroll (Transcript, page 323). Even if PECo needed capacity immediately, Limerick 1 at its current cost would be excessively expensive, since new CTs (and especially life extensions) would fulfill the capacity requirement at a tiny fraction of Limerick's cost. On the other hand, Limerick 1 could be desirable even if PECo had a 100% reserve margin, if it had been completed at a much lower cost, it it could be expected to operate at an 80% capacity factor, if its O&M costs were low, and so on.

Q: In defining excess capacity should the Commission identify specific utility actions which will not be allowed as justification for plant additions like Limerick 1?

A: Yes. The Commission should not allow utilities to use the following actions to define new capacity:

- The premature retirement of existing plant, raising short- and long-run costs, but reducing excess capacity penalties.

- The failure to maintain and renovate existing plants, to make retirement more plausible.

- The failure to pursue economical fuel conversions and life extensions, to reduce excess capacity.

- Supporting PJM actions which increase required reserves, either for the pool or for the individual utilities, so that the utilities' reserves seen more reasonable.

- Encouraging low load-factor end uses, and discouraging load shifting and conservation, so as to increase peak load and thus the utility's capacity requirement.

- Delaying plant construction, even if that results in much higher costs, as that the in-service date occurs at a time of lower reserves.

- Selling off economical plant (or entering into long-term sales of the capacity), to create a "need" for new expensive plant.

- Opposing the development of cogenerators and small power producers, even where those facilities would reduce retail revenue requirements, so as to increase the "need" for utility-owned capacity.

The utilities should be put on notice that they will find little reward in these counter-productive actions, and in some cases will even be harmed by them.

Q: In the previous section, you presented a range of phase-in options. Do you have any specific recommendation for the Commission in this regard?

A: I do have a specific recommendation as regards the phase-in approach. It is important to bear in mind that I have not considered all of the issues which the Commission might wish to incorporate in its determination of the level of rate recovery to be allowed for Limerick 1 in 1986 or subsequent years. For example, as I noted in the previous Section, I have not reviewed either the financial condition of PECo, the effect on PECo of various levels of cash or non-cash earnings, or the effect on customers of alternative PECo financial conditions; nor have I reviewed the prudence of PECo's generation planning or construction management. The rate level allowed by the Commission might properly reflect consideration of these or other factors beyond the scope of my testimony. My recommendation is based on the analysis of Limerick 1 costs and benefits in Sections 2 and 3 of this testimony, and on the equity considerations discussed in Section 5.

To the extent that the Commission finds that the costs of Limerick 1 are prudent and determines that financial considerations do not constrain the phase-in, I would recommend that PECo be allowed to collect base rates for Limerick 1, starting in 1986, of $187 million. This figure is composed of $150 million of PECo's anticipated fuel savings, plus $37 million in reliability benefits (the costs avoided by retiring Richmond 9, Southwark 1&2, and the CT's). This figure will probably exceed the benefits of Limerick 1, due to PECo's optimistic capacity factor and high oil price projections.

Q: How could future recovery for Limerick 1 be determined?

A: There are several possible regulatory structures which could be used to update cost recovery as the benefits from the plant rise. The Commission could require PECo to file a new rate case whenever it wishes to argue for greater recovery. Alternatively, the Commission could establish a rate rider mechanism, which would allow for revision of rate recovery in a more limited context, and which would limit the scope of the issues to review of PECo projections of costs and benefits. In either of these formats, some reconciliation mechanism should be included, to discourage overestimation of avoided costs or of Limerick 1 capacity factor. The reconciliation might simply consist of reducing the next year's savings projection by the error in the previous year's projection.

A third approach would be to establish now the cost recovery for each year of the unit's life. The Commission might initiate a proceeding, without the limitations of the suspension period in the present case, to

- determine the conditions, if any, under which PECo will be allowed to charge ratepayers for more than the value of Limerick,

- establish a series of annual avoided-cost values (in cents kWh and dollars per kW-year) to be used in future Limerick cost-recovery, and

- create a ratemaking mechanism to adjust Limerick cost recovery over time, to reflect the changing avoided-cost values and differences in Limerick performance, without requiring rate-case review.

Q: Does this conclude your testimony?

A: Yes.

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TABLE 2.1: CALCULATION OF CAPACITY ALTERNATIVES TO LIMERICK 1
All Capacity in Rated MegaWatts

in Year	PECo Load Proj.	Required Reserve % of Load	Load + Reserve [1]	Capacity After PECo Retirements without Limerick	Short-fall [2]	Life Extension Capacity [3]: R 9 & S 1&2	D 7&8	CTs	Cr 2	Sch 1	Total Extended Capacity	Short-fall after Extension [4]	Previous. Added Capacity [5]	New CTs Added to Replace Limerick 1 [6]	Life Extension Capacity Attributable to Limerick 1 [7]
1986	6160	22.50%	7546	6803	743	504		458			962	-219	0	0	962
1987	6180	21.90%	7533	6803	730	504		458			962	-232	0	0	962
1988	6200	22.00%	7564	6803	761	504		458			962	-201	0	0	962
1989	6220	23.80%	7700	6791	909	504	253	458			1215	-306	0	0	1,055
1990	6240	24.20%	7750	6791	959	504	253	458			1215	-256	0	0	1,055
1991	6260	25.80%	7875	6337	1538	504	253	458	201		1416	122	0	122	933
1992	6320	23.80%	7824	6337	1487	504	253	458	201		1416	71	122	0	933
1993	6380	24.60%	7949	6337	1612	504	253	458	201		1416	196	122	74	859
1994	6440	25.00%	8050	6168	1882	504	253	458	201	169	1585	297	196	101	758
1995	6500	25.00%	8125	6168	1957	504	253	458	201	169	1585	372	297	75	683
1996	6560	25.00%	8200	6168	2032	504	253	458	201	169	1585	447	372	75	608
1997	6620	25.00%	8275	6168	2107	504	253		201	169	1127	980	447	533	75
1998	6700	25.00%	8375	6168	2207	504	253		201	169	1127	1055	980	75	0
1999	6780	25.00%	8475	6168	2307	504	253		201	169	1127		1055		
2000	6860	25.00%	8575	6168	2407	504	253		201	169	1127				
2001	6940	25.00%	8675	6168	2507	504	253		201	169	1127				
2002	7020	25.00%	8775	6168	2607	504	253		201	169	1127				
2003	7100	25.00%	8875	6168	2707	504	253		201	169	1127				
2004	7180	25.00%	8975		0	504	253		201	169	1127				
2005							253		201	169	623				
2006							253		201	169	623				
2007										169	169				
2008										169	169				

Notes: All data from PECo Statement No.14 (C.H.Rush Testimony); Life Extension Capacity from Schedule 7 erratum.

1. PECo Load + % Reserve.
2. Load + Reserve Required less Capacity after retirements and without Limerick.
3. Scheduled Retirements include the following plants with or without Diesels: R 9 = Richmond 9 (166 MW), S 1& 2 = Southwark 1 & 2 (+Diesel, 338 MW), D 7&8 = Delaware 7 & 8 (+Diesel, 253 MW), CTs = Combustion Turbines (458 MW), Cr 2 = Cromby 2 (201 MW), Sch 1= Schuylkill 1 (+Diesel, 169 MW).
4. Shortfall capped at 1055, to limit this calculation to replacement of Limerick 1 only.
5. Cumulative capacity added up to current year.
6. Capacity needed to cover shortfall.
7. The lesser of Total Extended Capacity and 1055 - Previously Added Capacity.

TABLE 2.2: COST OF RETAINING OLD CAPACITY COMPARED TO PJM CAPACITY CHARGE, 1986-2024

	Life Extension Carrying Cost										PECo Projections PJM Capacity Charge	
	Rich.9 & Southw.1&2 504 MW		Delaware 7&8 253 MW		Rich. & Plym. Meetg. CTs 458 MW		Cromby 2 201 MW		Schuylkill 1 169		PJM Rate	PJM Doubled
Year	$ Million [1]	$/kW-yr	$ Million	$/kW-yr	$ Million	$/kW-yr	$ Million [2]	$/kW-yr	$ Million [2]	$/kW-yr	$/kW [3]	$/kW [3]
1985	$3	$6				$0					$53	$106
1986	$34	$68			$3	$7					$57	$113
1987	$34	$68			$5	$11					$60	$120
1988	$32	$64			$5	$11					$64	$128
1989	$31	$61	$8	$32	$5	$11					$68	$137
1990	$31	$62	$7	$28	$6	$13					$72	$145
1991	$30	$59	$31	$123	$6	$13	$17	$83			$77	$153
1992	$29	$57	$29	$116	$6	$13	$16	$82			$81	$163
1993	$24	$48	$28	$110	$6	$13	$16	$78			$86	$172
1994	$23	$45	$26	$102	$7	$15	$15	$72	$17	$99	$91	$183
1995	$23	$46	$25	$99	$6	$13	$14	$71	$16	$93	$97	$194
1996	$22	$44	$24	$94	$7	$16	$14	$67	$15	$89	$103	$205
1997	$21	$43	$22	$88	$62	$135	$13	$64	$14	$83	$109	$218
1998	$21	$41	$21	$83	$58	$127	$12	$60	$14	$81	$115	$231
1999	$20	$39	$20	$77	$55	$121	$11	$57	$13	$77	$122	$245
2000	$19	$38	$18	$72	$53	$115	$11	$53	$12	$73	$126	$251
2001			$18	$72	$50	$109	$10	$52	$12	$69	$137	$275
2002			$18	$70	$48	$104	$10	$50	$11	$65	$146	$291
2003			$17	$67	$46	$100	$10	$48	$10	$61	$154	$309
2004			$16	$64	$43	$95	$9	$46	$10	$59	$164	$327
2005			$15	$61	$41	$89	$9	$44	$10	$57	$173	$347
2006					$39	$86			$9	$55	$184	$368
2007					$37	$81			$9	$53	$195	$390
2008					$35	$76			$9	$51	$207	$413
2009					$33	$73					$219	$438
2010					$31	$68					$232	$464
2011					$30	$65					$246	$492
2012											$261	$522
2013											$276	$553
2014											$293	$586
2015											$311	$621
2016											$329	$658
2017											$349	$698
2018											$370	$740
2019											$392	$784
2020											$416	$831
2021											$441	$881
2022											$467	$934
2023											$495	$990
											$525	$1,050

Costs in $Million:

	Rich.9 & Southw.1&2	Delaware 7&8	Cromby 2	Schuylkill 1
Life Extension:	$106	$90	$47	$44
Starting in:	1986	1991	1991	1994
Extended Life:	15	15	14	11
O&M first year:	$7	$8	$4	$4

Source: IR-OCA-2-21 IR-OCA-2-21 IR-OCA-2-22 PECo St15,I-840361, p.4-2

O&M Source: IR-OCA-2-23 IR-OCA-2-21 IR-OCA-2-22 (Weighted Average, Rich,Southw, Delaw)

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Notes Table 2.2:

1. $72 Million to extend Southwork starting 1/86, $34 for Richmond starting in 1991.
2. Cromby 2 and Schuylkill 1 Life Extension Capital Cost approximated from the engineering portion of this cost in 1985$ (PECo Statement 15, p.4-2) using the ratio of Delaware 7&8 Total Life Ext. Cost ($90 M) in 1989$, to the engineering portion ($62.7 M) in 1985$, and adjusting for further inflation at 6% per year to the starting year.
   O&M Approximations: Cromby 2 O&M cost in year t = Richmond 9 and Southwark 1 & 2 O&M in year (t-5) plus Delaware 7 & 8 O&M in year t per MW; inflated at 6%.
   Schuylkill 1 O&M cost in year t = Cromby 2 O&M cost in year (t-3) per MW; inflated at 6%.
3. PJM Cap. Charge from IR-OCA-2-25b,Item 9, p.1

TABLE 2.3: COST OF NEW COMBUSTION TURBINE CAPACITY AVOIDED BY LIMERICK 1

Year Added:	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	Total CT Capacity Added to Date MW [2]	O&M $/kW [3]	Total O&M ($Mill)	Total Cost of new CTs ($Mill)
Cost/kW [1]:	$382.7	$405.7	$430.0	$455.8	$483.2	$512.2	$542.9	$575.5	$610.0	$646.6				
MW Added:	0	122	0	74	101	75	75	533	75	0				
Total Cost: $Mill	0	$49.5	$0.0	$33.9	$48.6	$38.4	$40.7	$306.7	$45.7	0				
Carrying Charges ($Million): [4] in Year														
1990	0										0	$0.71	$0.00	$0.00
1991	0	$12.3									122	$0.75	$0.09	$12.35
1992	0	$11.5	$0.0								122	$0.80	$0.10	$11.59
1993	0	$10.8	$0.0	$8.4							196	$0.85	$0.17	$19.35
1994	0	$10.2	$0.0	$7.9	$12.0						297	$0.90	$0.27	$30.32
1995	0	$9.5	$0.0	$7.4	$11.3	$9.5					372	$0.95	$0.35	$38.05
1996	0	$8.9	$0.0	$7.0	$10.6	$8.9	$10.1				447	$1.01	$0.45	$45.89
1997	0	$8.3	$0.0	$6.5	$10.0	$8.4	$9.4	$75.9			980	$1.07	$1.05	$119.58
1998	0	$7.7	$0.0	$6.1	$9.3	$7.9	$8.9	$71.2	$11.3		1055	$1.13	$1.20	$123.54
1999	0	$7.0	$0.0	$5.7	$8.7	$7.4	$8.4	$66.8	$10.6	0	1055	$1.20	$1.27	$115.88
2000	0	$6.4	$0.0	$5.2	$8.1	$6.9	$7.8	$62.9	$10.0	0	1055	$1.28	$1.35	$108.75
2001	0	$6.2	$0.0	$4.8	$7.5	$6.4	$7.3	$59.0	$9.4	0	1055	$1.35	$1.43	$102.14
2002	0	$5.9	$0.0	$4.4	$6.9	$5.9	$6.8	$55.2	$8.8	0	1055	$1.43	$1.51	$95.47
2003	0	$5.7	$0.0	$4.2	$6.3	$5.5	$6.3	$51.3	$8.2	0	1055	$1.52	$1.60	$89.11
2004	0	$5.4	$0.0	$4.1	$6.1	$5.0	$5.8	$47.5	$7.7	0	1055	$1.61	$1.70	$83.11
2005	0	$5.1	$0.0	$3.9	$5.8	$4.8	$5.3	$43.6	$7.1	0	1055	$1.71	$1.80	$77.35
2006	0	$4.9	$0.0	$3.7	$5.6	$4.6	$5.1	$39.7	$6.5	0	1055	$1.81	$1.91	$71.95
2007	0	$4.6	$0.0	$3.5	$5.3	$4.4	$4.9	$38.4	$5.9	0	1055	$1.92	$2.02	$69.05
2008	0	$4.3	$0.0	$3.3	$5.0	$4.2	$4.7	$36.7	$5.7	0	1055	$2.03	$2.14	$66.16
2009	0	$4.1	$0.0	$3.1	$4.8	$4.0	$4.4	$35.1	$5.5	0	1055	$2.15	$2.27	$63.24
2010	0	$3.8	$0.0	$3.0	$4.5	$3.8	$4.2	$33.4	$5.2	0	1055	$2.28	$2.41	$60.32
2011	0	$3.5	$0.0	$2.8	$4.2	$3.6	$4.0	$31.8	$5.0	0	1055	$2.42	$2.55	$57.42
2012	0	$3.3	$0.0	$2.6	$4.0	$3.4	$3.8	$30.1	$4.7	0	1055	$2.57	$2.71	$54.53
2013	0	$3.0	$0.0	$2.4	$3.7	$3.1	$3.6	$28.4	$4.5	0	1055	$2.72	$2.87	$51.62
2014	0	$2.7	$0.0	$2.2	$3.5	$2.9	$3.3	$26.8	$4.2	0	1055	$2.88	$3.04	$48.77
2015	0	$2.4	$0.0	$2.0	$3.2	$2.7	$3.1	$25.2	$4.0	0	1055	$3.06	$3.22	$45.91
2016		$0.0	$0.0	$1.9	$2.9	$2.5	$2.9	$23.5	$3.8	0	1055	$3.24	$3.42	$40.85
2017			$0.0	$1.7	$2.7	$2.3	$2.7	$21.8	$3.5	0	1055	$3.43	$3.62	$38.27
2018				$0.0	$2.4	$2.1	$2.5	$20.2	$3.3	0	1055	$3.64	$3.84	$34.24
2019					$0.0	$1.9	$2.2	$18.5	$3.0	0	1055	$3.86	$4.07	$29.71
2020						$0.0	$2.0	$16.8	$2.8	0	1055	$4.09	$4.31	$25.92
2021							$0.0	$15.2	$2.5	0	1055	$4.33	$4.57	$22.24
2022								$0.0	$2.3	0	1055	$4.60	$4.85	$7.11
2023									$0.0	0	1055	$4.87	$5.14	$5.14
2024										0	1055	$5.16	$5.45	$5.45

Notes:
1. Attachment IR-OCA-19-11, Exh. App B4-18b. $215 M multiplied by 1.41 to escalate to 1986.
2. Assumes CTs continue to operate to end of Limerick 1 projected life.
3. Attachment IR-OCA-19-11, Exh. App B4-18b. $0.4 M multiplied by 1.41 to escalate to 1986.
4. CT annual cost (capital cost) expensed over 25 years using "% Carrying Charge Rate" from Attachment IR-UUC/UP-2-27(b).

TABLE 2.4: CAPACITY VALUE OF LIMERICK

Year	Total Cost Life Extensions $Million [1]	Fraction of Life Extension Attributable to Limerick 1 [2]	Total Cost Life Extensions Attributable to Limerick 1 $Million [3]	Total Cost New CTs $Million [4]	Total $Million [5]	PECo Cap. Charge x Shortfall after retirements, w/out Limerick $Million [6]	$Million [7]
1985	$3		0	$0.00	$0.00	$0.00	$0.00
1986	$37	1.00	$37.12	$0.00	$37.12	$42.04	$84.08
1987	$39	1.00	$39.18	$0.00	$39.18	$43.99	$87.99
1988	$37	1.00	$37.41	$0.00	$37.41	$48.61	$97.23
1989	$44	0.87	$38.08	$0.00	$38.08	$62.07	$124.15
1990	$44	0.87	$38.34	$0.00	$38.34	$69.40	$138.80
1991	$83	0.66	$54.82	$12.35	$67.18	$80.92	$161.84
1992	$81	0.66	$53.23	$11.59	$64.82	$85.77	$171.54
1993	$74	0.61	$44.80	$19.35	$64.15	$90.92	$181.84
1994	$87	0.48	$41.46	$30.32	$71.78	$96.37	$192.75
1995	$84	0.43	$36.30	$38.05	$74.35	$102.16	$204.31
1996	$82	0.38	$31.45	$45.89	$77.33	$108.29	$216.57
1997	$71	0.07	$4.70	$119.58	$124.29	$114.78	$229.57
1998	$67	0.00	$0.00	$123.54	$123.54	$121.67	$243.35
1999	$64			$115.88	$115.88	$128.97	$257.95
2000	$60			$108.75	$108.75	$132.50	$264.99
2001	$40			$102.14	$102.14	$144.93	$289.85
2002	$39			$95.47	$95.47	$153.62	$307.24
2003	$37			$89.11	$89.11	$162.84	$325.68
2004	$35			$83.11	$83.11	$172.61	$345.22
2005	$34			$77.35	$77.35	$182.97	$365.94
2006	$9			$71.95	$71.95	$193.95	$387.90
2007	$9			$69.05	$69.05	$205.59	$411.18
2008	$9			$66.16	$66.16	$217.92	$435.84
2009	$0			$63.24	$63.24	$230.99	$461.98
2010	$0			$60.32	$60.32	$244.85	$489.71
2011	$0			$57.42	$57.42	$259.55	$519.10
2012	$0			$54.53	$54.53	$275.12	$550.25
2013	$0			$51.62	$51.62	$291.63	$583.27
2014	$0			$48.77	$48.77	$309.14	$618.27
2015	$0			$45.91	$45.91	$327.68	$655.37
2016	$0			$40.85	$40.85	$347.35	$694.70
2017	$0			$38.27	$38.27	$368.18	$736.37
2018	$0			$34.24	$34.24	$390.28	$780.55
2019	$0			$29.71	$29.71	$413.70	$827.39
2020	$0			$25.92	$25.92	$438.52	$877.04
2021	$0			$22.24	$22.24	$464.83	$929.67
2022	$0			$7.11	$7.11	$492.73	$985.45
2023	$0			$5.14	$5.14	$522.29	$1,044.58
2024	$0			$5.45	$5.45	$553.62	$1,107.24

Notes:

1. See Table 2.2, sum of Life Extension Costs in $Million. Beginning in 1997, the cost of retaining the Richmond and Plymouth Combustion Turbines is excluded.
2. See Table 2.1, Column 7 divided by Col. "Total Extended Capacity"
3. [1] x [2]
4. See Table 2.3.
5. [3] + [4]
6. See Table 2.1, PECo Required Load x Capacity Charge

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TABLE 2.5: PECo FUEL AND AVOIDED COST PROJECTIONS

Year	#6, 1%S Oil PECo Estimated Price $/BBL	#6, 1%S Oil PECo Estimated Price $/MMBTU	PECo Avoided Cost $/kWh	Heat Rate At Which Oil Price = Avoided Cost Btu/kWh	Avoided Cost - Cogeneration Fuel at 5000 BTu/kWh current $/kWh	Avoided Cost - Cogeneration Fuel at 5000 BTu/kWh constant 1986$/kWh
	[1]	[2]	[3]	[4]	[5]	[6]
1986	$26.75	$4.25	$0.0384	9,022	$0.0171	$0.0171
1987	$28.90	$4.60	$0.0396	8,608	$0.0166	$0.0176
1988	$31.50	$5.01	$0.0415	8,291	$0.0165	$0.0185
1989	$34.30	$5.46	$0.0482	8,826	$0.0209	$0.0249
1990	$37.40	$5.95	$0.0572	9,613	$0.0274	$0.0346
1991	$40.80	$6.49	$0.0640	9,861	$0.0315	$0.0422
1992	$44.06	$7.01	$0.0723	10,321	$0.0373	$0.0529
1993	$47.59	$7.57	$0.0867	11,449	$0.0488	$0.0734
1994	$51.40	$8.18	$0.1093	13,373	$0.0684	$0.1091
1995	$55.51	$8.83	$0.1234	13,972	$0.0792	$0.1338
1996	$59.95	$9.54	$0.1438	15,086	$0.0962	$0.1722
1997	$64.74	$10.30	$0.1556	15,111	$0.1041	$0.1977
1998	$69.92	$11.12	$0.1580	14,207	$0.1024	$0.2060
1999	$75.52	$12.01	$0.1676	13,949	$0.1075	$0.2293
2000	$81.56	$12.97	$0.1801	13,884	$0.1153	$0.2606
2001	$88.08	$14.01	$0.1855	13,237	$0.1154	$0.2766
2002	$95.13	$15.13	$0.2280	15,071	$0.1524	$0.3871
2003	$102.74	$16.34	$0.2207	13,502	$0.1389	$0.3741
2004	$110.96	$17.65	$0.2481	14,055	$0.1598	$0.4561
2005	$119.84	$19.06	$0.2671	14,012	$0.1718	$0.5197
2006	$129.42	$20.59	$0.2845	13,820	$0.1816	$0.5823
2007	$139.78	$22.23	$0.3075	13,833	$0.1964	$0.6676
2008	$150.96	$24.01	$0.3509	14,613	$0.2308	$0.8318
2009	$163.04	$25.93	$0.3451	13,307	$0.2154	$0.8228
2010	$176.08	$28.01	$0.3943	14,080	$0.2543	$1.0297
2011	$190.17	$30.25	$0.4290	14,183	$0.2778	$1.1921
2012	$205.38	$32.67	$0.4478	13,707	$0.2844	$1.2940
2013	$221.81	$35.28	$0.4971	14,090	$0.3207	$1.5466
2014	$239.56	$38.10	$0.5651	14,831	$0.3746	$1.9148
2015	$258.72	$41.15	$0.5657	13,747	$0.3599	$1.9503
2016	$279.42	$44.44	$0.6553	14,744	$0.4331	$2.4874
2017	$301.77	$48.00	$0.7124	14,841	$0.4724	$2.8758
2018	$325.91	$51.84	$0.7118	13,731	$0.4526	$2.9208
2019	$351.99	$55.99	$0.7995	14,280	$0.5196	$3.5542
2020	$380.14	$60.47	$0.8856	14,647	$0.5833	$4.2295
2021	$410.56	$65.30	$0.9243	14,154	$0.5978	$4.5945
2022	$443.40	$70.53	$1.0611	15,045	$0.7084	$5.7719
2023	$478.87	$76.17	$1.1918	15,647	$0.8110	$7.0036
2024	$517.18	$82.26	$1.2558	15,266	$0.8445	$7.7305

Notes: 1. From IR-OCA-1-11b through 1991. Escalated at 8% thereafter (IR-OCA-15-8)
2. [1] divided by 6.287
3. Table 3.1, Column 6, $/MWH/1000
4. [3] / [2] x 1,000,000
5. [3] - [2] x 5,000/1,000,000
6. Deflated at 6%.

TABLE 2.6: NEPOOL NUCLEAR DATA

(A) OBJECTIVE CAPABILITY (MW) WITH NEW NUCLEAR UNITS

	Number of New Nuclear Units					
Year	0	1	2	3	4	5
81/82	21880	22445				
82/83	23127	23526	23924	24323		
83/84		24626	25047	25468	25889	
84/85			26035	26480	26925	27370

Source: 8/12/76 NEPOOL Executive Committee Minutes.

(B) DERIVATION OF NUCLEAR FIRM LOAD CARRYING CAPACITY

Year	Increase In Reserve Per Nuclear Unit (MW)	Nuclear Reduction In Other Capacity Req. (MW)	Firm Load Carried (MW)	Ratio of Firm Load to Nuclear Capacity
	[1]	[2]	[3]	[4]
81/82	565	585	504.3	0.44
82/83	398.7	751.3	647.7	0.56
83/84	421	729	628.4	0.55
84/85	445	705	607.8	0.53
Average				0.52

Notes: 1. Calculated from data in part (A) above.

2. 1150-[1].

3. [2]/1.16; 16% reserves required for 1981/82 and 82/83 with no new nuclear capacity, from 6/24/76 NEPOOL Executive Committee minutes.

4. [3]/1150.

TABLE 2.7: EFFECTIVE LOAD CARRYING CAPABILITY

	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%		
	1055	800	25.0%	791.25	637.74	60.4%	80.6%		
	1055	800	27.5%	764.88	605.87	57.4%	79.2%	1.000	
	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%	1.240	
	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%	1.596	
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%	1.204	
	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%	1.210	1.227
	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%	1.266	
	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%	1.412	
									1.362
Delaware 8	124	800	23.3% [5]	95.11	93.34	75.3%	98.1%	1.311	
Cromby 2	201	800	16.8% [5]	167.23	163.50	81.3%	97.8%	1.416	
Schuylkill 1	166	800	24.2% [5]	125.83	122.56	73.8%	97.4%	1.286	

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 2.8 (a): CALCULATION OF CAPACITY ALTERNATIVES TO LIMERICK 1

All Capacity in terms of Effective Reliability of Limerick 1 MegaWatts, except where noted "Rated MW".

in Year	PECo Load Proj.	Required Reserve % of Load	Load + Reserve [1]	Capacity After PECo Retirements without Limerick	Shortfall [2]	Life Extension [3] Effective Reliability Capacity: R 9 & S 1&2	D 7&8	CTs	Cr 2	Sch 1	Total Extended Capacity	Shortfall after Extension [4]	Previous Added Capacity [5] (Rated MW)	New CTs Added to Replace Limerick 1 [6] (Rated MW)	Life Extension Capacity Attributable to Limerick 1 [7]
1986	6160	22.50%	7546	6803	743	618		568			1186	-443	0	0	1,055
1987	6180	21.90%	7533	6803	730	618		568			1186	-456	0	0	1,055
1988	6200	22.00%	7564	6803	761	618		568			1186	-425	0	0	1,055
1989	6220	23.80%	7700	6791	909	618	345	568			1531	-622	0	0	1,055
1990	6240	24.20%	7750	6791	959	618	345	568			1531	-572	0	0	1,055
1991	6260	25.80%	7875	6337	1538	618	345	568	285		1816	-277	0	0	1,055
1992	6320	23.80%	7824	6337	1487	618	345	568	285		1816	-328	0	0	1,055
1993	6380	24.60%	7949	6337	1612	618	345	568	285		1816	-203	0	0	1,055
1994	6440	25.00%	8050	6168	1882	618	345	568	285	217	2033	-151	0	0	1,055
1995	6500	25.00%	8125	6168	1957	618	345	568	285	217	2033	-76	0	0	1,055
1996	6560	25.00%	8200	6168	2032	618	345	568	285	217	2033	-1	0	0	1,055
1997	6620	25.00%	8275	6168	2107	618	345		285	217	1465	642	0	402	413
1998	6700	25.00%	8375	6168	2207	618	345		285	217	1465	742	402	63	313
1999	6780	25.00%	8475	6168	2307	618	345		285	217	1465	842	465	63	213
2000	6860	25.00%	8575	6168	2407	618	345		285	217	1465	942	528	63	113
2001	6940	25.00%	8675	6168	2507	618	345		285	217	1465	1042	590	63	13
2002	7020	25.00%	8775	6168	2607	618	345		285	217	1465	1055	653	8	0
2003	7100	25.00%	8875	6168	2707	618	345		285	217	1465	1055	661	0	0
2004	7180	25.00%	8975	6168	2807	618	345		285	217	1465	1055	661	0	0
2005							345		285	217	847		661		
2006							345		285	217	847				
2007										217	217				
2008										217	217				

Notes: All data from Tables 2.1 and 2.7.

1. PECo Load + % Reserve.
2. Load + Reserve Required less Capacity after retirements and without Limerick.
3. Scheduled Retirements include the following plants with or without Diesels: R 9 = Richmond 9 (166 MW), S 1& 2 = Southwark 1 & 2 (+Diesel, 338 MW), D 7&8 = Delaware 7 & 8 (+Diesel, 253 MW), CTs = Combustion Turbines (458 MW), Cr 2 = Cromby 2 (201 MW), Sch 1= Schuylkill 1 (+Diesel, 169 MW). Rated MW were converted to Effective Reliability of Limerick 1 MegaWatts using ELCC ratios calculated in Table 2.7.
4. Shortfall capped at 1055, to limit this calculation to replacement of Limerick only.
5. In Rated MegaWatts, cumulative capacity added up to current year.
6. In Rated MegaWatts, capacity needed to cover shortfall.

TABLE 2.8 (b): COST OF NEW COMBUSTION TURBINE CAPACITY, TO PROVIDE LIMERICK 1 RELIABILITY

Year Added:	1996	1997	1998	1999	2000	2001	2002	2003	Total CT Capacity Added to Date Rated MW	O&M $/kW	Total O&M ($Mill)	Total Cost of new CTs ($Mill)
Cost/kW [1]:	$542.9	$575.5	$610.0	$646.6	$685.4	$726.5	$770.1	$816.3				
MW Added:	0	402	63	63	63	63	8	0				
Total Cost: $Mill	0.0	231.5	38.2	40.5	42.9	45.5	6.2	.0				
Carrying Charges ($/kW): in Year												
1990									0	$0.71	$0.00	$0.00
1991									0	$0.75	$0.00	$0.00
1992									0	$0.80	$0.00	$0.00
1993									0	$0.85	$0.00	$0.00
1994									0	$0.90	$0.00	$0.00
1995									0	$0.95	$0.00	$0.00
1996	0.0								0	$1.01	$0.00	$0.00
1997	0.0	57.3							402	$1.07	$0.43	$57.75
1998	0.0	53.7	9.5						465	$1.13	$0.53	$63.70
1999	0.0	50.4	8.9	10.0					528	$1.20	$0.63	$69.95
2000	0.0	47.5	8.3	9.4	10.6				590	$1.28	$0.75	$76.59
2001	0.0	44.6	7.8	8.8	10.0	11.3			653	$1.35	$0.88	$83.34
2002	0.0	41.6	7.4	8.3	9.4	10.6	1.5		661	$1.43	$0.95	$79.72
2003	0.0	38.7	6.9	7.8	8.8	9.9	1.4	0	661	$1.52	$1.00	$74.58
2004	0.0	35.8	6.4	7.3	8.3	9.3	1.4	0	661	$1.61	$1.06	$69.52
2005	0.0	32.9	5.9	6.8	7.7	8.8	1.3	0	661	$1.71	$1.13	$64.46
2006	0.0	30.0	5.4	6.3	7.2	8.2	1.2	0	661	$1.81	$1.20	$59.45
2007	0.0	29.0	4.9	5.8	6.6	7.6	1.1	0	661	$1.92	$1.27	$56.36
2008	0.0	27.7	4.8	5.2	6.1	7.0	1.0	0	661	$2.03	$1.34	$53.30
2009	0.0	26.5	4.6	5.1	5.6	6.5	1.0	0	661	$2.15	$1.42	$50.56
2010	0.0	25.2	4.4	4.9	5.4	5.9	0.9	0	661	$2.28	$1.51	$48.13
2011	0.0	24.0	4.2	4.6	5.1	5.7	0.8	0	661	$2.42	$1.60	$46.04
2012	0.0	22.7	4.0	4.4	4.9	5.5	0.8	0	661	$2.57	$1.70	$43.95
2013	0.0	21.5	3.8	4.2	4.7	5.2	0.7	0	661	$2.72	$1.80	$41.85
2014	0.0	20.2	3.5	4.0	4.4	5.0	0.7	0	661	$2.88	$1.91	$39.79
2015	0.0	19.0	3.3	3.8	4.2	4.7	0.7	0	661	$3.06	$2.02	$37.71
2016	0.0	17.7	3.1	3.5	4.0	4.5	0.6	0	661	$3.24	$2.14	$35.62
2017	0.0	16.5	2.9	3.3	3.8	4.2	0.6	0	661	$3.43	$2.27	$33.56
2018	0.0	15.2	2.7	3.1	3.5	4.0	0.6	0	661	$3.64	$2.41	$31.53
2019	0.0	14.0	2.5	2.9	3.3	3.7	0.5	0	661	$3.86	$2.55	$29.47
2020	0.0	12.7	2.3	2.7	3.1	3.5	0.5	0	661	$4.09	$2.70	$27.43
2021	0	11.4	2.1	2.4	2.8	3.2	0.5	0	661	$4.33	$2.87	$25.38
2022		0	1.9	2.2	2.6	3.0	0.4	0	661	$4.60	$3.04	$13.18
2023			0	2.0	2.4	2.7	0.4	0	661	$4.87	$3.22	$10.73
2024				0.0	2.1	2.5	0.4	0	661	$5.16	$3.41	$8.41
2025					0.0	2.2	0.3	0	661	$5.47	$3.62	$6.21
2026						0.0	0.3	0	661	$5.80	$3.83	$4.14
2027							0.0	0	661	$6.15	$4.06	$4.06
2028								0	661	$6.52	$4.31	$4.31

TABLE 2.8 (c): CAPACITY VALUE OF LIMERICK

Costs in terms of Effective Reliability of Limerick 1 MegaWatts

Year	Total Cost Life Extensions $Million [1]	Fraction of Life Extension attributable to Limerick 1 [2]	Total Cost Life Extensions attributable to Limerick 1 $Million [3]	Total Cost New CTs $Million [4]	Total $Million [5]	PECo Cap. Charge x Shortfall after retirements, w/out Limerick $Million [6]	$Million [7]
1985	$3		0	$0.00	$0.00	$0.00	$0.00
1986	$37	0.89	$33.01	$0.00	$33.01	$42.04	$84.08
1987	$39	0.89	$34.84	$0.00	$34.84	$43.99	$87.99
1988	$37	0.89	$33.27	$0.00	$33.27	$48.61	$97.23
1989	$44	0.69	$30.22	$0.00	$30.22	$62.07	$124.15
1990	$44	0.69	$30.43	$0.00	$30.43	$69.40	$138.80
1991	$84	0.58	$48.65	$0.00	$48.65	$80.92	$161.84
1992	$81	0.58	$47.23	$0.00	$47.23	$85.77	$171.54
1993	$74	0.58	$43.20	$0.00	$43.20	$90.92	$181.84
1994	$86	0.52	$44.60	$0.00	$44.60	$96.37	$192.75
1995	$84	0.52	$43.79	$0.00	$43.79	$102.16	$204.31
1996	$82	0.52	$42.61	$0.00	$42.61	$108.29	$216.57
1997	$71	0.28	$19.96	$57.75	$77.71	$114.78	$229.57
1998	$68	0.21	$14.43	$63.70	$78.13	$121.67	$243.35
1999	$64	0.15	$9.28	$69.95	$79.24	$128.97	$257.95
2000	$60	0.08	$4.65	$76.59	$81.24	$132.50	$264.99
2001	$40	0.01	$0.36	$83.34	$83.70	$144.93	$289.85
2002	$39	.00	$.00	$79.72	$79.72	$153.62	$307.24
2003	$37	.00	$.00	$74.58	$74.58	$162.84	$325.68
2004	$35	.00	$.00	$69.52	$69.52	$172.61	$345.22
2005	$34	0.00	$0.00	$64.46	$64.46	$182.97	$365.94
2006	$9			$59.45	$59.45	$193.95	$387.90
2007	$9			$56.36	$56.36	$205.59	$411.18
2008	$9			$53.30	$53.30	$217.92	$435.84
2009	$0			$50.56	$50.56	$230.99	$461.98
2010	$0			$48.13	$48.13	$244.85	$489.71
2011	$0			$46.04	$46.04	$259.55	$519.10
2012	$0			$43.95	$43.95	$275.12	$550.25
2013	$0			$41.85	$41.85	$291.63	$583.27
2014	$0			$39.79	$39.79	$309.14	$618.27
2015	$0			$37.71	$37.71	$327.68	$655.37
2016	$0			$35.62	$35.62	$347.35	$694.70
2017	$0			$33.56	$33.56	$368.18	$736.37
2018	$0			$31.53	$31.53	$390.28	$780.55
2019	$0			$29.47	$29.47	$413.70	$827.39
2020	$0			$27.43	$27.43	$438.52	$877.04
2021	$0			$25.38	$25.38	$464.83	$929.67
2022	$0			$13.18	$13.18	$492.73	$985.45
2023	$0			$10.73	$10.73	$522.29	$1,044.58
2024	$0			$8.41	$8.41	$553.62	$1,107.24

Notes:

1. Same as in Table 2.4, sum of Life Extension Costs from Table 2.2 in $Million. Beginning in 1997, the cost of retaining the Richmond and Plymouth Combustion Turbines is excluded.
2. See Table 2.1, Column 7 divided by Col. "Total Extended Capacity"
3. [1] x [2]
4. See Table 2.3.
5. [3] + [4]
6. See Table 2.1, PECo Required Load x Capacity Charge

TABLE 3.1: PECO PROJECTIONS OF LIMERICK 1 SAVINGS AND CAPACITY FACTOR

YEAR	FUEL SAVINGS ($ million)	GENERATION MWH	FUEL SAVINGS ($/MWH)	LIMERICK 1 FUEL COST ($ million)	LIMERICK 1 FUEL ($/MWH)	COST OF AVOIDED ENERGY ($/MWH)	LIMERICK 1 CAPACITY FACTOR
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1986	$151	5245600	$29	$51	$10	$38	56.8%
1987	$186	5699100	$33	$39	$7	$40	61.7%
1988	$209	5764600	$36	$30	$5	$42	62.4%
1989	$322	7522300	$43	$40	$5	$48	81.4%
1990	$282	5460700	$52	$30	$5	$57	59.1%
1991	$321	5543100	$58	$34	$6	$64	60.0%
1992	$480	7281800	$66	$47	$6	$72	78.8%
1993	$423	5342500	$79	$40	$7	$87	57.8%
1994	$561	5524100	$102	$43	$8	$109	59.8%
1995	$843	7334400	$115	$62	$8	$123	79.4%
1996	$735	5450000	$135	$49	$9	$144	59.0%
1997	$799	5471300	$146	$52	$9	$156	59.2%
1998	$1,073	7252100	$148	$73	$10	$158	78.5%
1999	$834	5321400	$157	$57	$11	$168	57.6%
2000	$979	5804600	$169	$66	$11	$180	62.8%
2001	$1,256	7241600	$173	$87	$12	$185	78.4%
2002	$1,176	5462800	$215	$70	$13	$228	59.1%
2003	$1,158	5593600	$207	$76	$14	$221	60.5%
2004	$1,684	7203800	$234	$103	$14	$248	77.9%
2005	$1,377	5469100	$252	$84	$15	$267	59.2%
2006	$1,502	5597800	$268	$91	$16	$284	60.6%
2007	$2,085	7178400	$290	$123	$17	$308	77.7%
2008	$1,827	5492600	$333	$100	$18	$351	59.4%
2009	$1,823	5598000	$326	$109	$19	$345	60.6%
2010	$2,685	7178500	$374	$146	$20	$394	77.7%
2011	$2,227	5469100	$407	$120	$22	$429	59.2%
2012	$2,386	5621100	$425	$131	$23	$448	60.8%
2013	$3,393	7178200	$473	$175	$24	$497	77.7%
2014	$2,947	5467200	$539	$143	$26	$565	59.2%
2015	$3,011	5598000	$538	$155	$28	$566	60.6%
2016	$4,511	7203800	$626	$209	$29	$655	77.9%
2017	$3,726	5471300	$681	$171	$31	$712	59.2%
2018	$3,798	5595800	$679	$185	$33	$712	60.5%
2019	$5,489	7178200	$765	$250	$35	$800	77.7%
2020	$4,659	5492400	$848	$206	$37	$886	59.4%
2021	$4,950	5595900	$885	$222	$40	$924	60.5%
2022	$7,319	7178400	$1,020	$298	$42	$1,061	77.7%
2023	$6,276	5471300	$1,147	$245	$45	$1,192	59.2%
2024	$6,789	5619000	$1,208	$267	$48	$1,256	60.8%

Notes 1. From Attachment IR-OCA-2-25b, Item 1, page 1, col. 6
2. From Attachment IR-OCA-2-25b, Item 2, page 1, col. 2
3. (Column [1]/Column [2])*1,000,000
4. From Attachment IR-OCA-2-25b, Item 2, page 2, col. 1
5. (Column [4]/Column [2])/1,000,000
6. Columns [3] + [5]
7. Column [2](/1055*no# hours in a year(8760 or 8784 if leap year)).

TABLE 3.2: LIMERICK 1 RATE IMPACT, Case 1: PECo Assumptions
($ million)

YEAR	TOTAL COSTS	TOTAL BENEFITS	BENEFITS LESS COSTS	RUNNING TOTAL	DISCOUNTED TOTALS AT: 10%	15%	20%
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1986	$858	$231	($626)	($626)	($569)	($544)	($522)
1987	$831	$275	($556)	($1,182)	($1,029)	($965)	($908)
1988	$812	$307	($505)	($1,687)	($1,408)	($1,297)	($1,200)
1989	$801	$466	($335)	($2,022)	($1,637)	($1,488)	($1,362)
1990	$780	$435	($345)	($2,367)	($1,851)	($1,660)	($1,500)
1991	$765	$483	($282)	($2,649)	($2,010)	($1,782)	($1,595)
1992	$751	$652	($99)	($2,748)	($2,061)	($1,819)	($1,622)
1993	$736	$608	($128)	($2,876)	($2,121)	($1,861)	($1,652)
1994	$717	$756	$40	($2,836)	($2,104)	($1,849)	($1,644)
1995	$717	$1,050	$333	($2,503)	($1,975)	($1,767)	($1,590)
1996	$710	$954	$245	($2,258)	($1,889)	($1,714)	($1,558)
1997	$713	$1,032	$319	($1,939)	($1,788)	($1,655)	($1,522)
1998	$728	$1,319	$592	($1,347)	($1,616)	($1,559)	($1,466)
1999	$719	$1,096	$377	($970)	($1,517)	($1,505)	($1,437)
2000	$728	$1,256	$528	($443)	($1,391)	($1,441)	($1,403)
2001	$745	$1,549	$804	$361	($1,216)	($1,355)	($1,359)
2002	$739	$1,487	$747	$1,108	($1,068)	($1,285)	($1,326)
2003	$749	$1,488	$739	$1,847	($935)	($1,226)	($1,298)
2004	$774	$2,034	$1,259	$3,106	($729)	($1,137)	($1,259)
2005	$769	$1,748	$978	$4,085	($584)	($1,077)	($1,233)
2006	$783	$1,895	$1,111	$5,196	($434)	($1,018)	($1,209)
2007	$814	$2,501	$1,688	$6,883	($226)	($940)	($1,178)
2008	$812	$2,268	$1,456	$8,339	($64)	($882)	($1,156)
2009	$831	$2,291	$1,460	$9,800	$84	($831)	($1,138)
2010	$870	$3,181	$2,310	$12,110	$298	($761)	($1,114)
2011	$870	$2,752	$1,882	$13,992	$456	($711)	($1,097)
2012	$895	$2,943	$2,048	$16,041	$612	($664)	($1,082)
2013	$944	$3,984	$3,040	$19,080	$823	($603)	($1,064)
2014	$947	$3,572	$2,625	$21,706	$988	($557)	($1,051)
2015	$980	$3,675	$2,695	$24,401	$1,143	($517)	($1,039)
2016	$1,037	$5,214	$4,177	$28,578	$1,360	($462)	($1,025)
2017	$1,040	$4,471	$3,432	$32,010	$1,523	($423)	($1,015)
2018	$1,081	$4,587	$3,506	$35,516	$1,674	($388)	($1,006)
2019	$1,159	$6,326	$5,167	$40,683	$1,876	($343)	($996)
2020	$1,178	$5,546	$4,367	$45,051	$2,031	($310)	($988)
2021	$1,245	$5,890	$4,645	$49,695	$2,182	($280)	($982)
2022	$1,366	$8,315	$6,948	$56,643	$2,386	($241)	($973)
2023	$1,439	$7,332	$5,893	$62,536	$2,544	($212)	($968)
2024	$1,645	$7,908	$6,263	$68,799	$2,696	($185)	($963)

Notes: 1. Attachment IR-OCA-2-25b, Item 1, page 1, col. 4
2. Attachment IR-OCA-2-25b, Item 1, page 1, col. 8
3. Attachment IR-OCA-2-25b, Item 1, page 1, col. 9

TABLE 3.3: LIMERICK 1 RATE IMPACT, Case 2: Total Requested Cost
($ million)

	ORIG COST & ADDITIONS			TOTAL COSTS				DISCOUNTED TOTALS AT:		
YEAR	CARRYING CHARGES	STATION O&M	OTHER O&M	(4)=(1)+(2)+(3)	TOTAL BENEFITS	NET BENEFITS	RUNNING TOTAL	10%	15%	20%
----	--------	-------	------	----------	--------	--------	-------	---	---	---
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
1986	$898	$79	$31	$1,008	$231	($776)	($776)	($706)	($675)	($647)
1987	$857	$85	$32	$974	$275	($699)	($1,476)	($1,284)	($1,204)	($1,133)
1988	$823	$93	$33	$949	$307	($642)	($2,118)	($1,766)	($1,626)	($1,504)
1989	$792	$101	$40	$933	$466	($467)	($2,584)	($2,085)	($1,893)	($1,729)
1990	$761	$111	$34	$906	$435	($470)	($3,055)	($2,377)	($2,127)	($1,918)
1991	$731	$117	$37	$885	$483	($402)	($3,457)	($2,604)	($2,301)	($2,053)
1992	$700	$124	$41	$866	$652	($214)	($3,671)	($2,714)	($2,381)	($2,113)
1993	$670	$132	$44	$845	$608	($238)	($3,909)	($2,825)	($2,459)	($2,168)
1994	$640	$140	$41	$820	$756	($64)	($3,973)	($2,852)	($2,477)	($2,180)
1995	$610	$148	$58	$815	$1,050	$235	($3,737)	($2,761)	($2,419)	($2,142)
1996	$601	$157	$48	$806	$954	$149	($3,589)	($2,709)	($2,387)	($2,122)
1997	$589	$166	$52	$807	$1,032	$226	($3,363)	($2,637)	($2,345)	($2,097)
1998	$577	$176	$65	$819	$1,319	$501	($2,863)	($2,492)	($2,263)	($2,050)
1999	$566	$187	$55	$807	$1,096	$288	($2,574)	($2,416)	($2,223)	($2,028)
2000	$555	$198	$62	$814	$1,256	$442	($2,133)	($2,311)	($2,168)	($1,999)
2001	$544	$210	$76	$829	$1,549	$720	($1,413)	($2,154)	($2,091)	($1,960)
2002	$533	$222	$65	$820	$1,487	$666	($746)	($2,022)	($2,030)	($1,930)
2003	$522	$236	$70	$828	$1,488	$660	($86)	($1,903)	($1,976)	($1,905)
2004	$512	$250	$88	$850	$2,034	$1,184	$1,097	($1,710)	($1,893)	($1,868)
2005	$502	$265	$76	$843	$1,748	$905	$2,002	($1,575)	($1,838)	($1,845)
2006	$492	$281	$82	$854	$1,895	$1,040	$3,042	($1,435)	($1,783)	($1,822)
2007	$483	$298	$102	$882	$2,501	$1,619	$4,662	($1,236)	($1,708)	($1,793)
2008	$474	$315	$89	$878	$2,268	$1,390	$6,052	($1,081)	($1,652)	($1,772)
2009	$465	$334	$95	$894	$2,291	$1,397	$7,449	($939)	($1,603)	($1,754)
2010	$457	$354	$120	$931	$3,181	$2,249	$9,698	($731)	($1,535)	($1,731)
2011	$449	$376	$104	$928	$2,752	$1,824	$11,522	($578)	($1,487)	($1,715)
2012	$441	$398	$111	$951	$2,943	$1,993	$13,515	($426)	($1,441)	($1,700)
2013	$434	$422	$141	$998	$3,984	$2,986	$16,501	($219)	($1,381)	($1,682)
2014	$428	$447	$122	$998	$3,572	$2,575	$19,076	($57)	($1,336)	($1,669)
2015	$423	$474	$131	$1,028	$3,675	$2,647	$21,722	$95	($1,296)	($1,658)
2016	$413	$503	$166	$1,082	$5,214	$4,132	$25,854	$310	($1,242)	($1,644)
2017	$406	$533	$143	$1,083	$4,471	$3,389	$29,243	$471	($1,203)	($1,634)
2018	$403	$565	$154	$1,122	$4,587	$3,465	$32,708	$620	($1,169)	($1,625)
2019	$403	$599	$195	$1,197	$6,326	$5,129	$37,837	$821	($1,125)	($1,615)
2020	$409	$635	$170	$1,214	$5,546	$4,332	$42,169	$975	($1,092)	($1,607)
2021	$423	$673	$182	$1,278	$5,890	$4,611	$46,780	$1,124	($1,062)	($1,601)
2022	$452	$713	$232	$1,397	$8,315	$6,918	$53,698	$1,327	($1,023)	($1,593)
2023	$510	$756	$201	$1,467	$7,332	$5,865	$59,562	$1,484	($994)	($1,587)
2024	$653	$801	$216	$1,671	$7,908	$6,237	$65,799	$1,636	($967)	($1,582)

[1] Appendix D-1, from Attachment IR-OCA-2-25b, Item 3,
page 4, col. 5
[2] Attachment IR-OCA-2-25b, Item 1, page 1, col. 2
[3] Attachment IR-OCA-2-25b, Item 1, page 1, col. 3
[4] Columns [1]+[2]+[3]
[5] Attachment IR-OCA-2-25b, Item 1, page 1, col. 8
[6] Column [5] - Column [4]

TABLE 3.4: LIMERICK 1 RATE IMPACT, Case 3a: Historical Capacity Factors, Realistic Capacity Costs
($ million)

YEAR	TOTAL COSTS	ACID RAIN SAVINGS	FUEL SAVINGS	CAPACITY COSTS AVOIDED	TOTAL BENEFITS	NET BENEFITS	RUNNING TOTAL	DISCOUNTED TOTALS AT: 10%	15%	20%
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1986	$1,008	$0	$130	$37	$168	($840)	($840)	($764)	($731)	($700)
1987	$974	$0	$124	$39	$163	($811)	($1,651)	($1,434)	($1,344)	($1,263)
1988	$949	$0	$150	$37	$187	($761)	($2,413)	($2,006)	($1,845)	($1,704)
1989	$933	$0	$236	$38	$274	($659)	($3,072)	($2,456)	($2,221)	($2,022)
1990	$906	$0	$246	$38	$285	($621)	($3,693)	($2,842)	($2,530)	($2,271)
1991	$885	$0	$285	$68	$353	($532)	($4,225)	($3,142)	($2,760)	($2,450)
1992	$866	$0	$396	$65	$461	($405)	($4,630)	($3,350)	($2,912)	($2,563)
1993	$845	$3	$390	$64	$457	($388)	($5,018)	($3,531)	($3,039)	($2,653)
1994	$820	$3	$500	$72	$575	($246)	($5,263)	($3,635)	($3,109)	($2,701)
1995	$815	$2	$688	$74	$765	($50)	($5,314)	($3,655)	($3,121)	($2,709)
1996	$806	$3	$666	$77	$746	($59)	($5,373)	($3,675)	($3,134)	($2,717)
1997	$807	$3	$720	$124	$847	$40	($5,333)	($3,663)	($3,127)	($2,712)
1998	$819	$2	$886	$124	$1,012	$193	($5,140)	($3,607)	($3,095)	($2,694)
1999	$807	$4	$772	$116	$892	$84	($5,056)	($3,585)	($3,083)	($2,688)
2000	$814	$3	$833	$109	$945	$131	($4,925)	($3,553)	($3,067)	($2,679)
2001	$829	$2	$1,038	$102	$1,143	$314	($4,611)	($3,485)	($3,034)	($2,662)
2002	$820	$3	$1,060	$95	$1,159	$339	($4,272)	($3,418)	($3,002)	($2,647)
2003	$828	$4	$1,020	$89	$1,113	$285	($3,987)	($3,367)	($2,979)	($2,636)
2004	$850	$3	$1,404	$83	$1,490	$640	($3,348)	($3,262)	($2,934)	($2,616)
2005	$843	$5	$1,240	$77	$1,322	$479	($2,869)	($3,191)	($2,905)	($2,604)
2006	$854	$5	$1,321	$72	$1,398	$544	($2,325)	($3,117)	($2,876)	($2,592)
2007	$882	$4	$1,739	$69	$1,812	$930	($1,395)	($3,003)	($2,833)	($2,575)
2008	$878	$6	$1,642	$66	$1,714	$836	($559)	($2,910)	($2,800)	($2,562)
2009	$894	$6	$1,604	$63	$1,673	$779	$220	($2,831)	($2,772)	($2,552)
2010	$931	$5	$2,239	$60	$2,304	$1,373	$1,593	($2,704)	($2,731)	($2,538)
2011	$928	$7	$2,005	$57	$2,069	$1,141	$2,733	($2,608)	($2,701)	($2,528)
2012	$951	$7	$2,096	$55	$2,158	$1,207	$3,940	($2,516)	($2,673)	($2,519)
2013	$998	$6	$2,830	$52	$2,887	$1,890	$5,830	($2,385)	($2,635)	($2,508)
2014	$998	$8	$2,654	$49	$2,710	$1,713	$7,543	($2,277)	($2,605)	($2,499)
2015	$1,028	$8	$2,649	$46	$2,703	$1,675	$9,218	($2,181)	($2,580)	($2,492)
2016	$1,082	$6	$3,759	$41	$3,807	$2,724	$11,942	($2,039)	($2,544)	($2,483)
2017	$1,083	$9	$3,354	$38	$3,401	$2,318	$14,260	($1,930)	($2,518)	($2,476)
2018	$1,122	$9	$3,342	$34	$3,385	$2,263	$16,523	($1,832)	($2,495)	($2,470)
2019	$1,197	$7	$4,578	$30	$4,615	$3,418	$19,941	($1,698)	($2,466)	($2,463)
2020	$1,214	$10	$4,188	$26	$4,224	$3,011	$22,952	($1,591)	($2,443)	($2,458)
2021	$1,278	$10	$4,356	$22	$4,388	$3,110	$26,062	($1,491)	($2,423)	($2,454)
2022	$1,397	$8	$6,104	$7	$6,119	$4,722	$30,784	($1,352)	($2,396)	($2,448)
2023	$1,467	$12	$5,649	$5	$5,665	$4,198	$34,982	($1,239)	($2,375)	($2,444)
2024	$1,671	$12	$5,966	$5	$5,983	$4,312	$39,295	($1,135)	($2,357)	($2,441)

Notes:
[1] Column [4] from Table 3.3
[2] Attachment IR-OCA-2-25b, Item 1, page 1, col. 5 multiplied by the average in Table 4.3 divided by Column [7] in Table 3.1.
[3] Attachment IR-OCA-2-25b, Item 1, page 1, col. 6 multiplied by the average in Table 4.3 divided by Column [7] in Table 3.1.
[4] Table 2.4, Column [5], Total $Million
[5] Columns [2]+[3]+[4]
[6] Columns [5]-[1]

TABLE 3.5: LIMERICK 1 RATE IMPACT, Case 3b: OCA Inputs
($ million)

YEAR	TOTAL COSTS	FUEL SAVINGS	AVOIDED CAPACITY COSTS	TOTAL BENEFITS	NET BENEFITS	RUNNING TOTAL	DISCOUNTED TOTALS AT: 10%	15%	20%
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
1986	$1,008	$195	$37	$232	($776)	($776)	($705)	($674)	($646)
1987	$974	$178	$39	$217	($757)	($1,533)	($1,331)	($1,247)	($1,172)
1988	$949	$199	$37	$236	($712)	($2,245)	($1,866)	($1,715)	($1,584)
1989	$933	$288	$38	$326	($607)	($2,852)	($2,281)	($2,062)	($1,877)
1990	$906	$240	$38	$278	($627)	($3,479)	($2,670)	($2,374)	($2,129)
1991	$885	$274	$68	$342	($543)	($4,023)	($2,977)	($2,609)	($2,311)
1992	$866	$392	$65	$457	($409)	($4,431)	($3,186)	($2,763)	($2,425)
1993	$845	$347	$64	$411	($434)	($4,865)	($3,389)	($2,905)	($2,526)
1994	$820	$510	$72	$582	($238)	($5,104)	($3,490)	($2,972)	($2,572)
1995	$815	$749	$74	$823	$8	($5,095)	($3,487)	($2,970)	($2,571)
1996	$806	$622	$77	$699	($106)	($5,201)	($3,524)	($2,993)	($2,585)
1997	$807	$688	$124	$812	$6	($5,196)	($3,522)	($2,992)	($2,585)
1998	$819	$921	$124	$1,045	$226	($4,970)	($3,457)	($2,955)	($2,563)
1999	$807	$708	$116	$824	$16	($4,953)	($3,452)	($2,953)	($2,562)
2000	$814	$788	$109	$897	$83	($4,871)	($3,433)	($2,943)	($2,557)
2001	$829	$1,002	$102	$1,104	$275	($4,596)	($3,373)	($2,913)	($2,542)
2002	$820	$985	$95	$1,080	$260	($4,336)	($3,321)	($2,889)	($2,530)
2003	$828	$966	$89	$1,055	$227	($4,108)	($3,280)	($2,871)	($2,522)
2004	$850	$1,407	$83	$1,490	$640	($3,468)	($3,176)	($2,826)	($2,502)
2005	$843	$1,114	$77	$1,191	$349	($3,120)	($3,124)	($2,805)	($2,493)
2006	$854	$1,234	$72	$1,306	$452	($2,668)	($3,063)	($2,781)	($2,483)
2007	$882	$1,701	$69	$1,770	$888	($1,780)	($2,954)	($2,740)	($2,467)
2008	$878	$1,429	$66	$1,495	$617	($1,163)	($2,885)	($2,715)	($2,457)
2009	$894	$1,491	$63	$1,554	$660	($503)	($2,818)	($2,692)	($2,449)
2010	$931	$2,140	$60	$2,200	$1,269	$766	($2,701)	($2,653)	($2,436)
2011	$928	$1,811	$57	$1,868	$940	$1,706	($2,622)	($2,628)	($2,428)
2012	$951	$1,948	$55	$2,003	$1,052	$2,758	($2,542)	($2,604)	($2,420)
2013	$998	$2,797	$52	$2,849	$1,851	$4,609	($2,413)	($2,567)	($2,409)
2014	$998	$2,404	$49	$2,453	$1,455	$6,064	($2,322)	($2,542)	($2,401)
2015	$1,028	$2,497	$46	$2,543	$1,515	$7,579	($2,235)	($2,519)	($2,395)
2016	$1,082	$3,646	$41	$3,687	$2,605	$10,184	($2,099)	($2,485)	($2,386)
2017	$1,083	$3,075	$38	$3,113	$2,031	$12,214	($2,003)	($2,462)	($2,380)
2018	$1,122	$3,205	$34	$3,239	$2,117	$14,331	($1,912)	($2,441)	($2,375)
2019	$1,197	$4,494	$30	$4,524	$3,327	$17,658	($1,782)	($2,412)	($2,368)
2020	$1,214	$3,919	$26	$3,945	$2,731	$20,389	($1,684)	($2,391)	($2,363)
2021	$1,278	$4,168	$22	$4,190	$2,912	$23,301	($1,590)	($2,372)	($2,359)
2022	$1,397	$6,106	$7	$6,113	$4,716	$28,017	($1,451)	($2,346)	($2,354)
2023	$1,467	$5,109	$5	$5,114	$3,647	$31,664	($1,354)	($2,328)	($2,350)
2024	$1,671	$5,709	$5	$5,714	$4,043	$35,708	($1,256)	($2,310)	($2,347)

Notes: [1] Column [4] from Table 3.3
[2] Col. 10 from Table"Sobig Results...",PECo run for OCA.
Includes acid rain effects.
[3] Table 2.4, Column [5], Total $Million
[4] Columns [2]+[3]
[5] Columns [4]-[1]

TABLE 3.6: LIMERICK 1 RATE IMPACT, Case 3c: OCA Fuel, Historical Capacity Factors
($ million)

YEAR	TOTAL COSTS	FUEL SAVINGS	CAPACITY COSTS AVOIDED	TOTAL BENEFITS	NET BENEFITS	RUNNING TOTAL	DISCOUNTED TOTALS AT: 10%	15%	20%
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
1986	$1,008	$160	$37	$197	($811)	($811)	($737)	($705)	($676)
1987	$974	$122	$39	$161	($813)	($1,624)	($1,409)	($1,320)	($1,241)
1988	$949	$148	$37	$185	($764)	($2,388)	($1,983)	($1,822)	($1,683)
1989	$933	$286	$38	$324	($609)	($2,997)	($2,399)	($2,171)	($1,976)
1990	$906	$206	$38	$245	($661)	($3,658)	($2,810)	($2,499)	($2,242)
1991	$885	$243	$68	$311	($574)	($4,232)	($3,134)	($2,747)	($2,434)
1992	$866	$423	$65	$488	($377)	($4,609)	($3,327)	($2,889)	($2,540)
1993	$845	$308	$64	$373	($473)	($5,082)	($3,548)	($3,044)	($2,649)
1994	$820	$453	$72	$525	($295)	($5,378)	($3,673)	($3,128)	($2,707)
1995	$815	$809	$74	$883	$68	($5,310)	($3,647)	($3,111)	($2,696)
1996	$806	$552	$77	$630	($176)	($5,486)	($3,709)	($3,149)	($2,719)
1997	$807	$611	$124	$735	($71)	($5,557)	($3,731)	($3,162)	($2,727)
1998	$819	$994	$124	$1,118	$299	($5,258)	($3,645)	($3,113)	($2,699)
1999	$807	$629	$116	$745	($63)	($5,320)	($3,661)	($3,122)	($2,704)
2000	$814	$700	$109	$809	($6)	($5,326)	($3,663)	($3,123)	($2,705)
2001	$829	$1,082	$102	$1,184	$355	($4,971)	($3,585)	($3,085)	($2,685)
2002	$820	$875	$95	$970	$150	($4,821)	($3,556)	($3,071)	($2,679)
2003	$828	$858	$89	$947	$119	($4,702)	($3,534)	($3,062)	($2,674)
2004	$850	$1,519	$83	$1,602	$752	($3,950)	($3,411)	($3,009)	($2,651)
2005	$843	$989	$77	$1,067	$224	($3,726)	($3,378)	($2,995)	($2,645)
2006	$854	$1,096	$72	$1,168	$313	($3,413)	($3,336)	($2,978)	($2,638)
2007	$882	$1,837	$69	$1,906	$1,023	($2,389)	($3,210)	($2,931)	($2,620)
2008	$878	$1,269	$66	$1,335	$457	($1,932)	($3,159)	($2,913)	($2,613)
2009	$894	$1,324	$63	$1,387	$493	($1,439)	($3,109)	($2,895)	($2,606)
2010	$931	$2,310	$60	$2,371	$1,440	$1	($2,976)	($2,852)	($2,591)
2011	$928	$1,608	$57	$1,666	$737	$738	($2,914)	($2,832)	($2,585)
2012	$951	$1,730	$55	$1,785	$834	$1,572	($2,850)	($2,813)	($2,579)
2013	$998	$3,020	$52	$3,071	$2,074	$3,646	($2,707)	($2,772)	($2,566)
2014	$998	$2,135	$49	$2,184	$1,186	$4,832	($2,632)	($2,751)	($2,560)
2015	$1,028	$2,218	$46	$2,263	$1,235	$6,068	($2,561)	($2,732)	($2,555)
2016	$1,082	$3,936	$41	$3,977	$2,895	$8,963	($2,410)	($2,694)	($2,545)
2017	$1,083	$2,731	$38	$2,769	$1,686	$10,649	($2,330)	($2,675)	($2,540)
2018	$1,122	$2,846	$34	$2,881	$1,759	$12,408	($2,255)	($2,658)	($2,536)
2019	$1,197	$4,852	$30	$4,882	$3,685	$16,092	($2,110)	($2,626)	($2,528)
2020	$1,214	$3,480	$26	$3,506	$2,292	$18,385	($2,029)	($2,609)	($2,524)
2021	$1,278	$3,702	$22	$3,724	$2,445	$20,830	($1,950)	($2,593)	($2,521)
2022	$1,397	$6,592	$7	$6,600	$5,202	$26,033	($1,797)	($2,563)	($2,515)
2023	$1,467	$4,537	$5	$4,542	$3,075	$29,108	($1,714)	($2,548)	($2,512)
2024	$1,671	$5,070	$5	$5,076	$3,404	$32,513	($1,632)	($2,533)	($2,509)

Notes: [1] Column [4] from Table 3.3

[2] Col. 10 from Table"Sobig Results...", PECo run for OCA, times ratio of Column [7], Table 4.3, to 60% assumed for OCA run. Includes acid rain effects.

[3] Table 2.4, Column [5], Total $Million

[4] Columns [2]+[3]

[5] Columns [4]-[1]

TABLE 3.7: LIMERICK RATE IMPACT

Case 4: OCA Fuel, Historical Capacity Factors, Continued Cost Trends

								DISCOUNTED TOTALS AT:		
Year	Carrying Charges	Station O&M	Other O&M	Total Costs	TOTAL BENEFITS	NET BENEFITS	RUNNING TOTAL	10%	15%	20%
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
1986	$898	$81	$31	$1,010	$197	($813)	($813)	($739)	($707)	($678)
1987	$863	$96	$32	$990	$161	($829)	($1,643)	($1,425)	($1,334)	($1,254)
1988	$833	$112	$33	$978	$185	($793)	($2,435)	($2,020)	($1,855)	($1,712)
1989	$806	$130	$40	$976	$324	($652)	($3,087)	($2,466)	($2,228)	($2,027)
1990	$780	$150	$34	$964	$245	($719)	($3,807)	($2,912)	($2,586)	($2,316)
1991	$754	$172	$37	$963	$311	($652)	($4,459)	($3,281)	($2,868)	($2,534)
1992	$728	$196	$41	$966	$488	($477)	($4,937)	($3,526)	($3,047)	($2,668)
1993	$703	$222	$44	$969	$373	($596)	($5,533)	($3,804)	($3,242)	($2,806)
1994	$678	$251	$41	$970	$525	($445)	($5,978)	($3,993)	($3,369)	($2,893)
1995	$653	$282	$58	$993	$883	($110)	($6,088)	($4,035)	($3,396)	($2,910)
1996	$650	$317	$48	$1,015	$630	($385)	($6,473)	($4,170)	($3,479)	($2,962)
1997	$644	$354	$52	$1,050	$735	($314)	($6,788)	($4,270)	($3,538)	($2,998)
1998	$639	$394	$65	$1,099	$1,118	$19	($6,769)	($4,265)	($3,535)	($2,996)
1999	$635	$439	$55	$1,129	$745	($384)	($7,153)	($4,366)	($3,589)	($3,026)
2000	$632	$487	$62	$1,180	$809	($372)	($7,525)	($4,455)	($3,635)	($3,050)
2001	$629	$539	$76	$1,244	$1,184	($60)	($7,584)	($4,468)	($3,641)	($3,053)
2002	$627	$596	$65	$1,288	$970	($318)	($7,902)	($4,531)	($3,671)	($3,067)
2003	$627	$658	$70	$1,354	$947	($407)	($8,309)	($4,604)	($3,703)	($3,083)
2004	$627	$725	$88	$1,440	$1,602	$163	($8,146)	($4,577)	($3,692)	($3,078)
2005	$628	$797	$76	$1,501	$1,067	($435)	($8,581)	($4,642)	($3,719)	($3,089)
2006	$630	$876	$82	$1,588	$1,168	($420)	($9,001)	($4,699)	($3,741)	($3,098)
2007	$634	$961	$102	$1,697	$1,906	$208	($8,793)	($4,673)	($3,731)	($3,094)
2008	$640	$1,053	$89	$1,782	$1,335	($447)	($9,240)	($4,723)	($3,749)	($3,101)
2009	$647	$1,153	$95	$1,895	$1,387	($507)	($9,747)	($4,775)	($3,767)	($3,107)
2010	$656	$1,262	$120	$2,037	$2,371	$333	($9,414)	($4,744)	($3,757)	($3,104)
2011	$666	$1,379	$104	$2,149	$1,666	($483)	($9,897)	($4,784)	($3,770)	($3,108)
2012	$679	$1,505	$111	$2,296	$1,785	($511)	($10,408)	($4,823)	($3,781)	($3,112)
2013	$695	$1,642	$141	$2,478	$3,071	$594	($9,815)	($4,782)	($3,769)	($3,108)
2014	$713	$1,790	$122	$2,625	$2,184	($441)	($10,256)	($4,810)	($3,777)	($3,110)
2015	$735	$1,949	$131	$2,815	$2,263	($552)	($10,807)	($4,842)	($3,785)	($3,113)
2016	$743	$2,122	$166	$3,030	$3,977	$947	($9,861)	($4,792)	($3,773)	($3,109)
2017	$761	$2,308	$143	$3,212	$2,769	($442)	($10,303)	($4,813)	($3,778)	($3,111)
2018	$791	$2,508	$154	$3,453	$2,881	($573)	($10,876)	($4,838)	($3,784)	($3,112)
2019	$746	$2,725	$195	$3,666	$4,882	$1,216	($9,660)	($4,790)	($3,773)	($3,110)
2020	$906	$2,958	$170	$4,034	$3,506	($528)	($10,188)	($4,809)	($3,777)	($3,111)
2021	$1,009	$3,209	$182	$4,400	$3,724	($677)	($10,864)	($4,831)	($3,782)	($3,112)
2022	$1,170	$3,480	$232	$4,882	$6,600	$1,718	($9,147)	($4,780)	($3,772)	($3,109)
2023	$1,447	$3,772	$201	$5,420	$4,542	($878)	($10,025)	($4,804)	($3,776)	($3,110)
2024	$2,070	$4,087	$216	$6,373	$5,076	($1,297)	($11,322)	($4,835)	($3,782)	($3,111)

Notes:
1. Revenue Required assuming historical capital additions.
2. Column 9, Table 4.8
3. Attachment IR-OCA-2-25b, Item 1, page 1, col. 3
4. [1] + [2] + [3].
5. Total Benefits from Table 3.6.

TABLE 3.8: SUMMARY OF COST-EFFECTIVENESS MEASURES

		Case 1	Case 2	Case 3a	Case 3b	Case 3c	Case 4
		Total	Total	Total	Total	Total	Total
Table		3.2	3.3	3.4	3.5	3.6	3.7
Crossover Year		1994	1995.	1997	1997	1998	NEVER*
Breakeven Year		2001	2004	2009	2010	2010	NEVER
Discounted	at 10%	2009	2015	NEVER	NEVER	NEVER	NEVER
Breakeven Year	at 15%	NEVER	NEVER	NEVER	NEVER	NEVER	NEVER
	at 20%	NEVER	NEVER	NEVER	NEVER	NEVER	NEVER
Cumulative Savings at Crossover($million)		($2,836)	($3,737)	($5,333)	($5,196)	($5,258)	NA
Terminal Discounted	at 10%	$2,696	$1,636	($1,135)	($1,256)	($1,632)	($4,835)
Savings($million)	at 15%	($185)	($967)	($2,357)	($2,310)	($2,533)	($3,782)
	at 20%	($963)	($1,582)	($2,441)	($2,347)	($2,509)	($3,111)

* Positive in individual years.

TABLE 3.9: COMPARISON OF COST EFFECTIVENESS, SUSQUEHANNA 2 AND LIMERICK 1
IN $/KW-YR

	SUSQUEHANNA 2 [1]			LIMERICK 1 [2]		
Year	Total Cost	Total Benefits	Net Benefits	Total Cost	Total Benefits	Net Benefits
1985	$518.7	$149.5	($369.2)			
1986	$524.6	$167.8	($356.8)	$812.8	$219.3	($593.5)
1987	$508.0	$222.5	($285.5)	$787.5	$260.5	($527.0)
1988	$517.7	$324.1	($193.7)	$769.3	$290.7	($478.6)
1989	$516.4	$425.3	($91.1)	$759.7	$442.1	($317.6)
1990	$513.6	$522.4	$8.8	$739.0	$412.5	($326.5)
1991	$513.8	$614.1	$100.4	$724.7	$457.5	($267.2)
1992	$518.1	$749.7	$231.6	$711.7	$617.6	($94.1)
1993	$525.9	$853.3	$327.4	$697.6	$576.1	($121.6)
1994	$543.0	$991.9	$448.9	$679.2	$717.0	$37.8
1995	$564.8	$1,099.7	$534.8	$679.5	$995.6	$316.1
1996	$588.8	$1,184.6	$595.8	$672.6	$904.6	$232.0
1997	$604.9	$1,288.2	$683.3	$675.8	$978.3	$302.5
1998	$629.6	$1,400.6	$771.0	$689.7	$1,250.4	$560.7
1999	$657.1	$1,517.8	$860.7	$681.5	$1,038.6	$357.2
2000	$601.2	$1,668.1	$1,066.9	$690.3	$1,190.4	$500.2
2001	$621.3	$1,785.8	$1,164.5	$706.6	$1,468.4	$761.8
2002	$645.7	$1,925.2	$1,279.5	$700.8	$1,409.1	$708.3
2003	$658.0	$2,059.3	$1,401.3	$710.1	$1,410.2	$700.1
2004	$684.9	$2,191.0	$1,506.1	$733.9	$1,927.8	$1,193.8
2005	$718.7	$2,315.9	$1,597.2	$729.3	$1,656.5	$927.2
2006	$733.5	$2,447.9	$1,714.4	$742.6	$1,795.8	$1,053.2
2007	$768.8	$2,587.4	$1,818.6	$771.3	$2,371.0	$1,599.6
2008	$811.3	$2,734.9	$1,923.6	$769.8	$2,150.0	$1,380.2
2009	$829.1	$2,890.8	$2,061.7	$787.2	$2,171.5	$1,384.3
2010	$874.0	$3,055.5	$2,181.5	$824.9	$3,014.7	$2,189.7
2011	$908.8	$3,229.7	$2,320.9	$824.7	$2,608.9	$1,784.2
2012	$949.2	$3,413.8	$2,464.6	$848.4	$2,790.0	$1,941.6
2013	$991.8	$3,608.4	$2,616.6	$895.0	$3,776.2	$2,881.2
2014	$1,038.7	$3,814.1	$2,775.3	$897.5	$3,386.1	$2,488.6
2015	$1,089.7	$4,031.5	$2,941.7	$928.7	$3,483.1	$2,554.4
2016	$1,146.2	$4,261.2	$3,115.1	$982.6	$4,942.2	$3,959.7
2017	$1,206.7	$4,504.1	$3,297.5	$985.3	$4,238.2	$3,252.9
2018	$1,273.3	$4,760.9	$3,487.5	$1,024.8	$4,348.0	$3,323.2
2019	$1,343.1	$5,032.2	$3,689.2	$1,098.3	$5,996.0	$4,897.7
2020	$1,417.3	$5,319.1	$3,901.8	$1,116.8	$5,256.6	$4,139.8
2021	$1,493.9	$5,622.3	$4,128.4	$1,180.4	$5,582.8	$4,402.4
2022	$1,530.7	$5,942.7	$4,412.0	$1,295.2	$7,881.3	$6,586.0
2023				$1,363.9	$6,949.6	$5,585.6
2024				$1,559.7	$7,495.8	$5,936.2

Notes: 1. Susquehanna 2 Costs & Benefits from PP&L Testimony, Docket #R-842651, Table 3.2. divided by PP&L Share of Capacity in GW from p. 40, IR-OCA-I-4a, Attachment 1 in R-842651.
2. Limerick 1 Costs & Benefits from Table 3.2, divided by 1.055 GW.

TABLE 4.1: COMPARISON OF CAPACITY FACTOR TO EQUIVALENT AVAILABILITY FACTOR
PJM NUCLEAR UNITS

		1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982
Calvert Cliffs 1	EAF						76.0	89.2	65.0	61.2	54.4	60.0	79.3	69.6
	CF						76.0	85.0	64.8	60.7	54.4	58.8	79.3	69.6
	EAF-CF						0.0	4.2	0.2	0.5	0.0	1.2	0.0	0.0
Calvert Cliffs 2	EAF								80.4	67.8	71.2	89.6	72.4	64.9
	CF								80.4	67.8	71.2	83.0	70.3	64.9
	EAF-CF								0.0	0.0	0.0	6.6	2.1	0.0
Three Mile Island 1	EAF					79.2	77.2	60.4	76.2	79.2	12.4	0.0	0.0	0.0
	CF					79.2	77.2	60.4	76.2	79.2	12.4	0.0	0.0	0.0
	EAF-CF					0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Peach Bottom 2	EAF					76.5	54.5	59.9	43.4	73.4	92.2	47.6	72.8	54.1
	CF					76.5	54.5	59.7	43.4	72.8	91.9	46.8	71.1	51.6
	EAF-CF					0.0	0.0	0.2	0.0	0.6	0.3	0.8	1.7	2.5
Peach Bottom 3	EAF						56.6	66.0	51.3	75.8	66.4	77.3	34.0	93.0
	CF						56.6	64.7	51.3	74.8	65.5	77.3	34.0	91.5
	EAF-CF						0.0	1.3	0.0	1.0	0.9	0.0	0.0	1.5
Salem 1	EAF								42.4	47.9	21.8	63.7	67.7	43.1
	CF								42.4	47.6	21.8	59.4	64.8	43.0
	EAF-CF								0.0	0.3	0.0	4.3	2.9	0.1
Salem 2	EAF												75.0	81.9
	CF												75.0	81.3
	EAF-CF												0.0	0.6
Oyster Creek	EAF	76.6	78.5	76.3	63.3	64.8	55.3	67.6	57.1	70.1	81.0	34.4	46.2	56.6
	CF	76.6	78.0	76.3	63.0	64.7	55.3	67.6	57.1	64.0	80.1	34.3	46.2	35.4
	EAF-CF	0.0	0.5	0.0	0.3	0.1	0.0	0.0	0.0	6.1	0.9	0.1	0.0	21.2

Average (EAF-CF) 1.03278

Source: Electric Power Research Institute, Nuclear Unit Operating Experience: 1980-1982 Update; April 1984, Appendix F. (EPRI NP-3480)

TABLE 4.2: BWR CAPACITY FACTOR REGRESSIONS

	Equation 1		Equation 2 [8]		Equation 3		Equation 4 [8]	
	Coef	t-stat	Coef	t-stat	Coef	t-stat	Coef	t-stat
CONSTANT	68.73%	6.7	74.86%	7.7	67.99%	6.6	74.34%	7.5
SIZE [1]	-2.55%	-2.1	-2.74%	-2.4	-2.47%	-2.1	-2.69%	-2.3
AGE5 [2]	4.24%	3.9	3.48%	3.4	4.34%	4.2	3.49%	3.5
REFUEL [3]	-10.33%	-4.1	-11.92%	-5.0	-9.54%	-3.8	-11.07%	-4.6
GT1000 [4]	9.96%	2.0	13.15%	2.8	9.70%	2.0	12.89%	2.7
YEAR INDICATORS [5]								
1979	3.08%	0.7	2.06%	0.5	---	---	---	---
1980	-4.39%	-1.0	-5.10%	-1.3	---	---	---	---
1981	-7.47%	-1.7	-8.25%	-2.0	---	---	---	---
1982	-9.32%	-2.1	-10.15%	-2.4	---	---	---	---
1983	-12.09%	-2.8	-13.04%	-3.2	---	---	---	---
1984	-19.36%	-4.5	-20.39%	-5.0	---	---	---	---
post-1979 [6]	---	---	---	---	-11.30%	-4.2	-11.84%	-4.6
ADJUSTED R-SQ		0.169		0.199		0.144		0.170
F STATISTIC		5.4		6.3		8.2		9.7
OBSERVATIONS [7]		216	[8]	213		216	[8]	213

Notes:
[1] SIZE = Design Electrical Rating (DER) in hundreds of MW.
[2] AGE5 = minimum of Age (years from COD to middle of current year), or 5.
[3] Refuel = number of refuelings in year (usually 0 or 1).
[4] GT1000 = 1, if SIZE > 1000, 0 otherwise.
[5] Indicator=1 in this year, 0 otherwise.
[6] 1980 or later.
[7] Full calendar years of BWR operation, >300 MW, 1974-84.
[8] Excludes Browns Ferry 1975-76.

TABLE 4.3: BWR CAPACITY FACTOR PROJECTIONS FOR LIMERICK 1

YEAR	Value of REFUEL	Equation 1: 1984 Conds.	Equation 1: Avg. 1980-84 Conds.	Equation 2: 1984 Conds.	Equation 2: Avg. 1980-84 Conds.	Equation 3: Avg. 1980-84 Conds.	Equation 4: Avg. 1980-84 Conds.	Average Eq. 2 and 4 1980-84 Conds.
		[1]	[2]	[3]	[4]	[5]	[6]	[7]
1986	0	34.49%	43.23%	40.49%	49.39%	42.45%	48.78%	49.09%
1987	1	28.41%	37.15%	32.04%	40.95%	37.24%	41.21%	41.08%
1988	1	32.65%	41.38%	35.52%	44.43%	41.58%	44.70%	44.56%
1989	0	47.21%	55.95%	50.92%	59.83%	55.46%	59.27%	59.55%
1990	1	41.12%	49.86%	42.48%	51.39%	50.25%	51.69%	51.54%
1991	1	43.24%	51.98%	44.22%	53.13%	52.42%	53.44%	53.28%
1992	0	53.57%	62.31%	56.14%	65.05%	61.96%	64.51%	64.78%
1993	1	43.24%	51.98%	44.22%	53.13%	52.42%	53.44%	53.28%
Mature Average		46.69%	55.42%	48.19%	57.10%	55.60%	57.13%	57.11%

Notes: All projections assume Limerick experiences favorable results of other BWR's > 100MW, through 1984.

All input values to equations are from Table 4.2. Calculated for a 1055 MW unit with COD of 1/1/86.

Mature Average reflects the repetition of 1991 to 1993 results.

Equations 2 and 4 exclude the direct effects of the Brown's Ferry cable fire.

TABLE 4.1: COMPARISON OF CAPACITY FACTOR PROJECTIONS

	Calendar Years of Experience						
	1	2	3	4	5	6	7+
Predicted Capacity Factors:	[1]						
PECO: [2]	56.8%	61.7%	62.4%	81.4%	59.1%	60.0%	65.0%
PLC [3]:	48.8%	40.8%	44.3%	59.3%	51.3%	56.8%	56.8%

As of: 31-Aug-85 Unit Years of Experience in each Calendar Year

Unit	COD	1	2	3	4	5	6	7+
Browns Ferry 1	01-Aug-74	0.42	1.00	1.00	1.00	1.00	1.00	5.67
Browns Ferry 2	01-Mar-75	0.84	1.00	1.00	1.00	1.00	1.00	4.68
Browns Ferry 3	01-Mar-77	0.84	1.00	1.00	1.00	1.00	1.00	2.67
Peach Bottom 2	05-Jul-74	0.49	1.00	1.00	1.00	1.00	1.00	5.67
Peach Bottom 3	23-Dec-74	0.02	1.00	1.00	1.00	1.00	1.00	5.67

Unit	Original DER (MW)	Actual [4]	PECO	PLC
Browns Ferry 1	1065	53.9%	64.7%	53.7%
Browns Ferry 2	1065	50.3%	64.3%	53.2%
Browns Ferry 3	1065	53.1%	64.1%	52.3%
Peach Bottom 2	1065	54.1%	64.6%	53.7%
Peach Bottom 3	1065	61.1%	64.9%	53.9%
Average [5]		54.5%	64.6%	53.4%

Notes: [1] First partial year
[2] From: Table 3.1
[3] DERCF Averages from Table 4.3, plus Size Difference*Size Coefficient
= PLC estimate + (10 MW)*(-2.72%/100 MW)
= PLC estimate - 0.27%
[4] Cumulative Net Elec. Energy/ Report Period Hours/
DER; From NRC Gray Book, August 1985.
[5] Weighted by experience.

TABLE 4.5: HISTORICAL CAPACITY FACTORS (OER)
Nuclear Units Similar in Characteristics to Limerick

UNIT	OER NET [3]	first full year	CAPACITY FACTOR BY CALENDAR YEAR [2] 1	2	3	4	5	6	7	8	9	10
BROWNS FERRY 1	1065	75	14.4%	13.9%	54.1%	62.4%	80.3%	64.8%	47.2%	84.5%	23.3%	84.1%
BROWNS FERRY 2	1065	76	16.8%	66.7%	59.5%	79.8%	60.1%	80.1%	47.7%	68.4%	43.3%	
BROWNS FERRY 3	1065	78	59.5%	58.8%	74.1%	67.1%	52.4%	57.8%	3.1%			
PEACH BOTTOM 2	1065	75	54.5%	59.5%	43.1%	72.8%	93.8%	46.4%	71.1%	51.4%	47.7%	26.0%
PEACH BOTTOM 3	1065	75	56.6%	64.7%	51.2%	74.7%	65.4%	77.3%	33.6%	91.5%	26.0%	79.8%
SUSQUEHANNA 1	1065	84	65.3%									
AVERAGES [1]												
per year:	1065		59.0%	62.4%	56.4%	71.4%	70.4%	65.3%	40.5%	73.9%	35.1%	63.3%
cumulative:	--			years 1-4:		62.5%				years 5+:	58.0%	

ADJUSTMENT FOR THE BROWNS FERRY FIRE [4]

Browns Ferry deviation [4]	86.7%	48.5%
unit-years		47
deviation/unit-year		2.9%

ADJUSTED AVERAGE

	1	2	3	4	5	6	7	8	9	10
per year: [5]	56.1%	59.5%	53.5%	68.5%	67.5%	62.4%	37.7%	71.1%	32.2%	60.4%
cumulative: [6]		years 1-4:		59.6%				years 5+:	55.1%	

Notes:
[1] Values for years 1 and 2 for Browns Ferry 1, and for year 1 for Browns Ferry 2 are excluded from average.
[2] Computed from NRC-reported net output and original OER.
[4] 2 * 59.0% - 14.4% - 16.8%, and 62.4%-13.9%, respectively.
[5] Simple averages minus Browns Ferry deviation per unit/year.
[6] Cumulative (unadjusted) averages minus Browns Ferry deviation per unit-year.

TABLE 4.6: RESULTS OF REGRESSIONS ON O&M DATA (All plants in dataset)

	Equation 1		Equation 2		Equation 3		Equation 4		Equation 5	
	Coef	t-stat	Coef	t-stat	Coef	t-stat	Coef	t-stat	Coef	t-stat
CONSTANT	-2.12	-7.94	-2.13	-8.15	-2.12	-7.94	-2.50	-9.60	-2.19	-8.77
ln(MW) [2]	0.53	21.15	0.52	21.17	--	--	--	--	--	--
ln(UNITS)	0.03	0.56	--	--	0.56	12.27	--	--	0.70	15.34
YEAR [3]	0.11	28.62	0.11	28.66	0.11	28.62	0.11	28.87	0.11	31.24
UNITS	--	--	0.03	0.96	--	--	0.35	12.53	--	--
ln(MW/unit)	--	--	--	--	0.53	21.15	0.53	21.36	0.48	20.23
NE [4]	--	--	--	--	--	--	--	--	0.28	8.78
Adjusted R-sq.		0.85		0.85		0.85		0.85		0.87
F statistic		1032.2		1033.5		1032.2		1043.9		904.3

Notes: [1] The dependent variable in each equation is ln(non-fuel O&M in 1983$)

[2] MW = number of MegaWatt in Design Electrical Rating (DER)

[3] YEAR = Calendar Year - 1900; e.g., 1985 = 85.

[4] NE is a dummy variable which measures whether the plant is located in the Northeast Region (defined as Handy Whitman's North Atlantic Region), where Susquehanna 2 is located. NE = 1 if located in Northeast Region, 0 if elsewhere.

TABLE 4.7: RESULTS OF REGRESSIONS ON O&M DATA (All plants > 300 MW)

	Equation 1		Equation 2		Equation 3		Equation 4		Equation 5	
	Coef	t-stat	Coef	t-stat	Coef	t-stat	Coef	t-stat	Coef	t-stat
CONSTANT	-4.38	-9.43	-4.16	-9.77	-4.38	-9.43	-4.81	-10.57	-4.46	-10.30
ln(MW) [2]	0.62	10.13	0.58	9.85	--	--	--	--	--	--
ln(UNITS)	-0.07	-0.85	--	--	0.55	12.93	--	--	0.67	15.88
YEAR [3]	0.13	28.31	0.13	28.36	0.13	28.31	0.13	28.67	0.13	30.73
UNITS	--	--	.00	-0.09	--	--	0.35	13.31	--	--
ln(MW/unit)	--	--	--	--	0.62	10.13	0.63	10.33	0.59	10.34
NE [4]	--	--	--	--	--	--	--	--	0.26	8.31
Adjusted R-sq.		0.77		0.77		0.77		0.78		0.80
F statistic		519.4		518.3		519.4		530.0		465.4

Notes: [1] The dependent variable in each equation is ln(non-fuel O&M in 1983$)

[2] MW = number of MegaWatt in Design Electrical Rating (DER)

[3] YEAR = Calendar Year - 1900; e.g., 1985 = 85.

[4] NE is a dummy variable which measures whether the plant is located in the Northeast Region (defined as Handy Whitman's North Atlantic Region), where Suscuehanna 2 is located. NE = 1 if located in Northeast Region, 0 if elsewhere.

TABLE 4.8: PROJECTIONS OF ANNUAL NON-FUEL O&M EXPENSE FOR LIMERICK 1 ($ million)

Year	PECO Projections	From Equation #5 (Table 4.7) [A]				From Equation #5 (Table 4.6) [B]			
		Compund real growth		Linear real growth		Compund real growth		Linear real growth	
	nominal	1983$	nominal	1983$	nominal	1983$	nominal	1983$	nominal
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
1986	~~$79~~	$85	$95	$85	$95	$73	$81	$73	$81
1987	$85	$97	$114	$97	$114	$81	$96	$81	$96
1988	$93	$111	$138	$109	$136	$91	$113	$90	$112
1989	$101	$127	$167	$122	$160	$102	$135	$99	$130
1990	$111	$145	$202	$134	$187	$114	$160	$108	$150
1991	$117	$165	$245	$146	$216	$128	$190	$116	$172
1992	$124	$189	$296	$158	$247	$143	$225	$125	$196
1993	$132	$216	$358	$170	$282	$161	$267	$134	$222
1994	$140	$246	$434	$182	$321	$180	$317	$142	$251
1995	$148	$281	$525	$194	$362	$201	$376	$151	$282
1996	$157	$321	$635	$206	$408	$225	$446	$160	$317
1997	$166	$366	$769	$218	$458	$252	$530	$169	$354
1998	$176	$418	$931	$230	$512	$283	$629	$177	$394
1999	$187	$478	$1,126	$242	$572	$316	$746	$186	$439
2000	$198	$545	$1,363	$254	$636	$354	$886	$195	$487
2001	$210	$623	$1,650	$267	$706	$397	$1,051	$203	$539
2002	$222	$711	$1,996	$279	$783	$444	$1,248	$212	$596
2003	$236	$811	$2,416	$291	$866	$497	$1,481	$221	$658
2004	$250	$926	$2,924	$303	$956	$557	$1,757	$230	$725
2005	$265	$1,058	$3,538	$315	$1,053	$623	$2,086	$238	$797
2006	$281	$1,208	$4,282	$327	$1,159	$698	$2,475	$247	$876
2007	$298	$1,379	$5,182	$339	$1,274	$782	$2,938	$256	$961
2008	$315	$1,574	$6,272	$351	$1,399	$875	$3,487	$264	$1,053
2009	$334	$1,797	$7,590	$363	$1,534	$980	$4,139	$273	$1,153
2010	$354	$2,052	$9,185	$375	$1,680	$1,097	$4,912	$282	$1,262
2011	$376	$2,343	$11,116	$387	$1,838	$1,229	$5,830	$291	$1,379
2012	$398	$2,675	$13,453	$399	$2,009	$1,376	$6,919	$299	$1,505
2013	$422	$3,054	$16,281	$412	$2,194	$1,540	$8,212	$308	$1,642
2014	$447	$3,486	$19,703	$424	$2,394	$1,725	$9,747	$317	$1,790
2015	$474	$3,980	$23,845	$436	$2,610	$1,931	$11,568	$325	$1,949
2016	$503	$4,544	$28,857	$448	$2,844	$2,162	$13,730	$334	$2,122
2017	$533	$5,188	$34,923	$460	$3,096	$2,421	$16,296	$343	$2,308
2018	$565	$5,923	$42,264	$472	$3,368	$2,711	$19,341	$352	$2,508
2019	$599	$6,763	$51,149	$484	$3,661	$3,035	$22,955	$360	$2,725
2020	$635	$7,721	$61,900	$496	$3,978	$3,398	$27,245	$369	$2,958
2021	$673	$8,815	$74,912	$508	$4,319	$3,805	$32,336	$378	$3,209
2022	$713	$10,064	$90,659	$520	$4,687	$4,261	$38,378	$386	$3,480
2023	$756	$11,491	$109,716	$532	$5,084	$4,770	$45,550	$395	$3,772
2024	$801	$13,119	$132,780	$545	$5,511	$5,341	$54,062	$404	$4,087

Notes: [1] From: Attachment IR OCA 2-25b, Item 1.
[2],[6] MW = 1101, UNITS = 1, NE = 1.
[3],[5],[7],[9] Assume 3.7% inflation in 1984, 3% in 1985, 4.5% in 1986, 5.0% in 1987, and 6.0% thereafter.
[4],[8] From 1988 on, projections increase by the amount of the difference between the 1986 and 1987 projections.
[A] Regressions originally performed on data from all plants > 300 MW.
[B] Regressions originally performed on data from all plants in database.

TABLE 4.9: NUCLEAR CAPITAL ADDITIONS

		Averages by Year (in $/kw-yr)	
	Year	All plants	Single units, > 800 MW
All years before and including:	1972	$1.43	—
	1973	$10.87	$38.90
	1974	$11.07	$26.82
	1975	$8.71	$19.72
	1976	$15.07	$2.98
	1977	$19.91	$12.78
	1978	$17.77	$25.94
	1979	$14.82	$16.75
	1980	$27.73	$27.97
	1981	$31.66	$28.33
	1982	$29.06	$24.80
	1983	$29.78	$26.42
	1984	$42.88	$34.45
Overall Average:		$20.74	$23.37
(# of obs.)		520	127
1978-84 Average:		$27.69	$26.49
(# of obs.)		314	97
1980-84 Average:		$32.29	$28.80
(# of obs.)		224	67

TABLE 4.10: PROJECTIONS OF CAPITAL ADDITIONS COSTS FOR LIMERICK ($million)

Year	PECo Capital Additions Budget [1]	OUR Extrapolation of Recent Historical Average [2]
1987	$4.19	$31.28
1988	$12.78	$33.60
1989	$13.66	$36.08
1990	$14.59	$38.75
1991	$15.58	$41.62
1992	$16.64	$44.70
1993	$17.77	$48.01
1994	$18.98	$51.56
1995	$20.27	$55.38
1996	$21.49	$59.47
1997	$22.78	$63.87
1998	$24.14	$68.60
1999	$25.59	$73.68
2000	$27.13	$79.13
2001	$28.75	$84.99
2002	$30.49	$91.27
2003	$32.31	$98.03
2004	$34.24	$105.28
2005	$36.30	$113.07
2006	$38.48	$121.44
2007	$40.79	$130.43
2008	$43.24	$140.08
2009	$45.83	$150.45
2010	$48.58	$161.58
2011	$51.49	$173.53
2012	$54.59	$186.38
2013	$57.86	$200.17
2014	$61.33	$214.98
2015	$65.01	$230.89
2016	$68.92	$247.98
2017	$73.04	$266.33
2018	$77.43	$286.03
2019	$82.07	$307.20
2020	$87.00	$329.93
2021	$92.22	$354.35
2022	$97.75	$380.57
2023	$103.62	$408.73
2024	$109.84	$438.98

Notes: 1. From Attachment IR-OCA-2-25b, Item 3; Original Cost + Capital Additions, 1986-2024
2. $28/kW in 1983$, multiplied by 1101 MW MGN, escalated with Handy Whitman index (region 1) to 1984$ and at 1.4 % above general inflation (1986: 4.5%, 1987: 5.0%, 1988+: 6.0%) thereafter.

TABLE 4.11: CHOOSING A UTILITY DISCOUNT RATE BASED ON THE COST OF RATEBASING INVESTMENTS

				tax	
Debt	50.0%	13.0%	6.5%	rate	50.0%
Equity	50.0%	16.0%	8.0%		

Weighted Average	14.50%
Weighted Average + 50% Tax Effect on Equity:	22.50%
Weighted Average - 50% Tax Effect on Debt:	11.25%

Year	Cash	Deprec. at 10%	Rate-making Return + Taxes	Total	Year-end Ratebase
0	1000				1000
1		100	225.0	325.0	900
2		100	202.5	302.5	800
3		100	180.0	280.0	700
4		100	157.5	257.5	600
5		100	135.0	235.0	500
6		100	112.5	212.5	400
7		100	90.0	190.0	300
8		100	67.5	167.5	200
9		100	45.0	145.0	100
10		100	22.5	122.5	0

Present Value at:

14.50%	1000	1269
22.50%	1000	1000
11.25%	1000	1417

FIGURE 2.1: COST COMPARISON

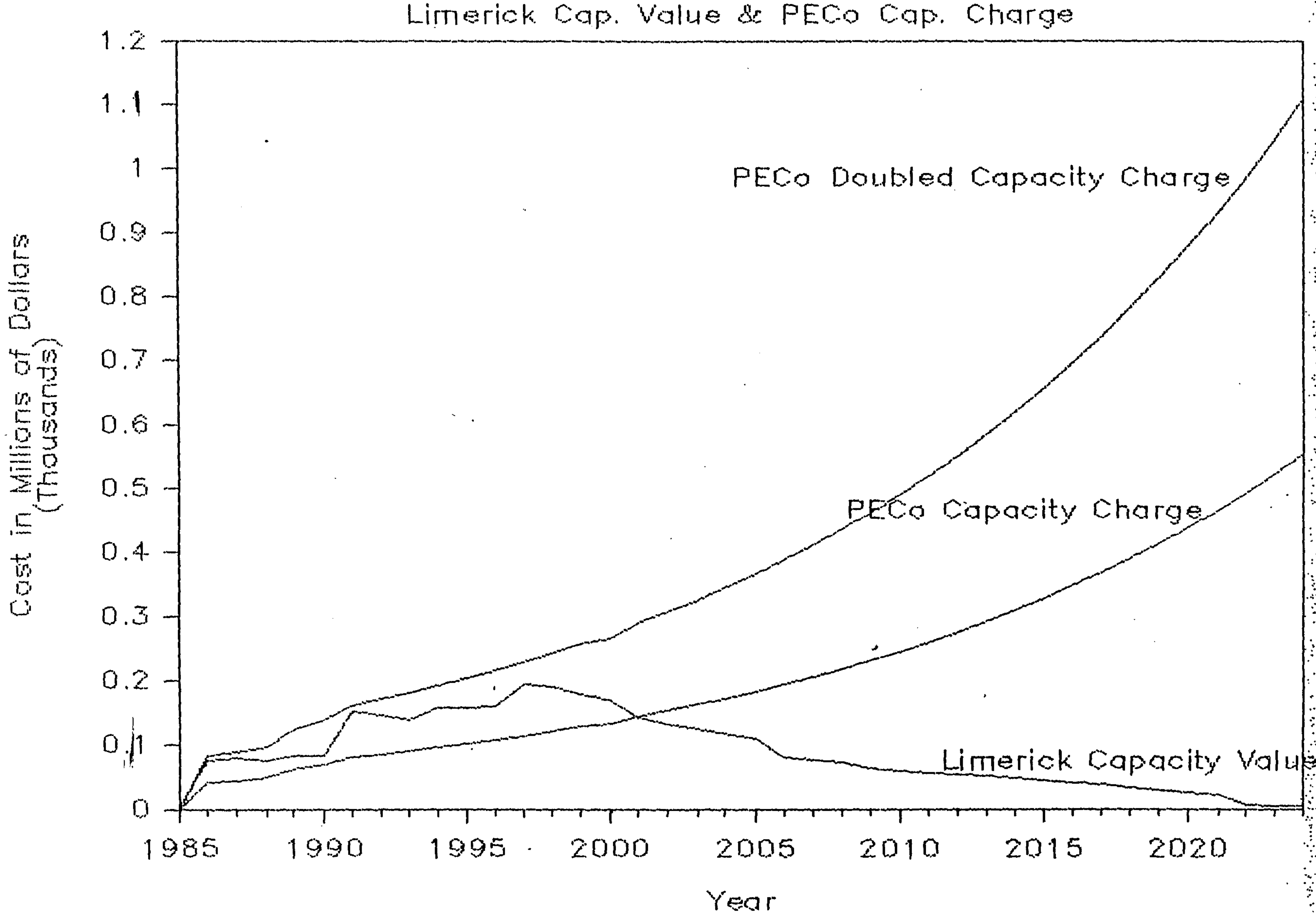
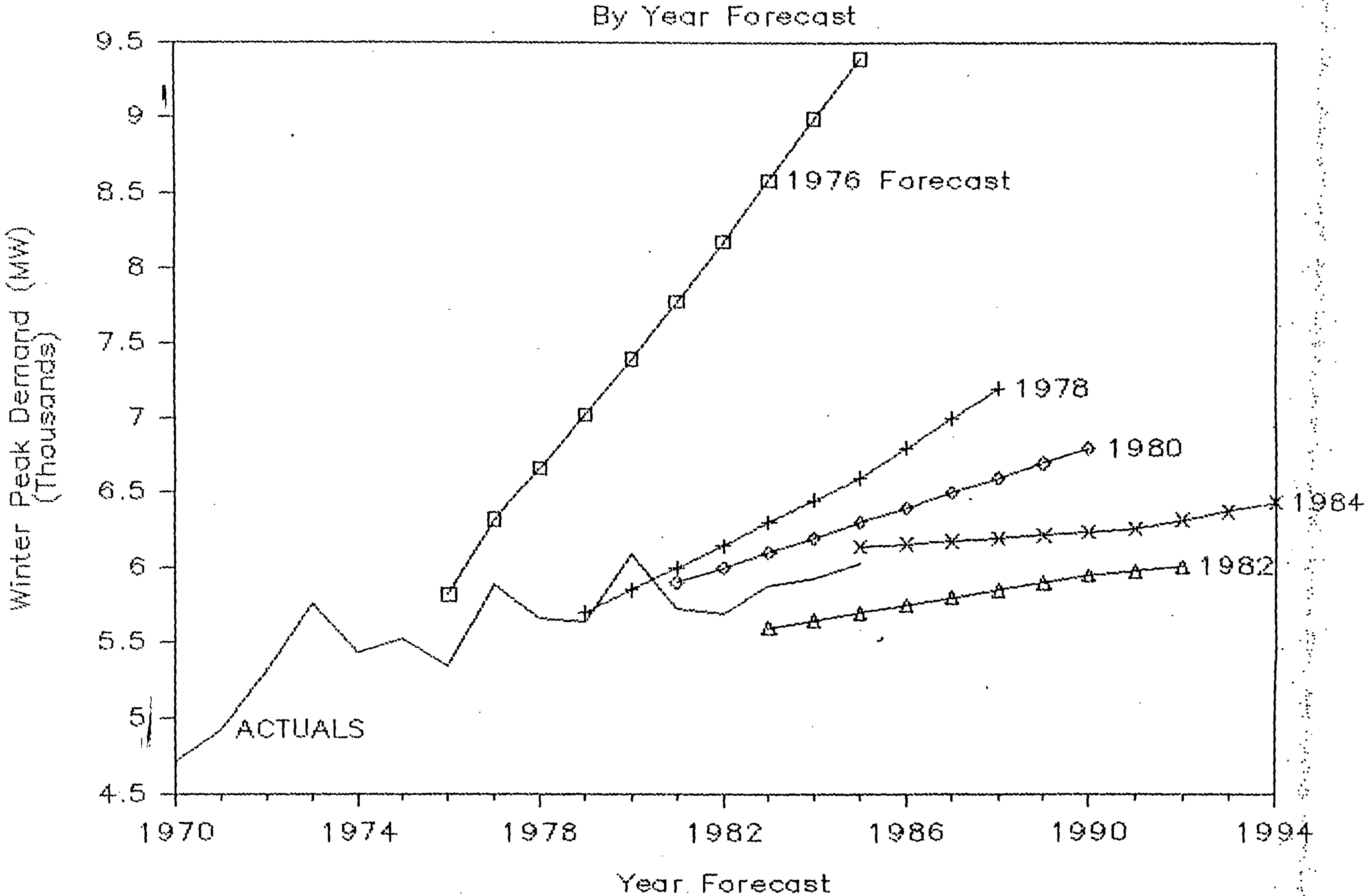


Figure 2.2: PECo Forecast History



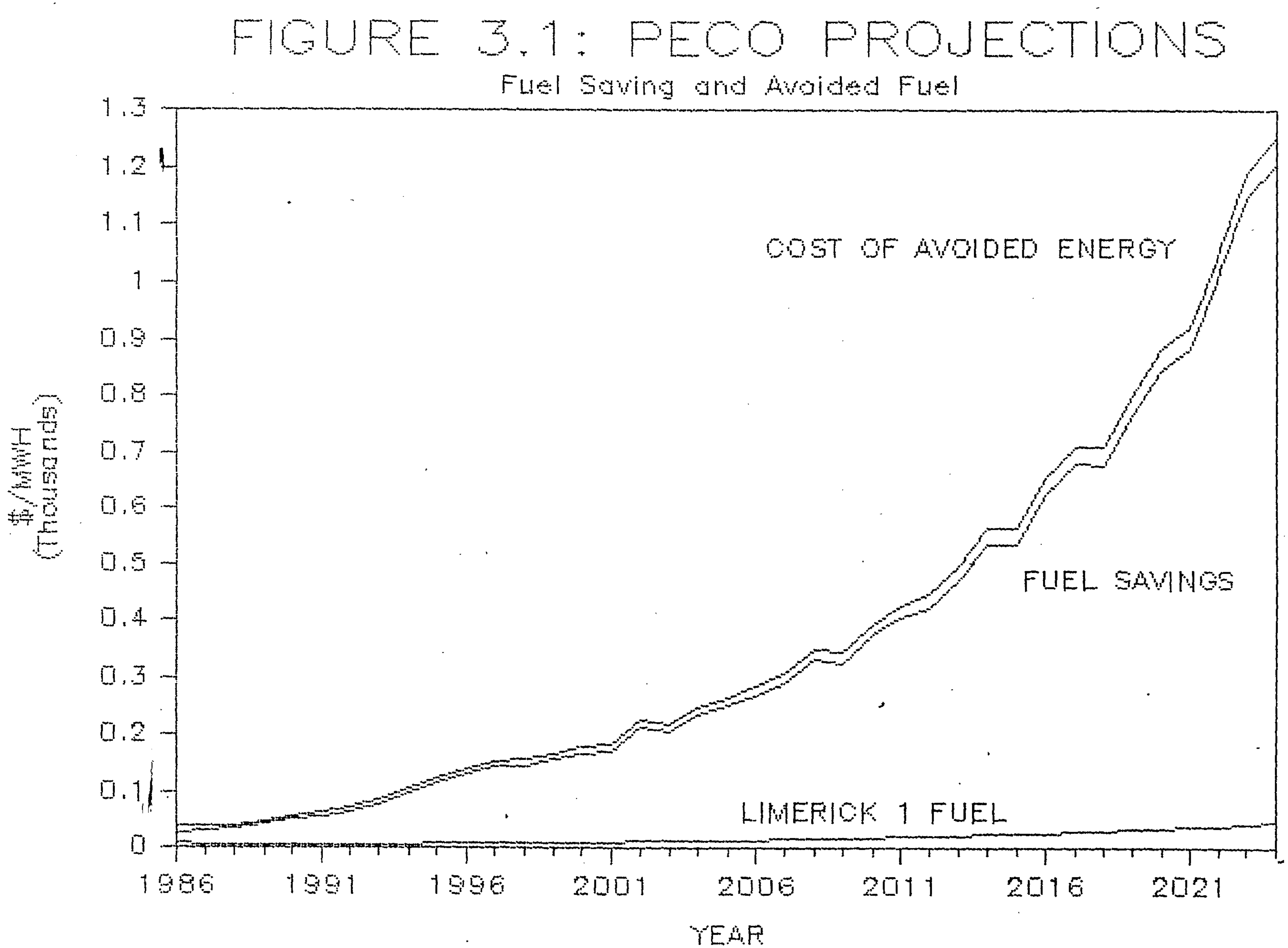


FIGURE 3.1: PECO PROJECTIONS
Fuel Saving and Avoided Fuel
$/MWH
(Thousands)
1.3
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
COST OF AVOIDED ENERGY
FUEL SAVINGS
LIMERICK 1 FUEL
1986
1991
1996
2001
2006
2011
2016
2021
YEAR

FIGURE 3.2: LIMERICK 1 RATE IMPACT

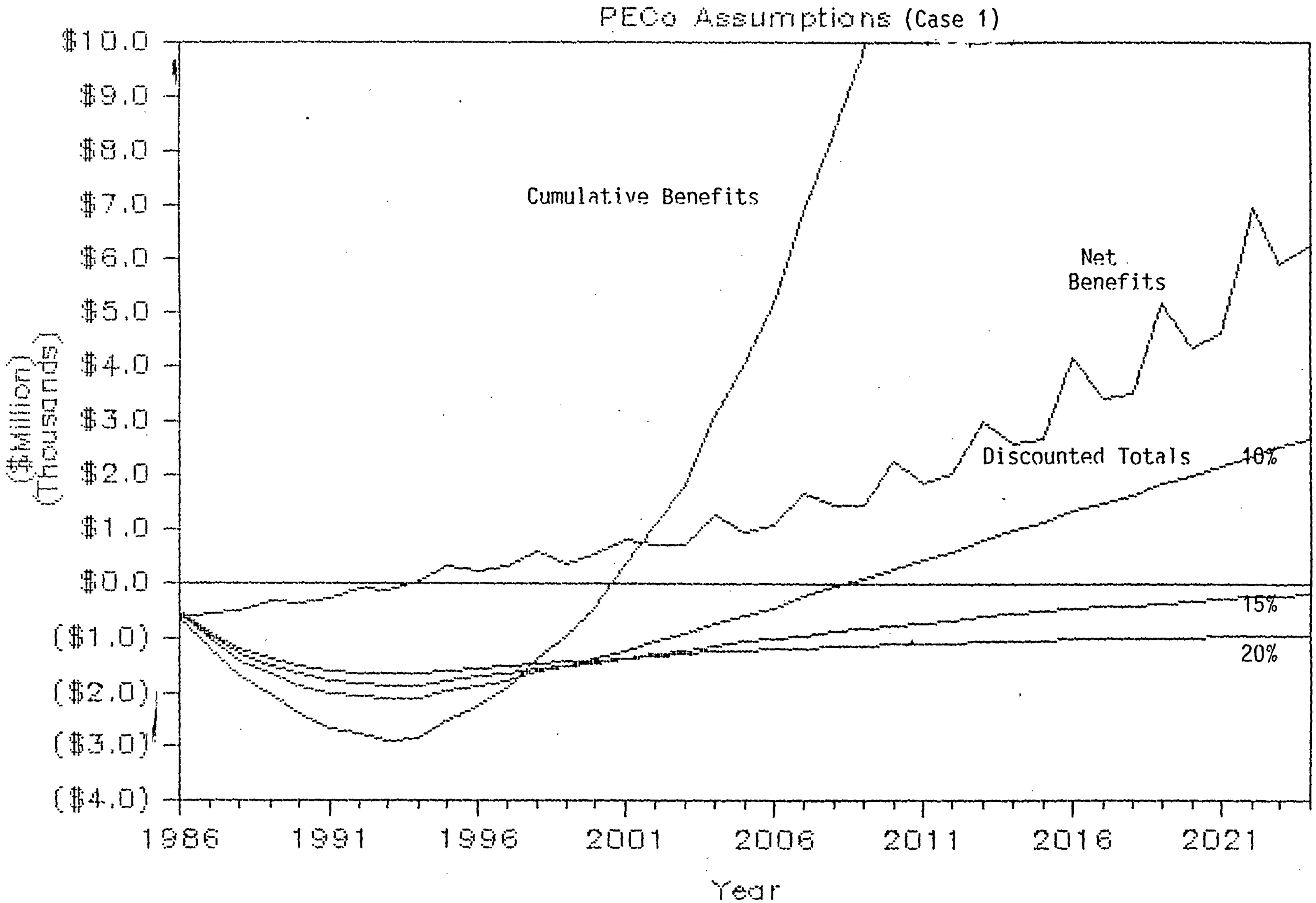


FIGURE 3.3: LIMERICK 1 RATE IMPACT

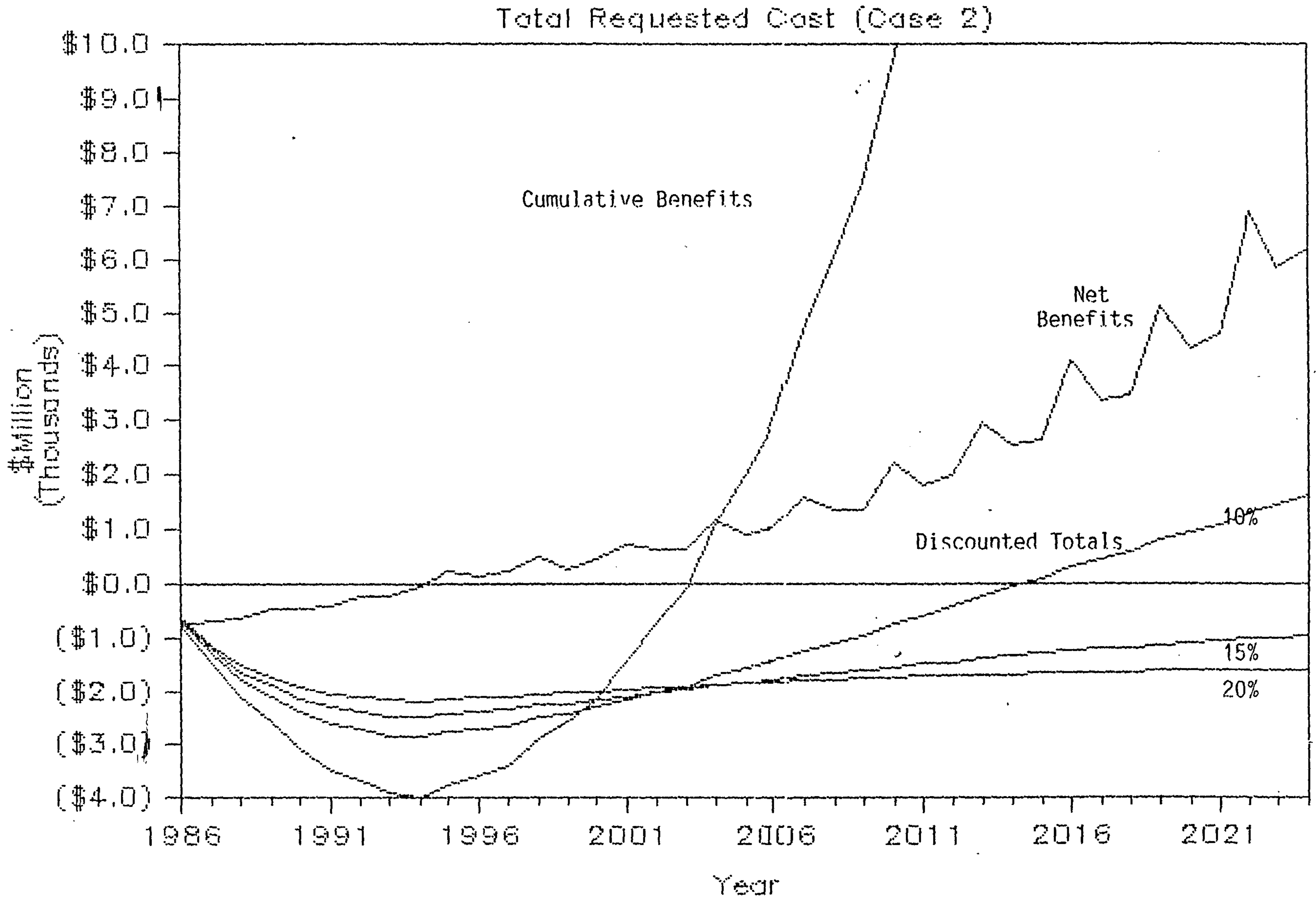


FIGURE 3.4: LIMERICK 1 RATE IMPACT

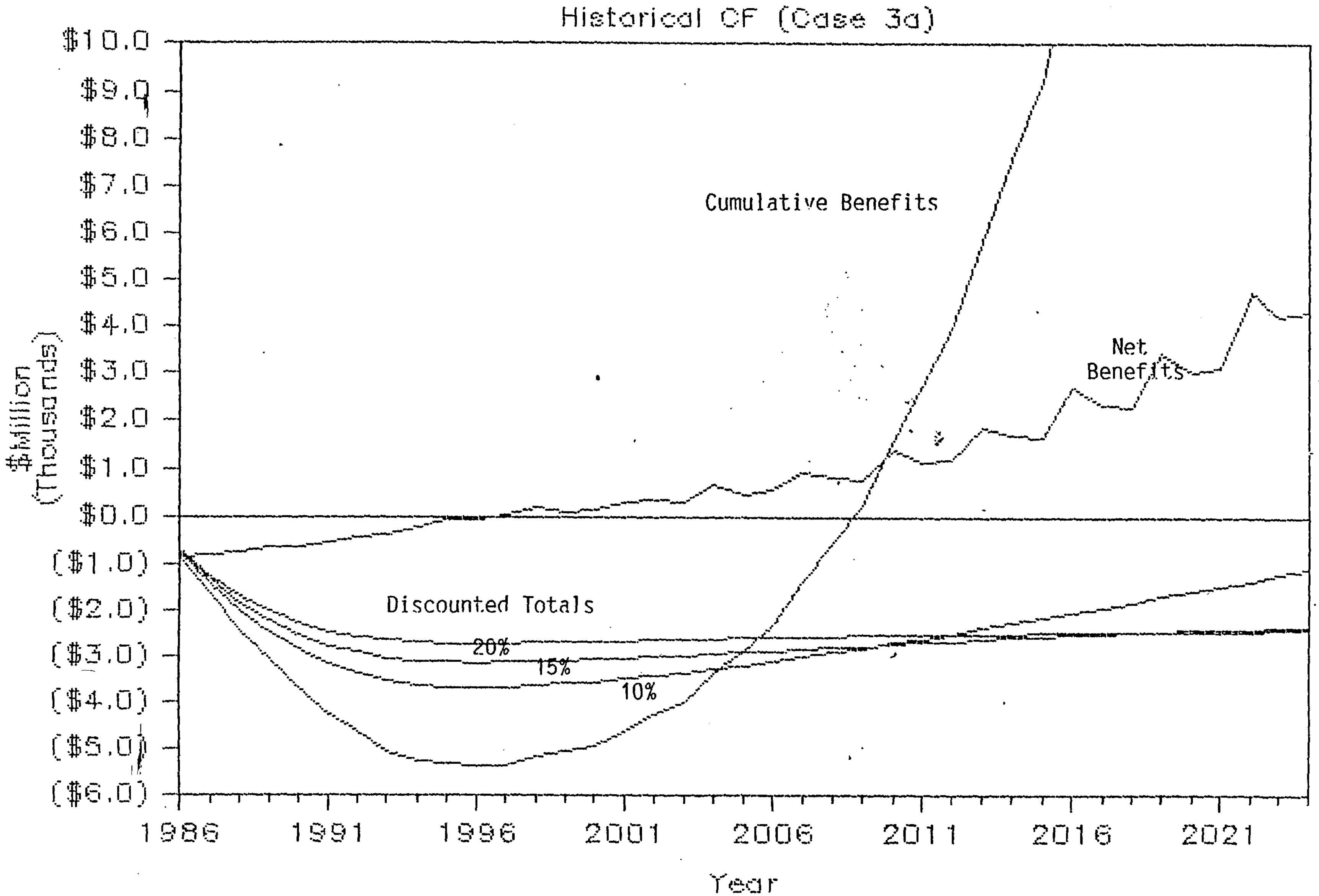


FIGURE 3.5: LIMERICK 1 RATE IMPACT

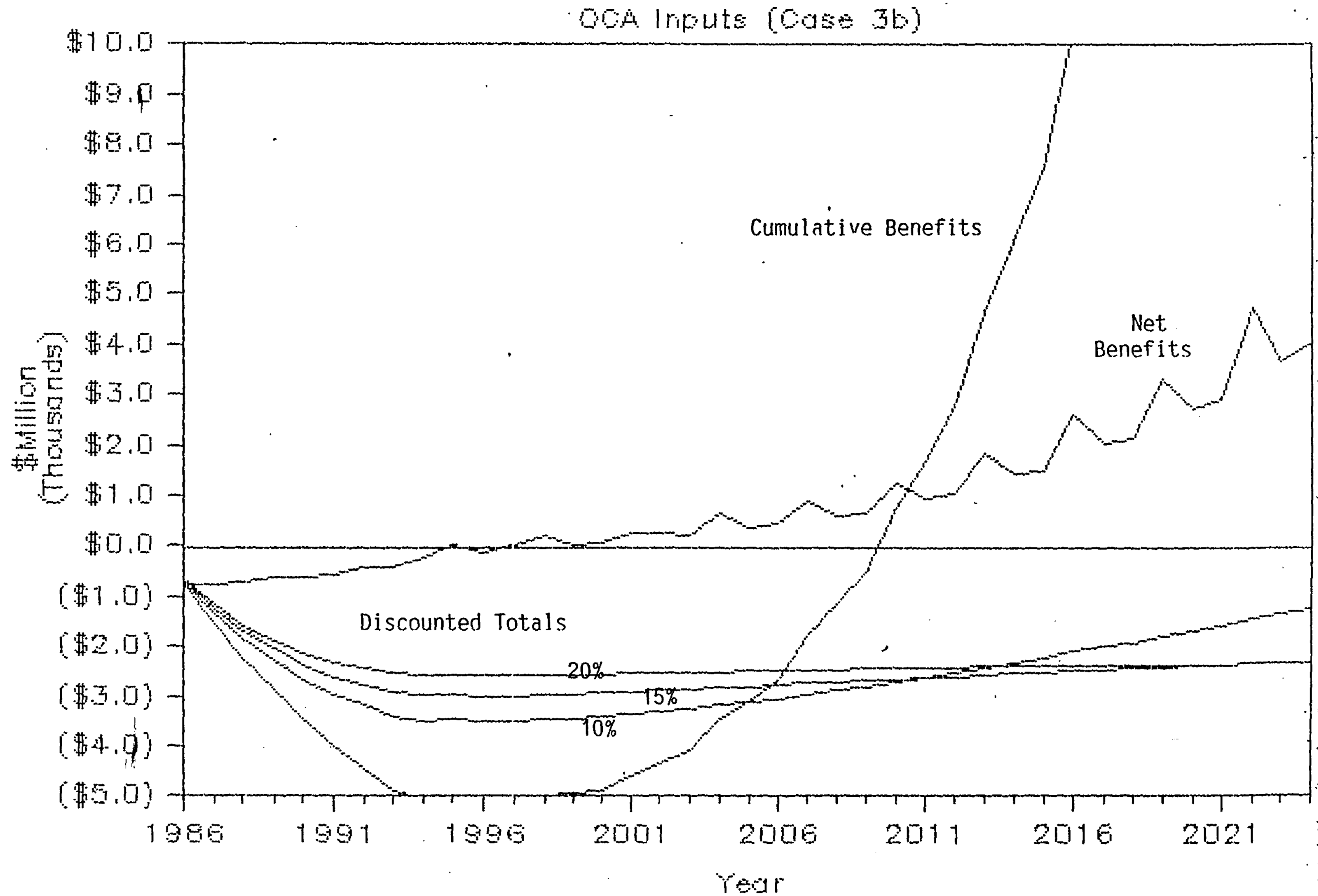
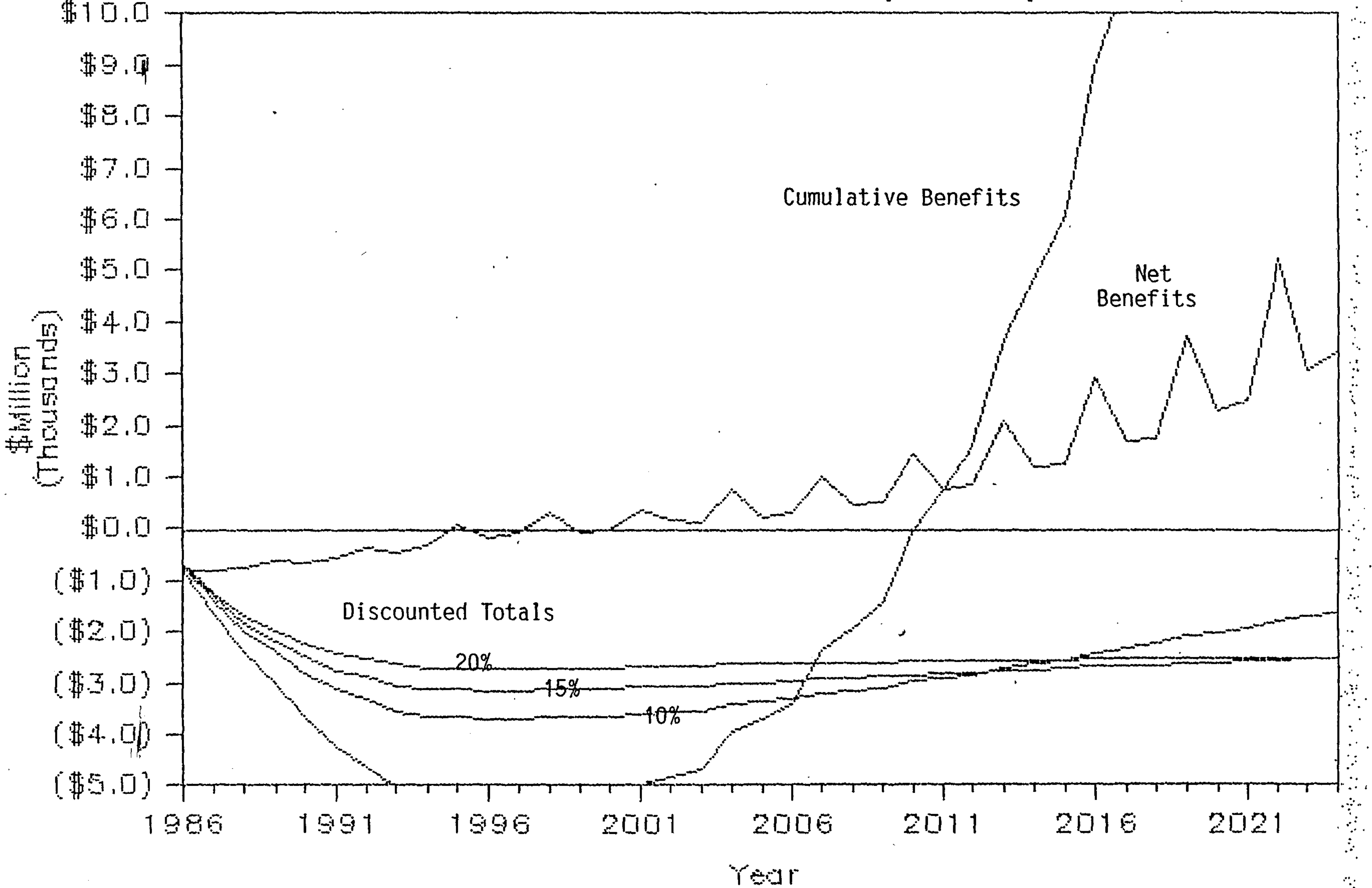


FIGURE 3.6: LIMERICK 1 RATE IMPACT

OCA Fuel, Historical CF (Case 3c)



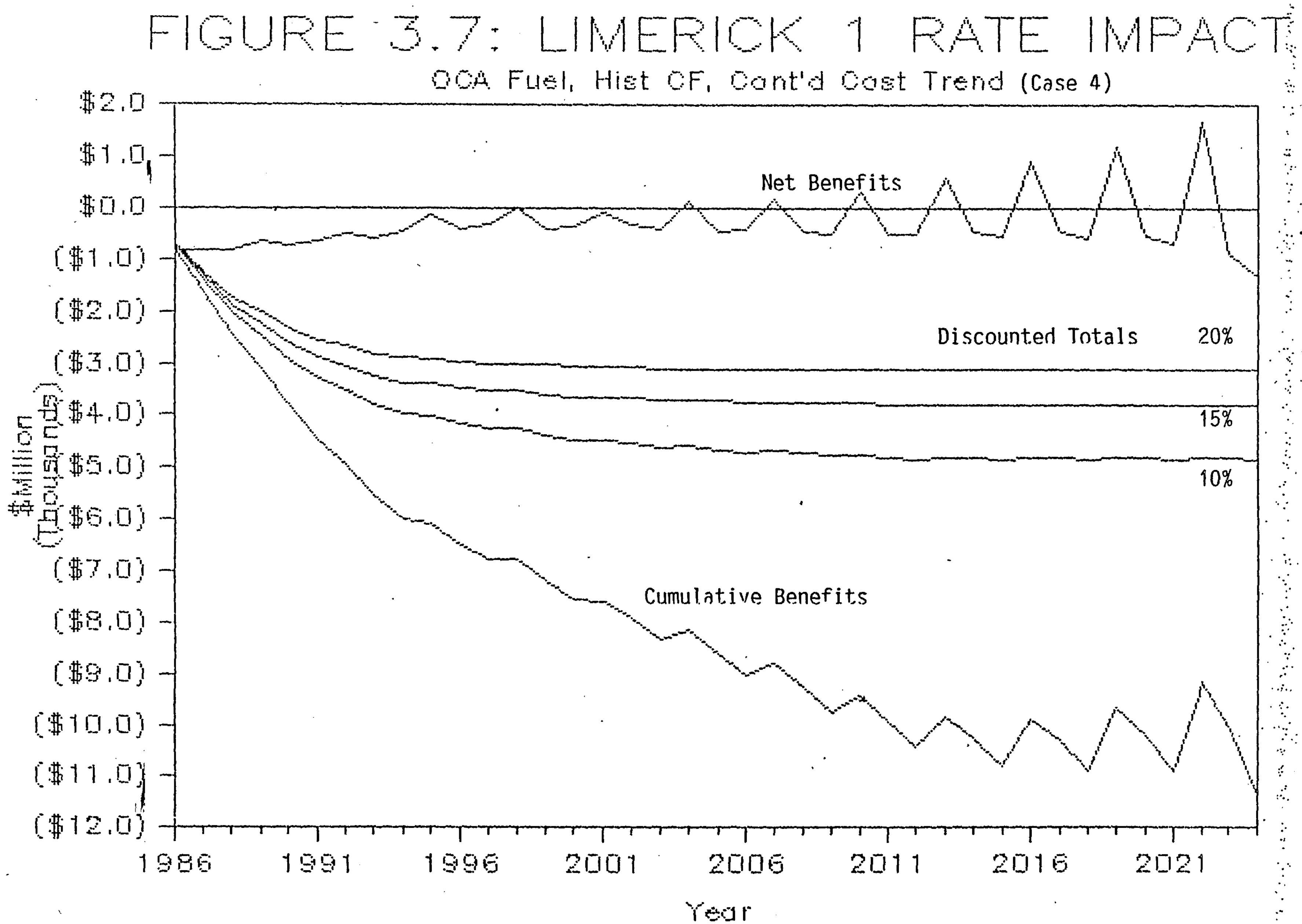
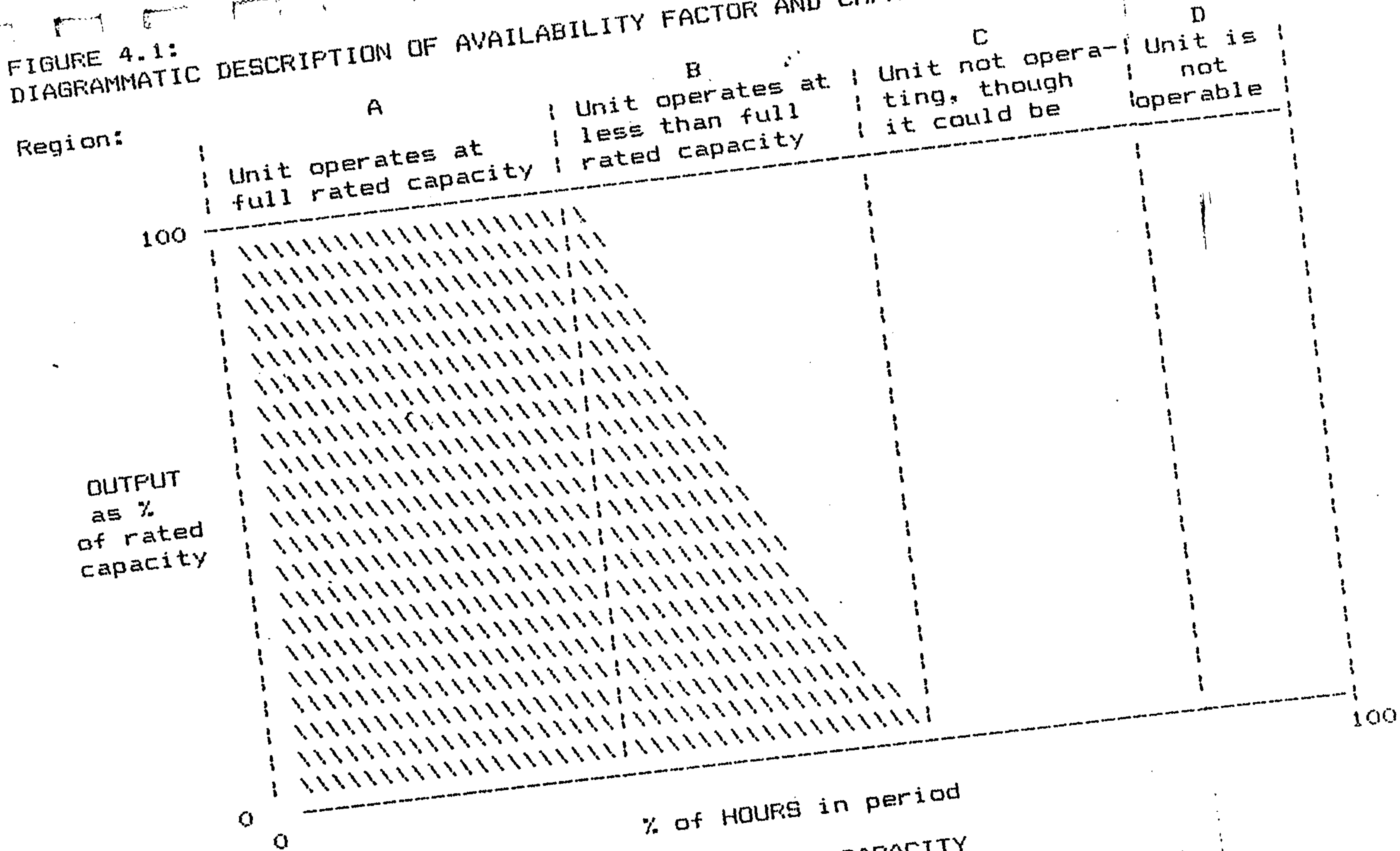


FIGURE 3.7: LIMERICK 1 RATE IMPACT
OCA Fuel, Hist CF, Cont'd Cost Trend (Case 4)
$2.0
$1.0
$0.0
($1.0)
($2.0)
($3.0)
($4.0)
($5.0)
($6.0)
($7.0)
($8.0)
($9.0)
($10.0)
($11.0)
($12.0)
$Million (Thousands)
Net Benefits
Discounted Totals
20%
15%
10%
Cumulative Benefits
1986
1991
1996
2001
2006
2011
2016
2021
Year

FIGURE 4.1:
DIAGRAMMATIC DESCRIPTION OF AVAILABILITY FACTOR AND CAPACITY FACTOR

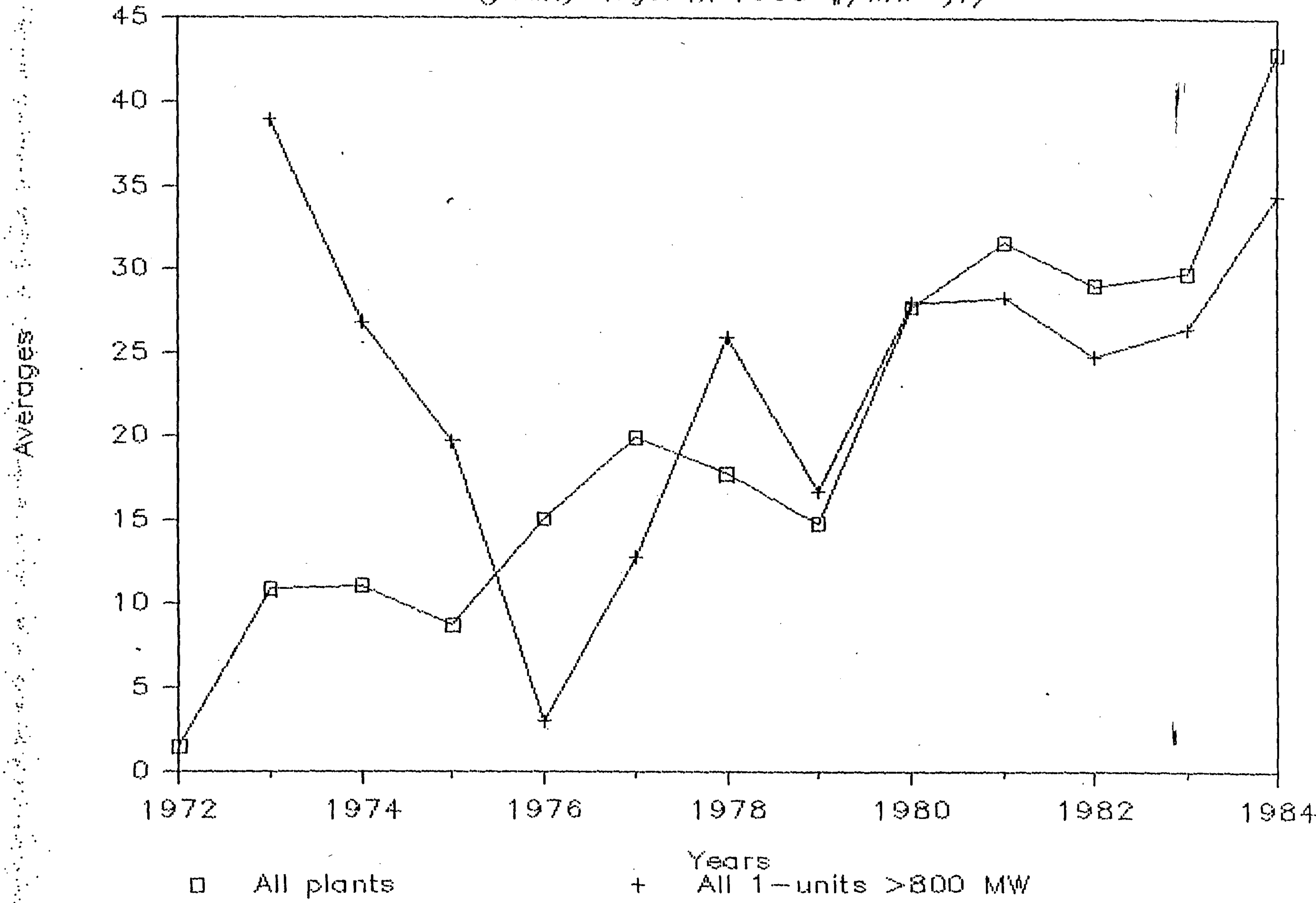


1. CAPACITY FACTOR = AVERAGE OUTPUT / RATED CAPACITY
   (Shaded Area / Area of Rectangle)

2. AVAILABILITY FACTOR = POSSIBLE HOURS OF PRODUCTION / TOTAL HOURS
   (Sum of widths A,B,C & D)

FIGURE 4.2: CAPITAL ADDITIONS

(yearly avgs. in 1983 $/MW-yr)



APPENDIX A

RESUME OF PAUL CHERNICK

PAUL L. CHERNICK

Analysis and Inference, Inc.
10 Post Office Square
Boston, Massachusetts 02109
(617) 542-0611

PROFESSIONAL EXPERIENCE

Research Associate, Analysis and Inference, Inc.

May, 1981 - present (Consultant, 1980-1981)

Research, consulting and testimony in various aspects of utility and insurance regulation. Designed self-insurance pool for nuclear decommissioning; estimated probability and cost of insurable events, and rate levels; assessed alternative rate designs. Projected nuclear power plant construction, operation, and decommissioning costs. Assessed reasonableness of earlier estimates of nuclear power plant construction schedules and costs. Reviewed prudence of utility construction decisions.

Consulted on utility rate design issues including small power producer rates; retail natural gas rates; public agency electric rates; and comprehensive electric rate design for a regional power agency. Developed electricity cost allocations between customer classes.

Reviewed district heating system efficiency. Proposed power plant performance standards. Analyzed auto insurance profit requirements. Designed utility-financed, decentralized conservation program. Analyzed cost-effectiveness of transmission lines.

Utility Rate Analyst, Massachusetts Attorney General
December, 1977 - May, 1981

Analyzed utility filings and prepared alternative proposals. Participated in rate negotiations, discovery, cross-examination, and briefing. Provided extensive expert testimony before various regulatory agencies.

Topics included: demand forecasting, rate design, marginal costs, time-of-use rates, reliability issues, power pool operations, nuclear power cost projections, power plant cost-benefit analysis, energy conservation and alternative energy development.

EDUCATION

S.M., Technology and Policy Program, Massachusetts Institute of Technology, February, 1978

S.B., Ci~~vil~~ Engineering Department, Massachusetts Institute of Technology, June, 1974

HONORARY SOCIETIES

Chi Epsilon (Civil Engineering)
Tau Beta Pi (Engineering)
Sigma Xi (Research)

OTHER HONORS

Institute Award, Institute of Public Utilities, 1981

PUBLICATIONS

Eden, P., Fairley, W., Aller, C., Vencill, C., Meyer, B., and Chernick, P., "Forensic Economics and Statistics: An Introduction to the Current State of the Art," The Practical Lawyer, June 1, 1985, pp. 25-36.

Chernick, P., "Power Plant Performance Standards: Some Introductory Principles," Public Utilities Fortnightly, April 18, 1985, pp. 29-33.

Chernick, P., "Opening the Utility Market to Conservation: A Competitive Approach," in Energy Industries in Transition, 1985-2000, Proceedings of the Sixth Annual North American Meeting of the International Association of Energy Economists, San Francisco, California, November, 1984, pp. 1133-1145.

Meyer, M., Chernick, P., and Fairley, W., "Insurance Market Assessment of Technological Risks," presented at the Annual Meeting of the Society of Risk Analysis, Knoxville, Tennessee, October, 1984.

Chernick, P., "Revenue Stability Target Ratemaking," Public Utilities Fortnightly, February 17, 1983, pp. 35-39.

Capacity/Energy Allocations for Generation and Transmission Plant," in Award Papers in Public Utility Economics and Regulation, Institute for Public Utilities, Michigan State University, 1982.

Chernick, P., Fairley, W., Meyer, M., and Scharff, L., Design, Costs and Acceptability of an Electric Utility Self-Insurance Pool for Assuring the Adequacy of Funds for Nuclear Power Plant Decommissioning Expense (NUREG/CR-2370), U.S. Nuclear Regulatory Commission, December, 1981.

Chernick, P., Optimal Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions (Report 77-1), Technology and Policy Program, Massachusetts Institute of Technology, September, 1977.

PRESENTATIONS

New England Utility Rate Forum; Plymouth, Massachusetts, October 11, 1985; "Lessons from Massachusetts on Long Term Rate for QF's"

National Association of State Utility Consumer Advocates; Williams Massachusetts, August 13, 1984; "Power Plant Performance".

National Conference of State Legislatures; Boston, Massachusetts, August 6, 1984; "Utility Rate Shock"

National Governors' Association Working Group on Nuclear Power Cost Overruns; Washington, D.C.; June 20, 1984; "Review and Modification of Regulatory and Rate Making Policy".

Annual Meeting of the American Association for the Advancement of Science, Session on Monitoring for Risk Management, Detroit, Michigan, May 27, 1983. "Insurance Market Assessment of Technological Risks".

EXPERT TESTIMONY

In each entry, the following information is presented in order: jurisdiction and docket number; title of case; client; date testimony filed; and subject matter covered. Abbreviations of jurisdictions include: MDPU (Massachusetts Department of Public Utilities); MEFSC (Massachusetts Energy Facilities Siting Council); PSC (Public Service Commission); and PUC (Public Utilities Commission).

1. MEFSC 78-12/MDPU 19494, Phase I; Boston Edison 1978 forecast; Mass. Attorney General; June 12, 1978.

   Appliance penetration projections, price elasticity, econometric commercial forecast, peak demand forecast. Joint testimony with S.C. Geller.

2. MEFSC 78-17; Northeast Utilities 1978 forecast; Mass. Attorney General; September 29, 1978.

   Specification of economic/demographic and industrial models, appliance efficiency, commercial model structure and estimation.

3. MEFSC 78-33; Eastern Utilities Associates 1978 forecast; Mass. Attorney General; November 27, 1978.

   Household size, appliance efficiency, appliance penetration, price elasticity, commercial forecast, industrial trending, peak demand forecast.

4. MDPU 19494, Phase II; Boston Edison Company Construction Program; Mass. Attorney General; April 1, 1979.

   Reviewed numerous aspects of the 1978 demand forecasts of nine New England electric utilities, constituting 92% of projected regional demand growth, and of the NEPOOL demand forecast. Joint testimony with S.C. Geller.

5. MDPU 19494, Phase II; Boston Edison Company Construction Program; Mass. Attorney General; April 1, 1979.

   Reliability, capacity planning, capability responsibility allocation, customer generation, co-generation rates, reserve margins, operating reserve allocation. Joint testimony with S. Finger.

6. Atomic Safety and Licensing Board, Nuclear Regulatory Commission 50-471; Pilgrim Unit 2, Boston Edison Company; Commonwealth of Massachusetts; June 29, 1979.

   Review of the Oak Ridge National Laboratory and the NEPOOL demand forecast models; cost-effectiveness of oil deplacement; nuclear economics. Joint testimony with S.C. Geller.

7. MDPU 19845; Boston Edison Time-of-Use Rate Case; Mass. Attorney General; December 4, 1979.

   Critiquing of utility marginal cost study and proposed rates; principles of marginal cost principles, cost derivation, and rate design; options for reconciling costs and revenues. Joint testimony with S.C. Geller. Testimony eventually withdrawn due to delay in case.

8. MDPU 20055; Petition of Eastern Utilities Associates, New Bedford G. & E., and Fitchburg G. & E. to purchase additional shares of Seabrook Nuclear Plant; Mass. Attorney General; January 23, 1980.

   Review of demand forecasts of three utilities purchasing Seabrook shares, Seabrook power costs, including construction cost, completion date, capacity factor, O & M expenses, interim replacements, reserves and uncertainties; alternative energy sources, including conservation, cogeneration, rate reform, solar, wood and coal prevention.

9. MDPU 20248; Petition of MMWEC to Purchase Additional Share of Seabrook Nuclear Plant; Mass. Attorney General; June 2, 1980.

   Nuclear power costs; update and extension of MDPU 20055 testimony.

10. MDPU 200; Massachusetts Electric Company Rate Case; Mass. Attorney General; June 16, 1980.

    Rate design; declining blocks, promotional rates, alternative energy, demand charges, demand ratchets; conservation: master metering, storage heating, efficiency standards, restricting resistance heating.

11. MEFSC 79-33; Eastern Utilities Associates 1979 Forecast; Mass. Attorney General; July 16, 1980.

    Customer projections, consistency issues, appliance efficiency, new appliance types, commercial specifications, industrial data manipulation and trending, sales and resale.

12. MDPU 243; Eastern Edison Company Rate Case; Mass. Attorney General; August 19, 1980.

Rate design: declining blocks, promotional rates, alternative energy, master metering.

13. Texas PUC 3298; Gulf States Utilities Rate Case; East Texas Legal Services; August 25, 1980.

Inter-class revenue allocations, including production plant in service, O & M, CWIP, nuclear fuel in progress, amortization of cancelled plant residential rate design; interrruptible rates; off-peak rates. Joint testimony with M.B. Meyer.

14. MEFSC 79-1; Massachusetts Municipal Wholesale Electric Company Forecast; Mass. Attorney General; November 5, 1980.

Cost comparison methodology; nuclear cost estimates; cost of conservation, cogeneration, and solar.

15. MDPU 472; Recovery of Residential Conservation Service Expenses; Mass. Attorney General; December 12, 1980.

Conservation as an energy source; advantages of per-kwh allocation over per-customer month allocation.

16. MDPU 535; Regulations to Carry Out Section 210 of PURPA; Mass. Attorney General; January 26, 1981 and February 13, 1981.

Filing requirements, certification, qualifying facility (QF) status, extent of coverage, review of contracts; energy rates; capacity rates; extra benefits of QF's in specific areas; wheeling; standardization of fees and charges.

17. MEFSC 80-17; Northeast Utilities 1980 Forecast; Mass. Attorney General; March 12, 1981 (not presented).

Specification process, employment, electric heating promotion and penetration, commercial sales model, industrial model specification, documentation of price forecast and wholesale forecast.

18. MDPU 558; Western Massachsuetts Electric Company Rate Case; Mass. Attorney General; May, 1981.

Rate design; declinig blocks, marginal cost, conservation impacts, promotional rates; conservation: terms and conditions limiting renewables, cogeneration, small power production; scope of current conservation program; efficient insulation levels; additional conservation opportunities.

19. MDPU 1048; Boston Edison Plant Performance Standards; Mass. Attorney General; May 7, 1982.

Critique of company approach, data, and statistical analysis; description of comparative and absolute approaches to standard-setting; proposals for standards and reporting requirements.

20. DCPSC FC785; Potomac Electric Power Rate Case: DC People's Counsel; July 29, 1982.

Inter-class revenue allocations, including generation, transmission, and distribution plant classification; fuel and O & M classification; distribution and service allocators. Marginal cost estimation, including losses.

21. NHPUC DE81-312; Public Service of New Hampshire - Supply and Demand; Conservation Law Foundation, et al., October 8, 1982.

Conservation program design, ratemaking, and effectiveness. Cost of nuclear power, including construction cost and duration, capacity factor, O & M, replacements, insurance, and decommissioning.

22. Massachusetts Division of Insurance; Hearing to Fix and Establish 1983 Automobile Insurance Rates; Massachusetts Attorney General; October, 1982.

Profit margin calculations, including methodology, interest rates, surplus flow, tax flows, tax rates, and risk premium.

23. Illinois Commerce Commission 82-0026; Commonwealth Edison Rate Case; Illinois Attorney General; October 15, 1982.

Review of Cost-Benefit Analysis for nuclear plant. Nuclear cost parameters (construction cost, O & M, capital additions, useful life, capacity factor), risks, discount rates, evaluation techniques.

24. New Mexico Public Service Commission 1794; Public Service of New Mexico Application for Certification; New Mexico Attorney General; May 10, 1983.

Review of Cost-Benefit Analysis for transmission line. Review of electricity price forecast, nuclear capacity factors, load forecast. Critique of company ratemaking proposals; development of alternative ratemaking.

25. Connecticut Public Utility Control Authority 830301; United Illuminating Rate Case; Connecticut Consumers Counsel; June 17, 1983.

    Cost of Seabrook nuclear power plants, including construction cost and duration, capacity factor, O & M, replacements, insurance, and decommissioning.

26. MDPU 1509; Boston Edison Plant Performance Standards; Massachusetts Attorney General; July 15, 1983.

    Critiquing of company approach and statistical analysis; regression model of nuclear capacity factor; proposals for standards and for standard-setting methodologies.

27. Massachusetts Division of Insurance; Hearing to Fix and Establish 1983 Automobile Insurance Rates; Massachusetts Attorney General; October, 1983.

    Profit margin calculations, including methodology, interest rates, surplus flow, tax rates, and recognition of risk.

28. Connecticut Public Utility Control Authority 83-07-15; Connecticut Light and Power Rate Case; Alloy Foundry; October 3, 1983.

    Industrial rate design. Marginal and embedded costs; classification of generation, transmission, and distribution expenses; demand U.S. energy charges.

29. MEFSC 83-24; New England Electric System Forecast of Electric Resources and Requirements; Massachusetts Attorney General; November 14, 1983, Rebuttal, February 2, 1984.

    Need for transmission line. Status of supply plan, especially Seabrook 2. Review of interconnection requirements. Analysis of cost-effectiveness for power transfer, line losses, generation assumptions.

30. Michigan PSC U-7775; Detroit Edison Fuel Cost Recovery Plan; Public Interest Research Group in Michigan; February 21, 1984.

    Review of proposed performance target for new nuclear power plant. Formulation of alternative proposals.

31. MDPU 84-25; Western Massachusetts Electric Company Rate Case; Mass. Attorney General; April 6, 1984.

Need for Millstone 3. Cost of completing and operating unit, cost-effectiveness compared to alternatives, and its effect on rates. Equity and incentive problems created by CWIP. Design of Millstone 3 phase-in proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

32. MDPU 84-49 and 84-50; Fitchburg Gas & Electric Financing Case; Massachusetts Attorney General; April 13, 1984.

Cost of completing and operating Seabrook nuclear units. Probability of completing Seabrook 2. Recommendations regarding FG&E and MDPU actions with respect to Seabrook.

33. Michigan PSC U-7785; Consumers Power Fuel Cost Recovery Plan; Public Interest Research Group in Michigan; April 16, 1984.

Review of proposed performance targets for two existing and two new nuclear power plants. Formulation of alternative proposals.

34. FERC ER81-749-000 and ER82-325-000; Montaup Electric Rate Cases; Massachusetts Attorney General; April 27, 1984.

Prudence of Montaup and Boston Edison in decisions regarding Pilgrim 2 construction: Montaup's decision to participate, the utilities' failure to review their earlier analyses and assumptions, Montaup's failure to question Edison's decisions, and the utilities' delay in canceling the unit.

35. Maine PUC 84-113; Seabrook 1 Investigation; Maine Public Advocate; September 13, 1984.

Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate effects. Recommendations regarding utility and PUC actions with respect to Seabrook.

36. MDPU 84-145; Fitchburg Gas and Electric Rate Case; Massachusetts Attorney General; November 6, 1984.

Prudence of Fitchburg and Public Service of New Hampshire in decisions regarding Seabrook 2 construction: FGE's decision to participate, the utilities' failure to review their earlier analyses and assumptions, FGE's failure to question PSNH's decisions, and the utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

37. Pennsylvania PUC R-842651; Pennsylvania Power and Light Rate Case; Pennsylvania Consumer Advocate; November, 1984.

Need for Susquehanna 2. Cost of operating unit, power output, cost-effectiveness compared to alternatives, and its effect on rates. Design of phase-in and excess capacity proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

38. NHPUC 84-200; Seabrook 1 Investigation; New Hampshire Public Advocate; November 15, 1984.

Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate and financial effects.

39. Massachusetts Division of Insurance; Hearing to Fix and Establish 1985 Automobile Insurance Rates; Massachusetts Attorney General; November, 1984.

Profit margin calculations, including methodology and implementation.

40. MDPU 84-152; Seabrook Unit 1 Investigation; Massachusetts Attorney General; December 12, 1984.

Cost of completing and operating Seabrook. Probability of completing Seabrook 1. Seabrook capacity factors.

41. Maine PUC 84-120; Central Maine Power Rate Case; Maine PUC Staff; December 11, 1984.

Prudence of Central Maine Power and Boston Edison in decisions regarding Pilgrim 2 construction: CMP's decision to participate, the utilities' failure to review their earlier analyses and assumptions, CMP's failure to question Edison's decisions, and the utilities' delay in canceling the unit. Prudence of CMP in the planning and investment in Sears Island nuclear and coal plants. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

42. Maine PUC 84-113; Seabrook 2 Investigation; Maine PUC Staff; December 14, 1984.

Prudence of Maine utilities and Public Service of New Hampshire in decisions regarding Seabrook 2 construction: decisions to participate and to increase ownership share, the utilities' failure to review their earlier analyses and assumptions, failure to question PSNH's decisions, and the utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

43. MDPU 1627; Massachusetts Municipal Wholesale Electric Company Financing Case; Massachusetts Executive Office of Energy Resources; January 14, 1985.

Cost of completing and operating Seabrook nuclear unit 1. Cost of conservation and other alternatives to completing Seabrook. Comparison of Seabrook to alternatives.

44. Vermont PSB 4936; Millstone 3: Costs and In-Service Date; Vermont Department of Public Service; January 21, 1985.

Construction schedule and cost of completing Millstone Unit 3.

45. MDPU 84-276; Rules Governing Rates for Utility Purchases of Power from Qualifying Facilities; Massachusetts Attorney General; March 25, 1985, and October 18, 1985.

Institutional and technological advantages of Qualifying Facilties (QF's). Potential for QF development. Goals of QF rate design. Parity with other power sources. Security requirements. Projecting avoided costs. Capacity credits. Pricing options. Line loss corrections.

46. MDPU 85-121; Investigation of the Reading Municipal Light Department; Wilmington (MA) Chamber of Commerce; November 12, 1985.

Calculation of return on investment for municipal utility. Treatment of depreciation and debt for ratemaking. Geographical discrimination in street lighting rates. Relative size of voluntary payments to Reading and other towns. Surplus and disinvestment. Revenue allocation.

47. Massachusetts Division of Insurance; Hearing to Fix and Establish 1986 Automobile Insurance Rates; Massachusetts Attorney General; November, 1985.

Profit margin calculations, including methodology, implementation, modeling of investment balances, income, and return to shareholders.

APPENDIX B
CAPACITY FACTOR DATA

10 POST OFFICE SQUARE, SUITE 970 — BOSTON, MASSACHUSETTS 02109 — (617) 542-0611

Unit	COD	Year	Age at 7/1	Orig. DER	Annual GWH	CF@ original DER (Calculated)	Total Number of Refuelings
Nine Mi Pt	Dec-69	70	0.54	610		0.0%	
Nine Mi Pt	Dec-69	71	1.54	610		0.0%	
Nine Mi Pt	Dec-69	72	2.55	610		0.0%	
Nine Mi Pt	Dec-69	73	3.55	610		0.0%	
Nine Mi Pt	Dec-69	74	4.55	610	3297	61.7%	1.000
Nine Mi Pt	Dec-69	75	5.55	610	3045	57.0%	1.000
Nine Mi Pt	Dec-69	76	6.55	610	4113	76.8%	0.000
Nine Mi Pt	Dec-69	77	7.55	610	2946	55.1%	1.000
Nine Mi Pt	Dec-69	78	8.55	610	4467	83.6%	0.000
Nine Mi Pt	Dec-69	79	9.55	610	3005	56.2%	1.000
Nine Mi Pt	Dec-69	80	10.55	610	4538	84.7%	0.000
Nine Mi Pt	Dec-69	81	11.55	610	3270	61.2%	1.000
Nine Mi Pt	Dec-69	82	12.55	610	1135	21.2%	0.000
Nine Mi Pt	Dec-69	83	13.55	610	2802	52.4%	0.000
Nine Mi Pt	Dec-69	84	14.55	610	3635	68.0%	1.000
Oyster Creek	Dec-69	70	0.54	650		0.0%	
Oyster Creek	Dec-69	71	1.54	650		0.0%	
Oyster Creek	Dec-69	72	2.55	650		0.0%	
Oyster Creek	Dec-69	73	3.55	650		0.0%	
Oyster Creek	Dec-69	74	4.55	650	3673	64.5%	1.000
Oyster Creek	Dec-69	75	5.55	650	3146	55.2%	1.064
Oyster Creek	Dec-69	76	6.55	650	3860	67.6%	0.936
Oyster Creek	Dec-69	77	7.55	650	3248	57.0%	1.000
Oyster Creek	Dec-69	78	8.55	650	3646	64.0%	1.000
Oyster Creek	Dec-69	79	9.55	650	4563	80.1%	0.000
Oyster Creek	Dec-69	80	10.55	650	1958	34.3%	1.000
Oyster Creek	Dec-69	81	11.55	650	2629	46.2%	0.000
Oyster Creek	Dec-69	82	12.55	650	2013	35.4%	0.000
Oyster Creek	Dec-69	83	13.55	650	205	3.6%	0.513
Oyster Creek	Dec-69	84	14.55	650	279	4.9%	0.487
Millstone 1	Mar-71	72	1.30	690		0.0%	
Millstone 1	Mar-71	73	2.30	690		0.0%	
Millstone 1	Mar-71	74	3.30	690	3604	59.6%	1.000
Millstone 1	Mar-71	75	4.30	690	3897	64.5%	0.000
Millstone 1	Mar-71	76	5.30	690	3752	61.9%	1.000
Millstone 1	Mar-71	77	6.30	690	4820	79.7%	0.000
Millstone 1	Mar-71	78	7.30	690	4655	77.0%	1.000
Millstone 1	Mar-71	79	8.30	690	4221	69.8%	1.000
Millstone 1	Mar-71	80	9.30	690	3390	55.9%	0.451
Millstone 1	Mar-71	81	10.30	690	2519	41.7%	0.549
Millstone 1	Mar-71	82	11.30	690	4078	67.5%	1.000
Millstone 1	Mar-71	83	12.30	690	5354	88.6%	0.000
Millstone 1	Mar-71	84	13.31	690	4323	71.5%	1.000
Monticello	Jul-71	72	0.96	545		0.0%	
Monticello	Jul-71	73	1.96	545		0.0%	
Monticello	Jul-71	74	2.96	545	2924	61.2%	1.000
Monticello	Jul-71	75	3.96	545	2879	60.3%	2.000
Monticello	Jul-71	76	4.97	545	3986	83.3%	0.000
Monticello	Jul-71	77	5.97	545	3569	74.8%	1.000

Unit	COD	Year	Age at 7/1	Orig. DER	Annual GWH	CF@ original DER (Calculated)	Total Number of Refuelings
Monticello	Jul-71	78	6.97	545	3856	80.8%	1.000
Monticello	Jul-71	79	7.97	545	4400	92.2%	0.000
Monticello	Jul-71	80	8.97	545	3454	72.1%	1.000
Monticello	Jul-71	81	9.97	545	3258	68.2%	1.000
Monticello	Jul-71	82	10.97	545	2421	50.7%	1.000
Monticello	Jul-71	83	11.97	545	4148	86.9%	0.000
Monticello	Jul-71	84	12.97	545	263	5.5%	0.947
Dresden 3	Nov-71	72	0.63	809		0.0%	
Dresden 3	Nov-71	73	1.63	809		0.0%	
Dresden 3	Nov-71	74	2.63	809	3200	45.2%	1.000
Dresden 3	Nov-71	75	3.63	809	2190	30.9%	1.000
Dresden 3	Nov-71	76	4.63	809	4035	56.8%	1.000
Dresden 3	Nov-71	77	5.63	809	5186	73.2%	0.000
Dresden 3	Nov-71	78	6.63	809	3832	54.1%	1.000
Dresden 3	Nov-71	79	7.63	809	3476	49.0%	0.000
Dresden 3	Nov-71	80	8.63	809	4330	60.9%	1.000
Dresden 3	Nov-71	81	9.63	809	5178	73.1%	0.000
Dresden 3	Nov-71	82	10.63	809	3888	54.9%	1.000
Dresden 3	Nov-71	83	11.63	809	4148	58.5%	0.432
Dresden 3	Nov-71	84	12.64	809	2106	29.7%	0.568
Dresden 2	Jun-72	73	1.04	809		0.0%	
Dresden 2	Jun-72	74	2.04	809	3380	47.7%	0.301
Dresden 2	Jun-72	75	3.04	809	2966	41.9%	0.699
Dresden 2	Jun-72	76	4.05	809	4372	61.5%	1.000
Dresden 2	Jun-72	77	5.05	809	3533	49.8%	1.000
Dresden 2	Jun-72	78	6.05	809	5704	80.5%	0.000
Dresden 2	Jun-72	79	7.05	809	4940	69.7%	1.000
Dresden 2	Jun-72	80	8.05	809	4581	64.5%	0.000
Dresden 2	Jun-72	81	9.05	809	3408	48.1%	1.000
Dresden 2	Jun-72	82	10.05	809	5123	72.3%	0.000
Dresden 2	Jun-72	83	11.05	809	3398	47.9%	1.000
Dresden 2	Jun-72	84	12.05	809	4460	62.9%	0.446
Vermont Yankee	Nov-72	73	0.62	514		0.0%	0.000
Vermont Yankee	Nov-72	74	1.62	514	2483	55.1%	1.000
Vermont Yankee	Nov-72	75	2.62	514	3561	79.1%	0.000
Vermont Yankee	Nov-72	76	3.63	514	3260	72.2%	1.000
Vermont Yankee	Nov-72	77	4.63	514	3538	78.5%	1.000
Vermont Yankee	Nov-72	78	5.63	514	3241	72.0%	1.000
Vermont Yankee	Nov-72	79	6.63	514	3449	76.6%	1.000
Vermont Yankee	Nov-72	80	7.63	514	2979	66.0%	1.000
Vermont Yankee	Nov-72	81	8.63	514	3569	79.3%	1.000
Vermont Yankee	Nov-72	82	9.63	514	4174	92.7%	0.000
Vermont Yankee	Nov-72	83	10.63	514	2874	63.8%	1.000
Vermont Yankee	Nov-72	84	11.63	514	3336	74.1%	0.000
Pilgrim 1	Dec-72	73	0.58	670		0.0%	
Pilgrim 1	Dec-72	74	1.58	670	1973	33.6%	0.000
Pilgrim 1	Dec-72	75	2.58	670	2587	44.1%	0.000
Pilgrim 1	Dec-72	76	3.58	670	2416	41.0%	1.000
Pilgrim 1	Dec-72	77	4.58	670	2652	45.2%	1.000

Unit	COD	Year	Age at 7/1	Orig. DER	Annual GWH	CF@ original DER (Calculated)	Total Number of Refuelings
Pilgrim 1	Dec-72	78	5.58	670	4737	80.7%	0.000
Pilgrim 1	Dec-72	79	6.58	670	4844	82.5%	0.000
Pilgrim 1	Dec-72	80	7.59	670	3044	51.7%	1.000
Pilgrim 1	Dec-72	81	8.59	670	3444	58.7%	0.499
Pilgrim 1	Dec-72	82	9.59	670	3287	56.0%	0.501
Pilgrim 1	Dec-72	83	10.59	670	4712	80.3%	0.057
Pilgrim 1	Dec-72	84	11.59	670	4	0.1%	0.943
Quad Cities 1	Feb-73	74	1.37	809	3563	50.3%	1.000
Quad Cities 1	Feb-73	75	2.37	809	4271	60.3%	0.000
Quad Cities 1	Feb-73	76	3.38	809	3393	47.7%	1.000
Quad Cities 1	Feb-73	77	4.38	809	3521	49.7%	1.000
Quad Cities 1	Feb-73	78	5.38	809	4721	66.6%	0.000
Quad Cities 1	Feb-73	79	6.38	809	4783	67.5%	1.000
Quad Cities 1	Feb-73	80	7.38	809	3442	48.4%	1.000
Quad Cities 1	Feb-73	81	8.38	809	5727	80.8%	0.000
Quad Cities 1	Feb-73	82	9.38	809	3245	45.8%	1.000
Quad Cities 1	Feb-73	83	10.38	809	5776	81.5%	0.000
Quad Cities 1	Feb-73	84	11.38	809	3350	47.3%	1.000
Quad Cities 2	Mar-73	74	1.30	809	4470	63.1%	0.068
Quad Cities 2	Mar-73	75	2.30	809	2745	38.7%	0.932
Quad Cities 2	Mar-73	76	3.30	809	4305	60.6%	1.000
Quad Cities 2	Mar-73	77	4.30	809	4369	61.7%	0.000
Quad Cities 2	Mar-73	78	5.30	809	4427	62.5%	1.000
Quad Cities 2	Mar-73	79	6.30	809	3981	56.2%	0.250
Quad Cities 2	Mar-73	80	7.30	809	3614	50.9%	0.750
Quad Cities 2	Mar-73	81	8.30	809	3768	53.2%	1.000
Quad Cities 2	Mar-73	82	9.30	809	5059	71.4%	0.000
Quad Cities 2	Mar-73	83	10.30	809	3151	44.5%	0.708
Quad Cities 2	Mar-73	84	11.30	809	4984	70.3%	0.292
Peach Bottom 2	May-74	75	1.13	1065	5082	54.5%	0.000
Peach Bottom 2	May-74	76	2.13	1065	5570	59.5%	1.000
Peach Bottom 2	May-74	77	3.13	1065	4023	43.1%	1.000
Peach Bottom 2	May-74	78	4.13	1065	6794	72.8%	1.000
Peach Bottom 2	May-74	79	5.13	1065	8754	93.8%	0.000
Peach Bottom 2	May-74	80	6.13	1065	4344	46.4%	1.000
Peach Bottom 2	May-74	81	7.13	1065	6631	71.1%	0.000
Peach Bottom 2	May-74	82	8.13	1065	4794	51.4%	1.000
Peach Bottom 2	May-74	83	9.13	1065	4451	47.7%	0.000
Peach Bottom 2	May-74	84	10.14	1065	2426	26.0%	0.593
Cooper	Jul-74	75	0.96	778	3854	56.5%	0.000
Cooper	Jul-74	76	1.96	778	3643	53.3%	1.000
Cooper	Jul-74	77	2.96	778	4540	66.6%	1.000
Cooper	Jul-74	78	3.96	778	4887	71.7%	1.000
Cooper	Jul-74	79	4.96	778	4995	73.3%	1.000
Cooper	Jul-74	80	5.97	778	3788	55.4%	1.000
Cooper	Jul-74	81	6.97	778	3851	56.5%	1.000
Cooper	Jul-74	82	7.97	778	5276	77.4%	1.000
Cooper	Jul-74	83	8.97	778	3343	49.3%	1.000
Cooper	Jul-74	84	9.97	778	3470	50.9%	0.311

Unit	COD	Year	Age at 7/1	Orig. DER	Annual GWH	CF@ original DER (Calculated)	Total Number of Refuelings
Browns Ferry 1	Aug-74	75	0.88	1065	1348	14.4%	0.000
Browns Ferry 1	Aug-74	76	1.88	1065	1301	13.9%	0.000
Browns Ferry 1	Aug-74	77	2.88	1065	5043	54.1%	0.862
Browns Ferry 1	Aug-74	78	3.88	1065	5818	62.4%	0.138
Browns Ferry 1	Aug-74	79	4.88	1065	7496	80.3%	0.358
Browns Ferry 1	Aug-74	80	5.88	1065	6062	64.8%	1.000
Browns Ferry 1	Aug-74	81	6.88	1065	4405	47.2%	1.000
Browns Ferry 1	Aug-74	82	7.88	1065	7881	84.5%	0.000
Browns Ferry 1	Aug-74	83	8.88	1065	2176	23.3%	0.995
Browns Ferry 1	Aug-74	84	9.88	1065	7848	84.1%	0.005
Peach Bottom 3	Dec-74	75	0.54	1065	5282	56.6%	0.000
Peach Bottom 3	Dec-74	76	1.55	1065	6050	64.7%	0.436
Peach Bottom 3	Dec-74	77	2.55	1065	4774	51.2%	0.564
Peach Bottom 3	Dec-74	78	3.55	1065	6966	74.7%	1.000
Peach Bottom 3	Dec-74	79	4.55	1065	6102	65.4%	1.000
Peach Bottom 3	Dec-74	80	5.55	1065	7234	77.3%	0.000
Peach Bottom 3	Dec-74	81	6.55	1065	3132	33.6%	1.000
Peach Bottom 3	Dec-74	82	7.55	1065	8532	91.5%	0.000
Peach Bottom 3	Dec-74	83	8.55	1065	2421	26.0%	1.000
Peach Bottom 3	Dec-74	84	9.55	1065	7446	79.8%	0.000
Duane Arnold	Feb-75	76	1.38	538	2489	52.7%	1.000
Duane Arnold	Feb-75	77	2.38	538	2900	61.5%	1.000
Duane Arnold	Feb-75	78	3.38	538	1228	26.0%	1.000
Duane Arnold	Feb-75	79	4.38	538	2899	61.5%	0.000
Duane Arnold	Feb-75	80	5.38	538	2770	58.6%	1.000
Duane Arnold	Feb-75	81	6.38	538	2220	47.1%	1.000
Duane Arnold	Feb-75	82	7.38	538	2280	48.4%	0.000
Duane Arnold	Feb-75	83	8.38	538	2324	49.3%	1.000
Duane Arnold	Feb-75	84	9.38	538	2718	57.7%	0.000
Browns Ferry 2	Mar-75	76	1.30	1065	1567	16.8%	0.000
Browns Ferry 2	Mar-75	77	2.30	1065	6225	66.7%	0.000
Browns Ferry 2	Mar-75	78	3.30	1065	5547	59.5%	1.000
Browns Ferry 2	Mar-75	79	4.30	1065	7441	79.8%	1.000
Browns Ferry 2	Mar-75	80	5.30	1065	5619	60.1%	1.000
Browns Ferry 2	Mar-75	81	6.30	1065	7472	80.1%	0.000
Browns Ferry 2	Mar-75	82	7.30	1065	4451	47.7%	0.664
Browns Ferry 2	Mar-75	83	8.30	1065	6386	68.4%	0.336
Browns Ferry 2	Mar-75	84	9.30	1065	4044	43.4%	0.317
Fitzpatrick	Jul-75	76	0.96	821	4156	57.6%	0.000
Fitzpatrick	Jul-75	77	1.96	821	3893	54.1%	1.000
Fitzpatrick	Jul-75	78	2.96	821	4197	58.4%	1.000
Fitzpatrick	Jul-75	79	3.96	821	2965	41.2%	0.000
Fitzpatrick	Jul-75	80	4.97	821	4335	60.1%	1.000
Fitzpatrick	Jul-75	81	5.97	821	4780	66.5%	0.477
Fitzpatrick	Jul-75	82	6.97	821	4960	69.0%	0.523
Fitzpatrick	Jul-75	83	7.97	821	4634	64.4%	1.000
Fitzpatrick	Jul-75	84	8.97	821	4899	68.1%	0.000
Brunswick 2	Nov-75	76	0.63	821	2487	34.5%	0.000
Brunswick 2	Nov-75	77	1.63	821	2437	33.9%	1.000

Unit	COD	Year	Age at 7/1	Orig. DER	Annual GWH	CF@ original DER (Calculated)	Total Number of Refuelings
Brunswick 2	Nov-75	78	2.63	821	4794	66.7%	0.000
Brunswick 2	Nov-75	79	3.63	821	3652	50.8%	1.000
Brunswick 2	Nov-75	80	4.63	821	1865	25.9%	0.000
Brunswick 2	Nov-75	81	5.63	821	3284	45.7%	0.000
Brunswick 2	Nov-75	82	6.63	821	1910	26.6%	1.000
Brunswick 2	Nov-75	83	7.63	821	3936	54.7%	0.000
Brunswick 2	Nov-75	84	8.63	821	1393	19.4%	1.000
Hatch 1	Dec-75	76	0.55	786	4134	59.9%	0.000
Hatch 1	Dec-75	77	1.55	786	3713	53.9%	1.000
Hatch 1	Dec-75	78	2.55	786	4227	61.4%	1.000
Hatch 1	Dec-75	79	3.55	786	3338	48.5%	1.000
Hatch 1	Dec-75	80	4.55	786	4791	69.4%	0.000
Hatch 1	Dec-75	81	5.55	786	2756	40.0%	1.000
Hatch 1	Dec-75	82	6.55	786	2878	41.8%	0.615
Hatch 1	Dec-75	83	7.55	786	3964	57.6%	1.385
Hatch 1	Dec-75	84	8.55	786	3597	52.2%	0.889
Browns Ferry 3	Mar-77	78	1.33	1065	5554	59.5%	1.000
Browns Ferry 3	Mar-77	79	2.33	1065	5483	58.8%	1.000
Browns Ferry 3	Mar-77	80	3.34	1065	6937	74.1%	0.684
Browns Ferry 3	Mar-77	81	4.34	1065	6247	67.0%	0.695
Browns Ferry 3	Mar-77	82	5.34	1065	4893	52.4%	0.532
Browns Ferry 3	Mar-77	83	6.34	1065	5394	57.8%	0.275
Browns Ferry 3	Mar-77	84	7.34	1065	291	3.1%	0.725
Brunswick 1	Mar-77	78	1.29	821	5123	71.2%	0.000
Brunswick 1	Mar-77	79	2.29	821	3169	44.1%	1.000
Brunswick 1	Mar-77	80	3.29	821	3940	54.6%	1.000
Brunswick 1	Mar-77	81	4.29	821	2556	35.5%	0.000
Brunswick 1	Mar-77	82	5.29	821	2922	40.6%	0.081
Brunswick 1	Mar-77	83	6.29	821	1389	19.3%	0.919
Brunswick 1	Mar-77	84	7.29	821	5032	70.0%	0.000
Hatch 2	Sep-79	80	0.82	795	3645	52.2%	0.539
Hatch 2	Sep-79	81	1.82	795	4478	64.3%	0.461
Hatch 2	Sep-79	82	2.82	795	3728	53.5%	1.000
Hatch 2	Sep-79	83	3.82	795	3809	54.7%	1.000
Hatch 2	Sep-79	84	4.82	795	1876	26.9%	0.000
Susquehanna 1	Jun-83	83	0.06	1065	3536	37.9%	0.000
Susquehanna 1	Jun-83	84	1.07	1065	6088	65.3%	0.000

APPENDIX C
O&M AND CAPITAL ADDITIONS DATA

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	O&M - Fuel	O&M -Fuel 1983 $	/MW-yr	Region	# of Units
Arkansas 1	74	902	233027	.	.	.	.	.	4	1
Arkansas 1	75	902	238751	5724	10407	4109	7034	11.54	4	1
Arkansas 1	76	902	242204	3453	5962	6015	9787	6.61	4	1
Arkansas 1	77	902	247069	4865	7997	8379	12883	8.87	4	1
Arkansas 1	78	902	253994	6925	10259	12125	17358	11.37	4	1
Arkansas 1	79	902	268130	14136	18641	18923	24935	20.67	4	1
Arkansas 1	80	NA	NA	.	.	.	.	.	4	1
Arkansas 1&2	81	1845	916567	.	.	.	.	.	4	2
Arkansas 1&2	82	1845	927141	10574	11034	54496	56588	5.98	4	2
Arkansas 1&2	83	1845	935827	8686	8686	66173	66173	4.71	4	2
Arkansas 1&2	84	1845	1017607	81780	80091	75818	73090	43.41	4	2
Beaver Valley	76	923	599697	.	.	.	.	.	1	1
Beaver Valley	77	923	598716	-981	-1525	14692	22590	-1.65	1	1
Beaver Valley	78	923	582408	-16308	-23883	22681	32470	-25.88	1	1
Beaver Valley	79	923	576367	-6041	-8067	22907	30185	-8.74	1	1
Beaver Valley	80	923	647575	71208	87849	34771	41966	95.18	1	1
Beaver Valley	81	924	671283	23708	26909	35838	39455	29.12	1	1
Beaver Valley	82	923	748515	77232	80791	49144	51030	87.53	1	1
Beaver Valley	83	905	829685	81170	81170	68156	68156	89.69	1	1
Beaver Valley	84	924	878844	49159	47244	71835	69249	51.12	1	1
Big Rock Point	63	54	14412	.	.	.	.	.	3	1
Big Rock Point	64	54	14349	-63	-221	666	1971	-4.10	3	1
Big Rock Point	65	75	13750	-599	-2106	715	2071	-28.07	3	1
Big Rock Point	66	75	13793	43	149	763	2140	1.99	3	1
Big Rock Point	67	75	13837	44	146	1086	2958	1.94	3	1
Big Rock Point	68	75	13926	89	287	865	2257	3.82	3	1
Big Rock Point	69	75	13958	32	96	933	2315	1.29	3	1
Big Rock Point	70	75	14324	366	1023	1062	2501	13.64	3	1
Big Rock Point	71	75	14554	230	593	1266	2840	7.91	3	1
Big Rock Point	72	75	14731	177	432	1412	3041	5.76	3	1
Big Rock Point	73	75	14815	84	195	1586	3230	2.60	3	1
Big Rock Point	74	75	16012	1197	2415	2263	4235	32.20	3	1
Big Rock Point	75	75	16587	575	1034	2584	4424	13.79	3	1
Big Rock Point	76	75	22907	6320	10702	3183	5179	142.70	3	1
Big Rock Point	77	75	23971	1064	1668	5125	7880	22.24	3	1
Big Rock Point	78	75	24409	438	639	3645	5218	8.52	3	1
Big Rock Point	79	75	27014	2605	3473	9232	12165	46.31	3	1
Big Rock Point	80	75	27262	248	304	8409	10149	4.06	3	1
Big Rock Point	81	75	33356	6094	6863	12970	14279	91.51	3	1
Big Rock Point	82	75	37068	3712	3862	15513	16108	51.49	3	1
Big Rock Point	83	75	39382	2314	2314	16561	16561	30.85	3	1
Big Rock Point	84	75	40105	723	701	12246	11805	9.35	3	1
Browns Ferry 1&2	75	2304	512653	.	.	.	.	.	2	2
Browns Ferry 1&2	76	2304	552357	39704	66749	16104	26204	28.97	2	2
Browns Ferry 1,2,3	77	3456	853325	.	.	.	.	.	2	3
Browns Ferry 1,2,3	78	3456	885991	32666	47072	45921	65740	13.62	2	3
Browns Ferry 1,2,3	79	3456	888350	2359	3092	55588	73249	0.89	2	3
Browns Ferry 1,2,3	80	3456	890428	2078	2485	66969	80827	0.72	2	3
Browns Ferry 1,2,3	81	3456	892715	2287	2503	85469	94095	0.72	2	3
Browns Ferry 1,2,3	82	3456	915514	22799	23404	92271	95813	6.77	2	3
Browns Ferry 1,2,3	83	3456	929490	13976	13976	108946	108946	4.04	2	3
Browns Ferry 1,2,3	84	3456	1037790	108300	106449	129996	125317	30.80	2	3
Brunswick 2	75	866	382246	.	.	.	.	.	2	1

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	O&M - Fuel	O&M -Fuel 1983 $	/MW-yr	Region	# of Units
Brunswick 2	76	866	389118	6872	11553	10518	17115	13.34	2	1
Brunswick 2&1	77	1733	707560	.	.	.	.	.	2	2
Brunswick 2&1	78	1733	714928	7368	10617	26633	38128	6.13	2	2
Brunswick 2&1	79	1733	750828	35900	47055	34206	45074	27.15	2	2
Brunswick 2&1	80	1733	776989	26161	31285	57516	69418	18.05	2	2
Brunswick 2&1	81	1733	803535	26546	29050	73150	80532	16.76	2	2
Brunswick 2&1	82	1755	805771	2236	2295	112235	116543	1.31	2	2
Brunswick 2&1	83	1733	893322	87551	87551	109814	109814	50.52	2	2
Brunswick 2&1	84	1733	1020910	127588	125407	103362	99642	72.36	2	2
Calvert Cliffs 1	75	918	428747	.	.	.	.	.	1	1
Calvert Cliffs 1	76	918	430674	1927	3216	8984	14619	3.50	1	1
Calvert Cliffs 1&2	77	1828	765995	.	.	.	.	.	1	2
Calvert Cliffs 1&2	78	1828	777711	11716	17158	25997	37217	9.39	1	2
Calvert Cliffs 1&2	79	1828	780095	2384	3183	36397	47961	1.74	1	2
Calvert Cliffs 1&2	80	1828	790988	10893	13439	41628	50242	7.35	1	2
Calvert Cliffs 1&2	81	1828	820215	29227	33173	50409	55496	18.15	1	2
Calvert Cliffs 1&2	82	1828	852313	32098	33577	61969	64348	18.37	1	2
Calvert Cliffs 1&2	83	1828	903868	51555	51555	52772	52772	28.20	1	2
Calvert Cliffs 1&2	84	1828	942111	38243	36753	62343	60099	20.11	1	2
Connecticut Yankee	68	600	91801	.	.	2047	5340	.	1	1
Connecticut Yankee	69	600	91841	40	121	2067	5129	0.20	1	1
Connecticut Yankee	70	600	93516	1675	4694	4479	10547	7.82	1	1
Connecticut Yankee	71	600	93669	153	395	3279	7354	0.66	1	1
Connecticut Yankee	72	600	93814	145	346	3749	8073	0.58	1	1
Connecticut Yankee	73	600	94016	202	459	6352	12935	0.76	1	1
Connecticut Yankee	74	600	106212	12196	24285	4935	9234	40.48	1	1
Connecticut Yankee	75	600	108921	2709	4842	9381	16059	8.07	1	1
Connecticut Yankee	76	600	114503	5582	9317	9419	15326	15.53	1	1
Connecticut Yankee	77	600	117238	2735	4252	9448	14527	7.09	1	1
Connecticut Yankee	78	600	121288	4050	5931	8736	12506	9.89	1	1
Connecticut Yankee	79	600	123037	1749	2335	18923	24935	3.89	1	1
Connecticut Yankee	80	600	137644	14607	18021	35155	42430	30.03	1	1
Connecticut Yankee	81	600	152552	14908	16921	37488	41271	28.20	1	1
Connecticut Yankee	82	600	167878	15326	16032	35723	37094	26.72	1	1
Connecticut Yankee	83	600	182739	14861	14861	48672	48672	24.77	1	1
Connecticut Yankee	84	600	191277	8538	8206	59889	57733	13.68	1	1
Cook 1	75	1089	538611	.	.	.	.	.	3	1
Cook 1	76	1089	544650	6039	10227	7047	11467	9.39	3	1
Cook 1	77	1089	552238	7588	11895	10012	15394	10.92	3	1
Cook 1&2	78	2200	996177	.	.	.	.	.	3	2
Cook 1&2	79	2285	1025829	29652	39536	26750	35249	17.30	3	2
Cook 1&2	80	2250	1074584	48755	59847	32409	39115	26.60	3	2
Cook 1&2	81	2285	1096310	21726	24468	37967	41799	10.71	3	2
Cook 1&2	82	2285	1118610	22300	23200	50859	52811	10.15	3	2
Cook 1&2	83	2285	1145590	26980	26980	59519	59519	11.81	3	2
Cook 1&2	84	2285	1169784	24194	23470	80435	77540	10.27	3	2
Cooper	74	835	246268	.	.	.	.	.	3	1
Cooper	75	835	269287	23019	41399	7386	12644	49.58	3	1
Cooper	76	835	269287	0	0	10211	16615	0.00	3	1
Cooper	77	835	302382	33095	51879	10218	15711	62.13	3	1
Cooper	78	836	384630	82248	120010	8306	11891	143.55	3	1
Cooper	79	836	384570	-60	-80	10232	13483	-0.10	3	1
Cooper	80	836	384569	-1	-1	19004	22936	.00	3	1

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	O&M - Fuel	O&M -Fuel 1983 $	/MW-yr	Region	# of Units
Cooper	81	778	383748	-821	-925	20455	22519	-1.19	3	1
Cooper	82	836	384358	610	635	23482	24383	0.76	3	1
Cooper	83	836	383609	-749	-749	30893	30893	-0.90	3	1
Cooper	84	836	383511	-98	-95	25699	24774	-0.11	3	1
Crystal River	77	801	365535	.	.	.	.	.	2	1
Crystal River	78	890	415173	49638	71528	15613	22351	80.37	2	1
Crystal River	79	890	419131	3958	5188	23992	31614	5.83	2	1
Crystal River	80	890	421055	1924	2301	39841	48085	2.59	2	1
Crystal River	81	801	384011	-37044	-40539	42313	46583	-50.61	2	1
Crystal River	82	801	385759	1748	1794	46796	48592	2.24	2	1
Crystal River	83	801	396620	10861	10861	67548	67548	13.55	2	1
Crystal River	84	890	452274	55654	54703	84681	81633	61.43	2	1
Davis-Besse	77	960	557966	.	.	.	.	.	3	1
Davis-Besse	78	906	635147	77181	112617	14096	20180	124.30	3	1
Davis-Besse	79	906	671140	35993	47991	21737	28643	52.97	3	1
Davis-Besse	80	962	738544	67404	82739	44630	53865	86.01	3	1
Davis-Besse	81	962	786437	47893	53938	41413	45592	56.07	3	1
Davis-Besse	82	962	846126	59689	62098	59955	62256	64.55	3	1
Davis-Besse	83	962	882523	36397	36397	49328	49328	37.83	3	1
Davis-Besse	84	963	1003254	120731	117119	60802	58614	121.67	3	1
Dresden 1	62	208	34180	.	.	.	.	.	3	1
Dresden 1	63	208	34442	262	921	1266	3804	4.43	3	1
Dresden 1	64	208	34468	26	91	1071	3169	0.44	3	1
Dresden 1	65	208	34451	-17	-60	1264	3660	-0.29	3	1
Dresden 1	66	208	34352	-99	-343	1163	3263	-1.65	3	1
Dresden 1	67	208	34366	14	46	1912	5208	0.22	3	1
Dresden 1	68	208	33467	-899	-2897	1673	4365	-13.93	3	1
Dresden 1	69	208	33968	501	1510	1788	4436	7.26	3	1
Dresden 1&2	70	1018	116609	.	.	.	.	.	3	2
Dresden 1,2,3	71	1828	220380	.	.	.	.	.	3	3
Dresden 1,2,3	72	1865	241479	21099	51526	9142	19686	27.63	3	3
Dresden 1,2,3	73	1865	235397	-6082	-14110	9050	18429	-7.57	3	3
Dresden 1,2,3	74	1865	237303	1906	3845	16731	31307	2.06	3	3
Dresden 1,2,3	75	1865	249177	11874	21355	32895	56313	11.45	3	3
Dresden 1,2,3	76	1865	256493	7316	12389	30092	48965	6.64	3	3
Dresden 1,2,3	77	1865	258522	2029	3181	26999	41513	1.71	3	3
Dresden 1,2,3	78	1865	276887	18365	26797	33932	48577	14.37	3	3
Dresden 1,2,3	79	1865	290785	13898	18531	44579	58742	9.94	3	3
Dresden 1,2,3	80	1865	303201	12416	15241	38130	46020	8.17	3	3
Dresden 1,2,3	81	1865	307054	3853	4339	40361	44434	2.33	3	3
Dresden 1,2,3	82	1865	331590	24536	25526	43740	45419	13.69	3	3
Dresden 1,2,3	83	1865	340169	8579	8579	47134	47134	4.60	3	3
Dresden 1,2,3	84	1865	472538	132369	128409	65921	63548	68.85	3	3
Duane Arnold	74	565	288821	.	.	.	.	.	3	1
Duane Arnold	75	565	279730	-9091	-16350	3839	6572	-28.94	3	1
Duane Arnold	76	565	279928	198	335	7050	11472	0.59	3	1
Duane Arnold	77	565	287561	7633	11966	7508	11544	21.18	3	1
Duane Arnold	78	597	282345	-5216	-7611	11916	17059	-12.75	3	1
Duane Arnold	79	597	306768	24423	32564	9528	12555	54.55	3	1
Duane Arnold	80	597	324186	17418	21381	18398	22205	35.81	3	1
Duane Arnold	81	597	339460	15274	17202	21956	24172	28.81	3	1
Duane Arnold	82	597	365309	25849	26892	29239	30361	45.05	3	1
Duane Arnold	83	597	397117	31808	31808	45949	45949	53.28	3	1

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	O&M - Fuel	O&M -Fuel 1983 $	/MW-yr	Region	# of Units
Duane Arnold	84	597	412435	15318	14860	34587	33342	24.89	3	1
Farley 1	77	888	727426	.	.	.	.	.	2	1
Farley 1	78	888	734519	7093	10221	12207	17475	11.51	2	1
Farley 1	79	888	751634	17115	22433	22545	29708	25.26	2	1
Farley 1	80	888	761329	9695	11594	25734	31059	13.06	2	1
Farley 1&2	81	1776	1541981	.	.	.	.	.	2	2
Farley 1&2	82	1777	1611172	69191	71028	52488	54503	39.97	2	2
Farley 1&2	83	1777	1642869	31697	31697	60275	60275	17.84	2	2
Farley 1&2	84	1777	1664849	21980	21604	76822	74057	12.16	2	2
Fitzpatrick	75	849	NA	.	.	.	.	.	1	1
Fitzpatrick	76	849	NA	.	.	10700	17411	.	1	1
Fitzpatrick	77	849	NA	.	.	17383	26728	.	1	1
Fitzpatrick	78	883	NA	.	.	19045	27265	.	1	1
Fitzpatrick	79	883	NA	.	.	25131	33115	.	1	1
Fitzpatrick	80	883	NA	.	.	33303	40194	.	1	1
Fitzpatrick	81	883	367141	.	.	36678	40380	.	1	1
Fitzpatrick	82	883	344597	-22544	-23583	31504	32713	-26.71	1	1
Fitzpatrick	83	883	373346	28749	28749	43170	43170	32.56	1	1
Fitzpatrick	84	883	429948	56602	54397	53796	51860	61.60	1	1
Fort Calhoun	73	481	173870	.	.	.	.	.	3	1
Fort Calhoun	74	481	175800	1930	3894	3413	6386	8.09	3	1
Fort Calhoun	75	481	178572	2772	4985	5962	10206	10.36	3	1
Fort Calhoun	76	481	178896	324	549	7449	12121	1.14	3	1
Fort Calhoun	77	481	179994	1098	1721	8493	13059	3.58	3	1
Fort Calhoun	78	481	180328	334	487	8116	11619	1.01	3	1
Fort Calhoun	79	481	180830	502	669	8504	11206	1.39	3	1
Fort Calhoun	80	481	192700	11870	14571	14332	17298	30.29	3	1
Fort Calhoun	81	481	198544	5844	6582	11472	12630	13.68	3	1
Fort Calhoun	82	481	211041	12497	13001	18934	19661	27.03	3	1
Fort Calhoun	83	481	221514	10473	10473	23860	23860	21.77	3	1
Fort Calhoun	84	502	230358	8844	8580	25239	24331	17.09	3	1
Ginna	70	517	83175	.	.	.	.	.	1	1
Ginna	71	517	83075	-100	-258	4391	9849	-0.50	1	1
Ginna	72	517	83982	907	2167	4082	8790	4.19	1	1
Ginna	73	517	85004	1022	2320	3536	7200	4.49	1	1
Ginna	74	517	87668	2664	5305	5391	10088	10.26	1	1
Ginna	75	517	89750	2082	3721	6597	11293	7.20	1	1
Ginna	76	517	93308	3558	5939	7356	11969	11.49	1	1
Ginna	77	517	114141	20833	32391	7942	12212	62.65	1	1
Ginna	78	517	121860	7719	11305	9819	14057	21.87	1	1
Ginna	79	517	129112	7252	9684	12819	16892	18.73	1	1
Ginna	80	517	136138	7026	8668	18924	22840	16.77	1	1
Ginna	81	517	159487	23349	26501	22482	24751	51.26	1	1
Ginna	82	517	182754	23267	24339	29570	30705	47.08	1	1
Ginna	83	517	214985	32231	32231	26956	26956	62.33	1	1
Ginna	84	517	236071	21086	20264	32679	31503	39.19	1	1
Hatch 1	76	850	390393	.	.	.	.	.	2	1
Hatch 1	77	850	396799	6406	9842	9799	15066	11.58	2	1
Hatch 1	78	850	409113	12314	17744	12268	17563	20.88	2	1
Hatch 1&2	79	1702	918419	.	.	.	.	.	2	2
Hatch 1&2	80	1700	947147	28728	34355	38486	46450	20.21	2	2
Hatch 1&2	81	1704	969365	22218	24314	62010	68268	14.27	2	2
Hatch 1&2	82	1704	1004824	35459	36400	67689	70287	21.36	2	2

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	O&M - Fuel	O&M -Fuel 1983 $	/MW-yr	Region	# of Units
Hatch 1&2	83	1701	1134116	129291	129291	107802	107802	76.03	2	2
Hatch 1&2	84	1701	1260053	125937	123785	139787	134756	72.79	2	2
Humboldt	63	60	24471	.	.	.	.	.	6	1
Humboldt	64	60	23786	-685	-2566	525	1554	-42.77	6	1
Humboldt	65	60	24176	390	1461	629	1822	24.35	6	1
Humboldt	66	60	22224	-1952	-7101	562	1577	-118.35	6	1
Humboldt	67	60	22480	256	892	630	1716	14.87	6	1
Humboldt	68	60	22619	139	465	582	1518	7.75	6	1
Humboldt	69	60	22688	69	222	646	1603	3.70	6	1
Humboldt	70	60	22764	76	230	619	1458	3.83	6	1
Humboldt	71	60	22850	86	243	926	2077	4.04	6	1
Humboldt	72	60	22947	97	256	897	1932	4.27	6	1
Humboldt	73	65	22998	51	128	915	1863	1.97	6	1
Humboldt	74	65	23171	173	381	1070	2002	5.86	6	1
Humboldt	75	65	24031	860	1648	1221	2090	25.35	6	1
Humboldt	76	65	24543	512	905	1980	3222	13.92	6	1
Humboldt	77	65	26726	2183	3535	3081	4737	54.39	6	1
Humboldt	78	65	28506	1780	2675	1635	2341	41.16	6	1
Humboldt	79	65	28567	61	83	1485	1957	1.27	6	1
Indian Point 1	63	275	126218	.	.	.	.	.	1	1
Indian Point 1	64	275	126255	37	131	2894	8564	0.48	1	1
Indian Point 1	65	275	126330	75	266	2626	7605	0.97	1	1
Indian Point 1	66	275	128891	2561	8808	2929	8217	32.03	1	1
Indian Point 1	67	275	128821	-70	-230	3184	8672	-0.84	1	1
Indian Point 1	68	275	128818	-3	-10	2831	7386	-0.03	1	1
Indian Point 1	69	275	127914	-904	-2736	2713	6731	-9.95	1	1
Indian Point 1	70	275	128083	169	474	3498	8237	1.72	1	1
Indian Point 1	71	275	128175	92	237	3962	8886	0.86	1	1
Indian Point 1	72	275	128938	763	1823	6950	14966	6.63	1	1
Indian Point 1&2	73	1288	334963	.	.	.	.	.	1	2
Indian Point 1&2	74	1288	340188	5225	10404	12737	23834	8.08	1	2
Indian Point 1&2	75	1288	348218	8030	14353	13195	22589	11.14	1	2
Indian Point 1&2	76	1288	359410	11192	18681	18285	29753	14.50	1	2
Indian Point 1&2	77	1288	370637	11227	17456	16525	25409	13.55	1	2
Indian Point 1&2	78	1288	377573	6936	10158	28167	40324	7.89	1	2
Indian Point 1&2	79	1288	379966	2393	3195	32643	43014	2.48	1	2
Indian Point 2	80	1013	329445	.	.	.	.	.	1	1
Indian Point 2	81	1013	398037	68592	77852	54506	60007	76.85	1	1
Indian Point 2	82	1013	461010	62973	65875	68664	71300	65.03	1	1
Indian Point 2	83	1013	477418	16408	16408	49910	49910	16.20	1	1
Indian Point 2	84	1013	503852	26434	25404	96839	93354	25.08	1	1
Indian Point 3	76	1125	NA	.	.	.	.	.	1	1
Indian Point 3	77	1125	NA	.	.	12654	19457	.	1	1
Indian Point 3	78	1068	NA	.	.	23318	33382	.	1	1
Indian Point 3	79	1068	NA	.	.	28884	38061	.	1	1
Indian Point 3	80	1013	NA	.	.	50357	60777	.	1	1
Indian Point 3	81	1013	493018	.	.	58174	64045	.	1	1
Indian Point 3	82	1013	522350	29332	30684	82542	85710	30.29	1	1
Indian Point 3	83	1013	538949	16599	16599	48682	48682	16.39	1	1
Indian Point 3	84	1013	560398	21449	20613	55982	53967	20.35	1	1
Kewaunee	74	535	202193	.	.	.	.	.	3	1
Kewaunee	75	535	203389	1196	2151	8945	15313	4.02	3	1
Kewaunee	76	535	205351	1962	3323	10727	17455	6.21	3	1

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	O&M - Fuel	O&M -Fuel 1983 $	/MW-yr	Region	# of Units
Kewaunee	77	535	205892	541	848	10924	16797	1.59	3	1
Kewaunee	78	535	209748	3856	5626	10430	14931	10.52	3	1
Kewaunee	79	535	213289	3541	4721	11323	14920	8.82	3	1
Kewaunee	80	535	214696	1407	1727	14843	17914	3.23	3	1
Kewaunee	81	535	227413	12717	14322	19334	21285	26.77	3	1
Kewaunee	82	535	236500	9087	9454	21978	22822	17.67	3	1
Kewaunee	83	535	252451	15951	15951	23926	23926	29.81	3	1
Kewaunee	84	535	259757	7306	7087	27829	26827	13.25	3	1
LaSalle	82	1078	1336166	.	.	.	.	.	3	1
LaSalle	83	1170	1344053	7887	7887	35379	35379	6.74	3	1
LaSalle 1&2	84	2341	2417914	.	.	.	.	.	3	1
Lacrosse	78	60	22991	.	.	.	.	.	3	1
Lacrosse	79	50	23132	141	188	3041	4007	3.76	3	1
Lacrosse	80	50	25987	2855	3505	3318	4005	70.09	3	1
Lacrosse	81	50	26237	250	282	3955	4354	5.63	3	1
Lacrosse	82	.	.	.	.	.	.	.	3	1
Lacrosse	83	.	.	.	.	.	.	.	3	1
Lacrosse	84	.	.	.	.	.	.	.	3	1
Maine Yankee	73	830	219225	.	.	.	.	.	1	1
Maine Yankee	74	830	221074	1849	3682	5232	9790	4.44	1	1
Maine Yankee	75	830	233710	12636	22586	6301	10787	27.21	1	1
Maine Yankee	76	830	235069	1359	2268	5261	8561	2.73	1	1
Maine Yankee	77	830	236454	1385	2153	8418	12943	2.59	1	1
Maine Yankee	78	864	237810	1356	1986	10817	15486	2.30	1	1
Maine Yankee	79	864	239987	2177	2907	9971	13139	3.36	1	1
Maine Yankee	80	864	246847	6860	8463	14028	16931	9.80	1	1
Maine Yankee	81	864	262240	15393	17471	20576	22653	20.22	1	1
Maine Yankee	82	864	269738	7498	7844	28554	29650	9.08	1	1
Maine Yankee	83	864	275713	5975	5975	21557	21557	6.92	1	1
Maine Yankee	84	864	295412	19699	18932	32495	31325	21.91	1	1
McGuire 1	81	1220	905601	.	.	.	.	.	1	1
McGuire 1	82	1220	909146	3545	3708	37258	38688	3.04	1	1
McGuire 1	83	1220	903347	-5799	-5799	56030	56030	-4.75	1	2
McGuire 1&2	84	2441	1935269	.	.	.	.	.	1	2
Millstone 1	71	661	96819	.	.	.	.	.	1	1
Millstone 1	72	661	97343	524	1252	7677	16532	1.89	1	1
Millstone 1	73	661	98837	1494	3391	7635	15547	5.13	1	1
Millstone 1	74	661	98745	-92	-183	9808	18353	-0.28	1	1
Millstone 1	75	661	99244	499	892	12065	20654	1.35	1	1
Millstone 1	76	661	125141	25897	43225	14040	22846	65.39	1	1
Millstone 1	77	661	127476	2335	3630	12637	19431	5.49	1	1
Millstone 1	78	661	139783	12307	18024	16448	23547	27.27	1	1
Millstone 1	79	661	153135	13352	17829	23060	30386	26.97	1	1
Millstone 1	80	661	167438	14303	17646	24784	29912	26.70	1	1
Millstone 1	81	661	247250	79812	90587	33270	36628	137.04	1	1
Millstone 1	82	661	275880	28630	29949	33465	34750	45.31	1	1
Millstone 1	83	662	282531	6651	6651	43569	43569	10.05	1	1
Millstone 1	84	662	300248	17717	17027	36867	35540	25.74	1	1
Millstone 2	75	909	418372	.	.	.	.	.	1	1
Millstone 2	76	909	426271	7899	13184	10929	17783	14.50	1	1
Millstone 2	77	909	448751	22480	34952	17377	26719	38.45	1	1
Millstone 2	78	909	463638	14887	21802	22288	31907	23.98	1	1
Millstone 2	79	909	464674	1036	1383	21931	28899	1.52	1	1

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	O&M - Fuel	O&M -Fuel 1983 $	/MW-yr	Region	# of Units
Millstone 2	80	909	477586	12912	15929	30163	36405	17.52	1	1
Millstone 2	81	909	495610	18024	20457	28877	31791	22.51	1	1
Millstone 2	82	909	529017	33407	34946	45248	46985	38.44	1	1
Millstone 2	83	909	557977	28960	28960	56452	56452	31.86	1	1
Millstone 2	84	910	566560	8583	8248	49539	47756	9.07	1	1
Monticello	71	568	105011	.	.	.	.	.	3	1
Monticello	72	568	104937	-74	-181	2567	5528	-0.32	3	1
Monticello	73	568	106869	1932	4482	5006	10194	7.89	3	1
Monticello	74	568	117996	11127	22448	5179	9691	39.52	3	1
Monticello	75	568	122106	4110	7392	8729	14943	13.01	3	1
Monticello	76	568	123362	1256	2127	6609	10754	3.74	3	1
Monticello	77	568	124390	1028	1611	11109	17081	2.84	3	1
Monticello	78	568	126488	2098	3061	9136	13079	5.39	3	1
Monticello	79	568	134937	8449	11265	10584	13947	19.83	3	1
Monticello	80	568	139725	4788	5877	21413	25844	10.35	3	1
Monticello	81	568	150407	10682	12030	18261	20104	21.18	3	1
Monticello	82	568	171425	21018	21866	30799	31981	38.50	3	1
Monticello	83	569	227698	56273	56273	22628	22628	98.93	3	1
Monticello	84	569	354921	127223	123417	43203	41648	216.98	3	1
Nine Mile Point	70	620	162235	.	.	.	.	.	1	1
Nine Mile Point	71	641	164492	2257	5822	2759	6188	9.08	1	1
Nine Mile Point	72	641	162416	-2076	-4961	3575	7698	-7.74	1	1
Nine Mile Point	73	641	163212	796	1807	4524	9212	2.82	1	1
Nine Mile Point	74	641	163389	177	352	6251	11697	0.55	1	1
Nine Mile Point	75	641	164189	800	1430	5810	9946	2.23	1	1
Nine Mile Point	76	641	181200	17011	28393	5330	8673	44.30	1	1
Nine Mile Point	77	641	188087	6887	10708	9743	14981	16.70	1	1
Nine Mile Point	78	641	187086	-1001	-1466	6382	9136	-2.29	1	1
Nine Mile Point	79	641	204080	16994	22692	11663	15368	35.40	1	1
Nine Mile Point	80	641	217371	13291	16397	32964	39785	25.58	1	1
Nine Mile Point	81	642	265015	47644	54076	26744	29443	84.23	1	1
Nine Mile Point	82	620	281922	16907	17686	21480	22304	28.53	1	1
Nine Mile Point	83	642	367746	85824	85824	25517	25517	133.68	1	1
Nine Mile Point	84	642	460273	92527	88922	26788	25824	138.51	1	1
North Anna 1	78	979	781739	.	.	.	.	.	2	1
North Anna 1	79	979	783864	2125	2785	19519	25720	2.85	2	1
North Anna 1&2	80	1959	1315869	.	.	.	.	.	2	2
North Anna 1&2	81	1959	1368195	52326	57262	28857	31769	29.23	2	2
North Anna 1&2	82	1959	1416217	48022	49297	43493	45162	25.16	2	2
North Anna 1&2	83	1959	1302075	-114142	-114142	40110	40110	-58.27	2	2
North Anna 1&2	84	1959	1312555	10480	10301	59187	57056	5.26	2	2
Oconee 1	73	886	155612	.	.	.	.	.	2	1
Oconee 1,2,3	74	2660	476443	.	.	.	.	.	2	3
Oconee 1,2,3	75	2660	476691	248	446	12449	21311	0.17	2	3
Oconee 1,2,3	76	2660	478793	2102	3534	16735	27231	1.33	2	3
Oconee 1,2,3	77	2660	490724	11931	18331	25038	38498	6.89	2	3
Oconee 1,2,3	78	2661	492689	1965	2832	29600	42375	1.06	2	3
Oconee 1,2,3	79	2661	498935	6246	8187	40177	52942	3.08	2	3
Oconee 1,2,3	80	2661	509438	10503	12560	52003	62764	4.72	2	3
Oconee 1,2,3	81	2666	520036	10598	11598	58789	64722	4.35	2	3
Oconee 1,2,3	82	2666	532168	12132	12454	88016	91394	4.67	2	3
Oconee 1,2,3	83	2667	539959	7791	7791	82851	82851	2.92	2	3
Oconee 1,2,3	84	2667	559053	19094	18768	93024	89676	7.04	2	3

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	O&M - Fuel	O&M -Fuel 1983 $	/MW-yr	Region	# of Units
Oyster Creek	70	550	89883	.	.	.	.	.	1	1
Oyster Creek	71	550	92121	2238	5773	3097	6946	10.50	1	1
Oyster Creek	72	550	92637	516	1233	3877	8349	2.24	1	1
Oyster Creek	73	550	92766	129	293	6311	12851	0.53	1	1
Oyster Creek	74	550	92198	-568	-1131	10678	19981	-2.06	1	1
Oyster Creek	75	550	97151	4953	8853	12310	21073	16.10	1	1
Oyster Creek	76	550	108545	11394	19018	10399	16921	34.58	1	1
Oyster Creek	77	550	112583	4038	6278	14833	22807	11.42	1	1
Oyster Creek	78	550	150459	37876	55470	15898	22759	100.85	1	1
Oyster Creek	79	550	161745	11286	15070	13055	17203	27.40	1	1
Oyster Creek	80	550	200255	38510	47510	37530	45296	86.38	1	1
Oyster Creek	81	550	222963	22708	25774	45254	49821	46.86	1	1
Oyster Creek	82	550	256407	33444	34985	60812	63146	63.61	1	1
Oyster Creek	83	550	331441	75034	75034	73246	73246	136.43	1	1
Oyster Creek	84	550	393346	61905	59493	83789	80774	108.17	1	1
Palisades	72	811	146687	.	.	.	.	.	3	1
Palisades	73	811	160284	13597	31545	3160	6435	38.90	3	1
Palisades	74	811	180063	19779	39902	11778	22039	49.20	3	1
Palisades	75	811	182297	2234	4018	9601	16436	4.95	3	1
Palisades	76	811	185272	2975	5038	9849	16024	6.21	3	1
Palisades	77	811	182068	-3204	-5022	6569	10100	-6.19	3	1
Palisades	78	811	199643	17575	25644	15393	22036	31.62	3	1
Palisades	79	811	194651	-4992	-6656	26344	34714	-8.21	3	1
Palisades	80	811	211505	16854	20689	19251	23235	25.51	3	1
Palisades	81	811	255491	43986	49538	44140	48595	61.08	3	1
Palisades	82	811	282667	27176	28273	38452	39928	34.86	3	1
Palisades	83	812	375573	92906	92906	57030	57030	114.46	3	1
Palisades	84	812	393781	18208	17663	51568	49712	21.76	3	1
Peach Bottom 2,3	74	2304	742158	.	.	.	.	.	1	2
Peach Bottom 2,3	75	2304	753981	11823	21132	12619	21602	9.17	1	2
Peach Bottom 2,3	76	2304	761722	7741	12921	30601	49793	5.61	1	2
Peach Bottom 2,3	77	2304	794094	32372	50332	46674	71766	21.85	1	2
Peach Bottom 2,3	78	2304	807496	13402	19627	39306	56270	8.52	1	2
Peach Bottom 2,3	79	2304	813792	6296	8407	40004	52714	3.65	1	2
Peach Bottom 2,3	80	2304	836708	22916	28271	56875	68644	12.27	1	2
Peach Bottom 2,3	81	2304	902169	65461	74298	72615	79943	32.25	1	2
Peach Bottom 2,3	82	2304	953400	51231	53592	81669	84804	23.26	1	2
Peach Bottom 2,3	83	2304	993310	39910	39910	105284	105284	17.32	1	2
Peach Bottom 2,3	84	2304	1047496	54186	52075	105513	101715	22.60	1	2
Pilgrim	72	655	321540	.	.	.	.	.	1	1
Pilgrim	73	655	239329	.	.	.	.	.	1	1
Pilgrim	74	655	235982	-3347	-6665	9527	17827	-10.18	1	1
Pilgrim	75	655	236464	482	862	7340	12565	1.32	1	1
Pilgrim	76	655	241440	4976	8306	16633	27065	12.68	1	1
Pilgrim	77	655	257579	16139	25093	15320	23556	38.31	1	1
Pilgrim	78	687	261758	4179	6120	14187	20310	8.91	1	1
Pilgrim	79	687	270428	8670	11577	18387	24229	16.85	1	1
Pilgrim	80	687	337986	67558	83346	27785	33534	121.32	1	1
Pilgrim	81	687	358680	20694	23488	34994	38526	34.19	1	1
Pilgrim	82	687	430711	72031	75350	42437	44066	109.68	1	1
Pilgrim	83	687	472831	42120	42120	47276	47276	61.31	1	1
Pilgrim	84	687	639225	166394	159911	57854	55772	232.77	1	1
Point Beach 1	71	523	73959	.	.	.	.	.	3	1

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	O&M - Fuel	O&M -Fuel 1983 $	/MW-yr	Region	# of Units
Point Beach 1&2	72	1047	145348	.	.	.	.	.	3	2
Point Beach 1&2	73	1047	161632	16284	37779	3647	7426	36.08	3	2
Point Beach 1&2	74	1047	161436	-196	-395	5229	9785	-0.38	3	2
Point Beach 1&2	75	1047	164224	2788	5014	6159	10544	4.79	3	2
Point Beach 1&2	76	1047	167125	2901	4913	6592	10726	4.69	3	2
Point Beach 1&2	77	1047	167699	574	900	8014	12322	0.86	3	2
Point Beach 1&2	78	1047	171189	3490	5093	7395	10587	4.86	3	2
Point Beach 1&2	79	1047	170668	-521	-695	12461	16420	-0.66	3	2
Point Beach 1&2	80	1047	172472	1804	2214	17904	21609	2.12	3	2
Point Beach 1&2	81	1047	188495	16023	18045	26820	29527	17.24	3	2
Point Beach 1&2	82	1047	192297	3802	3955	31951	33177	3.78	3	2
Point Beach 1&2	83	1048	194910	2613	2613	36667	36667	2.49	3	2
Point Beach 1&2	84	1048	224646	29736	28847	42054	40540	27.54	3	2
Prairie Isl. 1	73	593	233234	.	.	.	.	.	3	1
Prairie Isl. 1&2	74	1186	405374	.	.	.	.	.	3	2
Prairie Isl. 1&2	75	1186	410207	4833	8692	7261	12430	7.33	3	2
Prairie Isl. 1&2	76	1186	413087	2880	4877	15574	25342	4.11	3	2
Prairie Isl. 1&2	77	1186	423966	10879	17054	17090	26277	14.38	3	2
Prairie Isl. 1&2	78	1186	425182	1216	1774	14214	20349	1.50	3	2
Prairie Isl. 1&2	79	1186	433659	8477	11303	15346	20222	9.53	3	2
Prairie Isl. 1&2	80	1186	444766	11107	13634	23175	27971	11.50	3	2
Prairie Isl. 1&2	81	1186	457082	12316	13870	26791	29495	11.70	3	2
Prairie Isl. 1&2	82	1186	478688	21606	22478	28169	29250	18.95	3	2
Prairie Isl. 1&2	83	1186	499848	21160	21160	31251	31251	17.84	3	2
Prairie Isl. 1&2	84	1186	539237	39389	38211	33298	32100	32.21	3	2
Quad Cities 1&2	72	1656	200149	.	.	.	.	.	3	2
Quad Cities 1&2	73	1656	211539	11390	26425	6290	12808	15.96	3	2
Quad Cities 1&2	74	1656	223882	12343	24901	9210	17234	15.04	3	2
Quad Cities 1&2	75	1656	237227	13345	24000	14777	25297	14.49	3	2
Quad Cities 1&2	76	1656	241480	4253	7202	16723	27211	4.35	3	2
Quad Cities 1&2	77	1656	247194	5714	8957	17756	27302	5.41	3	2
Quad Cities 1&2	78	1656	252951	5757	8400	22168	31736	5.07	3	2
Quad Cities 1&2	79	1656	263741	10790	14387	23420	30861	8.69	3	2
Quad Cities 1&2	80	1656	273075	9334	11457	38686	46691	6.92	3	2
Quad Cities 1&2	81	1656	278524	5449	6137	37272	41033	3.71	3	2
Quad Cities 1&2	82	1656	311157	32633	33950	42185	43805	20.50	3	2
Quad Cities 1&2	83	1657	327125	15968	15968	44940	44940	9.64	3	2
Quad Cities 1&2	84	1656	314168	-12957	-12569	53179	51265	-7.59	3	2
Rancho Seco	75	928	343620	.	.	.	.	.	6	1
Rancho Seco	76	928	343438	-182	-322	7193	11704	-0.35	6	1
Rancho Seco	77	928	336050	-7388	-11964	14000	21526	-12.89	6	1
Rancho Seco	78	928	338792	2742	4121	11834	16941	4.44	6	1
Rancho Seco	79	928	339538	746	1012	13720	18079	1.09	6	1
Rancho Seco	80	928	353574	14036	17441	28408	34286	18.79	6	1
Rancho Seco	81	928	365651	12077	13716	35542	39129	14.78	6	1
Rancho Seco	82	928	369225	3574	3722	36330	37724	4.01	6	1
Rancho Seco	83	929	372144	2919	2919	52588	52588	3.14	6	1
Rancho Seco	84	929	447331	75187	73115	57961	55875	78.75	6	1
Robinson	71	768	77753	.	.	.	.	.	2	1
Robinson	72	768	81999	4246	10369	1780	3833	13.50	2	1
Robinson	73	768	82113	114	264	4609	9385	0.34	2	1
Robinson	74	768	83272	1159	2359	4780	8944	3.07	2	1
Robinson	75	768	84982	1710	3075	6360	10888	4.00	2	1

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	O&M - Fuel	O&M -Fuel 1983 $	/MW-yr	Region	# of Units
Robinson	76	768	85234	252	424	5903	9605	0.55	2	1
Robinson	77	768	89540	4306	6616	6859	10546	8.61	2	1
Robinson	78	768	93410	3870	5577	14355	20550	7.26	2	1
Robinson	79	768	101253	7843	10280	15142	19953	13.39	2	1
Robinson	80	768	110025	8772	10490	22085	26655	13.66	2	1
Robinson	81	769	113858	3833	4195	21788	23987	5.45	2	1
Robinson	82	769	125878	12020	12339	43164	44821	16.05	2	1
Robinson	83	769	128046	2168	2168	38174	38174	2.82	2	1
Robinson	84	769	264701	136655	134319	66077	63698	174.67	2	1
Salem 1	77	1170	850318	.	.	.	.	.	1	1
Salem 1	78	1170	850983	665	974	22311	31940	0.83	1	1
Salem 1	79	1169	898641	47658	63637	42508	56013	54.42	1	1
Salem 1	80	1170	938748	40107	49480	59684	72034	42.29	1	1
Salem 1&2	81	2343	1758749	.	.	.	.	.	1	2
Salem 1&2	82	2343	1806872	48123	50341	156615	162626	21.49	1	2
Salem 1&2	83	2344	1897751	90879	90879	175555	175555	38.78	1	2
Salem 1&2	84	2345	1750198	-147553	-141804	183714	177102	-60.46	1	2
San Onofre 1	68	450	80855	.	.	1481	3864	.	6	1
San Onofre 1	69	450	84439	3584	11533	1975	4900	25.63	6	1
San Onofre 1	70	450	84714	275	832	2236	5265	1.85	6	1
San Onofre 1	71	450	85369	655	1847	2412	5410	4.10	6	1
San Onofre 1	72	450	85547	178	470	3518	7576	1.05	6	1
San Onofre 1	73	450	85821	274	688	5839	11890	1.53	6	1
San Onofre 1	74	450	86244	423	931	5559	10402	2.07	6	1
San Onofre 1	75	450	86438	194	372	8668	14839	0.83	6	1
San Onofre 1	76	450	95496	9058	16011	10490	17069	35.58	6	1
San Onofre 1	77	450	162475	66979	108463	8123	12490	241.03	6	1
San Onofre 1	78	450	181601	19126	28746	14517	20782	63.88	6	1
San Onofre 1	79	450	192599	10998	14922	11669	15376	33.16	6	1
San Onofre 1	80	450	211109	18510	23000	31089	37522	51.11	6	1
San Onofre 1	81	450	251119	40010	45441	24396	26858	100.98	6	1
San Onofre 1	82	456	298461	47342	49306	36830	38244	108.13	6	1
San Onofre 1&2	83	1577	2223209	.	.	.	.	.	6	1
San Onofre 1,2,3	84	2704	3800541	.	.	.	.	.	6	1
Sequoyah 1	81	1220	983542	.	.	.	.	.	2	1
Sequoyah 1&2	82	2441	1606807	.	.	.	.	.	2	2
Sequoyah 1&2	83	2441	1664882	58075	58075	68588	68588	23.79	2	2
Sequoyah 1&2	84	2441	1677261	12379	12167	76755	73993	4.98	2	2
St. Lucie 1	76	850	470223	.	.	.	.	.	2	1
St. Lucie 1	77	850	486230	16007	24594	7528	11575	28.93	2	1
St. Lucie 1	78	850	495038	8808	12692	15814	22639	14.93	2	1
St. Lucie 1	79	850	499602	4564	5982	14392	18964	7.04	2	1
St. Lucie 1	80	850	505287	5685	6799	16381	19771	8.00	2	1
St. Lucie 1	81	850	513640	8353	9141	23240	25585	10.75	2	1
St. Lucie 1	82	850	529891	16251	16682	21853	22692	19.63	2	1
St. Lucie 1&2	83	1573	1817237	.	.	.	.	.	2	2
St. Lucie 1&2	84	1573	1884557	67320	66169	58729	56615	42.05	2	2
Sumner 1	84	636	865050	.	.	44797	43185	.	2	2
Surry 1	72	847	246707	.	.	.	.	.	2	1
Surry 1&2	73	1695	396860	.	.	.	.	.	2	2
Surry 1&2	74	1695	402096	5236	10656	9878	18484	6.29	2	2
Surry 1&2	75	1695	406409	4313	7757	15270	26141	4.58	2	2
Surry 1&2	76	1695	408516	2107	3542	14796	24076	2.09	2	2

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	O&M - Fuel	O&M -Fuel 1983 $	/MW-yr	Region	# of Units
Surry 1&2	77	1695	412236	3720	5715	15977	24566	3.37	2	2
Surry 1&2	78	1695	419952	7716	11119	19323	27663	6.56	2	2
Surry 1&2	79	1695	409703	-10249	-13434	23313	30720	-7.93	2	2
Surry 1&2	80	1695	556083	146380	175052	29458	35554	103.28	2	2
Surry 1&2	81	1695	750969	194886	213271	31185	34332	125.82	2	2
Surry 1&2	82	1695	783058	32089	32941	33088	34358	19.43	2	2
Surry 1&2	83	1695	805393	22335	22335	57158	57158	13.18	2	2
Surry 1&2	84	1695	822239	16846	16558	59146	57017	9.77	2	2
Susquehanna 1	84	1037	1774663	.	.	.	.	.	2	2
Three Mile Isl. 1	74	871	398337	.	.	.	.	.	1	1
Three Mile Isl. 1	75	871	400928	2591	4631	14226	24354	5.32	1	1
Three Mile Isl. 1	76	871	399425	-1503	-2509	17840	29029	-2.88	1	1
Three Mile Isl. 1	77	871	398895	-530	-824	13287	20430	-0.95	1	1
Three Mile Isl. 1	78	871	361902	-36993	-54177	17954	25703	-62.20	1	1
Three Mile Isl. 1	79	871	407936	46034	61469	11842	15604	70.57	1	1
Three Mile Isl. 1	80	NA	NA	.	.	NA	NA	.	1	1
Three Mile Isl. 1	81	870	441596	.	.	54048	59503	.	1	1
Trojan	76	1216	451978	.	.	.	.	.	6	1
Trojan	77	1216	460666	8688	14069	13628	20954	11.57	6	1
Trojan	78	1216	466419	5753	8647	15204	21766	7.11	6	1
Trojan	79	1216	486705	20286	27523	16957	22344	22.63	6	1
Trojan	80	1216	503279	16574	20594	25790	31127	16.94	6	1
Trojan	81	1216	548765	45486	51661	32205	35455	42.48	6	1
Trojan	82	1216	565576	16811	17509	30629	31805	14.40	6	1
Trojan	83	1216	573894	8318	8318	30345	30345	6.84	6	1
Trojan	84	1216	581283	7389	7185	46089	44430	5.91	6	1
Turkey Point 3	72	760	108709	.	.	.	.	.	2	1
Turkey Point 3&4	73	1519	231239	.	.	.	.	.	2	2
Turkey Point 3&4	74	1519	235496	4257	8663	9660	18076	5.70	2	2
Turkey Point 3&4	75	1519	244256	8760	15754	15493	26522	10.37	2	2
Turkey Point 3&4	76	1519	255705	11449	19248	18602	30269	12.67	2	2
Turkey Point 3&4	77	1519	267648	11943	18350	15109	23232	12.08	2	2
Turkey Point 3&4	78	1519	273441	5793	8348	18602	26630	5.50	2	2
Turkey Point 3&4	79	1519	284431	10990	14405	22511	29663	9.48	2	2
Turkey Point 3&4	80	1519	293654	9223	11030	30830	37210	7.26	2	2
Turkey Point 3&4	81	1519	305503	11849	12967	30274	33329	8.54	2	2
Turkey Point 3&4	82	1519	417224	111721	114687	32066	33297	75.50	2	2
Turkey Point 3&4	83	1520	527224	110000	110000	47776	47776	72.37	2	2
Turkey Point 3&4	84	1520	585304	58080	57087	60054	57892	37.56	2	2
Vermont Yankee	72	514	172042	.	.	.	.	.	1	1
Vermont Yankee	73	563	184481	12439	28237	4957	10094	50.15	1	1
Vermont Yankee	74	563	185158	677	1348	5692	10651	2.39	1	1
Vermont Yankee	75	563	185739	581	1038	7682	13151	1.84	1	1
Vermont Yankee	76	563	193886	8147	13598	7912	12874	24.15	1	1
Vermont Yankee	77	563	196331	2445	3801	9775	15030	6.75	1	1
Vermont Yankee	78	563	198837	2506	3670	11191	16021	6.52	1	1
Vermont Yankee	79	563	200835	1998	2668	14208	18722	4.74	1	1
Vermont Yankee	80	563	217575	16740	20652	22586	27260	36.68	1	1
Vermont Yankee	81	563	226115	8540	9693	26795	29499	17.22	1	1
Vermont Yankee	82	563	231880	5765	6031	33764	35060	10.71	1	1
Vermont Yankee	83	563	255209	23329	23329	46312	46312	41.44	1	1
Vermont Yankee	84	563	259856	4647	4466	43203	41648	7.93	1	1
Yankee-Rowe	62	152	38162	.	.	.	.	.	1	1

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	O&M - Fuel	O&M -Fuel 1983 $	/MW-yr	Region	# of Units
Yankee-Rowe	63	185	38398	236	837	1312	3942	4.52	1	1
Yankee-Rowe	64	185	38622	224	795	1121	3317	4.29	1	1
Yankee-Rowe	65	185	38766	144	511	1403	4063	2.76	1	1
Yankee-Rowe	66	185	39390	624	2146	1505	4222	11.60	1	1
Yankee-Rowe	67	185	39560	170	559	1307	3560	3.02	1	1
Yankee-Rowe	68	185	39572	12	38	1501	3916	0.21	1	1
Yankee-Rowe	69	185	39623	51	154	1602	3975	0.83	1	1
Yankee-Rowe	70	185	39636	13	36	1558	3669	0.20	1	1
Yankee-Rowe	71	185	40271	635	1638	1745	3914	8.85	1	1
Yankee-Rowe	72	185	41500	1229	2937	2912	6271	15.87	1	1
Yankee-Rowe	73	185	42507	1007	2286	2437	4962	12.36	1	1
Yankee-Rowe	74	185	44473	1966	3915	3958	7391	21.16	1	1
Yankee-Rowe	75	185	46101	1628	2910	4557	7801	15.73	1	1
Yankee-Rowe	76	185	46566	465	776	4976	8097	4.20	1	1
Yankee-Rowe	77	185	48332	1766	2746	6966	10711	14.84	1	1
Yankee-Rowe	78	185	48912	580	849	7653	10956	4.59	1	1
Yankee-Rowe	79	185	52192	3280	4380	10150	13375	23.67	1	1
Yankee-Rowe	80	185	55285	3093	3816	22250	26854	20.63	1	1
Yankee-Rowe	81	185	63717	8432	9570	22069	24296	51.73	1	1
Yankee-Rowe	82	185	72149	8432	8821	24320	25253	47.68	1	1
Yankee-Rowe	83	185	72503	354	354	18987	18987	1.91	1	1
Yankee-Rowe	84	185	75554	3051	2933	26422	25471	15.85	1	1
Zion 1	73	1098	275989	.	.	.	.	.	3	1
Zion 1&2	74	2196	565819	.	.	.	.	.	3	2
Zion 1&2	75	2196	567987	2168	3899	12735	21801	1.78	3	2
Zion 1&2	76	2196	571762	3775	6393	18268	29725	2.91	3	2
Zion 1&2	77	2196	577903	6141	9626	18104	27837	4.38	3	2
Zion 1&2	78	2196	586396	8493	12392	20383	29180	5.64	3	2
Zion 1&2	79	2196	594941	8545	11393	26954	35518	5.19	3	2
Zion 1&2	80	2196	625788	30847	37865	37655	45447	17.24	3	2
Zion 1&2	81	2196	639723	13935	15694	44864	49392	7.15	3	2
Zion 1&2	82	2196	650175	10452	10874	52617	54637	4.95	3	2
Zion 1&2	83	2196	680259	30084	30084	48670	48670	13.70	3	2
Zion 1&2	84	2196	689803	9544	9259	56860	54814	4.22	3	2

APPENDIX D
CARRYING COST CALCULATIONS

APPENDIX D-1: LIMERICK 1 COSTS
WITH 100% COMMON

REVENUE REQUIREMENTS
FROM CARRYING CHARGES
LIM1 & 100% COMMON
MILLIONS$

ORIGCOST+ADDIT	$3,812.652	$4.189	$12.781	$13.657	$14.592	$15.578	$16.639	$17.772	$18.980	$20.271	$21.489	$22.780
VINTAGE	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
1	$896.03	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2	$854.90	$0.90										
3	$817.66	$0.85	$2.77									
4	$783.76	$0.80	$2.59	$2.97								
5	$750.57	$0.75	$2.44	$2.78	$3.18							
6	$717.21	$0.71	$2.30	$2.61	$2.98	$3.41						
7	$683.87	$0.67	$2.17	$2.47	$2.80	$3.19	$3.65					
8	$650.53	$0.62	$2.03	$2.32	$2.65	$3.00	$3.42	$3.92				
9	$617.18	$0.58	$1.90	$2.18	$2.49	$2.83	$3.22	$3.67	$4.21			
10	$583.83	$0.54	$1.77	$2.04	$2.34	$2.66	$3.03	$3.45	$3.94	$4.51		
11	$571.48	$0.49	$1.64	$1.89	$2.18	$2.50	$2.85	$3.25	$3.70	$4.22	$4.81	
12	$556.38	$0.48	$1.50	$1.75	$2.02	$2.33	$2.67	$3.06	$3.48	$3.97	$4.50	$5.13
13	$541.29	$0.47	$1.48	$1.60	$1.87	$2.16	$2.49	$2.86	$3.27	$3.73	$4.22	$4.80
14	$526.19	$0.46	$1.43	$1.57	$1.71	$1.99	$2.31	$2.67	$3.06	$3.51	$3.97	$4.50
15	$511.09	$0.45	$1.39	$1.53	$1.68	$1.83	$2.13	$2.47	$2.85	$3.28	$3.73	$4.23
16	$496.00	$0.43	$1.35	$1.48	$1.63	$1.79	$1.95	$2.28	$2.64	$3.05	$3.49	$3.97
17	$480.90	$0.42	$1.31	$1.44	$1.58	$1.73	$1.91	$2.08	$2.43	$2.83	$3.24	$3.71
18	$465.82	$0.40	$1.27	$1.39	$1.53	$1.68	$1.85	$2.03	$2.22	$2.60	$3.00	$3.45
19	$450.72	$0.39	$1.22	$1.34	$1.48	$1.62	$1.79	$1.97	$2.17	$2.37	$2.76	$3.18
20	$435.63	$0.38	$1.18	$1.30	$1.42	$1.57	$1.72	$1.90	$2.10	$2.31	$2.51	$2.92
21	$420.53	$0.36	$1.14	$1.25	$1.37	$1.51	$1.66	$1.83	$2.02	$2.23	$2.44	$2.66
22	$405.44	$0.35	$1.10	$1.20	$1.33	$1.45	$1.60	$1.77	$1.95	$2.15	$2.35	$2.58
23	$390.34	$0.34	$1.06	$1.16	$1.27	$1.40	$1.54	$1.70	$1.87	$2.06	$2.26	$2.49
24	$375.24	$0.32	$1.02	$1.11	$1.22	$1.34	$1.48	$1.63	$1.80	$1.98	$2.18	$2.39
25	$360.16	$0.31	$0.97	$1.07	$1.17	$1.29	$1.42	$1.56	$1.73	$1.90	$2.09	$2.29
26	$345.06	$0.30	$0.93	$1.02	$1.12	$1.23	$1.36	$1.50	$1.65	$1.82	$2.00	$2.19
27	$329.97	$0.28	$0.89	$0.98	$1.07	$1.18	$1.30	$1.43	$1.58	$1.74	$1.91	$2.09
28	$314.87	$0.27	$0.85	$0.93	$1.02	$1.12	$1.24	$1.36	$1.50	$1.66	$1.82	$1.99
29	$299.78	$0.26	$0.80	$0.89	$0.97	$1.07	$1.18	$1.30	$1.43	$1.57	$1.73	$1.89
30	$284.68	$0.24	$0.76	$0.84	$0.92	$1.01	$1.11	$1.23	$1.35	$1.49	$1.64	$1.80
31	$269.59	$0.23	$0.72	$0.79	$0.87	$0.96	$1.05	$1.16	$1.28	$1.41	$1.55	$1.70
32	$254.49	$0.22	$0.68	$0.75	$0.82	$0.90	$0.99	$1.09	$1.21	$1.33	$1.46	$1.60
33	$239.40	$0.20	$0.64	$0.70	$0.77	$0.85	$0.93	$1.03	$1.13	$1.25	$1.37	$1.50
34	$224.31	$0.19	$0.60	$0.65	$0.72	$0.79	$0.87	$0.96	$1.06	$1.16	$1.28	$1.40
35	$209.21	$0.18	$0.55	$0.61	$0.66	$0.73	$0.81	$0.89	$0.98	$1.08	$1.19	$1.30
36	$194.12	$0.16	$0.51	$0.56	$0.61	$0.68	$0.75	$0.82	$0.91	$1.00	$1.10	$1.21
37	$179.02	$0.15	$0.47	$0.52	$0.56	$0.62	$0.69	$0.76	$0.83	$0.92	$1.01	$1.11
38	$163.93	$0.13	$0.43	$0.47	$0.51	$0.57	$0.63	$0.69	$0.76	$0.84	$0.92	$1.01
39	$148.83	$0.12	$0.39	$0.43	$0.46	$0.51	$0.57	$0.62	$0.69	$0.75	$0.83	$0.91
Sum:	$17,800.00	$15.40	$46.25	$48.59	$50.98	$53.50	$56.17	$58.94	$61.80	$64.72	$67.36	$70.00
NPV at:												
9.70%	$6,444.00	$5.41	$15.03	$14.62	$14.22	$13.82	$13.43	$13.07	$12.71	$12.35	$11.91	$11.50

ORIGCOST+ADDIT	$24.144	$25.593	$27.126	$28.753	$30.485	$32.312	$34.243	$36.301	$38.484	$40.794	$43.240	$45.832
VINTAGE	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2												
3												
4												
5												
6												
7												
8												
9												
10												
11												
12												
13	$5.46											
14	$5.11	$5.83										
15	$4.79	$5.45	$6.22									
16	$4.50	$5.10	$5.81	$6.64								
17	$4.22	$4.80	$5.44	$6.20	$7.09							
18	$3.94	$4.50	$5.11	$5.81	$6.62	$7.59						
19	$3.66	$4.19	$4.79	$5.45	$6.20	$7.08	$8.11					
20	$3.38	$3.89	$4.46	$5.10	$5.81	$6.62	$7.56	$8.69				
21	$3.10	$3.59	$4.13	$4.75	$5.43	$6.20	$7.07	$8.09	$9.31			
22	$2.82	$3.28	$3.81	$4.39	$5.05	$5.79	$6.62	$7.56	$8.67	$9.99		
23	$2.73	$2.98	$3.48	$4.04	$4.67	$5.38	$6.18	$7.07	$8.09	$9.29	$10.73	
24	$2.63	$2.89	$3.16	$3.69	$4.29	$4.97	$5.73	$6.59	$7.56	$8.66	$9.98	$11.54
25	$2.52	$2.77	$3.05	$3.34	$3.92	$4.56	$5.29	$6.11	$7.04	$8.09	$9.29	$10.72
26	$2.41	$2.65	$2.92	$3.23	$3.54	$4.15	$4.85	$5.63	$6.52	$7.52	$8.66	$9.98
27	$2.30	$2.53	$2.79	$3.08	$3.41	$3.74	$4.40	$5.15	$6.00	$6.96	$8.05	$9.29
28	$2.19	$2.41	$2.66	$2.94	$3.25	$3.60	$3.96	$4.67	$5.48	$6.39	$7.43	$8.62
29	$2.08	$2.30	$2.53	$2.79	$3.09	$3.42	$3.80	$4.19	$4.95	$5.82	$6.81	$7.94
30	$1.98	$2.18	$2.40	$2.65	$2.93	$3.25	$3.60	$4.01	$4.43	$5.25	$6.19	$7.27
31	$1.87	$2.06	$2.27	$2.50	$2.77	$3.07	$3.40	$3.79	$4.23	$4.69	$5.57	$6.59
32	$1.76	$1.94	$2.13	$2.36	$2.61	$2.89	$3.21	$3.57	$3.99	$4.46	$4.96	$5.92
33	$1.65	$1.82	$2.00	$2.21	$2.45	$2.71	$3.01	$3.35	$3.74	$4.18	$4.70	$5.24
34	$1.54	$1.70	$1.87	$2.07	$2.29	$2.53	$2.81	$3.13	$3.50	$3.91	$4.39	$4.94
35	$1.44	$1.58	$1.74	$1.92	$2.13	$2.36	$2.62	$2.91	$3.25	$3.64	$4.08	$4.60
36	$1.33	$1.46	$1.61	$1.78	$1.97	$2.18	$2.42	$2.69	$3.01	$3.36	$3.77	$4.25
37	$1.22	$1.34	$1.48	$1.63	$1.81	$2.00	$2.22	$2.47	$2.76	$3.09	$3.47	$3.90
38	$1.11	$1.22	$1.35	$1.49	$1.65	$1.82	$2.02	$2.25	$2.51	$2.81	$3.16	$3.56
39	$1.00	$1.10	$1.22	$1.34	$1.49	$1.64	$1.83	$2.03	$2.27	$2.54	$2.85	$3.21
Sum:	$72.74	$75.56	$78.43	$81.40	$84.47	$87.55	$90.71	$93.95	$97.31	$100.65	$104.09	$107.57
NPV at:												
9.70%	$11.08	$10.69	$10.31	$9.94	$9.59	$9.24	$8.91	$8.59	$8.28	$7.97	$7.68	$7.40

							****					
ORIGCOST+ADDIT	$48.583	$51.491	$54.587	$57.863	$61.327	$65.012	$68.917	$73.042	$77.430	$82.070	$87.004	$92.221
VINTAGE	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2												
3												
4												
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19												
20												
21												
22												
23												
24												
25	$12.43											
26	$11.54	$13.42										
27	$10.73	$12.45	$14.53									
28	$9.98	$11.56	$13.46	$15.77								
29	$9.24	$10.73	$12.48	$14.59	$17.18							
30	$8.50	$9.92	$11.57	$13.51	$15.88	$18.80						
31	$7.76	$9.10	$10.67	$12.50	$14.67	$17.35	$15.62					
32	$7.02	$8.29	$9.77	$11.50	$13.54	$16.00	$15.62	$17.79				
33	$6.28	$7.47	$8.87	$10.50	$12.43	$14.73	$15.62	$17.79	$20.58			
34	$5.54	$6.66	$7.97	$9.50	$11.32	$13.48	$15.62	$17.79	$20.58	$.00		
35	$5.20	$5.85	$7.07	$8.50	$10.20	$12.23	$15.62	$17.79	$20.58	$24.28	$29.43	
36	$4.81	$5.46	$6.17	$7.51	$9.09	$10.98	$15.62	$17.79	$20.58	$24.28	$29.43	$37.81
37	$4.41	$5.01	$5.72	$6.51	$7.97	$9.72	$15.62	$17.79	$20.58	$24.28	$29.43	$37.81
38	$4.02	$4.57	$5.21	$5.99	$6.86	$8.47	$15.62	$17.79	$20.58	$24.28	$29.43	$37.81
39	$3.63	$4.12	$4.71	$5.40	$6.25	$7.22	$15.62	$17.79	$20.58	$24.28	$29.43	$37.81
Sum:	$111.09	$114.61	$118.20	$121.78	$125.39	$128.98	$140.58	$142.32	$144.06	$121.40	$147.15	$151.24
NPV at:												
9.70%	$7.13	$6.86	$6.61	$6.36	$6.12	$5.89	$5.66	$5.44	$5.23	$3.98	$4.83	$4.72

ORIGCOST+ADDIT	$97.753	$103.622	$109.836	TOTAL YEAR BY YEAR REVENUE REQ ON COST	LAND REV REQ	TOTAL REV REQ
VINTAGE	2022	2023	2024			
1	$0.00	$0.00	$0.00	$896.03	$1.50	$897.53
2				$855.80	$1.50	$857.30
3				$821.28	$1.50	$822.78
4				$790.12	$1.50	$791.62
5				$759.72	$1.50	$761.22
6				$729.22	$1.50	$730.72
7				$698.82	$1.50	$700.32
8				$668.49	$1.50	$669.99
9				$638.26	$1.50	$639.76
10				$608.11	$1.50	$609.61
11				$599.01	$1.50	$600.51
12				$587.27	$1.50	$588.77
13				$575.70	$1.50	$577.20
14				$564.31	$1.50	$565.81
15				$553.12	$1.50	$554.62
16				$542.11	$1.50	$543.61
17				$531.33	$1.50	$532.83
18				$520.81	$1.50	$522.31
19				$510.49	$1.50	$511.99
20				$500.45	$1.50	$501.95
21				$490.67	$1.50	$492.17
22				$481.25	$1.50	$482.75
23				$472.13	$1.50	$473.63
24				$463.40	$1.50	$464.90
25				$455.09	$1.50	$456.59
26				$447.20	$1.50	$448.70
27				$439.83	$1.50	$441.33
28				$433.00	$1.50	$434.50
29				$426.81	$1.50	$428.31
30				$421.39	$1.50	$422.89
31				$411.79	$1.50	$413.29
32				$404.87	$1.50	$406.37
33				$401.10	$1.50	$402.60
34				$377.13	$1.50	$378.63
35				$407.21	$1.50	$408.71
36				$421.79	$1.50	$423.29
37	$51.88			$450.78	$1.50	$452.28
38	$51.88	$80.14		$508.49	$1.50	$509.99
39	$51.88	$80.14	$165.26	$651.75	$1.50	$653.25
Sum:	$155.64	$160.28	$165.26	$21,516.12		$21,574.62
NPV at:						
9.70%	$4.63	$4.54	$4.47			

APPENDIX D-2: LIMERICK 1 COSTS
WITH 100% COMMON AND HISTORICAL CAPITAL ADDITIONS

REVENUE REQUIREMENTS
FROM CARRYING CHARGES
LIM1 & 100% COMMON
MILLIONS$

ORIGCOST+ADDIT	$3,812.652	$31.281	$33.596	$36.082	$38.752	$41.620	$44.700	$48.008	$51.560	$55.376	$59.473	$63.874
VINTAGE	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
1	$896.03	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2	$854.90	$6.72										
3	$817.66	$6.35	$7.28									
4	$783.76	$5.97	$6.81	$7.85								
5	$750.57	$5.60	$6.41	$7.34	$8.45							
6	$717.21	$5.30	$6.05	$6.90	$7.91	$9.11						
7	$683.87	$5.00	$5.70	$6.53	$7.44	$8.52	$9.81					
8	$650.53	$4.63	$5.34	$6.13	$7.04	$8.02	$9.19	$10.59				
9	$617.18	$4.33	$4.99	$5.76	$6.61	$7.56	$8.65	$9.91	$11.44			
10	$583.83	$4.03	$4.65	$5.39	$6.21	$7.11	$8.14	$9.32	$10.70	$12.32		
11	$571.48	$3.66	$4.31	$4.99	$5.79	$6.68	$7.66	$8.78	$10.05	$11.53	$13.31	
12	$556.38	$3.58	$3.94	$4.62	$5.36	$6.23	$7.17	$8.27	$9.45	$10.85	$12.45	$14.38
13	$541.29	$3.51	$3.89	$4.23	$4.97	$5.77	$6.59	$7.73	$8.88	$10.19	$11.68	$13.46
14	$526.19	$3.44	$3.76	$4.15	$4.54	$5.32	$6.21	$7.21	$8.31	$9.59	$10.99	$12.62
15	$511.09	$3.36	$3.65	$4.04	$4.46	$4.89	$5.72	$6.67	$7.74	$8.96	$10.32	$11.86
16	$496.00	$3.21	$3.55	$3.91	$4.33	$4.78	$5.24	$6.16	$7.17	$8.33	$9.66	$11.13
17	$480.90	$3.14	$3.44	$3.80	$4.20	$4.62	$5.13	$5.62	$6.60	$7.73	$8.97	$10.40
18	$465.82	$2.99	$3.34	$3.67	$4.06	$4.49	$4.97	$5.48	$6.03	$7.10	$8.30	$9.67
19	$450.72	$2.91	$3.21	$3.54	$3.93	$4.33	$4.81	$5.32	$5.89	$6.47	$7.64	$8.92
20	$435.63	$2.84	$3.10	$3.43	$3.77	$4.19	$4.62	$5.13	$5.70	$6.31	$6.95	$8.19
21	$420.53	$2.69	$3.00	$3.30	$3.64	$4.03	$4.46	$4.94	$5.49	$6.09	$6.75	$7.46
22	$405.44	$2.61	$2.89	$3.17	$3.53	$3.87	$4.30	$4.78	$5.30	$5.87	$6.50	$7.23
23	$390.34	$2.54	$2.79	$3.06	$3.37	$3.74	$4.14	$4.59	$5.08	$5.63	$6.25	$6.98
24	$375.24	$2.39	$2.68	$2.93	$3.24	$3.58	$3.98	$4.40	$4.89	$5.41	$6.03	$6.70
25	$360.16	$2.31	$2.55	$2.83	$3.11	$3.45	$3.81	$4.21	$4.70	$5.19	$5.78	$6.42
26	$345.06	$2.24	$2.44	$2.69	$2.97	$3.29	$3.65	$4.05	$4.48	$4.97	$5.54	$6.14
27	$329.97	$2.09	$2.34	$2.59	$2.84	$3.15	$3.49	$3.86	$4.29	$4.75	$5.29	$5.86
28	$314.87	$2.02	$2.23	$2.46	$2.71	$2.99	$3.33	$3.67	$4.07	$4.53	$5.04	$5.58
29	$299.78	$1.94	$2.10	$2.35	$2.58	$2.86	$3.17	$3.51	$3.88	$4.29	$4.79	$5.30
30	$284.68	$1.79	$2.00	$2.22	$2.44	$2.70	$2.98	$3.32	$3.67	$4.07	$4.54	$5.05
31	$269.59	$1.72	$1.89	$2.09	$2.31	$2.56	$2.82	$3.13	$3.48	$3.85	$4.29	$4.77
32	$254.49	$1.64	$1.79	$1.98	$2.18	$2.40	$2.66	$2.94	$3.29	$3.63	$4.04	$4.49
33	$239.40	$1.49	$1.68	$1.85	$2.04	$2.27	$2.50	$2.78	$3.07	$3.41	$3.79	$4.21
34	$224.31	$1.42	$1.58	$1.72	$1.91	$2.11	$2.34	$2.59	$2.88	$3.17	$3.54	$3.93
35	$209.21	$1.34	$1.45	$1.61	$1.75	$1.95	$2.18	$2.40	$2.66	$2.95	$3.29	$3.65
36	$194.12	$1.19	$1.34	$1.48	$1.62	$1.82	$2.01	$2.22	$2.47	$2.73	$3.04	$3.39
37	$179.02	$1.12	$1.24	$1.37	$1.49	$1.66	$1.85	$2.05	$2.25	$2.51	$2.80	$3.11
38	$163.93	$0.97	$1.13	$1.24	$1.35	$1.52	$1.69	$1.86	$2.06	$2.29	$2.55	$2.83
39	$148.83	$0.90	$1.03	$1.14	$1.22	$1.36	$1.53	$1.67	$1.87	$2.05	$2.30	$2.55
Sum:	$17,800.00	$115.00	$121.57	$128.38	$135.39	$142.94	$150.90	$159.21	$167.88	$176.80	$186.43	$196.28
NPV at:												
9.70%	$6,444.00	$40.40	$39.50	$38.63	$37.77	$36.92	$36.09	$35.31	$34.52	$33.73	$32.98	$32.24

ORIGCOST+ADDIT	$68.601	$73.678	$79.130	$84.985	$91.274	$98.028	$105.283	$113.073	$121.441	$130.428	$140.079	$150.445
VINTAGE	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2												
3												
4												
5												
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7												
8												
9												
10												
11												
12												
13	$15.51											
14	$14.52	$16.78										
15	$13.61	$15.69	$18.14									
16	$12.79	$14.68	$16.95	$19.63								
17	$11.99	$13.82	$15.87	$18.33	$21.23							
18	$11.19	$12.95	$14.91	$17.17	$19.82	$23.03						
19	$10.40	$12.06	$13.97	$16.11	$18.56	$21.48	$24.93					
20	$9.60	$11.20	$13.01	$15.07	$17.40	$20.08	$23.24	$27.07				
21	$8.81	$10.33	$12.05	$14.04	$16.26	$18.81	$21.74	$25.20	$29.38			
22	$8.01	$9.44	$11.11	$12.98	$15.12	$17.57	$20.35	$23.55	$27.36	$31.94		
23	$7.76	$8.58	$10.15	$11.94	$13.98	$16.32	$19.00	$22.02	$25.53	$29.70	$34.76	
24	$7.47	$8.32	$9.22	$10.91	$12.84	$15.08	$17.62	$20.53	$23.86	$27.69	$32.33	$37.88
25	$7.16	$7.97	$8.90	$9.87	$11.74	$13.83	$16.26	$19.03	$22.22	$25.87	$30.10	$35.19
26	$6.85	$7.63	$8.52	$9.55	$10.60	$12.59	$14.91	$17.54	$20.57	$24.04	$28.05	$32.76
27	$6.54	$7.28	$8.14	$9.10	$10.21	$11.35	$13.53	$16.04	$18.93	$22.25	$26.08	$30.49
28	$6.22	$6.94	$7.76	$8.69	$9.73	$10.92	$12.18	$14.55	$17.29	$20.43	$24.07	$28.30
29	$5.91	$6.62	$7.38	$8.25	$9.25	$10.38	$11.68	$13.05	$15.62	$18.61	$22.06	$26.06
30	$5.63	$6.28	$7.00	$7.83	$8.77	$9.86	$11.07	$12.49	$13.98	$16.79	$20.05	$23.86
31	$5.31	$5.93	$6.62	$7.39	$8.29	$9.31	$10.45	$11.81	$13.35	$14.99	$18.04	$21.63
32	$5.00	$5.58	$6.21	$6.98	$7.81	$8.77	$9.87	$11.12	$12.59	$14.26	$16.07	$19.43
33	$4.69	$5.24	$5.83	$6.53	$7.34	$8.22	$9.25	$10.43	$11.80	$13.36	$15.23	$17.20
34	$4.38	$4.89	$5.46	$6.12	$6.86	$7.68	$8.64	$9.75	$11.04	$12.50	$14.22	$16.22
35	$4.09	$4.55	$5.08	$5.67	$6.38	$7.16	$8.06	$9.06	$10.26	$11.64	$13.22	$15.10
36	$3.78	$4.20	$4.70	$5.26	$5.90	$6.61	$7.44	$8.38	$9.50	$10.74	$12.21	$13.95
37	$3.47	$3.86	$4.32	$4.82	$5.42	$6.07	$6.83	$7.69	$8.71	$9.88	$11.24	$12.80
38	$3.15	$3.51	$3.94	$4.40	$4.94	$5.52	$6.21	$7.01	$7.92	$8.98	$10.24	$11.69
39	$2.84	$3.17	$3.56	$3.96	$4.46	$4.98	$5.63	$6.32	$7.16	$8.12	$9.23	$10.54
Sum:	$206.68	$217.52	$228.79	$240.59	$252.91	$265.61	$278.89	$292.64	$307.07	$321.80	$337.21	$353.10
NPV at:												
9.70%	$31.49	$30.78	$30.07	$29.39	$28.70	$28.04	$27.39	$26.74	$26.12	$25.49	$24.89	$24.29

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ORIGCOST+ADDIT	$161.578	$173.535	$186.376	$200.168	$214.981	$230.889	$247.975	$266.325	$286.033	$307.200	$329.932	$354.347
VINTAGE	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2												
3												
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20												
21												
22												
23												
24												
25	$41.34											
26	$38.38	$45.23										
27	$35.69	$41.96	$49.61									
28	$33.19	$38.96	$45.96	$54.55								
29	$30.73	$36.16	$42.61	$50.47	$60.22							
30	$28.27	$33.43	$39.50	$46.74	$55.67	$66.77						
31	$25.81	$30.67	$36.43	$43.24	$51.43	$61.62	$56.20					
32	$23.35	$27.94	$33.36	$39.78	$47.46	$56.82	$56.20	$64.87				
33	$20.89	$25.18	$30.29	$36.32	$43.57	$52.31	$56.20	$64.87	$76.92			
34	$18.43	$22.45	$27.21	$32.86	$39.68	$47.87	$56.20	$64.87	$76.02	$.00		
35	$17.29	$19.72	$24.14	$29.40	$35.76	$43.43	$56.20	$64.87	$76.02	$90.88	$111.60	
36	$16.00	$18.40	$21.07	$25.98	$31.86	$39.00	$56.20	$64.87	$76.02	$90.88	$111.60	$145.28
37	$14.67	$16.88	$19.53	$22.52	$27.94	$34.52	$56.20	$64.87	$76.02	$90.88	$111.60	$145.28
38	$13.37	$15.40	$17.79	$20.72	$24.05	$30.08	$56.20	$64.87	$76.02	$90.88	$111.60	$145.28
39	$12.07	$13.89	$16.08	$18.68	$21.91	$25.64	$56.20	$64.87	$76.02	$90.88	$111.60	$145.28
Sum:	$369.46	$386.26	$403.57	$421.28	$439.55	$458.07	$505.83	$518.93	$532.17	$454.42	$558.02	$581.12
NPV at:												
9.70%	$23.71	$23.13	$22.56	$22.00	$21.45	$20.91	$20.38	$19.94	$19.32	$14.91	$18.31	$18.15

ORIGCOST+ADDIT VINTAGE	$380.569 2022	$408.731 2023	$438.977 2024	TOTAL YEAR BY YEAR REVENUE REQ ON COST	LAND REV REQ	TOTAL REV REQ
						Table 3.7
1	$0.00	$0.00	$0.00	$896.03	$1.50	$897.53
2				$861.62	$1.50	$863.12
3				$831.29	$1.50	$832.79
4				$804.39	$1.50	$805.89
5				$778.37	$1.50	$779.87
6				$752.48	$1.50	$753.98
7				$726.87	$1.50	$728.37
8				$701.45	$1.50	$702.95
9				$676.44	$1.50	$677.94
10				$651.71	$1.50	$653.21
11				$648.24	$1.50	$649.74
12				$642.69	$1.50	$644.19
13				$637.79	$1.50	$639.29
14				$633.62	$1.50	$635.12
15				$630.22	$1.50	$631.72
16				$627.52	$1.50	$629.02
17				$625.79	$1.50	$627.29
18				$625.00	$1.50	$626.50
19				$625.21	$1.50	$626.71
20				$626.55	$1.50	$628.05
21				$629.00	$1.50	$630.50
22				$632.94	$1.50	$634.44
23				$638.27	$1.50	$639.77
24				$645.22	$1.50	$646.72
25				$654.00	$1.50	$655.50
26				$664.75	$1.50	$666.25
27				$677.73	$1.50	$679.23
28				$693.24	$1.50	$694.74
29				$711.63	$1.50	$713.13
30				$733.45	$1.50	$734.95
31				$741.04	$1.50	$742.54
32				$759.02	$1.50	$760.52
33				$789.28	$1.50	$790.78
34				$744.83	$1.50	$746.33
35				$904.03	$1.50	$905.53
36				$1,007.28	$1.50	$1,008.78
37	$201.98			$1,168.47	$1.50	$1,169.97
38	$201.98	$316.11		$1,445.32	$1.50	$1,446.82
39	$201.98	$316.11	$660.49	$2,068.13	$1.50	$2,069.63
Sum:	$605.93	$632.22	$660.49	$30,310.91		$30,369.41
NPV at:						
9.70%	$18.02	$17.92	$17.86			

APPENDIX E
FORCED OUTAGE RATE COMPUTATION

APPENDIX E
EQUIVALENT AVAILABILITY FACTOR (EAF),
YEARLY VALUES AND AVERAGE OF 1980-84 VALUES

	UNIT	1980	1981	1982	1983	1984	AVERAGE EAF 1980-84
	Richmond 9	--	88.1%	89.6%	79.4%	28.2%	71.3%
	Southwark 1	78.4%	85.0%	67.3%	69.8%	64.4%	71.6%
	Southwark 2	66.3%	72.0%	79.7%	78.6%	68.8%	74.8%
	Southwark 0	99.8%	90.9%	82.7%	86.8%	66.0%	81.6%
CTs:	Plymouth 9	61.4%	57.7%	93.1%	27.7%	0.0%	44.6%
	Plymouth 15	36.4%	23.7%	36.4%	27.4%	0.0%	21.9%
	Richmond 21	97.4%	93.1%	65.1%	82.5%	94.9%	83.9%
	Richmond 22	95.3%	98.1%	91.5%	98.0%	96.1%	95.9%
	Richmond 31	92.7%	99.3%	93.5%	91.9%	95.0%	94.9%
	Richmond 32	97.9%	89.0%	49.2%	93.0%	91.9%	80.8%
	Richmond 41	89.9%	84.5%	96.7%	99.5%	90.9%	92.9%
	Richmond 42	55.2%	54.0%	93.4%	64.9%	68.0%	70.1%
	Richmond 43	92.0%	87.7%	63.1%	64.7%	82.7%	74.6%
	Richmond 44	86.6%	92.0%	96.5%	82.4%	3.2%	68.5%
	Richmond 51	95.2%	94.1%	99.8%	94.8%	99.2%	97.0%
	Richmond 52	96.9%	99.2%	98.8%	95.3%	88.1%	95.4%
	Richmond 61	67.7%	38.9%	4.0%	0.0%	4.2%	11.8%
	Richmond 62	95.0%	61.4%	99.8%	90.1%	92.4%	85.9%
	Richmond 71	18.6%	48.6%	90.6%	87.0%	95.4%	80.4%
	Richmond 72	90.9%	86.0%	85.6%	58.8%	97.0%	81.9%
	Richmond 73	90.2%	97.8%	76.3%	82.0%	87.1%	85.8%
	Richmond 74	50.4%	80.0%	0.0%	0.0%	0.0%	22.0%
Average CT:		78.8%	78.6%	75.1%	70.7%	64.2%	71.6%

Note: Source Documents: Attachment IR-OCA-6-22
Attachment IR-OCA-2-22e

APPENDIX F
DISCOUNT RATE SURVEY

App F

SURVEY RESULTS

During the week of December 9th, a survey of a sample of BOMA members was conducted to determine the payback (in years) on energy conservation and energy conversion measures expected by Philadelphia area building managers. The responses fell into the same categories with absolutely no exceptions. All of the managers expect a payback in the range of two to four years. None of them would consider an investment that would take any longer than five years to pay back the initial investment. This reflects a higher discount rate than that which DOE has used in its text.

Question 1: In considering investments in energy conservation measures (i.e. boiler conversions, additional insulation, lighting changes), what is the number of years of payback you would consider reasonable?

Question 2: What is the maximum number of years you would tolerate for such investments

COMPANY	CONTACT	# OF YRS EXPT'D	MAX. TOLERABLE
Reliance	J. Lawrence	3.4-4.5	5
Strawbridge (retailer)	D. Mechlin	2	2
1211 Chestnut	A. Swotes	2-3	4-5
Jcksn. Cross	W. Lee	3	3
Chstnt Mgmt.	H. Conn	3	5
Cush. & Wkfld.	C. Conwell	2	5
MassMutual	K. Domanski	2-3	3
Cush. & Wkfld.	J. Geist	3	5
Chas. Kahn	C. Kahn, Jr.	1 (lowest)	5
BBRC	M. Maher	3	5
IVB	S. Murphy	3	5
Alb. Einstein (hosp.)	T. McCandless	3.5-4 (fed. [illegible])	4
Thom. Jefferson (hosp.)	G. Prouty	2-3	5

APPENDIX G
COST ALLOCATION PAPER

Award Papers in Public Utility Economics and Regulation

1982
MSU Public Utilities Papers

Institute of Public Utilities
Graduate School of Business Administration
Michigan State University
East Lansing

Capacity/Energy Classifications and Allocations for Generation and Transmission Plant

Paul L. Chernick
and
Michael B. Meyer

In the current ratemaking system, every electric utility rate case necessarily covers three conceptually distinct subjects: estimation of total revenue needs and total revenue deficiency; allocation of total revenue needs and total revenue deficiency to the various customer classes (revenue allocation); and allocation of revenue needs within each customer class to various customers with differing usage patterns (rate design). As a result of many interrelated factors — such as the rapid increase in oil prices since 1973, the passage of the Public Utility Regulatory Polices Act of 1978, and the widespread recognition of the benefits of increased conservation incentives and of prices more accurately reflecting the costs of service — a major reform movement is under way in the United States to modify the way in which the electric utility industry accomplishes the revenue allocations among customers within classes, usually referred to as rate design. Initiatives to institute time-of-use pricing, marginal cost pricing, and lifeline rates are only a few examples of these suggested rate design reforms.

By comparison, although the second step in the ratemaking process, which involves revenue allocations between customer classes, is as important as the rate design step in every respect, it has so far attracted much less attention. This relative lack of attention to interclass revenue allocations exists among regulators, in the academic journal literature, in the industry's efforts and attention, and in the positions taken by would-be rate reformers. In short, the recent flurry of activity, discussion, and controversy over the rate design process has, by and large, not affected the interclass revenue allocation process.

The problem can be briefly stated. Revenue allocations are made to customer classes based upon the estimated costs of serving the classes. However, as the costs being allocated in the current ratemaking system are embedded costs,[1] and as a large percentage of these are joint costs, these allocations are essentially judgmental and cannot be rigorously justified by analytical methods. Furthermore, the present allocation methodologies were designed and adopted in a time when generation plant additions were not usually made for energy cost savings purposes, and when the $/kw costs of the different types of installed generation capacity varied over a much narrower range than do the various generation technologies currently available. Thus the present allocation methodologies require reexamination for two reasons: their lack of a rigorous analytical justification, and their nonresponsiveness to current generation planning considerations.

This paper first describes the traditional solution to the revenue allocation problem as it is widely applied in the United States today. It then recommends an improvement to the current practice, focusing upon the causes for constructing different types of generating capacity in terms of $/kw of capital cost, ¢/kwh of energy cost, and expected capacity factors. The last section offers brief concluding remarks.

The Traditional Solution

The interclass revenue allocation problem (the second of the three ratemaking steps) has traditionally been solved itself in three steps. First, costs are *functionalized* in production, transmission, subtransmission, and distribution cost categories depending upon the purpose served by the operating expense or capital expenditure. Second, these costs are *classified* as energy related, demand related, or customer related. Third, the demand portions of these costs are *allocated* by some method to the various customer classes.[2]

Functionalization can be based upon fairly clear-cut engineering considerations for most capital expenditures. With the exception of the joint cost problem, which appears for some overhead and administrative expenses, functionalization is not very controversial; it is quite uncontroversial as to the capital expenditures under consideration here, for example, for generation and transmission plant.

The steps of classification and allocation, however, are potentially quite arguable, at least as they are currently applied to generation and transmission plant capital expenditures. First, all or essentially all costs for these items are joint costs. With few exceptions, generation plant capital expenditures are usually classified as entirely demand related.[3] Second, once the generation plant capital expenditures are classified as entirely demand related, they are then allocated to the various customer classes by essentially arbitrary (but long-established) methods, such as the contribution to system coincident peak, the noncoincident peak, the average-and-excess, the weighted average of the contributions to summer and winter peaks, or the twelve monthly peaks methods.

The second step, which currently classfies all (or almost all) generation plant to demand, does not appear to be justified in view of the fact that different generating technologies (with different $/kw and ¢/kwh costs) are installed to serve different parts of the load duration curve at different load factors. In other words, a large percentage of generation plant capital costs are currently incurred to minimize total generation costs, including energy costs [Crew and Kleindorfer 1976; Wenders 1976].

The third step, which currently allocates all demand-related generation plant capital costs to peak or some intuitively derived alternate measure of peak, is not justified because it is well established that off-peak demand contributes measurably to total system reliability needs [Vardi and others 1977; compare Kahn 1971 at I:89–103].

Indeed, the traditional solution tends to conflate the problems of classification and allocation. It may be hypothesized that much of the motivation for the use (in step three) of allocation methods other than the contribution to coincident system peak method stems from a desire on the part of electric utilities to correct in some rough and intuitive fashion for the problems caused by the classification (in step two) of all generation plant capital expenditures to demand, which, in fact, appears to understate substantially the energy-related portion of these expenditures. In other words, it seems plausible that the utility industry *is* attempting to compensate for the under-recognition of energy-related expenses in step two by intuitive means in step three, through the use of allocation methods other than the contribution to system peak method, although no attempt is made to measure the relative size of the "mistake" and the corresponding "correction."

The Minimum-Cost Reliability Serving Method

We believe a set of classification and allocation principles may be derived which can satisfy the concerns raised above. Since cost classifications are more a matter of subjective measures of equity than of objective measures of efficiency, the derivations will not consist of the mathematical progression of equations that characterizes the development of efficient pricing structures. Rather, we will present a series of principles, joined by logical arguments and occasionally restated in the form of equations. We start with our fundamental principles:

> *Principle 1:* The reliability related portion of power supply production investments and nonfuel expenses is the minimum cost associated with providing the desired reliability level, or the actual reliability level, if that is lower. The remaining power supply production costs should be classified as energy.

This principle embodies a "reliability first" conception of system planning. When the utility builds generation capacity it first concentrates on maintaining adequate reliability; only after a reliable system is provided do the planners turn their attention to fuel cost reductions. Since both system reliability and energy costs are designed in simultaneously, the reliability first assumption refers more to a conceptual hierarchy of priorities than to a temporal sequence.[4]

We base our classification technique on the reliability first principle for two reasons. First, we believe it is historically correct. System planners have traditionally been more worried by the prospect of disconnecting customers and shedding load than by an increase in running costs. While attitudes may have changed somewhat in the 1970s, due to large increases in fuel costs, most utility systems probably embody this order of priorities. Second, Principle 1 provides us with fairly specific and tractable directions for deriving a classification scheme. While implementation of the principle is not without complications and controversy, it is relatively easy to determine whether a classification approach is generally consistent with it. We recognize that Principle 1 is not the only contender for a fundamental principle of classification, and we present alternatives in Appendix A.

Principle 1, and other classification principles, are stated in terms of dividing power supply costs into energy-related and reliability related components. The use of reliability in lieu of the more common term demand reflects our concern that the latter has been too long associated with peak load and capacity, and that old habits of thought are hard to break. In reassessing the relationships among capacity, reliability, and load shape, it is advantageous to start with as clean a slate as possible.

The confusion between reliability serving costs and the larger class of capacity costs (or fixed or capital costs) is deeply rooted in the utility industry and often confuses analysis of a variety of issues. For example, a recent article on load management and oil-backout policies concluded that the Long Island Lighting Company (Lilco)

> can justify having higher reserves than required for reliability . . . to substitute nuclear base-loaded plants for oil base-loaded plants. As Lilco's system becomes more heavily nuclear the relationship of its fixed costs to its variable costs will change substantially. Nuclear plants have relatively high-capital costs and low-fuel costs; whereas, oil plants have relatively low-capital costs and high-fuel costs. If we assume that future rates will generally track costs, then demand-related charges will have to rise in relation to energy-related charges. Then assuming all other things being equal for the moment, rates for low-load factor customers will rise faster than rates for high-load factor customers. Since residential customers, as a class, almost always have significantly lower load factors than the industrial customer class, one result from Lilco's converting to a lower cost operating system through installing nuclear plants is likely to be relatively higher residential rates in respect to industrial rates [Koger 1980].

In other words, the implicit assumption that capital costs must be recovered from demand-related charges leads Koger to conclude that residential customers should pay for the nuclear plants that are built to reduce the industrial customers' fuel charges. Clearly, a new mode of thinking about fixed costs is required.

Another set of clear examples of the inadequacy of the prevalent allocation of all fixed costs to demand involves the treatment of fuel storage and treatment facilities. If an oil desulfurization unit, or a coal gasifier, is owned by a supplier who sells the high quality product to the utility, the cost of the treatment facility is rolled into the fuel cost and is therefore treated as an energy charge. If the uility buys is own treatment facilities, they would generally be treated as part of fixed plant and allocated to demand. In either case, the treatment facilities serve exactly the same purpose: to reduce fuel costs. All extra fixed costs incurred to reduce fuel costs are clearly energy related, regardless of whether the extra cost is located at a supplier's plant or beside the utility's generator. The same is true of the additional cost of a coal plant as compared to a less expensive gas-fired plant: The incremental investment is a fuel-saving measure and should be classified as energy serving.[5]

Principle 1 implies that the reliability related portion of a power supply system is the lowest cost system which would provide a particular level of reliability. Certainly, reliability users should not be charged for more reliability than they are actually receiving, so the reliability of the reference, low-cost system need never exceed actual levels. Where the actual reliability is greater than or equal to target reliability, the reference system should generally be designed to the target levels. This follows from the observation that excess capacity is generally the result of the long lead times of base load units (which caused accidental overcapacity starting around 1974 in many parts of the country) and of the effort to replace oil and gas-fired generators with other fuels (which will cause intentional overcapacity in the 1980s). In general, the hypothetical minimum-cost reliability serving system will consist of relatively small units with short lead times and will not consider fuel costs at all. Thus, the reference system should not incorporate overcapacity, unless unusual circumstances (such as a very abrupt drop in load) suggest that the overcapacity would have occurred even to an all-peaking system.

> *Principle 2:* For any generation unit built after 1963, the reliability related cost is generally that of an array of gas turbines with the same contribution to reliability and of the same vintage.

Gas turbines are chosen as the standard reference system because they are cheap and site independent. Under some circumstancs, other types of capacity (building conventional or pumped hydro, retaining obsolete generators, special purchase agreements) may be known to be cheaper for some amount of capacity; this will vary among systems, depending on the extent of current hydro development and purchases and of information on past and future options. Where identified, such cheaper capacity should be used as the basis for reliability/energy classifications. The 1963 cutoff was chosen to reflect the fact that gas turbines were not widely available prior to that date, as evidenced by the fact that the Handy-Whitman price index for gas turbines originated in 1964.

We interpret "the same contribution to reliability" to mean the effective load carrying capability (ELCC) or something quite similar. ELCC [Garver 1965] is the amount of additional firm load that a generating unit allows a system to accommodate without violating its reliability constraint. Thus, if the system can carry 11,000 MW without the unit, and 11,500 MW with it, the unit's ELCC is 500 MW.

Ideally, it would be desirable to model the ELCC of each unit in the utility's actual system to reflect the effect of the utility's load curve, generation mix, and tie lines. Since the ELCC of a large marginal unit increases as the number of such units increases (the sixth 500 MW coal plant has a higher ELCC than the first), the ELCC of each unit should ideally be determined by adding the units in chronological order to the current system of pre-1964 units and peaking units. This level of detail and specificity will not always be possible; we suggest a simplified alternative below.

One might also wish to construct the reference system from the actual system on a unit-by-unit basis, accounting for plant in service, return, non-fuel O&M expense, accumulated depreciation, deferred taxes, depreciation expense, property taxes, and income taxes to develop a total cost in the rate year for each unit. There are three drawbacks to this approach. First, the calculations may be very time consuming for systems with many units and may be virtually impossible if units within a plant (possibly of very different sizes, vintages, and ELCC's) are aggregated in the available accounting data. Second, the components of the reference system must be "aged" to determine accumulated depreciation, deferred taxes, additions to capital cost, and property taxes, which requires assumptions regarding past and present tax treatments, depreciation rates, and capital additions. Third, if accumulated depreciation is reassigned from demand to energy along with the associated plant, the (low load factor) groups who paid for depreciation expense in the past will not generally receive the benefits of the accumulated depreciation they contributed; thus, the detailed accounting does not, in itself, produce as great an increase in equity as might be hoped.

In a previous application [Meyer and Chernick 1980], we simplified the modeling by assuming that all current cost components (except O&M) vary in proportion to initial construction cost, so that for unit i,

$$CGT_i = CM(BY) \times \frac{HW(COD)}{HW(BY)} \times ELCF_i \times MW_i \qquad (1)$$

where

- CGT_i = cost of a gas turbine equivalent to unit i under the terms of Principle 1;
- $CM(BY)$ = cost per MW of gas turbine index as of the base year;
- $HW(COD)$ = Handy-Whitman gas turbine index as of the commercial operation date of unit i;
- $HW(BY)$ = Handy-Whitman gas turbine index as of the base year;
- $ELCF_i$ = effective load carrying factor, defined as (ELCC/MW for unit i ÷ ELCC/MW for gas turbines); and
- MW_i = capacity in MW of unit i.

For nonfuel O&M expense for unit i,

$$OGT_i = OM \times ELCF(i) \times MW(i), \qquad (2)$$

where

- OGT_i = O&M expense for unit i attributable to reliability; and
- OM = current year nonfuel fixed O&M cost/MW for gas turbines.

> *Principle 3:* Steam units built prior to 1964 in primarily thermal systems may be regarded as entirely reliability related, unless a hydroelectric or other specific alternative was available.

Before 1964, units were not so specifically designed for peak or base load service; older units generally served as peaking plants, and the newest units provided the base load. Among today's base load plant types, before 1964 nuclear units were rare and heavily subsidized, while coal units, much less encumbered than at present by environmental regulations, were not much different in terms of initial capital cost per kw of capacity from oil-fired steam units. Before the gas turbine, the only real peaking alternative for thermal systems appears to have been the diesel, which has rarely been used on a large scale. For systems on which a reasonable series of diesel cost estimates can be developed, perhaps the method we suggest for post-1963 units can be pushed back some years. For systems with hydro capacity, the technique discussed in Principle 6 below may be helpful.

In general, the pre-1964 units will not be a large portion of the power production supply costs for three reasons. First, pre-1964 capacity is generally a small portion of total capacity. Second, the original cost of the old units was low; for example, Handy-Whitman all steam generation cost index for the North Atlantic Region in 1960 was 158 versus 505 in 1980. Third, the older units are largely depreciated; even a unit completed in 1963 would be about 50 percent depreciated for ratemaking purposes by 1980, and older units would be even more depreciated. Thus, the classification of old units will not generally be very important to the final allocations.

Exceptions may arise if old units have recently added pollution control or fuel conversion equipment, which would not have been necessary if the unit were a peaking plant for which the cost of fuel was relatively unimportant. Such equipment, especially in the case of coal conversion projects, may have a larger effect on rates than does the remaining balance of the unit and is generally 100 percent energy related.

> *Principle 4:* Where construction work in progress (CWIP) is included in the rate base, only the CWIP which would have accrued on a gas turbine of similar service date is attributable to reliability; the remainder is energy related.

One reason base load plants are so expensive is that they take a long time to build, during which period interest charges must be paid. If the interest portion of the construction cost is to be transferred to the rate payers, then the energy users, who receive most of the benefit from the plant, should also bear most of that interest cost.

Where CWIP is an extraordinary measure, permitted only for especially expensive investment, the gas turbine equivalent would have resulted in no CWIP at all, and all CWIP charges may be attributable to energy. This is particularly true when the unit for which CWIP is allowed is not required for reliability in the near future. If CWIP is allowed on all generation, then the amount of the CWIP on unit i in year Y attributable to reliability is

$$CWGT_i = CM(BY) \times \frac{HW(COD)}{HW(BY)} \times ELCF(i) \times MW(i) \times F(COD - Y) \times P, \quad (3)$$

where

$F(t)$ = the fraction of the final cost of a gas turbine which is invested t years before the COD; and

P = fraction of CWIP allowed in the rate base.

The F function is probably an S-curve, but we approximate it linearly as

$$F(t) = (L-t)/L \text{ for } L > t,\ 0 \text{ for } L \leqslant t, \quad (4)$$

where

L = construction time for gas turbines.

Two problems arise in applying Equation 3. First, COD is an estimate and, especially for nuclear plants, probably an underestimate. Using utility estimates of COD will frequently overestimate F. Second, again because COD is an estimate, $HW(COD)$ must be synthesized from a recent HW and an anticipated inflation rate. Neither difficulty is insurmountable and neither should obscure the basic reality; only a small portion of CWIP is attributable to reliability.

> *Principle 5:* Amortization of the cost of a canceled generation project should only be assigned to reliability to the extent comparable costs would have been incurred for an equivalent gas-turbine addition planned for the same COD.

The same principles apply here as in the case of CWIP. Base load plants require extensive advance preparation which is sometimes lost when events render further development impractical or inappropriate. In the mid-1970s, falling demand and rising oil prices resulted in cancellation of several oil-fired plants on which sizable sums had already been expended. More recently, regulatory actions, budget constraints, and continued conservation have resulted in the cancellation of numerous nuclear units.

In most cases, these cancellations occurred long before a gas-turbine project with the same planned COD would have required much commitment beyond (at most) land acquisition. Since the value of the site is seldom included in the amortization, essentially no amortization would have been necessary if gas turbines had been planned instead of base load units.

> *Principle 6:* For high load factor hydroelectric facilities built prior to 1963, the reliability related portion can be determined from the cost per kw for pumped hydro storage or a low load factor conventional hydroelectric facility of the same vintage.

Just as thermal plants are built more expensively than would be necessary if they were solely designed to meet reliability needs, so are hydroelectric plants. In the case of thermal plants, additional investment (in the form of building steam plants rather than gas turbines) buys lower heat rates (in Btu/kwh) and the ability to use cheaper fuels (in ¢/Btu). In the case of hydroelectric plants, additional investment buys higher capacity factors through such devices as larger capacity storage ponds. In either case, the additional cost is incurred to reduce fuel costs and accommodate high load factor customers and therefore should be classified as energy related.

Isolating the reliability related portion of hydroelectric facility costs involves two problems not encountered in analyzing thermal systems. First, hydroelectric plants exist on a continuum of capacity factors, from base load units (which may operate at 70 percent or greater capacity factors), to peaking units (which operate at capacity factors below 20 percent), to pumped storage hydroelectric units (which contribute no net energy and are designed for varying storage cycles). It is not always obvious what type of hydroelectric plant would represent the portion of the actual plant attributable to reliability. Second, unlike gas turbines, hydroelectric capacity costs ($/kw) are highly site dependent. Thus, for each utility system, the cost of an additional kw of hydroelectric capacity varies with the amount of hydroelectric capacity already installed as well as with the capacity factors of the existing system and of the additions to the system. Therefore, some technique must be devised to separate the reliability serving portion of hydroelectric capacity on a utility-specific basis. (In some regions, such as New England, in which utilities commonly own generation outside their service territories, the perspective may be broadened to the region. This ameliorates, but does not remove entirely, the problem).

The first problem may be resolved by reference to the utility's load curves. On a system which experiences sharp, short-duration peaks, very low load factor pumped storage plants might provide adequate reliability; on a system with broader peaks and relatively high off-peak loads (precluding pumping), conventional hydroelectric facilities with higher capacity factors may be needed to carry load. An approximation to the capacity factor needed to replace the hydroelectric portion of a utility system can be determined from the load factor of the portion of the load duration curve corresponding to the installed capacity. Figure 1 illustrates this approach for a utility with 30 percent of its capacity in hydroelectric units. Note that serving the top 30 percent of the load duration curve requires a capacity factor of only about 10 percent. A more rigorous approach to selecting the reliability-serving hydroelectric component would involve the application of simulation models to determine the amount of each type of hydroelectric capacity required to maintain the reliability constraint; the least expensive alternative would be the reliability serving substitute for the existing hydroelectric capacity.

The second problem, relating to the variability of hydroelectric capacity development costs, can be resolved in several ways, depending on the kind of capacity which is being treated as reliability serving and on the extent of specific data about the system. If pumped storage hydroelectric capacity is an appropriate substitute for existing capacity, the cost of that pumped storage capacity may be available from site-specific or from generic regional studies.[6] Similarly, the cost of developing new low load factor hydroelectric facilities, or increasing the installed capacity (while decreasing the capacity factor) at existing sites, may have been previously established.[7]

If such economic studies are not available for enough low capacity factor sites to establish an alternative reliability serving system, or if such studies have excluded the most economical sites, currently occupied by high capacity factor hydroelectric facilities, it may be possible to estimate a general regional relationship between the capacity factor of a hydroelectric development at a site and the \$/kw cost for that site. For example, an "economy of intensity" relationship, analogous to the traditional economy of scale, might be estimated as

$$\frac{\text{cost of plant 1 (\$/kw)}}{\text{cost of plant 2 (\$/kw)}} = \left[\frac{\text{capacity factor of plant 1}}{\text{capacity factor of plant 2}}\right]^m, \qquad (5)$$

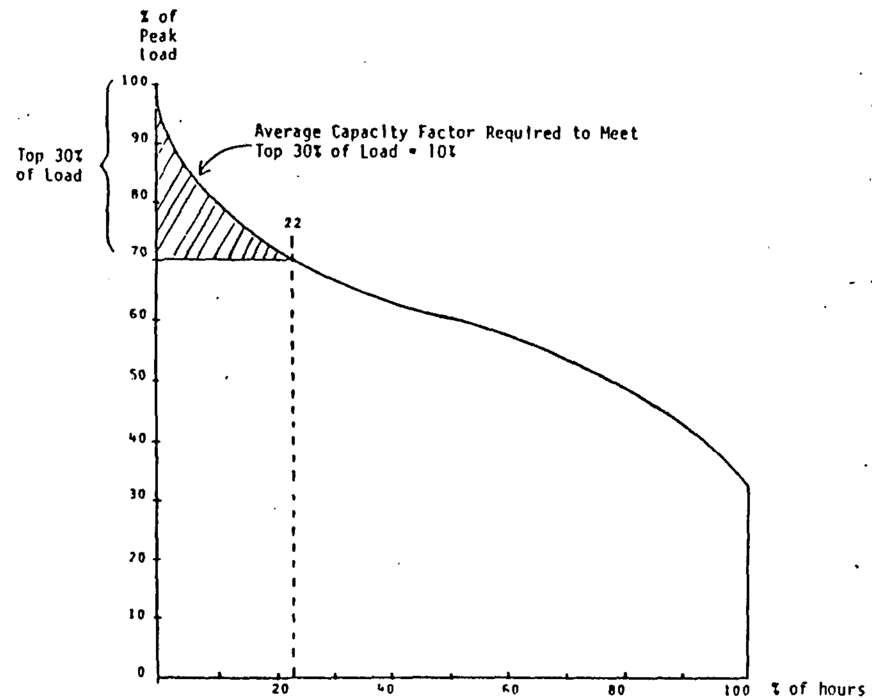

Figure 1. *Calculation of Required Hydro Capacity Factor for Typical Load Duration Curve and 30 Percent Hydro Capacity*

where plants 1 and 2 are alternative hydroelectric developments at the same site, and m is the economy of intensity factor. Once the value of m has been determined for a representative set of hydroelectric sites, Equation (5) could then be applied to other representative sites by letting plant 2 be the existing facility (with known cost and capacity factor), assigning plant 1 the desired capacity factor for the reliability serving plant, and solving for the cost of plant 1 at the site of plant 2. Of course, alternative formulations of Equation (5) are possible. Furthermore, to the extent that they are available, detailed site-specific cost studies would be preferable to any such extrapolation.

Whether established through detailed studies or by a generalized relationship, the total low load factor, low cost hydroelectric capacity which could be developed at existing sites will generally exceed the actual installed capacity at those sites. In addition, considerable conventional and pumped hydroelectric capacity may be available at new sites. The cost of this excess of reliability serving hydroelectric capacity, beyond that which would have been required to serve the same reliability as the existing hydroelectric capacity, can be used as the reliability serving component of the pre-1964 steam capacity (assuming the excess hydroelectric capacity is less expensive than the pre-1964 steam plants) and of the post-1964 generating capacity (assuming the excess hydroelectric capacity is less expensive than the gas turbine of equivalent ELCC).

> *Principle 7:* The reliability related cost of the power supply transmission is the cost of the minimum transmission system required to interconnect the minimum-cost reliability serving generation alternative to the utility system's load centers.

For most utilities, large portions of the transmission system exist to minimize total energy costs rather than to maintain reliable service. For example, some transmission lines are required solely to connect remote base load plants to the rest of the transmission grid. These remote base load plants are, of course, largely energy serving, and the motivation for their MW size, fuel type, and remote location are connected to their energy rather than their reliability aspects. Similarly, transmission lines connecting a system's load centers must be reinforced to accommodate the large and variable power flows resulting from the existence of large units and their consequent "lumpy" dispatch patterns and outages. Further reinforcement is typically added to allow for economic dispatch of the base load generation over a variety of load levels, spatial distributions of loads, generation outages, and transmission outages. If the generation system consisted solely of small gas turbines located near load centers, fewer miles of transmission lines would be needed, and the remaining lines would have lower kva capacities. The same result would generally apply for a generation system consisting of old steam units, as these were generally located close to load centers, so long as no provision was made for economic dispatch among the system's various steam generation units.

The minimum reliability serving transmission network will thus be comprised of a set of lines connecting load centers, with some extensions to peaking hydro facilities, if any. The cost of this system can be extrapolated from the cost per kva-mile of the existing system,

disaggregated as necessary by area, voltage level, and location of line (overhead versus underground).

> *Principle 8:* The cost of tie lines between utility systems should be considered to be entirely energy serving unless they serve to replace peaking capacity. To the extent that they do replace peaking capacity, the reliability serving portion is that equivalent to minimum-cost reliability serving generation.

In keeping with the reliability first concept of Principle 1, it is appropriate to treat tie lines as entirely reliability serving if they provide ELCC more economically than peaking capacity could provide ELCC. If the tie lines cannot be entirely justified on such a basis, then the reliability serving portion can be identified from Equation (1), where unit i is a tie line or a set of tie lines to another utility.

> *Principle 9:* Reliability related costs should be allocated to customer classes on the basis of class contribution to the system's reliability needs.

An appropriate allocator for reliability related costs will have to reflect what caused the reliability related costs to be incurred. Such costs are not incurred solely to meet one annual system coincident peak, or even a few monthly peaks, but to maintain reliable service throughout the year. Such reliability measures as loss of load probability (LOLP) and loss of energy expectation (LOEE) recognize the overall reliability level at each point of the load duration curve and thus provide the basis for appropriate allocators.

Class contributions to system hourly loads are now estimated by most major utilities for their PURPA §133 filings, and hourly estimates of reliability measures, especially LOLP, are widely available from standard programs. Thus, the class share of reliability serving costs can be determined as

$$S(j) = \sum_{h} M(h) \times L(j,h) \div L(h), \tag{6}$$

where

$S(j)$ = reliability allocator to class j;
$M(h)$ = reliability index, such as LOLP, in hour h;
$L(j,h)$ = load in hour h for class j; and
$L(h)$ = load in hour h for entire system.

If Equation (6) cannot be estimated, due to lack of data, then some arbitrary *ad hoc* allocator may be required. Such an allocator should reflect as much of the system load duration curve as possible, while emphasizing the relatively greater importance of the higher portions of the curve. In general, appropriate allocations will lie somewhere between those based solely on peak demand (which recognize only a few hours at the top of the load duration curve) and those based solely on energy (which recognize all hours on the load duration curve equally).

> *Principle 10:* Energy-related costs for each unit should generally be allocated to customer classes on the basis of class share of energy use (adjusted for losses) at the times of utilization of the unit.

While a reasonable argument can be made that the energy costs should be attributed equally to all periods, it appears fairer to time-differentiate both the fixed and variable components of energy costs. This procedure recognizes that the classes with high off-peak usage allow for the construction and operation of generally less expensive (on a kwh basis) base load plants, while those with heavily on-peak usage require more expensive (per kwh) peaking or intermediate units. The assignment of energy costs to periods may be based on actual or simulated data but should not be unduly sensitive to plant performance or demand patterns peculiar to the test year.

Finally, the relationship between the methodology proposed here and the "marginalist" cost allocation methodologies used by several state commissions (notably California, Montana, and Oregon) should be noted. Interclass revenue allocations based on marginalist principles are neither required nor indicated by efficient pricing theory. *Any* interclass revenue allocation methodology, whether embedded or marginalist in nature, by definition creates class revenue constraints which may require pricing away from "pure" marginal costs. In general, it is not possible to determine which interclass revenue allocation method provides a "better" second-best solution to designing rates; this is true of both embedded and marginalist revenue allocation methods. In sum, the reasons for pricing rates at marginal costs (in rate design) do not necessarily extend to interclass revenue allocations.

In light of this, the embedded cost revenue allocation methodology proposed here is a reasonable alternative to marginalist revenue allocation methodologies, but it cannot be said to be either more or less efficient (due to the second-best problem) than those. It is thus presented as appropriate for commissions which, for one reason or another, do not want to adopt marginalist revenue allocation methodologies but do wish to modify and improve on the traditional embedded cost revenue allocation methodologies widely in use today.

Conclusion

Because of the joint cost nature of many of the costs incurred in the production of electric power, it must be recognized that any interclass revenue allocation method is based upon judgment and not upon principles which can be rigorously derived from efficient pricing theory. However, once this is recognized, equity nevertheless demands that regulators and electric utilities do the best job possible of reflecting the various classes' responsibility for costs in rates. Given this necessity, it is submitted that the alternative interclass revenue allocation method advanced here reflects the realities of present generation planning, in which a large percentage of total generation and transmission capacity costs are incurred to serve most or all of the load duration curve and to minimize the total generation (including fuel) costs. The more traditional methods, which evolved when the capacity costs per kw of the various generation technologies existed in a narrower range, and when most or all capacity costs were in fact incurred in order to serve reliability, do not reflect those realities as well as does our method.

APPENDIX A

Alternatives to Principle I

The reliability-first principle proposed here as Principle I is put forth on the basis that it appears best to reflect the realities of current generation planning. However, it is certainly not the only possible basis for revenue allocations. Alternative approaches include energy-first allocation and load curve methods. This appendix briefly describes these two possible alternatives.

Energy-first allocation would allocate as an energy cost the portion of generation unit investment costs and operating and maintenance expenses which is justified on the unit's fuel-cost savings, with the remaining portion allocated to reliability. Some difficulty may arise in the definition of fuel savings; for example, if the generation alternative is an all-gas turbine system, some utility systems would find that their entire generating capacity and associated transmission investments are energy-related by that standard. The methodology may have some appeal for systems with excess capacity, mostly in oil-fired and gas-fired units, which are adding coal or nuclear capacity explicitly to reduce the use of the oil and gas units. In these cases, the energy-serving portion can be determined by comparison with the existing system. Unfortunately, variations in cost (in $/kw) in the new capacity, which is clearly intended as energy-serving, are reflected in the net classification to reliability, which does not seem appropirate.

With respect to load curve allocation methods, some interesting work has been started on allocating production costs by fitting units under the load curve, and allocating responsibility for the generation plant to the customer classes which use them [for example, Charles T. Main, Inc. 1980]. This approach is still quite incomplete: Such elementary concepts as reliability measures and ELCC have not yet been incorporated. Treatment of other issues, such as excess capacity, is still apparently done on an *ad hoc* basis without any substantial foundation. If the conceptual model can be expanded from the current deterministic form to a more reasonable probabilistic form, generalized to recognize the difference between potential contribution to energy supply (such as the capacity factor or the equivalent availability factor) and to reliability (such as ELCC), and made more rigorous, allocations based upon dispatching generators under a load curve may represent a compromise between the energy-first and the reliability-first approaches.

Notes

1. One can conceive of ratemaking systems in the future in which this would not be the case. For example, interclass revenue allocations can be performed using each class's contribution to marginal costs as the basis for allocations. Similarly, a "pure" marginal cost based rate design system would presumably omit the interclass revenue allocation step entirely and would set each class's rates based upon class marginal costs modified by Ramsey pricing, without setting class revenue constraints.
2. See NARUC [1973] at pp. 5–10 (functionalization), pp. 30–39 (classifications between energy-related and demand-related costs), and pp. 40–53 (allocation of demand-related costs).
3. See NARUC [1973] at pp. 30–35, exempting only some hydro generating capacity from the general rule that generation plant capital expenditures are demand related.
4. Applications of this principle in current utility allocation practice are uncommon, but some examples exist. Bonneville Power Administration [1981] applies simple variants of a reliability first approach for allocation of both thermal and hydro generation costs.
5. The coal plant can be thought of as a gas-fired plant with a built-in coal gasifier.
6. For example, NEPOOL has estimated that pumped storage hydroelectric capacity is available in New England for $315/kw, in 1980 dollars, up to at least 7,500 Mw [NEPOOL 1977].
7. Such studies for New England include Campbell [1977]; Acres American, Inc. [1979]; and New England River Basins Commission [1980].

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APPENDIX H
COMPARISON OF OIL PRICE PROJECTIONS

APPENDIX H: COMPARISON OF OIL PRICE FORECASTS
#6 Oil, 1% Sulfur, $/BBL

Year		ORI Forecast	% Increase	OCA Forecast	% Increase	PECo Forecast	% Increase
----		--------	----------	--------	----------	--------	----------
		[1]	[2]	[3]	[4]	[5]	[6]
1985		$26.06	--	$26.50	--	$26.50	--
1986		$23.93	-8.17%	$27.56	4.0%	$26.75	0.94%
1987		$22.21	-7.19%	$28.94	5.0%	$28.90	8.04%
1988		$22.53	1.44%	$30.38	5.0%	$31.50	9.00%
1989		$23.36	3.68%	$31.90	5.0%	$34.30	8.89%
1990		$24.32	4.11%	$33.50	5.0%	$37.40	9.04%
1991		$25.75	5.88%	$35.84	7.0%	$40.80	9.09%
1992		$27.18	5.55%	$38.35	7.0%	$44.47	9.00%
1993		$29.08	6.99%	$41.04	7.0%	$48.47	9.00%
1994		$31.47	8.22%	$43.91	7.0%	$52.84	9.00%
1995		$34.33	9.09%	$46.98	7.0%	$57.59	9.00%
1996		$38.14	11.10%	$50.27	7.0%	$62.78	9.00%
1997		$43.39	13.77%	$53.79	7.0%	$68.43	9.00%
1998		$50.06	15.37%	$57.56	7.0%	$74.58	9.00%
1999		$57.69	15.24%	$61.59	7.0%	$81.30	9.00%
2000		$66.27	14.87%	$65.90	7.0%	$88.61	9.00%
2001		$75.33	13.67%	$71.83	9.0%	$96.59	9.00%
2002		$83.92	11.40%	$78.29	9.0%	$105.28	9.00%
2003		$92.50	10.22%	$85.34	9.0%	$114.76	9.00%
2004		$101.08	9.28%	$93.02	9.0%	$125.08	9.00%
2005		$109.66	8.49%	$101.39	9.0%	$136.34	9.00%
2006		$120.15	9.57%	$110.52	9.0%	$148.61	9.00%
CUMULATI	10%	$322.03		$374.36		$444.93	
PRESE	15%	$205.62		$245.32		$282.76	
VALUE A	20%	$144.63		$175.15		$196.43	

Notes:

[1] From ORI August 1985 Energy Price Forecast for Philadelphia Electric

[2] From PECo, Attachment IR-OCA-1-11

APPENDIX I

LIMERICK ECONOMIC COMPARISONS

Attachment IR-C

38 PAGES

PHILADELPHIA ELECTRIC COMPANY

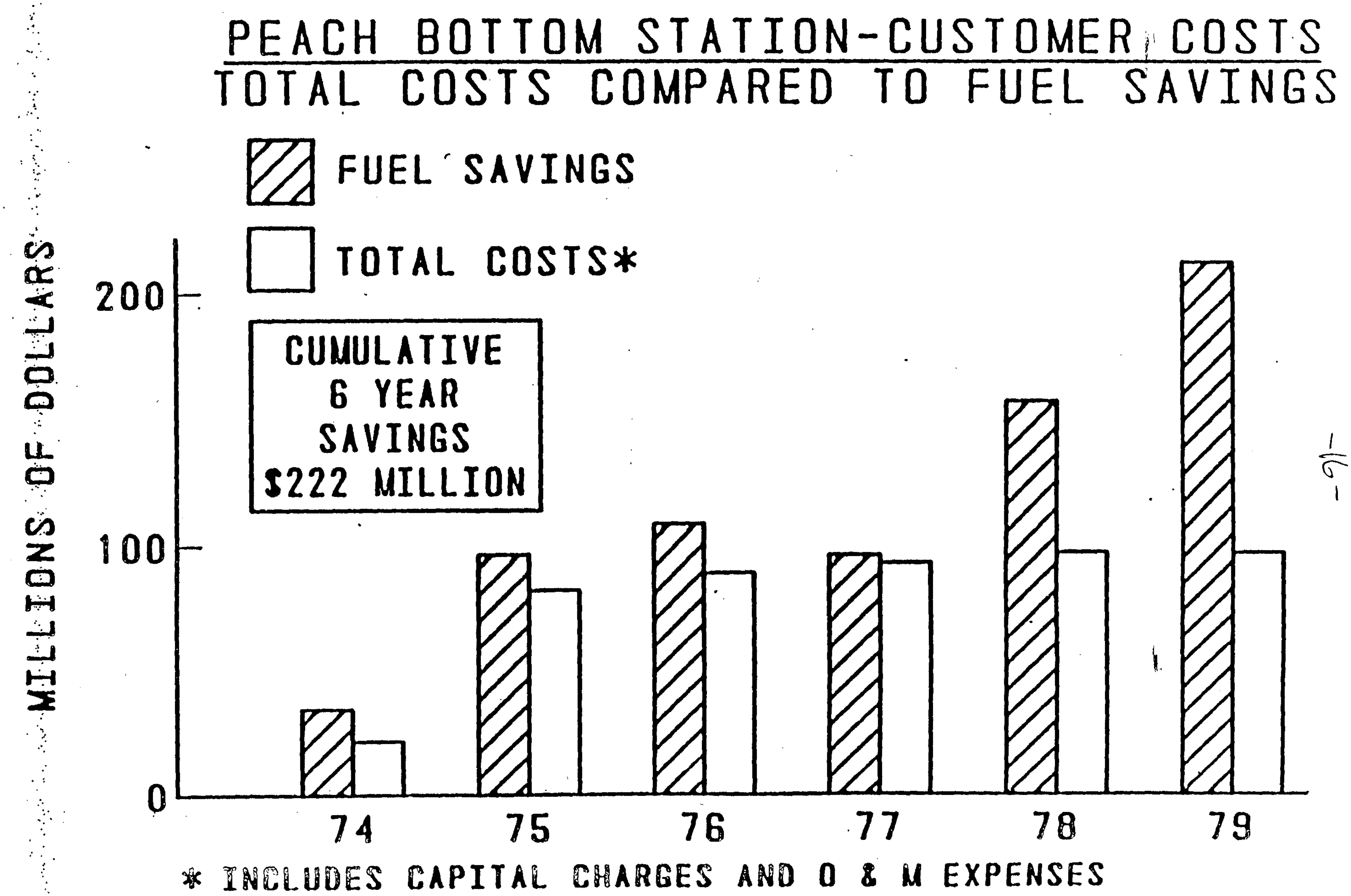
PHILADELPHIA

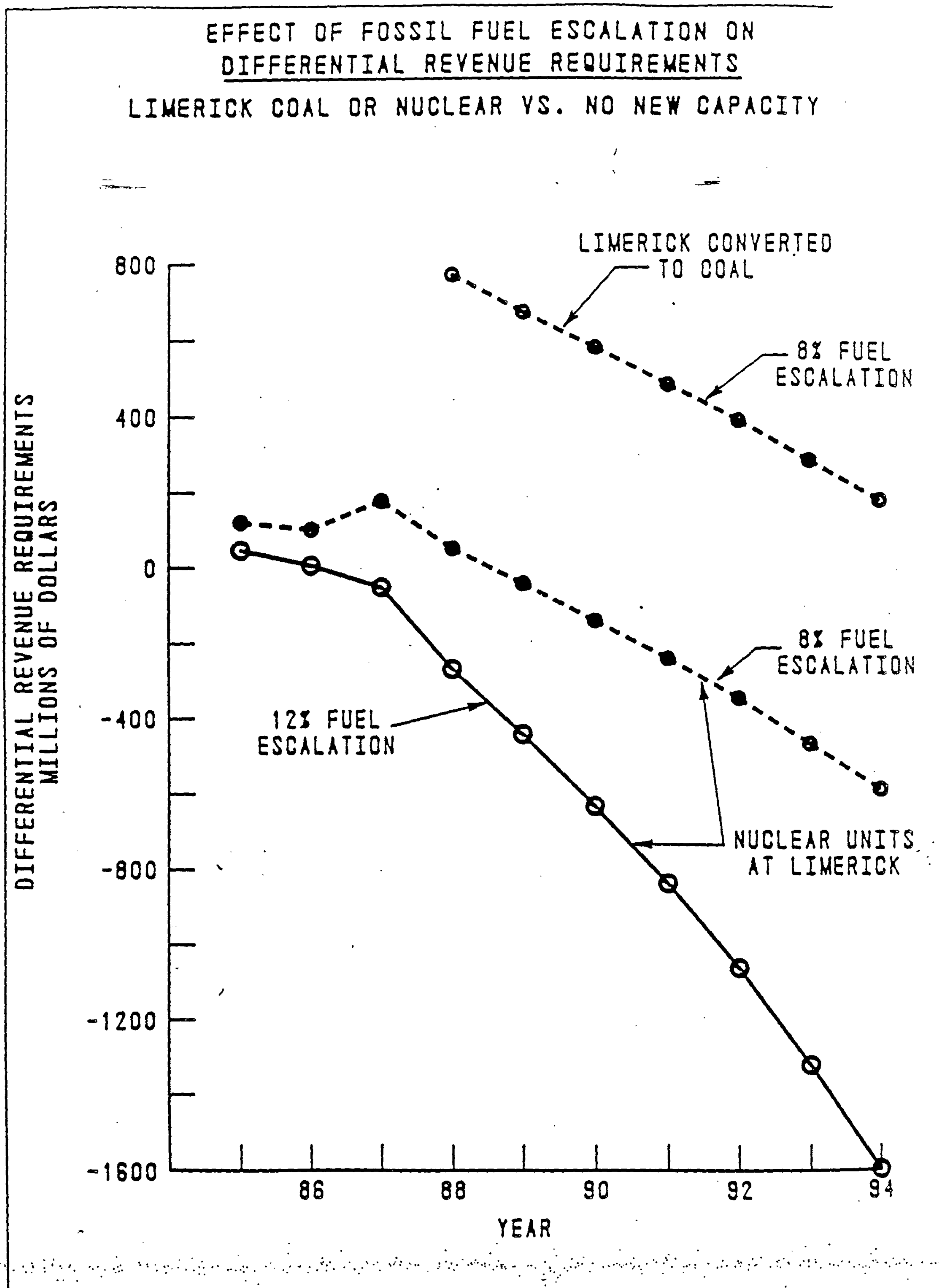
COMPARISON OF THE LIMERICK NUCLEAR STATION
WITH OTHER ALTERNATIVES UPDATED TO
SEPTEMBER 1980

WJC
JEB?
CE AFT
TJL
VJB AJK
DMH
EK

Copies Bob Daly 5/17 /Returned

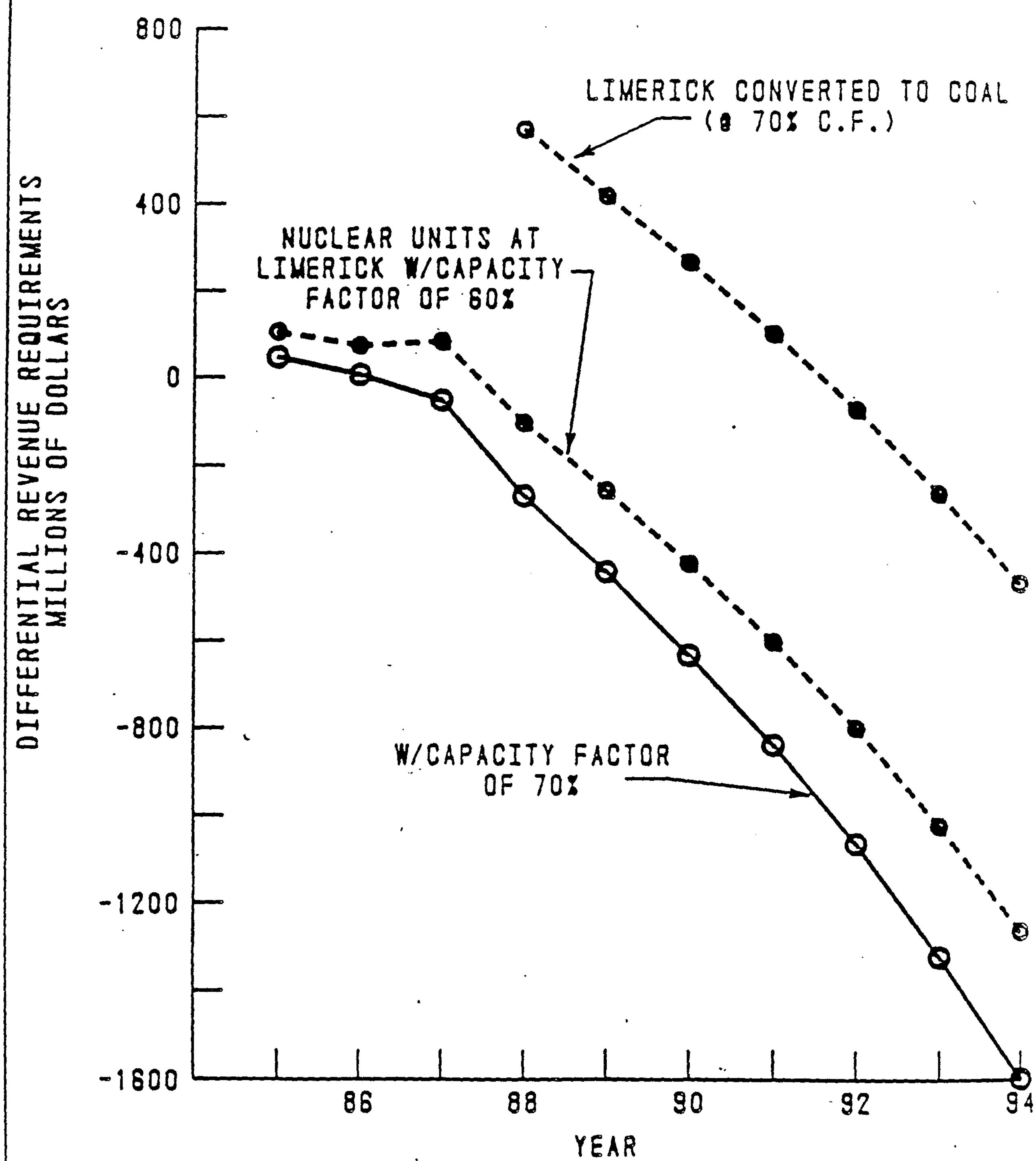
System Planning Division
September 5, 1980


PEACH BOTTOM STATION-CUSTOMER COSTS
TOTAL COSTS COMPARED TO FUEL SAVINGS
FUEL SAVINGS
TOTAL COSTS*
CUMULATIVE
6 YEAR
SAVINGS
$222 MILLION
MILLIONS OF DOLLARS
200
100
0
74
75
76
77
78
79
* INCLUDES CAPITAL CHARGES AND O & M EXPENSES


EFFECT OF FOSSIL FUEL ESCALATION ON
DIFFERENTIAL REVENUE REQUIREMENTS
LIMERICK COAL OR NUCLEAR VS. NO NEW CAPACITY
LIMERICK CONVERTED TO COAL
8% FUEL ESCALATION
8% FUEL ESCALATION
12% FUEL ESCALATION
NUCLEAR UNITS AT LIMERICK
DIFFERENTIAL REVENUE REQUIREMENTS
MILLIONS OF DOLLARS
800
400
0
-400
-800
-1200
-1600
86
88
90
92
94
YEAR

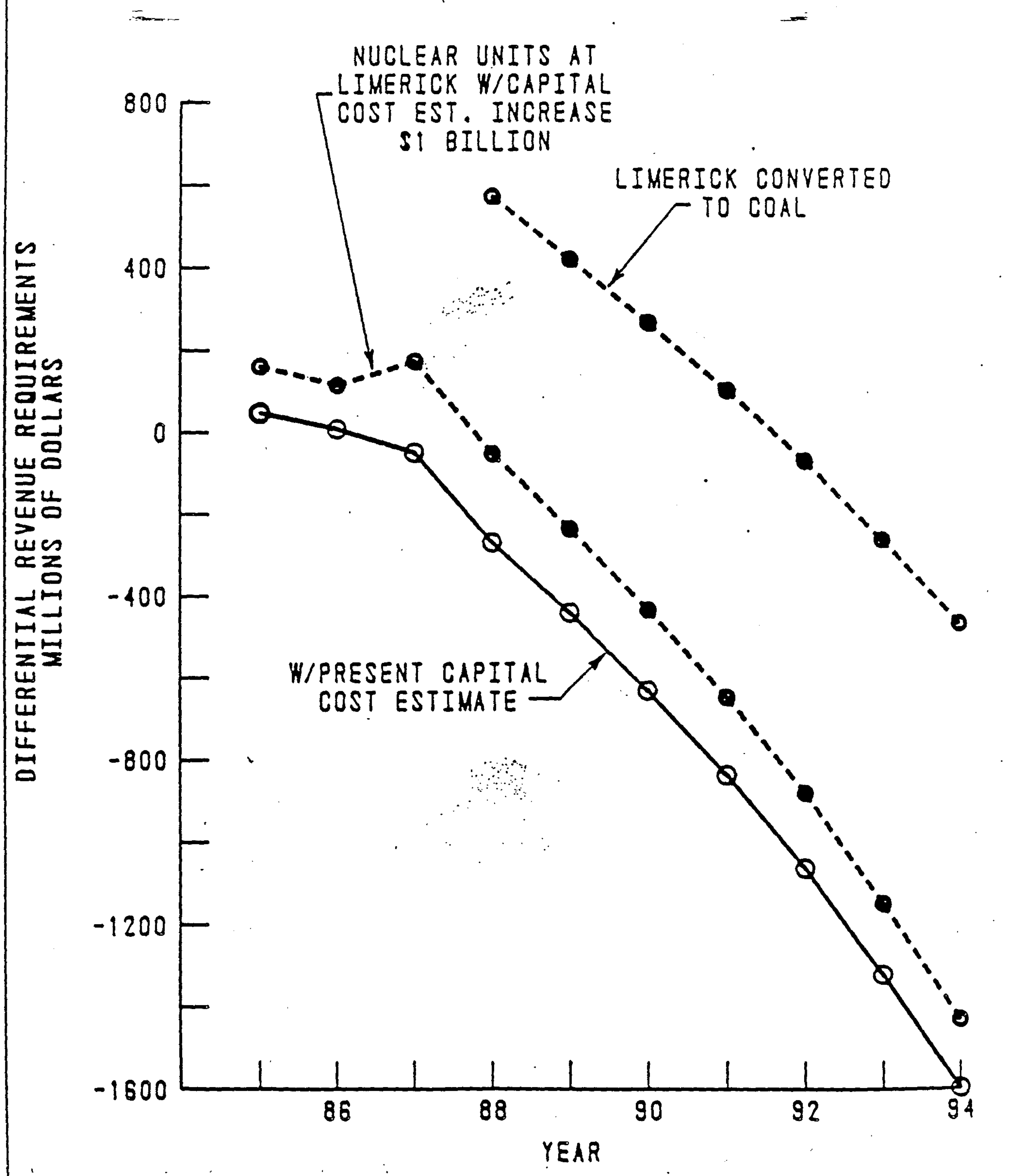
EFFECT OF NUCLEAR CAPACITY FACTOR ON DIFFERENTIAL REVENUE REQUIREMENTS

LIMERICK COAL OR NUCLEAR VS. NO NEW CAPACITY



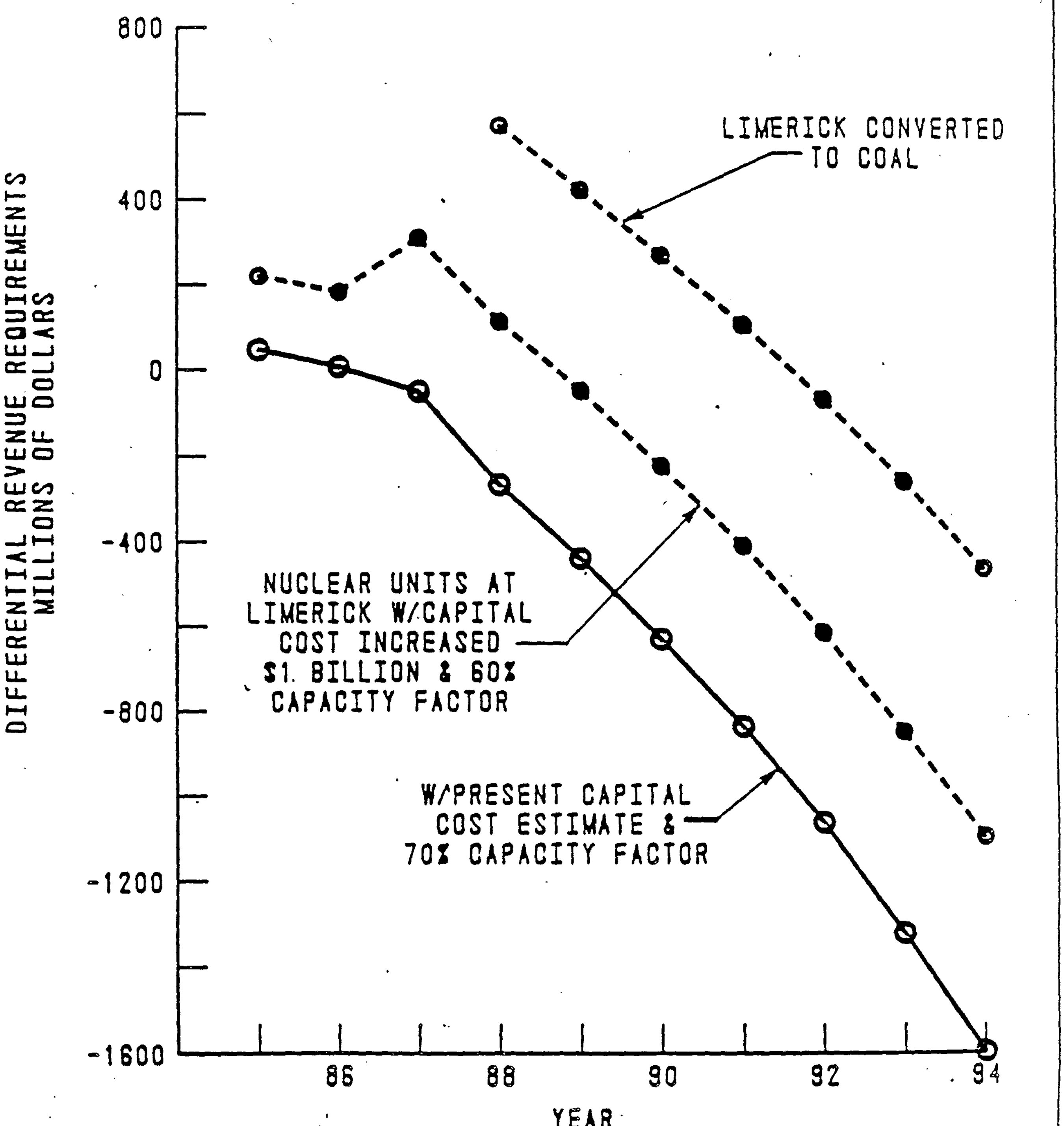
EFFECT OF INCREASED NUCLEAR CAPITAL COSTS
ON DIFFERENTIAL REVENUE REQUIREMENTS

LIMERICK COAL OR NUCLEAR VS. NO NEW CAPACITY



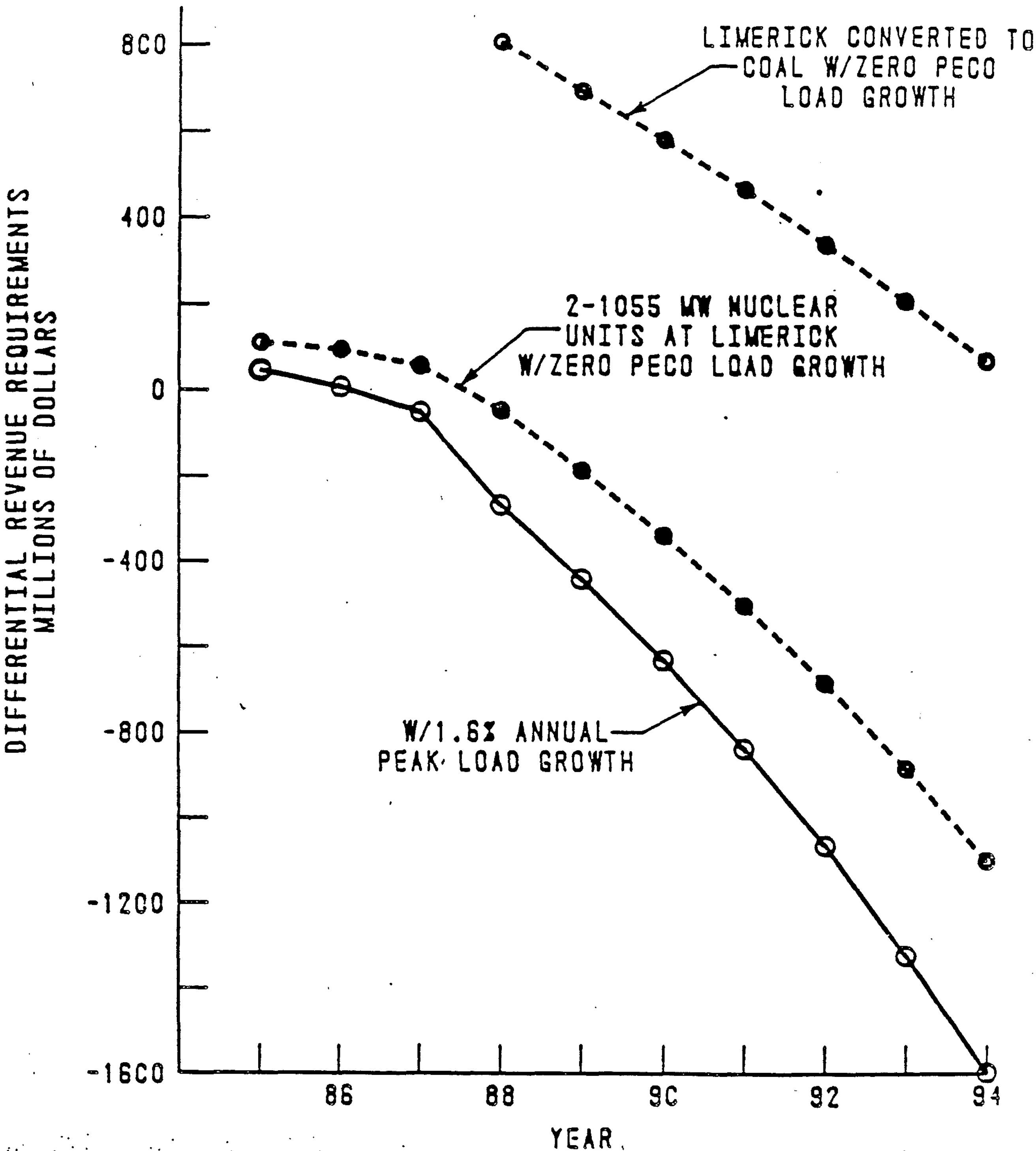
EFFECT OF NUCLEAR CAPACITY FACTOR & CAPITAL COS
ON DIFFERENTIAL REVENUE REQUIREMENTS

LIMERICK COAL OR NUCLEAR VS. NO NEW CAPACITY



EFFECT OF ZERO LOAD GROWTH FOR PECO
ON DIFFERENTIAL REVENUE REQUIREMENTS

LIMERICK COAL OR NUCLEAR VS. NO NEW CAPACITY



Attachment IR-OCA

43 PAGES

PHILADELPHIA ELECTRIC COMPANY

PHILADELPHIA

COMPARISON OF THE LIMERICK NUCLEAR STATION WITH OTHER ALTERNATIVES

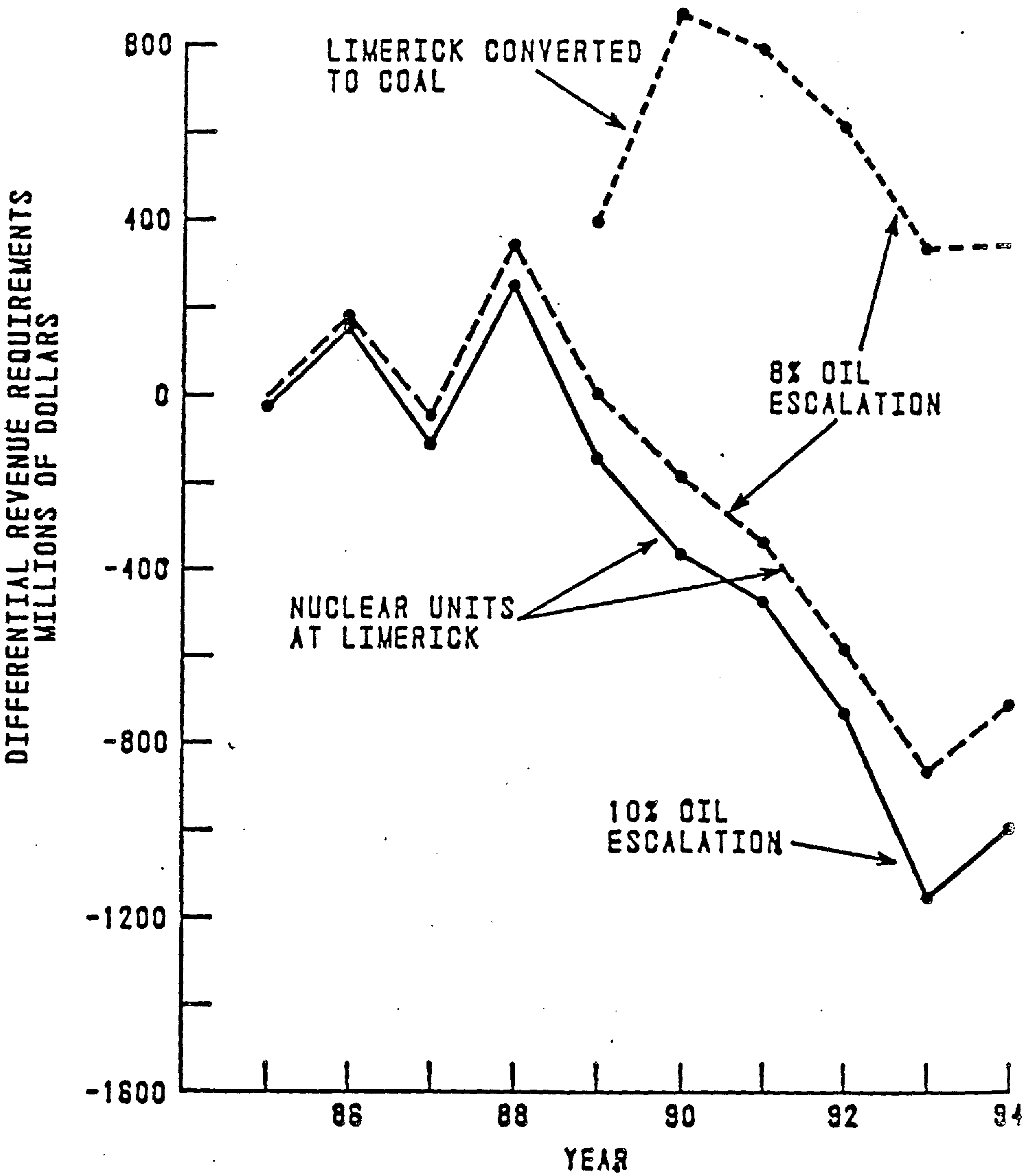
UPDATED TO JANUARY 1981

File C-33

System Planning Division
January 27, 1981

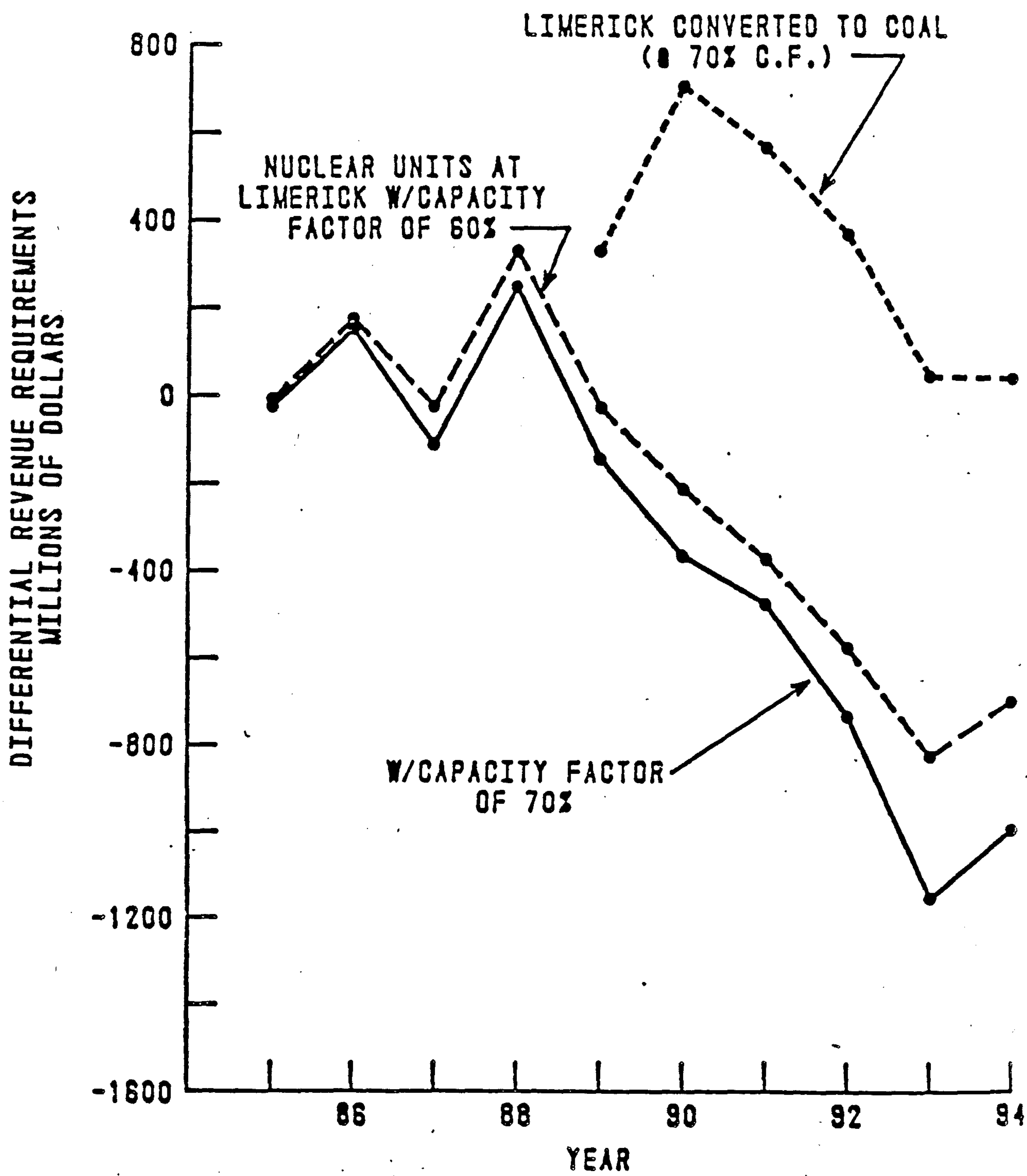
EFFECT OF OIL ESCALATION ON
DIFFERENTIAL REVENUE REQUIREMENTS

LIMERICK COAL OR NUCLEAR VS. NO NEW CAPACITY



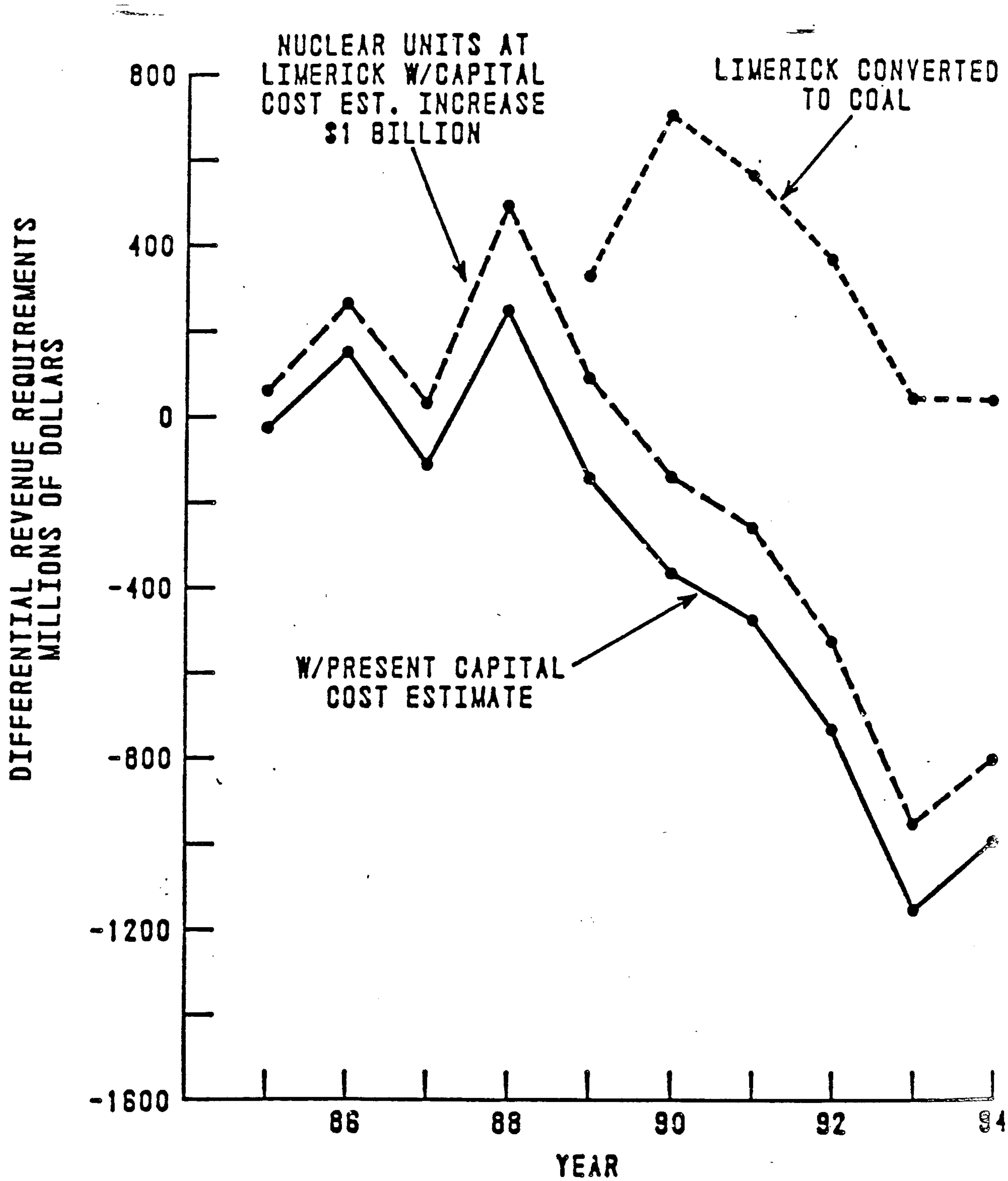
EFFECT OF NUCLEAR CAPACITY FACTOR ON DIFFERENTIAL REVENUE REQUIREMENTS

LIMERICK COAL OR NUCLEAR VS. NO NEW CAPACITY



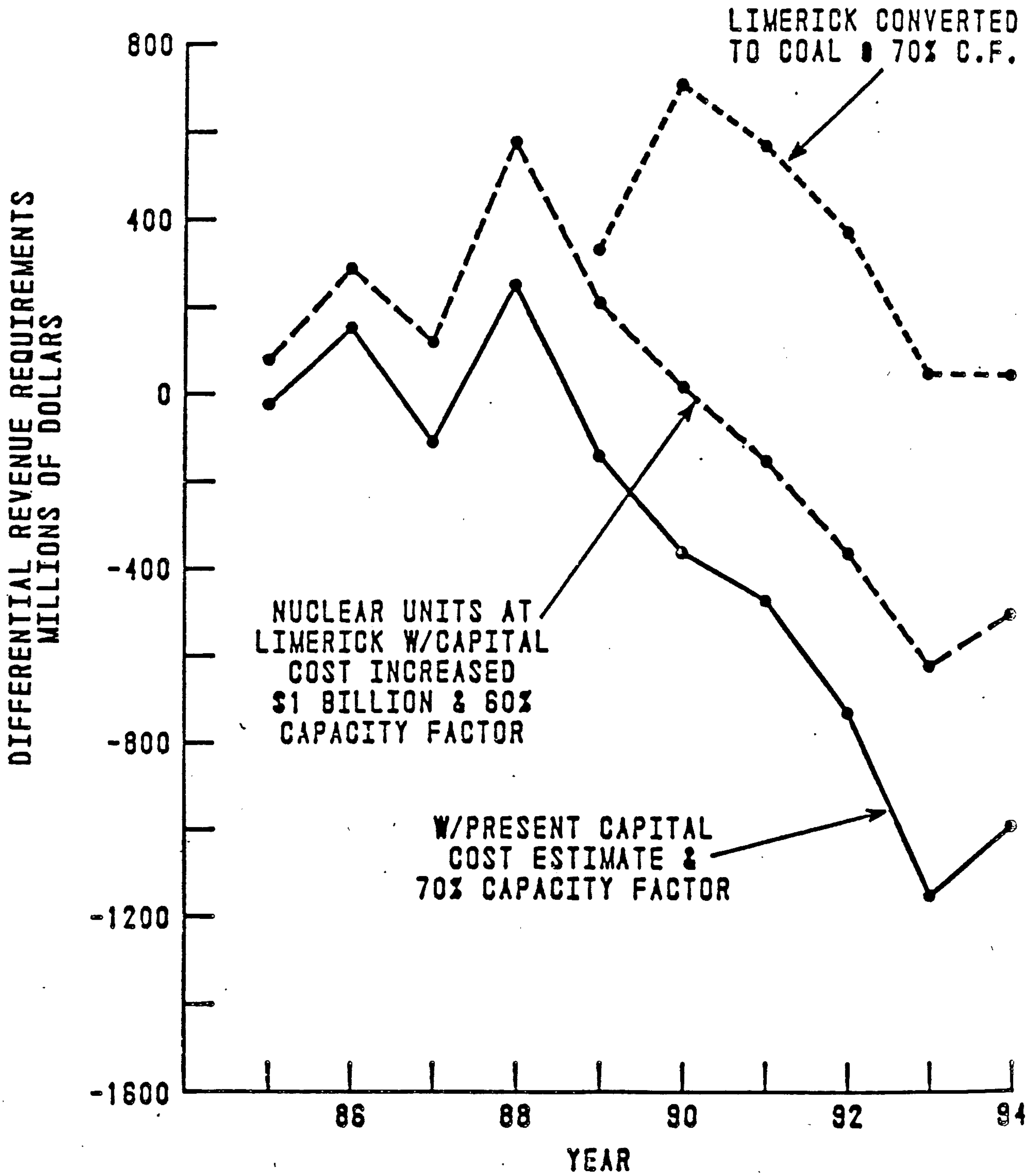
EFFECT OF INCREASED NUCLEAR CAPITAL COSTS
ON DIFFERENTIAL REVENUE REQUIREMENTS

LIMERICK COAL OR NUCLEAR VS. NO NEW CAPACITY



EFFECT OF NUCLEAR CAPACITY FACTOR & CAPITAL COST
ON DIFFERENTIAL REVENUE REQUIREMENTS

LIMERICK COAL OR NUCLEAR VS. NO NEW CAPACITY



#49
Supplem'l

Table of Contents

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.

----

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

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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

non-deductible financing costs (equity 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, <u>if investors believe PECo's projections</u> 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 rises 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 non sequiturs 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

uptr1/26-feb-86

TABLE A-2: EFFECTIVE LOAD CARRYING CAPABILITY
Limerick 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 LIMERICK 1 GROSS BENEFITS,
AS FUNCTION OF AGE

YEAR	TOTAL BENEFITS	PRESENT VALUE OF REMAINING BENEFITS	ECONOMIC DEPRECIATION -d(P.V.)	GROSS REALISTIC BENEFITS	PRESENT VALUE OF REMAINING BENEFITS	ECONOMIC DEPRECIATION -d(P.V.)
	[1]	[2]		[3]	[2]	
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	($708)
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	$756	$18,536	($1,085)	$575	$13,928	($815)
1995	$1,050	$19,577	($1,042)	$765	$14,704	($776)
1996	$954	$20,426	($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)	$1,398	$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.

UPTR3/26-Feb-86

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

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.

WORKPAPERS OF PAUL L. CHERNICK
TO ACCOMPANY SURREBUTTAL TESTIMONY

ANALYSIS AND INFERENCE, INC. RESEARCH AND CONSULTING

10 POST OFFICE SQUARE, SUITE 970 ~ BOSTON, MASSACHUSETTS 02109 ~ (617) 542-0611

general linear models procedure

dependent variable: cf

estimable functions for Eq. 2--Mature CF

This procedure duplicates our regression results for Equation 2, Tables 4.2 & 4.3, then lists confidence limits and predicted values of each observation.

effect	coefficients
intercept	1
der	1055
age5	5
refuel	0.67
gt1000	1
if79	0
if80	0.2
if81	0.2
if82	0.2
if83	0.2
if84	0.2

general linear models procedure

Equation 2

dependent variable: cf

source	df	sum of squares	mean square	f value	pr > f	r-square	c.v.
model	10	1.54070217	0.15407022	6.26	0.0001	0.236629	27.2259
error	202	4.97035302	0.02460571		root mse		cf mean
corrected total	212	6.51105519			0.15686207		0.57615023

source	df	type i ss	f value	pr > f	df	type iii ss	f value	pr > f
der	1	0.02512014	1.02	0.3135	1	0.14365184	5.84	0.0166
age5	1	0.05336756	2.17	0.1424	1	0.27648443	11.24	0.0010
refuel	1	0.39586464	16.09	0.0001	1	0.60641969	24.65	0.0001
gt1000	1	0.20982617	8.53	0.0039	1	0.19447715	7.90	0.0054
if79	1	0.17209921	6.99	0.0088	1	0.00637808	0.26	0.6112
if80	1	0.01627578	0.66	0.4170	1	0.03948516	1.60	0.2067
if81	1	0.00064858	0.03	0.8712	1	0.09913282	4.03	0.0461
if82	1	0.00198686	0.08	0.7766	1	0.14505382	5.90	0.0161
if83	1	0.06032644	2.45	0.1190	1	0.25578006	10.40	0.0015
if84	1	0.60518678	24.60	0.0001	1	0.60518678	24.60	0.0001

t for h0: pr > |t|

parameter	estimate	t for h0: parameter=0	pr > ^t^	std error of estimate
intercept	0.71059887	7.67	0.0001	0.09757373
der	-0.00027367	-2.42	0.0166	0.00011326
age5	0.03470453	3.35	0.0010	0.01037693
refuel	-0.11921958	-4.96	0.0001	0.02401479
gt1000	-0.13147528	-2.81	0.0054	0.04676573
if79	0.02063345	0.51	0.6112	0.04052705
if80	-0.05101295	-1.27	0.2067	0.04026998
if81	-0.08251021	-2.01	0.0461	0.04110710
if82	-0.10145818	-2.43	0.0161	0.04178705
if83	-0.13040988	-3.22	0.0015	0.04044782
if84	-0.20388467	-4.96	0.0001	0.04111098
Eq. 2--Mature Cf	0.57154618	22.07	0.0001	0.02589412

Estimate

observation	observed value	predicted value	residual	lower 95% cl individual	upper 95% cl individual
1	0.47700000	0.56227793	-0.08527793	0.24900902	0.87554684
2	0.45200000	0.49946632	-0.04746632	0.18666328	0.81226937
3	0.59600000	0.55533829	0.04066171	0.24359147	0.86708511
4	0.61200000	0.58319320	0.02880680	0.26900289	0.89738352
5	0.61700000	0.62071228	-0.00371228	0.30790207	0.93352249
6	0.64500000	0.60976562	0.03523438	0.29729873	0.92223250
7	0.33600000	0.62020180	-0.28420180	0.30496548	0.93543812
8	0.50300000	0.45563781	0.04736219	0.14070048	0.77057514
9	0.63100000	0.56431554	0.06668446	0.24902808	0.87960300
10	0.55100000	0.54506560	0.00593440	0.22700476	0.86312644

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general linear models procedure

Confidence limits for individual predicted values for each obs.

dependent variable: cf

observation	observed value	predicted value	residual	lower 95% cl individual	upper 95% cl individual
11	0.56500000	0.56907939	-0.00407939	0.25283590	0.88532288
12	0.41900000	0.54961307	-0.13061307	0.23748937	0.86173677
13	0.30900000	0.53425085	-0.22525085	0.22163510	0.84686660
14	0.64500000	0.70934240	-0.06434240	0.39557911	1.02310568
15	0.60300000	0.49875816	0.10424184	0.17981812	0.81769820
16	0.57000000	0.63636532	-0.06636532	0.32292952	0.94980112
17	0.55200000	0.61778860	-0.06578860	0.30452265	0.93105456
18	0.54500000	0.62792573	-0.08292573	0.31059870	0.94525276
19	0.56600000	0.60740285	-0.04140285	0.28859278	0.92621293
20	0.44100000	0.65498633	-0.21398633	0.34141511	0.96855755
21	0.60300000	0.60964192	-0.00664192	0.29576634	0.92351749
22	0.38700000	0.49609436	-0.10909436	0.18310985	0.80907886
23	0.79100000	0.69906971	0.09193029	0.38209040	1.01604901
24	0.34500000	0.54583283	-0.20083283	0.22839914	0.86326653
25	0.53300000	0.48464435	0.04835565	0.17125855	0.79803015
26	0.61500000	0.54886036	0.06613964	0.23592410	0.86179661
27	0.56800000	0.56903539	-0.00103539	0.25526988	0.88280089
28	0.52700000	0.53014931	-0.00314931	0.21213949	0.84815913
29	0.57600000	0.55731173	0.01868827	0.24082929	0.87379417
30	0.59900000	0.55262840	0.04637160	0.23511440	0.87014240
31	0.61900000	0.61447199	0.00452801	0.30135420	0.92758978
32	0.83300000	0.77232969	0.06067031	0.45580223	1.08885715
33	0.76800000	0.75558490	0.01241510	0.44010566	1.07106414

general linear models procedure

dependent variable: cf

	observation	observed value	predicted value	residual	lower 95% cl individual	upper 95% cl individual	
	164	0.56000000	0.57797741	-0.01797741	0.26129533	0.89465950	
	165	0.45800000	0.48044719	-0.02244719	0.16245659	0.79843778	
	166	0.71400000	0.59966676	0.11433324	0.28173151	0.91760201	
	167	0.92700000	0.68039842	0.24660158	0.35947828	1.00131856	
1983	168	0.23300000	0.51350851	-0.28050851	0.19419266	0.83282436	Browns Ferry 1
	169	0.68400000	0.59207421	0.09192579	0.27339495	0.91075348	2
	170	0.57800000	0.59934661	-0.02134661	0.28057183	0.91812139	3
	171	0.19300000	0.45786057	-0.26486057	0.14030079	0.77543636	
	172	0.54700000	0.56743136	-0.02043136	0.24926534	0.88559739	
	173	0.49100000	0.45997945	0.03102055	0.14275780	0.77720110	
	174	0.47900000	0.45149579	0.02750421	0.13380565	0.76910592	
	175	0.58500000	0.51921251	0.06578749	0.20225085	0.83617416	
	176	0.49300000	0.52565944	-0.03265944	0.20634110	0.84497779	
	177	0.64100000	0.44821179	0.19578821	0.13041091	0.76601267	
	178	0.57600000	0.41189058	0.16410942	0.09286575	0.73091541	
	179	0.54700000	0.41428137	0.13271863	0.09625307	0.73230968	
	180	0.88600000	0.60328169	0.28271831	0.28576875	0.92079463	
	181	0.86900000	0.64296335	0.22603665	0.32303994	0.96288677	
	182	0.52400000	0.62517502	-0.10117502	0.30673688	0.94361316	
	183	0.03600000	0.55306871	-0.51706871	0.23642666	0.86971076	
	184	0.47700000	0.63213199	-0.15513199	0.31260261	0.95166137	Peach Bottom 2
	185	0.26000000	0.51291242	-0.25291242	0.19358008	0.83221475	3
	186	0.80300000	0.60195951	0.20104049	0.28453333	0.91938569	
	187	0.81500000	0.57071536	0.24428464	0.25272107	0.88870965	
	188	0.44500000	0.48630790	-0.04130790	0.16931588	0.80329992	
	189	0.37900000	0.46029640	-0.08129640	0.12984786	0.79074495	- Susquehanna 1
	190	0.63800000	0.53222744	0.10577256	0.21220606	0.85224882	
	191	0.84100000	0.55806110	0.28293890	0.23893135	0.87718785	Browns Ferry 1
1984	192	0.43400000	0.52086459	-0.08686459	0.20233375	0.83939543	2
	193	0.03100000	0.47222300	-0.44122300	0.15343832	0.79100768	3
	194	0.70000000	0.49395657	0.20604343	0.17616819	0.81174494	
	195	0.19400000	0.37473699	-0.18073699	0.05664038	0.69283360	
	196	0.50900000	0.46864694	0.04035306	0.15204771	0.78524618	
	197	0.62900000	0.44406863	0.18493137	0.12719148	0.76094278	
	198	0.29700000	0.42952385	-0.13252385	0.11260822	0.74643947	
	199	0.57700000	0.57140422	0.00559578	0.25162179	0.89118665	
	200	0.68100000	0.49395657	0.18704343	0.17616819	0.81174494	
	201	0.52200000	0.39754869	0.12445131	0.08031730	0.71478009	
	202	0.26900000	0.49481068	-0.22581068	0.17742462	0.81219674	
	203	0.71500000	0.41058732	0.30441268	0.09333289	0.72784174	
	204	0.05500000	0.45658761	-0.40158761	0.13729810	0.77587713	
	205	0.68000000	0.43248065	0.24751935	0.11441538	0.75054592	
	206	0.04900000	0.48269362	-0.43369362	0.16606330	0.79932395	
	207	0.26000000	0.48795998	-0.22795998	0.16938559	0.80653438	Peach Bottom 2
	208	0.79800000	0.55865719	0.23934281	0.23951534	0.87779905	3
	209	0.00100000	0.42285616	-0.42185616	0.10568715	0.74002518	
	210	0.47300000	0.37802099	0.09497901	0.06011343	0.69592854	
	211	0.70300000	0.46242845	0.24057155	0.14545628	0.77940061	
	212	0.65300000	0.42195398	0.23104602	0.09606623	0.74784174	- Susquehanna 1
	213	0.74100000	0.57797222	0.16302778	0.25744748	0.89849696	

general linear models procedure

general linear models procedure

Confidence Limits for mean predicted value for each observation (Equation 2)

dependent variable: cf

observation	observed value	predicted value	residual	lower 95% cl for mean	upper 95% cl for mean
11	0.56500000	0.56907939	-0.00407939	0.50317770	0.63498109
12	0.41900000	0.54961307	-0.13061307	0.50772881	0.59149733
13	0.30900000	0.53425085	-0.22525085	0.48884495	0.57965675
14	0.64500000	0.70934240	-0.06434240	0.65661209	0.76207270
15	0.60300000	0.49875816	0.10424184	0.42093889	0.57657743
16	0.57000000	0.63636532	-0.06636532	0.58561999	0.68711065
17	0.55200000	0.61778860	-0.06578860	0.56810311	0.66747409
18	0.54500000	0.62792573	-0.08292573	0.55700654	0.69881192
19	0.56600000	0.60740285	-0.04140285	0.53011798	0.68468773
20	0.44100000	0.65498633	-0.21398633	0.60341116	0.70656150
21	0.60300000	0.60964192	-0.00664192	0.55624749	0.66303635
22	0.38700000	0.49609436	-0.10909436	0.44821546	0.54397325
23	0.79100000	0.69906971	0.09193029	0.62972296	0.76841645
24	0.34500000	0.54583283	-0.20083283	0.47443789	0.61722777
25	0.53300000	0.48464435	0.04835565	0.43420879	0.53507991
26	0.61500000	0.54886036	0.06613964	0.50129790	0.59642282
27	0.56800000	0.56903539	-0.00103539	0.51629184	0.62177893
28	0.52700000	0.53014931	-0.00314931	0.45623493	0.60406369
29	0.57600000	0.55731173	0.01868827	0.49027278	0.62135068
30	0.59900000	0.55262840	0.04637160	0.48087724	0.62437956
31	0.61900000	0.61447199	0.00452801	0.56572944	0.66321454
32	0.83300000	0.77232969	0.06067031	0.70507850	0.83958088
33	0.76800000	0.75558490	0.01241510	0.69345408	0.81771572
34	0.67600000	0.63304871	0.04295129	0.58466440	0.68143301
35	0.59500000	0.54349068	0.05150932	0.48214656	0.60483481
36	0.64700000	0.59055550	0.05644450	0.52814601	0.65296498
37	0.41000000	0.57055129	-0.16055129	0.53131639	0.60978618
38	0.47700000	0.52555472	-0.04855472	0.48069403	0.57041541
39	0.60600000	0.52277196	0.08322804	0.47796364	0.56758027
40	0.72200000	0.61498251	0.10701749	0.55797918	0.67198583
41	0.54100000	0.58603138	-0.04503138	0.52903451	0.64302826
42	0.66700000	0.66862363	-0.00162363	0.60521393	0.73203333
43	0.33900000	0.46139779	-0.12239779	0.40463747	0.51815811
44	0.66600000	0.51942888	0.14657112	0.47694476	0.56191301
45	0.49800000	0.58190566	-0.08390566	0.52480427	0.63900706
46	0.73200000	0.70112524	0.03087476	0.63518924	0.76706124
47	0.61500000	0.56493384	0.05006616	0.50354242	0.62632527
48	0.54100000	0.47287668	0.06812332	0.41975466	0.52599871
49	0.53900000	0.46819336	0.07080664	0.41233575	0.52405096
50	0.79700000	0.73369157	0.06330843	0.67384741	0.79353572
51	0.74800000	0.65415365	0.09384635	0.59752270	0.71078460
52	0.55100000	0.63636532	-0.08536532	0.58561999	0.68711065
53	0.57000000	0.62541866	-0.05541866	0.57647317	0.67436414
54	0.43100000	0.57827522	-0.14727522	0.51957589	0.63697455
55	0.51200000	0.61007392	-0.09807392	0.55384672	0.66631312
56	0.45200000	0.60533582	-0.15333582	0.56122771	0.64944393
57	0.49700000	0.56033925	-0.06333925	0.51010644	0.61057207
58	0.61700000	0.67677607	-0.05977607	0.61860724	0.73494489
59	0.78600000	0.64976704	0.13623296	0.59152672	0.70800736
60	0.62400000	0.70713089	-0.08313089	0.64301018	0.77125160
61	0.59500000	0.58418859	0.01081141	0.52524022	0.64313695

general linear models procedure

general linear models procedure

dependent variable: cf

	observation	observed value	predicted value	residual	lower 95% cl for mean	upper 95% cl for mean	
	164	0.56000000	0.57797741	-0.01797741	0.51000219	0.64595261	
	165	0.45800000	0.48044719	-0.02244719	0.40661559	0.55427878	
	166	0.71400000	0.59966676	0.11433324	0.52607389	0.67325964	
	167	0.92700000	0.68039842	0.24660158	0.59482491	0.76597192	
1983	168	0.23300000	0.51350851	-0.28050851	0.43416306	0.59285396	Browns Ferry 1
	169	0.68400000	0.59207421	0.09192579	0.51533074	0.66881769	2
	170	0.57800000	0.59934661	-0.02134661	0.52220747	0.67648575	3
	171	0.19300000	0.45786857	-0.26486857	0.38587978	0.52985737	
	172	0.54700000	0.56743136	-0.02043136	0.49284779	0.64201494	
	173	0.49100000	0.45997945	0.03102055	0.38953327	0.53042563	
	174	0.47900000	0.45149579	0.02750421	0.37932041	0.52367116	
	175	0.58500000	0.51921251	0.06578749	0.44994649	0.58847852	
	176	0.49300000	0.52565944	-0.03265944	0.44630395	0.60501493	
	177	0.64400000	0.44821179	0.19578821	0.37520160	0.52122198	
	178	0.57600000	0.41189058	0.16410942	0.33372454	0.49005662	
	179	0.54700000	0.41428137	0.13271863	0.34028751	0.48827523	
	180	0.88600000	0.60328169	0.28271831	0.53153523	0.67502815	
	181	0.86900000	0.64296335	0.22603665	0.56120712	0.72471958	
	182	0.52400000	0.62517502	-0.10117502	0.54943906	0.70091099	
	183	0.03600000	0.55306871	-0.51706871	0.48528025	0.62085718	
	184	0.47700000	0.63213199	-0.15513199	0.55193153	0.71233245	Peach Bottom 2
	185	0.26000000	0.51291242	-0.25291242	0.43350067	0.59232417	3
	186	0.80300000	0.60195951	0.20104049	0.53059798	0.67332104	
	187	0.81500000	0.57071536	0.24428464	0.49686784	0.64456289	
	188	0.44500000	0.48630790	-0.04130790	0.41690308	0.55571273	
	189	0.37900000	0.46029640	-0.08129640	0.34398076	0.57661204	Susquehanna 1
	190	0.63800000	0.53222744	0.10577256	0.45008869	0.61436619	
	191	0.84100000	0.55806110	0.28293890	0.47948011	0.63664208	Browns Ferry 1
1984	192	0.43400000	0.52086459	-0.08686459	0.44473980	0.59698938	2
	193	0.03100000	0.47222300	-0.44122300	0.39504295	0.54940305	3
	194	0.70000000	0.49395657	0.20604343	0.42100082	0.56691231	
	195	0.19400000	0.37473699	-0.18073699	0.30045010	0.44902388	
	196	0.50900000	0.46864694	0.04035306	0.40105875	0.53623513	
	197	0.62900000	0.44406863	0.18493137	0.37520416	0.51293310	
	198	0.29700000	0.42952385	-0.13252385	0.36046880	0.49857889	
	199	0.57700000	0.57140122	0.00559578	0.49020145	0.65260699	
	200	0.68100000	0.49395657	0.18704343	0.42100082	0.56691231	
	201	0.52200000	0.39754869	0.12445131	0.32705865	0.46803874	
	202	0.26900000	0.49481068	-0.22581068	0.42362783	0.56599354	
	203	0.71500000	0.41058732	0.30441268	0.33999369	0.48118094	
	204	0.05500000	0.45658761	-0.40158761	0.37734822	0.53582701	
	205	0.68000000	0.43248065	0.24751935	0.35832807	0.50663322	
	206	0.04900000	0.48269362	-0.43369362	0.41495993	0.55042732	
	207	0.26000000	0.48795998	-0.22795998	0.41165316	0.56426681	Peach Bottom 2
	208	0.79800000	0.55865719	0.23934281	0.48001487	0.63729952	3
	209	0.00100000	0.42285616	-0.42185616	0.35264740	0.49306493	
	210	0.47300000	0.37802099	0.09497901	0.30451784	0.45149414	
	211	0.70300000	0.46242845	0.24057155	0.39311437	0.53174253	
	212	0.65300000	0.42195398	0.23104602	0.31930936	0.52459860	Susquehanna 1
	213	0.74100000	0.57797222	0.16302778	0.49389371	0.66205073	

general linear models procedure

PSNH PUBLIC SERVICE
Company of New Hampshire

January 14, 1983

Mr. Vincent J. Iacopino
Executive Director and Secretary
State of New Hampshire
Public Utilities Commission
Eight Old Suncook Road, Building #1
Concord, NH 03301

Re: NHPUC Docket No. DE 81-312, Supply and Demand

Dear Mr. Iacopino:

In accordance with the "PSNH Motion For Leave To Withdraw and Refile Direct Case", filed by PSNH on December 1, 1982 and granted by the NHPUC on the same date, PSNH herewith submits its revised direct testimony in NHPUC Docket No. DE81-312, an Investigation into the Supply and Demand for electricity.

PSNH is also submitting, as part of its revised direct case, portions of the October 27, 1982 direct testimony. The portions of the October 27, 1982 testimony which are being resubmitted are the direct testimonies of:

a) Frederick R. Plett
b) Kathlyne M. Hadley
c) William H. Hieronymus
d) Joseph J. Staszowski
e) John E. Lyons
f) John M. Perkins
g) Ian A. Forbes
h) James T. Rodier

PSNH withdrew its entire October 27, 1982 direct case on December 1, 1982 since it was not clear at the time we withdrew the case how much of the information contained within that filing would have to be revised.

Since the entire October 27, 1982 case is on file with the NHPUC and is in the possession of all of the parties in this docket, PSNH is not physically reproducing the portions of its October 27, 1982 direct testimony which it is resubmitting today; to do so would be merely a mechanical exercise.

Very truly yours,

Frederick R. Plett

Frederick R. Plett
Director
Corporate Strategic Planning

FRP:sk

cc: Service List

A. Seabrook Station is currently projected to cost $5.242 billion. Messrs. Dennis McLain and Alan Ebner will discuss the Seabrook cost estimates and in-service dates in greater detail.

Q. Mr. Plett, do these revisions change the Company's long-term demand and supply strategies that were outlined in your initial testimony?

A. No. The strategies outlines in "New Energy Horizons" (Attachment Plett 1 to my direct testimony filed on October 27, 1982) indicate that PSNH plans to manage its peak load growth at an average annual rate of increase of 1.5 percent to the year 2001. PSNH also plans to complete construction of both of the Seabrook units as rapidly as possible and reduce its ownership in the project from 35 percent to 28 percent if it is at all possible. As I indicated in my original testimony, PSNH continually evaluates its strategies to see if they are still appropriate when key assumptions change - such as the cost of fuel or the cost of Seabrook Station. We recently used our models to test the appropriateness of the strategies outlined in "New Energy Horizons" using revised assumptions that reflect recent revisions for the cost of fuel and Seabrook cost and in-service dates. We also conducted further "sensitivity analysis" to test the appropriateness of our strategies under different ownership scenarios, a delay scenario and a significantly higher Seabrook cost estimate. These scenarios are described in the matrix labeled Plett Exhibit 1. All scenarios use a 1.5% growth rate in sales and demand and the new oil and coal forecast.

What our sensitivity analysis showed us is that even when we revised our assumptions to very high levels, i.e., a $7 billion cost projection for Seabrook Station, the strategies outlined in "New Energy Horizons" remain reasonable and desirable for both our stockholders and customers.

Q. Mr. Plett, you apparently have assumed three different cost and schedule combinations for Seabrook. Which of the three represent PSNH's official estimate?

A. As mentioned previously, a cost of $5.242 billion and in-service dates of December 31, 1984 and July 31, 1987 respectively.

Q. What do the other cost and schedule combinations represent?

A. The other trajectories, leading to total costs of approximately $6 and $7 billion respectively, are simply sensitivity tests. The $5.242 billion estimate is a good estimate, not subject to further escalation in the order of magnitude previously experienced, since the only remaining cost to complete is essentially labor. NRC regulation is unlikely to escalate as it did in the immediate post-TMI period. However, in recognition of the possibility of some further cost increase, we tested the $6 billion trajectory and the very high $7 billion trajectory as well.

pre-TMI

Q. Mr. Plett, will you describe the results of these latest scenarios in greater detail.

THE STATE OF NEW HAMPSHIRE
BEFORE
THE PUBLIC UTILITIES COMMISSION

Public Service Company of New Hampshire
Investigation Into Supply/Demand

REBUTTAL TESTIMONY OF WILLIAM H. HIERONYMUS

Q. Are you the same William H. Hieronymus who has filed testimony previously in this proceeding?

A. Yes, I am.

Q. And are your occupation history and qualifications stated in that testimony?

A. Yes, they are.

Q. What is the purpose of your rebuttal testimony in this case?

A. I will be critiquing aspects of the direct testimony of certain witnesses for the Conservation Law Foundation and the staff of the New Hampshire Public Utilities Commission. The main portion of my testimony will focus on their use of regression-based techniques to forecast the cost of Seabrook as well as its capacity factor. Regression analysis underlies the estimates of Seabrook cost presented by Dr. Rosen and Messrs. Chernick and Gantz, as well as Dr. Rosen's capacity factor estimate. Mr. Chernick's supplemental testimony also contains a pseudo-regression estimate of capacity factor based on other Yankee plants. I will also comment briefly on Dr. Rosen's regression analysis of O&M escalation for nuclear plants.

Q. You have stated that your testimony will focus on regression-based forecasts of Seabrook cost and performance. Can you briefly explain the theory which underlies the use of regression analysis in forecasting?

A. The application of regression techniques to forecasting relies on fundamental assumptions. The first assumption is that sta analysis can be used to untangle the complex relationships the quantity of interest (e.g., plant cost) and its causes relationships existed in the past. The second assump

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Table 16 provides a quick comparison of the various regressions discussed so far. The cost per kilowatt and total station cost figures are given for both Dr. Rosen's and PHB's database.

Q. Please describe this table.

A. The first column gives the results of regressions without a regulation related variable. The second column uses the regulation variable, and shows the attendant reduction in estimated cost. The third column assumes the 1976 licensing date is used along with the regulation related variable. Finally, the fourth column assumes PSNH's in-service dates are used as well as their inflation and AFUDC rates.

The upper portion of the table relates to Dr. Rosen's database. The first row uses the Northeast regional dummy throughout, while the second row uses the Mid-Atlantic and New England regional dummies. The third row uses no regional dummies. The last three rows repeat the same analysis, but applied to PHB's database.

One can find, for example, Dr. Rosen's original specification and $7.6 billion plant cost in the upper left-hand corner.

As explained in the text of this testimony, a better, more accurate model would involve using a regulation related variable, the 1976 licensing date and the two regional dummies. This corresponds to column 3, row 2 for Dr. Rosen's data, and column 3, row 5 for PHB's data.

My estimate of cost for Seabrook based on Dr. Rosen's commercial operation dates is as follows:

	Direct Cost $/kW ±2 Std. Errors
SEA1:	$1,291 ± 246
SEA2:	$1,179 ± 236

Total Cost = $5.7 billion

This, of course, assumes Dr. Rosen's in-service dates, AFUDC rates, and inflation rates through the construction period. As can be seen from column 4, if PSNH's assumptions for these variables are used, the estimated cost drops to $5.1 billion.

Thus, in as far as is possible with regression analysis, it appears the company's estimate of cost is in line with the historical record.

Q. Dr. Hieronymus, what reservations do you have about your estimate of a 1980 direct construction dollar cost of $5.7 billion for the Seabrook plants?

A. I think that it is as reasonable an estimate as can be achieved using the methodology that was employed by Dr. Rosen; that is, the use of regression analysis to estimate historical relationships which are then projected into the future. I do, however, have reservations about the use of regression analysis for forecasting capital costs.

Q. What are your reservations in this regard?

A. First, as noted earlier, the available data are not very good for this type of analysis. The historical time frame for the primary variable is very short, less than six years for the critical LICDATE variable. Furthermore, the relevant factors, those influencing plant capital costs, were undergoing changes that are highly correlated, making reliable regression analysis extremely difficult. Second, the Seabrook plants fall well outside the range of data that was used to estimate the regression equations. This inability to predict with accuracy can be seen by the 95 percent confidence interval of the cost estimate, which is roughly plus or minus 20 percent. Even this relatively broad interval understates the true range of forecast error since it assumes we know each of the components of the forecast with certainty. This is clearly untrue with respect to inflation and AFUDC rates, the completion date of the plant, and the level of regulatory activity. Finally, the use of a regression equation estimated with historical data to forecast the future assumes that causal relationships, many unobserved and undefined, will remain unchanged in the future.

Further, in applying this methodology to forecasting the cost of partially completed plants, no use is made of information on the cost and construction progress to date. Applied literally, the regression approach would predict the same constant dollar direct dollar construction cost for Seabrook irrespective of whether the plant was barely begun or nearly complete, and irrespective of whether construction cost to date had been markedly low or markedly high. While the regression approach may provide useful insights into the likely cost of plants which are substantially incomplete, I would be very reluctant to assert that it yields a superior alternative to engineering-based cost estimates for plants for which a major portion of outlays have been made.

Q. I note that both Dr. Rosen's equation and your equation forecast direct construction costs for Seabrook Unit 2 which are very close to

NUREG/CR-1881
SAND81-0018

Statistical Analysis of Power Plant Capacity Factors Through 1979

Manuscript Completed: December 1980
Date Published: April 1981

Prepared by
R. G. Easterling

Sandia National Laboratories
Albuquerque, NM 87185

Prepared for
Applied Statistics Branch
Office of Management and Program Analysis
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555
NRC FIN B1321

Data: Same as 2.2.

Fitted Model: $\hat{CF} = 40.5 + \hat{P}_i + 4.9$ (AGE5),
where $\hat{P}_i$ denotes the estimated plant effect. For the purpose of estimation, the plant effects are treated as fixed. For the subsequent purpose of prediction for a hypothetical plant, the plant effects are treated as random and $\hat{P}_i$ is set equal to zero in order to obtain a nominal prediction.

A.O.V.

Source	df	SS	MS	EMS
Regression (AGE5)	1	2763.4	2763.4	
Plants (adj. for AGE5)	14	3316.1	236.9	$\sigma_e^2 + 6.6\,\sigma_p^2$
Residual	84	9403.5	111.9	σ_e^2

Estimated Variance components:

Within plant variation: $\hat{\sigma}_e^2 = 111.9$

Among plants variation: $\hat{\sigma}_p^2 = 18.9$

Test Statistics: The F-test statistic for comparing the among plants variation to the within plant variation is F = 2.12, on 14 and 84 degrees of freedom, which is significant at about the 2% level. The F-statistic for regression equals 24.7, which is significant at much less than the .05% level.

3. PWR Results

3.1. Data: All unit-year capacity factors (163 observations)

Fitted Model: $\hat{CF} = 75.7 - 3.5\,(MGN/100) + 3.4\,(AGE)$

Residual Mean Square = 187.4

3.2. Data: Same as 3.1 except three outliers omitted.

Fitted Model: $\hat{CF} = 73.1 - 3.3\,(MGN/100) + 4.0\,(AGE)$

Residual Mean Square = 137.1

3.3. Data: Same as 3.2.

Fitted Model: $\hat{CF} = 77.3 - 3.2\,(MGN/100) + 2.4\,(AGE5)$

Residual Mean Square = 139.9

Test Statistics: The t-statistics for MGN and AGE5 are -6.8 and 3.0 respectively, and these are both significant at less than the 0.1% level.

5. Statistical Prediction Intervals

5.1. Nuclear Plants

Statistical prediction intervals for the capacity factors of hypothetical plants have three components:

1. the nominal, or point value, estimated from the fitted model,
2. the imprecision of that estimate,
3. the inherent variability of annual capacity factors.

Prediction intervals also account for the amount of data going into the various estimates. Their purpose is to identify a range in which the capacity factor of a hypothetical plant should fall, in order to be consistent with the observed data. Three time periods will be considered: years 2-5, 6-10, and 2-10. Predictions for the life of a plant, say 30 years, can be obtained under appropriate assumptions, but because ten years is about the maximum experience of any plants in the data base, attention is limited here to that period.

The analysis results of subsections 2.5, 3.5, and 3.6 give the models from which predicted capacity factors are calculated. For years 2-5, the average AGE5 value is (2 + 3 + 4 + 5)/4 = 3.5, for years 6-10, AGE5 = 5, and for years 2-10 the average AGE5 value is 4.33. For a hypothetical plant, P_i is taken to be zero. The following nominal predictions are thus obtained:

	Years		
Plants	2-5	6-10	2-10
BWRs	57.7%	65.0%	61.7%
PWRs (450-600MW)	68.8	72.5	70.8
PWRs (760-1216MW)	55.5	57.9	56.8

The estimated variance of these estimates is given by

$$s^2(\hat{CF}) = \frac{\hat{\sigma}_p^2}{p} + \frac{\hat{\sigma}_e^2 \sum (1/n_i)}{p^2} + s_b^2(\text{AGE5}_o - \overline{\text{AGE5}})^2,$$

where p is the number of plants in the data base used to obtain CF, $\hat{\sigma}_p^2$ and $\hat{\sigma}_e^2$ are estimated variance components among and within plants, n_i is the number of observations for plant i, s_b^2 is the estimated variance of the coefficient of AGE5 (obtained from the regression analyses), AGE5_o is the particular value of AGE5 for which the prediction is made, and AGE5 is the average value of AGE5 over the data on which the prediction is based. This average is an unweighted average of the individual plant average AGE5s. The following table gives values of $s^2(\hat{CF})$:

	Years		
Plants	2-5	6-10	2-10
BWRs	2.8	4.4	3.1
PWRs (450-600MW)	4.1	5.1	3.9
PWRs (760-1216MW)	5.2	8.5	6.5

The variance of a plant average over r unit-years is

$$\sigma^2(\mathrm{CF}) = \underbrace{\sigma_p^2}_{=18.9} + \boxed{\sigma_e^2/r. \quad \approx \frac{111.9}{r}} \approx 23.4 \text{ for } r = 25$$

This variance can be estimated by replacing σ_p^2 and σ_e^2 by their estimates. The estimates for σ_e^2 used here are different from those obtained from the analysis of variance because the outlying observations, not included in the A.O.V., are now included. The residuals for the outliers were squared and added to the Within Plant SS and then the MS calculated as an estimate of σ_e^2. The total prediction error is then obtained by adding the estimate of $\sigma^2(\mathrm{CF})$ to $s^2(\hat{\mathrm{CF}})$. This yields the following prediction error variances, s^2. Parenthetic entries are the effective degrees of freedom associated with these estimated prediction error variances.

	Years		
Plants	2-5	6-10	2-10
BWRs	57.1 (23)	51.7 (21)	37.8 (12)
PWRs (450-600MW)	40.5 (12)	36.7 (10)	27.1 (5)
PWRs (760-1216MW)	119.0 (23)	112.4 (23)	92.9 (18)

(The prediction errors variances are linear combinations of independent mean squares, so by methods given, e.g., in Reference [7], p. 369, an effective degrees of freedom can be obtained.)

Statistical prediction intervals are given by the nominal prediction plus and minus a multiple of the square root of these prediction error variances. The multiple is obtained from tables of the Student's t distribution and is a function of the desired confidence level (95% is used here) and the appropriate degrees of freedom. The results of these calculations, also given in section 1 of the main report, are:

$\sqrt{23.4} \times 1.96 = 9.48$

	Years		
	2-5	6-10	2-10
BWRs	58 ± 16%	65 ± 15%	62 ± 13%
PWRs (450-600 MW)	69 ± 14%	73 ± 14%	71 ± 13%
PWRs (760-1216 MW)	56 ± 23%	58 ± 22%	57 ± 20%

TABLE 3.4: LIMERICK 1 RATE IMPACT, Case 3a: Historical Capacity Factors, Realistic Capacity Costs ($ million)

YEAR	TOTAL COSTS	ACID RAIN SAVINGS	FUEL SAVINGS	CAPACITY COSTS AVOIDED	TOTAL BENEFITS	Ben-OC	PV econ Dep		YEAR	ORIG COST & ADDITIONS CARRYING CHARGES	STATION O&M	[illegible]
	(1)	(2)	(3)	(4)	(5)					[1]	[2]	[illegible]
1986	$1,008	$0	$130	$37	$168	$57	$5,819		1986	$858	$79	[illegible]
1987	$974	$0	$124	$39	$163	$46	$6,326	($507)	1987	$831	$85	[illegible]
1988	$949	$0	$150	$37	$187	$61	$6,894	($568)	1988	$812	[illegible]	[illegible]
1989	$933	$0	$236	$38	$274	$133	$7,501	($607)	1989	$801	[illegible]	
1990	$906	$0	$246	$38	$285	$140	$8,096	($595)	1990	$780	[illegible]	
1991	$885	$0	$285	$68	$353	$198	$8,741	($645)	1991	$765	[illegible]	
1992	$866	$0	$396	$65	$461	$296	$9,391	($650)	1992	$751	[illegible]	
1993	$845	$3	$390	$64	$457	$282	$10,006	($615)	1993	$735	[illegible]	
1994	$820	$3	$500	$72	$575	$394	$10,695	($689)	1994	$717	[illegible]	
1995	$815	$2	$688	$74	$765	$559	$11,338	($643)	1995	$717	[illegible]	[illegible]
1996	$806	$3	$666	$77	$746	$541	$11,879	($540)	1996	$710	[illegible]	[illegible]
1997	$807	$3	$720	$124	$847	$629	$12,490	($611)	1997	$713	$166	[illegible]
1998	$819	$2	$886	$124	$1,012	$770	$13,072	($582)	1998	$728	$176	$65
1999	$807	$4	$772	$116	$892	$650	$13,570	($498)	1999	$719	$187	$55
2000	$814	$3	$833	$109	$945	$685	$14,236	($666)	2000	$728	$198	$62
2001	$829	$2	$1,038	$102	$1,143	$858	$14,932	($696)	2001	$745	$210	$76
2002	$820	$3	$1,060	$95	$1,159	$872	$15,523	($591)	2002	$739	$222	$65
2003	$828	$4	$1,020	$89	$1,113	$807	$16,157	($634)	2003	$749	$236	$70
2004	$850	$3	$1,404	$83	$1,490	$1,152	$16,917	($760)	2004	$774	$250	$88
2005	$843	$5	$1,240	$77	$1,322	$981	$17,406	($489)	2005	[illegible]	[illegible]	$76
2006	$854	$5	$1,321	$72	$1,398	$1,036	$18,113	($707)	2006	[illegible]	[illegible]	[illegible]
2007	$882	$4	$1,739	$69	$1,812	$1,413	$18,835	($721)	2007	[illegible]	[illegible]	$102
2008	$878	$6	$1,642	$66	$1,714	$1,310	$19,249	($414)	2008	$812	$315	$89
2009	$894	$6	$1,604	$63	$1,673	$1,244	$19,807	($557)	2009	$831	$334	$95
2010	$931	$5	$2,239	$60	$2,304	$1,829	$20,484	($677)	2010	$870	$354	$120
2011	$928	$7	$2,005	$57	$2,069	$1,589	$20,641	($157)	2011	$870	$376	$104
2012	$951	$7	$2,096	$55	$2,158	$1,648	$21,054	($413)	2012	$895	$398	$111
2013	$998	$6	$2,830	$52	$2,887	$2,324	$21,448	($394)	2013	$944	$422	$141
2014	$998	$8	$2,654	$49	$2,710	$2,141	$21,205	$244	2014	$947	$447	$122
2015	$1,028	$8	$2,649	$46	$2,703	$2,090	$21,120	$84	2015	$980	$474	$131
2016	$1,082	$6	$3,759	$41	$3,807	$3,137	$21,071	$49	2016	$1,037	$503	$166
2017	$1,083	$9	$3,354	$38	$3,401	$2,725	$19,978	$1,094	2017	$1,040	$533	$143
2018	$1,122	$9	$3,342	$34	$3,385	$2,666	$19,191	$787	2018	$1,081	$565	$154
2019	$1,197	$7	$4,578	$30	$4,615	$3,821	$18,387	$804	2019	$1,159	$599	$195
2020	$1,214	$10	$4,188	$26	$4,224	$3,419	$16,349	$2,037	2020	$1,178	$635	$170
2021	$1,278	$10	$4,356	$22	$4,388	$3,533	$14,516	$1,833	2021	$1,245	$673	$182
2022	$1,397	$8	$6,104	$7	$6,119	$5,174	$12,391	$2,125	2022	$1,366	$713	$232
2023	$1,467	$12	$5,649	$5	$5,665	$4,708	$8,418	$3,972	2023	$1,439	$756	$201
2024	$1,671	$12	$5,966	$5	$5,983	$4,966	$4,527	$3,892	2024	$1,645	$801	$216

TABLE 2.5: FECo FUEL AND AVOIDED COST PROJECTIONS (REVISED 2/10)

Year	#6, 1%S Oil FECo Estimated Price $/BBL.	$/MMBTU	FECo Avoided Cost $/kWh	Heat Rate At Which Oil Price = Avoided Cost Btu/kWh	Avoided Cost - Cogeneration Fuel at 5000 BTu/kWh current $/kWh	constant 1986$/kWh
----	[1]	[2]	[3]	[4]	[5]	[6]
1986	$26.75	$4.25	$0.0384	9,022	$0.0171	$0.0171
1987	$28.90	$4.60	$0.0396	8,608	$0.0166	$0.0156
1988	$31.50	$5.01	$0.0415	8,291	$0.0165	$0.0147
1989	$34.30	$5.46	$0.0482	8,826	$0.0209	$0.0175
1990	$37.40	$5.95	$0.0572	9,613	$0.0274	$0.0217
1991	$40.80	$6.49	$0.0640	9,861	$0.0315	$0.0236
1992	$44.47	$7.07	$0.0723	10,226	$0.0370	$0.0261
1993	$48.47	$7.71	$0.0867	11,240	$0.0481	$0.0320
1994	$52.84	$8.40	$0.1093	13,008	$0.0673	$0.0422
1995	$57.59	$9.16	$0.1234	13,466	$0.0776	$0.0459
1996	$62.78	$9.99	$0.1438	14,406	$0.0939	$0.0524
1997	$68.43	$10.88	$0.1556	14,298	$0.1012	$0.0533
1998	$74.58	$11.86	$0.1580	13,319	$0.0987	$0.0490
1999	$81.30	$12.93	$0.1676	12,958	$0.1029	$0.0482
2000	$88.61	$14.09	$0.1801	12,779	$0.1096	$0.0485
2001	$96.59	$15.36	$0.1855	12,071	$0.1086	$0.0453
2002	$105.28	$16.75	$0.2280	13,618	$0.1443	$0.0568
2003	$114.76	$18.25	$0.2207	12,089	$0.1294	$0.0480
2004	$125.08	$19.90	$0.2481	12,468	$0.1486	$0.0521
2005	$136.34	$21.69	$0.2671	12,315	$0.1586	$0.0524
2006	$148.61	$23.64	$0.2845	12,035	$0.1663	$0.0519
2007	$161.99	$25.77	$0.3075	11,936	$0.1787	$0.0526
2008	$176.57	$28.08	$0.3509	12,493	$0.2105	$0.0584
2009	$192.46	$30.61	$0.3451	11,272	$0.1920	$0.0503
2010	$209.78	$33.37	$0.3943	11,818	$0.2275	$0.0562
2011	$228.66	$36.37	$0.4290	11,795	$0.2471	$0.0576
2012	$249.24	$39.64	$0.4478	11,295	$0.2495	$0.0549
2013	$271.67	$43.21	$0.4971	11,504	$0.2811	$0.0583
2014	$296.12	$47.10	$0.5651	11,998	$0.3296	$0.0645
2015	$322.77	$51.34	$0.5657	11,019	$0.3090	$0.0570
2016	$351.82	$55.96	$0.6553	11,710	$0.3755	$0.0654
2017	$383.49	$61.00	$0.7124	11,679	$0.4074	$0.0669
2018	$418.00	$66.49	$0.7118	10,706	$0.3794	$0.0588
2019	$455.62	$72.47	$0.7995	11,032	$0.4372	$0.0639
2020	$496.63	$78.99	$0.8856	11,212	$0.4907	$0.0677
2021	$541.32	$86.10	$0.9243	10,735	$0.4938	$0.0642
2022	$590.04	$93.85	$1.0611	11,306	$0.5918	$0.0726
2023	$643.14	$102.30	$1.1918	11,651	$0.6803	$0.0788
2024	$701.03	$111.50	$1.2558	11,262	$0.6983	$0.0763

Notes:
1. From IR-OCA-1-11b through 1991. Escalated at 9% thereafter (IR-OCA-15-8)
2. [1] divided by 6.287
3. Table 3.1, Column 6, $/MWH/1000
4. [3] / [2] x 1,000,000
5. [3] - [2] x 5,000/1,000,000
6. Deflated at 6%.