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THE STATE OF MAINE
BEFORE THE PUBLIC UTILITIES COMMISSION

RE: INVESTIGATION OF SEABROOK INVOLVEMENT BY MAINE UTILITIES

DOCKET No. 84-113

TESTIMONY OF PAUL CHERNICK
ON BEHALF OF THE
MAINE PUBLIC ADVOCATE

September 13, 1984

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TESTIMONY OF PAUL CHERNICK

ON BEHALF OF THE MAINE PUBLIC ADVOCATE

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 over 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, 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: 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 New England utility load forecasts, including those of Northeast Utilities, Boston Edison, the NEPOOL forecasts, and various smaller utilities, and predicted that growth rates would be lower than the utilities expected. Many of my specific criticisms have been incorporated in subsequent forecasts, load growth has almost universally been lower than the utilities forecast, and my general conclusions have been implicitly accepted by the repeated downward revisions in utility forecasts.

My projections of nuclear power costs have been more recent. However, utility projections have already confirmed many of my projections. For example, in the Pilgrim 2 construction permit proceeding (NRC 50-471), Boston Edison was projecting a cost of $1.895 billion. With techniques similar to those used in this testimony, I projected a cost between $3.40 and $4.93 billion in my testimony of June, 1979. Boston Edison's final cost estimate (issued when Pilgrim 2 was cancelled) stood at $4.0 billion.

In MDPU 20055,[1] 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. Thus, PSNH has moved its in-service date estimates, and increased its cost estimates, substantially towards my projections.[2] Figure 1.1 compares the history of PSNH cost estimates for the Seabrook plant to my estimates.

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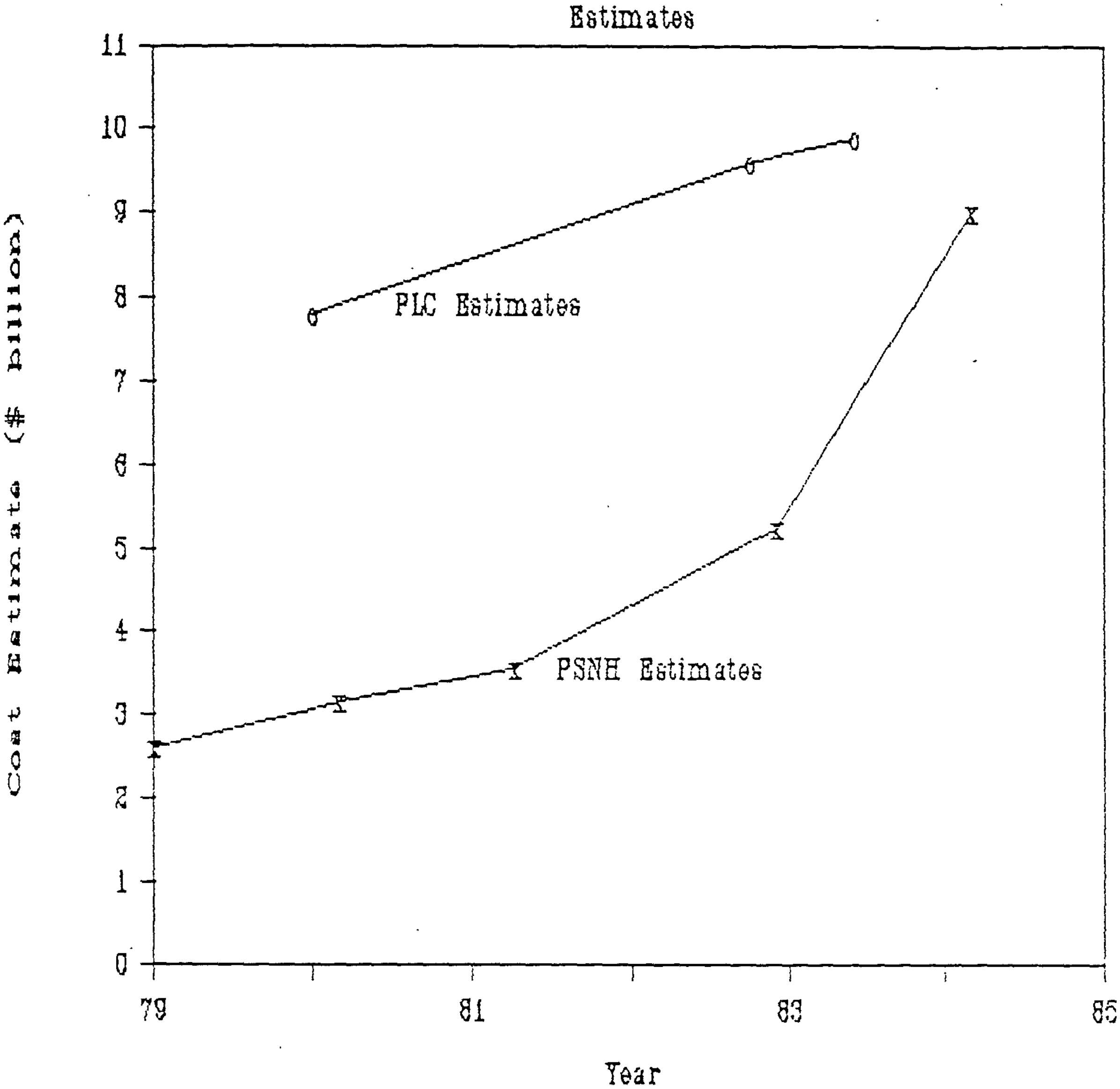
1. Complete citations for each procedding in which I have testified are provided in my resume, Appendix A to this testimony.

2. As will be discussed below, the significance of PSNH cost estimates since March is unclear.

Figure 1.1: History of Seabrook Cost



In MDPU 20055 and again in MDPU 20248, I criticized PSNH's failure to recognize capital additions (increase in plant investment during the operating life), its error in ignoring real escalation in O & M, and its wildly unrealistic estimate of an 80% mature capacity factor (even the Massachusetts utilities seeking to purchase Seabrook shares were more realistic about capacity factors). I suggested interim replacements of $9.48/kw-yr., annual O & M increases of $1.5 million/unit (both in 1977 $) and 60% capacity factors. Since about 1982, PSNH has projected capital additions, escalated real O & M at about 1% (about $0.1 million per unit annually), and projected a somewht more reasonable mature capacity factor of 72%. Thus, PSNH has implicitly accepted my criticisms, even though the 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 1979-81 confirms the patterns of large capital additions, rapid O & M escalation, and low capacity factors. The 60% 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 now Central Maine Power[3]).

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3. See NERA (1984).

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 projections were inconsistent with reality. While utilities have generally made some concessions to experience, nuclear cost and performance estimates continue to be optimistic, and hence it is still quite easy to improve on them.

Q: Has your recent nuclear cost testimony been reflected favorably in regulatory decisions?

A: Yes. Substantial parts of my testimony over the last two years on such subjects as Seabrook 1 and 2 and Millstone 3 have been adopted or cited with approval by public utility commissions. Specifically, substantial parts of my testimony (and my conclusions) on behalf of the Conservation Law Foundation and others in NHPUC DE 81-312 relating to Seabrook 1 and 2, were adopted by the NHPUC in its decision in that case. Similarly, my Seabrook cost testimony on behalf of the Connecticut Consumers Council in CPUCA 830301 was basically adopted by the CPUCA in its decision in that case. Additionally, my testimony relating to Millstone 3 on behalf of the Massachusetts Attorney General in the most recent Western Massachusetts Electric Company rate case, DPU 84-25, was cited with approval by the DPU in its decision in that case.

I also should add that other pieces of my testimony on Seabrook related issues have been submitted to various commissions but have not yet been acted upon. My testimony on behalf of the Massachusetts Attorney General in Fitchburg Gas & Electric Company financing case, DPU 84-49 and 84-50, and my testimony in a New England Electric System long range demand and supply forecasting case, EFSC 83-24, fall into this category.

Q: What is the subject of your testimony?

A: I have been asked to review the current status of Unit 1 of the Seabrook nuclear power plant. I have specifically been asked to review whether the unit is likely to enter service, how much it would cost to complete and operate, and whether its completion would be desirable.

Q: How is your testimony structured?

A: Section 2 considers the issues facing New England utilities and regulators in connection with Seabrook, and presents recommendations regarding appropriate actions for the Maine utilities. Section 3 derives estimates of the cost of the Seabrook units, in 1984 dollars, including operating costs and capacity factor. Section 4 converts the 1984 dollar estimates to ratemaking terms, in mixed constant dollars. Section 5 discusses the comparison of Seabrook to alternative supply-planning and demand-plannning options. Finally, Section 6 presents my conclusions and recommendations for the Commission.

2 - CURRENT SEABROOK ISSUES

Q: Has the status of Seabrook construction changed substantially in recent months?

A: Yes. The official cost estimates for this plant have increased from $5.2 billion last year, to $9 billion in March 1984, as illustrated in Figure 1.1; United Engineers and Constructors (UE&C), the architect/engineer for the project, estimated the cost of the plant at $10.1 billion and the cost of Unit 1 at $5.07 billion.[4] Cost estimates for Seabrook 1 are given in Table 3.11. The projected in-service dates of the two units have slipped from 1984 and 1987 last year, to 1986 and 1990 in March. PSNH now projects that Unit 1 will cost $4.5 billion. As a result of these cost increases and schedule delays, PSNH is very restricted in its ability to raise capital, has defaulted on debt payments (although those debt have since been restructured), has suspended common and preferred dividends, and faces the possibility of insolvency in the near future. The joint owners, including the Maine utilities, have been asked to assist PSNH in various ways, although it now appears that none of the bailout plans will

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4. These figures are from what MAC calls the "Baseline" estimate, and what Nielsen-Wurster terms the "1983 Preliminary Baseline Estimate"; the UE&C document has apparently never been released.

come to fruition, or even be presented to regulators.[5] A majority of the ownership group has voted to cancel Seabrook 2, and even PSNH has voted for cancelation, under certain conditions. The cost and schedule histories of the Seabrook 1, and my projections for its cost and schedule, are discussed in Section 3 of this testimony.

Q: What issues do the Maine utilities face regarding Seabrook?

A: I believe that there are three areas of primary importance to the Maine utilities with regard to Seabrook at this time. These areas are:

1. the status of Seabrook 1,
2. the effect of recent developments on the future prospects of Unit 1, and
3. the PSNH bailout plans.

I will discuss each of these subjects below.

Q: Please describe the recent changes which affect the future of Seabrook 1.

A: The significant developments appear to be

- the severe financial crisis at PSNH, and to some lesser extent other joint owners;
- the arrival of Mr. Derrickson from Florida Power and Light (FP&L) to manage the project for PSNH;
- the sharp rifts between PSNH, the other joint owners, and the architect/engineer, United Engineers and Constructors (UE&C);

5. The NH Electric Coop's purchase of PSNH's Maine Yankee share was too advantageous to the Coop to qualify as a bailout.

- and the resulting reorganization of the Seabrook project, including the formation of New Hampshire Yankee.

Q: How have the financial problems of the joint owners affected the status of Seabrook 1?

A: Unit 1 construction has been virtually suspended since April due to PSNH's financial crisis. In the three months preceding the April shut-down, Seabrook construction was costing over $10 million per week. In May and June, construction was essentially halted, and expenditures ran at about $2.4 million weekly. Since June, the rate of weekly expenditures has risen to $4 million, the maximum level which PSNH appears to be able to support until some longer-range financial fix is found, which does not seem likely until at least sometime early next year. Thus, the current construction level (after subtracting out the no-progress level of $2.4 million/week) is equivalent to only 21% of full construction.

While the financial problems of PSNH are probably the most severe, and the most troublesome for the project, due to the large share of the plant which it owns, it is not the only troubled owner. United Illuminating (UI), the second-largest owner, has cut its common dividend, has been unable to obtain short-term additional financing or issue debt, and has also taken such extraordinary measures to raise capital as selling its accounts receivable.

Q: What is your understanding of the proposals regarding financial assistance from other utilities to PSNH?

A: It is my understanding that the joint owners have discussed, and in some cases agreed to, a series of plans which would reduce PSNH's exposure to Seabrook-related problems by shifting those problems to the other joint owners, other NEPOOL members, and their customers. These plans included

1. diverting a portion of Hydro Quebec savings from New England ratepayers to PSNH shareholders, to pay a portion of PSNH's costs for Seabrook 2, in exchange for an agreement by PSNH to cancel the unit, and perhaps to prevent some unspecified New Hampshire retaliation against the Hydro Quebec line;

2. suggesting that the joint owners make low-interest or zero-interest loans, or other contributions to PSNH, to enable it to continue construction of Unit 1;

3. guaranteeing PSNH's share of Seabrook payments by an agreement from the joint owners to buy out PSNH's share at $1500/kw if it can not continue its payments;

4. financing all (or most) Seabrook construction through a separate corporation (Newbrook), which would require all the participating joint owners to stand behind one another's (and hence PSNH's) financing; and

5. financing through Newbrook, without guarantees across

owners, but equalizing all the participating owners' financing costs, by averaging PSNH's risk with that of the relatively more secure joint owners, who would then pay higher rates so that PSNH could pay lower rates.

All of these arrangements and suggestions appear to have been abandoned.

Q: What should the Maine utilities do with regard to these various plans to help PSNH out of its current financial distress?

A: I do not believe that the Maine utilities (or any other joint owners) should do anything to assist PSNH, for three basic reasons. First, these proposals do not appear to have any real benefits for the other utilities' ratepayers or shareholders; both groups have enough problems without taking on those of PSNH.

Second, PSNH's troubles are primarily self-inflicted, so the company does not warrant any special consideration. PSNH has consistently produced particularly low and unrealistic cost estimates for Seabrook. These cost estimates were accompanied by correspondingly unrealistic schedules (at times, the most agressive schedules in the country) and inflated estimates of construction progress. This behavior has been so extreme that PSNH has subsequently been forced to report negative progress (i.e., to revise the estimate of current construction progress below the inflated level reported months before) in three cost estimates since 1979. It would have been very difficult for PSNH not to know that its estimates were highly optimistic. PSNH has repeatedly ignored warnings from regulators and its joint owners regarding the dangers, and even the futility, of attempting to build Unit 2.

Third, it is not clear that a moderate-sized bailout, say a \$200 million[6] bailout, will save PSNH. As demonstrated in Sections 3 and 4, completing Unit 1 will cost at least 50% more than PSNH predicts, will probably cost twice as much (bringing the total cost of the unit to about \$6 billion), and may cost as much as PSNH was expecting to spend for both units (or about \$9 billion). It is difficult to see how a utility which is already unable to raise capital could absorb part of the cost of a write-off from Unit 2, and still finance an additional billion dollars (PSNH's share of the remaining cost to reach \$6 billion), for a plant which will require a massive rate increase, if and when it enters service.

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6. It is my understanding that this is the size of the former utility proposal for Seabrook 2 assistance through diversion of HQ savings.

Q: Does the current version of the Newbrook financing plan offer any significant hope of solving the financial problems of PSNH and the other joint owners?

A: Not much. The current financing plans basically require that the joint owners with weak financial support raise their shares of the estimated completion cost in advance of the start of full construction. This approach is not likely to solve the underlying problems because

- The financing plans appear to be premised on a cost to go of $4.6 billion or less.

- The cost of the plant is likely to exceed $6 billion, and will almost certainly top $5 billion.

- The plans do nothing to insure continuing access to capital markets, especially in the wake of quite plausible bankruptcy fillings by other utilities with severe financial problems resulting from nuclear construction programs, such as Long Island Lighting, Public Service of Indiana, or Consumers Power.

Q: Does the possibility that PSNH's troubles could result in the cancelation of Unit 1 provide any justification for the bailout by the joint owners or other New England utilities and ratepayers?

A: Not at all. As I demonstrate in Sections 3 and 4, Seabrook 1 is not likely to pay for the costs of completing and running it, even without side payments to PSNH. Most ratepayers in New England would probably be better off if Seabrook 1 were canceled today, than if it were finished, even if the ratepayers have to pay for every dime of the investment to date.[7]

The best that can be hoped for (and this is extremely optimistic) is that Seabrook 1 will have slightly positive net benefits over the course of its useful life. It can not be worth very much more investment to secure those benefits, even if they exist. This is particularly true if the ratepayers in the 1980's are being asked to bear additional burdens for a plant which will raise their rates for the rest of the century.[8]

Q: Is assistance to PSNH to facilitate completion of Unit 1 any more appealing than assistance in covering the costs of abandoning Unit 2?

A: Not really. As I noted above, Unit 1 is just not attractive enough to justify any extraordinary expense on its behalf;

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7. I am not suggesting that utilities will or should recover all Seabrook costs to date. The advantage of cancelation over completion remains unchanged if an equal dollar value of sunk costs is charged to shareholders in both cases.

8. See Section 4.

the ordinary expenses alone will be bad enough.

Q: Is any form of Seabrook bailout a better deal for the joint owners if they receive the right to purchase ownership shares in Seabrook 1 for less than PSNH's investment to date?

A: Absolutely not. The value of Seabrook 1 to New England is probably less than the cost of completing and operating it, even ignoring sunk cost, so no utility should want to increase its ownership share, even if the plant were being given away. It is not clear whether any utilities are willing to pay even a nominal sum for Seabrook entitlements; if there are any such utilities, the Maine utilities should certainly attempt to negotiate a sale of their shares. If utility can sell out at any substantial price, such as half of the investment to date (which would amount to about $1000 to $1500/kw), its customers and shareholders would be quite fortunate.

Q: Please discuss the effect of the reorganizations on the Seabrook 1 project.

A: Most of the events related to the current reorganizations can only spell more trouble in managing the plant. The removal of UE&C and PSNH from positions of authority, the general climate of suspicion between the various entities, the revision of lines of communication and responsiblity, and of course the suspension of construction and disruption of the workforce all seem likely to introduce further confusion and delay, at least in the short run. On the other hand, the joint owners seem to be placing great confidence in Mr. Derrickson and in the eventually reorganized management structure. This confidence strikes me as ill-founded, or at least over-stated.

Q: What has been the experience at other nuclear units when the management structure has been changed radically?

A: Removal of the construction manager (which is usually also the architest-engineer) from its post is a drastic and unusual move. I know of only two plants at which a similar change has taken place: WPPSS 2 and South Texas. In neither case was the situation exactly analogous to that at Seabrook,[9] but they may provide some insights into the prospects for Seabrook.

At WPPSS 2, Burns & Roe was replaced as construction manager in February 1978 by the utility, which apparently believed that it could perform the management task more efficiently. Since that time, the cost estimate has tripled, and the scheduled in-service date has slipped four years.

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9. For example, in neither case were the owners under such severe financial stress and uncertainty as are the Seabrook owners. Also, I know of no instance in which the lead participant in a nuclear construction project has lost its management authority.

At South Texas, Brown & Root was dismissed as A/E and constructor in late 1981, and replaced by Bechtel and EBASCO. The cost estimate increased by about 50% at the time of the switch, and has more than doubled again since then. The first unit is not due to enter service until 1987, so more cost escalation is certainly possible.

Q: Is it reasonable to expect that Mr. Derrickson will be able to complete Seabrook 1 on schedule and within the current budget?

A: I do not believe so. While Mr. Derrickson is to be congratulated for completing St. Lucie 2 very quickly, and close to schedule, it should be noted that he is not a miracle worker. At St. Lucie, he was working

- in a stable, financially viable utility, Florida Power & Light (FP&L),

- with an established team which developed its skills on three previous nuclear units, including St. Lucie 1, of which Unit 2 was a duplicate, and

- with a single architect-engineering firm.

At Seabrook, he will be

- starting with the existing fragmented structure of PSNH, Yankee Atomic, UE&C, and Fuel Supply Services (an FP&L

subsidiary);

- forming new functional and corporate organizations;
- adding some participation from three addition A/E's: Bechtel, Ebasco, and Stone & Webster;[10]
- ultimately directing a team which has never built a plant together before, and much of which has not even worked together on Seabrook previously;
- building a first unit;
- and operating under the oversight of MAC, the Executive Committee of the Joint Owners (ECJO), and the joint owners themselves.

Since all the responsible entities (PSNH, UE&C, Yankee, and MAC) put together were only able to identify a couple hundred million dollars in cost overruns as recently as the end of 1983 (only 3 months before the $4 or $5 billion cost increase, depending on whether one uses UE&C's figures or PSNH's), Mr. Derrickson's ability to decisively influence events with a staff drawn largely from the same organizations seems highly questionable.

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10. Mr. Derrickson has annouced that employees of these organizations will be working on the project; the number and role of the personnel, and the role of their employers, is not clear. Since these firms were both A/E and constructor for, respectively, Midland, WPPSS 3&5, and Shoreham, this may be an issue of some concern.

It should also be remembered that the claims being made for Derrickson, et al. have been made before for UE&C, Yankee Atomic, and MAC.

Q: Were the experiences at St. Lucie 2 and the other FP&L nuclear plants significantly different than industry experience?

A: St. Lucie 2 was built much closer to schedule than most other nuclear units. When it received its construction permit, in May, 1977, St. Lucie 2 was expected to enter operation in May 1983; it was actually declared commercial in August, 1983. This is considerably better than typical utility experience.

Despite its excellent schedule performance, St. Lucie 2 experienced considerable cost overruns. At the time of its construction permit, the plant was projected to cost $850 million; it was actually completed for $1450 million, or 68% over budget. The other FP&L plants, including St. Lucie 1, where Mr. Derrickson also had important roles, were more typical in their cost and schedule overruns. The cost and schedule histories of the four FP&L nuclear units are given in Table 3.13 of this testimony.

Q: Does the history of nuclear plant construction indicate that Mr. Derrickson is likely to be able to repeat his limited success in building St. Lucie 2 at Seabrook?

A: In addition to the differences between the St. Lucie and Seabrook situations, the uneven nature of Mr. Derrickson's experience at the two St. Lucie units, and the uncertainty about Mr. Derrickson's importance in the relative success at St. Lucie 2, it is not clear how replicable nuclear construction success is. Several utilities which have been successful in building one unit inexpensivelyly and/or rapidly have not been successful in later efforts, including

- Consumers Power experience at Palisades versus Midland,
- Niagara Mohawk Power experience at Nine Mile Point 1 versus Nine Mile Point 2,
- Philadelphia Electric experience at Peach Bottom versus Limerick,
- Commonwealth Edison experience at several earlier plants (particularly Zion) versus Byron and Braidwood,
- Mid-South Utilities experience at Arkansas 1&2 versus Grand Gulf 1 and Waterford.

Since these utilities were unable to repeat their earlier successes, it is not clear that whatever Mr. Derrickson learned at FP&L will be readily transferable to Seabrook.

Q: Does PSNH's recent offer to accept a cost cap for Seabrook 1 offer much assurance regarding the cost of the plant?

A: Not really. PSNH's cost cap is basically an empty gesture. If Seabrook 1 is cancelled, PSNH is almost certain to be bankrupt: the write-off would exceed the utility's equity. Therefore, PSNH has nothing to lose by continuing construction, and its management, at least, has something to gain by delaying bankruptcy. If the unit is actually completed, it is possible that PSNH will be allowed to collect more than the cap, either under one of the loopholes left in the cap, or simply because the New Hampshire PUC may chose to allow greater recovery. On the other hand, with or without the formal cap, PSNH will have a hard time collecting even its share of a $4 billion cost, given the dramatic rate effect of the plant, so it may not be giving up much even if it is held to the cap.

Q: What should the Maine utilities's response be to the recent changes in the estimates of Seabrook 1 risk, cost, and schedule?

A: The Maine utilities should certainly not increase their commitment or exposure to Unit 1, either directly or indirectly. The cost figures which I present in Sections 3 and 4 of this testimony indicate that Unit 1 is probably more expensive than alternative power sources, may well be more expensive than continued reliance on oil, and will be extremely difficult to finance.

Q: What are the options available to the PUC at this point?

A: The Commission has several alternatives.

1. It could order the utilities out of Seabrook 1, as fast as possible, as the Connecticut DPUC did with respect to Seabrook 2. Given the lack of a market for Seabrook 1 shares, and the reluctance of many of the joint owners to proceed without a total commitment by all the owners, this sort of order would probably result in the cancelation of the unit.

2. It could allow the utilities to continue their participation under normal procedures, but refuse long-term financing as anticipated in the Newbrook agreement. It appears that the owners are unwilling to proceed without the pre-financing of the current estimated cost, and Seabrook 1 would go into a construction limbo, or be canceled, if any state Commission prevented the pre-financing.

3. The Commission could allow the Newbrook financing, but condition that approval on receipt of greater assurances from UE&C and/or other contractors, regarding the construction schedule and total construction cost. It is unlikely that any financially competent contractor would offer anything like a turnkey contract for Seabrook, given the uncertainty in

the eventual scope of the project, so this sort of order would probably result in cancelation.

4. In addition to any of the previous options, the Commission may encourage the utilities to attempt recovery from PSNH and UE&C, for the damages done them by the misrepresentation of cost and schedule at the time of the 1979/80 sales of PSNH shares in Seabrook. PSNH cost and schedule estimates have never been sincere best estimates, and have often been much more optimistic than standard industry practice.[11]

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11. In addition, it is not clear that Amendment #10 to the JOA, under which CMP increased its share of the plant and MPS and BHE bought into it, ever became effective. One of the requirements for the transfer, incorporated from the failed Amendment 7, was that the Massachusetts DPU approve "the financing by MMWEC of the increase in the Ownership Share of MMWEC". The DPU and MMWEC thought that the financing approved would pay for the completion of the additional share, but it is now clear that the approved financing will not pay for all of the increase. Hence, the transfer may not have taken place, in which case the Maine utilities may not have any liability for future Seabrook costs, and PSNH may well owe the other utilities their purchase price and the amounts they have spent in the past.

3 - THE COST OF POWER FROM SEABROOK 1

3.1 - INTRODUCTION

Q: How have you estimated the cost of Seabrook Unit 1?

A: I have attempted to determine realistic estimates for the duration of Seabrook construction, its construction costs, and the various costs of running and decommissioning the unit. Based upon analyses of historical performance and trends:

1. I do not expect Seabrook 1 to come on line before 1988, at the earliest; completion of the unit may be impossible.

2. I expect that Unit 1 would cost at least $6 billion (and quite likely more) to complete.

3. Capacity factors for units of Seabrook's size and type will probably average in the range of 50% to 55%.

4. I expect non-fuel O & M to escalate much faster than general inflation; the capital cost of the plant will also increase significantly during its lifetime.

Including decommissioning, insurance, fuel, and other factors listed above, power from Seabrook 1 would cost about 13 or 14 cents/kWh, in levelized 1984 dollars. The actual prices charged to ratepayers will include inflation and will be much larger, as discussed in the next section. Sunk costs account for about 7 cents/kWh, so the costs of completing and running Seabrook 1 are likely to be about 6.5 cents/kWh, in 1984 dollars.

A detailed analysis of these costs is presented below, including a comparison of my estimates to the most recent available by PSNH. As I discussed in the preceding section, the management of the Seabrook project has been in rapid flux, with new organizations and projections announced almost weekly. Therefore, some of the references to PSNH below may also include NH Yankee or other entities which the joint owners or PSNH establish over time.

Q: Please explain your use of the term "levelized 1984 dollars".

A: Rather than simply expressing costs in mixed current dollars in the various years of Seabrook operation, I restate costs in two steps. First, I deflate all costs to 1984 dollars, so they are comparable to prices which utilities (and their customers) are paying today. Second, I levelize costs over the life of the plant, as if the same real (inflation-adjusted) cost were to be charged each year. Thus, when I refer to 7 cents/kwh (for example) in 1984 dollars, this is equivalent to 8.3 cents charged in nominal 1987 dollars, 15 cents in 1997, 27 cents in 2007, and 48 cents/kwh in 2017, at a 6% inflation rate. Figure 3.1 graphs these two curves, and several related cost recovery curves.

Q: How do these levelized constant dollars compare to levelized nominal dollars and to ratemaking charges for a nuclear plant?

A: Levelized constant dollars charge the same cost in 1984 dollars to each year, while levelized nominal dollars (such as those presented by CMP in 1 OPA 61) charge the same amount each year in current nominal dollars. Since a fixed amount of nominal dollars is worth less as time goes by, nominal levelization is equivalent to falling real charges, and requires higher initial rates to produce the same present value. Figure 3.1 includes levelized nominal dollars with the same present value (at 14% discount rate) as the constant-levelized example, for

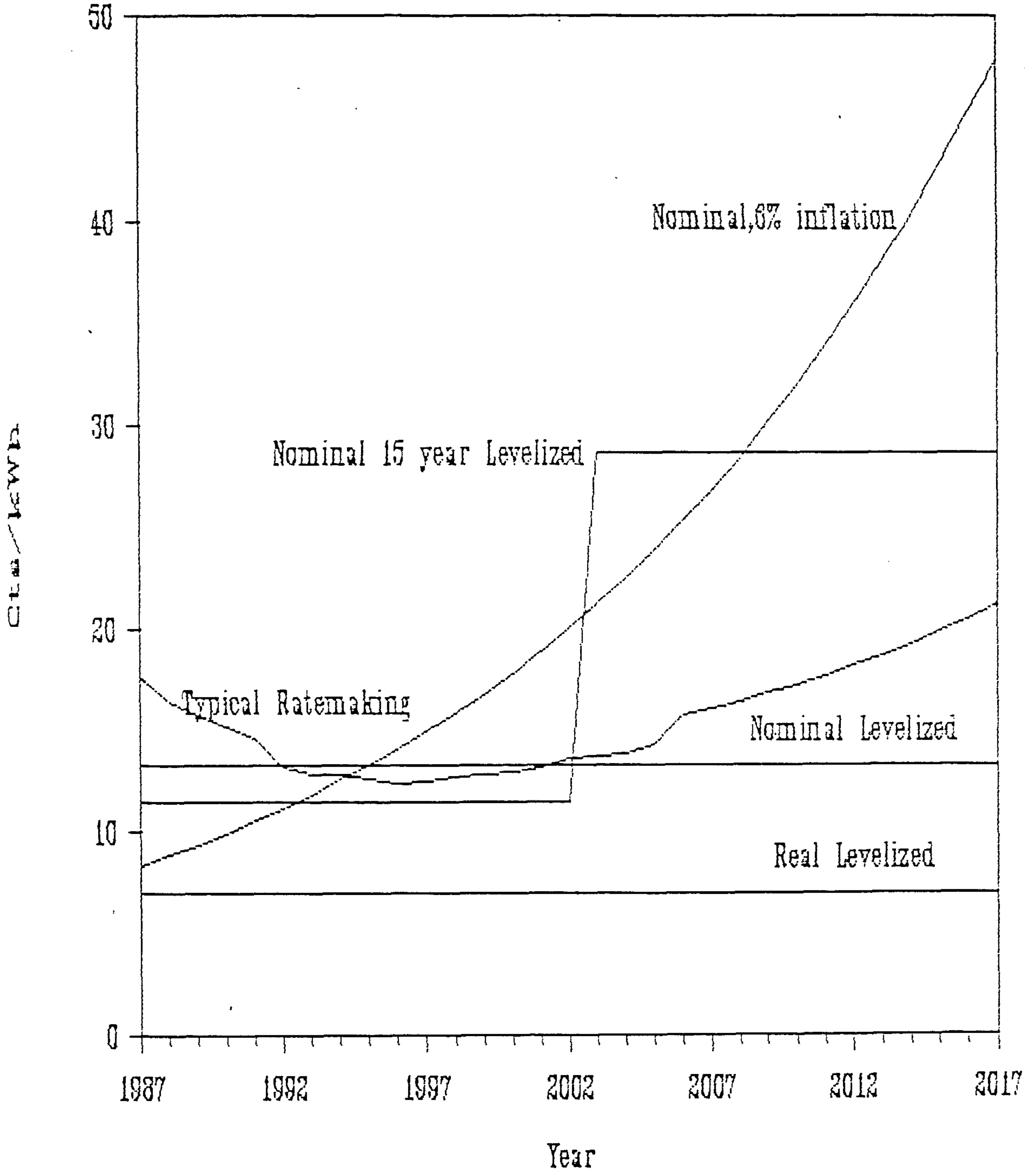
- 30-year levelization, at 13.3 cents which is somewhat longer than the likely useful life of Seabrook 1, and

- two consecutive 15-year levelization periods, the first of which is of comparable duration to current small power producer contracts, at 11.4 and 28.6 cents.

Traditional ratemaking charges even more per kwh in the early

Figure 3.1: Levelized Dollar

Comparison



years of a plant's life, when it is not yet depreciated and is operating at a low capacity factor. An example of this cost recovery pattern is also shown in Figure 3.1.[12]

Q: Why do you present your results in the levelized present-value form?

A: The levelized present-value form has several advantages. First, it presents the cost of the plant as a single number, rather than as a series of figures which change over time. Second, the cost is expressed in 1984 dollars, which are comparable to current costs, and thus easier to relate to familiar costs, such as those of oil, or conservation investments. Third, the levelized present-value cost is not distorted by the year of operation of a plant, so the cost of a coal unit starting operation in 1992 can be fairly compared to a nuclear unit which goes commercial in 1987, for example. Fourth, the levelized cost reflects the cost of power throughout the plant's life, which is fairer than first-year or first-decade comparisons.

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12. The cost pattern is taken from NU's projections for Millstone 3, scaled to have the same present value as our other examples.

3.2 - CONSTRUCTION DURATION

Q: Are there specific reasons to believe that Seabrook will reach commercial operation somewhat after the date projected by PSNH?

A: Yes. Those reasons include:

1. PSNH'S allowance for the interval between operating license issuance (OLIS) and commercial operation date (COD) is much shorter than recent experience.

2. PSNH projections of rates of construction progress have been consistently over-optimistic in the past.

3. PSNH's projections are inconsistent with historic rates of construction progress on Seabrook.

4. PSNH's estimates of Seabrook COD's, based on UE&C projections, have always been over-optimistic in the past, and there is little reason to believe that the last revision, which is more optimistic than UE&C, will be correct.

5. PSNH's construction duration projection for Seabrook 1, once the most aggressive in the nation, is now quite similar to those of other nuclear plants at similar stages of construction, and actual nuclear construction durations have almost always exceeded projections by

substantial amounts.

Q: What is the recent experience for the start-up interval from OLIS to COD?

A: Table 3.1 provides this data for all units in commercial operation which have received operating licenses since the beginning of 1978.[13] The shortest start-up period, 4.1 months, was that of St. Lucie 2. The corresponding intervals for the other units range from 8.1 months, to over 20 months, with a 16-plant average of 13.5 months. In addition, Diablo Canyon 1, which has been listed as 99% or more complete since at least late 1977, received a low power operating license in September, 1981, only to have it suspended two months later, and restored only in April, 1984. Its full power license is currently held up in the courts. Diablo Canyon 1 will increase the average start-up period when (and if) it finally reaches commercial operation, if the earlier license date is used. Four other units have received operating licenses, but have not yet reached commercial operation: Grand Gulf 1 received a low power license on 6/16/82, and a full power license on 7/31/84; LaSalle 2 received a low power license on 12/16/83, and a full power license on 3/23/84; WPPSS 2

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13. This analysis is complicated somewhat by the apparent use of two commercial operation dates (COD's) for some units, such as San Onofre and La Salle: one date is used for ratemaking and another for other purposes. I have used the COD reported to the NRC, where possible.

TABLE 3.1: 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 [4]	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
AVERAGE:			13.45

Notes: [1] From NRC Gray Books 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.

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

[4] Utility had previously announced COD of 10/20/82; apparently now amended.

received a low-power license on 12/20/83 and a full one on 4/13/84; and Susquehanna 2 received a low power license on 3/19/84, and a full power license on 6/27/84. Grand Gulf will certainly increase the average startup when it enters service; the effect of the other units can not yet be determined, but all are more than four months from their first license.

Q: What is PSNH's projection for the Seabrook start-up period?

A: PSNH currently projects a start-up period of only four months for Seabrook 1.[14] This projection is considerably more optimistic than would be suggested by the historical experience. If PSNH's projections of construction progress and operating license date were correct, but the start-up period were the average 13.5 month duration from Table 3.1, Seabrook 1 would enter commercial operation in June, 1987.

Q: To what extent has PSNH over-estimated the past rate of Seabrook construction?

A: At the end of the first quarter of 1979, PSNH estimated that Unit 1 was 18.85% complete, and that it would be 39.13% complete one year later, for annual progress of 20.28%. But at the end of the first quarter of 1980, Unit 1 was estimated

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14. PSNH does not appear to have published an estimate of OLIS for its new schedule, so I have used the very similar fuel load date.

to be only 36.70% complete: the reported progress was 17.85%, or 88% of the projected rate. In fact, the reported progress was apparently greater than the actual progress, since a period of negative reported progress followed.

In March 1980, PSNH produced a new construction estimate, which projected that Unit I would be 67.7% complete by June, 1981; but reported completion in June, 1981 was only 50.8%. Over this 15-month period, reported progress was only 45.5% of projected progress. Table 3.2 presents these calculations and repeats them through the estimates of November 1982 and March 1984.[15] Averaging the progress ratio (weighted by the months covered by each estimate), and ignoring PSNH's over-optimism in the March, 1980, progress report, produces an average progress-to-estimate ratio for the last 60 month period of 48.9%. Stated differently, each percentage point progress in construction has taken over twice as long as PSNH expected.

As of 3/84, PSNH predicted that Seabrook was 22 months from fuel load. If the progress-to-estimate ratio for this estimate turns out to be the historical 50%, fuel load would

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15. PSNH has been gradually increasing its estimate of completion percentage since March, despite the lack of substantial construction at the plant. As can be seen from the historical record, PSNH has overstated progress in the past when under financial and regulatory pressure.

TABLE 3.2: RATIO OF REPORTED TO FORECAST PROGRESS: SEABROOK 1

Date:	Mar-79	Mar-80	Jun-81
a. Forecast Construction Stage (% complete) [1]		39.13%	67.7%
b. Reported Construction Stage (% complete)	18.9%	36.70%	50.8%
c. Forecast Progress (forecast increase from last reported % complete) [2]		20.28%	31.0%
d. Reported Actual Progress Since Last Report		17.85%	14.1%
e. Progress Ratio (Reported/Forecast Progress)		0.88	0.45

AVERAGE PROGRESS RATIO FOR SEABROOK 1: 0.489

Notes: [1] As forecast at previous date listed.

occur 44 months after 3/84, or in 11/87. PSNH currently projects that Seabrook is 20 months from fuel load. If construction continues to take twice as long as projected, fuel would be loaded 40 months from now, or December, 1987. Adding a year and a month for start-up produces an in-service date of December 1988 or January 1989.

Table 3.3 repeats this analysis for the August 1984 PSNH estimate of 80% completion, which has not been reconciled with the 73% report in March, and may represent a repetition of PSNH's past practice of over-reporting progress in times of financial and regulatory stress. If the 80% figure is as reliable as typical PSNH practice, the average progress-to-estimate ratio has been 53.1%. A continuation of this trend will would result in fuel load in October 1987, and commercial operation 13 months later, or November 1988.

Q: What are PSNH's historic rates of construction progress, and what in-service date do those rates suggest?

A: From March 1979 to March 1984, reported progress on Unit 1 averaged 0.90% per month. PSNH has projected sustained peak monthly construction rates of approximately 2% for Unit 1. PSNH has also predicted that the last 10% or so of construction will proceed more slowly, at about 0.7% per month, or about 35% of the peak rate.

TABLE 3.3: RATIO OF REPORTED TO FORECAST PROGRESS: SEABROOK 1
USING AUGUST 1984 CONSTRUCTION STAGE

Date:	Mar-79	Mar-80	Jun-81	Nov-82	Aug-84
a. Forecast Construction Stage (% complete) [1]		39.13%	67.7%	82.0%	99.0%
b. Reported Construction Stage (% complete)	18.9%	36.70%	50.8%	65.6%	80.0%
c. Forecast Progress (forecast increase from last reported % complete) [2]		20.28%	31.0%	31.2%	33.4%
d. Reported Actual Progress Since Last Report		17.85%	14.1%	14.8%	14.4%
e. Progress Ratio (Reported/Forecast Progress)		0.88	0.45	0.48	0.43

AVERAGE PROGRESS RATIO FOR SEABROOK 1: 0.531

Notes: [1] As forecast at previous date listed.

If PSNH is only able to maintain a reported rate of progress on Unit 1 of 1.0% per month (still somewhat better than the historic level) from 73% in March 1984 through the 90% completion point, and 35% of that rate (or .35%/month) thereafter, construction will take 17 months past March 1984 to reach 90% complete, plus 29 more months for the last 10%, and will end about January 1988. Starting at the currently claimed 80% completion, 90% would be reached in October 1985, and 100% in March 1988. Allowing 13 months for startup produces a commercial operation date estimate between February and April 1989.

Q: Has PSNH changed its projections for the Seabrook 1 commercial operation date substantially over the last few years?

A: Yes. As shown in Table 3.4, the COD was estimated as 11/81 in December 1976. Over the last seven years, PSNH has slipped its estimate of the Seabrook 1 COD 57 months to 8/86.

Q: If the historical patterns of COD slippage continue, when would the Seabrook units actually reach commercial operation?

A: Table 3.4 derives the COD progress ratio[16] from each earlier estimate to the March 1984 estimate. The COD progress ratio

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16. These are not the same as the percent-complete progress ratios discussed above.

TABLE 3.4: PROJECTION OF SEABROOK 1 SCHEDULE SLIPPAGE/March 1984 PSNH Estimate

1. Date of PSNH Estimate:	Dec-76	Mar-78	Jan-79	Mar-80	Apr-81	Dec-82	Mar-84
2. PSNH: ESTIMATED C.O.D.	Nov-81	Dec-82	Apr-83	Apr-83	Feb-84	Dec-84	Jul-86
3. PSNH: MONTHS UNTIL C.O.D.	59	57	51	37	34	24	28
4. TOTAL PROGRESS TO NEXT ESTIMATE (months)	2	6	14	3	10	-4	--
5. TOTAL PROGRESS TO MARCH 1984 (months)	30	28	22	8	6	-4	--
6. ELAPSED TIME TO MARCH 1984 (months)	87	72	62	48	35	15	--
7. PROGRESS RATIO TO MARCH 1984 (%)	35.1%	39.6%	36.2%	17.7%	15.8%	-30.0%	--
8. PROJECTED MONTHS TO GO	80	71	77	159	178	NA	--
9. PROJECTED C.O.D.	Nov-90	Feb-90	Aug-90	Jun-97	Jan-99	NA	--

TABLE 3.5: PROJECTION OF SEABROOK 1 SCHEDULE SLIPPAGE/August 1984 PSNH Estimate

1. Date of PSNH Estimate:	Dec-76	Mar-78	Jan-79	Mar-80	Apr-81	Dec-82	Aug-84
2. PSNH: ESTIMATED C.O.D.	Nov-81	Dec-82	Apr-83	Apr-83	Feb-84	Dec-84	Aug-86
3. PSNH: MONTHS UNTIL C.O.D.	59	57	51	37	34	24	24
4. TOTAL PROGRESS TO NEXT ESTIMATE (months)	2	6	14	3	10	0	--
5. TOTAL PROGRESS TO AUGUST 1984 (months)	35	33	27	13	10	0	--
6. ELAPSED TIME TO AUGUST 1984 (months)	92	77	67	53	40	20	--
7. PROGRESS RATIO TO AUGUST 1984 (%)	38.1%	42.9%	40.3%	24.5%	25.1%	0.16%	--
8. PROJECTED MONTHS TO GO	74	65	70	114	111	17052	--
9. PROJECTED C.O.D.	Oct-90	Jan-90	Jun-90	Feb-94	Dec-93	never	--

Notes: line 3 = line 2 - line 1
line 5 = line 3 - 28 mos. (or 24 mos.)
line 6 = Mar-84 (or Aug-84) - line 1
line 7 = line 5 / line 6
line 8 = line 3 / line 6
line 9 = Mar-84 (or Aug-84) + line 8

is the reduction in months left in the construction schedule (that is, progress towards the COD), divided by elapsed months. If the schedule did not change between estimates, the progress ratio would be 1.0. For various time periods ending with the 3/84 estimate, the progress ratio for Seabrook 1 ranges from less than zero to almost 40%. For example, for each month that went by from March 1980 to March 1984, completion drew nearer by only .177 months (about 5 days). To put it another way, it has taken Seabrook 1 at least 2.5 months to get one month closer to completion (using the 40% progress ratio from 3/78, the best period on record). Table 3.5 repeats this calculation for the current COD estimate of 8/86.

Tables 3.4 and 3.5 extrapolate the historic trends to determine when Unit 1 would enter service, assuming that PSNH continues to be as wrong about its COD as it has been in the past. These dates assume that the estimated completion dates continue to recede as they have in the past. Depending on the time period used for trending, Unit 1 could be expected to enter service between January 1990 and the end of the century, or based upon the last two years, never.

Q: What are the construction duration projections for other nuclear power plants, and how do they compare to those for Seabrook?

A: Table 3.6 lists the reported percent complete and the scheduled in-service date for each of the twenty nuclear units which were within 15 percentage points of the reported percent complete for Seabrook 1 as of December 31, 1983.[17] On average, the seventeen with scheduled in-service dates averaged about 74.9% complete and were projected to reach commercial operation in December, 1986. At its reported construction pace over the last year,[18] Seabrook 1 was about three months behind the average. Table 3.6 also updates the status of this cohort to the present time. Two previously scheduled units and one indefinite unit have now been canceled, and the average COD for the other 15 is January 1987, from an average completion of 75.2%. Based on reported percentage complete, PSNH's projection of the Seabrook 1 COD was six or eight months more optimistic than others in the industry.

Q: Have the construction duration estimates of the nuclear industry as a whole generally been accurate?

A: No. The U.S. nuclear industry has been universally over-confident in its construction schedule projections.

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17. At that time, PSNH estimated that Unit 1 was 78.7% complete. As of March 1984, PSNH revised its estimate to 73%; I use this figure for this comparison.

18. PSNH reports progress from 65.6% complete in November 1982 to 73% complete at the end of February 1984, or about 0.6% per month.

TABLE 3.6: DECEMBER 31, 1983 ESTIMATED COMMERCIAL OPERATION DATES
Percent complete comparable to Seabrook 1 (58% to 88%)

Unit	Construction Stage (% complete) Dec. 1983	Estimated COD Dec. 1983	Current [2]
Midland 1	85% [1]	indef. [1]	canceled [1]
Shearon Harris 1	85%	Mar-86	Mar-86
Midland 2	85%	Jun-86	canceled [1]
Palo Verde 3	83.2%	Dec-86	Jun-87 [3]
Clinton 1	82.4%	Nov-86	Nov-86
River Bend 1	82%	Dec-85	Dec-85
Millstone 3	81%	May-86	May-86
Hope Creek 1	81%	Dec-86	Feb-86
Beaver Valley 2	78.1%	May-86	Oct-86
Nine Mile Point 2	78%	Oct-86	Oct-86
Bellefonte 1	76%	Apr-86	Apr-89
Bellefonte 2	76%	Apr-91	Apr-91
WNP-3	75% [1]	indef. [1]	indef. [1]
Seabrook 1	73% [1]	Jul-86 [1]	Aug-86 [1]
Braidwood 1	70%	Oct-85	Feb-86
Byron 2	67%	Nov-85	Feb-86
Comanche Peak 2	65% [3]	Jun-86 [3]	Jun-86 [3]
WNP-1	63% [1]	indef. [1]	indef.
Catawba 2	61.9%	Jun-87	Jun-87
Watts Bar 2	61%	Oct-86	Oct-86 [4]
Marble Hill 1	60%	Dec-88	canceled [1]
AVERAGE 1.	74.9%	Dec-86	Jan-87
2.	75.2%		

Source: Nuclear News/February 1984 and August 1984.

Notes: [1] Excluded from average below.
[2] August, 1984.
[3] Month not stated; June assumed.

Appendix B presents the estimated and actual construction durations for all the units which have reached commercial operation and for which I have been able to obtain both the actual cost and one or more estimates of the in-service date made when the plant was believed to be over one year from COD.[19] Table 3.7 summarizes the results of that analysis. For the typical estimate in the two-to-three year range (comparable to the 3/84 estimate for Seabrook 1), the actual construction duration was more than twice the projected remaining duration. The August 1984 Seabrook estimate lies on the boundary between the two-to-three year range and the one-to-two year range, for which the actual duration averaged just a bit under twice the projected duration.

As of the March, 1984 estimate, Seabrook 1 was anticipated to be 28 months from COD. As discussed above, this was more optimistic than the standard industry projection for a unit at Seabrook's stage of completion, so assuming only the industry average amount of schedule slippage is probably optimistic. Multiplying the projected 28-month interval by 2.100 yields a prediction of commercial operation 59 months from March 1984, or in February 1989. Currently, PSNH is

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19. I excluded all units under 300 MW (most of which were very early, in any case). The other 75 domestic LWR's are included, except for Connecticut Yankee (for lack of data), and the two units which went commercial in 1984 and have not yet been tranfered to my completed plant set.

TABLE 3.7: HISTORICAL NUCLEAR DURATION MYOPIA

Estimated Time to Completion (years)	Number of Estimates	Average Projected Time to Complete (years)	Average Duration Ratio
1 - 1.99	220	1.417	1.983
2 - 2.99	175	2.397	2.100
3 - 3.99	103	3.444	1.957
4 - 4.99	63	4.398	1.752
5 +	82	5.773	1.582

projecting that Seabrook 1 will be in commercial operation in 24 months. Doubling this interval yields a prediction of commercial operation 48 months from August 1984, or in August 1988.

This analysis assumes that PSNH is just as over-optimistic as, and that the comparison group of utilities is slightly more pessimistic than, the historical group from which the duration ratio was estimated. It is possible that other utilities are much more realistic (more than the six-to-nine months I credited to Seabrook) now than they were in the 1960's and 1970's, and hence that PSNH's estimate is a bit better than the historical average. The historical experience appears to have been quite stable over time, however, and there is no evidence of any recent emergence of a learning curve.

Q: What dates are realistic estimates for commercial operation at Seabrook?

A: Table 3.8 summarizes my previous calculations. Over all, if the historic trends continued, Seabrook 1 might enter commercial operation around the end of the decade. It is unlikely that many nuclear units will still be under construction at that point: those not completed will be canceled either voluntarily or when their owners can no longer pay for them. If Seabrook 1 is to be completed, PSNH

TABLE 3.8: SUMMARY OF COMMERCIAL OPERATION PROJECTIONS

PROJECTION METHOD	PROJECTED COMMERCIAL OPERATION based on COD estimate of: 3/84	8/84
1. Completion Progress Ratio	Dec-88	Nov-88
2. Past Progress Rates	Feb-89	Apr-89
3. Schedule Slippage (most optimistic)	Feb-90	Jan-90
4. Industry Schedule Myopia	Feb-89	Aug-88

must do much better in maintaining its schedule than has been industry experience or its own experience. We may approximate such an improvement by using the most favorable of the preceding results, from the schedule myopia analysis, and using the 80% completion reported in August 1984, which predicts a COD in August, 1988.

3.3 - CAPITAL COSTS

Q: Are PSNH's estimates of Seabrook capital costs consistent with historical experience?

A: No. There is considerable evidence which indicates that PSNH is still being optimistic in its projection of Seabrook's final cost. This evidence includes the historical tendency of architect/engineers (A/E's) and utilities to underestimate nuclear construction costs, and the continuing increases in cost estimates for nuclear plants under construction, and particularly for Seabrook.

Q: How does the past record of A/E cost estimates indicate that the capital cost projections for Seabrook are apt to be low?

A: In a report prepared by Analysis and Inference for the NRC (Chernick, et al., 1981), we calculated the ratio of actual to forecast costs for several nuclear power plants, and derived four regression equations estimating the relationship between real cost overruns and the length of time into the future for which the forecast is being made. We defined this relationship as myopia: a failure to forecast future cost increases.

I have recently completed an analysis of both nominal and real cost myopia using the most intuitively appealing of the equations developed in the NRC report, and a much larger data base. The equation is

$$R = (1 + m)^t$$

where R is the ratio of actual to expected costs in nominal or real dollars, depending on the analysis, m is the calculated myopia factor, and t is the expected years to completion at the time of the estimate. A total of 591 estimates for more than one year in the future were available for 60 of the 63 non-turnkey units which have reached commercial operation,[20] based on DOE compilations of a series of utility reports to the AEC, ERDA, and now the EIA of the DOE. These are versions of the "Quarterly Progress Report on Status of Reactor Construction" identified as Form HQ-254, and later as Form EIA-254. Some supplementary data was taken from compilations of these quarterly utility reports (AEC, various; ERDA, various), and from other reports by various utilities for their own units. Appendix B provides the data for estimates for more than a year into the future, along with the nominal cost overrun and the value of m (the myopia factor) for each estimate.

Table 3.9 presents the nominal cost overrun and myopia factor

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20. I do not yet have the final cost of McGuire 2 and San Onofre 3, which entered service in 1984, and I have not found any source of cost estimates for Connecticut Yankee which gives the month of either the estimates or the projected operation date.

TABLE 3.9: NOMINAL COST OVERRUNS AND MYOPIA FACTORS

Estimated Time to Completion	Number of Estimates	Average Cost Ratio	Average Myopia
(years)			
1 - 1.99	190	1.428	27.1%
2 - 2.99	167	2.055	33.1%
3 - 3.99	91	2.415	27.5%
4 - 4.99	61	2.827	25.1%
5 +	82	3.676	22.6%

for each of several ranges of projected duration, or **t**. As noted above, PSNH's value of **t** is consistent with the industry consensus, given the reported state of completion for Seabrook.

The average estimate in the 2 - 2.99 year range had an actual-to-forecast nominal cost ratio of 2.055, and a myopia factor of 33.1%. Evaluating that myopia factor for the 2.33 year duration projected in 3/84 for Seabrook 1, would result in a cost ratio of 1.947[21]. Multiplying PSNH's forecast cost of $4.55 billion (or $3957/kw) by 2.055 yields a corrected estimate of $9.35 billion (or $8131/kw); using the specific cost ratio derived from the projected duration and the average myopia factor (1.95) produces a corrected estimate of $8.87 billion.

The average cost ratio in the 1 - 2.99 year range was 1.721, and the average myopia factor was 29.9%, which for the two-year duration of the 8/84 estimate predicts a cost ratio of 1.687. Multiplying these cost ratios by the $4.5 billion cost August estimate produces corrected estimates in the range of $7.59 - 7.74 billion.

Q: What were the results of your myopia analysis in real dollars?

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21. $1.331^{2.33}$.

A: Appendix B deflates the estimated and actual nominal costs by the GNP deflator, and calculates the cost overruns and myopia in real terms. Thus, the effects of actual general inflation between the estimated and actual inservice dates are eliminated from the computation. As demonstrated in Chernick, et al. (1981), projections of actual inflation rates have not been very far off for most of the time period of interest; in any case, inflation projections are not available for most of the nuclear cost estimates. The average value of the real cost overrun and the real myopia factor for each group of cost forecasts are reproduced in Table 3.10. For the Seabrook estimate of March 1984, the estimated time to completion was again 2.33 years for Unit 1, so the relevant results are those for t between 2 and 3 years, for which the average real cost ratio was 1.669 Stated alternatively, the cost overrun was 66.9%. The average myopia for those estimates was 22.8%; raised to the 2.33 power, this myopia factor predicts a cost overrun of 61.4%. Applying these cost overruns to the estimate of $4.55 billion produces an adjusted estimate in the range of $7.34 to $7.59 billion in July 1986. Adding 6% inflation to an in-service date of August 1988 raises the cost to $8.29 to $8.57 billion for the unit.

Repeating this analysis for the August 1984 estimate of $4.5 billion, using the average real cost ratio of 1.468 and the

TABLE 3.10: REAL COST OVERRUNS AND MYOPIA FACTORS

Estimated Time to Completion (years)	Number of Estimates	Average Real Cost Ratio	Average Real Myopia
1 - 1.99	190	1.293	19.0%
2 - 2.99	167	1.669	22.8%
3 - 3.99	91	1.865	18.8%
4 - 4.99	61	2.193	18.6%
5 +	82	2.751	17.6%

real myopia factor of 20.8% for the 1 - 2.99 year range (for a cost ratio of $1.208^2 = 1.459$), produces corrected estimates in August 1986 dollars of about $6.6 billion. With two years of inflation, this would be about $7.4 billion.

Q: Have you performed a similar analysis for Seabrook's cost history?

A: Yes. Table 3.11 derives the annual percentage rates of increase in the Seabrook cost estimates[22] from various starting points to the March 1984 estimate. There is no evidence that the annual rate of escalation of PSNH's estimate has stabilized appreciably in recent years. The latest cost estimate represented an average cost trend of around 50% annually, while the average annual percentage increase in the Seabrook cost estimate from 12/76 to 3/80 was only 15%.

Given a COD, and assuming the continuation of a historic rate of escalation in the cost estimate, we can calculate the value of the cost estimate at the time Seabrook enters service. For PSNH's Unit 1 COD estimate of 7/86, 2.33 years of escalation must be added: at 22% annually, this would

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22. The cost data is from PSNH's reports to DOE: the division of costs between units appears to be different than the divisions in PSNH's public pronouncements, supporting my earlier contention that PSNH has (at least recently) manipulated the cost accounting to favor Unit 2.

TABLE 3.11: GROWTH RATES IN PSNH COST ESTIMATES FOR SEABROOK 1, TO MARCH 1984

DATE OF ESTIMATE:	Dec-76	Mar-78	Jan-79	Mar-80	Apr-81	Dec-82	Mar-84
1. MONTHS SINCE LAST ESTIMATE	—	15	10	14	13	20	15
2. MONTHS TO Mar-84	87	72	62	48	35	15	0
3. ESTIMATED COST ($ million)	$1,007	$1,340	$1,294	$1,493	$1,735	$2,540	$4,550
4. INCREASE SINCE LAST ESTIMATE (%)	--	33.1%	-3.4%	15.4%	16.2%	46.4%	79.1%
5. INCREASE SINCE LAST ESTIMATE (ANNUALIZED)	--	25.8%	-4.1%	13.1%	14.9%	25.7%	59.7%
6. INCREASE TO Mar-84 (%)	351.8%	239.6%	251.6%	204.8%	162.2%	79.1%	--
7. INCREASE TO Mar-84 (ANNUAL)	23.2%	22.6%	27.6%	32.2%	39.3%	59.7%	--
8. FINAL COST IF TREND CONTINUES							
a. TO: Jul-86 (million)	$7,403	$7,327	$8,042	$8,730	$9,860	$13,563	--
b. TO: Aug-88 (million)	$11,441	$11,220	$13,385	$15,635	$19,693	$36,023	--

increase the final cost by about 60%, to around $7 billion. Using an optimistic, but realistic, estimate of the COD derived above (8/88), we must add about 2 more years of cost estimate revisions. This translates to a unit cost estimate of $11 billion (or $9500/kw) when the unit goes commercial.

Table 3.12 repeats this analysis, using the August 1984 cost estimate as the end point. If the 20.8% annual escalation continues though August 1986, the plant will cost $6.6 billion; by August 1988, this would reach $9.6 billion.

Q: To what do you attribute the consistent pattern of cost overruns in nuclear construction?

A: One of the problems has certainly been that nuclear power plant cost estimates have been targets for cost control, rather than unbiased predictors or financial guides. This issue is discussed at some length in Meyer (1984). UI has also recognized this problem, as demonstrated by the testimony of its President and other officials before the CPUCA filed 8/1/84:

> The project management estimate, used by the project manager to control construction of the facility, should be established as a challenging but achievable goal. Depending upon the degree of challenge desired, the project management estimate should have a probability of 10% to 30% of not being exceeded . . . [T]he project management estimate serves the need to maintain tight project controls . . .

Unfortunately, much less than 10% of nuclear cost estimates

TABLE 3.12: GROWTH RATES IN PSNH COST ESTIMATES FOR SEABROOK 1, TO AUGUST 1984

DATE OF ESTIMATE:	Dec-76	Mar-78	Jan-79	Mar-80	Apr-81	Dec-82	Aug-84
1. MONTHS SINCE LAST ESTIMATE	—	15	10	14	13	20	20
2. MONTHS TO Aug-84	92	77	67	53	40	20	0
3. ESTIMATED COST ($ million)	$1,007	$1,340	$1,294	$1,493	$1,735	$2,540	$4,500
4. INCREASE SINCE LAST ESTIMATE (%)	--	33.1%	-3.4%	15.4%	16.2%	46.4%	77.2%
5. INCREASE SINCE LAST ESTIMATE (ANNUALIZED)	--	25.8%	-4.1%	13.1%	14.9%	25.7%	41.0%
6. INCREASE TO Aug-84 (%)	346.9%	235.8%	247.8%	201.4%	159.4%	77.2%	--
7. INCREASE TO Aug-84 (ANNUAL)	21.6%	20.8%	25.1%	28.4%	33.2%	41.0%	--
8. FINAL COST IF TREND CONTINUES							
a. TO: Aug-86 (million)	$7,184	$7,074	$7,670	$8,159	$8,879	$10,150	--
b. TO: Aug-88 (million)	$10,810	$10,498	$12,236	$13,756	$16,144	$20,801	--

have been achieved, so the cost control function seems to have been overdone. It also appears that nuclear cost estimates routinely exclude effects of future, pending, and newly effective regulations which have not yet been reflected in the plant drawings, and of the other complications of building a nuclear plant.

Q: Do any of the recent developments in the management of the Seabrook project indicate that any of your results are pessimistic?

A: No. As I noted in the previous section, the new problems Seabrook faces are at least as impressive as are the eventual advantages of the management reorganization. Therefore, it is not clear whether the future experience for Seabrook 1 should be expected to be better or worse than past Seabrook or industry experience. The most substantial basis for optimism is the hope[23] that Mr. Derrickson can repeat some of his relatively successful experience at FP&L. Even if Seabrook 1 were built as close to the current budget as the St. Lucie units were, there would be considerable cost overruns. The cost estimate histories of the four FP&L units are displayed in Table 3.13. Since the St. Lucie units were the ones for which Mr. Derrickson had the greatest responsibility, these seem to be most relevant to an

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23. It is not much more than hope.

TABLE 3.13: COST AND SCHEDULE ESTIMATE HISTORIES
FP&L NUCLEAR UNITS

Unit Name	Date of Estimate Year	Qtr	Estimated Cost	COD		Years to COD	Cost Ratio	Myopia	Duration Ratio
Turkey Point 3	67	3	66	70	?	2.75	1.65	1.199	1.909
Turkey Point 3	69	3	99	71	?	1.75	1.10	1.055	1.857
Turkey Point 3	70	1	111	71	?	1.25	0.98	0.983	2.200
	Actual		109	72	12				
Turkey Point 4	67	3	66	71	?	3.75	1.92	1.190	1.600
Turkey Point 4	69	3		72	?	2.75			1.455
Turkey Point 4	70	1	80	72	?	2.25	1.58	1.227	1.556
Turkey Point 4	70	4	81	72	?	1.50	1.57	1.348	1.833
Turkey Point 4	71	1	83	72	?	1.25	1.53	1.403	2.000
Turkey Point 4	71	2	96	72	?	1.00	1.32	1.321	2.250
Turkey Point 4	71	4	126	72	12	1.00	1.01	1.006	1.750
	Actual		127	73	9				
St. Lucie 1	69	2	123	73	6	4.00	3.95	1.410	1.750
St. Lucie 1	69	3	123	73	5	3.67	3.95	1.455	1.841
St. Lucie 1	70	4	200	74	6	3.50	2.43	1.289	1.571
St. Lucie 1	71	2	203	74	6	3.00	2.39	1.338	1.667
St. Lucie 1	71	4	218	74	6	2.50	2.23	1.378	1.800
St. Lucie 1	72	1	235	74	6	2.25	2.07	1.381	1.889
St. Lucie 1	72	2	269	75	5	2.92	1.81	1.225	1.371
St. Lucie 1	72	4	318	75	5	2.42	1.53	1.192	1.448
St. Lucie 1	73	1	318	75	6	2.25	1.53	1.207	1.444
St. Lucie 1	73	4	318	75	12	2.00	1.53	1.236	1.250
St. Lucie 1	74	2	366	75	12	1.50	1.33	1.208	1.333
St. Lucie 1	74	4	401	75	12	1.00	1.21	1.212	1.500
	Actual		486	76	6				
St. Lucie 2	72	4	360	78	10	5.83	3.97	1.267	1.829
St. Lucie 2	73	1	360	79	12	6.75	3.97	1.227	1.543
St. Lucie 2	74	1	360	80	12	6.75	3.97	1.227	1.395
St. Lucie 2	74	2	360	79	12	5.50	3.97	1.285	1.667
St. Lucie 2	74	4	537	79	12	5.00	2.66	1.216	1.733
St. Lucie 2	75	3	537	80	12	5.25	2.66	1.205	1.508
St. Lucie 2	75	4	620	80	12	5.00	2.31	1.182	1.533
St. Lucie 2	76	3	620	82	12	6.25	2.31	1.143	1.107
St. Lucie 2	76	4	850	82	12	6.00	1.68	1.091	1.111
St. Lucie 2	77	2	850	83	5	5.92	1.68	1.092	1.042
St. Lucie 2	78	3	845	83	5	4.67	1.69	1.119	1.054
St. Lucie 2	78	4	919	83	5	4.42	1.56	1.105	1.057
St. Lucie 2	80	2	1100	83	5	2.92	1.30	1.094	1.086
	Actual		1430	83	8				

Notes: All estimates for 1 or more years into the future included.
Unknown months (indicated by "?") assumed to be June.

examination of his record. If Seabrook 1 myopia[24] were as small as that of St. Lucie 2, the cost would still rise by about $(1.086)^{2.33}$ = 21% from the March estimate of $4.55 billion, to about $5.5 billion. If the experience at St. Lucie 1 (like Seabrook 1, a first unit at the site, and not a duplicate) is a better guide, the cost of Seabrook 1 will rise $1.20^{2.33}$ = 53%, to $7.0 billion. Using the informal August 1984 estimate of $4.5 billion as the basis for the projection, St. Lucie 2 experience would predict an increase of 1.086^2 = 18%, to $5.3 billion, and St. Lucie 1 would indicate an increase of 1.236^2 = 53%, to $6.9 billion. Even if we give equal weight to the experience from the two St. Lucie units, the eventual cost of Seabrook 1 would be expected to be $6.1 or $6.2 billion.

Q: What Seabrook construction cost estimates do you find most reasonable?

A: Table 3.14 displays the results of the various methodologies I used. The estimates for Seabrook 1 range from about $6 to $11 billion. Past errors in inflation projections probably account for some of the results at the top end of the range. I will use $6 billion (or $5200/kw), a very optimistic figure, in my subsequent analysis, even though it is hard to see how PSNH can meet that cost target, if any of the

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24. Using the myopia factors for duration expectations closest to Seabrook's.

TABLE 3.14: SUMMARY OF CONSTRUCTION COST PROJECTIONS (in $ billion)

METHOD	C.O.D.	PROJECTED CONSTRUCTION COST based on cost estimate of: 3/84	8/84
1. Real Myopia			
	PSNH	$7.4	$6.6
	Realistic [1]	$8.4	$7.4
2. Nominal Myopia			
	Cost Ratio	$9.4	$7.6
	Myopia Factor	$8.9	$7.7
3. Seabrook Cost Estimate History			
	PSNH	$7.3	$6.6
	Realistic [1]	$11.2	$9.6
4. St. Lucie Experience		$6.2	$6.1

Notes: [1] C.O.D. of August, 1988.

historical trends continue.

Q: How do these total cost figures compare to the cost of completing Seabrook?

A: A portion of the total construction costs are sunk: either invested in property which cannot be sold to recover the cost, or committed in contracts which cannot be fully voided. PSNH reports having spent $1,063,600 on Seabrook 1 through 5/31/84, which would bring the total cost of the plant to that date to about $2.99 billion (assuming that PSNH's AFUDC rate was close to the average). Including cash expenditures of $15 million in June and $4 million per week for the remaining 26 weeks of the year, and AFUDC of 5.7% (10% AFUDC rate for 7/12 year) of the May balance, the total investment in Seabrook 1 by the end of 1984 will be about $3.3 billion, leaving a cost to go of at least $2.7 billion, and probably much more.

3.4 - CAPACITY FACTOR

Q: How can the annual kilowatt-hours output of electricity from each kilowatt of Seabrook 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 PSNH are wholly unrealistic, it may be helpful to consider the role of capacity factors in determining the cost of Seabrook power, before estimating those factors.

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

$$CF = Output/(RC \times hours)$$

where CF = capacity factor, and

RC = rated capacity.

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

On the other hand, an availability factor 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 3.2. 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.

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

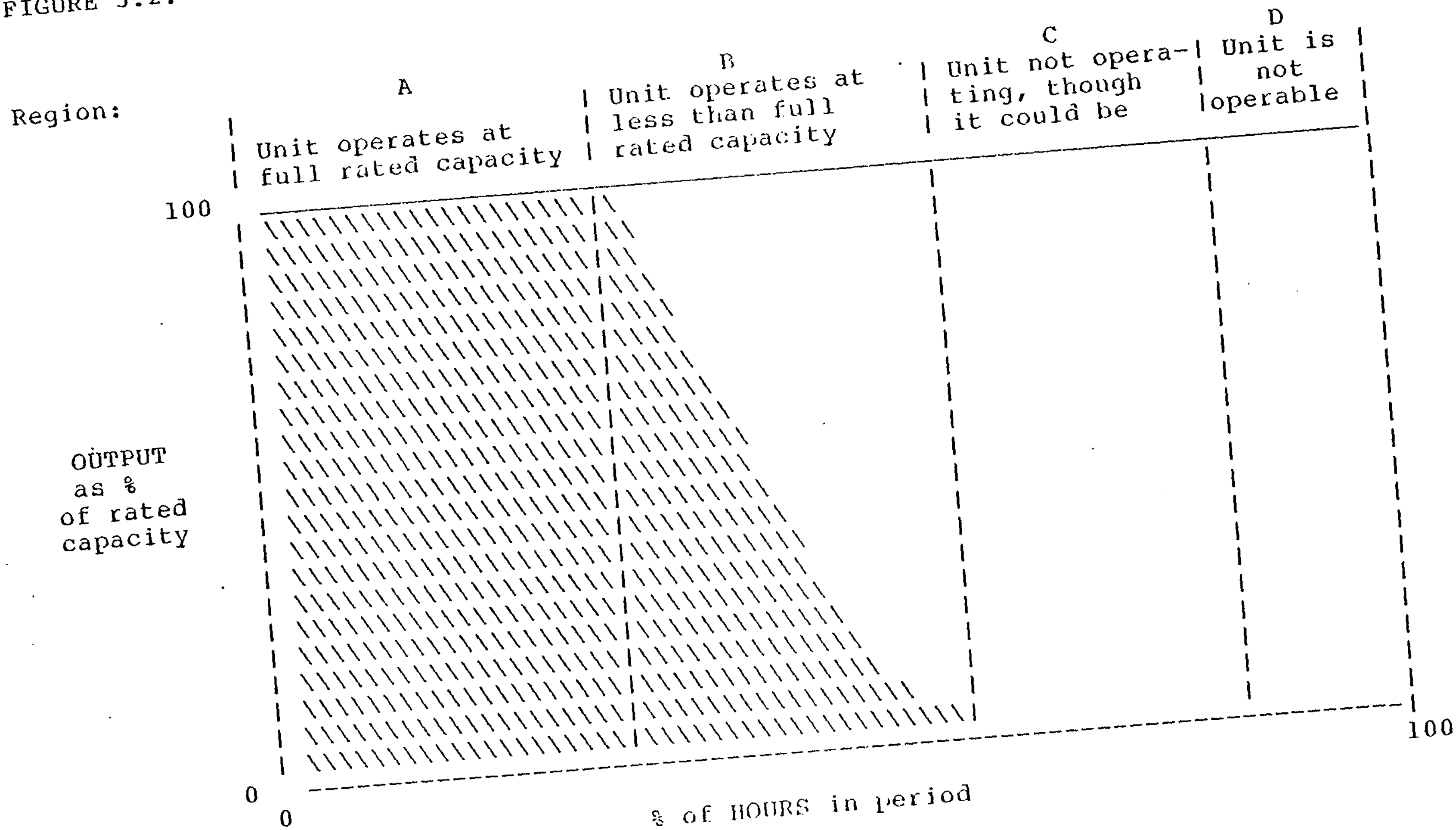
A: The three most common measures of capacity are

Maximum Dependable Capacity (MDC);

Design Electric Rating (DER); and

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

FIGURE 3.2: 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)

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 IGN, which are fixed at the time the plant is designed and built. Furthermore, many plants' MDC's have never reached their DER's or IGN's.

Humboldt Bay has been retired after fourteen years, and Dresden 1 after 18 years, without getting their MDC's up to their DER's. 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 DER's, throughout the unit's life.

The use of MDC capacity factors in forecasting Seabrook power cost would present no problem if the MDC's for Seabrook were known for each year of its life. Unfortunately, these capacities will not be known until Seabrook actually operates and its various problems and limitations appear. All that is known now are initial estimates of the DER and IGN, which I take to be 1150 MW and 1194 MW, respectively. Since it is impossible to project output without consistent definitions of Capacity Factor and Rated Capacity, only DER and IGN capacity factors are useful for planning purposes. Using MDC capacity factors with DER ratings is as inappropriate as multiplying a kilometers/liter fuel efficiency measure by miles to try to estimate gallons of gasoline consumed; the units are different, and in the case of MDC, unknown.

Actually, DER designations have also changed for some plants. The new, and often lower, DER's will produce different observed capacity factors than the original DER's. For 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 1150 MW expectation for Seabrook. This problem can also be avoided through the use of the MGN ratings.

Q: Are PSNH's projections of Seabrook capacity factors (60% in the first partial year of operation, rising to 70% in year seven) reasonable?

A: No, they are significantly overstated. PSNH (like most of the New England utilities) ignores all previous analyses of reactor performance, and instead bases its projections on a 1973 EBASCO estimate, which used no actual data, modified slightly to partially reflect New England experience with much smaller units through the mid-1970's.

Q: Have any studies been performed of the historic capacity factors for operating reactors?

A: Yes. Several statistical analyses of the capacity factors of actual operating nuclear plants have been performed, including those for the Council on Economic Priorities (CEP) (Komanoff, 1978), Sandia Laboratories studies for the NRC (Easterling, 1979, 1981), a series of studies by National Economic Research Associates (NERA) (Perl, 1978, 1982; NERA, 1984), and my own analyses of PWR capacity factors.

The CEP study utilized data through 1977 and projected a levelized capacity factor for the first ten full operating years for Westinghouse 1150 MW reactors at 54.8%. This projection is based on a statistical analysis which predicts a 46.1% capacity factor in year 1, rising to 62.3% in year 10. An alternative model found that capacity factors actually peak in year 5, at 59.1% and slowly decline to 55.2% in year 10, indicating that maturation does not continue to improve capacity factors indefinitely. However, in recognition of a perceived improvement in plants completed after 1973, Komanoff increases his 10 year levelized projection by 1.8 percentage points, over the historic trend.

The first NRC study projects capacity factors on the basis of maximum generator nameplate (MGN). The prediction for an 1194 MW (MGN) PWR, expressed in terms of an 1150 MW DER, would be 51.6% in the second full year of operation, 55.0% in the third full year, and 58.3% thereafter. No further maturation was detected. All results for the first partial year and first full year of operation are excluded. Assuming that first year capacity factors are as good as second year capacity factors, a plant with a 30-year life would average 57.7% over its life, or 56.1% levelized at a 10% discount rate.

The second NRC study uses the same methodology and reaches similar, if somewhat more pessimistic, conclusions. Easterling develops several equations for PWR's, using different data sets and different maturation periods, and concludes that maturation may continue through year 5. Table 3.15 shows the results of the equations which can be evaluated for Seabrook. The first equation uses all data and

TABLE 3.15: CAPACITY FACTOR EQUATIONS AND PROJECTIONS FROM EASTERLING

Equation	3.1	3.2	3.3	3.4
Coefficients:				
Constant	75.7	73.1	77.3	68.3
AGE	3.4	4.0		
AGE5			2.4	2.3
MGN/100	-3.5	-3.3	-3.2	-2.3
Capacity Factor Value at Age:				
2	42.3	43.3	45.6	47.2
3	45.8	47.4	48.1	49.6
4	49.3	51.6	50.6	52.0
5	49.3	51.6	53.0	54.3
25-yr levelized	47.7	49.7	51.0	52.4
35-yr levelized	47.8	49.8	51.1	52.5

Notes: [1] AGE takes values 2, 3 and 4.
[2] AGE5 takes values 2, 3, 4 and 5.

four-year maturation, the second excludes three unit-years of particularly poor performance, the third introduces 5-year maturation, and last excludes all data from units under 700 MW. Levelized average capacity factors from these equations range from 48% to 53%.

The first NERA study presents capacity factor estimates of 63.6% for 1100 MW PWR's and 63.1% for 1200 MW plants, again excluding initial partial years of operation. These figures appear to represent levelized averages of the values generated by a regression equation, which predicts 1150 MW plant capacity factors of 54.8% in year one, rising to 66.5% in year 30. As previously noted, however, the projection of continued maturation past year 10 (or even year 5) is not supported by the historic record. The NERA projection for year 10 is 65.3% and that for year five is 63.8%.

The second NERA study uses a very different functional form in the capacity factor equation, and mixes in BWR's and some very small units.[25] The equation predicts capacity factors for a unit like Seabrook of 53% in the first year, rising to

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25. In general, these very small units do not fall on the size trend of the larger units. In fact, it may be impossible for them to do so, since extrapolating the size trends observed in the 500 - 1000 MW range back to the 100-MW range may produce capacity factor projections close to or exceeding 100%. As a result, small units are apt to reduce the estimated size coefficient.

63% in year 5. The NERA study itself uses a 59% overall capacity factor in its cost calculations.

The most recent NERA study (NERA 1984) performs a regression analysis on PWR's alone, but still includes some very small units. Data through 1981 is used in the regression, but only the best performance, observed in the period 1975 to 1978, is actually used in the projection. On this basis, NERA concludes that the appropriate levelized capacity factor for 1150 MW PWR's is 60%. This is a rather optimistic assumption, excluding some 59% of NERA's data, primarily to remove all effects of the problems of 1979-81. These problems included the effects of the Three Mile Island accident, which in itself can hardly be considered unique; the frequency of major accidents will be discussed below. Other problems in the post-1979 period had nothing to do with the TMI accident: examples include the computational errors in earthquake-resistant design features discovered in 1979[26], problems with steam-generator corrosion and pipe cracking, and the failure of SCRAM mechanisms at Salem. Assuming that the future is like the average of NERA's data,[27] the levelized projection would be some 5.8 percentage points lower, or about 54.2%.

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26. These errors resulted in lengthy shutdowns for several units, including Maine Yankee.

27. Of the data used in the regression, 24% was prior to 1975, 41% was from 1975-78, and 35% was from 1979-81.

I have performed a series of regressions on the performance of domestic PWR's of more than 400 MW capacity.[28] The basic data set included all full unit-years through 1982, for all units except for Palisades (which was the object of the original study). Since Palisades has been a particularly poorly-performing unit, including it would probably decrease capacity factor projections. A total of 312 unit-years were thus available.

Two types of analysis were conducted in this study. First, I analyzed all the available data, regressing capacity factor against plant age and size. This analysis produced the equations shown in Table 3.16. Equation 2 varies from Equation 1 by the limitation of the maturation effect to the first five years of unit life. Equation 2 is preferable to Equation 1, both statistically and in terms of prior expectations,[29] but the age variable is still weak, both statistically and practically.

Second, I examined the post-1978 data, to determine whether there were any post-TMI effects which might be confounding

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28. Throughout this comparative analysis, I used the original DER rating (or the earliest one I could identify), as reported for each unit to the AEC or NRC.

29. Power plant performance is expected to improve with maturation, not deteriorate.

TABLE 3.16: SIMPLE REGRESSIONS ON PWR CAPACITY FACTORS

	EQUATION 1		EQUATION 2	
	Coefficient	t-statistic	Coefficient	t-statistic
Constant	83.84%		78.99%	
Size [1]	-0.03%	-6.0	-0.03%	-5.8
Age [2]	-0.09%	-0.3	-	-
Age5 [3]	-	-	0.91%	1.6
Adjusted R	0.324		0.334	
F-stat	19.3		20.6	

Notes: [1] Size = DER MW rating
[2] Age = years from commercial operation to middle of current year.
[3] Age5 = minimum of Age and 5

the age variable,[30] and which might also have practical significance. This analysis produced the equations shown in Table 3.17. Indeed, performance in each year from 1979 on has been significantly worse (in both the statistical and practical senses of "significant") than performance in the pre-TMI period. The best estimate of the effect varies from year to year, but these differences are small compared to the variation in each year; the best overall fit is achieved by Equation 5, which treats all of the post-TMI years as equivalent. If future conditions continue as they have since 1979, Equation 5 would project a 42.5% capacity factor for Seabrook in its first full year, rising to 53.7% in the fifth year and thereafter. If conditions revert to pre-1979 status, capacity factors for Seabrook would be expected to be 7.5 percentage points higher.

Therefore, average life-time capacity-factor estimates for units like Seabrook would seem to lie in the range of 50% to 60%, 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 the first NRC study derived 95% prediction intervals of about 10% in years 2 to 5, 8% in years 2 to 10, and 7.3% for years 2 to 28. Roughly speaking,

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30. Post-TMI data will tend to be data later in unit life.

TABLE 3.17: PWR CAPACITY FACTOR REGRESSIONS WITH YEAR DUMMIES

	EQUATION 3 Coef.	t-stat.	EQUATION 4 Coef.	t-stat.	EQUATION 5 Coef.	t-stat.
Constant		0.731		0.731		0.730
Size [1]	-0.02%	-4.3	0.02%	-4.3	-0.02%	-4.3
Age5	2.23%	3.2	2.23%	3.2	2.24%	3.3
Year Dummies [2]						
1979	-7.37%	-2.5	-7.36%	-2.5	-	-
1980	-8.99%	-2.9	-8.99%	-2.9	-	-
1981	-6.01%	-1.9	-	-	-	-
1982	-7.63%	-2.5	-	-	-	-
1981 or 1982	-	-	-6.84%	-2.7	-	-
1979 - 1982	-	-	-	-	-7.50%	-3.5
Adjusted R		0.369		0.372		0.378
F statistic		9.2		11.0		18.2

Notes: [1] Size = Design Electrical Rating (DER) in MW.
[2] Dummy = 1 in this year, 0 otherwise.

those earlier, more optimistic NRC results predict that 19 out of every 20 nuclear units of the Seabrook size and type would have average lifetime capacity factors between 50.3% and 64.9%, with the 20th unit having a capacity factor outside that range. Actually, the variation would be somewhat larger, due to the greater variation in the first partial year and the first full year.[31]

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

A: Easterling's studies are fully reviewable (unlike the NERA studies) and were conducted to advocate nuclear power development (unlike the CEP study), so based on these studies, I feel most comfortable using the levelized value of 52% from the most optimistic equation in Easterling (1981). This value is also consistent with my own analysis.

Q: Do PSNH or the Maine utilities project reasonable capacity factors for Seabrook?

A: No. Table 3.18 displays the difference between PSNH's projections, BHE's projections (the only available annualized projections from the Maine utilities), and Easterling's results. CMP uses flat capacity factors of 60% and 73% in

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31. 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.

TABLE 3.18: COMPARISON OF CAPACITY FACTOR PREDICTIONS

		Calendar Years of Experience						
		1	2	3	4	5	6	7+
Predicted Capacity Factors:		[2]						
Easterling [1]		47.2%	47.2%	47.2%	49.6%	52.0%	54.3%	54.3%
PSNH		60.0%	63.0%	65.0%	65.0%	65.0%	65.0%	70.0%
Bangor Hydro [3]		59.0%	61.7%	61.7%	63.3%	65.0%	66.6%	66.6%
		Unit Years of Experience in each Calendar Year						
As of:	31-Dec-83							
	COD							
Salem 1	30-Jun-77	0.51	1.00	1.00	1.00	1.00	1.00	1.00
Zion 1	31-Dec-73	0.00	1.00	1.00	1.00	1.00	1.00	5.01
Zion 2	17-Sep-74	0.29	1.00	1.00	1.00	1.00	1.00	4.00
Cook 1	27-Aug-75	0.35	1.00	1.00	1.00	1.00	1.00	3.01
Cook 2	01-Jul-78	0.50	1.00	1.00	1.00	1.00	1.00	0.00
Trojan	20-May-76	0.62	1.00	1.00	1.00	1.00	1.00	2.00

Notes:
[1] See Table 3.15: Equation 3.4.
[2] First partial year.
[3] From BHE Docket # 84-113, Staff Request No.3, Item 13.

its two cost cases, with no maturation, while I have been unable to locate any independent projection by MPS, which generally appears to adopt CMP assumptions. The capacity factors assumed by PSNH and BHE (and indeed by most New England utilities) are much too high. This should not be very surprising: PSNH's projections are based on the NEPOOL GTF assumptions, which were derived in 1973 without the use of any actual nuclear capacity factor data. The high-end CMP projection is similarly unrealistic, while the low-end projection is only somewhat optimistic.

As a check on the accuracy of the NRC/Easterling capacity factors, compared to the utility projections, I have performed the calculations presented in Table 3.19. For the six PWR's over 1000 MW which had entered service by 1979 (all of which have Westinghouse reactors, as does Seabrook), the average capacity factor through 1983 was 56.3%. The capacity factor estimates which I derived from Easterling (1981) predict an average of 53.0%, while PSNH would predict an average of 66.1%, and BHE would predict 64.4%. Clearly, the utility expectations (with the possible exception of CMP's 60% figure) are out of line with reality. While the performance of these six units slightly exceeds Easterling's projections, it is not clear which is the better predictor. Easterling has more data, especially in mature years, but includes smaller units. The actual six-unit average will

TABLE 3.19: COMPARISON OF CAPACITY FACTOR PROJECTIONS

Unit	Original DER MW	Actual [1]	Easterling [2]	PSNH	BHE [3]
Salem 1	1090	48.2%	51.9%	65.1%	63.7%
Zion 1	1050	56.4%	54.6%	67.3%	65.1%
Zion 2	1050	58.6%	54.2%	66.8%	64.8%
Cook 1	1090	60.3%	52.9%	66.4%	64.5%
Cook 2	1100	64.2%	51.0%	64.2%	63.2%
Trojan	1130	50.1%	51.4%	65.6%	64.1%
Average [4]		56.3%	53.0%	66.1%	64.4%

Notes:
1. Cumulative Net Elec. Energy/ Report Period Hours/ DER; From NRC Gray Book, Dec. 31,1983.
2. Includes 2.4 points per 100 MW decrease in size.
3. Using data from BHE Docket No. 84-113
4. Weighted by experience.

vary with refueling schedules and has less data. At most, the actual data suggests a 2.7% upward revision in the Easterling actual, to a levelized average of about 54.7%.

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

A: Yes. Table 3.20 presents the annual capacity factors for the units used in the previous analysis, through December 1983. The analysis also performed with the addition of the four large PWR's which entered commercial operation in 1981. I have accepted a suggestion[32] that the very low capacity factors for Trojan in 1978 and for Salem 1 in 1979 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 problem can not occur for Seabrook.[33] Hence, I delete these two observations from the individual year calculations, and instead reflect the probability of a major problem by computing the average effect. For example, compared to the results for all the other plants, these two events reduced capacity factors by an total of 65.8 percentage points from

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32. The suggestion was originally made by Northeast Utilities, in Calderone (1982), which is one of the sources for BHE's capacity factor analysis. Tables 3.20 and 3.21 are essentially corrections of Calderone's study.

33. In fact, it appears that something <u>worse</u> has happened at Salem 2 in 1983.

TABLE 3.20: HISTORICAL CAPACITY FACTORS (DER)
Nuclear Units Similar in Characteristic to Seabrook
Unadjusted data.

UNIT	DER NET [3]	first year	1	2	3	4	5	6	7	8	9	10
			CAPACITY FACTOR BY CALENDAR YEAR [2]									
ZION 1	1050	74	37.8%	53.4%	51.6%	54.7%	73.6%	60.2%	70.6%	67.3%	51.0%	43.7%
ZION 2	1050	75	52.5%	50.3%	68.2%	73.2%	51.8%	57.2%	57.2%	56.1%	67.2%	
COOK 1	1090	76	71.1%	50.1%	65.8%	59.3%	67.5%	71.0%	56.1%	55.4%		
TROJAN	1130	77	65.6%	16.8%	53.2%	61.2%	64.9%	48.5%	41.2%			
SALEM 1	1090	78	47.4%	21.4%	59.4%	64.8%	42.9%	56.3%				
COOK 2	1100	79	61.8%	69.3%	66.3%	72.6%	72.8%					
SEQUOYAH 1	1148	82	48.8%	73.0%								
SALEM 2	1115	82	81.3%	7.5%								
MCGUIRE 1	1180	82	41.6%	44.8%								
SEQUOYAH 2	1148	82	50.8%	89.0%								
AVERAGES: ALL UNITS [1]	1106		55.9%	52.0%	60.7%	64.3%	62.2%	58.7%	56.3%	59.6%	59.1%	43.7%
FIRST SIX	1085		56.0%	55.8%								

Notes:
[1] Values for year 2 for Trojan and Salem 1 are excluded from average.
[2] Computed from NRC-reported net output and original DER.
[3] Original reported value.

average second year performance, in 53.0 unit-years of experience, for a 1.2% reduction in all capacity factors. This calculation is shown in Table 3.21. Depending on the data set used, the average capacity factor which results from this analysis is 56.9% to 57.6%; the mature capacity factor is actually lower, in the 55.8% to 56.1% range. This approach also indicates that Easterling's results are very close to the performance of large PWR's, and that CMP's 60% capacity factor projection lies at the high end of the reasonable range. I will use a levelized capacity factor of 55% in subsequent analyses.

TABLE 3.21: ADJUSTMENT OF 1000-MW PWR CAPACITY FACTORS FOR DEVIATIONS AT SALEM 1 AND TROJAN

BY CALENDAR YEAR	1	2	3	4	5	6	7	8	9	10
AVERAGE ALL UNITS [1]	55.9%	52.0%	60.7%	64.3%	62.2%	58.7%	56.3%	59.6%	59.1%	43.7%
Salem/Trojan deviation [2]		65.8%								
unit-years [3]		53								
deviation/unit-year		1.2%								
Average adjusted for Salem/Trojan [5]	54.6%	50.8%	59.5%	63.1%	61.0%	57.4%	55.0%	58.4%	57.9%	42.4%
all years	56.9%									
>5 years	56.2%									
AVERAGE FIRST SIX UNITS [1]	56.0%	55.8%	60.7%	64.3%	62.2%	58.7%	56.3%	59.6%	59.1%	43.7%
Salem/Trojan deviation [4]		73.3%								
unit-years [3]		43.5								
deviation/unit-year		1.7%								
Average adjusted for Salem/Trojan [5]	54.3%	54.1%	59.1%	62.6%	60.6%	57.0%	54.6%	57.9%	57.4%	42.0%
all years	57.5%									
>5 years	55.7%									

3.5 - CARRYING CHARGES

Q: What annual carrrying charge should be applied to the cost of Seabrook?

A: For the real-levelized cost analysis, I have assumed a 10% real cost of capital (including income taxes)[34] and a unit lifetime of 25 years, as a compromise between possibilities of 20 years and 30 years. The shorter lifetime is based on an analysis of the experience of smaller nuclear units, as discussed in Chernick, et al. (1981, pp. 101-109), while the longer lifetime is a more standard industry assumption.[35] I also use a 1% levelized property tax rate. Over 25 years, the levelized annual fixed charges for capital, and depreciation would be 11%, or 12% with property taxes. With this fixed charge rate and a 55% capacity factor, each $1000/kw results in a levelized carrying cost of 2.49 cents/kWh, so $4000/kw yields a carrying charge of 10 cents/kWh, for example.

Q: What other costs must be added to the Seabrook carrying costs to determine the total cost of Seabrook power?

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34. This choice seems somewhat low at this point.

35. In addition to the small units which were discussed in Chernick, et al., 1981, San Onofre 1 has been out of service for about two years and may also have been retired de facto after only 14 years of service.

A: The other components of the costs of Seabrook which are directly assignable to that plant are:

- fuel;
- non-fuel operation and maintenance (O&M) expense;
- interim replacements (capital additions);
- insurance; and
- decommissioning.

3.6 - FUEL COST

Q: What nuclear fuel costs have you used?

A: I used BHE's estimates of Seabrook fuel costs, which start at 1.0 cent/kWh in 1987, and rise at 7.5% annually. Deflating these costs at 6% (which seems to be the generally accepted inflation projection) and levelizing the constant-dollar results (at 10%) yields nuclear fuel costs of about 1.13 cents/kWh in 1987 dollars, or 0.95 cent/kWh in 1984 dollars.[36] The costs would probably be higher on a realistic schedule, due to the increased interest costs.

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36. I assume 4% general inflation in 1984 and 6% thereafter.

3.7 - NON-FUEL O & M

Q: Are the estimates by PSNH and the Maine utilities of Seabrook non-fuel O & M expense reasonable?

A: No. PSNH and BHE base their O & M cost forecasts on recent O & M costs for Maine Yankee, but assume that nuclear O & M increases only at about the inflation rate, despite very rapid historical growth rates in nuclear O & M. Table 3.22 reports the annual O & M for the Millstone, Pilgrim and Yankee units since their first full year of operation.[37] The average annual growth rate in the O & M figures reported for New England nuclear units through 1982 ranges from 16% to 27% for the various units, in nominal terms. Table 3.22 also displays the GNP inflation index for each year, and the constant-dollar escalation of the O & M expenses. Even after subtracting inflation, O & M expense has been rising at 8% to 18% annually.

Table 3.23 presents the 1982 O & M cost for each of the six commercial-sized New England nuclear units. The table also presents the least-squares estimates of annual linear growth

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37. The very small Yankee Rowe unit is omitted, but the time pattern of its O&M costs is quite similar to those of the larger units.

TABLE 3.22: NEW ENGLAND NUCLEAR O & M HISTORIES

Year	Conn. Yankee	Mill-stone 1	Mill-stone 2	Pilgrim	Vermont Yankee	Maine Yankee	GNP Deflator
				($ thousand)			
1968	2,047						82.54
1969	2,067						86.79
1970	4,479						91.45
1971	3,279						96.01
1972	3,749	7,677					100.00
1973	6,352	7,635		4,797	4,957	4,034	105.75
1974	4,935	9,808		9,527	5,692	5,232	115.08
1975	9,381	12,065		7,340	7,682	6,301	125.79
1976	9,419	14,040	10,929	16,633	7,912	5,261	132.34
1977	9,448	12,637	17,377	15,320	9,775	8,418	140.05
1978	8,736	16,448	22,288	14,187	11,191	10,817	150.42
1979	18,923	23,060	21,931	18,387	14,208	9,971	163.42
1980	35,155	24,784	30,163	27,785	22,586	14,028	178.42
1981	37,488	33,270	28,877	34,994	26,795	20,576	195.14
1982	35,722	33,463	45,247	42,437	33,764	28,556	206.88
Annual Growth Rate to 1982:							
Nominal:	22.7%	15.9%	22.5%	27.4%	23.8%	24.3%	7.7%
Real:	14.87%	7.74%	17.62%	18.25%	14.87%	15.36%	

TABLE 3.23: CALCULATION OF AVERAGE NEW ENGLAND EXPERIENCE
Non-Fuel Nuclear O & M Expense, Constant Dollars

Unit	Period Analyzed	1982 O & M	Least - Squares Annual Growth: Linear Increase	Least - Squares Annual Growth: Geometric Increase
		(1000)	(1000 1983$)	
Conn. Yankee	1969-82	$35,722	$2,477.2	15.4%
Millstone 1	1972-82	$33,463	$2,102.8	9.0%
Millstone 2	1976-82	$45,247	$3,674.1	12.9%
Pilgrim	1973-82	$42,437	$3,327.2	15.3%
Vermont Yankee	1973-82	$33,764	$2,712.6	15.1%
Maine Yankee	1973-82	$28,556	$2,008.6	13.7%
AVERAGES:				
1982$		$36,532	$2,717.1	13.5%
1984$ [1]		$39,600		

Notes: [1] 1984$=1982$*1.0423*1.04

(in 1983 dollars) and of annual geometric growth rates,[38] and the six-unit average of each parameter. Each unit is analyzed from its first full year of service through 1982.

Table 3.24 extrapolates the linear and geometric average trends and displays the 1987 nominal O & M cost and the levelized O & M cost (in 1984$) for Seabrook over a 25 year life. Protracted geometric growth in real O & M cost would probably lead to retirement of the all nuclear units around the turn of the century, as they would then be prohibitively expensive to operate (unless the alternatives managed to be even more expensive).

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. To be on the optimistic side, I have assumed a continuation of the linear trends in New England nuclear cost escalation,

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38. The curves all fit the data fairly well; if there is an overall difference in fit, it is the geometric curves which better follow the data.

TABLE 3.24: ANNUAL NON-FUEL O & M EXPENSE FOR SEABROOK
Extrapolated from New England Experience

Year	LINEAR 1983 $ (thousand)	LINEAR Current $ (thousand)	GEOMETRIC 1983 $ (thousand)	GEOMETRIC Current $ (thousand)
1987	$54,033	$66,431	$74,917	$92,458
1992	$68,327	$110,413	$141,235	$228,230
1997	$82,621	$179,513	$266,260	$578,511
2002	$96,915	$283,121	$501,959	$1,466,396
2007	$111,208	$436,816	$946,305	$3,716,987
2012	$125,502	$662,810	$1,783,995	$9,421,733
2017	$139,796	$992,681	$3,363,230	$23,881,990
2022	$154,090	$1,471,180	$6,340,439	$60,535,514
LEVELIZED				
1987-2012: [1]	$72,232	$131,270	$277,767	$583,087
1997-2022:	$100,820	$325,042	$987,203	$1,089,408

Notes: 1. Approximately the useful life of Seabrook 1.

which would produce 25-year real levelized O&M costs of about $66/kw in 1984 dollars.

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 O & M trends?

A: I believe that it is. Several more major nuclear accidents or near-misses are likely to occur before the scheduled end of Seabrook operation. Various recent estimates of major accident probabilities range from 1/200 to 1/1000 per reactor year (See Chernick, et al., 1981; Miniarick and Kukielka, 1982). Thus, major accidents can be expected every two to ten years once 100 reactors are operating. If anything, the 1968-83 period has been relatively favorable for nuclear operations.

3.8 - CAPITAL ADDITIONS

Q: What is a reasonable estimate of capital additions to Seabrook?

A: I gathered data 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 1981. The data for each plant includes all years in which no units were added or deleted, and for which the data was not clearly in error. Average plant size in the dataset was 841 MW. The available experience totalled 378 unit-years of operation, and the average annual capital addition was $18.5/kw, or about $21.3 million annually for a Seabrook unit in 1983 dollars, or $19.2/kw in 1984 dollars.

3.9 - INSURANCE

Q: What value have you used for the cost of insuring Seabrook?

A: I have assumed that PSNH obtains the following insurance for unit 1:

1. liability coverage of $160 million, for the 1981 average premium of $380,000;

2. property coverage of $300 million from the commercial pool (ANI//MAERP), at the high-end premium of $1.75 million;

3. additional property coverage of $375 million from the self-insurance pool (NML) for the TMI 1 premium of $1.38 million;

4. replacement power coverage of $156 million from the self-insurance pool (NEIL) for $1.69 million;

5. decommissioning accident coverage of one billion dollars for $2.19 million; and

6. non-accident-initiated premature decommissioning coverage of $250 million for $2.42 million.

All values are 1981 dollars from Chernick, et al. (1981), except for the NEIL premium, which is from the NEIL circular of December 18, 1979. The decommissioning insurance may be from new or existing pools. These coverages have total estimated premiums of $9.81 million in 1981 dollars, or about $11.4 million in 1984 dollars (incuding just GNP inflation). While only the liability and some property coverage are currently required, failure to utilize insurance exposes the ratepayers and stockholders of the owners to additional costs, which may be greater (on the average) than the insurance premium. Indeed, even with all the insurance listed, the owners would still not be fully covered in the event of the total and permanent loss of Seabrook.

On a cents-per-kWh basis, $11.4 million annually is $9.5/kw or 0.2 cents/kWh.

3.10 - DECOMMISSIONING

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

A: Chernick, _et al_. (1981) estimates that non-accidental decommissioning of a large reactor will cost about $250 million in 1981 dollars. This is equivalent to about $311 million in 1984 dollars (using the nuclear inflation figures discussed above), or about $270/kw for Seabrook. 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 earn essentially zero real return, the annual contribution (in 1984 dollars) would be about $9.4 per kw-year over a 25 year life.

3.11 - TOTAL SEABROOK GENERATION COST

Q: What is your estimate of the cost of power from Seabrook?

A: I estimate that the total cost of power from Seabrook 1 will be about 13 or 14 cents/kWh, levelized in 1984 dollars. Excluding sunk costs as of the end of 1984, the remaining cost is still about 6.5 cents/kWh. These figures are derived in Table 3.25. The costs in Table 3.25 are all in 1984 constant levelized dollars, to make them easier to compare to today's prices and the costs of current power supply options. The actual prices charged will include inflation and will not be levelized, unless the PUC chooses to depart dramatically from conventional ratemaking.

TABLE 3.25: TOTAL POWER COSTS FOR SEABROOK

Cost Basis	SEABROOK UNIT #1	
	Entire Cost	Remaining Costs
Cost per kw		
Construction Costs	$4,216	$1,347
Fixed Charge Rate	12.0%	12.0%
Cost per kw-yr		
Annual Capital Costs	$506	$162
Non-fuel O&M	$66	$66
Capital Additions	$19	$19.2
Insurance	$10	$10
Decommissioning	$9	$9
Total Non-fuel	$610	$266
Capacity Factor	55%	55%
Cost per kwh (cents)		
Non-fuel	12.7	5.5
Fuel	1.0	1.0
Total	13.7	6.5

Notes: All costs are levelized in real 1984 dollars.
Assumptions for Unit 1:
Aug-88 COD, Total Cost $6 billion, $3.3 billion sunk.

4 - SEABROOK 1 COSTS: NOMINAL DOLLARS AND RATE EFFECTS

Q: What do the constant-dollar costs you estimated for Seabrook in the previous section imply for the effect of the unit on rates?

A: There are several important implications. First, Seabrook power will be very expensive. The power will cost 23-32 cents/kwh (depending on whose cost and capacity factor estimates are used) in the first year, falling to 15-20 cents around 2000, and then rising again. Second, the plant will raise total rates for the Maine utilities by $100-150 million in its first full year of service, under normal ratemaking, and will not reduce annual revenue requirements until after the year 2000, and probably never (again, depending on which cost estimates are used). Third, the total cumulative rate effect of Seabrook 1 will be a net increase over its useful life; the plant is unlikely to ever pay back the initial investment, even without considering the time value of money. Thus, Seabrook 1 will cost its customers more than it saves them over the first 20 or 25 years of the unit's life. Fourth, Seabrook 1 will never pay back the initial ratepayer investment, in present value dollars. Fifth, using the more realistic assumptions presented in this testimony about capacity factors, construction costs, or O&M expenses, would lead to the conclusion that customers may be better off if the plant were canceled promptly and replaced with existing oil plants and new coal capacity, than if it were completed, even ignoring the special risks of participation in Seabrook.

Q: What is the unit's major benefit to the Maine utilities and to the NEPOOL system?

A: Seabrook 1 is being built almost exclusively for fuel displacement purposes. Like all nuclear units, it will provide lower fuel costs than the oil plants which NEPOOL currently has in abundance.

Q: Have you analyzed the cost-effectiveness of Seabrook 1 as a energy source?

A: I have compared the cost of Seabrook 1 under traditional ratemaking to the cost of the existing oil plants and the new coal plants, which the utilities assume it would displace, under a variety of assumptions regarding Seabrook 1 cost and reliability. This is a fairly lenient type of comparison: an investment may be substantially suboptimal, but still be less expensive than burning oil or building coal capacity. I have not attempted to identify the most economical option for reducing oil use or replacing Seabrook 1; my results indicate that Seabrook is so expensive that even new coal capacity is more economical.

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

A: Table 4.1 lists, and Figure 4.1 displays, BHE and CMP projections of Seabrook 1 fuel costs and BHE's projections of replacement power: either the fuel costs of the oil-burning plants Seabrook 1 would be backing out,[1] or the cost of building and running a new coal plant. The differential against oil starts in 1988 at about 4 cents per kwh, and rises to 13 cents per kwh by 2000, while the nuclear/coal differential starts at 13.6 cents in 1995 and stays fairly stable until almost 2010. These savings are substantial, but they come at the even greater cost of building and operating Seabrook 1. Table 4.1 also compares the total costs BHE and CMP project[2] for Seabrook 1 to BHE's projections of the cost of replacement energy from oil and coal.

Q: How cost-effective is Seabrook 1 under the utilities' current assumptions?

A: It is clear from the information presented in Table 4.1 that

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1. BHE assumes that it would also be paying a capacity charge for the oil plant from 1988 on, but this would not necessarily be the case for all the utilities. CMP, for example, projects adequate capacity into the 1990's, and depending on the rate of load growth and small power development, existing oil plants may continue to be the marginal power supply for CMP (and NEPOOL) through this century.

2. For CMP, I use the more reasonable 60% capacity factor. MPS apparently accepts CMP's analysis.

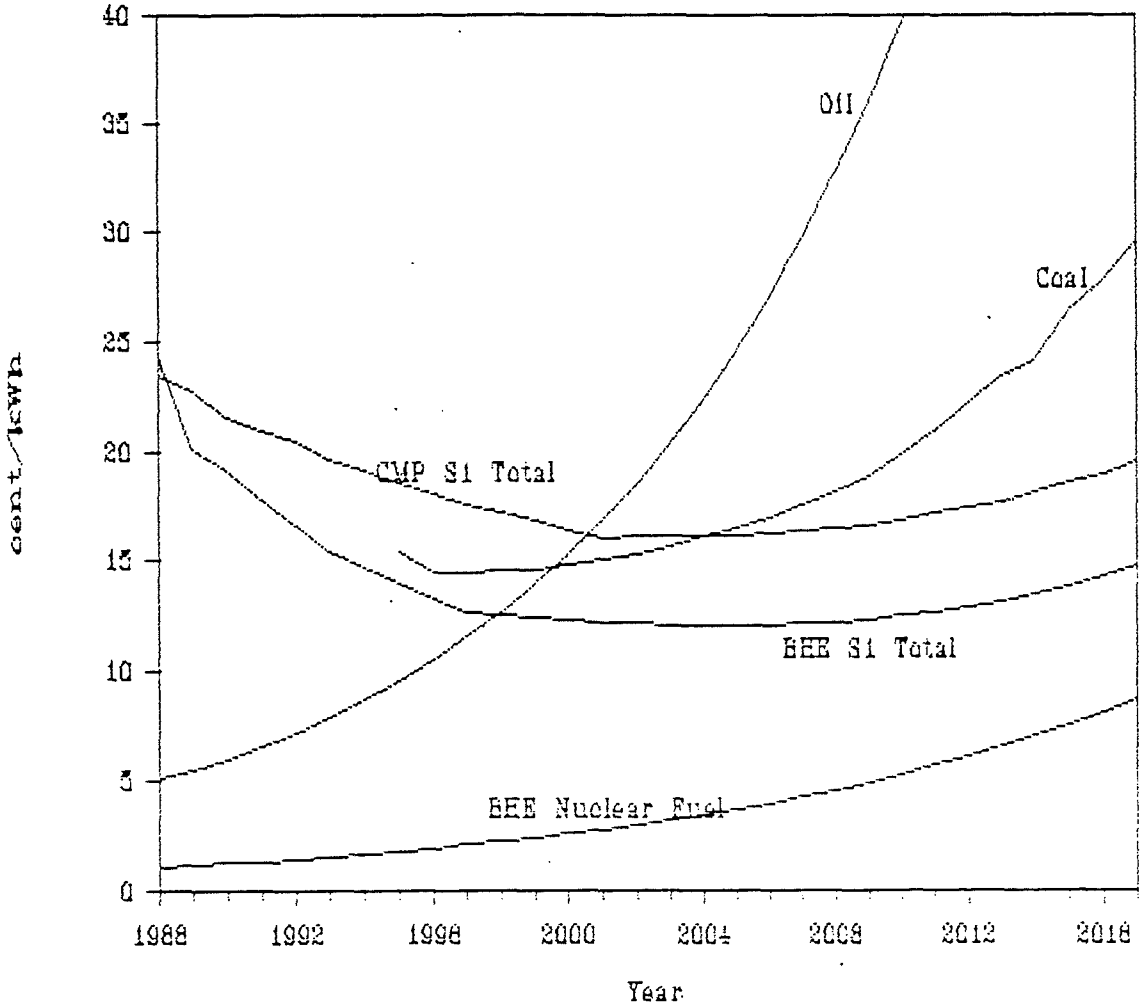
TABLE 4.1: UTILITY PROJECTIONS OF SEABROOK, OIL AND COAL COSTS
in Cts/kWh

Year	Existing Oil Fuel Cost	Total New Coal Plant Cost	Seabrook Fuel Cost		Seabrook Total Cost	
			CMP	BHE	CMP	BHE
	[1]	[2]	[3]	[4]	[5]	[6]
1988	5.1		1.1	1.1	23.5	25.37
1989	5.5		1.2	1.2	22.8	21.30
1990	6.0		1.3	1.2	21.6	20.40
1991	6.6		1.4	1.3	21.0	19.18
1992	7.2		1.5	1.4	20.4	18.01
1993	7.9		1.6	1.5	19.6	16.95
1994	8.7		1.7	1.7	19.2	16.36
1995	9.6	15.4	1.8	1.8	18.5	15.79
1996	10.5	14.5	1.9	1.9	18.1	15.25
1997	11.5	14.5	2.0	2.1	17.6	14.73
1998	12.7	14.6	2.2	2.2	17.2	14.74
1999	13.9	14.6	2.3	2.4	16.8	14.79
2000	15.3	14.8	2.5	2.6	16.4	14.86
2001	16.8	15.1	2.7	2.8	16.0	14.96
2002	18.5	15.3	2.9	3.0	16.1	15.10
2003	20.3	15.7	3.1	3.2	16.1	15.27
2004	22.4	16.1	3.3	3.4	16.2	15.49
2005	24.6	16.5	3.5	3.7	16.2	15.74
2006	27.0	17.0	3.7	4.0	16.3	16.04
2007	29.7	17.6	4.0	4.2	16.4	16.39
2008	32.6	18.2	4.3	4.6	16.5	16.80
2009	35.8	18.9	4.6	4.9	16.7	17.26
2010	39.4	19.9	4.9	5.3	16.9	17.78
2011	43.3	21.0	5.3	5.7	17.2	18.37
2012	47.6	22.2	5.6	6.1	17.5	19.02
2013	52.3	23.5	6.0	6.6	17.7	19.76
2014	57.5	24.2	6.4	7.0	18.2	20.57
2015	63.2	26.4	6.9	7.6	18.6	21.47
2016	69.4	27.9	7.4	8.1	19.1	22.47
2017	76.3	29.7	7.9	8.8	19.6	23.57
			[7]		[7]	

Sources: [1] BHE 3Staff8 and BHE 10PA-68
[2] BHE 3Staff8.
[3] CMP 10PA-61, 60%. 100*Col.4/Col.5
[4] BHE: 1.075 * 7.5% per yr.
[5] 10PA-61, 60%. Col.6
[6] 10PA-61, Exh.61-1. Divided by GWH
[7] Year 2017 extrapolated from previous 2 yrs.

Figure 4.1: Utility Projections

Seabrook, Oil and Coal Costs



even the utilities expect that the costs of Seabrook 1 will exceed the benefits of the unit for most of its useful life. Depending on capacity factor and other assumptions, the utilities project that Seabrook power is more expensive than fossil power until sometime between 2000 and 2005.

Q: Have you calculated the ratemaking cost of Seabrook 1 for the cost and performance figures you derived in the previous section?

A: Yes. Table 4.2 presents the cost of Seabrook 1 in annual cents/kwh for the values I derived above, except that it uses utility assumptions for decommissioning costs and useful life, since it is the utility projections (as modified by the Commission) which will determine these depreciation and decommissioning costs passed on to ratepayers in the short term, although future ratepayers might be left with the bill for earlier and more expensive retirement of the plant.[3] The details of this analysis may be found in Appendix C; it is largely modeled after the analysis by BHE in 1 OPA 61, which is the most detailed cost analysis from the utilites I have had the opportunity to review in this case. Figure 4.2 plots the results of this analysis, along with utility assumptions regarding replacement fuel costs. Under these more realistic

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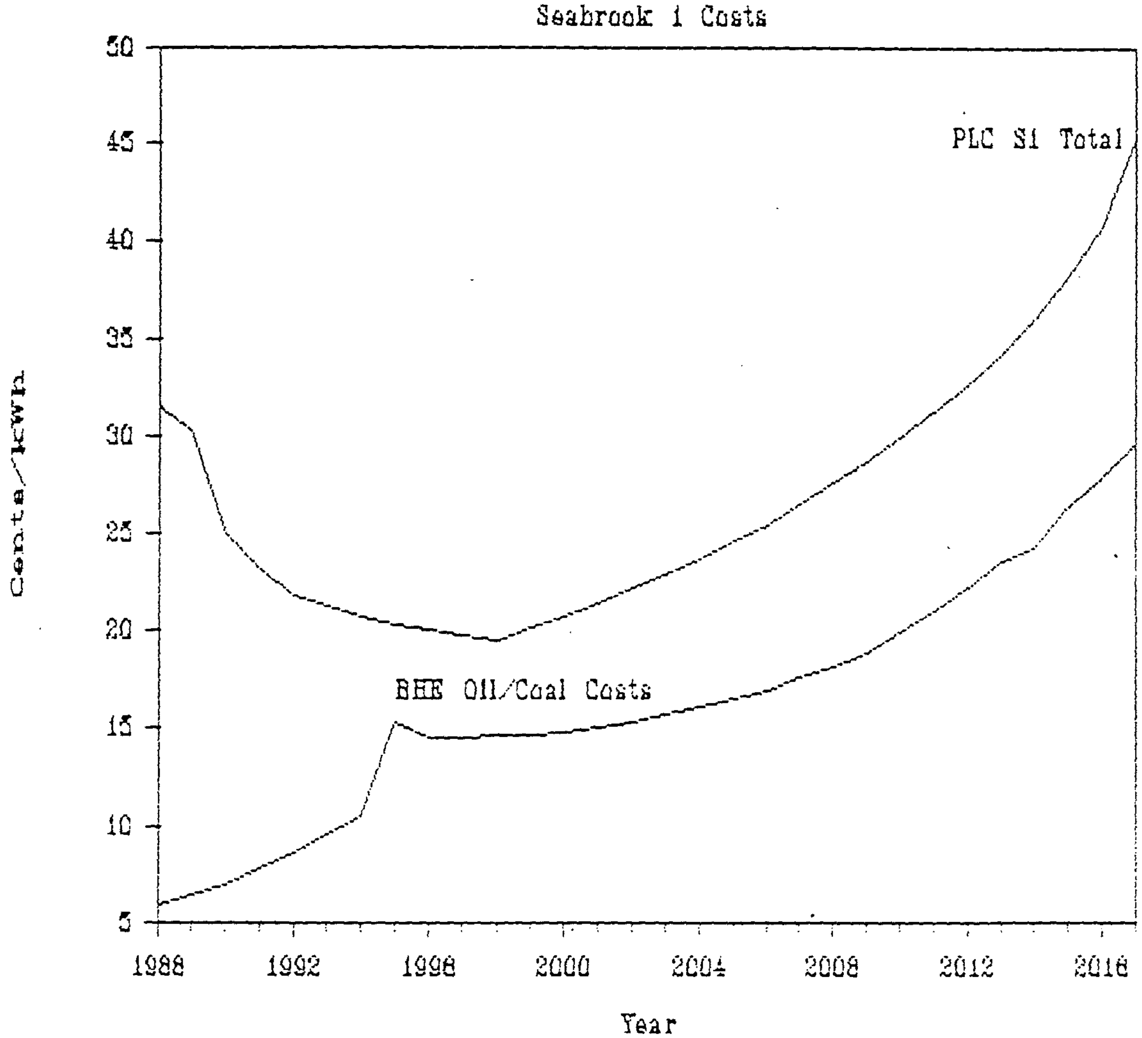
3. Both utility decommissioning allowances and transmission charges are so small that I leave them out of the analysis altogether. Each of them would add a mill or so to the total cost to the ratepayers.

TABLE 4.2: PLC PROJECTIONS OF SEABROOK COSTS
(in Cents/kWh)

Year	Existing Oil Fuel Cost	Total New Coal Plant Cost	BHE Nuclear Fuel	PLC Seabrook Non-Fuel	PLC Seabrook Total
	[1]	[2]	[3]	[4]	[5]
1988	5.1		1.1	30.4	31.5
1989	5.5		1.2	29.1	30.3
1990	6.0		1.2	23.8	25.0
1991	6.6		1.3	21.9	23.2
1992	7.2		1.4	20.3	21.7
1993	7.9		1.5	19.7	21.2
1994	8.7		1.7	19.1	20.7
1995	9.6	15.4	1.8	18.6	20.4
1996	10.5	14.5	1.9	18.1	20.1
1997	11.5	14.5	2.1	17.7	19.8
1998	12.7	14.6	2.2	17.4	19.6
1999	13.9	14.6	2.4	17.8	20.2
2000	15.3	14.8	2.6	18.2	20.8
2001	16.8	15.1	2.8	18.7	21.5
2002	18.5	15.3	3.0	19.2	22.2
2003	20.3	15.7	3.2	19.7	22.9
2004	22.4	16.1	3.4	20.3	23.7
2005	24.6	16.5	3.7	20.9	24.6
2006	27.0	17.0	4.0	21.6	25.5
2007	29.7	17.6	4.2	22.2	26.5
2008	32.6	18.2	4.6	23.0	27.5
2009	35.8	18.9	4.9	23.8	28.7
2010	39.4	19.9	5.3	24.6	29.9
2011	43.3	21.0	5.7	25.5	31.2
2012	47.6	22.2	6.1	26.5	32.6
2013	52.3	23.5	6.6	27.7	34.2
2014	57.5	24.2	7.0	29.0	36.0
2015	63.2	26.4	7.6	30.5	38.1
2016	69.4	27.9	8.1	32.6	40.7
2017	76.3	29.7	8.8	36.5	45.2

Sources: [1], [2] See Table 4.1
[3] See Calculation Appendix C
[4] See Appendix C

Figure 4.2: PLC Projections



assumptions, Seabrook 1 power is never less expensive than the coal plant, and only beats oil fuel costs in 2005.

Q: Have you determined whether the early losses to customers are recovered by the later savings, even for the utility set of assumptions?

A: Yes. In order to do so, it was first necessary to express all costs in annual dollar costs. Table 4.3 presents the total annual non-fuel Seabrook 1 costs projected by each Maine utility, along with the fuel savings at CMP's 60% capacity factor and BHE's replacement fuel costs.[4] I will call this Case 1. From the cost and fuel savings, I compute the net cost of Seabrook 1 (after subtracting replacement power savings), the cumulative net cost and discounted net cost at a 14% discount rate. In Table 4.4, as Case 2, I restate my best estimates of the costs as millions of dollars per year for the customers of the three Maine utilities, along with the corresponding costs of replacing Seabrook 1 energy with BHE's projected mix of oil and new coal, net cost, cumulative net cost, and discounted cumulative net cost.

It should be noted that even the realistic case is probably

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4. This case combines a low capacity factor (from the utilities' perspective) with a high replacement power cost, and is thus a "median" utility projection.

TABLE 4.3: COMPARISON OF SEABROOK COSTS AND BENEFITS
Case 1: Utility Assumptions (in $ millions)

Year	Seabrook Non-Fuel Costs CMP	BHE	MPS	Total	Fuel Savings	Net Cost	Cumulative Net Cost	Discounted Net Cost
	[1]	[2]	[3]		[4]			
1988	82.1	31.4	19.8	133.3	28.2	105.1	105.1	92.2
1989	79.1	27.2	19.1	125.4	30.7	94.7	199.8	165.1
1990	74.3	25.9	18.0	118.2	33.7	84.5	284.3	222.1
1991	71.9	24.7	17.4	114.0	37.8	76.2	360.5	267.2
1992	69.4	23.6	16.8	109.8	41.9	67.8	428.4	302.5
1993	66.3	22.5	16.0	104.8	46.6	58.3	486.6	329.0
1994	64.2	21.4	15.5	101.1	51.7	49.4	536.0	348.8
1995	61.3	20.4	14.8	96.5	79.7	16.8	552.8	354.6
1996	59.2	19.4	14.3	92.9	73.6	19.3	572.1	360.6
1997	57.1	18.5	13.8	89.4	72.8	16.6	588.7	365.1
1998	55.0	18.3	13.3	86.6	72.5	14.1	602.8	368.4
1999	53.0	18.1	12.8	83.9	71.5	12.4	615.3	371.0
2000	51.0	17.9	12.3	81.3	71.6	9.7	624.9	372.7
2001	49.1	17.8	11.9	78.7	72.2	6.5	631.4	373.8
2002	48.6	17.7	11.8	78.1	72.2	5.9	637.3	374.6
2003	47.9	17.6	11.6	77.1	73.2	3.9	641.2	375.1
2004	47.2	17.6	11.4	76.2	74.2	2.0	643.2	375.3
2005	46.5	17.6	11.2	75.4	75.0	0.3	643.5	375.3
2006	45.9	17.6	11.1	74.6	76.3	-1.7	641.8	375.2
2007	45.3	17.7	11.0	74.0	78.1	-4.1	637.7	374.9
2008	44.8	17.8	10.8	73.5	79.8	-6.3	631.5	374.5
2009	44.4	18.0	10.7	73.1	81.9	-8.8	622.7	374.0
2010	44.0	18.2	10.6	72.8	85.6	-12.7	610.0	373.4
2011	43.6	18.5	10.5	72.7	89.7	-17.0	593.0	372.6
2012	43.3	18.9	10.5	72.6	94.2	-21.6	571.4	371.8
2013	43.1	19.3	10.4	72.8	99.1	-26.4	545.0	370.9
2014	43.0	19.7	10.4	73.1	100.4	-27.3	517.7	370.1
2015	42.9	20.3	10.4	73.5	110.1	-36.6	481.1	369.2
2016	42.5	20.9	10.3	73.6	115.6	-42.0	439.2	368.3

Sources: [1] CMP, 84-113, 10PA-61, Visicalc File Seab2, 60% C.F.
[2] BHE, 10PA-61, Exh. 61-1, divided by 1000.
[3] MPS Non-Fuel = CMP Non-Fuel x 1.46%/6.04%. See [1].
[4] BHE, 84-113, 3Staff8, Table 8-1.

TABLE 4.4: COMPARISON OF SEABROOK COSTS AND BENEFITS
Case 2: PLC Assumptions (in $ millions)

Year	Non-Fuel Cost	Fuel Savings	Net Cost	Cumulative Net Cost	Discounted Net Cost
	[1]	[2]	[3]		
1988	148.6	23.6	125.0	125.0	109.6
1989	142.4	25.7	116.7	241.7	199.4
1990	122.0	29.5	92.4	334.1	261.8
1991	117.1	34.7	82.5	416.6	310.6
1992	113.4	40.0	73.4	489.9	348.7
1993	109.8	44.5	65.4	555.3	378.5
1994	106.5	49.4	57.1	612.4	401.3
1995	103.7	76.1	27.7	640.0	411.0
1996	101.2	70.3	30.9	670.9	420.5
1997	98.9	69.5	29.4	700.4	428.5
1998	96.9	69.2	27.7	728.1	435.0
1999	99.3	68.3	31.0	759.1	441.5
2000	101.8	68.4	33.4	792.5	447.5
2001	104.4	69.0	35.4	827.9	453.2
2002	107.2	69.0	38.3	866.1	458.6
2003	110.2	70.0	40.2	906.4	463.5
2004	113.4	70.9	42.5	948.9	468.1
2005	116.7	71.7	45.1	994.0	472.3
2006	120.3	72.9	47.4	1041.3	476.3
2007	124.1	74.6	49.5	1090.9	479.9
2008	128.2	76.2	52.0	1142.9	483.2
2009	132.6	78.2	54.4	1197.4	486.2
2010	137.4	81.7	55.7	1253.0	489.0
2011	142.5	85.6	56.9	1309.9	491.4
2012	148.2	90.0	58.2	1368.1	493.6
2013	154.4	94.7	59.7	1427.8	495.6
2014	161.6	95.8	65.8	1493.6	497.5
2015	170.3	105.2	65.1	1558.7	499.2
2016	182.0	110.4	71.6	1630.2	500.8

Sources: [1] See Appendix C: Total Non-fuel Costs.
[2] BHE 3 Staff 8
[3] = [1] - [2]

somewhat optimistic, since it assumes the lowest capital cost I can justify, a very long useful life, and neglects transmission and decommissioning costs. The analysis is also biased towards Seabrook by the absence of any credit for the terminal value of the coal plant, which would be less than 25 years old when Seabrook reaches its utility-assumed retirement age of 30 years. On the other hand, in simplifying the utility cost projections, I have not reflected the effect of falling costs of capital over time.

It should come as no suprise that customers would initially be charged more for Seabrook 1 than it will save them, even under the utility assumptions. For the utility case, the first year in which Seabrook 1 would save customers money on balance would be 2006. At that point, the cumulative net cost[5] of the plant to Maine electric customers would have reached $643 million for the three utilities. The future benefits would never make up for the excess costs already charged to customers, and even in 2016 the cumulative net cost would be $439 million. Since simple breakeven never occurs, neither will discounted breakeven, at any positive discount rate. At a 14% discount rate, the present value of the cost to ratepayers would be almost $370 million.

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5. This figure is calculated as the sum of the net cost over previous years.

For my Case 2, Seabrook 1 is more expensive than the alternatives for _every_ year. By 2016, the cumulative net cost reaches $1.63 billion, and the discounted net cost is $500 million.

Figure 4.3 displays the cost to Maine customers of Seabrook 1 net of fuel savings for each year of its life, under the Case 1 utility assumptions, for traditional ratemaking treatment.[6] Figure 4.4 repeats this analysis for Case 2, my cost results.

Q: Have you performed any other cost analyses?

A: I have also modelled the cost of writing off Seabrook 1 to Maine ratepayers under one conventional ratemaking technique for my realistic assumptions. For comparability, this Case 3 assumes that the $3.3 billion sunk cost accrues another 1.1 billion dollars of AFUDC (at 10%) to 1/1/88, and is then written off evenly over 29 years, like a mortgage, with 10% AFUDC accruing on the balance. Table 4.5 presents the results of this analysis; the cumulative discounted cost is only $317 million, much less than the cumulative cost of completing and running the plant. Even if the entire cost

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6. Most utility phase-in proposals would have little effect on this analysis beyond the few years of the phase-in period itself.

Figure 4.3: Case 1: Utility Assumptions

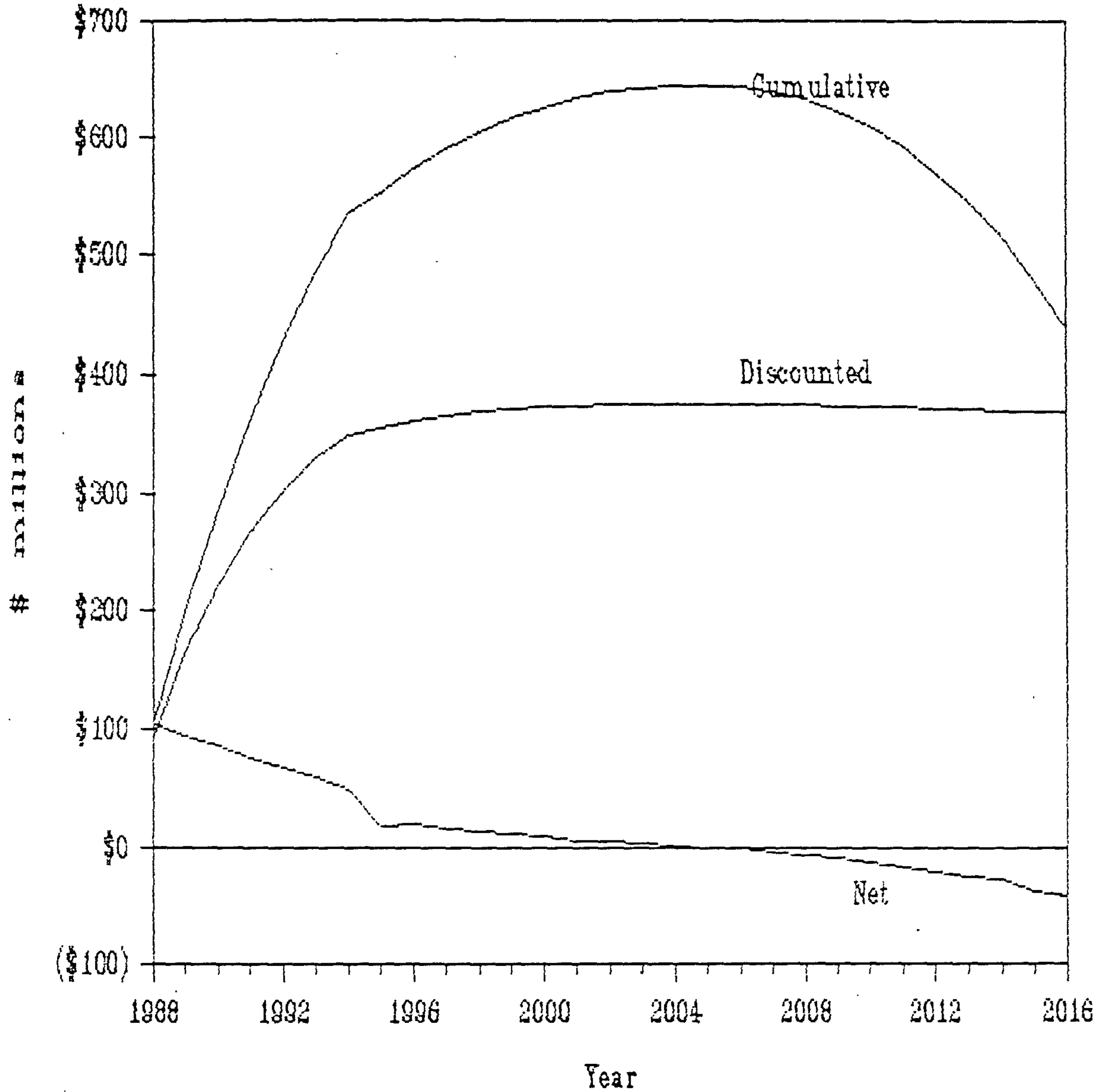

Figure 4.4: Case 2: PLC Assumptions

Comparison of Costs and Benefits

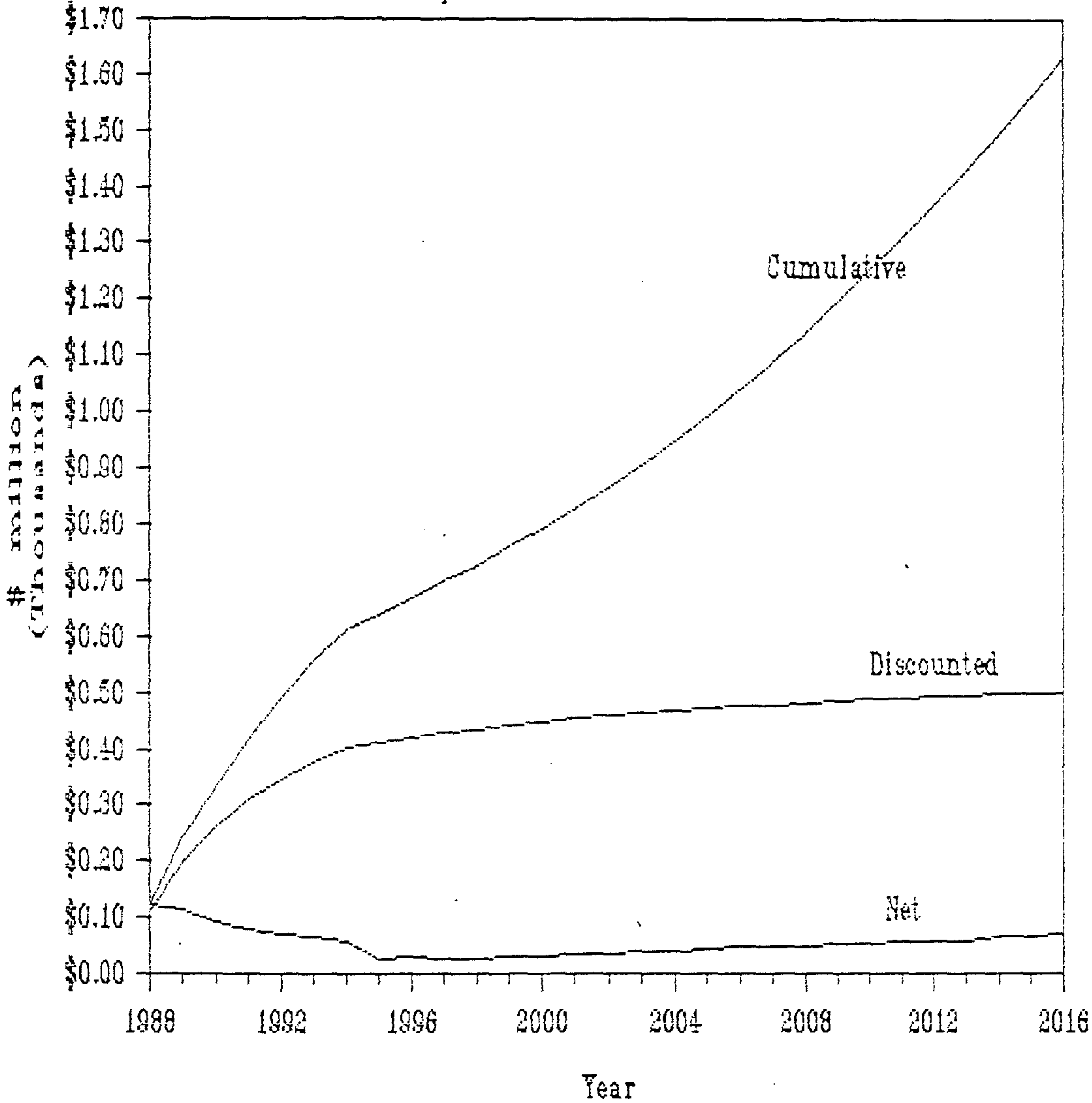

TABLE 4.5: COST OF SEABROOK WRITE-OFF
Case 3: PLC Assumptions. (in $ million)

Year	Seabrook Recovery Cost	Cumulative Cost	Discounted Cost
1988	45.4	45.4	39.8
1989	45.4	90.8	74.8
1990	45.4	136.2	105.4
1991	45.4	181.6	132.3
1992	45.4	227.1	155.9
1993	45.4	272.5	176.6
1994	45.4	317.9	194.7
1995	45.4	363.3	210.7
1996	45.4	408.7	224.6
1997	45.4	454.1	236.9
1998	45.4	499.5	247.6
1999	45.4	544.9	257.0
2000	45.4	590.3	265.3
2001	45.4	635.7	272.6
2002	45.4	681.2	278.9
2003	45.4	726.6	284.5
2004	45.4	772.0	289.4
2005	45.4	817.4	293.7
2006	45.4	862.8	297.5
2007	45.4	908.2	300.8
2008	45.4	953.6	303.7
2009	45.4	999.0	306.2
2010	45.4	1044.4	308.4
2011	45.4	1089.9	310.4
2012	45.4	1135.3	312.1
2013	45.4	1180.7	313.6
2014	45.4	1226.1	314.9
2015	45.4	1271.5	316.1
2016	45.4	1316.9	317.1

Maine Utility Share = 9.67% of $4.4 billion at 1/1/88 =
$425.48 million.

were recovered in 1987, it would only amount to about $405 million.[7]

Q: Are the discount rate, and the cost effects, you used applicable to individual customers or only to ratepayers as a class?

A: My calculations are meaningful for all ratepayers collectively, but not individually. Due to load growth (if loads grow substantially), the later benefits of Seabrook 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 do as well as the system as a whole. New customers and those with rapidly increasing energy consumption may realize positive cumulative benefits faster than I calculated, while customers who conserve in response to the high rates caused by Seabrook 1, or who leave the system, do even worse than the average.[8]

Customers also vary in terms of their discount rates. The

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7. Some of the savings result from having the unamortized balance accrue AFUDC, rather than placing it in rate base; it is less expensive for the utility to finance the balance than for the customers to do so. A portion of this effect may be captured by innovative ratemaking, regardless of whether the plant is finished.

8. The elderly and financially stressed industrial and commercial customers are particularly likely to pay for Seabrook 1 without receiving commensurate benefits.

14% rate, which I used in my calculations, is typical of current average utility costs of capital, and is therefore consistent with standard utility practice. While this rate may be appropriate for certain general utility purposes, it is almost certainly lower than the discount rate that many ratepayers would apply in making their own oil-backout decisions. This would be particularly true for customers with limited access to capital, such as low-income households, and financially strapped industrial operations. In addition, it seems likely that investors would demand an expected return substantially higher than 14% to incur the risks faced by the companies and their customers from Seabrook construction and operation. Higher discount rates would imply even higher discounted net present costs.

Q: What does this analysis tell us about the economics of continued construction of Seabrook?

A: Comparing Case 3 to Cases 1 and 2 indicates that the present value to ratepayers of completing and operating the plant is likely to be negative, even compared to conventional alternatives: continuing to burn oil, and then building a coal-fired plant. It therefore appears that Maine electric customers would be better off if Seabrook 1 were canceled promptly than if the unit were completed. They have very little to gain from completing the plant, and enormous potential losses. These conclusions are valid regardless of how the Commission chooses to treat the currently sunk costs of Seabrook, so long as the treatment is the same for cancelation and completion.

Q: What else can be concluded from these analyses?

A: First, even using utility projections, Seabrook 1 will not save money for customers who pay for the plant's early, uneconomic years. Second, given those projections, most customers would be better off if Seabrook 1 had never been started, or had been canceled long ago. Third, if Seabrook's cost and performance are consistent with past experience and trends, it is almost certain to be a poor investment for virtually all the ratepayers, and for customers as a whole.

5 - COMPARING SEABROOK TO ALTERNATIVE POWER SOURCES

Q: How do your estimates of Seabrook 1 incremental costs compare to the rates currently offered for co-generators and small power producers in Maine?

A: If completing and running Seabrook 1 costs 6.5 cents per kwh in 1984 dollars, this would be equivalent to 12.4 cents/kwh in nominal terms levelized over the next 30 years (assuming 6% inflation), or if we consider only the fifteen-year horizon of a typical small-power contract, it would be equivalent to 10.6 cents/kwh. Since traditional ratemaking front-loads the costs of capital recovery, the actual levelized value over the first fifteen years would be higher than 10.6 cents; my approach is structured as if charges for the plant were to rise with inflation, and therefore defers more of the costs past 15 years.

Since CMP's rate for fifteen-year purchase contracts has been set at 9.4 cents/kwh in nominal terms, any power purchased under these contracts is likely to be a bargain, at least compared to Seabrook 1 power costs. Even if CMP renews those contracts after the first fifteen years by adding fifteen years of inflation at 6%, or at 22.5 cents/kwh, the power will still be cheaper than Seabrook, which would cost 26.6 cents/kwh in nominal levelized dollars (again working from my real-levelized 6.5 cents in 1984$) over its second fifteen-year period, if it survives that long.

The 9.4 cents currently offered for purchased power could rise to 10.6 cents for the period 1988-2002, without rising above the cost of Seabrook.

Q: Are 10.6 cents/kwh in a small power producer contract and 10.6 cents per kwh in expected Seabrook costs equivalent from the utility's or ratepayers' viewpoint?

A: No. The small power producer gets paid only if it produces power. The utility and/or its customers must cover the cost of Seabrook whether or not it operates. Therefore, the financial and economic risks (which are not necessarily the same as the power supply risks I discuss below) of Seabrook are greater than those of a small power producer at the same expected costs, and under those circumstances, the small producer power would be preferable.

Q: Is it likely that renewing the current contracts will require prices of 22.5 cents/kwh?

A: I think not. Once cogenerators, refuse-burning plants, hydro-electric facilities, and the like have been built and operated for fifteen years, the cost of keeping them in operation should be very low. Depending on the regulatory environment (such as whether the small producers have the right to wheeling power to other customers at regulated rates), the cost of fuel (for the cogenerators, in particular), and the economic viability of the user of cogenerated heat, the contracts may be renewed at the original rate, or even less.

Q: Can you compare the relative risk of reliance on conservation programs, congeneration, and small power producers, to the risk of completing and operating Seabrook?

A: Yes, it least in general terms. The types of risks involved are quite different, and quantification is often difficult. In most respects, however, Seabrook is a much riskier power source.

Consider, for example, the availability of power in 15 years. As I noted above, once a small producer is built, it is likely to be available for a long time. Hydro plants are certainly not going to be relocated, and may well last a century. Most cogenerating industrial and commercial firms (or their facilities, which are often more durable than the corporate entities) will also stay in the area, for access to materials, labor, or customers; if the firms fail, both their supply contribution and their demand contribution (including their effect on residential sales and electricity sales the firms' suppliers and other related commercial and industrial activities) are lost simultaneously, so the net effect is smaller than a corresponding loss of central station capacity. Similarly, many conservation investments (such as insulation, or appliance efficiency improvements) are likely to last as long as the end use with which they are associated.

More importantly, the small power producers, cogenerators, and conservation investments diversify the risk of outages or premature retirements much better than does Seabrook. The loss of any one small power producer causes a much smaller problem for New England, Maine, or any particular utility than would the loss of Seabrook 1, either short-run (for a few hours, days, or weeks) or long-run (for months, years, or permanently). For example, the New England capacity situation was apparently somewhat tighter than usual this summer, largely because of simultaneous outages at a few nuclear plants; hundreds of small power producers would have to become unavailable simultaneous to have a similar effect.

Q: Is it possible for several small producers to become unavailable simultaneously due to a common cause?

A: Certainly. A severe drought would drastically curtail hydro generation, a recession in the forest products industry (or serious acid rain damage) might cut down on cogeneration at most paper mills, and introduction of a more desirable (but less energy efficient) generation of a major appliance (say, refrigerators) could undo a significant portion of an earlier conservation program. But most of these events, while they might be simultaneous, would not be fast, and would allow the utilities months or years to secure alternative sources, or to implement a new round of conservation investments.

Nuclear units can also be taken out of service by a common cause, as evidenced by the effects of the Three Mile Island accident, or the Stone & Webster computational error which shut down Maine Yankee in 1978. From the viewpoint of reliability, or energy adequacy, the loss of all small hydro, or all wood-fired cogeneration, would be much less serious than loss of all New England nuclear units. If any of the Maine utilities becomes highly dependent on a single type of small power producer, subject to common cause outages, it would be well advised to arrange power swaps with other utilities' power purchases (or central stations) to diversify the risk. This sort of technological risk-sharing is not possible to any great extent with New England nuclear plants, since they represent such a large share of total NEPOOL capacity and energy.

Q: Are there any special risks associated with nuclear plants, other than the common-cause outages, and the size of

Seabrook, which you have already discussed?

A: Yes, of at least two kinds. First, there are the unique construction and completion problems related to nuclear safety concerns. Plants which appear to be progressing smoothly can be held up for months or years by last-minute problems, as with Palo Verde 1, Grand Gulf, Diablo Canyon (the 1981 OL suspension), and Byron. Plants close to physical completion (Zimmer, Midland) have even been canceled due to the cost of correcting safety problems. Many of these problems were not anticipated two years before they occurred, and there is no way of telling what, if any, suprises will turn up at Seabrook in 1986. One example of a problem which could delay or prevent the operation of Seabrook 1 would be the adequacy of emergency planning. PSNH's Preliminary Prospectus of July 6, 1984, indicates that at least some of the seven Massachusetts municipalities for which emergency plans must be developed under current NRC regulations are opposing the development of the plans, and/or the adequacy of proposals to date. Since NRC requires certification of the plans by the Governor of the affected state, and since Governor Dukakis has indicated that he will not certify the Massachusetts plan over the objection of any Massachusetts municipality, a single town could conceivably prevent Seabrook from receiving an operating license. Of course, the NRC may change its rules, or Governor Dukakis eventually be succeeded by someone with a different position, or he may change his mind, or all the communities may be satisfied by some future plan. None of these eventualities appear to be occurring in time to allow licensing of Shoreham, which faces similar local opposition.[9]

The second special uncertainty with nuclear plants is the lack of significant experience with older plants, in terms of operating costs, reliability, and particularly useful life. No plant of more than 300 MW has even reached its sixteenth birthday, and the experience of the smaller units is not encouraging, as discussed in Section 3 in connection with the useful life of the plants.

Q: Do you believe that there is considerable potential for development of conservation, small power production, and other alternative to Seabrook, if that unit is not built?

A: There is much evidence to support that view. First, it is widely recognized that there are large energy conservation investments which are economical at current energy prices, but which have not been pursued by consumers due to lack of information, capital, or inclination. CMP's consultant notes that:

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9. There are differences between the Shoreham and Seabrook situations, since Shoreham's opposition comes from the county in which the plant is located, and Shoreham also has emergency generator problems. It is not clear how much opposition Seabrook faces from NH communities, or what the state's response will be.

> While [increased insulation and appliance efficiency] are clearly economic at current prices, numerous studies have shown that many household do _not_ make conservation investments which are economic. CMP's experience is consistent with this finding. (NERA, 1984, p. IV-5)

Thus, there is a stock of untapped potential conservation investments in existing end uses which is economical at current prices, and an even larger stock which is economical at prices competitive with Seabrook. In the commercial and industrial sectors, there are probably similar opportunities in cogeneration, some of which can be tapped by proper price signals, and some of which may require direct utility involvement in design, financing, and risk-sharing.

Utility resourcefulness and success in utilizing unconventional supply sources has been dependent in the past on the utilities' situation. For example, New England utilities seem to have become much more interested in (and successful at) obtaining agreements to purchase Hydro Quebec power as Pilgrim 2 construction became less likely. Perhaps the most aggressive conservation and small power production programs in the country are found in California, where licensing and construction problems with central stations left the utilities with little choice but to innovate.

Q: Will the rate increases due to Seabrook affect the need for the plant?

A: The price elasticity impact of Seabrook 1 will certainly reduce the need for new capacity, regardless of whether the unit is completed or not. The exact magnitude of the effect will depend on such factors as the ratemaking treatment allowed, the extent of rate increases before Seabrook affects rates, the other cost increases which coincide with Seabrook, and the elasticities assumed. Roughly speaking, it appears that Seabrook would raise CMP's rates by 10-15% in the first year, with corresponding increases for BHE of 30% and MPS of about 50%. The subsequent years would tend to experience smaller real increases, although the loss of sales due to the initial Seabrook rate increases will require some additional base rate increases to maintain utility earnings. The long-run demand effects[10] of the first year price rise would be a 5-13% reduction in CMP's sales, a 12-25% decrease for BHE, and a 18-33% reduction in MPS's sales.

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10. The range reflects long-run elasticities of 0.5 to 1.0; I consider the higher end more likely.

6 - CONCLUSIONS AND RECOMMENDATIONS

Q: Please summarize the major conclusions of your analyses.

A: If the Maine utilities continue to participate in building Seabrook 1, the Commission should expect to see:

- further delays in the commercial operation date,
- additional cost overruns,
- poor performance and high operating costs after start-up, and
- large rate increase requests, both before the unit enters service[11] and upon completion.

Should the Commission decide that it wants the plant to be completed, it must be prepared to provide continuing, almost unconditional support to the utilities for the rest of the construction period. Regardless of the level of support from this Commission (and even if the other New England states are also highly supportive and cooperative), the potential remains for further crises in the construction, financing, amd licensing of Seabrook 1; such crises could easily result

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11. CMP has recently requested CWIP for its Seabrook share.

in Seabrook becoming a dry hole. The utilities may well put billions of dollars more into the unit, without ever receiving any power. Once it is finished, the utilities and their customers will still face considerable risks, due to the uncertainties in nuclear plant reliability, longevity, and operating and decommissioning costs.

On the other hand, even if the plant is canceled promptly, there will still be very large sunk costs to be apportioned between ratepayers and shareholders, without any hope of eventual benefits. Cancelation will also require the utilities to start planning for their sources of replacement power, including the development of small power producers, cogenerators, and conservation programs.

Q: Which strategy is less expensive for ratepayers?

A: That will depend on several factors, including the cost of replacement power, whether Seabrook construction and operating performance are better or worse than historical trends, and whether the financial fixes being developed now can hold throughout the rest of the construction period. If there is much (relatively) low-cost power and conservation available, if Seabrook suffers from unusually severe construction or operating problems, <u>or</u> if the plant can not be completed for financial reasons, immediate cancelation is the better alternative. If Seabrook must be replaced by new conventional coal plant construction; if it hits no construction, licensing or operating snags; _and_ if adequate financing through the final completion date can be secured; then completion may be preferable. I believe that the former conditions are more likely to be met than the latter, but there are risks either way.

Q: Do you have any specific recommendations for the Commission?

Q: Yes, I have two recommendations. First, regardless of whether the Commission believes that cancelation is less expensive than completion, it is clear from the utilities' own figures that they would be better off if they could sell their shares, even for much less than their investment to date. Thus, the Commission should order the utilities to dispose of their shares, if at all possible, for virtually any price they can get.[2]

Second, regardless of whether the Maine utilities continue their role in the project, they really should attempt to recover the damages they suffered as a result of the misleading information they received on cost, schedule, and

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2. If no utilities, engineering firms, or other investors are interested in purchasing a portion of Seabrook 1, even without Seabrook 2 and at a substantial discount from book value, the Commission will have received further confirmation that the costs of completing Unit 1 exceed its value. The lack of a market for the plant at any price (which appears likely), would strengthen the argument for prompt cancelation.

construction progress. Therefore, I believe that it would be approriate for the Commission to strongly urge the utilities to explore their legal recourse against PSNH and UE&C.

Q: Does this conclude your testimony?

A: Yes.

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3. Calderone, J.W., Millstone Point Unit 3 Capacity Factor Projections, Northeast Utilities, October, 1983.

4. 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.

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7. ERDA, "Central Station Nuclear Plants", various dates (approximately semi-annual), 1966 - 1976; published by AEC before 1975.

8. Komanoff, Charles, Nuclear Plant Performance, Update 2, (New York, NY: Komanoff Energy Associates), 1978.

9. Komanoff, Charles, Power Plant Cost Escalation, (New York, NY: Komanoff Energy Associates), 1981.

10. Meyer, M.B., "Nuclear Power Plant Cost Underestimation: Mechanisms and Corrections," Public Utilities Fortnightly, February 16, 1984.

11. Minarick, J.W. and Kukielka, C.A., "Precursors to Potential Severe Core Damage Accidents 1969-79," NUREG/CR-2497, 1982.

12. Mooz, W.E., Cost Analysis of Light Water Reactor Power Plants, prepared for the Department of Energy, Rand Corporation Report R-2304-DOE, June, 1978.

13. Mooz, W.E., A Second Cost Analysis of Light Water Reactor Power Plants, Rand Corporation Report R-2504-RC, December, 1979.

14. NEPLAN, Development of NEPOOL Capability Responsibility Cs and Es for the Period 11/1/85-10/31/89, May 1983.

15. "The Economics of Nuclear Power," NERA, June 3, 1982.

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

17. Perl, Lewis J., A Second Cost Analysis of Light Water Reactor Power Plants, Rand Corporation Report R-2504-RC, December, 1979.

18. Perl, Lewis J., "Estimated Costs of Coal and Nuclear Generation", presented to the New York Society of Security Analysts, December 12, 1978.

Appendix A:

Resume of Paul Chernick

PAUL L. CHERNICK

Analysis and Inference, Inc.
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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.

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. Reviewed cost-effectiveness analyses for 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., Civil 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

Fairley, W., Meyer, M., and Chernick, P., "Insurance Market Assessment of Technological Risks," presented at the Session on Monitoring for Risk Management, Annual meeting of the American Association for the Advancement of Science, Detroit, Michigan, May 27, 1983.

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

Chernick, P., and Meyer, M., "An Improved Methodology for Making 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.

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); PUC (Public Utilities Commission); and PSC (Public Service 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.

   Review of 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 displacement; nuclear economics. Joint testimony with S.C. Geller.

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

   Critique 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 conversion.

9. MDPU 20248; Petition of Massachusetts Municipal Wholesale Electric Company 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. PUCT 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; interruptible 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 §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 Massachusetts Electric Company Rate Case; Mass. Attorney General; May, 1981.

    Rate design; declining 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. District of Columbia PSC 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. New Hampshire PUC 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.

    Critique 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; relative importance of demand and 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. Operation of Northeast Utilities Generation and Transmission agreement, and implications for capacity planning and ratemaking. 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.

Appendix B:

Myopia Data

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia Factor	REAL Cost Ratio	REAL Myopia Factor	Duration Ratio
Nine Mile Point 1	162	Dec-69	186.9	Jun-68	134	Jun-69	154.4	1.00	1.21	1.211	1.21	1.211	1.50
Nine Mile Point 1	162	Dec-69	186.9	Dec-68	134	Dec-69	154.4	1.00	1.21	1.211	1.21	1.211	1.00
Surry 2	155	May-73	146.9	Mar-72	147	Mar-73	139.0	1.00	1.06	1.057	1.06	1.057	1.17
Kewaunee	203	Jun-74	176.7	Mar-72	134	Mar-73	126.7	1.00	1.52	1.518	1.39	1.395	2.25
Kewaunee	203	Jun-74	176.7	Jun-72	158	Jun-73	149.4	1.00	1.29	1.287	1.18	1.183	2.00
Kewaunee	203	Jun-74	176.7	Sep-72	163	Sep-73	154.1	1.00	1.25	1.248	1.15	1.147	1.75
Peach Bottom 3	223	Dec-74	194.1	Dec-73	284	Dec-74	246.8	1.00	0.79	0.786	0.79	0.786	1.00
Arkansas 1	239	Dec-74	207.5	Mar-73	200	Mar-74	173.8	1.00	1.19	1.194	1.19	1.194	1.75
Fitzpatrick	419	Jul-75	333.1	Jun-73	301	Jun-74	261.6	1.00	1.39	1.392	1.27	1.274	2.08
St. Lucie 1	486	Jun-76	367.4	Dec-74	401	Dec-75	318.8	1.00	1.21	1.213	1.15	1.153	1.50
Beaver Valley 1	599	Oct-76	452.4	Jun-74	419	Jun-75	333.1	1.00	1.43	1.429	1.36	1.358	2.34
Beaver Valley 1	599	Oct-76	452.4	Dec-74	451	Dec-75	358.5	1.00	1.33	1.328	1.26	1.262	1.84
Crystal River 3	419	Mar-77	299.2	Mar-74	283	Mar-75	225.0	1.00	1.48	1.481	1.33	1.330	3.00
Farley 1	727	Dec-77	519.4	Jun-76	614	Jun-77	438.4	1.00	1.18	1.185	1.18	1.185	1.50
North Anna 2	542	Dec-80	303.8	Mar-78	467	Mar-79	285.8	1.00	1.16	1.161	1.06	1.063	2.76
Lasalle 1	1367	Oct-82	660.8	Jun-80	1107	Jun-81	567.3	1.00	1.23	1.235	1.16	1.165	2.33
Sumner 1	1283	Jan-84	579.4	Jun-82	1174	Jun-83	544.5	1.00	1.09	1.093	1.06	1.064	1.59
Turkey Point 4	127	Sep-73	119.9	Jun-71	96	Jun-72	96.0	1.00	1.32	1.320	1.25	1.248	2.25
Turkey Point 4	127	Sep-73	119.9	Dec-71	126	Dec-72	126.0	1.00	1.01	1.006	0.95	0.952	1.75
Prairie Isl 1	233	Dec-73	220.5	Dec-71	190	Dec-72	190.5	1.00	1.22	1.224	1.16	1.158	2.00
Browns Ferry 3	334	Mar-77	238.2	Jun-75	246	Jun-76	185.9	1.00	1.36	1.355	1.29	1.281	1.75
Farley 2	750	Jul-81	384.3	Sep-79	684	Sep-80	383.4	1.00	1.10	1.096	1.00	1.003	1.83
Sequoyah 1	984	Jul-81	504.0	Jun-79	632	Jun-80	354.2	1.00	1.56	1.555	1.42	1.422	2.08
Lasalle 1	1367	Oct-82	660.8	Mar-79	808	Mar-80	452.9	1.00	1.69	1.690	1.46	1.458	3.58
Lasalle 1	1367	Oct-82	660.8	Dec-79	1003	Dec-80	562.2	1.00	1.36	1.362	1.18	1.175	2.83
Prairie Isl 1	233	Dec-73	220.5	Sep-72	210	Oct-73	198.9	1.08	1.11	1.100	1.11	1.100	1.15
Cooper	269	Jul-74	234.0	Jun-72	207	Jul-73	195.7	1.08	1.30	1.275	1.20	1.179	1.92
Arkansas 1	239	Dec-74	207.5	Sep-72	185	Oct-73	174.9	1.08	1.29	1.266	1.19	1.171	2.08
Rancho Seco	344	Apr-75	273.2	Sep-73	328	Oct-74	285.0	1.08	1.05	1.044	0.96	0.961	1.46
Trojan	452	Dec-75	359.3	Sep-74	366	Oct-75	291.0	1.08	1.23	1.215	1.23	1.215	1.15
Indian Point 3	570	Aug-76	430.7	Sep-73	400	Oct-74	347.6	1.08	1.43	1.387	1.24	1.219	2.73
Beaver Valley 1	599	Oct-76	452.4	Sep-74	451	Oct-75	358.5	1.08	1.33	1.300	1.26	1.240	1.93
Sequoyah 1	984	Jul-81	504.0	Sep-78	632	Oct-79	386.7	1.08	1.56	1.505	1.30	1.278	2.62
Sumner 1	1283	Jan-84	579.4	Sep-82	1174	Oct-83	544.5	1.08	1.09	1.086	1.06	1.059	1.23
Browns Ferry 1	276	Aug-74	240.0	Sep-71	185	Oct-72	185.1	1.08	1.49	1.447	1.30	1.271	2.69
Brunswick 2	389	Nov-75	309.3	Dec-73	339	Jan-75	269.5	1.08	1.15	1.136	1.15	1.136	1.77
Browns Ferry 3	334	Mar-77	238.2	Dec-74	149	Jan-76	112.6	1.08	2.24	2.102	2.11	1.995	2.07
North Anna 1	782	Jun-78	519.7	Mar-76	567	Apr-77	404.9	1.08	1.38	1.345	1.28	1.259	2.08
Nine Mile Point 1	162	Dec-69	186.9	Dec-67	134	Jan-69	154.4	1.09	1.21	1.192	1.21	1.192	1.84
Calvert Cliffs 2	335	Apr-77	239.4	Dec-75	251	Jan-77	179.2	1.09	1.34	1.305	1.34	1.305	1.23
Three Mile I. 1	401	Sep-74	348.4	Jun-73	393	Aug-74	341.5	1.17	1.02	1.017	1.02	1.017	1.07
Zion 2	292	Sep-74	253.7	Mar-72	235	May-73	222.2	1.17	1.24	1.205	1.14	1.120	2.15
Beaver Valley 1	599	Oct-76	452.4	Mar-74	419	May-75	333.1	1.17	1.43	1.358	1.36	1.300	2.22
Salem 2	820	Oct-81	420.2	Mar-78	619	May-79	378.8	1.17	1.32	1.273	1.11	1.093	3.08
Surry 1	247	Dec-72	246.7	Dec-70	189	Feb-72	189.0	1.17	1.31	1.256	1.31	1.256	1.71
Zion 1	276	Dec-73	261.0	Jun-71	232	Aug-72	232.0	1.17	1.19	1.160	1.12	1.106	2.14
Browns Ferry 1	276	Aug-74	240.0	Mar-71	185	May-72	185.1	1.17	1.49	1.408	1.30	1.249	2.93
McGuire 1	906	Dec-81	464.1	Dec-78	549	Feb-80	307.7	1.17	1.65	1.534	1.51	1.421	2.57
Surry 2	155	May-73	146.9	Dec-71	145	Mar-73	137.1	1.25	1.07	1.057	1.07	1.057	1.13
Peach Bottom 3	223	Dec-74	194.1	Sep-73	316	Dec-74	274.6	1.25	0.71	0.757	0.71	0.757	1.00
Brunswick 2	389	Nov-75	309.3	Sep-73	309	Dec-74	268.5	1.25	1.26	1.203	1.15	1.120	1.73
Brunswick 1	318	Mar-77	227.4	Dec-75	329	Mar-77	234.9	1.25	0.97	0.974	0.97	0.974	1.00

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia Factor	REAL Cost Ratio	REAL Myopia Factor	Duration Ratio
Brunswick 1	318	Mar-77	227.4	Dec-74	281	Mar-76	212.3	1.25	1.13	1.105	1.07	1.056	1.80
Davis-Besse 1	672	Nov-77	480.2	Dec-75	533	Mar-77	380.6	1.25	1.26	1.205	1.26	1.205	1.54
Summer 1	1283	Jan-84	579.4	Sep-80	827	Dec-81	423.8	1.25	1.55	1.422	1.37	1.285	2.67
Turkey Point 3	109	Dec-72	108.7	Mar-70	111	Jun-71	115.6	1.25	0.98	0.983	0.94	0.952	2.20
Surry 2	155	May-73	146.9	Sep-71	141	Dec-72	141.0	1.25	1.10	1.081	1.04	1.034	1.33
Prairie Isl 1	233	Dec-73	220.5	Sep-71	148	Dec-72	147.8	1.25	1.58	1.440	1.49	1.377	1.80
Kewaunee	203	Jun-74	176.7	Sep-71	134	Dec-72	134.0	1.25	1.52	1.396	1.32	1.248	2.20
Peach Bottom 2	531	Jul-74	461.1	Jun-72	352	Sep-73	332.9	1.25	1.51	1.388	1.39	1.298	1.66
Oconee 3	160	Dec-74	139.4	Mar-73	137	Jun-74	119.0	1.25	1.17	1.134	1.17	1.134	1.40
Rancho Seco	344	Apr-75	273.2	Mar-73	327	Jun-74	284.2	1.25	1.05	1.040	0.96	0.969	1.67
San Onofre 2	2502	Aug-83	1160.3	Mar-81	2010	Jun-82	971.6	1.25	1.24	1.191	1.19	1.152	1.93
Summer 1	1283	Jan-84	579.4	Mar-80	827	Jun-81	423.8	1.25	1.55	1.420	1.37	1.284	3.07
Turkey Point 4	127	Sep-73	119.9	Mar-71	83	Jun-72	83.0	1.25	1.53	1.402	1.44	1.341	2.00
Crystal River 3	419	Mar-77	299.2	Jun-75	420	Sep-76	317.4	1.25	1.00	0.998	0.94	0.954	1.40
Brunswick 1	318	Mar-77	227.4	Mar-75	281	Jun-76	212.3	1.25	1.13	1.105	1.07	1.056	1.60
Davis-Besse 1	672	Nov-77	480.2	Jun-75	461	Sep-76	348.3	1.25	1.46	1.351	1.38	1.292	1.93
Farley 2	750	Jul-81	384.3	Jun-79	687	Sep-80	335.0	1.25	1.09	1.072	1.00	0.999	1.66
Cook 1	545	Aug-75	433.0	Dec-73	427	Apr-75	339.5	1.33	1.28	1.201	1.28	1.201	1.25
Hatch 1	390	Dec-75	310.4	Dec-72	282	Apr-74	245.0	1.33	1.38	1.277	1.27	1.194	2.25
Lasalle 1	1367	Oct-82	660.8	Dec-80	1184	Apr-82	572.3	1.33	1.15	1.114	1.15	1.114	1.38
Vermont Yankee	184	Nov-72	184.5	Mar-70	133	Jul-71	138.5	1.33	1.39	1.278	1.33	1.240	2.00
Surry 1	247	Dec-72	246.7	Jun-70	189	Oct-71	196.9	1.33	1.31	1.221	1.25	1.184	1.88
Three Mile I. 1	401	Sep-74	348.4	Mar-73	373	Jul-74	324.1	1.33	1.07	1.056	1.07	1.056	1.13
Duane Arnold	280	Feb-75	222.5	Sep-72	192	Jan-74	166.8	1.33	1.46	1.327	1.33	1.241	1.81
Browns Ferry 2	276	Mar-75	219.6	Mar-73	149	Jul-74	129.5	1.33	1.85	1.588	1.69	1.486	1.50
Rancho Seco	344	Apr-75	273.2	Jun-72	264	Oct-73	249.6	1.33	1.30	1.219	1.09	1.070	2.12
Calvert Cliffs 1	431	May-75	342.4	Jun-72	250	Oct-73	236.4	1.33	1.72	1.504	1.45	1.320	2.18
Fitzpatrick	419	Jul-75	333.1	Jun-72	301	Oct-73	284.6	1.33	1.39	1.282	1.17	1.125	2.31
Cook 1	545	Aug-75	433.0	Jun-72	416	Oct-73	393.4	1.33	1.31	1.224	1.10	1.075	2.37
Cook 1	545	Aug-75	433.0	Jun-73	427	Oct-74	371.0	1.33	1.28	1.200	1.17	1.123	1.62
Indian Point 3	570	Aug-76	430.7	Mar-73	317	Jul-74	275.5	1.33	1.80	1.553	1.56	1.398	2.60
Browns Ferry 3	334	Mar-77	238.2	Jun-69	149	Oct-70	163.0	1.33	2.24	1.830	1.46	1.329	5.81
North Anna 1	782	Jun-78	519.7	Dec-75	536	Apr-77	382.7	1.33	1.46	1.327	1.36	1.258	1.87
Sequoyah 1	984	Jul-81	504.0	Mar-78	535	Jul-79	327.1	1.33	1.84	1.580	1.54	1.383	2.50
McGuire 1	906	Dec-81	464.1	Mar-78	549	Jul-79	335.9	1.33	1.65	1.456	1.38	1.274	2.82
Susquehanna 1	1947	Jun-83	902.9	Sep-80	1841	Jan-82	889.7	1.33	1.06	1.043	1.01	1.011	2.06
Surry 2	155	May-73	146.9	Jun-71	139	Oct-72	139.0	1.34	1.12	1.087	1.06	1.042	1.43
Farley 1	727	Dec-77	519.4	Jun-75	487	Oct-76	368.0	1.34	1.49	1.350	1.41	1.294	1.87
Millstone 2	426	Dec-75	338.9	Dec-73	380	May-75	302.1	1.41	1.12	1.085	1.12	1.085	1.41
Susquehanna 1	1947	Jun-83	902.9	Dec-81	2292	May-83	1062.9	1.41	0.85	0.891	0.85	0.891	1.06
Fort Calhoun 1	176	Sep-73	166.2	Dec-71	159	May-73	150.4	1.42	1.11	1.074	1.11	1.074	1.24
Zion 1	276	Dec-73	261.0	Dec-70	232	May-72	232.0	1.42	1.19	1.131	1.12	1.087	2.12
Palisades	147	Dec-71	152.8	Mar-69	110	Aug-70	120.3	1.42	1.33	1.225	1.27	1.184	1.94
Three Mile I. 1	401	Sep-74	348.4	Jun-72	328	Nov-73	310.2	1.42	1.22	1.152	1.12	1.085	1.59
Rancho Seco	344	Apr-75	273.2	Sep-72	300	Feb-74	260.7	1.42	1.15	1.100	1.05	1.034	1.82
Calvert Cliffs 1	431	May-75	342.4	Sep-72	250	Feb-74	217.2	1.42	1.72	1.467	1.58	1.378	1.88
Farley 1	727	Dec-77	519.4	Sep-74	456	Feb-76	344.6	1.42	1.60	1.390	1.51	1.336	2.29
North Anna 2	542	Dec-80	303.8	Mar-77	426	Aug-78	283.2	1.42	1.27	1.185	1.07	1.051	2.65
Oconee 2	160	Sep-74	139.4	Sep-71	137	Feb-73	129.6	1.42	1.17	1.117	1.08	1.053	2.11
Hatch 1	390	Dec-75	310.4	Sep-72	184	Mar-74	159.9	1.49	2.12	1.654	1.94	1.558	2.17
North Anna 2	542	Dec-80	303.8	Sep-77	426	Mar-79	260.7	1.49	1.27	1.175	1.17	1.108	2.17
Surry 1	247	Dec-72	246.7	Dec-69	189	Jun-71	196.9	1.50	1.31	1.195	1.25	1.163	2.00
Cook 1	545	Aug-75	433.0	Dec-72	427	Jun-74	371.0	1.50	1.28	1.176	1.17	1.109	1.78

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia Factor	REAL Cost Ratio	REAL Myopia Factor	Duration Ratio
Cook 2	452	Jul-78	300.2	Dec-76	437	Jun-78	290.5	1.50	1.03	1.022	1.03	1.022	1.05
Summer 1	1283	Jan-84	579.4	Dec-80	1032	Jun-82	498.8	1.50	1.24	1.156	1.16	1.105	2.06
Turkey Point 4	127	Sep-73	119.9	Dec-70	81	Jun-72	81.0	1.50	1.57	1.348	1.48	1.299	1.83
Calvert Cliffs 1	431	May-75	342.4	Dec-71	210	Jun-73	198.6	1.50	2.05	1.614	1.72	1.438	2.28
St. Lucie 1	486	Jun-76	367.4	Jun-74	366	Dec-75	291.0	1.50	1.33	1.208	1.26	1.168	1.33
Crystal River 3	419	Mar-77	299.2	Jun-73	283	Dec-74	245.9	1.50	1.48	1.299	1.22	1.140	2.50
Calvert Cliffs 2	335	Apr-77	239.4	Jun-74	273	Dec-75	217.0	1.50	1.23	1.147	1.10	1.068	1.89
Farley 1	727	Dec-77	519.4	Dec-75	589	Jun-77	420.6	1.50	1.24	1.151	1.24	1.151	1.33
Arkansas 1	239	Dec-74	207.5	Mar-72	175	Sep-73	165.5	1.50	1.36	1.230	1.25	1.162	1.83
Browns Ferry 3	334	Mar-77	238.2	Mar-74	149	Sep-75	118.5	1.50	2.24	1.709	2.01	1.591	2.00
Calvert Cliffs 2	335	Apr-77	239.4	Mar-74	273	Sep-75	217.0	1.50	1.23	1.147	1.10	1.068	2.05
Sequoyah 1	984	Jul-81	504.0	Mar-77	475	Sep-78	315.5	1.50	2.07	1.624	1.60	1.366	2.88
Lasalle 1	1367	Oct-82	660.8	Jun-79	918	Dec-80	514.5	1.50	1.49	1.303	1.28	1.181	2.22
Salem 1	850	Jun-77	607.2	Mar-75	678	Sep-76	512.3	1.51	1.25	1.162	1.19	1.119	1.50
Davis-Besse 1	672	Nov-77	480.2	Mar-75	434	Sep-76	327.9	1.51	1.55	1.337	1.46	1.288	1.77
Sequoyah 2	623	Jun-82	301.3	Mar-79	632	Sep-80	354.2	1.51	0.99	0.991	0.85	0.898	2.16
Millstone 2	426	Dec-75	338.9	Sep-72	282	Apr-74	245.0	1.58	1.51	1.299	1.38	1.228	2.06
Browns Ferry 3	334	Mar-77	238.2	Sep-73	149	Apr-75	118.5	1.58	2.24	1.665	2.01	1.556	2.21
Sequoyah 2	623	Jun-82	301.3	Dec-80	1094	Jul-82	528.8	1.58	0.57	0.700	0.57	0.700	0.95
Farley 1	727	Dec-77	519.4	Dec-74	456	Jul-76	344.6	1.58	1.60	1.343	1.51	1.296	1.90
Farley 2	750	Jul-81	384.3	Sep-78	652	Apr-80	365.4	1.58	1.15	1.093	1.05	1.032	1.79
Browns Ferry 2	276	Mar-75	219.6	Jun-72	149	Jan-74	129.5	1.59	1.85	1.476	1.69	1.395	1.73
Rancho Seco	344	Apr-75	273.2	Mar-72	215	Oct-73	203.3	1.59	1.60	1.344	1.34	1.205	1.94
Calvert Cliffs 1	431	May-75	342.4	Mar-72	210	Oct-73	198.6	1.59	2.05	1.573	1.72	1.410	2.00
Surry 2	155	May-73	146.9	Mar-71	138	Oct-72	138.0	1.59	1.13	1.078	1.06	1.040	1.37
Oconee 1	156	Jul-73	147.1	Sep-69	109	May-71	113.3	1.66	1.42	1.237	1.29	1.167	2.30
Three Mile I. 1	401	Sep-74	348.4	Sep-72	363	May-74	315.4	1.66	1.10	1.062	1.10	1.062	1.20
Beaver Valley 1	599	Oct-76	452.4	Sep-73	409	May-75	325.1	1.66	1.46	1.258	1.39	1.220	1.86
North Anna 2	542	Dec-80	303.8	Sep-76	363	May-78	241.3	1.66	1.49	1.273	1.26	1.149	2.56
Sequoyah 1	984	Jul-81	504.0	Sep-76	475	May-78	315.5	1.66	2.07	1.551	1.60	1.326	2.91
Pilgrim 1	239	Dec-72	239.3	Jan-70	153	Sep-71	159.6	1.66	1.56	1.307	1.50	1.276	1.75
Surry 2	155	May-73	146.9	Sep-70	138	May-72	138.0	1.66	1.13	1.074	1.06	1.038	1.60
Fort Calhoun 1	176	Sep-73	166.2	Sep-71	125	May-73	118.2	1.66	1.41	1.227	1.41	1.227	1.20
Calvert Cliffs 2	335	Apr-77	239.4	Dec-73	243	Aug-75	193.2	1.66	1.38	1.213	1.24	1.138	2.00
North Anna 2	542	Dec-80	303.8	Dec-76	381	Aug-78	253.3	1.66	1.42	1.236	1.20	1.115	2.40
Vermont Yankee	184	Nov-72	184.5	Jul-70	154	Mar-72	154.0	1.67	1.20	1.114	1.20	1.114	1.40
Three Mile I. 1	401	Sep-74	348.4	Mar-72	206	Nov-73	194.8	1.67	1.95	1.490	1.79	1.416	1.50
Farley 1	727	Dec-77	519.4	Jun-74	415	Feb-76	313.6	1.67	1.75	1.399	1.66	1.353	2.10
North Anna 2	542	Dec-80	303.8	Mar-76	311	Nov-77	222.1	1.67	1.74	1.395	1.37	1.206	2.85
Three Mile I. 1	401	Sep-74	348.4	Mar-71	261	Nov-72	261.0	1.67	1.54	1.293	1.33	1.188	2.09
Susquehanna 1	1947	Jun-83	902.9	Jun-79	1285	Feb-81	658.3	1.67	1.52	1.282	1.37	1.208	2.39
Turkey Point 3	109	Dec-72	108.7	Sep-69	99	Jun-71	103.1	1.75	1.10	1.055	1.05	1.031	1.86
Surry 1	247	Dec-72	246.7	Sep-69	165	Jun-71	171.9	1.75	1.50	1.259	1.44	1.230	1.86
Calvert Cliffs 2	335	Apr-77	239.4	Sep-73	243	Jun-75	193.2	1.75	1.38	1.202	1.24	1.131	2.05
Three Mile I. 2	715	Dec-78	475.6	Aug-76	637	May-78	423.5	1.75	1.12	1.069	1.12	1.069	1.32
Peach Bottom 2	531	Jul-74	461.1	Jun-71	288	Mar-73	272.3	1.75	1.84	1.418	1.69	1.351	1.76
Cook 1	545	Aug-75	433.0	Jun-71	356	Mar-73	336.6	1.75	1.53	1.275	1.29	1.155	2.38
Brunswick 1	318	Mar-77	227.4	Jun-75	328	Mar-77	234.2	1.75	0.97	0.983	0.97	0.983	1.00
Salem 1	850	Jun-77	607.2	Dec-73	497	Sep-75	394.7	1.75	1.71	1.360	1.54	1.279	2.00
Davis-Besse 1	672	Nov-77	480.2	Sep-74	434	Jun-76	327.9	1.75	1.55	1.284	1.46	1.243	1.81
Sequoyah 2	623	Jun-82	301.3	Sep-78	632	Jun-80	354.2	1.75	0.99	0.992	0.85	0.912	2.14
Sequoyah 2	623	Jun-82	301.3	Sep-79	442	Jun-81	226.5	1.75	1.41	1.217	1.33	1.177	1.57
Duane Arnold	280	Feb-75	222.5	Mar-72	177	Dec-73	167.4	1.75	1.58	1.299	1.33	1.177	1.67

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia Factor	REAL Cost Ratio	REAL Myopia Factor	Duration Ratio
Millstone 2	426	Dec-75	338.9	Mar-73	341	Dec-74	296.3	1.75	1.25	1.136	1.14	1.080	1.57
Crystal River 3	419	Mar-77	299.2	Dec-74	375	Sep-76	283.4	1.75	1.12	1.065	1.06	1.032	1.28
Browns Ferry 3	334	Mar-77	238.2	Mar-73	149	Dec-74	129.5	1.75	2.24	1.584	1.84	1.416	2.28
Sequoyah 1	984	Jul-81	504.0	Dec-75	364	Sep-77	259.6	1.75	2.71	1.765	1.94	1.460	3.19
San Onofre 2	2502	Aug-83	1160.3	Mar-80	1824	Dec-81	934.7	1.75	1.37	1.198	1.24	1.131	1.95
Oconee 2	160	Sep-74	139.4	Mar-71	109	Dec-72	109.0	1.75	1.47	1.246	1.28	1.150	2.00
Summer 1	1283	Jan-84	579.4	Mar-79	756	Dec-80	423.7	1.75	1.70	1.352	1.37	1.195	2.76
Vermont Yankee	184	Nov-72	184.5	Sep-69	120	Jul-71	125.0	1.83	1.54	1.265	1.48	1.237	1.73
Trojan	452	Dec-75	359.3	Sep-73	334	Jul-75	265.5	1.83	1.35	1.180	1.35	1.180	1.23
McGuire 1	906	Dec-81	464.1	Sep-77	466	Jul-79	285.2	1.83	1.94	1.438	1.63	1.305	2.32
Surry 1	247	Dec-72	246.7	Jun-69	165	Apr-71	171.9	1.83	1.50	1.246	1.44	1.218	1.91
Oconee 2	160	Sep-74	139.4	Sep-70	109	Jul-72	109.0	1.83	1.47	1.235	1.28	1.144	2.18
Browns Ferry 2	276	Mar-75	219.6	Sep-71	149	Jul-73	141.0	1.83	1.85	1.400	1.56	1.274	1.91
Beaver Valley 1	599	Oct-76	452.4	Dec-72	340	Oct-74	295.4	1.83	1.76	1.362	1.53	1.262	2.09
Zion 1	276	Dec-73	261.0	Jun-70	232	Apr-72	232.0	1.83	1.19	1.099	1.12	1.066	1.91
Browns Ferry 1	276	Aug-74	240.0	Jun-70	149	Apr-72	149.1	1.83	1.85	1.400	1.61	1.296	2.27
Three Mile I. 1	401	Sep-74	348.4	Dec-70	262	Oct-72	262.0	1.83	1.53	1.261	1.33	1.168	2.04
Browns Ferry 2	276	Mar-75	219.6	Jun-70	149	Apr-72	149.1	1.83	1.85	1.400	1.47	1.235	2.59
Browns Ferry 3	334	Mar-77	238.2	Jun-70	149	Apr-72	149.1	1.83	2.24	1.551	1.60	1.291	3.68
San Onofre 2	2502	Aug-83	1160.3	Dec-79	1740	Oct-81	891.7	1.83	1.44	1.219	1.30	1.154	2.00
McGuire 1	906	Dec-81	464.1	Mar-77	466	Jan-79	285.2	1.84	1.94	1.436	1.63	1.304	2.59
Calvert Cliffs 2	335	Apr-77	239.4	Mar-75	253	Jan-77	180.6	1.84	1.33	1.165	1.33	1.165	1.13
North Anna 1	782	Jun-78	519.7	Mar-75	536	Jan-77	382.7	1.84	1.46	1.228	1.36	1.181	1.77
Fort Calhoun 1	176	Sep-73	166.2	Jun-69	92	May-71	95.8	1.91	1.91	1.403	1.73	1.334	2.22
Sequoyah 1	984	Jul-81	504.0	Jun-76	364	May-78	241.7	1.91	2.71	1.682	2.09	1.468	2.66
McGuire 1	906	Dec-81	464.1	Jun-76	384	May-78	255.3	1.91	2.36	1.566	1.82	1.367	2.37
Rancho Seco	344	Apr-75	273.2	Jun-71	215	May-73	203.3	1.92	1.60	1.277	1.34	1.167	2.00
Crystal River 3	419	Mar-77	299.2	Dec-72	283	Nov-74	245.9	1.92	1.48	1.227	1.22	1.108	2.22
North Anna 1	782	Jun-78	519.7	Dec-73	431	Nov-75	342.6	1.92	1.81	1.364	1.52	1.243	2.35
Fort Calhoun 1	176	Sep-73	166.2	Dec-70	125	Nov-72	125.0	1.92	1.41	1.194	1.33	1.160	1.43
North Anna 2	542	Dec-80	303.8	Dec-75	301	Nov-77	214.9	1.92	1.80	1.359	1.41	1.198	2.61
Calvert Cliffs 2	335	Apr-77	239.4	Mar-73	204	Feb-75	162.2	1.92	1.64	1.295	1.48	1.225	2.13
Millstone 1	97	Mar-71		Mar-69		Mar-70		1.00					2.000
Point Beach 1	74	Dec-70		Dec-69		Dec-70		1.00					1.000
Point Beach 2	71	Oct-72		Sep-70		Sep-71		1.00					2.085
Indian Point 2	206	Aug-73		Dec-70		Dec-71		1.00					2.668
Ginna	83	Jul-70		Sep-68		Oct-69		1.08					1.691
Millstone 1	97	Mar-71		Sep-69		Oct-70		1.08					1.382
Quad Cities 1	100	Feb-73		Jun-70		Jul-71		1.08					2.471
Dresden 2	83	Jul-70		Dec-68		Jan-70		1.08					1.457
Millstone 1	97	Mar-71		Dec-68		Jan-70		1.08					2.071
Oyster Creek 1	90	Dec-69		Mar-67		Apr-68		1.09					2.534
Indian Point 2	206	Aug-73		Mar-69		May-70		1.17					3.789
Quad Cities 2	100	Mar-73		Mar-71		May-72		1.17					1.712
Dresden 3	104	Nov-71		Mar-70		Jun-71		1.25					1.335
Oyster Creek 1	90	Dec-69		Sep-66		Jan-68		1.33					2.437
Indian Point 2	206	Aug-73		Jun-69		Oct-70		1.33					3.125
Quad Cities 1	100	Feb-73		Mar-70		Jul-71		1.33					2.193
Indian Point 2	206	Aug-73		Dec-69		May-71		1.41					2.595
Dresden 3	104	Nov-71		Mar-69		Aug-70		1.42					1.882
Point Beach 1	74	Dec-70		Mar-69		Aug-70		1.42					1.236
Point Beach 2	71	Oct-72		Mar-70		Aug-71		1.42					1.824

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia Factor	REAL Cost Ratio	REAL Myopia Factor	Duration Ratio
Oyster Creek 1	90	Dec-69		Jun-66		Dec-67		1.50					2.334
Dresden 3	104	Nov-71		Jun-69		Dec-70		1.50					1.611
Indian Point 2	206	Aug-73		Sep-68		Apr-70		1.58					3.111
Dresden 2	83	Jul-70		Sep-67		Apr-69		1.58					1.789
Quad Cities 1	100	Feb-73		Jun-69		Jan-71		1.59					2.316
Dresden 3	104	Nov-71		Dec-68		Aug-70		1.66					1.752
Oyster Creek 1	90	Dec-69		Mar-66		Dec-67		1.75					2.142
Quad Cities 1	100	Feb-73		Dec-68		Oct-70		1.83					2.277
Point Beach 2	71	Oct-72		Sep-69		Aug-71		1.91					1.611
Millstone 1	97	Mar-71		Sep-67		Aug-69		1.92					1.824
For: 1 <= t < 2													
No. of data points:								220	190	190	190	190	220
Average								1.417	1.429	1.271	1.293	1.190	1.983
Standard Deviation:								0.298	0.343	0.194	0.248	0.154	0.592
Fort Calhoun 1	176	Sep-73	166.2	Sep-69	92	Sep-71	95.8	2.00	1.91	1.383	1.73	1.317	2.00
Brunswick 2	389	Nov-75	309.3	Dec-72	256	Dec-74	222.5	2.00	1.52	1.233	1.39	1.179	1.46
Trojan	452	Dec-75	359.3	Sep-72	243	Sep-74	211.2	2.00	1.86	1.364	1.70	1.305	1.62
St. Lucie 1	486	Jun-76	367.4	Dec-73	318	Dec-75	252.8	2.00	1.53	1.237	1.45	1.206	1.25
Brunswick 1	318	Mar-77	227.4	Dec-73	269	Dec-75	213.8	2.00	1.18	1.088	1.06	1.031	1.62
Browns Ferry 3	334	Mar-77	238.2	Aug-72	149	Aug-74	129.5	2.00	2.24	1.496	1.84	1.356	2.29
Calvert Cliffs 2	335	Apr-77	239.4	Jun-72	204	Jun-74	177.3	2.00	1.64	1.282	1.35	1.162	2.42
Farley 1	727	Dec-77	519.4	Dec-73	395	Dec-75	314.0	2.00	1.84	1.357	1.65	1.286	2.00
North Anna 1	782	Jun-78	519.7	Dec-72	407	Dec-74	353.7	2.00	1.92	1.386	1.47	1.212	2.75
Lasalle 1	1367	Oct-82	660.8	Sep-77	675	Sep-79	413.0	2.00	2.03	1.423	1.60	1.265	2.54
Kewaunee	203	Jun-74	176.7	Jun-70	123	Jun-72	123.0	2.00	1.65	1.286	1.44	1.199	2.00
Kewaunee	203	Jun-74	176.7	Sep-70	123	Sep-72	123.0	2.00	1.65	1.286	1.44	1.199	1.87
Peach Bottom 2	531	Jul-74	461.1	Mar-71	277	Mar-73	261.9	2.00	1.92	1.384	1.76	1.327	1.67
Peach Bottom 2	531	Jul-74	461.1	Dec-70	230	Dec-72	230.0	2.00	2.31	1.519	2.00	1.416	1.79
Crystal River 3	419	Mar-77	299.2	Sep-71	190	Sep-73	179.7	2.00	2.21	1.485	1.67	1.290	2.75
Sequoyah 1	984	Jul-81	504.0	Sep-75	324	Sep-77	231.3	2.00	3.04	1.742	2.18	1.476	2.91
Sequoyah 2	623	Jun-82	301.3	Mar-78	535	Mar-80	299.6	2.00	1.17	1.080	1.01	1.003	2.12
Browns Ferry 1	276	Aug-74	240.0	Sep-69	149	Oct-71	155.3	2.08	1.85	1.345	1.55	1.233	2.36
Prairie Isl 2	177	Dec-74	153.8	Sep-72	160	Oct-74	138.7	2.08	1.11	1.051	1.11	1.051	1.08
Browns Ferry 2	276	Mar-75	219.6	Sep-69	149	Oct-71	155.3	2.08	1.85	1.345	1.41	1.181	2.64
Beaver Valley 1	599	Oct-76	452.4	Sep-72	342	Oct-74	297.2	2.08	1.75	1.309	1.52	1.224	1.96
Browns Ferry 3	334	Mar-77	238.2	Sep-72	149	Oct-74	129.5	2.08	2.24	1.473	1.84	1.340	2.16
Browns Ferry 3	334	Mar-77	238.2	Sep-69	149	Oct-71	155.3	2.08	2.24	1.473	1.53	1.228	3.60
Prairie Isl 1	233	Dec-73	220.5	Sep-70	148	Oct-72	147.8	2.08	1.58	1.245	1.49	1.212	1.56
Three Mile I. 1	401	Sep-74	348.4	Jun-70	184	Jul-72	184.0	2.08	2.18	1.453	1.89	1.359	2.04
Three Mile I. 1	401	Sep-74	348.4	Sep-70	197	Oct-72	197.0	2.08	2.04	1.406	1.77	1.315	1.92
Cook 1	545	Aug-75	433.0	Sep-71	356	Oct-73	336.6	2.08	1.53	1.226	1.29	1.128	1.88
Farley 1	727	Dec-77	519.4	Mar-73	294	Apr-75	233.7	2.08	2.47	1.545	2.22	1.467	2.28
North Anna 1	782	Jun-78	519.7	Mar-73	407	Apr-75	323.6	2.08	1.92	1.368	1.61	1.255	2.52
Farley 2	750	Jul-81	384.3	Mar-77	689	Apr-79	421.6	2.08	1.09	1.042	0.91	0.957	2.08
Surry 2	155	May-73	146.9	Mar-70	138	Apr-72	138.0	2.09	1.13	1.059	1.06	1.031	1.52
Browns Ferry 2	276	Mar-75	219.6	Mar-71	149	Apr-73	141.0	2.09	1.85	1.344	1.56	1.237	1.92
Calvert Cliffs 2	335	Apr-77	239.4	Dec-71	168	Jan-74	146.0	2.09	2.00	1.393	1.64	1.268	2.56
North Anna 1	782	Jun-78	519.7	Dec-74	504	Jan-77	359.9	2.09	1.55	1.234	1.44	1.193	1.68

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia Factor	REAL Cost Ratio	REAL Myopia Factor	Duration Ratio
Sequoyah 1	984	Jul-81	504.0	Dec-74	324	Jan-77	231.3	2.09	3.04	1.703	2.18	1.452	3.15
Farley 2	750	Jul-81	384.3	Mar-78	635	Apr-80	355.9	2.09	1.18	1.083	1.08	1.038	1.60
Palisades	147	Dec-71	152.8	Mar-68	89	May-70	97.3	2.17	1.65	1.260	1.57	1.232	1.73
Beaver Valley 1	599	Oct-76	452.4	Mar-73	340	May-75	270.3	2.17	1.76	1.299	1.67	1.269	1.66
North Anna 1	782	Jun-78	519.7	Sep-73	407	Nov-75	323.6	2.17	1.92	1.352	1.61	1.245	2.19
Sequoyah 2	623	Jun-82	301.3	Mar-77	475	May-79	290.4	2.17	1.31	1.134	1.04	1.017	2.42
Susquehanna 1	1947	Jun-83	902.9	Mar-81	2276	May-83	1055.3	2.17	0.86	0.931	0.86	0.931	1.04
Maine Yankee	219	Dec-72	219.2	Mar-70	181	May-72	181.0	2.17	1.21	1.092	1.21	1.092	1.27
Peach Bottom 2	531	Jul-74	461.1	Mar-70	230	May-72	230.0	2.17	2.31	1.470	2.00	1.378	2.00
Three Mile I. 1	401	Sep-74	348.4	Sep-71	296	Nov-73	279.9	2.17	1.35	1.150	1.24	1.106	1.38
Three Mile I. 1	401	Sep-74	348.4	Mar-70	184	May-72	184.0	2.17	2.18	1.432	1.89	1.342	2.08
Oconee 3	160	Dec-74	139.4	Sep-71	137	Nov-73	129.6	2.17	1.17	1.075	1.08	1.034	1.50
North Anna 1	782	Jun-78	519.7	Mar-74	446	May-76	337.0	2.17	1.75	1.295	1.54	1.221	1.96
Sequoyah 1	984	Jul-81	504.0	Jun-74	313	Aug-76	236.1	2.17	3.15	1.697	2.13	1.419	3.27
McGuire 1	906	Dec-81	464.1	Dec-76	384	Feb-79	235.0	2.17	2.36	1.485	1.97	1.369	2.31
Summer 1	1283	Jan-84	579.4	Mar-78	675	May-80	378.3	2.17	1.90	1.345	1.53	1.217	2.69
Surry 1	247	Dec-72	246.7	Dec-68	165	Mar-71	171.9	2.25	1.50	1.196	1.44	1.175	1.78
Salem 1	850	Jun-77	607.2	Dec-72	425	Mar-75	337.9	2.25	2.00	1.362	1.80	1.298	2.00
Surry 2	155	May-73	146.9	Dec-69	138	Mar-72	138.0	2.25	1.13	1.054	1.06	1.028	1.52
Peach Bottom 2	531	Jul-74	461.1	Dec-69	218	Mar-72	218.0	2.25	2.43	1.486	2.12	1.396	2.04
Brunswick 2	389	Nov-75	309.3	Dec-71	210	Mar-74	182.5	2.25	1.85	1.316	1.70	1.265	1.74
Brunswick 1	318	Mar-77	227.4	Sep-73	251	Dec-75	199.5	2.25	1.27	1.112	1.14	1.060	1.56
North Anna 1	782	Jun-78	519.7	Sep-72	360	Dec-74	312.8	2.25	2.17	1.412	1.66	1.253	2.56
Arkansas 2	640	Mar-80	358.7	Dec-75	393	Mar-78	261.3	2.25	1.63	1.242	1.37	1.151	1.89
Three Mile I. 1	401	Sep-74	348.4	Jun-69	162	Sep-71	168.7	2.25	2.47	1.496	2.06	1.380	2.33
Peach Bottom 3	223	Dec-74	194.1	Jun-72	316	Sep-74	274.6	2.25	0.71	0.857	0.71	0.857	1.11
St. Lucie 1	486	Jun-76	367.4	Mar-72	235	Jun-74	204.2	2.25	2.07	1.381	1.80	1.298	1.89
St. Lucie 1	486	Jun-76	367.4	Mar-73	318	Jun-75	252.8	2.25	1.53	1.208	1.45	1.181	1.45
Beaver Valley 1	599	Oct-76	452.4	Sep-71	286	Dec-73	270.4	2.25	2.09	1.389	1.67	1.257	2.26
Calvert Cliffs 2	335	Apr-77	239.4	Mar-72	168	Jun-74	146.0	2.25	2.00	1.359	1.64	1.246	2.26
Salem 1	850	Jun-77	607.2	Sep-74	678	Dec-76	512.3	2.25	1.25	1.106	1.19	1.078	1.22
Summer 1	1283	Jan-84	579.4	Sep-78	675	Dec-80	378.3	2.25	1.90	1.330	1.53	1.208	2.37
Fort Calhoun 1	176	Sep-73	166.2	Mar-70	125	Jun-72	125.0	2.25	1.41	1.163	1.33	1.135	1.56
Turkey Point 4	127	Sep-73	119.9	Mar-70	80	Jun-72	80.0	2.25	1.58	1.227	1.50	1.197	1.56
Kewaunee	203	Jun-74	176.7	Mar-70	121	Jun-72	121.0	2.25	1.68	1.259	1.46	1.183	1.89
Arkansas 2	640	Mar-80	358.7	Mar-75	339	Jun-77	242.1	2.25	1.89	1.326	1.48	1.191	2.22
Farley 2	750	Jul-81	384.3	Jun-75	365	Sep-77	260.6	2.25	2.05	1.377	1.47	1.188	2.70
Sequoyah 1	984	Jul-81	504.0	Mar-74	313	Jun-76	236.1	2.25	3.15	1.663	2.13	1.400	3.26
Farley 2	750	Jul-81	384.3	Dec-76	572	Apr-79	350.0	2.33	1.31	1.123	1.10	1.041	1.97
Sequoyah 1	984	Jul-81	504.0	Dec-72	225	Apr-75	178.5	2.33	4.38	1.885	2.82	1.561	3.68
Cooper	269	Jul-74	234.0	Dec-70	207	Apr-73	195.7	2.33	1.30	1.119	1.20	1.080	1.54
Beaver Valley 1	599	Oct-76	452.4	Jun-72	311	Oct-74	270.2	2.33	1.93	1.324	1.67	1.247	1.86
Calvert Cliffs 2	335	Apr-77	239.4	Sep-72	204	Jan-75	162.2	2.33	1.64	1.237	1.48	1.182	1.96
Salem 1	850	Jun-77	607.2	Dec-70	237	Apr-73	224.1	2.33	3.59	1.729	2.71	1.533	2.79
Farley 2	750	Jul-81	384.3	Dec-77	662	Apr-80	371.0	2.33	1.13	1.055	1.04	1.015	1.54
Browns Ferry 2	276	Mar-75	219.6	Sep-70	149	Jan-73	141.0	2.34	1.85	1.302	1.56	1.209	1.92
Calvert Cliffs 1	431	May-75	342.4	Sep-70	170	Jan-73	160.8	2.34	2.53	1.489	2.13	1.382	2.00
Indian Point 3	570	Aug-76	430.7	Mar-71	256	Jul-73	242.1	2.34	2.23	1.409	1.78	1.280	2.34
Calvert Cliffs 2	335	Apr-77	239.4	Sep-74	256	Jan-77	182.8	2.34	1.31	1.123	1.31	1.123	1.11
Arkansas 2	640	Mar-80	358.7	Jun-75	339	Oct-77	242.1	2.34	1.89	1.313	1.48	1.183	2.03
Arkansas 2	640	Mar-80	358.7	Sep-75	369	Jan-78	245.3	2.34	1.73	1.266	1.46	1.177	1.93
Sequoyah 1	984	Jul-81	504.0	Sep-74	313	Jan-77	223.1	2.34	3.15	1.634	2.26	1.418	2.92
Farley 2	750	Jul-81	384.3	Sep-74	363	Jan-77	259.2	2.34	2.07	1.364	1.48	1.184	2.92

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia Factor	REAL Cost Ratio	REAL Myopia Factor	Duration Ratio
Susquehanna 1	1947	Jun-83	902.9	Sep-79	1607	Jan-82	776.7	2.34	1.21	1.086	1.16	1.067	1.60
St. Lucie 1	486	Jun-76	367.4	Dec-72	318	May-75	252.8	2.41	1.53	1.192	1.45	1.168	1.45
Davis-Besse 1	672	Nov-77	480.2	Dec-72	349	May-75	277.4	2.41	1.93	1.312	1.73	1.255	2.04
Three Mile I. 1	401	Sep-74	348.4	Dec-69	180	May-72	180.0	2.41	2.23	1.393	1.94	1.315	1.97
Prairie Isl 2	177	Dec-74	153.8	Dec-71	145	May-74	125.6	2.41	1.22	1.087	1.22	1.087	1.24
Davis-Besse 1	672	Nov-77	480.2	Sep-73	409	Feb-76	309.1	2.42	1.64	1.228	1.55	1.200	1.72
Sequoyah 1	984	Jul-81	504.0	Jun-72	213	Nov-74	184.7	2.42	4.63	1.885	2.73	1.515	3.76
Nine Mile Point 1	162	Dec-69	186.9	Jun-66	88	Nov-68	106.6	2.42	1.84	1.288	1.75	1.261	1.45
Browns Ferry 2	276	Mar-75	219.6	Sep-67	124	Feb-70	136.0	2.42	2.22	1.390	1.61	1.219	3.10
Browns Ferry 3	334	Mar-77	238.2	Sep-71	149	Feb-74	129.5	2.42	2.24	1.395	1.84	1.286	2.27
Susquehanna 1	1947	Jun-83	902.9	Sep-78	1293	Feb-81	662.5	2.42	1.51	1.184	1.36	1.136	1.96
Peach Bottom 2	531	Jul-74	461.1	Sep-69	206	Mar-72	206.0	2.50	2.58	1.461	2.24	1.381	1.93
Cook 1	545	Aug-75	433.0	Sep-70	339	Mar-73	320.6	2.50	1.61	1.209	1.35	1.128	1.97
St. Lucie 1	486	Jun-76	367.4	Dec-71	218	Jun-74	189.4	2.50	2.23	1.378	1.94	1.303	1.80
Beaver Valley 1	599	Oct-76	452.4	Dec-71	286	Jun-74	248.5	2.50	2.09	1.344	1.82	1.271	1.93
Davis-Besse 1	672	Nov-77	480.2	Jun-72	304	Dec-74	264.2	2.50	2.21	1.374	1.82	1.270	2.17
Farley 1	727	Dec-77	519.4	Jun-73	294	Dec-75	233.7	2.50	2.47	1.437	2.22	1.376	1.80
North Anna 1	782	Jun-78	519.7	Dec-71	344	Jun-74	298.9	2.50	2.27	1.389	1.74	1.248	2.60
Sequoyah 1	984	Jul-81	504.0	Jun-73	225	Dec-75	178.5	2.50	4.38	1.806	2.82	1.515	3.23
Sequoyah 1	984	Jul-81	504.0	Dec-73	225	Jun-76	169.6	2.50	4.38	1.806	2.97	1.546	3.03
Farley 2	750	Jul-81	384.3	Dec-74	363	Jun-77	259.2	2.50	2.07	1.337	1.48	1.171	2.63
Trojan	452	Dec-75	359.3	Mar-72	233	Sep-74	202.5	2.50	1.94	1.303	1.77	1.258	1.50
Beaver Valley 1	599	Oct-76	452.4	Jun-71	219	Dec-73	207.1	2.50	2.73	1.495	2.18	1.367	2.13
Salem 1	850	Jun-77	607.2	Jun-71	237	Dec-73	224.1	2.50	3.59	1.666	2.71	1.489	2.40
North Anna 2	542	Dec-80	303.8	Mar-75	301	Sep-77	214.9	2.51	1.80	1.265	1.41	1.148	2.30
Salem 2	820	Oct-81	420.2	Mar-74	496	Sep-76	374.8	2.51	1.65	1.222	1.12	1.047	3.03
Trojan	452	Dec-75	359.3	Dec-72	284	Jul-75	225.8	2.58	1.59	1.197	1.59	1.197	1.16
North Anna 2	542	Dec-80	303.8	Dec-72	227	Jul-75	180.5	2.58	2.39	1.401	1.68	1.224	3.10
Farley 2	750	Jul-81	384.3	Sep-76	499	Apr-79	305.3	2.58	1.50	1.171	1.26	1.093	1.37
Millstone 2	426	Dec-75	338.9	Sep-71	252	Apr-74	219.0	2.58	1.69	1.226	1.55	1.184	1.65
Hatch 1	390	Dec-75	310.4	Sep-70	184	Apr-73	174.0	2.58	2.12	1.338	1.78	1.251	2.03
Cook 2	452	Jul-78	300.2	Sep-75	437	Apr-78	290.5	2.58	1.03	1.013	1.03	1.013	1.10
Sequoyah 1	984	Jul-81	504.0	Dec-71	213	Jul-74	184.7	2.58	4.63	1.810	2.73	1.475	3.71
Browns Ferry 2	276	Mar-75	219.6	Mar-68	124	Oct-70	136.0	2.58	2.22	1.362	1.61	1.204	2.71
Beaver Valley 1	599	Oct-76	452.4	Mar-72	309	Oct-74	268.5	2.58	1.94	1.292	1.68	1.224	1.77
Browns Ferry 3	334	Mar-77	238.2	Mar-68	124	Oct-70	136.0	2.58	2.68	1.465	1.75	1.242	3.48
Salem 1	850	Jun-77	607.2	Mar-72	336	Oct-74	291.5	2.58	2.53	1.433	2.08	1.328	2.03
North Anna 2	542	Dec-80	303.8	Mar-73	227	Oct-75	180.5	2.58	2.39	1.400	1.68	1.223	3.00
Sequoyah 2	623	Jun-82	301.3	Jun-76	364	Jan-79	222.4	2.58	1.71	1.232	1.35	1.125	2.32
Farley 2	750	Jul-81	384.3	Jun-74	338	Jan-77	241.3	2.59	2.22	1.361	1.59	1.197	2.74
Fort Calhoun 1	176	Sep-73	166.2	Sep-68	92	May-71	95.8	2.66	1.91	1.275	1.73	1.230	1.88
Lasalle 1	1367	Oct-82	660.8	Sep-76	585	May-79	358.0	2.66	2.34	1.376	1.85	1.259	2.28
Three Mile I. 1	401	Sep-74	348.4	Sep-69	162	May-72	162.0	2.66	2.47	1.405	2.15	1.333	1.88
Oconee 2	160	Sep-74	139.4	Sep-69	109	May-72	109.2	2.66	1.47	1.155	1.28	1.096	1.88
North Anna 2	542	Dec-80	303.8	Sep-73	227	May-76	171.5	2.66	2.39	1.386	1.77	1.239	2.72
Sequoyah 2	623	Jun-82	301.3	Sep-75	324	May-78	215.4	2.66	1.92	1.278	1.40	1.134	2.53
Arkansas 2	640	Mar-80	358.7	Jun-74	318	Feb-77	227.1	2.67	2.01	1.299	1.58	1.187	2.15
North Anna 2	542	Dec-80	303.8	Mar-74	240	Nov-76	181.4	2.67	2.26	1.356	1.68	1.213	2.53
Turkey Point 4	127	Sep-73	119.9	Sep-69	41	Jun-72	41.0	2.75	3.09	1.508	2.92	1.478	1.46
Three Mile I. 1	401	Sep-74	348.4	Dec-68	150	Sep-71	156.2	2.75	2.67	1.430	2.23	1.339	2.09
Beaver Valley 1	599	Oct-76	452.4	Sep-70	219	Jun-73	207.1	2.75	2.73	1.442	2.18	1.329	2.21
North Anna 1	782	Jun-78	519.7	Sep-71	310	Jun-74	269.4	2.75	2.52	1.400	1.93	1.270	2.46
North Anna 1	782	Jun-78	519.7	Jun-71	308	Mar-74	267.6	2.75	2.54	1.403	1.94	1.273	2.55

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia Factor	REAL Cost Ratio	REAL Myopia Factor	Duration Ratio
Arkansas 2	640	Mar-80	358.7	Sep-74	318	Jun-77	227.1	2.75	2.01	1.290	1.58	1.181	2.00
Lasalle 1	1367	Oct-82	660.8	Dec-76	585	Sep-79	358.0	2.75	2.34	1.362	1.85	1.250	2.12
North Anna 1	782	Jun-78	519.7	Mar-72	344	Dec-74	298.9	2.75	2.27	1.348	1.74	1.223	2.27
North Anna 2	542	Dec-80	303.8	Dec-74	264	Sep-77	188.5	2.75	2.05	1.299	1.61	1.189	2.18
Salem 2	820	Oct-81	420.2	Dec-73	497	Sep-76	375.2	2.75	1.65	1.200	1.12	1.042	2.85
Salem 1	850	Jun-77	607.2	Mar-70	237	Dec-72	237.0	2.75	3.59	1.590	2.56	1.407	2.63
Indian Point 3	570	Aug-76	430.7	Sep-68	156	Jul-71	162.5	2.83	3.65	1.581	2.65	1.412	2.81
North Anna 2	542	Dec-80	303.8	Sep-72	208	Jul-75	165.4	2.83	2.61	1.403	1.84	1.240	2.92
Oconee 3	160	Dec-74	139.4	Sep-70	109	Jul-73	103.1	2.83	1.47	1.146	1.35	1.113	1.50
Indian Point 3	570	Aug-76	430.7	Sep-69	156	Jul-72	156.0	2.83	3.65	1.580	2.76	1.432	2.46
Indian Point 3	570	Aug-76	430.7	Sep-70	218	Jul-73	206.1	2.83	2.61	1.404	2.09	1.297	2.10
Hatch 2	515	Sep-79	315.1	Jun-76	512	Apr-79	313.3	2.83	1.01	1.002	1.01	1.002	1.15
Peach Bottom 3	223	Dec-74	194.1	Dec-70	221	Oct-73	209.0	2.83	1.01	1.004	0.93	0.974	1.41
Crystal River 3	419	Mar-77	299.2	Jun-69	148	Apr-72	148.0	2.83	2.83	1.444	2.02	1.282	2.73
North Anna 2	542	Dec-80	303.8	Jun-73	227	Apr-76	171.5	2.83	2.39	1.360	1.77	1.223	2.65
Farley 2	750	Jul-81	384.3	Jun-77	689	Apr-80	386.2	2.83	1.09	1.030	1.00	0.998	1.44
McGuire 1	906	Dec-81	464.1	Jun-74	220	Apr-77	157.1	2.83	4.12	1.648	2.95	1.466	2.65
Sequoyah 2	623	Jun-82	301.3	Jun-74	313	Apr-77	223.1	2.83	1.99	1.276	1.35	1.112	2.32
Browns Ferry 3	334	Mar-77	238.2	Mar-71	149	Jan-74	129.5	2.84	2.24	1.328	1.84	1.239	2.11
St. Lucie 1	486	Jun-76	367.4	Jun-72	269	May-75	213.8	2.91	1.81	1.225	1.72	1.204	1.37
St. Lucie 2	1430	Aug-83	663.2	Jun-80	1100	May-83	510.1	2.91	1.30	1.094	1.30	1.094	1.09
Summer 1	1283	Jan-84	579.4	Jun-76	493	May-79	301.7	2.91	2.60	1.389	1.92	1.251	2.60
Zion 2	292	Sep-74	253.7	Jun-70	213	May-73	201.4	2.92	1.37	1.114	1.26	1.082	1.46
Three Mile I. 2	715	Dec-78	475.6	Jun-75	630	May-78	418.8	2.92	1.14	1.045	1.14	1.045	1.19
Browns Ferry 2	276	Mar-75	219.6	Mar-67	117	Feb-70	128.3	2.92	2.35	1.340	1.71	1.202	2.74
Arkansas 2	640	Mar-80	358.7	Mar-74	273	Feb-77	194.9	2.92	2.34	1.338	1.84	1.232	2.05
Susquehanna 1	1947	Jun-83	902.9	Mar-78	1195	Feb-81	612.6	2.92	1.63	1.182	1.47	1.142	1.30
Point Beach 2	71	Oct-72		Dec-69		Dec-71		2.00					1.418
Oyster Creek 1	90	Dec-69		Sep-65		Nov-67		2.17					1.962
Quad Cities 2	100	Mar-73		Mar-70		May-72		2.17					1.384
Quad Cities 2	100	Mar-73		Dec-68		Apr-71		2.33					1.823
Millstone 1	97	Mar-71		Mar-67		Aug-69		2.42					1.653
Quad Cities 1	100	Feb-73		Sep-67		Mar-70		2.50					2.171
Quad Cities 2	100	Mar-73		Jun-69		Jan-72		2.58					1.450
Dresden 2	83	Jul-70		Mar-66		Feb-69		2.92					1.482
For: 2 <= t < 3													
No. of data points:								175	167	167	167	167	175
Average								2.397	2.055	1.331	1.669	1.228	2.100
Standard Deviation:								0.279	0.734	0.183	0.449	0.132	0.585

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia	REAL Cost Ratio	REAL Myopia	Duration Ratio
For: 3 <= t < 4													
No. of data points:								103	91	91	91	91	103
Average								3.444	2.415	1.275	1.865	1.188	1.957
Standard Deviation:								0.295	0.930	0.141	0.565	0.100	0.590
Duane Arnold	280	Feb-75	222.5	Dec-69	138	Dec-73	130.5	4.00	2.03	1.193	1.71	1.143	1.29
St. Lucie 1	486	Jun-76	367.4	Jun-69	123	Jun-73	116.3	4.00	3.95	1.410	3.16	1.333	1.75
Lasalle 1	1367	Oct-82	660.8	Dec-74	445	Dec-78	295.8	4.00	3.07	1.324	2.23	1.223	1.96
Vermont Yankee	184	Nov-72	184.5	Sep-66	88	Oct-70	96.2	4.08	2.10	1.199	1.92	1.173	1.51
Browns Ferry 2	276	Mar-75	219.6	Sep-66	117	Oct-70	128.3	4.08	2.35	1.233	1.71	1.141	2.08
Arkansas 2	640	Mar-80	358.7	Sep-72	230	Oct-76	173.9	4.08	2.78	1.285	2.06	1.194	1.84
Sequoyah 1	984	Jul-81	504.0	Sep-69	187	Oct-73	176.4	4.08	5.27	1.503	2.86	1.293	2.90
Sequoyah 2	623	Jun-82	301.3	Sep-69	187	Oct-73	176.4	4.08	3.34	1.344	1.71	1.140	3.12
Cooper	269	Jul-74	234.0	Mar-68	127	Apr-72	127.0	4.08	2.12	1.202	1.84	1.161	1.55
Farley 2	750	Jul-81	384.3	Mar-73	268	Apr-77	191.4	4.08	2.80	1.287	2.01	1.186	2.04
Three Mile I. 1	401	Sep-74	348.4	Mar-67	100	May-71	104.2	4.17	4.01	1.395	3.34	1.336	1.80
Zion 2	292	Sep-74	253.7	Mar-69	194	May-73	183.5	4.17	1.51	1.103	1.38	1.081	1.32
Salem 1	850	Jun-77	607.2	Mar-67	139	May-71	144.8	4.17	6.12	1.544	4.19	1.411	2.46
McGuire 1	906	Dec-81	464.1	Sep-71	220	Nov-75	174.9	4.17	4.12	1.404	2.65	1.264	2.46
Susquehanna 1	1947	Jun-83	902.9	Sep-76	1032	Nov-80	578.4	4.17	1.89	1.165	1.56	1.113	1.62
Surry 1	247	Dec-72	246.7	Dec-66	130	Mar-71	135.4	4.25	1.90	1.163	1.82	1.152	1.41
Peach Bottom 2	531	Jul-74	461.1	Dec-66	138	Mar-71	143.7	4.25	3.85	1.373	3.21	1.316	1.79
North Anna 1	782	Jun-78	519.7	Dec-69	281	Mar-74	244.2	4.25	2.78	1.272	2.13	1.195	2.00
Surry 2	155	May-73	146.9	Dec-67	112	Mar-72	112.0	4.25	1.39	1.080	1.31	1.066	1.27
Salem 1	850	Jun-77	607.2	Sep-67	152	Dec-71	158.3	4.25	5.59	1.500	3.84	1.372	2.29
Salem 1	850	Jun-77	607.2	Dec-67	152	Mar-72	152.0	4.25	5.59	1.500	3.99	1.385	2.24
Davis-Besse 1	672	Nov-77	480.2	Sep-70	266	Dec-74	231.1	4.25	2.53	1.244	2.08	1.193	1.69
Sequoyah 2	623	Jun-82	301.3	Sep-70	187	Dec-74	162.1	4.25	3.34	1.328	1.86	1.157	2.76
Oconee 3	160	Dec-74	139.4	Mar-69	93	Jun-73	87.6	4.25	1.73	1.138	1.59	1.116	1.35
Hatch 1	390	Dec-75	310.4	Mar-69	151	Jun-73	142.3	4.25	2.59	1.250	2.17	1.200	1.59
Beaver Valley 1	599	Oct-76	452.4	Mar-69	189	Jun-73	178.7	4.25	3.17	1.312	2.53	1.244	1.78
Millstone 2	426	Dec-75	338.9	Dec-69	183	Apr-74	159.0	4.33	2.33	1.216	2.13	1.191	1.38
Cook 1	545	Aug-75	433.0	Dec-67	235	Apr-72	235.0	4.33	2.32	1.214	1.84	1.151	1.77
Cook 2	452	Jul-78	300.2	Dec-67	235	Apr-72	235.0	4.33	1.92	1.163	1.28	1.058	2.44
Arkansas 2	640	Mar-80	358.7	Jun-71	190	Oct-75	151.0	4.33	3.37	1.323	2.37	1.221	2.02
San Onofre 2	2502	Aug-83	1160.3	Jun-77	1320	Oct-81	676.4	4.33	1.90	1.159	1.72	1.133	1.42
Summer 1	1283	Jan-84	579.4	Sep-72	297	Jan-77	212.1	4.33	4.32	1.402	2.73	1.261	2.61
Pilgrim 1	239	Dec-72	239.3	Feb-67	105	Jul-71	109.4	4.41	2.28	1.205	2.19	1.194	1.32
Oconee 1	156	Jul-73	147.1	Dec-66	76	May-71	79.1	4.41	2.05	1.176	1.86	1.151	1.49
St. Lucie 2	1430	Aug-83	663.2	Dec-78	919	May-83	426.2	4.41	1.56	1.105	1.56	1.105	1.06
Summer 1	1283	Jan-84	579.4	Dec-74	355	May-79	217.2	4.41	3.61	1.338	2.67	1.249	2.06
Prairie Isl 1	233	Dec-73	220.5	Dec-67	105	May-72	105.1	4.42	2.22	1.198	2.10	1.183	1.36
Oconee 2	160	Sep-74	139.4	Dec-67	88	May-72	87.9	4.42	1.83	1.146	1.59	1.110	1.53
Peach Bottom 3	223	Dec-74	194.1	Sep-68	145	Mar-73	137.1	4.50	1.54	1.101	1.42	1.080	1.39
North Anna 2	542	Dec-80	303.8	Sep-70	184	Mar-75	146.3	4.50	2.95	1.272	2.08	1.177	2.28
Kewaunee	203	Jun-74	176.7	Dec-67	85	Jun-72	85.0	4.50	2.39	1.214	2.08	1.177	1.44
Duane Arnold	280	Feb-75	222.5	Jun-69	133	Dec-73	125.8	4.50	2.10	1.180	1.77	1.135	1.26
Hatch 2	515	Sep-79	315.1	Sep-73	404	Apr-78	268.6	4.58	1.27	1.054	1.17	1.036	1.31
Cooper	269	Jul-74	234.0	Sep-67	133	Apr-72	133.0	4.58	2.02	1.166	1.76	1.131	1.49
Summer 1	1283	Jan-84	579.4	Jun-73	297	Jan-78	197.4	4.59	4.32	1.376	2.93	1.265	2.31
Oconee 1	156	Jul-73	147.1	Sep-66	78	May-71	81.6	4.66	1.99	1.159	1.80	1.135	1.47

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia	REAL Cost Ratio	REAL Myopia	Duration Ratio
Peach Bottom 2	531	Jul-74	461.1	Mar-68	163	Mar-71	169.8	3.00	3.26	1.482	2.72	1.396	2.11
Brunswick 1	318	Mar-77	227.4	Dec-72	214	Dec-75	170.1	3.00	1.49	1.142	1.34	1.102	1.42
Sequoyah 2	623	Jun-82	301.3	Dec-72	225	Dec-75	178.5	3.00	2.78	1.406	1.69	1.191	3.17
Peach Bottom 3	223	Dec-74	194.1	Mar-70	221	Mar-73	209.0	3.00	1.01	1.003	0.93	0.976	1.58
Duane Arnold	280	Feb-75	222.5	Dec-70	148	Dec-73	140.0	3.00	1.89	1.237	1.59	1.167	1.39
Hatch 1	390	Dec-75	310.4	Jun-70	184	Jun-73	174.0	3.00	2.12	1.285	1.78	1.213	1.83
St. Lucie 1	486	Jun-76	367.4	Jun-71	203	Jun-74	176.4	3.00	2.40	1.338	2.08	1.277	1.67
Arkansas 2	640	Mar-80	358.7	Dec-73	273	Dec-76	206.3	3.00	2.34	1.328	1.74	1.202	2.08
Sequoyah 2	623	Jun-82	301.3	Sep-74	313	Sep-77	223.1	3.00	1.99	1.259	1.35	1.105	2.58
Sequoyah 2	623	Jun-82	301.3	Jun-72	213	Jul-75	168.9	3.08	2.93	1.418	1.78	1.207	3.25
Browns Ferry 1	276	Aug-74	240.0	Sep-67	124	Oct-70	136.0	3.08	2.22	1.295	1.76	1.202	2.24
Browns Ferry 3	334	Mar-77	238.2	Sep-70	149	Oct-73	141.0	3.08	2.24	1.299	1.69	1.186	2.11
Salem 1	850	Jun-77	607.2	Sep-71	308	Oct-74	267.6	3.08	2.76	1.390	2.27	1.304	1.87
Zion 1	276	Dec-73	261.0	Mar-69	205	Apr-72	205.0	3.09	1.35	1.101	1.27	1.081	1.54
Peach Bottom 3	223	Dec-74	194.1	Mar-71	263	Apr-74	228.5	3.09	0.85	0.948	0.85	0.948	1.22
Farley 2	750	Jul-81	384.3	Dec-73	329	Jan-77	234.9	3.09	2.28	1.306	1.64	1.173	2.46
Sequoyah 1	984	Jul-81	504.0	Mar-71	213	Apr-74	184.7	3.09	4.63	1.643	2.73	1.385	3.35
Salem 2	820	Oct-81	420.2	Mar-71	237	Apr-74	205.9	3.09	3.46	1.495	2.04	1.260	3.43
McGuire 1	906	Dec-81	464.1	Dec-74	384	Jan-78	255.3	3.09	2.36	1.321	1.82	1.214	2.27
Fort Calhoun 1	176	Sep-73	166.2	Mar-69	92	May-72	92.0	3.17	1.91	1.227	1.81	1.205	1.42
Oconee 2	160	Sep-74	139.4	Mar-69	93	May-72	92.6	3.17	1.73	1.189	1.51	1.138	1.74
McGuire 1	906	Dec-81	464.1	Sep-73	220	Nov-76	166.2	3.17	4.12	1.563	2.79	1.383	2.60
Sequoyah 2	623	Jun-82	301.3	Jun-73	225	Aug-76	169.6	3.17	2.78	1.380	1.78	1.199	2.84
Sequoyah 2	623	Jun-82	301.3	Dec-73	225	Feb-77	160.3	3.17	2.78	1.380	1.88	1.220	2.68
Surry 1	247	Dec-72	246.7	Dec-67	144	Mar-71	150.0	3.25	1.71	1.180	1.64	1.166	1.54
Surry 2	155	May-73	146.9	Dec-68	123	Mar-72	123.0	3.25	1.26	1.075	1.19	1.056	1.36
Peach Bottom 3	223	Dec-74	194.1	Dec-69	203	Mar-73	192.0	3.25	1.10	1.030	1.01	1.003	1.54
Brunswick 2	389	Nov-75	309.3	Dec-70	195	Mar-74	169.4	3.25	2.00	1.237	1.83	1.204	1.51
Brunswick 1	318	Mar-77	227.4	Dec-71	181	Mar-75	143.9	3.25	1.76	1.190	1.58	1.151	1.62
Salem 2	820	Oct-81	420.2	Dec-72	425	Mar-76	321.1	3.25	1.93	1.224	1.31	1.086	2.72
McGuire 1	906	Dec-81	464.1	Dec-72	220	Mar-76	166.2	3.25	4.12	1.546	2.79	1.372	2.77
Sequoyah 2	623	Jun-82	301.3	Dec-71	213	Mar-75	168.9	3.25	2.93	1.393	1.78	1.195	3.23
Pilgrim 1	239	Dec-72	239.3	Jun-68	122	Sep-71	127.4	3.25	1.96	1.229	1.88	1.214	1.39
Arkansas 2	640	Mar-80	358.7	Sep-73	275	Dec-76	207.8	3.25	2.33	1.297	1.73	1.183	2.00
Lasalle 1	1367	Oct-82	660.8	Sep-75	498	Dec-78	331.1	3.25	2.74	1.364	2.00	1.237	2.18
Kewaunee	203	Jun-74	176.7	Mar-69	109	Jun-72	109.0	3.25	1.87	1.211	1.62	1.160	1.61
Cook 1	545	Aug-75	433.0	Jun-69	235	Sep-72	235.0	3.25	2.32	1.295	1.84	1.207	1.90
Hatch 1	390	Dec-75	310.4	Mar-70	185	Jun-73	174.9	3.25	2.11	1.258	1.77	1.193	1.77
Cook 2	452	Jul-78	300.2	Jun-69	235	Sep-72	235.0	3.25	1.92	1.222	1.28	1.078	2.79
Millstone 2	426	Dec-75	338.9	Dec-70	239	Apr-74	207.7	3.33	1.78	1.190	1.63	1.158	1.50
North Anna 2	542	Dec-80	303.8	Mar-72	198	Jul-75	157.4	3.33	2.74	1.353	1.93	1.218	2.63
Farley 2	750	Jul-81	384.3	Dec-75	477	Apr-79	291.9	3.33	1.57	1.145	1.32	1.086	1.68
Calvert Cliffs 2	335	Apr-77	239.4	Sep-70	128	Jan-74	111.2	3.33	2.62	1.335	2.15	1.258	1.97
Arkansas 2	640	Mar-80	358.7	Jun-73	275	Oct-76	207.8	3.33	2.33	1.288	1.73	1.178	2.02
Salem 2	820	Oct-81	420.2	Mar-70	237	Jul-73	224.1	3.33	3.46	1.451	1.87	1.207	3.47
McGuire 1	906	Dec-81	464.1	Sep-74	365	Jan-78	242.7	3.33	2.48	1.313	1.91	1.215	2.17
Three Mile I. 1	401	Sep-74	348.4	Dec-67	124	May-71	129.2	3.41	3.23	1.410	2.70	1.337	1.98
Summer 1	1283	Jan-84	579.4	Dec-76	635	May-80	355.9	3.41	2.02	1.229	1.63	1.153	2.07
Peach Bottom 2	531	Jul-74	461.1	Sep-67	163	Mar-71	169.8	3.50	3.26	1.402	2.72	1.331	1.95
Peach Bottom 3	223	Dec-74	194.1	Sep-69	193	Mar-73	182.5	3.50	1.16	1.043	1.06	1.018	1.50
Cook 2	452	Jul-78	300.2	Sep-70	339	Mar-74	294.6	3.50	1.33	1.085	1.02	1.005	2.24
St. Lucie 1	486	Jun-76	367.4	Dec-70	200	Jun-74	173.8	3.50	2.43	1.289	2.11	1.239	1.57
Beaver Valley 1	599	Oct-76	452.4	Dec-69	192	Jun-73	181.6	3.50	3.12	1.384	2.49	1.298	1.95

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia	REAL Cost Ratio	REAL Myopia	Duration Ratio
North Anna 2	542	Dec-80	303.8	Dec-71	198	Jun-75	157.4	3.50	2.74	1.333	1.93	1.207	2.57
Arkansas 1	239	Dec-74	207.5	Jun-69	132	Dec-72	132.0	3.50	1.81	1.184	1.57	1.138	1.57
Salem 2	820	Oct-81	420.2	Jun-71	237	Dec-74	205.9	3.50	3.46	1.425	2.04	1.226	2.95
Trojan	452	Dec-75	359.3	Mar-71	228	Sep-74	198.1	3.50	1.98	1.216	1.81	1.185	1.36
Farley 1	727	Dec-77	519.4	Sep-71	259	Apr-75	205.9	3.58	2.81	1.334	2.52	1.295	1.75
Hatch 2	515	Sep-79	315.1	Sep-75	513	Apr-79	313.9	3.58	1.00	1.001	1.00	1.001	1.12
Hatch 2	515	Sep-79	315.1	Sep-74	513	Apr-78	341.0	3.58	1.00	1.001	0.92	0.978	1.40
Farley 2	750	Jul-81	384.3	Jun-73	268	Jan-77	191.4	3.59	2.80	1.332	2.01	1.215	2.25
Summer 1	1283	Jan-84	579.4	Jun-74	355	Jan-78	236.0	3.59	3.61	1.431	2.45	1.285	2.67
Maine Yankee	219	Dec-72	219.2	Sep-68	131	May-72	131.0	3.66	1.67	1.151	1.67	1.151	1.16
Oconee 1	156	Jul-73	147.1	Sep-67	93	May-71	96.5	3.66	1.68	1.152	1.53	1.122	1.59
Fort Calhoun 1	176	Sep-73	166.2	Sep-67	70	May-71	72.9	3.66	2.51	1.286	2.28	1.252	1.64
Prairie Isl 2	177	Dec-74	153.8	Sep-70	112	May-74	97.5	3.66	1.58	1.133	1.58	1.133	1.16
St. Lucie 1	486	Jun-76	367.4	Sep-69	123	May-73	116.3	3.66	3.95	1.455	3.16	1.369	1.84
Three Mile I. 2	715	Dec-78	475.6	Sep-70	285	May-74	247.7	3.66	2.51	1.286	1.92	1.195	2.24
Three Mile I. 2	715	Dec-78	475.6	Sep-71	345	May-75	274.3	3.66	2.07	1.220	1.73	1.162	1.97
Three Mile I. 2	715	Dec-78	475.6	Sep-74	580	May-78	385.6	3.66	1.23	1.059	1.23	1.059	1.15
Salem 2	820	Oct-81	420.2	Sep-71	308	May-75	244.9	3.66	2.66	1.306	1.72	1.159	2.75
Susquehanna 1	1947	Jun-83	902.9	Mar-77	1097	Nov-80	615.0	3.67	1.77	1.169	1.47	1.110	1.70
Oconee 3	160	Dec-74	139.4	Sep-69	109	Jun-73	103.3	3.75	1.47	1.108	1.35	1.083	1.40
Brunswick 1	318	Mar-77	227.4	Jun-71	182	Mar-75	144.7	3.75	1.75	1.161	1.57	1.128	1.53
Three Mile I. 2	715	Dec-78	475.6	Aug-72	465	May-76	351.4	3.75	1.54	1.122	1.35	1.084	1.68
North Anna 2	542	Dec-80	303.8	Sep-71	191	Jun-75	151.8	3.75	2.84	1.321	2.00	1.203	2.47
Arkansas 1	239	Dec-74	207.5	Mar-69	138	Dec-72	138.0	3.75	1.73	1.157	1.50	1.115	1.53
Nine Mile Point 1	162	Dec-69	186.9	Sep-64	68	Jul-68	82.4	3.83	2.39	1.255	2.27	1.239	1.37
Indian Point 3	570	Aug-76	430.7	Sep-67	154	Jul-71	160.4	3.83	3.70	1.407	2.69	1.294	2.34
Browns Ferry 1	276	Aug-74	240.0	Dec-66	117	Oct-70	128.3	3.83	2.35	1.250	1.87	1.178	2.00
Crystal River 3	419	Mar-77	299.2	Jun-68	113	Apr-72	113.0	3.83	3.71	1.408	2.65	1.289	2.28
Arkansas 2	640	Mar-80	358.7	Dec-71	200	Oct-75	159.0	3.83	3.20	1.355	2.26	1.236	2.15
Sequoyah 1	984	Jul-81	504.0	Jun-70	187	Apr-74	162.1	3.83	5.27	1.543	3.11	1.344	2.89
Sequoyah 2	623	Jun-82	301.3	Jun-70	187	Apr-74	162.1	3.83	3.34	1.370	1.86	1.176	3.13
Calvert Cliffs 1	431	May-75	342.4	Mar-69	124	Jan-73	117.3	3.84	3.47	1.383	2.92	1.322	1.61
Oconee 1	156	Jul-73	147.1	Jun-67	86	May-71	89.3	3.92	1.81	1.164	1.65	1.136	1.55
Browns Ferry 1	276	Aug-74	240.0	Sep-66	117	Aug-70	128.3	3.92	2.35	1.244	1.87	1.174	2.02
Three Mile I. 1	401	Sep-74	348.4	Jun-67	106	May-71	110.4	3.92	3.78	1.405	3.16	1.341	1.85
Salem 1	850	Jun-77	607.2	Jun-67	149	May-71	155.2	3.92	5.71	1.560	3.91	1.417	2.55
Three Mile I. 2	715	Dec-78	475.6	Jun-73	525	May-77	374.9	3.92	1.36	1.082	1.27	1.063	1.40
Susquehanna 1	1947	Jun-83	902.9	Dec-76	1032	Nov-80	578.2	3.92	1.89	1.176	1.56	1.121	1.66
Indian Point 2	206	Aug-73		Jun-66		Jun-69		3.00					2.389
Ginna	83	Jul-70		Mar-66		Jun-69		3.25					1.332
Oyster Creek 1	90	Dec-69		Jun-64		Oct-67		3.33					1.651
Quad Cities 2	100	Mar-73		Sep-67		Mar-71		3.50					1.572
Ginna	83	Jul-70		Dec-65		Jun-69		3.50					1.309
Point Beach 1	74	Dec-70		Sep-66		Apr-70		3.58					1.187
Millstone 1	97	Mar-71		Dec-65		Aug-69		3.67					1.431
Quad Cities 1	100	Feb-73		Jun-66		Mar-70		3.75					1.780
Point Beach 1	74	Dec-70		Jun-66		Apr-70		3.83					1.174
Monticello	105	Jun-71		Jun-66		May-70		3.92					1.277
Robinson 2	78	Mar-71		Jun-66		May-70		3.92					1.213
Dresden 3	104	Nov-71		Mar-66		Feb-70		3.92					1.445

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia	REAL Cost Ratio	REAL Myopia	Duration Ratio
For: 3 <= t < 4													
No. of data points:								103	91	91	91	91	103
Average								3.444	2.415	1.275	1.865	1.188	1.957
Standard Deviation:								0.295	0.930	0.141	0.565	0.100	0.590
Duane Arnold	280	Feb-75	222.5	Dec-69	138	Dec-73	130.5	4.00	2.03	1.193	1.71	1.143	1.29
St. Lucie 1	486	Jun-76	367.4	Jun-69	123	Jun-73	116.3	4.00	3.95	1.410	3.16	1.333	1.75
Lasalle 1	1367	Oct-82	660.8	Dec-74	445	Dec-78	295.8	4.00	3.07	1.324	2.23	1.223	1.96
Vermont Yankee	184	Nov-72	184.5	Sep-66	88	Oct-70	96.2	4.08	2.10	1.199	1.92	1.173	1.51
Browns Ferry 2	276	Mar-75	219.6	Sep-66	117	Oct-70	128.3	4.08	2.35	1.233	1.71	1.141	2.08
Arkansas 2	640	Mar-80	358.7	Sep-72	230	Oct-76	173.8	4.08	2.78	1.285	2.06	1.194	1.84
Sequoyah 1	984	Jul-81	504.0	Sep-69	187	Oct-73	176.4	4.08	5.27	1.503	2.86	1.293	2.90
Sequoyah 2	623	Jun-82	301.3	Sep-69	187	Oct-73	176.4	4.08	3.34	1.344	1.71	1.140	3.12
Cooper	269	Jul-74	234.0	Mar-68	127	Apr-72	127.0	4.08	2.12	1.202	1.84	1.161	1.55
Farley 2	750	Jul-81	384.3	Mar-73	268	Apr-77	191.4	4.08	2.80	1.287	2.01	1.186	2.04
Three Mile I. 1	401	Sep-74	348.4	Mar-67	100	May-71	104.2	4.17	4.01	1.395	3.34	1.336	1.80
Zion 2	292	Sep-74	253.7	Mar-69	194	May-73	183.5	4.17	1.51	1.103	1.38	1.081	1.32
Salem 1	850	Jun-77	607.2	Mar-67	139	May-71	144.8	4.17	6.12	1.544	4.19	1.411	2.46
McGuire 1	906	Dec-81	464.1	Sep-71	220	Nov-75	174.9	4.17	4.12	1.404	2.65	1.264	2.46
Susquehanna 1	1947	Jun-83	902.9	Sep-76	1032	Nov-80	578.4	4.17	1.89	1.165	1.56	1.113	1.62
Surry 1	247	Dec-72	246.7	Dec-66	130	Mar-71	135.4	4.25	1.90	1.163	1.82	1.152	1.41
Peach Bottom 2	531	Jul-74	461.1	Dec-66	138	Mar-71	143.7	4.25	3.85	1.373	3.21	1.316	1.79
North Anna 1	782	Jun-78	519.7	Dec-69	281	Mar-74	244.2	4.25	2.78	1.272	2.13	1.195	2.00
Surry 2	155	May-73	146.9	Dec-67	112	Mar-72	112.0	4.25	1.39	1.080	1.31	1.066	1.27
Salem 1	850	Jun-77	607.2	Sep-67	152	Dec-71	158.3	4.25	5.59	1.500	3.84	1.372	2.29
Salem 1	850	Jun-77	607.2	Dec-67	152	Mar-72	152.0	4.25	5.59	1.500	3.99	1.385	2.24
Davis-Besse 1	672	Nov-77	480.2	Sep-70	266	Dec-74	231.1	4.25	2.53	1.244	2.08	1.188	1.69
Sequoyah 2	623	Jun-82	301.3	Sep-70	187	Dec-74	162.1	4.25	3.34	1.328	1.86	1.157	2.76
Oconee 3	160	Dec-74	139.4	Mar-69	93	Jun-73	87.6	4.25	1.73	1.138	1.59	1.116	1.35
Hatch 1	390	Dec-75	310.4	Mar-69	151	Jun-73	142.8	4.25	2.59	1.250	2.17	1.200	1.59
Beaver Valley 1	599	Oct-76	452.4	Mar-69	189	Jun-73	178.7	4.25	3.17	1.312	2.53	1.244	1.78
Millstone 2	426	Dec-75	338.9	Dec-69	183	Apr-74	159.0	4.33	2.33	1.216	2.13	1.191	1.38
Cook 1	545	Aug-75	433.0	Dec-67	235	Apr-72	235.0	4.33	2.32	1.214	1.84	1.151	1.77
Cook 2	452	Jul-78	300.2	Dec-67	235	Apr-72	235.0	4.33	1.92	1.163	1.28	1.058	2.44
Arkansas 2	640	Mar-80	358.7	Jun-71	190	Oct-75	151.0	4.33	3.37	1.323	2.37	1.221	2.02
San Onofre 2	2502	Aug-83	1160.3	Jun-77	1320	Oct-81	676.4	4.33	1.90	1.159	1.72	1.133	1.42
Summer 1	1283	Jan-84	579.4	Sep-72	297	Jan-77	212.1	4.33	4.32	1.402	2.73	1.261	2.61
Pilgrim 1	239	Dec-72	239.3	Feb-67	105	Jul-71	109.4	4.41	2.28	1.205	2.19	1.194	1.32
Oconee 1	156	Jul-73	147.1	Dec-66	76	May-71	79.1	4.41	2.05	1.176	1.86	1.151	1.49
St. Lucie 2	1430	Aug-83	663.2	Dec-78	919	May-83	426.2	4.41	1.56	1.105	1.56	1.105	1.06
Summer 1	1283	Jan-84	579.4	Dec-74	355	May-79	217.2	4.41	3.61	1.338	2.67	1.249	2.06
Prairie Isl 1	233	Dec-73	220.5	Dec-67	105	May-72	105.1	4.42	2.22	1.198	2.10	1.183	1.36
Oconee 2	160	Sep-74	139.4	Dec-67	88	May-72	87.9	4.42	1.83	1.146	1.59	1.110	1.53
Peach Bottom 3	223	Dec-74	194.1	Sep-68	145	Mar-73	137.1	4.50	1.54	1.101	1.42	1.080	1.39
North Anna 2	542	Dec-80	303.8	Sep-70	184	Mar-75	146.3	4.50	2.95	1.272	2.08	1.177	2.28
Kewaunee	203	Jun-74	176.7	Dec-67	85	Jun-72	85.0	4.50	2.39	1.214	2.08	1.177	1.44
Duane Arnold	280	Feb-75	222.5	Jun-69	133	Dec-73	125.8	4.50	2.10	1.180	1.77	1.135	1.26
Hatch 2	515	Sep-79	315.1	Sep-73	404	Apr-78	268.6	4.58	1.27	1.054	1.17	1.036	1.31
Cooper	269	Jul-74	234.0	Sep-67	133	Apr-72	133.0	4.58	2.02	1.166	1.76	1.131	1.49
Summer 1	1283	Jan-84	579.4	Jun-73	297	Jan-78	197.4	4.59	4.32	1.376	2.93	1.265	2.31
Oconee 1	156	Jul-73	147.1	Sep-66	78	May-71	81.6	4.66	1.99	1.159	1.80	1.135	1.47

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia	REAL Cost Ratio	REAL Myopia	Duration Ratio
Salem 2	820	Oct-81	420.2	Sep-74	496	May-79	303.5	4.66	1.65	1.114	1.38	1.072	1.52
Lucie 2	1430	Aug-83	663.2	Sep-78	845	May-83	391.9	4.66	1.69	1.119	1.69	1.119	1.05
ne Yankee	219	Dec-72	219.2	Sep-67	100	May-72	100.0	4.67	2.19	1.183	2.19	1.183	1.13
ne Mile Point 1	162	Dec-69	186.9	Mar-64	68	Nov-68	82.4	4.67	2.39	1.205	2.27	1.192	1.23
Susquehanna 1	1947	Jun-83	902.9	Mar-76	1047	Nov-80	586.8	4.67	1.86	1.142	1.54	1.097	1.55
Salem 1	850	Jun-77	607.2	Sep-66	139	May-71	144.8	4.70	6.12	1.470	4.19	1.356	2.29
Three Mile I. 2	715	Dec-78	475.6	Aug-69	214	May-74	186.0	4.75	3.34	1.289	2.56	1.219	1.96
Trojan	452	Dec-75	359.3	Dec-69	227	Sep-74	197.3	4.75	1.99	1.156	1.82	1.135	1.26
Farley 1	727	Dec-77	519.4	Jun-70	203	Apr-75	161.4	4.83	3.58	1.302	3.22	1.274	1.55
Arkansas 2	640	Mar-80	358.7	Dec-70	183	Oct-75	145.5	4.83	3.50	1.296	2.47	1.205	1.91
Sequoyah 2	623	Jun-82	301.3	Dec-68	161	Oct-73	152.2	4.83	3.87	1.323	1.98	1.152	2.79
Peach Bottom 3	223	Dec-74	194.1	Mar-68	145	Jan-73	137.1	4.84	1.54	1.093	1.42	1.074	1.40
Calvert Cliffs 1	431	May-75	342.4	Mar-68	125	Jan-73	118.2	4.84	3.45	1.291	2.90	1.246	1.48
Calvert Cliffs 2	335	Apr-77	239.4	Mar-69	105	Jan-74	91.2	4.84	3.19	1.271	2.62	1.221	1.67
Oconee 2	160	Sep-74	139.4	Jun-67	86	May-72	85.8	4.92	1.87	1.136	1.63	1.104	1.47
Point Beach 2	71	Oct-72		Mar-67		Apr-71		4.08					1.368
Quad Cities 2	100	Mar-73		Sep-66		Mar-71		4.50					1.445
For: 4 <= t < 5													
No. of data points:								63	61	61	61	61	63
Average								4.398	2.827	1.251	2.193	1.186	1.752
Standard Deviation:								0.256	1.186	0.117	0.715	0.085	0.481
Oconee 3	160	Dec-74	139.4	Jun-68	88	Jun-73	83.1	5.00	1.83	1.128	1.68	1.109	1.30
Duane Arnold	280	Feb-75	222.5	Dec-68	107	Dec-73	101.2	5.00	2.62	1.212	2.20	1.171	1.23
Hatch 1	390	Dec-75	310.4	Jun-68	160	Jun-73	151.3	5.00	2.44	1.195	2.05	1.155	1.50
North Anna 1	782	Jun-78	519.7	Mar-69	185	Mar-74	160.9	5.00	4.23	1.334	3.23	1.265	1.85
St. Lucie 2	1430	Aug-83	663.2	Dec-74	537	Dec-79	328.6	5.00	2.66	1.216	2.02	1.151	1.73
Arkansas 1	239	Dec-74	207.5	Dec-67	132	Dec-72	132.0	5.00	1.81	1.126	1.57	1.095	1.40
St. Lucie 2	1430	Aug-83	663.2	Dec-75	620	Dec-80	347.5	5.00	2.31	1.182	1.91	1.138	1.53
Sequoyah 1	984	Jul-81	504.0	Sep-68	161	Oct-73	152.2	5.08	6.11	1.429	3.31	1.266	2.52
Zion 1	276	Dec-73	261.0	Mar-67	164	Apr-72	164.0	5.09	1.68	1.108	1.59	1.096	1.33
Calvert Cliffs 1	431	May-75	342.4	Dec-67	123	Jan-73	116.3	5.09	3.50	1.279	2.94	1.236	1.46
Crystal River 3	419	Mar-77	299.2	Mar-67	110	Apr-72	110.0	5.09	3.81	1.301	2.72	1.217	1.97
Fitzpatrick	419	Jul-75	333.1	Mar-68	224	May-73	211.8	5.17	1.87	1.129	1.57	1.092	1.42
McGuire 1	906	Dec-81	464.1	Sep-70	179	Nov-75	142.3	5.17	5.06	1.369	3.26	1.257	2.18
Lasalle 1	1367	Oct-82	660.8	Mar-73	407	May-78	270.6	5.17	3.36	1.264	2.44	1.189	1.86
Prairie Isl 1	233	Dec-73	220.5	Mar-67	100	May-72	100.0	5.17	2.33	1.178	2.21	1.165	1.31
Surry 2	155	May-73	146.9	Dec-66	108	Mar-72	108.0	5.25	1.44	1.072	1.36	1.060	1.22
Brunswick 1	318	Mar-77	227.4	Dec-70	194	Mar-76	146.6	5.25	1.64	1.099	1.55	1.087	1.19
Davis-Besse 1	672	Nov-77	480.2	Sep-69	201	Dec-74	174.7	5.25	3.35	1.259	2.75	1.212	1.56
Salem 2	820	Oct-81	420.2	Dec-67	128	Mar-73	121.0	5.25	6.41	1.425	3.47	1.268	2.64
Lasalle 1	1367	Oct-82	660.8	Sep-72	407	Dec-77	290.6	5.25	3.36	1.260	2.27	1.169	1.92
Lasalle 1	1367	Oct-82	660.8	Sep-73	430	Dec-78	285.9	5.25	3.18	1.247	2.31	1.173	1.73
Beaver Valley 1	599	Oct-76	452.4	Mar-68	150	Jun-73	141.8	5.25	3.99	1.302	3.19	1.247	1.64
San Onofre 2	2502	Aug-83	1160.3	Mar-74	655	Jun-79	400.8	5.25	3.82	1.291	2.89	1.224	1.79
St. Lucie 2	1430	Aug-83	663.2	Sep-75	537	Dec-80	301.0	5.25	2.66	1.205	2.20	1.162	1.51
Millstone 2	426	Dec-75	338.9	Dec-68	179	Apr-74	155.5	5.33	2.38	1.177	2.18	1.157	1.31
Hatch 2	515	Sep-79	315.1	Dec-72	330	Apr-78	219.4	5.33	1.56	1.087	1.44	1.070	1.27

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia	REAL Cost Ratio	REAL Myopia	Duration Ratio
Lasalle 1	1367	Oct-82	660.8	Jun-73	407	Oct-78	270.6	5.33	3.36	1.255	2.44	1.182	1.75
Lasalle 1	1367	Oct-82	660.8	Jun-70	360	Oct-75	286.2	5.33	3.80	1.284	2.31	1.170	2.31
San Onofre 2	2502	Aug-83	1160.3	Jun-76	1210	Oct-81	620.1	5.33	2.07	1.146	1.87	1.125	1.34
Peach Bottom 3	223	Dec-74	194.1	Sep-67	145	Jan-73	137.1	5.34	1.54	1.084	1.42	1.067	1.36
Rancho Seco	344	Apr-75	273.2	Dec-67	134	May-73	126.7	5.42	2.56	1.190	2.16	1.152	1.35
Oconee 3	160	Dec-74	139.4	Dec-67	93	Jun-73	87.6	5.50	1.73	1.105	1.59	1.088	1.27
Duane Arnold	280	Feb-75	222.5	Jun-68	103	Dec-73	97.4	5.50	2.72	1.199	2.28	1.162	1.21
St. Lucie 2	1430	Aug-83	663.2	Jun-74	360	Dec-79	220.3	5.50	3.97	1.285	3.01	1.222	1.67
Trojan	452	Dec-75	359.3	Mar-69	197	Sep-74	171.2	5.50	2.29	1.163	2.10	1.144	1.23
Farley 1	727	Dec-77	519.4	Sep-69	164	Apr-75	130.4	5.58	4.44	1.306	3.98	1.281	1.48
Beaver Valley 1	599	Oct-76	452.4	Dec-67	150	Jul-73	141.8	5.58	3.99	1.281	3.19	1.231	1.58
Farley 2	750	Jul-81	384.3	Sep-71	233	Apr-77	166.4	5.58	3.22	1.233	2.31	1.162	1.76
Calvert Cliffs 1	431	May-75	342.4	Jun-67	118	Jan-73	111.6	5.59	3.65	1.261	3.07	1.222	1.42
Susquehanna 1	1947	Jun-83	902.9	Sep-73	810	May-79	495.7	5.66	2.40	1.168	1.82	1.112	1.72
Oconee 2	160	Sep-74	139.4	Sep-66	75	May-72	75.4	5.66	2.13	1.143	1.85	1.115	1.41
Salem 2	820	Oct-81	420.2	Sep-67	128	May-73	121.0	5.66	6.41	1.388	3.47	1.246	2.49
Lasalle 1	1367	Oct-82	660.8	Sep-71	360	May-77	257.1	5.66	3.80	1.266	2.57	1.181	1.96
Trojan	452	Dec-75	359.3	Dec-68	196	Sep-74	170.3	5.75	2.31	1.156	2.11	1.139	1.22
St. Lucie 2	1430	Aug-83	663.2	Dec-72	360	Oct-78	239.3	5.83	3.97	1.267	2.77	1.191	1.83
Calvert Cliffs 2	335	Apr-77	239.4	Mar-68	106	Jan-74	92.1	5.84	3.16	1.218	2.60	1.178	1.56
Summer 1	1283	Jan-84	579.4	Mar-71	234	Jan-77	167.1	5.84	5.48	1.338	3.47	1.237	2.20
Hatch 2	515	Sep-79	315.1	Jun-70	189	Apr-76	142.8	5.88	2.72	1.186	2.21	1.144	1.57
St. Lucie 2	1430	Aug-83	663.2	Jun-77	850	May-83	394.2	5.91	1.68	1.092	1.68	1.092	1.04
Zion 2	292	Sep-74	253.7	Jun-67	153	May-73	144.7	5.92	1.91	1.115	1.75	1.100	1.23
Susquehanna 1	1947	Jun-83	902.9	Dec-74	945	Nov-80	529.6	5.92	2.06	1.130	1.70	1.094	1.44
Pilgrim 1	239	Dec-72	239.3	Jul-65	70	Jul-71	72.9	6.00	3.42	1.227	3.28	1.219	1.24
Davis-Besse 1	672	Nov-77	480.2	Dec-68	180	Dec-74	156.4	6.00	3.74	1.246	3.07	1.206	1.49
Susquehanna 1	1947	Jun-83	902.9	Jun-69	150	27560	119.2	6.00	12.98	1.533	7.57	1.401	2.33
San Onofre 2	2502	Aug-83	1160.3	Jun-73	655	Jun-79	400.3	6.00	3.82	1.250	2.89	1.194	1.69
St. Lucie 2	1430	Aug-83	663.2	Dec-76	850	Dec-82	410.9	6.00	1.68	1.091	1.61	1.083	1.11
Oconee 3	160	Dec-74	139.4	Jun-67	92	Jun-73	87.1	6.00	1.74	1.097	1.60	1.082	1.25
Lasalle 1	1367	Oct-82	660.8	Dec-71	360	Dec-77	257.1	6.00	3.80	1.249	2.57	1.170	1.81
San Onofre 2	2502	Aug-83	1160.3	Jun-70	213	Jun-76	160.9	6.00	11.75	1.508	7.21	1.390	2.19
Millstone 2	426	Dec-75	338.9	Mar-68	146	Apr-74	126.9	6.08	2.92	1.193	2.67	1.175	1.27
San Onofre 2	2502	Aug-83	1160.3	Sep-75	1142	Oct-81	585.2	6.08	2.19	1.138	1.98	1.119	1.30
Peach Bottom 3	223	Dec-74	194.1	Dec-66	125	Jan-73	118.2	6.09	1.79	1.100	1.64	1.085	1.31
Calvert Cliffs 2	335	Apr-77	239.4	Dec-67	107	Jan-74	93.0	6.09	3.13	1.206	2.58	1.168	1.53
Susquehanna 1	1947	Jun-83	902.9	Sep-74	810	Nov-80	454.0	6.17	2.40	1.153	1.99	1.118	1.42
St. Lucie 2	1430	Aug-83	663.2	Sep-76	620	Dec-82	299.7	6.25	2.31	1.143	2.21	1.136	1.11
San Onofre 2	2502	Aug-83	1160.3	Mar-70	189	Jun-76	142.8	6.25	13.24	1.511	8.12	1.398	2.15
Millstone 2	426	Dec-75	338.9	Dec-67	150	Apr-74	130.3	6.33	2.84	1.179	2.60	1.163	1.26
San Onofre 2	2502	Aug-83	1160.3	Mar-75	1142	Jul-81	585.2	6.34	2.19	1.132	1.98	1.114	1.33
Susquehanna 1	1947	Jun-83	902.9	Dec-72	703	May-79	430.2	6.41	2.77	1.172	2.10	1.123	1.64
Prairie Isl 2	177	Dec-74	153.8	Dec-67	80	May-74	69.3	6.41	2.22	1.132	2.22	1.132	1.09
San Onofre 2	2502	Aug-83	1160.3	Dec-71	409	Jun-78	271.9	6.50	6.12	1.321	4.27	1.250	1.79
Farley 2	750	Jul-81	384.3	Sep-70	183	Apr-77	130.7	6.58	4.10	1.239	2.94	1.178	1.65
San Onofre 2	2502	Aug-83	1160.3	Dec-74	893	Jul-81	457.6	6.58	2.80	1.169	2.54	1.152	1.32
Calvert Cliffs 2	335	Apr-77	239.4	Jun-67	105	Jan-74	91.2	6.59	3.19	1.193	2.62	1.158	1.49
Susquehanna 1	1947	Jun-83	902.9	Sep-69	150	Jun-76	113.3	6.75	12.98	1.462	7.97	1.360	2.04
San Onofre 2	2502	Aug-83	1160.3	Sep-71	363	Jun-78	241.3	6.75	6.89	1.331	4.81	1.262	1.77
St. Lucie 2	1430	Aug-83	663.2	Mar-73	360	Dec-79	220.3	6.75	3.97	1.227	3.01	1.177	1.54
St. Lucie 2	1430	Aug-83	663.2	Mar-74	360	Dec-80	201.8	6.75	3.97	1.227	3.29	1.193	1.39
Susquehanna 1	1947	Jun-83	902.9	Jun-71	373	Jun-78	247.9	7.00	5.22	1.266	3.64	1.203	1.71

Unit Name	Actuals Cost	Actuals COD	Act.Cost 1972$	Date of Estimate	Estimated Cost	Estimated COD	Est.Cost 1972$	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia	REAL Cost Ratio	REAL Myopia	Duration Ratio
Susquehanna 1	1947	Jun-83	902.9	Mar-72	645	May-79	394.4	7.16	3.02	1.167	2.29	1.123	1.57
Susquehanna 1	1947	Jun-83	902.9	Dec-71	526	May-79	322.1	7.41	3.70	1.193	2.80	1.149	1.55
Susquehanna 1	1947	Jun-83	902.9	Dec-70	250	Jun-78	166.2	7.50	7.79	1.315	5.43	1.253	1.67

For: 5 <= t

No. of data points:	82	82	82	82	82	82
Average	5.773	3.676	1.226	2.751	1.176	1.582
Standard Deviation:	0.607	2.441	0.102	1.357	0.073	0.350

APPENDIX C

NOMINAL COST CALCULATIONS

COMPUTATION OF SEABROOK NOMINAL ANNUAL COST

		common	40%	15%	6.0%	
firstyr	1988	preferred	10%	12%	1.2%	
share	9.7%	debt	50%	13%	6.5%	
(% of plant)		weighted			13.7%	
cost	6,000,000	/w taxes @	50.86%		20.7%	
deprate	3.3%					
proptax	0.5%					

year	accum deprec	[1] accum deferred taxes	accum capital additions	invest base	return+ income taxes	[6] book deprec	prop taxes	[2] O&M	[3] insurance	total non-fuel costs
1	9670	-		570530	117852	19340	2901	6908	1600	148601
2	29010	14353	2809	539646	111472	18608	2901	7688	1697	142366
3	47618	89576	5787	448792	92705	16028	2901	8537	1798	121969
4	63647	103193	8943	422304	87233	15641	2901	9460	1906	117141
5	79288	113217	12289	399984	82623	15384	2901	10463	2021	113391
6	94672	123246	15836	378118	78106	15125	2901	11552	2142	109826
7	109796	133271	19595	356728	73688	14864	2901	12735	2270	106457
8	124660	141504	23580	337616	69740	14679	2901	14017	2407	103744
9	139339	149738	27804	318929	65879	14497	2901	15408	2551	101236
10	153836	157971	32282	300675	62109	14318	2901	16916	2704	98947
11	168154	166204	37029	282870	58431	14143	2901	18548	2866	96890
12	182297	158289	42059	281673	58184	14825	2901	20316	3038	99264
13	197122	150373	47391	280096	57858	15561	2901	22229	3220	101770
14	212683	142462	53044	278099	57446	16359	2901	24299	3414	104419
15	229042	134547	59036	275648	56939	17228	2901	26537	3619	107224
16	246270	126631	65387	272687	56328	18179	2901	28956	3836	110199
17	264449	118715	72120	269156	55598	19225	2901	31569	4066	113360
18	283674	110804	79256	264978	54735	20383	2901	34393	4310	116721
19	304057	102889	86821	260075	53722	21673	2901	37441	4568	120305
20	325730	94973	94839	254336	52537	23121	2901	40731	4842	124133
21	348851	87058	103339	247630	51152	24763	2901	44281	5133	128230
22	373614	79147	112348	239787	49532	26643	2901	48111	5441	132628
23	400257	71231	121899	230610	47636	28826	2901	52241	5767	137371
24	429084	63315	132022	219823	45408	31403	2901	56693	6113	142518
25	460487	55400	142752	207065	42772	34511	2901	61491	6480	148156
26	494998	47484	154127	191844	39628	38369	2901	66661	6869	154429
27	533367	39573	166183	173443	35827	43361	2901	72230	7281	161601
28	576728	31658	178964	150778	31146	50259	2901	78228	7718	170252
29	626987	23742	192511	121982	25197	60991	2901	84685	8181	181955
30	687978	15827	206871	83266	17200	83266	2901	91635	8672	203674
31	771244	7916	222092	23132	4778	ERR	2901	99115	9192	ERR

Notes: [1] From: BHE 10PA-61, acc.def.tax/gross invest.
[2] See Table 3.23. SHARE*[36532*1.043+2717.1*(yr-1982)]*1.04*(1.06^(yr-1984))
[3] 13110*SHARE*(1.06^(yr - 1984))

[4] capital additions	[5] capacity factor	non-fuel cents/ kwh	BHE fuel cents/ kwh	total cents/ kwh
2809	50%	30.4	1.1	31.5
2978	50%	29.1	1.2	30.3
3156	53%	23.8	1.2	25.0
3346	55%	21.9	1.3	23.2
3547	57%	20.3	1.4	21.7
3759	57%	19.7	1.5	21.2
3985	57%	19.1	1.7	20.7
4224	57%	18.6	1.8	20.4
4477	57%	18.1	1.9	20.1
4746	57%	17.7	2.1	19.8
5031	57%	17.4	2.2	19.6
5333	57%	17.8	2.4	20.2
5653	57%	18.2	2.6	20.8
5992	57%	18.7	2.8	21.5
6351	57%	19.2	3.0	22.2
6732	57%	19.7	3.2	22.9
7136	57%	20.3	3.4	23.7
7565	57%	20.9	3.7	24.6
8018	57%	21.6	4.0	25.5
8500	57%	22.2	4.2	26.5
9010	57%	23.0	4.6	27.5
9550	57%	23.8	4.9	28.7
10123	57%	24.6	5.3	29.9
10731	57%	25.5	5.7	31.2
11374	57%	26.5	6.1	32.6
12057	57%	27.7	6.6	34.2
12780	57%	29.0	7.0	36.0
13547	57%	30.5	7.6	38.1
14360	57%	32.6	8.1	40.7
15221	57%	36.5	8.8	45.2
16135	57%	ERR	9.4	ERR

Notes: [4] 22126*share*1.04*(1.06^(yr - 1984))
[5] Easterling + 3%
[6] Remaining life method, investment base

35R

THE STATE OF MAINE
BEFORE THE PUBLIC UTILITIES COMMISSION

RE: INVESTIGATION OF SEABROOK INVOLVEMENT BY MAINE UTILITIES	DOCKET No. 84-113

REBUTTAL TESTIMONY OF PAUL CHERNICK
ON BEHALF OF THE
MAINE PUBLIC ADVOCATE

October 5, 1984

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REBUTTAL TESTIMONY OF PAUL CHERNICK

ON BEHALF OF THE MAINE PUBLIC ADVOCATE

1 - INTRODUCTION

Q: Are you the same Paul Chernick you filed direct testimony in this case?

A: Yes.

Q: What topics does this rebuttal testimony cover?

A: It covers four areas of the utilities' filings. First, I consider the nature and purpose of PSNH's cost and schedule estimates for Seabrook, both historically and at the present.. Second, I review the composition of the current Seabrook management team. Third, I discuss the problems with the approach taken by Wile and Perl. Fourth, I discuss a few of the problems with the NEPOOL analysis of Seabrook economics, as presented by Mr. Bolbrock.[1]

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1. RELIABILITY AND COST ANALYSIS OF NOT COMPLETING SEABROOK 1 FROM A NEW ENGLAND SYSTEM PLANNING PERSPECTIVE, NEPLAN Staff, June 1, 1984.

2 - PSNH COST ESTIMATION

Q: Turning to your first topic, Seabrook construction cost estimates and construction duration estimates, what additional rebuttal testimony do you have?

A: I would like to direct the Commission's attention to the Dittmar/Ward testimony filed in Docket 84-120 by CMP, and in Docket 84-80 by MPS. The Dittmar/Ward testimony (pp. 22-26) and section IV of the underlying MAC report dated 8/29/84 (the Dittmar/Ward Appendix) confirm my basic point that the Seabrook cost and construction duration estimates which were produced by UE&C and PSNH during the entire history of the project were biased on the low side and were not unbiased best estimates.[2] Dittmar and Ward repeatedly make the point that these estimates were aggressive but achievable (at least "theoretically"), and that the use of aggressive estimates is prudent for construction management purposes. I have two additional points to make on this issue, besides pointing out the degree to which Dittmar and Ward confirm my testimony that these estimates have historically been intentionally biased on the low side.

----

2. I use the term "biased" in the statistical sense of not providing an accurate estimate on average, in the long run.

Q: What is your first point?

A: First, whatever may be the case about whether or not it is prudent <u>for construction management purposes</u> to use intentionally biased estimates, it is very clear that intentionally biased estimates should <u>not</u> be used for generation planning purposes, for financial planning purposes, for use by regulators, or for use by investors. Thus, if the current PSNH/Derrickson cost estimate were only as aggressive as past PSNH estimates, it might be a good construction management tool, but it would be essentially useless for addressing the issue before the Commission: is Seabrook I worth completing?

Q: What is your second point?

A: Second, I would like to point out that the current PSNH/Derrickson construction cost and duration estimates do more than simply continue the long PSNH tradition of producing construction management <u>targets</u> (intentionally biased on the low side) and then presenting them to regulators as if they were unbiased, best estimates upon which generation planning decisions could be properly made.

The recent history of these estimates is quite revealing. UE&C continued its past performance by producing a $10.1 billion cost estimate of Seabrook I and II ($5.07 billion for

Seabrook I alone), with a Seabrook I COD of 4/17/87. This was produced by UE&C on 1/28/84, and is described as the "1983 Preliminary Baseline Estimate" by Neilsen-Wurster. See pp. 3 and 7 of the Neilsen-Wurster Report dated 5/14/84. Although this UE&C estimate should probably be thought of as continuing UE&C's long tradition of intentionally biased estimates, PSNH rejected this $10.1 billion estimate and promptly produced a $9.0 billion estimate. This is the estimate issued by PSNH on 3/1/84, which was adopted by PSNH as the "1983 Baseline Estimate" and which MAC refers to as a "baseline" estimate but which MAC said had only a 10% chance of being met with respect to schedule and a 20%-30% chance of being met with respect to costs. See 4/26/84 MAC Report. PSNH, however, then immediately (by 4/16/84) changed the name of this $9.0 billion "baseline" estimate to a "worst case" estimate, in order to help justify its $6.9 billion estimate (the "Target Estimate") issued on 4/16/84.

In short, PSNH was not pleased with the UE&C $10.1 billion estimate (presumably already biased on the low side), and has attempted to make it disappear by asserting that it was never "adopted." The $9.0 billion 3/1/84 "baseline" estimate (presumably still further biased) has been re-named retroactively a "worst case" budget, and a "target" budget of $6.9 billion ($4.1 billion for Seabrook I) was produced. All this was accomplished in four short months. If the

Dittmar/Ward testimony does not convince the MPUC that the current Derrickson estimate (candidly named a "Target Estimate") is deliberately biased on the low side, this history should certainly help.

3 - PSNH PROJECT MANAGEMENT STAFF

Q: What considerations do you wish to bring to the Commission's attention regarding the composition of the project management staff for Seabrook?

A: There are two central points. The first is the tautological observation that each member of the management either is new to Seabrook, and for the most part to working with the other members of the organization, or is a holdover from the old UE&C and Yankee Atomic staff which has produced a string of unrealistic estimates. My direct testimony contrasted some of the problems which the new members must expect to face, compared to working (at St. Lucie 2, for example) on a duplicate unit for a stable utility in an established organizational structure. Clearly, it is very optimistic to expect these managers to be as effective under Seabrook conditions as they were under near-ideal conditions.

Q: How responsible was UE&C for the past inaccurate cost and schedule projections?

A: UE&C was primarily responsible for developing the cost and schedule projections. While PSNH at times required UE&C to use more optimistic assumptions than UE&C originally proposed, these changes were relatively small compared to the inherent optimism in the UE&C estimates, and I am not aware of any evidence that UE&C protested the changes. This relationship, and the PSNH-directed changes in assumptions, are discussed in the Dittmar/Ward testimony offered by CMP in Docket 84-120, and by MPS in Docket 84-80.

Q: How responsible was Yankee for the past inaccurate cost and schedule projections?

A: Yankee was responsible for reviewing the cost and schedule projections on behalf of PSNH and the joint owners, as well as for some construction management activities. Yankee does not appear to have recognized any of the major errors in any of the previous PSNH/UE&C estimates; or if it did recognize the errors, it does not seem to have alerted PSNH or the joint owners to them.

Q: Since the cost and schedule estimates were never intended to be realistic predictions of actual performance, but rather targets for optimal performance, as you have documented above, is it possible that UE&C and Yankee were competently setting goals for construction management purposes?

A: Had those two organizations only communicated with PSNH, it would be conceivable that they were unaware that the construction control budgets they were preparing and reviewing were being misrepresented as realistic estimates of final costs for financial planning and economic evaluation.

Given the very public nature of the debate over Seabrook's costs and benefits, this level of innocence is hardly credible.

Q: Is it possible that these organizations simply considered their responsiblity to be limited to providing PSNH with the information it requested, and that they would have acknowledged the weaknesses of the cost estimates, had they been asked?

A: No. Employees of both organizations testified in support of cost and schedule estimates which they knew, or should have known, were unrealistic. For example, Alan Ebner, Project Manager for UE&C at Seabrook, filed testimony in NHPUC 81-312 in early 1983 that

> "We are confident that the revised estimate is a true reflection of the cost to build the Seabrook Station. the reason for this is as follows:
>
> 1. The current status of engineering and construction.
>
> 2. The detail in which the estimate is prepared.
>
> 3. The extensive review of each portion of the estimate by qualified individuals up through and including senior management.
>
> 4. The extensive data base of historical site-specific information used as a guide for estimating costs to complete.
>
> 5. The systematic approach used in developing the estimate.
>
> 6. The inclusion of allowances for specific increases and contingency for general increases.

7. Confidence in the ability to achieve the new scheduled completion dates."(Ebner Attachment 2, page 14, NHPUC 81-312)

There are at least three remarkable aspects to this list. First, the assertions are familiar: similar claims have been made for each estimate since at least 1980. Second, the major differences between Mr. Derrickson's reasons for confidence in the current official estimates and Mr. Ebner's reasons for confidence in the 1982 estimate lie in Mr. Derrickson's rejection of some of Mr. Ebner's 'advantages'. For example, as I read his direct testimony, Mr. Derrickson seems to base his cost estimate on the rejection of site-specific data (see pages 11 and 12 of Derrickson prefiled); similarly, from his discovery responses (in MDPU 84-152, particularly), it appears that his cost reduction estimates are ballpark targets, rather than products of the detailed estimation, of which Mr. Ebner was so proud. Third, and perhaps most remarkable, the man who was so confident of the accuracy of the $5.2 billion estimate (for both Seabrook 1 and 2) still heads UE&C's organization.

Q: Were there similar examples of UE&C employees supporting PSNH's misleading cost estimates in proceedings in Maine?

A: The one example with which I am familiar is the testimony of G.F. Cole in MPUC Docket 81-114, supporting the same $5.2 billion estimate. While Mr. Cole was less effusive in his direct testimony than Mr. Ebner, he certainly did not indicate that the "estimate" was really only a goal.

Q: Did Yankee employees engage in the same sort of behavior?

A: Yes. In October 1982, only a month before the $5.2 billion estimate, Paul T. Welch, the Yankee Construction Engineer "responsible for the implementation of the Owners Cost Control Program . . . and . . . review of the Seabrook Construction Cost Estimate", filed written testimony in NHPUC 81-312 that the current cost estimate was $3.56 billion, that "there are no certain changes that can be identified by cost amounts from the on-going review in preparation of the November, 1982 revised estimate", that Unit 1 was 98 days behind schedule, and that only about $100 million in cost overruns from the current schedule had been identified.[3] A month later, the cost rose $1600 million, the Unit 1 schedule was slipped 10 months, and Unit 2 was slipped 11 months.[4] When PSNH filed its revised case after the new estimate, Mr. Welch's testimony was withdrawn, to be replaced by Mr. Ebner's testimony.[5] Mr. Ebner testified that the first compilation of the new total project estimate had been

----

3. This is the sum of $45 million from UE&C review of contracts and purchase orders, 98 days of slippage at $15 million per month, plus AFUDC.

4. The Unit 2 COD projection was set back another 3 months in December.

5. Mr. Ebner's testimony has now, in a sense, been replaced by Mr. Derrickson's testimony, which may deserve as much weight as its predecessors.

available in early September, and was subjected to a series of reviews of UE&C and Yankee before the November 23 presentation to PSNH, which is difficult to reconcile with Mr. Welch's professed lack of knowledge of the estimate in October. Despite his experience with the $3.56 billion estimate, Mr. Welch prefiled testimony before this Commission in Docket 81-114 which presented the $5.2 billion estimate without any caveats, and certainly without disclosing that it was still only a construction management guide.

PSNH's $5.2 billion estimate depended on a projection of a three month interval from fuel load to commercial operation. In NHPUC 81-312, Yankee supplied the Startup Test Department Manager from Seabrook, Dennis McLain, to testify that "three months is well within reason". This assertion was based on the duration of the tests specified in the Westinghouse Startup Manual; in the light of the actual experience (such as that provided in Table 3.1 of my direct), the assertion is preposterous.

Q. What do you conclude from this history on the part of UE&C and Yankee employees?

A. I have no way of knowing whether the behavior of these individuals constituted incompetence, or mere self-deception. In any case, the continued involvement of these men and their organizations in the planning, management, and cost projections for Seabrook construction can hardly allow for any great confidence in the new PSNH management organization for the project, or in the products of that organization.

4 - THE WILE/PERL TESTIMONY

Q: What aspects of the testimony of Wile and Perl will you be discussing?

A: I have comments on four subjects related to this testimony:

1. the track record of NERA on nuclear plant costs and load forecasting,

2. the choice of discount rates used in the testimony,

3. the inherent limitations of the techniques used for forecasting nuclear plant construction costs, and

4. the specific problems in NERA's applications of those techniques.

Q: What is the track record of NERA on nuclear plant costs and load forecasting?

A: It is fairly dismal. In 1978 NERA was testifying that ten-year load growth for the New England Electric System was likely to be in the range of 3.8% to 6.1% annually, for 1985 energy requirements of about 21900 to 26600 GWH. (Testimony of L. Guth, NEFSC 78-24). NEES now projects energy requirements of about 17800 GWH for 1985, and growth of about

1.6% annually out to 1998. That same year, Dr. Perl predicted (Perl, 1978) that the historic problems of the nuclear industry would soon end, and predicted that nuclear plants could be completed for $2300/kw in 1990.[6] In 1981, he repeated this error, assuming that there would be no real escalation in nuclear plant costs beyond 1979 (Testimony before the Pennsylvania Public Utility Commission, on behalf of Philadelphia Electric Co., April 9, 1981, Docket No. I-80100341). In 1982, Dr. Perl assumed that real cost increases stopped in 1981 (The Economics of Nuclear Power, June 3, 1982). In his current testimony, Dr. Perl once again is unwilling to extrapolate the history of bad news for the nuclear power industry.

Q: Are the discount rates used in the Wile/Perl study appropriate?

A: I think not. The discount rate used should reflect the degree of risk involved in the projected stream of costs and benefits. If Seabrook just broke even for the customers (had a 0 net present value) at 14%, for example, it would be equivalent to a return of 14%. For an investment with the risk characteristics of Seabrook, this is an implausibly low

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6. To his credit, Dr. Perl acknowledged that his projections were subject to great uncertainty.

target return, roughly equivalent to a seven-year payback.[7] This is roughly the return one would expect from an investment half as risky as a widely diversified stock market portfolio.[8] I would suggest that Seabrook is considerably riskier than the stock market as a whole.[9]

In addition, when electric ratepayers have the opportunity to make conservation investments, even ones much less risky than Seabrook, they generally appear to require returns well in excess of 14%. Industrial firms, for example, will rarely make non-productive investments with expected paybacks of more than four years, and for some firms this target is less than one year. Similarly, Hausman[10] found that residential consumers used real discount rates of 15-25% in comparing appliances of differing efficiencies. These high discount

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7. 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 Seabrook grow over its lifetime, the payback would be later than seven years.

8. If return is to increase proportionately with risk, an investment about intermediate in risk between risk-free Treasury securities (yielding about 10%) and a market-wide mutual fund (which would be expected to yield 8-9 points more, or about 18-19%), should yield about 14%.

9. The Commissioners may assess this degree of risk by asking themselves what expected return would induce them as individuals to invest directly in Seabrook.

10. "Individual Discount Rates and the Purchase and Utilization of Energy-Saving Durables," **Bell Journal of Economics**, Spring 1979, pages 33-54.

rates indicate (1) that Wile and Perl, and Lovins, are correct in asserting that there are large amounts of unutilized conservation opportunities which are economical at utility costs of finance, and (2) that most consumers would not be willing to pay the costs of Seabrook, if they could expect a savings return of only 14%, and they would not even consider it at the 9-10% discount rate which Wile and Perl appear to prefer. Thus, the Wile/Perl result that Seabrook has a barely positive value at a 14% discount rate is equivalent to a determination that the plant has a negative net value at any reasonable discount rate.[11]

The basis for NERA's choice of discount rate is not stated, so I can not determine why they believe a 10% return (approximately equivalent to risk-free Treasury security yields) would compensate ratepayers for the risks of Seabrook. However, Dr. Perl refered in cross-examination to the "neutrality" of the after-tax cost of money for

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11. Some of the utilities' analyses indicate that the net benefits of completing Seabrook increase as the discount rate increases, which is highly counter-intuitive, given the nature of Sebrook front-loaded costs and late benefits. This result appears to be an artifact of the rate treatment assumed for cancelation: a very short recovery period which artificially front-loads the cancelation cost to the consumer. The completion/cancelation decision should be based on the economics and risks of the situation, not on ratemaking considerations which will not be finalized until the plant is completed or cancelled. Once the fate of the plant is determined, the equity and financial integrity issues raised by the ratemaking choices can be addressed.

discounting (e.g., p. B-79). He apparently believes that the present value of an expenditure is the same, regardless of whether the cost is expensed or capitalized, so long as the discount rate is return net of the debt tax shield, and thus that he has constructed his analysis so that consumers will be indifferent between expensing and capitalizing costs. There appear to be two errors in this analysis. First, the "after tax cost of money" Dr. Perl defines is only relevant to the company if (a) revenues do not vary with financial structure (which is true for most corporations, but not for utilities), or if (b) there is no cash return on the investment (which is true for AFUDC, but not for rate base). 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 consumers would be indifferent between expensing and capitalizing expenditures. This point is illustrated in Table R-1: under traditional rate-base treatment, the utility is paid a cash return on its investment, and it must therefore pay additional taxes if it capitalizes, rather than expenses, the $1000 cost in the example. Hence, the discount rate at which the consumers are "neutral" between expensing and capitalizing is the overall rate of return, plus income taxes. Only if the capitalized investment yields no current return will the net-of-tax rate be the discount rate at which ratepayers are indifferent between expensing and capitalizing the cost.

Secondly, while the preceding calculation is an interesting one, it only determines the breakeven discount rate in the choice between capitalizing and expensing costs, not what actual consumer discount rates are. Since the various revenue models used in this proceeding estimate costs to consumers, only the consumers' actual time preferences should matter in selecting a discount rate.[12] For that purpose, the weighted average return (say 14%) seems to be a minimum reasonable level, with the return plus taxes (more like 20%) representing a more likely preference.

Q: What are the inherent limitations of the techniques used for forecasting nuclear plant construction costs in the Wile/Perl testimony?

A: There are three generic problems with the approach to nuclear cost projections, which are intrinsic to any regression analysis across plants. First, the data on construction costs are not well suited to comparison between plants, since the cost of each plant will depend on the amount of escalation included (and hence on the amount of work

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12. Dr. Perl seems to recognize the distinction between utility discount rates and consumer discount rates (Transcript C-79 to 80), so it is not clear why he prefers the utility rate in his analysis.

performed in each year), the utility's AFUDC rates, and whether CWIP was included in rate base (and if so, how much and for how long). Correcting for differences in prevailing prices, financing costs, and accounting practices, to produce comparable cost figures for individual plants, requires tremendous amounts of data, or some strong assumptions. The same is true for such other site-specific and company-specific factors as labor-management relations, and the accounting treatment of nuclear-related overhead.

Second, there is an intrinsic selectivity bias in this technique: the successful plants are included in the data base, while the canceled or delayed plants are not. This problem is particularly severe for later cohorts, for which only a few exceptional plants have entered service (and the data base).[13] Treating these exceptions as if they were typical of their cohorts understates the time-related cost trend.

Third, the results of these projections are very sensitive to the functional forms and independent variables chosen, especially where it is necessary to project the effects of variables well beyond the range of the historic data. For

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13. The same may be true for large plants, which are concentrated in the later cohorts.

example, the continual increase in plant cost with time can be modeled as a function of construction permit (CP) issuance date, commercial operation date (COD), the average of the CP and COD dates, the number (or MW) of plants in service (or under construction) at the CP or COD, the cumulative operating experience in plant-years (or MW-years) at the CP or COD, the number of NRC regulations issued during construction,[14] and so forth. Each of those variables may be transposed as a logarithm, an exponential, a reciprocal, a power or root, and more. Each variation may produce a different projection for a particular unit, especially for one near or beyond the end of the data set, such as Seabrook.

Q: Are the same generic problems applicable to Dr. Rosen's cost regressions?

A: Yes. In particular, the selectivity bias may explain the very low cost results which the ESRG model projects for Seabrook. In general, however, the ESRG data and specification seem reasonable, and their results may represent the best that can be done currently with this technique.

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14. "Regulation" may be defined in several ways, to include regulatory guides, bulletins, and so on, and the number of the applicable document can be measured as an average number issued per year of construction, total issued during construction, total issued at CP or COD, etc.

Q: How do your cost projection techniques differ from those of NERA and ESRG?

A: First of all, my cost analyses compare the final cost of each completed plant to the earlier estimates for that plant, rather than comparing the final cost of one plant to the final cost of another plant. Thus, to the extent that accounting and other plant-specific factors are known and constant throughout the project, my comparisons already adjust for them. Also, while the myopia analyses use only completed plants, and are thus subject to the selectivity bias, they measure average relationships, rather than trends, and are therefore less sensitive to biases in any particular part of the data set.[15] Finally, since my independent variable (duration, or t) has a value for Seabrook which is well within the historic data range, functional form has little affect on my results, as demonstrated in Chernick, et al. (1981).

Q: What are the specific problems in NERA's applications of the regression techniques in this case?

A: There are too many problems to go into them all, but a few of

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15. The selectivity bias can be reduced by also conducting studies of the cost and schedule slippage of units under construction, as my direct testimony did for Seabrook's cost and schedule history. These analyses usually produce even gloomier projections than the myopia analyses of completed plant cost overruns.

the obvious one are:

1. Irrelevant and clearly inappropriate data is included. Two of NERA's four regressions on nuclear capital cost include turnkey and demonstration plants, and the other two may include a couple of the very small, very early, government-subsidized demonstration plants.

2. Irrelevant variables are included. One of NERA's variables is licensing time (from CP application to CP receipt), which can hardly be expected to have any major influence on construction cost, especially when time is measured by CP reciept.

3. Variables are included which have effects which are not significantly different from zero, without any justification. The licensing time variable is one good example, as are some of the "Experience" variables (which are clearly cross-correlated).

4. Time is measured by another in NERA's long series of idiosyncratic specifications. The only indicator for the time-related cost increases is the CP date, which is not even presented as a date, but only as a year: thus, December 1970 is treated as identical to February 1970, even though it is much closer to February 1971. Every NERA study of nuclear costs seems to use a different treatment of time, including

- commercial operation date
- mid-point of construction
- arbitrary cohorts of plants in chronological order (e.g., "the first five", "the next ten")

The absence of any variable to reflect construction period length means that NERA can not incorporate any effect (except for escalation and AFUDC) of Seabrook's construction permit suspensions, cash flow crises, and other delays.

5. Documentation is almost non-existent. No data is provided, the derivation of "costs prevailing in 1979 with no AFUDC" is not described, the authors do not explain how they "extrapolated the historical trend for three years" (NERA Exhibit-1, page III-2), the inputs used for the Seabrook extrapolation and for the standardization of other plants to Seabrook characteristics are not specified, and so on.

6. Half of NERA's cost estimates for Seabrook are derived from the standardization (to Seabrook characteristics) of utility cost estimates for other nuclear plants. Given the historical accuracy of other utilities in projecting plant costs, this analysis only tells us that the NERA estimate of $4.8 billion appears to be consistent with industry practice, and thus that the

current PSNH $4.5 billion estimate would be even higher if it were produced by the average utility for a plant with average problems. It would appear that my myopia analyses were overly optimistic, in that they started with an exceptionally low utility estimate.

7. No recognition of the special problems of Seabrook (financial constraints on construction schedules, permit suspension) is incorporated in the NERA estimates.

Q: Are similar problems found in other parts of the NERA study?

A: Yes. For example, the capacity factor regression

1. is based on an unidentified "sample" of units,

2. includes data from the tiny reactors of the early 1960's, which can hardly be expected to fit on the same size curve as the commercial-sized units of post-1967 vintage, and

3. assumes that future performance will equal that of the best identifiable past period.

5 - BOLBROCK TESTIMONY

Q: What problems have you identified with the NEPOOL study of Seabrook 1 economics, presented in the testimony of Mr. Bolbrock?

A: There are at least five such problems, including the capacity factors chosen for Seabrook 1, the treatment of the Hydro Quebec purchase, the assumed retirement of capacity immediately prior to a projected capacity shortfall, the limited treatment of coal conversion potential, and the treatment of alternative power sources.

Q: What problems arise in the treatment of Seabrook capacity factors?

A: NEPOOL uses absolutely implausible capacity factors, starting at 50% in 1986/87 (NEPOOL's assumed first year for the unit) and rising rapidly, to mature at 73.65% for 1991/92 and thereafter. As I noted in my direct testimony, these capacity factors are totally inconsistent with the historical record. Contrary to Mr. Bolbrock's assertion (Transcript D-42 to D-44), neither the mature forced outage rate nor the immaturity multipliers derive from New England experience, or even national nuclear experience: both were selected by EBASCO in 1973, based solely on fossil experience. If Mr.

Bolbrock had consulted the discovery response on this topic (BHE 7STAFF-3, Enclosure 2, Exhibits 6 and 7), he would have seen that the sources listed were 1973 and 1976 GTF Reports, so they could not very well have included much actual nuclear experience. Mr. Bolbrock's lack of understanding of this fundamental (and unchanging) aspect of NEPOOL's analysis must call into question his understanding of the rest of the study assumptions.

Despite the attention paid in the report itself to the results of runs with "updated" forced outage rates, those rates do not appear to be specified anywhere (including BHE 7STAFF-3), and are therefore not subject to review. Given NEPLAN's long history of careless treatment of plant reliability, these unstated and undocumented assumptions, and the analyses which depend on them, should be given no weight.

Q: How is the Hydro Quebec purchase treated?

A: NEPLAN assumes that Hydro Quebec (HQ) power is severely limited in the winter, to only a 37% availability, and that the overall capacity factor of the line will be only about 57%.[16] The only basis given for this assumption is Mr.

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16. On cross-examination, Mr. Bolbrock admitted that the HQ interconnection had been modeled as having a capacity factor of only 57%, but hastened to volunteer the information that the line

Bolbrock's statement that, since HQ "negotiated very hard to have that [amount of allowed interruption] we assumed for this purpose[17] that there will be that type of interruption" (Transcript D-20). Obviously, there are many reasons for parties to negotiations, particularly in long-term contracts, to keep their options open; for example, HQ may be concerned about its capacity situation into the next century. NEPLAN does not appear to have examined whether Quebec's current load and supply situation would require the line to be operated at only a 57% capacity factor, and to be completely shut down 63% of the winter peak months. Essentially, NEPLAN has assumed worst case HQ availability and capacity factors. To the extent that the availability of power from Quebec over the planned facilities has been understated, both the reliability and cost benefits of Seabrook are overstated.

Q: How does the study mishandle the assumed retirement of capacity immediately prior to a projected capacity shortfall?

A: Hundreds of MW of gas turbine capacity[18] are assumed to be retired in the late 1980's and all through the 1990's, despite the fact that NEPLAN projects the need for 100-1700

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would "likely" be used at a higher load factor than his study had recognized.

17. The purpose alluded to is, of course, justifying the completion of Seabrook 1.

18. The same is true for oil-fired steam capacity.

MW more gas turbine capacity[19] as early as 1994. Mr. Bolbrock acknowledges that NEPLAN has not studied the need to replace these units, and that the utilities, which scheduled the retirements, use depreciation life as one of the criteria (Transcript D-24 to 25). Most of these peakers have run very little in the last decade, because NEPOOL's large reserve margins have rendered them largely superfluous. Therefore, in terms of their useful lives, these units should be much younger than their depreciation reserves would indicate, and should be able to run through the period in which NEPLAN has assumed large turbine capacity additions, if they were needed.

It appears unlikely that these units will be needed, however. Utilities are showing very little interest in keeping gas turbines operational, and are retiring them once they no longer contribute to rate base; Mr. Bolbrock's example of NU retiring a turbine simply because its step-up transformer failed is a good example.[20] The utilities would not be so eager to dispose of these plants if they thought the capacity would be needed in a decade or so, as Mr.

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19. The requirement is more sensitive to the mysterious "updated" outage rates than to whether Seabrook is completed.

20. The turbines which Mr. Bolbrock postulates for the 1990's will require new step-up transformers, along with new turbine-generators.

Bolbrock suggests.

Therefore, the costs associated with NEPLAN's large projected influx of peaking capacity in the 1990's should be heavily discounted. Unfortunately, the study does not indicate what portion of the alleged cost advantage of Seabrook completion is due to the cost of new turbine construction, so we can not readily determine whether this is an important part of NEPLAN's result.

Q: How is the treatment of coal conversion potential limited?

A: Again, NEPLAN does not seem to have done any analysis of its own, but only accepted the projections of the individual utilities. Some of these utilities, specifically NU, appear to be playing down coal conversion until their own nuclear projects, specifically Millstone 3, are completed. This is understandable; the rate effects of Millstone, while better than those of Seabrook, are serious enough even if coal conversion is not presented as an alternative. Thus, some 400 MW of coal-convertible capacity (West Springfield and Devon) listed in Enclosure 2 to 7STAFF-3, are not converted in the NEPLAN Seabrook study (see Table A-1 or A-2). There may be other such omissions: NEPLAN does not provide a list of the coal conversions assumed. On the other hand, while Mr. Bolbrock tells us (Transcript D-11) that Bridgeport and New Boston conversions are assumed in the study, the documentation supplied in 7STAFF-3, Enclosure 1, Exhibit 14, does not list them as converted. Thus, it appears that coal conversion potential is understated. In addition, under NEPLAN's projects, coal conversion does not vary with the fate of Seabrook, even though they are at least partially competitive strategies for reducing oil use.

Q: What are the problems in NEPLAN's treatment of alternative power sources?

A: There are several such problems. First, as Maine has demonstrated, large amounts of customer-owned generation can be developed at costs well below the cost of completing and running Seabrook, and the allowance for such generation in the NEPLAN study is inadequate. Second, the amounts of customer-owned and utility-owned alternative power sources are not allowed to increase if Seabrook is canceled, thus requiring that the capacity and energy from Seabrook be replaced by less economical sources. Third, no conservation programs are contemplated, either with Seabrook or as an alternative to Seabrook, other than the generally modest programs (often as much concerned with promotion as with conservation) which may be reflected in the NEPOOL forecast.

Q: What do you conclude from your review of the NEPLAN study?

A: First, the study is not well enough documented to allow a comprehensive review. Second, it is clear that many of the study assumptions which favor Seabrook are incorrect, while others lack substantiation. Bearing in mind that NEPLAN has a long history of erroneous and unfortunate capacity planning projections, particularly regarding the economics of nuclear power, I would recommend that the Commission give this study little weight.

6 - CONCLUSION

Q: Do you have any additional comments upon the utilities' arguments that sunk costs should be ignored and that only incremental costs be reviewed in deciding whether to complete Unit 1?

A: Since the beginning of this project[21] there have been a series of estimates of increasing costs and delayed operation dates. There has not been, nor is there now, any reason to expect that each new estimate was, or will be, the end of the bad news. Despite that, the project has continued, at least in part, on the assumption that the sunk costs should not be wasted and that the additional costs would be modest. Given this history, it is more likely than not that the utilities' current estimate will be subsequently revised, with all concerned facing a yet again increased incremental cost. The time has come to put an end to this pattern of deferring on this unit the judgment that is now clearly required.

Q: Does this conclude your rebuttal testimony?

A: Yes.

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21. In this regard, it is interesting that PSNH began construction of Seabrook upon receipt of a construction permit despite the clear probability of an appeal of the granting of the construction permit and unresolved issues involving the Environmental Protection Agency. PSNH may have decided that the chances of a revocation of its construction permit would be reduced if construction had already started, giving rise to the argument that the wisest course was to finish the plant and convert the money that had been spent into a productive asset.