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THE STATE OF NEW HAMPSHIRE
BEFORE THE PUBLIC UTILITIES COMMISSION

RE: INVESTIGATION OF PSNH FINANCING PLAN TO COMPLETE CONSTRUCTION OF SEABROOK UNIT 1

DOCKET No. 84-200

TESTIMONY OF PAUL CHERNICK ON BEHALF OF THE PUBLIC ADVOCATE

November 15, 1984

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ON BEHALF OF THE NEW HAMPSHIRE 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 this Commission and such other 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 Connecticut Department of Public Utility Control, the Michigan Public Service Commission, the Maine Public Utilities 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] Table 1.1 lists the PSNH and UE&C

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1. Complete citations for each proceeding 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.

cost estimates for Seabrook, while Figure 1.1 compares the history of PSNH cost estimates for the Seabrook plant to my estimates.

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 xxMassachusetts utilitiesxx seeking to purchase Seabrook shares were more realistic about capacity factors). I suggested capital additions[3] 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 somewhat 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

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3. To the best of my knowledge, this was the first quantitative analysis of actual capital additions to nuclear plants.

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[4]).

On a related matter, I have been treating Humboldt and Dresden 1 as retired since 1981 (see Chernick, et al. 1981). Humboldt was retired in 1983 and the retirement of Dresden 1 became official at the beginning of September 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

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4. See NERA (1984).

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, my testimony in a New England Electric System long range demand and supply forecasting case, EFSC 83-24, and my testimony in Maine's generic Seabrook case, PUC 84-113, fall into this category.

Q: What is the subject of your testimony?

A: I have been asked to review the cost and schedule of Unit 1 of the Seabrook nuclear power plant. I have specifically been asked to review when (and whether) the unit is likely to enter service, how much it would cost to complete and operate, and how much power it can be expected to produce.

Q: How is your testimony structured?

A: Section 2 considers some of the problems currently facing the Seabrook owners. Section 3 derives estimates of the cost of Seabrook Unit 1, in 1984 dollars and nominal dollars, including operating costs and capacity factor. Section 4 estimates the financial and rate effects of Seabrook for PSNH and its customers. Section 5 discusses the comparison of Seabrook to alternatives, Section 6 reviews the NEPOOL study of Seabrook, and Section 7 presents my conclusions and recommendations.

2 - CURRENT SEABROOK ISSUES

2.1 - Introduction

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.[5] 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 debts have since been restructured), has suspended common and preferred dividends, and faces the possibility of insolvency in the near future. The joint owners, including have been

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5. 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.

asked to assist PSNH in various ways, although it now appears that none of the bailout plans will come to fruition, or even be presented to regulators.[6] 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: 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);
- and the resulting reorganization of the Seabrook project, including the formation of New Hampshire Yankee.

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

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. Other particularly financially stressed owners include Fitchburg Gas & Electric and Maine

Public Service.

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: 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 Newbrook resolution itself, dated May 14, 1984, appears to require pre-financing for a plant cost of only about $4.6 billion, or a $0.5 billion overrun from the April Target Budget. No provision appears to have been made for any particular schedule extension.

- The financing plans developed by many of the joint owners under the May resolution apparently assume a delay in the plant's inservice date, bringing the total assumed cost to the neighborhood of $5.5 billion.

- The October 16, 1984, resolution reduced the cash cost requirement to $1 billion, and hence the total assumed cost of Seabrook to about $5 billion, if the plans (including completion of all financings) are all in place by January 1, 1985; fortunately, this condition appears impossible to meet under the current schedule for the MDPU generic case, and the requirement of a second set of company-specific MDPU cases before the financings can commence.[7]

- The cost of the plant is very likely to exceed $6 billion, and may well go much higher.

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

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7. It is particularly interesting that this reduction in the cash cost requirement was requested by Mr. Hildreth, who did not believe that the markets could absorb the $1.3 billion financing (Notes of 7/26/84 Seabrook Financial Officers meeting, Bangor Hydroelectric.

2.2 - The Target Cost Estimate

Q: To what do you attribute the consistent pattern of cost overruns Seabrook and in other 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 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: Other than UI, have any of the Joint Owners conceded this point?

A: Yes. Two of the Maine Joint Owners have filed testimony by MAC employees (Dittmar and Ward, 1984), which confirms the basic point that the Seabrook cost and schedule estimates have been intentionally understated, during the entire history of the process.

> PSNH established schedules that required superior effort. This strategy is generally appropriate because it demands the best possible performance from contractors. (Dittmar and Ward, 1984, page 25)
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> If a budget is based on an overly conservative (high) estimate which establishes easily attained goals, a project's cost is likely to rise to fulfill the prediction. The use of aggressive targets is a management approach which, when reasonably applied, provides incentive for improving performance. If unrealistic cost or schedule targets are maintained too long, a project can be affected adversely. In such situations, it is difficult to hold people accountable for goals that they know are unrealistic. Morale problems may occur which could reduce productivity, cause delays or increase cost. A more serious consequence of managing too unrealistically aggressive targets may occur if activities are improperly sequenced such that work cannot be accomplished efficiently because of artificially induced constraints. (ibid, page IV-6).

Dittmar and Ward consider the use of these aggressive estimates to be prudent for construction management purposes, and they may well be correct. But estimates which were only "theoretically achievable" (ibid., page IV-25,IV-26) should not be confused with best estimates, which provide unbiased[8] expectations for future costs.

Q: How does the current PSNH Revised Target Estimate of $4.5 billion compare to unbiased projections and to PSNH's past practice?

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 issues before the Commission: whether Seabrook I is worth completing, and whether it can be completed, given the financial conditions of the participants.

Second, the current PSNH construction cost and duration estimates appear to be even more aggressive than the long PSNH tradition, which produced a series of construction management <u>targets</u> (intentionally biased on the low side) and

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8. "Unbiased" means neither high nor low on the average.

then presented 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 1 and 2 ($5.07 billion for Seabrook 1 alone), with a Seabrook 1 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 Nielsen-Wurster.[9] 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 (1984) 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. Nonetheless, PSNH, promptly (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.

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9. See pp. 3 and 7, Nielsen-Wurster (1984).

In short, it appears that 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) has been produced. All this was accomplished in four short months. If there were any doubt that the current PSNH estimate (candidly named a "Target Estimate") is deliberately biased on the low side, this history should certainly help place the estimate in perspective.

Q: Does PSNH's recent offer to accept a cost cap for Seabrook 1 offer much assurance regarding the cost of the plant, or of PSNH's faith in the current cost estimate?

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.[10] 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

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10. This situation could change if the CWIP statute is amended or overturned.

collect more than the cap, either under one of the loopholes left in the cap, or simply because the New Hampshire PUC may choose 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 $4.5 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.

2.3 - The PSNH/Seabrook Project Management

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,[11] the revision of lines of communication and responsibility, 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

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11. This suspicion is evidenced, for example, by references in minutes of Joint Owners meetings to threats of suits by the owners against UE&C and its parent company, Raytheon.

change has taken place: WPPSS 2 and South Texas. In neither case was the situation exactly analogous to that at Seabrook. 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. Even if the situations were exactly analogous, it would be difficult to determine whether the management changes accelerated or retarded the cost and schedule slippage at each plant. Nonetheless, these examples 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. WPPSS initiated what it called "integrated management", a term which Mr. Derrickson has also used to describe his approach at Seabrook. Since the transition in management, the WPPSS 2 cost estimate has tripled, and the scheduled in-service date has slipped four years.

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 recreate the management and construction organization of St. Lucie 2 at Seabrook?

A: There are certainly some reasons to doubt that he will. 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;

- dealing with severe financial limitations;

- working for and with several corporations which must be mutually suspicious, and have even threatened legal action against one another;

- adding some participation from three additional A/E's: Bechtel, Ebasco, and Stone & Webster;[12]

- 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 the Management Analysis Corporation (MAC), the Executive Committee of the Joint Owners (ECJO), and the joint owners themselves.

Q: You have described some of the contrasts between the situation faced by the new members of the PSNH Seabrook management staff to the environment they worked in at St. Lucie. Do the members of the current management team who are holdovers from the previous organization have a record of reliable and candid cost estimates?

A: No. UE&C and Yankee are largely responsible for the previous cost and schedule estimates, and half of the current project management is from those organizations. The record of PSNH's

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12. Mr. Derrickson has announced 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.

staff, of course, speaks for itself.

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 appear to have been 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.

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; 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 other states than New Hampshire?

A: The one example with which I am familiar is the testimony of G.F. Cole in Maine PUC 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 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.[13] A month later, the cost rose $1600 million, the Unit 1 schedule was slipped 10 months, and Unit 2 was slipped 11 months.[14]

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13. 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.

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

When PSNH filed its revised case after the new estimate, Mr. Welch's testimony was withdrawn, to be replaced by Mr. Ebner's testimony.[15] Mr. Ebner testified that the first compilation of the new total project estimate had been available in early September, and was subjected to a series of reviews by 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 the Maine 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 mangement 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 this testimony), the

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15. 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.

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, disingenuousness, 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.

Since all the responsible entities (PSNH, UE&C, and Yankee) put together were only able to identify about $200 million dollars in cost overruns[16] 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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16. Known and Potential Changes, "Seabrook Station Project Estimates Status Report", 12/83

2.4 - St. Lucie and Seabrook

Q: Does the fact that Mr. Derrickson was Project Manager for St. Lucie 2 provide any assurance that a management organization including him as Project Manager can 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, and that no one person builds a nuclear plant. There are also very specific reasons for believing that the St. Lucie 2 experience can not be repeated at Seabrook.

Q: Were the experiences at St. Lucie 2 and the other FP&L nuclear plants at which Mr. Derrickson had management roles 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 (both faster and closer to the original post-permit schedule) than utility experience with typical nuclear plants; indeed, it appears St. Lucie 2 was an atypically advantaged nuclear unit, for reasons which have nothing to do with construction management.

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 inexpensively 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: Have you attempted to quantify the influence of any of the advantages of St. Lucie 2, compared to Seabrook?

A: Yes. It would be difficult to measure the effects of some of the advantages, such as a financially sound utility and a stable management, because of the lack of precedents for situations as bad as that at Seabrook. One of St. Lucie's advantages which I was able to address was its status as a second unit at which construction significantly trailed that of the first unit; in fact, St. Lucie 2 received a Limited Work Authorization (LWA) in the same year Unit 1 went commercial, and received a construction permit (CP) the next year. This timing has frequently been listed as one of the factors which made St. Lucie 2 faster to build, and easier to build on schedule, than most nuclear plants.[17] A study of construction at Three Mile Island 2 (Touche Ross, 1978) noted that the cost and schedule estimates at that ill-fated unit were much more stable once Unit 1 entered service than they had been previously. These observations prompted me to look for a pattern in the estimation performance of trailing second units.[18] Perhaps the utility, A/E, and constructor at each of these plants learned something in completing Unit 1 which allowed for better cost estimation at Unit 2.

I restricted my analysis to plants at which the units entered service more than 2 years apart. It would be difficult to verify meaningful trends in a period of less than two years, and apparent cost differences observed while both units are under construction may be due more to changes in the accounting of joint costs than to actual differences in construction or forecasting success. Despite these limitations, it would be interesting to extend the analysis to twin units which were separated by less than two years. Other plants were excluded from this study for other reasons: Arkansas Nuclear because the two units have different reactor

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17. See Engineering News Record (1984a, 1984b) and Winslow (1984).

18. Thanks are also due to Montaup Electric and to Central Maine Power, whose attorneys repeatedly pointed out to me on cross-examination that Hatch 2 had also experienced low cost and schedule overruns after Hatch 1 entered service.

suppliers; Millstone because the units have different reactor manufacturers, A/E's and constructors; and Indian Point 2 and 3 because the units differ significantly in size and were completed by different utilities.[19]

This screening left seven eligible pairs, which are listed in Table 2.1, along with measures of cost growth (as annual %) and schedule slippage (expressed as a slippage ratio: months delay in the COD estimate divided by months elapsed). The time intervals used in the analysis were selected by visual inspection of graphs of expected COD and cost as a function of estimate date, as shown in Figures 2.1 to 2.14. For all seven pairs, striking reductions in cost growth rate occur for the second unit after completion of the first unit, as compared to the earlier results for either unit. The same reduction in slippage ratio is observed in five of the seven pairs: the two exceptions are North Anna 2 and Salem 2, both of which were nearly ready for operating licenses at the time of the Three Mile Island accident, and were thus especially vulnerable to licensing delays.[20] This effect can not be

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19. The sale of Indian Point 3 to PASNY in mid-construction, and in the midst of Con Edison's financial crisis, may have affected both construction and accounting. In any case, Indian Point 3 does not show the trailing-unit effect.

20. These delays may have been due to purely regulatory factors, such as a lack of NRC staff for licensing reviews, and to technical factors, such as the time taken for last-minute inspections and modifications which would not have been on

attributed to chance: if improvement were as likely as no improvement, and the fourteen observations were independent, the chance of observing these twelve improvements (or more) would be less than 1%. More striking is the fact that none of the plants show significantly worse performance for either measure after Unit 1 COD: if deterioration were as likely as no deterioration, the odds of seeing zero deteriorations in fourteen trials would be 1 to 16383.

Of the seven second units, St. Lucie 2 showed the worst cost growth rate after Unit 1 COD, but the best schedule slippage ratio.

Q: Is there any evidence regarding the ability of the construction managers of these trailing second units to carry their accuracy in cost and schedule projection from the trailing second units to other nuclear plants?

A: I have only been able to identify one such case. The managers who were responsible for constructing Hatch 2 have moved along to Georgia Power's other nuclear plant, Vogtle; at least three of the managers from Hatch 2 are working on Vogtle, each at one level of responsibility higher than he held at Hatch. Figure 2.15 displays the cost estimate histories of Hatch and Vogtle: clearly, neither Georgia Power

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critical path for units further from completion.

nor its employees have been able to repeat the Hatch 2 success at Vogtle.

Q: What does this analysis tell us about the probability of the schedule and cost control success at St. Lucie 2 being repeated at Seabrook?

A: It is obvious that something special happened at St. Lucie 2, and there has been some naive tendency to attribute this to Mr. Derrickson's presence, and thus to assume that his presence would have the same effect at Seabrook. In fact, it appears that what was so special at St. Lucie 2 was its status as a trailing second unit, and particularly the second unit which trailed its predecessor by the greatest time period, receiving its construction permit only after the first unit entered commercial operation. This effect is interesting in itself, and may be useful for projecting the costs of a few second units whose predecessors have already reached commercial operation, but offers no particular hope for Seabrook 1. If Seabrook 1 were ever completed, experience suggests that it would then be possible to produce a fairly reliable estimate of the cost of Seabrook 2 cost and COD. It does not appear that this situation will ever occur; if it does, it does not appear that anyone will be interested in the cost of Seabrook 2 by then.

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 at least 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 at least 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[21] charge the same cost in 1984 dollars to each year, while levelized nominal dollars 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.

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21. I use this term interchangably with "real-levelized dollars". In general, "constant", "real", and "present value" dollars all refer to the same concept.

Traditional ratemaking charges even more per kwh in the early 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.[22]

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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22. 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.[23] 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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23. 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.

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 on the average start-up period can not yet be determined, but all are more than four months from their first license.

Q: Are the utilities which built the plants listed in Table 3.1, and in your previous answer, experienced in nuclear startup?

A: Some of them certainly are. Grand Gulf is Mid-South Utilities' third nuclear unit, as Three Mile Island 2 was for GPU; Hatch 2 and Farley 2 are the Southern Company's third and fourth units; North Anna 2 is VEPCO's fourth unit; the Sequoyah units are TVA's fourth and fifth units, as the McGuire units are for Duke; and the La Salle units are Commonwealth Edison's eighth and nine nuclear units. Of the 16 units in the Table, only two are their utilities' first nuclear units, as Seabrook will be for PSNH. Even if Seabrook is considered as a Yankee plant,[24] the utilities in Table 3.1 can hardly be described as inexperienced in comparison. In particular, Commonwealth Edison is more experienced in nuclear start-up than Yankee, and TVA and Duke were both as experienced when their last unit listed in Table

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24. It is not clear why it should be so considered.

3.1 was completed as Yankee will be when (and if) Seabrook is completed.[25] Furthermore, most of the utilities represented in Table 3.1 and the previous answer have more recent experience than Yankee, which has not been involved in a nuclear plant start-up since 1972, before the Brown's Ferry fire, the TMI accident, and even the formation of the NRC.

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.[26] 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?

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25. This calculation assumes that Yankee Atomic was responsible for construction and startups of all four Yankee units: Central Maine Power and Northeast Utilities appear to consider Maine and Connecticut Yankee, respectively, to be <u>their</u> responsibility, not Yankee Atomic's.

26. 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 a large extent, fuel load can not be scheduled: the utility can only be ready for an operating license, and hope it will receive one promptly, so that fuel load can start.

A: At the end of the first quarter of 1979,[27] 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 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.[28] 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 months period of 48.9%. Stated differently, each percentage point

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27. I start this analysis after the end of the permit suspensions, and after Seabrook construction had passed the early stages of construction, in which progress is expected to be much slower.

28. 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.

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 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. Appendix D provides illustrations of this practice, from PSNH's own reports. 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.[29]

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

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29. This relationship can be seen in Appendix D.

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[30] from each earlier estimate to the March 1984 estimate. The COD progress ratio 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

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

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.[31] 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,[32] 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

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31. At that time, PSNH estimated that Unit 1 was 88.8% complete. As of March 1984, PSNH revised its estimate to 73%; I use this figure for this comparison.

32. 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.

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. Since Seabrook is subject to stricter financial limitations than the other units, including construction suspension or slowdown equivalent to a suspension of at least seven months, the relative optimism may be more than eight months.

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. 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.[33] 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

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33. 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 transfered to my completed plant set.

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 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 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, 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.[34]

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34. This particular modelling technique was an original development, but it is similar to approaches taken by Blake, _et al_., 1976, and by Merrow, _et al_., 1981.

I have recently completed an analysis of both nominal and real cost myopia using the most intuitively appealing[35] 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,[36] 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

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35. The cost ratio equals 1.0 for t = 0, and the error rate increases with the remoteness of expected operation.

36. I do not yet have the final costs 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.

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 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.[37] 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

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37. $(1.331)^{2.33}$.

August cost 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?

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 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 these myopia techniques been successfully applied previously?

A: Yes. In MDPU 20055, in 1980, PSNH was projecting that Seabrook would cost $2.8 billion; based on a very limited data set, my myopia analysis predicted a cost of $5.9-11.5 billion. In CPUCA 83-03-01, PSNH was predicting a cost of $5.2 billion; myopia analysis corrected this to $10.5-11.3 billion. Since the last known UE&C estimate for a two-unit Seabrook plant was for $10.1 billion, it is clear that myopia analysis has been more successful than conventional estimation techniques in predicting the cost of Seabrook, and has allowed me to predict each cost increase at least a year or two before PSNH did.

Myopia analysis was also the basis for my predicting in 1979 that the cost of Pilgrim 2, then estimated by Boston Edison at $1.895 billion, would increase to $3.8-4.9 billion. In September 1981, Boston Edison canceled the unit, and announced a cost estimate of $4 billion. In October 1982, Commonwealth Edison was predicting that the Braidwood plant would cost $2.74 billion. Myopia analysis (in my testimony in ICC 82-0026) suggested that it would cost $4.78 to $5.25 billion, plus inflation during any delay in the units' startup dates. The final results are not yet in, since the first unit is scheduled for commercial operation between 7/86 and 4/87, with the second unit following by a year, but the utility's cost estimate for Braidwood now stands at $3.68 - $3.94 billion, including a delay of 9-18 months.

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[38] 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 March cost estimate represented an average cost trend of around 60% annually, while the average annual percentage

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38. 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, perhaps indicating that PSNH manipulated the cost accounting in the late 1970's and early 1980's to favor Unit 2.

increase in the Seabrook cost estimate from 12/76 to 3/80 was only 13%.

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 to the current estimate: at 22% annually, lower than any of the increases in line 7 of Table 3.11, this would 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: 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 potential 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[39] 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 examination of his record. If Seabrook 1 myopia[40] 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. As discussed in Section 2, trailing second units, such as St. Lucie 2, have stable cost and schedule histories, regardless of who builds them. If the experience at St. Lucie 1 (which is more comparable to Seabrook 1, as a first unit at the site) 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

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39. It is not much more than hope.

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

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. For capacity planning purposes, a best estimate or most likely expectation is required, and I would recommend the use of a range from $6 billion (or $5200/kw), a very optimistic figure,[41] to a more conservative $8 billion. For financial planning, a conservative figure is required: I would recommend the use of an $8 billion cost for that purpose, with the understanding that the plant may not be operable even after $8 billion have been spent. For construction management, Mr. Derrickson's $4.5 billion target may be useful, but if UI is correct that the target should have a 10-30% chance of being achieved, the target should probably

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41. It is hard to see how PSNH can meet that cost target, if any of the historical trends continue.

be more like $5.5 billion.[42]

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 of the 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.

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42. If a decision is made to go forward with Seabrook 1 construction, the choice of the target should be left to project management.

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

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

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).

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.[43]

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.

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43. If DER is properly defined, it is hard to see how MDC can exceed it. Thus, MDC will always be less than or equal to DER, and if anything prevents operation at full DER, it will be strictly less.

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: 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; NERA, 1982, 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 four-year maturation, the second excludes three unit-years of particularly poor performance, the third introduces 5-year maturation, and the 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.[44] The equation predicts capacity factors for a unit like Seabrook of 53% in the first year, rising to 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

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44. 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.

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,[45] 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,[46] the levelized projection would be some 5.8 percentage points lower, or about 54.2%.

I have performed a series of regressions on the performance of domestic PWR's of more than 400 MW capacity.[47] The basic data set included all full unit-years through 1982, for all units except for Palisades (which was the object of the

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

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

47. 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.

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. The data is provided in Appendix E.

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,[48] 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 the age variable,[49] 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

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

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

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, 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.[50]

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: Does PSNH project reasonable capacity factors for Seabrook?

A: No. Table 3.18 displays the difference between PSNH's projections and Easterling's results. The capacity factors assumed by PSNH are much too high. This should not be very surprising. 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.

As a check on the accuracy of the NRC/Easterling capacity

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50. 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.

factors, compared to the PSNH projections, I have performed the calculations presented in Tables 3.18 and 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 53.8%, while PSNH would predict an average of 68.1%. Clearly, PSNH's expectations 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 vary with refueling schedules and has less data; much of which is from before 1979. At most, the actual data suggests a 2.5% upward revision in the Easterling actual, to a levelized average of about 54.5%.

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 is also performed with the addition of the four large PWR's which entered commercial operation in 1981. I have accepted a suggestion[51] that the very low capacity

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51. The suggestion was originally made by Northeast Utilities, in Calderone (1982). Table 3.19 is essentially a correction of

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.[52] 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 a total of 65.8 percentage points from average second year performance, in 51.0 unit-years of experience, for a 1.3% 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 57.5%; the mature capacity factor is actually lower, in the 55.7% to 56.1% range. This approach also indicates that Easterling's results are very close to the performance of large PWR's. I will use a levelized capacity factor of 55% in subsequent analyses.

Calderone's study.

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

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) and a unit lifetime of 25 years, as a compromise between possibilities of 20 years and 30 years. The 10% figure is a ballpark estimate of the cost of capital in the long run, reflecting both the cost of capital to the utility (before the costs are flowed through to the customers) and the cost of capital to customers (once they actually have to pay the costs of the plant). At a 16% debt rate and 17% equity, 50/50 debt/equity ratio, and a 50% tax rate on equity return, an investor-owned utility's overall cost of capital is 23%, or 17% real with a 6% inflation rate. Those finance rates are probably too low to reflect the risk of nuclear investment, but they also do not reflect tax credits and accelerated depreciation. For the customers, an appropriate discount rate must be at least 10% real, which is equivalent to a six-year payback or a 16% nominal return (less than the stock market). Overall, the 10% discount rate seems somewhat low at this point.

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.[53] I also use a 0.5% levelized property tax rate. Over 25 years, the levelized annual fixed charges for capital, and depreciation would be 11%, or 11.5% with property taxes. With this fixed charge rate and a 55% capacity factor, each $1000/kw results in a levelized carrying cost of 2.39 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?

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.

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53. 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.

3.6 - Fuel Cost

Q: What nuclear fuel costs have you used?

A: I used PSNH's estimates of Seabrook fuel costs, which start at 1.34 cent/kWh in 1988, and rise to 2.4 cents in 2005. For the last 10 years of the projection, the escalation rate is 5% annually, and I project that out for the rest of the plant's life. 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 0.94 cent/kWh in 1984 dollars.[54] The costs would probably be higher on a realistic schedule, due to the increased interest costs.

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

3.7 - Non-Fuel O & M

Q: Are PSNH's estimates of Seabrook non-fuel O & M expense reasonable?

A: No. PSNH uses an engineering analysis of O & M costs, which does nothing to address the historical trends of rapidly increasing O&M costs, and seems to use no historical data. Table 3.22 reports the annual O & M for the Millstone, Pilgrim and Yankee units since their first full year of operation.[55] The average annual growth rate in the O & M figures reported for New England nuclear units through 1983 ranges from 17.1% to 26.4% 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 9% to 18% annually.

Table 3.23 presents the 1983 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 (in 1983 dollars) and of annual geometric growth rates,[56] and

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55. 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.

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

the six-unit average of each parameter. Each unit is analyzed from its first full year of service through 1983.

Q: Have you similarly examined the national history of nuclear O&M?

A: Yes. Appendix C lists the non-fuel O&M for each full operating year from 1968 to the most recent data available. Years in which units were added have been eliminated. Table 3.24 presents the results of five regressions using the data for plants of more than 300 MW, from Appendix C, in 1983 dollars. A total of 413 observations were available. All five equations indicate that real O&M costs have increased at 13.6% to 13.8% annually,[57] and that the economies-of-scale factor for nuclear O&M is about 0.50 to 0.57, so doubling the size of a plant (in Equations 1 and 2) or of a unit (in Equations 3 and 4) increases the O&M cost by about 42-48%. Equations 1 and 2 indicate that, once total plant size has been accounted for, the number of units is inconsequential, and the effect on O&M expense is statistically insignificant: indeed, the two equations disagree on the sign of the small effects they do detect. Equations 3 and 4 both measure size as MW per unit, and they both find that the effect of adding a second identical unit is just a little less than the

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better follow the data.

57. Due to rounding, not all of these variations are evident from Table 3.24.

effect of doubling the size of the first unit: 43% for Equation 3 and 39% for Equation 4.[58] Equation 5 tests for extra costs in the Northeast, which are commonly found in studies of nuclear plant construction and operating costs, but is otherwise identical to Equation 3. Indeed, there is a highly significant differential: Northeast plants cost 28% more to operate than other plants (using the definition of North Atlantic from the Handy-Whitman index). This Equation is the most satisfactory of the national regression results.

Q: What O&M cost projection do you use in your Seabrook cost analysis?

A: Table 3.25 extrapolates the New England linear and geometric average trends, and the national regression results evaluated for Seabrook, and displays the annual 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 all the 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).

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58. The two equations do treat extra units differently after the second: a third unit increases costs by another 39% (or 55% of the first-unit cost) in Equation 4, but only by 23% (or 33% of the first-unit cost) in Equation 3. The treatment of additional units in Equation 3 seems more plausible, in that each succeeding unit should be progressively less expensive to run.

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. San Onofre 1, a 430-mw unit which entered service in 1968, has been shut down since February, 1982, and has no firm plans for restart. To be on the optimistic side, I have assumed a continuation of the linear trends in New England nuclear cost escalation; using the average experience of the existing units would produce 25-year real levelized O&M costs of about $71.8/kw in 1984 dollars. However, since the national regressions indicate clearly that larger units have higher O&M costs than small ones, it is appropriate to increase this cost by 31%, to $94.1, to reflect the difference between Seabrook's size and that of the existing New England nuclear units.[59]

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

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59. This percentage is the average over the six existing units of the size effect, predicted by Equation 5, for an increase in size from the unit's MGN to the 1194 MGN of Seabrook.

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). Since the implicit probability assessments of insurers agree with the engineering models of actual 1970's performance, the weight (and perhaps the entirety) of the evidence supports the conclusions that additional major accidents must be expected. 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: Appendix C contains 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 1983. (The data for 1983 are from **Nucleonics Week.**) 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. The available experience totalled 477 plant-years of operation, and the average annual capital addition was $19.4/kw-yr (in MGN terms), or about $23.2 million annually for a Seabrook unit in 1983 dollars, using the appropriate Handy-Whitman deflator for each region. As Figure 3.3 and Table 3.26 show, the amounts of capital additions have increased over time. Over the last seven years, the average may have stabilized at about $26.2/KW-yr, or it may be increasing at about $\$2/\text{kw-yr}^2$. If capital additions decline to the $26.2/kw-yr level, Seabrook capital additions will be $31.3 million in 1983 Handy-Whitman dollars. Assuming that the Handy-Whitman index applicable to New England nuclear construction continues to run about 1.4 percentage points ahead of the GNP deflator, as it has for the 1970-83 period, we would expect 5.4% nuclear inflation in 1984, and 7.4% thereafter. The levelized value over a 20 year life would be $30.6/kw in 1984 GNP 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.

Q: What decommissioning cost does PSNH assume?

A: PSNH uses a decommissioning cost estimate of $170 million in 1984 dollars.

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 14 to 17 cents/kWh, levelized in 1984 dollars. The major uncertainty, and the only one I reflect in this range, is the completion cost of the unit. Excluding sunk costs as of the end of 1984, the remaining cost is still about 7 to 10 cents/kWh.[60] These figures are derived in Table 3.27. The costs in Table 3.27 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.

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60. Of course, if more money is spent on Seabrook and it is then cancelled, the incremental cost per kwh is infinite. It is entirely possible that another billion dollars or more could be spent on the unit, without it ever generating any power.

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 two important implications. First, Seabrook power will be very expensive. The power will cost at least 34 cents/kwh (depending on the final cost) in the first year, falling to a minimum cost of something over 22 cents in the early 1990's, and then rising again. Second, the plant will raise total rates for PSNH by about half a billion dollars in its first full year of service, under normal ratemaking, and will never produce lower rates than other conventional sources.

Q: What is the unit's major benefit to PSNH 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 an 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 range of assumptions regarding Seabrook 1 cost. 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, PSNH projections of Seabrook 1 fuel costs, oil and coal costs, and Bangor Hydro estimates of the total cost of building and running a new coal plant.[61] The differential against oil starts in 1988 at about 4.4 cents per kwh, and rises to 15.5 cents per kwh by 2000, while the nuclear/coal fuel differential starts at about 3.1 cents in 1995 and rises to 22 cents in 2017. The difference between the cost of nuclear fuel and that of new coal plant power starts at 14 cents in 1995 and rises to 25.2

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61. PSNH's estimate for coal plant busbar costs are for a unit entering service in 2001, half-way through Seabrook's life. The nominal dollar costs of that unit are not comparable with those of Seabrook, and it is difficult to anticipate the technological nature of coal plants entering service in the twenty-first century.

cents in 2017. These savings are substantial, but they come at the even greater cost of building and operating Seabrook 1.

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 in Section 3, including a $6 billion construction cost, except that it uses a 31-year useful life, more typical of utility practice, since it is the utility projections (as modified by the Commission) which will determine the depreciation 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.[62] The details of this analysis may be found in Appendix F. Figure 4.2 plots the results of this analysis, along with utility assumptions regarding replacement energy costs. Under these more realistic assumptions, Seabrook 1 power is never less expensive than the BHE coal plant, and only beats oil fuel costs in 2010.

Q: Have you determined whether the early losses to customers are

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62. Both utility estimated 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.

recovered by the later savings?

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 from my best estimates (again with the optimistic $6 billion cost figures), restated as millions of dollars per year for PSNH customers, along with the corresponding costs of replacing Seabrook 1 energy with BHE's projected costs of oil (higher than PSNH's projections) to 1994, and BHE's new coal plant cost projection thereafter.[63] 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 15% discount rate.

It should be noted that even the realistic case is probably somewhat optimistic, since it assumes the lowest capital cost I can justify, a rather 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

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63. While this analysis is intentionally favorable to PSNH, even using PSNH's oil price projections would tend to overstate the savings from Seabrook operation. Much of PSNH's share of Seabrook power will have to be sold at NEPOOL savings rates, or through negotiations in a buyers' market. On the other hand, PSNH projects higher coal fuel costs than does BHE, although this may reflect different assumptions regarding plant design and fuel quality.

years old when (and if) Seabrook reaches retirement age at 30 years.

It should come as no suprise that customers would be charged more for Seabrook 1 than it will save them. Seabrook is more expensive than the alternatives for <u>every</u> year. By 2016, the cumulative net cost reaches $8.8 billion; At a 15% discount rate, the present value of the cost to ratepayers would be almost $2.2 billion.

Figure 4.3 displays the cost to PSNH customers of Seabrook 1 net of fuel savings for each year of its life, under my cost results, for traditional ratemaking treatment.[64]

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 may be 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

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

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.[65]

Customers also vary in terms of their discount rates. The 15% 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: Is PSNH's use of a 10% discount rate in evaluating customer

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

savings from Seabrook appropriate?

A: I think not. It is important to recall that this discount rate is being used to discount cash charges to customers,[66] and should therefore reflect the time and risk preferences of the customers, rather then of PSNH itself, or of its shareholders. 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 10%, for example, it would be equivalent to a return of 10%. For an investment with the risk characteristics of Seabrook, this is an implausibly low target return, roughly equivalent to a ten-year payback.[67] This is roughly the return one would expect from an investment approximately equivalent to risk-free Treasury securities or the insured bank deposits to which PSNH refers. I do not believe that any reasonable person would suggest that Seabrook is as safe an investment as government bonds.[68]

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66. It is meaningless to apply discount rates to anything other than cash, and the discounting is applied to net customer savings, not to PSNH's cash outlays.

67. 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 ten years.

68. The Commissioners may assess the degree of risk by asking themselves what expected return would induce _them_ as individuals to invest directly in Seabrook.

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 10%, and even well in excess of the 15% that I use as a discount rate. 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 (1979) found that residential consumers used real discount rates of 15-25% in comparing appliances of differing efficiencies. These high discount rates indicate that most consumers would not be willing to pay the costs of Seabrook, if they could expect a savings return of only 15% nominal (PSNH's "high" discount rate), which is only about 9% real, and that they would not even consider it at the 10% discount rate.

Given the consideration outlined above, the 15% discount rate is probably a minimum reasonable value, and a considerably higher figure (say 20%) may be appropriate. The 15% value would reflect an investment only a bit more than half as risky as a widely diversified stock market portfolio.[69]

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69. 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 9 points more, or about 19%), should yield about 14.5%. PSNH's comparison of its discount rates

Q: What 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.

Q: What would the effect be on PSNH if Seabrook were completed at $6 billion and the NHPUC capped cost recovery at PSNH's share of a $4.5 billion cost?

A: PSNH would suffer a pre-tax loss of $531 million, on top of some $280 million lost from Seabrook 2. If PSNH had a large enough tax liability to fully utilize the resultant tax declaration, the total after-tax loss would be approximately halved, to roughly $400 million. This is about half the current book value of PSNH's equity, and about twice the market value of that equity. If PSNH's tax liability is inadequate, the loss would be larger.

Q: And if the cost of Seabrook rises to $8 billion?

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to actual market returns in a relatively weak period is meaningless: since equity investors take risks, they clearly expect higher average returns than investors in low-risk or risk-free debt.

A: If PSNH is able to finance its share of this cost (by no means certain), its loss on Seabrook 1 would rise to \$1.25 billion, or \$1.5 billion including Unit 2, before taxes, and at least \$760 million after taxes.

Q: If Seabrook costs \$6 billion, and if PSNH rate increases for Seabrook are limited to 10-15% annually, what would be the effect on PSNH?

A: If rates are only allowed to increase 10% annually to cover Seabrook costs, it would require some 14 years (to 2001) for the shareholders to recover the deferred charges. This estimate assumes that the difference between traditional and phase-in ratemaking in each year is deferred, and accrues a carrying charge (minus taxes on the debt portion), just as if it were accruing AFUDC, and that the accrual credit is fully taxable. The deferred charges would exceed \$1 billion in 1994 and 1995.

The situation for the shareholders is much improved at a 15% annual rate of increase. The deferred balance would peak at less than \$600 million in 1992, and would be eliminated by 1996. Even so, this would require annual increases of 15% just for Seabrook for over 8 years, increasing PSNH's rates to more than 3.5 times their current levels.

5 - COMPARING SEABROOK TO ALTERNATIVE POWER SOURCES

Q: How can your estimates of Seabrook 1 incremental costs compare to contract rates for power from co-generators and small power producers?

A: If completing and running Seabrook 1 costs 6.5 cents per kwh in 1984 dollars, for example, 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.

Any power purchased for less than 10 cents/kwh on long term contracts is likely to be a bargain, at least compared to Seabrook 1 power costs. Even if PSNH renews those contracts after the first fifteen years by adding fifteen years of inflation at 6%, the power will still be cheaper than Seabrook, which would cost 26.6 cents/kwh in nominal levelized dollars (again working from an optimistic real-levelized 6.5 cents in 1984$) over its second fifteen-year period, if it survives that long.

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 increasing the power purchase rate by the same amount as accrued inflation to the renewal date?

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, at 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 from 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, or PSNH 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 PSNH became 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 (more than once), 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.[70] Since the 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

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70. Most of the towns involved have also forbidden approval of the emergency plan by town officials until it has been approved by the town meeting.

occurring in time to allow licensing of Shoreham, which faces similar local opposition.[71]

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 seventeenth 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. According to the Maine utilities:

> While [increased insulation and appliance efficiency] are clearly economic at current prices, numerous studies have shown that many household do

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71. 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.

> _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 under traditional ratemaking Seabrook would raise PSNH's rates by at least 100% in the first year. 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 cover fixed costs. The long-run demand effects[72] of the first year price increase would be a 30-50% reduction in PSNH's sales.

Q: What effect would this loss of sales have on PSNH's ability to raise rates enough to pay for the plant?

A: My analysis of the phase-in options assumed that sales remained constant over the phase-in period. If rising rates, and the foreseeability of further rate increases, drive away industrial load and encourage massive conservation and fuel switching, it may not be possible for PSNH shareholders to ever recover their investment in Seabrook, regardless of the number of years of the phase-in.

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

6 - THE NEPOOL STUDY

Q: What problems have you identified with the NEPOOL study of Seabrook 1 economics, presented as Attachment 5 to Mr. Staszowski's testimony?

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 Section 3, these capacity factors are totally inconsistent with the historical record. Richard Bolbrock, the Director of the NEPLAN Staff, which prepared the Seabrook study, asserted in MPUC 84-113 that these capacity factors are based on New England experience; in fact, 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. The origin of these asssumptions is clear in NEPLAN's documentation of the study, which lists 1973 and 1976 GTF Reports as the source of these inputs. Those early studies could not very well have included much actual nuclear experience, and in fact the study relied on fossil-plant data. Mr. Bolbrock's lack of understanding of this fundamental (and unchanging) aspects of NEPOOL's analysis must call into question the care taken in selecting 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, 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%.[73] The only basis I have seen for this assumption is Mr. Bolbrock's statement that, since HQ "negotiated very hard to have that [amount of allowed interruption] we assumed for this purpose[74] that there will be that type of interruption." 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 time in 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?

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73. 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 would "likely" be used at a higher load factor than his study had recognized. This and subsequent references to Mr. Bolbrock's testimony refer to Maine PUC 84-113.

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

A: Hundreds of MW of gas turbine capacity[75] 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 MW more gas turbine capacity[76] as early as 1994. Mr. Bolbrock has acknowledged that NEPLAN has not studied the need to replace these units, and that the utilties, which scheduled the retirements, use depreciation life as one of the criteria. 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.[77] The utilities would

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

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

77. For example, Mr. Bolbrock cited an example of NU retiring a turbine simply because its step-up transformer failed. The turbines which Mr. Bolbrock postulates for the 1990's will require new step-up transformers, along with new turbine-generators.

not be so eager to dispose of these plants if they thought the capacity would be needed in a decade or so, as the NEPOOL study 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 economics of Millstone, while better than those of Seabrook, are bad enough even if coal conversion is not presented as an alternative. Thus, at least 400 MW of coal-convertable capacity at West Springfield and Devon 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, so fuel conversions can only be determined for units scheduled for retirement or renovation. Thus, it appears that coal conversion potential is understated, and it is impossible to determine by how much. In addition, 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.

7 - CONCLUSIONS AND RECOMMENDATIONS

Q: Please summarize the major conclusions of your analyses.

A: If PSNH continues to build Seabrook 1, the Commission should expect to see:

- further delays in the commercial operation date,
- additional cost overruns,
- additional financing requirements beyond the current Newbrook plan,
- poor performance and high operating costs after start-up, and
- large rate increase requests, after the completion of the plant.

Should the Commission decide that it wants the plant to be completed, it must be prepared to provide continuing, almost unconditional support 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 in Seabrook becoming a dry hole.[78] 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

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78. For example, Mr. Hildreth has apparently indicated that the markets will not absorb PSNH's share of the financing to cover $1.3 billion in future Seabrook cash costs; let alone the amounts which are likely to be necessary.

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; <u>and</u> 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: If cancellation of Seabrook 1 would result in PSNH's bankruptcy, and if the Commission wishes to avoid the costs associated with that bankruptcy, does the Commission have any choice except to approve all financings and other arrangements which are necessary for the completion of Seabrook, no matter how onerous to the ratepayers?

A: Yes. First, it is not clear that bankruptcy is the worst outcome for the ratepayers; its costs may well be less than the costs associated with attempting to complete Seabrook. Second, if the CWIP statute prevents the Commission from following the course of action which results in the lowest overall costs, the Commission should attempt to have the statute overturned or amended, so that it does not prohibit recovery of prudently incurred costs of cancelled plants. Third, it is not at all certain that continuation of construction of Seabrook will prevent the bankruptcy of PSNH: many problems may still prevent Seabrook from ever operating, regardless of how much money has been spent on it, and even if it operates, it is not inconceivable that the problems associated with the large revenue requirements, rate shock, and loss of load associated with the plant might still leave PSNH insolvent.

Q: Does this conclude your testimony?

A: Yes.

8 - GLOSSARY

COD progress ratio
The ratio of reduction in expected months until COD, to the months elapsed between estimates. See Tables 3.4 and 3.5. This ratio is 100% if the COD remains constant between estimates, and is less than 100% if the COD has slipped between estimates.

cost ratio The actual completed cost of a nuclear unit, divided by the cost estimated at some previous time. I use the **average cost ratio** for a relevant group of cost estimates, as an approximation of the likely cost ratio for current cost estimates for Seabrook: that is, I multiply the current official estimates for Seabrook by the average cost ratio to project the final cost for Seabrook. See Tables 3.9 and 3.10, and Appendix B.

duration ratio The actual time required between a utility cost estimate for a nuclear unit and the COD of that unit, divided by the utility's estimated value of that interval (the duration, or years-to-go, or **t**). Duration ratios are applied to Seabrook in a manner analogous to the cost ratios. See Table 3.7 and Appendix B.

completion progress ratio
The ratio of the projected increase in physical completion as projected at the beginning of an interval (generally between cost estimates and revisions of percent completion), to the reported increase in physical completion as reported at the end of the interval. See Tables 3.2 and 3.3.

myopia analysis
A general term for the computation and application of cost ratios, myopia factors, and duration ratios.

myopia factor The cost ratio, annualized by the utility estimate of years to COD (**t**), by raising the cost ratio to the power of **1/t**. Again, the average myopia factor from a set of historic estimates can be applied as a correction to the current estimate for Seabrook by raising the myopia factor to the current estimate for **t**, and multiplying the result by the current cost estimate. See Tables 3.9 and 3.10, and Appendix B.

St. Lucie experience
As used in Table 3.14, this term refers to the average cost overrun experience at the St. Lucie plants, as described in Secton 3.2.

Seabrook cost estimate history
As used in Table 3.14, this term refers to the results of my analyses of cost trends for Seabrook, Tables 3.11 and 3.12.

slippage ratio This term is used in Table 2.1 to describe the rate at which the estimated COD of the various units receded as time went by. It is the ratio of (months delay in COD) to (months elapsed between estimate). It is 0 if the COD remains the same, and 100% if the COD moves back at the rate of one year per year: thus, it is equal to 100% minus the COD progress ratio.

9 - TABLES AND FIGURES

TABLE 1.1: SEABROOK PROJECT ESTIMATES

Estimate Date	Estimate ($ million)			Commercial Operation Date		Percent Complete [1]		
	Unit 1	Unit 2	Total	Unit 1	Unit 2	Unit 1	Unit 2	
Feb-72	486	486	973	11/79	11/81	0.0%	0.0%	
Mar-73	570	570	1140	11/79	11/81	0.0%	0.0%	
Aug-73	587	587	1175	11/79	11/81	0.0%	0.0%	
Jun-74	650	650	1300	11/79	11/81	0.0%	0.0%	
Mar-75	772	772	1545	11/80	11/82	0.0%	0.0%	
Dec-76	1007	1007	2015	11/81	11/83	1.0%	1.0%	
Jan-78	1360	995	2355	12/82	12/84	8.0%	2.0%	
Jan-79	1309	1301	2610	4/83	2/85	18.9%	2.8%	
Apr-80	1527	1593	3120	4/83	2/85	37.0%	7.2%	
Apr-81	1735	1825	3560	2/84	5/86	50.8%	8.2%	
Nov-82	2540	2580	5120	12/84	3/87	68.8%	16.9%	
Dec-82	2540	2709	5249	12/84	7/87	68.8%	16.9%	
Jan-84 [2]	5070	5030	10100	4/87	?	88.8%	29.3%	
Mar-84	4550	4452	9002	7/86	12/90	71.7%	20.2%	[3]
Apr-84	4100	2760	6860	2/86	7/88	--	--	
Aug-84	4479	--	--	8/86	--	80.0%	--	

Sources: DPU 84-152, AG Request AG 1-86 (a), 9/84.
DPU 20055, AG P-18, PSNH Plant Cost Est. History.
Division between units from: EIA, HQ254 Reports.

Notes: [1] PSNH Progress Reports.
[2] UE&C Estimate as reported by MAC and Neilsen-Wurster.
[3] Direct Craft Manhours, as of 12/83.

Figure 1.1: History of Seabrook Cost

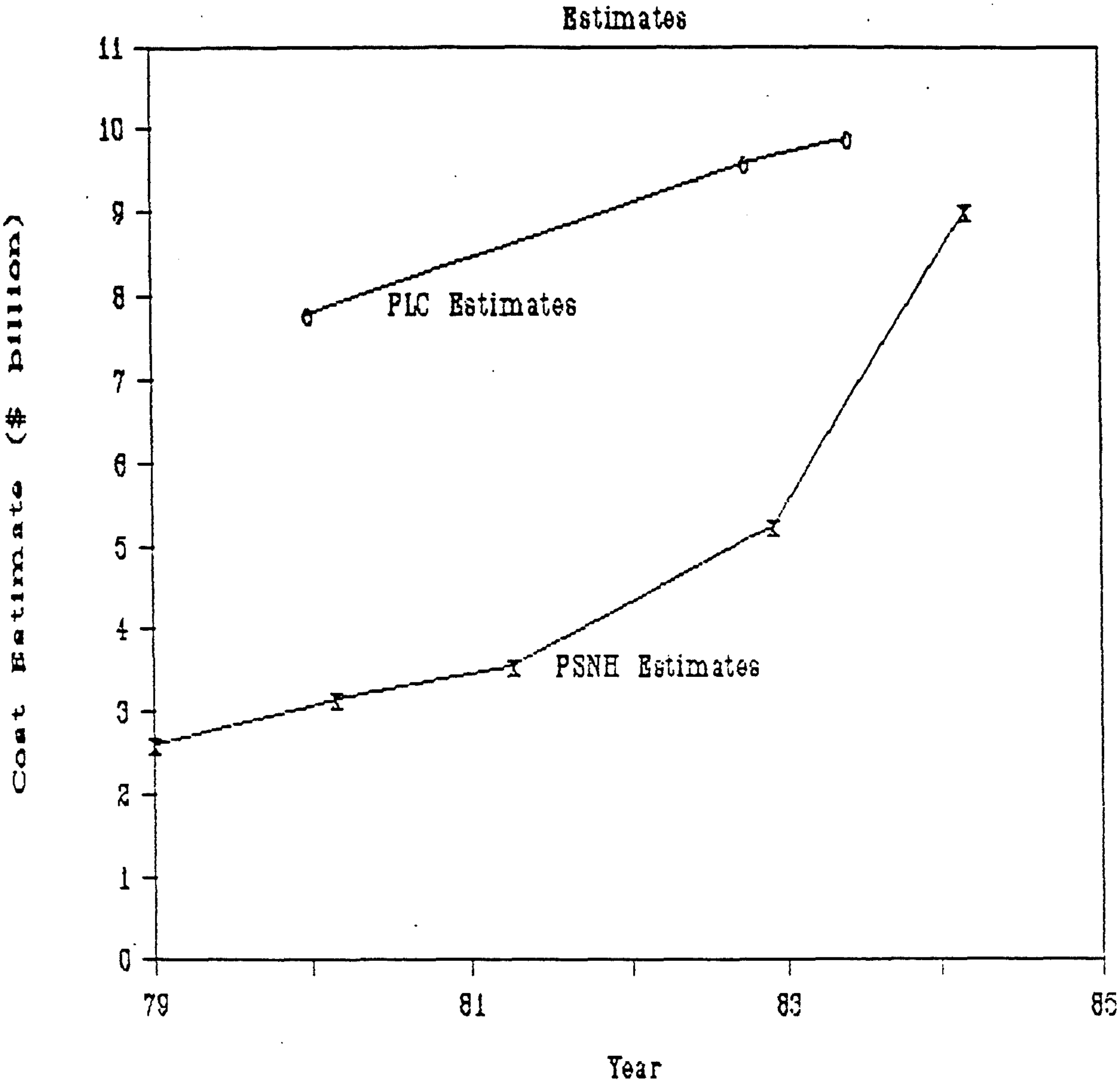

TABLE 2.1: SUMMARY OF TRAILING SECOND UNIT ANALYSIS

Plant	Unit	COST GROWTH RATE [3] Before COD1	After COD1 [1]	SLIPPAGE RATIO [4] Before COD1	After COD1
Cook	1	14.60%	--	0.473	--
	2	10.43%	1.16%	0.893	0.088
Farley	1	21.01%	--	0.562	--
	2	24.88%	2.10%	0.706	0.306
Hatch	1	13.87%	--	0.435	--
	2	26.48%	0.08%	0.5631/0.3635 [2]	0.105
North Anna	1	14.23%	--	0.607	--
	2	14.75%	5.57%	0.667	0.678
Salem	1	19.27%	--	0.620	--
	2	12.75%	8.16%	0.729	0.675
t. Lucie	1	17.53%	--	0.364	--
	2	21.04%	8.80%	1.018	0.041
Three Mile Island	1	18.65%	--	0.522	--
	2	18.17%	3.70%	1.000	0.131

Notes:
1. COD1 is the Commercial Operation Date of the first unit.
2. Before/after Unit 2 Construction Permit Issuance.
3. Annual rate of increase.
4. Years of delay in projected COD, divided by years elapsed.

Figure 2.1: COOK

Cost Overruns

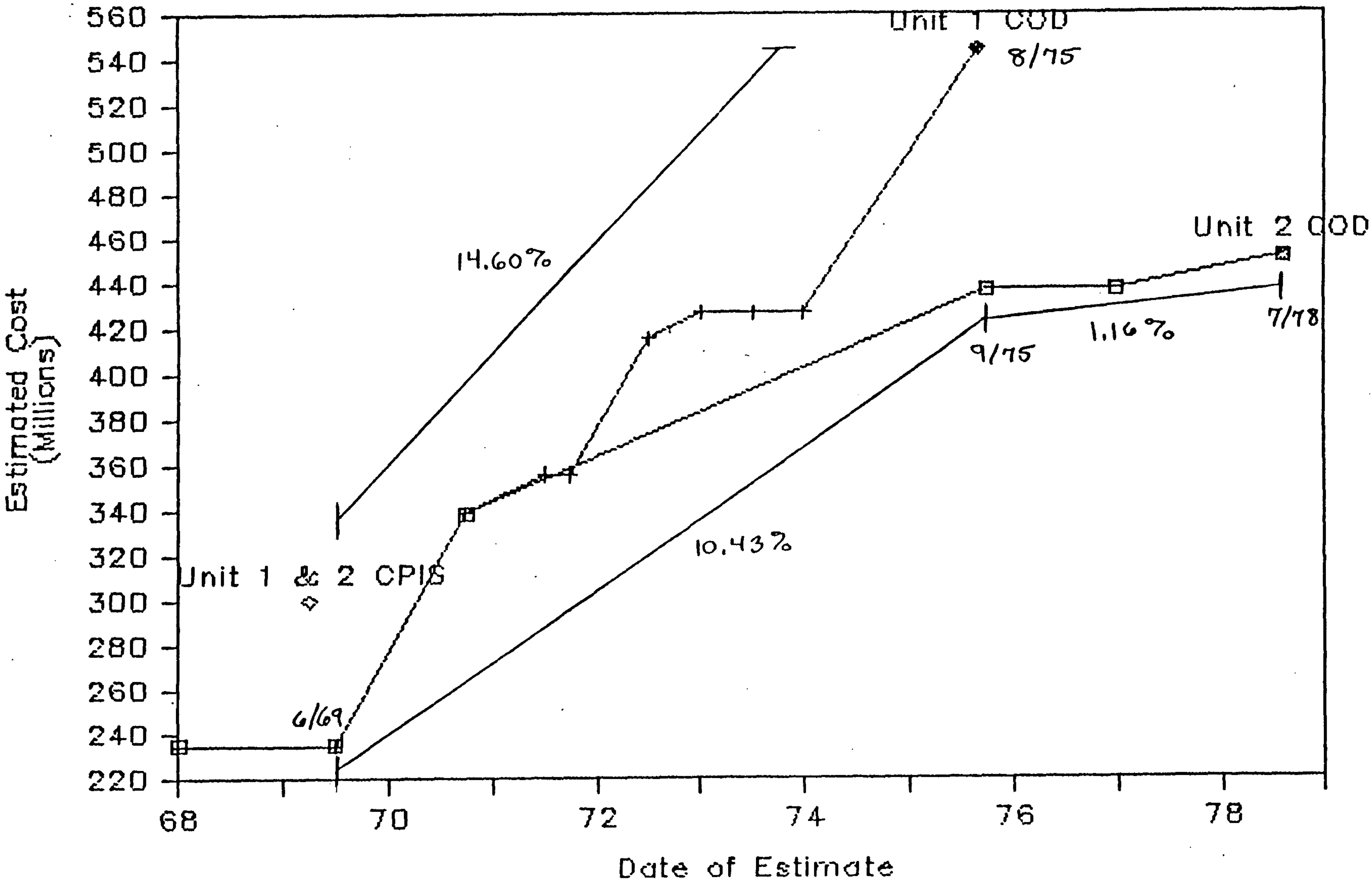

Figure 2.2: COOK

Schedule Slippage

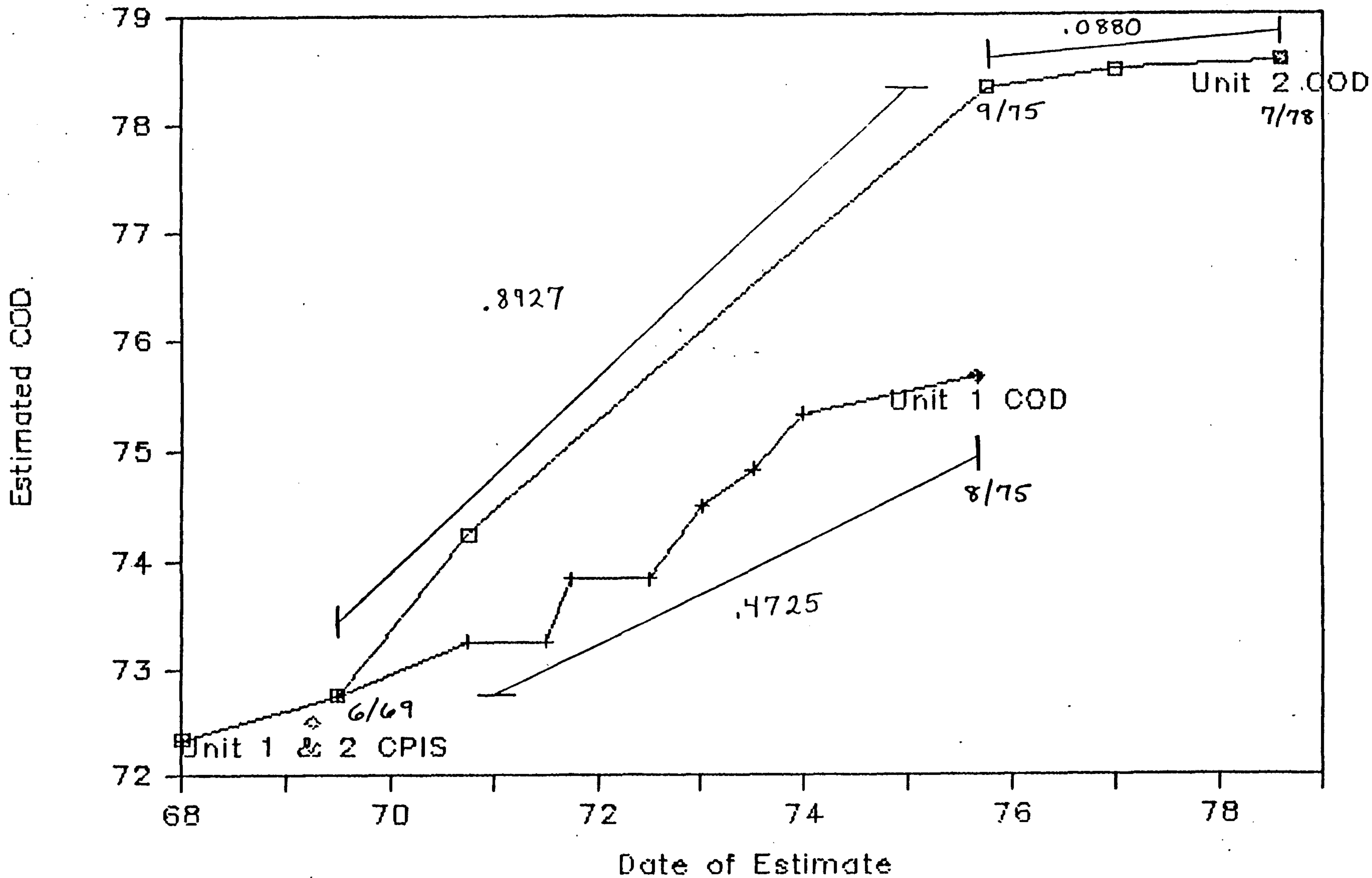

Figure 2.3: FARLEY

Cost Overruns

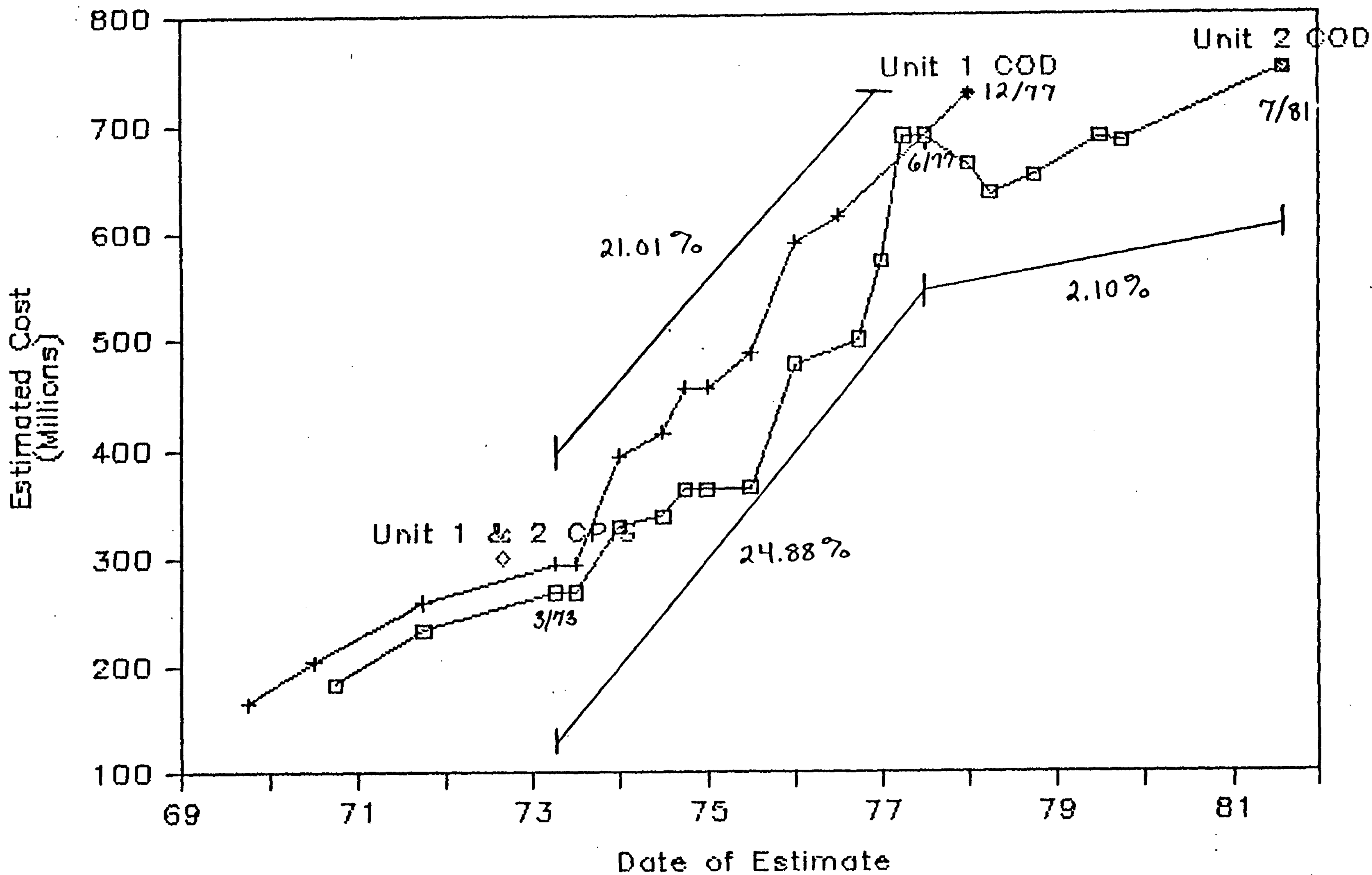

Figure 2.4: FARLEY

Schedule Slippage

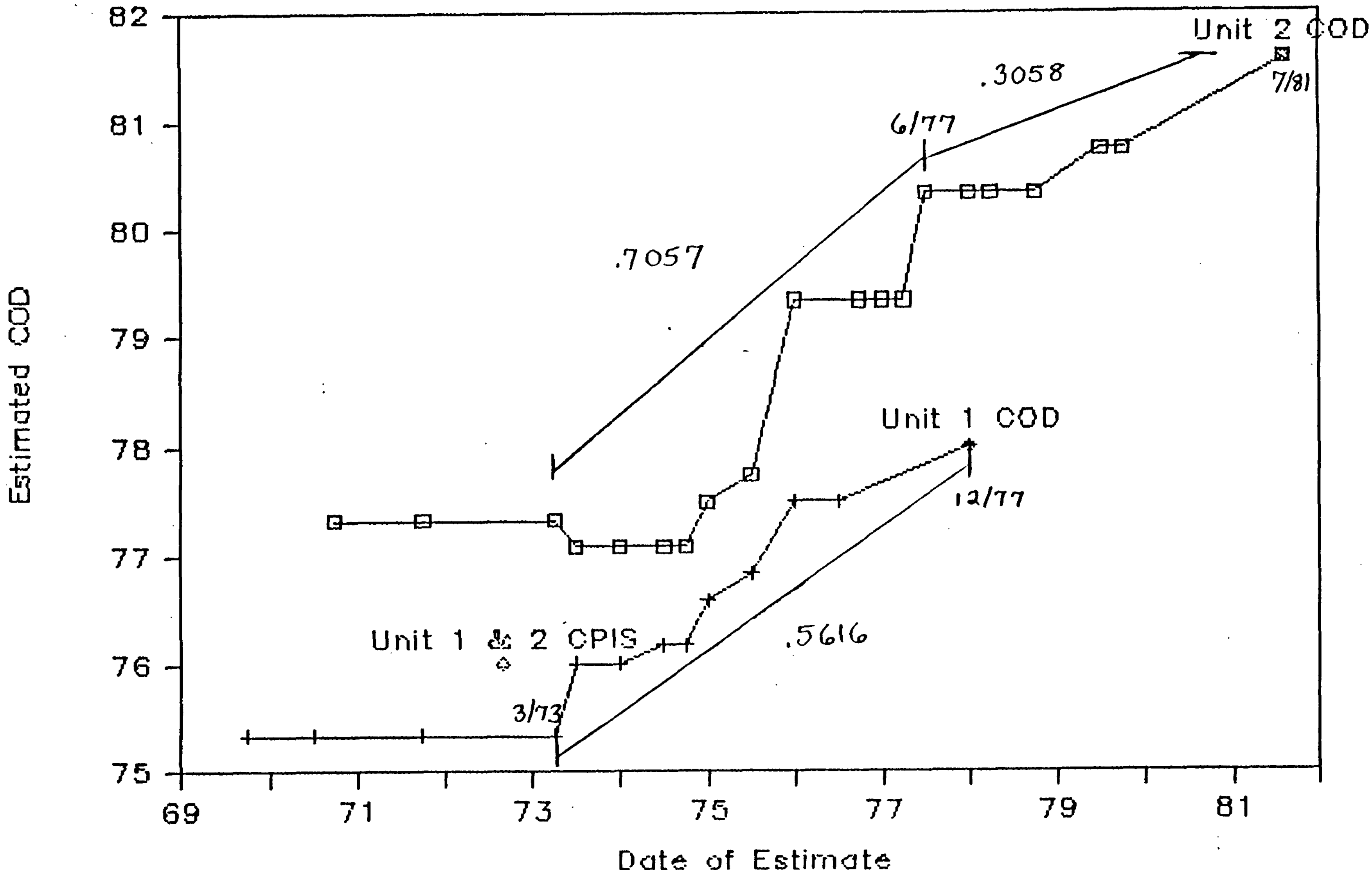

Figure 2.5: HATCH

Cost Overruns

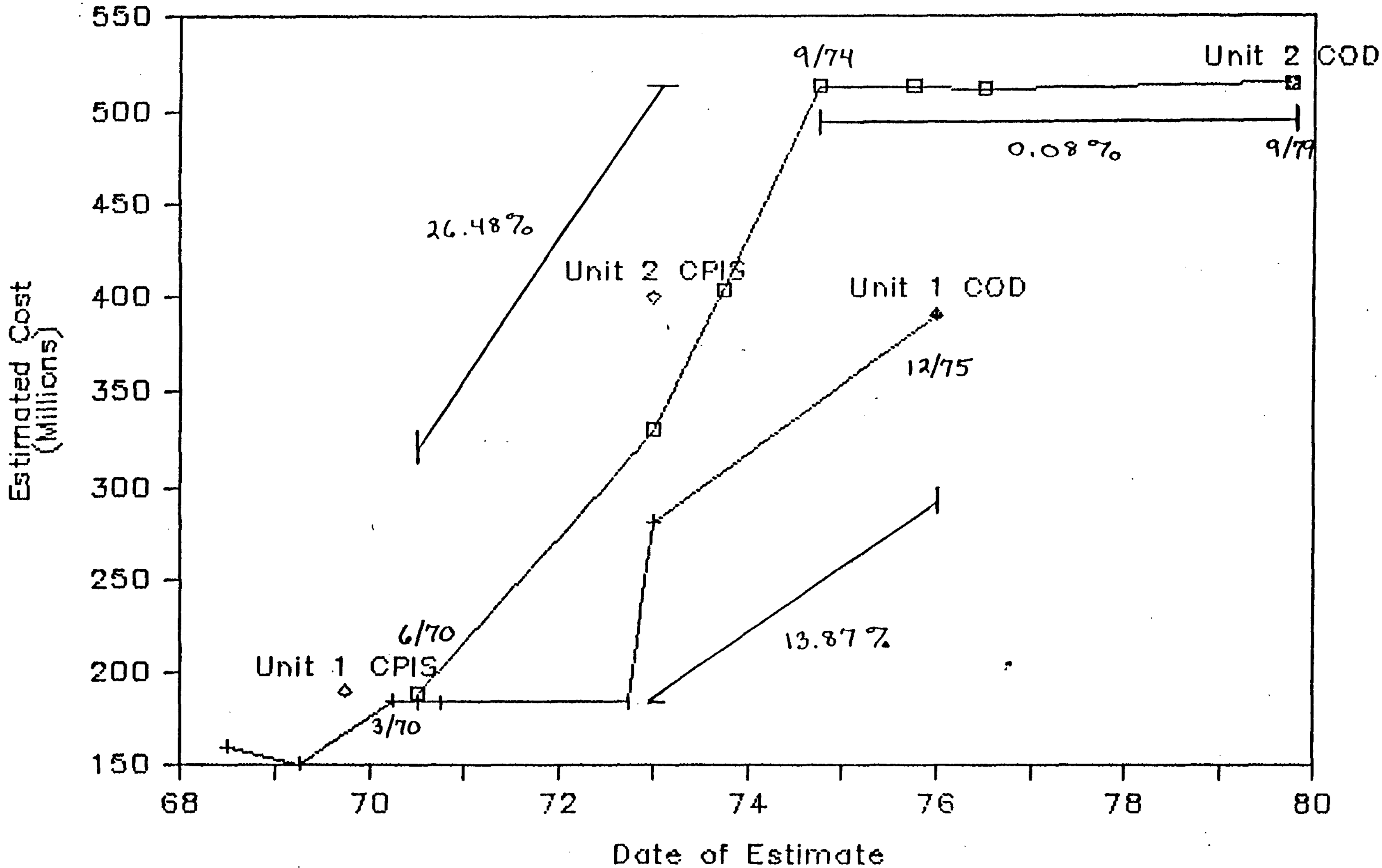

Figure 2.6: HATCH

Schedule Slippage

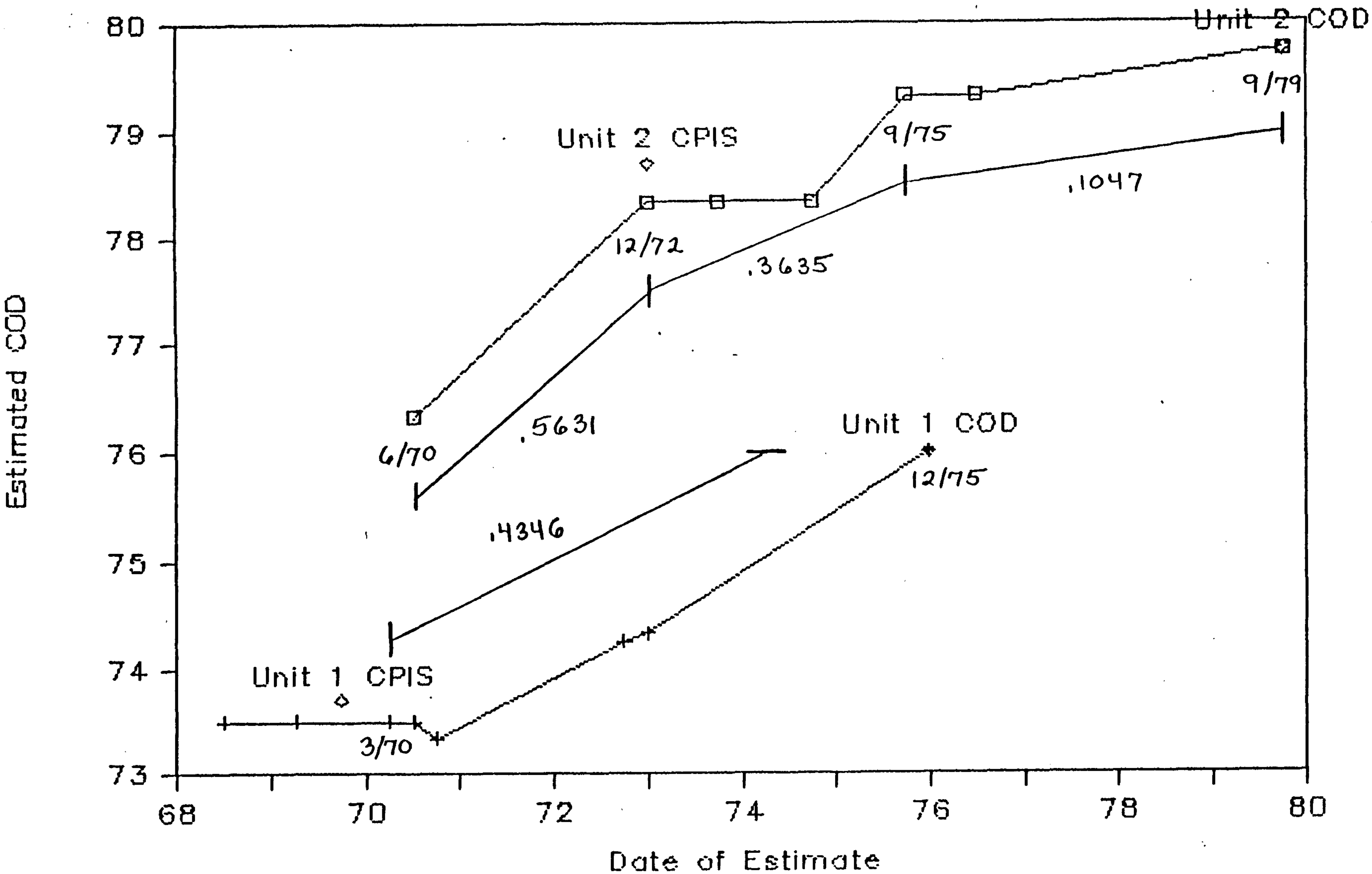

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Figure 2.7: NORTH ANNA

Cost Overruns

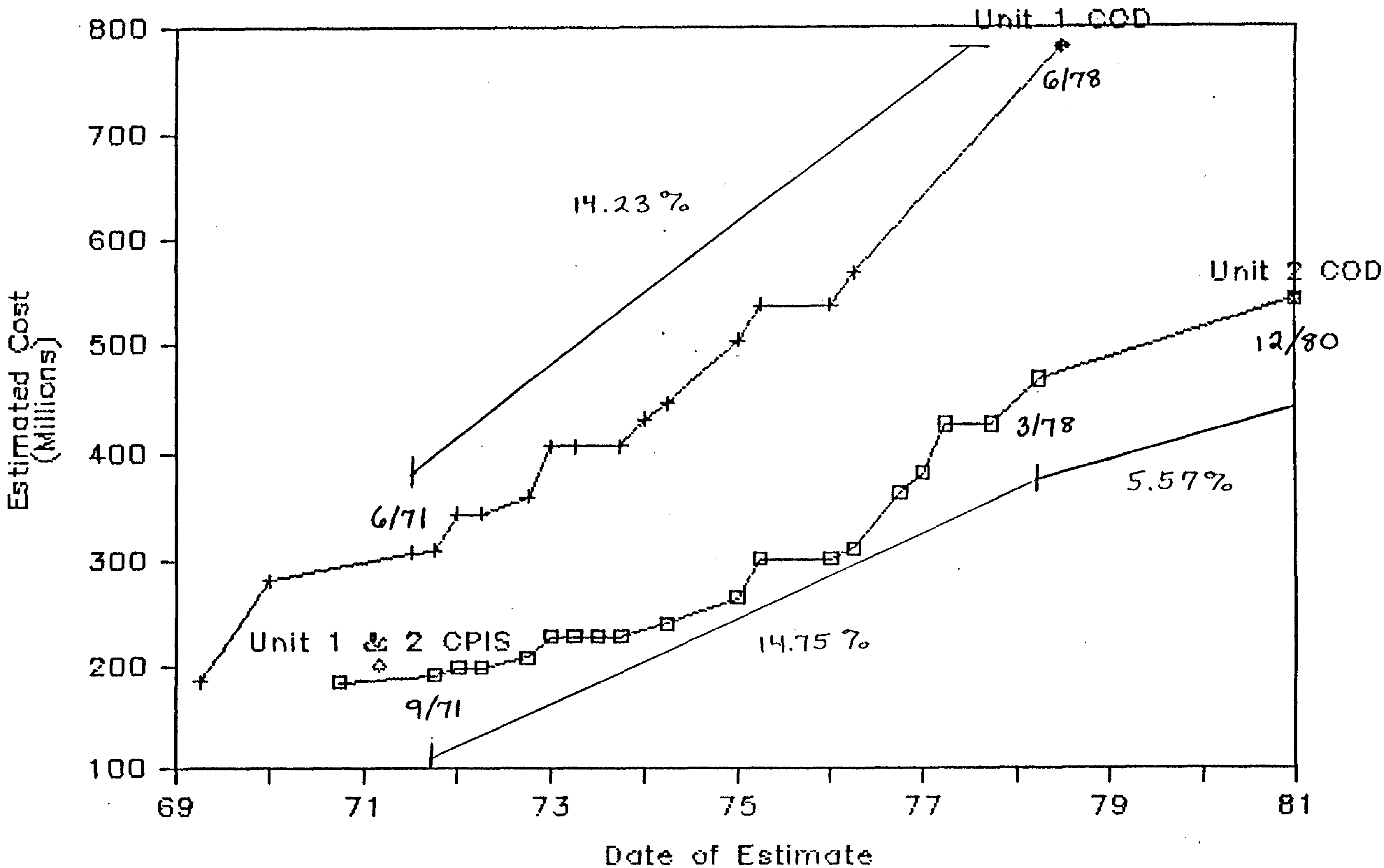

Figure 2.8: NORTH ANNA

Schedule Slippage

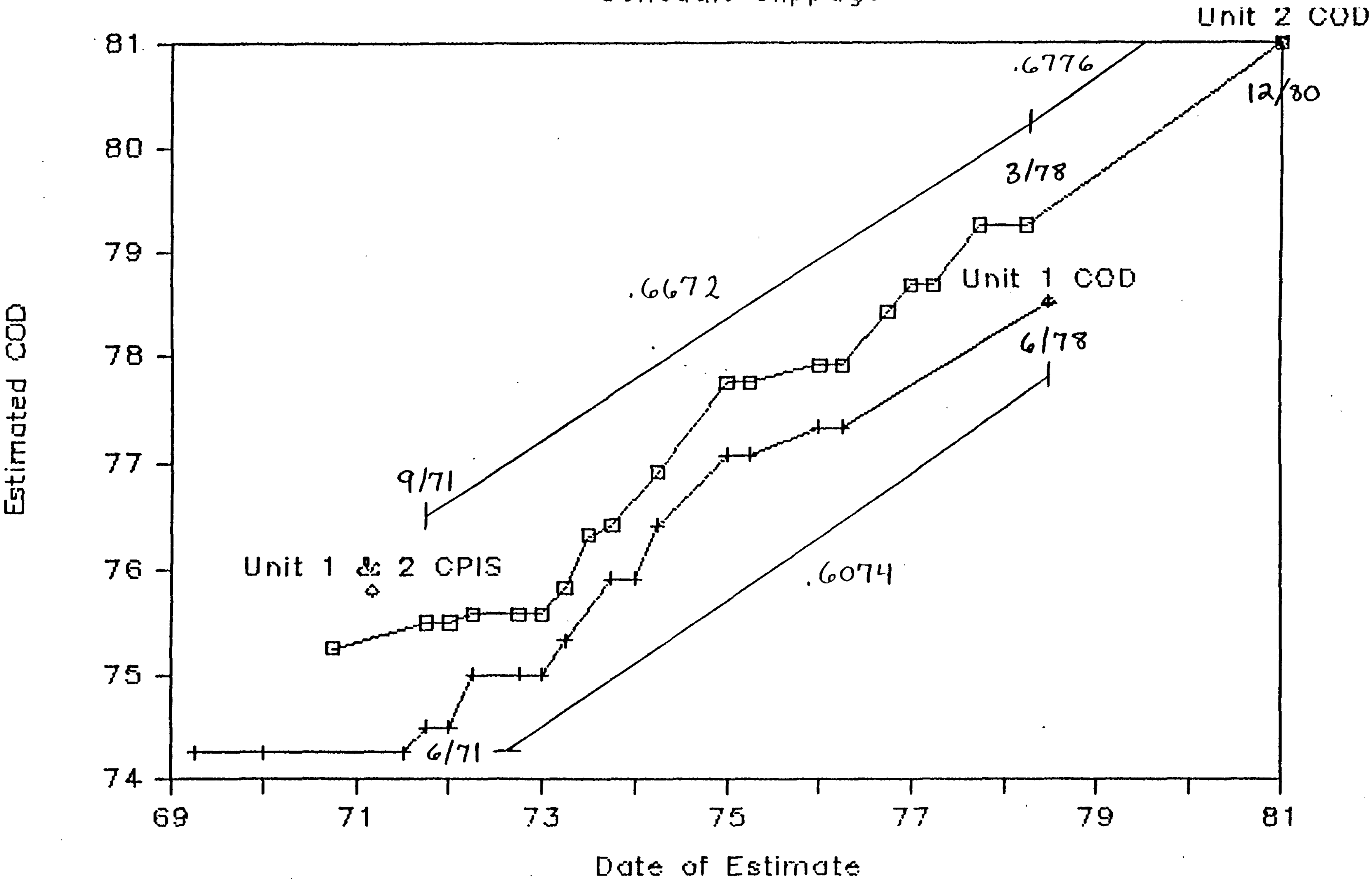

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Figure 2.9: SALEM

Cost Overruns

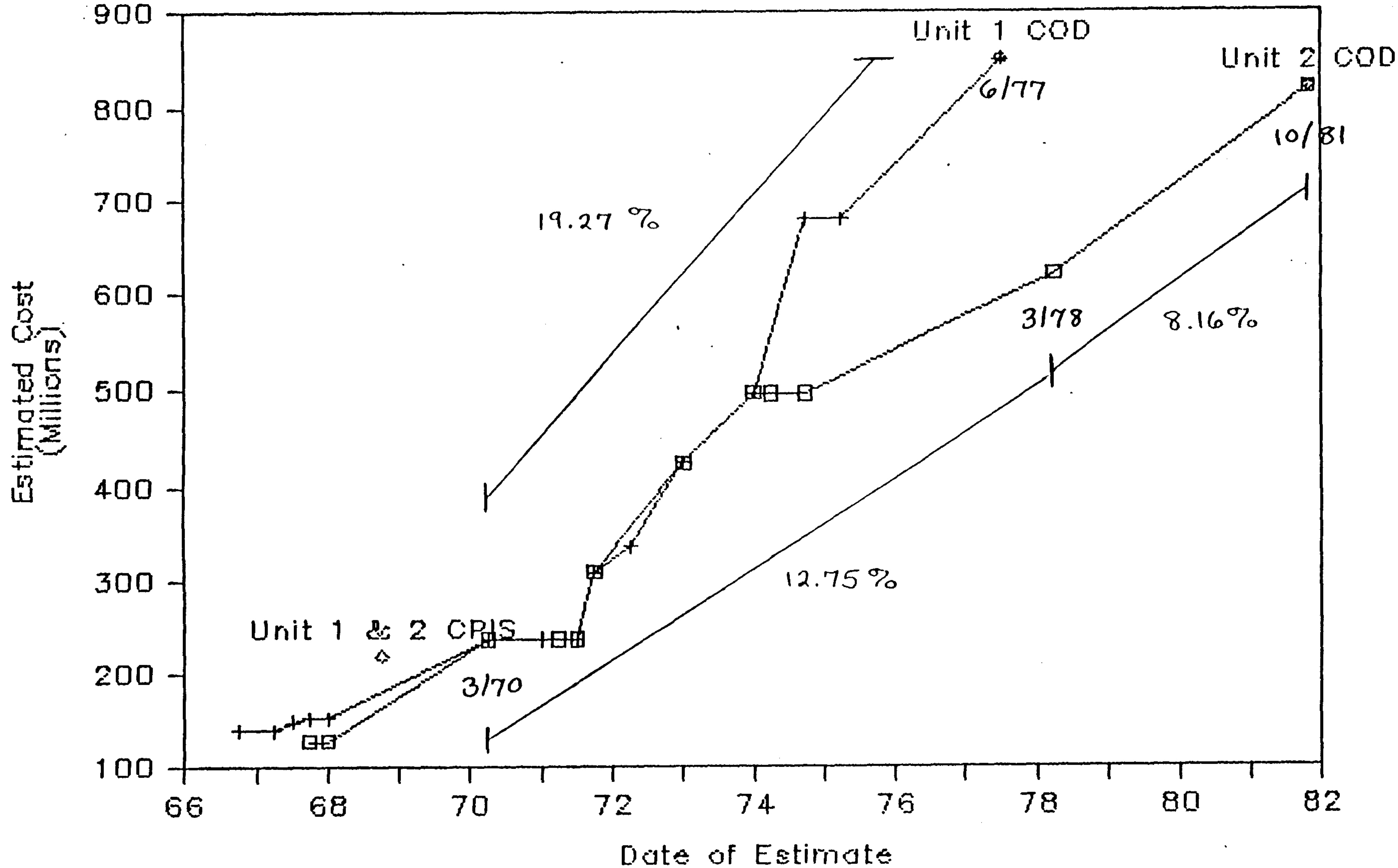


Figure 2.10: SALEM

Schedule Slippage

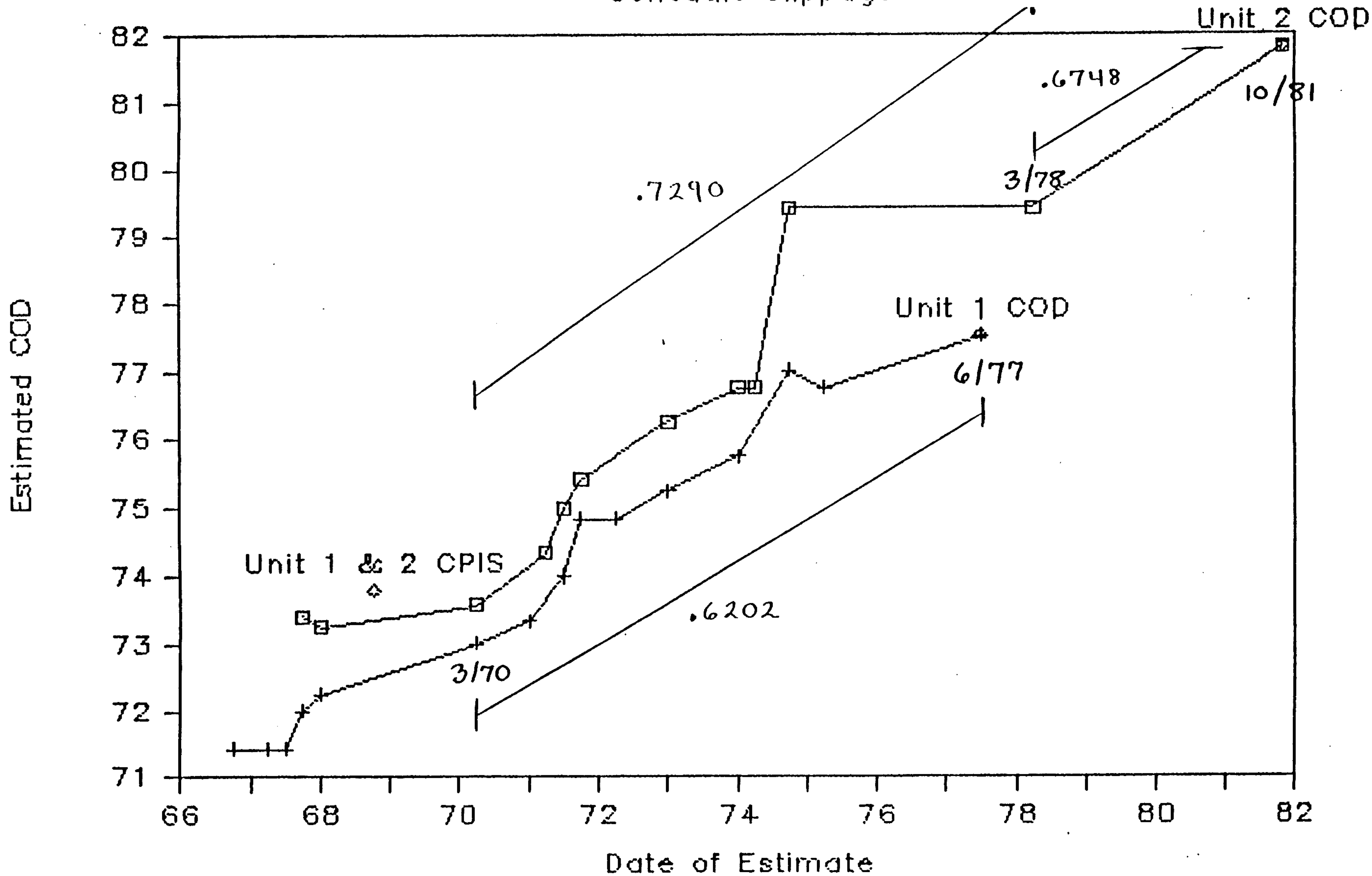


Figure 2.11: ST. LUCIE

Cost Overruns

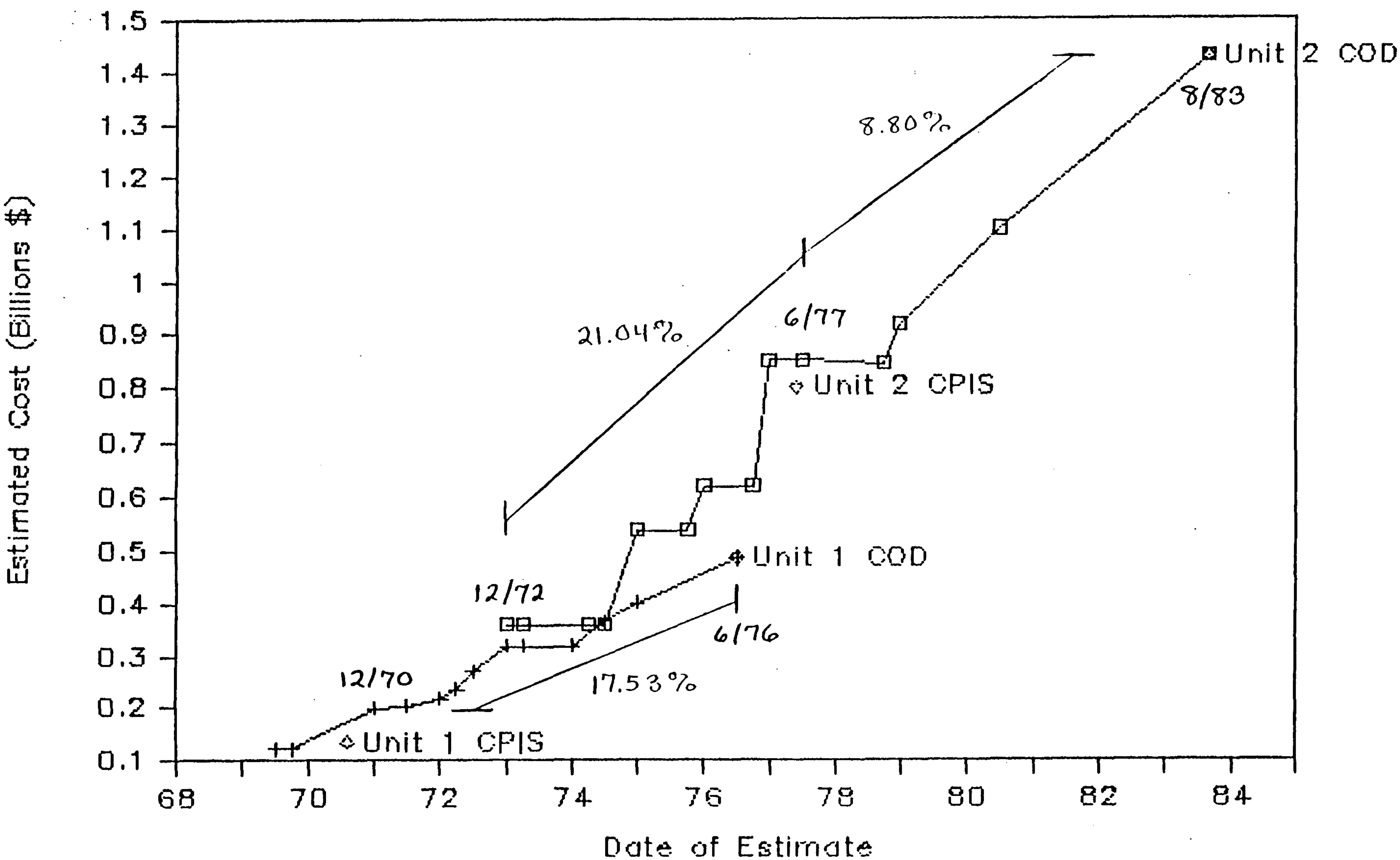


Figure 2.12: ST. LUCIE

Schedule Slippage

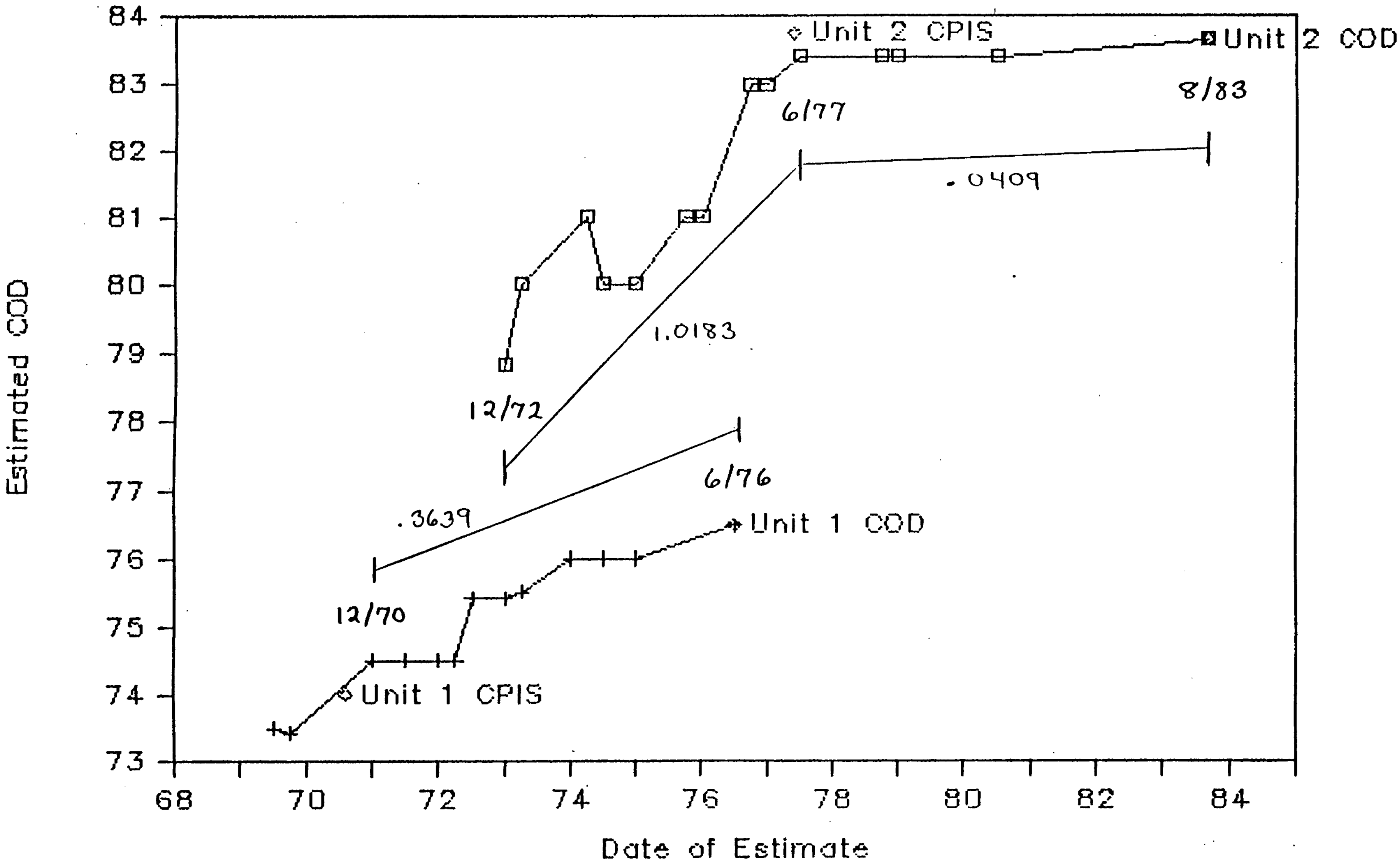


Figure 2.13: THREE MILE ISLAND

Cost Overruns

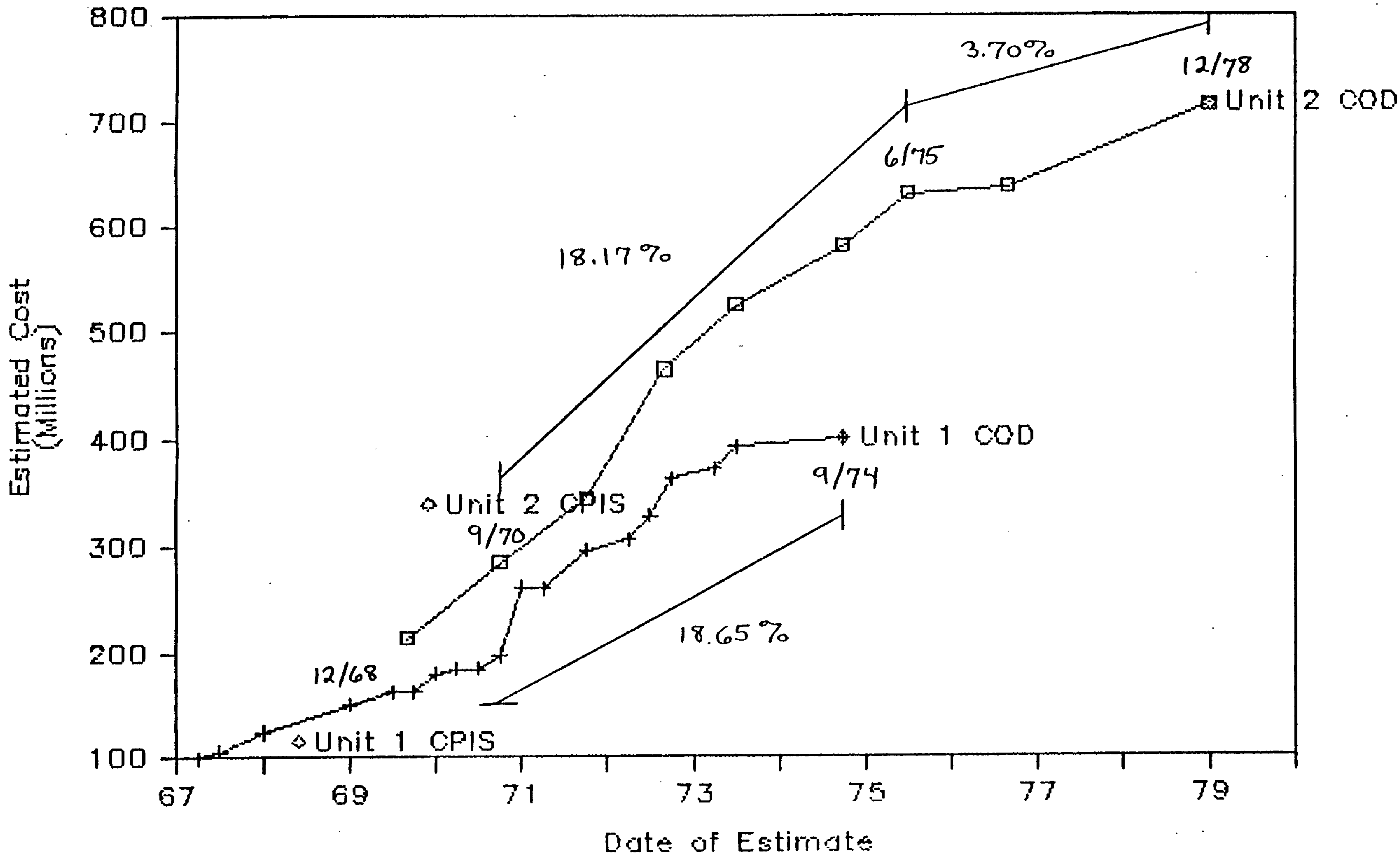


Figure 2.14: THREE MILE ISLAND

Schedule Slippage

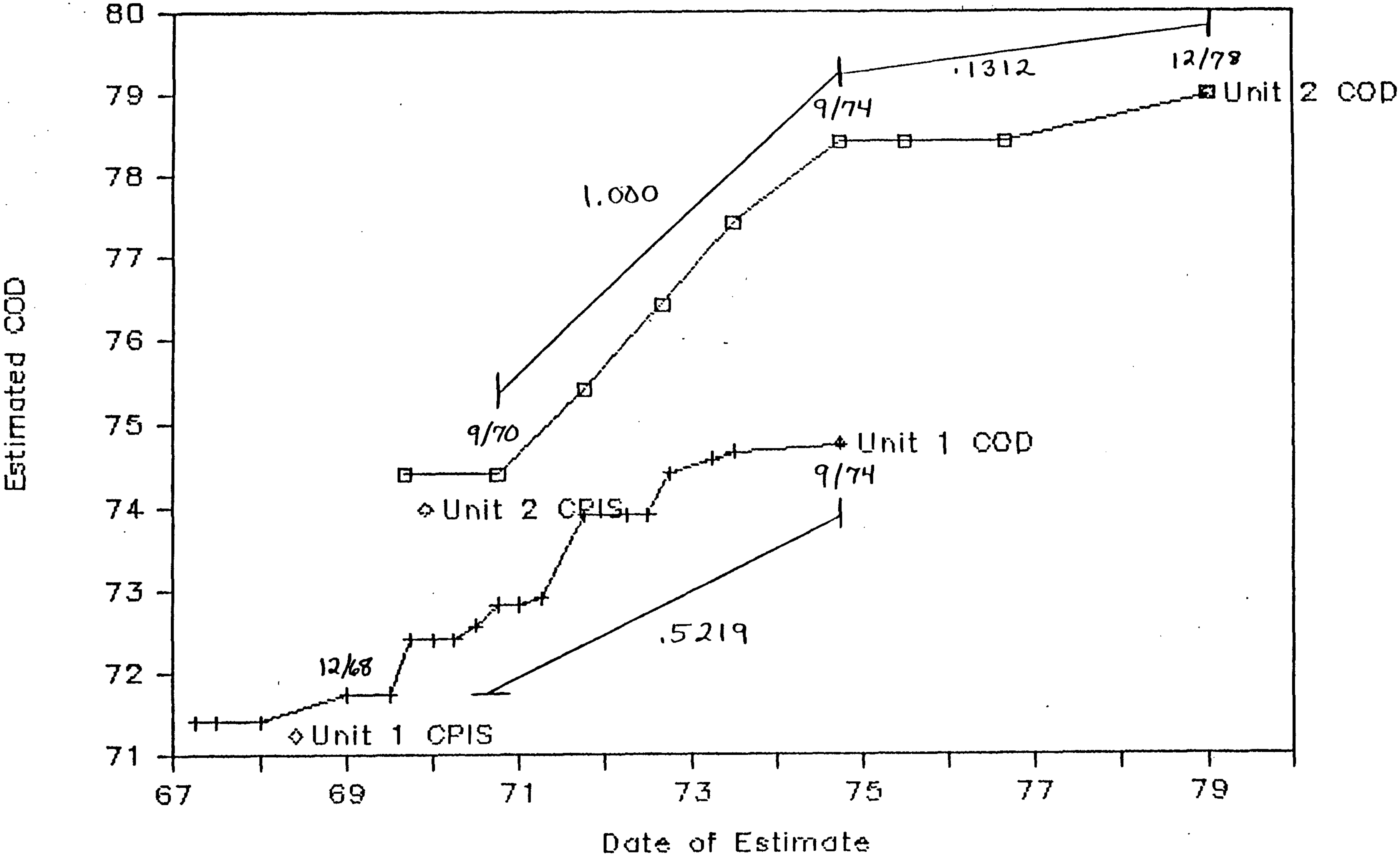


Figure 2.15: Georgia Power

Nuclear Cost Estimate Histories

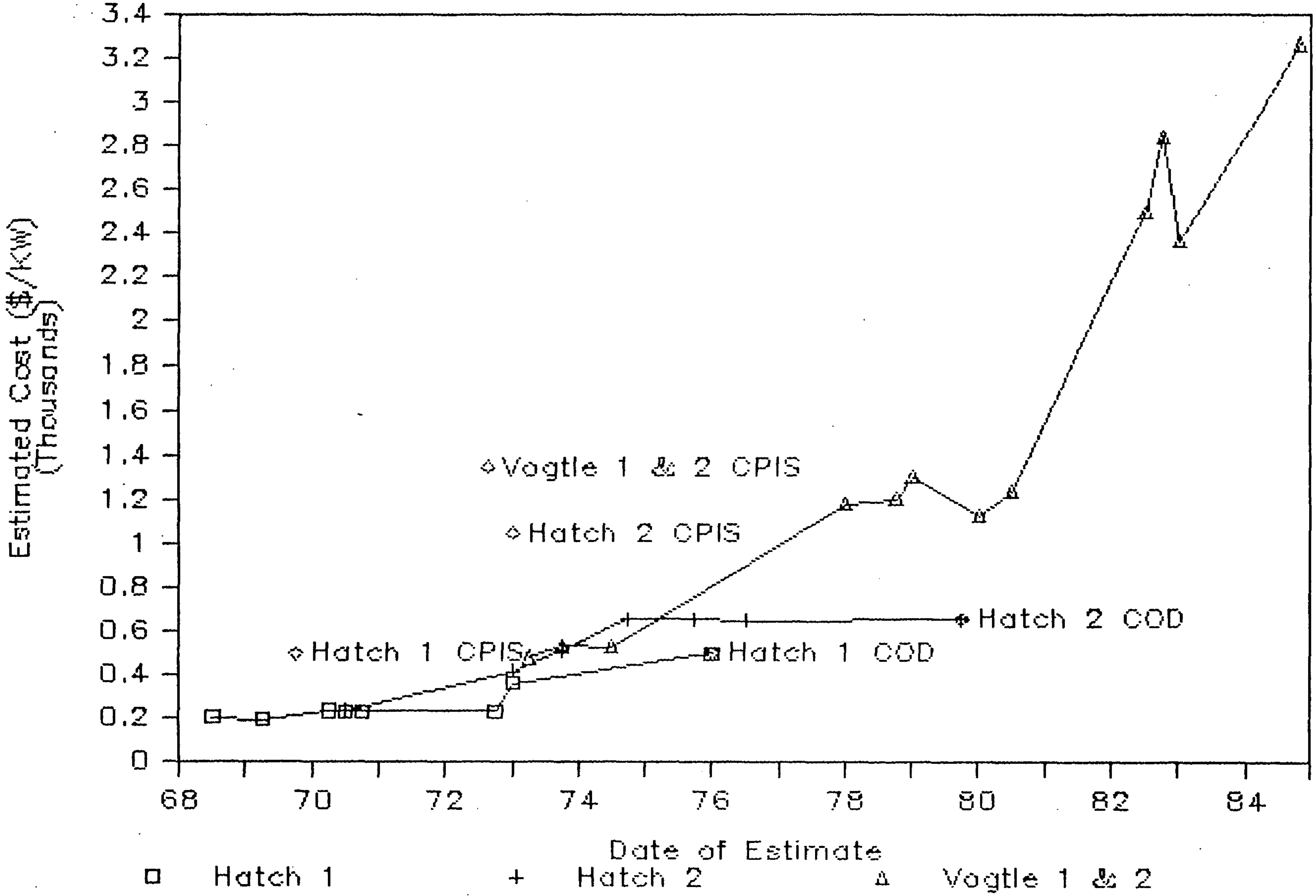


TABLE 3.1: RECENT EXPERIENCE IN START-UP INTERVALS

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.

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

Date:	Mar-79	Mar-80	Jun-81	Nov-82	Mar-84
a. Forecast Construction Stage (% complete) [1]		39.13%	67.7%	82.0%	96.0%
b. Reported Construction Stage (% complete)	18.9%	36.70%	50.8%	65.6%	73.0%
c. Forecast Progress (forecast increase from last reported % complete) [2]		20.28%	31.0%	31.2%	30.4%
d. Reported Actual Progress Since Last Report		17.85%	14.1%	14.8%	7.4%
e. Progress Ratio (Reported/Forecast Progress)		0.88	0.45	0.48	0.24

AVERAGE PROGRESS RATIO FOR SEABROOK 1: 0.489

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

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.

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
PSNH's December 1976 estimate was prepared in October 1976.

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.
[4] TVA News, 7/12/84, reports COD: 1987.

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

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

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%

TABLE 3.10: REAL COST OVERRUNS AND MYOPIA FACTORS

Estimated Time to Completion	Number of Estimates	Average Real Cost Ratio	Average Real Myopia
(years)			
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%

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	--

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	--

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.

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.

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.

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

TABLE 3.17: PWR CAPACITY FACTOR REGRESSIONS WITH YEAR DUMMIES

	EQUATION 3 Coef.	EQUATION 3 t-stat.	EQUATION 4 Coef.	EQUATION 4 t-stat.	EQUATION 5 Coef.	EQUATION 5 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.

TABLE 3.18: COMPARISON OF CAPACITY FACTOR PREDICTIONS

		Calendar Years of Experience						
Predicted Capacity Factors:		1 [2]	2	3	4	5	6	7+
Easterling [1]		47.2%	47.2%	49.6%	52.0%	54.3%	54.3%	54.3%
PSNH		59.0%	61.0%	65.0%	67.0%	69.0%	72.0%	72.0%

As of:	31-Dec-83	Unit Years of Experience in each Calendar Year						
	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.

TABLE 3.19: COMPARISON OF CAPACITY FACTOR PROJECTIONS

Unit	Original DER MW	Actual [1]	Easterling [2]	PSNH
Salem 1	1090	48.2%	53.0%	67.0%
Zion 1	1050	56.4%	55.3%	69.4%
Zion 2	1050	58.6%	55.0%	68.8%
Cook 1	1090	60.3%	53.8%	68.3%
Cook 2	1100	64.2%	52.3%	66.1%
Trojan	1130	50.1%	52.4%	67.5%
Average [3]		56.3%	53.8%	68.1%

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. Weighted by experience.

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

UNIT	DER NET [3]	first year	CAPACITY FACTOR BY CALENDAR YEAR [2] 1	2	3	4	5	6	7	8	9	10
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.

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]		51								
deviation/unit-year		1.3%								
Average adjusted for Salem/Trojan [5]	54.6%	50.7%	59.5%	63.0%	60.9%	57.4%	55.0%	58.3%	57.8%	42.4%
all years	56.9%									
>5 years	56.1%									
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								
deviation/unit-year		1.7%								
Average adjusted for Salem/Trojan [5]	54.3%	54.1%	59.0%	62.6%	60.5%	57.0%	54.6%	57.9%	57.4%	42.0%
all years	57.5%									
>5 years	55.7%									

Notes: [1] From Table 3.18
[2] 2*52.0% - 16.8% - 21.4%.
[3] 1983 weighted as .75 years; excludes Salem 1 and Trojan second years.
[4] 2*55.8% - 16.8% - 21.4%.
[5] Simple averages minus Salem/Trojan deviation per unit/year.

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
1983	48,671	43,569	56,452	46,268	46,310	21,557	215.63

Annual Growth Rate to 1983:

Nominal:	23.5%	17.1%	26.4%	25.4%	25.0%	18.2%	4.9%
Real:	15.86%	9.20%	17.92%	16.81%	16.44%	10.11%	

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

Unit	Period Analyzed	1983 O & M	Least - Squares Annual Growth: Linear Increase	Geometric Increase
		(1000)	(1000 1983$)	
Conn. Yankee	1968-83	$48,671	$2,726.4	15.6%
Millstone 1	1971-83	$43,569	$2,466.3	11.7%
Millstone 2	1976-83	$56,452	$4,523.1	14.2%
Pilgrim	1973-83	$46,268	$3,453.2	14.8%
Vermont Yankee	1973-83	$46,310	$3,281.3	16.2%
Maine Yankee	1973-83	$21,557	$1,933.1	12.7%
AVERAGES:				
1983$		$43,805	$3,063.9	14.2%
1984$ [1]		$45,557	$3,186.5	

Notes: [1] 1984$=1983$*1.04

TABLE 3.24: RESULTS OF REGRESSION ON O&M DATA

	Equation 1		Equation 2		Equation 3		Equation 4		Equation 5	
	Coef	t-stat	Coef	t-stat	Coef	t-stat	Coef	t-stat	Coef	t-stat
CONSTANT	-3.76	-6.88	-3.48	-6.92	-3.76	-6.88	-4.14	-7.77	-3.90	-7.49
ln(MW) [2]	0.56	7.86	0.50	7.33	--	--	--	--	--	--
ln(UNITS)	-0.05	-0.48	--	--	0.52	10.41	--	--	0.63	12.58
YEAR [3]	0.13	22.45	0.13	22.60	0.13	22.45	0.13	22.78	0.13	23.93
UNITS	--	--	0.03	0.54	--	--	0.33	10.98	--	--
ln(MW/unit)	--	--	--	--	0.56	7.86	0.57	8.04	0.54	7.95
NE [4]	--	--	--	--	--	--	--	--	0.25	6.69
Adjusted R		0.71		0.71		0.71		0.71		0.73
F statistic		329.2		329.2		329.2		340.1		284.4

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

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

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

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

TABLE 3.25: ANNUAL NON-FUEL O & M EXPENSE FOR SEABROOK ($thousand)
EXTRAPOLATED FROM NEW ENGLAND AND NATIONAL EXPERIENCE

Year	Linear N.E. Experience		Geometric N.E. Experience		National Experience	
	1984$	Current$	1984$	Current$	1984$	Current$
	[2]	[4]	[3]	[4]		
1987	$58,303	$69,439	$77,510	$92,316	$75,867	$88,654
1988	$61,489	$77,628	$88,524	$111,760	$86,344	$106,950
1989	$64,675	$86,550	$101,103	$135,298	$98,267	$129,023
1990	$67,862	$96,263	$115,469	$163,795	$111,837	$155,650
1991	$71,048	$106,830	$131,877	$198,294	$127,281	$187,772
1992	$74,235	$118,319	$150,615	$240,058	$144,857	$226,524
1993	$77,421	$130,802	$172,017	$290,619	$164,860	$273,273
1994	$80,608	$144,356	$196,460	$351,829	$187,626	$329,670
1995	$83,794	$159,066	$224,375	$425,931	$213,535	$397,706
1996	$86,981	$175,022	$256,258	$515,641	$243,023	$479,783
1997	$90,167	$192,320	$292,671	$624,245	$276,582	$578,798
1998	$93,354	$211,063	$334,257	$755,724	$314,775	$698,249
1999	$96,540	$231,364	$381,753	$914,894	$358,243	$842,350
2000	$99,726	$253,340	$435,998	$1,107,589	$407,713	$1,016,191
2001	$102,913	$277,121	$497,951	$1,340,869	$464,014	$1,225,909
2002	$106,099	$302,844	$568,707	$1,623,283	$528,090	$1,478,907
2003	$109,286	$330,655	$649,517	$1,965,179	$601,014	$1,784,118
2004	$112,472	$360,714	$741,810	$2,379,085	$684,009	$2,152,318
2005	$115,659	$393,189	$847,217	$2,880,167	$778,464	$2,596,505
2006	$118,845	$428,263	$967,601	$3,486,787	$885,962	$3,132,361
2007	$122,032	$466,130	$1,105,092	$4,221,174	$1,008,306	$3,778,806
2008	$125,218	$507,000	$1,262,119	$5,110,237	$1,147,543	$4,558,661
2009	$128,405	$551,096	$1,441,459	$6,186,555	$1,306,008	$5,499,459
2010	$131,591	$598,658	$1,646,282	$7,489,566	$1,486,356	$6,634,416
2011	$134,777	$649,944	$1,880,209	$9,067,017	$1,691,608	$8,003,601
2012	$137,964	$705,229	$2,147,376	$10,976,711	$1,925,203	$9,655,353
LEVELIZED						
1987-2012: [1]	$82,579	$151,610	$332,626	$657,524	$309,429	$598,589
$/kW-yr	$71.8	$131.8	$289.2	$571.8	$269.1	$520.5

Notes: 1. Approximately the useful life of Seabrook 1.
2. Average New England 1983 nuclear O&M,plus (year-1984) times average annual increase, both in 1984$, from Table 3.23.
3. Average New England 1983 nuclear O&M, in 1984$, times (1 + average geometric increase) ^ (year-1984), from Table 3.23
4. At 6% inflation.

TABLE 3.26: NUCLEAR CAPITAL ADDITIONS

	Year	Average 1983$/kW-yr
All Years Before and Including:	72	3.46
	73	11.82
	74	8.55
	75	8.71
	76	15.07
	77	21.06
	78	27.34
	79	14.62
	80	26.13
	81	30.97
	82	27.94
	83	31.57
Overall Average:		19.41
1978-83 Average:		26.24
Total # Observations:		477

TABLE 3.27: TOTAL POWER COSTS FOR SEABROOK, 1984 DOLLARS

	$6 Billion		$8 Billion	
Cost Basis	Entire Cost	Remaining Costs	Entire Cost	Remaining Costs
Cost per kw				
Construction Costs	$4,216	$1,347	$5,621	$2,752
Fixed Charge Rate	11.5%	11.5%	11.5%	11.5%
Cost per kw-yr				
Annual Capital Costs	$485	$155	$646	$316
Non-fuel O&M	$94	$94	$94	$94
Capital Additions	$31	$31	$31	$31
Insurance	$10	$10	$10	$10
Decommissioning	$9	$9	$9	$9
Total Non-fuel	$629	$299	$790	$460
Capacity Factor	55%	55%	55%	55%
Cost per kwh (cents)				
Non-fuel	13.1	6.2	16.4	9.6
Fuel	0.9	0.9	0.9	0.9
Total	14.0	7.1	17.3	10.5

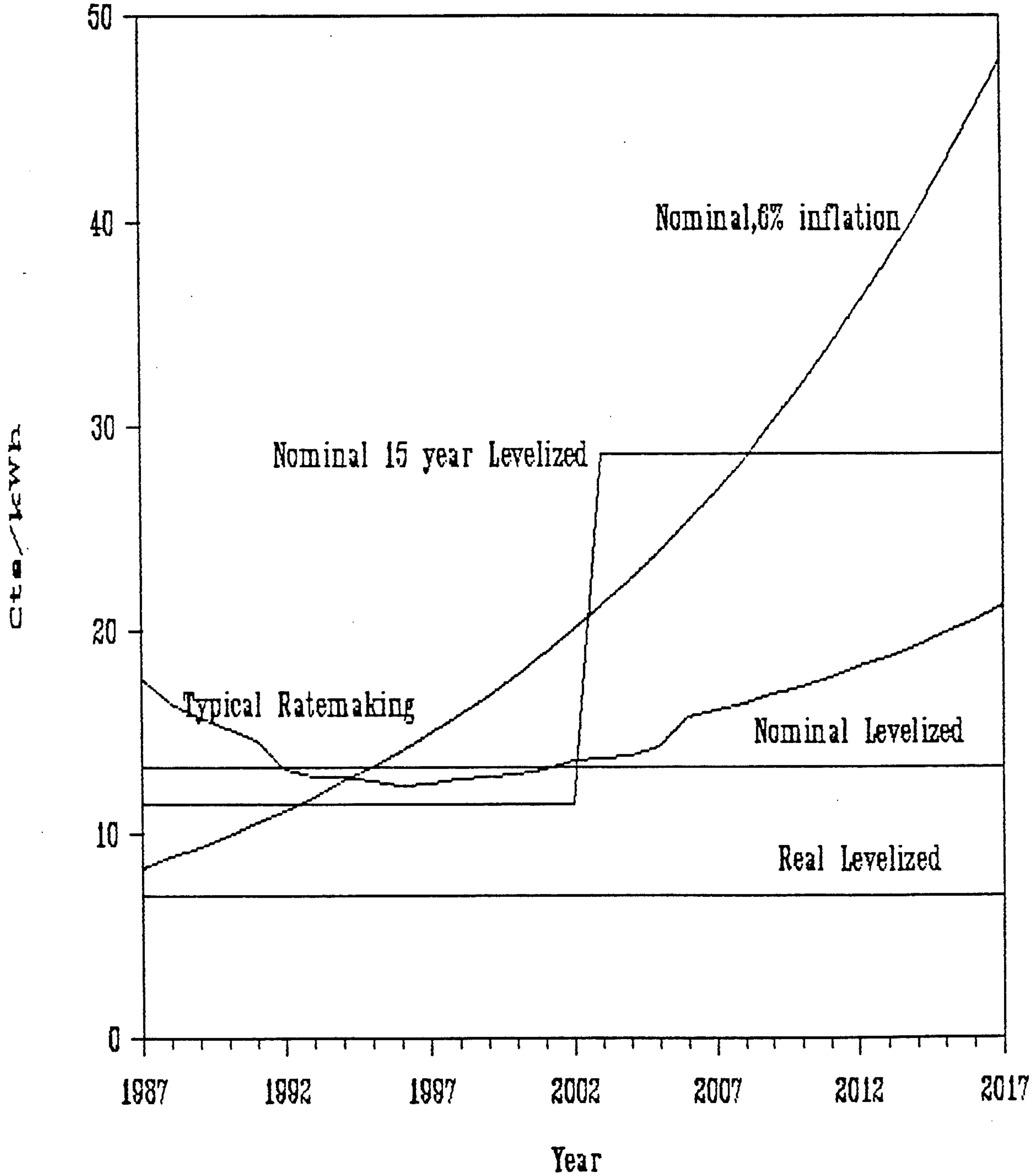
ASSUMPTIONS:

Aug-88 COD	Aug-88 COD
Total Cost $6 billion, $3.3 billion sunk.	Total Cost $8 billion, $3.3 billion sunk.

Note: All Costs are in levelized 1984 dollars.

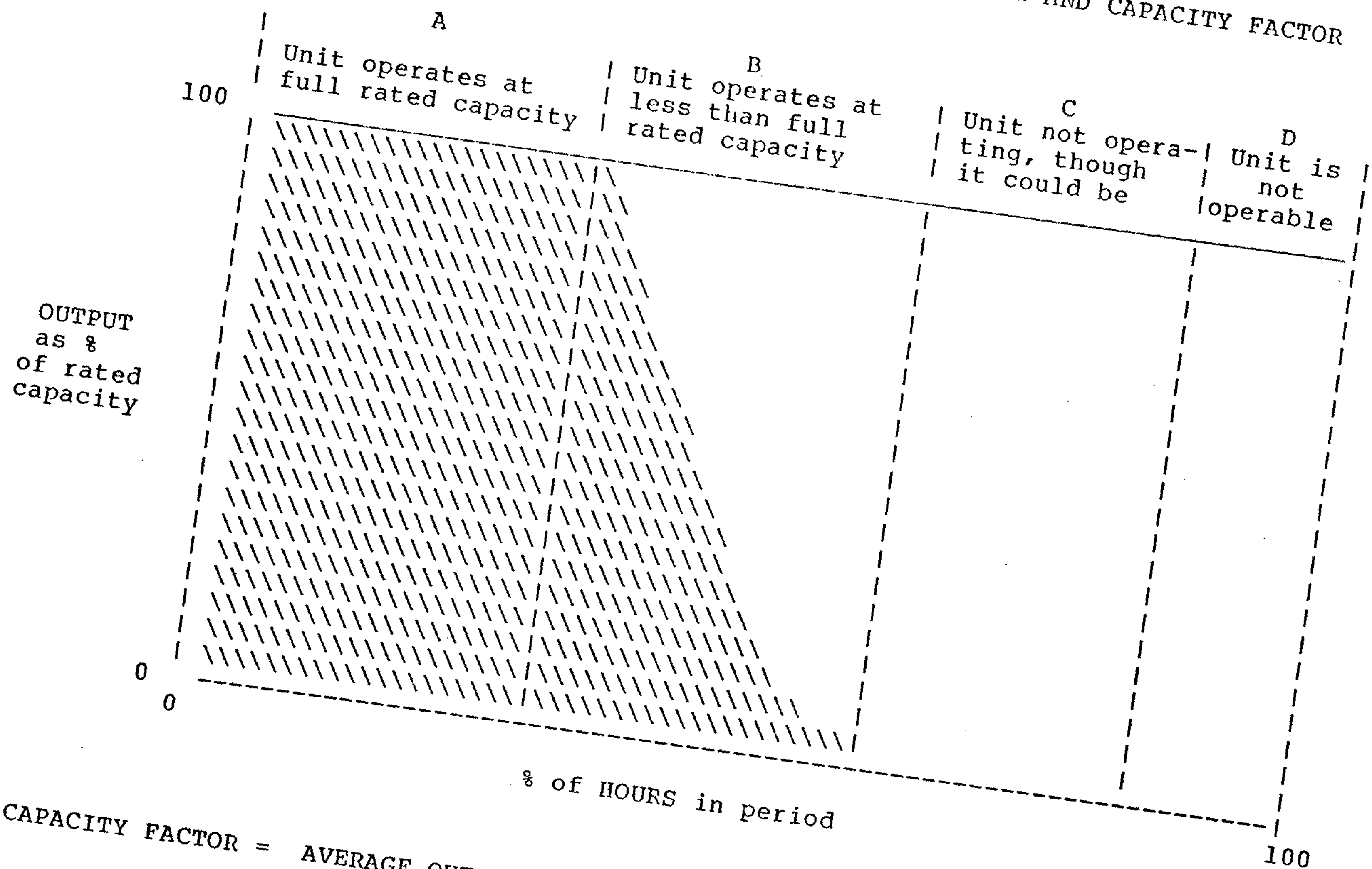
Figure 3.1: Levelized Dollar

Comparison



.2: DIAGRAMMATIC DESCRIPTION OF AVAI BILITY FACTOR AND CAPACITY FACTOR

Region:



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)

Figure 3.3: Nuclear Capital Additions

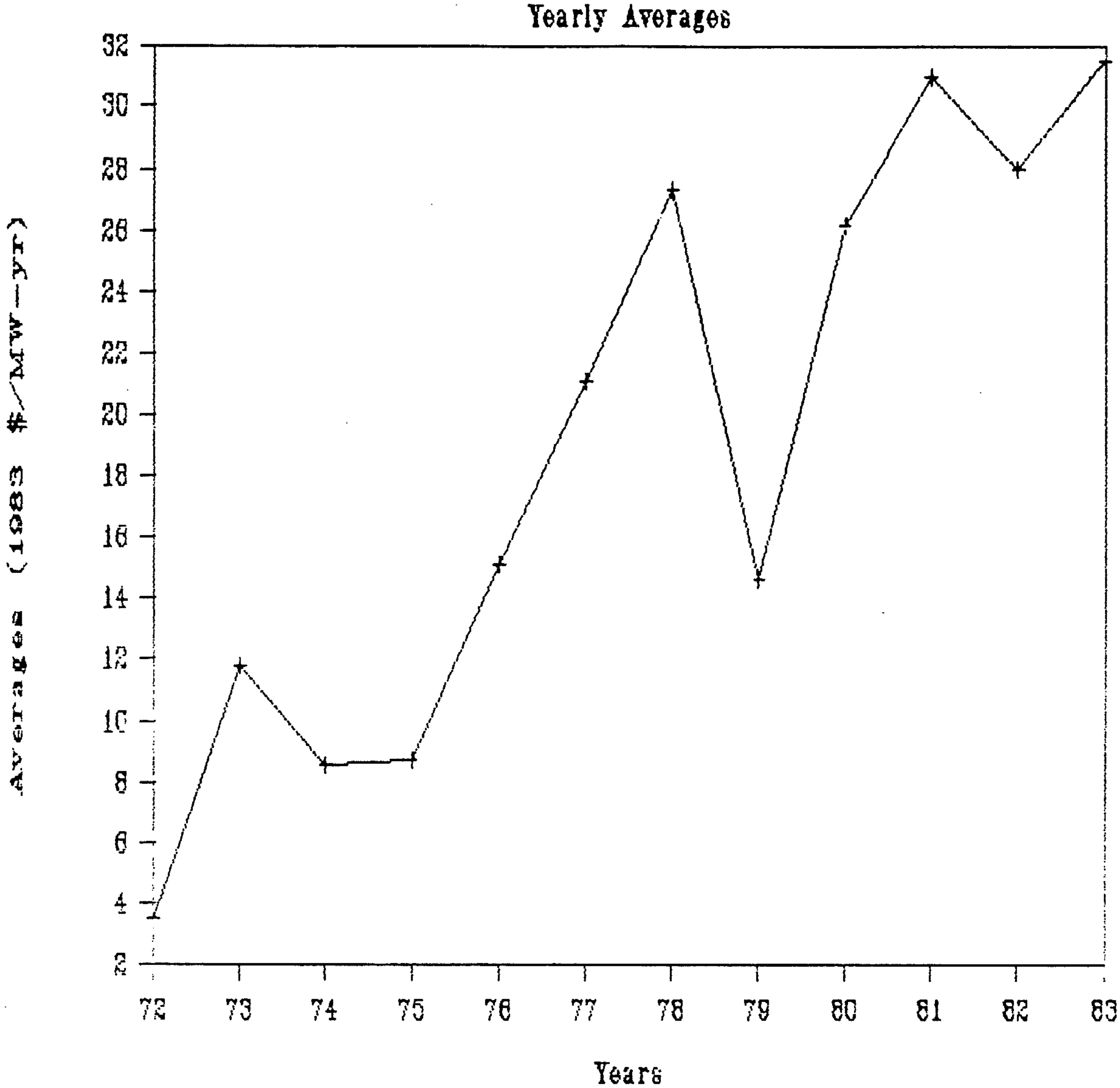


TABLE 4.1: PSNH PROJECTIONS OF SEABROOK, OIL AND COAL COSTS in Cts/kWh

Year	PSNH Existing Oil Fuel Cost [1]	PSNH Coal [2]	BHE New Coal Fuel Cost	PSNH Nuclear Fuel [3]
1988	5.65	2.29		1.3
1989	6.19	2.51		1.4
1990	6.78	2.75		1.4
1991	7.48	3.03		1.4
1992	8.25	3.35		1.4
1993	9.10	3.69		1.5
1994	10.04	4.07		1.5
1995	11.08	4.49	15.4	1.4
1996	12.11	4.91	14.5	1.4
1997	13.24	5.37	14.5	1.5
1998	14.48	5.87	14.6	1.6
1999	15.83	6.41	14.6	1.7
2000	17.31	7.01	14.8	1.8
2001	18.60	7.54	15.1	1.9
2002	19.99	8.10	15.3	2.0
2003	21.48	8.70	15.7	2.1
2004	23.08	9.35	16.1	2.3
2005	24.81	10.05	16.5	2.4
2006 [4]	26.89	10.90	17.0	2.5
2007	29.15	11.81	17.6	2.7
2008	31.60	12.80	18.2	2.8
2009	34.25	13.88	18.9	3.0
2010	37.13	15.05	19.9	3.1
2011	40.25	16.31	21.0	3.3
2012	43.63	17.68	22.2	3.4
2013	47.29	19.16	23.5	3.6
2014	51.26	20.77	24.2	3.8
2015	55.57	22.52	26.4	4.0
2016	60.23	24.41	27.9	4.2
2017	65.29	26.46	29.7	4.5
2018	70.77	28.68		4.7
2019	76.72	31.09		5.0
2020	83.16	33.70		5.2

Sources:
1. Staszowski Testimony, Table IV-4, No.6 oil, 10000 BTU/kWh.
2. Staszowski Testimony, Table IV-5, 1530 kWh/Ton.
3. Staszowski Testimony, Table IV-6.
4. 2006-2020 extrapolated at 1995-2005.

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

Year	Existing Oil Fuel Cost	Coal Fuel	Total New Coal Plant Cost	PSNH Nuclear Fuel	PLC Seabrook Non-Fuel	PLC Seabrook Total
	[1]	[2]	[3]	[4]	[5]	[6]
1988	5.6	2.3		1.3	33.6	34.9
1989	6.2	2.5		1.4	32.3	33.7
1990	6.8	2.7		1.4	26.5	27.9
1991	7.5	3.0		1.4	24.5	25.9
1992	8.3	3.3		1.4	22.9	24.4
1993	9.1	3.7		1.5	22.4	23.8
1994	10.0	4.1		1.5	21.8	23.3
1995	11.1	4.5	15.4	1.4	21.5	22.9
1996	12.1	4.9	14.5	1.4	21.2	22.6
1997	13.2	5.4	14.5	1.5	20.9	22.5
1998	14.5	5.9	14.6	1.6	20.7	22.4
1999	15.8	6.4	14.6	1.7	21.5	23.2
2000	17.3	7.0	14.8	1.8	22.2	24.0
2001	18.6	7.5	15.1	1.9	23.0	24.9
2002	20.0	8.1	15.3	2.0	23.9	25.9
2003	21.5	8.7	15.7	2.1	24.8	26.9
2004	23.1	9.4	16.1	2.3	25.7	28.0
2005	24.8	10.1	16.5	2.4	26.8	29.2
2006	26.9	10.9	17.0	2.5	27.9	30.4
2007	29.1	11.8	17.6	2.7	29.1	31.7
2008	31.6	12.8	18.2	2.8	30.4	33.2
2009	34.3	13.9	18.9	3.0	31.7	34.7
2010	37.1	15.0	19.9	3.1	33.2	36.3
2011	40.2	16.3	21.0	3.3	34.8	38.1
2012	43.6	17.7	22.2	3.4	36.6	40.0
2013	47.3	19.2	23.5	3.6	38.6	42.2
2014	51.3	20.8	24.2	3.8	40.8	44.6
2015	55.6	22.5	26.4	4.0	43.5	47.5
2016	60.2	24.4	27.9	4.2	47.1	51.3
2017	65.3	26.5	29.7	4.5	53.7	58.2
2018	70.8	28.7		4.7	43.1	47.8
2019	76.7	31.1		5.0		
2020	83.2	33.7		5.2		

Sources: [1], [2], [4] See Table 4.1
[3] Bangor-Hydro IR 3Staff8, Maine PUC 84-113.
[5] See Appendix F

TABLE 4.3: COMPARISON OF SEABROOK COSTS AND BENEFITS
PLC Assumptions ($ millions)

Year	PLC Non-Fuel Cost	Fuel Savings	Net Cost	Cumulative Net Cost	Discounted Net Cost
	[1]	[2]	[3]		
1988	604.1	82.1	522.0	522.0	457.9
1989	581.0	90.4	490.6	1012.7	835.4
1990	500.4	106.0	394.4	1407.0	1101.6
1991	483.3	126.2	357.1	1764.1	1313.0
1992	470.8	147.1	323.7	2087.8	1481.2
1993	459.4	165.0	294.4	2382.2	1615.3
1994	449.0	186.0	263.0	2645.2	1720.4
1995	441.5	287.1	154.5	2799.7	1774.5
1996	435.3	268.4	166.9	2966.5	1825.9
1997	430.2	266.7	163.4	3130.0	1869.9
1998	426.4	266.9	159.5	3289.4	1907.7
1999	440.9	264.9	176.0	3465.5	1944.2
2000	456.4	266.7	189.6	3655.1	1978.7
2001	472.8	270.8	202.0	3857.0	2011.0
2002	490.3	272.9	217.4	4074.5	2041.5
2003	509.0	278.7	230.4	4304.8	2069.8
2004	529.0	284.4	244.6	4549.4	2096.1
2005	550.3	289.8	260.6	4809.9	2120.8
2006	573.1	297.4	275.7	5085.7	2143.6
2007	597.6	307.0	290.6	5376.3	2164.8
2008	623.9	316.4	307.5	5683.8	2184.4
2009	652.1	327.7	324.4	6008.2	2202.6
2010	682.6	345.0	337.6	6345.7	2219.2
2011	715.7	364.3	351.5	6697.2	2234.3
2012	752.0	385.3	366.6	7063.8	2248.1
2013	792.2	408.3	383.9	7447.8	2260.9
2014	838.1	418.7	419.4	7867.1	2273.1
2015	893.1	459.7	433.3	8300.5	2284.1
2016	967.1	486.2	480.9	8781.4	2294.9

Sources: [1] See Appendix F: Total Non-Fuel Costs.
[2] BHE Energy Costs - PSNH Nuclear Fuel
[3] = [1] - [2].

Figure 4.1: Utility Projections

Seabrook, Oil and Coal Costs

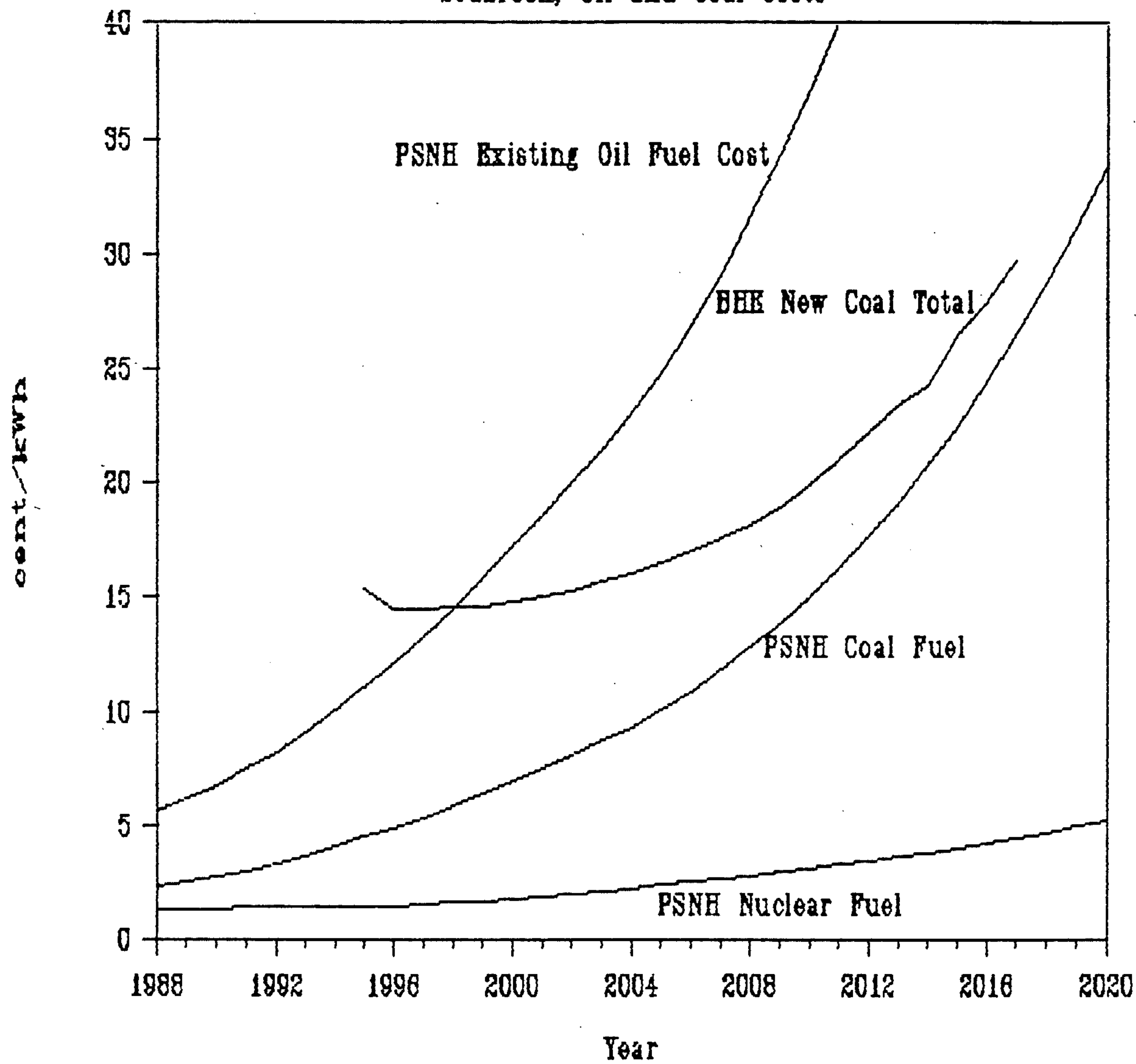


Figure 4.2: PLC Projections

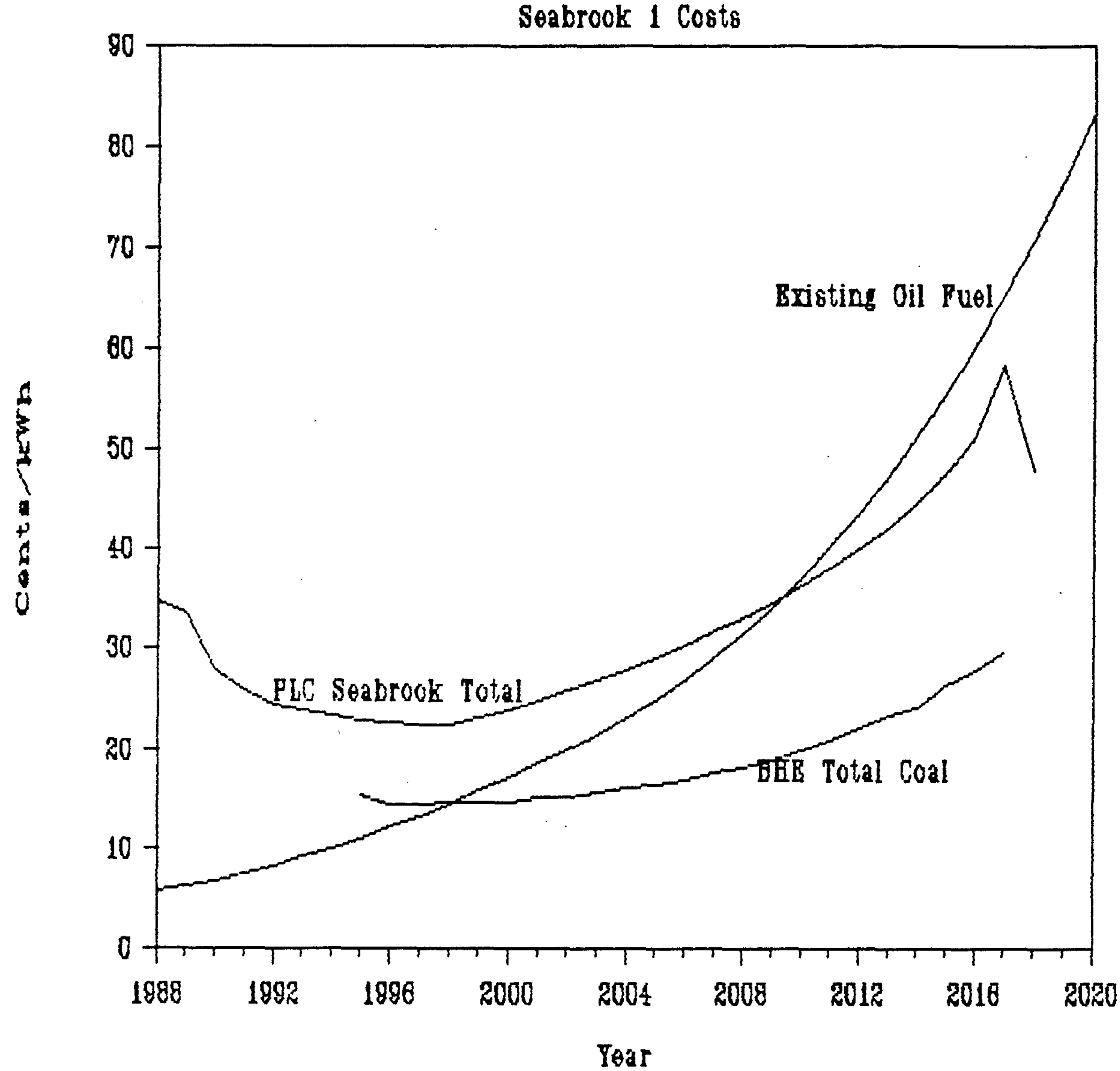
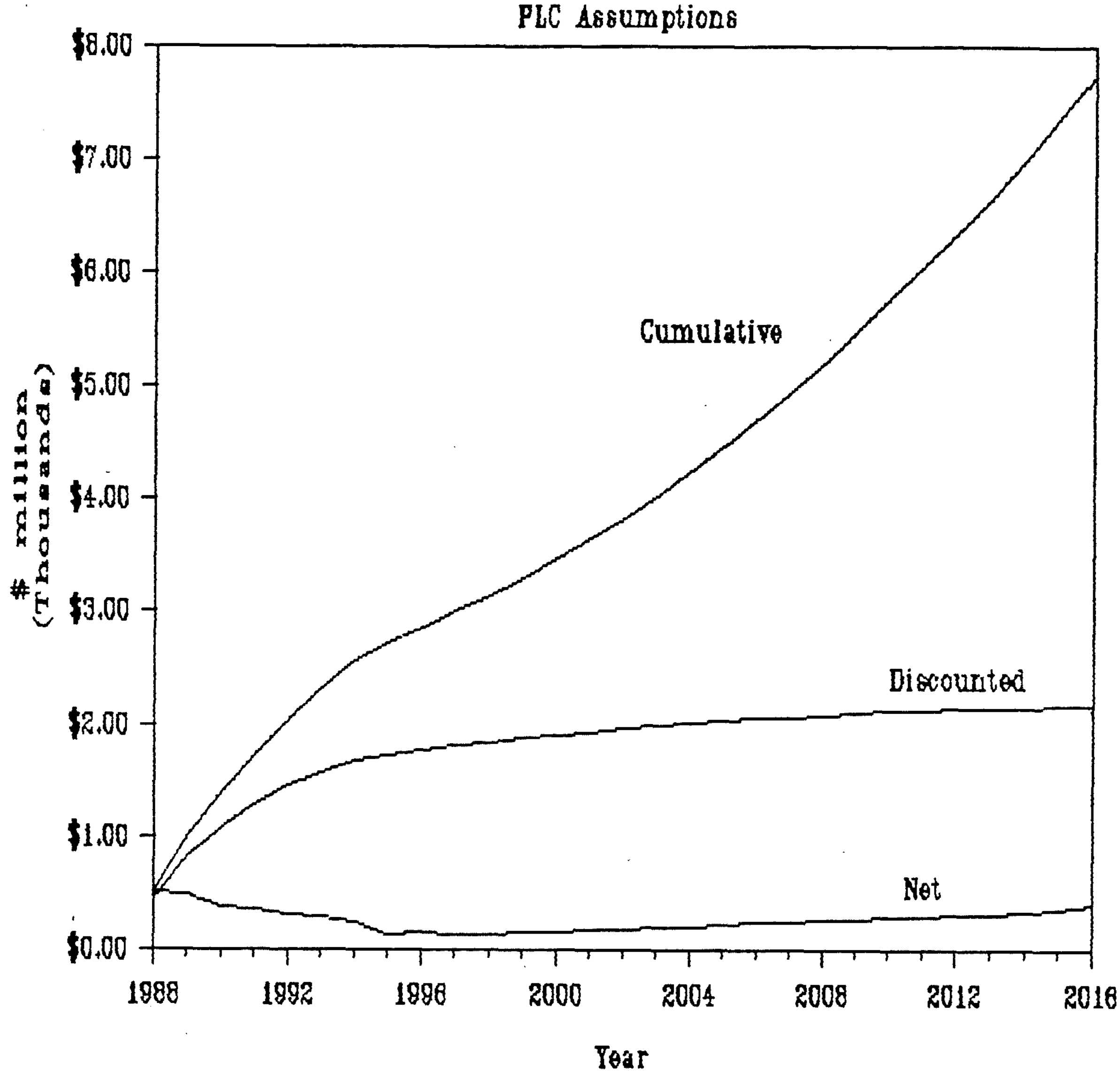


Figure 4.3: Seabrook Costs and Benefits



APPENDIX A

RESUME OF PAUL CHERNICK

PAUL L. CHERNICK

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

PROFESSIONAL EXPERIENCE

Research Associate, Analysis and Inference, Inc.
May, 1981 - present (Consultant, 1980-1981)

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

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 1984 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. Equity and incentive problems created by CWIP. Design of Millstone 3 phase-in proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

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

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

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

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

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

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

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

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

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

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

37. Pennsylvania PUC R-842651; Pennsylvania Power and Light Rate Case; Pennsylvania Consumer Advocate; November 14, 1984.

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

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

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

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

    Profit margin calculations, including methodology and implementation.

APPENDIX B

COST AND SCHEDULE HISTORIES

)t 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
Summer 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	1.28	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
quoyah 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
_asalle 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
Summer 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
)rry 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	385.0	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	113.8	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	295.2	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	2.87
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	1.428	1.271	1.293	1.190	1.983
Standard Deviation:								0.288	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
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	2.82
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	1.80
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

	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia Factor	REAL Cost Ratio	REAL Myopia Factor	Duration Ratio
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 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	1.87
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	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
St. 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
Maine 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
Nine 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

	Est. Years to COD	NOMINAL Cost Ratio	NOMINAL Myopia	REAL Cost Ratio	REAL Myopia	Duration Ratio
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

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
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	160.8	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	1.428	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

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	400.8	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

O&M AND CAPITAL ADDITIONS DATA

NON-FUEL O&M AND CAPITAL ADDITIONS DATA

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	/MW-yr	O&M - Fuel	O&M -F 1983 $	New Unit Date	2nd Unit Same Year
Arkansas 1	74	902	233027				0		19-Dec-74	
Arkansas 1	75	902	238751	5724	10407	11.54	4109	7044		
Arkansas 1	76	902	242204	3453	5962	6.61	6015	9801		
Arkansas 1	77	902	247069	4865	7997	8.87	8379	12901		
Arkansas 1	78	902	253994	6925	10259	11.37	12125	17381		
Arkansas 1	79	902	268130	14136	18641	20.67	18923	24969		
Arkansas 1	80	NA	NA				NA	NA	26-Mar-80	
Arkansas 1&2	81	1845	916567				54422	60136		
Arkansas 1&2	82	1845	927141	10574	11034	5.98	54496	56801		
Arkansas 1&2	83	1853	935827	8686	8686	4.69	64928	64928		
Beaver Valley	76	923	599697				1777	2895	30-Sep-76	
Beaver Valley	77	923	598716	-981	-1525	-1.65	14692	22621		
Beaver Valley	78	923	582408	-16308	-23883	-25.88	22681	32514		
Beaver Valley	79	923	576367	-6041	-8067	-8.74	22907	30225		
Beaver Valley	80	923	647575	71208	87849	95.18	34771	42023		
Beaver Valley	81	924	671283	23708	26909	29.12	35838	39601		
Beaver Valley	82	923	748515	77232	80791	87.53	49144	51223		
Beaver Valley	83	923	803564	55049	55049	59.64	65738	65738		
Big Rock Point	63	54	14412				645	1941	15-Dec-62	
Big Rock Point	64	54	14349	-63	-221	-4.10	666	1973		
Big Rock Point	65	75	13750	-599	-2106	-28.07	715	2073		
Big Rock Point	66	75	13793	43	149	1.99	763	2143		
Big Rock Point	67	75	13837	44	146	1.94	1086	2962		
Big Rock Point	68	75	13926	89	287	3.82	865	2260		
Big Rock Point	69	75	13958	32	96	1.29	933	2318		
Big Rock Point	70	75	14324	366	1023	13.64	1062	2504		
Big Rock Point	71	75	14554	230	593	7.91	1266	2843		
Big Rock Point	72	75	14731	177	432	5.76	1412	3045		
Big Rock Point	73	75	14815	84	195	2.60	1586	3234		
Big Rock Point	74	75	16012	1197	2415	32.20	2263	4240		
Big Rock Point	75	75	16587	575	1034	13.79	2584	4430		
Big Rock Point	76	75	22907	6320	10702	142.70	3183	5186		
Big Rock Point	77	75	23971	1064	1668	22.24	5125	7891		
Big Rock Point	78	75	24409	438	639	8.52	3645	5225		
Big Rock Point	79	75	27014	2605	3473	46.31	9232	12181		
Big Rock Point	80	75	27262	248	304	4.06	8409	10163		
Big Rock Point	81	75	33356	6094	6863	91.51	12970	14332		
Big Rock Point	82	75	37068	3712	3862	51.49	15513	16169		
Big Rock Point	83	75	39382	2314	2314	30.85	16416	16416		
Browns Ferry 1&2	75	2304	512653				6626	11358	01-Aug-74	01-Mar-75
Browns Ferry 1&2	76	2304	552357	39704	66749	28.97	16104	26239		
Browns Ferry 1,2,3	77	3456	853325				19305	29723	01-Mar-77	
Browns Ferry 1,2,3	78	3456	885991	32666	47072	13.62	45921	65829		
Browns Ferry 1,2,3	79	3456	888350	2359	3092	0.89	55588	73347		
Browns Ferry 1,2,3	80	3456	890428	2078	2485	0.72	66969	80936		
Browns Ferry 1,2,3	81	3456	892715	2287	2503	0.72	85469	94443		
Browns Ferry 1,2,3	82	3456	915514	22799	23404	6.77	92271	96174		
Browns Ferry 1,2,3	83							0		
Brunswick 2	75	866	382246				4473	7668	03-Nov-75	
Brunswick 2	76	866	389118	6872	11553	13.34	10518	17138		

NON-FUEL O&M AND CAPITAL ADDITIONS DATA

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	/MW-yr	O&M - Fuel	O&M -F 1983 $	New Unit Date	2nd Unit Same Year
Brunswick 1&2	77	1733	707560				25378	39074	18-Mar-77	
Brunswick 1&2	78	1733	714928	7368	10617	6.13	26633	38179		
Brunswick 1&2	79	1733	750828	35900	47055	27.15	34206	45134		
Brunswick 1&2	80	1733	776989	26161	31285	18.05	57516	69511		
Brunswick 1&2	81	1733	803535	26546	29050	16.76	73150	80831		
Brunswick 1&2	82	1755	805771	2236	2295	1.31	112235	116982		
Brunswick 1&2	83	1698	892994	87223	87223	51.37	64972	64972		
Calvert Cliffs 1	75	918	428747				4241	7270	08-May-75	
Calvert Cliffs 1	76	918	430674	1927	3216	3.50	8984	14638		
Calvert Cliffs 1&2	77	1828	765995				20158	31037	01-Apr-77	
Calvert Cliffs 1&2	78	1828	777711	11716	17158	9.39	25997	37267		
Calvert Cliffs 1&2	79	1828	780095	2384	3183	1.74	36397	48025		
Calvert Cliffs 1&2	80	1828	790988	10893	13439	7.35	41628	50310		
Calvert Cliffs 1&2	81	1828	820215	29227	33173	18.15	50409	55702		
Calvert Cliffs 1&2	82	1828	852313	32098	33577	18.37	61969	64590		
Calvert Cliffs 1&2	83	1770	903868	51555	51555	29.13	50301	50301		
Connecticut Yankee	68	600	91801				2047	5348	01-Jan-68	
Connecticut Yankee	69	600	91841	40	121	0.20	2067	5135		
Connecticut Yankee	70	600	93516	1675	4694	7.82	4479	10561		
Connecticut Yankee	71	600	93669	153	395	0.66	3279	7364		
Connecticut Yankee	72	600	93814	145	346	0.58	3749	8084		
Connecticut Yankee	73	600	94016	202	459	0.76	6352	12952		
Connecticut Yankee	74	600	106212	12196	24285	40.48	4935	9247		
Connecticut Yankee	75	600	108921	2709	4842	8.07	9381	16081		
Connecticut Yankee	76	600	114503	5582	9317	15.53	9419	15347		
Connecticut Yankee	77	600	117238	2735	4252	7.09	9448	14547		
Connecticut Yankee	78	600	121288	4050	5931	9.89	8736	12523		
Connecticut Yankee	79	600	123037	1749	2335	3.89	18923	24969		
Connecticut Yankee	80	600	137644	14607	18021	30.03	35155	42487		
Connecticut Yankee	81	600	152552	14908	16921	28.20	37488	41424		
Connecticut Yankee	82	600	167878	15326	16032	26.72	35723	37234		
Connecticut Yankee	83	600	182739	14861	14861	24.77	48671	48671		
Cook 1	75	1089	538611				1662	2849	23-Aug-75	
Cook 1	76	1089	544650	6039	10227	9.39	7047	11482		
Cook 1	77	1089	552238	7588	11895	10.92	10012	15415		
Cook 1&2	78	2200	996177				15707	22516	01-Jul-78	
Cook 1&2	79	2285	1025829	29652	39536	17.30	26750	35296		
Cook 1&2	80	2250	1074584	48755	59847	26.60	32409	39168		
Cook 1&2	81	2285	1096310	21726	24468	10.71	37967	41954		
Cook 1&2	82	2285	1118610	22300	23200	10.15	50859	53010		
Cook 1&2	83	2222	1145590	26980	26980	12.14	57904	57904		
Cooper	74	835	246268				2691	5042	15-Jul-74	
Cooper	75	835	269287	23019	41399	49.58	7386	12661		
Cooper	76	835	269287	0	0	0.00	10211	16637		
Cooper	77	835	302382	33095	51879	62.13	10218	15732		
Cooper	78	836	384630	82248	120010	143.55	8306	11907		
Cooper	79	836	384570	-60	-80	-0.10	10232	13501		
Cooper	80	836	384569	-1	-1	.00	19004	22967		
Cooper	81	778	383748	-821	-925	-1.19	20455	22603		
Cooper	82	836	384358	610	635	0.76	23482	24475		

NON-FUEL O&M AND CAPITAL ADDITIONS DATA

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	/MW-yr	O&M - Fuel	O&M -F 1983 $	New Unit Date	2nd Unit Same Year
Cooper	83									
Crystal River	77	801	365535				7600	11701	13-Mar-77	
Crystal River	78	890	415173	49638	71528	80.37	15613	22382		
Crystal River	79	890	419131	3958	5188	5.83	23992	31657		
Crystal River	80	890	421055	1924	2301	2.59	39841	48150		
Crystal River	81	801	384011	-37044	-40539	-50.61	42313	46756		
Crystal River	82	801	385759	1748	1794	2.24	46796	48775		
Crystal River	83	868	396620	10861	10861	12.51	63505	63505		
Davis-Besse	77	960	271283				295	454	31-Dec-77	
Davis-Besse	78	906	635147	363864	530921	586.01	14096	20207		
Davis-Besse	79	906	671140	35993	47991	52.97	21737	28681		
Davis-Besse	80	962	738544	67404	82739	86.01	44630	53938		
Davis-Besse	81	962	786437	47893	53938	56.07	41413	45761		
Davis-Besse	82	962	846126	59689	62098	64.55	59955	62491		
Davis-Besse	83	934	870233	24107	24107	25.81	51099	51099		
Dresden 1	62	208	34180				1252	3823		
Dresden 1	63	208	34442	262	921	4.43	1266	3809		
Dresden 1	64	208	34468	26	91	0.44	1071	3174		
Dresden 1	65	208	34451	-17	-60	-0.29	1264	3665		
Dresden 1	66	208	34352	-99	-343	-1.65	1163	3267		
Dresden 1	67	208	34366	14	46	0.22	1912	5215		
Dresden 1	68	208	33467	-899	-2897	-13.93	1673	4371		
Dresden 1	69	208	33968	501	1510	7.26	1788	4442		
Dresden 1&2	70	1018	116609				2294	5409	11-Aug-70	
Dresden 1,2,3	71	1828	220380				3639	8173	15-Oct-71	
Dresden 1,2,3	72	1865	241479	21099	51526	27.63	9142	19713		
Dresden 1,2,3	73	1865	235397	-6082	-14110	-7.57	9050	18453		
Dresden 1,2,3	74	1865	237303	1906	3845	2.06	16731	31350		
Dresden 1,2,3	75	1865	249177	11874	21355	11.45	32895	56389		
Dresden 1,2,3	76	1865	256493	7316	12389	6.64	30092	49031		
Dresden 1,2,3	77	1865	258522	2029	3181	1.71	26999	41569		
Dresden 1,2,3	78	1865	276887	18365	26797	14.37	33932	48642		
Dresden 1,2,3	79	1865	290785	13898	18531	9.94	44579	58821		
Dresden 1,2,3	80	1865	303201	12416	15241	8.17	38130	46082		
Dresden 1,2,3	81	1865	307054	3853	4339	2.33	40361	44599		
Dresden 1,2,3	82	1865	331590	24536	25526	13.69	43740	45590		
Dresden 1,2,3	83	1666	331590	0	0	0.00	44800	44800		
Duane Arnold	74	565	288821				2121	3975	22-Jun-74	
Duane Arnold	75	565	279730	-9091.42	-16350	-28.94	3839	6581		
Duane Arnold	76	565	279928	198	335	0.59	7050	11487		
Duane Arnold	77	565	287561	7633.428	11966	21.18	7508	11560		
Duane Arnold	78	597	282345	-5216.42	-7611	-12.75	11916	17082		
Duane Arnold	79	597	306768	24423	32564	54.55	9528	12572		
Duane Arnold	80	597	324186	17418	21381	35.81	18398	22235		
Duane Arnold	81	597	339460	15274	17202	28.81	21956	24261		
Duane Arnold	82	597	365309	25849	26892	45.05	29239	30476		
Duane Arnold	83							0		
Farley 1	77	888	727426				462	711	01-Dec-77	
Farley 1	78	888	734519	7093	10221	11.51	12207	17499		
Farley 1	79	888	751634	17115	22433	25.26	22545	29748		

NON-FUEL O&M AND CAPITAL ADDITIONS DATA

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	/MW-yr	O&M - Fuel	O&M -F 1983 $	New Unit Date	2nd Unit Same Year
Farley 1	80	888	761329	9695	11594	13.06	25734	31101		
Farley 1&2	81	1776	1541981				41427	45777	30-Jul-81	
Farley 1&2	82	1777	1611172	69191	71028	39.97	52488	54708		
Farley 1&2	83	1722	1642869	31697	31697	18.41	57333	57333		
Fitzpatrick	75	849	NA				6902	11831	15-Jul-75	
Fitzpatrick	76	849	NA				10700	17434		
Fitzpatrick	77	849	NA				17383	26764		
Fitzpatrick	78	883	NA				19045	27301		
Fitzpatrick	79	883	NA				25131	33160		
Fitzpatrick	80	883	NA				33303	40248		
Fitzpatrick	81	883	367141				36678	40529		
Fitzpatrick	82	883	344597	-22544	-23583	-26.71	31504	32836		
Fitzpatrick	83							0		
Fort Calhoun	73	481	173870				529	1079	15-Sep-73	
Fort Calhoun	74	481	175800	1930	3894	8.09	3413	6395		
Fort Calhoun	75	481	178572	2772	4985	10.36	5962	10220		
Fort Calhoun	76	481	178896	324	549	1.14	7449	12137		
Fort Calhoun	77	481	179994	1098	1721	3.58	8493	13076		
Fort Calhoun	78	481	180328	334	487	1.01	8116	11634		
Fort Calhoun	79	481	180830	502	669	1.39	8504	11221		
Fort Calhoun	80	481	192700	11870	14571	30.29	14332	17321		
Fort Calhoun	81	481	198544	5844	6582	13.68	11472	12677		
Fort Calhoun	82	481	211041	12497	13001	27.03	18934	19735		
Fort Calhoun	83							0		
Fort St. Vrain	79	343	105610				12121	15993		
Fort St. Vrain	80	342	101459	-4151	-5095	-14.90	16884	20405		
Fort St. Vrain	81	342	120884	19425	21877	63.97	18796	20770		
Fort St. Vrain	82	342	112793	-8091	-8418	-24.61	20316	21175		
Fort St. Vrain	83	342	134684	21891	21891	64.01	NA	NA		
Ginna	70	517	83175				3199	7543	15-Jul-70	
Ginna	71	517	83075	-100	-258	-0.50	4391	9862		
Ginna	72	517	83982	907	2167	4.19	4082	8802		
Ginna	73	517	85004	1022	2320	4.49	3536	7210		
Ginna	74	517	87668	2664	5305	10.26	5391	10101		
Ginna	75	517	89750	2082	3721	7.20	6597	11309		
Ginna	76	517	93308	3558	5939	11.49	7356	11986		
Ginna	77	517	114141	20833	32391	62.65	7942	12228		
Ginna	78	517	121860	7719	11305	21.87	9819	14076		
Ginna	79	517	129112	7252	9684	18.73	12819	16914		
Ginna	80	517	136138	7026	8668	16.77	18924	22871		
Ginna	81	517	159487	23349	26501	51.26	22482	24843		
Ginna	82	517	182754	23267	24339	47.08	29570	30821		
Ginna	83	496	214985	32231	32231	64.98	25839	25839		
Hatch 1	76	850	390393				5867	9560	31-Dec-75	
Hatch 1	77	850	396799	6406	9842	11.58	9799	15087		
Hatch 1	78	850	409113	12314	17744	20.88	12268	17586		
Hatch 1&2	79	1702	918419				27094	35750	05-Sep-79	
Hatch 1&2	80	1700	947147	28728	34355	20.21	38486	46512		
Hatch 1&2	81	1704	969365	22218	24314	14.27	62010	68521		
Hatch 1&2	82	1704	1004824	35459	36400	21.36	67689	70552		

NON-FUEL O&M AND CAPITAL ADDITIONS DATA

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	/MW-yr	O&M - Fuel	O&M -F 1983 $	New Unit Date	2nd Unit Same Year
Hatch 1&2	83	1633	1134116	129291	129291	79.17	105745	105745		
Humboldt	63	60	24471				331	996		
Humboldt	64	60	23786	-685	-2566	-42.77	525	1556		
Humboldt	65	60	24176	390	1461	24.35	629	1824		
Humboldt	66	60	22224	-1952	-7101	-118.35	562	1579		
Humboldt	67	60	22480	256	892	14.87	630	1718		
Humboldt	68	60	22619	139	465	7.75	582	1520		
Humboldt	69	60	22688	69	222	3.70	646	1605		
Humboldt	70	60	22764	76	230	3.83	619	1460		
Humboldt	71	60	22850	86	243	4.04	926	2080		
Humboldt	72	60	22947	97	256	4.27	897	1934		
Humboldt	73	65	22998	51	128	1.97	915	1866		
Humboldt	74	65	23171	173	381	5.86	1070	2005		
Humboldt	75	65	24031	860	1648	25.35	1221	2093		
Humboldt	76	65	24543	512	905	13.92	1980	3226		
Humboldt	77	65	26726	2183	3535	54.39	3081	4744		
Humboldt	78	65	28506	1780	2675	41.16	1635	2344		
Humboldt	79	65	28567	61	83	1.27	1485	1959		
Humboldt	80	65	NA				1587	1918		
Humboldt	81	65	NA				2073	2291		
Indian Point 1	63	275	126218				2762	8310	15-Sep-62	
Indian Point 1	64	275	126255	37	131	0.48	2894	8575		
Indian Point 1	65	275	126330	75	266	0.97	2626	7615		
Indian Point 1	66	275	128891	2561	8808	32.03	2929	8228		
Indian Point 1	67	275	128821	-70	-230	-0.84	3184	8684		
Indian Point 1	68	275	128818	-3	-10	-0.03	2831	7396		
Indian Point 1	69	275	127914	-904	-2736	-9.95	2713	6740		
Indian Point 1	70	275	128083	169	474	1.72	3498	8248		
Indian Point 1	71	275	128175	92	237	0.86	3962	8898		
Indian Point 1	72	275	128938	763	1823	6.63	6950	14986		
Indian Point 1&2	73	1288	334963				14854	30288	15-Aug-73	
Indian Point 1&2	74	1288	340188	5225	10404	8.08	12737	23866		
Indian Point 1&2	75	1288	348218	8030	14353	11.14	13195	22619		
Indian Point 1&2	76	1288	359410	11192	18681	14.50	18285	29793		
Indian Point 1&2	77	1288	370637	11227	17456	13.55	16525	25443		
Indian Point 1&2	78	1288	377573	6936	10158	7.89	28167	40378		
Indian Point 1&2	79	1288	379966	2393	3195	2.48	32643	43072		
Indian Point 2	80	1013	329445				32964	39839		
Indian Point 2	81	1013	398037	68592	77852	76.85	54506	60229		
Indian Point 2	82	1013	461010	62973	65875	65.03	68664	71568		
Indian Point 2	83	1022	477418	16408	16408	16.05	48549	48549		
Indian Point 3	76	1125	NA				2460	4008	30-Aug-76	
Indian Point 3	77	1125	NA				12654	19483		
Indian Point 3	78	1068	NA				23318	33427		
Indian Point 3	79	1068	NA				28884	38112		
Indian Point 3	80	1013	NA				50357	60859		
Indian Point 3	81	1013	493018				58174	64282		
Indian Point 3	82	1013	522350	29332	30684	30.29	82542	86033		
Indian Point 3	83	NA	NA				NA	NA		
Kewaunee	74	535	202193				7222	13532	16-Jun-74	

NON-FUEL O&M AND CAPITAL ADDITIONS DATA

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	/MW-yr	O&M - Fuel	O&M -F 1983 $	New Unit Date	2nd Unit Same Year
Kewaunee	75	535	203389	1196	2151	4.02	8945	15334		
Kewaunee	76	535	205351	1962	3323	6.21	10727	17478		
Kewaunee	77	535	205892	541	848	1.59	10924	16819		
Kewaunee	78	535	209748	3856	5626	10.52	10430	14952		
Kewaunee	79	535	213289	3541	4721	8.82	11323	14941		
Kewaunee	80	535	214696	1407	1727	3.23	14843	17939		
Kewaunee	81	535	227413	12717	14322	26.77	19334	21364		
Kewaunee	82	535	236500	9087	9454	17.67	21978	22908		
Kewaunee	83	563	252718	16218	16218	28.81	22603	22603		
LaSalle	82	1078	1336166				4819	5023		
LaSalle	83	1122	1344053	7887	7887	7.03	32800	32800		
Lacrosse	78	60	22991				2638	3782		
Lacrosse	79	50	23132	141	188	3.76	3041	4013		
Lacrosse	80	50	25987	2855	3505	70.09	3318	4010		
Lacrosse	81	50	26237	250	282	5.63	3955	4370		
Lacrosse	82							0		
Lacrosse	83							0		
Maine Yankee	73	830	219225				4034	8226	01-Jan-73	
Maine Yankee	74	830	221074	1849	3682	4.44	5232	9803		
Maine Yankee	75	830	233710	12636	22586	27.21	6301	10801		
Maine Yankee	76	830	235069	1359	2268	2.73	5261	8572		
Maine Yankee	77	830	236454	1385	2153	2.59	8418	12961		
Maine Yankee	78	864	237810	1356	1986	2.30	10817	15506		
Maine Yankee	79	864	239987	2177	2907	3.36	9971	13157		
Maine Yankee	80	864	246847	6860	8463	9.80	14028	16954		
Maine Yankee	81	864	262240	15393	17471	20.22	20576	22737		
Maine Yankee	82	864	269738	7498	7844	9.08	28554	29762		
Maine Yankee	83	864	275713	5975	5975	6.92	21557	21557		
McGuire 1	81	1220	905601				2716	3001	01-Dec-81	
McGuire 1	82	1220	909146	3545	3708	3.04	37258	38834		
McGuire 1&2	83	2440	903347				42131	42131	01-Mar-84 ?	
Millstone 1	71	661	96819				3256	7313	28-Dec-70	
Millstone 1	72	661	97343	524	1252	1.89	7677	16554		
Millstone 1	73	661	98837	1494	3391	5.13	7635	15568		
Millstone 1	74	661	98745	-92	-183	-0.28	9808	18378		
Millstone 1	75	661	99244	499	892	1.35	12065	20682		
Millstone 1	76	661	125141	25897	43225	65.39	14040	22876		
Millstone 1	77	661	127476	2335	3630	5.49	12637	19457		
Millstone 1	78	661	139783	12307	18024	27.27	16448	23579		
Millstone 1	79	661	153135	13352	17829	26.97	23060	30427		
Millstone 1	80	661	167438	14303	17646	26.70	24784	29953		
Millstone 1	81	661	247250	79812	90587	137.04	33270	36763		
Millstone 1	82	661	275880	28630	29949	45.31	33465	34880		
Millstone 1	83	662	282531	6651	6651	10.05	43569	43569		
Millstone 2	75	909	418372				7	12	26-Dec-75	
Millstone 2	76	909	426271	7899	13184	14.50	10929	17807		
Millstone 2	77	909	448751	22480	34952	38.45	17377	26755		
Millstone 2	78	909	463638	14887	21802	23.98	22288	31950		
Millstone 2	79	909	464674	1036	1383	1.52	21931	28938		
Millstone 2	80	909	477586	12912	15929	17.52	30163	36454		

- NON-FUEL O&M AND CAPITAL ADDITIONS DATA

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	/MW-yr	O&M - Fuel	O&M -F 1983 $	New Unit Date	2nd Unit Same Year
Millstone 2	81	909	495610	18024	20457	22.51	28877	31909		
Millstone 2	82	909	529017	33407	34946	38.44	45248	47162		
Millstone 2	83	910	557977	28960	28960	31.82	56452	56452		
Monticello	71	568	105011				1429	3209	30-Jun-71	
Monticello	72	568	104937	-74	-181	-0.32	2567	5535		
Monticello	73	568	106869	1932	4482	7.89	5006	10208		
Monticello	74	568	117996	11127	22448	39.52	5179	9704		
Monticello	75	568	122106	4110	7392	13.01	8729	14963		
Monticello	76	568	123362	1256	2127	3.74	6609	10768		
Monticello	77	568	124390	1028	1611	2.84	11109	17104		
Monticello	78	568	126488	2098	3061	5.39	9136	13097		
Monticello	79	568	134937	8449	11265	19.83	10584	13965		
Monticello	80	568	139725	4788	5877	10.35	21413	25879		
Monticello	81	568	150407	10682	12030	21.18	18261	20178		
Monticello	82	568	171425	21018	21866	38.50	30799	32102		
Monticello	83	580	227698	56273	56273	97.02	21963	21963		
Nine Mile Point	70	620	162235				1716	4046	15-Dec-69	
Nine Mile Point	71	641	164492	2257	5822	9.08	2759	6196		
Nine Mile Point	72	641	162416	-2076	-4961	-7.74	3575	7709		
Nine Mile Point	73	641	163212	796	1807	2.82	4524	9225		
Nine Mile Point	74	641	163389	177	352	0.55	6251	11713		
Nine Mile Point	75	641	164189	800	1430	2.23	5810	9960		
Nine Mile Point	76	641	181200	17011	28393	44.30	5330	8685		
Nine Mile Point	77	641	188087	6887	10708	16.70	9743	15001		
Nine Mile Point	78	641	187086	-1001	-1466	-2.29	6382	9149		
Nine Mile Point	79	641	204080	16994	22692	35.40	11663	15389		
Nine Mile Point	80	641	217371	13291	16397	25.58	32964	39839		
Nine Mile Point	81	642	265015	47644	54076	84.23	26744	29552		
Nine Mile Point	82	620	281922	16907	17686	28.53	21480	22388		
Nine Mile Point	83	640	367746	85824	85824	134.10	25248	25248		
North Anna 1	78	979	781739				6521	9348	06-Jun-78	
North Anna 1	79	979	783864	2125	2785	2.85	19519	25755		
North Anna 1&2	80	1959	1315869				25390	30685	14-Dec-80	
North Anna 1&2	81	1959	1368195	52326	57262	29.23	28857	31887		
North Anna 1&2	82	1959	1416217	48022	49297	25.16	43493	45333		
North Anna 1&2	83	1894	1472934	56717	56717	29.95	49578	49578		
Oconee 1	73	886	155612				911	1858	16-Jul-73	
Oconee 1,2,3	74	2660	476443				6982	13082	09-Sep-74	16-Dec-74
Oconee 1,2,3	75	2660	476691	248	446	0.17	12449	21340		
Oconee 1,2,3	76	2660	478793	2102	3534	1.33	16735	27267		
Oconee 1,2,3	77	2660	490724	11931	18331	6.89	25038	38550		
Oconee 1,2,3	78	2661	492689	1965	2832	1.06	29600	42432		
Oconee 1,2,3	79	2661	498935	6246	8187	3.08	40177	53013		
Oconee 1,2,3	80	2661	509438	10503	12560	4.72	52003	62848		
Oconee 1,2,3	81	2666	520036	10598	11598	4.35	58789	64962		
Oconee 1,2,3	82	2666	532168	12132	12454	4.67	88016	91739		
Oconee 1,2,3	83	2733	539959	7791	7791	2.85	77956	77956		
Oyster Creek	70	550	89883				1953	4605	15-Dec-69	
Oyster Creek	71	550	92121	2238	5773	10.50	3097	6956		
Oyster Creek	72	550	92637	516	1233	2.24	3877	8360		

NON-FUEL O&M AND CAPITAL ADDITIONS DATA

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	/MW-yr	O&M - Fuel	O&M -F 1983 $	New Unit Date	2nd Unit Same Year
Oyster Creek	73	550	92766	129	293	0.53	6311	12868		
Oyster Creek	74	550	92198	-568	-1131	-2.06	10678	20008		
Oyster Creek	75	550	97151	4953	8853	16.10	12310	21102		
Oyster Creek	76	550	108545	11394	19018	34.58	10399	16944		
Oyster Creek	77	550	112583	4038	6278	11.42	14833	22838		
Oyster Creek	78	550	150459	37876	55470	100.85	15898	22790		
Oyster Creek	79	550	161745	11286	15070	27.40	13055	17226		
Oyster Creek	80	550	200255	38510	47510	86.38	37530	45357		
Oyster Creek	81	550	222963	22708	25774	46.86	45254	50006		
Oyster Creek	82	550	256407	33444	34985	63.61	60812	63384		
Oyster Creek	83	650	331441	75034	75034	115.44	72992	72992		
Palisades	72	811	146687				753	1624	15-Nov-71	
Palisades	73	811	160284	13597	31545	38.90	3160	6443		
Palisades	74	811	180063	19779	39902	49.20	11778	22069		
Palisades	75	811	182297	2234	4018	4.95	9601	16458		
Palisades	76	811	185272	2975	5038	6.21	9848	16046		
Palisades	77	811	182068	-3204	-5022	-6.19	6569	10114		
Palisades	78	811	199643	17575	25644	31.62	15393	22066		
Palisades	79	811	194651	-4992	-6656	-8.21	26344	34760		
Palisades	80	811	211505	16854	20689	25.51	19251	23266		
Palisades	81	811	255491	43986	49538	61.08	44140	48775		
Palisades	82	811	282667	27176	28273	34.86	38452	40078		
Palisades	83	810	375573	92906	92906	114.70	55154	55154		
Pathfinder	67	75	24932				769	2097	25-May-67	
Peach Bottom 1	67	46	10692				849	2316	01-Jun-67	
Peach Bottom 1	68	46	10624	-68	-217	-4.73	1666	4352		
Peach Bottom 1	69	46	10658	34	103	2.24	1481	3680		
Peach Bottom 1	70	46	10719	61	171	3.72	1537	3624		
Peach Bottom 1	71	46	10890	171	441	9.59	1731	3888		
Peach Bottom 1	72	46	10821	-69	-165	-3.58	1873	4039		
Peach Bottom 1	73	46	11369	548	1244	27.04	1605	3273		
Peach Bottom 1	74	46	10485	-884	-1760	-38.27	1050	1967		
Peach Bottom 2,3	74	2304	742158				1791	3356	05-Jul-74	23-Dec-74
Peach Bottom 2,3	75	2304	753981	11823	21132	9.17	12619	21632		
Peach Bottom 2,3	76	2304	761722	7741	12921	5.61	30601	49860		
Peach Bottom 2,3	77	2304	794094	32372	50332	21.85	46674	71862		
Peach Bottom 2,3	78	2304	807496	13402	19627	8.52	39306	56346		
Peach Bottom 2,3	79	2304	813792	6296	8407	3.65	40004	52785		
Peach Bottom 2,3	80	2304	836708	22916	28271	12.27	56875	68736		
Peach Bottom 2,3	81	2304	902169	65461	74298	32.25	72615	80240		
Peach Bottom 2,3	82	2304	953400	51231	53592	23.26	81669	85123		
Peach Bottom 2,3	83	2196	975127	21727	21727	9.89	116074	116074		
Pilgrim	72	655	321540				144	311	09-Dec-72	
Pilgrim	73	655	239329				4797	9781		
Pilgrim	74	655	235982	-3347	-6665	-10.18	9527	17851		
Pilgrim	75	655	236464	482	862	1.32	7340	12582		
Pilgrim	76	655	241440	4976	8306	12.68	16633	27101		
Pilgrim	77	655	257579	16139	25093	38.31	15320	23588		
Pilgrim	78	687	261758	4179	6120	8.91	14187	20337		
Pilgrim	79	687	270428	8670	11577	16.85	18387	24261		

NON-FUEL O&M AND CAPITAL ADDITIONS DATA

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	/MW-yr	O&M - Fuel	O&M -F 1983 $	New Unit Date	2nd Unit Same Year
Pilgrim	80	687	337986	67558	83346	121.32	27785	33580		
Pilgrim	81	687	358680	20694	23488	34.19	34994	38668		
Pilgrim	82	687	430711	72031	75350	109.68	42437	44232		
Pilgrim	83	685	427831	-2880	-2880	-4.20	46268	46268		
Point Beach 1	71	523	73959				1309	2940	31-Dec-70	
Point Beach 1&2	72	1047	145348				2305	4970	30-Sep-72	
Point Beach 1&2	73	1047	161632	16284	37779	36.08	3647	7436		
Point Beach 1&2	74	1047	161436	-196	-395	-0.38	5229	9798		
Point Beach 1&2	75	1047	164224	2788	5014	4.79	6159	10558		
Point Beach 1&2	76	1047	167125	2901	4913	4.69	6592	10741		
Point Beach 1&2	77	1047	196801	29676	46519	44.43	8014	12339		
Point Beach 1&2	78	1047	171189	-25612	-37371	-35.69	7395	10601		
Point Beach 1&2	79	1047	170668	-521	-695	-0.66	12461	16442		
Point Beach 1&2	80	1047	172472	1804	2214	2.12	17904	21638		
Point Beach 1&2	81	1047	188495	16023	18045	17.24	26820	29636		
Point Beach 1&2	82	1047	192297	3802	3955	3.78	31951	33302		
Point Beach 1&2	83	1048	194910	2613	2613	2.49	34273	34273		
Prairie Isl. 1	73	593	233234				101	206	16-Dec-73	
Prairie Isl. 1&2	74	1186	405374				4216	7900	21-Dec-74	
Prairie Isl. 1&2	75	1186	410207	4833	8692	7.33	7261	12447		
Prairie Isl. 1&2	76	1186	413087	2880	4877	4.11	15574	25376		
Prairie Isl. 1&2	77	1186	423966	10879	17054	14.38	17090	26313		
Prairie Isl. 1&2	78	1186	425182	1216	1774	1.50	14214	20376		
Prairie Isl. 1&2	79	1186	433659	8477	11303	9.53	15346	20249		
Prairie Isl. 1&2	80	1186	444766	11107	13634	11.50	23175	28008		
Prairie Isl. 1&2	81	1186	457082	12316	13870	11.70	26791	29604		
Prairie Isl. 1&2	82	1186	478688	21606	22478	18.95	28169	29360		
Prairie Isl. 1&2	83	1120	499848	21160	21160	18.89	29383	29383		
Quad Cities 1&2	72	1656	200149				2033	4384	15-Aug-72	15-Sep-72
Quad Cities 1&2	73	1656	211539	11390	26425	15.96	6290	12826		
Quad Cities 1&2	74	1656	223882	12343	24901	15.04	9210	17257		
Quad Cities 1&2	75	1656	237227	13345	24000	14.49	14777	25331		
Quad Cities 1&2	76	1656	241480	4253	7202	4.35	16723	27248		
Quad Cities 1&2	77	1656	247194	5714	8957	5.41	17756	27338		
Quad Cities 1&2	78	1656	252951	5757	8400	5.07	22168	31778		
Quad Cities 1&2	79	1656	263741	10790	14387	8.69	23420	30902		
Quad Cities 1&2	80	1656	273075	9334	11457	6.92	38686	46754		
Quad Cities 1&2	81	1656	278524	5449	6137	3.71	37272	41186		
Quad Cities 1&2	82	1656	311157	32633	33950	20.50	42185	43970		
Quad Cities 1&2	83	1666	320341	9184	9184	5.51	44448	44448		
Rancho Seco	75	928	343620				11607	19897	17-Apr-75	
Rancho Seco	76	928	343438	-182	-322	-0.35	7193	11720		
Rancho Seco	77	928	336050	-7388	-11964	-12.89	14000	21555		
Rancho Seco	78	928	338792	2742	4121	4.44	11834	16964		
Rancho Seco	79	928	339538	746	1012	1.09	13720	18103		
Rancho Seco	80	928	353574	14036	17441	18.79	28408	34333		
Rancho Seco	81	928	365651	12077	13716	14.78	35542	39274		
Rancho Seco	82	928	369225	3574	3722	4.01	36330	37867		
Rancho Seco	83							0		
Robinson	71	768	77753				1918	4308	07-Mar-71	

NON-FUEL O&M AND CAPITAL ADDITIONS DATA

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	/MW-yr	O&M - Fuel	O&M -F 1983 $	New Unit Date	2nd Unit Same Year
Robinson	72	768	81999	4246	10369	13.50	1780	3838		
Robinson	73	768	82113	114	264	0.34	4609	9398		
Robinson	74	768	83272	1159	2359	3.07	4780	8956		
Robinson	75	768	84982	1710	3075	4.00	6360	10902		
Robinson	76	768	85234	252	424	0.55	5903	9618		
Robinson	77	768	89540	4306	6616	8.61	6859	10561		
Robinson	78	768	93410	3870	5577	7.26	14355	20578		
Robinson	79	768	101253	7843	10280	13.39	15142	19980		
Robinson	80	768	110025	8772	10490	13.66	22085	26691		
Robinson	81	769	113858	3833	4195	5.45	21788	24076		
Robinson	82	769	125878	12020	12339	16.05	43164	44990		
Robinson	83	739	128046	2168	2168	2.93	37309	37309		
Salem 1	77	1170	850318				12707	19565	30-Jun-77	
Salem 1	78	1170	850983	665	974	0.83	22311	31983		
Salem 1	79	1169	898641	47658	63637	54.42	42508	56088		
Salem 1	80	1170	938748	40107	49480	42.29	59684	72131		
Salem 1&2	81	2343	1758749				77502	85640	13-Oct-81	
Salem 1&2	82	2343	1806872	48123	50341	21.49	156615	163239		
Salem 1&2	83	2294	1739122	-67750	-67750	-29.53	160582	160582		
San Onofre 1	68	450	80855				1481	3869	01-Jan-68	
San Onofre 1	69	450	84439	3584	11533	25.63	1975	4907		
San Onofre 1	70	450	84714	275	832	1.85	2236	5272		
San Onofre 1	71	450	85369	655	1847	4.10	2412	5417		
San Onofre 1	72	450	85547	178	470	1.05	3518	7586		
San Onofre 1	73	450	85821	274	688	1.53	5839	11906		
San Onofre 1	74	450	86244	423	931	2.07	5559	10416		
San Onofre 1	75	450	86438	194	372	0.83	8668	14859		
San Onofre 1	76	450	95496	9058	16011	35.58	10490	17092		
San Onofre 1	77	450	162475	66979	108463	241.03	8123	12507		
San Onofre 1	78	450	181601	19126	28746	63.88	14517	20810		
San Onofre 1	79	450	192599	10998	14922	33.16	11669	15397		
San Onofre 1	80	450	211109	18510	23000	51.11	31089	37573		
San Onofre 1	81	450	251119	40010	45441	100.98	24396	26958		
San Onofre 1	82	456	298461	47342	49306	108.13	36830	38388		
San Onofre 2	83	1127	2145708				-12790	-12790	08-Aug-83	
Sequoyah 1	81	1220	983542				19216	21234	01-Jul-81	
Sequoyah 1&2	82	2441	1606807				47756	49776	01-Jun-82	
Sequoyah 1&2	83							0		
Shippingport	80	100	32125				7375	8913		
Shippingport	81	100	32123	-2	-2	-0.02	8601	9504		
Shippingport	82	100	NA				6122	6381		
St. Lucie 1	76	850	470223				3249	5294	21-Dec-76	
St. Lucie 1	77	850	486230	16007	24594	28.93	7528	11591		
St. Lucie 1	78	850	495038	8808	12692	14.93	15814	22670		
St. Lucie 1	79	850	499602	4564	5982	7.04	14392	18990		
St. Lucie 1	80	850	505287	5685	6799	8.00	16381	19797		
St. Lucie 1	81	850	513640	8353	9141	10.75	23240	25680		
St. Lucie 1	82	850	529891	16251	16682	19.63	21853	22777		
St. Lucie 1&2	83	1706	1817237				28845	28845	08-Aug-83	
Surry 1	72	847	246707				607	1309	22-Dec-72	

NON-FUEL O&M AND CAPITAL ADDITIONS DATA

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	/MW-yr	O&M - Fuel	O&M -F 1983 $	New Unit Date	2nd Unit Same Year
Surry 1&2	73	1695	396860				5102	10403	01-May-73	
Surry 1&2	74	1695	402096	5236	10656	6.29	9878	18509		
Surry 1&2	75	1695	406409	4313	7757	4.58	15270	26176		
Surry 1&2	76	1695	408516	2107	3542	2.09	14796	24108		
Surry 1&2	77	1695	412236	3720	5715	3.37	15977	24599		
Surry 1&2	78	1695	419952	7716	11119	6.56	19323	27700		
Surry 1&2	79	1695	409703	-10249	-13434	-7.93	23313	30761		
Surry 1&2	80	1695	556083	146380	175052	103.28	29458	35602		
Surry 1&2	81	1695	750969	194886	213271	125.82	31185	34459		
Surry 1&2	82	1695	783058	32089	32941	19.43	33088	34487		
Surry 1&2	83	1648	805393	22335	22335	13.55	55428	55428		
Three Mile Isl. 1	74	871	398337				3351	6279	02-Sep-74	
Three Mile Isl. 1	75	871	400928	2591	4631	5.32	14226	24386		
Three Mile Isl. 1	76	871	399425	-1503	-2509	-2.88	17840	29068		
Three Mile Isl. 1	77	871	398895	-530	-824	-0.95	13287	20458		
Three Mile Isl. 1	78	871	361902	-36993	-54177	-62.20	17954	25737		
Three Mile Isl. 1	79	871	407936	46034	61469	70.57	11842	15625		
Three Mile Isl. 1	80	NA	NA				NA	NA		
Three Mile Isl. 1	81	435	220798				27024	29862		
Three Mile Isl. 2	78	961	715466				0	0	30-Dec-78	
Three Mile Isl. 2	79	961	719294	3828	5112	5.32	12402	16364		
Three Mile Isl. 2	80	NA	NA				NA	NA		
Three Mile Isl. 2	81	480	358321				8394	9275		
Trojan	76	1216	451978				5921	9647	20-May-76	
Trojan	77	1216	460666	8688	14069	11.57	13628	20983		
Trojan	78	1216	466419	5753	8647	7.11	15204	21795		
Trojan	79	1216	486705	20286	27523	22.63	16957	22374		
Trojan	80	1216	503279	16574	20594	16.94	25790	31169		
Trojan	81	1216	548765	45486	51661	42.48	32205	35587		
Trojan	82	1216	565576	16811	17509	14.40	30629	31924		
Trojan	83	1216	573894	8318	8318	6.84	28841	28841		
Turkey Point 3	72	760	108709				247	533	04-Dec-72	
Turkey Point 3&4	73	1519	231239				4059	8277	07-Sep-73	
Turkey Point 3&4	74	1519	235496	4257	8663	5.70	9660	18100		
Turkey Point 3&4	75	1519	244256	8760	15754	10.37	15493	26558		
Turkey Point 3&4	76	1519	255705	11449	19248	12.67	18602	30309		
Turkey Point 3&4	77	1519	267648	11943	18350	12.08	15109	23263		
Turkey Point 3&4	78	1519	273441	5793	8348	5.50	18602	26666		
Turkey Point 3&4	79	1519	284431	10990	14405	9.48	22511	29703		
Turkey Point 3&4	80	1519	293654	9223	11030	7.26	30830	37260		
Turkey Point 3&4	81	1519	305503	11849	12967	8.54	30274	33453		
Turkey Point 3&4	82	1519	417224	111721	114687	75.50	32066	33422		
Turkey Point 3&4	83	1456	527224	110000	110000	75.55	45517	45517		
Vermont Yankee	72	514	172042				414	893	30-Nov-72	
Vermont Yankee	73	563	184481	12439	28237	50.15	4957	10108		
Vermont Yankee	74	563	185158	677	1348	2.39	5692	10665		
Vermont Yankee	75	563	185739	581	1038	1.84	7682	13169		
Vermont Yankee	76	563	193886	8147	13598	24.15	7912	12892		
Vermont Yankee	77	563	196331	2445	3801	6.75	9775	15050		
Vermont Yankee	78	563	198837	2506	3670	6.52	11191	16043		

NON-FUEL O&M AND CAPITAL ADDITIONS DATA

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	/MW-yr	O&M - Fuel	O&M -F 1983 $	New Unit Date	2nd Unit Same Year
Vermont Yankee	79	563	200835	1998	2668	4.74	14208	18747		
Vermont Yankee	80	563	217575	16740	20652	36.68	22586	27296		
Vermont Yankee	81	563	226115	8540	9693	17.22	26795	29609		
Vermont Yankee	82	563	231880	5765	6031	10.71	33764	35192		
Vermont Yankee	83	563	255209	23329	23329	41.44	46310	46310		
Yankee-Rowe	62	152	38162				1282	3915	01-Jul-60	
Yankee-Rowe	63	185	38398	236	837	4.52	1312	3947		
Yankee-Rowe	64	185	38622	224	795	4.29	1121	3322		
Yankee-Rowe	65	185	38766	144	511	2.76	1403	4068		
Yankee-Rowe	66	185	39390	624	2146	11.60	1505	4228		
Yankee-Rowe	67	185	39560	170	559	3.02	1307	3565		
Yankee-Rowe	68	185	39572	12	38	0.21	1501	3921		
Yankee-Rowe	69	185	39623	51	154	0.83	1602	3980		
Yankee-Rowe	70	185	39636	13	36	0.20	1558	3674		
Yankee-Rowe	71	185	40271	635	1638	8.85	1745	3919		
Yankee-Rowe	72	185	41500	1229	2937	15.87	2912	6279		
Yankee-Rowe	73	185	42507	1007	2286	12.36	2437	4969		
Yankee-Rowe	74	185	44473	1966	3915	21.16	3950	7401		
Yankee-Rowe	75	185	46101	1628	2910	15.73	4557	7812		
Yankee-Rowe	76	185	46566	465	776	4.20	4976	8108		
Yankee-Rowe	77	185	48332	1766	2746	14.84	6966	10725		
Yankee-Rowe	78	185	48912	580	849	4.59	7653	10971		
Yankee-Rowe	79	185	52192	3280	4380	23.67	10150	13393		
Yankee-Rowe	80	185	55285	3093	3816	20.63	22250	26890		
Yankee-Rowe	81	185	63717	8432	9570	51.73	22069	24386		
Yankee-Rowe	82	185	72149	8432	8821	47.68	24320	25349		
Yankee-Rowe	83	185	72503	354	354	1.91	18987	18987		
Zion 1	73	1098	275989				44	90	15-Oct-73	
Zion 1&2	74	2196	565819				9234	17302	15-Sep-74	
Zion 1&2	75	2196	567987	2168	3899	1.78	12735	21830		
Zion 1&2	76	2196	571762	3775	6393	2.91	18268	29765		
Zion 1&2	77	2196	577903	6141	9626	4.38	18104	27874		
Zion 1&2	78	2196	586396	8493	12392	5.64	20383	29219		
Zion 1&2	79	2196	594941	8545	11393	5.19	26954	35565		
Zion 1&2	80	2196	625788	30847	37865	17.24	37655	45508		
Zion 1&2	81	2196	639723	13935	15694	7.15	44864	49575		
Zion 1&2	82	2196	650175	10452	10874	4.95	52617	54842		
Zion 1&2	83	2170	680259	30084	30084	13.86	45956	45956		

APPENDIX D

PSNH REVISIONS OF SEABROOOK COMPLETION ESTIMATES

SEABROOK STATION PROGRESS REPORT NO. 37

FOR THE QUARTER ENDED

SEPTEMBER 30, 1982

PSNH PUBLIC SERVICE
Company of New Hampshire

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

SEABROOK NUCLEAR PROJECTS NO. 1 & 2

CONSTRUCTION PROGRESS

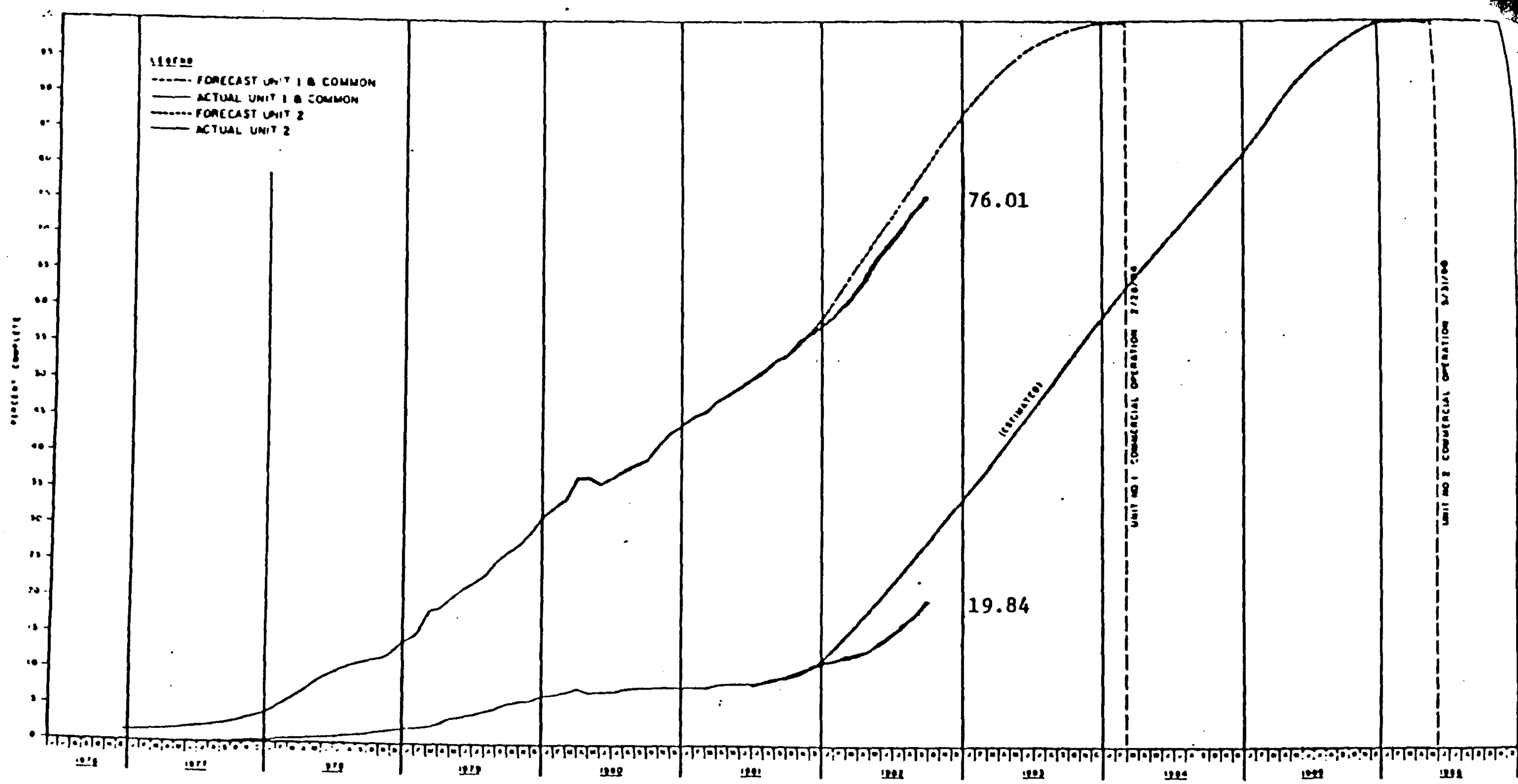


FIGURE 1

SEABROOK STATION PROGRESS REPORT NO. 38

FOR THE QUARTER ENDED

DECEMBER 31, 1982

PSNH PUBLIC SERVICE

Company of New Hampshire

printed. The consultant was retained by the Project to upgrade the state plan for the Station in parallel with the development of the State's Vermont Yankee plan. Upon publishing, the state plan will go to the Federal Emergency Management Agency for review and approval.

In Massachusetts, discussions will soon be held regarding preparation of the area plan. It is understood that the Massachusetts Civil Defense Agency wishes the Project to support preparation of the plan as was done in New Hampshire.

In both states, new civil defense directors have been appointed by the newly elected governors. In New Hampshire, the early indications are that the Agency will be revitalized and expedite decisions the project requires. Recent decisions place responsibility for the public notification system installation with the state and preparation of all educational materials with the Project. An early meeting in Massachusetts is anticipated to define responsibilities in that state.

Local planning for 22 surrounding towns is being done by a consultant paid for by the project but directed by the New Hampshire Civil Defense Agency.

The Station emergency plan and procedures are progressing in preparation and review.

The emergency exercise is scheduled for the week of May 16, 1984. All activities, including the EOF, are scheduled with this in mind.

IV. CONSTRUCTION

The cumulative progress, as of December 1982 was:

Unit 1 and Common	68.80 percent complete
Unit 2	16.88 percent complete
Total Project	51.41 percent complete

During the quarter, the manual craft manning level was reduced to a target level of 6000 while maintaining milestone achievements as previously planned. During December, the manual and non-manual payroll at Seabrook averaged 8100.

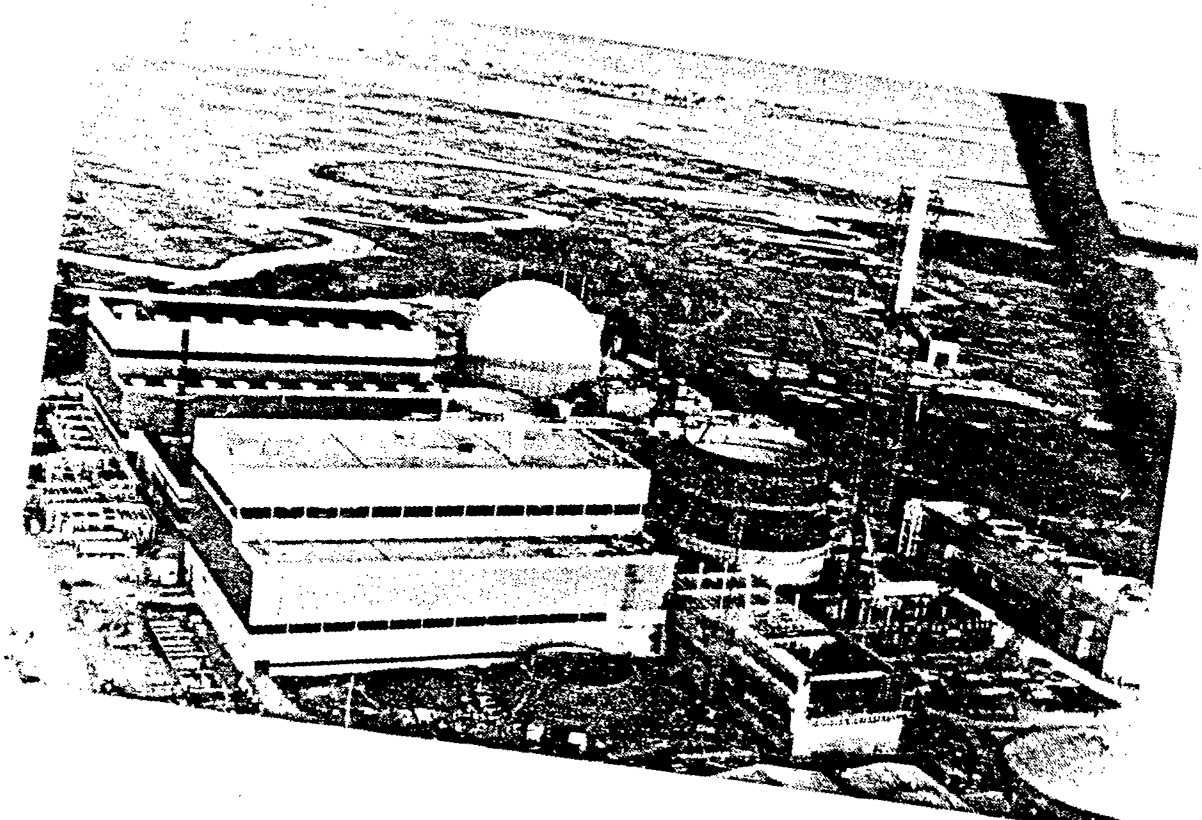
The construction status of the major facilities as of December 31, 1982, expressed as percent complete based upon earned manhours, is shown below and on the following page:

Building and Equipment	Percent Complete
Administration Building	97
Circulating Water Tunnels	93
Circulating Water Pumphouse/Service Water Pumphouse	75

SEABROOK STATION PROGRESS REPORT NO. 42

FOR THE QUARTER ENDED

DECEMBER 31, 1983



SEABROOK STATION

JANUARY 7, 1984

PSNH

Public Service of New Hampshire

IV. CONSTRUCTION

The cumulative progress, as of December 31, 1983, based on earned manhours was:

Unit 1 and Common	88.81 percent
Unit 2	29.25 percent
Total Project	69.25 percent

During the quarter, the peak manual craft manning level was 5,957 in October, down from the previous quarter. Seasonal layoffs and the reduced workforce on Unit 2 contributed to this reduction. The manual and non-manual payroll at Seabrook averaged 8,362 during the quarter.

The construction status of major facilities as of December 31, 1983, expressed as a percent complete based upon earned manhours, is shown below. A visual report on construction progress is presented in the photographs at the end of this report.

	Unit 1 & Common	Unit 2
	November 1983*	December 1983
Buildings and Equipment		
Administration Building	100	
Circulating Water Tunnels	98	
Circulating Water Pump/Service Water Pump House	91	
Control Building	92	37
Cooling Tower	92	
Diesel Generator Building	80	37
Emergency Feedwater Building/ MS/FW Enclosure	83	10
Equipment Vault	95	36
Fire Pumphouse	100	
Fuel Storage Building	86	41
Guard House	100	
Non-Essential Switchgear Room	89	19
Penetration Shield Tunnel	78	27
Primary Auxiliary Building	69	21
Reactor Containment Building	76	35
Sewage Treatment Plant	100	
Switchyard	99	
Turbine Generator Building	91	25
Waste Processing Building	77	
Yard Work	85	

*Unit 1 building percentage complete for December 1983 not available due to revisions of the 1983 budget.

Significant accomplishments during the quarter include tunnel work 100 percent complete, continuation of structural steel and concrete installation for the Solid Radwaste System, installation of all cable tray and supports in containment Unit 1.

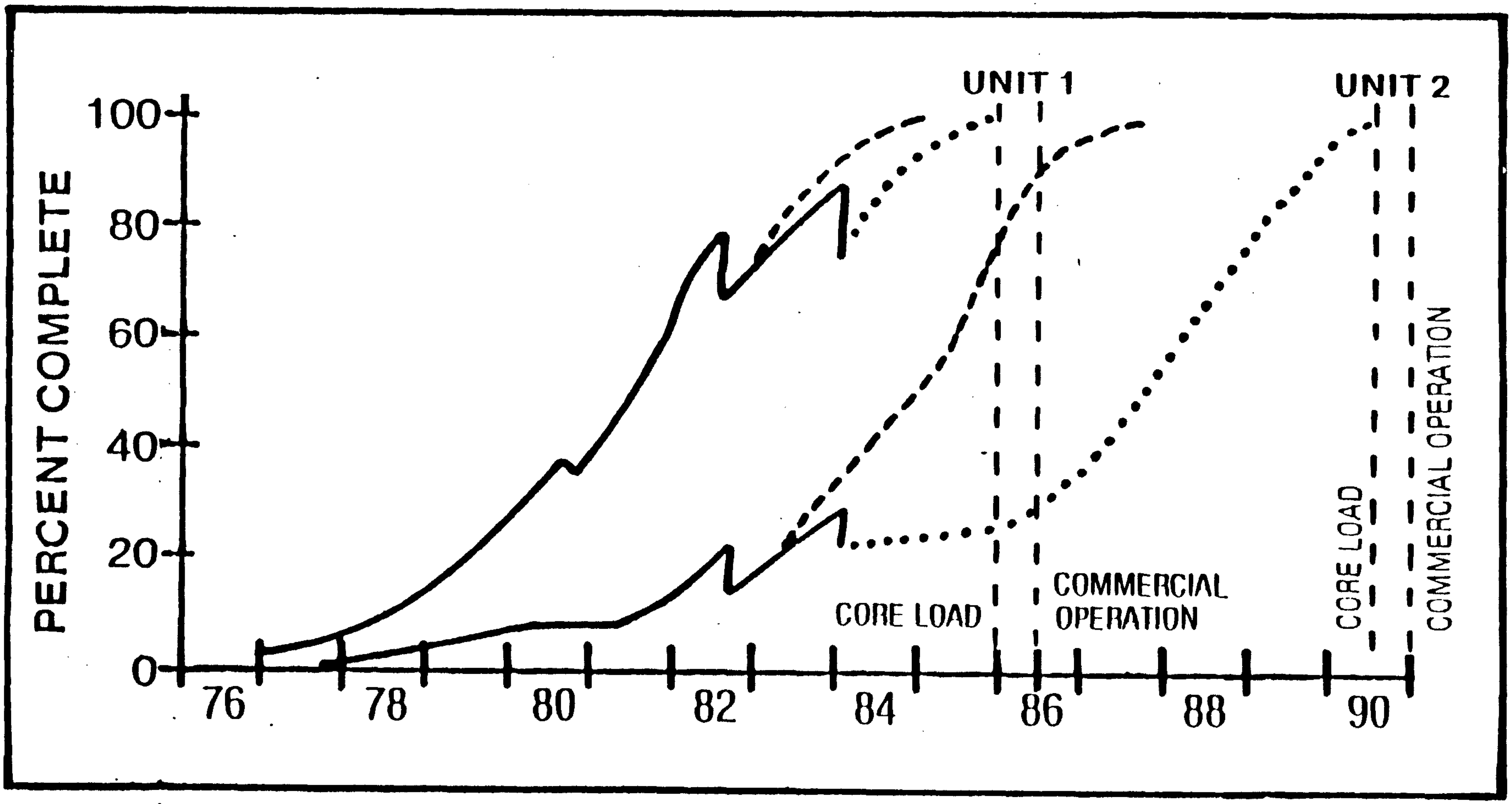
SCHEDULE AND COST ESTIMATE PRESENTATION

MARCH 1984

SEABROOK STATION

PSNH
Public Service of New Hampshire

CONSTRUCTION PROGRESS
TOTAL PROJECT



PUBLIC SERVICE OF NEW HAMPSHIRE PSNH

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APPENDIX E

CAPACITY FACTOR DATA

Unit Name	ID#	DER (mw)	Data year	post TMI	Age5	CE	CF GWH/DER /8.76	GWH
San Onofre 1	1	450	68	0	0.50	0	0.319	1262
Conn Yankee	2	575	68	0	0.50	0	0.593	2995
San Onofre 1	1	450	69	0	1.50	0	0.661	2607
Conn Yankee	2	575	69	0	1.50	0	0.722	3639
Conn Yankee	2	575	70	0	2.50	0	0.702	3538
San Onofre 1	1	450	70	0	2.50	0	0.776	3059
San Onofre 1	1	450	71	0	3.50	0	0.838	3303
Point Beach 1	4	497	71	0	0.58	0	0.752	3274
Ginna	3	490	71	0	1.00	0	0.630	2705
Conn Yankee	2	575	71	0	3.50	0	0.831	4187
Ginna	3	490	72	0	2.00	0	0.547	2356
Palisades	6	821	72	0	0.58	0	0.245	1765
San Onofre 1	1	450	72	0	4.50	0	0.711	2812
Point Beach 1	4	497	72	0	1.58	0	0.670	2925
Robinson 2	5	707	72	0	1.33	0	0.778	4829
Conn Yankee	2	575	72	0	4.50	0	0.851	4300
Surry 1	8	823	73	0	0.58	0	0.480	3461
Point Beach 1	4	497	73	0	2.58	0	0.630	2743
Turkey Point 3	9	745	73	0	0.58	0	0.510	3328
Point Beach 2	7	497	73	0	0.75	0	0.690	3004
Ginna	3	490	73	0	3.00	0	0.791	3396
Robinson 2	5	707	73	0	2.33	0	0.608	3764
Palisades	6	821	73	0	1.58	0	0.335	2411
Maine Yankee	10	790	73	0	0.58	1	0.484	3351
Conn Yankee	2	575	73	0	5.00	0	0.481	2425
San Onofre 1	1	450	73	0	5.00	0	0.575	2267
Surry 1	8	823	74	0	1.58	0	0.460	3318
Point Beach 1	4	497	74	0	3.58	0	0.722	3142
Palisades	6	821	74	0	2.58	0	0.011	78
Robinson 2	5	707	74	0	3.33	0	0.777	4813
Oconee 1	12	886	74	0	1.00	0	0.515	3998
Point Beach 2	7	497	74	0	1.75	0	0.730	3178
Maine Yankee	10	790	74	0	1.58	1	0.516	3574
Turkey Point 3	9	745	74	0	1.58	0	0.555	3624
Indian Point 2	13	873	74	0	0.92	0	0.435	3324
Zion 1	17	1050	74	0	0.58	0	0.378	3478
Ginna	3	490	74	0	4.00	0	0.489	2097
San Onofre 1	1	450	74	0	5.00	0	0.798	3145
Fort Calhoun	15	457	74	0	0.83	1	0.603	2416
Turkey Point 4	14	745	74	0	0.83	0	0.658	4293
Surry 2	11	823	74	0	1.17	0	0.365	2635
Prairie Island 1	16	530	74	0	0.58	0	0.309	1433
Conn Yankee	2	575	74	0	5.00	0	0.864	4351
Turkey Point 4	14	745	75	0	1.83	0	0.611	3990
Turkey Point 3	9	745	75	0	2.58	0	0.670	4375
Oconee 2	19	886	75	0	0.83	0	0.640	4968
Oconee 1	12	886	75	0	2.00	0	0.681	5286
Palisades	6	821	75	0	3.58	0	0.338	2428
Zion 1	17	1050	75	0	1.58	0	0.534	4909
Point Beach 2	7	497	75	0	2.75	0	0.859	3741
Zion 2	21	1050	75	0	0.83	0	0.525	4829
Prairie Island 2	24	530	75	0	0.58	0	0.684	3176

Unit Name	ID#	DER (mw)	Data year	post TMI	Age5	CE	CF GWH/DER /8.76	GWH
Maine Yankee	10	790	75	0	2.58	1	0.651	4502
San Onofre 1	1	450	75	0	5.00	0	0.823	3245
Arkansas 1	23	850	75	0	0.58	0	0.655	4880
Surry 2	11	823	75	0	2.17	0	0.701	5053
Conn Yankee	2	575	75	0	5.00	0	0.818	4121
Oconee 3	22	986	75	0	0.58	0	0.583	5037
Fort Calhoun	15	457	75	0	1.83	1	0.520	2081
Prairie Island 1	16	530	75	0	1.58	0	0.796	3694
Ginna	3	490	75	0	5.00	0	0.708	3041
Surry 1	8	823	75	0	2.58	0	0.543	3917
Indian Point 2	13	873	75	0	1.92	0	0.639	4885
Point Beach 1	4	497	75	0	4.58	0	0.671	2922
TMI 1	20	819	75	0	0.83	0	0.772	5542
Robinson 2	5	707	75	0	4.33	0	0.673	4171
Kewaunee	18	560	75	0	1.08	0	0.681	3341
Turkey Point 4	14	745	76	0	2.83	0	0.576	3772
Surry 1	8	823	76	0	3.58	0	0.608	4397
Kewaunee	18	560	76	0	2.08	0	0.688	3383
Surry 2	11	823	76	0	3.17	0	0.462	3343
Millstone 2	28	828	76	0	0.58	1	0.624	4539
TMI 1	20	819	76	0	1.83	0	0.603	4336
Oconee 2	19	886	76	0	1.83	0	0.543	4229
Turkey Point 3	9	745	76	0	3.58	0	0.660	4320
Palisades	6	821	76	0	4.58	0	0.395	2847
Indian Point 2	13	873	76	0	2.92	0	0.296	2268
Point Beach 2	7	497	76	0	3.75	0	0.862	3762
Zion 1	17	1050	76	0	2.58	0	0.516	4757
Prairie Island 2	24	530	76	0	1.58	0	0.572	2661
Zion 2	21	1050	76	0	1.83	0	0.503	4641
Robinson 2	5	707	76	0	5.00	0	0.785	4874
Ginna	3	490	76	0	5.00	0	0.479	2061
Maine Yankee	10	790	76	0	3.58	1	0.854	5929
Arkansas 1	23	850	76	0	1.58	0	0.521	3888
Oconee 3	22	986	76	0	1.58	0	0.549	4755
Calvert Cliffs 1	26	845	76	0	1.17	1	0.849	6304
Prairie Island 1	16	530	76	0	2.58	0	0.702	3269
Conn Yankee	2	575	76	0	5.00	0	0.797	4028
San Onofre 1	1	450	76	0	5.00	0	0.626	2473
Cook 1	27	1090	76	0	0.92	0	0.711	6805
Point Beach 1	4	497	76	0	5.00	0	0.780	3404
Oconee 1	12	886	76	0	3.00	0	0.513	3994
Rancho Seco	25	913	76	0	1.25	0	0.275	2205
Fort Calhoun	15	457	76	0	2.83	1	0.547	2195
Indian Point 3	30	873	77	0	0.92	0	0.722	5518
San Onofre 1	1	450	77	0	5.00	0	0.592	2333
Ginna	3	490	77	0	5.00	0	0.705	3028
St. Lucie 1	32	802	77	0	0.58	1	0.761	5344
Fort Calhoun	15	457	77	0	3.83	1	0.748	2993
Surry 1	8	823	77	0	4.58	0	0.697	5024
Maine Yankee	10	790	77	0	4.58	1	0.743	5145
Surry 2	11	823	77	0	4.17	0	0.618	4457
Oconee 1	12	886	77	0	4.00	0	0.508	3944

Unit Name	ID#	DER (mw)	Data year	post TMI	Age5	CE	CF GWH/DER /8.76	GWH
TMI 1	20	819	77	0	2.83	0	0.761	5463
Oconee 3	22	986	77	0	2.58	0	0.607	5239
Trojan	29	1130	77	0	1.17	0	0.656	6492
Point Beach 1	4	497	77	0	5.00	0	0.847	3687
Turkey Point 3	9	745	77	0	4.58	0	0.685	4471
Prairie Island 1	16	530	77	0	3.58	0	0.800	3715
Turkey Point 4	14	745	77	0	3.83	0	0.562	3666
Rancho Seco	25	913	77	0	2.25	0	0.735	5880
Zion 1	17	1050	77	0	3.58	0	0.547	5034
Indian Point 2	13	873	77	0	3.92	0	0.681	5210
Zion 2	21	1050	77	0	2.83	0	0.682	6275
Millstone 2	28	828	77	0	1.58	1	0.599	4343
Cook 1	27	1090	77	0	1.92	0	0.501	4786
Palisades	6	821	77	0	5.00	0	0.707	5085
Conn Yankee	2	575	77	0	5.00	0	0.797	4013
Prairie Island 2	24	530	77	0	2.58	0	0.836	3882
Calvert Cliffs 1	26	845	77	0	2.17	1	0.660	4882
Kewaunee	18	560	77	0	3.08	0	0.723	3546
Beaver Valley 1	31	852	77	0	0.75	0	0.398	2970
Point Beach 2	7	497	77	0	4.75	0	0.832	3622
Oconee 2	19	886	77	0	2.83	0	0.493	3825
Robinson 2	5	707	77	0	5.00	0	0.683	4230
Arkansas 1	23	850	77	0	2.58	0	0.685	5103
Trojan	29	1130	78	0	2.17	0	0.168	1666
Prairie Island 2	24	530	78	0	3.58	0	0.845	3924
Rancho Seco	25	913	78	0	3.25	0	0.624	4988
Crystal River 3	33	825	78	0	1.33	0	0.359	2592
Robinson 2	5	707	78	0	5.00	0	0.643	3980
Farley 1	37	829	78	0	0.58	0	0.815	5920
Salem 1	35	1090	78	0	1.08	0	0.474	4529
Ginna	3	490	78	0	5.00	0	0.750	3219
San Onofre 1	1	450	78	0	5.00	0	0.680	2679
Indian Point 3	30	873	78	0	1.92	0	0.714	5457
St. Lucie 1	32	802	78	0	1.58	1	0.712	5000
Maine Yankee	10	790	78	0	5.00	1	0.774	5355
Surry 1	8	823	78	0	5.00	0	0.652	4704
Oconee 1	12	886	78	0	5.00	0	0.651	5054
Surry 2	11	823	78	0	5.00	0	0.745	5372
Oconee 3	22	986	78	0	3.58	0	0.702	6064
TMI 1	20	819	78	0	3.83	0	0.791	5674
Point Beach 1	4	497	78	0	5.00	0	0.872	3795
Conn Yankee	2	575	78	0	5.00	0	0.935	4708
Prairie Island 1	16	530	78	0	4.58	0	0.821	3811
Turkey Point 3	9	745	78	0	5.00	0	0.690	4501
Davis-Besse 1	36	906	78	0	0.67	0	0.329	2612
Turkey Point 4	14	745	78	0	4.83	0	0.580	3788
Indian Point 2	13	873	78	0	4.92	0	0.571	4369
Zion 1	17	1050	78	0	4.58	0	0.736	6770
Millstone 2	28	828	78	0	2.58	1	0.620	4500
Zion 2	21	1050	78	0	3.83	0	0.732	6732
Palisades	6	821	78	0	5.00	0	0.365	2624
Calvert Cliffs 2	34	845	78	0	1.25	1	0.706	5227

Unit Name	ID#	DER (mw)	Data year	post TMI	Age5	CE	CF GWH/DER /8.76	GWH
Cook 1	27	1090	78	0	2.92	0	0.658	6287
Beaver Valley 1	31	852	78	0	1.75	0	0.332	2480
Kewaunee	18	560	78	0	4.08	0	0.793	3890
Arkansas 1	23	850	78	0	3.58	0	0.705	5250
Point Beach 2	7	497	78	0	5.00	0	0.886	3859
Oconee 2	19	886	78	0	3.83	0	0.617	4786
Fort Calhoun	15	457	78	0	4.83	1	0.712	2849
Calvert Cliffs 1	26	845	78	0	3.17	1	0.632	4676
Conn Yankee	2	575	79	1	5.00	0	0.817	4116
Point Beach 2	7	497	79	1	5.00	0	0.851	3707
Calvert Cliffs 2	34	845	79	1	2.25	1	0.742	5489
Prairie Island 1	16	530	79	1	5.00	0	0.627	2911
Cook 2	38	1100	79	1	1.33	0	0.618	5953
Prairie Island 2	24	530	79	1	4.58	0	0.903	4193
Davis-Besse 1	36	906	79	1	1.67	0	0.394	3129
Rancho Seco	25	913	79	1	4.25	0	0.714	5712
Fort Calhoun	15	457	79	1	5.00	1	0.916	3666
Robinson 2	5	707	79	1	5.00	0	0.647	4005
Indian Point 2	13	873	79	1	5.00	0	0.628	4805
Salem 1	35	1090	79	1	2.08	0	0.214	2043
Kewaunee	18	560	79	1	5.00	0	0.701	3439
San Onofre 1	1	450	79	1	5.00	0	0.851	3356
Millstone 2	28	828	79	1	3.58	1	0.602	4364
St. Lucie 1	32	802	79	1	2.58	1	0.695	4885
Oconee 1	12	886	79	1	5.00	0	0.644	5000
Surry 1	8	823	79	1	5.00	0	0.313	2255
Oconee 3	22	986	79	1	4.58	0	0.377	3260
Surry 2	11	823	79	1	5.00	0	0.085	612
Point Beach 1	4	497	79	1	5.00	0	0.702	3055
Trojan	29	1130	79	1	3.17	0	0.532	5267
Crystal River 3	33	825	79	1	2.33	0	0.521	3762
Turkey Point 3	9	745	79	1	5.00	0	0.441	2875
Ginna	3	490	79	1	5.00	0	0.690	2961
Turkey Point 4	14	745	79	1	5.00	0	0.589	3845
Maine Yankee	10	790	79	1	5.00	1	0.656	4539
Zion 1	17	1050	79	1	5.00	0	0.602	5537
Oconee 2	19	886	79	1	4.83	0	0.769	5968
Zion 2	21	1050	79	1	4.83	0	0.518	4760
Cook 1	27	1090	79	1	3.92	0	0.593	5660
Calvert Cliffs 1	26	845	79	1	4.17	1	0.567	4194
Indian Point 3	30	873	79	1	2.92	0	0.627	4795
Beaver Valley 1	31	852	79	1	2.75	0	0.238	1778
Palisades	6	821	79	1	5.00	0	0.477	3433
North Anna 1	39	907	79	1	1.08	0	0.527	4189
Farley 1	37	829	79	1	1.58	0	0.240	1744
Arkansas 1	23	850	79	1	4.58	0	0.446	3323
Rancho Seco	25	913	80	1	5.00	0	0.551	4415
Point Beach 1	4	497	80	1	5.00	0	0.567	2477
Calvert Cliffs 2	34	845	80	1	3.25	1	0.864	6413
Point Beach 2	7	497	80	1	5.00	0	0.822	3588
Cook 1	27	1090	80	1	4.92	0	0.675	6462
Prairie Island 1	16	530	80	1	5.00	0	0.667	3106

Unit Name	ID#	DER (mw)	Data year	post TMI	Age5	CE	CF GWH/DER /8.76	GWH
Crystal River 3	33	825	80	1	3.33	0	0.463	3354
Prairie Island 2	24	530	80	1	5.00	0	0.745	3469
Farley 1	37	829	80	1	2.58	0	0.632	4604
Calvert Cliffs 1	26	845	80	1	5.00	1	0.611	4534
Ginna	3	490	80	1	5.00	0	0.719	3094
Robinson 2	5	707	80	1	5.00	0	0.517	3211
Indian Point 3	30	873	80	1	3.92	0	0.400	3071
Salem 1	35	1090	80	1	3.08	0	0.594	5684
Maine Yankee	10	790	80	1	5.00	1	0.635	4404
San Onofre 1	1	450	80	1	5.00	0	0.207	817
North Anna 1	39	907	80	1	2.08	0	0.707	5632
St. Lucie 1	32	802	80	1	3.58	1	0.738	5200
Oconee 2	19	886	80	1	5.00	0	0.498	3879
Surry 1	8	823	80	1	5.00	0	0.342	2473
Palisades	6	821	80	1	5.00	0	0.330	2380
Surry 2	11	823	80	1	5.00	0	0.310	2242
Cook 2	38	1100	80	1	2.33	0	0.693	6692
Trojan	29	1130	80	1	4.17	0	0.612	6073
Fort Calhoun	15	457	80	1	5.00	1	0.501	2011
Turkey Point 3	9	745	80	1	5.00	0	0.670	4387
Kewaunee	18	560	80	1	5.00	0	0.738	3632
Turkey Point 4	14	745	80	1	5.00	0	0.589	3854
Oconee 1	12	886	80	1	5.00	0	0.657	5117
Zion 1	17	1050	80	1	5.00	0	0.706	6515
Conn Yankee	2	575	80	1	5.00	0	0.705	3563
Zion 2	21	1050	80	1	5.00	0	0.572	5279
Indian Point 2	13	873	80	1	5.00	0	0.556	4264
Beaver Valley 1	31	852	80	1	3.75	0	0.040	301
Oconee 3	22	986	80	1	5.00	0	0.602	5218
Millstone 2	28	828	80	1	4.58	1	0.671	4882
Davis-Besse 1	36	906	80	1	2.67	0	0.263	2094
Arkansas 1	23	850	80	1	5.00	0	0.507	3782
Point Beach 1	4	497	81	1	5.00	0	0.601	2615
Oconee 3	22	886	81	1	5.00	0	0.726	5637
Palisades	6	821	81	1	5.00	0	0.482	3463
Calvert Cliffs 1	26	845	81	1	5.00	1	0.825	6110
Arkansas 2	40	912	81	1	1.33	1	0.541	4324
Conn Yankee	2	575	81	1	5.00	0	0.807	4063
Point Beach 2	7	497	81	1	5.00	0	0.854	3720
Cook 2	38	1100	81	1	3.33	0	0.663	6385
Prairie Island 1	16	530	81	1	5.00	0	0.827	3839
Davis-Besse 1	36	906	81	1	3.67	0	0.550	4363
Prairie Island 2	24	530	81	1	5.00	0	0.666	3093
Fort Calhoun	15	457	81	1	5.00	1	0.537	2150
Rancho Seco	25	913	81	1	5.00	0	0.329	2631
Indian Point 2	13	873	81	1	5.00	0	0.399	3055
Robinson 2	5	707	81	1	5.00	0	0.566	3504
Kewaunee	18	560	81	1	5.00	0	0.768	3769
Salem 1	35	1090	81	1	4.08	0	0.648	6191
Millstone 2	28	828	81	1	5.00	1	0.840	6092
San Onofre 1	1	450	81	1	5.00	0	0.198	779
North Anna 2	41	907	81	1	0.58	0	0.711	5653

Unit Name	ID#	DER (mw)	Data year	post TMI	Age5	CE	CF GWH/DER /8.76	GWH
St. Lucie 1	32	802	81	1	4.58	1	0.704	4947
Oconee 2	19	886	81	1	5.00	0	0.669	5190
Surry 1	8	823	81	1	5.00	0	0.330	2377
Calvert Cliffs 2	34	845	81	1	4.25	1	0.732	5416
Surry 2	11	823	81	1	5.00	0	0.714	5150
Crystal River 3	33	825	81	1	4.33	0	0.565	4084
Trojan	29	1130	81	1	5.00	0	0.649	6424
Ginna	3	490	81	1	5.00	0	0.774	3323
Turkey Point 3	9	745	81	1	5.00	0	0.140	912
Maine Yankee	10	790	81	1	5.00	1	0.753	5212
Turkey Point 4	14	745	81	1	5.00	0	0.690	4505
Oconee 1	12	886	81	1	5.00	0	0.386	2996
Zion 1	17	1050	81	1	5.00	0	0.673	6193
Cook 1	27	1090	81	1	5.00	0	0.710	6782
Zion 2	21	1050	81	1	5.00	0	0.572	5257
Indian Point 3	30	873	81	1	4.92	0	0.397	3033
Arkansas 1	23	850	81	1	5.00	0	0.658	4901
Beaver Valley 1	31	852	81	1	4.75	0	0.625	4662
North Anna 1	39	907	81	1	3.08	0	0.584	4638
Farley 1	37	829	81	1	3.58	0	0.360	2616
Farley 2	42	829	81	1	0.00	0	0.729	5295
Beaver Valley 1	31	852	82	1	5.00	0	0.360	2688
Oconee 2	19	886	82	1	5.00	0	0.443	3437
Arkansas 2	40	912	82	1	2.33	1	0.477	3807
Oconee 3	22	986	82	1	5.00	0	0.245	2117
Calvert Cliffs 2	34	845	82	1	5.00	1	0.676	5005
Palisades	6	821	82	1	5.00	0	0.465	3345
Cook 1	27	1090	82	1	5.00	0	0.561	5353
Point Beach 1	4	497	82	1	5.00	0	0.621	2702
Crystal River 3	33	825	82	1	5.00	0	0.680	4916
Point Beach 2	7	497	82	1	5.00	0	0.828	3606
Farley 1	37	829	82	1	4.58	0	0.718	5216
Prairie Island 1	16	530	82	1	5.00	0	0.844	3918
Fort Calhoun	15	457	82	1	5.00	1	0.870	3482
Prairie Island 2	24	530	82	1	5.00	0	0.831	3858
Indian Point 2	13	873	82	1	5.00	0	0.581	4447
Rancho Seco	25	913	82	1	5.00	0	0.421	3367
Kewaunee	18	560	82	1	5.00	0	0.780	3825
Robinson 2	5	707	82	1	5.00	0	0.364	2252
Millstone 2	28	828	82	1	5.00	1	0.691	5009
Salem 1	35	1090	82	1	5.00	0	0.429	4095
North Anna 1	39	907	82	1	4.08	0	0.302	2398
Salem 2	44	1115	82	1	0.75	0	0.813	7942
Oconee 1	12	886	82	1	5.00	0	0.664	5153
San Onofre 1	1	450	82	1	5.00	0	0.129	510
Conn Yankee	2	575	82	1	5.00	0	0.901	4538
St. Lucie 1	32	802	82	1	5.00	1	0.966	6785
Davis-Besse 1	36	906	82	1	4.67	0	0.405	3218
Sequoyah 1	43	1128	82	1	1.00	0	0.497	4909
Ginna	3	490	82	1	5.00	0	0.561	2408
Surry 1	8	823	82	1	5.00	0	0.761	5483
Maine Yankee	10	790	82	1	5.00	1	0.654	4524

Unit Name	ID#.	DER (mw)	Data year	post TMI	Age5	CE	CF GWH/DER /8.76	GWH
Surry 2	11	823	82	1	5.00	0	0.762	5492
North Anna 2	41	907	82	1	1.58	0	0.509	4047
Trojan	29	1130	82	1	5.00	0	0.485	4802
Cook 2	38	1100	82	1	4.33	0	0.726	6996
Turkey Point 3	9	745	82	1	5.00	0	0.577	3766
Indian Point 3	30	873	82	1	5.00	0	0.188	1436
Turkey Point 4	14	745	82	1	5.00	0	0.589	3845
Calvert Cliffs	126	845	82	1	5.00	1	0.724	5362
McGuire 1	45	1180	82	1	0.58	0	0.416	4302
Arkansas 1	23	850	82	1	5.00	0	0.500	3721
Zion 1	17	1050	82	1	5.00	0	0.510	4695
Zion 2	21	1050	82	1	5.00	0	0.561	5158

APPENDIX F

NOMINAL ANALYSIS

COMPUTATION OF SEABROOK NOMINAL ANNUAL COST ($thousand)

		common	33%	16%	5.3%
firstyr	1988	preferred	11%	13%	1.4%
share	35.6%	debt	56%	18%	10.1%
(% of plant)		weighted			16.9%
cost	6,000,000	/w taxes @	51.66%		23.2%
deprate	3.3%				
proptax	$10.6 million in 1986, escalating			6%	

year	accum deprec	[1] accum deferred taxes	accum capital additions	invest base	return+ income taxes	[6] book deprec	prop taxes
1	35600	-		2100400	486956	71200	4240
2	106800	52841	15065	1991424	461691	68670	4494
3	175470	329775	31245	1662000	385318	59357	4764
4	234827	379903	48622	1569892	363963	58144	5050
5	292971	416808	67285	1493506	346254	57443	5353
6	350414	453730	87329	1419185	329023	56767	5674
7	407181	490636	108856	1347040	312297	56127	6015
8	463308	520947	131977	1283722	297618	55814	6375
9	519122	551258	156808	1222429	283408	55565	6758
10	574687	581568	183477	1163222	269681	55392	7163
11	630078	611879	212119	1106162	256452	55308	7593
12	685386	582738	242881	1110757	257517	58461	8049
13	743847	553597	275919	1114475	258380	61915	8532
14	805762	524473	311402	1117167	259004	65716	9044
15	871478	495332	349511	1118701	259359	69919	9586
16	941397	466190	390440	1118852	259394	74590	10161
17	1015987	437049	434398	1117361	259049	79812	10771
18	1095799	407925	481608	1113884	258243	85683	11417
19	1181482	378784	532312	1108046	256889	92337	12102
20	1273819	349643	586768	1099306	254863	99937	12829
21	1373756	320502	645254	1086996	252009	108700	13598
22	1482456	291378	708068	1070234	248123	118915	14414
23	1601371	262236	775530	1047923	242950	130990	15279
24	1732361	233095	847984	1018528	236135	145504	16196
25	1877865	203954	925800	979981	227198	163330	17168
26	2041195	174813	1009374	929366	215464	185873	18198
27	2227068	145689	1099133	862376	199933	215594	19289
28	2442662	116548	1195533	772324	179055	257441	20447
29	2700103	87406	1299068	647558	150130	323779	21674
30	3023882	58265	1410264	464116	107601	464116	22974
31	3487999	29141	1529688	148549	34439	276811	24352

Notes: 1. From: MPUC 84-113, acc.def.tax/gross invest.
2. See Tables 3.23-25: SHARE*[45557+3186.5*(yr-1983)]*1.06^(yr-1984).
3. 13110*SHARE*(1.06^(yr - 1984))

[2] O&M	[3] insurance	total non-fuel costs	[4] capital additions	[5] capacity factor	non-fuel cents/ kWh	PSNH fuel cents/ kWh	total cents/ kWh
35842	5892	604130	15065	50%	33.6	1.3	34.9
39905	6246	581006	16180	50%	32.3	1.4	33.7
44326	6620	500385	17377	53%	26.5	1.4	27.9
49134	7018	483309	18663	55%	24.5	1.4	25.9
54360	7439	470848	20044	57%	22.9	1.4	24.4
60035	7885	459385	21527	57%	22.4	1.5	23.8
66196	8358	448993	23120	57%	21.8	1.5	23.3
72880	8860	441547	24831	57%	21.5	1.4	22.9
80128	9391	435250	26669	57%	21.2	1.4	22.5
87984	9955	430175	28642	57%	20.9	1.5	22.5
96494	10552	426399	30762	57%	20.7	1.6	22.4
105708	11185	440920	33038	57%	21.5	1.7	23.2
115680	11856	456363	35483	57%	22.2	1.8	24.0
126468	12568	472799	38109	57%	23.0	1.9	24.9
138135	13322	490321	40929	57%	23.9	2.0	25.9
150746	14121	509013	43958	57%	24.8	2.1	26.9
164374	14968	528973	47210	57%	25.7	2.3	28.0
179094	15866	550303	50704	57%	26.8	2.4	29.2
194988	16818	573135	54456	57%	27.9	2.5	30.4
212145	17827	597601	58486	57%	29.1	2.7	31.7
230660	18897	623863	62814	57%	30.4	2.8	33.2
250632	20031	652115	67462	57%	31.7	3.0	34.7
272170	21233	682622	72454	57%	33.2	3.1	36.3
295391	22507	715732	77816	57%	34.8	3.3	38.1
320418	23857	751972	83574	57%	36.6	3.4	40.0
347386	25288	792209	89759	57%	38.6	3.6	42.2
376436	26806	838058	96401	57%	40.8	3.8	44.6
407721	28414	893078	103534	57%	43.5	4.0	47.5
441405	30119	967107	111196	57%	47.1	4.2	51.3
477664	31926	1104281	119425	57%	53.7	4.5	58.2
516685	33842	886129	128262	57%	43.1	4.7	47.8

Notes:
4. 26.24*1150*share*1.054*(1.074^(yr - 1984));see Table 3.26.
5. Easterling + 3%
6. Remaining life method, investment base.

COMPUTATION OF SEABROOK NOMINAL ANNUAL COST ($thousand)

		common	33%	16%	5.3%
firstyr	1988	preferred	11%	13%	1.4%
share	35.6%	debt	56%	18%	10.1%
(% of plant)		weighted			16.9%
cost	8,000,000	/w taxes @	51.66%		23.2%
deprate	3.3%				
proptax	$10.6 million in 1986, escalating			6%	

year	accum deprec	[1] accum deferred taxes	accum capital additions	invest base	return+ income taxes	[6] book deprec	prop taxes
1	47467	-		2800533	649275	94933	4240
2	142400	70454	15065	2650211	614424	91387	4494
3	233787	439700	31245	2205759	511382	78777	4764
4	312564	506537	48622	2077521	481652	76945	5050
5	389509	555744	67285	1970032	456732	75770	5353
6	465279	604974	87329	1865076	432399	74603	5674
7	539882	654181	108856	1762793	408685	73450	6015
8	613332	694596	131977	1672049	387647	72698	6375
9	686030	735010	156808	1583768	367180	71989	6758
10	758019	775425	183477	1498033	347304	71335	7163
11	829354	815839	212119	1414926	328036	70746	7593
12	900101	776984	242881	1413796	327774	74410	8049
13	974511	738129	275919	1411279	327191	78404	8532
14	1052915	699297	311402	1407190	326242	82776	9044
15	1135691	660442	349511	1401378	324895	87586	9586
16	1223277	621587	390440	1393575	323086	92905	10161
17	1316182	582732	434398	1383483	320746	98820	10771
18	1415003	543900	481608	1370705	317784	105439	11417
19	1520441	505045	532312	1354825	314102	112902	12102
20	1633343	466190	586768	1335234	309560	121385	12829
21	1754728	427336	645254	1311190	303986	131119	13598
22	1885847	388503	708068	1281717	297153	142413	14414
23	2028260	349649	775530	1245621	288784	155703	15279
24	2183963	310794	847984	1201227	278492	171604	16196
25	2355567	271939	925800	1146294	265756	191049	17168
26	2546616	233084	1009374	1077674	249848	215535	18198
27	2762151	194252	1099133	990730	229691	247683	19289
28	3009833	155397	1195533	878303	203626	292768	20447
29	3302601	116542	1299068	727925	168762	363962	21674
30	3666563	77687	1410264	514013	119169	514013	22974
31	4180577	38855	1529688	158257	36690	286519	24352

Notes: 1. From: MPUC 84-113, acc.def.tax/gross invest.
2. See Tables 3.23-25: SHARE*[45557+3186.5*(yr-1983)]*1.06^(yr-1984).
3. 13110*SHARE*(1.06^(yr - 1984))

[2] O&M	[3] insurance	total non-fuel costs	[4] capital additions	[5] capacity factor	non-fuel cents/ kWh	PSNH fuel cents/ kWh	total cents/ kWh
35842	5892	790182	15065	50%	43.9	1.3	45.2
39905	6246	756456	16180	50%	42.0	1.4	43.4
44326	6620	645870	17377	53%	34.2	1.4	35.6
49134	7018	619799	18663	55%	31.4	1.4	32.8
54360	7439	599653	20044	57%	29.2	1.4	30.6
60035	7885	580596	21527	57%	28.3	1.5	29.7
66196	8358	562704	23120	57%	27.4	1.5	28.8
72880	8860	548461	24831	57%	26.7	1.4	28.1
80128	9391	535447	26669	57%	26.1	1.4	27.5
87984	9955	523740	28642	57%	25.5	1.5	27.0
96494	10552	513421	30762	57%	25.0	1.6	26.6
105708	11185	527126	33038	57%	25.7	1.7	27.4
115630	11856	541663	35483	57%	26.4	1.8	28.2
126468	12568	557098	38109	57%	27.1	1.9	29.0
138135	13322	573524	40929	57%	27.9	2.0	29.9
150746	14121	591020	43958	57%	28.8	2.1	30.9
164374	14968	609679	47210	57%	29.7	2.3	31.9
179094	15866	629600	50704	57%	30.6	2.4	33.0
194988	16818	650913	54456	57%	31.7	2.5	34.2
212145	17827	673747	58486	57%	32.8	2.7	35.4
230660	18897	698260	62814	57%	34.0	2.8	36.8
250632	20031	724643	67462	57%	35.3	3.0	38.2
272170	21233	753169	72454	57%	36.7	3.1	39.8
295391	22507	784189	77816	57%	38.2	3.3	41.4
320418	23857	818248	83574	57%	39.8	3.4	43.3
347386	25288	856254	89759	57%	41.7	3.6	45.3
376436	26806	899904	96401	57%	43.8	3.8	47.6
407721	28414	952975	103534	57%	46.4	4.0	50.4
441405	30119	1025922	111196	57%	49.9	4.2	54.2
477664	31926	1165746	119425	57%	56.7	4.5	61.2
516685	33842	898088	128262	57%	43.7	4.7	48.4

Notes:
4. 26.24*1150*share*1.054*(1.074^(yr - 1984));see Table 3.26.
5. Easterling + 3%
6. Remaining life method, investment base.