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THE STATE OF MAINE
BEFORE THE PUBLIC UTILITIES COMMISSION

RE: CENTRAL MAINE POWER COMPANY, PROPOSED INCREASE IN RATES	DOCKET No. 84-120

TESTIMONY OF PAUL CHERNICK ON BEHALF OF THE MAINE PUBLIC UTILITIES COMMISSION STAFF

December 11, 1984

Table of Contents

TESTIMONY OF PAUL CHERNICK

ON BEHALF OF THE ATTORNEY GENERAL

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 Attrney 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 need for new power supply investments, and the likely costs of those investments, particularly in nuclear power, and the availability and cost of alternatives to proposed supply sources.

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

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

A: Yes. I have testified approximately thirty-five 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 New Hampshire Public Utilities Commission, the Connecticut Department of Public Utility Control, the Michigan Public Service Commisssion, the Pennsylvania 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, and predicted that growth rates would be lower than the utilities expected. Many of my criticisms have been incorporated in subsequent forecasts, and load growth has almost universally been lower than the utility forecast. For example, in MDPU 19494, I reviewed the 1978 CMP load forecast and identified several aspects of that forecast which were inconsistent with the historical record, or otherwise projected load growth without appropriate support. The history of CMP load forecasts is presented in Figure 1.1.

In DPU 19494 and NRC 50-471, I reviewed the NEPOOL forecast, both for the 1978 edition (which was the last version to be compiled as the sum of the utilities' own forecasts) and the 1979 edition (the first of the new end-use forecasts by state). I identified many overstatements and other errors in both versions. The 1978 version predicted a winter peak in 1983/84 of 19670 MW (compared to 15019 MW in 1977/78), and a ten-year growth rate of 4.5%; corresponding figures from the 1979 forecast were 19755 MW and 3.8% growth. Actual 1983/84 winter peak was 15949 MW, and the 1984 NEPOOL forecast predicts 2.0% annual growth in the long term. The history of NEPOOL load forecasts is presented in Figure 1.2.

A similar situation arose in MDPU 19494, Phase I, and MEFSC 78-33. My joint testimony with Susan Geller, filed June 12, 1978, discussed in considerable detail some of the errors and overstatements in Boston Edison's 1978 forecast. A number of other witnesses addressed other problems with the methodology. That 1978 BECo forecast projected a peak of 2427 MW in 1983 and 2966 MW in 1988, as compared to an actual 1983 peak of 2233 MW, and a current forecast of 2399 MW in 1988. Figure 1.3 shows the evolution of BECo's load forecasts.

My analyses of other utility forecasts, including Northeast Utilities, Public Service of New Hampshire, and various smaller utilities, have been similarly confirmed by the low load growth over the past few years, and by repeated downward revisions in utility forecasts.

My projections of nuclear power costs have been somewhat more recent, but utility projections have already confirmed my analyses. 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 canceled in September 1981) stood at $4.0 billion. Figure 1.4 illustrates the history of Pilgrim 2 cost estimates, which are listed in Table 1.

In MDPU 20055, 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 cost estimate of $9 billion, with in-service dates of 7/86 and 12/90. In June 1983, I updated my analysis for CPUCA 83-03-01, and estimated a total cost of $10.3 billion, with COD's of 11/86 and 3/91.[1] Thus, PSNH's estimates of Seabrook in-service dates and costs have increased by a factor of more than three since the filing of DPU 20055, and are now relatively close to my projections. Figure 1.5 compares the history of PSNH cost estimates for Seabrook to my estimates, and Table 1.2 lists PSNH's projections of Seabrook cost and schedule.

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.

Q: What is the subject of your testimony?

A: I have been asked to review the information available to Central Maine Power (CMP) and Boston Edison (BECo) in connection with their various decisions to initiate and continue their involvement in the Pilgrim 2 nuclear power plant construction project. I have specifically been asked to determine what a responsible and prudent utility would

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1. Those results were averages, which included methodologies which I knew to be biased on the low side. The methods used in this testimony produced COD estimates of 10/87 and 6/94.

have known at critical points in the project, and to describe appropriate responses to the information which was available at those times. In addition, I will review the prudence of CMP's corresponding decisions with respect to the Sears Island project.

Q: How is your testimony structured?

A: The second section of my testimony will discuss the state of the nuclear power industry in 1972, when Central Maine Power (CMP) signed the Pilgrim 2 Joint Ownership Agreement, and describe some of the facts of which CMP was, or should have been, aware at that time. I will then consider, in section 3, the changes in circumstances between 1972 and 1976, a point at which Boston Edison (BECo) believed that Pilgrim 2 was close to receiving its construction permit, and identify some of the concerns with which the Pilgrim 2 participants should have been dealing. The fourth portion of this testimony will consider the state of the industry, Pilgrim 2, and the participants in December, 1978, following the first major financial crises of New England utilities. In the fifth section, I will review the same issues as of mid-1980, after the accident at Three Mile Island. Section six repeats contemporaneous cost-benefit analyses for realistic Pilgrim costs, and Section seven considers the financial consequences of building Pilgrim 2. In my Pilgrim 2 conclusions (Section eight), I will summarize and interpret the results of the previous sections, and suggest appropriate actions for the utilities and the Commission, in light of the facts I present. Finally, Section nine reviews the history and prudence of CMP's decisions with regard to Sears Island.

2 - THE NUCLEAR INDUSTRY IN 1972

Q: Why is the status of the commercial nuclear power industry in 1972 pertinent to this proceeding?

A: It was in 1972 that CMP decided to sign the Pilgrim 2 Joint Ownership agreement, obligating CMP to pay 2.85% of project costs.

Q: When it entered into the ownership agreement, were there any particular considerations of which CMP should have been aware?

A: Yes. A major utility such as CMP, and indeed any utility with large enough a staff to keep up with the general industry literature,[2] should have been aware of two crucial facts:

1. Nuclear cost estimates were unreliable and almost always understated,

2. Nuclear plant construction costs were increasing, so that the units ordered, started, or completed in any year were more expensive than those of the year before,

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2. Examples of this literature would include **Electrical World** and **Power Engineering** magazines.

3. Nuclear plant construction schedules were increasing, and the times from order to construction permit, and from permit to commercial operation, grew longer for each new cohort of plants, and

4. Nuclear schedules were unpredictable and usually stretched out well beyond the expectations of the owners and their architect/engineers.

Q: On what do you base this statement?

A: I have two sources. First, there is the data itself. Table 2.1 summarizes the cost estimate histories of all the commercial nuclear power plants which were in commercial operation by the end of 1972, and which were built without any extraordinary cost guarantees.[3] For each of these six units, Table 2.1 lists the actual commercial operation date (COD), the actual construction cost, the date of the first cost estimate for which I was able to obtain suitable data, and the estimated cost and COD for that estimate. It is certainly not difficult to determine that both the cost estimates and construction schedules of these units grew significantly during their planning and construction.

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3. I have excluded both the turnkey plants, for which the manufacturers provided at least partial cost caps, and the reactors for which the federal government provided cost sharing.

My cost and schedule history data is drawn from the database listed in Appendix B, which shows all of the changes in cost or schedule indicated in cost estimate history summaries provided by the Energy Information Administration (EIA). Those summaries are condensations of the Quarterly Construction Progress Reports (Form HQ-254 and Form EIA-254) filed by most nuclear utilities with the Atomic Energy Commission (AEC), and later with its successor agencies, the Energy Research and Development Administration (ERDA) and EIA. This data base also includes later estimates for these units. Where important data was missing from the HQ-254's, data from various published sources was used, supplemented with data provided directly by the utilities, where available. Final cost and commercial operation date (COD) information, for example, is generally from reports to the FPC and the FERC, and the operation date information may therefore differ from NRC figures.

To quantify the extent of the errors in cost and schedule estimation for these six units, I have computed four statistics for each estimate: the projected years to COD (or "duration") at the time of the estimate, the ratio of final cost to the projected cost at the time of the estimate (the "cost ratio"); the cost ratio expressed as a growth rate, annualized by the estimated time to completion (the "myopia factor"); and the ratio of the actual remaining time until commercial operation to the projected time (the "duration ratio"). These terms are all fairly self-explanatory, except for myopia, which is defined as

$$(\text{cost ratio})^{(1/\text{estimated duration})}$$

Roughly speaking, the average myopia indicates that the actual cost of these units was typically 18% greater than the estimate, for each year that construction was expected to take. The cost ratio demonstrates that the average plant cost over twice as much to complete as initially estimated, while the duration ratio indicates that the plants took almost half again as long as was projected.

Q: Why do you present the data and the results in this form?

A: The raw data on cost estimate histories indicate that cost overruns and schedule slippage was routine, and nearly universal. This relationship would be clearly apparent to any observer. It is more difficult to determine (and particularly to quantify) just what lesson the observer should have learned from the data. I do not believe, for example, that it is fair to assume that each utility involved in nuclear construction should have done regression analyses on the cost trends, as were later performed by Bupp, et al., Komanoff, Perl, and ESRG. Those are fairly sophisticated approaches, which are sensitive to the exact data and functional forms used in the analyses. Looking at the percentage cost overrun, or annualizing that value, or comparing actual and projected construction durations, all strike me as being simple, obvious ways of summarizing the large and growing experience of nuclear construction. These were the kinds of questions which I asked, and the kind of analyses I undertook, when I first found out in 1978 and 1979 that nuclear plant cost and schedule estimates were frequently incorrect. I am not suggesting that CMP should have performed exactly the same summary calculations that I present in this testimony, but I _am_ suggesting that CMP should have examined the uncertainties and contingencies involved in nuclear investments,[4] that CMP should have done some simple analysis of the historical data, and that the same general conclusions could have been reached through several types of analysis, including an informal examination of the data. Therefore, I believe that it is appropriate to judge CMP's prudence _as if_ it had these calculations before it, since it should have been familiar with the data and should have noted (formally or informally, rigorously or intuitively) the same patterns and relationships I present.

Q: What do these results imply for Pilgrim 2?

A: If the nuclear industry's ability to forecast costs had not

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4. As I will show below, the utility industry literature provided ample notice that nuclear plant construction was not "business as usual."

improved, it would be appropriate to apply these results to the initial cost and schedule estimates for Pilgrim 2 ($402 million and a COD of 11/78, or 6.75 years from the 2/72 estimate date), to produce revised or corrected estimates. Multiplying $402 million by the average cost ratio of 2.07 produces a corrected cost estimate of $832 million. However, the estimated duration for Pilgrim 2 was somewhat longer than for the units in Table 2.1, so applying the all-units average myopia factor of 18.1% for 6.75 years would produce a cost ratio of 3.07, and a Pilgrim 2 cost of $1236 million. Finally, multiplying the estimated Pilgrim 2 duration ratio by the average duration ratio of 1.44 produces a corrected duration estimate of 9.72 years, and a COD of 11/81. Corresponding calculations for the three plants for which Bechtel was architect/engineer (A/E) or constructor (it had both roles at Pilgrim 2) would result in slightly lower cost estimates and a somewhat longer construction period. Thus, if the factors which had caused other nuclear power plant estimates to be incorrect also operated for Pilgrim 2, it would be considerably more expensive and time-consuming to construct than was implied by the official projections from BECo and Bechtel.

Q: Have you performed any other analyses of the nuclear power plant cost and schedule information available by the end of 1972?

A: Yes. Table 2.2 repeats the duration analysis in Table 2.1, but for the turnkey and demonstration units excluded from the previous table. As would be expected, the cost estimates for the turnkey units tended to be considerably more stable than for the conventionally priced units, but the two demonstration units for which I have data are even worse than the later commercial units. The duration ratio for this entire set is nearly as bad as for the commercial units, while the duration ratio for Bechtel plants is a substantial improvement over the Bechtel commercial units, but still would indicate a duration of about 8.8 years (to 12/80) for Pilgrim 2 if the experience continued.

Tables 2.3 and 2.4 list the units which were planned or under construction as of the end of 1972, and for which at least two cost or schedule estimates were available. For each unit, these tables list the earliest available estimate and the most recent estimate as of the end of 1972. I have computed two summary statistics. The first statistic is the "cost growth rate", simply the annual rate of increase in the cost estimate, from the first projection to the most recent. The second statistic is the "progress ratio", which is the ratio of progress towards completion (the decrease in projected months to operation), divided by elapsed months, both calculated from the first available estimate to the most recent estimate as of 12/72. The data from which this analysis is taken may also be found in Appendix B. To calculate the effect on Pilgrim 2 if these trends had extended to its cost and schedule evolution, we may divide the projection of 6.75 years by the experience-weighted[5] average progress ratio of 45%, to yield a corrected duration of 15 years (indicating that Pilgrim 2 would have been completed in 2/87) and increased the cost estimate of $402 million by 15 years of cost growth at 18.6% annually, for a final cost of $5.2 billion. The experience in the Bechtel estimates was slightly worse in both cost growth and progress rate, and would indicate that Pilgrim 2 would cost $7.3 billion and enter service in 11/87 if that experience continued.

Q: What significance do these results have for CMP's decision to enter into the Pilgrim 2 joint ownership agreement?

A: They indicate that both CMP and BECo knew, or should have known, while CMP was deciding to join in constructing Pilgrim 2, that construction cost and duration estimates for other nuclear units had been significantly understated, and thus that the cost and schedule estimates for Pilgrim 2 were likely to be less reliable than estimates for other (non-nuclear) utility projects. Both utilities should also

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5. Throughout this testimony, whenever averages are calculated on both a simple and an experience-weighted basis, I use the weighted averages in the text.

have been aware that continuation of these trends would have resulted in a very expensive plant, or in one which was simply impossible to complete. As it happens, both of these events occurred.

Q: Are there any particular reasons to believe that CMP and BECo knew, or should have known, that nuclear cost and schedule estimates were subject to very large overruns?

A: Yes. The cost and schedule estimate histories for New England nuclear units which entered commercial operation by 1972 are listed in Table 2.5.[6] The cost data for Connecticut Yankee and Millstone 1 reflect their turnkey status. The Maine Yankee actual data is somewhat understated since it was declared "commercial" at 75% power. These units were in the figurative back yard of both utilities, and in some cases in their laps; BECo owns Pilgrim 1 as well as 5% of Connecticut Yankee; and CMP is the lead utility at Maine Yankee (owning 38%), and is also a participant in the Vermont (4%) and Connecticut (6%) Yankee plants. The 240% cost overrun at Pilgrim 1 is especially significant, since exactly the same utility and architect/engineer (A/E) were involved in that unit as in the Pilgrim 2 estimate.

In light of both the national and the regional experience

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6. Yankee Rowe is omitted for lack of data.

with completed nuclear plants, and the national experience with those still under construction, it would not have been reasonable to place much faith in the quality of conventional cost estimates for Pilgrim 2.

Q: Mr. Chernick, the Hearing Examiner's Report in Phase I of Maine PUC 84-113, considered your application of myopia analysis in that phase:

> "It is a blind leap of faith to assume that the error in the Seabrook cost and performance estimates will mimic the error made by the nuclear industry on average. Therefore, Mr. Chernick's approach serves only a limited useful purpose. However, Mr. Chernick does point out a valid criticism of the industry, and that is, for whatever reasons, cost estimates and target dates have historically been overly optimistic. While that certainly does not mean they will be "off" by the same factor in this case, it is relevant to the amount of weight to be afforded those estimates."

How is this assessment of your approach relevant to this case?

A: As I read this passage of the Report, it is supportive of my application of cost and schedule estimate analyses in this proceeding.[7] I am certainly not suggesting that CMP should have performed any particular computation and accepted the result as inevitable, nor that they should have accepted the results on "blind faith". I do believe that, failing some

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7. I believe that the Report is also supportive of the purpose of my analyses in Phase I of MPUC 84-113, but that is no longer of direct interest, so I will not discuss it further.

strong evidence to the contrary, the historical record of nuclear cost and schedule estimation errors is "relevant to the amount of weight to be afforded" to new nuclear cost and schedule estimates. In short, the utility estimate must be presumed to be seriously understated (at least until shown to be otherwise) and a much higher cost and much longer schedule must be expected.

Q: Was this the case throughout the planning and construction of Seabrook 2?

A: The tendency for nuclear cost and schedule estimates to be understated was evident in the early 1970's, and continuation of the cost overrun pattern should have been considered possible, at least in sensitivity analyses. By 1976, there had been enough experience to establish a rebuttable presumption that underestimation in nuclear construction was a continuing phenomenon. In contrast, for most engineering estimates, including nuclear plant estimates in the 1960's, the rebuttable presumption would be that the estimates were unbiased, if uncertain.

Q: What was the second source of your belief that CMP and BECo should have known in 1972 that nuclear cost and schedule estimates were likely to be unreliable and understated?

A: It was common knowledge within the utility industry that nuclear plant costs and schedules had been subject to what were then considered to be shocking amounts of escalation and slippage. Representatives of one architect/engineer (or A/E), Gilbert Associates, identified a large number of problems facing nuclear construction:

> The utility industry, about eight years ago, believed that a large light water reactor plant could be built for $125 per kilowatt or less. Today plants to be completed about eight years hence are generally being estimated at close to $400 per kilowatt, which is more than a 300 percent increase in expected costs over an eight-year period. Nuclear plant costs, then, have not merely evolved in eight years; they have exploded.
>
> Of course, not all utility executives accept estimates of $400 per kilowatt for their future plants. They believe that they can build plants for less. Maybe they can. Perhaps they are more fortunate than most utilities with regard to such factors as construction labor, site availability, and environmental opposition within their service areas. On the other hand, maybe they are continuing the industry's past record of underestimating nuclear plant costs.
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> Any analysis of past and current estimates quickly indicates the fact that almost all past estimates and many current estimates are far below what will actually be experienced. . .
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> This analysis, which covers 1968 estimates for plants to be completed in the early 1970's on which adequate cost data could be compiled, shows that original cost estimates were about $150 per kilowatt lower than will actually be experienced for those plants. . .
>
> The full cost impact of environmental and safeguards backfitting has not yet been realized. In fact, the door has just been opened to cost increases resulting from environmental activity.
>
> While it is true that very few new safeguards have been introduced since 1968, existing requirements have been broadened, and the study depth extended. There is no real indication of policy change nor saturation of areas requiring design analyses for contingency situations. The cost of providing a

> "safe plant" will continue to increase in the foreseeable future.
>
> This will probably add a significant amount each year to plant cost. (McTague, et al. 1972)

The same problem was described by employees of another A/E (Burns and Roe) as

> The rising trend of construction and capital costs for new electrical generating plants is a matter of major importance and of increasing concern to the entire utility industry. (Roe and Young 1972)

Those authors discussed several reasons for the increased costs, including construction delays and unanticipated complexity of work, especially for nuclear plants, and observed that

> Of course current licensing problems with nuclear plants must be cleared up if [potential nuclear] cost advantages are to be realized,

and concluded that

> In summary, still another crisis is at hand in the electrical generating industry. Continuation of the rapid growth which has been occurring in capital costs will make financing and provision of badly needed increases in electrical generating capacity even more difficult to achieve. The task is clear, but the solutions will not come easily. A combined effort by business, labor, government and the public will be necessary if the rapid growth of plant costs is to be controlled . . .

Electrical World's annual series of nuclear surveys indicated similar concerns. For example, the 1971 survey, entitled "Nuclear Schedules Face Uncertainty", observed that

> The big news is the continuing stretchout in schedules. In last year's survey, 1975 was the "big year," with more than 20,000 Mw scheduled for commercial operation. Reappraisals during the year now place the total for 1975 at only 13,049 Mw, and shift the peak to 1977. . .
>
> The National Environmental Policy Act, and particularly the Calvert Cliff court decision forcing new AEC interpretation of that law, have recently added even more dramatic uncertainties to plant schedules. Indeed, says Walter Mitchell III, VP of Southern Nuclear Engineering, pending changes in licensing procedures brought about by the Calvert Cliff's decision may soon make obsolete many of the schedule dates tabulated on the following pages.

and the 1972 survey, although it was headlined "Lead Times Stabilizing", noted that

> 58 units in this year's listing show scheduled completion dates that have been set back since last year.
>
> Some optimism has been shown in the schedules reported by utilities for 1974-75, suggests Mitchell. "Several 1975 schedules look hard to meet," he says. Perhaps significantly, only two units are now scheduled for 1976.

The Federal Power Commission (FPC) also recognized and publicized the problems of the nuclear power industry. In the **National Power Survey**, in 1970, the FPC observed

> Because the nuclear industry is in a stage of dynamic growth, it is difficult to establish precise data for the present and future costs of nuclear plants. The nuclear industry today is characterized by an unprecedented commitment of new technology which has been reflected in capital costs attributed to delayed deliveries of vital components, the introduction of new or more stringent codes and standards, changes in regulatory requirements, and the extension of construction schedules coupled with current high interest rates and escalation in costs of labor,

> equipment and materials.[8]
>
> An indication of the escalation in estimated capital costs for a 1,000 mw LWR plant is provided in Table II-11 which shows that the approximately $135 per kw estimates for this size plant made in March 1967 had increased to about $220 per kw when estimated in June of 1968, and to more than $320 in 1970. It will be noted that the estimates for virtually all of the components of the plant direct and indirect costs increased substantially. These increases in combination with lengthening construction schedules, labor rates andinterest costs resulted in an estimated overall plant cost in 1970 of almost 2 1/2 times that estimated in 1967. . . .
>
> It is estimated that cost reductions will accrue in the future through increased business volume and acquired experiences in construction techniques and component design factors. These reductions could be in the order of $10-$15/kw. Other factors that can have a profound influence on cost are licensing requirements, site preparation, cooling water requirements, labor productivity, and rates, inflation, etc. that make future predictions highly unpredictable.
>
> The very large capital requirements for nuclear plants make their costs sensitive to interest rates, taxes, insurance, depreciation, etc. The comparatively long periods required for licensing and construction can cause considerable variations in interest during construction. Slippage in construction schedules, regardless of the reasons, thus can result in a significant increase in the capital cost of a nuclear plant. Adhering to the shortest possible schedule of construction is one of the most serious problems facing the industry now and in the foreseeable future. (pages IV-1-56 to 58)

The report also quoted some of the concerns of Philip Sporn, Chairman of American Electric Power (page II-4-22), and included the following disclaimer below a chart of projected

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8. In 1970, inflation was running around 5%, and corporate bonds were yielding 8-9%.

nuclear plant costs:

> IN THE PERIOD SINCE THE CHART WAS PRODUCED (JANUARY 1, 1968) COSTS HAVE BEEN RISING SHARPLY: CONSIDER THIS FACT WHEN REFERRING TO CHART. (page II-1-33)

The FPC also commented on the rising costs of nuclear plants in the introduction to the 1970 edition of the annual **Steam Plant Books** (FPC, various), the FPC staff provided a summary that would be repeated, in almost the same terms, year after year:

> In the first nine months of 1971, [announcements for new capacity additions] were 69% fossil and 31% nuclear . . ., illustrating the continuing acceptance of nuclear power by utilities, despite sharp capital cost increases and well publicized licensing difficulties. In the 1965-68 period, the average capital cost of nuclear units ordered was about $150/kWe. However, as a result of longer construction periods, added environmental equipment and high rates of escalation, the capital costs of nuclear units ordered in 1970 has been estimated to average about $250/kWe, by the time they come into operation. For 1971 the comparable figure has been estimated to be about $300/kWe. . .
>
> In 1970, the increasing national concern for the environment began to affect nuclear projects. Environmental organizations intervened in a number of licensing proceedings; AEC regulations on radioactive discharges were criticized as too permissive; and the National Environmental Policy Act of 1969 required new AEC procedures and the preparation of environmental statements for each plant. In 1971, in the Calvert Cliffs decision, the courts held that the AEC's environmental review procedures were inadequate, raising the prospect of regulatory delays for a significant number of new nuclear units.
>
> Delays of a year or more from scheduled commercial operation dates are being experienced for many nuclear units. The causes include technical and construction problems, increasingly detailed AEC reviews, the inexperience of many utilities and their architect-engineers with nuclear power, and

the impact of environmental legislation and opposition.

This, and each of the subsequent revisions in expectations, seems to have been a suprise to the FPC staff, which accompanied each announcement with its judgement that growth in nuclear capacity was inevitable and desirable.

Q: How should these facts have affected the behavior of BECo and CMP in 1972?

A: BECo should have realized that its cost estimates, which were methodologically similar to earlier, understated estimates, were also subject to significant overruns. As the lead utility in Pilgrim 2, BECo had a moral, and perhaps a legal, responsibility to inform its potential partners of the risks they were undertaking, and to clearly identify its cost estimate as a routine nuclear plant cost estimate, subject to all the problems of that genre.[9] Similar obligations may extend to Bechtel.

Furthermore, it is increasingly clear that many nuclear cost estimates were never intended to be predictions of the final cost of the plant: they were budget targets and cost-control

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9. Examples of these problems would include the exclusion of many potential costs, the failure to incorporate sufficient contingency for current and future regulatory changes, and the absence of an allowance for the problems of building a plant whose design is still changing.

documents. This issue is discussed at some length in Meyer (1984). Employees of MAC, in testimony filed by Central Maine Power in this proceeding summarize this practice with respect to Seabrook:

> PSNH established schedules that required superior effort. This strategy is generally appropriate because it demands the best possible performance from contractors. (Dittmar and Ward, page 25)

The MAC analysis further considered the tradeoffs between conservative and optimistic estimates, and explained the construction management advantages of intentionally optimistic estimates:

> 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)

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: Should CMP have been aware of the same considerations?

A: Assuming even the most cursory familiarity with industry publications and experience, CMP also should have been aware of the previous problems in the nuclear industry. CMP is about half the size of BECo, but is as large as PSNH, which was the lead participant in the Seabrook plants, and CMP actually had plans through part of the 1970's to build one or two Pilgrim-size nuclear units. Thus, CMP was, or should have been, well positioned to monitor the problems of the nuclear industry and to compare Pilgrim 2 estimates to the erroneous estimates of the past. In fact, CMP has not offered any evidence to suggest that CMP ever reviewed any estimate it received from BECo, at least until 1980, in the light of industry (or New England) experience. If this was due to vigorous BECo representations, CMP may have been an excessively credulous victim. If CMP's confidence in the cost and schedule estimates were entirely due to CMP's failure to credit current experience, CMP would appear to have been acting in an imprudent and irresponsible manner.

By the time it signed the participation agreement, CMP should have been in a position to extract from BECo either more realistic estimate ranges, or the information necessary to estimate a reasonable CMP contingency. Its apparent failure to do so also appears to be imprudent, unless BECo's behavior was such as to transfer the responsibility to BECo. For example, if BECo assured CMP that the estimate actually included a 100% contingency, while it only included a 3% contingency, CMP may argue that it attempted to act in a responsible manner, but was defrauded by BECo (and perhaps Bechtel as well) to secure CMP's participation in the project. If, on the other hand, CMP's reliance on the BECo/Bechtel estimates resulted entirely from the absence of any active inquiry by CMP, that reliance must be considered negligent. Given the size, sophistication, and expansion plans of CMP, the first possibility is less credible than it would be for much smaller utilities. In any case, the division of responsibility between the utilities and contractors may be settled elsewhere and should not affect the utilities' rates.

Q: Were CMP and its professional staff large enough to understand, review, and monitor the Pilgrim cost projections?

A: Certainly. It is clear that CMP, and virtually any New England utility with a supply planning program, had access to enough information to raise serious questions about the quality of the cost estimates it was receiving from BECo. CMP is a fairly large utility by New England standards, was building a major steam-elctric plant (Wyman #4), and for a few years in the 1970's was itself planning to construct a nuclear unit. Thus, CMP would have been hard-pressed not to be aware of the problems of the nuclear industry in the early 1970's. There is no evidence to suggest that CMP then attempted to set up any sort of monitoring process, either internally or in conjunction with other small utilities, to assure that it would be prepared to respond if the historic pattern continued.

Q: Why are you certain that CMP could have identified these problems?

A: Because I spotted these problems in 1979, under circumstances much less favorable than those of CMP's staff. My initial observations were based on only a couple of cost estimate histories, I had only been involved in utility planning for about two years, and I had no access to the utility literature or other utilities, but a pattern of substantial cost overruns quickly became obvious. The calculation of cost ratios, myopia factors, and duration ratios were simple ways of quantifying very important phenomena, requiring no strong assumptions or complex calculations. I can not imagine why any utility with an established power-supply planning process would not have noticed the same problems.

Q: Is it your opinion that CMP's decision to sign the joint ownership agreement was imprudent?

A: Not necessarily. It was certainly imprudent for any utility to sign such an agreement and then fail to monitor (and critically assess) developments for most of the next decade, as CMP appears to have done. It is possible that participating in Pilgrim <u>in itself</u>, coupled with a commitment to due diligence in the future, may have been a reasonable decision at the time.

Q: Considering the problems you have described, how could such a commitment be reasonable?

A: While nuclear power had serious problems, so did the other conventional generation alternatives which were perceived to be available in 1972. Oil prices were expected to rise, although not nearly as much as they actually rose later in the decade. There was considerable uncertainty regarding the extent and cost of future environmental constraints on coal combustion. Several power supply options available today were not generally considered to be on the table in 1972: Quebec was an inconceivably distant power source, New England hydro potential seemed trivial compared to the perceived need, and fostering conservation and customer-owned power generation was simply anathema to utilities in the early 1970's. Thus, it is hard to say that CMP erred in signing the Pilgrim Joint Ownership Agreement, or similar agreements for other nuclear plants, without allowing a certain amount of hindsight to influence our judgement.

Q: What then is the ultimate significance of the state of the nuclear industry in 1972, in terms of the issues in this case?

A: There are two central points which can be drawn from the facts I laid out. First, as discussed previously, CMP's failure to acknowledge the weakness of the Pilgrim cost and schedule estimates can only be attributed to irresponsible and/or incompetent behavior on the part of either CMP or BECo.[10] Second, even if CMP somehow believed that BECo's projections were the best available estimates, it should at least have recognized that the projections were subject to tremendous uncertainty. <u>At a minimum</u>, choosing to participate in Pilgrim created a responsiblity for CMP to monitor the progress of the project, and of its cost

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10. Again, the same considerations may apply to Bechtel.

estimates, and to be prepared to react appropriately if the historical trends continued or accelerated. The same can be said, even more emphatically, of BECo's responsibility as the sponsor of the project.

Q: Given the nature of the joint owners' agreement, was there any advantage for any of the joint owners in monitoring Pilgrim 2 cost estimates? Did any of the joint owners other than BECo have any control over the project?

A: Despite their lack of formal control, it is clear that joint owners can have significant influence over the fate of a nuclear unit. This influence is seen most clearly in the case of Seabrook 2, in the effect of the 1983/84 opposition by United Illuminating, Connecticut Light and Power, and Central Maine Power, with lesser contributions from other utilities. Another visible example is Dayton Power and Light's opposition to the completion of the Zimmer nuclear plant. The public opposition to (or even doubt of) pursuing Pilgrim 2 by one of the joint owners might well have led to the cancelation or mothballing of the unit much earlier, and hence saved all the owners millions of dollars.

In particular, intervention in the regulatory proceedings (particularly those of the NRC, the MDPU, particularly in DPU 19494, and other state utility regulators) by a joint owner which believed (or suspected) that construction was impossssible, or excessively expensive, would have made it very difficult for those agencies to continue to support the plant. The same could be said for the filing of a lawsuit, even if it eventually proved to be unsuccessful. BECo presumably would have been aware of this possibility,[11] and would almost certainly have cooperated with CMP's efforts to review the cost estimates, rather than face a public confrontation. Throughout the construction of Pilgrim 2, CMP had a great deal of power, and even the facts of 1972 should have alerted CMP to the possibility that it would have to exercise that power.

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11. If one believes that BECo really was not aware of the state of the nuclear industry throughout the 1970's, it may be conceivable that it would not have spotted its significant liabilities in the event of a public disagreement with a joint owner. If this were the case, CMP could have pointed out BECo's vulnerability.

3 - NUCLEAR PROBLEMS IN THE MID-1970's

Q: You have described the problems of the nuclear industry in the early 1970's. How had the situation changed by the end of 1976?

A: There were two kinds of important developments in this period. First, all the problems which I described above persisted and expanded. Second, the direct and indirect effects of the first oil price shock started to change the basic environment in which utilities operated.

Q: Please describe the continuing problems of the nuclear industry.

A: Table 3.1 updates to the end of 1976 the previous analyses (Tables 2.1 and 2.2) of cost and schedule slippage in completed nuclear units. By this time, BECo expected the Pilgrim 2 would soon receive a construction permit (CP), so the summary statistics are computed from the estimate immediately preceding the CP, to the actual cost (or completion date). On this basis, the average cost ratio[12] is 2.21, the average myopia factor is 22%, and the average duration ratio is 1.55. The cost results are not very

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12. Turnkey plants are excluded from the cost analysis.

different than those in the previous analysis, through 1972, but the duration ratio is somewhat worse than the 1972 result. If the BECo estimate for Pilgrim 2 dated 10/76 were actually the final pre-CP estimate, and if the Pilgrim 2 cost and schedule changed as much during construction as did those of the 49 units in Table 3.1, it would have cost $3.1 to $6.1 billion, and would have entered service in 4/88. The experience of the 18 Bechtel units in Table 3.1 was only marginally better than the average of all units, and would have resulted in a Pilgrim 2 cost of $3.0 to $5.8 billion, and a COD of 9/87.

In Table 3.2, I repeat the analysis of the cost and schedule slippage of nuclear units under construction (see Tables 2.3 and 2.4), updated to the end of 1976. This analysis only includes slippage after construction permit receipt: the first estimate is defined as in Table 3.1. If Pilgrim 2 experienced throughout its construction the average progress ratio and cost growth rate this group had from CP to 12/76, and if the 10/76 estimate for Pilgrim 2 were in fact the last pre-CP estimate, construction would have required 22.5 years,[13] to sometime near the end of the century, and the

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13. This is BECo's estimate of 7.42 years, divided by the progress ratio of 33%.

unit would have cost $43 billion.[14] These results indicate that Pilgrim 2 could not both have repeated this experience and have been completed.

The experience for Bechtel cost and schedule estimates for units under construction in this period was not significantly different than that of other units. The progress rate was slightly better, and the cost growth rate was slightly worse.

Q: Do you make any particular assumptions in applying the historical experience to Pilgrim 2?

A: Yes. Projecting the historical experience would have been appropriate in 1976 if one had assumed that the situation in 1976 and into the future was as unsettled as the previous decade, and that the Pilgrim 2 estimate was consistent with utility practice. I believe that a reading of the utility press from that period supports the first assumption (which is not subject to any rigorous test in any case). The second assumption is more empirical. Table 3.3 lists the other units without CP's as of 12/76, from **Nuclear News** (2/77). The average of these 54 units was scheduled for completion in January of 1986. First units were scheduled for somewhat

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14. The average cost growth rate of 16.5%, over 22.5 years, would increase the price by a factor of over 30 times.

earlier operation, averaging February 1985; thus, the schedule estimate for Pilgrim 2 at the early end of the range of industry expectations. However, Pilgrim had been in the licensing process for some years at this point, so its schedule was probably consistent with industry practice.

Q: Was there any more New England experience by 1976?

A: Yes. Millstone 2 entered service in December 1975. Table 3.4 displays the cost estimate history of Millstone 2, which was by far the most expensive nuclear unit in the region. While neither BECØ nor CMP has any direct interest in Millstone 2, it would be particularly difficult for any New England utility not to be aware of the history of this relatively local unit.

Q: Were there any particular reasons for other New England utilities to take note of the cost and schedule overruns for Millstone 2?

A: Yes. Previous capacity additions were almost always welcome for reliability purposes, and most additions also reduced costs when they entered service or soon thereafter. Public agencies were primarily concerned with the adequacy of power supply, and the only capacity problem was a potential shortage. The situation was rather different for Millstone 2, which caused considerable consternation when it was completed. The unit was unnecessary and expensive excess capacity at the time it entered service. As I will discuss below, the radical reduction in load growth following the oil price increases of 1973-74 had left New England utilities (including NU, the sole owner of Millstone 2) with enormous reserve margins. The construction cost of the plant was so high that even post-embargo oil prices did not make it cost-effective in the short run, and there was initially concern that it might not be cheaper than oil over its life as a whole.[15] The Attorney General opposed (unsuccessfully) the inclusion of Millstone 2 in the rate base of Western Massachusetts Electric Company (WMECo) on the grounds that the unit's capacity was surplus to the utility's needs.

Q: Did the electric utility literature continue to note the persistence of these problems?

A: Yes. The Senior Editor of **Power Engineering** magazine wrote that

> The nuclear power industry continues to miss schedules, and more slippage appears to be ahead. . . Based on past performance and anticipating new impediments, it seems unlikely that [the current construction] target will be met.
>
> Low [construction] time estimates have been characteristic of both the AEC and the utility forecasts. Part has been due to tight targeting and part to external causes. Both are understandable in moderation. It taxes reason, however, to explain all the announcements of new plants in the past three years that estimated commercial operation in six to eight years . . .

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15. This problem was solved by the Iranian revolution in 1979.

> The great bulk of recently announced plants are now planned for 8 to 10 years, and considerable additional slippage lies ahead for these units. . .
>
> The AEC still is changing the important ground rules, . . . and the nuclear community seems to profit little from some pretty plain and important lessons of recent history. . .
>
> More likely, of course, the schedule [of nuclear additions in 1979-81] will not hold. . . (Olds 1973)

Pilgrim 2 would have been one of the "new plants in the past three years that estimated commercial operation in six to eight years", with more aggressive schedules than "The great bulk of recently announced plants . . . now planned for 8 to 10 years," for which "considerable additional slippage lies ahead". The next year, Olds headlined his review "Power Plant Capital Costs Going Out of Sight" (Olds 1974). In that article, he presented extensive data on nuclear cost estimates, and subsequent revisions, for the period 1965-74, and computed that estimates had been rising 26% annually since 1970:

> From the mid-1960's on, power plant capital costs have risen faster than estimators can get their numbers changed. In spite of intensive study by many experts, the skyrocket performance of plant costs has defied complete analysis. . .
>
> It is obvious . . . that as plants get closer to their completion dates, their reported costs tend to jump. It may be expected that the 1967-68 averages [for plants ordered in those years] will increase still further.

Olds also warned that

> In spite of the steep increase in estimated costs, these probably will fall far short of the actual completed plant costs unless there is a sharp break in the influences that are forcing costs up so dramatically. . .
>
> In general, the 26% increase rate since 1970 reflects four factors: (1) inflation in cost of labor, material, services and money; (2) increase in scope, or material content of plants. . . ; (3) recognition that base line estimates in 1965-69 were far too low; and (4) belated recognition that slippage was of major proportions. . .
>
> The influence of the regulatory arm [of the AEC] on schedules still is totally unpredictable. The branch has kept a moving target before the utilities for a long time while proclaiming standardization and schedule shortening. As of May, the record shows that the 54 plants holding construction permits have been slipping their fuel loading dates at the rate of 0.37 months per month.

Another year later, the same author reviewed the history of nuclear plant schedules and concluded

> . . . schedule slippage has been going on for a decade. . . A study of the 10 years of changes in nuclear plant status thus discloses a steady increase in estimated time to complete plants, and that these estimates have been about two years too optimistic all along . . . Slippage became worrisome in 1969 when, in just that year, an average of one plant in six slipped a year. . . The average slippage per plant, as announced, generally increased steadily through 1973. Then in 1974, 201 net plant years of slippage were announced, nearly half of the 10-year total for the 226 plants. (Olds 1975)

Things did not improve dramatically the next year, either

> While the slippage in the nuclear program in 1975 was less than it was in 1974, it was not comfortably less, and was larger than for any other year except 1974. Setbacks were spread about evenly over the whole year, and were most severe for plants that had been ordered in the 1971-74 years. . .

> Costs continue to grow at a rapid rate, and the postponed plants are going to be much higher in cost as each year passes. . .
>
> [In 1970-75,] AEC's regulatory people kept promising shorter licensing, but kept taking longer. In addition, a torrent of guides and procedural changes forced additional delays on the industry. It took time to digest the changes, to retrofit the engineering, the procedures, and to retrofit in the field. The moving target exercise was a tragedy. . .
>
> These years thus were particularly difficult ones for the industry. Accurate scheduling was impossible, and costs sped upward without any possibility of control by the industry. . .
>
> When the AEC was dissolved, an important nuclear advocate was lost. (Olds 1976)

Some other examples from the nuclear literature of this period would include:

> [T]he trend of nuclear plant costs [for plants ordered in the 1960's] was more or less correctly anticipated, but the absolute magnitude seems to have been badly misestimated. For example, in 1968 the reactors were expected to cost only $180/kw. Our actual estimate of cost of reactors ordered that year is about $430/kw. . . [both in constant] 1973 dollars; i.e., there has been a systematic discrepancy of more than a factor of 2. . . [T]his difference between expected and actual costs has not been narrowing with time. Indeed it has been growing. . . [We] predict, taking the more conservative of the two [regression] estimates, that reactor cost will continue to increase at an average rate of $34 [constant 1973 dollars] per year, if nothing happens to change the relative impact of the various independent variables. (Bupp, _et al._, 1974)
>
> Florida Power Corporation has announced it has abandoned its plans to construct the unnamed two-unit nuclear station it had scheduled for operation in the mid-1980's. . . "We believe nuclear power still holds the promise of being the long-range answer to adequate electric supplies as well as a means of achieving national energy independence." FPC president Andrew Hines said .

. . "However, we feel it is not in our customers' best interest at this time to proceed with our previously announced plans. There is too much governmental uncertainty as well as an almost unknown cost factor for construction for us to plunge ahead into the morass." . . . In 1973, the projected cost of the facility was $1.4 billion. More recent estimates had set the cost of construction as $2.6 billion, and the utility said there was strong indication that escalation would continue in the years ahead. (**Nuclear News** 1976)

All of us know that power generation costs and prices have run rampant since 1969, but many may not realize how much they have changed. . . Projected [nuclear power unit investment] costs . . . have increased about four times since early 1969, an average of 21% per year compounded. . . In 1969, it was assumed that a nuclear unit could be placed in service about six years after authorization. Today the time span between authorization and the expected date of commercial serivce is slightly over nine years. (Brandfon 1976)

For nuclear plants, . . . both the derived curve and the specific plant data suggest that the error in cost prediction was increasing rapidly through the latter half of the 1960's [from 37% overruns for plants completed in 1971 to 115% for plants completed in 1975], largely because plants begun in the mid-to-late sixties were delayed and made more costly by imposition of unanticipated environmental and safety-related requirements . . . ; unexpected inflation also played a significant role. (Blake, et al., 1976)

[W]ere it not for these [recent sharp increases in fuel costs], the long-run economic viability of nuclear reactors as a competitive generating alternative would indeed be questionable. . . All things considered, [and even assuming nuclear costs of only $883/kw in 1985, compared to BECo's estimate of $1007/kw for Pilgrim 2 in 1983] it appears that purely on economic grounds and ignoring capital shortage problems resulting from state regulation of electricity rates, the future of the U.S. nuclear reactor industry is less bright than recent government forecasts indicate. (Joskow and Baughman 1976)

Q: Did the series of **Electrical World** annual reviews continue in this period?

A: Yes. Nuclear surveys were published in October of 1973 through 1975. The 1976 survey was published in January of 1977. The prose portions of these documents are worth reading in their entirety, to establish the pattern of continuing concern, optimism, and dashed hopes. Some highlights include 1973:

"Nuclear Survey: A Record Year"

> Reactor orders soar but lead times slip.
>
> Schedule slippage among previously committed plants is a continuing problem. Of the units committed before Sept. 15, 1972, but not yet in commercial service, 63 units were reported this year with no schedule change, 45 had been set back one year, 6 two years, and 2 three years.

1974: "Nuclear Survey: Orders and Cancellations"

> Mixed bag of statistics shows commitments to new units running about as predicted, but mid-year inflationary forces caused widespread cancellations and delays in construction programs. . .
>
> Unfortunately, these figures do not openly reveal the crisis in the nuclear power industry that is being caused by spiraling inflation; they appear, instead, to herald a healthy industrial posture. . .
>
> The most important truths in the industry today are not to be found in growth-rate statistics, but in reports of cancellations, indefinite postponements, and scheduled construction stretchouts. . .

As utilities have moved to cover financial situations by paring construction budgets, changes in nuclear schedules were occurring almost daily during the late summer. . .

When the tabulation closed, 75 units (or about 36% of the 2Ø6 listed) had new completion dates that were at least one year later than originally planned. A few of these are plants under construction where construction has lagged schedule, but the vast majority are utility-ordered stretchouts and average about 2 years for each delayed unit. . .

Last year, AEC licensing delays and intervention by small groups of diehards with talented lawyers represented the major challenges to nuclear power. This year, the old problems have not gone away, but the major contention comes from pervasive financial conditions that are not exclusively nuclear.

1975: "Nuclear Survey: Cancellations and Delays"

Industry falters as uncertainties mount in the areas of financial commitments, load-growth demands, regulatory delays, fuel-cycle inadequacies, and unpredictable social and political hindrances.

The year covered by this report (Sept. 15, 1974 to Sept. 15, 1975) ended on a downward trend. Two major stations were indefinitely postponed late in the period, and this wiped out slight gains that had been posted earlier. The net result: a narrow loss . . .

Uncertainty is now the name of the game as utility executives scramble to hold on to what they see in their load-growth predictions, balanced against what they can afford. . .

Soaring costs have been charged with forcing seven major units off the schedules this year. . .

Utility executives are well aware that delays are going to be costly; nevertheless, within the period covered by this report, 84 units (9Ø,Ø48 Mw, or 72% of all capacity scheduled to go on line after 1975) has been delayed for periods ranging from one to seven years.

1977: "Nuclear Survey: Market Still Depressed"

> About 67,000 Mw of nuclear capacity were deferred in 1975 and at least 40,000 Mw in 1976. This means that almost all future nuclear additions have been rescheduled.
>
> Above all, potential reactor buyers now want assurance from the government that, once they have approved designs and construction permits, they can proceed with assurance that their nuclear plants will be licensed and permitted to operate effectively.
>
> Based on NRC's performance, the utilities are widely convinced that they cannot manage their own economic destinies in such an uncertain environment; therefore, they are being scared away from nuclear power.

Q: Did the series of FPC reviews continue?

A: Yes. The **Steam Plant Book** observed

> In the 1965-1968 period, the average capital cost of nuclear units ordered was about $150/kWe. However, it was estimated that the average capital cost of nuclear units ordered in 1972 would be about $429/kWe by the time that units come on-line; an increase attributable to such factors as inadequate quality control in manufacturing and in field construction, labor problems, added environmental equipment and high rates of escalation. For 1973 the comparable figure was estimated to be slightly higher at about $449/kWe. . .
>
> Increasing national concern for the environment continues to affect nuclear projects. Following the 1971 Calvert Cliffs decision, the Atomic Energy Commission issued a revised statement of policy and amended its regulations to broaden the scope of environmental issues it will consider in licensing proceedings. . .
>
> Delays of two to four years from scheduled commercial operation dates are being experienced for many nuclear units, due to late delivery of equipment by manufacturers; faulty installation of equipment; strikes by manufacturer's employees,

construction employees, or electric system employees; inclement weather; as well as increasingly detailed AEC reviews, and the inexperience of many utilities and their architect engineers with nuclear power. These and other difficulties have prompted some utilities to reassess their nuclear plans. Although many problems confront the utilities in their nuclear planning, prompting some utilities to reassess their nuclear plants, they are proceeeding with increasing emphasis on nuclear plant additions to their system generation mix. (1972, pages XIV - XV)

In the 1969-1973 period, the average capital cost of nuclear units ordered was approximately \$427/KWe. However, since 1970 nuclear plant construction costs have been escalating at more than 15 percent a year. The latest updated (March 1975) average capital cost of nuclear units ordered in 1973 was projected to be about \$608/KWe by the time the units are completed and placed in commercial operation. This increasing cost trend of nuclear units is attributable to such factors as increased design complexity, inadequate quality control in manufacturing and in field construction, shortage of skilled labor, added environmental equipment to meet newly established environmental and safety standards, and escalating costs of equipment, materials and wages. For 1974 the comparable figure was estimated to be slightly higher at about \$627/KWe. With projected production costs of about 5.0 mills/kWh for these units, the total cost of electricity generation from nuclear plants ordered in 1974 will be in the neighborhood of 20-22 mills/kWh. The average capital cost for nuclear units in operation on December 31, 1973 was \$204/KWe. . .

Increasing national concern for the environment continues to affect nuclear projects. Following the 1971 Calvert Cliffs decision, the AEC issued a revised statement of policy and amended its regulations to broaden the scope of environmental issues it will consider in licensing proceedings. The broadened environmental protection requirements, mandated by Federal legislation, increased the length of time required to process environmental impact statements. License applications on which licensing action had been taken had to be reeexamined and a more extensive environmental review performed. Increasing requirements for environmental protection and plant

> safety features contributed to significant delays in scheduled lead times of many nuclear units. However, the principal cause is attributable to delays in construction, i.e., late delivery of equipment by manufacturers; faulty installation of equipment; strikes by manufacturer's employees, construction employees, or electric system employees; inclement weather; increasingly detailed AEC reviews, and the inexperience of many utilities and their architect engineers with nuclear power. Although many problems confront the utilities in their nuclear planning, prompting some utilities to reassess their nuclear plans, they are proceeding with increasing emphasis on nuclear plant additions to their system generation mix. (1973, pages XV - XVI)
>
> Projected nuclear plant investment costs which have been escalating at more than 15 percent per year since 1970 continued at that pace during 1974. The latest updated (March 1976) average capital cost of nuclear units ordered in 1974 was projected to be about $690/kwe when the units are completed and placed in commercial operation. This increasing cost trend of nuclear units is attributable to such factors as increased design complexity, inadequate quality control in manufacturing and in field construction, shortage of skilled labor, added environmental equipment to meet newly established more stringent environmental and safety standards, and escalating costs of equipment, materials and wages. For 1975 the comparable figure was estimated to be slightly higher at about $694/KWe. (1974, pages XV - XVI)

The 1974 report also repeated the second paragraph I quoted from the 1973 report, verbatim.

Q: Taken as a whole, were these observations any different from those you described in the previous section?

A: Yes, in two respects. First, the general tenor of the comments moved perceptibly over the years, from an early sense of annoyance and puzzlement with these cost and schedule problems, to a later sense of deeper concern.

Second, the continuing assurances that last year was the end of the trend, and that next year would see the industry turn around, were beginning to wear a little thin. The initial observations emphasized that the problems were a bit more complex than the industry had thought, but now they were largely under control and the "learning curve" could take over, leading the industry to faster, cheaper construction, and better cost estimation. By the mid-1970's, the regular reader of the utility magazines would have been through several cycles of bad news, followed by promises of better results in the short term, followed by more delays and overruns, and by some familiar promises.[16] In addition, the learning curve seemed to have largely disappeared from the discussion: the problem for the foreseeable future was to stop the slippage.

Q: What new problems had arisen since 1972?

A: The oil embargo and subsequent dramatic rise in oil prices had several important effects. On the one hand, it improved the relative economics of any technology which promised to reduce oil consumption. On the other hand, it greatly increased the cost of electricity, particularly in New

----

16. Many authors also continued to express suprise at the size of the increases, even after the pattern had persisted for a decade. Also, even in the middle of a recitation of the industry's woes, many authors paused to express their faith in the need for nuclear power, and in the eventual recovery of the industry.

England; reduced load growth to virtually unprecedented levels (often to negative growth); encouraged conservation actions and the development of conservation technologies; increased inflation; and greatly increased the financial stress on utilities.

Q: What was the effect of reduced load growth on nuclear construction?

A: The changes in most utility load forecasts (those of CMP, NEPOOL and BECoare illustrated in Figures 1.1, 1.2, and 1.3) had two effects. First, the reduced need for power plants made it harder to justify building any new generation, including nuclear plants, and raised the possibility that new units might not be needed for long periods after they entered service. Second, lower sales resulted in reduced internal generation of funds, which compounded the financial stress caused by the higher oil prices themselves.

Q: How did conservation affect nuclear power?

A: The reduction in load growth was largely due to conservation, of course: this demonstrated that continual increases in electricity consumption were not inevitable. In particular, it became clear that conservation was an alternative to new power supplies, and that conservation could be encouraged by higher prices and by organized regulatory and incentive programs. For the most part, those programs did not get off the ground until the late 1970's, and there was considerable hope in the utility industry in 1976 (and even later) that the conservation effects of the last few years would soon disappear, overtaken by a wave of "pent-up demand".

Q: How did the first oil price shock induce financial stress for utilities constructing nuclear power plants?

A: As I noted above, reduced load growth resulted in lower sales and lower earnings than the utilities would have expected. At the same time, the higher cost of oil, and subsequent inflation throughout the economy, greatly increased the utilities' expenses. The pinch between rising costs and falling sales expectations limited the ability of many utilities to finance the construction programs they had planned in more affluent years. In the next section, I discuss how this problem caught up with PSNH, UI, and NU; Section 8 considers financial issues in more detail.

Q: What other changes occurred in the mid-1970's other than those related to the increase in oil prices?

A: The March 1975 cable fire at the Brown's Ferry nuclear power plant, as the most serious accident to that time at a commercial light water reactor, seems to have been a sort of watershed for the newly formed NRC in two respects. First, it alerted the agency to the possibility that significant safety problems could slip past its initial screening, and thus be present in units under construction or even in operation. Second, it must have driven home the point that those problems would not disappear if the NRC ignored them; a major design flaw could have disastrous consequences for the credibility of the agency and the industry which it was charged with regulating, however gently. Thus, nuclear safety regulation was bound to intensify, rather than relax, despite the (probably correct) perception of the industry that regulation was killing it and despite all political representations to the contrary.

4 - FINANCIAL CRUNCH: 1977 AND 1978

Q: Did the situation of the nuclear industry, and Pilgrim 2 in particular, improve in the first two years following Seabrook's receipt of a construction permit?

A: No. Cost escalation and schedule slippage continued nationwide, Seabrook's construction was interrupted by unresolved environmental issues, and some of the major owners reached the limits of their ability to finance the plant.

Q: What was the national experience with cost overruns and schedule slippage in 1977 and 1978?

A: Table 4.1 continues the analysis of Table 3.1, for those plants which entered commercial operation in 1977 and 1978. On the whole, these two years were even worse for cost overruns by completed plants than was the previous decade. Applying the experience of these 10 units to the current estimate for Pilgrim 2 would produce a corrected cost estimate of $5.6 to $11.2 billion, and a commercial operation date of November 1992. Including the experience of the units completed by 1976 would moderate this somewhat, producing an estimated completion date of 12/89 and a cost estimate of $4.5 - 8.4 billion. No new Bechtel units entered service in this period.

Table 4.2 repeats the slippage calculations of Table 3.2, both for the continuing (1976 to 1978) slippage of the units in Table 3.2 which were still not finished in 1978, and for the total slippage to 1978 of some 19 additional units which were not included in Table 3.2 because they had no new cost or schedule estimates by the end of 1976. On the average, the cost estimate for this group of units was increasing at 16.8% annually, and they were making only 39.7% of the scheduled progress towards completion: for each year that went by, they were getting less than 5 months closer to completion. If Pilgrim 2 progressed as slowly, and if its cost escalated as rapidly, as the average of this group, then it would require 17.9 more years (to 3/96) and would cost $30 billion to complete. Bechtel plants did some what better in this period: their cost estimates increased only 12% annually and their progress rate was 50%, indicating that their COD estimates were slipping only six months per year. If Pilgrim had actually received its construction permit by early 1976, and if it had repeated the experience of these 17 Bechtel units, it would only have cost $9.4 billion when it was completed in July 1992.

Table 4.3 compares the schedule projection for Pilgrim 2 to that of other units which did not yet hold construction permits in December 1978. The shrinkage in the number of units awaiting CP's since 1976 (Table 3.3) is clearly evident. The average of the 22 plants still scheduled for completion had an estimated COD of 8/88. First units were scheduled for somewhat earlier operation, with an average 7/87 COD. Thus, the schedule estimate for Pilgrim 2 was considerably more optimistic than average, but was not out of line with a few of the other estimates, and extrapolation of historical experience to Pilgrim 2 would have been only mildly optimistic.

Q: Did observers within the nuclear industry continue to report the problems you described in previous sections?

A: Yes. Again, the A/E's identified the past pattern, although they were loath to admit that their current efforts were subject to the same problems:

> Increases in power plant costs between estimating dates of 1969 and 1978 can be attributed to inflation and to statutory and regulatory requirements. About 22 percent of the increase is due to inflation and 78 percent due [sic] to statutory and regulatory changes.
>
> Over a twelve-year period in operating dates (1976-1988) estimated power plant investment requirements have increased by a factor of approximately seven. . .
>
> [These estimates] do not include any sums specifically intended to cover future, and presently unknown, additional safety or environmental requirements. However, in view of our past experience with the continual ratcheting of environmental and safety requirements and economic and political uncertainties, they do include contingency items of about . . . 17 percent for a nuclear plant. (Bennett and Kettler 1978)

> . . . Harold E. Vann, vice president-power, United Engineers & Constructors [said] "The 10-year schedule for nuclear plants is not compatible with the time period betweeen investment made and revenues received . . . The high investment cost also complicated this problem. It is commonly known in the investment community that announcement of expansion plans adversely affects the price of a utility's equity. (**Nuclear Industry** 1977a)
>
> Ebasco Services Incorporated is projecting that "there will be few domestic nuclear power plants announced by utilities in 1977. This opinion is based on the conditional nature of new construction permits, and [fuel cycle concerns.]" (ibid.)
>
> Bechtel said "it anticipates regulatory agencies will continue to change licensing criteria and it therefore seems unlikely that nuclear units will become standardized." (ibid.)
>
> Ebasco especially wanted to note its concern with the indicated trend of review and backfitting of operating plants to meet current guides. "We believe," it said, "that a broad policy of requiring retrofit without a demonstrated need, or benefit to the public commensurate with cost, is detrimental to the public interest at a time when public concern for energy independence should be answered with an accelerated commitment to nuclear power." (ibid.)
>
> Brown & Root's senior vice president, M. M. Finch, sees prospects for shortening [nuclear] power plant construction schedules as "unlikely." Expecting costs and scheduling to escalate in the future as they have in the past, Finch believes that this will change only with the recognition of the absolute necessity of the nuclear option. "If we are to have a viable nuclear industry," Finch warns, " there must be an absolute commitment to resolving the many significant items that have been plaguing the nuclear industry for so long." (Meanwhile, just <u>maintaining</u> construction schedules is a more realistic hope, Finch says, because the "barriers" to shortening schedules are formidable.) (Jacobson 1977; parentheses and emphasis in original)

From Burns and Roe came the observations that:

It is clear that nuclear power is in deep trouble. . . In the first eight months of 1979 alone, 67 nuclear plants were either deferred or cancelled, and the Nuclear Regulatory Commission has imposed a temporary moratorium on the licensing of nuclear power plants. . .

The nuclear plant cost [projection] has a wider range [than the coal plant estimate] because it is felt that there is greater uncertainty in estimating future costs of nuclear plants than there is with coal plants.

These cost projections . . . are based on . . . current known regulatory requirements. It is important to keep this in mind because actual . . . regulatory requirements experienced over the life of a project are likely to be different. . .

Today's estimates for the 1992 plants are more than 10 times as large as the estimates that were made in 1969 for nuclear units scheduled to start up in 1976. Although the projected costs of nuclear and coal costs are very high, the nation's options are limited, at least through the end of the century.

This study of available cost data for U.S. power plants has indicated that costs are likely to increase significantly for all types of plants over the next several years, at least. The base cost numbers have been established, and major reasons for cost increase have been identified. From this point, it can be said that the final actual costs of nuclear plants now underway are expected to be 3 to 4 times as high as the original estimates. . .

In 1974 and 1975, . . . less than 3 million engineering man-hours were required for a single unit plant. Today, the figure is about 4.5 million man-hours for the single unit plant. The earlier studies showed 11-12 craft man-hours per kilowatt of capacity in the single unit plant; today, the craft man-hours exceed 15 per kilowatt. . .

As a final point, it was noted during the course of this detailed cost study that the available actual cost data often do not reflect the ultimate total capital costs. This is true to the extent that costs are not updated to include subsequent expenditures for compliance with new regulations. (Budwani 1980)

F. C. Olds commented extensively on the growth in safety regulation:

> [H]ow safe is safe enough [for nuclear plants]? This question has been asked but never answered in terms of a limit to be placed on NRC requirements. Consequently, as long as a reviewer can conceive of a way to reduce pollution or risk, he is likely to require it. . .
>
> [Adding 1975 and 1976 to the regulatory picture] can best be described as ratcheting gone wild. During 1976, an average of three new requirements having significant impact on NSSS design were issued by the NRC every month. Obviously this situation has a severe adverse impact; imagine the picture by the end of the 12-year period now needed to get a plant on line. . .
>
> Where all this ratcheting will end is anybody's guess. The primary cause is the open-ended [Atomic Energy] Act that more or less directs reviewers to ratchet, and creates an ungovernable situation. . .
>
> Replication . . . met with some success until a regulatory ratchet was applied to the process. . . [A]n expensive change was required of [a duplicate] plant. In turn, this was whipsawed back on the original plant, which now was under construction. (Olds 1977)

The next year, Olds (1978) reached his most graphic in describing the problems of the industry. The lead-in included the observations that "starting in in 1974, announcements of setbacks in nuclear plant schedules began in earnest. Most of the apparent delays, however, reflected the fact that many plants at that time carried unrealistic completion dates and had no chance of meeting them.

This has continued throughout 1976-77, but with an additional feature. Real lead time has continued to increase at about one year per year; hence, the published schedules still are running behind. Plant costs now are time-dominated and increase as fast as lead time", and the body of the article went on to remark:

> Table 1 shows what has happened to the schedules of the 66 nuclear units that had gone into commercial operation by the end of 1977, and gives an estimate of probable completions in 1978. From the data in this table, it will be shown that during the four years, 1974-77, lead time for these units from NSSS order to commercial operation was increasing by nearly one year per year. Subsequent tables will look at units scheduled for later years . . . [In 1970-1972] There were some hints of future trouble, but there were always the promises that the course for nuclear plants would be smoothed out and shortened. The industry could not be criticized severely for having too much optimism at that time. . .
>
> By 1973, however, hardly anyone should have hoped for lead times for new bookings as low as nine years. Beyond 1973, there were hopes for reduced times via standardization of plant designs, multiple orders for identical units, standardized licensing reviews, pre-licensed shop-fabricated units, and other good things promised by Washington. Largely, these hopes for time reductions have been thwarted thus far.

Florida Power and Light was also quite colorful in its description of the problems which resulted in the cancelation of the South Dade units:

> . . . Robert Uhrig, vice president for nuclear and general engineering, said he didn't see how any utility "that has to defend its actions to a public service commission could justify a business decision to 'go nuclear' in the present environment". . . "The nuclear licensing process has been destabilized to the point where sound

> business decisions cannot be exercised with respect to nuclear facilities. Sound business is dependent upon predictable time schedules and costs, and neither is present in today's era of uncertainty." (**Nuclear Industry** 1977b)

Electrical World continued its increasingly gloomy reviews:

> This year's nuclear survey . . .tends to reinforce the gloom of the "big four" manufacturers that was expressed last year in both trade journals and the popular press. . .
>
> Several dates for scheduled commercial operation of plants have been postponed - some indefinitely - and there have also been cancellations. . .
>
> FPL announced in mid-1977 that it would not commit itself to any future nuclear plants as of that time. The utility cited regulatory uncertainties at both state and federal levels as its principal reason. . .
>
> The Omaha Public Power District told **Electrical World** that its overriding reasons for canceling Ft. Calhoun 2 were (1) excessively high estimated cost per installed kw, (2) lower-than-expected load growth projected for its service area, and (3) a more than $200-million interest charge on capital before commercial operation would begin. . .
>
> The number of "indefinites" [sic] has dropped over the past year from nine to seven, with an accompanying "decrease" of almost 2,000 Mw in generating capacity. But this encouraging portent could be canceled when one realizes that the chance of all - or any - of the "indefinites" being built is slim indeed.(**Electrical World**, "1978 Nuclear Plant Survey")

Q: Did the FPC surveys continue?

A: Yes. The language of the **Steam Plant Book** summaries was becoming quite repetitive:

> Projected nuclear plant investment costs which have been trending upward since 1970 increased again in 1975. The latest updated (January 1977) average capital cost of nuclear units ordered in 1975 was

> projected to be about $766/KWe by the time the units are completed and placed in commercial operation. This increasing cost trend of nuclear units is attributable to such factors as increased design complexity, inadequate quality control in manufacturing and in field construction, shortage of skilled labor, added environmental equipment to meet newly established more stringent environmental and safety standards, and escalating costs of equipment, materials and wages. For units ordered in 1976 the comparable figure was estimated to be about $797/KWe. (1975, pages XIII - XIV; published 1/78)
>
> Projected nuclear plant investment costs which have been trending upward since 1970 increased again in 1977. The latest updated (January 1978) average capital cost of nuclear units ordered in 1977 was projected to be about $829/KWe by the time the units are completed and placed in commercial operation. This increasing cost trend of nuclear units is attributable to such factors as increased design complexity, inadequate quality control in manufacturing and in field construction, shortage of skilled labor, added environmental equipment to meet newly established more stringent environmental and safety standards, and escalating costs of equipment, materials and wages. (1977, page XIII; published 12/78)

The language of the 1976 report was identical to that in the 1975 report, which was issued after the 1976 data was available.

Q: Are you aware of any detailed assessments by nuclear utilities of the problems they faced in this period?

A: Yes. Detroit Edison has prepared a report on the construction of its Fermi 2 nuclear power plant (Detroit Edison 1983), which presents an overview of nuclear regulation in the 1970's. Chapter 10 of that report, entitled "1978: Nuclear Design Changes", includes the following observations, written in the present tense:

> For Fermi 2 and other nuclear plants in construction, numerous additional government and industry standards leading to changes in reactor design, quality assurance practices and new equipment have a drastic effect on cost. Regulations for nuclear plants grow to 784 in 1978 from 277 in 1975. As a result, the real cost to construct nuclear power plants in the United States increases by an alarming 142 percent from the end of 1971 to the end of 1978. During this time, Fermi 2's construction costs increase nearly 150 percent in real dollars. This escalation occurs even after removing inflation in the costs of standard construction inputs--labor, materials, and equipment.
>
> Nuclear design changes, in particular, are characterized by "ripple effects" that carry beyond the immediate component or system being altered. The result is that the total impact on cost is inevitably larger than the sum of the parts. Moreover, many of the changes at Fermi 2 and other nuclear plants are mandated during construction, as new safety rules emerge. This "ratcheting" of regulations during construction greatly complicates the design and construction efforts.
>
> Fermi 2, in fact, is being built in an "environment of constant change" that makes the control or even estimation of costs extremely difficult. The result is that the construction process falls prey to logistical problems that magnify the direct impacts of increased standards. Construction contracts must be let on a "cost-plus fixed-fee" basis, backfits during construction are common, and this often means construction workers cannot be efficiently deployed and labor productivity suffers. These problems would continue throughout the duration of the project.
>
> Cost-plus fixed-fee contracts become unavoidable at Fermi 2. Although some construction contracts provide for a fixed price - usually tied to an agreed upon inflation index - such arrangements are not feasible when the scope of the work is subject to continuing significant changes. . .
>
> Changes in quality-assurance regulations beginning in 1970 have a severe affect on Fermi 2's cost and schedule. It is truly a balancing act to control

> costs and, at the same time, ensure that the design is reliable, safe and meets licensing requirements. Increased engineering costs are the smallest part of the impact resulting from compliance with the new quality-assurance regulations.
>
> As quality-assurance standards become more complex and the growth of regulations causes design changes in the mid-1970's, the impact on Fermi 2 is far-reaching, especially when construction is in progress. Previously purchased material must be replaced, usually at higher prices. Already completed construction work is torn down and reassembled according to new specifications. Valuable time is lost while construction crews wait for new equipment and materials to be delivered.
>
> Another result of design and quality-assurance changes is the negative impact they sometimes have on labor productivity. Some construction workers lose motivation to do good work if they become frustrated by design changes that cause constant retrofitting of already completed tasks.

The Atomic Industrial Forum (AIF) published a study (Perl 1978) by National Economic Research Associates (NERA) which found, among other things, that nuclear plant costs were increasing at an annual rate of 10% above general inflation. NERA concluded that nuclear power would be cheaper than coal, but only after assuming that the escalation in nuclear costs would stop abruptly. The study recognized that its "estimates are highly uncertain and hinge upon a number of speculative assumptions" and invited its readers to "substitute your jüdgement for" NERA's. Indeed, NERA acknowledged that "If the historic pattern continues and if the cost of coal facilities escalates at a lower rate than nuclear, eventually nuclear will become an uneconomic technology." Many of the results of the NERA study indicated that the nuclear industry was in grave difficulty in 1978, and could only be saved by dramatic improvements compared to past performance.

Q: Did the interest in organized conservation programs as alternatives to conventional energy sources produce tangible results in this time period?

A: Some significant programs started up in this period. Examples would include the Federal appliance efficiency standards, higher thermal integrity standards in new building codes, and California's efforts in governmental and utility-sponsored conservation programs.

Q: How did regulatory scrutiny affect nuclear power?

A: State regulators started to inquire as to the need for the construction programs, whose protection the utilities frequently presented as a major reason for rate relief. This scrutiny took many forms. In California, for example, the Sundesert nuclear plant was subjected to lengthy state hearings which led to its rejection and cancelation in 1978. The Wisconsin PSC undertook similar reviews of the need for planned facilities in that state, and concluded that further nuclear investments were inappropriate, which finally resulted in the cancelation of three nuclear units in that state.[17] More careful regulatory oversight was clearly emerging by 1978.

Q: Did Pilgrim experience many of the problems which plagued the industry in this period?

A: Yes. As shown in Table 1.1, the Pilgrim cost estimate increased again by 35.7% in 1978 (or 21.3% annually between the 10/76 and 5/78 estimates), and the anticipated construction permit had not materialized. Meanwhile, the in-service date for the unit had slipped by 15 months in a period of 19 months, and the scheduled COD remained over 7 years in the future. As demonstrated by Figures 1.2 and 1.3, the load forecasts for the lead participant and for the region were falling rapidly, slightly eroding the economic value of the plant, and more significantly eroding the financial strength of the owners and potential owners.

Q: What special problems afflicted the Pilgrim 2 project in this period?

A: Other than the failure to receive a construction permit, the major immediate difficulty concerned EECo's financial

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17. The chairman of the Wisconsin commission at that time, Charles Cicchetti, later testified on cost recovery mechanisms in MDPU 906 on behalf of Boston Edison. Prof. Cicchetti testified in some detail that he was aware, and utility managers should have been aware, in the early to mid-70's of several of the problems regarding nuclear plant cost overruns and schedule slippage, and utility financial stress discussed above.

situation, which was so severe that even the NRC staff (which had even supported PSNH's financial qualifications to build Seabrook) expressed doubts about BECo's ability to finance its Pilgrim 2 share.

Q: Was BECo's difficulty in financing its nuclear construction program in this period unique?

A: No, it was not even unusual. Delays in the in-service dates of nuclear plants, suspension of construction, and even cancelations, were often attributed to the financial condition of the constructing utility. Close to home, Northeast Utilities (NU) decided in 1977 to stretch out construction of Millstone 3, moving the scheduled in-service date back from 1982 to 1986, due to the unit's strain on NU's finances. As I will show in Section 7, BECo's nuclear commitment in Pilgrim 2 was much larger, in proportion to the size of the utility, than NU's nuclear commitment (primarily to Millstone 3) and comparable to UI's unacceptable commitment (mostly to Seabrook). Therefore, it should hardly have suprised any of the Pilgrim owners that BECo's ability to finance Pilgrim was marginal at best. As I will discuss in the next section, BECo was well aware of the problems it would face.

Q: Was CMP aware of BECo's difficulties in this period?

A: Yes. The notes of Mr. Monty from a meeting of the Pilgrim 2

Joint Owners on September 8, 1978 read in part:

> "A financial presentation was made by Tyrell of B. E. Based on their latest studies, by 1985 only 35% of their financing requirements will be generated internally and 79% of their earnings will be AFC. These conditions are intolerable. . .
>
> Galligan stated that the project was not viable without CWIP or some other alternative not yet known. With a cutback the project can go forward until July 1979. . .
>
> Staszesky stressed they were not talking of delay. I'm not sure of their political problems, but delay is inevitable under any of the cutback alternatives. Galligan's position that they must cancel, if that is necessary, by July 1979 if they are to maintain a viable corporation sounds odd to me also. B. E. will be into the project for over $100,000,000 and they are choosing among alternatives which make $10 million dollar differences. They appear to be in a situation where Galligan is still listening to his engineers while his financial people are telling him that the plant is impossible as things are going. Corporately, they appear to be coming to the same realization that we did about four years ago when we were agonizing over Sears Island. . .
>
> My guess is that they will press for CWIP and eventually delay the plant. With their earnings picture and the size of their investment to date it is hard to see how they can afford to cancel. The situation has all the makings of another very expensive nuclear plant." (Staff Exh. 57, PUC 82-266)

5 - MID-1980: THREE MILE ISLAND AND REGULATORY REVIEW

Q: What is the significance of the June 1980 date for CMP's participation in the Pilgrim project?

A: This date was more than a year after the Three Mile Island accident. The participants by then had sufficient information to allow them to conclude with virtual certainty that the problems of nuclear power, and particularly those of units still awaiting construction permits, would not soon improve. Also, BECo's cost estimates were revised twice in the spring of 1980, raising the cost estimate for Pilgrim by 85% over the 5/78 estimate (an annual rate of increase of over 36%), and acknowledging almost five years of delay in the COD over the last two years.

Q: What important developments occurred for Pilgrim 2 and CMP's participation, in the period from late 1978 to the summer of 1980?

A: Five groups of events took place. First, BECo received some important warnings (both external and internal) regarding its nuclear construction program, including information about the cost of Pilgrim 2, its schedule, and its financial feasibility. Second, CMP expressed grave doubts about the economics and feasibility of new nuclear construction.

Third, the attempts by PSNH, NU, and UI to reduce their commitment to Seabrook were not wholly successful, due to saturation of the market for nuclear plant shares among New England utilities, with a situation of scarcity changing to a situation of surplus. PSNH was also unable to sell its Pilgrim 2 shares. Fourth, the TMI accident further accelerated the ongoing changes in nuclear regulation. Fifth, the general deterioration in the economics of nuclear power continued, accompanied by a virtual torrent of plant cancelations.

Q: What warning signals did BECo receive in this period?

A: The external warnings came primarily in two reviews of the Pilgrim 2 construction program, MDPU 19494 (part of which was a joint hearing with MEFSC 78-12) and the hearings in NRC 50-471, which took place in the summer of 1979.[18] In the first phase of MDPU 19494, a number of witnesses, myself included, pointed out errors, overstatements, inconsistencies, and unsupported assumptions which biased the BECo load forecast upward. As a result, the MEFSC, which has a statutory responsibility to review utility forecasts, took the very unusual step of rejecting the BECo forecast filed as part of MDPU 19494. As Figure 1.3 demonstrates, BECo's

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18. CMP was also a party to MDPU 19494, and thus should have been familiar with the issues and problems raised in this case. Unfortunately, Mr. Kelly indicated that CMP was not following the case (U3238 Tr. 1082 - 1083).

forecasts have proven to be consistently overstated.

In the second phase of MDPU 19494, I produced a similar analysis of the (then new) NEPOOL forecasting methodology, and (with Susan Geller) a review of the forecasts of all the major NEPOOL participants. Our testimony discussed numerous errors in each of these forecasts, which in most cases were at least as poorly documented and as over-optimistic as BECo's forecast. Figure 1.3 demonstrates that our overall criticism was well taken, and that the NEPOOL forecast has indeed declined continually both before and since our review.[19]

MDPU 19494, Phase 2, also reviewed the cost estimate for Pilgrim 2. Among the points brought to BECo's attention were the cost overrun of more than 100% for Pilgrim 1, and the fact that contingency figures had been manipulated to prevent

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19. Our testimony also reviewed the CMP forecast. In the Sears Island case (U3238), the Staff (through its consultants, Arthur D. Little) and the Office of Energy Resources (through its Staff and its consultant, Dr. Tietenberg) presented alternative forecasts that were substantially lower than that of CMP. Arthur D. Little also testified that the NEPOOL forecast substantially overestimated growth. The Commission's decision in U3238 concluded that all forecasts presented overestimated future demand. For analysis purposes, the Commission utilized a modified Office of Energy Resources forecast. The Commission's findings on the NEPOOL forecast were more limited, but it did state that Arthur D. Little's analysis raised serious doubt regarding the reliability of the NEPOOL forecast.

new A/E estimates of base costs from increasing the total reported cost of Pilgrim 2. Before he realized that his company had engaged in the latter practice, Mr. Staszesky testified that he "resented the implication" that BECo would manipulate contingency in that way.[20]

Q: Were these warnings repeated in NRC 50-471?

A: Yes. Again, Ms. Geller and I laid out the fallacies in the BECo and NEPOOL forecasts. In addition, I projected out the cost of Pilgrim 2 based upon the regression analysis by Mooz (1978) and based upon the record of BECo and Bechtel in projecting the cost of Pilgrim 1. Depending on the method used, and even without any schedule slippage, the historical trends indicated that Pilgrim 2 was likely to be completed for $3.40 billion to $4.93 billion, rather than the $1.895 billion BECo was projecting at the time.

Q: Did BECo receive any new warnings in NRC 50-471?

A: Yes. Paul Levy, who had recently been (and who is again) Chairman of the MDPU, testified on the financial difficulties

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20. The most favorable interpretation which can be placed on this episode is that a supposedly new cost estimate was simply a realignment of an old estimate, and that the total cost therefore reflected no new information. At worst, BECo was arbitrarily and unjustifiably reducing its contingency allowance as new costs were identified, to prevent the total cost estimate from reaching $1.9 billion. In any case, it is clear that BECo did not take seriously the job of accurately and consistently projecting a contingency allowance.

BECo would face if it attempted to construct Pilgrim 2. He pointed out that internal BECo studies indicated that construction of the plant would be difficult or impossible, given BECo's current and likely future financial condition, and concluded that the exceptional rate relief that BECo would require was unlikely.

Q: These were all external warnings to BECO. What were the internal warnings which you mentioned?

A: Internal studies of the feasibility of financing Pilgrim 2 actually informed BECo management that this undertaking would be extremely difficult well before the regulatory reviews of the construction program discussed above. In July of 1978, two studies were produced by BECo management and presented to the Board of Directors. One of these documents (BECo 1978a) concluded that

> ...management can no longer recommend that we continue to license and construct Pilgrim II with a 59 percent ownership share.
>
> The major constraint is financial and controls all other alternatives.
>
> One constraint which makes it impossible to continue with 59% ownership is the lack of CWIP in rate base in Massachusetts.
>
> [W]e tested a sell-down position . . . and found it unworkable without CWIP, and also tested a 30% ownership position . . . We believe the 30% ownership level is marginally acceptable as a financial risk without CWIP, and propose that this become the sell-down minimum level for continuing with this alternative.

The second study (BECo 1978b) included the following observations:

> [AFUDC] will represent 36% of earnings per share in 1979 and increase annually to the point where it will represent 80% of earnings per share in 1982, 92% in 1983, 93% in 1984, and 95% in 1985.
>
> ...$961 million of new external funds must be raised to complete [Pilgrim 2].
>
> [I]t does not appear that it would be easy to attract institutional buyers [of BECo stock] in the future.
>
> [T]he quality of the company's common stock would be low [due to the high AFUDC component.]
>
> [T]he company would need a substantial rate increase at the time the unit goes into operation...
>
> [To finance Pilgrim 2], the company must issue $770 million of additional first mortgage bonds or other long term debt. . . . the company is going into this project with a triple B/Baa bond rating.
>
> If during the construction period the company were to suffer adverse financial experience and have its ratings lowered to . . . double B or Ba, the company would in effect be unable to sell additional debt securities, or if it did so, such securities could only be sold at a substantial increase in the cost of money.
>
> [BECo] would need a substantial rate increase at the very moment the unit goes into operation. The rate increase associated with base revenues is estimated to be $270 million, and it will be necessary to argue the use of six million barrels of oil annually at a net reduction to the consumer in fuel adjustment revenues of $184 million, or a net increase to the consumer of $86 million. . . . The $270 million rate increase is predicated on the capital and fuel costs of the nuclear plant. Any additional capital expenditures associated with the plant will of necessity increase the required annual rate increases. . . . The savings in the fuel adjustment revenues are predicated on a cost of fuel of $32 per barrel. . . . [E]very change of one dollar in the cost of a barrel of fuel from

> that $32 figure would increase or decrease the savings in fuel clause revenues by $6 million.
>
> [T]here are a number of independent parties who have the ability to interfere with the construction of a nuclear plant and drastically affect its cost, construction time requirement and the scheduled operation date. . . Of more importance is the fact that no single party, public or private, has the ability to individually and successfully control either the timely construction, the ultimate cost, or the scheduled operation date of the unit.
>
> Building [Pilgrim 2] for peak with relatively low annual load factors [due to the excess capacity caused by Pilgrim 2] at a cost of $1,700 per kw compared to $227 per kw for Mystic 7 and $353 per kw for Pilgrim I will result in the company's continuing its relatively high rates.
>
> Because of the high cost of construction and the related necessary rate increase that must follow, the issue of a relatively low capacity factor after Pilgrim II goes into service could contribute to a delay in adding the unit to rate base. The financial implications of such a delay would obviously be disasterous.
>
> In summary, the increased cost of construction, the decreased sales forecast, the current triple B rating, the adverse regulatory and judicial climate and possible action on the part of intervenors have substantially increased the financial risks resulting from the construction on a nuclear plant. . .

These observations describe a grim future for BECo, had it succeeded in commencing construction of Pilgrim 2. The financial requirements of constructing the plant would virtually eliminate cash earnings, at a time when BECo was already having difficulty in raising capital.[21] The authors

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21. I do not mean to suggest that BECo was facing a "locked box" when it approached the capital markets, only that BECo's financing options were restricted, and the rates it paid were

of these analyses forsaw the situation in which PSNH has placed itself, and recommended that BECo avoid that fate, if at all possible. Since these analyses were prepared in 1978, BECo should have been able to foresee then that Pilgrim 2 was unlikely to ever be completed.

Q: Were the assumptions under which these projections were made reasonable?

A: There were three assumptions which were clearly not reasonable. First, the construction cost used in these studies is very close to BECo's official estimate at the time, $1895 million.[22] The authors anticipated that some cost overrun from this estimate was likely, and in fact it was essentially inevitable; this would likely trigger the "adverse financial experience" which could close off BECo's current bond market. Second, the schedule for Pilgrim 2 was quite aggressive, and was unlikely to be met; any delay in the COD would further increase the AFUDC burden on the company. Third, while an immediate rate increase at COD would be vital, it was also quite unlikely.

Since AFUDC would represent almost all of the company's earnings, a rate increase coinciding with the unit's

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increased, relative to its experience early in the Pilgrim 2 project.

22. $1700/kw is equivalent to $1955 million for the plant.

in-service date (when AFUDC would cease to accrue) would be essential. Unfortunately for BECo, the MDPU, which regulates over 90% of BECo's sales, then used an average test-year rate base,[23] so only half of the cost of Pilgrim 2 could be expected to enter the rate base in the first case in which it was included. Further, the MDPU used (and still uses) an historic test year, which would prevent BECo from filing a rate case for a few months after commercial operation, while test year data was assembled. Including the six month suspension period allowed by Massachusetts law, and fully used by the MDPU in virtually all rate cases, BECo would have to expect a delay of nine months to a year between the Pilgrim 2 COD and the reflection of even half of the plant's cost in rates. This could easily result in a year of zero earnings, even if nothing else went wrong at the same time. The fact that Pilgrim 2 would tend to increase rates, and keep them high, would not make it any easier to obtain exceptionally favorable treatment from the MDPU.

Financial analysts would presumably be aware of these facts, and the ratings and pricing of BECo's securities would reflect the financial and regulatory risks which BECo was assuming. This would tend to depress the price of BECo's stock, making equity financing less attractive, while

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23. Of course, exceptions could be made.

increasing BECo's interest costs, and further increasing the AFUDC burden. If this spiral had continued long enough, BECo might well have joined PSNH and LILCo on the list of utilities foreclosed from conventional capital markets.

Q: What was BECo's rationale for continuing despite these problems?

A: The only financial justification which BECo has ever offered (at least to my knowledge) for continuing Pilgrim 2 construction past 1978 was that it had arranged for a large line of bank credit. This arrangement would provide an alternative to long-term financing for BECo, but it would not substantially reduce the share of its earnings which would be AFUDC, nor would it guarantee continued access to the capital markets if the cost of the plant rose further. Mr. Webb expressed some skepticism about the viability of BECo's financing plan (U 3238 Tr. 1157 - 1159).

Q: How did BECo's projected financial condition compare to conditions CMP considered acceptable for its own planning?

A: Mr. Webb has testified that a utility would have difficulty in financing if 60% of earnings were AFUDC (U3238, Tr. 1148), and would definitely be stressed at the 80% level (U3238, Tr. 1151). It therefore seems likely that, had CMP reviewed BECo's financial condition, it would have concluded that BECo's financial stress would become unbearable, even at

BECo's cost estimate. Since CMP clearly considered nuclear plant cost estimates to be subject to at least moderate increases, it might well have concluded that Pilgrim 2 was financially infeasible.

Q: What significant developments affected the nuclear industry nationally in this period?

A: There were several important events or trends:

1. The cost estimates continued to increase, and the schedules continued to slip, for those units which were not canceled.

2. Nuclear unit cancelations, which first exceeded new orders in 1975, were continuing at unprecedented rates in the late 1970's and especially in 1980, while the last new orders occurred in 1978.

3. The accident at Three Mile Island, and other NRC actions, dashed any hope of rapid recovery in the industry, and accelerated many of the previous adverse trends.

Q: Did the cost estimates and schedule projections for nuclear plants improve between 1976 and 1980?

A: No. Table 5.1 presents summaries of the cost and schedule histories of plants which entered service between January 1979 and June 1980. This Table is comparable to Tables 2.1, 2.2, 3.1, and 4.1. The calculated summary statistics indicate a slight improvement over the previous two years (but not over the previous decade as a whole), but this is eclipsed by the fact that only two units reached commercial operation in this 18 month period. This is partially the result of new safety requirements following the TMI accident, but the trend was evident in 1978, as well, when only three units reached commercial operation. Even the fact that only the two units listed in Table 5.1 were in their startup phase, between operating license and commercial operation, when the TMI accident occurred, is evidence that the number of units nearing completion was shrinking. Considering that the apparent improvement in the ratios over the 1977-78 trough was really due entirely to an exceptional performance by Hatch 2,[24] while Arkansas 2 cost experience was as bad as average, and its schedule slippage was worse, the 1980 data indicate that the situation had not improved, and in fact had deteriorated considerably. Applying the cumulative results through 6/80 to the 6/80 estimate for Pilgrim 2 would predict a cost of $8.4 to $27.4 billion dollars, and an in-service date of 5/96, while the results for Hatch 2 and Arkansas 2

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24. Once a first unit is completed, there is some tendency for a substantially identical second unit at the same site to experience unusually small cost and schedule slippage. This tendency is observed when the second unit lags the first by more than two years. Hatch 2 is one good example of this effect; St. Lucie 2 is another celebrated case. I am not sure that CMP could have been expected to see this pattern; if it did, the Hatch 2 experience would have to be discounted as a model for Pilgrim 2.

alone would project a cost of $9.6 - $27.4 billion and an in-service date of 1/97. Extrapolating the cumulative Bechtel experience through 1980 would have produced estimates of $7.8 to $23.6 billion, and a 1/95 COD.

Table 5.2 updates the slippage analysis from Table 4.2. The cost and schedules as of both 12/78 and 6/80 are listed, along with the percentage increase in the cost estimate, and the months of slippage in the in-service date. The schedule for the average of these 77 units had slipped by almost as much as the time between the estimates, producing essentially no progress, and the average cost estimate had increased about 18% annually. Unless the schedule performance improved, the average plant would never be completed (and in fact, many of the units with negative progress in Table 5.2 have since been canceled.)

The Bechtel units in this Table did substantially better (or their big cost estimate increases were delayed past 6/80). If Pilgrim 2 were as fortunate in its schedule as the average Bechtel plant in this period, it would have entered commercial operation in 5/96, and if its cost only increased by 11% annually, it still would have cost $18.6 billion; the later its completion, the worse this result was likely to be. As we have seen, even BECo's ability to complete the unit on its schedule and at its cost projection was highly questionable; on either a financial or an economic basis, it was only reasonable to expect that a continuation of recent trends would have been fatal to Pilgrim 2, and possibly to the utility as well.

Table 5.3 compares the schedule projection for Pilgrim 2 to that of other units which were on order but did not have construction permits in December 1980 (since I have not been able to find the same data tabulated for 6/80). The striking points evident in this Table are that very few plants without permits were still on the order books, and only two of them presumed specific completion dates. Thus, the utility industry had largely accepted the impossibility (or undesirability) of starting new nuclear construction projects.

Q: Please describe the history of cancelations of ordered reactors within the US nuclear industry.

A: Figure 5.1 portrays the annual and cumulative cancelations, through 1983. Figure 5.2 presents the number of new orders, the number of cancelations, and the net change in orders in the same period. While some of the canceled units had construction permits, units awaiting permits were more heavily hit by the wave of cancelations. Table 5.4 lists the plants canceled in 1977-80, with the construction status of each.

Q: How did NRC regulation change in this period?

A: Even before the Three Mile Island (TMI) accident, the NRC was demonstrating a more cautious attitude towards potential safety problems. Where problems and solutions were identifiable, the NRC was increasingly reluctant to allow plants to operate without the solutions.[25] The best example of this trend was the order which shut down several units in 1978, after an error was found in a Stone and Webster seismic design program. While this action by the NRC was widely criticized within the industry as "over-reaction," that criticism was largely ended by the TMI accident.

The accident at TMI further increased the NRC's reluctance to take unnecessary risks with potential safety problems at reactors under construction or in operation. It was widely perceived that another TMI-scale accident might well be a fatal blow to commercial nuclear power development, and almost any cost imposed on individual plants was preferable to collapse of the industry.

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25. The NRC was less willing to address the difficult, "generic" issues which might bring into question the viability of the industry.

Another effect of the TMI was that NRC staff attention was largely diverted to the agency's most immediate problems, and away from construction permit issuance. The first priority was to address the issues raised by the accident for existing reactors, followed by consideration of the problems of units nearing completion, and then those of units well under construction and likely to be completed. Construction permit applications had the lowest of priorities, and it was not clear when, if at all, the NRC staff would again be willing or able to devote substantial resources to the permit hearings. Not only would the NRC be likely to examine new units much more closely before issuing construction permits and operating licenses, but it would be conducting the examinations (especially for construction permits) with reduced staff commitments.

Q: Did the utility industry literature continue to reflect the problems of the industry?

A: Yes. From **Electrical World**'s 1979 Nuclear Plant Survey comes these observations:

> If you were disturbed by the statistics contained in last year's nuclear-plant survey, the 1979 roundup won't help to settle your stomach. Unit cancellations, delays, and postponements are on the rise, while the total number of reactor commitments, through 1995, has dropped alarmingly.
>
> Another very disturbing element is the large number of postponements and delays in commercial operation, ranging from one year to as long as six years, with a concomitant increase - from seven to eleven - in the number of units now in the

> "indefinite" column. Just as discouraging is a new listing: two units in the "work suspended" designation.
>
> Although we usually endeavor to be upbeat and optimistic in seeking the oft-elusive silver lining in a cloudy report, this time around offers us an unprecedented challenge.

The 1980 Survey, headlined "No reactors sold; More Cancellations", was more terse:

> Since last year's survey, the commercial operation dates of some 80 units have been postponed, from one year to indefinitely, and nuclear commitments are down from last year's 195 units . . . to 193 units . . .

The **Steam Plant Book** continued its review of the state of the industry in the 1978 edition, which was published in December 1980:

> Projected nuclear plant investment costs which have been trending upward since 1970 increased again in 1978. The latest average capital cost of nuclear units ordered in 1978 was projected to be about $920/kWe (1978 dollars) by the time the units are completed and placed in commercial operation. An insufficient number of units were ordered in 1978 to provide a trend indicative for that specific year. The cost per kW of installed capacity ranged from $815/kW to $1070/kW in 1978 dollars. The overall increasing cost trend of nuclear units is attributable to such factors as increased design complexity, inadequate quality control in manufacturing and in field construction, shortage of skilled labor, added environmental equipment to meet newly established, more stringent environmental and safety standards, and escalating costs of equipment, materials and wages. (page xv)

Q: Was CMP aware of the problems of Pilgrim 2, BECo, and the industry in this time period?

A: CMP was certainly aware of industry problems, including the financial problems at Millstone 3, the effects of Three Mile Island on regulatory and investor confidence in nuclear investments, the upward trend in cost estimates, the continuing slippage in schedules, and the diffficulty in licensing new plants. CMP was also aware that BECo and Pilgrim 2 were in trouble.

On the subject of the reliability of BECo's schedule, Mr. Kelly testified in May 1979 that "the plant is now scheduled for 1985 in December. I question that highly -- they can make December 85 and it doesn't appear to us to be prudent management to invest in Pilgrim 2" (U3238 Tr. 183), and in June 1979 that "And now it's scheduled for December 1985, and I'll tell you frankly there's no way they can build it in 1985. It's going to slip but they just haven't faced that issue yet." (U3238 Tr. 1082) It is not clear why CMP thought that it was imprudent to invest further in Pilgrim 2, but that it was not necessary to act to limit CMP's exposure to further Pilgrim investments without the immediate prospect of a CP. Specifically referring to Seabrook, but discussing nuclear issues in general, Mr. Kelly observed that

> There is a certain amount of risk involved in the nuclear capacity and I believe the last two or three months have borne that out very clearly. . . [Seabrook would be cheaper in terms of KW cost than the anticipated cost of Sears Island] [u]nder the current cost that they estimate, assuming they're accurate . . . Not knowing what's going to happen out of the NRC after the latest events, there are some people . . . that say it will be

> more expensive than coal, but I don't know. (ibid, page 184).

This is, of course, the fundamental problem with nuclear power: the plants are generally economical at their projected costs, but the projections have little chance of becoming reality. Furthermore, Mr. Kelly did not expect the uncertainties and problems surrounding nuclear power development to be resolved soon:

> Q: Okay. So right now you're generally pretty lukewarm to any nuclear. Is that right?
>
> A: That is correct. That's exactly correct.
>
> Q: But that could change momentarily, say within weeks?
>
> A: No, sir. I doubt if it'll change within weeks. I suspect it'll take years before they get straightened out. With Three Mile Island it'll probably take a year --

His rebuttal testimony discussed these issues further:

> Q: Mr. Kelly, are you aware of the original and current schedules for the Seabrook, Pilgrim, Millstone and Montague nuclear plants which are suggested in the ADL optimistic nuclear options?
>
> A: Yes, I am. The original in-service dates for Seabrook 1 and 2 was 1979 and 1981 and the current dates are 1983 and 1985. The original in-service date for Pilgrim 2 was 1978 and the current dates is 1985. The original in-service date for Millstone 3 was 1979 and the present date is 1986. The original in-service dates for Montague 1 and 2 were 1981 and 1983 and are now some time in the early 1990's. This constitutes a four year delay for Seabrook; a seven year delay for Pilgrim 2; a seven year delay for Millstone 3 and an estimated ten year delay for the Montague Station.
>
> Q: What have been the primary causes of these delays?

A: Nuclear plant delays in New England have in general been based on a decline in load growth, financial problems, and regulatory and licensing delays. Whiles there is some reason to believe that the load growth rates have stabilized, there is little, in my opinion, to justify the belief that financial problems or licensing and regulatory delays are going to be significantly reduced in the short term especially in regard to nuclear plants. Mr. Monty has more to say on this point.

Q: Do you believe Mr. Heuchling's assumed nuclear delays are reasonable?

A: Mr. Heuchling's assumed nuclear delays are consistent with the past history of delay and from that point of view they are not unreasonable. However, Mr. Heuchling's major theme is that nuclear delays are controlled primarily by reduced load growth in New England. While Mr. Heuchling's testimony is unclear on this point he may also be suggesting that with higher load growth in New England more nuclear plants could be brought on line. If this is an underlying assumption by Mr. Heuchling, he would necessarily be ignoring the huge impact regulatory and licensing delays have had on nuclear plants in new England and nation-wide. With the Three Mile Island incident fresh in the mind of the public and government and Central Maine's own experience with Maine Yankee, I see little reason to assume that the impact of regulatory delays will be removed or reduced with regard to nuclear power. My primary concern is with the situation where load growth is higher than Mr. Talbot has assumed for New England and Maine and that nuclear plants will not be able to be built on a schedule to meet that load growth because of financial and regulatory problems.

Indeed, Mr. Monty did have more to say on the subject:

> . . . I would consider the Company's . . . probability of getting 459 megawatts from a 1992 nuclear plant to be no greater than 25%. . . I base this judgement primarily on the current public attitude toward nuclear power prevailing since the Three Mile Island incident and the construction delays and regulatory difficulities encountered in the construction of nuclear plants even prior to the Three Mile Island incident. . . [B]ased on these same considerations, I view the probability that nuclear plant construction will proceed on

> schedule in New England to be no greater than 50% . . . (Rebuttal, page 13)

Mr. Monty also offered his opinions that "indefinite postponement of nuclear construction in New England", "an extraordinary escalation of nuclear costs", and "a failure of the regulatory process such that power plant construction in New England falls behind the actual load growth", all

> have a high probability of occurrence. First, the postponement of nuclar power plant construction in New England rather than being a matter of judgement, is a matter of history. There is not a single nuclear plant proposed for New England which has not been significantly delayed. The Sears Island Nuclear Plant was cancelled because of regulatory requirements; the two Montague units have been indefinitely postponed because the Massachusetts Energy Facilities Siting Council has refused to hold the required siting hearings. The two Charlestown units do not have a site. As a result of court action the constructing utility has been unable to buy the Charlestown site from the General Services Administration. The Pilgrim No. 2 unit still does not have a construction permit although the project started eight years ago and has been almost continuously in the courts and before regulatory bodies for the entire period. The Nuclear Regulatory Commission recently announced a moratorium on new permits and there are currently several bills before Congress calling for a moratorium on nuclear power plant construction. The Millstone No. 3 plant is currently being constructed on a delayed schedule because of the inability of the principal owner to finance a normal construction schedule. This plant which was originally scheduled for completion in 1979 is now scheduled to be finished in 1986. The two Seabrook units are currently being built following two halts to plant construction caused by controversies over the cooling water systems and the appropriateness of the plant site. Most recently the plant has been rescued from a third construction halt by the purchase of part of the ownership interest of Public Service Company of New Hampshire by utilities in the other New England states. I have also included Exhibit Monty-6 which shows nuclear plant deferrals and cancellations in 1977 and 1978.

In 1977 there were six reactors cancelled, totalling 6,384 MW and in 1978 there were twelve reactors cancelled, totalling 12,433 MW. This data and exhibit were taken from the Atomic Industrial Forum, Inc. publication INFO dated December 31, 1978. All in all, the construction outlook for all nuclear power plants is highly questionable at the present time.

Second, nuclear power plant costs have already undergone an extraordinary escalation. A 800 megawatt nuclear plant such as Maine Yankee which was completed in 1972 at a cost of less than $300 a kilowatt. A 1200 megawatt plant scheduled for completion in 1987 will probably cost about $1700 a kilowatt. This increase represents almost 500% cost escalation in 15 years, an escalation appreciably higher than expected for the cost of living index. Much, if not most of the increase has resulted from added requirements imposed by the Nuclear Regulatory Commission. In light of the Three Mile Island incident is certainly reasonable to assume the Nuclear Regulatory Commission requirements and the attendant added costs will increase the extraordinary escalation of nuclear costs . . .

Finally, the failure of the regulatory process in allowing nuclear plant construction to progress on schedule is a fully demonstrated fact of history. Not a single New England nuclear plant has been built on schedule since Maine Yankee was completed in 1972. Every nuclear plant currently in process in New England has been delayed in some manner by the regulatory process as I have already discussed. To assume that substantial further delay will not be encountered in my opinion is to engage in wishful thinking. In light of delays of seven to ten years or more already encountered by the plants now contemplated, there should be little confidence that future delays will not be beyond the time the plants are needed to meet actual load growth. Regulatory issues such as nuclear safety and construction work in progress are highly emotionally matters as evidenced by the public mood in the aftermath of the Three Mile Island incident and by the recent New Hampshire gubernatorial election, where "construction work in progress" was a majof campaign issue. Public pressures are very likely in the future to delay the completion of nuclear plants beyond the dates when they are required to meet actual load growth.

This was a fairly scathing denunciation of nuclear power, and certainly indicates that CMP was not blind to the problems of the technology.[26]

Mr. Webb also discussed the regulatory, financial, and risk problems of nuclear power in his rebuttal testimony:

> It is a generally accepted theory that due to the regulatory process governing rates of electric utilities, periods of extended "heavy" financing are also periods of financing deterioration. It is further generally true that weaker credits must pay more for borrowed funds. Therefore, if we assume that the "optimistic nuclear option" significantly increases CMP's external capital requirements during the 1979-1983 period, it is also reasonable to assume that CMP's overall cost of capital will tend to be greater than it otherwise would have been. . .
>
> General federal government and regulatory ambivalence toward the nuclear industry coupled with the Three Mile Island incident and the shutdown of various nuclear plants has created an attitude of uncertainty in the marketplace regarding utilities involved with nuclear generation. Clearly all of the evidence is not yet in, but it is equally clear that the marketplace is presently demanding a premium for investing in nuclear-related utilities. CMP Exhibit No. Webb-1 shows that for the period since the accident at Three Mile Island through May 21, 1979, the New York Stock Exchange Utility Index declined 3.8%, while utilities with significant current or future nuclear generation declined 6.7%. During this same

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26. Mr. Monty's list also included an endorsement of the NEPOOL forecast, indicating that his perceptions were not infallible. However, that endorsement consisted only of the claims that the NEPOOL staff was professional and that its model was large, new, and "state of the art"; compared to his specific arguments on other topics, this point was very general.

> period Central Maine Power Company stock declined 10.5%. How long this "nuclear premium" will be reflected in the marketplace is difficult to say, but the financial risks associated with nuclear generation, which have been highlighted since the Three Mile Island incident and subsequent shutdowns, are obviously weighting heavily on the minds of investors and may well indicate a slow return to the point where no "market premium" is associated with nuclear intensive companies . . .
>
> The "optimistic nuclear option" in general assumes there is no additional business of financial risk associated with basing the energy future of this state and the financial well-being of the owners of Central Maine Power Company totally on the future of nuclear generation. In my opinion, that is not reasonable, especially when we face the unanswered questions of spent fuel disposal, decommissioning costs and methodology, regulatory delay and social and political opposition. Although I believe that nuclear power is essential to the energy future of this country, I also believe that any decision regarding a major new commitment to nuclear at this point in time must consider the potential financial impact of these many risks.

Mr. Kelly claimed to be unfamiliar with BECo's financial problems (U3238, Tr. 1082-3), but since the relative stress on BECo would be much larger than that on NU, even non-financial utility officers certainly could and should have expected financial difficulties at Pilgrim, and other CMP employees (such as Mr. Monty and Mr. Webb) anticipated such problems.

6 - ECONOMIC ANALYSIS

Q: How have you investigated the economic desirability of Pilgrim 2?

A: I have compared the cost of energy from Pilgrim 2 to the cost of energy from new coal plants, using my estimates of Pilgrim cost and NEPOOL estimates (NEPLAN 1976) for most other inputs. This analysis as of 1976 is presented in Table 6.1. Since CMP has not provided its own analyses (and apparently did not perform any analyses) for most of the Pilgrim planning and construction period, this NEPOOL report provides my best estimates of CMP's assumptions at this time. In fact, CMP relied on these studies in later analyses, and these coal plant costs were similar to CMP's estimates of Sears Island costs. Many of the assumptions are highly favorable to nuclear power, including

- the absence of decommissioning charges
- the absence of capital additions
- the lack of any real escalation (that is, above the level of inflation) in nuclear O&M expenses
- the use of a very high nuclear capacity factor.

In addition, the Pilgrim cost estimate used in Table 6.1 is the average of the results for completed units in Table 3.1, rather than the more pessimistic results for the units under construction in Table 3.2. Even in Table 3.1, the myopia results, which recognize the construction stage (and expected remaining duration) of the plant, are more pessimistic than the results from the historic cost ratios, which neglect the long expected construction period for Pilgrim 2.

Tables 6.2 and 6.3 update this analysis to 1978 and 1980, respectively. NEPLAN revised its maintenance assumptions in 1979 (NEPOOL Planning Committee, 1979). Table 6.2 and 6.3 also compare the cost of Pilgrim 2 power to the cost of energy from existing oil plants, as estimated by CMP in January 1979 and February 1980, and provided in the restrospective analyses of Exhibits Webb-15, Webb-17 and Webb-18 in 82-266.[27] These tables contain the same sources of nuclear optimism as Table 6.1.

Q: Was there evidence by 1976 to suggest that these assumptions were optimistic?

A: Yes. Table 6.4 lists the annual non-fuel O&M expenses for all nuclear plants in operation for each year from 1968 to 1981. Table 6.5 provides the booked plant cost for each plant

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27. CMP has not provided comparable information for 1976.

for each year in the same period, along with the increase in the cost in nominal and constant dollars. O&M expense were clearly increasing much faster than inflation, and capital costs for existing plants were also increasing. Table 6.6 lists the capacity factor for each PWR of more than 300 MW, for each full year of operation through 1981, along with the average capacity factors for all experience, experience in years 1 to 4 (immature years), and experience after year 4 (mature years) as of 1975, 1977, and 1979, corresponding to the data available in 1976, 1978, and 1980, respectively. Since the average size of these units was less than that of Pilgrim, and since virtually all observers (including NEPOOL) have expected and found that large units have lower capacity factors than small units, even applying these historical capacity factors to Pilgrim would be optimistic. Nonetheless, the historic capacity factors were consistently less than NEPLAN and CMP projections for Pilgrim. Column B of Tables 6.1 through 6.3 demonstrates the effect of using cumulative average PWR capacity factors instead of NEPLAN's baseless assumptions.

Q: How do these results compare to the results of Mr. Webb's retrospective analyses of Pilgrim 2 costs in Exhibits Webb-15, 17 and 18 in PUC 82-266?

A: Tables 6.7 and 6.8 repeat these analyses, but increase the fixed charges by the ratio of the average projection of

Pilgrim's cost from historical experience (from Tables 6.2 and 6.3) to BECo's cost estimate used in Mr. Webb's exhibits. These Tables also start in the year indicated as Pilgrim's first year of operation in Table 6.2 and 6.3, and compute a cumulative discounted difference at the discount rates derived in those Tables. Even using CMP's capacity factors, Table 6.7 indicates that a realistic review of the dependability of BECo's cost estimate would have indicated that Pilgrim 2 would be much more expensive than oil. Table 6.8 indicates that even in 1980, CMP's assumptions would indicate that power from Pilgrim would not pay off against oil until near the end of the unit's life (if ever), even if CMP believed that construction of Pilgrim 2 was still possible. Furthermore, both the nuclear and oil cost projections in this Table are so high that it is difficult to believe that other, less expensive options were not available.

Figure 6.1 reproduces Exhibit Webb-15, but adds a realistic Pilgrim busbar cost, derived by multiplying BECo's capital cost recovery (in mills/kwh) by the ratio of my realistic cost estimate for Pilgrim ($4512 million) to BECo's estimate used in preparing the Webb-15 ($1521 million). The cost advantage of the BECo Pilgrim estimate over coal is obliterated by an increase of this magnitude (which is only 11% greater than the BECo cost estimate at cancellation) and would have been eliminated by a cost increase as small as 50%. Therefore, Exhibit Webb-15 demonstrates that Pilgrim 2 power was virtually certain to cost more than power from BECo's hypothetical coal plant.

Q: What do you conclude from these analyses?

A: Each of these analyses indicates that the use of a realistic Pilgrim 2 cost estimate, incorporating the experience of past cost overrruns, combined with standard NEPOOL assumptions for other parameters, would have resulted in the conclusion that Pilgrim 2 power would be more expensive than power from new coal units, for any analysis performed from 1976 to 1980. This is true despite the use of the optimistic nuclear assumptions I cited above. In addition, Pilgrim 2 would have been found to be more expensive than oil in 1978, and barely competitive in 1980.

Q: Were these the only comparisons that CMP should have conducted at the time?

A: No. Once Pilgrim 2 was found to be uneconomical compared to continued oil consumption or new coal plant construction, it still remained to be determined whether the coal and oil options were the best choices. Other alternatives which should have been considered as early as 1976 included aggressive conservation programs, coal conversions of existing capacity on CMP's system and elsewhere in New

England (CMP might, for example, have offered to purchase BECo's efficient Edgar station and converted it to coal, rather than allowing BECo to dismantle it), customer-owned or utility-owned cogeneration (fired by wood, coal, or oil), small hydro plants, trash-burning facilities, and purchases from (or co-operative development in) Canada. It is my understanding that CMP never studied most of these options seriously during the period of its Pilgrim investment, and those which it did pursue only entered its supply plans rather late in the 1970's or in the early 1980's, and were never seriously compared to Pilgrim. For example, in commissioning a study of cogeneration potential by C. T. Main, CMP basically assumed the results of the study (U3238 Tr. Q-22 to Q-25). Had CMP analyzed the issue without prior biases, it would almost certainly have found that cogeneration is not "too small, too costly, of too geographically diffuse" to justifiy significant development, and much of the cogeneration capacity now in the pipeline could have started up years earlier. The same is true, of course, of other small power producers.

7 - FINANCIAL ANALYSIS

Q: What is the difference between economic feasibility and financial feasibility?

A: Economic feasibility is desirability of the plant from a cost-benefit perspective, in terms of its costs compared to alternative sources of power. Financial feasibility is the ability "to get from here to there", to actually pay for the investment. The previous section presents a very strong case that Pilgrim 2 was not economically feasible as far back as 1976. But even if the plant were economically feasible, compared to a hypothetical (and worse-case) alternative of burning oil over the life of the unit, it could not be built if it were financially infeasible. This is the situation that Seabrook is in now: neither unit is likely to be economically feasible, but we will never know, since Unit 2 has become financially infeasible and Unit 1 is likely to follow soon.

Q: How did the relative size of BECo's proposed nuclear construction program compare to those of other New England utilities?

A: Table 7.1 compares the 1972/73 commitment (in MW's and in projected dollar costs) by NU and UI in nuclear plants planned for operation in the late 1970's and early 1980's (Seabrook, Millstone 3, and Pilgrim 2) to BECo's commitment.[28] The table also lists various measures of the size of the utilities, such as peak demand, sales, revenues, and net plant in service, and the ratios of the size measures to their nuclear commitments. The relative burden on BECo would have been about the same as those on NU, and a third or half of those on UI, by these various measures. Thus, it would have appeared in 1972 that, unless most major New England utilities were stressed by its nuclear construction program, BECo would not be. UI was more vulnerable, and PSNH still more so.

Q: Did this relationship persist throughout the period of Pilgrim 2 construction?

A: Yes. Tables 7.2 through 7.4 update this analysis to 1976, 1978, and 1980, respectively. Since UI originally attempted to sell Seabrook shares in 1976 to alleviate its financial problems, and renewed its attempt in 1978, and since NU deferred construction of Millstone 3 in 1977, and offered its share of Pilgrim and Seabrook for sale in 1976 for similar reasons, these utilities were financial canaries for the

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28. The next set of units (Sears Island, Montague, and NEPCo) would result in substantially later cash flows, and are really not comparable to the three plants used in this analysis. The timing of the later plants was also more uncertain for much of the period of interest, due to the very limited stage of their licensing efforts.

other New England utilities. By 1976, BECo was more exposed than NU in a couple of important measures, such as Net Income and Common Equity. By 1978, BECo was not much better off than UI in those measures (and worse off in the Net Income to Nuclear Cost ratio), and worse off than NU by most measures. By 1980, BECo was more burdened than NU by all measures, and more heavily burdened than UI by most of the cost ratio measures, despite the fact that both NU and UI were carrying larger nuclear commitments than they found prudent.

From CMP's viewpoint, it is particularly significant that BECo was carrying a greater nuclear commitment than CMP found prudent for itself. Tables 7.3 and 7.4 include financial data for CMP, at the nuclear investment levels which CMP found excessive in Mr. Monty's testimony in the second round of U3238 (filed 8/22/80): 280 MW of Seabrook, 28 MW of Millstone 3, and 33 MW of Pilgrim 2. Mr. Monty described this case as "deleterious", producing "significantly higher risk" for CMP and creating serious effects on CMP's financial status, at least without CWIP in ratebase (which BECo never had any reason to expect). Assuming that this unacceptable burden was also recognizable in 1978, CMP's internal analysis provides a benchmark for the nuclear burden on BECo. In 1978, BECo was carrying larger proportional nuclear costs than CMP's unacceptable case, and the situation deteriorated further in 1980.

Thus, the financial problems for BECo's commitment to Pilgrim 2 should have been evident to CMP as early as 1978, and certainly by 1980.

Q: What would Tables 7.1 through 7.4 look like if realistic cost estimates for Pilgrim 2 were substituted for BECo's estimates?

A: The cost of Pilgrim, and hence the cost burden for BECo would increase dramatically. Considering that BECo's burden was already much heavier than that of utilities which were admittedly over-extended, even at their own cost estimates,[29] at least after 1978, observers familiar with the data I present in Sections 2 to 5 should have known that BECo's investment in Pilgrim was ambitious in 1976, risky in 1978, and impossible by 1980, after the TMI accident. Whatever was true of the risks of BECo's involvement in Pilgrim was also true for participation by other parties who were dependent on BECo's ability to finance its share of the plant. As discussed in Sections 2 thorugh 5, CMP should have been familiar with the history of the nuclear industry, and should have anticipated just such cost escalation as has actually

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29. Perhaps one of the reasons that NU, UI, CMP and other utilities limited, or attempted to limit, their nuclear exposure to the extent that they did, was the realization that the cost estimates used in their financial projections were optimistic, and that the actual results were almost certain to be worse.

occurred, and should have recognized that the chances of completing Pilgrim 2 were slim. In addition, CMP had been put on notice by BECo in September 1978 that BECo was having significant financial difficulties with Pilgrim, and Mr. Monty apparently agreed, as demonstrated by his notes from the Joint Owners' Meeting (see Section 4).

8 - PILGRIM 2 CONCLUSIONS AND RECOMMENDATIONS

Q: Please summarize the conclusions of the previous sections.

A: We may conclude that

- Nuclear cost estimates have never been reliable, either before or after the issuance of a construction permit.
- Nuclear power plants have consistently failed to meet their construction schedules.
- Pilgrim had problems at least equal to those of the industry as a whole.
- Pilgrim 2 could not have been built for any of the cost estimates BECo produced, or been completed on the BECo schedules, and these facts should have been apparent to BECo and most of the joint owners.
- It was foreseeable throughout the Pilgrim 2 construction period that the unit would impose tremendous financial strain on BECo.
- Pilgrim 2 was not cost-competitive with new coal plant construction as far back as 1976.
- Had Pilgrim 2 been completed, it would have operated at

much lower capacity factors than assumed in the utility cost-benefit analyses.

Thus, the termination of the Pilgrim 2 project was inevitable, desirable, and long past due when it finally occurred. Utilities have never known the scope of nuclear projects until they are completed, or actually until they are retired. This fact was clear to me in 1979, and it should have been clear much earlier to BECo and CMP (which had access to data I have only recently seen, and probably much which I still have not seen).

Q: Was BECo ever realistic in its interpretation of the NRC licensing process, even in retrospect?

A: No. Mr. Francis Staszesky, BECo's Executive Vice President and then President through most of the Pilgrim 2 investment period, indicated in recent testimony that 1981 NRC regulations providing for post-construction-permit reviews of design came as a shock to the BECo:

> For the first time we were faced with the prospect of obtaining a construction permit and commencing on-site construction before we would know what the ultimate design requirements would be. We considered this to present a grave risk. (Staszesky, 1984, p. 17)
>
> For the first time we were confronted with the situation where resolution of design-requirements issues would not occur prior to construction permit issuance, thus significantly increasing uncertainty as to final project form, schedule and cost. (p. 22)

> Under normal circumstances, the issuance of the construction permit marks the end of a significant portion of the uncertainties associated with major projects of long duration. Under normal circumstances, the issuance of the constructioon permit means that you finally know when construction can begin, you finally have a more concrete handle on when the project should come into commercial operation, and you finally have project scope and design fairly well tied down. These factors all affect project cost, which in turn affects economic desirability, and relative certainty as to these factors means that a judgment as to the feasibility of proceeding can be made, as of the issuance of the construction permit. The change in procedures at NRC that occurred subsequent to June, 1980, meant that these certainties would not be available and it meant that the uncertainties that are characteristic of the pre-on-site construction phase would now continue after the commencement of on-site construction and after the expenditure of the costs of on-site construction. This was an important new factor in the equation. (pp. 22-23)

In fact, there was very little new in the "equation", as is demonstrated by the actual cost and schedule histories, and the quotes which I presented in the earlier sections of this testimony. The NRC may have changed the letter of its licensing procedures in 1981, but it was simply recognizing the reality: utilities have never known the scope of nuclear projects until they are completed, or actually until they are retired. The certainty to which Mr. Staszesky refers did not exist at any time during the licensing of Pilgrim 2, as shown by the experience of dozens of other plants. This fact was clear to me in 1979, and it should have been clear much earlier to BECo (which had access to data I have only recently seen, and probably much which I still have not seen). Indeed, it appears that CMP was more realistic about

Pilgrim's prospects (and those of new nuclear units in general) than was BECo, and that CMP's failure to force BECo to confront reality contributed to the eventual size of the loss for all the participants.

Q: What are your conclusions regarding the prudence of the major decisions to participate in, and attempt to construct, Pilgrim 2?

A: Reviewing the preceding information and analysis, I conclude that a reasonable observer, with access to the information reasonably available to CMP would have concluded:

1. As a general matter, participating in a nuclear power plant construction program may well have been prudent in 1972, so long as it was accompanied by a commitment to continued monitoring of developments in the industry and in the particular project, and with the knowledge that nuclear cost projections were highly unreliable.

2. Continuing the Pilgrim 2 project past 1976, in the absence of a construction permit, was extremely questionable. No further major expenditures should have been undertaken without a thorough and candid assessment of the costs, benefits, and risks of continued expenditures. Such an analysis would probably (i.e., with greater than a 50% probability) have indicated that cancelation of the plant was

economically and financially justified. Hence, cancelation would have been easy to defend without any study, and continued investments were indefensible.

3. By the end of 1978, the accumulation of bad news had progressed to the point that cancelation was almost certain to be preferred in any honest appraisal of the Pilgrim 2 project.

4. As soon after the Three Mile Island accident as the participants' reaction time would allow (certainly by early in 1980), cancelation was absolutely and certainly required. Any avoidable or deferable expenditures past mid-1979 were clearly imprudent.

Q: How would these conclusions have affected the behavior of CMP and BECo, had they been acting prudently?

A: In 1972, and throughout the early 1970's, all utilities with nuclear investments should have been monitoring the evolution of the numerous problems of the nuclear industry. By 1976, both BECo and CMP should have been carefully and critically re-examining the economics, and the financial viability, of the project, with the knowledge that the official cost and schedule estimates were almost certain to be over-optimistic. If BECo were not willing to undertake such studies, CMP should have performed on its own, or with other joint owners, or attempted to force BECo to take the problems seriously. Had those studies been performed, the plant would probably have been cancelled; at the very least, direct expenditures would have been virtually eliminated.

By 1978, CMP should have been publicly opposing continuation of Pilgrim 2, if BECo had not yet canceled the unit, or at least stopped any direct expenditures. BECo should have been carefully considering any additional expenditures, and should almost certainly have canceled the plant by that time.

By early 1980, Pilgrim 2 certainly should have been canceled.

Q: If BECo had acted as you suggest they should have, would even BECo and its customers be better off today than they are?

A: Yes. The losses suffered by both BECo's ratepayers and its shareholders would have been limited. Even with the excessive delay in the cancelation decision, investors were relieved when it finally occured: Value Line headlined the removal of the "nuclear monkey" from management's back. In addition, the stockholders and/or customers of the several other New England utilities (including CMP) which were joint owners in the Pilgrim 2 project would be better off today.

Q: How would you recommend that this Commission treat CMP's investment in Pilgrim 2 for ratemaking purposes?

A: I would recommend that the Commission disallow all costs beyond the end of 1976. This is based on my conclusion that an honest appraisal of the project at that date would probably have recommended cancelation at this date. Since CMP did not conduct any such inquiry (nor attempt to force BECo to conduct one), its investment beyond that date appears to be totally due to CMP's imprudence.

My other recommendations are more conditional. First, I believe that the Commission should determine whether it wishes to disallow costs after the time at which CMP's behavior became imprudent, or only at the time when prudent behavior would have resulted in a different substantive outcome. This is equivalent to the question of whether a driver is imprudent as soon as he falls asleep behind the wheel, or whether that behavior only becomes imprudent when the car hits someone. If the Commission chooses the first standard, then none of CMP's investment should be recovered from ratepayers.

Second, if the Commission does allow CMP to recover any of its costs after 1976, CMP should not recover more than half of the direct costs for 1977 and 1978, more than 15% of its costs from the end of 1978 through mid-1980, or any costs beyond mid-1980. These fractions correspond to my assessment of the probability that an unbiased review of the project would endorse continued investment at each date.

Q: Do you have any opinion as to whether CMP or BECo should bear the portion of the costs which are not recovered from CMP's ratepayers?

A: Not really. As I noted above, this question hinges on the nature of BECo's representations and responsibilities to CMP. I do not believe that this potential dispute between the utilities and their contractors should in any way affect the Commission's decision in this proceeding, however, since the only issue here is whether CMP's customers should be paying these costs.

Q: Does this conclude your testimony on Pilgrim 2?

A: Yes.

9 - SEARS ISLAND NUCLEAR AND COAL PROJECTS

Q: How is this section of your testimony structured?

A: I consider four periods in the history of CMP's plans to construct a major generating facility at Sears Island. The first period is 1974-1977, when CMP attempted to build a nuclear unit at the site. The second period is 1977 when CMP canceled the nuclear project and initiated the coal project. The third period is 1977-1979 when CMP petitioned for and was denied a Certificate of Public Convenience and Necessity for the coal project. The fourth period is 1980-1984 when CMP petitioned for rehearing and subsequently deferred and then canceled the coal project.

9.1 - Sears Island Nuclear Project (1974 - 1977)

Q: What were the circumstances surronding CMP's decision to initiate the Sears Island Nuclear Project in 1974?

A: 1974 was a period of transition. Until 1973, CMP and other utilities in New England and nationally had experienced a long period of stable, high rates of growth in demand. CMP, like other utilities, had expected this growth to continue indefinitely. This long upward trend was broken by the Oil

Embargo and the related price increases and supply disruptions. Similarly, utilities had been ordering more nuclear plants in the years before 1974 despite the increasing evidence of problems with cost, scheduling, and licensing. In 1974, orders for new plants continued but deferrals and cancelations also began due to financial problems and reduced demand.

Q: Was it prudent for a New England utility for a New England utility to initiate a nuclear project in 1974?

A: As discussed in Section 3, it was clear by 1974 that nuclear plants had encountered substantial problems concerning cost, schedule, and licensing and that it was likely that these problems would continue and probably intensify. By 1974, the outlook for load growth had become much less certain, but CMP (like most utilities) expected that fairly high growth rates would resume after the interruption caused by the Oil Embargo. New England utilities were also seeking to reduce their dependence on oil-fired generation, and the alternatives appeared quite limited to the utilities as discussed in Section 2. In this context, it was not imprudent to commence a nuclear project. However, any utility embarking on this course should have been aware of the risks - the serious problems with nuclear, the increasing difficulties utilities faced in financing construction programs, and the possibility that load growth would be substantially lower than pre-embargo.

Q: Was a project the size of Sears Island within the financial capablities of CMP?

A: I have not examined this issue rigorously. However, CMP's nuclear exposure (assuming that it retained ownership of 700 MW) would have been clearly less than that of PSNH, but greater than that of BECo, and generally comparable to that of UI. Thus, Sears Island Nuclear would have been a large financial commitment for CMP, but not extreme by New England standards.

Q: Did CMP manage the Sears Island Project in a manner that reduced the risks associated with a nuclear project?

A: CMP's conduct of the Sears Island Project was substantially more effective in this regard than that of many other utilities. According to CMP's response to Discovery Request 4MPUC-7, "Central Maine specifically withheld release-to--manufacture authorization for components, which included related detailed design and fabrication of such components . . ." In April 1975, when seismic problems were encountered, licensing expenditures were curtailed. In November 1975, expenditures were stopped pending resolution of the seismic issue. The project was canceled in January 1977. Overall, the rate of expenditures was relatively low and appears to have been limited to those required to support licensing efforts.

By contrast, Boston Edison did not effectively limit its expenditures on Pilgrim 2. Despite the lack of a construction permit, manufacturing of components was allowed to go forward. Boston Edison continued a high rate of expenditures for several years while it was unwilling to accept the fact that licensing and financial problems made eventual cancelation inevitable. PSNH has similarly continued expenditures at fairly high levels on Seabrook (paticularly on Unit 2) despite licensing and financial problems which suggested that the efforts might well be futile.

Q: Was CMP's decision to cancel the Sears Island Nuclear Project prudent?

A: In light of the seismic issues as well as the increasing tide of other problems facing nuclear plants, the decision to cancel was certainly prudent. As demonstrated in Sections 3 and 6, cancelation of Pilgrim 2 would probably have been recommended by an objective analysis of that plant, which had a few advantages over Sears Island. Pilgrim was further along in licensing, lacked the seismic problems, and was at an existing nuclear site. Given CMP's cautious approach to nuclear commitments, it is plausible that CMP also would have canceled Pilgrim 2 near this point, had it been CMP's direct

9.2 - Initiation of the Sears Island Coal Project (1977)

Q: Please describe CMP's load forecast and construction program after the Sears Island Nuclear Project was canceled in January 1977.

A: By 1977, it was becoming increasingly evident that energy use patterns would be substantially different in the post-1973 period. All energy prices had risen and these price increases were inducing substantial conservation.

CMP's load forecasts were slow to recognize these fundamental changes. While CMP did continue to experience substantial demand growth in the 1974-1977 period, the regional and national effects of higher costs should have been evident. CMP's forecasting methodology in this period did not adequately reflect the factors changing the industry, as I discuss further in my testimony in PUC 84-113, Phase 2. It is important to note that load growth was a more important justification for Sears Island Coal than for nuclear units, with their much lower fuel costs.

CMP was also slow to recognize the role that it could play in managing energy demand. By 1977, some utilities and regulatory commissions had begun to use rate design and other incentives to encourage conservation, small power production, and increased load factors. It appears that these options did not occur to CMP.

In 1977, CMP was participating as a joint owner in 6 nuclear units under construction or proposed (Seabrook 1 & 2, Millstone 3, Pilgrim 2, Montague 1 & 2). Even with the cancelation of the Sears Island Nuclear Project, nuclear power continued to dominate CMP's construction program (together with Wyman 4).

Q: What were CMP's power supply options in 1977?

A: CMP's major options for additional capacity can be effectively divided into 3 groups:

- Increased ownership in nuclear units under construction or proposed
- Constructing a new coal plant as a lead participant
- Other, such as Canadian imports, hydro, and cogeneration

Q: Please evaluate the option of increased ownership in nuclear units that were already underway.

A: By 1977, all of the nuclear plants underway in New England were facing very serious difficulties. Seabrook 1 & 2 had serious licensing problems. Both NU and UI had attempted unsuccessfully in 1976 to reduce their ownership in Seabrook. Millstone 3's lead participant, NU, was experiencing financial difficulties. Pilgrim 2 did not yet have a construction permit, nor did Montague. CMP was fortunate in having just reduced its nuclear commitment by cancelling Sears Island; expanded ownership in these other projects was not an attractive option. By 1977, commencing a new nuclear unit as a lead participant was even less advisable.

Q: What were CMP's options for adding coal capacity?

A: At this time, no projects to construct new coal plants were underway in New England. Thus, constructing a new coal unit as a lead participant was the only option available to CMP for adding coal capacity. Nationally, coal was viewed by utilities as the leading alternative to nuclear for new capacity.

New coal facilities did face substantial uncertainties concerning environmental regulations. The capital cost of new coal plants was increasing rapidly, at a rate substantially in excess of inflation, apparently due to the addition of scrubbers and other pollution control equipment. This rate of increase was still much smaller than for nuclear plants, and coal plants also seemed to be much less vulnerable to regulatory changes once licenses were received.

Furthermore, new coal capacity had not been constructed in New England for some time, so there was little regional experience in building coal plants under the increasingly strict environmental regulations. The only coal plant in regular operation in New England was PSNH's Merrimack facility, the second (and last) unit of which entered service in 1968. Many other plants had been converted from coal to oil to meet environmental standards.

In addition, lead participation in a coal unit would place a heavy financing burden on CMP. These financing requirements would be in addition to the requirements of CMP's shares in 6 nuclear units. The burdens might have been reduced or spread out by building more small units. Merrimack's two units were 100 MW and 350 MW, compared to 568 MW at Sears Island.

Q: Given the options available in 1977, could CMP have met its future capacity needs without an increased commitment to either nuclear or coal capacity?

A: This is certainly true in retrospect. It is likely that a more reasonable load forecast would have indicated that CMP needed much less capacity than it anticipated. A positive approach to cogeneration and small power production would have satisfied much of this reduced need, and conservation could have taken up any remainder.

Thus, CMP could have designed a capacity plan in 1977 that did not require increased commitment to nuclear or coal. However, such a plan would have required that CMP be at the forefront in terms of load forecasting, conservation, and development of hydro, cogeneration, and other alternatives. This is a standard that few, if any, utilities could meet at this time. New approaches to capacity planning were being considered by regulators in states such as California and Wisconsin, but utility planning was just beginning to shift from emphasis on high demand growth and construction of coal and nuclear plants, towards cogeneration, renewables, and conservation.

Q: Was it prudent for CMP to commence the Sears Island Coal Project in 1977?

A: The decision to commence the Sears Island Coal Project was not imprudent for CMP, although a more sophisticated approach to load forecasting, conservation, and alternatives might have caused CMP to reduce its emphasis on this option. Having commenced a coal project, it was incumbent on CMP to recognize the substantial risks and uncertainties involved and act to limit its exposure.

9.3 - Petition for Certificate of Public Convenience and Necessity (1977 - 1979)

Q: How did CMP respond to risks associated with the Sears Island Coal Project?

A: CMP instituted policies to substantially restrict expenditures prior to receipt of regulatory approvals. CMP's Specification for Engineering, Design Services, Construction Management Option on Sears Island Coal Unit No. 1 states:

> CMP has adopted a Project philosophy of minimizing front-end engineering and design costs until major licensing and permit approvals have been obtained. To that end CMP contemplates only authorizing those engineering and design services necessary for the support of license and permit applications during 1978 and early 1979.
>
> Following submittal of the major license and permit applications, Architect-Engineer support services shall be reduced to a minimum level during the license application review and approval phase. While some engineering and design services will be performed during this early period most conceptual design engineering and all detailed engineering will be performed after receipt or assurance of receipt of key permits necessary to assure successful completion of the project.
>
> Further, it is CMP's present intention to make only those commitments that are required to support license and permit applications and to perform minimum site evaluations necessary to support these objectives. (Page 4-1)

As on the Sears Island Nuclear Project, "Central Maine specifically withheld release-to-manufacture authorization for components, which included related detailed design and fabrication of such components . . .(CMP response to Discovery Request 4MPUC-7)" This conservative policy concerning expenditures during licensing can be contrasted with Boston Edison's mangement of the Pilgrim 2 project.

Q: How did load forecasts change during the 1977-1979 period?

A: Between January and October 1978, CMP's forecast for 1988/89 winter peak fell by 170 MW. CMP did not issue a new forecast for the next year and a half.

Q: How did the outlook for Canadian imports, cogeneration, and other alternatives change during this period?

A: Interest in Canadian power imports to New England had increased, but the utilities were not encouraging reliance on that source. Cogeneration and small power production received important support from Federal PURPA legislation, as well as continuing development in California and elsewhere. Federal and state conservation programs were also taking shape.

Q: What effect did these changes have on utility construction programs?

A: By 1979, it was no longer necessary that a utility be at the forefront to realize that changing circumstances were making construction of large central station generation plants less attractive. There was growing recognition that new capacity was becoming increasingly expensive and difficult to finance and that load growth was slowing down. Furthermore, it was becoming clearer that utilities could manage growth, and that conservation and alternative sources such as cogeneration could significantly reduce the need for new capacity. The California and Wisconsin PUC's and the utilities regulated by them had moved away from constructing nuclear and other large central station capacity toward conservation and other alternatives. The Pacific Northwest Power Act, passed in 1980, gave explicit precedence to conservation and alternative sources over new nuclear and coal units.

Q: How did CMP react to this changing environment?

A: CMP was slow to react. In 1979, CMP was still forecasting demand based largely on an extrapolation of historical trends. CMP believed that the potential contribution of cogeneration and alternatives was quite small. CMP's opinion is well summarized in its response to Item 29 of the Sears Island General Order No. 39 filing:

> The capacity and energy needs of the Petitioner can best be filled by an economical base loaded generating station.
>
> Alternatives considered and discussed here are nuclear power, oil-fired thermal stations, hydroelectric within the Petitioner's system and from proposed federal projects, and purchased power. Studies to covered in an additional report will include conservation, wind, solar, biomass, thermal gradients, and geothermal. In general these alternatives are either too limited in supply, technically unproven or uneconomic for large scale use.

Q: Was CMP aware that its demand forecast might be substantially too high and that its evaluation of cogeneration and alternatives might be unduly pessimistic?

A: During 1979, CMP received several indications that its capacity planning might be relying on outdated techniques and judgments. In the Sears Island proceeding (U3238), the Staff (through its consultants, Arthur D. Little) and the Office of Energy Resources (through its staff and its consultant, Dr. Tietenberg) presented alternative forecasts for the CMP service area that were substantially lower than that of the utility.

Arthur D. Little also noted that cogeneration might have a substantial impact on CMP's capacity needs. In particular, it testified that expanded self-generation by the pulp and paper industry could be expected; sales to this industry, that currently accounted for 18% of CMP's total, might disappear by the 1990's (Tr. 818-820).

CMP was also a party in MDPU 19494 where I testified that its load forecast was seriously flawed and overstated. That testimony is attached to my testimony in Phase 2 of 84-113.

Q: Was CMP prudent in its continued expenditures and efforts to license the Sears Island Coal Project?

A: The question of whether CMP was prudent turns on the standard which the Commission decides to apply and, to a lesser extent, the Commission's evaluation of CMP's actions concerning nuclear power at this time. If the Commission chooses a standard of average utility practice, CMP was certainly not imprudent. In 1979, most utilities (in New England and nationally) were still relying on construction of nuclear and coal units to meet projections of rapid load growth.

If the Commission chooses above average utility practice as a standard, then CMP may not have been prudent in persisting with Sears Island. A utility with capacity planning much above average would have realized by 1979 that slower demand growth and increased conservation, cogeneration, and alternatives would delay or eliminate the need for new coal capacity. Proceeding with licensing of a coal unit might still have been justified as an insurance policy against uncertainties concerning the price and availability of oil and the mounting problems with the construction and operation of nuclear plants. Proceeding with licensing of the Sears Island Coal Project was a way of maintaining an option for diversifying CMP's fuel supply.

Q: What criterion can be used to evaluate the value of the Sears Island Project as an insurance policy?

A: Such an insurance policy is prudent only if the "coverage" was cost effective and not unduly risky of itself. Thus, it must meet these criteria:

1. The risks being insured against were substantial enough to require insurance;
2. This policy was more cost effective than other available methods of CMP's exposure to risk;
3. The proposed coal unit could be licensed and constructed if necessary.

Q: How would you evaluate the insurance value of the Sears Island Project in light of these criteria?

A: In terms of Criterion 1, the risks relating to oil and nuclear were certainly large enough that diversification of fuel supply could be considered a substantial benefit.

In terms of Criterion 2, it was increasingly clear during the 1977-1979 period that certain alternatives would be cheaper than new coal capacity. In particular, conservation investments such as increased insulation and improved appliance efficiency were likely to be more cost effective than any type of new capacity. It was also becoming more likely that some Canadian imports and cogeneration would be available at a cost competitive with that of power provided by a new coal unit, although it was not clear that these strategies would replace all oil use on the CMP system.

It should also be noted that coal units were experiencing fairly rapid cost escalation. Although the problem was less severe than that facing nuclear plants, coal capital costs were rising more rapidly than inflation. This escalation reflected the increasingly stringent environmental restrictions and general increases in construction costs.

In terms of Criterion 3, it was substantially uncertain whether a coal unit could be licensed at the Sears Island site. The principal uncertainty relates to air quality.[30] The complexities of this issue are beyond the scope of my expertise. For purposes of my review of the project, I have assumed that it was reasonable for CMP to proceed under the assumption that a coal facility <u>might</u> be licensed at this site. Even if the Sears Island Coal Project could be licensed, CMP acknowledged that it might have had difficulty financing the project.

Q: How do CMP's actions concerning nuclear power affect the justification of Sears Island as an insurance policy?

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30. There was also a possibility that once-through cooling would not be permitted, thus requiring cooling towers and a substantial increase in the cost of the plant.

A: During this period, the problems with nuclear intensified greatly, most notably due to Three Mile Island. As a result, it can be argued that the Sears Island Coal Project became more valuable as insurance against the delay and cancelation of nuclear units. However, CMP's purchase of additional Seabrook capacity and its continued participation in the Pilgrim 2 project can also be viewed as insurance (albeit not very cost effective). CMP bought more Seabrook because it thought it needed the capacity and to help insure completion of the project, as is discussed in my testimony in 84-113, Phase 2. CMP's justification for continued involvement in Pilgrim 2 are similar, although it has also argued that it was trapped with no acceptable way to disengage.

Simultaneous involvement in Sears Island, Pilgrim 2, and Seabrook (at an increased level) meant that CMP was paying too much for insurance against problems with oil supply and implementing conservation and alternatives. This is not to say that CMP had effectively purchased more insurance than it needed. Involvement in Pilgrim 2 was effectively no real insurance since the unit was unlikely to ever be completed. Similarly, additional Seabrook ownership was effectively only a small amount of insurance since it was unlikely that Unit 2 would be completed; even Unit 1's completion was questionable. The Sears Island Coal Project probably did have significant insurance value, but CMP's ability to license and finance the unit was by no means a certainty. CMP's increased involvement in Seabrook and continued involvement in Pilgrim 2 intensified these potential financing problems.

Q: Please summarize your conclusions on whether CMP's expenditures on the Sears Island Coal Project were prudent in the 1977-1979 period?

A: Under a standard of average utility practice, these expenditures were prudent given that they appear to have been limited to those required for licensing.

Under a standard of above average utility practice, the continued expenditures through the end of the period are more questionable. If the Commission accepts my conclusion that by 1979 it was unlikely that either Pilgrim 2 or Seabrook 2 would be completed (and questionable whether Seabrook 1 would be completed), then expenditures on Sears Island are justified as insurance. However, if the Commission finds that CMP was prudent in its purchase of additional Seabrook shares and continued participation in Pilgrim 2, it should then evaluate whether the insurance value of these nuclear projects made continued expenditures on the Sears Island Project superfluous.

9.4 - Petition for Rehearing, Deferral, and Cancelation (1980 - 1984)

Q: What was the status of CMP's capacity planning process after the Commission's decision on December 31, 1979?

A: The Commisssion's decision in U3238 was a clear indication of the severity of the problems with CMP's capacity planning process. If CMP had been previously unaware of the seriousness of its failure to more accurately forecast demand, this decision demonstrated unmistakably that the utility had to revamp its forecasting effort. The Commission's findings on power supply alternatives were more limited, but it was concerned that CMP may have substantially understated the costs of the Sears Island Coal project. It also noted the uncertainties concerning environmental licensing at the Sears Island site and specifically encouraged CMP to more fully explore cogeneration and Canadian imports. Finally, the Commission required that in any future proceedings reviewing the need for a particular facility that CMP provide a rigorous evaluation of all alternatives and combinations of alternatives.

Q: Was CMP prudent in its continuing effort to license the Sears Island Coal Project after the Commission's decision on December 31, 1979?

A: If CMP had previously been aggressive in upgrading its forecasting capabilities and in encouraging conservation, cogeneration, and alternatives, it might not have continued in its efforts to license the Sears Island Project. However CMP had not been aggressive in this way, so it was faced with the need to make important capacity planning decisions without a reliable assessment of demand and supply alternatives. Even if CMP now fully realized the inadequacies of its previous capacity planning, it could not instantaneously remedy these problems. Development of high quality demand and supply forecasts is an ongoing process. It is reasonable to expect that substantially improved forecasts could be produced within a year, but refinement of this process and development of programs to encourage conservation, cogeneration, and alternatives can require several years. An above-average utility would have been in a position to respond rapidly to the Commission's decision, but that above-average utility would also have presented a very different case and might well have been planning for a much later Sears Island COD.

CMP's experience in this period was more typical for utilities than it had been previously. It was forced to adjust to a new set of realities. The state-of-the-art in capacity planning has evolved rapidly in the period after 1980. Four years after the Commission's decision in the

Sears Island case, CMP now has a greatly improved capacity planning process. Its current load forecast is much more sophisticated than previous versions. CMP is actively encouraging development of cogeneration and other alternatives, and it is substantially above average in the contribution of these sources to its power supply. However in the context of average utility practice in 1980, CMP's decision to continue expenditures on the Sears Island Coal Project and to petition the Commission for a rehearing were not imprudent.

Q: How did load forecasts change during the 1980-1984 period?

A: CMP improved its forecasting capability and the effect of long term changes in the energy picture, such as higher prices and conservation, became clearer. CMP's substantially reduced its forecasts. In 1979, CMP was projecting 1741 MW of peak demand in the 1987/88 power year. By 1983, it was not predicting this level of demand until after the year 2000, and the 1987/88 demand forecast was 1378 MW. The need for new capacity thus receded further into the future.

Q: How did the energy supply picture change during this period?

A: Real oil prices were declining and concerns about long term oil supply were diminished. The substantial role that cogeneration and other alternatives could play in meeting Maine's electric needs became more widely accepted. The contribution of these sources increased steadily: from 1.3% of CMP's system generation in 1980 to 5.1% in 1982 to an estimated 12.5% in 1984. Substantial Canadian imports have already been contracted for, at prices below that of oil. These developments postponed the need for new central station capacity both in terms of meeting load growth and to displace existing oil fired generation. Meanwhile, the cost of new central station capacity (including the Sears Island Coal Project and the various nuclear units) continued to increase.

Q: What effect did these changing circumstances have on the Sears Island Coal Project?

A: Licensing efforts were suspended in May 1982 and the project was formally canceled in April 1984. The factors behind the demise of the project are identified in a memo from R.L. Bean to the CMP Power Committee dated March 1, 1984:

> A. A substantial decrease in trend of load growth occurred from early 1970's of 6-7% to 1983 at 2-2.5%.
>
> B. Advantage of economy of scale is negated by excessive investment cost represented in overbuild of capacity.
>
> C. Strategic scheduling of smaller sized units should reduce construction time, lessen AFUDC component, and better fit unpredictable load growth.
>
> D. Little interest remains today in joint ownership of units where outside owners have no control, although the unit purchase concept is still a viable arrangement.

> E. Smaller sized units minimize overbuild, decrease capital requirements, offer about the same heat rate and require lower reserve for a given system loss of load probability.
>
> F. CMP's present conceptual design for Sears Island may be obsolete by mid-nineties.
>
> G. Possible availability of alternative Canadian power, cogeneration and conservation in substantial amounts, plus some internal power developments, offer a solution to CMP's energy supply needs to at least the late 1990's.

John Rowe, in a letter to the Joint Owners on March 15, 1984 notes:

> As you are aware, the power planning environment which justified the Sears Island Project in 1977 has radically changed. Declining load growth, escalating costs, availablity of alternative sources of power, as well as other significant factors have contributed to the declining viability of the Sears Island Project.

Q: How did expenditures on the Sears Island Project in the 1980-1984 period compare with those in the 1977-1979 period?

A: Expenditures during the 1980-1984 period can be divided into three time periods. Prior to May 1982, direct expenditures continued at a substantial level somewhat lower than in the 1977-1979 period. Direct expenditures declined sharply during the remainder of 1982. AFUDC accrual ceased in December 1982 and direct expenditures were very limited after that.

The magnitude of expenditures prior to May 1982 appears to be in keeping with CMP's stated policy of minimizing front-end costs and limiting expenditures to those required to support licensing. CMP's policy after May 1982 was stated in Progress Report No. 18 For the Quarter Ended June 1982:

> The decision to defer the Sears Island Coal Unit #1 Project to November 1995 was made on May 20, 1982. Project efforts were immediately directed at terminating work where possible. Phasing down of work will continue to an orderly completion with the intent to minimize further exposure to the Joint Owners. Project controls have been developed to assure that these objectives are met. It is expected that the bulk of the ongoing expenses will be at a minimum by the end of 1982.

CMP continued AFUDC accrual for six months after the Commission's June 17, 1982 Order Granting Voluntary Dismissal of the Petition for Rehearing. It is my understanding that this is in keeping with Commission's policy concerning AFUDC on projects where construction work is suspended.

Q: Was it prudent for CMP to continue expenditures on the Sears Island Coal Project during the 1980-1984 period?

A: Under the average utility practice standard, CMP's direct expenditures were prudent at least through the middle of 1981 and possibly through the entire period. Under this standard, it is reasonable to allow at least a year and a half for CMP to revamp its capacity planning process and decide to suspend or cancel work on the project. The Sears Island Coal Project had continuing but declining insurance value. At the high end of the range, it was reasonable for CMP to consume two and a half years between the Decison on December 31, 1979 and suspension of work on the project. Cancelation in June 1982, rather than suspension of work would appear to have relatively little effect on direct expenditures, since direct expenditures after that date were quite limited.

Under a standard of above average utility practice, the appropriate cut-off date for prudence of direct expenditures ranges from early 1980 to early 1981.[31] As discussed previously, a utility with above average capacity planning might have canceled or suspended work on the Sears Island Coal Project after the Commissions decision on December 31, 1979. At the other end of the range, it is reasonable to allow a year for the utility to further upgrade its capacity planning process. During this time, CMP could have become reasonably certain that reduced demand growth and a combination of other alternatives would eliminate or at least substantially delay the need for the Sears Island Coal Project.

Q: Do you have any opinion as to whether CMP should have canceled or suspended construction when it stopped attempts to license the plant?

----

31. Unless of course, the Commission selects an early cut-off date based on the considerations discussed earlier in this section.

A: Not any strong opinions, in general. However, by 1982 the likelihood of resuming licensing of this plant was so remote that I see no reason not to have canceled by that point.

Q: Does this conclude you testimony?

A: Yes.

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TABLE 1.1: PILGRIM 2 COST AND SCHEDULE ESTIMATES

Estimate Date	Cost Estimate ($ million)	Commercial Operation Date	Projected CP Issue Date
Feb-72	402	Nov-78	Jan-74
Apr-73	655	Aug-80	Aug-75
Mar-75	1221	Oct-82	Oct-76
Oct-76	1396	Mar-84	Jul-77
May-78	1895	Jun-85	Mar-79
Mar-79	1895	Dec-85	Mar-79
May-80	3220	May-89	Jul-79
Jun-80	3515	Mar-90	?
Sep-81	3975	Mar-90	?

Sources: Montaup Electric Company, Docket No. ER81-749-000 and ER82-325-000, Exh. (MEC-701)
Start of Construction from: EIA-254 Progress Reports

TABLE 1.2: SEABROOK PROJECT ESTIMATES

Estimate Date	Cost 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.
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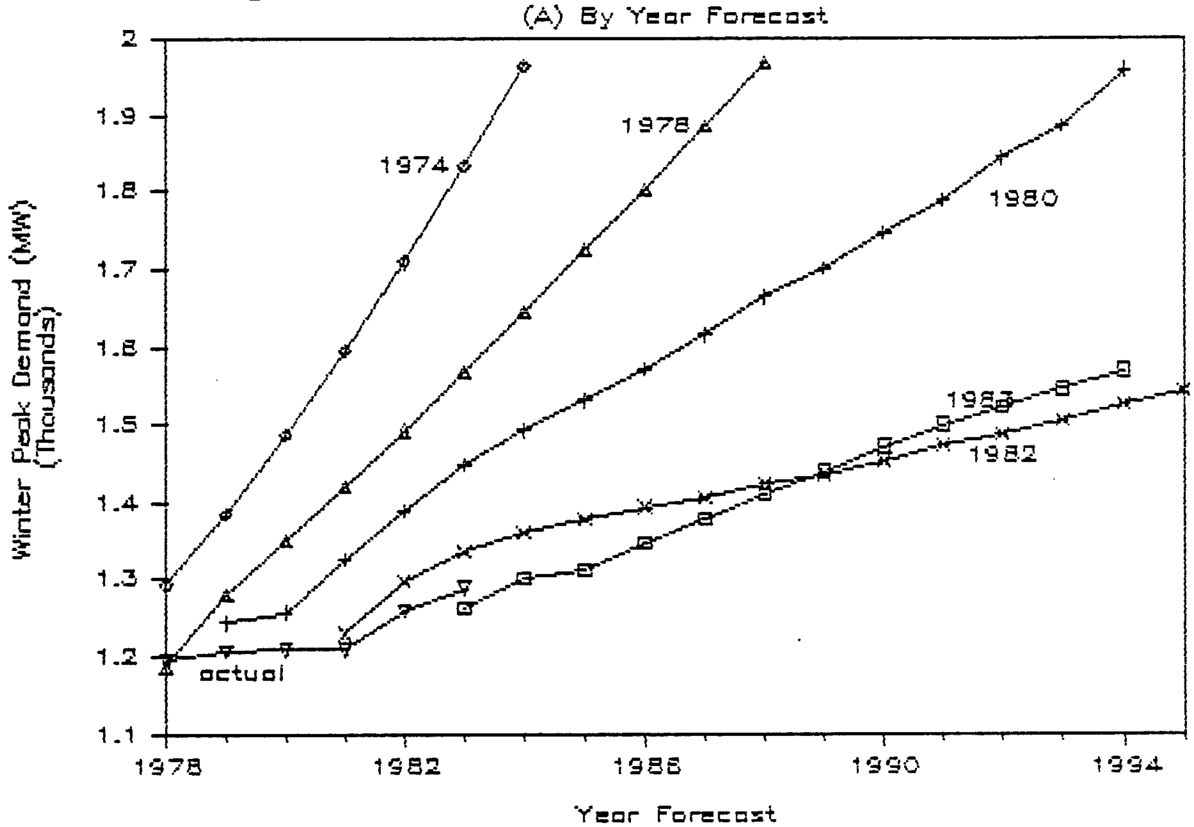
Division between units from: EIA, HQ254 Reports.

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 CMP Forecast History

(A) By Year Forecast



(B) By Date of Forecast

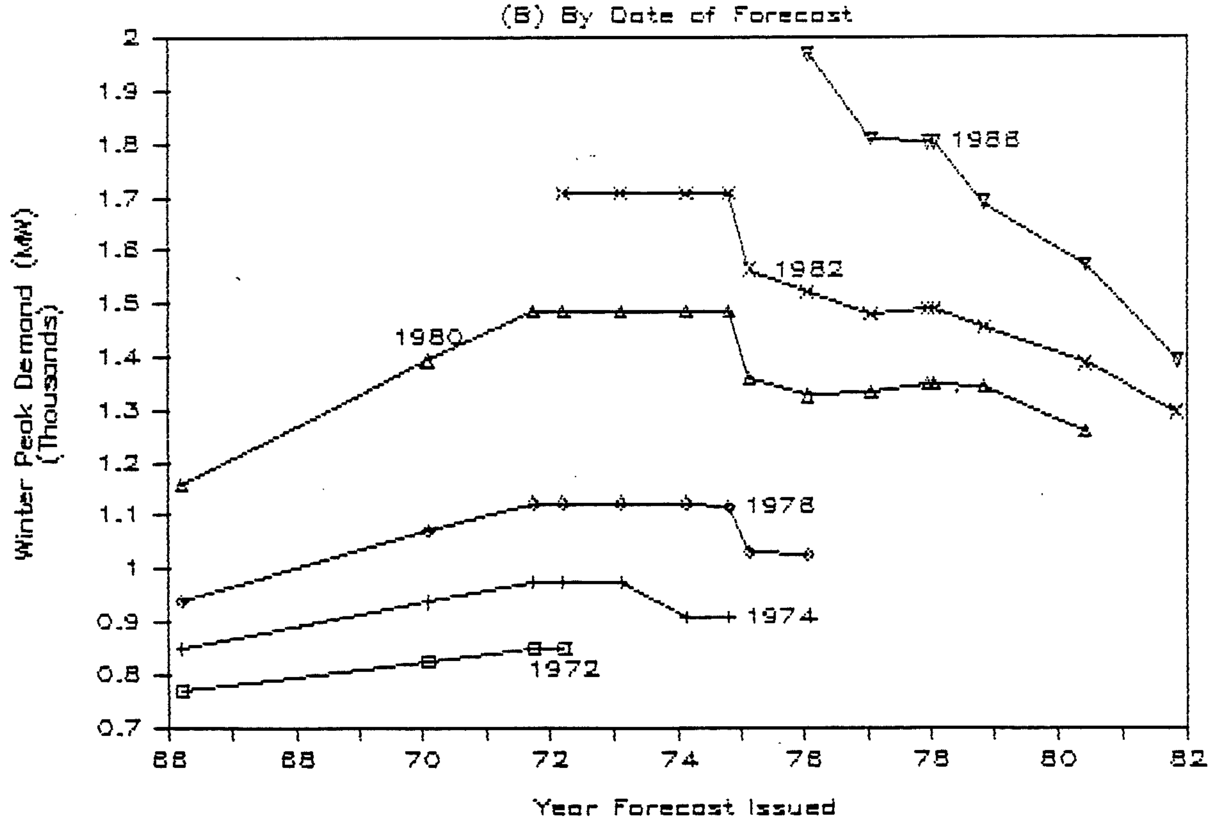
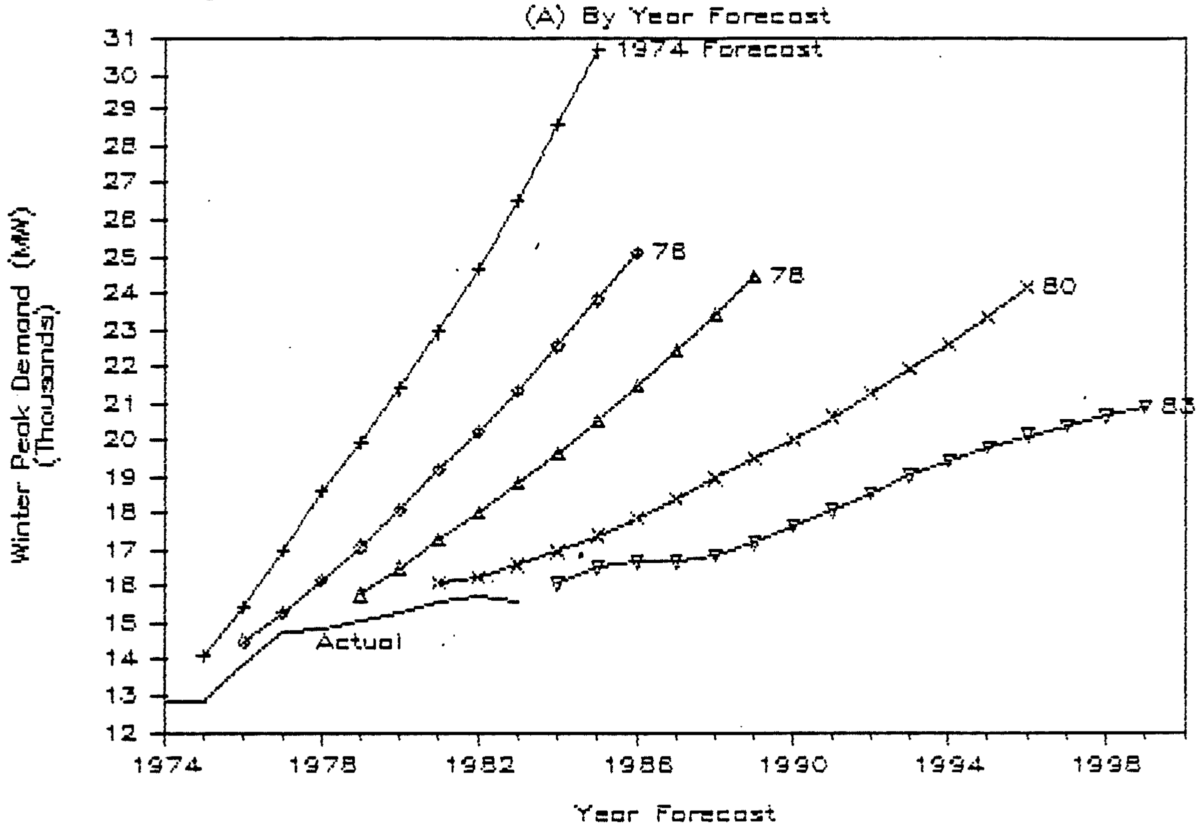


Figure 1.2: NEPOOL Forecast History



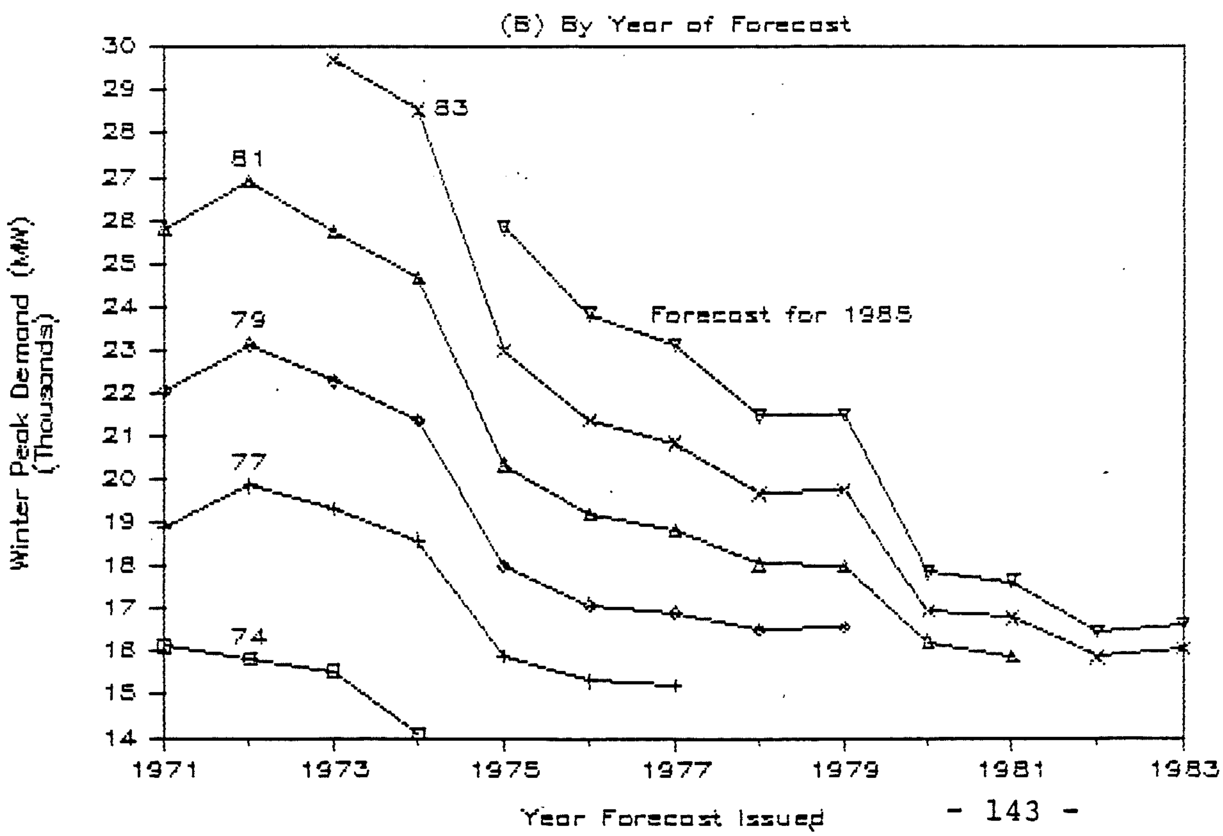
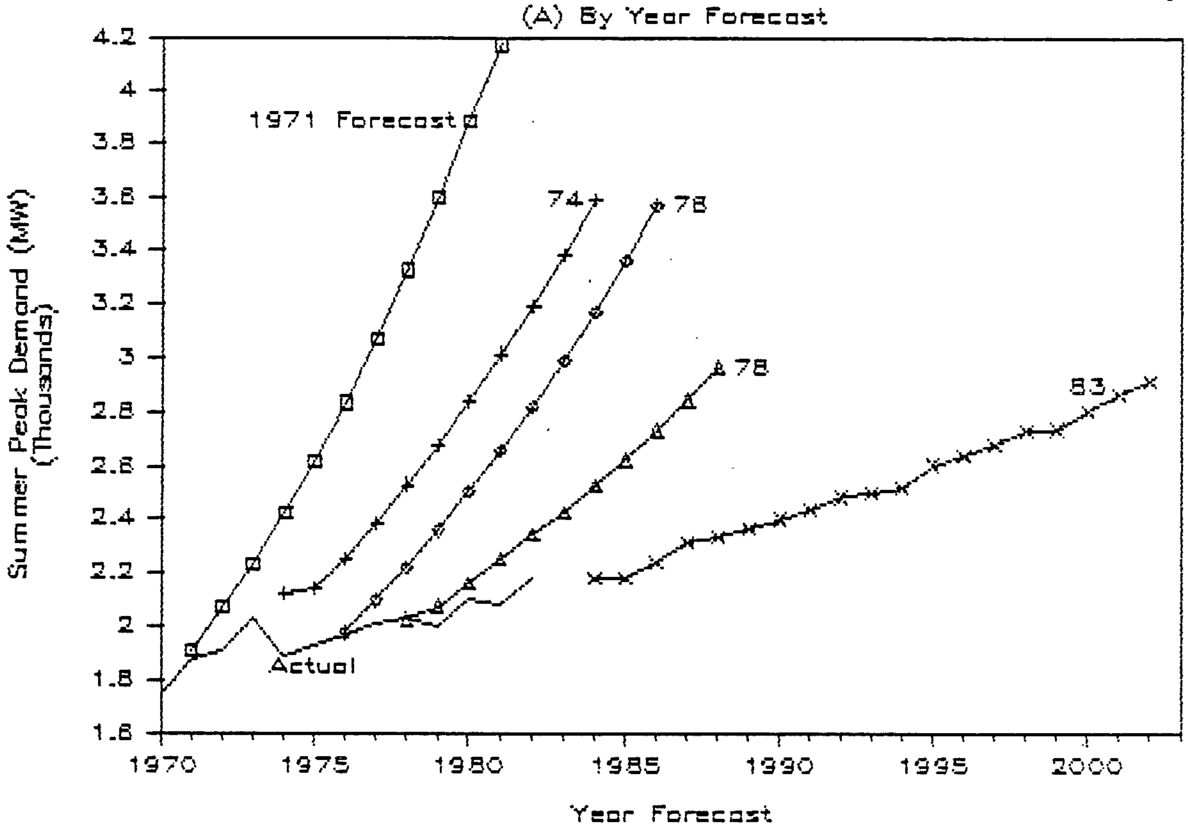


Figure 1.3: BECo Forecast History



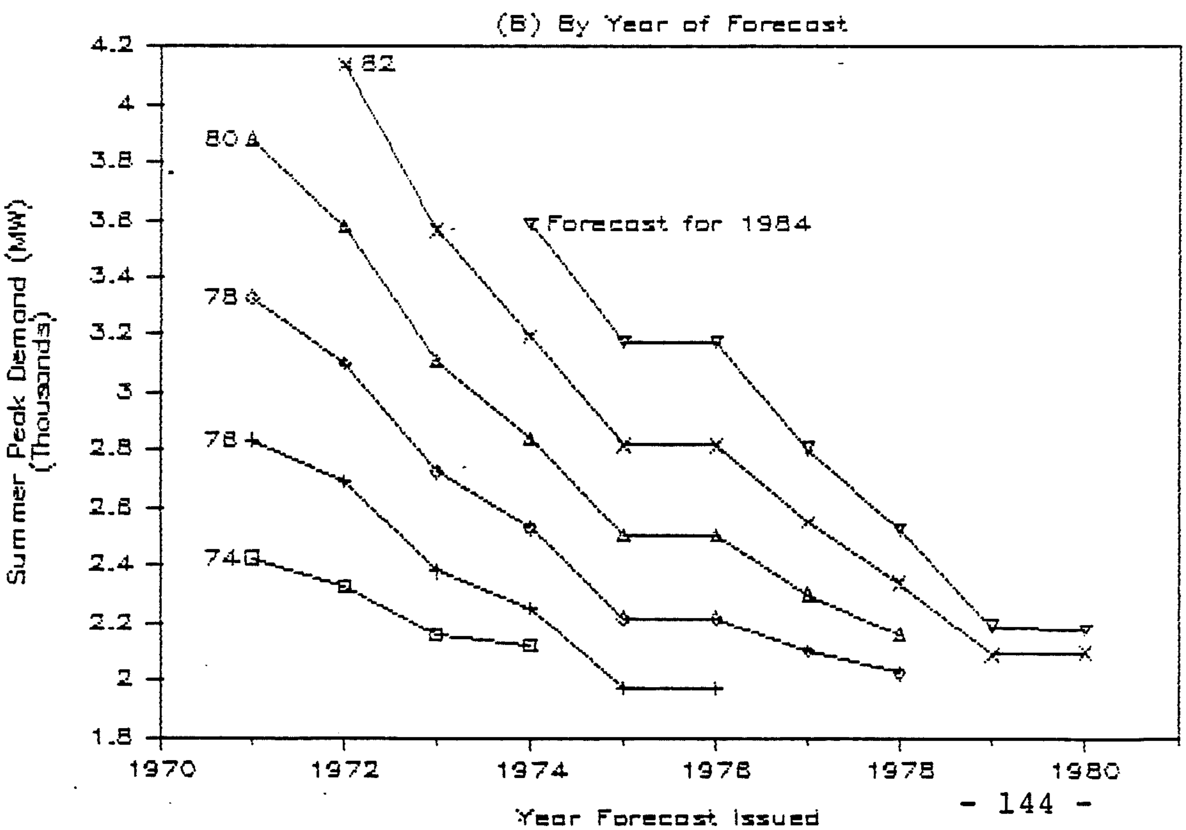


Figure 1.4: Pilgrim 2 Cost Estimates

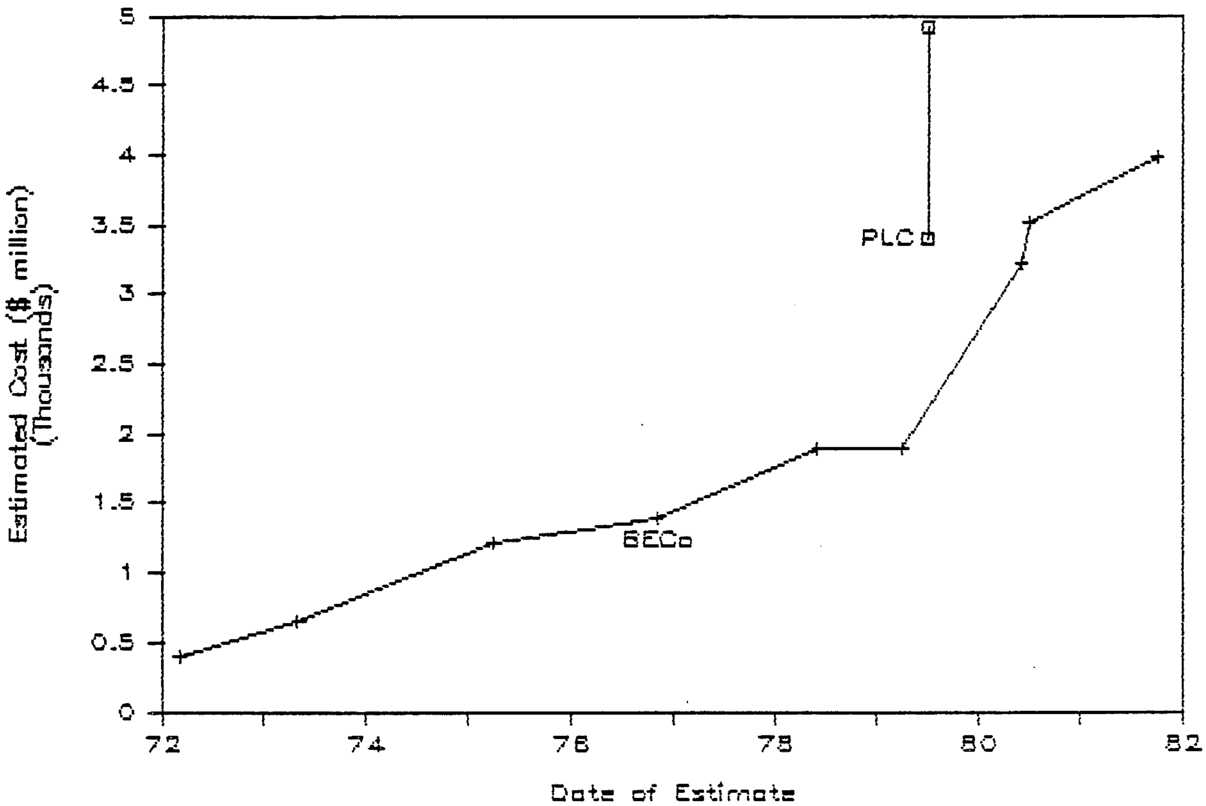


Figure 1.5: History of Seabrook Cost

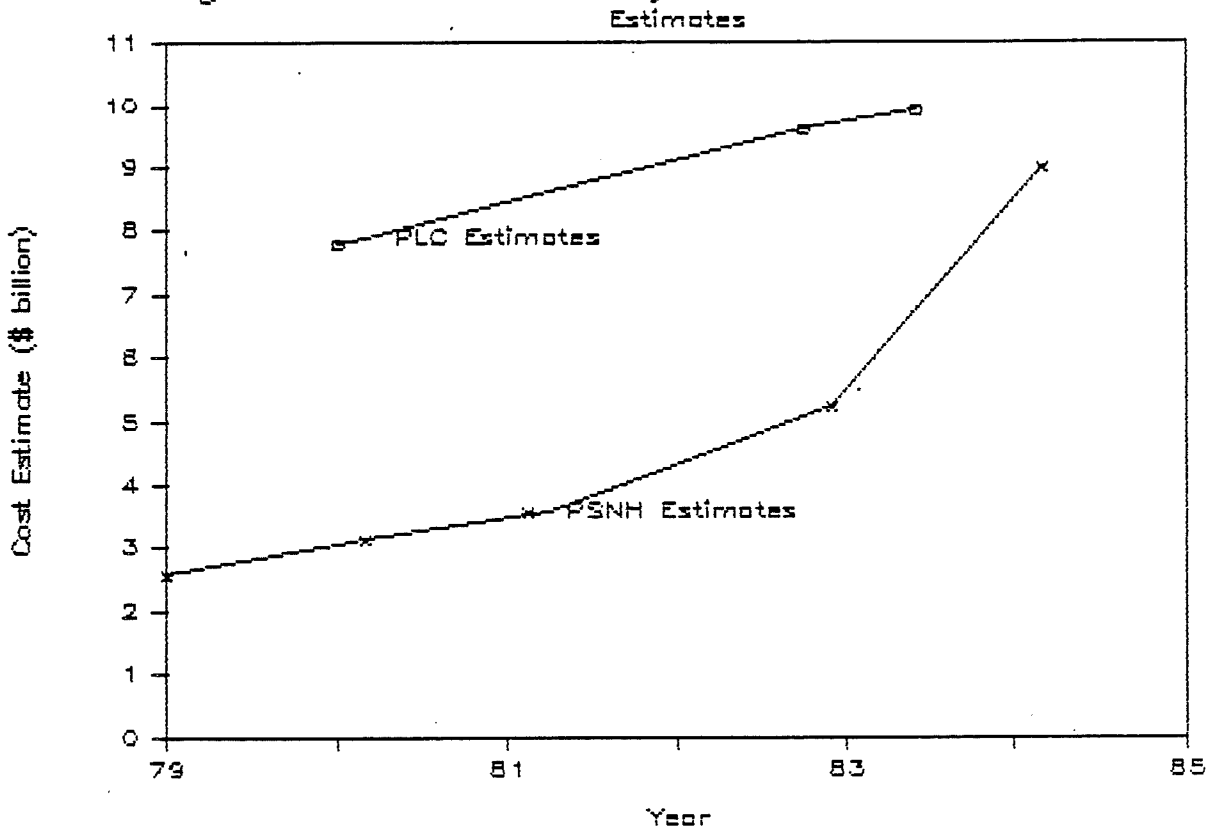


TABLE 2.1: COMPLETED NON-TURNKEY NUCLEAR UNITS, with COD before December, 1972

	Unit Name	--Actual--- Cost	COD	------Estimates----- Date of Est.	Cost	COD	Years to COD	--Nominal--- Cost Ratio	Myopia	Duration Ratio	% Comp
	Nine Mile Point 1	162	Dec-69	Mar-64	68	Nov-68	4.67	2.39	1.205	1.23	0.0
+++	Palisades	147	Dec-71	Mar-68	89	May-70	2.17	1.65	1.259	1.73	31.0
	Vermont Yankee	172	Nov-72	Sep-66	88	Oct-70	4.08	1.95	1.178	1.51	0
+++	Pilgrim 1	231	Dec-72	Jul-65	70	Jul-71	6.00	3.30	1.220	1.24	
+++	Turkey Point 3	109	Dec-72	Sep-69	99	Jun-71 [1]	1.75	1.10	1.055	1.86	52.2
	Maine Yankee	219	Dec-72	Sep-67	100	May-72	4.67	2.19	1.183	1.13	
	Surry 1	247	Dec-72	Dec-66	130	Mar-71	4.25	1.90	1.163	1.41	0.1
	AVERAGES All Units						3.94	2.07	1.181	1.44	
	NUMBER of DATAPOINTS						7	7	7	7	
	AVERAGES Bechtel Units						3.30	2.02	1.18	1.61	
	NUMBER of DATAPOINTS						3	3	3	3	

Notes: 1. From AEC. Month not given, June assumed.
+ Constructor=Bechtel
++ Architect/Engineer=Bechtel
+++ A/E and Constructor=Bechtel

TABLE 2.2: COMPLETED TURNKEY AND DEMONSTRATION UNITS, with COD before December, 1972

	Unit Name	--Actuals--- Cost	COD	---First Available--- Estimates Date of Est.	Cost	COD	Est. Years to COD	Cost Ratio	Myopia	Duration Ratio	% Comp
	Indian Point 1 [1]	126	Sep-62	Jun-60	68	Jan-62	1.58	1.86	1.478	1.42	78
	Humboldt [1]	24	Aug-63	Jun-60	3	Oct-62	2.33	8.16	2.458	1.36	0.0
	Oyster Creek 1	90	Dec-69	Jun-64	59	Oct-67	3.33	1.52	1.135	1.65	0.0
+	Ginna	83	Jul-70	Dec-65	64	Jun-69	3.50	1.30	1.078	1.31	0.0
	Dresden 2	83	Jul-70	Mar-66	79 [2]	Feb-69	2.92	1.05	1.016	1.49	6.0
+++	Point Beach 1	74	Dec-70	Jun-66	61	Apr-70	3.83	1.21	1.052	1.17	0.0
+++	Millstone 1	97	Mar-71	Dec-65	81 [2]	Aug-69	3.67	1.20	1.050	1.43	0.0
	Robinson 2	78	Mar-71	Jun-66	76	May-70	3.92	1.02	1.006	1.21	0.0
+++	Monticello	105	Jun-71	Jun-66	74 [2]	May-70	3.92	1.42	1.093	1.28	0.0
	Dresden 3	104	Nov-71	Mar-66	81 [2]	Feb-70	3.92	1.28	1.065	1.45	2.0
+++	Point Beach 2	71	Oct-72	Mar-67	54	Apr-71	4.08	1.32	1.071	1.37	0.0
	AVERAGE All Units						3.36	1.94	1.227	1.38	
	NUMBER OF DATAPOINTS						11	11	11	11	
	AVERAGE All Units Except Indian Pt and Humboldt						3.68	1.26	1.063	1.37	
	NUMBER OF DATAPOINTS						9	9	9	9	
	AVERAGE Bechtel Units						3.80	1.29	1.069	1.31	
	NUMBER OF DATAPOINTS						5	5	5	5	

Notes:
1. Demonstration units
2. Cost estimate as of 9/66
+ Constructor=Bechtel
++ Architect/Engineer=Bechtel
+++ A/E and Constructor=Bechtel

TABLE 2.3: COST GROWTH IN UNITS PLANNED OR UNDER CONSTRUCTION BY DECEMBER, 1972

Unit Name	-----Estimates------ Date of Est.	Cost	COD	Years to COD	Years Elapsed	Cost Growth Rate	% Complete
Arkansas 1	Dec-67	132	Dec-72	5.00			0.0
	Sep-72	185	Oct-73	1.08	4.76	7.4%	86.8
Arkansas 2	Dec-70	183	Oct-75	4.83			0.0
	Sep-72	230	Oct-76	4.08	1.75	13.9%	6.9
Duane Arnold	Jun-68	103	Dec-73	5.50			0.0
	Sep-72	192	Jan-74	1.33	4.25	15.8%	69.0
Calvert Cliffs 1	Jun-67	118	Jan-73	5.58			0.0
	Sep-72	250	Feb-74	1.42	5.26	15.3%	72.0
Calvert Cliffs 2	Jun-67	105	Jan-74	6.58			0.0
	Sep-72	204	Jan-75	2.33	5.26	13.5%	56.0
Davis-Besse 1	Dec-68	180	Dec-74	6.00			0.0
	Dec-72	349	May-75	2.42	4.00	18.0%	40.0
Farley 1	Sep-69	164	Apr-75	5.58			0.0
	Sep-71	259	Apr-75	3.58	2.00	25.7%	6.0
Farley 2	Sep-70	183	Apr-77	6.58			0.0
	Sep-71	233	Apr-77	5.58	1.00	27.3%	0.0
Hatch 1	Mar-69	151	Jun-73	4.25			1.5
	Dec-72	282	Apr-74	1.33	3.76	18.1%	69.0
Hatch 2	Jun-70	189	NA	NA			NA
	Dec-72	330	Apr-78	5.33	2.50	24.9%	11.0
Millstone 2	Dec-67	150	Apr-74	6.33			0.0
	Sep-72	282	Apr-74	1.58	4.76	14.2%	49.0
Oconee 1	Sep-70	109	Jul-71	0.83			80.0
	Dec-72	137	Jun-73	0.50	2.25	10.7%	99.5
Oconee 2	Sep-70	109	Jul-72	1.83			50.0
	Sep-71	137	Feb-73	1.42	1.00	25.7%	71.0
Oconee 3	Sep-70	109	Jul-73	2.83			25.0
	Sep-71	137	Nov-73	2.17	1.00	25.7%	43.0
Peach Bottom 2	Dec-66	138	NA	NA			0.0
	Jun-72	352	Sep-73	1.25	5.50	18.5%	72.0
Peach Bottom 3	Dec-66	125	NA	NA			NA
	Jun-72	316	Sep-74	2.25	5.50	18.4%	50.0
Rancho Seco	Dec-67	134	May-73	5.42			0.0
	Sep-72	300	Feb-74	1.42	4.76	18.5%	78.0
San Onofre 2	Mar-70	189	Jun-76	6.25			0.0
	Dec-72	360	Oct-78	5.84	2.76	26.3%	0.0
Trojan	Dec-68	196	Sep-74	5.75			0.0
	Dec-72	284	Jul-75	2.58	4.00	9.7%	57.0
Turkey Point 4	Mar-70	80	NA	NA			66.7
	Dec-72	106	Jul-73	0.58	2.76	10.7%	99.0
Grand Gulf 1	Jun-72	600	Dec-78	6.50			0
	Dec-72	656	Jun-79	6.50	0.50	19.5%	0
Hope Creek 1	Mar-70	574	Mar-75	5.00			0
	Dec-72	1139	May-79	6.42	2.76	28.2%	0
Limerick 1	Mar-70	252	Mar-75	5.00			0
	Dec-72	694	Aug-78	5.67	2.76	44.4%	1
Limerick 2	Mar-70	223	Mar-77	7.00			0
	Dec-72	512	Jan-80	7.08	2.76	35.2%	1
Midland 1	Dec-71	277	May-77	5.42			2
	Dec-72	383	Feb-79	6.17	1.00	38.1%	2
Midland 2	Dec-71	277	May-78	6.42			2
	Dec-72	383	Feb-80	7.17	1.00	38.1%	2

TABLE 2.3: COST GROWTH IN UNITS PLANNED OR UNDER CONSTRUCTION BY DECEMBER, 1972

Unit Name	Date of Est.	Cost	COD	Years to COD	Years Elapsed	Cost Growth Rate	% Complete
	-----Estimates------						
San Onofre 3	Mar-70	189	Jun-76	6.25			0
	Dec-71	409	NA	NA	1.75	55.3%	0
Bailly	Mar-67	113	Dec-72	5.76			NA
	Jun-72	244	Jun-77	5.00	5.26	15.8%	0
Shearon Harris 3	Jun-71	935	Mar-77	5.75			0
	Dec-72	1095	Mar-78	5.25	1.50	11.1%	0
Diablo Canyon 1	Mar-66	154	Mar-72	6.01			0
	Jun-72	320	Mar-75	2.75	6.26	12.4%	46.5
Diablo Canyon 2	Dec-68	151	Jul-74	5.58			0
	Jun-72	282	Mar-76	3.75	3.50	19.5%	9.9
Beaver Valley 2	Dec-71	296	Mar-78	6.25			0
	Mar-72	360	Mar-78	6.00	0.25	119.3%	0
Bellefonte 1	Dec-71	312	Jul-77	5.59			0
	Dec-72	348	Sep-79	6.75	1.00	11.3%	0
Bellefonte 2	Dec-71	312	Jul-77	6.75			
	Dec-72	348	Jun-80	6.75	1.00	11.3%	0
Byron 1	Jun-71	400	Oct-78	7.34			0
	Sep-72	464	May-79	6.67	1.25	12.6%	0
Byron 2	Jun-71	350	Oct-79	8.34			0
	Jun-72	422	Mar-80	7.75	1.00	20.5%	0
Fermi 2	Mar-69	221	Feb-74	4.93			0
	Dec-72	439	Aug-76	3.67	3.76	20.0%	28.5
LaSalle 2	Jun-70	300	Oct-76	6.34			0
	Sep-72	330	Sep-78	6.00	2.25	4.3%	0
McGuire 2	Sep-70	179	Nov-76	6.17			0
	Sep-71	220	Mar-77	5.50	1.00	22.9%	0
Nine Mile Point 2	Dec-71	370	Jul-78	6.59			0
	Sep-72	370	Nov-78	6.17	0.75	0.0%	0
Shearon Harris 1	Jun-71	234	Mar-77	5.75			0
	Dec-72	274	Mar-78	5.25	1.50	11.1%	0
Shearon Harris 2	Jun-71	234	Jun-78	5.75			0
	Dec-72	274	Mar-79	5.25	1.50	11.1%	0
Shoreham	Mar-67	105	May-73	6.17			0
	Jun-72	309	May-77	4.92	5.26	22.8%	1.5
Waterford 3	Sep-70	230	Jan-77	6.34			0
	Sep-72	350	Jan-77	4.34	2.00	23.3%	0.5
Watts Bar 1	Dec-71	301	Aug-76	4.67			0
	Dec-72	324	May-77	4.42	1.00	7.6%	0
Watts Bar 2	Dec-71	301	May-77	4.42			
	Dec-72	324	Feb-78	4.42	1.00	7.6%	
Zimmer 1	Dec-69	199	Jan-75	5.09			0
	Dec-72	311	Aug-77	4.67	3.00	16.0%	1
Summer 1	Mar-71	234	Jan-77	5.84			0.0
	Sep-72	297	Jan-77	4.33	1.51	17.1%	0.0
Susquehanna 1	Jun-69	150	27560	6.00			0.0
	Dec-72	703	May-79	6.41	3.50	55.4%	0.0
Lasalle 1	Jun-70	360	Oct-75	5.33			0.0
	Sep-72	407	Dec-77	5.25	2.25	5.6%	0.0
Sequoyah 2	Dec-68	161	Oct-73	4.83			0.0
	Dec-72	225	Dec-75	3.00	4.00	8.7%	NA
McGuire 1	Sep-70	179	Nov-75	5.17			0.0
	Dec-72	220	Mar-76	3.25	2.25	9.6%	9.0

TABLE 2.3: COST GROWTH IN UNITS PLANNED OR UNDER CONSTRUCTION BY DECEMBER, 1972

Unit Name	-----Estimates------ Date of Est.	Cost	COD	Years to COD	Years Elapsed	Cost Growth Rate	% Complete
Salem 2	Sep-67	128	May-73	5.66			0.0
	Dec-72	425	Mar-76	3.25	5.25	25.7%	NA
Sequoyah 1	Sep-68	161	Oct-73	5.08			0.0
	Dec-72	225	Apr-75	2.33	4.25	8.1%	45.0
North Anna 2	Sep-70	184	Mar-75	4.50			NA
	Dec-72	227	Jul-75	2.58	2.25	9.8%	28.2
Three Mile I. 2	Aug-69	214	May-74	4.75			NA
	Aug-72	465	May-76	3.75	3.00	29.5%	25.0
Cook 2	Dec-67	235	Apr-72	4.33			NA
	Sep-70	339	Mar-74	3.50	2.75	14.2%	19.0
North Anna 1	Mar-69	185	Mar-74	5.00			0.0
	Dec-72	407	Dec-74	2.00	3.76	23.4%	55.0
Salem 1	Sep-66	139	May-71	4.70			0.0
	Dec-72	425	Mar-75	2.25	6.25	19.6%	53.0
Browns Ferry 3	Mar-68	124	Oct-70	2.58			12.0
	Sep-72	149	Oct-74	2.08	4.51	4.1%	
Crystal River 3	Mar-67	110	Apr-72	5.09			0.0
	Dec-72	283	Nov-74	1.92	5.76	17.8%	63.5
Brunswick 1	Dec-70	194	Mar-76	5.25			4.0
	Dec-72	214	Dec-75	3.00	2.00	5.0%	42.0
WNP 2	Mar-71	187	Sep-77	6.50			0
	Sep-72	374	Sep-77	5.00	1.51	58.4%	NA
AVERAGES All Units							
Simple					2.86	20.8%	
Weighted by Years					--	18.6%	
NUMBER OF DATAPOINTS:					63	63	
AVERAGES Bechtel Units							
Simple					2.95	23.2%	
Weighted by Years					--	20.2%	
NUMBER OF DATAPOINTS:					26	26	

Notes: + Constructor=Bechtel
++ Architect/Engineer=Bechtel
+++ A/E and Constructor=Bechtel

TABLE 2.4: SCHEDULE SLIPPAGE IN UNITS PLANNED OR UNDER CONSTRUCTION BY DECEMBER, 1972

Unit Name	Date of Estimate	Estimated Cost	COD	Years to COD	Years Elapsed	Progress Ratio	% Complete
+++ Arkansas 1	Dec-67	132	Dec-72	5.01			0.0
	Sep-72	185	Oct-73	1.08	4.76	82.5%	86.8
+++ Arkansas 2	Dec-70	183	Oct-75	4.84			0.0
	Sep-72	230	Oct-76	4.08	1.75	42.8%	6.9
+++ Duane Arnold	Jun-68	103	Dec-73	5.50			0.0
	Sep-72	192	Jan-74	1.33	4.25	98.0%	69.0
+++ Calvert Cliffs 1	Jun-67	118	Jan-73	5.59			0.0
	Sep-72	250	Feb-74	1.42	5.26	79.4%	72.0
+++ Calvert Cliffs 2	Jun-67	105	Jan-74	6.59			0.0
	Sep-72	204	Jan-75	2.33	5.26	81.0%	56.0
+++ Davis-Besse 1	Dec-68	180	Dec-74	6.00			0.0
	Dec-72	349	May-75	2.41	4.00	89.7%	40.0
++ Farley 1	Sep-69	164	Apr-75	5.58			0.0
	Sep-71	259	Apr-75	3.58	2.00	100.0%	6.0
++ Farley 2	Sep-70	183	Apr-77	6.59			0.0
	Sep-71	233	Apr-77	5.59	1.00	100.0%	0.0
++ Hatch 1	Jun-68	NA	Jun-73	5.00			0.0
	Dec-72	282	Apr-74	1.33	4.50	81.5%	69.0
Millstone 2	Dec-67	150	Apr-74	6.34			0.0
	Sep-72	282	Apr-74	1.58	4.76	100.0%	49.0
++ Oconee 1	Sep-70	109	Jul-71	0.83			80.0
	Dec-72	137	Jun-73	0.50	2.25	14.7%	99.5
++ Oconee 2	Sep-70	109	Jul-72	1.83			50.0
	Sep-71	137	Feb-73	1.42	1.00	41.1%	71.0
++ Oconee 3	Sep-70	109	Jul-73	2.83			25.0
	Sep-71	137	Nov-73	2.17	1.00	66.3%	43.0
+++ Peach Bottom 2	Mar-68	163	Mar-71	3.00			4.4
	Jun-72	352	Sep-73	1.25	4.25	41.1%	72.0
+++ Peach Bottom 3	Mar-68	145	Jan-73	4.84			1.6
	Jun-72	316	Sep-74	2.25	4.25	60.8%	50.0
+++ Rancho Seco	Dec-67	134	May-73	5.42			0.0
	Sep-72	300	Feb-74	1.42	4.76	84.1%	78.0
++ Trojan	Dec-68	196	Sep-74	5.75			0.0
	Dec-72	284	Jul-75	2.58	4.00	79.3%	57.0
+++ Turkey Point 4	Sep-71	96	Jul-72	0.83			75.5
	Dec-72	106	Jul-73	0.58	1.25	20.1%	99.0
+++ Grand Gulf 1	Jun-72	600	Dec-78	6.50			0
	Dec-72	656	Jun-79	6.50	0.50	0.5%	0
+++ Hope Creek 1	Mar-70	574	Mar-75	5.00			0
	Dec-72	1139	May-79	6.42	2.76	-51.3%	0
+++ Limerick 1	Mar-70	252	Mar-75	5.00			0
	Dec-72	694	Aug-78	5.67	2.76	-24.2%	1
+++ Limerick 2	Mar-70	223	Mar-77	7.01			0
	Dec-72	512	Jan-80	7.09	2.76	-3.0%	1
+++ Midland 1	Jun-68	NA	Feb-74	5.67			0
	Dec-72	383	Feb-79	6.17	4.50	-11.1%	2
+++ Midland 2	Mar-68	NA	Feb-75	6.93			0
	Dec-72	383	Feb-80	7.17	4.76	-5.2%	2
+++ San Onofre 3	Mar-70	189	Jun-76	6.26			0
	Sep-72	NA	Apr-79	6.58	2.51	-13.0%	
++ Vogtle 1	Sep-71	NA	Apr-78	6.59			0
	Dec-72	570	Apr-80	7.34	1.25	-60.0%	0

TABLE 2.4: SCHEDULE SLIPPAGE IN UNITS PLANNED OR UNDER CONSTRUCTION BY DECEMBER, 1972

	Unit Name	Date of Estimate	Estimated Cost	Estimated COD	Years to COD	Years Elapsed	Progress Ratio	% Complete
++	Vogtle 2	Sep-71	NA	Apr-79	7.59			0
		Dec-72	NA	Apr-81	8.34	1.25	-60.0%	0
	Bailly	Mar-67	113	Dec-72	5.76			NA
		Jun-72	244	Jun-77	5.00	5.26	14.4%	0
	Shearon Harris 3	Jun-71	935	Mar-77	5.75			0
		Dec-72	1095	Mar-78	5.25	1.50	33.5%	0
+	WNP 2	Mar-71	187	Sep-77	6.51			0
		Sep-72	374	Sep-77	5.00	1.51	100.0%	NA
	Summer 1	Mar-71	234	Jan-77	5.84			0.0
		Sep-72	297	Jan-77	4.34	1.51	100.0%	0.0
+++	San Onofre 2	Mar-70	189	Jun-76	6.26			0.0
		Dec-72	360	Oct-78	5.84	2.76	15.3%	0
+++	Susquehanna 1	Jun-69	150	27560	6.00			0.0
		Dec-72	703	May-79	6.42	3.50	-11.8%	0.0
	Lasalle 1	Jun-70	360	Oct-75	5.34			0.0
		Sep-72	407	Dec-77	5.25	2.25	3.8%	0.0
	Sequoyah 2	Dec-68	161	Oct-73	4.84			0.0
		Dec-72	225	Dec-75	3.00	4.00	45.9%	NA
	McGuire 1	Sep-70	179	Nov-75	5.17			0.0
		Dec-72	220	Mar-76	3.25	2.25	85.3%	9.0
	Salem 2	Sep-67	128	May-73	5.67			0.0
		Dec-72	425	Mar-76	3.25	5.25	46.0%	NA
	Sequoyah 1	Sep-68	161	Oct-73	5.08			0.0
		Dec-72	225	Apr-75	2.33	4.25	64.8%	45.0
	North Anna 2	Sep-70	184	Mar-75	4.50			NA
		Dec-72	227	Jul-75	2.58	2.25	85.2%	28.2
++	Hatch 2	Jun-70	189	Apr-76	5.88			NA
		Dec-72	330	Apr-78	5.33	2.50	21.8%	11.0
	Three Mile I. 2	Aug-69	214	May-74	4.75			NA
		Aug-72	465	May-76	3.75	3.00	33.3%	25.0
	Cook 2	Dec-67	235	Apr-72	4.34			NA
		Sep-70	339	Mar-74	3.50	2.75	30.4%	19.0
	North Anna 1	Mar-69	185	Mar-74	5.00			0.0
		Dec-72	407	Dec-74	2.00	3.76	79.9%	55.0
	Salem 1	Sep-66	139	May-71	4.71			0.0
		Dec-72	425	Mar-75	2.25	6.25	39.3%	53.0
	Browns Ferry 3	Mar-68	124	Oct-70	2.59			12.0
		Sep-72	149	Oct-74	2.08	4.51	11.2%	
	Crystal River 3	Mar-67	110	Apr-72	5.09			0.0
		Dec-72	283	Nov-74	1.92	5.76	55.1%	63.5
	Brunswick 1	Dec-70	194	Mar-76	5.25			4.0
		Dec-72	214	Dec-75	3.00	2.00	112.4%	42.0
	Diablo Canyon 1	Mar-66	154	Mar-72	6.01			0
		Jun-72	320	Mar-75	2.75	6.26	52.1%	46.5
	Diablo Canyon 2	Dec-68	151	Jul-74	5.58			0
		Jun-72	282	Mar-76	3.75	3.50	52.3%	9.9
	Beaver Valley 2	Dec-71	296	Mar-78	6.25			0
		Mar-72	360	Mar-78	6.00	0.25	100.0%	0
	Bellefonte 1	Dec-70	NA	Jul-77	6.59			0
		Dec-72	348	Sep-79	6.75	2.00	-8.3%	0
	Bellefonte 2	Dec-70	NA	Apr-78	7.34			0
		Dec-72	348	Jun-80	7.50	2.00	-8.3%	0

TABLE 2.4: SCHEDULE SLIPPAGE IN UNITS PLANNED OR UNDER CONSTRUCTION BY DECEMBER, 1972

Unit Name	Date of Estimate	Estimated Cost	COD	Years to COD	Years Elapsed	Progress Ratio	% Complete
Byron 1	Jun-71	400	Oct-78	7.34			0
	Sep-72	464	May-79	6.67	1.25	53.7%	0
Byron 2	Jun-71	350	Oct-79	8.34			0
	Jun-72	422	Mar-80	7.75	1.00	58.5%	0
Fermi 2	Mar-69	221	Feb-74	4.93			0
	Dec-72	439	Aug-76	3.67	3.76	33.5%	28.5
LaSalle 2	Jun-70	300	Oct-76	6.34			0
	Sep-72	330	Sep-78	6.00	2.25	14.9%	0
McGuire 2	Sep-70	179	Nov-76	6.17			0
	Sep-71	220	Mar-77	5.50	1.00	67.1%	0
Nine Mile Point 2	Dec-71	370	Jul-78	6.59			0
	Sep-72	370	Nov-78	6.17	0.75	55.3%	0
Shearon Harris 1	Jun-71	234	Mar-77	5.75			0
	Dec-72	274	Mar-78	5.25	1.50	33.5%	0
Shearon Harris 2	Jun-71	234	Jun-78	7.01			0
	Dec-72	274	Mar-79	6.25	1.50	50.3%	0
Shoreham	Mar-67	105	May-73	6.17			0
	Jun-72	309	May-77	4.92	5.26	23.9%	1.5
Waterford 3	Sep-70	230	Jan-77	6.34			0
	Sep-72	350	Jan-77	4.34	2.00	100.0%	0.5
Watts Bar 1	Dec-70	NA	Aug-76	5.67			0
	Dec-72	324	May-77	4.42	2.00	62.7%	0
Watts Bar 2	Dec-70	NA	May-77	6.42			NA
	Dec-72	324	Feb-78	5.17	2.00	62.2%	
Zimmer 1	Dec-69	199	Jan-75	5.09			0
	Dec-72	311	Aug-77	4.67	3.00	14.0%	1

	Years Elapsed	Progress Ratio
AVERAGES All Units		
Simple:	2.95	43.4%
Weighted by Years:	--	45.0%
NUMBER OF DATAPOINTS:	65	65
AVERAGES Bechtel Units		
Simple:	2.96	35.4%
Weighted by Years:	--	42.8%
NUMBER OF DATAPOINTS:	30	30

Notes: + Constructor=Bechtel
++ Architect/Engineer=Bechtel
+++ A/E and Constructor=Bechtel

TABLE 2.5: COST AND SCHEDULE ESTIMATE HISTORIES
of New England Nuclear Units to December, 1972

Unit Name	Date of Estimate	----Estimates----- Cost	COD
Connecticut Yankee	1962	86	1967
	1963	99	1967
	1967	104	1967
	Actual	104	Jan-68
+++ Millstone 1	Dec-65		Aug-69
	Mar-67	81	Aug-69
	Sep-67	84	Aug-69
	Dec-68	90	Jan-70
	Mar-69	90	Mar-70
	Sep-69	92	Oct-70
	Jun-70	92	Nov-70
	Sep-70	92	Dec-70
	Dec-70	92	Feb-71
	Actual	97	Mar-71
Vermont Yankee	Sep-66	88	Oct-70
	Sep-69	120	Jul-71
	Mar-70	133	Jul-71
	Feb-71		Oct-71
	Jul-71	154	Mar-72
	Dec-71		Sep-72
	Actual	184	Nov-72
+++ Pilgrim 1	Mar-64		Oct-71
	Jul-65	70	Jul-71
	Feb-67	105	Jul-71
	Jun-68	122	Sep-71
	Jan-70	153	Sep-71
	Jun-70		Dec-71
	Mar-71		Nov-71
	Mar-71		Apr-72
	Sep-72		Nov-72
	Actual	239	Dec-72
Maine Yankee	Sep-67	100	May-72
	Sep-68	131	May-72
	Mar-70	181	May-72
	Actual	219	Dec-72

Notes: + Constructor=Bechtel
++ Architect/Engineer=Bechtel
+++ A/E and Constructor=Bechtel

Unit Name	Actuals Cost	Actuals COD	C.P. issued	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	Nominal Cost Ratio	Nominal Myopia Factor	Duration Ratio	% Complete
Nine Mile Point	162	Dec-69		Sep-64	68	Jul-68	3.83	2.39	1.255	1.37	0.0
Oyster Creek 1	90	Dec-69		Jun-64		Oct-67	3.33			1.65	0.0
Dresden 2	83	Jul-70		Mar-66		Feb-69	2.92			1.48	6.0
Ginna	83	Jul-70		Mar-66		Jun-69	3.25			1.33	0.0
+++ Point Beach 1	74	Dec-70		Sep-66		Apr-70	3.58			1.19	0.0
+++ Millstone 1	97	Mar-71		Dec-65		Aug-69	3.67			1.43	0.0
Robinson 2	78	Mar-71		Jun-66		May-70	3.92			1.21	0.0
+++ Monticello	105	Jun-71		Jun-66		May-70	3.92			1.28	0.0
Dresden 3	104	Nov-71		Mar-66		Feb-70	3.92			1.45	2.0
+++ Palisades	147	Dec-71		Mar-68	89	May-70	2.17	1.65	1.260	1.73	31.0
++ Point Beach 2	71	Oct-72		Mar-67		Apr-71	4.08			1.37	0.0
Vermont Yankee	172	Nov-72		Sep-66	88	Oct-70	4.08	1.95	1.178	1.51	0
Maine Yankee	219	Dec-72		Sep-68	131	May-72	3.66	1.67	1.151	1.16	
+++ Pilgrim 1	231	Dec-72		Jun-68	122	Sep-71	3.25	1.89	1.216	1.39	
Surry 1	247	Dec-72		Dec-67	144	Mar-71	3.25	1.71	1.180	1.54	4.3
+++ Turkey Point 3	109	Dec-72		Sep-69	99	Jun-71	1.75	1.10	1.055	1.86	52.2
Quad Cities 1	100	Feb-73		Jun-66		Mar-70	3.75			1.78	0.0
Quad Cities 2	100	Mar-73		Sep-66		Mar-71	4.50			1.45	0.0
Surry 2	150	May-73		Dec-67	112	Mar-72	4.25	1.34	1.071	1.27	1.4
+++ Oconee 1	156	Jul-73		Sep-67	93	May-71	3.66	1.68	1.152	1.59	1.0
Indian Point 2	206	Aug-73		Jun-66		Jun-69	3.00			2.39	7.0
Fort Calhoun 1	174	Sep-73		Sep-67	70	May-71	3.66	2.49	1.282	1.64	0.0
+++ Turkey Point 4	123	Sep-73		Sep-69	41	Jun-72	2.75	2.99	1.489	1.46	52.2
Prairie Isl 1	233	Dec-73		Dec-67	105	May-72	4.42	2.22	1.198	1.36	0.5
Zion 1	276	Dec-73		Mar-67	164	Apr-72	5.09	1.68	1.108	1.33	0
Kewaunee	202	Jun-74		Dec-67	85	Jun-72	4.50	2.38	1.212	1.44	0.0
Cooper	246	Jul-74		Mar-68	127	Apr-72	4.08	1.94	1.176	1.55	0.9
+++ Peach Bottom 2	522	Jul-74		Sep-67	163	Mar-71	3.50	3.20	1.395	1.95	1.0
Browns Ferry 1	256	Aug-74		Dec-66	117	Oct-70	3.83	2.19	1.226	2.00	1.0
++ Oconee 2	160	Sep-74		Jun-67	86	May-72	4.92	1.87	1.135	1.47	0.0
Three Mile I. 1	398	Sep-74		Dec-67	124	May-71	3.41	3.21	1.408	1.98	1
Zion 2	290	Sep-74		Jun-67	153	May-73	5.92	1.90	1.114	1.23	0
+++ Arkansas 1	233	Dec-74		Dec-67	132	Dec-72	5.00	1.77	1.120	1.40	0
++ Oconee 3	160	Dec-74		Jun-67	92	Jun-73	6.00	1.74	1.096	1.25	0.0
+++ Peach Bottom 3	220	Dec-74		Sep-67	145	Jan-73	5.34	1.52	1.081	1.36	NA
Prairie Isl 2	172	Dec-74		Dec-67	80	May-74	6.41	2.16	1.127	1.09	0.5
Duane Arnold	202	Feb-75		Dec-69	138	Dec-73	4.00	1.46	1.100	1.29	0.0
Browns Ferry 2	256	Mar-75		Sep-66	117	Oct-70	4.08	2.18	1.211	2.08	1.0
+++ Rancho Seco	344	Apr-75		Dec-67	134	May-73	5.42	2.56	1.190	1.35	0.0
+++ Calvert Cliffs 1	429	May-75		Mar-69	124	Jan-73	3.84	3.46	1.382	1.61	3.0
Fitzpatrick	419	Jul-75		Mar-68	224	May-73	5.17	1.87	1.129	1.42	1.0
Cook 1	538	Aug-75		Dec-67	235	Apr-72	4.33	2.29	1.211	1.77	NA
Brunswick 2	382	Nov-75		Dec-70	195	Mar-74	3.25	1.96	1.230	1.51	10.0
++ Hatch 1	390	Dec-75		Mar-69	151	Jun-73	4.25	2.59	1.250	1.59	1.5
Millstone 2	418	Dec-75		Dec-69	183	Apr-74	4.33	2.28	1.210	1.38	0.0
++ Trojan	452	Dec-75		Dec-69	227	Sep-74	4.75	1.99	1.156	1.26	0.0
St. Lucie 1	470	Jun-76		Sep-69	123	May-73	3.66	3.82	1.442	1.84	1

Unit Name	Actuals Cost	Actuals COD	C.P. issued	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	Nominal Cost Ratio	Nominal Myopia Factor	Duration Ratio	% Complete
Indian Point 3	570	Aug-76		Sep-68	156	Jul-71	2.83	3.65	1.581	2.81	NA
Beaver Valley 1	599	Oct-76		Dec-69	192	Jun-73	3.50	3.12	1.384	1.95	0.5
AVERAGE All Units (1969-1976):								2.21	1.22	1.55	
NUMBER OF DATAPOINTS:								37	37	49	
AVERAGE Bechtel Units (1969-1976):								2.14	1.21	1.47	
NUMBER OF DATAPOINTS:								14	14	18	

Notes: + Constructor=Bechtel
++ Architect/Engineer=Bechtel
+++ A/E and Constructor=Bechtel

TABLE 3.2: UNITS UNDER CONSTRUCTION, in December, 1976.

	Unit Name	C.P. issued	Date of Estimate	Estimated Cost	COD	Est. Years to COD	Years Elapsed	Cost Growth Rate	Progress Rate	% Comp
	Diablo Canyon 1	Apr-68	Mar-66	154	Mar-72	6.01				0
			Sep-76	530	Jun-77	0.75	10.51	12.5%	50.0%	98.5
	Browns Ferry 3	Jul-68	Mar-68	124	Oct-70	2.59				12.0
			Jun-75	246	Jun-76	1.00	7.25	9.9%	21.8%	
	Salem 1	Sep-68	Dec-67	152	Mar-72	4.25				0.0
			Mar-75	678	Sep-76	1.51	7.25	22.9%	37.9%	90.5
	Salem 2	Sep-68	Dec-67	128	Mar-73	5.25				0.0
			Sep-74	496	May-79	4.67	6.76	22.2%	8.7%	48.1
	Crystal River 3	Sep-68	Jun-68	113	Apr-72	3.84				0.0
			Jun-75	420	Sep-76	1.25	7.00	20.6%	36.9%	95.0
	Cook 2	Mar-69	Dec-67	235	Apr-72	4.34				NA
			Dec-76	437	Jun-78	1.50	9.01	7.1%	31.5%	82.4
+++	Calvert Cliffs 2	Jul-69	Mar-69	105	Jan-74	4.84				2.0
			Dec-75	251	Jan-77	1.09	6.76	13.8%	55.6%	92.1
	Three Mile I. 2	Nov-69	Aug-69	214	May-74	4.75				NA
			Aug-76	637	May-78	1.75	7.01	16.8%	42.9%	81.0
	Brunswick 1	Feb-70	Dec-70	194	Mar-76	5.25				4.0
			Dec-75	329	Mar-77	1.25	5.00	11.1%	80.0%	86.0
	Sequoyah 1	May-70	Sep-69	187	Oct-73	4.08				1.5
			Sep-76	475	May-78	1.66	7.01	14.3%	34.6%	80.0
	Sequoyah 2	May-70	Sep-69	187	Oct-73	4.08				1.5
			Jun-76	364	Jan-79	2.59	6.75	10.4%	22.2%	NA
	Diablo Canyon 2	Dec-70	Sep-69	185	Jul-74	4.83				0
			Jun-76	425	Jun-77	1.00	6.75	13.1%	56.8%	79
	North Anna 1	Feb-71	Dec-69	281	Mar-74	4.25				1.1
			Mar-76	567	Apr-77	1.08	6.25	11.9%	50.6%	88.8
	North Anna 2	Feb-71	Sep-70	184	Mar-75	4.50				NA
			Dec-76	381	Aug-78	1.67	6.25	12.3%	45.3%	76.3
++	Farley 1	Feb-71	Jun-70	203	Apr-75	4.84				0.0
			Jun-76	614	Jun-77	1.00	6.01	20.2%	63.9%	91.0
+++	Davis-Besse 1	Mar-71	Sep-70	266	Dec-74	4.25				2.0
			Dec-75	533	Mar-77	1.25	5.25	14.1%	57.2%	95.0
++	Farley 2	Aug-72	Sep-71	233	Apr-77	5.59				0.0
			Dec-76	572	Apr-79	2.33	5.25	18.6%	61.9%	42.0
	Fermi 2	Sep-72	Jun-72	409	Apr-76	3.84				20.4
			Jun-75	899	Sep-80	5.26	3.00	30.0%	-47.4%	45
	Zimmer 1	Oct-72	Sep-71	288	Oct-76	5.09				0
			Sep-76	531	Jan-79	2.33	5.01	13.0%	55.0%	58.1
+++	Arkansas 2	Dec-72	Sep-72	230	Oct-76	4.08				6.9
			Dec-75	393	Mar-78	2.25	3.25	17.9%	56.5%	56.4
++	Hatch 2	Dec-72	Jun-70	189	Apr-76	5.88				NA
			Jun-76	512	Apr-79	2.83	6.01	18.1%	50.7%	57.0
+++	Midland 1	Dec-72	Dec-71	277	May-77	5.42				2
			Jun-76	700	Mar-82	5.75	4.50	22.9%	-7.4%	13
+++	Midland 2	Dec-72	Dec-71	277	May-78	6.42				2
			Jun-76	700	Mar-81	4.75	4.50	22.9%	37.0%	16
	Watts Bar 1	Jan-73	Dec-72	324	May-77	4.42				0
			Sep-76	475	Jun-79	2.75	3.75	10.8%	44.5%	51
	Watts Bar 2	Jan-73	Dec-72	324	Feb-78	5.17				

TABLE 3.2: UNITS UNDER CONSTRUCTION, in December, 1976.

	Unit Name	C.P. issued	Date of Estimate	Estimated Cost	COD	Est. Years to COD	Years Elapsed	Cost Growth Rate	Progress Rate	% Comp
			Sep-76	475	Mar-80	3.50	3.75	10.8%	44.6%	
	McGuire 1	Feb-73	Dec-72	220	Mar-76	3.25				9.0
			Dec-76	384	Feb-79	2.17	4.00	14.9%	27.0%	81.2
	McGuire 2	Feb-73	Sep-71	220	Mar-77	5.50				0
			Dec-76	384	Feb-80	3.17	5.25	11.2%	44.4%	55.6
	Summer 1	Mar-73	Sep-72	297	Jan-77	4.34				0.0
			Dec-76	635	May-80	3.42	4.25	19.6%	21.6%	42.5
+	WNP 2	Mar-73	Sep-72	374	Sep-77	5.00				NA
			Dec-76	901	Sep-80	3.75	4.25	23.0%	29.4%	35.8
	Forked River 1	Jul-73	Mar-75	694	May-82	7.17				0.5
			Dec-76	894	May-83	6.42	1.76	15.5%	43.1%	0.5
	Lasalle 1	Sep-73	Jun-73	407	Oct-78	5.34				0.0
			Dec-76	585	Sep-79	2.75	3.50	10.9%	73.8%	45.0
	LaSalle 2	Sep-73	Jun-73	330	Oct-79	6.34				0
			Dec-76	400	Sep-80	3.75	3.50	5.6%	73.7%	37
+++	San Onofre 2	Oct-73	Jun-73	655	Jun-79	6.00				0.0
			Jun-76	1210	Oct-81	5.34	3.00	22.7%	22.2%	23.0
+++	San Onofre 3	Oct-73	Jun-70	213	Jun-76	6.00				0
			Dec-76	996	Jan-83	6.09	6.51	26.7%	-1.3%	20
+++	Susquehanna 1	Nov-73	Sep-73	810	May-79	5.67				0.0
			Dec-76	1032	Nov-80	3.92	3.25	7.7%	53.7%	39.6
+++	Susquehanna 2	Nov-73	Mar-74	575	Jun-81	7.26				1
			Sep-76	706	May-82	5.67	2.51	8.5%	63.5%	21.2
	Bailly Nuclear 1	May-74	Jun-72	244	Jun-77	5.00				0
			Dec-76	674	Nov-82	5.92	4.50	25.3%	-20.4%	0.5
	Beaver Valley 2	May-74	Mar-74	560	Jun-79	5.25				0
			Sep-76	922	May-82	5.67	2.51	22.0%	-16.4%	0.5
+++	Limerick 1	Jun-74	Mar-74	694	Oct-79	5.59				1
			Jun-76	1212	Apr-83	6.84	2.25	28.1%	-55.3%	28.6
+++	Limerick 2	Jun-74	Mar-74	539	Apr-82	8.09				4
			Jun-76	539	Apr-85	8.84	2.25	0.0%	-33.2%	
	Nine Mile Point 2	Jun-74	Mar-74	609	May-79	5.17				0
			Jun-76	793	Oct-82	6.34	2.25	12.4%	-51.8%	1.4
	North Anna 3	Jul-74	Mar-74	396	Mar-78	4.00				3.3
			Mar-76	653	Apr-81	5.09	2.00	28.4%	-54.2%	6.9
	North Anna 4	Jul-74	Jun-74	281	Mar-79	4.75				1.6
			Mar-76	423	Nov-81	5.67	1.75	26.3%	-52.7%	1.6
	Millstone 3	Aug-74	Mar-73	650	May-79	6.17				NA
			Jan-76	1010	May-82	6.33	2.84	16.8%	-5.8%	NA
+++	Grand Gulf 1	Sep-74	Sep-73	656	Sep-79	6.00				0
			Sep-76	935	Jun-80	3.75	3.00	12.5%	75.0%	32.5
+++	Grand Gulf 2	Sep-74	Sep-73	571	Sep-81	8.01				NA
			Sep-76	775	Sep-83	7.00	3.00	10.7%	33.4%	6.5
+++	Hope Creek 1	Nov-74	Sep-74	1972	Dec-81	7.25				0
			Sep-76	2580	May-84	7.67	2.00	14.4%	-20.7%	2
	Waterford 3	Nov-74	Jun-74	445	Jun-80	6.01				0.5
			Sep-76	815	Apr-81	4.58	2.25	30.8%	63.1%	15
	Bellefonte 1	Dec-74	Sep-74	482	Dec-79	5.25				0
			Sep-76	587	Jun-80	3.75	2.00	10.3%	75.0%	24

TABLE 3.2: UNITS UNDER CONSTRUCTION, in December, 1976.

Unit Name	C.P. issued	Date of Estimate	Estimated Cost	COD	Est. Years to COD	Years Elapsed	Cost Growth Rate	Progress Rate	% Comp
Bellefonte 2	Dec-74	Sep-74	482	Dec-79	5.25				
		Sep-76	587	Mar-81	4.50	2.00	10.3%	37.6%	
Comanche Peak 1	Dec-74	Mar-74	355	Jan-80	5.84				0
		Dec-76	690	Jan-80	3.08	2.76	27.3%	100.0%	40
Comanche Peak 2	Dec-74	Mar-74	355	Jan-82	7.84				0
		Dec-76	690	Jan-82	5.09	2.76	27.3%	100.0%	17
Surry 3	Dec-74	Sep-74	525	Dec-80	6.25				0
		Jun-76	1074	Apr-86	9.84	1.75	50.5%	-204.7%	0
Surry 4	Dec-74	Mar-74	254	Jun-81	7.26				0
		Jun-76	765	Apr-87	10.84	2.25	63.1%	-158.8%	0
Catawba 2	Aug-75	Dec-74	542	Jan-82	7.09				0
		Dec-76	542	Jun-83	6.50	2.00	0.0%	29.4%	9.5
WNP 1	Dec-75	Mar-75	990	Sep-80	5.51				0
		Dec-76	1057	Sep-81	4.75	1.76	3.8%	43.1%	1.8
Braidwood 1	Dec-75	Sep-75	618	Oct-81	6.09				0.25
		Sep-76	718	Oct-81	5.08	1.00	16.1%	100.0%	6
Braidwood 2	Dec-75	Dec-74	442	Oct-82	7.84				0
		Sep-76	486	Oct-82	6.08	1.75	5.6%	100.0%	4
Byron 1	Dec-75	Sep-75	551	Oct-80	5.09				1
		Dec-76	664	Mar-81	4.25	1.25	16.1%	67.0%	14
Byron 2	Dec-75	Sep-75	478	Oct-82	7.09				1
		Sep-76	489	Oct-82	6.08	1.00	2.3%	100.0%	9

	Years Elapsed	Cost Growth Rate	Progress Rate
AVERAGES All Units:			
Simple	7.36	17.1%	28.2%
Weighted by years	-	16.5%	33.0%
NUMBER OF DATAPOINTS:	60	60	60
AVERAGES Bechtel Units:			
Simple	4.09	16.8%	30.1%
Weighted by years	-	17.8%	35.4%
NUMBER OF DATAPOINTS:	18	18	18

Notes: + Constructor=Bechtel
++ Architect/Engineer=Bechtel
+++ A/E and Constructor=Bechtel

TABLE 3.3: UNITS WITHOUT CONSTRUCTION PERMIT IN DECEMBER, 1976

Unit Name	Date Ordered	Estimated COD
Pilgrim 2	Mar-72	Mar-84
*Sears Island	Nov-74	Jun-86 [1]
*Jamesport 1	Jun-73	Jun-83 [1]
Jamesport 2	Feb-74	Jun-85 [1]
*NEP-1	May-74	Jun-84 [1]
NEP-2	May-74	Jun-86 [1]
*Montague 1	Jun-74	Apr-86
Montague 2	Jun-74	Jan-88
*Douglas Point 1	Sep-72	Jan-87 [1]
Douglas Point 2	Sep-72	indef.
*Greene County	Jun-74	Sep-84
*Atlantic 1	Sep-72	May-85
Atlantic 2	Sep-72	May-87
*PSE&G Floating Plant 1	Nov-73	Jun-90 [1]
PSE&G Floating Plant 2	Nov-73	Jun-92 [1]
*Sterling	Jul-73	Apr-84
Zimmer 2	Jan-74	Jun-87 [1]
*Greenwood 2	Apr-72	Mar-84
Greenwood 3	Apr-72	Jun-86
*Central Iowa		Jun-85 [2]
*Wolf Creek	Jul-73	Apr-82
*Tyrone 1	Jul-73	May-85
*Erie-1	Jul-76	Apr-84
Erie-2	Jul-76	Apr-86
Fort Calhoun 2	Aug-74	indef.
*Marble Hill 1	Aug-74	Jun-82 [1]
Marble Hill 2	Aug-74	Jun-84 [1]
*Koshkonong 1		Feb-85
Koshkonong 2		Jul-86
*Barton 1	Dec-72	indef.
Barton 2	Dec-72	indef.
*CP&L 1		Mar-89
CP&L 2		Mar-91
*Perkins 1	Apr-73	Jan-85
Perkins 2	Apr-73	Jan-87
Perkins 3	Apr-73	Jan-90
*South Dade-1	May-75	indef.
South Dade-2	May-75	indef.
*Phipps Bend 1	Aug-74	Apr-84
Phipps Bend 2	Aug-74	Apr-85
*Yellow Creek 1	Aug-74	Mar-85
Yellow Creek 2	Aug-74	Mar-86
*Blue Hills 1	Feb-73	indef.
Blue Hills 2	May-74	indef.
*Allens Creek 1	Mar-73	Jun-85 [1]
*Black Fox 1	Dec-73	Jun-83 [1]
Black Fox 2	Dec-73	Jun-85 [1]
*Pebble Springs 1	Feb-73	Jul-85
Pebble Springs 2	May-74	Jul-88

*Skagit 1	Dec-73	Jul-83
Skagit 2	Jul-74	Jul-86
*Sundesert 1	Jul-75	indef.
Sundesert 2	Jul-75	indef.

AVERAGES		
All Units		Jan-86
First units (except Pilgrim 2)		Feb-85

Source: Nuclear News, February 1977

Notes: * First units.

1. Month not given, June assumed.
2. "Mid-1980s" assumed to be June, 1985.

TABLE 3.4: MILLSTONE 2 COST ESTIMATE HISTORY

Unit Name	Date of Estimate	----Estimates---- Cost	COD
Millstone 2	Dec-67	150	Apr-74
	Mar-68	146	Apr-74
	Dec-68	179	Apr-74
	Dec-69	183	Apr-74
	Dec-70	239	Apr-74
	Sep-71	252	Apr-74
	Sep-72	282	Apr-74
	Mar-73	341	Dec-74
	Dec-73	380	May-75
	Sep-74	399	Aug-75
	Jun-75	399	Oct-75
	Sep-75	416	Nov-75
	Dec-75	416	Dec-75
	Actual	426	Dec-75

TABLE 4.1: COST AND SCHEDULE SLIPPAGE: PLANTS WITH COD IN 1977 and 1978

Unit Name	Actuals Cost	Actuals COD	C.P. issued	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	Nominal Cost Ratio	Nominal Myopia Factor	Duration Ratio	% Complete
Browns Ferry 3	301	Mar-77		Mar-68	124	Oct-70	2.58	2.42	1.408	3.48	12.0
Brunswick 1	318	Mar-77		Dec-70	194	Mar-76	5.25	1.64	1.099	1.19	4.0
Crystal River 3	366	Mar-77		Jun-68	113	Apr-72	3.83	3.24	1.359	2.28	0.0
Calvert Cliffs 2	335	Apr-77		Mar-69	105	Jan-74	4.84	3.19	1.271	1.67	2.0
Salem 1	850	Jun-77		Dec-67	152	Mar-72	4.25	5.59	1.500	2.24	0.0
Davis-Besse 1	558	Nov-77		Sep-70	266	Dec-74	4.25	2.10	1.190	1.69	2.0
Farley 1	727	Dec-77		Jun-70	203	Apr-75	4.83	3.58	1.302	1.55	0.0
North Anna 1	782	Jun-78		Dec-69	281	Mar-74	4.25	2.78	1.272	2.00	1.1
Cook 2	444	Jul-78		Dec-67	235	Apr-72	4.33	1.89	1.158	2.44	NA
Three Mile I. 2	715	Dec-78		Aug-69	214	May-74	4.75	3.34	1.289	1.96	NA
AVERAGE All Units (1977-1978):								2.98	1.28	2.05	
NUMBER OF DATAPOINTS:								10	10	10	
AVERAGE All Units (1969-1978):								2.38	1.23	1.63	
NUMBER OF DATAPOINTS:								47	47	59	

Notes: + Constructor=Bechtel
++ Architect/Engineer=Bechtel
+++ A/E and Constructor=Bechtel

TABLE 4.2: UNITS PLANNED OR UNDER CONSTRUCTION, in December, 1978.

Unit Name	C.P. issued	Date of Estimate	Estimated Cost	COD	Est. Years to COD	Years Elapsed	Cost Growth Rate	Progress Rate	% Comp
Diablo Canyon 1	Apr-68	Sep-76	530	Jun-77	0.75				98.5
		Jun-78	672	Jun-79	1.00	1.75	14.5%	-14.4%	99.2
Salem 2	Sep-68	Sep-74	496	May-79	4.66				48.1
		Mar-78	619	May-79	1.17	3.50	6.5%	99.9%	90.6
Sequoyah 1	May-70	Sep-76	475	May-78	1.66				80.0
		Sep-78	632	Oct-79	1.08	2.00	15.4%	29.0%	92.0
Sequoyah 2	May-70	Jun-76	364	Jan-79	2.58				NA
		Sep-78	632	Jun-80	1.75	2.25	27.8%	37.1%	78.0
Diablo Canyon 2	Dec-70	Jun-76	425	Jun-77	1.00				79
		Dec-78	548	Jun-80	1.50	2.50	10.7%	-20.0%	96.9
North Anna 2	Feb-71	Dec-76	381	Aug-78	1.66				76.3
		Mar-78	467	Mar-79	1.00	1.25	17.7%	53.4%	90.4
++ Farley 2	Aug-72	Dec-76	572	Apr-79	2.33				42.0
		Sep-78	652	Apr-80	1.58	1.75	7.8%	42.7%	72.4
Fermi 2	Sep-72	Jun-75	899	Sep-80	5.26				
		Mar-77	882	Dec-80	3.76	1.75	-1.1%	85.8%	
Zimmer 1	Oct-72	Sep-76	531	Jan-79	2.33				58.1
		Mar-78	664	Jan-80	1.84	1.50	16.1%	33.2%	81.3
Watts Bar 1	Jan-73	Sep-76	475	Jun-79	2.75				51
		Dec-78	617	Jun-80	1.50	2.25	12.3%	35.4%	87
Watts Bar 2	Jan-73	Sep-76	475	Mar-80	3.50				
		Dec-78	617	Mar-81	2.25	2.25	12.3%	55.5%	68
McGuire 1	Feb-73	Dec-76	384	Feb-79	2.17				81.2
		Dec-78	549	Feb-80	1.17	2.00	19.6%	50.0%	96.0
McGuire 2	Feb-73	Dec-76	384	Feb-80	3.17				55.6
		Mar-78	549	Mar-81	3.00	1.25	33.2%	13.4%	51
Summer 1	Mar-73	Dec-76	635	May-80	3.41				42.5
		Sep-78	675	Dec-80	2.25	1.75	3.6%	66.5%	77.0
WNP 2	Mar-73	Dec-76	901	Sep-80	3.75				35.8
		Mar-78	1001	Sep-80	2.50	1.25	8.8%	100.3%	60.7
Forked River 1	Jul-73	Dec-76	894	May-83	6.42				0.5
		Dec-78	1150	Dec-83	5.00	2.00	13.4%	70.7%	4.1
Lasalle 1	Sep-73	Dec-76	585	Sep-79	2.75				45.0
		Sep-77	675	Sep-79	2.00	0.75	21.0%	99.9%	55.0
LaSalle 2	Sep-73	Dec-76	400	Sep-80	3.75				37
		Dec-78	580	Sep-80	1.75	2.00	20.4%	100.0%	59
+++ San Onofre 2	Oct-73	Jun-76	1210	Oct-81	5.33				23.0
		Jun-77	1320	Oct-81	4.33	1.00	9.1%	99.9%	44.0
+++ San Onofre 3	Oct-73	Dec-76	996	Jan-83	6.08				20
		Jun-77	1080	Jan-83	5.58	0.50	17.6%	100.3%	30
+++ Susquehanna 1	Nov-73	Dec-76	1032	Nov-80	3.92				39.6
		Sep-78	1293	Feb-81	2.42	1.75	13.8%	85.5%	76.1
+++ Susquehanna 2	Nov-73	Sep-76	706	May-82	5.67				21.2
		Sep-78	787	May-82	3.67	2.00	5.6%	100.0%	51.7
Beaver Valley 2	May-74	Sep-76	922	May-82	5.67				0.5
		Sep-78	1415	May-84	5.67	2.00	23.9%	-0.1%	26
Bailly Nuclear 1	May-74	Dec-76	674	Nov-82	5.92				0.5
		Dec-78	850	Dec-84	6.01	2.00	12.3%	-4.2%	0.5
+++ Limerick 1	Jun-74	Jun-76	1212	Apr-83	6.83				28.6
		Jun-77	1635	Apr-83	5.83	1.00	34.9%	100.0%	32
+++ Limerick 2	Jun-74	Jun-76	539	Apr-85	8.83				15.3
		Jun-77	949	Apr-85	7.83	1.00	76.1%	100.0%	22

	Unit Name	C.P. issued	Date of Estimate	Estimated Cost	COD	Est. Years to COD	Years Elapsed	Cost Growth Rate	Progress Rate	% Comp
++	Vogtle 1	Jun-74	Mar-74	631	Apr-80	6.08				0
			Dec-77	1537	Nov-84	6.92	3.76	26.7%	-22.2%	5
++	Vogtle 2	Jun-74	Sep-73	543	Apr-81	7.58				0
			Dec-78	1297	Nov-87	8.92	5.25	18.0%	-25.4%	3
	Nine Mile Point 2	Jun-74	Jun-76	793	Oct-82	6.34				1.4
			Dec-78	1954	Oct-84	5.84	2.50	43.4%	19.9%	24.1
	North Anna 3	Jul-74	Mar-76	653	Apr-81	5.09				6.9
			Mar-78	1012	Oct-83	5.59	2.00	24.5%	-25.1%	7
	North Anna 4	Jul-74	Mar-76	423	Nov-81	5.67				1.6
			Mar-78	660	Sep-84	6.51	2.00	24.9%	-41.8%	3.7
	Millstone 3	Aug-74	Jun-76	998	May-82	5.92				9.9
			Sep-78	1980	May-86	7.67	2.25	35.6%	-77.7%	24.5
+++	Grand Gulf 1	Sep-74	Sep-76	935	Jun-80	3.75				32.5
			Dec-77	1174	Apr-81	3.33	1.25	20.0%	33.4%	57.9
+++	Grand Gulf 2	Sep-74	Sep-76	775	Sep-83	7.00				6.5
			Dec-77	954	Jan-84	6.08	1.25	18.1%	73.4%	2.4
+++	Hope Creek 1	Nov-74	Sep-76	2580	May-84	7.67				2
			Jun-78	2890	May-84	5.92	1.75	6.7%	100.1%	8.5
	Waterford 3	Nov-74	Sep-76	815	Apr-81	4.58				15
			Sep-78	1110	Oct-81	3.08	2.00	16.7%	74.9%	48.8
	Bellefonte 1	Dec-74	Sep-76	587	Jun-80	3.75				24
			Sep-78	792	Sep-81	3.00	2.00	16.2%	37.4%	60
	Bellefonte 2	Dec-74	Sep-76	587	Mar-81	3.75				
			Sep-78	792	Jun-82	3.75	2.00	16.2%	0.0%	42
	Comanche Peak 1	Dec-74	Dec-76	690	Jan-80	3.08				40
			Jun-77	850	Jan-81	3.59	0.50	51.9%	-101.1%	39
	Comanche Peak 2	Dec-74	Dec-76	690	Jan-82	5.09				17
			Jun-77	850	Jan-83	5.59	0.50	51.9%	-100.5%	9.67
	Catawba 1	Aug-75	Dec-74	542	Jan-81	6.09				0.7
			Mar-78	673	Jul-81	3.34	3.25	6.9%	84.7%	28
	Catawba 2	Aug-75	Dec-76	542	Jun-83	6.50				9.5
			Mar-78	673	Jan-83	4.84	1.25	19.0%	133.2%	22
+	WNP 1	Dec-75	Dec-76	1057	Sep-81	4.75				1.8
			Mar-78	1164	Dec-82	4.75	1.25	8.0%	0.0%	9.3
	Braidwood 1	Dec-75	Sep-76	718	Oct-81	5.08				6
			Dec-78	902	Oct-81	2.84	2.25	10.7%	100.0%	45
	Braidwood 2	Dec-75	Sep-76	486	Oct-82	6.08				4
			Dec-78	601	Oct-82	3.84	2.25	9.9%	100.0%	36
	Byron 1	Dec-75	Dec-76	664	Mar-81	4.25				14
			Dec-78	984	Sep-81	2.75	2.00	21.7%	74.8%	52
	Byron 2	Dec-75	Sep-76	489	Oct-82	6.08				9
			Dec-78	624	Oct-82	3.84	2.25	11.4%	100.0%	42
	Clinton 1	Feb-76	Dec-75	705	Jun-81	5.50				0
			Dec-78	1297	Dec-82	4.00	3.00	22.5%	50.0%	36
	Clinton 2	Feb-76	Dec-75	604	Jun-84	8.51				0
			Dec-77	1059	Jun-88	10.51	2.00	32.4%	-99.9%	0
+++	Callaway 1	Apr-76	Mar-76	780	Oct-81	5.58				1
			Dec-77	1122	Oct-82	4.83	1.75	23.0%	42.8%	11.2
	Callaway 2	Apr-76	Mar-76	739	Apr-83	7.09				0.2
			Sep-78	1306	Apr-87	8.58	2.50	25.5%	-59.7%	0.4
+++	Palo Verde 1	May-76	Dec-75	975	May-82	6.42				0
			Sep-78	760	May-82	3.67	2.75	-8.7%	99.9%	28.5

Unit Name	C.P. issued	Date of Estimate	Estimated Cost	COD	Est. Years to COD	Years Elapsed	Cost Growth Rate	Progress Rate	% Comp
+++ Palo Verde 2	May-76	Dec-75	845	May-84	8.42				0
		Sep-78	598	May-84	5.67	2.75	-11.8%	99.9%	7.8
+++ Palo Verde 3	May-76	Mar-76	950	Jun-86	9.50				0
		Sep-78	702	Jun-86	7.75	2.50	-11.4%	69.9%	0.5
Seabrook 1	Jul-76	Mar-75	772	Nov-80	5.68				0
		Jan-78	1360	Dec-82	4.92	2.84	22.1%	26.7%	8
Seabrook 2	Jul-76	Mar-75	772	Nov-82	7.68				0
		Jan-78	995	Dec-84	6.92	2.84	9.3%	26.6%	2
River Bend 1	Mar-77	Dec-76	934	Sep-81	4.75				4
		Jun-78	1172	Sep-84	6.26	1.50	16.4%	-100.4%	5
Hartsville A-1	May-77	Dec-76	602	Feb-83	6.17				1
		Sep-78	853	Jun-83	4.75	1.75	22.0%	81.2%	13
Hartsville A-2	May-77	Dec-76	602	Feb-84	7.17				
		Sep-78	853	Jun-84	5.75	1.75	22.0%	81.1%	
Hartsville B-1	May-77	Sep-76	602	Aug-83	6.92				
		Sep-77	854	Dec-83	6.25	1.00	41.8%	66.6%	
Hartsville B-2	May-77	Jun-76	601	Aug-84	8.17				NA
		Sep-77	854	Dec-84	7.25	1.25	32.4%	73.3%	
Perry 1	May-77	Mar-77	1011	Dec-81	4.76				5.4
		Dec-78	1159	May-83	4.42	1.75	8.1%	19.4%	33.2
Perry 2	May-77	Mar-77	1011	Jun-83	6.25				5.4
		Sep-78	1318	May-85	6.67	1.50	19.3%	-27.5%	20.2
St. Lucie 2	May-77	Dec-76	850	Dec-82	6.00				0.7
		Dec-78	919	May-83	4.42	2.00	4.0%	79.3%	16.8
Cherokee 1	Dec-77	Mar-77	336	Jan-84	6.84				0.5
		Mar-78	392	Jan-85	6.84	1.00	16.8%	-0.3%	1
Cherokee 2	Dec-77	Mar-77	336	Jul-86	9.34				0.5
		Mar-78	392	Jan-87	8.84	1.00	16.8%	49.6%	2
Cherokee 3	Dec-77	Mar-77	336	Jan-89	11.85				0.5
		Mar-78	392	Jan-89	10.85	1.00	16.8%	100.0%	1
Shoreham	Jan-78	Sep-77	1188	Sep-80	3.00				62
		Dec-78	1337	Dec-80	2.00	1.25	9.9%	80.0%	78
WNP 4	Feb-78	Dec-77	1232	Jun-84	6.50				2.8
		Sep-78	1982	Jun-85	6.75	0.75	88.4%	-33.2%	7.6
AVERAGES All Units									
Simple:						1.87	19.3%	40.6%	
Weighted by years:						-	16.8%	39.7%	
NUMBER OF DATAPOINTS:						69	69	69	
AVERAGES Bechtel Units									
Simple:						1.96	14.9%	64.7%	
Weighted by years:						-	12.0%	50.1%	
NUMBER OF DATAPOINTS:						17	17	17	

Notes: + Constructor=Bechtel
++ Architect/Engineer=Bechtel
+++ A/E and Constructor=Bechtel

TABLE 4.3: UNITS WITHOUT CONSTRUCTION PERMIT IN DECEMBER, 1978.

Unit Name	Date Ordered	Estimated COD
Pilgrim 2	Mar-72	Jun-85
*NEP-1	May-74	Jun-86 [1]
NEP-2	May-74	Jun-88 [1]
*NYSEG-1	Jul-77	indef.
NYSEG-2	Jul-77	indef.
*Montague 1	Jun-74	Jun-89 [2]
Montague 2	Jun-74	Jun-91 [3]
*Greene County	Jun-74	May-89
*Carroll County-1	Dec-78	Jun-88 [1]
Carroll County-2	Dec-78	Jun-89 [1]
*Greenwood 2	Apr-72	Jun-89 [1]
Greenwood 3	Apr-72	Jun-91 [1]
*Central Iowa		indef
*Erie 1	Jul-76	Apr-86
Erie 2	Jul-76	Apr-88
*Haven 1	Jul-73	Jun-87
*Perkins 1	Apr-73	Jan-88
Perkins 2	Apr-73	Jul-91
Perkins 3	Apr-73	Jan-93
Palo Verde-4	Aug-77	May-88
Palo Verde-5	Aug-77	May-90
*Allens Creek 1	Mar-73	Jun-85 [1]
*Pebble Springs 1	Feb-73	Mar-87
Pebble Springs 2	May-74	Apr-89
*Skagit 1	Dec-73	Jul-85
Skagit 2	Jul-74	Jul-87
AVERAGES		
All units		Aug-88
First units (except Pilgrim 2)		Jul-87

Source: Nuclear News, February 1979

Notes: * First units

1. Month not given, June assumed.
2. "1988-1990" COD assumed to be June 1989.
3. "1990-1992" COD assumed to be June 1991.

TABLE 5.1: COST AND SCHEDULE SLIPPAGE: PLANTS WITH COD IN 1979 AND FIRST HALF OF 1980

	Actuals			Estimates				---Nominal----			
Unit Name	Cost	COD	C.P. issued	Date of Estimate	Total Cost	COD	Est. Years to COD	Cost Ratio	Myopia Factor	Duration Ratio	% Complete
++ Hatch 2	509	Sep-79		Jun-70	189	Apr-76	5.88	2.69	1.184	1.57	NA
+++ Arkansas 2	640	Mar-80		Sep-72	230	Oct-76	4.08	2.78	1.285	1.84	6.9
AVERAGE All Units (1979-1980):								2.74	1.234	1.71	
NUMBER OF DATAPOINTS:								2	2	2	
AVERAGE All Units (1969-1980):								2.39	1.23	1.63	
NUMBER OF DATAPOINTS:								49	49	61	
AVERAGE Bechtel Units (1969-1980):								2.22	1.22	1.50	
NUMBER OF DATAPOINTS:								16	16	20	

Notes: + Constructor=Bechtel
++ Architect/Engineer=Bechtel
+++ A/E and Constructor=Bechtel

	Unit Name	C.P. issued	Date of Estimate	Estimated Cost	COD	Est. Years to COD	Years Elapsed	Cost Growth Rate	Progress Rate	% Comp
	Diablo Canyon 1	Apr-68	Jun-78	672	Jun-79	1.00				99.2
			Mar-80	880	Jun-81	1.25	1.75	16.7%	-14.4%	99.2
	Sequoyah 1	May-70	Sep-78	632	Oct-79	1.08				92.0
			Jun-79	632	Jun-80	1.00	0.75	0.0%	10.6%	98.0
	Sequoyah 2	May-70	Sep-78	632	Jun-80	1.75				78.0
			Sep-79	442	Jun-81	1.75	1.00	-30.1%	0.0%	84.0
	Diablo Canyon 2	Dec-70	Dec-78	548	Jun-80	1.50				96.9
			Dec-79	721	Jun-81	1.50	1.00	31.6%	0.0%	97.9
++	Farley 2	Aug-72	Sep-78	652	Apr-80	1.58				72.4
			Sep-79	684	Sep-80	1.00	1.00	4.9%	58.0%	83.7
	Fermi 2	Sep-72	Jun-75	899	Sep-80	5.26				45
			Jun-80	1283	Mar-82	1.75	5.01	7.4%	70.1%	79.4
	Zimmer 1	Oct-72	Mar-78	664	Jan-80	1.84				81.3
			Jun-80	1027	Apr-82	1.83	2.25	21.3%	0.2%	93.8
	Watts Bar 1	Jan-73	Dec-78	617	Jun-80	1.50				87
			Jun-80	720	May-82	1.92	1.50	10.8%	-27.6%	87
	Watts Bar 2	Jan-73	Dec-78	617	Mar-81	2.25				68
			Jun-80	720	Feb-83	2.67	1.50	10.8%	-28.1%	72
	McGuire 2	Feb-73	Mar-78	549	Mar-81	3.00				51
			Jun-80	635	Sep-82	2.25	2.25	6.7%	33.3%	83
	Summer 1	Mar-73	Sep-78	675	Dec-80	2.25				77.0
			Mar-80	827	Jun-81	1.25	1.50	14.5%	66.7%	94.8
	WNP 2	Mar-73	Mar-78	1001	Sep-80	2.50				60.7
			Jun-80	2392	Jan-83	2.58	2.25	47.2%	-3.7%	85.2
	Lasalle 1	Sep-73	Sep-77	675	Sep-79	2.00				55.0
			Jun-80	1107	Jun-81	1.00	2.75	19.7%	36.3%	98.0
	LaSalle 2	Sep-73	Dec-78	580	Sep-80	1.75				59
			Jun-80	786	Jun-82	2.00	1.50	22.4%	-16.4%	78
+++	San Onofre 2	Oct-73	Jun-77	1320	Oct-81	4.33				44.0
			Mar-80	1824	Dec-81	1.75	2.75	12.5%	93.9%	86.0
+++	San Onofre 3	Oct-73	Jun-77	1080	Jan-83	5.58				30
			Mar-80	1216	Jan-83	2.83	2.75	4.4%	100.0%	60
+++	Susquehanna 1	Nov-73	Sep-78	1293	Feb-81	2.42				76.1
			Sep-79	1607	Jan-82	2.34	1.00	24.3%	8.5%	70.0
+++	Susquehanna 2	Nov-73	Sep-78	787	May-82	3.67				51.7
			Jun-80	1082	Aug-82	2.17	1.75	19.9%	85.7%	53
	Beaver Valley 2	May-74	Sep-78	1415	May-84	5.67				26
			Dec-79	2024	May-86	6.42	1.25	33.2%	-60.1%	35.2
	Bailly Nuclear 1	May-74	Dec-78	850	Dec-84	6.01				0.5
			Sep-79	1100	Jun-87	7.75	0.75	41.0%	-232.8%	0.5
+++	Limerick 1	Jun-74	Jun-77	1635	Apr-83	5.83				32
			Jun-79	1695	Apr-83	3.83	2.00	1.8%	100.0%	52
+++	Limerick 2	Jun-74	Jun-77	949	Apr-85	7.83				22
			Jun-79	909	Apr-85	5.83	2.00	-2.1%	100.0%	35
+++	Vogtle 1	Jun-74	Dec-77	1537	Nov-84	6.92				5
			Jun-80	1746	May-85	4.92	2.50	5.2%	80.0%	10
+++	Vogtle 2	Jun-74	Dec-78	1297	Nov-87	8.92				3
			Jun-80	988	Nov-87	7.42	1.50	-16.6%	99.9%	4
	Nine Mile Point 2	Jun-74	Dec-78	1954	Oct-84	5.84				24.1
			Jun-80	1953	Oct-84	4.34	1.50	.0%	100.0%	37.7
	North Anna 3	Jul-74	Mar-78	1012	Oct-83	5.59				7
			Sep-79	1428	Apr-86	6.59	1.50	25.7%	-66.3%	7

Unit Name	C.P. issued	Date of Estimate	Estimated Cost	COD	Est. Years to COD	Years Elapsed	Cost Growth Rate	Progress Rate	% Comp
North Anna 4	Jul-74	Mar-78	660	Sep-84	6.51				3.7
		Sep-79	956	Apr-87	7.59	1.50	27.9%	-71.6%	3.7
+++ Grand Gulf 1	Sep-74	Dec-77	1174	Apr-81	3.33				57.9
		Dec-79	1203	Apr-82	2.33	2.00	1.2%	50.0%	80
+++ Grand Gulf 2	Sep-74	Dec-77	954	Jan-84	6.08				2.4
		Jun-80	878	Apr-86	5.83	2.50	-3.3%	10.0%	23
+++ Hope Creek 1	Nov-74	Jun-78	2890	May-84	5.92				8.5
		Jun-80	4310	Dec-86	6.50	2.00	22.1%	-29.1%	23.5
Waterford 3	Nov-74	Sep-78	1110	Oct-81	3.08				48.8
		Sep-79	1229	Feb-82	2.42	1.00	10.7%	66.3%	69.5
Bellefonte 1	Dec-74	Sep-78	792	Sep-81	3.00				60
		Sep-79	1001	Sep-83	4.00	1.00	26.4%	-100.0%	69
Bellefonte 2	Dec-74	Sep-78	792	Jun-82	3.75				42
		Sep-79	1001	Jun-84	4.75	1.00	26.4%	-100.3%	48
Comanche Peak 1	Dec-74	Jun-77	850	Jan-81	3.59				39
		Mar-79	850	Jun-81	2.25	1.75	0.0%	76.3%	68.8
Comanche Peak 2	Dec-74	Jun-77	850	Jan-83	5.59				9.67
		Mar-79	850	Jun-83	4.25	1.75	0.0%	76.3%	26.4
Catawba 1	Aug-75	Mar-78	673	Jul-81	3.34				28
		Jun-80	754	Mar-84	3.75	2.25	5.2%	-18.3%	73
Catawba 2	Aug-75	Mar-78	673	Jan-83	4.84				22
		Jun-80	754	Sep-85	5.25	2.25	5.2%	-18.3%	15
++ South Texas 1	Dec-75	Sep-75	676	Oct-80	5.08				0
		Sep-79	1208	Feb-84	4.42	4.00	15.6%	16.7%	48.3
++ South Texas 2	Dec-75	Sep-75	676	Mar-82	6.50				0
		Sep-79	1208	Feb-86	6.42	4.00	15.6%	2.1%	15
WNP 1	Dec-75	Mar-78	1164	Dec-82	4.75				9.3
		Jun-80	2498	Jun-85	5.00	2.25	40.3%	-11.1%	41.1
Braidwood 1	Dec-75	Dec-78	902	Oct-81	2.84				45
		Jun-80	1585	Oct-85	5.34	1.50	45.6%	-166.6%	56
Braidwood 2	Dec-75	Dec-78	601	Oct-82	3.84				36
		Jun-80	1011	Oct-86	6.34	1.50	41.4%	-166.6%	44
Byron 1	Dec-75	Dec-78	984	Sep-81	2.75				52
		Jun-80	1483	Oct-83	3.33	1.50	31.4%	-38.7%	69
Byron 2	Dec-75	Dec-78	624	Oct-82	3.84				42
		Jun-80	922	Oct-84	4.34	1.50	29.7%	-33.4%	55
Clinton 1	Feb-76	Dec-78	1297	Dec-82	4.00				36
		Mar-80	1397	Dec-82	2.75	1.25	6.1%	100.0%	66
++ Callaway 1	Apr-76	Dec-77	1122	Oct-82	4.83				11.2
		Mar-80	1261	Oct-82	2.58	2.25	5.3%	100.0%	64
Callaway 2	Apr-76	Sep-78	1306	Apr-87	8.58				0.4
		Jun-80	1609	Jun-88	8.00	1.75	12.7%	33.3%	0.7
+++ Palo Verde 1	May-76	Sep-78	760	May-82	3.67				28.5
		Jun-80	1429	May-83	2.92	1.75	43.4%	42.8%	68.3
+++ Palo Verde 2	May-76	Sep-78	598	May-84	5.67				7.8
		Jun-80	820	May-84	3.92	1.75	19.8%	100.0%	37.7
+++ Palo Verde 3	May-76	Sep-78	702	Jun-86	7.75				0.5
		Jun-80	1125	Jun-86	6.00	1.75	30.9%	100.0%	10.8
Seabrook 1	Jul-76	Jan-78	1360	Dec-82	4.50				8
		Apr-80	1527	Apr-83	3.00	2.25	5.3%	66.9%	37.0
Seabrook 2	Jul-76	Jan-78	995	Dec-84	6.76				2
		Jun-80	1558	Feb-85	4.67	2.42	20.4%	86.3%	7.2

Unit Name	C.P. issued	Date of Estimate	Estimated Cost	COD	Est. Years to COD	Years Elapsed	Cost Growth Rate	Progress Rate	% Comp
River Bend 1	Mar-77	Jun-78	1172	Sep-84	6.26				5
		Mar-80	1679	Apr-84	4.09	1.75	22.8%	123.9%	11.9
St. Lucie 2	May-77	Dec-78	919	May-83	4.41				16.8
		Jun-80	1100	May-83	2.91	1.50	12.7%	99.9%	45.1
++ Wolf Creek	May-77	Mar-77	1029	Apr-83	6.08				1
		Dec-79	1296	Apr-83	3.33	2.75	8.7%	99.9%	47.9
Hartsville A-1	May-77	Sep-78	853	Jun-83	4.75				13
		Sep-79	1418	Jul-86	6.84	1.00	66.3%	-208.5%	21
Hartsville A-2	May-77	Sep-78	853	Jun-84	5.75				
		Sep-79	1418	Jul-87	7.84	1.00	66.3%	-208.2%	8
Perry 1	May-77	Dec-78	1159	May-83	4.42				33.2
		Jun-80	1701	May-84	3.92	1.50	29.1%	33.2%	59.4
Perry 2	May-77	Sep-78	1318	May-85	6.67				20.2
		Jun-80	2157	May-88	7.92	1.75	32.5%	-71.5%	46.5
St. Lucie 2	May-77	Dec-78	919	May-83	4.42				16.8
		Jun-80	1100	May-83	2.92	1.50	12.7%	100.0%	45.1
Hartsville B-1	May-77	Sep-77	854	Dec-83	6.25				NA
		Sep-79	1418	Jun-89	9.76	2.00	28.9%	-175.2%	15
Hartsville B-2	May-77	Sep-77	854	Dec-84	7.25				NA
		Sep-79	1418	Jun-90	10.76	2.00	28.9%	-175.1%	5
Cherokee 1	Dec-77	Mar-78	392	Jan-85	6.84				1
		Mar-80	402	Jan-90	9.84	2.00	1.3%	-149.8%	15
Cherokee 2	Dec-77	Mar-78	392	Jan-87	8.84				2
		Mar-80	402	Jan-92	11.84	2.00	1.3%	-149.8%	1
Cherokee 3	Dec-77	Mar-78	392	Jan-89	10.85				1
		Mar-80	402	Jan-94	13.85	2.00	1.3%	-149.8%	1
Shearon Harris 1	Jan-78	Dec-77	1039	Mar-84	6.25				1.7
		Jun-80	1208	Mar-85	4.75	2.50	6.2%	60.0%	32.8
Shearon Harris 2	Jan-78	Dec-77	1039	Mar-86	6.25				1.7
		Jun-80	1208	Mar-88	4.75	2.50	6.2%	60.0%	3.7
Shoreham	Jan-78	Dec-78	1337	Dec-80	2.00				78
		Jun-80	1213	Feb-83	2.67	1.50	-6.3%	-44.5%	85.5
Shearon Harris 3	Jan-78	Dec-77	1039	Mar-90	12.25				0.5
		Jun-80	1208	Mar-94	13.76	2.50	6.2%	-60.0%	0.5
Shearon Harris 4	Jan-78	Dec-77	1039	Mar-88	10.25				0.5
		Jun-80	1208	Mar-92	11.76	2.50	6.2%	-60.0%	0.5
Phipps Bend 1	Jan-78	Dec-77	876	Aug-84	6.67				0
		Sep-79	1440	Mar-87	7.50	1.75	32.8%	-47.4%	7
Phipps Bend 2	Jan-78	Dec-77	876	Aug-85	7.67				0
		Jun-80	1440	May-94	13.92	2.50	22.0%	-249.9%	4
WNP 4	Feb-78	Sep-78	1982	Jun-85	6.75				7.6
		Mar-80	3086	Jun-86	6.25	1.50	34.4%	33.3%	14.5
Marble Hill 1	Apr-78	Dec-77	511	Sep-82	4.75				NA
		Jun-80	2001	Dec-86	6.50	2.50	72.6%	-70.0%	20
Marble Hill 2	Apr-78	Mar-78	353	Jan-84	5.84				0.4
		Jun-80	1383	Dec-87	7.50	2.25	83.2%	-73.8%	9
WNP 3	Apr-78	Mar-78	1561	Sep-83	5.51				2.3
		Sep-79	2256	Dec-84	5.25	1.50	27.7%	16.8%	16.6
WNP 5	Apr-78	Mar-78	1887	Jul-85	7.34				0
		Jun-80	3705	Jun-87	7.00	2.25	34.9%	14.9%	6.7

Unit Name	C.P. issued	Date of Estimate	Estimated Cost	COD	Est. Years to COD	Years Elapsed	Cost Growth Rate	Progress Rate	% Comp
	AVERAGES All Units								
	Simple:					1.90	18.9%	-6.3%	
	Weighted by years:					-	18.0%	0.9%	
	NUMBER OF DATAPOINTS:					77	77	77	
	AVERAGES Bechtel Units								
	Simple:					2.21	11.3%	64.1%	
	Weighted by years:					-	11.0%	61.1%	
	NUMBER OF DATAPOINTS:					19	19	19	

Notes: + Constructor=Bechtel
++ Architect/Engineer=Bechtel
+++ A/E and Constructor=Bechtel

TABLE 5.3: UNITS WITHOUT CONSTRUCTION PERMIT IN DECEMBER, 1980.

Unit Name	Date Ordered	Estimated COD
Pilgrim 2	Mar-72	indef.
Carroll County 1	Dec-78	Oct-92
Carroll County 2	Dec-78	Oct-93
Central Iowa		indef.
Perkins 1	Apr-73	indef.
Perkins 2	Apr-73	indef.
Perkins 3	Apr-73	indef.
Cherokee 2	Apr-73	Jan-93
Cherokee 3	Apr-73	indef.
River Bend	Jun-72	indef.
Allens Creek 1	Mar-73	Nov-87
Pebble Springs 1	Feb-73	indef.
Pebble Springs 2	May-74	indef.
Skagit 1	Dec-73	indef.
Skagit 2	Jul-74	indef.

Source: Nuclear News, February, 1981

TABLE 5.4: PLANT CANCELATIONS: 1977-1980

Unit Name	Year of Cancelation	Construction Status	% Complete
Alan Barton 1	1977	order	
Alan Barton 2		order	
Douglas Point 1		order	
Ft. Calhoun 2		order	
South Dade 1		order	
South Dade 2		order	
Surry 3		cp	0%
Surry 4		cp	0%
Sears Island		order	
Atlantic 1	1978	order	
Atlantic 2		order	
Blue Hills 1		order	
Blue Hills 2		order	
Haven 2		order	
Islote		order	
S.R. 1		order	
S.R. 2		order	
Sundesert 1		order	
Sundesert 2		order	
PSE&G Co. unit 1		order	
PSE&G Co. unit 2		order	
Wm. H. Zimmer 2		order	
Greene County	1979	order	
NEP-1		order	
NEP-2		order	
Palo Verde 4		order	
Palo Verde 5		order	
Tyrone 1		cp	0%
Davis-Besse 2	1980	limited work auth.	0%
Davis-Besse 3		limited work auth.	0%
Erie 1		order	
Erie 2		order	
Forked River 1		cp	5%
Greenwood 2		order	
Greenwood 3		order	
Haven 1		order	
Jamesport 1		cp	0%
Jamesport 2		cp	0%
Montague 1		order	
Montague 2		order	
New Haven 1		order	
New Haven 2		order	
North Anna 4		cp	4%
Sterling		cp	0%

Source: Atomic Industrial Forum, "Background Info", January, 1984.

Figure 5.1: Plant Cancellations:

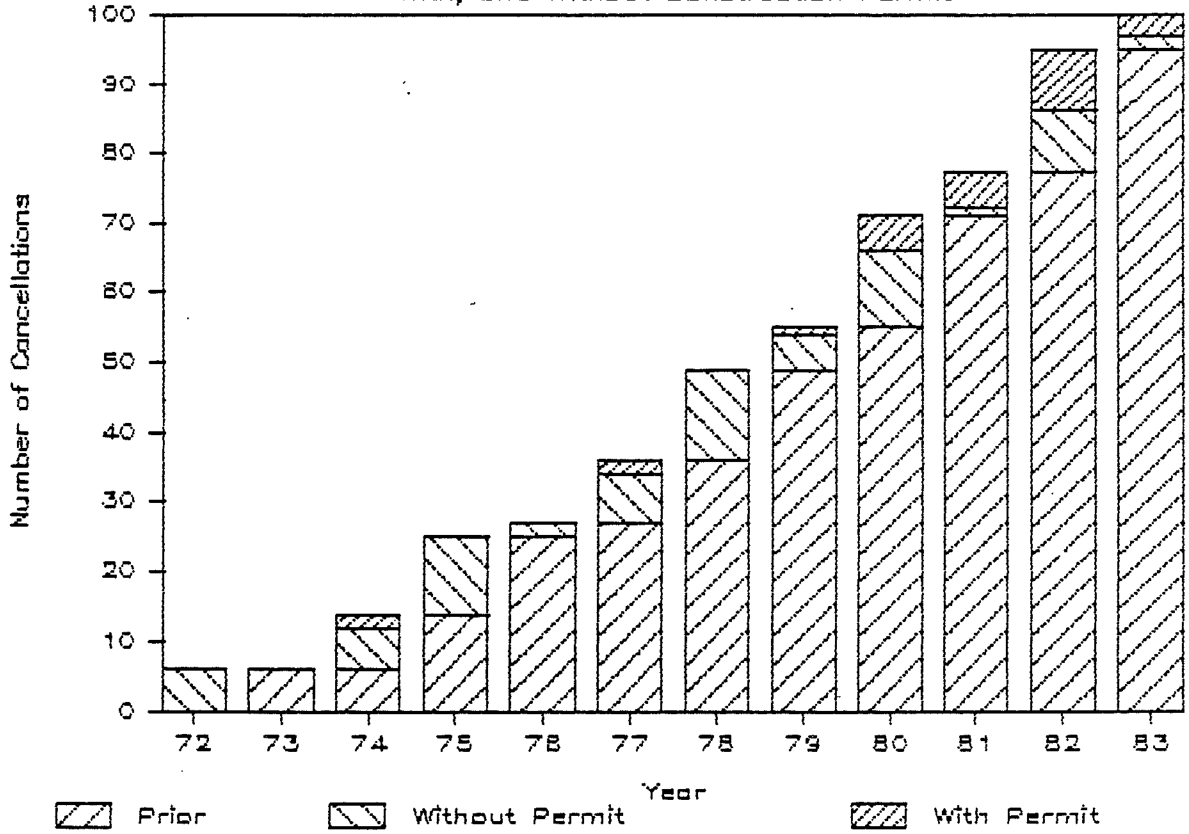


Figure 5.2: NET NUCLEAR ORDERS

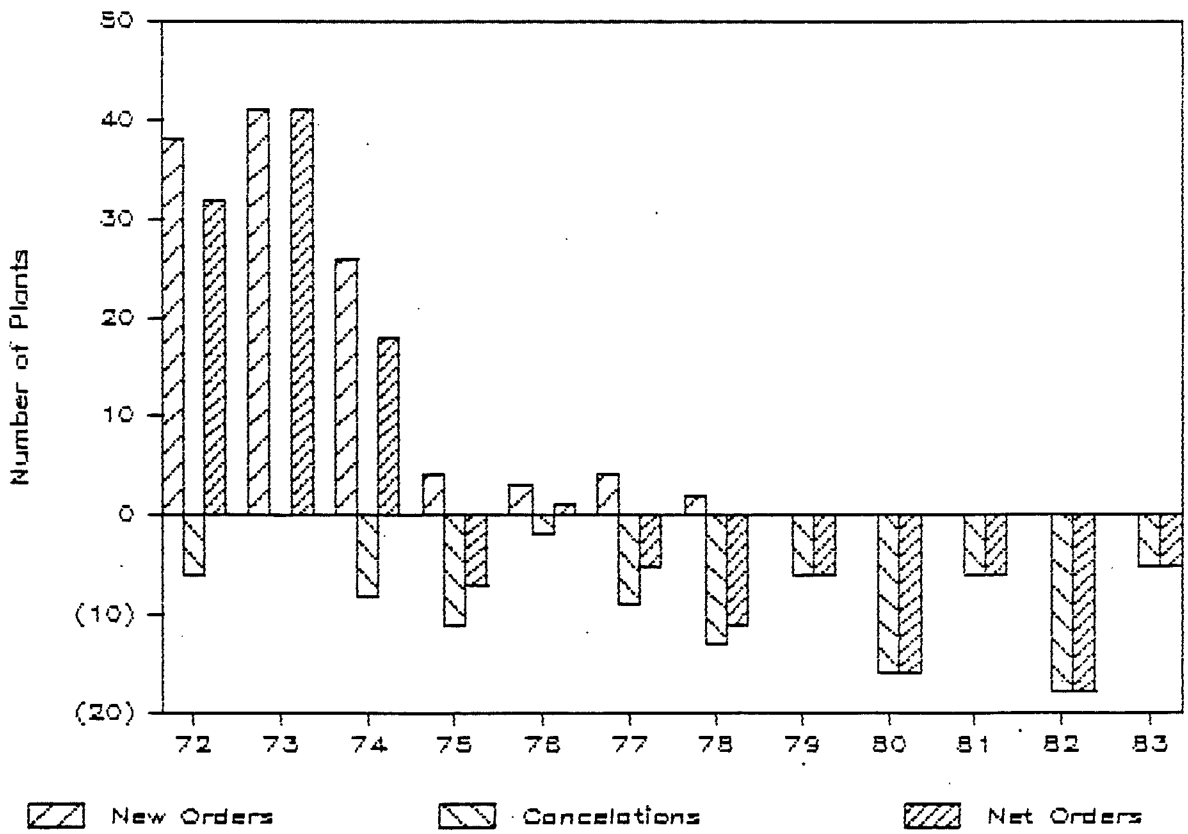


TABLE 6.1: BUSBAR COST COMPARISON, 1976

	Pilgrim 2		Coal
	A	B	C
Based on BECO Cost Estimate of:	Oct-76	Oct-76	
PLC Revised Cost Estimate:	$4,512 [1]	$4,512	$936 [2]
PLC Revised COD Estimate:	Dec-87 [3]	Dec-87	Dec-87 [4]
In-core Fuel	$215 [5]	$215	
Total Investment	$4,727	$4,727	
Sunk Cos $85 plus AFUDC to COD	$244	$244	
Net Investment	$4,483	$4,483	$936
Levelized Carrying Charges:	18.7% [6]	18.7%	18.7%
Annual Cost:	$838	$838	$175
O&M:	$46 [7]	$46	$64 [7]
Capacity Factor:	73.2% [5]	68.3% [8]	73.2% [5]
Non-fuel cents/kwh:	11.99	12.85	4.67
Fuel:	1.58 [9]	1.58	5.06 [10]
Total cents/kwh:	13.57	14.43	9.73

Notes: [1] Average of Table 3.1 results for Pilgrim 2 at
all unit cost ratio =
Bechtel cost ratio =
all unit myopia for years =
Bechtel myopia for years =

[6] Bond rate = average of Aaa and Baa.
Cost of money = bond rate + 1.6% = discount rate, from NEPLAN (1976)
= 10.7%
Carrying Charge = cost of money + 8%, from NEPLAN (1976)
= 18.7%

[10] Coal price 1980 = 1.76 cents/kwh, from NEPLAN (1976) fuel costs at 9800 BTU/kwh.

* All other notes are listed after Tables 6.1 - 6.3.
All dollar costs are in $ million for the unit.
Inflation = 6.2% Fuel Inflation= 6.2%
Inflation, 1980 to COD, with 30 year levelization
= 2.870 Fuel Inflation= 2.870

TABLE 6.2: BUSBAR COST COMPARISON, 1978

	Pilgrim 2		Coal	Oil
	A	B	C	D
Based on BECO Cost Estimate of:	May-78	May-78		
PLC Revised Cost Estimate:	$7,446 [1]	$7,446	$1,156 [2]	
PLC Revised COD Estimate:	Jun-91 [3]	Sep-90	Jun-91 [4]	
In-core Fuel	$265 [5]	$265		
Total Investment	$7,711	$7,711	$1,156	
Sunk Cost $236 with AFUDC to COD	$774	$774		
Net Investment	$6,937	$6,937		
Levelized Carrying Charges:	18.7% [6]	18.7%	18.7%	
Annual Cost:	$1,298	$1,298	$216	
O&M:	$57 [7]	$57	$79 [7]	
Capacity Factor:	73.2% [5]	67.3% [8]	73.2% [5]	
Non-fuel cents/kwh:	18.37	19.99	5.77	
Fuel:	1.95 [9]	1.95	6.24 [10]	8.86 [10]
Total cents/kwh:	20.32	21.94	12.01	8.86

Notes: [1] Average of myopia and cost ratio results for Pilgrim 2 in Table 4.1, for Bechtel through 1978, all units through 1978, and all units in 1977 and 1978; total of six results.

[6] Bond rate = average of Aaa and Baa.
Cost of money = bond rate + 1.6% = discount rate, from NEPLAN (1976).
= 10.7%
Carrying charge = cost of money + 8%, from NEPLAN (1976).
= 18.7%

[10] Coal price 1980 = 1.76 cents/kwh, from NEPLAN (1976) fuel costs at 9800 BTU/kwh.
Oil price 1980 = 2.50 ,from Exh. Webb-17, PUC 82-266, 3.59 cents in 1986, deflated at 6.2% to 1980.

* All other notes are listed after Tables 6.1 - 6.3.

Inflation	= 6.2%	fuel = 6.2%	oil = 6.2%
Inflation, 1980 to COD, with 30 year levelization	= 3.540	= 3.540	= 3.540

TABLE 6.3: BUSBAR COST COMPARISON, 1980

	Pilgrim 2		Coal	Oil
	A	B	C	D
Based on BECO Cost Estimate of:	Jun-80	Jun-80		
PLC Revised Cost Estimate:	$16,790 [1]	$16,790	$1,493 [2]	
PLC Revised COD Estimate:	Sep-95 [3]	Sep-95	Sep-95 [4]	
In-core Fuel	$307 [5]	$307		
Total Investment	$17,097	$17,097		
Sunk Cost $375 plus AFUDC to COD	$1,536	$1,536		
Net Investment	$15,560	$15,560	$1,493	
Levelized Carrying Charges:	22.4% [6]	22.4%	22.4%	
Annual Cost:	$3,486	$3,486	$334	
O&M:	$66 [7]	$66	$92 [7]	
Capacity Factor:	70.1% [11]	64.4% [8]	67.1% [5]	
Non-fuel cents/kwh:	50.28	54.73	9.07	
Fuel:	2.26 [9]	2.26	7.24 [10]	56.04
Total cents/kwh:	52.54	56.99	16.32	56.04

Notes: [1] Average of myopia and cost ratio results for Pilgrim 2, from Table 5.1, for Bechtel experience through 1980, all all experience through 1980, and Bechtel experience in 1979 and 1980; six results.

[6] Bond rate = average of Aaa and Baa.
Cost of money = bond rate + 1.6% = discount rate, from NEPLAN (1976).
= 14.4%
Carrying charge = cost of money + 8%, from NEPLAN (1976).
= 22.4%

[10] Coal price 1980 = 1.76 cents/kwh, from NEPLAN (1976).
Oil price 1980 = 5.44 , from Exh. Webb-18, PUC 82-266, 11.66 cents in 1988, deflated by 10% to 1980.

[11] Forced outage rates from NEPLAN (1976), maintenance from NEPOOL (1979).

* All other notes are listed after Tables 6.1 - 6.3.

Inflation	= 6.2%	fuel inf. 6.2%	oil inf.	10.0%
Inflation, 1980 to COD, with 30 year levelization	= 4.106	4.106		10.303

Notes to Tables 6.1 - 6.3
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[1] See each table.

[2] NEPLAN (1976) projection for 800 MW coal plant in 1980$ inflated to Pilgrim 2 COD.

[3] Average of Table 3.1 (or 4.1 or 5.1, as applicable) results for all unit and Bechtel duration ratios, times projected Pilgrim duration.

[4] Equal to Pilgrim COD, for consistency.

[5] NEPLAN (1976).

[6] See each table.

[7] NEPLAN (1976) projection in 1980$, inflated to COD and levelized over 30 years. Includes variable O&M at capacity factor specified below.

[8] From Table 6.6, levelized over a 30 year life.

[9] NEPLAN (1976), inflated and levelized.

[10] See each table.

TABLE 6.4: ANNUAL NUCLEAR O&M EXPENSES, 1968-1981 ($1000)

Plant:	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981
Arkansas 1								4109	6015	8379	12125	18923	NA	
Arkansas 1&2														54422
Beaver Valley									1777	14692	22681	22907	34771	35838
Big Rock Point	865	933	1062	1266	1412	1586	2263	2584	3183	5125	3645	9232	8409	12970
Browns Ferry 1&2								6626	16104					
Browns Ferry 1,2&3										19305	45921	55588	66969	85469
Brunswick 2								4473	10518					
Brunswick 1&2										25378	26633	34206	57516	73150
Calvert Cliffs 1								4241	8984					
Calvert Cliffs 1&2										20158	25997	36397	41628	50409
Connecticut Yankee	2047	2067	4479	3279	3749	6352	4935	9381	9419	9448	8736	18923	35155	37488
Cook 1								1662	7047	10012				
Cook 1&2											15707	26750	32409	37967
Cooper							2691	7386	10211	10218	8306	10232	19004	20455
Crystal River										7600	15613	23992	39841	42313
Davis-Besse										295	14096	10564	44630	41413
Dresden 1	1673	1788												
Dresden 1&2			2294											
Dresden 1,2&3				3639	9142	9050	16731	32895	30092	26999	33932	44579	38130	40361
Duane Arnold							2121	3839	7050	7508	11916	9528	18398	21956
Farley 1										462	12207	22545	25734	
Farley 1&2														41427
Fitzpatrick								6902	10700	17383	19045	25131	33303	36678
Fort Calhoun						529	3413	5962	7449	8493	8116	8504	14332	11472
Fort St. Vrain												12121	16884	18796
Ginna			3199	4391	4082	3536	5391	6597	7356	7942	9819	12819	18924	22482
Hatch 1									5867	9799	12268	13574		
Hatch 1&2													38486	62134
Humboldt	582	646	619	926	897	915	1070	1221	1980	3081	1635	1485	1587	2073
Indian Point 1	2831	2713	3498	3962	6950									
Indian Point 1&2						14854	12737	13195	18285	16525				
Indian Point 2											28167	32643	32964	54506
Indian Point 3									2460	12654	23318	28884	50357	58174

Plant:	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981
Kewaunee							7222	8945	10727	10924	10430	11323	14843	19334
Lacrosse											2638	3041	3318	3955
Maine Yankee						4034	5232	6301	5261	8418	10817	9971	14028	20576
McGuire														2716
Millstone 1				3256	7677	7635	9808	12065	14040	12637	16448	23060	24784	33270
Millstone 2								7	10929	17377	22288	21931	30163	28877
Monticello				1429	2567	5006	5179	8729	6609	11109	9136	10584	21413	18261
Nine Mile Point			1716	2759	3575	4524	6251	5810	5330	9743	6382	11663	32964	26744
North Anna 1											6521	19519		
North Anna 1&2													25390	28857
Oconee 1						911								
Oconee 1,2&3							6982	12449	16735	25038	29600	40177	52003	58789
Oyster Creek			1953	3097	3877	6311	10678	12310	10399	14833	15898	13055	37530	45254
Palisades					753	3160	11778	9601	9848	6569	15393	26344	19251	44140
Peach Bottom 1	1666	1481	1537	1731	1873	1605	1050							
Peach Bottom 2&3							1791	12619	30601	46674	39306	40004	56875	72615
Pilgrim					144	4797	9527	7340	16633	15320	14187	18387	27785	34994
Point Beach 1														
Point Beach 1&2				1309	2305	3647	5229	6159	6592	8014	7395	12461	17904	26820
Prairie Island 1						101								
Prairie Island 1&2							4216	7261	15574	17090	14214	15346	23175	26791
Quad Cities 1&2					2033	6290	9210	14777	16723	17756	22168	23420	38686	37272
Rancho Seco								11607	7193	14000	11834	13720	28408	35542
Robinson				1918	1780	4609	4780	6360	5903	6859	14355	15142	22085	21788
Salem 1										12707	22311	42508	59684	
Salem 1&2														77502
San Onofre	1481	1975	2236	2412	3518	5839	5559	8668	10490	8123	14517	11669	31089	24396
Sequoyah														19216
St. Lucie									3249	7528	15814	14392	16381	23240
Surry 1					607									
Surry 1&2					607	5102	9878	15270	14796	15977	19323	23313	29458	31185

Plant:	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981
Three Mile Island 1							3351	14226	17840	13287	17954	11842	NA	27024
Three Mile Island 2												12402	NA	8394
Trojan									5921	13628	15204	16957	25790	32205
Turkey Point 3					247									
Turkey Point 3&4						4059	9660	15493	18602	15109	18602	22511	30830	30274
Vermont Yankee					414	4957	5692	7682	7912	9775	11191	14208	22586	26795
Yankee-Rowe	1501	1602	1558	1745	2912	2437	3950	4557	4976	6966	7653	10150	22250	22069
Zion 1						44								
Zion 1&2							9234	12735	18268	18104	20383	26954	37655	44864

Year	Arkansas Total Cost	Arkansas Cost Increase	Arkansas 1983 $	Beaver Valley Total Cost	Beaver Valley Cost Increase	Beaver Valley 1983 $	Big Rock Point Total Cost	Big Rock Point Cost Increase	Big Rock Point 1983 $	Browns Ferry Total Cost	Browns Ferry Cost Increase	Browns Ferry 1983 $
1968							13926	89	287			
1969							13958	32	96			
1970							14324	366	1023			
1971							14554	230	593			
1972							14731	177	432			
1973							14815	84	195			
1974	233027						16012	1197	2415			
1975	238751	5724	10407				16587	575	1034	512653 **		
1976	242204	3453	5962	284856			22907	6320	10702	552357	39704	66749
1977	247069	4865	7997	598716	313860	487988	23971	1064	1668	853325 ***		
1978	253994	6925	10259	582408	-16308	-23883	24409	438	639	885991	32666	47072
1979	268130	14136	18641	576367	-6041	-8067	27014	2605	3473	888350	2359	3092
1980	NA			647575	71208	87849	27262	248	304	890428	2078	2485
1981	916567 **			671283	23708	26909	33356	6094	6863	892715	2287	2503

Year	Brunswick Total Cost	Brunswick Cost Increase	Brunswick 1983 $	Calvert Cliffs Total Cost	Calvert Cliffs Cost Increase	Calvert Cliffs 1983 $	Connecticut Yankee Total Cost	Connecticut Yankee Cost Increase	Connecticut Yankee 1983 $	Cook Total Cost	Cook Cost Increase	Cook 1983 $
1968							91801					
1969							91841	40	121			
1970							93516	1675	4694			
1971							93669	153	395			
1972							93814	145	346			
1973							94016	202	459			
1974							106212	12196	24285			
1975	382246			428747			108921	2709	4842	538611		
1976	389118	6872	11553	430674	1927	3216	114503	5582	9317	544650	6039	10227
1977	707560 **			765995 **			117238	2735	4252	552238	7588	11895
1978	714928	7368	10617	777711	11716	17158	121288	4050	5931	996177 **		
1979	750828	35900	47055	780095	2384	3183	123037	1749	2335	1025829	29652	39536
1980	776989	26161	31285	790988	10893	13439	137644	14607	18021	1074584	48755	59847
1981	803535	26546	29050	820215	29227	33173	152552	14908	16921	1096310	21726	24468

Year	Cooper Total Cost	Cooper Cost Increase	Cooper 1983 $	Crystal River Total Cost	Crystal River Cost Increase	Crystal River 1983 $	Davis-Besse Total Cost	Davis-Besse Cost Increase	Davis-Besse 1983 $	Peach Bottom 2 and 3 Total Cost	Peach Bottom 2 and 3 Cost Increase	Peach Bottom 2 and 3 1983 $
1968												
1969												
1970												
1971												
1972												
1973												
1974	246268									742158		
1975	269287	23019	41399							753981	11823	21132
1976	269287	0	0							761722	7741	12921
1977	302382	33095	51879	365535			271283			794094	32372	50332
1978	384630	82248	120010	415173	49638	71528	635147	363864	530921	807496	13402	19627
1979	384570	-60	-80	419131	3958	5188	326174	-308973	-411964	813792	6296	8407
1980	384569	-1	-1	421055	1924	2301	738544	412370	506190	836708	22916	28271
1981	383748			384011	-37044	-40539	786437	47893	53938	902169	65461	74298

* = unit 1 retired. ** = 2 units in service. *** = 3 units in service

Year	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $
	Dresden			Duane Arnold			Farley			Fitzpatrick		
1968	33467	-899	-2897									
1969	33968	501	1510									
1970	116609 **											
1971	220380 ***											
1972	241479	21099	51526									
1973	235397	-6082	-14110									
1974	237303	1906	3845	288821								
1975	249177	11874	21355	279730	-9091.4	-16350				NA		
1976	256493	7316	12389	279928	198	335				NA		
1977	258522	2029	3181	287561	7633.42	11966	727426			NA		
1978	276887	18365	26797	282345	-5216.4	-7611	734519	7093	10221	NA		
1979	290785	13898	18531	306768	24423	32564	751634	17115	22433	NA		
1980	303201	12416	15241	324186	17418	21381	761329	9695	11594	NA		
1981	307054	3853	4339	339460	15274	17202	1541981 **			367141		

Year	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $
	Fort Calhoun			Fort St. Vrain			Ginna			Hatch		
1968												
1969												
1970							83175					
1971							83075	-100	-258			
1972							83982	907	2167			
1973	173870						85004	1022	2320			
1974	175800	1930	3894				87668	2664	5305			
1975	178572	2772	4985				89750	2082	3721			
1976	178896	324	549				93308	3558	5939	390393		
1977	179994	1098	1721				114141	20833	32391	396799	6406	9842
1978	180328	334	487				121860	7719	11305	4466		
1979	180830	502	669	105610			129112	7252	9684	657326		
1980	192700	11870	14571	101459			136138	7026	8668	947147 **		
1981	198544	5844	6582	120884			159487	23349	26501	693789		

Year	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $
	Humboldt			Indian Point 1 and 2			Indian Point 3			Kewaunee		
1968	22619	139	465	128818	-3	-10						
1969	22688	69	222	127914	-904	-2736						
1970	22764	76	230	128083	169	474						
1971	22850	86	243	128175	92	237						
1972	22947	97	256	128938	763	1823						
1973	22998	51	128	334963 **								
1974	23171	173	381	340188	5225	10404				202193		
1975	24031	860	1648	348218	8030	14353				203389	1196	2151
1976	24543	512	905	359410	11192	18681	NA			205351	1962	3323
1977	26726	2183	3535	370637	11227	17456	NA			205892	541	848
1978	28506	1780	2675	377573 +	6936	10158	NA			209748	3856	5626
1979	28567	61	83	379966	2393	3195	NA			213289	3541	4721
1980	NA			329445			NA			214696	1407	1727
1981	NA			398037	68592	77852	493018			227413	12717	14322

+ = unit 1 retired, ** = 2 units in service, *** = 3 units in service

Year	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $
====	Lacrosse			Maine Yankee			McGuire			Millstone 1		
1968												
1969												
1970												
1971										96819		
1972										97343	524	1252
1973				219225						98837	1494	3391
1974				221074	1849	3682				98745	-92	-183
1975				233710	12636	22586				99244	499	892
1976				235069	1359	2268				125141	25897	43225
1977				236454	1385	2153				127476	2335	3630
1978	22991			237810	1356	1986				139783	12307	18024
1979	23132	141	188	239987	2177	2907				153135	13352	17829
1980	25987	2855	3505	246847	6860	8463				167438	14303	17646
1981	26237	250	282	262240	15393	17471	905601			247250	79812	90587

Year	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $
====	Millstone 2			Monticello			Nine Mile Point			North Anna		
1968												
1969												
1970							162235					
1971				105011			164492	2257	5822			
1972				104937	-74	-181	162416	-2076	-4961			
1973				106869	1932	4482	163212	796	1807			
1974				117996	11127	22448	163389	177	352			
1975	418372			122106	4110	7392	164189	800	1430			
1976	426271	7899	13184	123362	1256	2127	181200	17011	28393			
1977	448751	22480	34952	124390	1028	1611	188087	6887	10708			
1978	463638	14887	21802	126488	2098	3061	187086	-1001	-1466	781739		
1979	464674	1036	1383	134937	8449	11265	204080	16994	22692	783864	2125	2785
1980	477586	12912	15929	139725	4788	5877	217371	13291	16397	1315869 **	0	0
1981	495610	18024	20457	150407	10682	12030	265015	47644	54076	1368195	52326	57262

Year	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $
====	Oconee			Oyster Creek			Palisades			Peach Bottom 1		
1968										10624		
1969										10658		
1970				89883						10719		
1971				92121	2238	5773				10890		
1972				92637	516	1233	146687			10821		
1973	155612			92766	129	293	160284	13597	31545	11369		
1974	476443 ***			92198	-568	-1131	180063	19779	39902	10485		
1975	476691	248	446	97151	4953	8853	182297	2234	4018			
1976	478793	2102	3534	108545	11394	19018	185272	2975	5038			
1977	490724	11931	18331	112583	4038	6278	182068	-3204	-5022			
1978	492689	1965	2832	150459	37876	55470	199643	17575	25644			
1979	498935	6246	8187	161745	11286	15070	194651	-4992	-6656			
1980	509438	10503	12560	200255	38510	47510	211505	16854	20689			
1981	520036	10598	11598	222963	22708	25774	255491	43986	49538			

+ = unit 1 retired. ** = 2 units in service. *** = 3 units in service

Year	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $
	Pilgrim			Point Beach			Prairie Island			Quad Cities		
1968												
1969												
1970												
1971				73959								
1972	321540			145348 **						200149		
1973	239329			161632	16284	37779	233234			211539	11390	26425
1974	235982	-3347	-6665	161436	-196	-395	405374 **			223882	12343	24901
1975	236464	482	862	164224	2788	5014	410207	4833	8692	237227	13345	24000
1976	241440	4976	8306	167125	2901	4913	413087	2880	4877	241480	4253	7202
1977	257579	16139	25093	196801	29676	46519	423966	10879	17054	247194	5714	8957
1978	261758	4179	6120	171189	-25612	-37371	425182	1216	1774	252951	5757	8400
1979	270428	8670	11577	170668	-521	-695	433659	8477	11303	263741	10790.3	14387
1980	337986	67558	83346	172472	1804	2214	444766	11107	13634	273075	9333.66	11457
1981	358680	20694	23488	188495	16023	18045	457082	12316	13870	278524	5449	6137

Year	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $
	Rancho Seco			Robinson			Salem			San Onofre		
1968										80855		
1969										84439	3584	11533
1970										84714	275	832
1971				77753						85369	655	1847
1972				81999	4246	10369				85547	178	470
1973				82113	114	264				85821	274	688
1974				83272	1159	2359				86244	423	931
1975	343620			84982	1710	3075				86438	194	372
1976	343438	-182	-322	85234	252	424				95496	9058	16011
1977	336050	-7388	-11964	89540	4306	6616	850318			162475	66979	108463
1978	338792	2742	4121	93410	3870	5577	850983	665	974	181601	19126	28746
1979	339538	746	1012	101253	7843	10280	898641	47658	63637	192599	10998	14922
1980	353574	14036	17441	110025	8772	10490	938748	40107.4	49480	211109	18510	23000
1981	365651	12077	13716	113858	3833	4195	1758749 **			251119	40010	45441

Year	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $
	Sequoyah			Shippingport			St. Lucie			Surry		
1968												
1969												
1970												
1971												
1972										246707		
1973										396860 **		
1974										402096	5236	10656
1975										406409	4313	7757
1976							470223			408516	2107	3542
1977							486230	16007	24594	412236	3720	5715
1978							495038	8808	12692	419952	7716	11119
1979							499602	4564	5982	409703	-10249	-13434
1980				32125			505287	5685	6799	556083	146380	175052
1981	983542			32123			513640	8353	9141	750969	194886	213271

* = unit 1 retired. ** = 2 units in service, *** = 3 units in service

Year	Three Mile Island 1 Total Cost	Cost Increase	1983 $	Three Mile Island 2 Total Cost	Cost Increase	1983 $	Trojan Total Cost	Cost Increase	1983 $	Turkey Point 3 and 4 Total Cost	Cost Increase	1983 $
1968												
1969												
1970												
1971												
1972										108709		
1973										231239 **		
1974	398337									235496	4257	8663
1975	400928	2591	4631							244256	8760	15754
1976	399425	-1503	-2509				451978			255705	11449	19248
1977	398895	-530	-824				460666	8688	14069	267648	11943	18350
1978	361902	-36993	-54177	715466			466419	5753	8647	273441	5793	8348
1979	407936	46034	61469	719294	3828	5112	486705	20286	27523	284431	10990	14405
1980	NA			NA			503279	16574	20594	293654	9223	11030
1981	220798			358321			548765	45486	51661	305503	11849	12967

Year	Vermont Yankee Total Cost	Cost Increase	1983 $	Yankee-Rowe Total Cost	Cost Increase	1983 $	Zion Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $
1968				39572	12	38						
1969				39623	51	154						
1970				39636	13	36						
1971				40271	635	1638						
1972	172042			41500	1229	2937						
1973	184481	12439	28237	42507	1007	2286	275989					
1974	185158	677	1348	44473	1966	3915	565819 **					
1975	185739	581	1038	46101	1628	2910	567987	2168	3899			
1976	193886	8147	13598	46566	465	776	571762	3775	6393			
1977	196331	2445	3801	48332	1766	2746	577903	6141	9626			
1978	198837	2506	3670	48912	580	849	586396	8493	12392			
1979	200835	1998	2668	52192	3280	4380	594941	8545	11393			
1980	217575	16740	20652	55285	3093	3816	625788	30847	37865			
1981	226115	8540	9693	1768			639723	13935	15694			

TABLE 6.6: ANNUAL PWR CAPACITY FACTORS, 1968-81 (%)

Plant	DER	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981
San Onofre 1	450	31.9%	66.1%	77.6%	83.8%	71.1%	57.5%	79.8%	82.3%	62.6%	59.2%	68.0%	85.1%	20.7%	19.8%
Conn Yankee	575	59.3%	72.2%	70.2%	83.1%	85.1%	48.1%	86.4%	81.8%	79.7%	79.7%	93.5%	81.7%	70.5%	80.7%
Ginna	490				63.0%	54.7%	79.1%	48.9%	70.8%	47.9%	70.5%	75.0%	69.0%	71.9%	77.4%
Point Beach 1	497				75.2%	67.0%	63.0%	72.2%	67.1%	78.0%	84.7%	87.2%	70.2%	56.7%	60.1%
Robinson 2	707					77.8%	60.8%	77.7%	67.3%	78.5%	68.3%	64.3%	64.7%	51.7%	56.6%
Palisades	821					24.5%	33.5%	1.1%	33.8%	39.5%	70.7%	36.5%	47.7%	33.0%	48.2%
Point Beach 2	497						69.0%	73.0%	85.9%	86.2%	83.2%	88.6%	85.1%	82.2%	85.4%
Surry 1	823						48.0%	46.0%	54.3%	60.8%	69.7%	65.2%	31.3%	34.2%	33.0%
Turkey Point 3	745						51.0%	55.5%	67.0%	66.0%	68.5%	69.0%	44.1%	67.0%	14.0%
Maine Yankee	790							51.6%	65.1%	85.4%	74.3%	77.4%	65.6%	63.5%	75.3%
Surry 2	823							36.5%	70.1%	46.2%	61.8%	74.5%	8.5%	31.0%	71.4%
Oconee 1	886							51.5%	68.1%	51.3%	50.8%	65.1%	64.4%	65.7%	38.6%
Indian Point 2	873							43.5%	63.9%	29.6%	68.1%	57.1%	62.8%	55.6%	39.9%
Turkey Point 4	745							65.8%	61.1%	57.6%	56.2%	58.0%	58.9%	58.9%	69.0%
Fort Calhoun	457							60.3%	52.0%	54.7%	74.8%	71.2%	91.6%	50.1%	53.7%
Prairie Island 1	530							30.9%	79.6%	70.2%	80.0%	82.1%	62.7%	66.7%	82.7%
Zion 1	1050							37.8%	53.4%	51.6%	54.7%	73.6%	60.2%	70.6%	67.3%
Kewaunee	560								68.1%	68.8%	72.3%	79.3%	70.1%	73.8%	76.8%
Oconee 2	886								64.0%	54.3%	49.3%	61.7%	76.9%	49.8%	66.9%
TMI 1	819								77.2%	60.3%	76.1%	79.1%			
Zion 2	1050								52.5%	50.3%	68.2%	73.2%	51.8%	57.2%	57.2%
Oconee 3	986								58.3%	54.9%	60.7%	70.2%	37.7%	60.2%	72.6%
Arkansas 1	850								65.5%	52.1%	68.5%	70.5%	44.6%	50.7%	65.8%
Prairie Island 2	530								68.4%	57.2%	83.6%	84.5%	90.3%	74.5%	66.6%
Rancho Seco	913									27.5%	73.5%	62.4%	71.4%	55.1%	32.9%
Calvert Cliffs 1	845									84.9%	66.0%	63.2%	56.7%	61.1%	82.5%
Cook 1	1090									71.1%	50.1%	65.8%	59.3%	67.5%	71.0%
Millstone 2	828									62.4%	59.9%	62.0%	60.2%	67.1%	84.0%
Trojan	1130										65.6%	16.8%	53.2%	61.2%	64.9%
Indian Point 3	873										72.2%	71.4%	62.7%	40.0%	39.7%
Beaver Valley 1	852										39.8%	33.2%	23.8%	4.0%	62.5%
St. Lucie 1	802										76.1%	71.2%	69.5%	73.8%	70.4%
Crystal River 3	825											35.9%	52.1%	46.3%	56.5%
Calvert Cliffs 2	845											70.6%	74.2%	86.4%	73.2%
Salem 1	1090											47.4%	21.4%	59.4%	64.8%
Davis-Besse 1	906											32.9%	39.4%	26.3%	55.0%
Farley 1	829											81.5%	24.0%	63.2%	36.0%
Cook 2	1100												61.8%	69.3%	66.3%
North Anna 1	907												52.7%	70.7%	58.4%
Arkansas 2	912														54.1%
North Anna 2	907														71.1%
Farley 2	829														72.9%

AVERAGES:	1975	1977	1979	1981
Cumulative	61.7%	62.8%	62.5%	61.5%
Immature Years (1-4)	59.6%	60.8%	60.0%	59.7%
Mature Years (5+)	73.0%	70.8%	67.7%	63.9%

TABLE 6.7: CENTRAL MAINE POWER COMPANY - PILGRIM 2
COST PROJECTIONS BASED ON DATA AVAILABLE JAN. 1979

Year	Pilgrim 2 Busbar Cost, cents/kWh Fixed Charges	Nuclear Fuel	Total	Oil Energy Cost Cents/kWh	Cost Difference Pilgrim-Oil	Cumulative Difference in PV @ 10.7%
1991	26.91	1.12	28.03	4.85	23.19	20.95
1992	25.95	1.19	27.14	5.15	21.99	38.89
1993	25.07	1.26	26.33	5.46	20.87	54.28
1994	23.94	1.34	25.28	5.80	19.48	67.25
1995	23.23	1.42	24.65	6.16	18.49	78.37
1996	22.14	1.51	23.65	6.55	17.11	87.67
1997	21.39	1.61	22.99	6.95	16.04	95.55
1998	20.68	1.71	22.38	7.38	15.00	102.20
1999	19.96	1.81	21.78	7.84	13.94	107.78
2000	19.30	1.92	21.22	8.33	12.89	112.45
2001	18.58	2.04	20.63	8.84	11.79	116.30
2002	17.91	2.17	20.08	9.39	10.69	119.46
2003	17.24	2.31	19.55	9.97	9.58	122.01
2004	16.57	2.45	19.02	10.59	8.43	124.04
2005	16.37	2.60	18.97	11.25	7.72	125.72
2006	16.07	2.76	18.83	11.94	6.89	127.08
2007	15.78	2.93	18.71	12.69	6.03	128.15
2008	15.49	3.11	18.60	13.47	5.13	128.97
2009	15.24	3.31	18.54	14.31	4.24	129.58
2010	14.98	3.51	18.50	15.19	3.30	130.02
2011	14.73	3.73	18.46	16.14	2.33	130.29
2012	14.52	3.96	18.49	17.14	1.35	130.44
2013	14.31	4.21	18.52	18.20	0.32	130.47

The assumptions used here are those described in
Exhibit Webb-17, PUC 82-266.
Fixed charges are Webb values, times (7446/ 1779).

TABLE 6.8: CENTRAL MAINE POWER COMPANY - PILGRIM 2
COST PROJECTIONS BASED ON DATA AVAILABLE JANUARY 1980

Year	Pilgrim 2 Busbar Cost, cents/kWh Fixed Charges	Nuclear Fuel	Total	Oil Energy Cost Cents/kWh	Cost Difference Pilgrim-Oil	Cumulative Difference in PV @ 14.4%
1995	60.66	1.42	62.09	22.72	39.36	34.41
1996	58.55	1.51	60.06	25.00	35.07	61.20
1997	56.59	1.61	58.20	27.50	30.70	81.71
1998	54.01	1.71	55.72	30.25	25.47	96.58
1999	52.21	1.81	54.02	33.27	20.75	107.17
2000	49.86	1.92	51.79	36.60	15.19	113.95
2001	48.30	2.04	50.34	40.26	10.08	117.88
2002	46.65	2.17	48.82	44.28	4.54	119.43
2003	45.09	2.31	47.39	48.71	-1.32	119.03
2004	43.44	2.45	45.89	53.58	-7.69	117.03
2005	41.88	2.60	44.48	58.94	-14.46	113.74
2006	40.39	2.76	43.15	64.83	-21.68	109.42
2007	38.82	2.93	41.76	71.32	-29.56	104.28
2008	37.34	3.11	40.45	78.45	-38.00	98.50
2009	36.87	3.31	40.18	86.30	-46.12	92.37
2010	36.24	3.51	39.75	94.92	-55.17	85.96
2011	35.54	3.73	39.27	104.42	-65.15	79.34
2012	34.91	3.96	38.87	114.86	-75.99	72.60
2013	34.28	4.21	38.49	126.34	-87.85	65.78
2014	33.74	4.47	38.21	138.98	-100.77	58.94
2015	33.19	4.75	37.93	152.88	-114.94	52.13

The assumptions used here are those described in
Exhibit Webb-18, PUC 82-266.
Fixed charges are Webb figures times (16790/2145).

FIG. 6.1: CORRECTED BUSBAR COMPARISON

(Exh. Webb-15, 82-266)

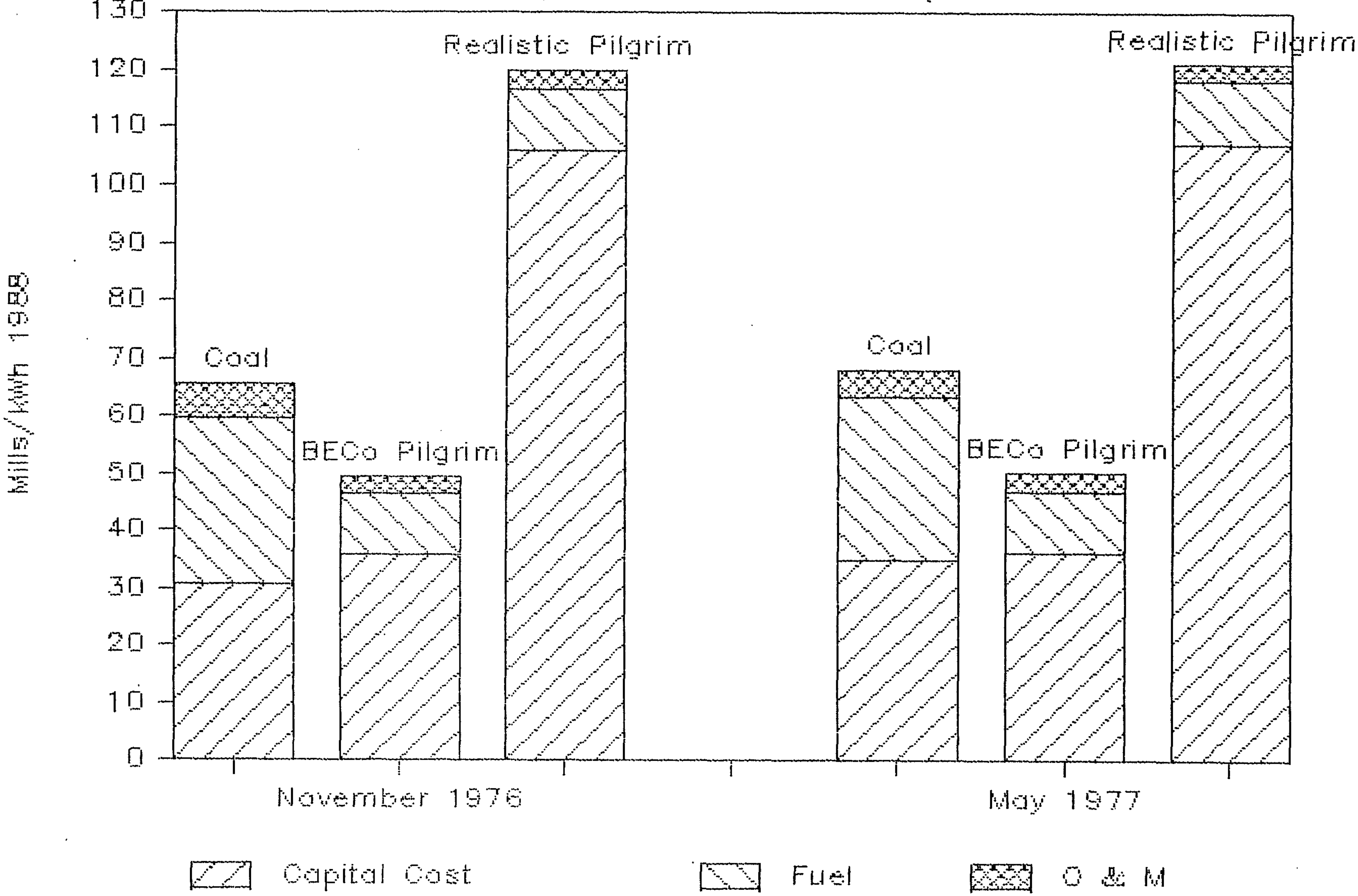

TABLE 7.1: COMPARISON OF FINANCIAL INDICATORS TO NUCLEAR COMMITMENT

INDICATOR for 1972

	UTILITY		
	BECo	NORTHEAST	UI
Peak Load (MW)	1,912	3,637	836
Sales (GWH)	9,906	17,515	4,388
Revenues ($ mill.)	$269.8	$473.0	$103.7
Net Income ($ mill.)	$35.9	$82.0	$13.9
Net Plant in Service ($ mill.)	$793.1	NA	$258.2
Book Common Equity ($ mill.)	$248.1	$570.4	$88.6
MW Nuclear Commitment	679	1290	540
Nuclear Cost Commitment ($ mill.)	$237.2	$458.4	$222.6

RATIO OF INDICATORS TO NUCLEAR COMMITMENT

	BECo	NORTHEAST	UI
Peak Load	2.8	2.8	1.5
Sales	14.6	13.6	8.1
Revenues	39.8%	36.7%	19.2%
Net Income	5.28%	6.36%	2.57%
Net Plant in Service	1.17	NA	0.48
Common Equity	0.37	0.44	0.16

RATIO OF INDICATORS TO NUCLEAR COST COMMITMENT

	BECo	NORTHEAST	UI
Revenues	113.8%	103.2%	46.6%
Net Income	15.12%	17.89%	6.24%
Net Plant in Service	3.34	NA	1.16
Common Equity	1.05	1.24	0.40

TABLE 7.2: COMPARISON OF FINANCIAL INDICATORS TO NUCLEAR COMMITMENT

INDICATOR for 1976	UTILITY		
	BECo	NORTHEAST	UI
Peak Load (MW)	1,970	3,774	863
Sales (GWH)	11,711	18,896	4,499
Revenues ($ mill.)	$552.9	$755.3	$193.8
Net Income ($ mill.)	$39.8	$111.5	$18.6
Net Plant in Service ($ mill.)	$1,155.4	$1,993.2	$375.4
Book Common Equity ($ mill.)	$303.3	$812.8	$142.0
MW Nuclear Commitment	679	1258	540
Nuclear Cost Commitment ($ mill.)	$823.6	$1,008.8	$478.9
RATIO OF INDICATORS TO NUCLEAR COMMITMENT			
Peak Load	2.9	3.0	1.6
Sales	17.3	15.0	8.33
Revenues	81.5%	60.1%	35.9%
Net Income	5.86%	8.87%	3.44%
Net Plant in Service	1.70	1.59	0.69
Common Equity	0.45	0.65	0.26
RATIO OF INDICATORS TO NUCLEAR COST COMMITMENT			
Revenues	67.1%	74.9%	40.5%
Net Income	4.83%	11.05%	3.88%
Net Plant in Service	1.40	1.98	0.78
Common Equity	0.37	0.81	0.30

TABLE 7.3: COMPARISON OF FINANCIAL INDICATORS TO NUCLEAR COMMITMENT

INDICATOR for 1978

	UTILITY			
	BECo	NORTHEAST	UI	CMP High-Risk
Peak Load (MW)	2,031	3,871	953	1173
Sales (GWH)	12,589	19,964	4,712	5,844
Revenues ($ mill.)	$613.0	841.4	$216.3	$208.2
Net Income ($ mill.)	$33.9	$108.3	$21.5	$29.6
Net Plant in Service ($ mill.)	$1,137.5	$2,011.8	$371.2	$513.2
Book Common Equity ($ mill.)	$355.0	$866.1	$177.6	$196.3
MW Nuclear Commitment	679	1023	540	342
Nuclear Cost Commitment ($ mill.)	$713.9	$1,455.9	$373.7	$241.8

RATIO OF INDICATORS TO NUCLEAR COMMITMENT

Peak Load	3.0	3.8	1.8	3.4
Sales	18.6	19.5	8.7	17.1
Revenues	90.3%	82.2%	40.0%	61.0%
Net Income	4.99%	10.59%	3.98%	8.67%
Net Plant in Service	1.68	1.97	0.69	1.50
Common Equity	0.52	0.85	0.33	0.57

RATIO OF INDICATORS TO NUCLEAR COST COMMITMENT

Revenues	85.9%	57.8%	57.9%	86.1%
Net Income	4.75%	7.44%	5.75%	12.25%
Net Plant in Service	1.59	1.38	0.99	2.12
Common Equity	0.50	0.59	0.48	0.81

TABLE 7.4: COMPARISON OF FINANCIAL INDICATORS TO NUCLEAR COMMITMENT

INDICATOR for 1980

	UTILITY			
	BECo	NORTHEAST	UI	CMP High-Risk
Peak Load (MW)	2,100	4.015	971	1193
Sales (GWH)	12,802	20.562	4,715	$6,038.5
Revenues ($ mill.)	$886.4	$1,324.5	364.1	$335.3
Net Income ($ mill.)	$51.7	$114.2	34.5	$26.4
Net Plant in Service ($ mill.)	$1,200.4	$2,140.8	$359.8	$625.8
Book Common Equity ($ mill.)	$431.9	$918.0	$223	$208.7
MW Nuclear Commitment	679	841	483	342
Nuclear Cost Commitment ($ mill.)	$2.073.9	$1.816.7	$757.7	$545.0

RATIO OF INDICATORS TO NUCLEAR COMMITMENT

Peak Load	3.1	4.8	2.0	3.5
Sales	18.9	24.5	9.8	17.7
Revenues	130.6%	157.5%	75.4%	98.2%
Net Income	7.61%	13.58%	7.15%	7.74%
Net Plant in Service	1.77	2.55	0.75	1.83
Common Equity	0.64	1.09	0.46	0.61

RATIO OF INDICATORS TO NUCLEAR COST COMMITMENT

Revenues	42.7%	72.9%	48.1%	61.5%
Net Income	2.49%	6.29%	4.55%	4.85%
Net Plant in Service	0.58	1.18	0.47	1.15
Common Equity	0.21	0.51	0.29	0.38

APPENDIX A

Resume of Paul L. 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 1983 Automobile Insurance Rates; Massachusetts Attorney General; October, 1983.

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

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

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

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

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

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

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

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

    Need for Millstone 3. Cost of completing and operating unit, cost-effectiveness compared to alternatives, and its effect on rates. 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.

40. MDPU 84-152; Seabrook Unit 1 Investigation; Massachusetts Attorney General; November 30, 1984.

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

41. Maine PUC 84-113; Seabrook 2 Investigation; Maine PUC Staff; December 11, 1984.

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

APPENDIX B

COST AND SCHEDULE ESTIMATE HISTORIES

I. Completed Plants

II. Incomplete Bechtel Plants

III. Incomplete Non-Bechtel Plants

IV. Canceled Bechtel Plants

V. Canceled Non-Bechtel Plants

VI. Estimates From Utilities

Completed Plants (APCOMP3, Myopia 44)

Unit Name	Actuals Cost	Actuals COD	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
Nine Mile Point	162	Dec-69	Mar-64	68	Nov-68	4.67	0.0
Nine Mile Point	162	Dec-69	Sep-64	68	Jul-68	3.83	0.0
Nine Mile Point	162	Dec-69	Jun-66	88	Nov-68	2.42	34.0
Nine Mile Point	162	Dec-69	Dec-67	134	Jan-69	1.09	75.0
Nine Mile Point	162	Dec-69	Jun-68	134	Jun-69	1.00	88.0
Nine Mile Point	162	Dec-69	Dec-68	134	Dec-69	1.00	94.0
Oyster Creek 1	90	Dec-69	Jun-64		Oct-67	3.33	0.0
Oyster Creek 1	90	Dec-69	Sep-65		Nov-67	2.17	18.0
Oyster Creek 1	90	Dec-69	Mar-66		Dec-67	1.75	30.0
Oyster Creek 1	90	Dec-69	Jun-66		Dec-67	1.50	33.0
Oyster Creek 1	90	Dec-69	Sep-66		Jan-68	1.33	41.0
Oyster Creek 1	90	Dec-69	Mar-67		Apr-68	1.09	66.4
Dresden 2	83	Jul-70	Mar-66		Feb-69	2.92	6.0
Dresden 2	83	Jul-70	Sep-67		Apr-69	1.58	59.0
Dresden 2	83	Jul-70	Dec-68		Jan-70	1.08	84.0
Ginna	83	Jul-70	Dec-65		Jun-69	3.50	0.0
Ginna	83	Jul-70	Mar-66		Jun-69	3.25	0.0
Ginna	83	Jul-70	Sep-68		Oct-69	1.08	80.0
Point Beach 1	74	Dec-70	Jun-66		Apr-70	3.83	0.0
Point Beach 1	74	Dec-70	Sep-66		Apr-70	3.58	0.0
Point Beach 1	74	Dec-70	Mar-69		Aug-70	1.42	53.2
Point Beach 1	74	Dec-70	Dec-69		Dec-70	1.00	71.8
Millstone 1	97	Mar-71	Dec-65		Aug-69	3.67	0.0
Millstone 1	97	Mar-71	Mar-67		Aug-69	2.42	21.7
Millstone 1	97	Mar-71	Sep-67		Aug-69	1.92	35.0
Millstone 1	97	Mar-71	Dec-68		Jan-70	1.08	72.4
Millstone 1	97	Mar-71	Mar-69		Mar-70	1.00	78.3
Millstone 1	97	Mar-71	Sep-69		Oct-70	1.08	86.0
Robinson 2	78	Mar-71	Jun-66		May-70	3.92	0.0
Monticello	105	Jun-71	Jun-66		May-70	3.92	0.0
Dresden 3	104	Nov-71	Mar-66		Feb-70	3.92	2.0
Dresden 3	104	Nov-71	Dec-68		Aug-70	1.66	54.0
Dresden 3	104	Nov-71	Mar-69		Aug-70	1.42	57.0
Dresden 3	104	Nov-71	Jun-69		Dec-70	1.50	66.0
Dresden 3	104	Nov-71	Mar-70		Jun-71	1.25	80.0
Palisades	147	Dec-71	Mar-68	89	May-70	2.17	31.0
Palisades	147	Dec-71	Mar-69	110	Aug-70	1.42	70.0
Point Beach 2	71	Oct-72	Mar-67		Apr-71	4.08	0.0
Point Beach 2	71	Oct-72	Sep-69		Aug-71	1.91	25.4
Point Beach 2	71	Oct-72	Dec-69		Dec-71	2.00	29.7
Point Beach 2	71	Oct-72	Mar-70		Aug-71	1.42	35.2
Point Beach 2	71	Oct-72	Sep-70		Sep-71	1.00	56.1
Vermont Yankee	172	Nov-72	Sep-66	88	Oct-70	4.08	0
Vermont Yankee	172	Nov-72	Sep-69	120	Jul-71	1.83	
Vermont Yankee	172	Nov-72	Mar-70	133	Jul-71	1.33	
Vermont Yankee	172	Nov-72	Jul-71	154	Mar-72	0.67	
Maine Yankee	219	Dec-72	Sep-67	100	May-72	4.67	
Maine Yankee	219	Dec-72	Sep-68	131	May-72	3.66	
Maine Yankee	219	Dec-72	Mar-70	181	May-72	2.17	
Pilgrim 1	231	Dec-72	Jul-65	70	Jul-71	6.00	

Completed Plants (APCOMP3, Myopia 44)

Unit Name	Actuals Cost	Actuals COD	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
Pilgrim 1	231	Dec-72	Feb-67	105	Jul-71	4.41	
Pilgrim 1	231	Dec-72	Jun-68	122	Sep-71	3.25	
Pilgrim 1	231	Dec-72	Jan-70	153	Sep-71	1.66	
Surry 1	247	Dec-72	Dec-66	130	Mar-71	4.25	0.1
Surry 1	247	Dec-72	Dec-67	144	Mar-71	3.25	4.3
Surry 1	247	Dec-72	Dec-68	165	Mar-71	2.25	15.2
Surry 1	247	Dec-72	Jun-69	165	Apr-71	1.83	33.7
Surry 1	247	Dec-72	Sep-69	165	Jun-71	1.75	45.7
Surry 1	247	Dec-72	Dec-69	189	Jun-71	1.50	45.6
Surry 1	247	Dec-72	Jun-70	189	Oct-71	1.33	79.5
Surry 1	247	Dec-72	Dec-70	189	Feb-72	1.17	88.6
Turkey Point 3	109	Dec-72	Sep-69	99	Jun-71	1.75	52.2
Turkey Point 3	109	Dec-72	Mar-70	111	Jun-71	1.25	66.7
Quad Cities 1	100	Feb-73	Jun-66		Mar-70	3.75	0.0
Quad Cities 1	100	Feb-73	Sep-67		Mar-70	2.50	26.0
Quad Cities 1	100	Feb-73	Dec-68		Oct-70	1.83	37.0
Quad Cities 1	100	Feb-73	Jun-69		Jan-71	1.59	64.0
Quad Cities 1	100	Feb-73	Mar-70		Jul-71	1.33	75.0
Quad Cities 1	100	Feb-73	Jun-70		Jul-71	1.08	82.0
Quad Cities 2	100	Mar-73	Sep-66		Mar-71	4.50	0.0
Quad Cities 2	100	Mar-73	Sep-67		Mar-71	3.50	16.0
Quad Cities 2	100	Mar-73	Dec-68		Apr-71	2.33	38.0
Quad Cities 2	100	Mar-73	Jun-69		Jan-72	2.58	47.0
Quad Cities 2	100	Mar-73	Mar-70		May-72	2.17	56.0
Quad Cities 2	100	Mar-73	Mar-71		May-72	1.17	82.0
Surry 2	150	May-73	Dec-66	108	Mar-72	5.25	0.0
Surry 2	150	May-73	Dec-67	112	Mar-72	4.25	1.4
Surry 2	150	May-73	Dec-68	123	Mar-72	3.25	6.3
Surry 2	150	May-73	Dec-69	138	Mar-72	2.25	20.8
Surry 2	150	May-73	Mar-70	138	Apr-72	2.09	25.8
Surry 2	150	May-73	Sep-70	138	May-72	1.66	37.4
Surry 2	150	May-73	Mar-71	138	Oct-72	1.59	48.8
Surry 2	150	May-73	Jun-71	139	Oct-72	1.34	68.9
Surry 2	150	May-73	Sep-71	141	Dec-72	1.25	76.2
Surry 2	150	May-73	Dec-71	145	Mar-73	1.25	83.3
Surry 2	150	May-73	Mar-72	147	Mar-73	1.00	88.0
Oconee 1	156	Jul-73	Sep-66	78	May-71	4.66	0.0
Oconee 1	156	Jul-73	Dec-66	76	May-71	4.41	0.0
Oconee 1	156	Jul-73	Jun-67	86	May-71	3.92	0.0
Oconee 1	156	Jul-73	Sep-67	93	May-71	3.66	1.0
Oconee 1	156	Jul-73	Sep-69	109	May-71	1.66	24.5
Indian Point 2	206	Aug-73	Jun-66		Jun-69	3.00	7.0
Indian Point 2	206	Aug-73	Sep-68		Apr-70	1.58	56.0
Indian Point 2	206	Aug-73	Mar-69		May-70	1.17	66.0
Indian Point 2	206	Aug-73	Jun-69		Oct-70	1.33	71.0
Indian Point 2	206	Aug-73	Dec-69		May-71	1.41	87.0
Indian Point 2	206	Aug-73	Dec-70		Dec-71	1.00	98.0
Fort Calhoun 1	174	Sep-73	Sep-67	70	May-71	3.66	0.0
Fort Calhoun 1	174	Sep-73	Sep-68	92	May-71	2.66	17.0
Fort Calhoun 1	174	Sep-73	Mar-69	92	May-72	3.17	21.0

Completed Plants (APCOMP3, Myopia 44)

Unit Name	Actuals Cost	Actuals COD	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
Fort Calhoun 1	174	Sep-73	Jun-69	92	May-71	1.91	25.0
Fort Calhoun 1	174	Sep-73	Sep-69	92	Sep-71	2.00	30.0
Fort Calhoun 1	174	Sep-73	Mar-70	125	Jun-72	2.25	47.0
Fort Calhoun 1	174	Sep-73	Dec-70	125	Nov-72	1.92	76.0
Fort Calhoun 1	174	Sep-73	Sep-71	125	May-73	1.66	89.0
Fort Calhoun 1	174	Sep-73	Dec-71	159	May-73	1.42	85.7
Turkey Point 4	123	Sep-73	Sep-69	41	Jun-72	2.75	52.2
Turkey Point 4	123	Sep-73	Mar-70	80	Jun-72	2.25	66.7
Turkey Point 4	123	Sep-73	Dec-70	81	Jun-72	1.50	65.4
Turkey Point 4	123	Sep-73	Mar-71	83	Jun-72	1.25	68.0
Turkey Point 4	123	Sep-73	Jun-71	96	Jun-72	1.00	72.0
Turkey Point 4	123	Sep-73	Dec-71	126	Dec-72	1.00	84.0
Prairie Isl 1	233	Dec-73	Mar-67	100	May-72	5.17	0.0
Prairie Isl 1	233	Dec-73	Dec-67	105	May-72	4.42	0.5
Prairie Isl 1	233	Dec-73	Sep-70	148	Oct-72	2.08	37.0
Prairie Isl 1	233	Dec-73	Sep-71	148	Dec-72	1.25	74.0
Prairie Isl 1	233	Dec-73	Dec-71	190	Dec-72	1.00	80.0
Prairie Isl 1	233	Dec-73	Sep-72	210	Oct-73	1.08	92.0
Zion 1	276	Dec-73	Mar-67	164	Apr-72	5.09	0
Zion 1	276	Dec-73	Mar-69	205	Apr-72	3.09	12
Zion 1	276	Dec-73	Jun-70	232	Apr-72	1.83	43
Zion 1	276	Dec-73	Dec-70	232	May-72	1.42	57
Zion 1	276	Dec-73	Jun-71	232	Aug-72	1.17	75
Kewaunee	202	Jun-74	Dec-67	85	Jun-72	4.50	0.0
Kewaunee	202	Jun-74	Mar-69	109	Jun-72	3.25	3.5
Kewaunee	202	Jun-74	Mar-70	121	Jun-72	2.25	13.5
Kewaunee	202	Jun-74	Jun-70	123	Jun-72	2.00	20.0
Kewaunee	202	Jun-74	Sep-70	123	Sep-72	2.00	28.0
Kewaunee	202	Jun-74	Sep-71	134	Dec-72	1.25	72.0
Kewaunee	202	Jun-74	Mar-72	134	Mar-73	1.00	87.0
Kewaunee	202	Jun-74	Jun-72	158	Jun-73	1.00	91.0
Kewaunee	202	Jun-74	Sep-72	163	Sep-73	1.00	95.0
Cooper	246	Jul-74	Sep-67	133	Apr-72	4.58	0.0
Cooper	246	Jul-74	Mar-68	127	Apr-72	4.08	0.9
Cooper	246	Jul-74	Dec-70	207	Apr-73	2.33	42.0
Cooper	246	Jul-74	Jun-72	207	Jul-73	1.08	81.1
Peach Bottom 2	522	Jul-74	Dec-66	138	Mar-71	4.25	0.0
Peach Bottom 2	522	Jul-74	Sep-67	163	Mar-71	3.50	1.0
Peach Bottom 2	522	Jul-74	Mar-68	163	Mar-71	3.00	4.4
Peach Bottom 2	522	Jul-74	Sep-69	206	Mar-72	2.50	35.0
Peach Bottom 2	522	Jul-74	Dec-69	218	Mar-72	2.25	43.0
Peach Bottom 2	522	Jul-74	Mar-70	230	May-72	2.17	48.0
Peach Bottom 2	522	Jul-74	Dec-70	230	Dec-72	2.00	70.0
Peach Bottom 2	522	Jul-74	Mar-71	277	Mar-73	2.00	77.0
Peach Bottom 2	522	Jul-74	Jun-71	288	Mar-73	1.75	80.0
Peach Bottom 2	522	Jul-74	Jun-72	352	Sep-73	1.25	72.0
Browns Ferry 1	256	Aug-74	Sep-66	117	Aug-70	3.92	0.0
Browns Ferry 1	256	Aug-74	Dec-66	117	Oct-70	3.83	1.0
Browns Ferry 1	256	Aug-74	Sep-67	124	Oct-70	3.08	8.0
Browns Ferry 1	256	Aug-74	Sep-69	149	Oct-71	2.08	31.0

Completed Plants (APCOMP3, Myopia 44)

Unit Name	Actuals Cost	Actuals COD	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
Browns Ferry 1	256	Aug-74	Jun-70	149	Apr-72	1.83	43.0
Browns Ferry 1	256	Aug-74	Mar-71	185	May-72	1.17	53.0
Browns Ferry 1	256	Aug-74	Sep-71	185	Oct-72	1.08	62.0
Oconee 2	160	Sep-74	Sep-66	75	May-72	5.66	0.0
Oconee 2	160	Sep-74	Jun-67	86	May-72	4.92	0.0
Oconee 2	160	Sep-74	Dec-67	88	May-72	4.42	0.0
Oconee 2	160	Sep-74	Mar-69	93	May-72	3.17	17.7
Oconee 2	160	Sep-74	Sep-69	109	May-72	2.66	24.5
Oconee 2	160	Sep-74	Sep-70	109	Jul-72	1.83	50.0
Oconee 2	160	Sep-74	Mar-71	109	Dec-72	1.75	68.0
Oconee 2	160	Sep-74	Sep-71	137	Feb-73	1.42	71.0
Three Mile I. 1	398	Sep-74	Mar-67	100	May-71	4.17	0
Three Mile I. 1	398	Sep-74	Jun-67	106	May-71	3.92	0
Three Mile I. 1	398	Sep-74	Dec-67	124	May-71	3.41	1
Three Mile I. 1	398	Sep-74	Dec-68	150	Sep-71	2.75	9
Three Mile I. 1	398	Sep-74	Jun-69	162	Sep-71	2.25	18
Three Mile I. 1	398	Sep-74	Sep-69	162	May-72	2.66	23
Three Mile I. 1	398	Sep-74	Dec-69	180	May-72	2.41	26.5
Three Mile I. 1	398	Sep-74	Mar-70	184	May-72	2.17	37.5
Three Mile I. 1	398	Sep-74	Jun-70	184	Jul-72	2.08	46
Three Mile I. 1	398	Sep-74	Sep-70	197	Oct-72	2.08	54.5
Three Mile I. 1	398	Sep-74	Dec-70	262	Oct-72	1.83	59.5
Three Mile I. 1	398	Sep-74	Mar-71	261	Nov-72	1.67	67.5
Three Mile I. 1	398	Sep-74	Sep-71	296	Nov-73	2.17	67
Three Mile I. 1	398	Sep-74	Jun-72	328	Nov-73	1.42	86
Three Mile I. 1	398	Sep-74	Sep-72	363	May-74	1.66	90
Three Mile I. 1	398	Sep-74	Mar-73	373	Jul-74	1.33	91
Three Mile I. 1	398	Sep-74	Jun-73	393	Aug-74	1.17	93
Zion 2	290	Sep-74	Jun-67	153	May-73	5.92	0
Zion 2	290	Sep-74	Mar-69	194	May-73	4.17	9
Zion 2	290	Sep-74	Jun-70	213	May-73	2.92	36
Zion 2	290	Sep-74	Mar-72	235	May-73	1.17	71
Arkansas 1	233	Dec-74	Dec-67	132	Dec-72	5.00	0
Arkansas 1	233	Dec-74	Mar-69	138	Dec-72	3.75	1.0
Arkansas 1	233	Dec-74	Jun-69	132	Dec-72	3.50	1.6
Arkansas 1	233	Dec-74	Mar-72	175	Sep-73	1.50	76.0
Arkansas 1	233	Dec-74	Sep-72	185	Oct-73	1.08	86.8
Arkansas 1	233	Dec-74	Mar-73	200	Mar-74	1.00	96.3
Oconee 3	160	Dec-74	Jun-67	92	Jun-73	6.00	0.0
Oconee 3	160	Dec-74	Dec-67	93	Jun-73	5.50	2.0
Oconee 3	160	Dec-74	Jun-68	88	Jun-73	5.00	7.0
Oconee 3	160	Dec-74	Mar-69	93	Jun-73	4.25	17.7
Oconee 3	160	Dec-74	Sep-69	109	Jun-73	3.75	24.5
Oconee 3	160	Dec-74	Sep-70	109	Jul-73	2.83	25.0
Oconee 3	160	Dec-74	Sep-71	137	Nov-73	2.17	43.0
Oconee 3	160	Dec-74	Mar-73	137	Jun-74	1.25	87.5
Peach Bottom 3	220	Dec-74	Dec-66	125	Jan-73	6.09	NA
Peach Bottom 3	220	Dec-74	Sep-67	145	Jan-73	5.34	NA
Peach Bottom 3	220	Dec-74	Mar-68	145	Jan-73	4.84	1.6
Peach Bottom 3	220	Dec-74	Sep-68	145	Mar-73	4.50	4.5

Completed Plants (APCOMP3, Myopia 44)

Unit Name	Actuals Cost	Actuals COD	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
Peach Bottom 3	220	Dec-74	Sep-69	193	Mar-73	3.50	12.0
Peach Bottom 3	220	Dec-74	Dec-69	203	Mar-73	3.25	13.0
Peach Bottom 3	220	Dec-74	Mar-70	221	Mar-73	3.00	13.0
Peach Bottom 3	220	Dec-74	Dec-70	221	Oct-73	2.83	30.0
Peach Bottom 3	220	Dec-74	Mar-71	263	Apr-74	3.09	37.0
Peach Bottom 3	220	Dec-74	Jun-72	316	Sep-74	2.25	50.0
Peach Bottom 3	220	Dec-74	Sep-73	316	Dec-74	1.25	91.0
Peach Bottom 3	220	Dec-74	Dec-73	284	Dec-74	1.00	94.0
Prairie Isl 2	172	Dec-74	Dec-67	80	May-74	6.41	0.5
Prairie Isl 2	172	Dec-74	Sep-70	112	May-74	3.66	5.0
Prairie Isl 2	172	Dec-74	Dec-71	145	May-74	2.41	20.0
Prairie Isl 2	172	Dec-74	Sep-72	160	Oct-74	2.08	35.0
Duane Arnold	202	Feb-75	Jun-68	103	Dec-73	5.50	0.0
Duane Arnold	202	Feb-75	Dec-68	107	Dec-73	5.00	0.0
Duane Arnold	202	Feb-75	Jun-69	133	Dec-73	4.50	0.0
Duane Arnold	202	Feb-75	Dec-69	138	Dec-73	4.00	0.0
Duane Arnold	202	Feb-75	Dec-70	148	Dec-73	3.00	10.0
Duane Arnold	202	Feb-75	Mar-72	177	Dec-73	1.75	50.0
Duane Arnold	202	Feb-75	Sep-72	192	Jan-74	1.33	69.0
Browns Ferry 2	256	Mar-75	Sep-66	117	Oct-70	4.08	1.0
Browns Ferry 2	256	Mar-75	Mar-67	117	Feb-70	2.92	3.0
Browns Ferry 2	256	Mar-75	Sep-67	124	Feb-70	2.42	8.0
Browns Ferry 2	256	Mar-75	Mar-68	124	Oct-70	2.58	12.0
Browns Ferry 2	256	Mar-75	Sep-69	149	Oct-71	2.08	31.0
Browns Ferry 2	256	Mar-75	Jun-70	149	Apr-72	1.83	43.0
Browns Ferry 2	256	Mar-75	Sep-70	149	Jan-73	2.34	NA
Browns Ferry 2	256	Mar-75	Mar-71	149	Apr-73	2.09	
Browns Ferry 2	256	Mar-75	Sep-71	149	Jul-73	1.83	
Browns Ferry 2	256	Mar-75	Jun-72	149	Jan-74	1.59	
Browns Ferry 2	256	Mar-75	Mar-73	149	Jul-74	1.33	
Rancho Seco	344	Apr-75	Dec-67	134	May-73	5.42	0.0
Rancho Seco	344	Apr-75	Jun-71	215	May-73	1.92	43.0
Rancho Seco	344	Apr-75	Mar-72	215	Oct-73	1.59	65.0
Rancho Seco	344	Apr-75	Jun-72	264	Oct-73	1.33	75.0
Rancho Seco	344	Apr-75	Sep-72	300	Feb-74	1.42	78.0
Rancho Seco	344	Apr-75	Mar-73	327	Jun-74	1.25	80.5
Rancho Seco	344	Apr-75	Sep-73	328	Oct-74	1.08	92.0
Calvert Cliffs 1	429	May-75	Jun-67	118	Jan-73	5.59	0.0
Calvert Cliffs 1	429	May-75	Dec-67	123	Jan-73	5.09	0.0
Calvert Cliffs 1	429	May-75	Mar-68	125	Jan-73	4.84	0.0
Calvert Cliffs 1	429	May-75	Mar-69	124	Jan-73	3.84	3.0
Calvert Cliffs 1	429	May-75	Sep-70	170	Jan-73	2.34	24.0
Calvert Cliffs 1	429	May-75	Dec-71	210	Jun-73	1.50	58.0
Calvert Cliffs 1	429	May-75	Mar-72	210	Oct-73	1.59	63.0
Calvert Cliffs 1	429	May-75	Jun-72	250	Oct-73	1.33	70.0
Calvert Cliffs 1	429	May-75	Sep-72	250	Feb-74	1.42	72.0
Fitzpatrick	419	Jul-75	Mar-68	224	May-73	5.17	1.0
Fitzpatrick	419	Jul-75	Jun-72	301	Oct-73	1.33	71.0
Fitzpatrick	419	Jul-75	Jun-73	301	Jun-74	1.00	91.0
Cook 1	538	Aug-75	Dec-67	235	Apr-72	4.33	NA

Completed Plants (APCOMP3, Myopia 44)

Unit Name	Actuals Cost	Actuals COD	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
Cook 1	538	Aug-75	Jun-69	235	Sep-72	3.25	1.0
Cook 1	538	Aug-75	Sep-70	339	Mar-73	2.50	19.0
Cook 1	538	Aug-75	Jun-71	356	Mar-73	1.75	40.0
Cook 1	538	Aug-75	Sep-71	356	Oct-73	2.08	44.0
Cook 1	538	Aug-75	Jun-72	416	Oct-73	1.33	50.5
Cook 1	538	Aug-75	Dec-72	427	Jun-74	1.50	58.0
Cook 1	538	Aug-75	Jun-73	427	Oct-74	1.33	70.5
Cook 1	538	Aug-75	Dec-73	427	Apr-75	1.33	73.4
Brunswick 2	382	Nov-75	Dec-70	195	Mar-74	3.25	10.0
Brunswick 2	382	Nov-75	Dec-71	210	Mar-74	2.25	46.0
Brunswick 2	382	Nov-75	Dec-72	256	Dec-74	2.00	78.0
Brunswick 2	382	Nov-75	Sep-73	309	Dec-74	1.25	79.0
Brunswick 2	382	Nov-75	Dec-73	339	Jan-75	1.08	88.0
Hatch 1	390	Dec-75	Jun-68	160	Jun-73	5.00	0.0
Hatch 1	390	Dec-75	Mar-69	151	Jun-73	4.25	1.5
Hatch 1	390	Dec-75	Mar-70	185	Jun-73	3.25	5.0
Hatch 1	390	Dec-75	Jun-70	184	Jun-73	3.00	7.5
Hatch 1	390	Dec-75	Sep-70	184	Apr-73	2.58	10.0
Hatch 1	390	Dec-75	Sep-72	184	Mar-74	1.49	63.0
Hatch 1	390	Dec-75	Dec-72	282	Apr-74	1.33	69.0
Millstone 2	418	Dec-75	Dec-67	150	Apr-74	6.33	0.0
Millstone 2	418	Dec-75	Mar-68	146	Apr-74	6.08	0.0
Millstone 2	418	Dec-75	Dec-68	179	Apr-74	5.33	0.0
Millstone 2	418	Dec-75	Dec-69	183	Apr-74	4.33	0.0
Millstone 2	418	Dec-75	Dec-70	239	Apr-74	3.33	10.0
Millstone 2	418	Dec-75	Sep-71	252	Apr-74	2.58	24.0
Millstone 2	418	Dec-75	Sep-72	282	Apr-74	1.58	49.0
Millstone 2	418	Dec-75	Mar-73	341	Dec-74	1.75	60.0
Millstone 2	418	Dec-75	Dec-73	380	May-75	1.41	69.0
Trojan	452	Dec-75	Dec-68	196	Sep-74	5.75	0.0
Trojan	452	Dec-75	Mar-69	197	Sep-74	5.50	0.0
Trojan	452	Dec-75	Dec-69	227	Sep-74	4.75	0.0
Trojan	452	Dec-75	Mar-71	228	Sep-74	3.50	3.6
Trojan	452	Dec-75	Mar-72	233	Sep-74	2.50	30.0
Trojan	452	Dec-75	Sep-72	243	Sep-74	2.00	52.0
Trojan	452	Dec-75	Dec-72	284	Jul-75	2.58	57.0
Trojan	452	Dec-75	Sep-73	334	Jul-75	1.83	72.0
Trojan	452	Dec-75	Sep-74	366	Oct-75	1.08	84.0
St. Lucie 1	470	Jun-76	Jun-69	123	Jun-73	4.00	1
St. Lucie 1	470	Jun-76	Sep-69	123	May-73	3.66	1
St. Lucie 1	470	Jun-76	Dec-70	200	Jun-74	3.50	9
St. Lucie 1	470	Jun-76	Jun-71	203	Jun-74	3.00	12
St. Lucie 1	470	Jun-76	Dec-71	218	Jun-74	2.50	17
St. Lucie 1	470	Jun-76	Mar-72	235	Jun-74	2.25	23
St. Lucie 1	470	Jun-76	Jun-72	269	May-75	2.91	25
St. Lucie 1	470	Jun-76	Dec-72	318	May-75	2.41	45
St. Lucie 1	470	Jun-76	Mar-73	318	Jun-75	2.25	48
St. Lucie 1	470	Jun-76	Dec-73	318	Dec-75	2.00	68
St. Lucie 1	470	Jun-76	Jun-74	366	Dec-75	1.50	76.9
St. Lucie 1	470	Jun-76	Dec-74	401	Dec-75	1.00	86

Completed Plants (APCOMP3, Myopia 44)

Unit Name	Actuals Cost	Actuals COD	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
Indian Point 3	570	Aug-76	Sep-67	154	Jul-71	3.83	NA
Indian Point 3	570	Aug-76	Sep-68	156	Jul-71	2.83	NA
Indian Point 3	570	Aug-76	Sep-69	156	Jul-72	2.83	NA
Indian Point 3	570	Aug-76	Sep-70	218	Jul-73	2.83	NA
Indian Point 3	570	Aug-76	Mar-71	256	Jul-73	2.34	NA
Indian Point 3	570	Aug-76	Mar-73	317	Jul-74	1.33	82.0
Indian Point 3	570	Aug-76	Sep-73	400	Oct-74	1.08	85.0
Beaver Valley 1	599	Oct-76	Dec-67	150	Jul-73	5.58	0.0
Beaver Valley 1	599	Oct-76	Mar-68	150	Jun-73	5.25	0.0
Beaver Valley 1	599	Oct-76	Mar-69	189	Jun-73	4.25	0.0
Beaver Valley 1	599	Oct-76	Dec-69	192	Jun-73	3.50	0.5
Beaver Valley 1	599	Oct-76	Sep-70	219	Jun-73	2.75	5.0
Beaver Valley 1	599	Oct-76	Jun-71	219	Dec-73	2.50	23.0
Beaver Valley 1	599	Oct-76	Sep-71	286	Dec-73	2.25	28.0
Beaver Valley 1	599	Oct-76	Dec-71	286	Jun-74	2.50	30.0
Beaver Valley 1	599	Oct-76	Mar-72	309	Oct-74	2.58	35.0
Beaver Valley 1	599	Oct-76	Jun-72	311	Oct-74	2.33	38.0
Beaver Valley 1	599	Oct-76	Sep-72	342	Oct-74	2.08	51.0
Beaver Valley 1	599	Oct-76	Dec-72	340	Oct-74	1.83	58.0
Beaver Valley 1	599	Oct-76	Mar-73	340	May-75	2.17	63.0
Beaver Valley 1	599	Oct-76	Sep-73	409	May-75	1.66	69.0
Beaver Valley 1	599	Oct-76	Mar-74	419	May-75	1.17	85.0
Beaver Valley 1	599	Oct-76	Jun-74	419	Jun-75	1.00	92.0
Beaver Valley 1	599	Oct-76	Sep-74	451	Oct-75	1.08	94.0
Beaver Valley 1	599	Oct-76	Dec-74	451	Dec-75	1.00	94.0
Browns Ferry 3	301	Mar-77	Mar-68	124	Oct-70	2.58	12.0
Browns Ferry 3	301	Mar-77	Jun-69	149	Oct-70	1.33	26.0
Browns Ferry 3	301	Mar-77	Sep-69	149	Oct-71	2.08	31.0
Browns Ferry 3	301	Mar-77	Jun-70	149	Apr-72	1.83	43.0
Browns Ferry 3	301	Mar-77	Sep-70	149	Oct-73	3.08	NA
Browns Ferry 3	301	Mar-77	Mar-71	149	Jan-74	2.84	
Browns Ferry 3	301	Mar-77	Sep-71	149	Feb-74	2.42	
Browns Ferry 3	301	Mar-77	Aug-72	149	Aug-74	2.00	
Browns Ferry 3	301	Mar-77	Sep-72	149	Oct-74	2.08	
Browns Ferry 3	301	Mar-77	Mar-73	149	Dec-74	1.75	
Browns Ferry 3	301	Mar-77	Sep-73	149	Apr-75	1.58	
Browns Ferry 3	301	Mar-77	Mar-74	149	Sep-75	1.50	
Browns Ferry 3	301	Mar-77	Dec-74	149	Jan-76	1.08	
Browns Ferry 3	301	Mar-77	Jun-75	246	Jun-76	1.00	
Brunswick 1	318	Mar-77	Dec-70	194	Mar-76	5.25	4.0
Brunswick 1	318	Mar-77	Jun-71	182	Mar-75	3.75	17.0
Brunswick 1	318	Mar-77	Dec-71	181	Mar-75	3.25	30.0
Brunswick 1	318	Mar-77	Dec-72	214	Dec-75	3.00	42.0
Brunswick 1	318	Mar-77	Sep-73	251	Dec-75	2.25	50.0
Brunswick 1	318	Mar-77	Dec-73	269	Dec-75	2.00	56.0
Brunswick 1	318	Mar-77	Dec-74	281	Mar-76	1.25	71.0
Brunswick 1	318	Mar-77	Mar-75	281	Jun-76	1.25	75.0
Brunswick 1	318	Mar-77	Jun-75	328	Mar-77	1.75	77.0
Brunswick 1	318	Mar-77	Dec-75	329	Mar-77	1.25	86.0
Crystal River 3	366	Mar-77	Mar-67	110	Apr-72	5.09	0.0

Completed Plants (APCOMP3, Myopia 44)

	Actuals			Estimates			
Unit Name	Cost	COD	Date of Estimate	Total Cost	COD	Est. Years to COD	% Complete
Crystal River 3	366	Mar-77	Jun-68	113	Apr-72	3.83	0.0
Crystal River 3	366	Mar-77	Jun-69	148	Apr-72	2.83	2.0
Crystal River 3	366	Mar-77	Sep-71	190	Sep-73	2.00	37.0
Crystal River 3	366	Mar-77	Dec-72	283	Nov-74	1.92	63.5
Crystal River 3	366	Mar-77	Jun-73	283	Dec-74	1.50	70.0
Crystal River 3	366	Mar-77	Mar-74	283	Mar-75	1.00	91.0
Crystal River 3	366	Mar-77	Dec-74	375	Sep-76	1.75	95.0
Crystal River 3	366	Mar-77	Jun-75	420	Sep-76	1.25	95.0
Calvert Cliffs 2	335	Apr-77	Jun-67	105	Jan-74	6.59	0.0
Calvert Cliffs 2	335	Apr-77	Dec-67	107	Jan-74	6.09	0.0
Calvert Cliffs 2	335	Apr-77	Mar-68	106	Jan-74	5.84	0.0
Calvert Cliffs 2	335	Apr-77	Mar-69	105	Jan-74	4.84	2.0
Calvert Cliffs 2	335	Apr-77	Sep-70	128	Jan-74	3.33	21.0
Calvert Cliffs 2	335	Apr-77	Dec-71	168	Jan-74	2.09	46.0
Calvert Cliffs 2	335	Apr-77	Mar-72	168	Jun-74	2.25	47.0
Calvert Cliffs 2	335	Apr-77	Jun-72	204	Jun-74	2.00	54.0
Calvert Cliffs 2	335	Apr-77	Sep-72	204	Jan-75	2.33	56.0
Calvert Cliffs 2	335	Apr-77	Mar-73	204	Feb-75	1.92	67.0
Calvert Cliffs 2	335	Apr-77	Sep-73	243	Jun-75	1.75	73.0
Calvert Cliffs 2	335	Apr-77	Dec-73	243	Aug-75	1.66	79.0
Calvert Cliffs 2	335	Apr-77	Mar-74	273	Sep-75	1.50	75.0
Calvert Cliffs 2	335	Apr-77	Jun-74	273	Dec-75	1.50	73.0
Calvert Cliffs 2	335	Apr-77	Sep-74	256	Jan-77	2.34	71.9
Calvert Cliffs 2	335	Apr-77	Mar-75	253	Jan-77	1.84	80.6
Calvert Cliffs 2	335	Apr-77	Dec-75	251	Jan-77	1.09	92.1
Salem 1	850	Jun-77	Sep-66	139	May-71	4.70	0.0
Salem 1	850	Jun-77	Mar-67	139	May-71	4.17	0.0
Salem 1	850	Jun-77	Jun-67	149	May-71	3.92	0.0
Salem 1	850	Jun-77	Sep-67	152	Dec-71	4.25	0.0
Salem 1	850	Jun-77	Dec-67	152	Mar-72	4.25	0.0
Salem 1	850	Jun-77	Mar-70	237	Dec-72	2.75	20.0
Salem 1	850	Jun-77	Dec-70	237	Apr-73	2.33	33.0
Salem 1	850	Jun-77	Jun-71	237	Dec-73	2.50	40.0
Salem 1	850	Jun-77	Sep-71	308	Oct-74	3.08	43.0
Salem 1	850	Jun-77	Mar-72	336	Oct-74	2.58	50.0
Salem 1	850	Jun-77	Dec-72	425	Mar-75	2.25	53.0
Salem 1	850	Jun-77	Dec-73	497	Sep-75	1.75	67.0
Salem 1	850	Jun-77	Sep-74	678	Dec-76	2.25	88.3
Salem 1	850	Jun-77	Mar-75	678	Sep-76	1.51	90.5
Davis-Besse 1	558	Nov-77	Dec-68	180	Dec-74	6.00	0.0
Davis-Besse 1	558	Nov-77	Sep-69	201	Dec-74	5.25	0.0
Davis-Besse 1	558	Nov-77	Sep-70	266	Dec-74	4.25	2.0
Davis-Besse 1	558	Nov-77	Jun-72	304	Dec-74	2.50	22.0
Davis-Besse 1	558	Nov-77	Dec-72	349	May-75	2.41	40.0
Davis-Besse 1	558	Nov-77	Sep-73	409	Feb-76	2.42	59.0
Davis-Besse 1	558	Nov-77	Sep-74	434	Jun-76	1.75	72.5
Davis-Besse 1	558	Nov-77	Mar-75	434	Sep-76	1.51	82.3
Davis-Besse 1	558	Nov-77	Jun-75	461	Sep-76	1.25	88.2
Davis-Besse 1	558	Nov-77	Dec-75	533	Mar-77	1.25	95.0
Farley 1	727	Dec-77	Sep-69	164	Apr-75	5.58	0.0

Completed Plants (APCOMP3, Myopia 44)

Unit Name	Actuals Cost	Actuals COD	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
Farley 1	727	Dec-77	Jun-70	203	Apr-75	4.83	0.0
Farley 1	727	Dec-77	Sep-71	259	Apr-75	3.58	6.0
Farley 1	727	Dec-77	Mar-73	294	Apr-75	2.08	35.5
Farley 1	727	Dec-77	Jun-73	294	Dec-75	2.50	42.3
Farley 1	727	Dec-77	Dec-73	395	Dec-75	2.00	62.7
Farley 1	727	Dec-77	Jun-74	415	Feb-76	1.67	75.0
Farley 1	727	Dec-77	Sep-74	456	Feb-76	1.42	79.2
Farley 1	727	Dec-77	Dec-74	456	Jul-76	1.58	81.0
Farley 1	727	Dec-77	Jun-75	487	Oct-76	1.34	86.0
Farley 1	727	Dec-77	Dec-75	589	Jun-77	1.50	90.0
Farley 1	727	Dec-77	Jun-76	614	Jun-77	1.00	91.0
North Anna 1	782	Jun-78	Mar-69	185	Mar-74	5.00	0.0
North Anna 1	782	Jun-78	Dec-69	281	Mar-74	4.25	1.1
North Anna 1	782	Jun-78	Jun-71	308	Mar-74	2.75	29.0
North Anna 1	782	Jun-78	Sep-71	310	Jun-74	2.75	33.0
North Anna 1	782	Jun-78	Dec-71	344	Jun-74	2.50	34.0
North Anna 1	782	Jun-78	Mar-72	344	Dec-74	2.75	43.2
North Anna 1	782	Jun-78	Sep-72	360	Dec-74	2.25	49.0
North Anna 1	782	Jun-78	Dec-72	407	Dec-74	2.00	55.0
North Anna 1	782	Jun-78	Mar-73	407	Apr-75	2.08	57.0
North Anna 1	782	Jun-78	Sep-73	407	Nov-75	2.17	65.4
North Anna 1	782	Jun-78	Dec-73	431	Nov-75	1.92	69.3
North Anna 1	782	Jun-78	Mar-74	446	May-76	2.17	72.0
North Anna 1	782	Jun-78	Dec-74	504	Jan-77	2.09	80.0
North Anna 1	782	Jun-78	Mar-75	536	Jan-77	1.84	78.2
North Anna 1	782	Jun-78	Dec-75	536	Apr-77	1.33	89.7
North Anna 1	782	Jun-78	Mar-76	567	Apr-77	1.08	88.8
Cook 2	444	Jul-78	Dec-67	235	Apr-72	4.33	NA
Cook 2	444	Jul-78	Jun-69	235	Sep-72	3.25	1.0
Cook 2	444	Jul-78	Sep-70	339	Mar-74	3.50	19.0
Cook 2	444	Jul-78	Sep-75	437	Apr-78	2.58	57.4
Cook 2	444	Jul-78	Dec-76	437	Jun-78	1.50	82.4
Three Mile I. 2	715	Dec-78	Aug-69	214	May-74	4.75	NA
Three Mile I. 2	715	Dec-78	Sep-70	285	May-74	3.66	NA
Three Mile I. 2	715	Dec-78	Sep-71	345	May-75	3.66	NA
Three Mile I. 2	715	Dec-78	Aug-72	465	May-76	3.75	25.0
Three Mile I. 2	715	Dec-78	Jun-73	525	May-77	3.92	27.0
Three Mile I. 2	715	Dec-78	Sep-74	580	May-78	3.66	60.0
Three Mile I. 2	715	Dec-78	Jun-75	630	May-78	2.92	68.0
Three Mile I. 2	715	Dec-78	Aug-76	637	May-78	1.75	81.0
Hatch 2	509	Sep-79	Jun-70	189	Apr-76	5.88	NA
Hatch 2	509	Sep-79	Dec-72	330	Apr-78	5.33	11.0
Hatch 2	509	Sep-79	Sep-73	404	Apr-78	4.58	15.0
Hatch 2	509	Sep-79	Sep-74	513	Apr-78	3.58	23.0
Hatch 2	509	Sep-79	Sep-75	513	Apr-79	3.58	32.0
Hatch 2	509	Sep-79	Jun-76	512	Apr-79	2.83	57.0
Arkansas 2	640	Mar-80	Dec-70	183	Oct-75	4.83	0.0
Arkansas 2	640	Mar-80	Jun-71	190	Oct-75	4.33	0.0
Arkansas 2	640	Mar-80	Dec-71	200	Oct-75	3.83	2.1
Arkansas 2	640	Mar-80	Sep-72	230	Oct-76	4.08	6.9

Completed Plants (APCOMP3, Myopia 44)

Unit Name	Actuals Cost	Actuals COD	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
Arkansas 2	640	Mar-80	Jun-73	275	Oct-76	3.33	13.6
Arkansas 2	640	Mar-80	Sep-73	275	Dec-76	3.25	16.9
Arkansas 2	640	Mar-80	Dec-73	273	Dec-76	3.00	18.0
Arkansas 2	640	Mar-80	Mar-74	273	Feb-77	2.92	25.0
Arkansas 2	640	Mar-80	Jun-74	318	Feb-77	2.67	33.5
Arkansas 2	640	Mar-80	Sep-74	318	Jun-77	2.75	39.8
Arkansas 2	640	Mar-80	Mar-75	339	Jun-77	2.25	42.7
Arkansas 2	640	Mar-80	Jun-75	339	Oct-77	2.34	46.1
Arkansas 2	640	Mar-80	Sep-75	369	Jan-78	2.34	50.4
Arkansas 2	640	Mar-80	Dec-75	393	Mar-78	2.25	56.4
North Anna 2	532	Dec-80	Sep-70	184	Mar-75	4.50	NA
North Anna 2	532	Dec-80	Sep-71	191	Jun-75	3.75	7.8
North Anna 2	532	Dec-80	Dec-71	198	Jun-75	3.50	10.0
North Anna 2	532	Dec-80	Mar-72	198	Jul-75	3.33	16.3
North Anna 2	532	Dec-80	Sep-72	208	Jul-75	2.83	25.0
North Anna 2	532	Dec-80	Dec-72	227	Jul-75	2.58	28.2
North Anna 2	532	Dec-80	Mar-73	227	Oct-75	2.58	31.0
North Anna 2	532	Dec-80	Jun-73	227	Apr-76	2.83	39.3
North Anna 2	532	Dec-80	Sep-73	227	May-76	2.66	42.0
North Anna 2	532	Dec-80	Mar-74	240	Nov-76	2.67	47.5
North Anna 2	532	Dec-80	Dec-74	264	Sep-77	2.75	58.1
North Anna 2	532	Dec-80	Mar-75	301	Sep-77	2.51	54.1
North Anna 2	532	Dec-80	Dec-75	301	Nov-77	1.92	64.2
North Anna 2	532	Dec-80	Mar-76	311	Nov-77	1.67	67.0
North Anna 2	532	Dec-80	Sep-76	363	May-78	1.66	75.0
North Anna 2	532	Dec-80	Dec-76	381	Aug-78	1.66	76.3
North Anna 2	532	Dec-80	Mar-77	426	Aug-78	1.42	80.1
North Anna 2	532	Dec-80	Sep-77	426	Mar-79	1.49	86.6
North Anna 2	532	Dec-80	Mar-78	467	Mar-79	1.00	90.4
Farley 2	781	Jul-81	Sep-70	183	Apr-77	6.58	0.0
Farley 2	781	Jul-81	Sep-71	233	Apr-77	5.58	0.0
Farley 2	781	Jul-81	Mar-73	268	Apr-77	4.08	5.3
Farley 2	781	Jul-81	Jun-73	268	Jan-77	3.59	10.8
Farley 2	781	Jul-81	Dec-73	329	Jan-77	3.09	17.0
Farley 2	781	Jul-81	Jun-74	338	Jan-77	2.59	27.8
Farley 2	781	Jul-81	Sep-74	363	Jan-77	2.34	34.5
Farley 2	781	Jul-81	Dec-74	363	Jun-77	2.50	41.6
Farley 2	781	Jul-81	Jun-75	365	Sep-77	2.25	42.5
Farley 2	781	Jul-81	Dec-75	477	Apr-79	3.33	41.0
Farley 2	781	Jul-81	Sep-76	499	Apr-79	2.58	42.0
Farley 2	781	Jul-81	Dec-76	572	Apr-79	2.33	42.0
Farley 2	781	Jul-81	Mar-77	689	Apr-79	2.08	42.0
Farley 2	781	Jul-81	Jun-77	689	Apr-80	2.83	45.0
Farley 2	781	Jul-81	Dec-77	662	Apr-80	2.33	53.2
Farley 2	781	Jul-81	Mar-78	635	Apr-80	2.09	57.0
Farley 2	781	Jul-81	Sep-78	652	Apr-80	1.58	72.4
Farley 2	781	Jul-81	Jun-79	687	Sep-80	1.25	82.3
Farley 2	781	Jul-81	Sep-79	684	Sep-80	1.00	83.7
Sequoyah 1	984	Jul-81	Sep-68	161	Oct-73	5.08	0.0
Sequoyah 1	984	Jul-81	Sep-69	187	Oct-73	4.08	1.5

Completed Plants (APCOMP3, Myopia 44)

Unit Name	Actuals Cost	Actuals COD	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
Sequoyah 1	984	Jul-81	Jun-70	187	Apr-74	3.83	5.0
Sequoyah 1	984	Jul-81	Mar-71	213	Apr-74	3.09	13.0
Sequoyah 1	984	Jul-81	Dec-71	213	Jul-74	2.58	25.0
Sequoyah 1	984	Jul-81	Jun-72	213	Nov-74	2.42	35.0
Sequoyah 1	984	Jul-81	Dec-72	225	Apr-75	2.33	45.0
Sequoyah 1	984	Jul-81	Jun-73	225	Dec-75	2.50	57.0
Sequoyah 1	984	Jul-81	Dec-73	225	Jun-76	2.50	63.0
Sequoyah 1	984	Jul-81	Mar-74	313	Jun-76	2.25	65.0
Sequoyah 1	984	Jul-81	Jun-74	313	Aug-76	2.17	67.0
Sequoyah 1	984	Jul-81	Sep-74	313	Jan-77	2.34	69.0
Sequoyah 1	984	Jul-81	Dec-74	324	Jan-77	2.09	65.0
Sequoyah 1	984	Jul-81	Sep-75	324	Sep-77	2.00	70.0
Sequoyah 1	984	Jul-81	Dec-75	364	Sep-77	1.75	70.0
Sequoyah 1	984	Jul-81	Jun-76	364	May-78	1.91	72.0
Sequoyah 1	984	Jul-81	Sep-76	475	May-78	1.66	80.0
Sequoyah 1	984	Jul-81	Mar-77	475	Sep-78	1.50	75.0
Sequoyah 1	984	Jul-81	Mar-78	535	Jul-79	1.33	86.0
Sequoyah 1	984	Jul-81	Sep-78	632	Oct-79	1.08	92.0
Sequoyah 1	984	Jul-81	Jun-79	632	Jun-80	1.00	98.0
Salem 2	820	Oct-81	Sep-67	128	May-73	5.66	0.0
Salem 2	820	Oct-81	Dec-67	128	Mar-73	5.25	0.0
Salem 2	820	Oct-81	Mar-70	237	Jul-73	3.33	NA
Salem 2	820	Oct-81	Mar-71	237	Apr-74	3.09	NA
Salem 2	820	Oct-81	Jun-71	237	Dec-74	3.50	NA
Salem 2	820	Oct-81	Sep-71	308	May-75	3.66	NA
Salem 2	820	Oct-81	Dec-72	425	Mar-76	3.25	NA
Salem 2	820	Oct-81	Dec-73	497	Sep-76	2.75	NA
Salem 2	820	Oct-81	Mar-74	496	Sep-76	2.51	41.0
Salem 2	820	Oct-81	Sep-74	496	May-79	4.66	48.1
Salem 2	820	Oct-81	Mar-78	619	May-79	1.17	90.6
McGuire 1	906	Dec-81	Sep-70	179	Nov-75	5.17	0.0
McGuire 1	906	Dec-81	Sep-71	220	Nov-75	4.17	0.0
McGuire 1	906	Dec-81	Dec-72	220	Mar-76	3.25	9.0
McGuire 1	906	Dec-81	Sep-73	220	Nov-76	3.17	22.2
McGuire 1	906	Dec-81	Jun-74	220	Apr-77	2.83	34.9
McGuire 1	906	Dec-81	Sep-74	365	Jan-78	3.33	36.9
McGuire 1	906	Dec-81	Dec-74	384	Jan-78	3.09	43.5
McGuire 1	906	Dec-81	Jun-76	384	May-78	1.91	74.2
McGuire 1	906	Dec-81	Dec-76	384	Feb-79	2.17	81.2
McGuire 1	906	Dec-81	Mar-77	466	Jan-79	1.84	75.6
McGuire 1	906	Dec-81	Sep-77	466	Jul-79	1.83	86.0
McGuire 1	906	Dec-81	Mar-78	549	Jul-79	1.33	86.0
McGuire 1	906	Dec-81	Dec-78	549	Feb-80	1.17	96.0
Sequoyah 2	623	Jun-82	Dec-68	161	Oct-73	4.83	0.0
Sequoyah 2	623	Jun-82	Sep-69	187	Oct-73	4.08	1.5
Sequoyah 2	623	Jun-82	Jun-70	187	Apr-74	3.83	5.0
Sequoyah 2	623	Jun-82	Sep-70	187	Dec-74	4.25	NA
Sequoyah 2	623	Jun-82	Dec-71	213	Mar-75	3.25	NA
Sequoyah 2	623	Jun-82	Jun-72	213	Jul-75	3.08	NA
Sequoyah 2	623	Jun-82	Dec-72	225	Dec-75	3.00	NA

Completed Plants (APCOMP3, Myopia 44)

Unit Name	Actuals Cost	Actuals COD	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
Sequoyah 2	623	Jun-82	Jun-73	225	Aug-76	3.17	NA
Sequoyah 2	623	Jun-82	Dec-73	225	Feb-77	3.17	NA
Sequoyah 2	623	Jun-82	Jun-74	313	Apr-77	2.83	NA
Sequoyah 2	623	Jun-82	Sep-74	313	Sep-77	3.00	NA
Sequoyah 2	623	Jun-82	Sep-75	324	May-78	2.66	NA
Sequoyah 2	623	Jun-82	Jun-76	364	Jan-79	2.58	NA
Sequoyah 2	623	Jun-82	Mar-77	475	May-79	2.17	65.0
Sequoyah 2	623	Jun-82	Mar-78	535	Mar-80	2.00	74.0
Sequoyah 2	623	Jun-82	Sep-78	632	Jun-80	1.75	78.0
Sequoyah 2	623	Jun-82	Mar-79	632	Sep-80	1.51	80.0
Sequoyah 2	623	Jun-82	Sep-79	442	Jun-81	1.75	84.0
Sequoyah 2	623	Jun-82	Dec-80	1094	Jul-82	1.58	96.0
Lasalle 1	1336	Oct-82	Jun-70	360	Oct-75	5.33	0.0
Lasalle 1	1336	Oct-82	Sep-71	360	May-77	5.66	0.0
Lasalle 1	1336	Oct-82	Dec-71	360	Dec-77	6.00	0.0
Lasalle 1	1336	Oct-82	Sep-72	407	Dec-77	5.25	0.0
Lasalle 1	1336	Oct-82	Mar-73	407	May-78	5.17	0.0
Lasalle 1	1336	Oct-82	Jun-73	407	Oct-78	5.33	0.0
Lasalle 1	1336	Oct-82	Sep-73	430	Dec-78	5.25	0.0
Lasalle 1	1336	Oct-82	Dec-74	445	Dec-78	4.00	4.0
Lasalle 1	1336	Oct-82	Sep-75	498	Dec-78	3.25	19.0
Lasalle 1	1336	Oct-82	Sep-76	585	May-79	2.66	39.0
Lasalle 1	1336	Oct-82	Dec-76	585	Sep-79	2.75	45.0
Lasalle 1	1336	Oct-82	Sep-77	675	Sep-79	2.00	55.0
Lasalle 1	1336	Oct-82	Mar-79	808	Mar-80	1.00	86.0
Lasalle 1	1336	Oct-82	Jun-79	918	Dec-80	1.50	89.0
Lasalle 1	1336	Oct-82	Dec-79	1003	Dec-80	1.00	93.0
Lasalle 1	1336	Oct-82	Jun-80	1107	Jun-81	1.00	98.0
Lasalle 1	1336	Oct-82	Dec-80	1184	Apr-82	1.33	99.0
Susquehanna 1	?1947.0	Jun-83	Jun-69	150	27560	6.00	0.0
Susquehanna 1	1947	Jun-83	Sep-69	150	Jun-76	6.75	0.0
Susquehanna 1	1947	Jun-83	Dec-70	250	Jun-78	7.50	0.0
Susquehanna 1	1947	Jun-83	Jun-71	373	Jun-78	7.00	0.0
Susquehanna 1	1947	Jun-83	Dec-71	526	May-79	7.41	0.0
Susquehanna 1	1947	Jun-83	Mar-72	645	May-79	7.16	0.0
Susquehanna 1	1947	Jun-83	Dec-72	703	May-79	6.41	0.0
Susquehanna 1	1947	Jun-83	Sep-73	810	May-79	5.66	0.0
Susquehanna 1	1947	Jun-83	Sep-74	810	Nov-80	6.17	4.0
Susquehanna 1	1947	Jun-83	Dec-74	945	Nov-80	5.92	8.0
Susquehanna 1	1947	Jun-83	Mar-76	1047	Nov-80	4.67	24.0
Susquehanna 1	1947	Jun-83	Sep-76	1032	Nov-80	4.17	32.1
Susquehanna 1	1947	Jun-83	Dec-76	1032	Nov-80	3.92	39.6
Susquehanna 1	1947	Jun-83	Mar-77	1097	Nov-80	3.67	44.0
Susquehanna 1	1947	Jun-83	Mar-78	1195	Feb-81	2.92	61.0
Susquehanna 1	1947	Jun-83	Sep-78	1293	Feb-81	2.42	76.1
Susquehanna 1	1947	Jun-83	Jun-79	1285	Feb-81	1.67	87.9
Susquehanna 1	1947	Jun-83	Sep-79	1607	Jan-82	2.34	70.0
Susquehanna 1	1947	Jun-83	Sep-80	1841	Jan-82	1.33	87.0
Susquehanna 1	1947	Jun-83	Mar-81	2276	May-83	2.17	91.0
Susquehanna 1	1947	Jun-83	Dec-81	2292	May-83	1.41	92.0

Completed Plants (APCOMP3, Myopia 44)

Unit Name	Actuals Cost	Actuals COD	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
San Onofre 2	2502	Aug-83	Mar-70	189	Jun-76	6.25	0.0
San Onofre 2	2502	Aug-83	Jun-70	213	Jun-76	6.00	0.0
San Onofre 2	2502	Aug-83	Sep-71	363	Jun-78	6.75	0.0
San Onofre 2	2502	Aug-83	Dec-71	409	Jun-78	6.50	0.0
San Onofre 2	2502	Aug-83	Jun-73	655	Jun-79	6.00	0.0
San Onofre 2	2502	Aug-83	Mar-74	655	Jun-79	5.25	0.0
San Onofre 2	2502	Aug-83	Dec-74	893	Jul-81	6.58	0.0
San Onofre 2	2502	Aug-83	Mar-75	1142	Jul-81	6.34	3.0
San Onofre 2	2502	Aug-83	Sep-75	1142	Oct-81	6.08	10.0
San Onofre 2	2502	Aug-83	Jun-76	1210	Oct-81	5.33	23.0
San Onofre 2	2502	Aug-83	Jun-77	1320	Oct-81	4.33	44.0
San Onofre 2	2502	Aug-83	Dec-79	1740	Oct-81	1.83	86.0
San Onofre 2	2502	Aug-83	Mar-80	1824	Dec-81	1.75	86.0
San Onofre 2	2502	Aug-83	Mar-81	2010	Jun-82	1.25	98.0
St. Lucie 2	1430	Aug-83	Dec-72	360	Oct-78	5.83	0
St. Lucie 2	1430	Aug-83	Mar-73	360	Dec-79	6.75	0
St. Lucie 2	1430	Aug-83	Mar-74	360	Dec-80	6.75	0
St. Lucie 2	1430	Aug-83	Jun-74	360	Dec-79	5.50	0
St. Lucie 2	1430	Aug-83	Dec-74	537	Dec-79	5.00	0
St. Lucie 2	1430	Aug-83	Sep-75	537	Dec-80	5.25	0
St. Lucie 2	1430	Aug-83	Dec-75	620	Dec-80	5.00	0
St. Lucie 2	1430	Aug-83	Sep-76	620	Dec-82	6.25	0.7
St. Lucie 2	1430	Aug-83	Dec-76	850	Dec-82	6.00	0.7
St. Lucie 2	1430	Aug-83	Jun-77	850	May-83	5.91	1
St. Lucie 2	1430	Aug-83	Sep-78	845	May-83	4.66	13
St. Lucie 2	1430	Aug-83	Dec-78	919	May-83	4.41	16.8
St. Lucie 2	1430	Aug-83	Jun-80	1100	May-83	2.91	45.1
Summer 1	1283	Jan-84	Mar-71	234	Jan-77	5.84	0.0
Summer 1	1283	Jan-84	Sep-72	297	Jan-77	4.33	0.0
Summer 1	1283	Jan-84	Jun-73	297	Jan-78	4.59	0.1
Summer 1	1283	Jan-84	Jun-74	355	Jan-78	3.59	2.5
Summer 1	1283	Jan-84	Dec-74	355	May-79	4.41	5.0
Summer 1	1283	Jan-84	Jun-76	493	May-79	2.91	33.0
Summer 1	1283	Jan-84	Dec-76	635	May-80	3.41	42.5
Summer 1	1283	Jan-84	Mar-78	675	May-80	2.17	67.0
Summer 1	1283	Jan-84	Sep-78	675	Dec-80	2.25	77.0
Summer 1	1283	Jan-84	Mar-79	756	Dec-80	1.75	82.4
Summer 1	1283	Jan-84	Mar-80	827	Jun-81	1.25	94.8
Summer 1	1283	Jan-84	Sep-80	827	Dec-81	1.25	95.9
Summer 1	1283	Jan-84	Dec-80	1032	Jun-82	1.50	96.7
Summer 1	1283	Jan-84	Jun-82	1174	Jun-83	1.00	100.0
Summer 1	1283	Jan-84	Sep-82	1174	Oct-83	1.08	100.0

Incomplete Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	COD	Est. Years to COD	% Complete
Callaway 1	Jun-74	839	Oct-81	7.33	0
Callaway 1	Dec-74	895	Oct-81	6.83	0
Callaway 1	Mar-76	780	Oct-81	5.58	1
Callaway 1	Dec-76	1088	Jun-82	5.50	2.7
Callaway 1	Jun-77	1088	Oct-82	5.33	6.9
Callaway 1	Dec-77	1122	Oct-82	4.83	11.2
Callaway 1	Mar-80	1261	Oct-82	2.58	64
Callaway 1	Dec-80	1533	Apr-83	2.33	74.6
Callaway 1	Sep-81	2100	Jan-84	2.33	75.5
Callaway 1	Sep-82	2850	Dec-84	2.25	84.5
Callaway 1	Dec-82	2850	Jun-85	2.50	86
Grand Gulf 1	Jun-72	600	Dec-78	6.50	0
Grand Gulf 1	Dec-72	656	Jun-79	6.50	0
Grand Gulf 1	Mar-73	656	Sep-79	6.50	0
Grand Gulf 1	Jun-73	656	Jun-79	6.00	0
Grand Gulf 1	Sep-73	656	Sep-79	6.00	0
Grand Gulf 1	Sep-75	689	Sep-79	4.00	11
Grand Gulf 1	Jun-76	689	Jun-80	4.00	25.9
Grand Gulf 1	Sep-76	935	Jun-80	3.75	32.5
Grand Gulf 1	Jun-77	935	Apr-81	3.83	48
Grand Gulf 1	Dec-77	1174	Apr-81	3.33	57.9
Grand Gulf 1	Mar-79	1203	Apr-81	2.08	77.4
Grand Gulf 1	Dec-79	1203	Apr-82	2.33	80
Grand Gulf 1	Dec-81	2391	Feb-83	1.17	96
Grand Gulf 1	Jun-82	2859	NA	NA	99
Grand Gulf 1	Sep-82	2859	Dec-83	1.25	99
Grand Gulf 2	Sep-73	571	Sep-81	8.00	NA
Grand Gulf 2	Sep-75	NA	Sep-83	8.00	1.6
Grand Gulf 2	Dec-75	699	Sep-83	7.75	6.5
Grand Gulf 2	Sep-76	775	Sep-83	7.00	6.5
Grand Gulf 2	Jun-77	775	Jan-84	6.58	1.7
Grand Gulf 2	Dec-77	954	Jan-84	6.08	2.4
Grand Gulf 2	Jun-79	878	Jan-84	4.58	11.6
Grand Gulf 2	Dec-79	878	Apr-85	5.33	23
Grand Gulf 2	Jun-80	878	Apr-86	5.83	23
Hope Creek 1	Mar-70	574	Mar-75	5.00	0
Hope Creek 1	Dec-71	1039	May-78	6.42	0
Hope Creek 1	Dec-72	1139	May-79	6.42	0
Hope Creek 1	Jun-73	1139	May-81	7.92	0
Hope Creek 1	Dec-73	1461	May-81	7.42	0
Hope Creek 1	Sep-74	1972	Dec-81	7.25	0
Hope Creek 1	Mar-75	1972	Dec-82	7.75	0
Hope Creek 1	Jun-75	2435	Jun-83	8.00	0
Hope Creek 1	Sep-75	1972	Dec-82	7.25	0
Hope Creek 1	Dec-75	2435	Dec-82	7.00	0
Hope Creek 1	Sep-76	2580	May-84	7.67	2
Hope Creek 1	Mar-78	2580	May-84	6.17	6
Hope Creek 1	Jun-78	2890	May-84	5.92	8.5
Hope Creek 1	Sep-79	3585	May-85	5.67	18.5
Hope Creek 1	Jun-80	4310	Dec-86	6.50	23.5
Hope Creek 1	Sep-80	4595	Dec-86	6.25	24
Hope Creek 1	Jun-81	5465	Dec-86	5.50	30.5

Incomplete Bechtel Plants

Unit Name	Date of Estimate	Estimates Total Cost	COD	Est. Years to COD	% Complete
Hope Creek 1	Sep-81	5512	Dec-86	5.25	33.3
Hope Creek 1	Mar-82	3518	Dec-86	4.75	46
Hope Creek 1	Sep-82	3521	Dec-86	4.25	55.6
Hope Creek 1	Dec-82	3780	Dec-86	4.00	60.6
Limerick 1	Mar-70	252	Mar-75	5.00	0
Limerick 1	Dec-70	414	Mar-75	4.25	1
Limerick 1	Jun-71	414	Sep-75	4.25	1
Limerick 1	Dec-71	414	Nov-76	4.92	1
Limerick 1	Sep-72	414	Aug-78	5.92	1
Limerick 1	Dec-72	694	Aug-78	5.67	1
Limerick 1	Jun-73	694	Apr-79	5.83	1
Limerick 1	Mar-74	694	Oct-79	5.58	1
Limerick 1	Sep-74	1212	Apr-81	6.58	2
Limerick 1	Dec-75	1212	Feb-81	5.17	18.5
Limerick 1	Jun-76	1212	Apr-83	6.83	28.6
Limerick 1	Jun-77	1635	Apr-83	5.83	32
Limerick 1	Jun-79	1695	Apr-83	3.83	52
Limerick 1	Dec-80	2515	Apr-85	4.33	57.6
Limerick 1	Jun-81	2566	Apr-85	3.83	65
Limerick 1	Sep-82	2566	Jan-84	1.33	93.9
Limerick 1	Dec-82	2657	Apr-85	2.33	83.1
Limerick 2	Mar-70	223	Mar-77	7.00	0
Limerick 2	Dec-70	303	Mar-77	6.25	0
Limerick 2	Dec-71	303	Nov-77	5.92	1
Limerick 2	Sep-72	303	Jan-80	7.33	1
Limerick 2	Dec-72	512	Jan-80	7.08	1
Limerick 2	Jun-73	512	Jun-80	7.00	1
Limerick 2	Mar-73	512	Mar-81	8.00	1
Limerick 2	Sep-73	539	Apr-82	8.58	1
Limerick 2	Mar-74	539	Apr-82	8.08	4
Limerick 2	Dec-74	539	Jul-82	7.58	8
Limerick 2	Jun-76	539	Apr-85	8.83	15.3
Limerick 2	Jun-77	949	Apr-85	7.83	22
Limerick 2	Jun-79	909	Apr-85	5.83	35
Limerick 2	Dec-80	1581	Oct-87	6.83	26.6
Limerick 2	Jun-81	1626	Oct-87	6.33	28.4
Limerick 2	Dec-82	3126	Oct-88	5.83	30
Midland 1	Jun-68	NA	Feb-74	5.67	0
Midland 1	Sep-70	NA	Nov-74	4.17	1
Midland 1	Dec-70	NA	Mar-76	5.25	2
Midland 1	Jun-71	NA	Sep-76	5.25	2
Midland 1	Sep-71	NA	May-77	5.67	2
Midland 1	Dec-71	277	May-77	5.42	2
Midland 1	Dec-72	383	Feb-79	6.17	2
Midland 1	Jun-73	385	Mar-80	6.75	2
Midland 1	Dec-73	470	Mar-80	6.25	2.6
Midland 1	Dec-74	470	Mar-82	7.25	9.1
Midland 1	Mar-75	700	Mar-82	7.00	9.1
Midland 1	Jun-76	700	Mar-82	5.75	13
Midland 1	Mar-82	1695	Jul-84	2.33	74
Midland 2	Mar-68	NA	Feb-75	6.92	0
Midland 2	Sep-70	NA	Nov-75	5.17	0.5

Incomplete Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
Midland 2	Dec-70	NA	Mar-77	6.25	2
Midland 2	Jun-71	NA	Sep-77	6.25	2
Midland 2	Sep-71	NA	May-78	6.67	2
Midland 2	Dec-71	277	May-78	6.42	2
Midland 2	Dec-72	383	Feb-80	7.17	2
Midland 2	Jun-73	385	Mar-79	5.75	2
Midland 2	Dec-73	470	Mar-79	5.25	2.6
Midland 2	Dec-74	470	Mar-81	6.25	9.1
Midland 2	Mar-75	700	Mar-81	6.00	9.1
Midland 2	Jun-76	700	Mar-81	4.75	16
Midland 2	Sep-82	1695	Dec-83	1.25	84
Palo Verde 1	Jun-74	606	May-81	6.92	0
Palo Verde 1	Sep-74	613	May-81	6.67	0
Palo Verde 1	Mar-75	1000	May-82	7.17	0
Palo Verde 1	Dec-75	975	May-82	6.42	0
Palo Verde 1	Dec-77	989	May-82	4.42	21.9
Palo Verde 1	Mar-78	1263	May-82	4.17	24.6
Palo Verde 1	Sep-78	760	May-82	3.67	28.5
Palo Verde 1	Mar-79	911	May-83	4.17	43
Palo Verde 1	Dec-79	938	May-83	3.42	55.7
Palo Verde 1	Mar-80	1354	May-83	3.17	62.3
Palo Verde 1	Jun-80	1429	May-83	2.92	68.3
Palo Verde 1	Sep-80	1457	May-83	2.67	74.3
Palo Verde 1	Mar-81	1453	May-83	2.17	83.8
Palo Verde 1	Dec-81	1579	May-83	1.42	92.8
Palo Verde 1	Mar-82	1670	May-83	1.17	96.5
Palo Verde 1	Mar-83	1671	May-84	1.17	99.3
Palo Verde 2	Sep-74	586	Nov-82	8.17	0
Palo Verde 2	Mar-75	827	May-84	9.17	0
Palo Verde 2	Dec-75	845	May-84	8.42	0
Palo Verde 2	Mar-78	769	May-84	6.17	7.3
Palo Verde 2	Sep-78	598	May-84	5.67	7.8
Palo Verde 2	Jun-79	710	May-84	4.92	17.6
Palo Verde 2	Dec-79	571	May-84	4.42	26.1
Palo Verde 2	Mar-80	827	May-84	4.17	31.6
Palo Verde 2	Jun-80	820	May-84	3.92	37.7
Palo Verde 2	Sep-80	948	May-84	3.67	43.9
Palo Verde 2	Mar-81	1016	May-84	3.17	55.5
Palo Verde 2	Sep-81	1075	May-84	2.67	68.5
Palo Verde 2	Mar-82	1136	May-84	2.17	82.6
Palo Verde 2	Mar-83	1136	Feb-85	1.92	96.9
Palo Verde 2	Jun-83	1136	Sep-85	2.25	97.9
Palo Verde 3	Sep-74	605	May-84	9.67	0
Palo Verde 3	Mar-75	941	May-86	11.17	0
Palo Verde 3	Dec-75	950	May-86	10.42	0
Palo Verde 3	Dec-76	950	Jun-86	9.50	0
Palo Verde 3	Mar-78	834	Jun-86	8.25	0.9
Palo Verde 3	Sep-78	702	Jun-86	7.75	0.5
Palo Verde 3	Jun-79	833	Jun-86	7.00	1.5
Palo Verde 3	Dec-79	746	Jun-86	6.50	4.5
Palo Verde 3	Mar-80	1088	May-86	6.17	7.6
Palo Verde 3	Jun-80	1125	Jun-86	6.00	10.8

Incomplete Bechtel Plants

Unit Name	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
Palo Verde 3	Sep-80	1212	Jun-86	5.75	12.9
Palo Verde 3	Mar-81	1255	Jun-86	5.25	18.6
Palo Verde 3	Sep-81	1227	Jun-86	4.75	26
Palo Verde 3	Mar-82	1487	May-86	4.17	36.7
Palo Verde 3	Dec-82	2474	May-86	3.42	52.5
Palo Verde 3	Mar-83	1487	May-86	3.17	61.7
Palo Verde 3	Jun-83	1487	Dec-86	3.50	70.8
San Onofre 3	Mar-70	189	Jun-76	6.25	0
San Onofre 3	Jun-70	213	Jun-76	6.00	0
San Onofre 3	Dec-71	409	NA	NA	0
San Onofre 3	Jun-73	655	NA	NA	0
San Onofre 3	Mar-74	655	Jun-80	6.25	0
San Onofre 3	Sep-74	655	Jun-81	6.75	0
San Onofre 3	Dec-74	812	Oct-82	7.83	0
San Onofre 3	Jun-75	934	Oct-82	7.33	1
San Onofre 3	Sep-75	934	Jan-83	7.33	3
San Onofre 3	Jun-76	990	Jan-83	6.58	17
San Onofre 3	Dec-76	996	Jan-83	6.08	20
San Onofre 3	Mar-77	990	Jan-83	5.83	24
San Onofre 3	Jun-77	1080	Jan-83	5.58	30
San Onofre 3	Dec-79	1160	Jan-83	3.08	63
San Onofre 3	Mar-80	1216	Jan-83	2.83	60
San Onofre 3	Sep-80	1216	Feb-83	2.42	66
San Onofre 3	Mar-81	1340	Jul-83	2.33	74
San Onofre 3	Mar-82	1415	Jul-83	1.33	86
San Onofre 3	Jun-82	1477	Sep-83	1.25	89
San Onofre 3	Sep-82	1668	Sep-83	1.00	91
San Onofre 3	Dec-82	1668	May-83	0.42	97
San Onofre 3	Mar-83	1668	Jan-84	0.83	92
Skagit 1	Mar-74	900	Jul-81	7.33	0
Skagit 1	Dec-74	900	Jul-82	7.58	0
Skagit 1	Mar-75	668	Jul-82	7.33	0
Skagit 1	Jun-75	984	Jul-82	7.08	0
Skagit 1	Dec-75	984	Jul-83	7.58	0
Skagit 1	Dec-76	1238	Jul-84	7.58	0
Skagit 1	Sep-77	1601	Mar-85	7.50	0
Skagit 1	Sep-78	1793	Sep-86	8.00	0
Skagit 1	Dec-78	1896	Sep-86	7.75	0
Skagit 1	Jun-79	2072	Jan-87	7.58	0
Skagit 1	Mar-81	4249	Jan-91	9.83	0
Skagit 2	Mar-75	561	Jul-85	10.33	0
Skagit 2	Jun-75	714	Jul-85	10.08	0
Skagit 2	Mar-76	714	Jul-86	10.33	0
Skagit 2	Sep-76	870	Jul-86	9.83	0
Skagit 2	Dec-77	1323	Mar-87	9.25	0
Skagit 2	Jun-78	1418	Sep-88	10.25	0
Skagit 2	Dec-78	1617	Sep-88	9.75	0
Skagit 2	Jun-79	1755	Jan-89	9.58	0
Skagit 2	Mar-81	3560	Jan-93	11.83	0
South Texas 1	Jun-75	574	Oct-80	5.33	NA
South Texas 1	Sep-75	676	Oct-80	5.08	0
South Texas 1	Mar-79	1004	Apr-82	3.08	44

Incomplete Bechtel Plants

Unit Name	Date of Estimate	Estimates Total Cost	COD	Est. Years to COD	% Complete
South Texas 1	Sep-79	1208	Feb-84	4.42	48.3
South Texas 1	Dec-81	1786	Feb-84	2.17	50
South Texas 2	Jun-75	574	Mar-82	6.75	NA
South Texas 2	Sep-75	676	Mar-82	6.50	0
South Texas 2	Mar-79	1004	Apr-83	4.08	12
South Texas 2	Sep-79	1208	Feb-86	6.42	15
South Texas 2	Dec-81	1717	Feb-86	4.17	18
Susquehanna 2	Mar-74	575	Jun-81	7.25	1
Susquehanna 2	Sep-74	575	Jun-82	7.75	1
Susquehanna 2	Dec-74	602	May-82	7.42	6
Susquehanna 2	Mar-75	662	May-82	7.17	1.8
Susquehanna 2	Jun-75	700	May-82	6.92	2
Susquehanna 2	Dec-75	689	May-82	6.42	6
Susquehanna 2	Mar-76	678	May-82	6.17	7
Susquehanna 2	Sep-76	706	May-82	5.67	21.2
Susquehanna 2	Mar-77	713	May-82	5.17	30
Susquehanna 2	Sep-77	710	May-82	4.67	35.9
Susquehanna 2	Mar-78	735	May-82	4.17	44.2
Susquehanna 2	Sep-78	787	May-82	3.67	51.7
Susquehanna 2	Jun-79	843	May-82	2.92	53.6
Susquehanna 2	Sep-79	1081	Jan-83	3.33	45
Susquehanna 2	Dec-79	1082	Jan-83	3.08	46
Susquehanna 2	Jun-80	1082	Aug-82	2.17	53
Susquehanna 2	Sep-80	1153	Aug-82	1.92	55
Susquehanna 2	Mar-81	1217	May-84	3.17	59
Susquehanna 2	Dec-81	1578	Nov-84	2.92	65
Susquehanna 2	Jun-82	1598	Nov-84	2.42	68
Vogtle 1	Sep-71	NA	Apr-78	6.58	0
Vogtle 1	Jun-72	NA	Apr-79	6.83	0
Vogtle 1	Sep-72	NA	Oct-79	7.08	0
Vogtle 1	Dec-72	570	Apr-80	7.33	0
Vogtle 1	Sep-73	630	Apr-80	6.58	0
Vogtle 1	Mar-74	631	Apr-80	6.08	0
Vogtle 1	Jun-74	629	Apr-80	5.83	0
Vogtle 1	Mar-77	629	Jun-83	6.25	0
Vogtle 1	Sep-77	NA	Nov-84	7.17	5
Vogtle 1	Dec-77	1537	Nov-84	6.92	5
Vogtle 1	Sep-78	1586	Nov-84	5.67	5
Vogtle 1	Dec-79	1567	Nov-84	4.92	5
Vogtle 1	Jun-80	1746	May-85	4.92	10
Vogtle 1	Jun-82	4085	Mar-87	4.75	25
Vogtle 1	Sep-82	4613	Mar-87	4.50	40.4
Vogtle 1	Dec-82	3722	Mar-87	4.25	45
Vogtle 2	Sep-71	NA	Apr-79	7.58	0
Vogtle 2	Jun-72	NA	Feb-80	7.67	0
Vogtle 2	Dec-72	NA	Apr-81	8.33	0
Vogtle 2	Mar-73	495	Apr-81	8.08	0
Vogtle 2	Sep-73	543	Apr-81	7.58	0
Vogtle 2	Jun-74	534	Apr-81	6.83	0
Vogtle 2	Dec-77	1075	Nov-85	7.92	3
Vogtle 2	Sep-78	1075	Nov-87	9.17	3
Vogtle 2	Dec-78	1297	Nov-87	8.92	3

Incomplete Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
Vogtle 2	Dec-79	924	Nov-87	7.92	3
Vogtle 2	Jun-80	988	Nov-87	7.42	4
Vogtle 2	Jun-82	1415	Sep-88	6.25	10
Vogtle 2	Sep-82	1653	Sep-88	6.00	12.3
Vogtle 2	Dec-82	1476	Sep-88	5.75	15
WNP 1	Sep-73	626	Sep-80	7.00	0
WNP 1	Mar-75	990	Sep-80	5.50	0
WNP 1	Dec-75	990	Mar-81	5.25	0.7
WNP 1	Jun-76	1147	Mar-81	4.75	1.2
WNP 1	Sep-76	1147	Sep-81	5.00	1.6
WNP 1	Dec-76	1057	Sep-81	4.75	1.8
WNP 1	Mar-77	1087	Sep-81	4.50	2.6
WNP 1	Sep-77	1087	Dec-82	5.25	5.8
WNP 1	Mar-78	1164	Dec-82	4.75	9.3
WNP 1	Mar-79	1772	Dec-83	4.75	22.2
WNP 1	Sep-79	2114	Dec-83	4.25	31.4
WNP 1	Jun-80	2498	Jun-85	5.00	41.1
WNP 1	Sep-80	2369	Jun-85	4.75	41.1
WNP 1	Jun-81	3460	Jun-86	5.00	51
WNP 2	Mar-71	187	Sep-77	6.50	0
WNP 2	Mar-72	193	Sep-77	5.50	0
WNP 2	Jun-72	227	Sep-77	5.25	0
WNP 2	Sep-72	374	Sep-77	5.00	NA
WNP 2	Sep-73	472	Sep-77	4.00	2
WNP 2	Dec-74	562	Sep-77	2.75	13
WNP 2	Mar-75	608	Jun-78	3.25	15.8
WNP 2	Sep-75	608	Sep-78	3.00	24.8
WNP 2	Dec-75	608	Jul-79	3.58	27.8
WNP 2	Mar-76	794	Jul-79	3.33	29.6
WNP 2	Jun-76	794	Dec-79	3.50	29.7
WNP 2	Sep-76	794	Jun-80	3.75	32
WNP 2	Dec-76	901	Sep-80	3.75	35.8
WNP 2	Mar-77	905	Sep-80	3.50	39.6
WNP 2	Mar-78	1001	Sep-80	2.50	60.7
WNP 2	Mar-79	1663	Sep-81	2.50	66.8
WNP 2	Sep-79	1757	Sep-81	2.00	77.6
WNP 2	Jun-80	2392	Jan-83	2.58	85.2
WNP 2	Sep-80	2306	Jan-83	2.33	85.3
WNP 2	Jun-81	2784	Feb-84	2.67	85.9
Wolf Creek	Dec-74	940	Apr-82	7.33	0
Wolf Creek	Mar-77	1029	Apr-83	6.08	1
Wolf Creek	Dec-79	1296	Apr-83	3.33	47.9
Wolf Creek	Sep-80	1653	Apr-84	3.58	68
Wolf Creek	Dec-81	1927	May-84	2.42	79
Wolf Creek	Sep-82	2440	Apr-85	2.58	80
Wolf Creek	Dec-82	2420	Apr-85	2.33	83.3

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
Diablo Canyon 1	Mar-66	154	Mar-72	6.01	0
Diablo Canyon 1	Dec-68	154	Jan-73	4.09	0
Diablo Canyon 1	Sep-69	202	Jan-73	3.34	2.2
Diablo Canyon 1	Mar-71	202	May-74	3.17	21
Diablo Canyon 1	Sep-71	320	May-74	2.67	27.5
Diablo Canyon 1	Jun-72	320	Mar-75	2.75	46.5
Diablo Canyon 1	Sep-73	320	Sep-75	2.00	72.2
Diablo Canyon 1	Dec-73	397	Sep-75	1.75	78.3
Diablo Canyon 1	Dec-74	397	May-76	1.42	90.6
Diablo Canyon 1	Sep-75	530	Aug-76	0.92	94.4
Diablo Canyon 1	Jun-76	530	Jun-76	0.00	97.8
Diablo Canyon 1	Sep-76	530	Jun-77	0.75	98.5
Diablo Canyon 1	Jun-77	672	Jun-77	0.00	99.2
Diablo Canyon 1	Sep-77	672	Jun-78	0.75	99.2
Diablo Canyon 1	Jun-78	672	Jun-79	1.00	99.2
Diablo Canyon 1	Jun-79	880	Jun-79	0.00	99.2
Diablo Canyon 1	Sep-79	880	Jun-80	0.75	99.2
Diablo Canyon 1	Mar-80	880	Jun-81	1.25	99.2
Diablo Canyon 1	Sep-80	1051	Jun-81	0.75	96.5
Diablo Canyon 1	Mar-81	1196	Jun-81	0.25	99.3
Diablo Canyon 1	Jun-81	1229	Jun-81	0.00	99.6
Diablo Canyon 1	Sep-81	1262	Jun-82	0.75	99.7
Diablo Canyon 1	Mar-82	1378	Jun-83	1.25	99.8
Diablo Canyon 2	Dec-68	151	Jul-74	5.58	0
Diablo Canyon 2	Sep-69	185	Jul-74	4.83	0
Diablo Canyon 2	Mar-71	185	May-75	4.17	0
Diablo Canyon 2	Sep-71	282	May-75	3.67	2.5
Diablo Canyon 2	Jun-72	282	Mar-76	3.75	9.9
Diablo Canyon 2	Sep-73	282	Jun-76	2.75	33
Diablo Canyon 2	Dec-74	425	Mar-77	2.25	50.2
Diablo Canyon 2	Sep-75	425	Aug-77	1.92	64.8
Diablo Canyon 2	Jun-76	425	Jun-77	1.00	79
Diablo Canyon 2	Jun-77	548	Jun-77	0.00	89.4
Diablo Canyon 2	Sep-77	548	Jun-78	0.75	90.9
Diablo Canyon 2	Mar-78	548	Jun-79	1.25	93.5
Diablo Canyon 2	Dec-78	548	Jun-80	1.50	96.9
Diablo Canyon 2	Jun-79	721	Jun-80	1.00	97.9
Diablo Canyon 2	Dec-79	721	Jun-81	1.50	97.9
Diablo Canyon 2	Sep-80	841	Jun-82	1.75	88.1
Diablo Canyon 2	Mar-81	986	Jun-82	1.25	90.2
Diablo Canyon 2	Jun-81	1025	Jun-82	1.00	90.5
Diablo Canyon 2	Sep-81	1043	Jun-82	0.75	91
Diablo Canyon 2	Mar-82	1126	Jun-83	1.25	91.2
Diablo Canyon 2	Dec-82	1126	Jun-84	1.50	95
Beaver Valley 2	Dec-71	296	Mar-78	6.25	0
Beaver Valley 2	Mar-72	360	Mar-78	6.00	0
Beaver Valley 2	Mar-73	360	Jun-79	6.25	0
Beaver Valley 2	Sep-73	393	Jun-79	5.75	0
Beaver Valley 2	Mar-74	560	Jun-79	5.25	0
Beaver Valley 2	Sep-74	685	Jun-81	6.75	0.05
Beaver Valley 2	Dec-74	685	Apr-81	6.34	0.05

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	COD	Est. Years to COD	% Complete
Beaver Valley 2	Mar-75	796	May-81	6.17	0.05
Beaver Valley 2	Jun-75	796	Apr-81	5.84	0.05
Beaver Valley 2	Sep-75	799	Apr-81	5.59	0.05
Beaver Valley 2	Dec-75	793	Apr-81	5.34	0.05
Beaver Valley 2	Jun-76	927	May-82	5.92	0.1
Beaver Valley 2	Sep-76	922	May-82	5.67	0.5
Beaver Valley 2	Mar-77	935	May-82	5.17	6
Beaver Valley 2	Jun-77	934	May-82	4.92	8
Beaver Valley 2	Dec-77	942	May-82	4.42	15
Beaver Valley 2	Jun-78	1010	May-82	3.92	20
Beaver Valley 2	Sep-78	1415	May-84	5.67	26
Beaver Valley 2	Sep-79	2024	May-84	4.67	34.5
Beaver Valley 2	Dec-79	2024	May-86	6.42	35.2
Beaver Valley 2	Sep-80	2203	May-86	5.67	41.2
Beaver Valley 2	Dec-81	2305	May-86	4.42	47.8
Beaver Valley 2	Dec-82	3076	May-86	3.42	58.1
Bellefonte 1	Dec-70	NA	Jul-77	6.59	0
Bellefonte 1	Dec-71	312	Jul-77	5.59	0
Bellefonte 1	Dec-72	348	Sep-79	6.75	0
Bellefonte 1	Dec-73	348	Dec-79	6.00	0
Bellefonte 1	Sep-74	482	Dec-79	5.25	0
Bellefonte 1	Mar-75	482	Jun-80	5.26	3
Bellefonte 1	Sep-76	587	Jun-80	3.75	24
Bellefonte 1	Sep-77	632	Jun-80	2.75	46
Bellefonte 1	Dec-77	632	Jun-80	2.50	52
Bellefonte 1	Sep-78	792	Sep-81	3.00	60
Bellefonte 1	Sep-79	1001	Sep-83	4.00	69
Bellefonte 1	Dec-80	1659	Dec-85	5.00	75
Bellefonte 1	Sep-81	1854	Jun-86	4.75	77
Bellefonte 1	Mar-82	1769	Jun-86	4.25	79
Bellefonte 1	Jun-82	1769	Nov-86	4.42	80
Bellefonte 1	Sep-82	2214	Nov-86	4.17	81
Bellefonte 2	Dec-70	NA	Apr-78	7.34	0
Bellefonte 2	Dec-71	312	Jul-77		
Bellefonte 2	Dec-72	348	Jun-80	7.50	0
Bellefonte 2	Dec-73	348	Sep-80	6.76	0
Bellefonte 2	Sep-74	482	Dec-79	5.25	
Bellefonte 2	Mar-75	482	Mar-81	6.01	0
Bellefonte 2	Sep-76	587	Mar-81	3.75	
Bellefonte 2	Sep-77	632	Mar-81	2.75	
Bellefonte 2	Dec-77	632	Mar-81	2.50	
Bellefonte 2	Sep-78	792	Jun-82	3.75	42
Bellefonte 2	Sep-79	1001	Jun-84	4.75	48
Bellefonte 2	Sep-80	1001	Sep-86	6.00	57
Bellefonte 2	Mar-81	1659	Sep-86	5.51	59
Bellefonte 2	Sep-81	1854	Sep-86	5.00	
Bellefonte 2	Mar-82	1769	Jun-87	5.25	64
Bellefonte 2	Jun-82	1769	Nov-87	5.42	67
Bellefonte 2	Sep-82	2214	Nov-87	5.17	60
Braidwood 1	Dec-72	501	Oct-79	6.84	0
Braidwood 1	Mar-73	517	Oct-79	6.59	0

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
Braidwood 1	Jun-73	517	Oct-80	7.34	0
Braidwood 1	Sep-73	513	May-80	6.67	0
Braidwood 1	Jun-74	567	May-80	5.92	0
Braidwood 1	Sep-74	567	Oct-81	7.09	0
Braidwood 1	Dec-74	616	Oct-81	6.84	0
Braidwood 1	Sep-75	618	Oct-81	6.09	0.25
Braidwood 1	Mar-76	716	Oct-81	5.59	1
Braidwood 1	Sep-76	718	Oct-81	5.08	6
Braidwood 1	Sep-77	829	Oct-81	4.08	21
Braidwood 1	Dec-78	902	Oct-81	2.84	45
Braidwood 1	Jun-79	991	Oct-82	3.34	53
Braidwood 1	Dec-79	1141	Oct-83	3.84	54
Braidwood 1	Jun-80	1585	Oct-85	5.34	56
Braidwood 1	Dec-80	1575	Oct-85	4.84	59
Braidwood 1	Dec-81	1635	Oct-85	3.84	61
Braidwood 2	Dec-72	446	Oct-80	7.84	0
Braidwood 2	Mar-73	413	Oct-80	7.59	0
Braidwood 2	Jun-73	428	Mar-82	8.75	0
Braidwood 2	Sep-73	428	Oct-81	8.09	0
Braidwood 2	Jun-74	417	Oct-81	7.34	0
Braidwood 2	Sep-74	417	Oct-82	8.09	0
Braidwood 2	Dec-74	442	Oct-82	7.84	0
Braidwood 2	Mar-76	485	Oct-82	6.59	1
Braidwood 2	Sep-76	486	Oct-82	6.08	4
Braidwood 2	Sep-77	519	Oct-82	5.08	18
Braidwood 2	Dec-78	601	Oct-82	3.84	36
Braidwood 2	Jun-79	679	Oct-83	4.34	42
Braidwood 2	Dec-79	769	Oct-84	4.84	43
Braidwood 2	Jun-80	1011	Oct-86	6.34	44
Braidwood 2	Dec-80	1015	Oct-86	5.84	47
Braidwood 2	Dec-81	1076	Oct-86	4.84	48
Braidwood 2	Mar-83	1276	Oct-86	3.59	53
Byron 1	Jun-71	400	Oct-78	7.34	0
Byron 1	Dec-71	400	Oct-79	7.84	0
Byron 1	Mar-72	400	Oct-78	6.59	0
Byron 1	Sep-72	464	May-79	6.67	0
Byron 1	Sep-73	464	May-80	6.67	0
Byron 1	Jun-74	537	May-80	5.92	0
Byron 1	Sep-74	537	Oct-80	6.09	0
Byron 1	Dec-74	550	Oct-80	5.84	0
Byron 1	Sep-75	551	Oct-80	5.09	1
Byron 1	Mar-76	663	Oct-80	4.59	6
Byron 1	Sep-76	664	Oct-80	4.08	12
Byron 1	Dec-76	664	Mar-81	4.25	14
Byron 1	Sep-77	835	Mar-81	3.50	27
Byron 1	Dec-77	862	Sep-81	3.75	33
Byron 1	Dec-78	984	Sep-81	2.75	52
Byron 1	Jun-79	1116	Oct-82	3.34	60
Byron 1	Dec-79	1168	Oct-82	2.84	65
Byron 1	Jun-80	1483	Oct-83	3.33	69
Byron 1	Dec-80	1481	Oct-83	2.83	73

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
Byron 1	Dec-81	1635	Feb-84	2.17	79
Byron 1	Mar-83	1979	Jun-84	1.25	89
Byron 2	Jun-71	350	Oct-79	8.34	0
Byron 2	Dec-71	350	Oct-80	8.84	0
Byron 2	Mar-72	350	Oct-79	7.59	0
Byron 2	Jun-72	422	Mar-80	7.75	0
Byron 2	Sep-73	422	May-81	7.67	0
Byron 2	Jun-74	438	May-81	6.92	0
Byron 2	Sep-74	428	Oct-82	8.09	0
Byron 2	Dec-74	477	Oct-82	7.84	0
Byron 2	Sep-75	478	Oct-82	7.09	1
Byron 2	Mar-76	487	Oct-82	6.59	6
Byron 2	Sep-76	489	Oct-82	6.08	9
Byron 2	Sep-77	538	Oct-82	5.08	23
Byron 2	Dec-78	624	Oct-82	3.84	42
Byron 2	Jun-79	702	Oct-83	4.34	48
Byron 2	Dec-79	732	Oct-83	3.84	53
Byron 2	Jun-80	922	Oct-84	4.34	55
Byron 2	Dec-80	924	Oct-84	3.84	59
Byron 2	Dec-81	1093	Feb-85	3.17	63
Carroll County 1	Jun-74	680	Oct-82	8.34	0
Carroll County 1	Sep-74	680	Oct-84	10.09	0
Carroll County 1	Jun-75	860	Oct-84	9.34	0
Carroll County 1	Dec-75	860	Oct-85	9.84	0
Carroll County 1	Mar-76	920	Oct-85	9.59	0
Carroll County 1	Dec-76	1080	Oct-85	8.84	0
Carroll County 1	Dec-78	2016	Oct-88	9.84	0
Carroll County 1	Jun-79	2230	Oct-90	11.34	0
Carroll County 1	Dec-79	2696	Oct-92	12.84	0
Carroll County 1	Jun-80	2891	Oct-92	12.34	0
Carroll County 1	Dec-80	3696	Oct-93	12.84	0
Carroll County 1	Dec-81	NA	Oct-93	11.84	0
Carroll County 1	Mar-82	NA	NA	NA	0
Carroll County 2	Jun-74	560	Oct-83	9.34	0
Carroll County 2	Sep-74	560	Oct-85	11.09	0
Carroll County 2	Jun-75	680	Oct-85	10.34	0
Carroll County 2	Dec-75	680	Oct-86	10.84	0
Carroll County 2	Mar-76	730	Oct-86	10.59	0
Carroll County 2	Dec-76	780	Oct-86	9.84	0
Carroll County 2	Dec-78	1250	Oct-89	10.84	0
Carroll County 2	Jun-79	1425	Oct-91	12.34	0
Carroll County 2	Dec-79	1724	Oct-93	13.84	0
Carroll County 2	Jun-80	1852	Oct-93	13.34	0
Carroll County 2	Dec-80	2414	Oct-94	13.84	0
Carroll County 2	Dec-81	NA	NA	NA	0
Catawba 1	Dec-72	317	NA	NA	NA
Catawba 1	Mar-73	317	Mar-79	6.00	0
Catawba 1	Jun-74	317	Jul-79	5.08	0
Catawba 1	Sep-74	498	Jan-81	6.34	0.5
Catawba 1	Dec-74	542	Jan-81	6.09	0.7
Catawba 1	Mar-77	649	Jul-81	4.34	11.5

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
Catawba 1	Mar-78	673	Jul-81	3.34	28
Catawba 1	Mar-79	754	Jul-81	2.34	47
Catawba 1	Sep-79	754	Jul-83	3.83	63
Catawba 1	Jun-80	754	Mar-84	3.75	73
Catawba 1	Sep-80	1034	Mar-84	3.50	76
Catawba 1	Mar-81	1369	Mar-84	3.00	82.2
Catawba 1	Dec-81	1361	Mar-84	2.25	86.4
Catawba 1	Jun-82	1361	Jun-85	3.00	90
Catawba 1	Dec-82	1800	Jun-85	2.50	92
Catawba 2	Dec-72	317	Mar-80	7.25	0
Catawba 2	Jun-74	317	May-80	5.92	0
Catawba 2	Sep-74	498	Jan-82	7.34	0
Catawba 2	Dec-74	542	Jan-82	7.09	0
Catawba 2	Dec-76	542	Jun-83	6.50	9.5
Catawba 2	Mar-77	649	Jan-83	5.84	11.5
Catawba 2	Mar-78	673	Jan-83	4.84	22
Catawba 2	Mar-79	754	Jan-83	3.84	37
Catawba 2	Sep-79	754	Jan-85	5.34	46
Catawba 2	Dec-79	754	Jan-85	5.09	12
Catawba 2	Jun-80	NA	Sep-85	5.25	15
Catawba 2	Sep-80	1034	Sep-85	5.00	16.7
Catawba 2	Mar-81	1369	Sep-85	4.51	29.5
Catawba 2	Dec-81	1567	Sep-85	3.75	35.5
Catawba 2	Jun-82	1567	Jun-87	5.00	45.6
Catawba 2	Dec-82	2100	Jun-87	4.50	47
Clinton 1	Sep-73	404	Jun-80	6.75	0
Clinton 1	Dec-73	435	Jun-80	6.50	0
Clinton 1	Dec-74	561	Jun-81	6.50	0
Clinton 1	Dec-75	705	Jun-81	5.50	0
Clinton 1	Sep-76	825	Jun-81	4.75	6
Clinton 1	Mar-77	825	Dec-81	4.76	10
Clinton 1	Dec-77	1051	Dec-81	4.00	20
Clinton 1	Mar-78	1220	Dec-82	4.76	27
Clinton 1	Dec-78	1297	Dec-82	4.00	36
Clinton 1	Mar-80	1397	Dec-82	2.75	66
Clinton 1	Dec-80	1742	Sep-83	2.75	73
Clinton 1	Mar-82	NA	Sep-83	1.50	82
Clinton 1	Jun-82	1819	Sep-84	2.25	83
Clinton 1	Mar-83	2181	Sep-84	1.51	87.8
Clinton 1	Jun-83	2868	Nov-86	3.42	80.9
Clinton 2	Sep-73	368	Jun-82	8.75	0
Clinton 2	Dec-73	367	Jun-83	9.50	0
Clinton 2	Dec-74	487	Jun-84	9.51	0
Clinton 2	Dec-75	604	Jun-84	8.51	0
Clinton 2	Sep-76	699	Jun-84	7.75	0
Clinton 2	Mar-77	699	Jun-88	11.26	0
Clinton 2	Dec-77	1059	Jun-88	10.51	0
Clinton 2	Mar-82	2181	Jun-88	6.26	3
Clinton 2	Mar-83	NA	Jun-88	5.26	3
Fermi 2	Mar-69	221	Feb-74	4.93	0
Fermi 2	Mar-70	250	Feb-74	3.93	0

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
Fermi 2	Sep-70	259	Feb-74	3.42	0
Fermi 2	Jun-71	328	Feb-75	3.67	4.8
Fermi 2	Dec-71	328	Oct-75	3.84	13.2
Fermi 2	Mar-72	409	Oct-75	3.59	17.2
Fermi 2	Jun-72	409	Apr-76	3.84	20.4
Fermi 2	Dec-72	439	Aug-76	3.67	28.5
Fermi 2	Sep-73	500	Apr-77	3.58	44.4
Fermi 2	Dec-73	501	Apr-77	3.33	47.6
Fermi 2	Jun-74	501	Apr-78	3.84	NA
Fermi 2	Sep-74	501	Apr-79	4.58	45
Fermi 2	Jun-75	899	Sep-80	5.26	45
Fermi 2	Mar-77	882	Dec-80	3.76	46
Fermi 2	Mar-79	973	Dec-80	7.76	78.7
Fermi 2	Jun-79	973	Mar-82	2.75	81.5
Fermi 2	Jun-80	1283	Mar-82	1.75	79.4
Fermi 2	Sep-80	1800	Nov-83	3.17	79.4
Fermi 2	Mar-81	1800	Nov-83	2.67	NA
Fermi 2	Jun-81	1968	Nov-83	2.42	85
Fermi 2	Sep-81	1994	Nov-83	2.17	87
Fermi 2	Sep-82	2346	Nov-83	1.17	92
Fermi 2	Jun-83	2696	Jul-84	1.08	96
Hartsville A-1	Mar-73	378.5	Dec-80	7.76	0
Hartsville A-1	Dec-74	601	Dec-80	6.01	0
Hartsville A-1	Sep-75	601	Dec-81	6.25	0
Hartsville A-1	Jun-76	601	Feb-83	6.67	0
Hartsville A-1	Sep-76	602	Feb-83	6.42	4
Hartsville A-1	Dec-76	602	Feb-83	6.17	1
Hartsville A-1	Jun-77	602	Jun-83	6.00	3
Hartsville A-1	Sep-77	854	Jun-83	5.75	5
Hartsville A-1	Sep-78	853	Jun-83	4.75	13
Hartsville A-1	Sep-79	1418	Jul-86	6.84	21
Hartsville A-1	Dec-80	NA	Jul-88	7.59	31
Hartsville A-1	Mar-81	1973	Jul-88	7.34	33
Hartsville A-1	Sep-81	3368	Apr-91	9.59	35
Hartsville A-2	Mar-73	379	Dec-81	8.76	0
Hartsville A-2	Jun-74	NA	Dec-81	7.51	0
Hartsville A-2	Sep-75	601	Dec-82	7.25	0
Hartsville A-2	Jun-76	601	Feb-84	7.67	0
Hartsville A-2	Sep-76	602	Feb-84	7.42	
Hartsville A-2	Dec-76	602	Feb-84	7.17	
Hartsville A-2	Jun-77	602	Jun-84	7.01	1
Hartsville A-2	Sep-77	854	Jun-84	6.75	
Hartsville A-2	Sep-78	853	Jun-84	5.75	
Hartsville A-2	Sep-79	1418	Jul-87	7.84	8
Hartsville A-2	Dec-80	NA	Jul-87	6.58	
Hartsville A-2	Mar-81	1973	Apr-89	8.09	25
Hartsville A-2	Sep-81	3368	Apr-92	10.59	27
LaSalle 2	Jun-70	300	Oct-76	6.34	0
LaSalle 2	Sep-71	300	May-78	6.67	0
LaSalle 2	Dec-71	300	Sep-78	6.76	0
LaSalle 2	Sep-72	330	Sep-78	6.00	0

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
LaSalle 2	Mar-73	330	Mar-79	6.00	0
LaSalle 2	Jun-73	330	Oct-79	6.34	0
LaSalle 2	Sep-73	343	May-79	5.67	0
LaSalle 2	Sep-74	343	Oct-79	5.08	3
LaSalle 2	Dec-74	358	Oct-79	4.84	3
LaSalle 2	Sep-75	399	Oct-79	4.08	14
LaSalle 2	Dec-76	400	Sep-80	3.75	37
LaSalle 2	Sep-77	513	Sep-80	3.00	45
LaSalle 2	Dec-78	580	Sep-80	1.75	59
LaSalle 2	Jun-79	729	Dec-81	2.50	69
LaSalle 2	Dec-79	699	Dec-81	2.00	74
LaSalle 2	Jun-80	786	Jun-82	2.00	78
LaSalle 2	Dec-80	874	Dec-82	2.00	81
LaSalle 2	Mar-81	874	Jun-83	2.25	81.5
LaSalle 2	Dec-81	1027	Oct-83	1.83	84
LaSalle 2	Jun-82	1026	Oct-83	1.33	87
LaSalle 2	Mar-83	1018	Apr-84	1.09	97
Marble Hill 1	Dec-74	600	Jun-83	8.50	0
Marble Hill 1	Jun-75	744	Jun-82	7.01	NA
Marble Hill 1	Jun-76	791	Jun-82	6.00	NA
Marble Hill 1	Sep-76	811	Jun-82	5.75	NA
Marble Hill 1	Dec-76	416	Jun-82	5.50	NA
Marble Hill 1	Mar-77	463	Jun-82	5.25	0
Marble Hill 1	Jun-77	505	Jun-82	5.00	0
Marble Hill 1	Sep-77	506	Jun-82	4.75	NA
Marble Hill 1	Dec-77	511	Sep-82	4.75	NA
Marble Hill 1	Jun-78	511	Oct-82	4.34	8
Marble Hill 1	Mar-79	989	NA	NA	19
Marble Hill 1	Jun-79	989	Oct-82	3.34	22.5
Marble Hill 1	Jun-80	2001	Dec-86	6.50	20
Marble Hill 1	Sep-81	2504	Dec-86	5.25	34
Marble Hill 1	Sep-82	2725	Dec-86	4.25	42.9
Marble Hill 2	Dec-74	600	Jun-84	9.51	0
Marble Hill 2	Jun-75	620	Jun-84	9.01	0
Marble Hill 2	Jun-76	670	Jun-84	8.01	0
Marble Hill 2	Sep-76	675	Jun-84	7.75	0
Marble Hill 2	Dec-76	385	Jun-84	7.50	0
Marble Hill 2	Mar-77	317	Jun-84	7.26	0
Marble Hill 2	Jun-77	346	Jun-84	7.01	0
Marble Hill 2	Dec-77	353	Jun-84	6.50	0.4
Marble Hill 2	Mar-78	353	Jan-84	5.84	0.4
Marble Hill 2	Mar-79	818	Jan-84	4.84	5.2
Marble Hill 2	Jun-80	1383	Dec-87	7.50	9
Marble Hill 2	Sep-81	1730	Dec-87	6.25	14
Marble Hill 2	Dec-81	1383	Dec-87	6.00	10
Marble Hill 2	Jun-82	1730	Dec-87	5.50	20
Marble Hill 2	Sep-82	2260	Dec-87	5.25	25
Marble Hill 2	Dec-82	2260	Jun-88	5.50	27.3
McGuire 2	Sep-70	179	Nov-76	6.17	0
McGuire 2	Mar-71	179	Mar-77	6.01	0
McGuire 2	Sep-71	220	Mar-77	5.50	0

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
McGuire 2	Sep-73	220	Sep-77	4.00	16.4
McGuire 2	Jun-74	220	Nov-77	3.42	27.7
McGuire 2	Sep-74	365	Jan-79	4.34	29.6
McGuire 2	Dec-74	384	Jan-79	4.09	35.3
McGuire 2	Jun-76	384	May-79	2.92	55.9
McGuire 2	Dec-76	384	Feb-80	3.17	55.6
McGuire 2	Mar-77	466	Jan-80	2.84	50.1
McGuire 2	Sep-77	466	Mar-81	3.50	54
McGuire 2	Mar-78	549	Mar-81	3.00	51
McGuire 2	Mar-79	635	Mar-81	2.00	56
McGuire 2	Sep-79	635	Apr-82	2.58	67
McGuire 2	Jun-80	635	Sep-82	2.25	83
McGuire 2	Sep-80	765	Sep-82	2.00	89
McGuire 2	Mar-81	921	Jun-83	2.25	90.2
McGuire 2	Dec-81	1059	Oct-83	1.83	93.7
McGuire 2	Sep-82	1059	Mar-84	1.50	97.2
McGuire 2	Dec-82	1069	Mar-84	1.25	98
Millstone 3	Mar-74	642	May-79	5.17	0
Millstone 3	Mar-75	793	Nov-79	4.67	5.8
Millstone 3	Dec-75	793	May-82	6.42	7.7
Millstone 3	Jun-76	998	May-82	5.92	9.9
Millstone 3	Mar-77	1173	May-82	5.17	12.3
Millstone 3	Dec-77	1173	May-86	8.42	18.3
Millstone 3	Sep-78	1980	May-86	7.67	24.5
Millstone 3	Dec-80	2573	May-86	5.42	33.3
Millstone 3	Dec-81	2577	May-86	4.42	43
Millstone 3	Dec-82	3539	May-86	3.42	60.3
Nine Mile Point 2	Dec-71	370	Jul-78	6.59	0
Nine Mile Point 2	Sep-72	370	Nov-78	6.17	0
Nine Mile Point 2	Dec-73	602	Nov-78	4.92	0
Nine Mile Point 2	Mar-74	609	May-79	5.17	0
Nine Mile Point 2	Mar-75	749	Oct-82	7.59	1
Nine Mile Point 2	Jun-76	793	Oct-82	6.34	1.4
Nine Mile Point 2	Mar-77	1107	Oct-82	5.59	9.5
Nine Mile Point 2	Jun-77	1156	Oct-82	5.34	12.9
Nine Mile Point 2	Dec-77	1505	Oct-83	5.84	17.5
Nine Mile Point 2	Dec-78	1954	Oct-84	5.84	24.1
Nine Mile Point 2	Mar-80	1963	Oct-84	4.59	37
Nine Mile Point 2	Jun-80	1953	Oct-84	4.34	37.7
Nine Mile Point 2	Dec-80	3612	Oct-86	5.84	29.5
Nine Mile Point 2	Mar-81	3727	Oct-86	5.59	27.7
Nine Mile Point 2	Dec-82	4174	Oct-86	3.84	56.7
Comanche Peak 1	Mar-74	355	Jan-80	5.84	0
Comanche Peak 1	Dec-76	690	Jan-80	3.08	40
Comanche Peak 1	Mar-77	690	Jan-81	3.84	37
Comanche Peak 1	Jun-77	850	Jan-81	3.59	39
Comanche Peak 1	Mar-79	850	Jun-81	2.25	68.8
Comanche Peak 1	Dec-80	1118	Jun-81	0.50	86
Comanche Peak 1	Mar-81	1118	Jun-82	1.25	88
Comanche Peak 1	Jun-82	1720	Jun-84	2.00	91
Comanche Peak 2	Mar-74	355	Jan-82	7.84	0

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
Comanche Peak 2	Dec-76	690	Jan-82	5.09	17
Comanche Peak 2	Mar-77	690	Dec-82	5.76	9
Comanche Peak 2	Jun-77	850	Jan-83	5.59	9.67
Comanche Peak 2	Mar-79	850	Jun-83	4.25	26.4
Comanche Peak 2	Sep-80	1118	Dec-82	2.25	50
Comanche Peak 2	Mar-81	1118	Jun-84	3.25	52
Comanche Peak 2	Jun-82	1720	Jun-85	3.00	55
Perry 1	Mar-74	617	Jun-79	5.25	0
Perry 1	Dec-74	676	Jun-79	4.50	0.5
Perry 1	Mar-75	676	Jun-80	5.26	0.5
Perry 1	Jun-75	774	Jun-80	5.01	1.8
Perry 1	Sep-76	1006	Dec-81	5.25	3.4
Perry 1	Mar-77	1011	Dec-81	4.76	5.4
Perry 1	Sep-77	988	Dec-81	4.25	13.3
Perry 1	Dec-78	1159	May-83	4.42	33.2
Perry 1	Mar-79	1185	May-83	4.17	37.7
Perry 1	Jun-79	1187	May-83	3.92	40.6
Perry 1	Jun-80	1701	May-84	3.92	59.4
Perry 1	Mar-81	1710	May-84	3.17	70.9
Perry 1	Sep-81	1884	May-84	2.67	78.8
Perry 1	Mar-83	2643	May-85	2.17	83.8
Perry 2	Mar-74	617	Jun-80	6.26	0
Perry 2	Dec-74	676	Jun-80	5.50	0.5
Perry 2	Mar-75	676	Apr-82	7.09	0.5
Perry 2	Jun-75	774	Apr-82	6.84	1.8
Perry 2	Sep-76	1006	Jun-83	6.75	3.4
Perry 2	Mar-77	1011	Jun-83	6.25	5.4
Perry 2	Sep-77	1123	Jun-83	5.75	6.3
Perry 2	Sep-78	1318	May-85	6.67	20.2
Perry 2	Mar-79	1367	May-85	6.17	22.5
Perry 2	Jun-79	1350	May-85	5.92	26.5
Perry 2	Jun-80	2157	May-88	7.92	46.5
Perry 2	Mar-81	2179	May-88	7.17	52.3
Perry 2	Jun-81	1808	May-88	6.92	39.8
Perry 2	Mar-83	2456	May-88	5.17	38.3
River Bend 1	Mar-73	390	Oct-79	6.59	0
River Bend 1	Jun-73	376	Feb-80	6.67	0
River Bend 1	Mar-74	376	Sep-80	6.51	0
River Bend 1	Jun-74	541	Sep-80	6.26	0
River Bend 1	Mar-75	541	Sep-81	6.51	0
River Bend 1	Dec-76	934	Sep-81	4.75	4
River Bend 1	Mar-77	934	Sep-83	6.51	5
River Bend 1	Dec-77	1172	Sep-83	5.75	5
River Bend 1	Jun-78	1172	Sep-84	6.26	5
River Bend 1	Sep-79	1172	Apr-84	4.59	5.4
River Bend 1	Mar-80	1679	Apr-84	4.09	11.9
River Bend 1	Sep-80	2273	Apr-84	3.58	30
River Bend 1	Sep-81	2275	Apr-84	2.58	38.2
River Bend 1	Dec-81	3645	Dec-85	4.00	46.1
River Bend 1	Sep-82	2474	Dec-85	3.25	51.6
River Bend 2	Mar-73	344	Sep-81	8.51	0

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
River Bend 2	Mar-74	344	Sep-82	8.51	0
River Bend 2	Jun-74	478	Sep-82	8.26	0
River Bend 2	Mar-75	478	Sep-83	8.51	0
River Bend 2	Dec-75	678	Sep-83	7.76	4
River Bend 2	Mar-77	678	Sep-85	8.51	5
River Bend 2	Dec-77	868	Sep-85	7.76	5
River Bend 2	Mar-79	868	NA	NA	5
Seabrook 1	Sep-68	NA	Oct-74	6.08	0
Seabrook 1	Dec-68	120	Oct-74	5.84	0
Seabrook 1	Mar-69	186	Oct-74	5.59	NA
Seabrook 1	Sep-69	186	May-75	5.67	NA
Seabrook 1	Jun-73	NA	Nov-79	6.42	0
Seabrook 1	Sep-73	946	Nov-79	6.17	0
Seabrook 1	Mar-74	473	Nov-79	5.67	0
Seabrook 1	Dec-74	523	Nov-79	4.92	0
Seabrook 1	Mar-75	585	Nov-80	5.68	0
Seabrook 1	Mar-76	585	Jun-81	5.25	0
Seabrook 1	Jun-76	585	Nov-81	5.42	0
Seabrook 1	Dec-76	684	Nov-81	4.92	1
Seabrook 1	Dec-77	1375	Dec-82	5.00	8
Seabrook 1	Jun-78	1340	Dec-82	4.50	13
Seabrook 1	Mar-79	1497	Apr-83	4.09	18.9
Seabrook 1	Jun-79	1294	Apr-83	3.84	26.7
Seabrook 1	Mar-80	1601	Apr-83	3.08	36.7
Seabrook 1	Jun-80	1493	Apr-83	2.83	39.7
Seabrook 1	Mar-81	1708	Feb-84	2.92	47
Seabrook 1	Dec-81	1735	Feb-84	2.17	54
Seabrook 1	Mar-83	2540	Dec-84	1.76	73.9
Seabrook 2	Sep-73	NA	Nov-79	6.17	0
Seabrook 2	Mar-74	473	Nov-79	5.67	0
Seabrook 2	Dec-74	523	Nov-81	6.92	0
Seabrook 2	Mar-75	585	Nov-82	7.68	0
Seabrook 2	Mar-76	585	Jun-83	7.25	0
Seabrook 2	Jun-76	585	Nov-83	7.42	0
Seabrook 2	Dec-76	684	Nov-83	6.92	1
Seabrook 2	Dec-77	825	Dec-84	7.01	1
Seabrook 2	Mar-78	980	Dec-84	6.76	2
Seabrook 2	Mar-79	1084	Feb-85	5.93	2.8
Seabrook 2	Jun-79	1287	Feb-85	5.68	5.3
Seabrook 2	Mar-80	1490	Feb-85	4.93	7.28
Seabrook 2	Jun-80	1558	Feb-85	4.67	7.55
Seabrook 2	Mar-81	1763	May-86	5.17	8
Seabrook 2	Dec-81	1825	May-86	4.42	9.2
Seabrook 2	Mar-83	2709	Jul-87	4.34	19.4
Shearon Harris 1	Jun-71	234	Mar-77	5.75	0
Shearon Harris 1	Dec-71	247	Mar-77	5.25	0
Shearon Harris 1	Dec-72	274	Mar-78	5.25	0
Shearon Harris 1	Sep-73	331	Mar-78	4.50	0
Shearon Harris 1	Dec-73	419	Oct-79	5.84	0
Shearon Harris 1	Jun-74	513	Mar-81	6.75	1.7
Shearon Harris 1	Sep-74	502	Mar-81	6.50	1

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
Shearon Harris 1	Dec-74	513	Mar-81	6.25	1.5
Shearon Harris 1	Jun-75	730	Mar-84	8.76	1.7
Shearon Harris 1	Dec-75	901	Mar-84	8.25	1.7
Shearon Harris 1	Dec-76	986	Mar-84	7.25	1.7
Shearon Harris 1	Dec-77	1039	Mar-84	6.25	1.7
Shearon Harris 1	Dec-79	1208	Mar-84	4.25	18.5
Shearon Harris 1	Jun-80	1208	Mar-85	4.75	32.8
Shearon Harris 1	Dec-80	1629	Sep-85	4.75	37
Shearon Harris 1	Sep-81	1630	Sep-85	4.00	70
Shearon Harris 1	Mar-82	1882	Sep-85	3.51	58
Shearon Harris 1	Sep-82	1882	Mar-86	3.50	70
Shearon Harris 1	Dec-82	2586	Mar-86	3.25	76
Shearon Harris 2	Jun-71	234	Jun-78	5.75	0
Shearon Harris 2	Dec-71	247	Jun-78	5.25	0
Shearon Harris 2	Dec-72	274	Mar-79	5.25	0
Shearon Harris 2	Sep-73	331	Mar-79	4.50	0
Shearon Harris 2	Dec-73	419	Mar-80	5.84	0
Shearon Harris 2	Jun-74	513	Jun-82	6.75	1
Shearon Harris 2	Sep-74	502	Jun-82	7.75	
Shearon Harris 2	Dec-74	513	Jun-82	7.50	
Shearon Harris 2	Jun-75	730	Mar-86	8.76	1.7
Shearon Harris 2	Dec-75	901	Mar-86	8.25	1.7
Shearon Harris 2	Dec-76	986	Mar-86	7.25	1.7
Shearon Harris 2	Dec-77	1039	Mar-86	6.25	1.7
Shearon Harris 2	Dec-79	1208	Mar-87	4.25	3
Shearon Harris 2	Jun-80	1208	Mar-88	4.75	3.7
Shearon Harris 2	Dec-80	1629	Mar-88	4.75	3.7
Shearon Harris 2	Sep-81	1630	Mar-89	4.00	4
Shearon Harris 2	Mar-82	1882	Mar-89	3.51	4
Shearon Harris 2	Sep-82	1882	Mar-90	3.50	4
Shearon Harris 2	Dec-82	2023	Mar-90	7.25	4
Shoreham	Mar-67	105	May-73	6.17	0
Shoreham	Jun-68	NA	May-73	4.92	0
Shoreham	Mar-69	182	May-75	6.17	0.5
Shoreham	Mar-70	218	May-75	5.17	0.5
Shoreham	Dec-71	309	Apr-77	5.34	1.5
Shoreham	Jun-72	309	May-77	4.92	1.5
Shoreham	Mar-73	309	Jul-77	4.34	1.5
Shoreham	Dec-73	461	Jul-77	3.58	6
Shoreham	Mar-74	461	May-78	4.17	11
Shoreham	Sep-74	695	May-78	3.67	20
Shoreham	Sep-75	695	Sep-78	3.00	43
Shoreham	Dec-75	695	May-79	3.42	47
Shoreham	Jun-76	969	May-79	2.92	55
Shoreham	Sep-77	1188	Sep-80	3.00	62
Shoreham	Sep-78	1293	Sep-80	2.00	75
Shoreham	Dec-78	1337	Dec-80	2.00	78
Shoreham	Jun-79	1581	May-81	1.92	80
Shoreham	Jun-80	1213	Feb-83	2.67	85.5
Shoreham	Sep-80	2213	Feb-83	2.42	88
Shoreham	Dec-80	NA	Mar-83	2.25	90

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
Shoreham	Mar-82	2493	Mar-83	1.00	91
Shoreham	Sep-82	2724	Sep-83	1.00	94.7
Shoreham	Dec-82	3150	Dec-83	1.00	95.6
St. Lucie 2	Dec-72	360	Oct-78	5.84	0
St. Lucie 2	Mar-73	360	Dec-79	6.76	0
St. Lucie 2	Mar-74	360	Dec-80	6.76	0
St. Lucie 2	Jun-74	360	Dec-79	5.50	0
St. Lucie 2	Dec-74	537	Dec-79	5.00	0
St. Lucie 2	Sep-75	537	Dec-80	5.25	0
St. Lucie 2	Dec-75	620	Dec-80	5.01	0
St. Lucie 2	Sep-76	620	Dec-82	6.25	0.7
St. Lucie 2	Dec-76	850	Dec-82	6.00	0.7
St. Lucie 2	Jun-77	850	May-83	5.92	1
St. Lucie 2	Sep-78	845	May-83	4.67	13
St. Lucie 2	Dec-78	919	May-83	4.42	16.8
St. Lucie 2	Jun-80	1100	May-83	2.92	45.1
St. Lucie 2	Jun-82	1270	May-83	0.92	84.1
St. Lucie 2	Sep-82	1420	May-83	0.66	89.7
St. Lucie 2	Mar-83	1420	Jul-83	0.33	97.3
Surry 3	Mar-74	NA	Jun-80	6.26	NA
Surry 3	Jun-74	525	Mar-80	5.75	0
Surry 3	Sep-74	525	Dec-80	6.25	0
Surry 3	Dec-74	525	May-83	8.42	0
Surry 3	Mar-75	728	May-83	8.17	0
Surry 3	Jun-75	781	May-83	7.92	0
Surry 3	Mar-76	781	Jun-86	10.26	0
Surry 3	Jun-76	1074	Apr-86	9.84	0
Surry 4	Mar-74	254	Jun-81	7.26	0
Surry 4	Jun-74	322	Mar-81	6.75	0
Surry 4	Sep-74	322	Dec-81	7.25	0
Surry 4	Dec-74	322	May-84	9.42	0
Surry 4	Mar-75	506	May-84	9.18	0
Surry 4	Jun-75	511	May-84	8.92	0
Surry 4	Mar-76	511	Jun-87	11.26	0
Surry 4	Jun-76	765	Apr-87	10.84	0
Waterford 3	Sep-70	230	Jan-77	6.34	0
Waterford 3	Sep-71	289	Jan-77	5.34	0
Waterford 3	Sep-72	350	Jan-77	4.34	0.5
Waterford 3	Mar-73	350	Oct-77	4.59	0.5
Waterford 3	Dec-73	445	Jun-79	5.50	0.5
Waterford 3	Jun-74	445	Jun-80	6.01	0.5
Waterford 3	Dec-74	710	Jun-80	5.50	1
Waterford 3	Dec-75	710	Apr-81	5.34	2.87
Waterford 3	Sep-76	815	Apr-81	4.58	15
Waterford 3	Sep-78	1110	Oct-81	3.08	48.8
Waterford 3	Sep-79	1229	Feb-82	2.42	69.5
Waterford 3	Sep-80	1229	Mar-83	2.50	78.2
Waterford 3	Dec-80	1489	Mar-83	2.25	81.9
Waterford 3	Mar-82	1808	Jul-83	1.33	93.9
Waterford 3	Sep-82	2057	Jan-84	1.33	93.9
Watts Bar 1	Dec-70	NA	Aug-76	5.67	0

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
Watts Bar 1	Dec-71	301	Aug-76	4.67	0
Watts Bar 1	Jun-72	301	May-77	4.92	0
Watts Bar 1	Dec-72	324	May-77	4.42	0
Watts Bar 1	Jun-73	324	Mar-78	4.75	2
Watts Bar 1	Dec-73	324	Jun-78	4.50	6
Watts Bar 1	Mar-74	340	Jun-78	4.25	8
Watts Bar 1	Jun-74	340	Nov-78	4.42	11
Watts Bar 1	Dec-74	391	Nov-78	3.92	19
Watts Bar 1	Jun-76	391	Jun-79	3.00	42
Watts Bar 1	Sep-76	475	Jun-79	2.75	51
Watts Bar 1	Sep-77	520	Jun-79	1.75	74
Watts Bar 1	Dec-77	520	Dec-79	2.00	76
Watts Bar 1	Sep-78	617	Dec-79	1.25	85
Watts Bar 1	Dec-78	617	Jun-80	1.50	87
Watts Bar 1	Sep-79	720	Sep-81	2.00	86
Watts Bar 1	Jun-80	720	May-82	1.92	87
Watts Bar 1	Dec-80	1093	Nov-82	1.92	83
Watts Bar 1	Mar-81	1093	Jan-84	2.84	86
Watts Bar 1	Sep-81	1271	Mar-84	2.50	77
Watts Bar 1	Mar-82	1257	Aug-84	2.42	80
Watts Bar 1	Jun-82	1257	Nov-84	2.42	81
Watts Bar 1	Sep-82	1697	Nov-84	2.17	87
Watts Bar 2	Dec-70	NA	May-77	6.42	NA
Watts Bar 2	Dec-71	301	May-77		
Watts Bar 2	Jun-72	301	Feb-78	5.67	NA
Watts Bar 2	Dec-72	324	Feb-78		
Watts Bar 2	Jun-73	324	Dec-78	5.50	NA
Watts Bar 2	Dec-73	324	Mar-79	5.25	NA
Watts Bar 2	Mar-74	340	Mar-79		
Watts Bar 2	Jun-74	340	Aug-79	5.17	NA
Watts Bar 2	Dec-74	391	Aug-79		
Watts Bar 2	Sep-75	NA	Aug-79	3.92	NA
Watts Bar 2	Jun-76	391	Mar-80	3.75	NA
Watts Bar 2	Sep-76	475	Mar-80		
Watts Bar 2	Sep-77	520	Mar-80		
Watts Bar 2	Dec-77	520	Sep-80	2.75	57
Watts Bar 2	Sep-78	617	Sep-80		
Watts Bar 2	Dec-78	617	Mar-81	2.25	68
Watts Bar 2	Sep-79	720	Jun-82	2.75	76
Watts Bar 2	Jun-80	720	Feb-83	2.67	72
Watts Bar 2	Dec-80	1093	Aug-83	2.67	70
Watts Bar 2	Mar-81	1093	Oct-84	3.59	74
Watts Bar 2	Sep-81	1271	Jan-85	3.34	63
Watts Bar 2	Mar-82	1257	Nov-85	3.67	60
Watts Bar 2	Jun-82	1257	Nov-85		
Watts Bar 2	Sep-82	1697	Dec-85	3.25	54
WNP 3	Mar-74	789	Sep-81	7.51	0
WNP 3	Mar-75	1178	Mar-82	7.01	0
WNP 3	Mar-76	1402	Mar-82	6.00	0
WNP 3	Mar-77	1482	May-83	6.17	0
WNP 3	Mar-78	1561	Sep-83	5.51	2.3

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
WNP 3	Mar-79	1948	Dec-84	5.76	11.2
WNP 3	Sep-79	2256	Dec-84	5.25	16.6
WNP 3	Sep-80	3130	Jun-86	5.75	22.2
WNP 3	Jun-81	3809	Dec-86	5.50	32
Yellow Creek 1	Mar-75	929	Apr-83	8.09	0
Yellow Creek 1	Sep-75	929	Jun-83	7.75	0
Yellow Creek 1	Mar-76	929	Jun-83	7.25	0
Yellow Creek 1	Jun-76	929	Mar-85	8.75	0
Yellow Creek 1	Sep-77	1048	Mar-85	7.50	0
Yellow Creek 1	Jun-78	1048	May-85	6.92	0
Yellow Creek 1	Sep-78	1172	May-85	6.67	0
Yellow Creek 1	Sep-79	1445	Nov-85	6.17	7
Yellow Creek 1	Dec-80	1364	Apr-88	7.34	18
Yellow Creek 1	Mar-81	1243	Apr-88	7.09	21
Yellow Creek 1	Sep-81	1938	Oct-90	9.09	28
Yellow Creek 1	Mar-82	NA	NA	NA	33
Yellow Creek 1	Sep-82	1938	Oct-90	8.09	33
Yellow Creek 2	Mar-75	929	Apr-84	9.09	NA
Yellow Creek 2	Sep-75	929	Jun-84	8.76	NA
Yellow Creek 2	Jun-76	929	Mar-86	9.75	NA
Yellow Creek 2	Sep-77	1048	Mar-86	8.50	
Yellow Creek 2	Jun-78	1048	May-86	7.92	NA
Yellow Creek 2	Sep-78	1172	Mar-86	7.50	
Yellow Creek 2	Sep-79	1445	Apr-88	8.59	2
Yellow Creek 2	Dec-80	1364	Apr-88	7.34	
Yellow Creek 2	Mar-81	1243	Apr-88	7.09	
Yellow Creek 2	Sep-81	1938	Apr-88	6.59	
Yellow Creek 2	Mar-82	NA	Apr-88	6.09	
Yellow Creek 2	Sep-82	1938			
Zimmer 1	Dec-69	199	Jan-75	5.09	0
Zimmer 1	Mar-70	210	Jan-75	4.84	NA
Zimmer 1	Sep-70	276	Jan-75	4.34	NA
Zimmer 1	Sep-71	288	Oct-76	5.09	0
Zimmer 1	Dec-72	311	Aug-77	4.67	1
Zimmer 1	Sep-74	434	Jan-79	4.34	19
Zimmer 1	Dec-75	502	Jan-79	3.09	40.5
Zimmer 1	Sep-76	531	Jan-79	2.33	58.1
Zimmer 1	Sep-77	531	Jul-79	1.83	77.2
Zimmer 1	Mar-78	664	Jan-80	1.84	81.3
Zimmer 1	Jun-79	850	Jan-81	1.59	92.8
Zimmer 1	Mar-80	850	Feb-82	1.92	92.8
Zimmer 1	Jun-80	1027	Apr-82	1.83	93.8
Zimmer 1	Dec-81	1258	Jan-83	1.08	96.8
Zimmer 1	Mar-82	1258	Jun-83	1.25	97.5
Zimmer 1	Jun-82	1258	Dec-83	1.50	97.96
Zimmer 1	Sep-82	1667	Jan-84	1.33	98.26
Zimmer 1	Dec-82	1667	NA	NA	98.3

Canceled Bechtel Plants

Unit Name	Date of Estimate	Estimates Total Cost	COD	Est. Years to COD	% Complete
Callaway 2	Jun-74	805	Apr-83	8.84	0
Callaway 2	Dec-74	863	Apr-83	8.34	0
Callaway 2	Mar-76	739	Apr-83	7.09	0.2
Callaway 2	Dec-76	1297	Apr-87	10.34	0.4
Callaway 2	Jun-77	1297	Apr-87	9.84	0.4
Callaway 2	Dec-77	1288	Apr-87	9.34	0.4
Callaway 2	Sep-78	1306	Apr-87	8.59	0.4
Callaway 2	Mar-80	1609	Apr-87	7.09	0.7
Callaway 2	Jun-80	1609	Jun-88	8.01	0.7
Callaway 2	Dec-80	1688	Apr-88	7.34	0.7
Callaway 2	Mar-81	1688	Apr-90	9.09	0.7

Canceled Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates Total Cost	COD	Est. Years to COD	% Complete
Bailly Nuclear 1	Mar-67	113	Dec-72	5.76	NA
Bailly Nuclear 1	Mar-70	161	Feb-76	5.93	NA
Bailly Nuclear 1	Sep-70	160	Feb-76	5.42	NA
Bailly Nuclear 1	Jun-72	244	Jun-77	5.00	0
Bailly Nuclear 1	Sep-74	447	Jun-77	2.75	0.5
Bailly Nuclear 1	Sep-75	447	Jun-95	19.76	0.5
Bailly Nuclear 1	Mar-76	447	Jun-85	9.26	0.5
Bailly Nuclear 1	Sep-76	674	Jun-85	8.75	0.5
Bailly Nuclear 1	Dec-76	674	Nov-82	5.92	0.5
Bailly Nuclear 1	Mar-77	705	Nov-82	5.67	0.5
Bailly Nuclear 1	Sep-77	705	Dec-82	5.25	0.5
Bailly Nuclear 1	Dec-77	705	Jun-84	6.50	0.5
Bailly Nuclear 1	Mar-78	850	Jun-84	6.26	0.5
Bailly Nuclear 1	Dec-78	850	Dec-84	6.01	0.5
Bailly Nuclear 1	Sep-79	1100	Jun-87	7.75	0.5
Bailly Nuclear 1	Dec-80	1100	Jun-89	8.50	0.5
Bailly Nuclear 1	Jun-81	1815	Jun-89	8.01	0.5
Cherokee 1	Sep-73	NA	Jan-81	7.34	0
Cherokee 1	Mar-74	NA	Sep-82	8.51	0
Cherokee 1	Jun-74	NA	Jan-82	7.59	0
Cherokee 1	Sep-74	248	Jan-84	9.34	NA
Cherokee 1	Dec-74	262	Jan-84	9.09	0
Cherokee 1	Dec-75	262	Jan-85	9.09	0
Cherokee 1	Mar-76	262	Jan-84	7.84	0
Cherokee 1	Mar-77	336	Jan-84	6.84	0.5
Cherokee 1	Dec-77	336	Jan-85	7.09	1
Cherokee 1	Mar-78	392	Jan-85	6.84	1
Cherokee 1	Mar-79	402	Jan-85	5.84	4
Cherokee 1	Jun-79	402	Jan-87	7.59	5
Cherokee 1	Mar-80	402	Jan-90	9.84	15
Cherokee 1	Sep-80	729	Jan-90	9.34	17
Cherokee 2	Mar-74	NA	Sep-83	9.51	0
Cherokee 2	Jun-74	NA	Apr-83	8.84	0
Cherokee 2	Sep-74	248	Jan-86	11.34	0
Cherokee 2	Dec-74	262	Jan-86	11.09	0
Cherokee 2	Dec-75	262	Jan-87	11.09	0
Cherokee 2	Mar-76	262	Jan-86	9.84	0
Cherokee 2	Mar-77	336	Jul-86	9.34	0.5
Cherokee 2	Dec-77	336	Jan-87	9.09	1
Cherokee 2	Mar-78	392	Jan-87	8.84	2
Cherokee 2	Mar-79	402	Jan-87	7.84	4
Cherokee 2	Jun-79	402	Jan-89	9.59	5
Cherokee 2	Mar-80	402	Jan-92	11.84	1
Cherokee 2	Sep-80	729	Jan-93	12.34	1
Cherokee 3	Mar-74	NA	Sep-84	10.51	0
Cherokee 3	Sep-74	248	Jan-88	13.34	0
Cherokee 3	Dec-74	262	Jan-88	13.09	0
Cherokee 3	Dec-75	262	Jan-89	13.10	0
Cherokee 3	Mar-76	262	Jan-88	11.84	0
Cherokee 3	Dec-76	262	Jun-89	12.51	0.5
Cherokee 3	Mar-77	336	Jan-89	11.85	0.5

Canceled Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates Total Cost	COD	Est. Years to COD	% Complete
Cherokee 3	Mar-78	392	Jan-89	10.85	1
Cherokee 3	Mar-79	402	Jan-89	9.85	4
Cherokee 3	Jun-79	402	Jan-91	11.59	4
Cherokee 3	Mar-80	402	Jan-94	13.85	1
Cherokee 3	Sep-80	729	Jan-95	14.34	1
Forked River 1	Mar-75	694	May-82	7.17	0.5
Forked River 1	Dec-76	894	May-83	6.42	0.5
Forked River 1	Jun-78	894	Dec-83	5.50	1
Forked River 1	Dec-78	1150	Dec-83	5.00	4.1
Hartsville B-1	Mar-73	379	Jun-81	8.26	NA
Hartsville B-1	Dec-74	601	Jun-81	6.50	
Hartsville B-1	Sep-75	601	Jun-82	6.75	NA
Hartsville B-1	Jun-76	601	Aug-83	7.17	NA
Hartsville B-1	Sep-76	602	Aug-83	6.92	
Hartsville B-1	Jun-77	602	Dec-83	6.50	NA
Hartsville B-1	Sep-77	854	Dec-83	6.25	
Hartsville B-1	Sep-79	1418	Jun-89	9.76	15
Hartsville B-2	Mar-73	379	Jun-82	9.26	0
Hartsville B-2	Jun-74	378	Jun-82	8.01	NA
Hartsville B-2	Sep-74	379	Jun-82	7.75	NA
Hartsville B-2	Sep-75	601	Jun-83	7.75	NA
Hartsville B-2	Jun-76	601	Aug-84	8.17	NA
Hartsville B-2	Jun-77	602	Dec-84	7.51	NA
Hartsville B-2	Sep-77	854	Dec-84	7.25	
Hartsville B-2	Sep-79	1418	Jun-90	10.76	5
Shearon Harris 3	Jun-71	234	Mar-77	5.75	0
Shearon Harris 3	Sep-71	246	Mar-77	5.50	0
Shearon Harris 3	Dec-72	274	Mar-78	5.25	0
Shearon Harris 3	Sep-73	331	Mar-78	4.50	0
Shearon Harris 3	Dec-73	419	Oct-79	5.84	0
Shearon Harris 3	Jun-74	513	Mar-81	6.75	1
Shearon Harris 3	Dec-77	1039	Mar-90	12.25	0.5
Shearon Harris 3	Dec-79	1208	Mar-91	11.25	0.5
Shearon Harris 3	Jun-80	1208	Mar-94	13.76	0.5
Shearon Harris 4	Dec-77	1039	Mar-88	10.25	0.5
Shearon Harris 4	Dec-79	1208	Mar-89	9.25	0.5
Shearon Harris 4	Jun-80	1208	Mar-92	11.76	0.5
North Anna 3	Mar-73	355	Apr-77	4.09	0.5
North Anna 3	Sep-73	355	Dec-77	4.25	2
North Anna 3	Dec-73	389	Dec-77	4.00	2
North Anna 3	Mar-74	396	Mar-78	4.00	3.3
North Anna 3	Jun-74	396	Dec-78	4.50	3.6
North Anna 3	Dec-74	432	Jun-80	5.50	3.6
North Anna 3	Mar-75	512	Dec-80	5.76	4.8
North Anna 3	Dec-75	512	Apr-81	5.34	6.9
North Anna 3	Mar-76	653	Apr-81	5.09	6.9
North Anna 3	Mar-77	818	Apr-82	5.09	6.9
North Anna 3	Sep-77	818	May-82	4.67	7
North Anna 3	Dec-77	818	Oct-83	5.84	7
North Anna 3	Mar-78	1012	Oct-83	5.59	7
North Anna 3	Mar-79	1012	Apr-86	7.09	7

Canceled Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates Total Cost	COD	Est. Years to COD	% Complete
North Anna 3	Sep-79	1428	Apr-86	6.59	7
North Anna 3	Dec-80	NA	Oct-89	8.84	7
North Anna 3	Mar-81	2175	Oct-89	8.59	7
North Anna 3	Dec-82	4053	Oct-89	6.84	8
North Anna 4	Mar-73	262	Apr-78	5.09	0.5
North Anna 4	Sep-73	262	Jun-78	4.75	2
North Anna 4	Dec-73	268	Jun-78	4.50	2
North Anna 4	Mar-74	281	Dec-79	5.76	1.6
North Anna 4	Jun-74	281	Mar-79	4.75	1.6
North Anna 4	Sep-74	281	Dec-79	5.25	1.7
North Anna 4	Dec-74	295	Dec-80	6.01	1.7
North Anna 4	Mar-75	347	Jul-81	6.34	2
North Anna 4	Dec-75	347	Nov-81	5.92	1.6
North Anna 4	Mar-76	423	Nov-81	5.67	1.6
North Anna 4	Mar-77	568	May-83	6.17	3.5
North Anna 4	Sep-77	568	Jun-83	5.75	3.7
North Anna 4	Dec-77	568	Sep-84	6.76	3.7
North Anna 4	Mar-78	660	Sep-84	6.51	3.7
North Anna 4	Mar-79	660	Apr-87	8.09	3.7
North Anna 4	Sep-79	956	Apr-87	7.59	3.7
Phipps Bend 1	Mar-75	780	Apr-82	7.09	0
Phipps Bend 1	Jun-75	780	Apr-82	6.84	0
Phipps Bend 1	Sep-75	780	Mar-83	7.50	0
Phipps Bend 1	Dec-75	780	Mar-83	7.25	0
Phipps Bend 1	Jun-76	780	Apr-84	7.84	0
Phipps Bend 1	Sep-77	876	Apr-84	6.59	0
Phipps Bend 1	Dec-77	876	Aug-84	6.67	0
Phipps Bend 1	Sep-78	872	Aug-84	5.92	1
Phipps Bend 1	Sep-79	1440	Mar-87	7.50	7
Phipps Bend 1	Dec-80	1440	Feb-89	8.18	14
Phipps Bend 1	Mar-81	2685	Feb-89	7.93	20
Phipps Bend 1	Sep-81	2685	Apr-94	12.59	25
Phipps Bend 1	Dec-82	NA	Apr-94	11.34	27
Phipps Bend 2	Mar-75	780	Apr-83	8.09	NA
Phipps Bend 2	Sep-75	780	Mar-84	8.50	0
Phipps Bend 2	Jun-76	780	Apr-85	8.84	NA
Phipps Bend 2	Sep-77	876	Apr-85		0
Phipps Bend 2	Dec-77	876	Aug-85	7.67	0
Phipps Bend 2	Sep-78	872	Aug-85		0
Phipps Bend 2	Sep-79	1440	Aug-89	9.92	1
Phipps Bend 2	Jun-80	1440	May-94	13.92	4
Phipps Bend 2	Dec-80	1440	Aug-89	8.67	NA
Phipps Bend 2	Dec-82	NA	NA	NA	5
WNP 4	Sep-74	NA	Jun-82	7.75	NA
WNP 4	Dec-74	NA	Mar-82	7.25	0
WNP 4	Jun-75	436	Mar-82	6.75	0
WNP 4	Jun-76	1095	Mar-82	5.75	0.5
WNP 4	Dec-76	1095	Mar-83	6.25	0.8
WNP 4	Mar-77	1003	Mar-83	6.00	1.3
WNP 4	Jun-77	1232	Mar-83	5.75	1.6
WNP 4	Dec-77	1232	Jun-84	6.50	2.8

Canceled Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
WNP 4	Mar-78	1610	Jun-84	6.26	3.2
WNP 4	Sep-78	1982	Jun-85	6.75	7.6
WNP 4	Mar-79	2302	Jun-85	6.26	11.6
WNP 4	Dec-79	3348	Jun-86	6.50	14.4
WNP 4	Mar-80	3086	Jun-86	6.25	14.5
WNP 4	Jun-81	4251	Jun-87	6.00	26.5
WNP 5	Mar-74	NA	Mar-83	9.01	0
WNP 5	Jun-75	439	Mar-83	7.75	0
WNP 5	Mar-76	1271	Apr-84	8.09	0
WNP 5	Sep-76	1271	Nov-84	8.17	0
WNP 5	Dec-76	1189	Jan-85	8.09	0
WNP 5	Mar-77	1470	Feb-85	7.93	0
WNP 5	Sep-77	1470	Mar-85	7.50	0
WNP 5	Dec-77	1470	Jul-85	7.59	0
WNP 5	Mar-78	1887	Jul-85	7.34	0
WNP 5	Mar-79	2224	Jun-86	7.26	1.8
WNP 5	Sep-79	2493	Jun-86	6.75	6.4
WNP 5	Jun-80	3705	Jun-87	7.00	6.7
WNP 5	Sep-80	3420	Jun-87	6.75	8.2
WNP 5	Jun-81	4845	Dec-87	6.50	14.3

Estimates from Utilities

Unit Name	Actuals Cost	Actuals COD	Date of Estimate	Total Cost	COD	Est. Years to COD
Pilgrim 2			Feb-72	402	Nov-78	6.8
Pilgrim 2			Apr-73	655	Aug-80	7.3
Pilgrim 2			Mar-75	1221	Oct-82	7.6
Pilgrim 2			Oct-76	1396	Mar-84	7.4
Pilgrim 2			May-78	1895	Jun-85	7.1
Pilgrim 2			Mar-79	1895	Dec-85	6.8
Pilgrim 2			May-80	3220	May-89	9.0
Pilgrim 2			Jun-80	3515	Mar-90	9.8
Pilgrim 2			Sep-81	3975	Mar-90	8.5
Seabrook 1			Feb-72	486	Nov-79	7.8
Seabrook 1			Mar-73	570	Nov-79	6.7
Seabrook 1			Aug-73	587	Nov-79	6.3
Seabrook 1			Jun-74	650	Nov-79	5.4
Seabrook 1			Mar-75	772	Nov-80	5.7
Seabrook 1			Dec-76	1007	Nov-81	4.9
Seabrook 1			Jan-78	1360	Dec-82	4.9
Seabrook 1			Jan-79	1309	Apr-83	4.2
Seabrook 1			Apr-80	1527	Apr-83	3.0
Seabrook 1			Apr-81	1735	Feb-84	2.8
Seabrook 1			Nov-82	2540	Dec-84	2.1
Seabrook 1			Dec-82	2540	Dec-84	2.0
Seabrook 1			Jan-84	5070	Apr-87	3.2
Seabrook 1			Mar-84	4550	Jul-86	2.3
Seabrook 1			Apr-84	4100	Feb-86	1.8
Seabrook 1			Aug-84	4479	Aug-86	2.0
Seabrook 2			Feb-72	486	Nov-81	9.8
Seabrook 2			Mar-73	570	Nov-81	8.7
Seabrook 2			Aug-73	587	Nov-81	8.3
Seabrook 2			Jun-74	650	Nov-81	7.4
Seabrook 2			Mar-75	772	Nov-82	7.7
Seabrook 2			Dec-76	1007	Nov-83	6.9
Seabrook 2			Jan-78	995	Dec-84	6.9
Seabrook 2			Jan-79	1301	Feb-85	6.1
Seabrook 2			Apr-80	1593	Feb-85	4.8
Seabrook 2			Apr-81	1825	May-86	5.1
Seabrook 2			Nov-82	2580	Mar-87	4.3
Seabrook 2			Dec-82	2709	Jul-87	4.6
Seabrook 2			Jan-84	5030	NA	NA
Seabrook 2			Mar-84	4452	Dec-90	6.8
Seabrook 2			Apr-84	2760	Jul-88	4.3
Seabrook 2			Aug-84	NA	NA	NA
Millstone 3			Jul-71	400	Apr-78	6.8
Millstone 3			Mar-73	650	May-79	6.2
Millstone 3			Jan-75	807.5	Nov-79	4.8
Millstone 3			Jan-76	1010	May-82	6.3
Millstone 3			Mar-77	1185	May-82	5.2
Millstone 3			Jul-78	2000	May-86	7.8
Millstone 3			Jul-80	2600	May-86	5.8