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STATE OF CONNECTICUT DOCKET NO. 83-03-01
DEPARTMENT OF PUBLIC UTILITY CONTROL

RE: APPLICATION OF THE UNITED ILLUMINATING COMPANY FOR AN INCREASE IN ITS RATES AND REVENUES AND AN INVESTIGATION OF THE SEABROOK NUCLEAR PROJECT

JUNE 17, 1983

# TESTIMONY OF PAUL CHERNICK

On Behalf of:

CONNECTICUT DIVISION OF CONSUMER COUNSEL

CONSERVATION LAW FOUNDATION OF NEW ENGLAND

CONNECTICUT CITIZEN ACTION GROUP, INC.

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## I. INTRODUCTION AND QUALIFICATIONS

Q. Mr. Chernick, would you state your name, occupation and businss 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 Massachusetts Institute of Technology in February, 1978 in Technology and Policy. I have been elected to memebership in the civil engineering honorary society Chi Epsilon, and the engineering honorary society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

During my graduate education, I was the teaching assistant for courses in systems analysis. I have served as a consultant to the National Consumer Law Center for two projects: teaching part of a short course in rate design and time-of-use rates, and assisting in preparation for an electric time-of-use rate design case. I was a Utility Analyst for the Massachusetts Attorney

General for over three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and evaluation of power supply options. My work considered the effects on conservation and the effects of conservation in all of these areas, including the cost, extent, effectiveness, and rate treatment of utility conservation programs.

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 twenty times on utility issues before such agencies as the Massachusetts Department of Public Utilities, the Massachusetts Energy Facilities Siting Council, the Texas Public Utilities Commission, 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 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 my testimony in MDPU 19494, Phase II, filed April 1, 1979, I described a large number of errors in UI's 1978 forecast, most of which would exaggerate growth rates. The 1978 low-band forecast projected a peak of 1025 MW in 1982 and 1188 MW in 1988. Since the 1982 peak was actually 952 MW, and since UI's current <u>base</u> forecast predicts 1029 MW in 1988, (with a low band of 880 MW) reality has confirmed my criticisms and UI has implicitly accepted them.

My analyses of other utility forecasts, including Boston Edison, Northeast Utilities, the NEPOOL forecasts, 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 more recent, and have yet to be fully confirmed. However, as time goes by, utility projections have tended to confirm my analyses. For example, in the Pilgrim 2 construction permit proceeding (NRC 50-471), Boston Edison was projecting a cost of $1.895 billion. With techniques similar to those used in this testimony, I projected a cost between $3.40 and $4.93 billion in my testimony of June, 1979. Boston Edison's final cost estimate (issued when Pilgrim 2 was cancelled) stood at $4.0 billion.

In MDPU 20055, 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 the current values of 12/84, 7/87, and $5.2 billion. Thus, PSNH has moved its in-service date estimates substantially towards my projections, and increased its cost estimates to a lesser extent.

In MDPU 20055 and again in MDPU 20248, I criticized PSNH's failure to recognize interim replacements, its error in ignoring real escalation in O & M, and its wildly unrealistic estimate of an 80% mature capacity factor (even the Massachusetts utilities seeking to purchase Seabrook shares were more realistic about capacity factors). I suggested interim replacements of $9.48/kw-yr., annual O & M increases of $1.5 million/unit (both in 1977 $) and 60% capacity factors. PSNH now includes capital additions, escalates real O & M at about 1% (about $0.1 million per unit annually), and projects a mature capacity factor of 72%. Thus, PSNH has implicitly accepted my criticisms, even though the O & M escalation and capacity factor projections are still very optimistic. While my original analyses (and the studies I relied on) were based on data only through 1978, experience in 1979-81 confirms the patterns of large capital additions, rapid O & M escalation, and low capacity factors. The 60% capacity factor figure, in particular, has been widely accepted by regulators (such as the California Energy Commission) and even utilities (such as Commonwealth Edison).

Critiquing and improving on utility load forecasts and nuclear power cost projections has not been very difficult over the last few years. Many other analysts have also noticed that various of these utility projections were inconsistent with reality. While other utilities have made some concessions to experience, PSNH's estimates for Seabrook costs continue to be exceedingly optimistic, and hence it is still quite easy for any competent reviewer to improve on them.

Q. What is the subject matter of your testimony in this case?

A. My clients asked me to estimate the cost of completing and operating the Seabrook units.

Q. What do you conclude from your examination of these issues?

A. I conclude that completing and operating Seabrook will cost around 5.6 cents/kwh for Unit 1 and 10.4 cents/kwh for Unit 2 in 1983 dollars. Including inflation, the first-year cost of the Seabrook units would be about 34 cents/kwh and 38 cents/kwh, respectively.

B. <u>COST OVERVIEW</u>

Q. How have you estimated the cost of Seabrook?

A. I have used generally optimistic estimates for the duration of Seabrook construction, its construction costs, and the various costs of running and decommissioning the units. Based upon analyses of historical performance and trends:

1. I do not expect Seabrook 1 to be on line before late 1986, or Seabrook 2 to be on line before early 1991.

2. I expect each unit to cost over $3 billion in 1983 dollars, not including general inflation to the actual on-line date. If the plant were completed, Unit 1 would cost about $5.4 billion, and Unit 2 about $4.5 billion, including inflation. The latter figure is academic, since Seabrook 2 is unlikely to be completed. It will probably either be cancelled in the near future, at substantial cost, or later, at a larger cost.

3. Capacity factors for the units will probably average in the range of 50% to 55%.

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

5. Including decommissioning, insurance, fuel, and other factors listed above, power from Seabrook 1 will cost about 11.4 cents/kwh, and that from Seabrook 2 will cost at least half a cent more, in levelized 1983 dollars. The actual prices charged to ratepayers will include inflation and will be much larger: about 34 cents/kwh for Unit 1 in its first year, and 38 cents/kwh for Unit 2. Sunk costs account for only about 5.8 cents for Unit 1 and 1.7 cents for Unit 2, so avoidable costs are about 10 cents/kwh for Unit 2, in 1983 dollars.

A detailed analysis of these costs is presented below. Since I do not have many specific UI estimates for Seabrook cost components, I will compare my estimates to those of PSNH. It is my understanding that UI generally accepts the PSNH estimates.

C. <u>CONSTRUCTION DURATION</u>

Q. Are PSNH's current estimates for the Seabrook in-service dates reasonable?

A. No. There are at least eight reasons for believing that the Seabrook units will reach commercial operation considerably after the dates projected by PSNH:

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

2. PSNH has consistently over-estimated the rate of construction progress in the past.

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

4. PSNH's estimates of Seabrook COD's have always been overoptimistic in the past, and there is no reason to believe we have seen the last revision.

5. Simple time trends on reactor construction duration indicate that the units may not be in service before the 1990's.

6. More sophisticated regression analyses are more optimistic, but still indicate that PSNH's in-service dates are optimistic.

7. PSNH's construction duration projections are inconsistent with those of other nuclear plants under construction.

8. Actual nuclear construction durations have almost always exceeded projections by substantial amounts.

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

A. Table 1 provides this data for all units which in commercial operation have received operating licenses since the beginning of 1978. The shortest start-up was 6.1 months, and the longest was almost 19 months, with a eleven-plant average of 11.5 months. In addition, Diablo Canyon I, which has been listed as 99% or more complete since at least late 1977, received an operating license in 1981, only to have it suspended two months later. Diablo Canyon I will increase the average start-up period when (and if) it finally reaches commercial operation.
Four other units received operating licenses in 1982: San Onofre 2 (February), Grand Gulf 1 (June), Summer (August) and San Onofre 3 (November). The first two of these units are already over a year from OLIS, and will increase the average startup. None of these units has reached commercial operation. Two units received operating licenses in 1983: McGuire 2 (March) and St. Lucie (April). Neither of these has reached commmercial operation.

Q. What is PSNH's projection for the Seabrook start-up periods?

A. PSNH currently projects a three-month start-up period for each Unit. These projections are completely out of line with the historical experience.

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

A. At the end of the first quarter of 1979, PSNH estimated that Unit I was 18.85% complete, and that it would be 39.13% complete one year later, for annual progress of 20.28%. But at the end of the first quarter of 1980, Unit I was estimated to be only 36.70% complete: the reported progress was 17.85%, or 88% of the projected rate. In fact, the reported progress was apparently greater than the actual progress, since a period of <u>negative</u> reported progress followed.

In March 1980, PSNH produced a new construction estimate, which projected that Unit I would be 67.7% complete by June, 1981; but reported completion in June, 1981 was only 50.8%. Over this 15-month period, reported progress was only 45.5% of projected progress. In June 1981, Unit I was projected to be about 84% complete by March 1983; Mr. Morgan reports that it was 70% complete (19.2% progress, or 59.6% of projected progress). Combining the 12 months covered by the 1979 construction estimate, the 15 months covered by the 1980 estimate, and the 21 months covered by the 1981 estimate, and ignoring PSNH's apparent over-optimism in the March, 1980, progress report, produces an average progress-to-estimate ratio for that 48 month period of 62.3%. Stated differently, construction has taken 60% longer than PSNH expected. Corresponding average progress-to-estimate ratio for the total project is derived in Table 2 as 50%; construction has taken twice as long as expected.

If construction of Unit I takes 60% longer than projected in November, 1982 (22 months to September 1984), the unit will be ready for an operating license 35 months later, or in October, 1985. If construction of the total project continues at 50% of projected rates (thus assuming that Unit 2 speeds up as Unit 1 slows down), completion will take 100% longer than projected. As of December 1982, completion of Unit 2 was projected 52 months in the future (to April, 1987): with 100% slippage, Unit 2 would be complete in 104 months, or August, 1991.

Adding a year for start-up produces in-service dates of October 1986 and August 1992.

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

A. From March 1979 to March 1983, reported progress on Unit 1 averaged 1.07% per month, and reported progress on Unit 2 averaged 0.32% per month. PSNH has projected sustained peak monthly construction rates of approximately 2.2% for Unit 1 and 2.0% for Unit 2. PSNH has also predicted that the last 8% or so of construction on each unit will proceed more slowly, at about 1% per month, or about 45% of the peak rate.

If PSNH is only able to maintain a reported rate of progress on Unit 1 of 1.1% per month (still somewhat better than the historic level) through the 92% completion point, and 45% of that rate (or .5%/month) thereafter, construction will take 20 months past March 1983 to reach 92% complete, plus 16 more months for the last 8%, and will end about March 1986.

If Unit 2 continues its past glacial construction rate until Unit 1 is complete in March, 1986 (at which point Unit 2 would be 29.5% complete), then accelerates to 1.1% per month until 92% complete, and reaches completion sixteen months later, that would stretch the Unit 2 completion date to April, 1992. If Unit I is completed later, or if Unit 2 cannot speed up until Unit I is in commercial operation, Unit 2 would be completed even later. On the other hand, it may be possible to build Unit 2 somewhat faster than 0.32% per month: for example, progress of 0.47% per month was reported for June 1981 to March 1983. At that faster rate, Seabrook 2 would be almost 35% complete in March, 1986, and could be finished by November, 1991.
An additional year must be added to any of these projections, for startup.

Q. Has PSNH changed its projections for Seabrook's dates of commercial operation substantially over the last few years?

A. Yes. As shown in Table 3, the COD's were estimated as 11/81 and 11/83 in December 1976. Over the last four years, PSNH has slipped its estimate of the Seabrook 1 COD 37 months to 12/84, and the Seabrook 2 estimate to 7/87.

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

A. Table 3 derives the COD progress ratios of each unit from each earlier estimate to the late 1982 estimate. The COD progress ratio is the reduction in months left in the construction schedule (that is, progress towards the COD), divided by elapsed months. If the schedule did not change between estimates, the progress ratio would be 1.0. For various time periods ending with the 11/82 estimate, the progress ratio for Seabrook 1 ranges from 37.5 to 57.1%; that is, for each month that went by, completion drew nearer by only .375 to .571 months (11 to 17 days). To put it another way, it took 1.75 months to 2.67 months to get one month closer to completion. For Seabrook 2, the progress ratio to 12/82 ranges from 12.1% to 45.6%; a month of progress has taken as much as 8 months of elapsed time.

Table 3 extrapolates the historic trends to determine when each unit will enter service, assuming that PSNH continues to be as wrong as it has been in the past. Depending on the time period used for trending, Unit #1 can be expected to enter service between July 1986, and June 1988, and Unit #2 between December 1992, and October 2020. (Excluding the results from the 3/80 estimate, the latest COD for Unit 2 would be February, 1998). These dates assume that the estimated completion dates continue to recede as they have in the past.

Q. What are the simple time trends to which you referred?

A. I have extended a study originally performed by MMWEC (Bentley and Denehy, 1979) based on the average durations reported in the NRC Yellow Book (Construction Status Report: Nuclear Power Plants, NUREG 0030) for plants which loaded fuel in particular years. MMWEC used data for 1973 to 1978, with 1979 estimates; I extended the data from 1970 through 1981. The Yellow Book defines duration as the period from construction start (roughly CPIS for most plants) to fuel load date (FLD). In extending the data to 1980 and 1981, I assumed the FLD equals OLIS. MMWEC suggested a two-year credit for second units to make their durations comparable to first units: I applied this credit fully to duplicate units with the same start-of-construction, and partially for second units which started construction after the first unit.

MMWEC's time trend indicated that it would be 1993 before the average first unit loading fuel would have been started in 1976, and 1997 before the second units were expected to have 1976 construction permits. The corresponding fuel load dates from my trending of duration on fuel load date are 1991 for Unit 1 and 1996 for Unit 2. Regressing average duration against the average starting date (FLD - duration) produces only slightly more favorable results: early 1991 and late 1995.

It should be noted that these simple trends on averaged data have two disadvantages. First, they lose much of the detail, since several units are treated as a single data point. Second, extrapolating trends out into the future assumes that all factors continue to change in the same way they did in the past. While this may be as reasonable an assumption as we can make about nuclear safety, regulation, and industrial structure, it is not true for the size of nuclear units. The average size of units loading fuel generally increased from 1970 (604 mw) through 1975 (944 mw), generally fell through 1979 (871 mw), and then rose dramatically again in 1980 (1007 mw) and 1981 (1160 mw). Thus, some of the apparent time trend may actually be the effect of increasing unit size. However, since plants loading fuel in 1976, 1977, 1978 all showed smaller size, but longer durations, than those fueling in 1975, size does not appear to be the dominant factor.

Q. What are the more sophisticated regression studies to which you refer?

A. The three such published studies of which I am aware are by Mooz (1978), Mooz (1979), and Komanoff (1980). The regression equation estimated by Mooz (1979) is presented in Table 4 and evaluated for Seabrook. These durations imply operating licenses in May, 1985 and April, 1986.

Unfortunately, the data base for the Mooz projection included estimated dates for operating licenses for 6 units. As Table 5 shows, these estimates were over-optimistic by a considerable amount. Since the mean date of construction permit for the units with estimated durations is later than the mean date for the sample, it is very likely that these under-estimates have biased the projection downwards. Mooz also deleted Diablo Canyon 1 and Salem 2 from his data set, which would tend to reduce the projections.

Komanoff did not use time in his duration regression, but instead included "cumulative nuclear capacity", the total MW capacity with construction permits or in operation before the subject reactor received its permit. Komanoff believes that this variable captures the impacts of heightened regulation better than a time variable would. Table 6 presents Komanoff's equation (omitting some dummy variables not applicable to Seabrook), and that data necessary to apply it in two variations.

Column 4 of Table 6 applies Komanoff's interpretation of the relationship between regulation and the size of the nuclear industry. This formulation implicitly assumes that the time-correlated effect will slow down, since the growth rate in the cumulative capacity variable in the data set is 52.6 times as great as the growth rate in the time variable (CPIS), but only 15.4 times as fast as CPIS from the end of the data set to the Seabrook CPIS. If anything, the experience of the last couple of years suggests that regulatory scrutiny is accelerating, rather than slowing down. Thus, Column 5 of Table 6 reformulates the equation so that the growth rate in construction durations does not slow down, but instead remains constant over time. This is accomplished by maintaining the ratio of cumulative capacity to CPIS found in the data set.

Komanoff suggests a second kind of variation when he notes that the 11% increase in construction duration for units with cooling towers cannot really be attributed to the towers themselves because

> cooling towers are not on the "critical path" of construction steps determining plant completion. Addition of a tower may indicate regulatory sensitivity to environmental concerns leading to additional measures to reduce nuclear hazards, adding to construciton time. This conjecture is unproven, however.
>
> (Komanoff, 1981, p. 210)

This description certainly seems to apply to the Seabrook units in general, and to the prolonged struggle over their cooling system in particular. If the Seabrook is treated as being more like the typical plant with cooling towers than the typical plant without tower, it is appropriate to add 11% to the durations. This interpretation is applied in the last row of Table 6.

Finally, Komanoff repeats Mooz's practice of using overly optimistic COD values for some recent plants, which are listed in Table 7. In fact, Komanoff intentionally used COD's which he knew were inaccurate, in an attempt to eliminate any effect of the TMI accident from his data set: his projections explicitly exclude all effects of TMI. Since it is also almost certain that TMI has increased the construction, and since future incidents are likely to further increase durations, Komanoff's data set is likely to produce optimistic duration projections. Komanoff also omitted the Diablo Canyon units from the data set, probably biasing the construction duration projection for future large units downwards. Depending on the variant assumed, Komanoff's results imply a COD between August, 1984 and November, 1986 for Unit 1, and between March, 1986 and December, 1988 for Unit 2.

It should also be noted that none of the regression techniques (the trend line analysis, Mooz's equation, and Komanoff's equation) reflects either the Seabrook permit suspensions or the current or future financial difficulties of PSNH, UI, and their partners. To the extent that Seabrook has experienced or will experience an atypical number of delays, its in-service date would be expected to be later than the projections.

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

A. Table 8 lists the reported percent complete and the scheduled in-service date for each nuclear unit which was within 15 percentage points of the reported percent complete for Seabrook 1 as of June 30, 1981. None of these 18 units were projected to be on line as early as Seabrook 1 (two units in Texas were scheduled for some time in 1984). On average, these eighteen units were 50% complete and were projected to reach commercial operation in December, 1985. Depending on construction pace, Seabrook 1 was one to two months behind the average. Table 8 also updates the status of this cohort to February 1983. At that point, two of the 18 units were on indefinite status, and the average COD for the other 16 was April 1986. Only one was expected to be commercial as early as Seabrook 1.

The same calculation can also be performed for Seabrook 2, but it is more constrained: few utilities are still making any effort to continue units less than 20% complete. Of the 17 units listed in Table 9, seven already had no scheduled in-service date in June, 1981. The other ten units averaged 8.3% complete (versus 8% for Seabrook 2) with an average predicted in-service date at that time of about March, 1989. Updating the analysis to February of 1983 finds 6 of the scheduled plants and 4 of the indefinite units cancelled. The remaining four plants averaged 22% complete, with a May 1988 in-service date. South Texas 2, which does not appear in Table 9 because it was previously listed as 23% complete with a 1986 COD, is now listed as 16% complete with a mid-1989 COD.

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

A. No. Table 10 presents the estimated and actual construction durations for all the units which have reached commercial operation and for which I have been able to obtain one or more in-service-date estimates made after (or only a month or two before) the construction permit was issued. Thus, delays in obtaining construction permits (a problem which Seabrook no longer faces) are not included in these figures. For the three estimates over four years into the future, the actual duration averaged 2.14 times the projected duration. For the fourteen estimates between three and four yars, the ratio averaged 2.31. For the nineteen estimates between two and three years, the average was 2.52.

As of the March, 1982 estimate, Seabrook 1 was anticipated to be 25 months from COD; in December, 1982, Unit 2 was projected to be 55 months from COD. Multiplying these intervals by 2.52 and 2.61, respectively, yields predictions of commercial operation in February, 1988 and December, 1994, if PSNH is just as over-optimistic as the builders of the thirteen units listed in Table 10. As noted above, PSNH is the <u>most</u> optimistic utility in the country as regards in-service dates for units at comparable stages of construction. It is possible that other utilities are generally more realistic now than they were in the 1960's and 1970's. It is also possible that PSNH's current over-optimism on its schedule exceeds the general level of over confidence both currently and historically.

That over-confidence on schedules has been universal within the U.S. nuclear industry. Of 172 U.S. units listed in the August, 1981 Nuclear News "World List of Nuclear Power Plants", all but three units have an "actual or expected" COD later than the "original schedule". The three exceptions are the Hanford-N plant and San Unofre 1, neither of which list original schedules, and Big Rock Point, for which the COD listed is incorrect.

Q. What dates are realistic for completion of construction and commercial operation at the Seabrook units?

A. Table 9 summarizes my previous calculations. This tabulation does not reflect several factors which could extend construction further, such as the erroneous data used in Mooz's and Komanoff's regressions and the effects of further Seabrook 1 delays on Unit 2. Over all, if the historic trends continue, Unit 1 may be in commercial operation by November, 1986, give or take a year. There is a greater range of estimates for Unit 2, but a singleminded effort might complete the plant by early 1991, with a plausible range of 1989 to 1994.

D. CAPITAL COSTS

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

A. No. Econometric studies, by L.J. Perl (1978, 1982) of National Economic Research Associates (NERA), by W.E. Mooz (1978, 1979) of the Rand Corporation, and by C. Komanoff (1981), all indicate that Seabrook will cost much more than PSNH claims. This conclusion is also supported by the historical tendency of architect/engineers (A/E's) and utilities to underestimate nuclear construction costs, and by the continuing increases in cost estimates for nuclear plants under construction.

Q. Please explain how the NERA studies indicate that PSNH's capital cost estimates are optimistic?

A. The first Perl study, which apparently was sponsored by the Atomic Industrial Forum, projects a capital cost of about $2245/kw (in 1990 dollars) for an 1150 mw first unit. The regression results indicate that second units are 23.6% less expensive than identical first units entering service in the same year. However, the 1990 cost projection appears to be based on three very doubtful assumptions:

1. 5.5% general inflation, 1977-1990;
2. 6% real escalation of nuclear costs, 1977-85; and

3. No real escalation of nuclear costs, 1985-90. The annual rate of CPI inflation from 1977 to 1981 ran about 10.7%; UI reports 6.1% CPI inflation in 1982 and projects 5.5% in 1983, 6.0% in 1984, and 6.5% thereafter. Also, since NERA's study indicates that real nuclear costs actually increased by 10% annually from 1960 to 1977, the inclusion of cost estimates with 6% real escalation from 1977 to 1985, and the exclusion of all escalation past that point, is unjustified by the historical record.

Removing the inflation and escalation estimates from NERA's 1990 projection produces a 1977 estimate of

$$\$2245/((1.055)^{13} \times (1.06)^{8} = \$702/\text{kw}$$

for a first unit and

$$\$702 \times .764 = \$536/\text{kw}$$

for a second unit entering service in 1977.

These figures are comparable to the extremes NERA presents for 1977 actual costs of $496 for an unusually inexpensive second unit to $902 for an unusually expensive first unit.

Nuclear input costs in the Northeast have actually increased by 36.6% from 1977 to 1981 (using January Handy-Whitman values for both years). From 1967 to 1980, the average annual increase in the CPI was 7.20%, while the Handy-Whitman averaged 7.88%, or 9.4% more. Applying this differential to UI's forecasts of CPI produces nuclear input inflation of 6.7% in 1982, 6.0% in 1983, 6.6% in 1984, and 7.1% thereafter. Thus, the total inflation from 1977 to 1983 is 1.366 x 1.067 x 1.060 = 1.545; multiplying 1977 dollars by 1.545 will give prices in 1983 dollars.

If the annual real growth in nuclear costs continue at the historical 10% level beyond 1977, and if the Seabrook units enter service in 11/86 and 2/91 respectively, then Unit I would be expected to cost

$$702 \times 1.545 \times 1.1^{9.33} = \$2639/\text{kw}$$

and Unit 2 would cost

$$536 \times 1.545 \times 1.1^{11.58} = \$2497/\text{kw}$$

both in 1983 dollars.

Q. What would these costs be in the nominal dollars used in ratemaking?

A. Adding in the nuclear inflation figures I derived above from UI's CPI figures, the nominal dollar costs would be

$3300/kw for Seabrook 1 and

$3644/kw for Seabrook 2.

Q. Can comparable figures be derived from the more recent Perl study?

A. Not readily. The basis of Perl's estimate 1 of $1727/kw (in 1982$), for a two-unit 1100 MW plant in the Northeast in 1985, is too obscure to allow extrapolation to Seabrook. For example, Perl assumes past cost trends stop, but is not clear where he stops them. Since he reports real escalation of 14.9% for each year that the construction midpoint advances, this is a significant issue. In any case, it is clear that nuclear escalation has not slowed dramatically since Perl's previous study.

Q. Other than the Perl studies, do the other regression studies support similar cost estimates for Seabrook?

A. Yes. The Mooz studies are fairly old at this point, and are similar in methodology to Komanoff's study, so I will only discuss the latter.

Table 12 presents the coefficients and applicable values for the three nuclear capital cost equations from Komanoff (1981). Table 13 evaluates the equations for the two Seabrook units, both with and without the "cooling tower" variable; Komanoff's comments on the cooling tower's impact on costs parallel his discussion of the schedule effect.

Taking the average costs predicted by the six methods, and adding in AFUDC by the methodology Komanoff used in estimating the equations, produces values of $2327.8/kw and $2511.2kw in 1979 dollars for the two units. Adding in inflation from 1979 to 1981 (19.5% overall), for 1982 (6.7%, as for Perl), and for 1983 (6.0%), converts these costs to $3146/kw and $3394/kw in 1983 dollars.

Adding inflation to COD's of 11/86 and 2/91 would raise these estimates to $3933/kw and $4955/kw, respectively. However, Komanoff's cost figures are not quite the same as accounting costs, and inflating them may not exactly reflect the ratemaking cost of the units.

Q. How does the past record of A/E cost estimates support the capital cost forecasts of the econometric models?

A. In a report prepared by Analysis and Inference for the NRC (Chernick, et al., 1981), we calculated the ratio of actual to forecast costs for several nucear power plants, and derived four equations estimating the relationship between real cost overruns and the length of time into the future for which the forecast is being made. We defined this relationship as myopia: a failure to forecast future cost increase. The data are displayed in Figure 1. The four equations are:

$$R = 1 + .204t \quad (1)$$

$$R = .598 + .300t \quad (2)$$

$$R = (1 + .147)^t \quad (3)$$

$$R = .844\ (1 + .195)^t \quad (4)$$

where $\underline{R}$ is the ratio of actual to expected costs in real dollars, and $\underline{t}$ is the expected years to completion at the time of the estimate. Table 14 evaluates these four equations for the lead times forecast by PSNH as of the late 1982 cost estimates, and for the industry consensus durations previously derived. It would not be appropriate to evaluate the equations with $\underline{t}$ equal to the most reasonable projection, since they were estimated from general industry duration projections in the 1960's and 1970's. To the extent that PSNH is more optimistic than general industry projections, PSNH's value of $\underline{t}$ is understated. On the other hand, the industry as a whole may be more realistic now then it was a decade ago, so current industry $\underline{t}$ values may be overstated somewhat for this pupose.

Averaging the results of the four equations (all of which are statistically significant at the 99.9% level), and of duration projections from PSNH and the industry, produces estimates of actual-to-forecast real cost ratios of 1.46 for Unit 1 and 2.04 for Unit 2. From PSNH's press release of 11/30/82, the cost per kw of Unit 1, plus all common costs and 75% of indirects, is now estimated at $2990 per kw; and for Unit 2, plus 25% of indirects, it was $1464/kw. The cost increase for Unit 2 announced in December ($120 million or $104/kw) brings that unit's cost estimate to $1568/kw. The allocations of common and indirect costs appear to be unusually skewed towards Unit 1. For example, the 1979 Seabrook estimate allocated half of the common costs and 57% of the indirect costs to Unit 2. Removing PSNH's inflation projection of 6.8% gives

$$2990/(1.068)^{1.42} = \$2723/\text{kw for Unit 1, and}$$

$$1568/(1.068)^{4.00} = \$1205/\text{kw for Unit 2,}$$

in mid-1983 dollars, with PSNH's allocations of indirects and common. There does not seem to be any current estimate of the common costs, so we can not normalize PSNH's treatment of these, but the extra 25% of indirects amounts to about 18.2% of the Seabrook 1 estimate, or $496/kw in 1983 dollars. A more standard allocation of indirects thus gives 1983 dollar estimates of

$2227/kw for Unit 1, and

$1701/kw for Unit 2.

Applying the average myopia adjustments produces estimates of $3251/kw for Unit 1 and $3470 for Unit 2, in 1983 dollars. Adding inflation to 11/86 and 2/91 produces cost estimates of

$4064/kw for Unit 1, and

$5066/kw for Unit 2.

Q. Have you performed a similar myopia analysis in nominal dollars?

A. Yes. I have evaluated Equation 3 (which I consider the most intuitively appealing of the myopia forms) in nominal terms for the 36 non-turnkey units which reached commercial operation by 1976, based on a series of AEC and ERDA compilations of quarterly utility reports (AEC, various; ERDA, various). Appendix B provides the data from this source for estimates over 2 years into the future, along with the value of m for each estimate. The average value of m is .32 between 2 and 3 years, .27 between 3 and 4 years, and .21 between 4 and 5 years, and .18 over 5 years.

Table 15 extrapolates the nominal cost of the Seabrook units from this myopia analysis, based on the recent Seabrook cost estimates discussed above, and both PSNH and utility duration estimates. Normalizing the treatment of indirects produces estimates of $4941/kw for Unit 1 and $4894 for Unit 2.

Q. Have you performed a similar analysis for the Seabrook units' cost history?

A. Yes. Table 16 derives the annual percentage rate increase in the Seabrook cost estimate from various starting points to the 11/82 and 12/82 estimates. The annual rate of escalation of PSNH's estimate has increased quite steadily: the more recent the time period over which the trend is averaged, the higher it is. For example, the average annual percentage increase in the Seabrook cost estimated was 17.3% from 12/76 to 12/82, and 26.0% from 4/81 to 12/82.

Given a COD for Unit 1 and assuming the continuation of a historic rate of escalation in the cost estimate, we can calculate the value of the cost
estimate at the time Unit 1 enters service. For the best estimate of Unit 1 COD derived above (11/86), we must add 3.92 years of cost estimate revisions, or a factor of 1.87 to 2.47 times, depending on the base period used. This translates to a plant cost estimate of $9.8 billion to $12.9 billion when Unit 1 goes commercial. Since the rate of cost estimate escalation has been increasing, these figures may be conservative. Also, note that this method is based on escalation of combined plant cost, and is inapplicable once Unit 1 enters service or Unit 2 is canceled. If construction continues on Unit 2 past the Unit 1 COD, the total plant cost estimate can be expected to continue escalating, although perhaps at a slower rate. At the historic escalation rates, eventual cancellation of Unit 2 appears to be

essentially inevitable, so projection of its cost past the Unit 1 COD is academic.

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

A. Table 17 displays the results of the various methodologies I used. The averages of the real-dollar estimates are about $3000/kw for Unit 1 and $3100/kw for Unit 2, in 1983 dollars; the nominal dollar averages are $4250/kw and $4650/kw. I will use these values in my subsequent analysis. The true values may vary from these estimates by several hundred dollars per kw in either direction: normal risk averse behavior would justify basing decisions on a value of nuclear plant cost which is higher than the expectation, to reflect the economic risks, but I have not included this factor in my cost calculations.

Q. How do these total cost figures compare to the cost of completing the units?

A. A portion of the total construction costs are sunk: either invested in property which cannot be sold to recover the cost, or committed in contracts which cannot be fully voided. UI projects total investment in Seabrook of $1443/kw by the end of 1983; this can be taken as a rough approximation of sunk costs. While UI rarely breaks out costs by unit, PSNH reported in November 1982 that $1430/kw had been spent on Unit 1 and $412/kw on Unit 2; applying the same ratio to UI's 1983 projection gives $2240/kw for Unit 1 and $646/kw for Unit 2, or $2176/kw and $627/kw in mid-1983 dollars. Thus, the avoidable costs of completing the units are about

$836/kw for Unit 1 and

$2493/kw for Unit 2 in 1983 dollars,

or

$1045/kw for Unit 1 and

$3640/kw for Unit 2 in nominal dollars.

E. <u>CAPACITY FACTOR</u>

Q. How can the annual kilowatt-hours output of electricity from each kilowatt of Seabrook capacity be estimated?

A. The average output of a nuclear plant is less than its capacity for several reasons, including refueling, other scheduled outages, unscheduled outages, and power reductions. Predictions of annual output are generally based on estimates of capacity factors. Since the capacity factor projections used by PSNH and UI are wholly unrealistic, it may be helpful to consider the role of capacity factors in determining the cost of Seabrook power, before estimating those factors.

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

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

where CF = capacity factor, and
RC = rated capacity.

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

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

The difference between capacity factor and availability factor is illustrated in Figure 2. The capacity factor is the ratio of the shaded area in regions A and B to the area of the rectangle, while the availability factor is the sum of the width of regions A, B, and C. Clearly, if the rated capacity is actually the maximum capacity of the unit, the availability factor will always be at least as large as the capacity factor and will generally be larger. Specifically, the availability factor includes the unshaded portion of region B, and all of region C, which are not included in the capacity factor.

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

A. The three most common measures of capacity are

> Maximum Dependable Capacity (MDC);
>
> Design Electric Rating (DER); and
>
> Installed or Maximum Generator Nameplate rating (IGN or MGN).

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

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

Humboldt Bay has been retired after fourteen years, and Dresden 1 after 18 years, without getting their MDC's up to their DER's. Connecticut Yankee has not done it in 15 years; nor Big Rock Point in 19 years; nor many other units which have operated for more than a decade, including Dresden units 2 and 3, and Oyster Creek. For only about one nuclear plant in five does MDC equal DER, and in only one case (Pilgrim) does the MDC exceed the DER. Therefore, capacity factors based on MDC will generally continue to be greater than those based on DER's, throughout the unit's life.

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

Actually, DER designations have also changed for some plants. The new, and often lower, DER's will produce different observed capacity factors than the original DER's. For example, Komanoff (1978) reports that Pilgrim's original DER was 670 mw, equal to its current MDC, not the 655 mw value now reported for DER. Therefore, in studying historical capacity factors for forecasting the performance of new reactors, it is appropriate to use the original DER ratings, which would seem to be the capacity measure most consistent with the 1150 mw expectation for Seabrook. This problem can also be avoided through the use of the MGN ratings.

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

A. Yes. Several statistical analyses of the capacity factors of actual operating nuclear plants have been performed, including those for the Council on Economic Priorities (CEP) (Komanoff, 1978), Sandia Laboratories studies for the NRC (Easterling, 1979, 1981) and the NERA studies perviously described (Perl, 1978, 1982).

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

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

The second NRC study uses the same methodology and reaches similar, if somewhat more pessimistic, conclusions. Easterling develops several equations for PWR's, using different data sets and different maturation periods, and concludes that maturation may continue through year 5. Table 18 shows the results of the equations which can be evaluated for Seabrook. The first equation uses all data and form-year maturation, the second excludes three unit-year of particularly poor performance, the third introduces 5-year maturation, and last excludes all data from units under 700 MW.

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

The second NERA study uses a very different functional form in the capacity factor equation, and mixes in BWR's and some very small units. The equation predicts capacity factors for a unit like Seabrook 1 of 53% in the first year, rising to 63% in year 5. The NERA study itself uses a 59% overall capacity factor in its cost calculations.

Therefore, average life-time capacity-factor estimate for units like Seabrook would seem to lie in the range of 50% to 60%, based on the historical record. There is a great deal of variation from the average, however; they typically explain less than a third of the variation in the data, and the first NRC study derived 95% prediction intervals of about 10% in years 2 to 5, 8% in years 2 to 10, and 7.3% for years 2 to 28. Roughly speaking, those earlier, more optimistic NRC results predict that 19 out of every 20 nuclear units of the Seabrook size and type would have average lifetime capacity factors between 50.3% and 64.9%, with the 20th unit having a capcity factor outside that range. Actually, the variation would be somewhat larger, due to the greater variation in the first partial year and the first full year.

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

A. Easterling studies are fully reviewable (unlike the NERA studies) and were conducted to advocate nuclear power development (unlike the CEP study), so I feel most comfortable using the levelized value of 52% from the most optimistic equation in Easterling (1981).

Q. Are the utility projections for Seabrook capacity factor reasonable?

A. No. Table 19 displays the difference between PSNH's projections, UI's projections, CL&P's projections, and Easterling's results. The capacity factors assumed by all three utilities are much too high. This should not be very surprising, for example, none of PSNH's sources actually contain any capacity factor data. UI has not otherwise provided capacity factor projections.

As a check on the accuracy of the NRC/Easterling capacity factors, compared to PSNH's projections, I have performed the calculations presented in Tables 19 and 20. For the six PWR's over 1000 MW which had entered service by 1979, the average capacity factor as of October 1982 was 59.6%. The capacity factor estimates which I derived from Easterling (1981) predict an average of 52.5%, while the utilities predict an average of 65.6 - 67.7%. Clearly, the utilities' expectations are out of line with reality. While the performance of these six units exceeds Easterling's projections, it is not clear which is the better predictor. Easterling has more data, especially in mature years, but includes smaller units. The actual six-unit average will vary with refueling schedules and has less data. At most, the actual data suggests a 5% upward revision in the Easteling actual, to about 57%.

Q. Has PSNH offered any justifications for these wildly unrealistic capacity factor projections?

A. Yes. PSNH has claimed that the various Yankee nuclear units have higher capacity factors than national averages and that, since the Yankee Atomic Energy Company has some relationship with both the Yankee plants and with the construction of Seabrook, that the same high capacity factors can be expected at Seabrook.

Q. Is it appropriate to compare Yankee plant capacity factors to average nuclear power plant capacity factors?

A. Not directly. Nuclear capacity factors vary with the size, age, and type of plant. Since there is no other PWR near the size of Yankee Rowe, comparisons to other units are nearly meaningless. The remaining three units can be compared to units of their own types, size, and age. Thus, Vermont Yankee must be compared to small BWR's, Connecticut Yankee to small PWR's, and Maine Yankee to medium-size PWR's. If performance is compared by age group, such as 2-5 years, all the comparison units must have reached age 5, or the poorer performance in the early years will bring down the average.

Q. Is it appropriate to extrapolate capacity factors for the Seabrook units from Yankee plant performance?

A. Without strong evidence of a causal influence of Yankee Atomic involvement in construction oversight on plant performance, there is no reason to favor Yankee plant data over industry-wide data for four reasons. First, other than the effect on cost and construction time of architect-engineer (A/E) experience, it has never been statistically demonstrated that any party involved in building nuclear plants is able to influence the outcome. Second, Yankee Atomic's role is a curious one, as it is neither A/E, nor constructor, nor utility (except with respect to Yankee Rowe); it is not clear what sort of effect one might look for in studying Yankee influence. Third, whatever role Yankee Atomic might have had on the swift asnd economical completion of the Yankee units has clearly been ineffective with respect to Seabrook. Finally, the Yankee data set is very small compared to the totally industry data set, and the variations due to luck and similar factors may be large.

On the whole, there does not seem to be any basis for concluding that Seabrook will perform more like the Yankee Plants than like those of Florida Power, or Commonwealth Edison.

Q. With those caveats, what is the best projection of Seabrook capacity factors from the Yankee data?

A. Using data supplied by PSNH, I projected the size trend of capacity factors for the "commercial sized" PWR's (Connecticut and Maine Yankee) out to Seabrook's size. The results are presented in Table 21. The Yankee PWR's display a size trend for performance quite similar to industry averages, suggesting average Seabrook capacity factors between 50% and 60%.

## F. CARRYING CHARGES

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

A. I have assumed a 10% real cost of capital (including income taxes), a 2.5% property tax rate, and unit lifetime of 25 years, as a compromise between possibilities of 20 years and 30 years. The shorter lifetime is based on an analysis of the experience of smaller nuclear units, as discussed in Chernick, et al. (1981, pp. 101-109), while the longer lifetime is a more standard industry assumption. Over 25 years, the levelized annual fixed charges for capital, depreciation, and property taxes would be 12.8%.

Table 22 displays the annual carrying cost per kwh of each Seabrook unit at a 25 year life, both for the remaining full cost and the first-year ratemaking carrying cost of the units.

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

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

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

G. FUEL COST

Q. What nuclear fuel costs have you used?

A. I used PSNH's 20-year levelized estimates of 1.33 cents/kwh for Seabrook 1 and 1.55 cents/kwh for Seabrook 2.

H. NON-FUEL O & M

Q. Is PSNH's estimate of Seabrook non-fuel O & M expense reasonable?

A. No. PSNH bases its O & M cost forecast on recent O & M costs for Maine Yankee, which has been an exceptionally inexpensive plant to operate. PSNH also assumes that nuclear O & M increases less than 1% annually in real terms (that is, rises only slightly faster than the inflation rate), despite very rapid historical growth rates in nuclear O & M. PSNH's historical figures for Yankee O & M (repeated in Table 22) apparently include costs not usually classified as plant O & M (e.g., insurance, administration, employee benefits), but they illustrate the general trend. The average annual growth rate in the O & M figures reported by PSNH for 1979-81 ranges from 36.8% to 44.5% for the various units, in a period of 12% CPI inflation. The costs nearly doubled in those two years.

Table 24 presents the 1980 O & M cost for each of the six New England nuclear units, excluding Yankee Rowe, which is much smaller than the other reactors. The table also presents the least-squares estimates of annual linear growth (in 1981 dollars) and of annual geometric growth rates, and the six-unit average of each parameter. Each unit is analyzed from its first full year of service through the latest year for which I could obtain the data (1980, except 1981 for Pilgrim).

Table 25 displays the first-year nominal O & M cost and the levelized O & M cost for each unit over a 25 year life, and for extrapolation of the linear and geometric average trends. Protracted geometric growth in real O & M cost would probably lead to retirement of the units around the turn of the century, as they would be prohibitively expensive to operate (unless the alternatives were even more expensive).

High costs of O & M and necessary capital additions were responsible for the retirement (formal or *de facto*) of Indian Point 1, Humboldt Bay, and Dresden 1, after only 12, 13, and 18 years of operation, respectively. Thus, rising costs caught up to most of the small pre-1965 reactors during the 1970's: only Big Rock Point and Mass. Yankee remain from that cohort. The operator of LaCrosse, a small reactor of 1969 vintage, has announced plans to retire it in the late 1980's. To be on the optimistic side, I have assumed a continuation of the linear trends in New England nuclear cost escalation.

Q. Is it appropriate to include the 1979-81 period, when the TMI accident and subsequent regulatory actions affected nuclear plant operation, in the analysis of nuclear O & M trends?

A. I believe that it is. Several more major nuclear accidents or near-misses are likely to occur before the scheduled end of Seabrook operation. Various recent estimates of major accident probabilities range from 1/200 to 1/1000 per reactor year (See Chernick, et al., 1981; Miniarick and Kukielka, 1982). Thus, major accidents can be expected every two to ten years once 100 reactors are operating. If anything, the 1968-81 period has been relatively favorable for nuclear operations.

## I. CAPITAL ADDITIONS

Q. Is PSNH's estimate of capital additions to the Seabrook units reasonable?

A. PSNH's estimates of annual capital additions (or interim replacements) is $10 million per unit, in 1981 dollars. UI uses about the same figure, stated as $14/kw-yr in 1987 dollars. This is the first acknowledgement I have seen by any of the co-owners that the cost of nuclear units increases after the in-service date. Furthermore, PSNH's estimate appears to be of the proper order-of-magnitude, if a little low.

Based on data gathered by CLF staff for fifteen plants, totalling 159 unit-years of operation, I derived an experience-weighted average annual capital addition of $10049 per MW in 1980 dollars. This equals $12.4/kw and about $14.3 million per Seabrook unit in 1983 dollars. The data includes all the New England plants over 300 MW, and all other plants completed by early 1973, and includes data through 1980, as available.

J. INSURANCE

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

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

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

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

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

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

e. decommissioning acccident coverage of one billion dollars for $2.19 million; and

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

All values are 1981 dollars from Chernick, et al. (1981), except for the NEIL premium, which is from the NEIL circular of December 18, 1979. The decommissioning insurances may be from new or existing pools. These coverages have total estimated premiums of $9.81 million in 1981 dollars, or about $11 million in 1983 dollars (incuding just CPI inflation). While only the liability and some property coverage are currently required, failure to utilize insurance exposes the ratepayers and stockholders of PSNH to additional costs, which may be greater (on the average) than the insurance premium. Indeed, even with all the insurance listed, PSNH would still not be fully covered in the event of the total and permanent loss of a Seabrook unit.

On a cents-per-kwh basis, $11 million per reactor annually is $9.5/kw or 0.2 cents/kwh.

K. DECOMMISSIONING

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

A. Chernick, et al. (1981) estimates that non-accidental decommissioning of a large reactor will cost about $250 million in 1981 dollars. This is equivalent to about $280 million in 1983 dollars (using the nuclear inflation figures from the discussion of the NERA construction cost estimate, above), or about $250/kw for Seabrook. Assuming that the decommissioning fund accumulates uniformly (in constant dollars) over the life of the plant, and that it is invested in risk-free assets (such as Treasury securities) which earn essentially zero real return, the annual contribution (in 1983 dollars) would be about $9.8 per kw-year over a 25 year life, 0.2 cents/kwh.

L. TOTAL SEABROOK GENERATION COST

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

A. I estimate that the total cost of power will be about 11 to 12 cents/kwh,levelized in 1983 dollars. Excluding sunk costs as of the end of remaining cost is about 5.6 cents/kwh for Seabrook 1, and 10.4 cents/kwh for Seabrook 2. These figures are derived in Table 26.

Q. Have you calculated the ratemaking cost of power from the Seabrook units?

A. Yes. Table 27 also derives the first year cost of power from each unit: about 34 cents/kwh for Unit 1 and 38 cents/kwh for Unit 2.

Q. Does this conclude your testimony?

A. Yes.

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| Unit | Date of Issuance, First Operating License[1] (OLIS) | Commercial Operation Date[2] (COD) | Start-up Interval[3] (months) |
|---|---|---|---|
| Three Mile Island 2 | 2/8/78(F) | 12/30/78 | 10.7 |
| Hatch 2 | 6/13/78(F) | 9/5/79 | 14.7 |
| Arkansas 2 | 9/1/78(F) | 3/26/80 | 18.8 |
| Sequoyah 1 | 2/29/80(L) | 7/1/81 | 16.1 |
| North Anna 2 | 4/11/80(L) | 12/14/80 | 8.1 |
| Salem 2 | 4/18/80(L) | 10/13/81 | 17.8 |
| Farley 2 | 10/23/80(L) | 7/30/81 | 9.2 |
| McGuire 1 | 1/23/81(Z) | 12/1/81 | 10.3 |
| Sequoyah 2 | 6/25/81(L) | 6/1/82[4] | 11.2 |
| LaSalle 1 | 4/17/82(L) | 10/20/82[5] | 6.1 |
| Susquehanna 1 | 7/17/82(L) | 6/8/83[5] | 10.7 |
| Average | | | 12.2 |

Table 1: Recent Experience in Start-up Intervals

Notes:

(1) From NRC Gray Books and "Nuclear Power Plants in the U.S.", Atomic Industrial Forum, 12/31/81. Full licenses are indicated by (F), low power licenses by (L), and zero-power licenses by (Z).

(2) Same sources as for OLIS.

(3) All months treated as having 30 days.

(4) Telephone inquiry, TVA.

(5) Telephone inquiry, NRC.

| Date | Mar-79 | Mar-80 | Jun-81 | Mar-83 |
|---|---|---|---|---|
| **Unit 1** | | | | |
| a. Reported % complete | 18.85 | 36.7 | 50.8 | 70 |
| b. Estimated % at Next Date | 39.13 | 67.7 | 84 | ------ |
| c. Forecast Progress | ------ | 20.28 | 31 | 33.2 |
| d. Reported Progress | ------ | 17.85 | 14.1 | 19.2 |
| e. Progress Ratio (d/c) | ------ | 0.88 | 0.45 | 0.58 |
| f. Average Progress Ratio | | 0.62 | | |
| **Project** | | | | |
| a. Reported % complete | 13.28 | 26.48 | 36.6 | 52 |
| b. Estimated % at Next Date | 30.15 | 55.8 | 71 | ------ |
| c. Forecast Progress | ------ | 16.87 | 29.32 | 34.4 |
| d. Reported Progress | ------ | 13.2 | 10.12 | 15.4 |
| e. Progress Ratio (d/c) | ------ | 0.78 | 0.35 | 0.45 |
| f. Average Progress Ratio | | 0.50 | | |

Table 2: Seabrook Construction History: Ratio of Reported to Forecast Progress

| | COMMERCIAL OPERATION DATE ESTIMATED IN: | | | | | | |
|---|---|---|---|---|---|---|---|
| | 12.76 | 3.78 | 1.79 | 3.8 | 4.81 | 11.82 | 12.82 |
| SEABROOK UNIT #1 | | | | | | | |
| 1. ESTIMATED COD | 11.81 | 12.82 | 4.83 | 4.83 | 2.84 | 12.84 | --- |
| 2. MONTHS TO GO | 59 | 57 | 51 | 37 | 34 | 25 | --- |
| 3. TOTAL PROGRESS SINCE LAST ESTIMATE (MONTHS) | --- | 2 | 6 | 14 | 3 | 9 | --- |
| 4. TOTAL PROGRESS TO 11/82 | 34 | 32 | 26 | 12 | 9 | --- | --- |
| 5. ELAPSED TIME TO 11/82 | 72 | 57 | 47 | 32 | 19 | --- | --- |
| 6. PROGRESS RATIO (%) TO 11/82 | 47.2% | 56.1% | 55.3% | 37.5% | 47.4% | --- | --- |
| 7. PROJECTED MONTHS TO GO | 53 | 45 | 45 | 67 | 53 | --- | --- |
| 8. PROJECTED COD | 4.87 | 8.86 | 8.86 | 6.88 | 4.87 | --- | --- |
| SEABROOK UNIT #2 | | | | | | | |
| 9. ESTIMATED COD | 11.83 | 12.84 | 2.85 | 2.85 | 5.86 | --- | 7.87 |
| 10. MONTHS TO GO | 83 | 81 | 73 | 59 | 61 | --- | 55 |
| 11. TOTAL PROGRESS SINCE LAST ESTIMATE (MONTHS) | --- | 2 | 8 | 14 | -2 | --- | 6 |
| 12. TOTAL PROGRESS TO 11/82 | 28 | 26 | 18 | 4 | 6 | --- | --- |
| 13. ELAPSED TIME TO 11/82 | 72 | 57 | 47 | 33 | 20 | --- | --- |
| 14. PROGRESS RATIO (%) TO 12/82 | 38.9% | 45.6% | 38.3% | 12.1% | 30.0% | --- | --- |
| 15. PROJECTED MONTHS TO GO | 141 | 121 | 144 | 454 | 183 | --- | --- |
| 16. PROJECTED COD | 8.94 | 12.92 | 11.94 | 10.2 | 2.98 | --- | --- |

Table 3: Projection of Seabrook Schedule Slippage

Notes: Line 6 equals line 4 divided by line 5.
Line 7 equals PSNH's 25 month estimate divided by the progress ratio in line 6.
Line 14 equals line 13 divided by line 12.
Line 15 equals 55 months divided by line 14.

| Variable Name | Meaning | Co-efficient | Value for Seabrook | Contribution to Construction Duration |
|---|---|---|---|---|
| Constant | | | | -268.4 |
| CPIS | date of construction permit | 4.53 | 76.5 | 346.5 |
| SIZE | in MW | 0.035 | 1150 | 40.3 |
| BW | Babcock & Wilcox dummy | 15.92 | 0 | |
| LN | ln of number of LWRs built by A/E | -6.91 | 1.87 (1) | -12.9 |
| DUP2 | Second unit | 11.54 | 0 [1] | 0 [11.54] |
| | construction duration, in months | | | 105.5 [117.0] |

Table 4: Calculation of Interval Between Construction Permit and Operating License, Seabrook Units as Predicted by Mooz (1979)

(1) Average for Seabrook units. Preceding five units are Brunswick 1 and 2, Indian Point 2 and 3, and WPPSS 1, now mothballed.

Figures in brackets for Seabrook 2.

| | Unit | Mooz Estimate Construction Time (1) | Mooz Estimate Operating License | Actual Date of Operating License (2) | Months of Under-Estimate |
|---|---|---|---|---|---|
| 1. | Sequoyah 1 | 104 | 1/79 | 2/80 | 13 |
| 2. | Diablo Canyon 2 | 83 | 11/77 | (3) | 67+ |
| 3. | North Anna 2 | 91 | 9/78 | 4/80 | 19 |
| 4. | Sequoyah 2 | 92 | 1/78 | 6/81 | 41 |
| 5. | Farley 2 | 86 | 10/79 | 10/80 | 12 |
| 6. | Arkansas 2 | 66 | 6/78 | 9/78 | 3 |

Table 5: Underestimate of Construction Duration in Mooz (1978)

Notes: (1) Months

(2) First Operating License

(3) Diablo Canyon 2 has not received a license

| Variable | Co-efficient[a] | Seabrook[b] | Contribution to Construction Duration | |
|---|---|---|---|---|
| Constant | .98 | | .98 | |
| MW | .358 | 1150 | 12.47 | |
| A-E experience | -.111 | 6 | .8196 | |
| Cumulative Nuclear Capacity | .185 | 114613[c] (115813)[c] | 8.629[d] (8.646)[d] | |
| Northeast Location | 1.12 | | 1.12 | |
| Second Unit | 1.20 | | 1.0 (1.2) | |
| Cooling Tower | 1.11 | | | |
| Total Without Cooling Tower | | | 96.8 (116.4) | 112.4[e] (134.9) |
| With Cooling Tower Variable | 1.11 | | 107.4 (129.2) | 124.8 (149.7) |

Table 6: Komanoff Nuclear Construction Duration Equation (months from CPIS to COD)

Notes :

a. Equation is multiplicative: MW, A-E, and cumulative capacity are raised to the power of their co-efficients, and the results are multiplied by the constant and applicalbe dummies.

b. Figures in parentheses are for Seabrook 2.

c. For constant time effect, Cumulative Capacity is equivalent to 256977.

d. For constant time effect, this factor is 10.019.

e. This column is total months, given constant time effect.

| Unit | Komanoff Estimated COD | Actual COD | Differences Between Actual and Estimated Duration (months) |
|---|---|---|---|
| Salem 2 | 12/79 | 10/81 | 22 |
| Sequoyah 1 | 2/80 | 7/81 | 17 |
| Sequoyah 2 | 10/80 | 6/82 | 20 |
| North Anna 2 | 12/79 | 3/80 | 3 |
| Diablo Canyon 1 | omitted | (1) | |
| Diablo Canyon 2 | omitted | (1) | |

Table 7 : Differences Between Komanoff COD Estimates and Actual Values

Notes :

(1) Neither Diablo Canyon unit has an active operating license. Commercial operation in 1983 is unlikely.

| Unit | Reported % Complete (1) as of 6/81 | Estimated Commercial Operation Date as of 6/81 (2) | as of 12/83 (5) |
|---|---|---|---|
| Limerick 1 | 63 | 4/85 | 4/85 |
| Braidwood 1 | 62 | 10/85 | 10/85 |
| Palo Verde 2 | 61 | 5/84 | 3/85 |
| South Texas 1 | 60 | 6 /84 (3) | 6/87 (3) |
| Byron 2 | 60 | 10/84 | 2/85 |
| Susquehanna 2 | 59 | 5/84 | 11/84 (4) |
| Bellefonte 2 | 59 | 9/86 | 11/87 |
| Watts Bar 2 | 58 | 10/84 | 12/85 |
| Comanche Peak 2 | 52 | 6 /84 (3) | 1/86 (4) |
| WPPSS 1 | 49.6 | 6/86 | indefinite |
| Braidwood 2 | 48 | 10/86 | 10/86 |
| Seabrook 1 | 48 | 2/84 | 12/84 |
| Harris 1 | 43 | 9/85 | 3/86 |
| Beaver Valley 2 | 41.6 | 5/86 | 5/86 |
| Perry 2 | 40 | 5/88 | 5/88 |
| Nine Mile Point 2 | 38 | 10/86 | 10/86 |
| Millstone 3 | 36 | 5/86 | 5/86 |
| Hope Creek 1 | 35 | 12/86 | 12/86 |
| Hartsville A1 | 34 | 7/88 | I |

Table 8 : Projected Completion Dates, Units comparable to Seabrook 1 in Stage of Completion.

Notes : (1) From Nuclear News, August, 1981. All units between 33% and 63% complete are listed.

(2) From Nuclear News, August, 1981.

(3) Month not given, June assumed.

(4) Month from TVA survey.

(5) Nuclear News, February, 1983.

| Unit | Reported% Completed (1) | Estimated Commercial Operation (2) as of 6/81 | Estimated Commercial Operation (3) as of 12/82 |
|---|---|---|---|
| Hope Creek 2 | 17.8 | 12/89 | Canceled |
| WPPSS 5 | 13.7 | 12/87 | Canceled |
| Marble Hill 2 | 11 | 10/87 (4) | 6/88 |
| North Anna 3 | 8.8 | /89 (5) | Canceled |
| Seabrook 2 | 8 | 5/86 | 3/87 |
| Harris 2 | 3 | 3/88 | 3/90 |
| Harris 3 | 1 | 3/94 | Canceled |
| Harris 4 | 1 | 3/92 | Canceled |
| Callaway 2 | 0.5 | 6/90 (4) | Canceled |
| Cherokee 1 | 18 | indefinite | |
| Hartsville B1 | 17 | indefinite | Canceled |
| Hartsville B2 | 7 | indefinite | Canceled |
| Phipps Bend 2 | 5 | indefinite | Canceled |
| Yellow Creek 2 | 3 | indefinite | indefinite |
| Clinton 2 | 0 | indefinite | indefinite |
| River Bend 2 | 0 | indefinite | indefinite |
| Vogtle 1 | 18 | 5/85 | 3/87 |
| Vogtle 2 | 10 | 11/86 | 9/88 |

Table 9 : Projected Completion Dates, Units Comparable to Seabrook 2 in Stage of Completion

Notes : (1) From Nuclear News, August, 1981. All units with CP and less than 20% complete are listed.

(2) Ibid.

(3) OP. Cit., February, 1981.

(4) Month not given, date assumed.

| Unit | Estimate Date | Estimated COD | Estimated Time to Complete (Years) | Actual COD | Actual Time to Complete (Years) | Ratio of Actual Time to Estimated Time |
|---|---|---|---|---|---|---|
| Millstone 2[1] | 11/70 | 4/74 | 3.42 | 12/75 | 5.08 | 1.49 |
| | 11/73 | 8/75 | 1.75 | | 2.08 | 1.19 |
| Pilgrim 1[2] | 6/68 | 9/71 | 3.25 | 12/72 | 4.50 | 1.38 |
| | 1/70 | 9/71 | 1.67 | | 2.92 | 1.75 |
| Cooper[3] | 7/68 | 4/72 | 3.75 | 7/74 | 6.00 | 1.6 |
| | 10/70 | 7/73 | 2.75 | | 3.75 | 1.36 |
| TMI 2[5] | 12/69 | 5/74 | 4.42 | 12/78 | 9.00 | 2.04 |
| | 12/70 | 5/74 | 3.42 | | 8.00 | 2.34 |
| | 12/71 | 5/65 | 3.42 | | 7.00 | 2.05 |
| | 12/72 | 5/76 | 3.42 | | 6.00 | 1.75 |
| | 12/73 | 5/77 | 3.42 | | 5.00 | 1.46 |
| | 12/74 | 5/78 | 3.42 | | 4.00 | 1.17 |
| | 12/75 | 5/78 | 2.42 | | 3.00 | 1.24 |
| | 12/76 | 5/79 | 1.42 | | 2.00 | 1.41 |
| Hatch 2[3] | 2/76 | 4/79 | 2.33 | 9/79 | 2.75 | 1.18 |
| Crystal River 3[3] | 1/75 | 9/76 | 1.67 | 3/77 | 2.17 | 1.26 |
| Maine Yankee[3] | 5/71 | 5/72 | 1.00 | 12/72 | 1.58 | 1.58 |
| Rancho Seco[3] | 8/73 | 10/74 | 1.17 | 4/75 | 1.67 | 1.43 |
| Salem 1[4] | 8/68 | 3/72 | 3.58 | 6/77 | 8.83 | 2.47 |
| | 9/69 | 3/72 | 2.5 | | 7.75 | 3.10 |
| | 1/71 | 12/73 | 2.92 | | 6.42 | 2.20 |
| | 1/71 | 12/73 | 2.42 | | 5.92 | 2.45 |
| | 7/72 | 3/75 | 2.67 | | 4.92 | 1.84 |
| | 7/73 | 9/75 | 2.17 | | 3.92 | 1.81 |
| | 7/74 | 12/76 | 2.42 | | 2.92 | 1.21 |
| Salem 2[4] | 8/68 | 3/73 | 4.58 | 10/81 | 13.17 | 2.88 |
| | 9/69 | 3/73 | 3.5 | | 12.08 | 3.45 |
| | 1/71 | 12/74 | 3.92 | | 10.75 | 2.73 |
| | 7/71 | 12/74 | 3.42 | | 10.25 | 3.00 |
| | 7/72 | 3/76 | 3.67 | | 9.25 | 2.52 |
| | 7/72 | 9/76 | 3.17 | | 8.25 | 2.60 |
| | 7/74 | 5/79 | 4.83 | | 7.25 | 1.50 |
| | 7/77 | 5/79 | 1.83 | | 4.25 | 2.32 |

Table 10 : Tendency of Utilities and A/E's to Underestimate Construction Time for Nuclear Power Plants

CONTINUED NEXT PAGE

| Unit | Estimate Date | Estimated COD | Estimated Time to Complete (Years) | Actual COD | Actual Time to Complete (Years) | Ratio of Actual Time to Estimated Time |
|---|---|---|---|---|---|---|
| Brown's Ferry 1[6] | 1/68 | 10/70 | 2.75 | 8/74 | 6.58 | 2.39 |
| | 1/70 | 10/71 | 1.75 | | 4.58 | 2.62 |
| | 1/71 | 4/72 | 1.25 | | 3.58 | 2.86 |
| Brown's Ferry 2[6] | 1/68 | 10/71 | 3.75 | 3/75 | 7.17 | 1.91 |
| | 1/70 | 4/72 | 2.25 | | 5.17 | 2.30 |
| | 1/71 | 1/73 | 2.00 | | 4.17 | 2.09 |
| | 1/72 | 7/73 | 1.50 | | 3.17 | 2.11 |
| | 1/73 | 4/74 | 1.25 | | 2.17 | 1.74 |
| Brown's Ferry 3[6] | 1/70 | 10/72 | 2.75 | 3/77 | 7.17 | 2.61 |
| | 1/71 | 10/73 | 2.75 | | 6.17 | 2.24 |
| | 1/72 | 2/74 | 2.08 | | 5.17 | 2.49 |
| | 1/73 | 10/74 | 1.75 | | 4.17 | 2.38 |
| | 1/74 | 4/75 | 1.25 | | 3.17 | 2.54 |
| | 1/75 | 1/76 | 1.00 | | 2.17 | 2.17 |
| Sequoyah 1[6] | 1/71 | 4/74 | 3.25 | 7/81 | 10.50 | 3.23 |
| | 1/72 | 7/74 | 2.5 | | 9.50 | 3.80 |
| | 1/73 | 4/75 | 2.25 | | 8.50 | 3.78 |
| | 1/74 | 6/76 | 2.42 | | 7.50 | 3.10 |
| | 1/75 | 1/77 | 2.00 | | 6.50 | 3.25 |
| | 1/76 | 9/77 | 1.67 | | 5.50 | 3.29 |
| | 1/77 | 5/78 | 1.33 | | 4.50 | 3.46 |

Table 10: Tendency of Utilities and A/E's to Underestimate Construction Time for Nuclear Power Plants

CONTINUED NEXT PAGE

| Unit | Estimate Date | Estimated COD | Estimated Time to Complete (Years) | Actual COD | Actual Time to Complete (Years | Ratio of Actual time to Estimated Time |
|---|---|---|---|---|---|---|
| Sequoyah 2 | | | | | | |
| | 1/71 | 12/74 | 3.83 | 6/82 | 11.42 | 2.98 |
| | 1/72 | 3/75 | 3.17 | | 10.42 | 3.29 |
| | 1/73 | 12/75 | 2.83 | | 9.42 | 3.33 |
| | 1/74 | 2/77 | 3.08 | | 8.42 | 2.73 |
| | 1/75 | 9/77 | 2.67 | | 7.42 | 2.78 |
| | 1/76 | 5/78 | 2.25 | | 6.42 | 2.85 |
| | 1/77 | 1/79 | 2.00 | | 5.42 | 2.71 |
| | 1/78 | 5/79 | 1.33 | | 4.42 | 3.32 |
| | 1/79 | 6/80 | 1.42 | | 3.42 | 2.41 |
| | 1/80 | 6/81 | 1.42 | | 2.42 | 1.70 |
| | 1/81 | 7/82 | 1.08 | | 1.42 | 1.31 |

Table 10 : Tendency of Utilities and A/E's to Underestimate Construction Time for Nuclear Power Plants

Notes :
1. From Information Response (IR) AG-7, Mass. D.P.U. 20279
2. From IR 33, NRC 50-471.
3. From IR AG-C-19, Mass. D.P.U. 20248 (RW Beck Data)
4. From "Construction Management Audit, Salem 1", May 1977, Theodore Barry and Associates.
5. From "Review of the TMI-2 Construction Project", Touche Ross & Co., Oct., 1978
6. From TVA reports.

## CONSTRUCTION DURATION STUDY

| Method | Seabrook 1 OLIS | Seabrook 1 COD | Seabrook 2 OLIS | Seabrook 2 COD |
|---|---|---|---|---|
| Past PSNH Progress-to Estimate Ratios | 10/85 | 10/86 | 8/92 | 8/93 |
| Past Completion Rates for Seabrook | 3/86 | 3/87 | 11/91 -4/92 | 11/92 -4/93 |
| Seabrook Slippage | | 7/86-6/88 | | 12/92-11/94 + |
| Time Trends | /91 | | /95-/96 | |
| Mooz (2) | 5/85 + | 5/86 + | 4/86 + | 4/87 + |
| Komanoff -minimum | | 8/84 + | | 3/86 |
| -"cooling tower" | | 6/85 + | | 3/87 |
| -time correction | | 10/85 + | | 9/87 |
| -combined adjustments | | 11/86 + | | 12/88 |
| Industry Consensus (3) | | 4/86 | | 5/88 |
| Industry Myopia (4) | | 2/88 | | 12/94 |
| Average of Estimates (1) | | 11/86 | | 3/91 |

Table 11: Summary of Construction Duration Predictions

Notes:
1. Averages omit simple time trend results, and use the average value from methods which produce more than one.
2. + indicates data or trend understated.
3. Not corrected for overall industry myopia, which would delay COD.
4. Not corrected for PSNH's greater optimism, which would delay COD.

| Variable | Value for Seabrook 1 [Seabrook 2] | Coefficients for Equation 8.1 | Equation 8.2 | Equation 8.3 |
|---|---|---|---|---|
| Constant | | 6.41 | .00114 | 16.2 |
| Northeast (1) | 1 | 1.28 | 1.33 | 1.28 |
| A-E experience | 6 [7] | -.105 | -.125 | -.094 |
| MW | 1150 | -.200 | -.203 | -.266 |
| Multiple (1) | 1 | .903 | .88 | .897 |
| Cooling Tower (1) | 0 (3) | 1.20 | 1.11 | 1.18 |
| Cumulative Capacity | 114613 [115814] | .577 | | .501 |
| CPIS (2) | 76.58 | | 1.236 | |
| Operating Experience (4) | 808 [1350] | | | .067 |

Table 12 : Coefficients and Variable Values for Komanoff Nuclear Cost Equations

Notes : 1. Dummy variables, included if applicable, set to 1.0 if not. "Dangling" variable not shown.

2. Factor is $1.236^{CPIS}$; for all other factors, the variable is raised to the power of the coefficient.

3. Or 1.0 if "Cooling Tower" designation applies.

4. In reactor-years as of the OLIS (assumed to be 11/86 and 2/90; five new reactors/year assumed, 1982 onwards.

| Equation | "Cooling Tower" | Predicted Cost[1] Seabrook 1 | Seabrook 2 |
|---|---|---|---|
| #1 | No | 1245.0 | 1232.4 |
| #1 | Yes | 1494.0 | 1478.9 |
| #2 | No | 2791.7 | 2738.6 |
| #2 | Yes | 3098.8 | 3039.8 |
| #3 | No | 1292.9 | 1325.9 |
| #3 | Yes | 1525.8 | 1564.6 |
| Average | | 1908.0 | 1896.7 |
| Real AFUDC[2] | | | |
| % increment | | 22.0% | 33.1% |
| $ kw | | 419.8 | 627.8 |
| Total with AFUDC, 1979 dollars/kw | | 2327.9 | 2524.5 |

Table 13 : Evaluation of Komanoff Cost Equations

Notes : (1) in 1979 dollars per kw, without real AFUDC

(2) $\text{AFUDC } \% = \frac{1 - (1.038)^N}{N \ln (1/1.038)} - 1$ , where

N = years from CPIS to COD. See Komanoff (1981, p. 244). N = 10.33 for Unit 1, 14.67 for Unit 2.

| Equation Number | Source of t value | Unit Seabrook 1 | Seabrook 2 |
|---|---|---|---|
| 1 | PSNH[1] | 1.424 | 1.934 |
| 2 | PSNH | 1.222 | 1.972 |
| 3 | PSNH | 1.330 | 1.874 |
| 4 | PSNH | 1.223 | 1.908 |
| Average | PSNH | 1.300 | 1.922 |
| 1 | Industry[2] | 1.698 | 2.107 |
| 2 | Industry | 1.624 | 2.224 |
| 3 | Industry | 1.598 | 2.103 |
| 4 | Industry | 1.552 | 2.217 |
| Average | Industry | 1.618 | 2.163 |
| Average | Overall | 1.459 | 2.043 |

Table 14 : Estimated Value of Actual-to-Forecast Real Cost of Seabrook Units, from Myopia Method

Notes : 1. $t$ = 2.08 years to 12/84 for Unit 1;
$t$ = 4.58 years to 7/87 for Unit.

2. $t$ 3.42 years to 4/86 for Unit 1;
$t$ 5.42 years to 5/88 for Unit 2.

| Unit | Source of t (value) | Value of m | (1+m)^t | Corrected Cost Estimate |
|---|---|---|---|---|
| | (1) | (2) | | (3) |
| 1 | PSNH (2.08) | .32 | 1.78 | |
| | Industry (3.42) | .27 | 2.26 | |
| | Average | | 2.02 | $6040/kw |
| 2 | PSNH (4.58) | .21 | 2.39 | |
| | Industry (5.42) | .18 | 2.45 | |
| | Average | | 2.42 | $3795/kw |
| 1 | Renormalized(4) Indirects | | | $4941/kw |
| 2 | | | | $4894/kw |

Table 15: Nominal Myopia Analysis

Notes:
1. See Table 14
2. From Appendix B
3. Based on cost estimates of $2990/kw for Unit 1 and $1568/kw for Unit 2.
4. Shifts 18.2% of Unit 1 cost to Unit 2.

| | DATE OF ESTIMATE | | | | | |
|---|---|---|---|---|---|---|
| | 12/76 | 3/78 | 1/79 | 3/80 | 4/81 | 12/82 |
| MONTHS BETWEEN ESTIMATES | --- | 15 | 10 | 14 | 13 | 20 |
| MONTHS TO 12/82 | 72 | 57 | 47 | 33 | 20 | --- |
| ESTIMATED COST ($M) | 2015 | 2345 | 2610 | 3160 | 3560 | 5240 |
| INCREASE SINCE LAST ESTIMATE (%) | --- | 16.4% | 11.3% | 21.1% | 12.7% | 47.2% |
| INCREASE SINCE LAST ESTIMATE (ANNUALIZED) | --- | 12.9% | 13.7% | 17.8% | 11.6% | 26.1% |
| INCREASE TO 12/82 (%) | 160.0% | 123.5% | 100.8% | 65.8% | 47.2% | --- |
| INCREASE TO 12/82 (ANNUAL) | 17.3% | 18.4% | 19.5% | 20.2% | 26.1% | --- |

Table 16: Growth Rates in PSNH Cost Estimates for Seabrook

| Method | Real (1983$) Estimates | | Nominal Estimates | |
|---|---|---|---|---|
| | Seabrook 1 | Seabrook 2 | Seabrook 1 | Seabrook 2 |
| Perl | $2,639 | $2,497 | $3,300 | $3,644 |
| Komanoff (1) | $3,146 | $3,394 | $3,933 | $4,955 |
| Real Myopia | $3,251 | $3,470 | $4,064 | $5,066 |
| Nominal Myopia | | | $4,941 | $4,894 |
| Seabrook Trends (average for 2 units) | | | | $4935 |
| Averages (2) | $3,012 | $3,120 | $4,248 | $4,697 |

Table 17: Cost Estimate Summary

Notes: 1. Not included in Nominal Average.

2. Includes Seabrook-trend estimate, divided between units in the same proportion as the average of the other four estimates.

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

Table 18: Capacity Factor Equations and Projections from Easterling (1981)

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

Calendar Years of Experience

| Predicted Capacity Factors | year: 1 (5) | 2 | 3 | 4 | 5 | 6 | 7+ |
|---|---|---|---|---|---|---|---|
| PSNH (1) | 59.0% | 61.0% | 65.0% | 67.0% | 69.0% | 72.0% | 72.0% |
| Easterling (2) | 47.2% | 47.2% | 47.2% | 49.6% | 52.0% | 54.3% | 54.3% |
| UI (3) | 59.0% | 61.0% | 64.0% | 68.0% | 68.0% | 73.0% | 73.0% |
| CL&P (4) | 60.0% | 63.0% | 65.0% | 65.0% | 65.0% | 65.0% | 70.0% |

| Unit Years of Experience as of 10 /31 /82 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Salem 1 | 6 /30 /77 | 0.51 | 1.00 | 1.00 | 1.00 | 1.00 | 0.83 | 0.00 |
| Zion 1 | 12 /31 /73 | 0.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 3.84 |
| Zion 2 | 9 /17 /74 | 0.29 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 2.83 |
| Cook 1 | 8 /27 /75 | 0.35 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.84 |
| Cook 2 | 7 / 1 /78 | 0.50 | 1.00 | 1.00 | 1.00 | 0.83 | 0.00 | 0.00 |
| Trojan | 5 /20 /76 | 0.62 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 0.83 |

Table 19: Comparison of Capacity Factor Predictions

Notes:
1. From PSNH response to Staff Request 32, NHPUC DE81-312
2. See text.
3. From UI LF-1, Att. B, "Specific Assumptions", p. 2.
4. From CL&P LF-1, Att. 1, p. 3.
5. First partial year.

| Unit | Actual (1) | Easterling (2) | PSNH | UI | CL&P |
| --- | --- | --- | --- | --- | --- |
| Salem 1 | 48.2% | 51.1% | 65.9% | 65.9% | 64.2% |
| Zion 1 | 58.0% | 54.5% | 69.1% | 69.5% | 66.9% |
| Zion 2 | 57.5% | 54.1% | 68.3% | 68.7% | 66.3% |
| Cook 1 | 63.6% | 52.2% | 67.8% | 68.0% | 65.8% |
| Cook 2 | 68.4% | 49.9% | 64.6% | 64.4% | 64.0% |
| Trojan | 50.6% | 50.8% | 66.7% | 66.9% | 64.9% |
| Average (3) | 57.6% | 52.5% | 67.5% | 67.7% | 65.6% |

Table 20: Comparisons of Capacity Factor Projections

Notes:
1. DER rating from NRC Gray Book, 11/82.
2. Includes 2.4 points per 100 MW decrease in size.
3. Weighted by experience.

| Unit | MW | Capacity Factor Yrs. 2-5 (1) | Capacity Factor Yrs. 6 + |
|---|---|---|---|
| 1. CN Yankee | 575 | 79.1 | 78.5 |
| 2. ME Yankee | 825 | 69.1 | 68.0 |
| 3. Change per | 100 MW (2) | 4 | 4.2 |
| 4. Seabrook (3) | 1,150 | 56.1 | 54.3 |

Table 21: Projection of Seabrook Capacity Factors from Yankee Data

Notes: 1. Year 2 is first full year.

2. (Row 1) - (Row 2) / 2.5.

3. (Row 2) + 3.25 (Row 3).

| Plant | 1979 | 1980 | 1981 | Annual % Increase |
|---|---|---|---|---|
| Maine Yankee | $16,737 | $21,327 | $31,324 | 36.8% |
| Conn. Yankee | $20,690 | $37,894 | $41,953 | 42.4% |
| Vermont Yankee | $16,320 | $25,497 | $31,177 | 38.2% |
| Mass. Yankee | $11,454 | $24,109 | $23,925 | 44.5% |

Table 23: Yankee Plant O&M, as defined by PSNH

Source: PSNH response to CLF request 2-3
NHPUC DE 81-312

| Unit | Period Analyzed | 1980 O & M ($1000) | Least - Squares Annual Growth: Linear Increase (1981$, 1000's) | Least - Squares Annual Growth: Geometric Increase |
|---|---|---|---|---|
| Conn. Yankee | 1968-80 | 35155 | 1854 | 13.8% |
| Millstone 1 | 1971-80 | 24783 | 1566 | 9.6% |
| Pilgrim | 1973-81 | 27785 | 2574 | 13.7 |
| Vermont Yankee | 1973-80 | 22588 | 1785 | 12.1% |
| Maine Yankee | 1973-80 | 14028 | 980 | 8.9% |
| Millstone 2 | 1976-80 | 30164 | 2913 | 12.1% |
| Average | | 25751 | 1933 | 11.7% |
| | | x 1.104 | | |
| 1981 $ | | 28428 | | |
| | | x 1.119 | x 1.119 | |
| 1983 $ | | 31811 | 2163 | |

Table 24: Calculation of Average New England Experience, Non-Fuel Nuclear O & M Expense, Constant Dollars

| Trend Type | Time Period | Seabrook Unit 1 | Seabrook Unit 2 |
|---|---|---|---|
| Linear | 1987/1992 | $58,690 | $84,340 |
| Linear | levelized 25 yrs, 1983$ | $63,084 | $71,736 |
| Geometric | 1987/1992 | $86,270 | $175,214 |
| Geometric | levelized 25 yrs, 1983$ | $208,993 | $325,345 |

Table 25: Annual Non-fuel O&M Expenses ($1000) Extrapolated from New England Experience

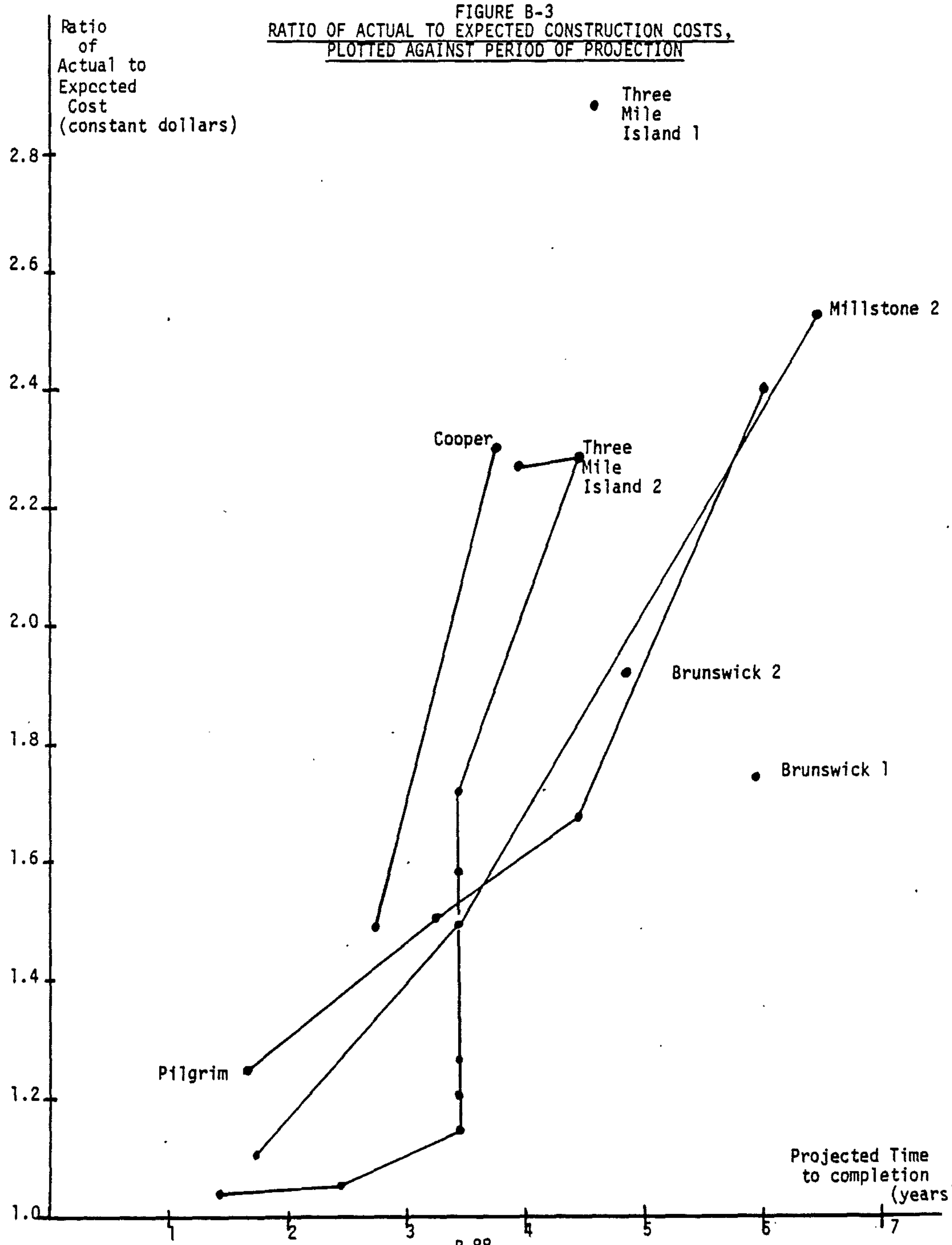
| Cost Basis: | Seabrook 1 Levelized Real (1983$) | Seabrook 1 First Year Nominal | Seabrook 2 Levelized Real (1983$) | Seabrook 2 First Year Nominal |
|---|---|---|---|---|
| Cost per kw | | | | |
| Construction Costs | $3,012 [ $836 ] | $4,248 | $3,120 [$2,493 ] | $4,673 |
| Fixed Charge Rate | 12.8% | 29.6% | 12.8% | 29.6% |
| Cost per kw-yr | | | | |
| Annual Capital Costs | $386 [ $107 ] | $1,257 | $399 [ $319 ] | $1,383 |
| Non-fuel O&M | $63 | $59 | $72 | $84 |
| Capital Additions | $13 | $16 | $13 | $19 |
| Insurance | $10 | $13 | $10 | $15 |
| Decommissioning | $13 | $16 | $13 | $19 |
| Total Non-fuel | $485 [ $206 ] | $1,361 | $507 [ $427 ] | $1,520 |
| Capacity Factor | 55% | 47% | 55% | 47% |
| Cost per kwh (cents) | | | | |
| Non-fuel | 10.1 [ 4.3 ] | 33.1 | 10.5 [ 8.9 ] | 36.9 |
| Fuel | 1.3 | 1.2 | 1.6 | 1.3 |
| Total | 11.4 [ 5.6 ] | 34.3 | 12.1 [ 10.4 ] | 38.2 |

Table 26: Total Power Costs for Seabrook Units

Notes: Figures in brackets are remaining costs.

Figure 1

FIGURE B-3
RATIO OF ACTUAL TO EXPECTED CONSTRUCTION COSTS,
PLOTTED AGAINST PERIOD OF PROJECTION




B-88

NOTE: Lines are drawn connecting estimates for the same reactors in chronological order of estimate date.

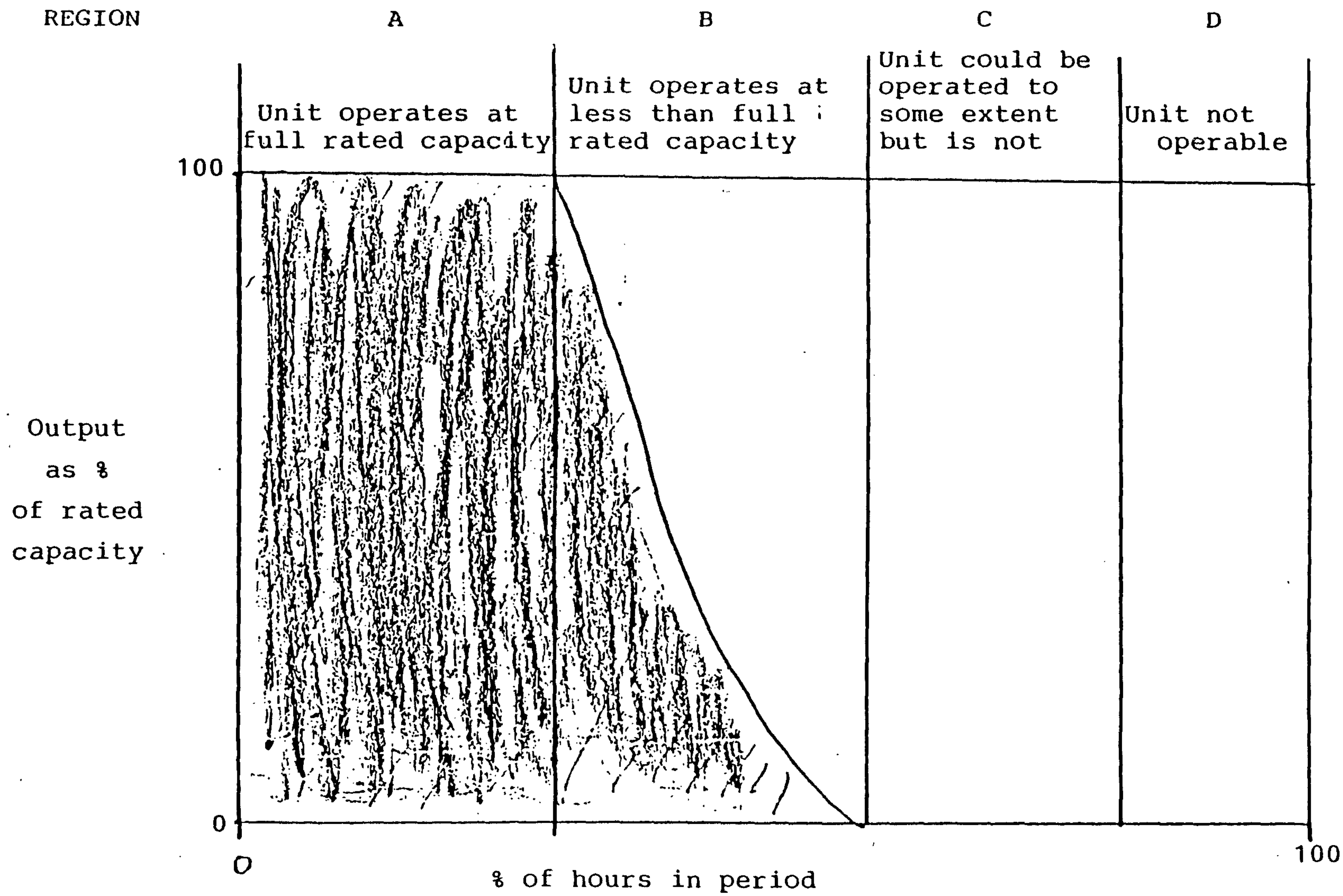



Figure 2: Diagrammatic Description of Availability Factor and Capacity Factor

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.

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

Analyzed utility filings and prepared alternative proposals. Participated in rate negotiations, discovery, cross-examinnation, 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.

Consultant, National Consumer Law Center, 1979

Taught portions of short term courses in cost allocation, rate design, and time-of-use rates. Assisted in preparation for time-of-use rate design case.

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

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); PUCT (Public Utilities Commission of Texas); ASLB, NRC (Atomic Safety and Licensing Board, Nuclear Regulatory Commission), DCPSC (District of Columbia Public Service Commission); and NHPUC (New Hampshire Public Utilities Commission).

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

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

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

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

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

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

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

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

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

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

6. ASLB, NRC 50-471; Pilgrim Unit 2, Boston Edison Company; Commonwealth of Massachusetts; June 29, 1979.

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

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

   Critique of utility marginal cost study and proposed rates; persentation 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. NDPU 20248; Petition of MMWEC to Purchase Additional Shares 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 for 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; costs 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) stauts, 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 yet 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. DCPSC FC785; Potomac Electric Power Rate Case: DC People's Counsel; July 29, 1982.

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

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

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

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

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

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

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

## APPENDIX B:

## COST MYOPIA DATA

| estdate | plant | est cost | est cod | actl cost | cstrat | CPIS | esttime | myopia |
|---|---|---|---|---|---|---|---|---|
| estdate | plant | est cost | est cod | actl cost | cstrat | CPIS | esttime | myopia |
| Mar-67 | Peach Bottom #3 | 120 | 74 | 377 | 3.142 | Jan-68 | 7.26 | 17.09% |
| Sep-66 | Peach Bottom #3 | 125 | 73 | 377 | 3.016 | Jan-68 | 6.75 | 17.76% |
| Sep-67 | Prairie Is. #2 | 98 | 74 | 177 | 1.806 | Jun-68 | 6.75 | 9.15% |
| Mar-67 | Arkansas 1 | 150 | 73 | 239 | 1.592 | Dec-68 | 6.26 | 7.71% |
| Mar-68 | Millstone #2 | 150 | 74 | 426 | 2.842 | Dec-70 | 6.25 | 18.17% |
| Mar-68 | Prairie Is. #2 | 98 | 74 | 177 | 1.806 | Jun-68 | 6.25 | 9.91% |
| Sep-67 | Arkansas 1 | 140 | 73 | 239 | 1.706 | Dec-68 | 5.75 | 9.73% |
| Sep-67 | Calvert Cliffs #1 | 118 | 73 | 431 | 3.650 | Jul-69 | 5.75 | 25.24% |
| Sep-67 | Cooper | 125 | 73 | 269 | 2.154 | Jun-68 | 5.75 | 14.27% |
| Sep-66 | Oconee #2 | 78 | 72 | 160 | 2.056 | Nov-67 | 5.75 | 13.35% |
| Sep-67 | Oconee #3 | 92 | 73 | 160 | 1.743 | Nov-67 | 5.75 | 10.14% |
| Sep-67 | Peach Bottom #3 | 125 | 73 | 377 | 3.016 | Jan-68 | 5.75 | 21.15% |
| Sep-67 | Zion #2 | 153 | 73 | 292 | 1.908 | Dec-68 | 5.75 | 11.89% |
| Sep-68 | Millstone #2 | 146 | 74 | 426 | 2.920 | Dec-70 | 5.75 | 20.48% |
| Sep-68 | Prairie Is. #2 | 93 | 74 | 177 | 1.903 | Jun-68 | 5.75 | 11.84% |
| Mar-67 | FitzPatrick | 100 | 72 | 419 | 4.190 | Apr-70 | 5.26 | 31.32% |
| Mar-67 | Kewaunee | 85 | 72 | 203 | 2.393 | Aug-68 | 5.26 | 18.05% |
| Mar-67 | Maine Yankee | 100 | 72 | 219 | 2.192 | Oct-68 | 5.26 | 16.10% |
| Mar-67 | Prairie Is. #1 | 100 | 72 | 233 | 2.332 | Jun-68 | 5.26 | 17.47% |
| Mar-67 | Surry #2 | 108 | 72 | 255 | 2.365 | Jun-68 | 5.26 | 17.79% |
| Mar-67 | Zion #1 | 100 | 72 | 276 | 2.760 | Dec-68 | 5.26 | 21.30% |
| Mar-68 | Beaver Valley #1 | 150 | 73 | 599 | 3.991 | Jun-70 | 5.25 | 30.14% |
| Mar-68 | Brunswick #2 | 112 | 73 | 389 | 3.474 | Feb-70 | 5.25 | 26.74% |
| Mar-68 | Calvert Cliffs #1 | 122 | 73 | 431 | 3.530 | Jul-69 | 5.25 | 27.13% |
| Mar-68 | D.Arnold | 107 | 73 | 280 | 2.616 | Jun-70 | 5.25 | 20.08% |
| Mar-68 | Hatch 1 | 150 | 73 | 390 | 2.603 | Sep-69 | 5.25 | 19.97% |
| Mar-68 | Oconee #3 | 93 | 73 | 160 | 1.725 | Nov-67 | 5.25 | 10.93% |
| Mar-66 | Pilgrim | 65 | 71 | 239 | 3.682 | Aug-68 | 5.25 | 28.15% |
| Mar-68 | Rancho Seco | 143 | 73 | 344 | 2.403 | Oct-68 | 5.25 | 18.15% |
| Mar-68 | St. Lucie 1 | 112 | 73 | 486 | 4.341 | Jul-70 | 5.25 | 32.23% |
| | | | | | 2.662 | | | 18.45% |
| Mar-66 | Turkey Pt. #4 | 63 | 71 | 127 | 2.013 | Apr-67 | 5.25 | 14.24% |
| Sep-67 | D.C. Cook #1 | 150 | 72 | 546 | 3.638 | Mar-69 | 4.75 | 31.22% |
| Sep-67 | Oconee #2 | 86 | 72 | 160 | 1.865 | Nov-67 | 4.75 | 14.01% |
| Sep-67 | Zion #1 | 164 | 72 | 276 | 1.683 | Dec-68 | 4.75 | 11.57% |
| Sep-66 | Browns Ferry #2 | 123 | 71 | 276 | 2.246 | May-67 | 4.75 | 18.56% |
| Sep-68 | Brunswick #2 | 130 | 73 | 389 | 2.993 | Feb-70 | 4.75 | 25.96% |
| Sep-69 | Brunswick #2 | 141 | 74 | 389 | 2.760 | Feb-70 | 4.75 | 23.82% |
| Sep-68 | Calvert Cliffs #1 | 125 | 73 | 431 | 3.446 | Jul-69 | 4.75 | 29.75% |
| Sep-68 | D.Arnold | 103 | 73 | 280 | 2.717 | Jun-70 | 4.75 | 23.42% |
| Sep-68 | Hatch 1 | 160 | 73 | 390 | 2.440 | Sep-69 | 4.75 | 20.65% |
| Sep-69 | Millstone #2 | 179 | 74 | 426 | 2.382 | Dec-70 | 4.75 | 20.04% |
| Sep-66 | Oconee #1 | 123 | 71 | 156 | 1.265 | Nov-67 | 4.75 | 5.07% |
| Sep-66 | Peach Bottom #2 | 125 | 71 | 377 | 3.016 | Jan-68 | 4.75 | 26.16% |
| Sep-68 | Peach Bottom #3 | 145 | 73 | 377 | 2.600 | Jan-68 | 4.75 | 22.28% |
| Sep-69 | Prairie Is. #2 | 92.5 | 74 | 177 | 1.914 | Jun-68 | 4.75 | 14.64% |
| Sep-68 | Rancho Seco | 134 | 73 | 344 | 2.564 | Oct-68 | 4.75 | 21.92% |
| Sep-69 | Trojan | 197 | 74 | 452 | 2.294 | Feb-71 | 4.75 | 19.10% |
| Mar-68 | Arkansas 1 | 140 | 72 | 239 | 1.706 | Dec-68 | 4.25 | 13.37% |
| Mar-67 | Browns Ferry #2 | 117. | 71 | 276 | 2.351 | May-67 | 4.25 | 22.25% |
| Mar-70 | Brunswick #2 | 161. | 74 | 389 | 2.409 | Feb-70 | 4.25 | 22.96% |
| Mar-68 | Cooper | 135 | 72 | 269 | 1.995 | Jun-68 | 4.25 | 17.62% |

| estdate | plant | est cost | est cod | actl cost | cstrat | CPIS | esttime | myopia |
|---|---|---|---|---|---|---|---|---|
| Mar-68 | D.C. Cook #1 | 141 | 72 | 546 | 3.870 | Mar-69 | 4.25 | 37.45% |
| Mar-67 | Ft. Calhoun | 70 | 71 | 176 | 2.511 | Jun-68 | 4.25 | 24.16% |
| Mar-68 | Kewaunee | 88 | 72 | 203 | 2.311 | Aug-68 | 4.25 | 21.76% |
| Mar-67 | Oconee #1 | 78 | 71 | 156 | 1.995 | Nov-67 | 4.25 | 17.62% |
| Mar-68 | Oconee #2 | 93 | 72 | 160 | 1.725 | Nov-67 | 4.25 | 13.67% |
| Mar-66 | Palisades | 75 | 70 | 147 | 1.956 | Mar-67 | 4.25 | 17.08% |
| Mar-67 | Peach Bottom #2 | 138 | 71 | 377 | 2.732 | Jan-68 | 4.25 | 26.64% |
| Mar-68 | Peach Bottom #3 | 145 | 72 | 377 | 2.600 | Jan-68 | 4.25 | 25.18% |
| Mar-68 | Prairie Is. #1 | 93 | 72 | 233 | 2.508 | Jun-68 | 4.25 | 24.12% |
| Mar-67 | Surry #1 | 130 | 71 | 247 | 1.898 | Jun-68 | 4.25 | 16.25% |
| Mar-68 | Surry #2 | 112 | 72 | 255 | 2.280 | Jun-68 | 4.25 | 21.38% |
| Mar-67 | Three Mile Is. | 110 | 71 | 401 | 3.645 | Nov-69 | 4.25 | 35.52% |
| Mar-70 | Trojan | 199 | 74 | 452 | 2.271 | Feb-71 | 4.25 | 21.27% |
| Mar-66 | Turkey Pt. #3 | 70 | 70 | 109 | 1.553 | Apr-67 | 4.25 | 10.90% |
| >4 years | | | | | 2.404 | | | 20.90% |
| Sep-68 | Arkansas 1 | 132 | 72 | 239 | 1.809 | Dec-68 | 3.75 | 17.12% |
| Sep-69 | Beaver Valley #1 | 189 | 73 | 599 | 3.168 | Jun-70 | 3.75 | 35.99% |
| Sep-66 | Browns Ferry #1 | 124 | 70 | 276 | 2.227 | May-67 | 3.75 | 23.80% |
| Sep-69 | Calvert Cliffs #1 | 124 | 73 | 431 | 3.473 | Jul-69 | 3.75 | 39.37% |
| Sep-68 | Cooper | 127 | 72 | 269 | 2.120 | Jun-68 | 3.75 | 22.19% |
| Sep-69 | D.Arnold | 133 | 73 | 280 | 2.105 | Jun-70 | 3.75 | 21.94% |
| Sep-68 | D.C. Cook #1 | 117. | 72 | 546 | 4.644 | Mar-69 | 3.75 | 50.60% |
| Sep-67 | FitzPatrick | 100 | 71 | 419 | 4.190 | Apr-70 | 3.75 | 46.52% |
| Sep-69 | FitzPatrick | 224 | 73 | 419 | 1.871 | Apr-70 | 3.75 | 18.17% |
| Sep-69 | Hatch 1 | 151 | 73 | 390 | 2.585 | Sep-69 | 3.75 | 28.82% |
| Sep-67 | Indian Pt. #3 | 159 | 71 | 570 | 3.585 | Aug-69 | 3.75 | 40.55% |
| Sep-68 | Kewaunee | 111 | 72 | 203 | 1.832 | Aug-68 | 3.75 | 17.52% |
| Sep-68 | Maine Yankee | 131 | 72 | 219 | 1.673 | Oct-68 | 3.75 | 14.71% |
| Sep-70 | Millstone #2 | 183 | 74 | 426 | 2.330 | Dec-70 | 3.75 | 25.29% |
| Sep-67 | Oconee #1 | 86 | 71 | 156 | 1.809 | Nov-67 | 3.75 | 17.13% |
| Sep-68 | Oconee #2 | 86 | 72 | 160 | 1.865 | Nov-67 | 3.75 | 18.08% |
| Sep-69 | Oconee #3 | 83 | 73 | 160 | 1.933 | Nov-67 | 3.75 | 19.20% |
| Sep-68 | Prairie Is. #1 | 92 | 72 | 233 | 2.535 | Jun-68 | 3.75 | 28.14% |
| Sep-69 | St. Lucie 1 | 123 | 73 | 486 | 3.953 | Jul-70 | 3.75 | 44.26% |
| Sep-67 | Three Mile Is. | 116 | 71 | 401 | 3.456 | Nov-69 | 3.75 | 39.19% |
| Sep-70 | Trojan | 227 | 74 | 452 | 1.991 | Feb-71 | 3.75 | 20.16% |
| Sep-67 | Turkey Pt. #4 | 66 | 71 | 127 | 1.921 | Apr-67 | 3.75 | 19.02% |
| Sep-66 | Vermont Yankee | 79 | 70 | 185 | 2.335 | Dec-67 | 3.75 | 25.38% |
| Sep-67 | Vermont Yankee | 88 | 71 | 185 | 2.097 | Dec-67 | 3.75 | 21.82% |
| Sep-69 | Zion #2 | 194 | 73 | 292 | 1.505 | Dec-68 | 3.75 | 11.52% |
| Mar-67 | Browns Ferry #1 | 117. | 70 | 276 | 2.351 | May-67 | 3.25 | 30.03% |
| Mar-71 | Brunswick #2 | 195 | 74 | 389 | 1.995 | Feb-70 | 3.25 | 23.65% |
| Mar-70 | Indian Pt. #3 | 156 | 73 | 570 | 3.654 | Aug-69 | 3.25 | 48.90% |
| Mar-71 | Millstone #2 | 239 | 74 | 426 | 1.784 | Dec-70 | 3.25 | 19.46% |
| Mar-71 | Prairie Is. #2 | 130 | 74 | 177 | 1.362 | Jun-68 | 3.25 | 9.95% |
| Mar-71 | St. Lucie 1 | 200 | 74 | 486 | 2.431 | Jul-70 | 3.25 | 31.38% |
| Mar-67 | Vermont Yankee | 88 | 70 | 185 | 2.097 | Dec-67 | 3.25 | 25.54% |
| Mar-68 | Oconee #1 | 93 | 71 | 156 | 1.673 | Nov-67 | 3.25 | 17.15% |
| Mar-68 | Surry #1 | 144 | 71 | 247 | 1.713 | Jun-68 | 3.25 | 18.00% |
| Mar-68 | Three Mile Is. | 124 | 71 | 401 | 3.233 | Nov-69 | 3.25 | 43.45% |
| 4>t>3 | | | | | 2.437 | | | 26.69% |
| Sep-70 | Arkansas 1 | 152 | 73 | 239 | 1.571 | Dec-68 | 2.75 | 17.85% |
| Sep-70 | Beaver Valley #1 | 192 | 73 | 599 | 3.118 | Jun-70 | 2.75 | 51.20% |
| Sep-69 | Browns Ferry #2 | 168 | 72 | 276 | 1.644 | May-67 | 2.75 | 19.81% |

| estdate | plant | est cost | est cod | actl cost | cstrat | CPIS | esttime | myopia |
|---|---|---|---|---|---|---|---|---|
| Sep-70 | D.Arnold | 156 | 73 | 280 | 1.794 | Jun-70 | 2.75 | 23.68% |
| Sep-70 | Hatch 1 | 184 | 73 | 390 | 2.122 | Sep-69 | 2.75 | 31.45% |
| Sep-69 | Indian Pt. #3 | 156 | 72 | 570 | 3.654 | Aug-69 | 2.75 | 60.17% |
| Sep-70 | Indian Pt. #3 | 218 | 73 | 570 | 2.615 | Aug-69 | 2.75 | 41.82% |
| Sep-69 | Kewaunee | 109 | 72 | 203 | 1.866 | Aug-68 | 2.75 | 25.46% |
| Sep-69 | Oconee #2 | 97 | 72 | 160 | 1.654 | Nov-67 | 2.75 | 20.06% |
| Sep-70 | Oconee #3 | 109 | 73 | 160 | 1.472 | Nov-67 | 2.75 | 15.08% |
| Sep-70 | Peach Bottom #3 | 221 | 73 | 377 | 1.706 | Jan-68 | 2.75 | 21.43% |
| Sep-71 | Peach Bottom #3 | 263 | 74 | 377 | 1.433 | Jan-68 | 2.75 | 13.99% |
| Sep-69 | Prairie Is. #1 | 92.5 | 72 | 233 | 2.521 | Jun-68 | 2.75 | 39.96% |
| Sep-71 | St. Lucie 1 | 203 | 74 | 486 | 2.395 | Jul-70 | 2.75 | 37.37% |
| Sep-71 | Trojan | 228 | 74 | 452 | 1.982 | Feb-71 | 2.75 | 28.25% |
| Sep-67 | Turkey Pt. #3 | 66 | 70 | 109 | 1.647 | Apr-67 | 2.75 | 19.89% |
| Sep-69 | Turkey Pt. #4 | 70 | 72 | 127 | 1.811 | Apr-67 | 2.75 | 24.11% |
| Sep-69 | Zion #1 | 205 | 72 | 276 | 1.346 | Dec-68 | 2.75 | 11.42% |
| Sep-70 | Zion #2 | 213 | 73 | 292 | 1.371 | Dec-68 | 2.75 | 12.15% |
| Sep-68 | Browns Ferry #2 | 124. | 71 | 276 | 2.218 | May-67 | 2.75 | 33.64% |
| Sep-68 | Indian Pt. #3 | 156 | 71 | 570 | 3.654 | Aug-69 | 2.75 | 60.25% |
| Sep-68 | Oconee #1 | 85 | 71 | 156 | 1.831 | Nov-67 | 2.75 | 24.61% |
| Sep-68 | Peach Bottom #2 | 163 | 71 | 377 | 2.313 | Jan-68 | 2.75 | 35.68% |
| Sep-68 | Pilgrim | 85 | 71 | 239 | 2.815 | Aug-68 | 2.75 | 45.74% |
| Mar-71 | Arkansas 1 | 159 | 73 | 239 | 1.502 | Dec-68 | 2.25 | 19.77% |
| Mar-71 | Beaver Valley #1 | 219 | 73 | 599 | 2.734 | Jun-70 | 2.25 | 56.21% |
| Mar-71 | Calvert Cliffs #1 | 170 | 73 | 431 | 2.534 | Jul-69 | 2.25 | 51.03% |
| Mar-71 | Cooper | 207 | 73 | 269 | 1.301 | Jun-68 | 2.25 | 12.38% |
| Mar-71 | D.Arnold | 148 | 73 | 280 | 1.891 | Jun-70 | 2.25 | 32.66% |
| Mar-71 | Hatch 1 | 134 | 73 | 390 | 2.913 | Sep-69 | 2.25 | 60.68% |
| Mar-71 | Indian Pt. #3 | 256 | 73 | 570 | 2.227 | Aug-69 | 2.25 | 42.62% |
| Mar-70 | Maine Yankee | 181 | 72 | 219 | 1.211 | Oct-68 | 2.25 | 8.86% |
| Mar-70 | Peach Bottom #2 | 163 | 72 | 377 | 2.313 | Jan-68 | 2.25 | 45.04% |
| Mar-70 | Three Mile Is. | 162 | 72 | 401 | 2.475 | Nov-69 | 2.25 | 49.46% |
| Mar-68 | Palisades | 89 | 70 | 147 | 1.648 | Mar-67 | 2.25 | 24.85% |
| Mar-68 | Peach Bottom #2 | 163 | 70 | 377 | 2.313 | Jan-68 | 2.25 | 45.11% |
| Mar-73 | St. Lucie 1 | 337 | 75 | 486 | 1.443 | Jul-70 | 2.25 | 17.68% |
| Mar-73 | Trojan | 284 | 75 | 452 | 1.592 | Feb-71 | 2.25 | 22.92% |
| 3>t>2 | | | | | 2.070 | | | 31.69% |