UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

before the

ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	
CONSOLIDATED EDISON OF NEW YORK, INC.	)	
(Indian Point Unit Number 2)	)	Docket Nos. 50-247-SP 50-286-SP
POWER AUTHORITY OF THE STATE OF NEW YORK	)	
(Indian Point Unit Number 3)	)	

TESTIMONY ON THE ECONOMIC COSTS OF CLOSING INDIAN POINT

Testimony of Vince Taylor

April 4, 1983

Union of Concerned Scientists
1384 Massachusetts Avenue
Cambridge, Massachusetts
02238

8304140168 830404
PDR ADOCK 05000247
T PDR

Q Please state your name, occupation, and business address.

A. My name is Vince Taylor. I am a senior economist for the Union of Concerned Scientists. My business address is 21 Elm Ave., Richford, Vermont, 05476.

Q. Please state your professional qualifications.

A. I have attached a summary of my professional experience and publications as Exhibit I.

Q. What are the purposes of your testimony?

A. The purposes of my testimony are: 1) to explain how the economic costs of closing the Indian Point nuclear plants should be calculated, 2) to provide an informed estimate of these costs, and 3) to review and comment upon previously made estimates of these costs, with particular emphasis on a study of the Rand Corporation.

Q. Would you briefly summarize the previous studies that you will consider in your testimony.

A. There are three studies: 1) In a November 1980 report, the General Accounting Office (GAO) estimated that the near-term costs of shutting down Indian Point 2 and 3 nuclear plants would exceed $600 million in the first year and that the 15 year cost to New York City ratepayers of a shutdown could be over $18 billion.[1] The near-term cost represented the GAO's estimate of the cost of replacing the lost nuclear generation with oil-fired generation, based upon information supplied by Consolidated Edison of New York (Con-Ed). The $18 billion fifteen-year figure represented estimates of the incremental revenue requirements (those above requirements with Indian Point open) of Con-Ed. The incremental revenue estimates were from a study performed for Con-Ed by Stone and Webster

Closing of Indian Point would also raise costs for the Power Authority of the State of New York (PASNY) and the GAO estimated that incremental revenue requirements for PASNY could amount "to as much as $600 million annually." (GAO Report, p.i.) No duration for this incremental cost was specified.

2) In a response to the GAO report (Exhibit II, attached) prepared for the Union of Concerned Scientists (UCS), co-authored with Charles Komanoff, I documented that the near-term costs of replacing the lost nuclear generation would be approximately $340 million per year and

that the upper limit of these costs in the longer-run would be $292 million per year (costs in 1980 dollars) if new coal capacity were built to replace the closed nuclear capacity.[2] Closing Indian Point would also avoid prospective major one-time expenditures to meet new safety requirements and for repairs to steam generators. I estimated these avoided expenses (savings from closure) to be $375-575 million, with a significant chance that the upper end of this range would be exceeded.

Because the GAO report did not make a comprehensive estimate of the total expected costs of closure, I did not attempt to make such an estimate in the UCS response to the GAO report. If my upper-limit estimates of replacement generating costs were summed for 15 years and the one-time savings subtracted, the figure would be $4.4 billion (1980 dollars), compared to the $18 billion plus figure cited by the GAO. I wish to stress, however, that $4.4 billion does <u>not</u> represent an accurate estimate of the economic costs of shutting Indian Point. For a number of reasons to be explained later, the economic cost would be substantially less than $4.4 billion.

The GAO has made no public response to the UCS critical evaluation.

3) Subsequently, PASNY hired the Rand Corporation to make a new estimate of the costs of closing Indian Point. Rand concluded that the costs "may lie anywhere between $7.7 billion and $17.4 billion" (in discounted 1980 dollars).[3] The authors state that their estimate can be compared to "<u>implicit</u> total cost estimates of $9.3 billion . . . , and $2.5 billion" by the GAO and UCS, respectively.*

---

* The Rand report also attributes an estimate of $4.0 billion to the Congressional Research Service (CRS), based on its published response to the original GAO report.[4] The CRS analysis focused on the question of how ratepayers and stockholders of Con-Ed should share any costs incurred by a shutdown. It did not purport to be a comprehensive analysis of the costs of shutdown and, therefore, did not consider many questions relevant to such an analysis. Rand produced the "CRS estimate" cited in its report by translating the fragmentary, qualitative criticisms of CRS into quantitative adjustments to GAO's estimates. The resulting figure is <u>not</u> a meaningful, independent estimate of the total costs of closure, as Rand attempts to suggest. To include it in the comparisons provides a false sense of comprehensiveness. I therefore omit the CRS estimate in the following discussion.

Q. Please describe Rand's methodology more fully.

A. The Rand estimates were intended to be comprehensive estimates of all of the additional costs (after netting out savings) that would be borne by the U.S. economy if the Indian Point units were "shut down immediately rather than at the end of their normally scheduled lives." (p.3.)* Rand terms these added costs incremental costs and distinguishes them from expenses that have already been incurred (sunk costs) or that would be incurred whether or not Indian Point is closed (unavoidable costs). Rand points out, correctly, that only incremental costs are relevant to the decision on whether or not to close the units.

Rand presents estimates of the total sum of the incremental costs of closure in terms of discounted 1980 dollars. By using 1980 dollars Rand eliminates inflation from the analysis. All future costs are calculated in dollars of the same purchasing power (that of 1980). Additionally, future costs are discounted back to 1980 at the compound interest rate of 5 percent per year. Thus a dollar of cost incurred in 1990 is discounted to \$.61 ($\$1/1.05^{10}$) in calculating the discounted cost of closure.

The rationale for discounting when summing costs and savings that occur at different times is that dollars in hand today are worth more (even aside from inflation) than those to be received (or paid) in the future. Fundamentally, this is because a dollar productively invested today will produce over its lifetime more than a dollar of additional output, that is, it will earn a positive rate of return. If society can invest and earn a 5 percent rate of return per year, it would be equally well off with an extra \$.61 today or an extra \$1.00 ($\$.61 \times 1.05^{10}$) ten years hence.

The rate of return on investment (after abstracting from inflation) is the appropriate rate to use in discounting. Because the economy has been so volatile during the past decade (and the future so uncertain), the choice of discount rate to use in the present case is not a simple matter. Rand considers a range of discount rates and uses 5 percent per

---

* All page references are to Reference 3 unless otherwise noted.

year in its final estimates and comparisons. I accept the 5 percent figure as a reasonable basis for comparing the various estimates of the cost of closure.

Rand considered four categories of costs in making its estimates of the total cost of closure:

> 1. Generating costs include all of the extra costs directly resulting from generating the required electricity at another, more costly, facility after Indian Point is shut down.
>
> 2. One-time costs include all of the one-time costs of decommissioning Indian Point and disposing of the spent fuel as well as all of the one-time savings associated with the now-planned activities and back-fits that will not be needed if Indian Point is shut down.
>
> 3. Business costs include all of the increased financial costs, the increased returns that will be demanded in both the bond market and the stock market if ConEd and PASNY attempt to remain viable and to continue to supply electricity to their service area after the Indian Point units are shut down.
>
> 4. Secondary costs include the indirect costs--the second, third, and later-round effects that are induced, or flow from, the imposition of the other costs. . . (p.4.)

High and low estimates were made for each category and combined to yield total high and low estimates.

Q. Did Rand accurately represent the estimates of the original GAO and UCS estimates and compare them fairly to the Rand estimates?

A. No, Rand did not. It attributed "implicit" total cost estimates of closure of $9.3 billion to the GAO report and $2.5 billion to the UCS report and compared them to its own range of $7.7 billion to $17.4 billion.

This comparison can be interpreted as lending strong support to the competence of the original GAO estimate and to repudiate the UCS estimate. The estimate attributed to the GAO appears prudently conservative compared to those of Rand, whereas the one attributed to UCS lies far below the bottom of Rand's range. The superficial impression conveyed by the summary comparison is not supported by the body of the document. A careful reading of the entire report reveals that <u>on almost every point of difference between the GAO and UCS on fact and economics, Rand sides with UCS</u>. In making its own estimates of the cost of closure, Rand essentially accepted the UCS estimates of the annual cost of replacement power and the

net, one-time savings from closure. These were the major items considered in the UCS analysis. These provide, as stated in the UCS report, an upper limit to the costs of closing Indian Point.

The Rand summary misleads the reader by representing that the GAO, UCS, and Rand estimates given there are comparable (arrived at by "applying a common set of assumptions and converting to common dollars," p.3). They are not. Rand's estimates include a major item, "secondary costs" (with a range of $2.3 to $6.9 billion), not even considered by the other estimators, and Rand's total cost estimate spans 25 years, whereas the figures cited for the GAO and UCS over only 12 years. Furthermore, the figure cited as the "GAO estimate" is not based on the estimates of the cost of replacement generation originally reported by the GAO. These estimates were first revised sharply downward by Rand (ironically enough, by making corrections suggested by UCS) before the summary figure was calculated. These elements of non-comparability expand the Rand estimate and shrink the GAO estimate from its original value so that the two appear in reasonable agreement.

Q. Do you accept as accurate the $2.5 billion estimate of the total costs of closure attributed to UCS by Rand?

A. No. This estimate was generated by Rand from estimates of replacement generating costs and one-time savings presented in the original UCS report. These were labeled in that report as <u>upper limit</u> costs because they did not take into account consumer responses to higher electricity prices, responses that would reduce the total cost to the economy. Taking these responses into account would produce a much lower estimate of total cost of closure.

Q. Have you prepared a comprehensive estimate of the total costs of closing Indian Point, taking into account the cost-reducing responses of consumers to higher electricity prices? If so, what is its value?

A. I have prepared a comprehensive estimate of costs of closure that is directly comparable to Rand's estimated range of $7.7 to $17.4 billion (discounted 1980 dollars). My estimate is $0.8 to 0.9 billion (discounted 1980 dollars). The basis for this calculation is described fully later in my testimony.

Q. Could you explain why your estimate is so much lower than Rand's?

A. My estimate is based on the same assumptions as Rand's with respect

to plant lifetime, treatment of inflation, and discount rate. There is little difference between my and Rand's estimates of replacement generating costs and one-time savings. The great difference arises in Rand's categories of business and secondary costs. Whereas Rand assigns large positive values to these categories ($3.3 to $12.8 billion for the two together), I find no evidence or reason to believe "business costs" (beyond those accounted for under replacement generating costs) would be significant, and I estimate that rather than resulting in added costs, the secondary effects (responses of consumers) would offset much of the initial cost impact. Thus, while consumers would initially bear the costs of replacing all of the generation lost by closing Indian Point, they would, over time, reduce their consumption of the higher-priced electricity, reducing the amount (and cost) of replacement generation. The reductions in electricity use would occur both because consumers would use electricity more efficiently and because they would shift some expenditure away from electricity to other goods (pure conservation). My estimate, the details of which are presented later, is that secondary responses will offset $3.2 billion of the estimated replacement generation costs of $4.4 billion (in discounted 1980 dollars). Taking into account the discounted value of one-time savings ($0.3 to $0.4 billion), I arrive at the comprehensive estimate of the costs of closure of $0.8 to 0.9 billion.

Q. Do you believe that actual closure costs could fall below $0.8 billion?

A. Yes. To make my estimate closely comparable to Rand's, except in the treatment of business and secondary costs, I accepted several assumptions that are not realistic and that bias my cost estimate upwards:

1) I used Rand's assumption that both Indian Point reactors would, in the absence of a regulatory order to shut down, operate for 25 more years (through 2005). This would imply lifespans of 32 years for Indian Point 3. No commercial reactors have operated this long, and several early power reactors (including Indian Point 1) have been shut down permanently well before this age by a combination of rising safety requirements and declining operating reliability; thus this is a highly questionable assumption.

2) I considered only near-term, one-time savings from closure in the original UCS report, and I did not revise this estimate of one-time savings. More distant major repairs, such as steam-generator replacement or treatment

for reactor-vessel embrittlement, and the imposition of major new safety requirements would be nearly certain to occur if the plants operated for another 25 years. These more distant one-time costs would be avoided by closure.

3) I used the historical average capacity factor of Indian Point reported in the original UCS report (57 percent) in calculating replacement generation. This average was based on data through December 1980.* Adding data for 1981 reduces the cumulative average for both reactors to 52 percent. Moreover, Indian Point 3 was shut down in late March 1982 for repairs to steam generators and will not return to service until September, at the earliest; thus it will be hard pressed in 1982 to match the dismal 36 percent capacity factors of 1980 and 1981. Thus the outlook is for a still lower cumulative capacity factor at the end of 1982. Using the cumulative capacity factors through 1981 in the calculations would reduce the estimated incremental costs of closure (and secondary offsets to these costs) by 9 percent.

Q. Can you explain more fully the differences between your and Rand's estimates?

A. Yes. I would like to explain these differences as part of an overall review of the Rand report. In the course of this review, I will:

1) note Rand's disclaimer of any independent expertise with respect to the data and methodologies underlying its estimates of the cost of closing Indian Point,
2) explain why Rand's comparisons of estimates of incremental generating costs are misleading,
3) show that Rand rejected most of the GAO cost estimates and accepted many of the UCS estimates,
4) show that Rand's estimates of "business costs" are without foundation,
5) explain how Rand erred in its treatment of "secondary costs,"
6) explain and document the economically correct way to calculate the effects of secondary responses by consumers on the comprehensive costs of closure, and
7) present a detailed calculation of the correctly estimated total costs of closing Indian Point.

---

* Excluding initial operation for Unit 2 in late 1973 and for Unit 3 in late 1976, during which the two units performed poorly and well, respectively.

Rand's Disclaimer of Competence

At the outset, Rand disclaims any independent expertise with respect to the data or methodologies that underlie its estimates of the cost of closing Indian Point:

> At the request of the Power Authority [of the State of New York], all materials used in constructing the cost estimations were obtained from the open literature. The authors of the report reviewed the available literature on the economic impact of closing the Indian Point facilities. In so doing, they made no attempt to verify either the underlying facts or the methodologies used in any of the studies cited herein, and they do not comment on the accuracy or reliability of those facts or methodologies. (Preface, p. iii, emphasis added.)

Having so restricted themselves, the authors would seem to have disqualified themselves from making any meaningful contribution to the debate over the costs of closing Indian Point, since the"accuracy and reliability" of the competing facts and methodologies are the essence of the matter at hand. If Rand cannot attest to the accuracy of the facts on which it bases its estimates, of what value are its estimates?

Although, in fact, the Rand researchers do exercise their own judgement in choosing among competing "facts" and estimates, they retreat to their "non-expert" position at crucial points. For example, in discussing business costs, they note that the only analysis of such costs in the reports reviewed were provided to the GAO by "Stone and Webster, a management consulting firm specializing in utility finance*," and that "the GAO documents that analysis strictly as a 'black box' exercise," meaning that no supporting evidence or methodology were given (p.35). They continue, "[B]ecause of the limited documentation of that [Stone and Webster] analysis [of business costs], we have little basis for developing a reasonable and defensible estimate of their magnitude at this time." (p.36.) This does not, however, deter Rand: "We do believe these costs could easily

---

* Not mentioned but certainly relevant, Stone and Webster is also one of the nation's largest architect-engineering firms engaged in constructing nuclear plants, including the two nuclear plants still under construction in New York State.

amount to $1 billion. So we use that as our lower estimate." (p.36, emphasis added.) Belief is the only basis given for this lower estimate! The Rand researchers base their upper estimate of business costs on the undocumented, unsubstantiated Stone and Webster estimate (of $5.0 billion), which they adjust upward* to $5.9 billion. (p.36.)

In this instance, Rand's selected use of a "non-expert" position allows it to accept and use an unsubstantiated figure that constitutes one-third of its high estimate of the total cost of closure.

Throughout the report, the restrictive ground rules set out by the Rand researchers are used to justify the "inability" to go beyond the GAO, UCS, and CRS reports for additional information to use to choose among competing assertions. For example, in examining estimates of replacement generating costs, Rand notes that, "The GAO does not explain or question the GE model it uses. Thus the causes of the large cost [estimate used by the GAO] for substitute generation remain obscure." (p.18.) Rather than pursuing the matter further, however, Rand states "In the absence of other information, our estimates must rely on the GE model output and the independent UCS estimates." (p.23.)

The UCS estimates were backed up by extensive, published, publicly available documentation. Rand could have pursued this documentation and used it to provide an independent, expert judgement of whether the GAO or UCS estimates were more realistic. This Rand authors chose not to do. Rather, they accepted the undocumented GAO estimate as the initial basis for their "high estimate" of replacement generating costs** and the UCS estimates for their own "low estimate."

---

* On extremely tenuous grounds. Rand's high estimate of replacement generating costs was 18 percent higher than the (Rand-corrected) GAO estimate of such costs, (reflecting the combined effects of Rand's longer time horizon and its discounting of future costs). The Rand authors' "thought it might be more realistic to relate the business costs to the generating costs." Thus they increased the $5.0 billion estimate of Stone and Webster by 18 percent to $5.9 billion.

** But then, inconsistently, adjusted them downward to almost the level of the UCS estimates.

By disqualifying themselves from judging the accuracy or reliability of the competing estimates, the Rand researchers have equally disqualified the accuracy and reliability of their own estimates, which are derived from the competing estimates.

Rand presents a range of estimates of the cost of closure, $7.7 to $17.4 billion, and attributes the large width of this range to "uncertainty." In reality, the width reflects the unwillingness of the Rand researchers to pursue an independent assessment of the facts in order to make an informed judgement of probable costs. The wide range of Rand estimates is more accurately attributable to ignorance -- ignorance that is primarily self-imposed.

Misleading Comparisons of Generating Costs

A major part of the cost of closing the Indian Point plants would be the cost of replacing the foregone nuclear generation. Rand terms this the incremental generating cost. Incremental costs would be incurred throughout the lifespan the plants would have in the absence of a decision to close them.

The Rand report states that:

> To construct an estimate of the total incremental generating costs that would be required by the closure of the Indian Point nuclear units we must sum the individual yearly estimates, and to do that we must discount the costs that would be incurred in years later than 1981 so as to properly represent the present value of the cost stream. (p.21.)

The discounted (present) value of future, annual incremental costs provides a meaningful estimate of the recurring costs associated with closure of Indian Point. Summing over the next 25 years may be, as Rand recommends, an appropriate time horizon, if the plants would remain operable for that long in the absence of a regulatory decision to close them. As noted previously, this assumption is questionable. Further, Rand does not consider the possibility of future major expenditures, if the nuclear plants continue to operate for 25 more years, to meet unknown but probable future regulatory upgrades and to provide for major overhauls of the plants. Rand estimates, thus, are biased upwards.

But even accepting the Rand assumptions as valid basis for comparison, they are not applied uniformly to the original GAO and UCS estimates to provide a fair means of comparing them.

Revisions of the original GAO estimates

The GAO estimates of replacement generating costs for the years 1982-92, as originally published, are not used by Rand. Rand arbitrarily deflated them by 9 percent per year, removing a major cause of the high estimate of closure costs originally reported by the GAO and a major objection of UCS to the original GAO estimate. Rand recognizes the impropriety of the original GAO methodology when discussing the affects of discounting on the calculated costs of closure:

> It [the GAO] assumes nearly a 10 percent inflation rate and does not discount. That assumption has deservedly exposed the GAO report to much criticism. (pp.24 and 25, emphasis added.)

Rand also subtracts the amount of taxes included in the original GAO estimates ($607 million for the 12 year period considered), stating "we agree with the UCS report that taxes paid on increased fuel inventories are not, properly speaking, resource costs; they simply represent transfers from the utilities to the state." (p.13.)

Finally, Rand changes the GAO assumption of a 69 percent future capacity factor for Indian Point to 60 percent, reducing the GAO estimates of incremental generating costs by an additional 13 percent.*

The Rand adjustments reduce the GAO's estimate of 12 years of closure costs from the original figure of $9.8 billion to $4.2 billion.

I do not object to Rand's making these adjustments to the GAO figures, in fact I applaud them but I do consider it misleading and objectionable to represent the adjusted figures as "GAO estimates," as the Rand report does in its Summary, in all of its figures that compare the various estimates, and in much of the discussion of the alternative estimates.

---

* But still not reducing it to a level that can be justified on the basis of historical operating experience.

Use of unequal time horizon

Rand compounds the misleading nature of its comparisons of total incremental costs by summing the GAO and UCS estimates of annual costs for 12 years but summing its own estimates for 25 years. This creates an enormous upward bias in the comparative Rand estimate, essentialy doubling it on an undiscounted basis from the value it would have had if calculated identically to the GAO and UCS estimates.

The Rand researchers do not try to hide this most peculiar and unnecessary divergence from comparability, but only the careful reader will detect it, especially since the Rand report mentions it only in the section on incremental costs and even there treats the 12 and 25 year estimates as though they were strictly comparable. The concluding paragraph in the section on incremental generating costs read:

> The Rand estimates, since they are based on 25 years of costs rather than only 12, are significantly larger than the others, especially at the lower rates of net discount. At the 5 percent net discount rate, however, our estimates are only slightly above the original [sic!] GAO estimate. Ours are $4.6 billion and $4.8 billion, while the GAO estimate is right at $4.1 billion. (p.25.)

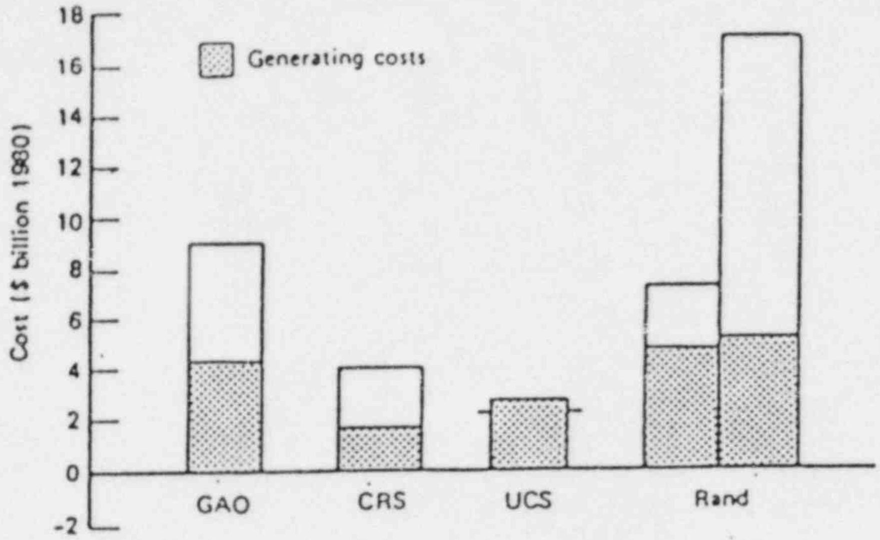
Implicit in this discussion is the assumption that the 12 and 25 year estimates are comparable, for otherwise the discussion would be meaningless--which of course it is.

Treating the 12 and 25 year estimates as though they are strictly comparable causes Figures 4 and 5 of the Rand report (reproduced here) to be extremely misleading. Exactly how misleading can be judged by the fact that the low Rand estimate and the UCS estimate of incremental generating costs that underlie these figures are identical, except that the 12th year UCS figure has been carried forward for 13 more years to produce the Rand estimate.

Rand has no quarrel with the UCS estimate of incremental generating costs, stating "As our lower estimate of incremental generating costs, we adopt the UCS estimate. The UCS report contends that the GAO estimates are too high and it presents reasonably well documented alternatives."* (p.22.) Further, Rand modified GAO's estimates, based on UCS

---

* Rand does make an unwarranted but relatively minor upward adjustment in the post-1987 UCS estimates, increasing them over our original values by $24 million per year. Evidently Rand did not understand that the higher, long-run nuclear O&M estimate we used reflects an empirical trend of rising, real O&M costs.



NOTE: Estimates are based on 5 percent annual rate of discount and assume that future inflation rate for these costs is equal to the general rate for the U.S. economy.

Fig. 4—Estimates of incremental generating costs

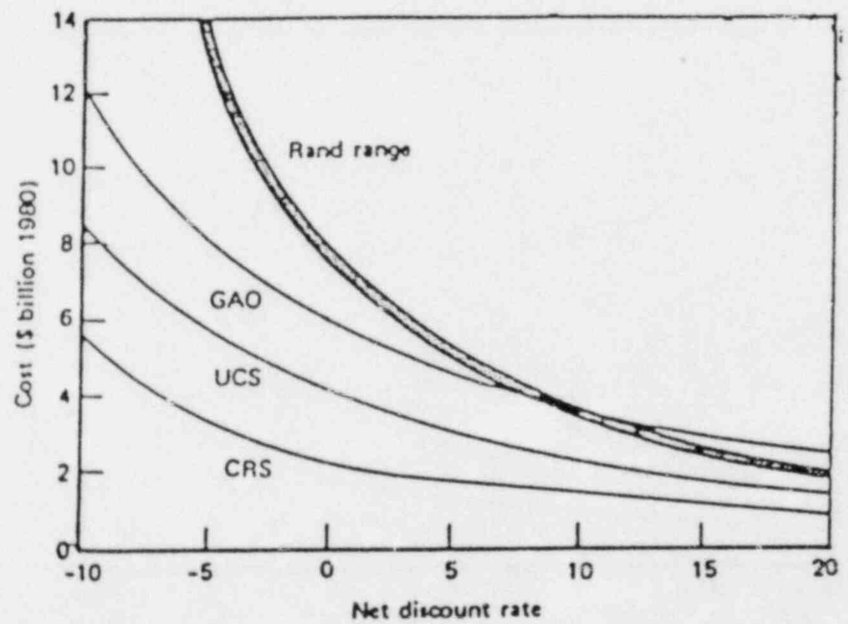


Fig. 5—Sensitivity of generating costs to the net discount rate

criticisms, so that its high estimate is virtually identical to the UCS-based low estimate.*

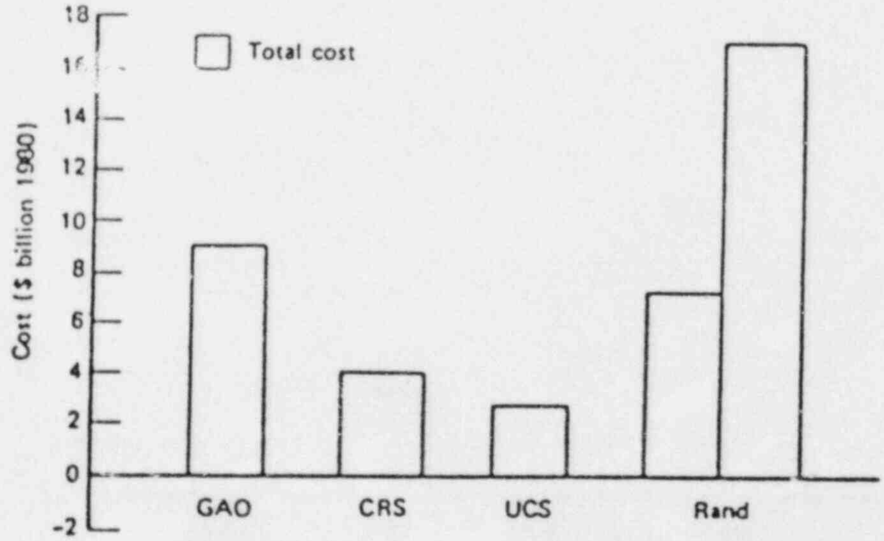
Yet although the Rand and UCS estimates are virtually identical and the original, unadjusted GAO estimates were much higher than Rand's estimates, Rand's Figures 4 and 5 convey exactly the opposite impression. The GAO and Rand estimates are represented as being close together, and the UCS estimates substantially smaller.

Assertion of comparability

I have dwelt at length on the misleading character of Rand's supposedly comparable estimates becasue the Rand report explicitly states that:

> Working primarily with their [UCS, GAO, and CRS] cost estimates, but applying a common set of assumptions and converting all data to common dollars, we estimate the total cost implicit in each of the three reports, and we synthesize from those three studies and from other generic material a range of total costs for closing Indian Point that we believe to be reasonably accurate. (p.3.)

The reader is told that the estimates generated by Rand are based on common assumptions and reported in common dollars; they are represented as being strictly comparable. Thus, what is the reader to think when shortly thereafter he or she is presented with Figure 3 (reproduced here) of the Rand report?



NOTE: Estimates are based on 5 percent annual rate of discount and assume that future inflation rate for these costs is equal to the general rate for the U.S. economy.

Fig. 3—Estimates of total costs of closure

---

* See Table 6, p.23.

What else except that the UCS estimates are unreasonably low, and that the GAO and Rand are in relatively good agreement?

Rand Criticizes the GAO and Agrees with UCS on Many Points

Because the summary figures of the Rand report convey a superficial impression of close agreement between the GAO and Rand, I want to emphasize that in many of the details, Rand was critical of the GAO and accepted the UCS estimates. A number of these points were quoted earlier. Consider also the following:

> We question the GAO's estimates of generating costs primarily because they rely on an undocumented costing model, unrealistic projections of IP-2 and IP-3's production capacity, an inadequate treatment of operation and maintenance costs, and an abbreviated time horizon. (p.18)

> The GAO does not explain or question the GE model it uses. Thus the causes of the large cost for substitute generation remain obscure . . . . We need to obtain and review the full output of the GE model before we can give full credibility to its output. (p.18.)

> The 69 percent production capacity used in the GE simulations and accepted by the GAO appears unjustified. The GAO never attempts to justify this figure; it just adopts it. We believe the national average of 60 percent would be a much more reasonable estimate for Indian Point's capacity over the next 12 years, particularly as the IP units have seldom achieved even that level . . . .* (pp.18-19.)

> The GAO assumes that Indian Point O&M costs would continue, apparently through 1992, even though the plant would be dismantled over a six-year period. We agree with the CRS and UCS that this is not proper . . . . (p.20.)

> We do not count the write-offs [of past investments] as part of closure costs. We feel they are expenses that have already been incurred. We agree with the UCS that they are sunk costs; they represent items that have already been used, or at least firmly contracted for, and thus will not be affected by the decision on the early closure petition. (pp.31-32)

---

* The historical cumulative average through December 1980 was 57 percent, the figure used by UCS in its analysis. By the end of 1981, the cumulative capacity factor had dropped to 52 percent (see prior discussion).

Concerning the one-time savings, we accept the ones suggested by the GAO and some portion of the additional safety-related costs discussed by the UCS. We believe there is no way to foretell the full total cost of required modifications. UCS places the estimate somewhere between \$153 million and \$353 million. We use their midpoint of \$253 million although we realize that it may turn out to be much higher.* (p.32.)

Close Agreement of Rand and UCS on
Incremental Generating Costs and One-Time
Costs and Savings

When Rand and UCS estimates are placed on a truly comparable basis, those for incremental costs and one-time costs and savings are in close agreement. This can be demonstrated by modifying the entries in Rand's Table 12 to make the estimates cover the same 25-year time horizon. I have done this, while simultaneously making several changes in the UCS estimates to restore them to the values originally reported by UCS.** In the original report, I did not make an estimate of decommissioning costs because I was not attempting a present-value calculation, to which they are relevant. For purposes of the present comparison, I accept the GAO-Rand point estimate, although I want to emphasize that I consider it almost pure speculation. Reliable estimates will not be available until after dismantlement of a large reactor has been attempted.

Table A presents both the original and modified estimates for Rand and UCS. As can be seen, when placed on a truly comparable basis, the Rand and UCS estimates are very close together. This closeness reflects Rand's acceptance of UCS's estimates in almost all cases.

---

* Except that Rand uses the mid-point rather than the range of UCS estimates, Rand's and UCS's estimates of one-time savings from closure are identical. See Tables 9 and 10, pp.30 & 32. Note that the last two columns of Table 9 are mislabeled with "CRS" rather than "UCS".

** These changes consist of 1) reducing the post-1987 incremental generating costs (see Table 3, Rand report) by \$24 million per year, 2) reducing non-recurring writeoffs on fuel to \$20 million, and 3) restoring the range of non-recurring savings (\$375-\$575 million) originally reported

Table A

Estimates of Selected Components of the
Cost of Closing Indian Point
(Billions of 1980 dollars)

	UCS		Rand
	Original (12 years)	Modified (25 years)	(25 years)
Undiscounted			
Generating Costs	3.9	7.6	8.0-8.2
One-Time Costs	0.0	0.0	0.0
One-Time Savings	(0.5)	(0.5)	(0.5)
Total	3.4	7.1	7.5-7.7
Discounted at 5%			
Generating Costs	2.9	4.4	4.6-4.8
One-Time Costs	0.0	0.1	0.1
One-Time Savings	(.4)	(.3-.4)	(.3)
Total	2.5	4.1-4.2	4.4-4.6

Rand's Estimates of Business Costs Have No Foundation

Rand defines the "business costs" of closure as those costs that would be incurred in addition to costs of replacement generation and obvious one-time costs and savings. Business costs include "such things as construction programs, financing options, and dividend policies . . . . They represent costs that will need to be incurred if Indian Point is closed and the utilities are to remain viable . . . " (p. 35.)

Rand's derivation of business costs (from Stone and Webster's "black Box" exercise) was reviewed in a previous section. The authors made high and low estimates in spite of their explicit recognition that, "we have little basis for developing a reasonable and defensible estimate of their magnitude at this time." (p.47.) The higher value they choose exceeds their high estimate of replacement generating costs ($10 billion versus $8.2 billion, undiscounted, Table 12, p.47). Yet, they are able to provide no justification for this value. Indeed, they simply accept the Stone & Webster "black box" estimate.*

Rand's method of estimating business costs fail to meet normal, minimum standards of scholarship. Rand needs to determine to what extent the costs of Con-Ed and PASNY will be increased by the closure of Indian Point beyond the incremental generation and one-time costs, which are calculated separately. In the Stone and Webster cases used by Rand to determine "business costs," items are varied, as UCS pointed out in its critique of the GAO report, that have nothing to do with the closure of Indian Point. As compared to the base case, the Indian Point closure case assumes a) higher rates of return on investment for Con-Ed, b) improved cash flow (accounting for over $2 billion), c) higher dividends to Con-Ed stockholders. These assumptions, which imply closure of Indian Point will bring great benefit to Con-Ed stockholders (at great expense to ratepayers), account for a major (but unspecified) portion of the cost increase over the

* It is notable that the entire section on business costs is two and a half pages, whereas 20 pages are devoted to incremental generating and one-time costs.

base case that Rand assigns to business costs. There is simply no valid way of using the Stone and Webster analysis, as presented, to derive a meaningful estimate of business costs as defined by Rand.

More fundamentally, aside from the absence of any reliable empirical estimate of the magnitude of business costs, there is no basis for arguing that "business costs," as defined by Rand, will be significant. These are supposed to represent costs in addition to all the costs treated elsewhere. But why should there be any significant other costs? Con-Ed and PASNY will continue in business, and they should not require substantial extra staff over a long time to handle affairs above and beyond those directly connected with shutting down Indian Point and providing replacement power, the costs of which are included in other categories.

There is the suggestion in Rand's definition of business costs that, for some reason, closing Indian Point will raise the costs of non-related construction programs, require Con-Ed to raise its dividends, or require Con-Ed and PASNY to pay higher interest rates to borrow money. But Rand presents no argument to support this vague suggestion.

It would be an argument difficult to make. The magnitude of the construction programs needed to replace Indian Point 2 and 3 (1500 megawatts of coal-fired capacity would suffice) should not strain the combined management capabilities of Con-Ed and PASNY to the point where the efficiency of other construction programs suffers. Nor would closure of Indian Point create some "special financing cost" not included in the analysis of replacement generating capacity. This analysis already allows for interest, depreciation, and return on equity and capital that are standard for the utility industry. Thus financing costs are already included.

It would be possible to argue that the regulatory decision to close Indian Point could raise investors' perceived risk of utility investment in general; thus raising the return required to attract funds and raising the overall cost of utility construction programs. A similar argument has been made in the context of supporting federal assistance in cleaning up Three Mile Island, in order to prevent GPU from going bankrupt.[5] The argument was that if GPU went bankrupt, all utilities would suffer from higher risk premiums.

Such arguments miss the point that the risk premium attached to nuclear utilities represents investors' best estimate of the additional financial risk associated with nuclear activities. These risks are real, as TMI and WPPSS* have demonstrated. They are not an artifact of administrative or regulatory decisions. To the extent that these risks are real, they cannot be reduced by regulatory permissiveness or federal subsidy. Such actions may transfer the burden of risks from one party to another (for example, from stockholders to ratepayers or taxpayers), but they will not affect the overall burden to society.

Because utilities do not operate in a competitive marketplace, regulation has the task of attempting to balance costs and risks at their optimum points. A decision to close Indian Point will change the balance of costs and risks in the utility sector, but the change will be in the direction of lesser societal risk. Indian Point is at issue in these hearings because it poses a danger to the population of the greater New York metropolitan area. Closing it and replacing it with coal-fired plants will eliminate this danger. Since Con-Ed bears some (although only a small part) of the financial risks of an Indian Point nuclear catastrophe, the risk premium associated with Con-Ed would <u>decrease</u> if Indian Point were closed

There is no theoretical or empirical justification for attributing any significant business costs, as defined by Rand, to a decision to close the Indian Point nuclear facility. The estimates of this cost category by Rand are without foundation and should be eliminated from

---

* WPPSS stands for Washington Public Power Supply System. It is now commonly pronounced WHOOPS in recognition of the financial debacle created by its ambitious 5-plant nuclear program started a decade ago and now in ruins. Estimated costs grew from $4 billion in the early 1970's to $24 billion before the impossibility of obtaining the necessary financing forced WPPS to terminate two plants between 20 and 30 percent complete (which will still incur termination expenses of about $340 million) and to suspend construction for 5 years on another plant 57 percent complete (raising estimated completion costs from $2.5 to 4.5 billion). WPPSS now faces the need to get voter approval for future bond issues, since Washington State voters recently passed an initiative to this effect. (<u>Nucleonics Week</u>, January 21, and April 22, and May 6, 1982.)

consideration.**

Q. Did Rand incorrectly estimate any other elements of closure cost?

A. Yes. Rand erred enormously in estimating what it terms secondary costs. The Rand authors stressed their belief in the importance of these costs: "We are convinced that secondary costs need to be counted and have estimated that they will range from $2 billion to nearly $7 billion [discounted 1980 dollars]." (p.40.) Secondary costs are meant to measure the cost implications of the secondary effects of higher electricity prices on the economy, and they are conceptually very important. In attempting to derive a methodology for measuirng these costs, however, Rand confused income transfers and fiscal effects with added costs. Rather than raising total economic costs, consumer responses to higher electricity prices must necessarily lower them. Families and businesses will substitute less expensive resources for the higher-priced electricity, reducing electricity consumption and, thereby, the total costs of foregoing Indian Point nuclear generation.

The section of the Rand report on secondary costs is vague and confused, making it difficult to trace the sources of error in the Rand estimates, but I will do my best. Several pages are devoted to talking about the possible effects of higher electricity prices on business, households, income, and employment, but a precise definition of secondary costs is never given. The authors stress their interest in the micro-economic detail of the effects of higher prices on types of business and households, asserting the importance of distributional issues for political decision-making. (p.39.) But, the aggregate measures of closure costs made by Rand, UCS, and the GAO are not intended to (and cannot) measure distributional effects. Thus Rand's criticism of aggregate economic models (p.39) because they don't capture such effects is misplaced. These effects do not need to be captured to accurately estimate secondary costs.

---

* It is noteworthy that the GAO, which included the Stone and Webster estimates of such costs in its Indian Point analysis, did not include any detectable allowance for added financing costs in its later study of the economic costs of closing the Zion nuclear plant located near Chicago.[6]

Rand then reviews a study of a nuclear phaseout in California. This study found that the phaseout, which would cause electricity prices to be about 15 percent higher in 1985 and 25 percent higher in 1995, would have almost no effect on the growth rate of the California economy between 1975 and 1995[7] (p.40.) Evidently, the analysis showed that secondary consumer responses would almost entirely nullify the effects of higher electricity prices on the economy. The Rand authors dismiss the relevance of this study to Indian Point on the grounds that "electricity prices in the [Indian Point] service area would increase substantially and almost immediately."(p. 40, emphasis in the original.) Although true that the increase would be immediate, it would amount to only about 10 percent.* To term this increase substantial is stretching the meaning of the word. Rand continues, "Even more important, the increase would be limited (or at least focused) on a rather small, well defined region. This could lead to changes in the location of firms and households, consequences totally ignored by other studies." (p.40, emphasis in the original.) Again, it is stretching the usual meaning of a word to term Metropolitan New York small, especially when discussing its economy.

Furthermore, the magnitude of the cost increase would not be large enough to cause many people or firms to consider relocating. For the residential customer consuming 500 kWh per month (more than the average Con-Ed customer), the increase would amount to about $5 (1980 dollars) per month. For the average New York manufacturer, a 10 percent increase in the cost of electricity would amount to an increase of just 0.2 percent in the total cost of manufacture.**

---

* The estimated immediate increase in costs is about $337 million per year. Con-Ed's 1980 revenues were estimated to equal $3,867 million (GAO Report, Table 3-12, p.47).

** Based on 1976 data for New York State for Value Added by Manufacture of $38.9 billion (Statistical Abstract of the United States, 1979, Government Printing Office, Washington, D.C.) and total electric utility revenues from Large Light and Power Sales of $754 million (Statistical Yearbook of the Electric Utility Industry, 1976, Edison Electric Institute, Washington, D.C., 1977).

Thus, the Rand reasons for rejecting the California study do not stand up to careful examination.

Without further discussion, Rand turns to its own method of estimating secondary costs: "To arrive at our estimates, we reviewed over a dozen studies that used various types of economic multipliers to trace secondary costs." (p.41.) Here is where the authors seem to have gone astray. Most of the studies reviewed treated the fiscal multiplier effects of an increase in expenditure. If I spend an extra $10, the person or store that receives it will in turn buy something else with most of it, and the recipient of that payment will also spend most of it, and so forth. Thus, the total additional purchasing power created by my initial expenditure is multiplied severalfold by the chain reaction. This fiscal-stimulus multiplier is the one taught in elementary macro-economic courses. It does not measure economic costs but the total economic stimulus flowing from an initial expenditure.

When there are unemployed resources in an area, the fiscal multiplier is useful for calculating the stimulus to employment of resources from a given investment or expenditure program. Such multipliers have no relevance to the measure of indirect costs associated with the closure of Indian Point. To use them, as Rand does, to estimate its vaguely defined "secondary costs" is an error at once so fundamental and so elementary as to raise serious questions about the competency of the Rand researchers in the field of economics.

The studies reviewed by Rand have multipliers that range from a negative value (unspecified) to 5.5. The study that produced a negative multiplier, implying consumer-response offsets greater than the initial cost increase, examined the effects of an increase in electricity prices in Buffalo, New York.[8] Rand dismisses this without evidence, simply stating:

> It is unusual to expect such a large reaction, and we view it as unrealistic, at least for a large metropolitan area such as the New York City/Westchester County service area of ConEd and PASNY. (p.42.)

The Rand review of multipliers also included a study that seems very relevant to Indian Point, although it treated a far more drastic case. This was a study of the effects of abolishing all nuclear power in Sweden by 1990, which would mean closing six operating nuclear plants

that provided 25 percent of the nations electricity in 1980 and foregoing the construction of additional, planned plants that were expected to supply 40 percent of electrical consumption in 1990.[9] This study was conducted in connection with the Swedish referendum on nuclear power held in 1980. The Rand report notes that this study "uses a multiplier of 0.7. A multiplier that is positive but less than unity indicates that the total (or welfare) costs of a particular policy are actually less than the direct costs alone would suggest."

Rand dismisses the relevance of the Swedish study, stating:

> It deals with an equilibrium situation. The markets always clear, unemployment is usually minimal, and prices and wages normally are quite flexible. Capital and labor easily substitute for all forms of energy. In such a situation, economic theory says that direct costs closely approximate total costs. (pp.33-34.)

The reference cited for the Swedish study (Reference 9) makes no mention of such a theoretical economy, but rather goes into extended detail about the dislocations and disruptions that would be caused by a nuclear prohibition. Further, the last sentence quoted above is in error. Consumers will respond to higher prices by reducing electricity consumption, thus bringing total costs below direct costs.

Throughout the section on secondary costs, the Rand authors reject the possibility that consumer responses could offset part of the direct costs. This blind spot is especially surprising because in the "Introduction," the authors explicitly recognize that:

> If the increased costs [due to closure of Indian Point] result in higher rates, and those rates reduce the use of electricity . . . . , <u>the incremental costs will be reduced</u> . . .
>
> The reports we reviewed either ignore or confuse these demand effects. We suspect that <u>they thus overestimate the incremental generating costs that would result from the closing of Indian Point by some unknown but perhaps</u> significant amount. (p.7, emphasis added.)

Having recognized the possible importance of secondary offsets, the authors immediately go on to say that estimating their magnitude will require research beyond the scope of their report; thus they propose to ignore them. As justification, they present their personal beliefs:

> We believe, however, that cost changes associated with

demand effects, while certainly important, are well within the range of uncertainty associated with the other major elements of cost, and thus should not affect our major conclusions." (p.7.)

But, it is not any great task to estimate the magnitude of the demand responses and their effect on closure costs, as I shall show later. Indeed, as has been noted, several of the studies reviewed by Rand performed this analysis for related cases.

In the face of all evidence to the contrary, much of which they marshal themselves, the Rand authors in estimating secondary costs reject those studies that have multipliers below one and focus on those that estimate (irrelevant) fiscal multipliers. In their final estimates, the Rand authors use multipliers of 1.5 and 2.5* to yield estimates of secondary costs of $2.3 to $6.9 billion discounted 1980 dollars.

Q. Could you explain how secondary costs should be calculated?

A. What Rand was evidently attempting in their section on secondary costs was commendable, that is to include economic costs not contained in the estimates of directly measured costs. Such costs (and savings) ought to be included in any comprehensive analysis. Where Rand erred was in carrying out this conceptually desirable step.

An unexpected rise in electricity prices may create temporary economic disruptions and perhaps induce some heavy users of electricity to move to lower-cost areas. These are true costs, but in the case at hand seem likely to be relatively small. As previously noted, the initial 10 percent cost increase would raise manufacturing costs by only a fraction of a percent. A rise of this amount would not disrupt the economy nor induce many firms to move.**

The major effects of a rise in electricity prices are its longer-term effects on consumer behavior. Users will cut their use of electricity by increasing the efficiency with which they use electricity (by, for example, installing more efficient appliances, air conditioners, and machinery,

---

* Which they term "conservative multipliers" (!) and justify with the statement, "which we consider most realistic," (p.45.) but with no supporting evidence.

** Firms sensitive to the cost of electricity have long since left the Con-Ed service area, which has the highest electricity rates of any metropolitan area in the continental United States.

and better insulation), by shifting some consumption to alternative fuels, and by simply consuming fewer electrical services.

The literature on the economic effects of higher energy prices is now, in the aftermath of the oil crisis, very large.[10] It is widely accepted among economists that over time, the secondary responses of consumers will offset much of the cost increases that underly a rise in overall energy prices.[11] I have shown elsewhere that, under assumptions appropriate to the U.S. economy, secondary responses would offset between 85 and 90 percent of the direct costs of a 10 percent increase in U.S. primary energy prices.* For a rise in the cost of electricity alone, the secondary offsets are a greater proportion of the initial cost increase because there are greater possibilities for substitution than for energy taken as a whole. Analyses of historical data in the U.S. suggest that the long-run elasticity of demand for electricity is in the range of -0.8 to -1.2, with -1.0 being a reasonable median estimate.[12] This means that a 10 percent increase in the price of electricity will, eventually, cause a 10 percent decrease in electricity consumption. The decrease will come about primarily because of substitution of other, cheaper resources for the higher-priced electricity.

Because the substitution possibilities for electricity (including increasing efficiency of use) are large, the final cost to society, after adjustments are made, will be only a small fraction of the initial, direct increase in cost.

<u>The magnitude of indirect monetary savings</u>

In the attached <u>Appendix</u>, I demonstrate that under assumptions appropriate to New York State, secondary consumer responses would, after consumers have had time to adjust fully to higher prices, offset 96 percent of the direct costs of a 10 percent rise in electricity prices.

This perhaps surprising result reflects the empirical evidence that there are many possibilities for substituting other resources for electricity, if a rise in prices makes such substitutions profitable.

---

* See Appendix C, Table C-1, Reference 10.

The above result applies only in the long-run, perhaps 10 to 20 years after the increase, when consumers have fully adjusted their stock of equipment, but a substantial part of the adjustment will take place quite quickly. A comprehensive econometric analysis of U.S. data found that 20 percent of the desired adjustment would take place in each year.[13] This implies that 50 percent of the total will occur within 3 years, 67 percent within 5 years, and 90 percent within 10 years.

My own research supports the conclusion that demand responds quite quickly to changes in price. I performed a detailed analysis of changes in electricity prices and sales of the Public Service Company of New Hampshire (which provides over 90 percent of the electricity consumed in New Hampshire).[14] The analysis was based on data covering the period 1960-1981. Demand responses within each of 4 customer classes were analyzed separately. Electricity prices were first adjusted for inflation; then changes in yearly electricity sales were related to the prior 3-year average of adjusted price changes. The elasticity of demand with respect to the 3-year-average price change was estimated to range from -.5 (for Industrial - Commercial and Service customers) to -1.0 (for Residential and General Service customers). For the company as a whole, the elasticity of demand with respect to the 3-year average price was -.82. This means that over the three years following a 10 percent increase in price, demand will decrease by 8 percent, other things remaining the same.

As longer-term effects of price changes were not considered in the New Hampshire analysis, the elasticity estimated there (of -.82 over 3 years) is consistent with a long-run elasticity of -1.0. The adjustment rate implied by the New Hampshire analysis is more rapid than the 20 percent rate found by the authors of Reference 13.

<u>The Cost of Closing Indian Point</u>

I have calculated the annual incremental costs of closing Indian Point, including secondary offsets. The calculations are based on the

model presented in the Appendix, with a long-run elasticity of demand of -1.0, assuming that 20 percent of the adjustment toward the desired long-run demand-level occurs each year. I used the UCS values for annual incremental generating costs of $337 for 1981-87 and $292 million thereafter. The results are presented in Table B, which also shows the discounted values of the costs of closure. The total incremental costs of closure for 25 years are $1.2 billion (discounted 1980 dollars).* Including net one-time savings (from Table A), the discounted net cost of closing Indian Point is $.8 to $.9 billion.

The Benefit of Closing Indian Point

In deciding whether or not to close Indian Point, the net economic costs of closure of approximately $1 billion need to be compared with the benefits from eliminating the risk of nuclear accidents at this facility. If there is a severe accident, millions of people and many billions of dollars of property will be at risk.

There is no agreed upon method for placing a monetary value on human life, nor can the probability of a nuclear accident at Indian Point

---

* Because most of the costs occur in the first years after shutdown, the difference between discounted and undiscounted costs is only $0.4 billion.

Table B

Incremental Costs of Closing Indian Point Allowing for Secondary Responses[1] (Millions of 1980 dollars)

Years	Incremental Costs Undiscounted	Discounted[2]
1981	273	259
1982	221	200
1983	179	155
1984	146	120
1985	119	94
1986	98	73
1987	81	57
1988	59	39
1989	49	32
1990	42	26
1991-95	140	74
1996-2000	86	36
2000-05	67	22
Totals	1560	1187

1. Based on replacement generation costs of 337 million during 1981-87 and $292 million thereafter.

2. Discounted to 1980 at 5 percent per year.

be estimated with any precision; thus no neat calculation is possible of the dollar benefits of eliminating accidents by closing Indian Point. Still, it is important to stress that closure would produce not only economic costs but economic benefits.

To illustrate the principles involved, but without attaching significance to the particular numbers used, consider the following. Suppose that each avoided death were worth $500,000 dollars and each avoided serious injury worth $50,000. Suppose further that the probability of a major accident producing 20,000 expected deaths, 50,000 serious injuries, and $40 billion in property damage and clean-up costs was one per thousand per year. Then, over the next 25 years, the probability of such an accident would be 25/1000 or 2.5 percent. The benefit of avoiding such an accident would be 20,000 x $500,000 + 50,000 x $50,000 + 40 billion = 52.5 billion. The expected value of the avoided accident would be .025 x $52.5 billion = $1.3 billion. This accident would occur on average 12.5 years in the future. Discounting by 5 percent over 12.5 years, the approximate present value of the benefit is $.7 billion.

The $.7 billion benefit figure is slightly below the calculated cost of closure of $.8 to $.9 billion. Rather modest (relative to the uncertainties involved) changes in assumptions would produce a benefit figure greater than the net cost. As all of the benefit assumptions were made merely for illustration, no special significance should be attached to the closeness of the result. To the extent, however, that the illustrative figures can be considered to be within the range of reasonableness, the result indicates that the economic dimension of the Indian Point issue is not clear cut.

Whether one judges that the benefits of closure exceed the costs depends upon the assessment probabilities and consequences of a major nuclear accident at Indian Point, an assessment impossible to conduct with any precision or confidence.

Appendix

Equilibrium Economic Costs of an Increase in Electricity Costs

Consider the following simple model:

(1) $Y = AE^{a} X^{1-a}$, where

Y = Total output (GNP)

E = Resources used to produce electricity.

X = Resources used to produce other output.

This model is appropriate for considering changes in electricity price because it implies an elasticity of substitution of 1.0, which is approximately the historical value in the U.S.*

The share of electricity in total production in New York State (in 1979) was about .036. Given the properties of the simple production function defined in (1), this implies

(2) $a = .036$

Without loss of generality, let $Y = 1.0$ and the prices of E and X(P_E and P_X) also equal 1.0, initially. Then, the value of inputs equals the value of outputs:

(3) $E_o + X_o = Y_o = 1.0$

Also, a condition of equilibrium is that:

(4) $\frac{P_E}{P_X} = \frac{a}{1-a} \cdot \frac{X}{E}$;

thus for $P_E = P_X = 1.0$,

(5) $\frac{X_o}{E_o} = \frac{1-a}{a}$,

and using (3), this can be solved to yield $X_o = .964$ and $E_o = .036$, and from (1), $A = 1.1677$.

Assume the price of E increases by 10 percent, that is $P_E^{1} = 1.1$. In the new equilibrium, $P_E^{1}/P_X^{1} = 1.1$, and

---

* The elasticity of substitution is essentially equal to the absolute value of the elasticity of demand. See Reference 12 for elasticity estimates.

$$(4') \quad \frac{a}{1-a} \cdot \frac{X_1}{E_1} = 1.1.$$

Using (3), this yields

$$X_1 = .9672 \text{ and } E_1 = .0328.$$

The new value of Y,

$$(1') \; Y, = A(E_1)^a \, (X_1)^{1-a} = .99985.$$

The loss due to the 10 percent increase in electricity costs is .015 percent of total output. The assumed initial increase in electricity costs was equal to .36 percent of total output. The final economic cost, after adjustments are made, is thus, only .015/.36, or 4 percent of the initial cost increase. The indirect savings are 96 percent of the initial cost increase.

References

1. Economic Impact of Closing the Indian Point Nuclear Facility, Report by the Comptroller General of the United States, U.S. General Accounting Office, November 7, 1980. Indian Point 1 is no longer licensed to operate and is not at issue.

2. Vince Taylor and Charles Komanoff, An Evaluation of "Economic Impact of Closing the Indian Point Nuclear Facility," A Report of the General Accounting Office, The Union of Concerned Scientists, Cambridge, Mass., December 3, 1980.

3. James Stucker, Charles Batten, Kenneth Solomon, Werner Hirsch, Costs of Closing the Indian Point Nuclear Power Plant, Rand Corporation, Santa Monica, California, R-2857-NYO, November 1981.

4. Carolyn Kay Brancato, "The Indian Point No. 2 Nuclear Facility," Congressional Research Service, December 5, 1980.

5. Made in a series of "Dear Colleague" letters from Allen Ertel (Dem., Pa.) in support of his bill (H.R. 2512) to provide increased insurance for nuclear utilities and for assistance in cleaning up TMI. Nuclear News, October 1981, p.106.

6. Economic Impact of Closing the Zion Nuclear Facility, Report of the Comptroller General, General Accounting Office, Washington, D.C., EMD-82.3, October 21, 1981.

7. Martin L. Baughman et al., Direct and Indirect Economic, Social, and Environmental Impacts of the Passage of the California Nuclear Power Plants Initiative, Center for Energy Studies, University of Texas at Austin, FEA/G-76/261, April 1976

8. J. H. Savitt, Electric Energy Usage and Regional Economic Development, Final Report, EPRI, Palo Alto, California, ES-187, August 1976.

9. Konsekvensutredningen, Suppose We Go Non-Nuclear....? Effects on the Economy, Employment, and the Environment in Sweden, Departementens Offsetcentral, Stockholm, 1980.

10. Vince Taylor, Energy: The Easy Path, Union of Concerned Scientists, Cambridge, Mass., January 1, 1979, explains in detail the potential for such responses and provides references to other literature.

11. William Hogan and Alan Manne, "Energy - Economy Interactions: The Fable of the Elephant and the Rabbit," in Modeling Energy - Economy Interactions: Five Approaches, Charles Hitch (Ed.), Resources for the Future, Washington, D.C., R-5, 1977, shows the basic economic reasoning behind this conclusion.

12. Lester Taylor "The Demand for Energy: A Survey of Price and Income Elasticities," in International Studies of the Demand for Energy, William Nordhaus (Ed.), North-Holland Publishing Co., New York, 1977.

13. Tim Mount and Tim Tyrell, Energy Demand: Conservation, Taxation, and Growth, Appendix to Chapter B, Report of the Panel on Energy Demand and Conservation of the Committee on Nuclear Energy and Alternative Energy Systems (CONAES), National Research Council, National Academy of Science, Washington, D.C., published as Cornell Agricultural Staff Paper No. 77-33, August 1977. See Table 2, p.18.

14. Testimony of Vince Taylor, Investigation Into The Supply And Demand For Electricity, Public Service Company of New Hampshire, New Hampshire Public Utilities Commission, Docket DE 81-312, October 8, 1982

AFFIDAVIT

State of Vermont
County of Franklin

On this 4th day of April, 1983, before me personally appeared Vince Taylor to me known and known to me to be the individual who executed the foregoing testimony and he thereupon duly acknowledged to me that he executed the same.

Vince Taylor

Before me
Pauline Lucie, Notary Public
Term Expires Feb 1987

EXHIBIT I

VINCENT D. TAYLOR
PROFESSIONAL QUALIFICATIONS

EDUCATION:

Bachelor of Science in Physics, California Institute of Technology, 1958.

Doctor of Philosophy in Economics, Massachusetts Institute of Technology, 1964.

PROFESSIONAL EXPERIENCE:

Economics Department, Rand Corporation, Santa Monica, California, 1961-1969; consultant to Capital Research, Inc., Los Angeles, on security selection, 1970-1973; senior staff member of Pan Heuristics, Los Angeles (a division of Science Application, Inc., La Jolla, California), 1974-1978; energy consultant to the Union of Concerned Scientists, 1979; senior staff of the Union of Concerned Scientists, 1980-82; economic consultant, 1982 to present.

PROFESSIONAL EXPERIENCE IN ENERGY-RELATED RESEARCH:

Beginning in 1974, my professional work has been exclusively on the economics of energy, with particular emphasis on the comparative economics of nuclear power and its alternatives. During the period 1974-1982, I performed research and wrote reports and articles on: the comparative economics of nuclear and coal generated electricity, forecasts of the future demand for energy, electricity, and nuclear electricity, the comparative economics of the use of uranium and plutonium on fuel for nuclear reactors, the economics of the uranium market, the economics of reprocessing of spent nuclear fuel, the comparative future energy potentials of nuclear power, synthetic fuels and improvements in the efficiency of energy use, the economic effects of the oil crisis, the contribution of electric utilities to oil consumption, and the economic implications of closing a nuclear power plant.

ENERGY-RELATED CONSULTING:

During the period 1974-1983, I have provided consulting services, research reports, or expert testimony for:

- The United States Arms Control and Disarmament Agency
- The Energy Research and Development Administration
- The California Energy Commission
- The Council on Environmental Quality
- The Nuclear Regulatory Commission
- The Pennsylvania Public Utility Commission
- The Vermont Public Service Board
- The Office of Technology Assessment
- The New Hampshire Public Utilities Commission

ENERGY-RELATED PUBLICATIONS:

The Uncertain Future of Nuclear Power, with Dennis Holliday, California Seminar on Arms Control and Foreign Policy, P.O. Box 925, Santa Monica, California, August 1975

Is Plutonium Really Necessary? Pan Heuristics, Los Angeles, Sept., 1976 (Revised)

The Myth of Uranium Scarcity, Pan Heuristics, Los Angeles, April 25, 1977.

How the U.S. Government Created the Uranium Crisis, Pan Heuristics, Los Angeles, June 1977 (Revised)

The Economics of Uranium and Plutonium, in "Moving Toward Life in a Nuclear Armed Crowd?", Minerva, Volume XV, Numbers 3 and 4 (combined issue), Autumn-Winter, 1977

Prepared Testimony of Dr. Vince Taylor in the Matter of GESMO, prepared for the California Energy Resources and Development Commission, Pan Heuristics, Los Angeles, March 4, 1977, Chapter A.

Energy: The Easy Path, prepared for the U.S. Arms Control and Disarmament Agency, January, 1979 (published by the Union of Concerned Scientists, Cambridge, Mass.)

The Easy Path Energy Plan, Union of Concerned Scientists, Cambridge, Massachusetts, May, 1979

"Science and Subjectivity," Technology Review, February, 1979.

"A Warning: E. F. Schumacher on the Energy Crisis," MANAS September 3, 1980.

"The End of the Oil Age," The Ecologist, October-November, 1980.

Swords from Plowshares, with Albert Wohlstetter, et. al., University of Chicago Press, Chicago and London, 1979.

Conservation, Equity, and Efficiency, testimony before the Vermont Public Service Board, Docket 4475, November 5, 1980

Electric Utilities: The Transition from Oil, testimony before the Subcommittee on Oversight and Investigations of the Committee on Interstate and Foreign Commerce Committee of the United States House of Representatives, December 9, 1980.

"Electric Utilities: A Time of Transition," Environment, Volume 23, No. 4, May 1981.

Testimony on the Economic Costs of Closing Indian Point, testimony before the Atomic Safety and Licensing Board of the Nuclear Regulatory Commission, Docket Nos. 50-247-SP and 50-286-SP (pending).

ENERGY-RELATED PUBLICATIONS (CONTINUED):

Testimony of Vince Taylor, Investigation Into The Supply And Demand For Electricity, Public Service Company of New Hampshire, New Hampshire Public Utilities Commission, Docket DE 81-312, October 8, 1982.

"Living Without Nuclear Energy," Nuclear Power: Both Sides, M. Kaku and J. Trainer (Editors), W. W. Norton, New York, 1982.

Exhibit II

Union of
CONCERNED
SCIENTISTS

AN EVALUATION OF "ECONOMIC IMPACT OF CLOSING THE INDIAN POINT NUCLEAR FACILITY," A REPORT OF THE GENERAL ACCOUNTING OFFICE

Vince Taylor
Charles Komanoff

December 3, 1980

Union of Concerned Scientists
1384 Massachusetts Avenue
Cambridge, Mass., 02238
(617) 547-5552
or
1725 I Street, N.W.
Washington, D.C., 20006
(202) 296-5600

AN EVALUATION OF "ECONOMIC IMPACT OF CLOSING THE INDIAN POINT NUCLEAR FACILITY," A REPORT OF THE GENERAL ACCOUNTING OFFICE

The GAO report does not provide an accurate assessment of the costs of closing Indian Point 2 and 3 nuclear plants. Due to a number of errors, it exaggerates both the short and long run costs of a shutdown.

SHORT-RUN COSTS

The GAO estimates that first year costs of a shutdown would exceed $600 million. This estimate assumes unrealistically high operating rates for the nuclear plants (a capacity factor of 69 percent versus a historical average of 57 percent).* It also assumes that nuclear fuel costs and operating and maintenance costs are the same whether or not the Indian Point plants are closed--an obvious error. Correcting for these factors, the near-term, net costs of closing Indian Point appear likely to be about $337 million per year (see Table 1, attached).

MAJOR EXPENDITURES SAVED BY CLOSURE

The GAO estimates that closing Indian Point would save future expenditures on major plant repairs and safety improvements of $220 million. This estimate, however, includes only a portion of likely future safety related expenses and does not even reflect all of the items costed in their report. In particular, costs of responding to NRC directives issued in response to TMI appear substantially underestimated, and no allowance is made for safety improvements now being considered by the NRC because of Indian Point's proximity to New York City. A more realistic assessment of future, non-recurring expenses that might be avoided by closing Indian Point is $374-575+ million, with a significant chance that the upper end of this range could be exceeded (see Table 3, attached).

ERRONEOUS GAO "COSTS" OF CLOSURE

Rather than the figure of $431 million given by the GAO ("Digest," page v) as the cost of closing Indian Point, the actual added cost of early closure seems likely to be only a few tens of millions of dollars.

The GAO cites a figure of $233 million as the cost of decommissioning the plant and moving and temporarily storing the spent fuel off-site.** Costs of these activities are erroneously counted as "costs of closing the units."

* See addendum

** Page v of the GAO report "Digest" mistakenly says that the cost is to "dispose of the waste fuel," but the text refers to moving it to temporary storage.

Decommissioning costs will be incurred whether the plants are closed now or later. If past trends toward rapid escalation of costs of activities involving radioactive materials continue, early closing would reduce rather than add to decommissioning costs. The cost of moving the spent fuel could be avoided by keeping the fuel on-site until permanent storage becomes available.

The GAO report also counts a loss of $198 million on fuel as a cost of closing. This is also an error. About one-half of the $198 million represents fuel already in the core, an equivalent amount of which must remain in the core throughout the lifetime of the plant. It represents part of the investment cost of the plant which has already been made and should not be counted as a new cost of closing the plant. The remainder of the $198 million is attributed to losses on fuel being fabricated; but since this fuel could be used in other Westinghouse reactors (perhaps with some modification) actual losses after deducting salvage value should be relatively small.

LONG-RUN COSTS OF REPLACING INDIAN POINT GENERATION

Erroneous GAO Estimates

The GAO estimate that closing Indian Point will cost Con-Ed ratepayers $18 billion over the next 15 years, ("Digest," p. i) is a gross exaggeration. The figure was generated by a model that included as "costs of closing Indian Point" such items as a) higher rates of return on investment for Con-Ed, b) improved cash flow (accounting for over $2 billion of the $18 billion), and c) higher dividends to Con-Ed stockholders. These factors account for a major (but unspecified) portion of the total. Further, high rates of inflation were assumed, and costs were reported in inflated dollars.

The GAO report estimates that closing Indian Point will cost the Power Authority of the State of New York (PASNY), which owns Indian Point 3, "as much as $600 million annually" ("Digest," page i). Not mentioned in the "Digest" is that this was the upper limit of a series of estimates provided by PASNY to the GAO. The lower limit was $23 million annually (after an initial first-year cost of $226 million; GAO Report, page 52), and the GAO provides no basis for suggesting where in this range of $23 million to $600 million per year the probable, correct answer might lie. Since the total short-run cost (which is higher than the long-run cost) to both Con-Ed and PASNY is about $325 million per year (Table 1), it is obvious that the cited figure of $600 million per year for PASNY alone is well beyond the bounds of possibility.

The True Upper Limit of Long-Run Costs

The true upper limit of long run costs of closing Indian Point is provided by the costs of constructing and operating equivalent new coal-fired capacity less the savings in fuel, operating and maintenance, and future investment costs from closing Indian Point. An estimate of this upper-limit cost, based on a comprehensive analysis of trends in the cost of constructing new coal-fired facilities, is $250 million per year (in 1980 dollars; Table 2, attached).

If Indian Point were to be closed, the added costs of replacement power would, initially, approximate $337 million per year. The costs of both fuel and replacement capacity would eventually fall to $250 million per year if new coal capacity were to be built to replace the capacity.

Coal-Conversion versus New Capacity

The GAO report does not consider the possibility of converting existing oil-fired capacity to coal to replace Indian Point. This may offer a quicker, cheaper alternative to building new coal-fired capacity. Costs of meeting stringent air pollution standards would not be a barrier to such conversions. At the current cost differential between oil and coal, fuel savings would pay for a technically advanced pollution control system, including high-efficiency precipitators and a sulfur-dioxide scrubber, in two and one-half years.

The Jamesport Coal Plant--An Early Possibility

The Long Island Lighting Company (LILCO) has received permission to build an 800 MW coal-fired plant at Jamesport. Reportedly, LILCO will not build this plant if it decides to go ahead with federally ordered coal conversions of existing oil-fired plants. If this is the case, the Jamesport plant could be built specifically to replace (about one-half of) Indian Point generating capacity. It could be available between 1986 and 1988, depending on the length of time required to obtain permits from the Environmental Protection Agency and, possibly, local governments.

Potentials for Conservation

The GAO report assumes that demand for electricity in the Con-Ed service area will increase by 7.8 percent between 1981 and 1988 (Table 3-5, p. 36). Between 1973 and 1979, demand in this area declined by 4 percent. Recent sharp increases in rates together with further increases that can be expected would cut demand further, especially if an effective, utility financed conservation program were instituted simultaneously.

A 10 percent reduction in electricity consumption would offset 40 percent of the loss in generation caused by closing Indian Point.

GAO EXAGGERATED EFFECTS ON PASNY CUSTOMERS

The GAO estimates that closing Indian Point would raise PASNY's average cost per kilowatt by 4.19 cents in 1981 to 6.24 cents in 1992 ("Digest," p. iv). The report states (page 45) that PASNY rate increases in 1981 would range from 45 to 95 percent of 1980 rates. These estimates are based, first, on inflated estimates of replacement power costs and, second, on the assumption that all costs of closing Indian Point 2 would be loaded onto customers in the Con-Ed franchise area, which accounts for only 40 percent of PASNY kilowatt sales.

If added costs are shared equally by all PASNY customers, the short-run estimate of costs given in Table 1 implies added costs for PASNY of 0.85 cents per KWH. This would represent an average increase of 14 percent for the 5 largest PASNY customers (Table 2-5, page 24).

Table 1

Short-Run Net Costs of Closing the
Indian Point Nuclear Plants
(1980 dollars)

1.	Plant Capacity	1838 MW		
2.	Capacity factor[a]	57%		
3.	Annual generation	9.168 billion KWH		
	Oil required for replacement generation			
		Low Sulfur	High Sulfur	Total
4.	Millions of barrels[b]	11.36	4.64	16.0
5.	Price/barrel[c]	$31.15	$26.77	
6.	Fuel Cost ($ million)[d]	353.9	124.2	$478.1 million
	Savings from closing Indian Point			
7.	Fuel savings @$.008/KWH[e]			$73.3 million
8.	O and M savings[f]			$67.9 million
9.	Total savings			$141.2 million
10.	Net Costs: (6) minus (9)			$337 million

---

a. Lifetime cumulative factor through June 1980.

b. From GAO report Table 3-7, page 38, with quantities shown for 1981 reduced by 17.4% to reflect a capacity factor of .57 percent for Indian Point rather than the 69 percent used by the GAO.

c. Average U.S. retail prices for first 6 months of 1980, Monthly Energy Review, Department of Energy, DOE/EIA 0035/80 (10). Price for high sulfur oil is that given for .3 to 1.0 percent sulfur. Actual consumption would include higher sulfur oil, which was $6.50 per barrel less than the cost used.

d. Fuel costs are the bulk of additional cost associated with oil generation of replacement power, since the generation will be from existing, operating facilities. Operating and maintenance for these plants will not vary greatly whether or not extra generation is demanded of them. The GAO report includes taxes as a cost, but these are not true economic costs but a transfer to the state.

(Notes to Table 1 Continued)

e. The GAO report (p.56) gives a Con-Ed estimate of \$46.7 million for a fuel reload for Indian Point 2. Based on a 60 percent capacity factor for 18 months, the cost per KWH is \$.0068. Adding \$.0012/KWH for interest and waste disposal costs gives \$.0080/KWH.

f. Operating and maintenance (O & M) costs for 1979 were \$59 million (GAO report, page 57). Applying a factor of 1.15 to account for inflation yield \$67.9 million.

Table 2

Net Long-Run Costs of Replacing Indian Point with New Coal-Fired Capacity[a]

(1979 dollars)

	Indian Point Data		
1.	Capacity		1838 MW
2.	Capacity factor		57%
3.	Annual Generation		9.168 billion KWH
	Savings from closing Indian Point		
4.	Non-Recurring[b]		$ 375 million
	Recurring[c]		
	O & M	$.0071/KWH	
	Fuel	.0109/KWH	
5.	Total recurring		.0180/KWH
	Coal Plant Data		
6.	Annual generation		9.168 billion KWH
7.	Capacity factor[d]		70 percent
8.	Capacity required		1500 MW
9.	Capital cost per KW		$936
10.	Total capital cost		$1404 million
	Recurring[c]		
	O & M	$.0071/KWH	
	Fuel Cost	.0241/KWH	
11.	Total recurring		$.0312/KWH
	Net cost of replacement power		
	Coal capital cost (9)		$1404 million
	Non-Recurring savings (4)		-375 million
12.	Net capital cost		$1029 million
13.	Real fixed charge rate[e]		10.0% per year
14.	Net capital cost per year		$102.9 million
15.	Net capital cost per KWH		$ .0114/KWH

	Recurring coal costs (11)	\$.0312/KWH
	Less recurring nuclear costs (5)	-.0180/KWH
16.	Net cost per KWH	\$.0246/KWH

17. Total annual net cost (3) x (16): \$225 million/year

18. Cost in 1980 dollars (11% inflation): \$250 million/year

---

a. All data on coal and future nuclear fuel costs are from Power Plant Escalation by Charles Komanoff (forthcoming 1981). Coal plant is assumed to be in operation in 1988.

b. See Table 3--Minimum estimates used here. Actual savings could exceed \$575 million.

c. Estimate by Charles Komanoff for levelized 1988-2017 costs, expressed in 1979 dollars.

d. Appropriate for plants of approximately 300 MW, the preferred size of unit.

e. Fixed charge in a non-inflationary environment, corresponding to the use of constant dollars in the analysis. Current dollar fixed charge rate equals the real rate plus the expected long-term rate of inflation.

Table 3

Non-Recurring Cost Savings from Closing Indian Point

(millions of dollars)

1.	Repairs to steam generators[a]	$145
2.	Budgeted safety improvements[a]	62
3.	Utility estimates of future budget additions for safety improvements[a]	23
4.	Emergency response planning[a]	
	Utility costs	8.8
	State costs	4.5
	County costs	1.5
5.	Study costs for IP cooling towers[a,b]	10.0
	Subtotal	254.8
6.	Additional costs of meeting post-TMI safety changes[c]	120+
7.	Costs of improving safety of reactors located near large population centers[d]	0--200+
	Subtotal	375--575+
8.	Cost of meeting future NRC requirements to resolve currently unresolved safety problems and future problems detected by operating experience[e]	Possibly very large

a. From GAO report

b. Costs are cited at $3.5-4 million per year for Con-Ed (page 57); no duration is given in the report. The study is assumed here to last for about 3 years.

c. Estimated costs included in the GAO report for implementing NRC safety improvements emerging from the post-Three Mile Island review are $26.9 million, plus some portion (unspecified) of the unbudgeted but estimated $23 million. The management of Rancho Seco recently raised their initial estimate (of March 1980) of $39.2-53.5 million to $85.7 million, primarily due to expansion of NRC requirements (Nucleonics Week, November 20, 1980). The review process is by no means completed and, thus, further increases can be expected. Even aside from these further increases, the Indian Point facility, which consists of two units of approximately the same size as Rancho Seco, can be expected to incur costs twice as great as Rancho Seco, or $170 million, $120 million more than included in the GAO report.

(Notes to Table 3 Continued)

d. The NRC is currently studying the issue of whether additional safety modifications should be required for plants located near large population centers, e.g. Indian Point. Design changes being considered are vented filtered containment pressure relief system, core retention devices, and hydrogen control (GAO report, page 17). No estimates were made in the GAO report of the possible range of costs. Very preliminary estimates were provided by Jim Myer, NRC project manager for these measures by telephone (December 2, 1980): The filtered containment system could range from $15-50 million; the hydrogen control system could range from small to $50 million; and the core rentention devices are not currently costed; thus the range is from zero (no requirements) to upwards of $100 million per reactor, or upwards of $200 million for the two Indian Point reactors.

e. The NRC currently recognizes 14 "unresolved safety issues," some with potentially serious consequences, and the NRC staff has proposed adding 7 more to the list. Additionally future operating experience (such as that provided by Three Mile Island) can be expected to reveal new problems that will need correction. No firm estimates are possible, but the upper limits are obviously very high and should not be completely ignored.

ADDENDUM

Indian Point Capacity Factor

There is no basis for the 69% capacity factor assumed for the Indian Point units and the GAO report (page 34). To date, Indian Point II and III have operated at lifetime average capacity factors of only 55% and 57%, respectively. Moreover, their year-by-year records fail to demonstrate the "operational maturity" that the report assumes. Unit II performance has improved somewhat over time, but Unit III performance has deteriorated, as the following table indicates.

INDIAN POINT CAPACITY FACTORS

Year	Unit II (873-MW)	Unit III (965-MW)
1974	43%	
1975	64%	
1976	30%	
1977	68%	65%
1978	57%	65%
1979	63%	57%
1980	56%	39%*
Average	55%	57%

* First 11 months.

Source: Net generation data from U.S. NRC "Gray Books."

Note: Table excludes initial Unit II operation in late 1973 and initial Unit III operation in late 1976, in which the units performed poorly and well, respectively.

Indian Point's poor generating performance is consistent with that of other large nuclear units. The 39 U.S. reactors of 800 MW capacity or greater registered a lifetime average capacity factor of only 54% through mid-1980. (See Komanoff, "U.S. Nuclear Plant Performance," Bulletin of Atomic Scientists, November 1980.) Contrary to nuclear industry assertions and government misperception, there has been little or no improvement in the performance of these large units over time. Any putative future improvement in Indian Point's capacity factors is likely to be offset by prospective more stringent regulations of nuclear plant operations.

STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

Investigation Into The Supply And Demand For Electricity, Public Service Company of New Hampshire	DE 81-312

Testimony of

Vince Taylor

On Behalf Of

THE CONSERVATION LAW FOUNDATION OF NEW ENGLAND, INC.,
THE NEW HAMPSHIRE ENERGY COALITION, AND
THE UNION OF CONCERNED SCIENTISTS

October 8, 1982

<u>AFFIDAVIT</u>

State of Vermont

County of Franklin

On this 28^{th} day of September 1982, before me personally appeared Vince Taylor to me known and known to me to be the individual who executed the foregoing testimony and he thereupon duly acknowledged to me that he executed the same.

Vince Taylor

Eileen J. McFadden
Notary
Comm expires Feb 1983

TABLE OF CONTENTS

Appendix B

Appendix C

QUALIFICATIONS

Q. Please state your name, occupation, and business address.

A. My name is Vince Taylor. I am an economic consultant. My business address is 21 Elm Ave., Richford, Vermont, 05476.

Q. Please state your professional qualifications.

A. I have attached a summary of my professional experience and publications as Appendix C. Briefly, my professional history includes a Ph.D. in economics from M.I.T., ten years in the Economics Department of the Rand Corporation, and eight years of work on problems related to the economics of energy, with emphasis on the economics of nuclear power and its alternatives.

This history, however, provides little by which to judge the usefulness of my testimony in this case. We are attempting here to peer forward into a murky future to discern what may happen to electricity demand. Foreseeing accurately what may occur requires more than mathematical models or economic analysis, although both are helpful tools. Most important is an ability to identify those factors that will be most instrumental in influencing the events of concern. No matter how complex and apparently sophisticated the analysis, or how credentialed the analyst, if influential determinants of the future are overlooked or ignored, the results can be wildly erroneous. One need look no further than the field of electricity demand forecasting to find examples of catastrophic failures.

The best credential for the present task is success at past similar efforts. I would like, therefore, to review my own record of forecasting in related areas.

The Price of Uranium

In 1977, the price of uranium was over $40 per pound, up from $10 per pound a few years earlier. Forecasts of future shortages and higher prices were nearly universal. Wall Street analysts were talking about $100 per pound. A government report on the economics of reprocessing spent nuclear fuel projected a price of $60 per pound for uranium before the year 2000.* The concern of government was how to prevent

---

* Benefit Analysis of Reprocessing and Recycling Light Water Reactor Fuel, U.S. Energy Research and Development Administration, ERDA 76-121, December 1976.

shortages that might impede the growth of nuclear power.

In 1977, I published two research reports that took issue with the conventional view.* In the first report, I stated:

> The major conclusion is that uranium needs in this century appear capable of being met from resources producible at less than $20 per pound of uranium oxide, and prices under $10 per pound in the first quarter of the twenty-first century seem at least a reasonable possibility . . . .**
>
> Current near-term shortages and high spot market prices are largely the result of artificial demands created by past nuclear-fuel enrichment policies of the U.S. government . . . The main danger, if policies are not revised [which they were not, until too late], is another cycle of boom to bust in the uranium industry.

My analysis of the uranium market was discussed in a Wall Street Journal editorial on April 13, 1977 and prompted heated denials of its accuracy from the government and several uranium producers.***

It took several years for the accuracy of what I was saying to be widely appreciated,**** but there is no longer any controversy. The market price recently reached $17 per pound, far below my price prediction for this century, reflecting the distress sales that are accompanying the present uranium glut.

I was able to foresee the coming uranium bust because I 1) understood the reason for the then-existing shortages, 2) determined that uranium supply would be very responsive to increases in uranium price, and 3) foresaw that prevailing predictions of nuclear-power growth were greatly exaggerated.

Growth of Nuclear Power

As part of the analysis of uranium demand, I projected future U.S.

---

* The Myth of Uranium Scarcity, Pan Heuristics, Los Angeles, April 1977, and How the U.S. Government Created the Uranium Crisis (and the Coming Uranium Bust), Pan Heuristics, Los Angeles, June, 1977 (revised).

** Prices are in 1976 dollars. Inflating to 1981 dollars, the two prices become $32 and $16 per pound.

*** Wall Street Journal, editorial page, May 19, 1977.

**** The spot-market price peaked in May 1978 at $43 per pound.

nuclear growth. The projected amounts of installed nuclear capacity were 110 gigawatts in 1985 and 336 gigawatts by the year 2000.* Industry figures projected 165 gigawatts by 1985,** and an official government mid-range projection for 2000 was 510 gigawatts.*** Present expectations have now fallen below my 1977 projection
were meant to be conservatively high in order to assess the adequacy of uranium resources.

My more accurate projections were based on an appreciation of 1) the likelihood of lower electricity growth, given the probability that real electricity prices would increase in the future, 2) the then-existing excess of generating capacity, which had accumulated as electricity growth slowed and which made near-term deferrals and cancellations inevitable, and 3) the economic problems of nuclear power, which made it likely that coal would be a serious competitor in the future.

The Economics of Reprocessing Nuclear Fuel

In the mid-1970's, it was generally assumed that reprocessing of spent nuclear fuel from power reactors would be a normal part of the fuel cycle. A major argument for this process, which would introduce plutonium, a nuclear-bomb material, into civilian commerce, was its favorable economics. Four studies released by industry and government in 1976 showed it would be profitable. In an analysis of these studies published in 1977,**** I concluded that reprocessing would be quite unprofitable. This conclusion was based on an appreciation of 1) the technical difficulties of reprocessing, which would lead to costs for reprocessing much higher than those assumed in the other studies, and 2) that the price of uranium, with which reprocessed fuels must compete, would be lower than assumed by the others. After my analysis was completed, a European reprocessor announced contract prices for reprocessing that were more than triple the average cost used by the others and 50

---

* The Myth, op. cit., Table 4, p.50.

** Nuclear News, August 1977.

*** E. Hanrahan, et. al., "World Requirements and Supply of Uranium," Office of Planning Analysis and Evaluation, U.S. ERDA, presented at the Atomic Industrial Forum International Conference on Uranium, Geneva, Switzerland, 14 September 1976.

**** The Economics of Uranium and Plutonium, in "Moving Toward Life in a Nuclear Armed Crowd?," Minerva, Volume XV, Numbers 3 and 4 (combined issue), Autumn-Winter, 1977.

percent higher than my estimate.* Uranium prices have fallen far below the value I used. Thus, there is at present no question about the profitability of reprocessing.

Solving the Energy Crisis

In the years following the oil embargo, U.S. government policy emphasized the need to expand domestic supplies of energy, especially nuclear power and synthetic fuels, as a solution to the energy crisis. In two reports published in 1979, I took issue with this policy.** In the first report, I concluded:

> The maximum contribution of nuclear power, synthetic fuels, fusion, etc. would be far too small to offset the decreases in oil and gas production that, in the conventional view, are expected to occur near the turn of the century . . . [but] improvements in the productivity of energy, without any contribution from nuclear power or other potentially dangerous forms of energy supply, can suffice to extend the lifetime of remaining conventional fuels to make them the dominant source of world energy supply until well beyond 2025, providing sufficient time for an unhurried transition to safe, renewable energy resources.

The jury is, of course, still out on this prediction, but the odds certainly would be considered by most to be more favorable now than when it was made.

In the second report, which was written before the Iranian revolution and the second round of oil price increases, I presented an alternative forecast to the Carter Administration's Second National Energy Plan (NEP II), which projected that U.S. energy consumption would increase by 18 percent from 1978 to 1985. I projected that a continuation of the existing trends toward improved energy productivity (efficiency) would hold the increase to 6 percent and predicted that a few relatively simple policy initiatives to increase movement toward increased energy efficiency could put 1985 energy consumption below that of 1978.

---

* Ibid.

** Energy: The Easy Path, January 1979, and The Easy Path Energy Plan, September 1979 (revised), Union of Concerned Scientist, Cambridge, Massachusetts

The oil price rises of 1979-81 provided more of an impetus toward improved efficiency of energy use than could any simple government policy initiatives. U.S. energy consumption in 1981 was 6 percent below the 1978 level, and it is now generally accepted that 1985 energy consumption will be below or close to the 1978 level.

The relative accuracy of my forecasts of energy consumption was due to my appreciation of the many possibilities for saving energy by improving the efficiency of its use, together with an ability to use existing economic analyses to estimate the quantitative magnitude of these possibilities.

Conclusion

In sum, I believe my past record reflects an ability to identify and concentrate attention on the most important determinants of the future trends under examination. This ability will be a crucial ingredient of success in the present case, because future demand for electricity within PSNH depends on very many factors. Only by identifying and focusing on the most important of these will it be possible to provide projections that accurately reflect future possibilities.

OBJECTIVES

Q. Please describe the objectives of your testimony.

A. The first objective of my testimony is to provide an improved methodology for projecting future electricity demand for PSNH. The methodology to be presented explicitly relates changes in electricity demand to changes in the real (inflation-adjusted) price of electricity and to changes in economic activity.

The inclusion of price changes in demand projections improves upon the methodology of Robert Camfield which the Commission found in its Report on DE 80-47 (October 19, 1981) to produce the "most reasonable estimate of growth of demand for PSNH of 3.00 percent annually through 1990," for a business-as-usual case. The model used by Mr. Camfield related economic activity and electricity demand but did not include electricity price as an explanatory variable. The Camfield model, thus, is unable to shed any light on how demand for electricity will be affected by changes in the cost of providing it, by changes in the rate structure, or by conservation programs such as the one proposed by Paul Chernik in his testimony in the present docket. The need for an improved basis for exploring these questions underlay the Commission's order to open the present docket.

The second objective of my testimony is to use the improved demand-projection model to illuminate the situation now facing PSNH. The dominant element of this situation is the Company's commitment to Seabrook. What are the implications for electricity demand and cost if the Company maintains its present ownership share and completes both units? How will variations in the cost of Seabrook affect future demand? What would happen to future demand and cost if Seabrook II were canceled? These and related questions are explicitly addressed in my testimony.

A third objective is to convince the Commission that the demand model presented here, or a similar model that explicitly incorporates price, should be required in future demand forecasts presented to it by the Staff and the Company. Only in this way can the Commission be assured that the demand projections used to justify proposed generating additions are consistent with the estimated costs of such additions.

CONCLUSIONS ON SUPPLY, DEMAND AND COST

Q. On the basis of your findings, what do you conclude about projected demand and the generation plans of PSNH?

A. One, future demand for electricity depends critically upon the cost of Seabrook to PSNH.

With the present PSNH ownership share of Seabrook, ten year projections of demand made with the same economic growth assumptions vary from plus 3.5 percent to minus 5.3 percent per year as Seabrook costs vary between low and high estimates of $3.6 and 8.6 billion. It follows, therefore, that:

Two, in order to make a meaningful determination of projected electricity growth for regulatory purposes, the Commission must first make a determination on the range within which Seabrook costs are expected to fall.

Three, if Seabrook costs are near to or exceed $5.5 billion, cancellation of Seabrook II will reduce future electricity costs and improve the balance between future demand and generation capability.

For a middle estimate of $5.5 billion for Seabrook, sales are projected to decline over the next 10 years. As a consequence, Seabrook II generation would be entirely surplus to PSNH needs through the end of the ten-year planning period. Cancellation would eliminate this surplus, while simultaneously reducing future electricity prices.*

Four, the present PSNH ownership of Seabrook exposes its customers to the risk of unprecedented rate increases.

The capital costs of Seabrook, which will not vary with electricity sales, will be the dominant element of electricity costs after Seabrook I comes on-line. If costs of Seabrook approach the high estimate, this alone would suffice to cause real electricity prices to nearly triple in the next eight years. But even with lower Seabrook costs, similar increases could occur if other uncertainties turned out unfavorably. Demand might fall significantly below the projected levels because of national economic problems or greater-than-anticipated effects of past price increases. Seabrook generation might fall far below expectations because of technical problems or an accident. Given the fixed nature of Seabrook costs, any

---

* Cancellation of Seabrook II would also be beneficial to ratepayers at costs less than the mid-range estimate. The minimum cost at which cancellation would be beneficial could be determined by projecting demand growth and electricity prices for different Seabrook costs.

of these would raise per unit electricity costs above projected levels.

Of course, uncertainties could turn out favorably and costs could be lower than anticipated. But, the question that needs to be considered is whether it is prudent to expose ratepayers to even a modest risk of tripled electricity rates.*

---

* A risk that is far more than modest if the testimony on Seabrook costs and performance presented in this docket by Richard Rosen is accurate.

FINDINGS ON SUPPLY, DEMAND AND COST

Q. What are the major findings of your testimony with respect to the supply, demand, and cost of electricity of electricity over the next 10 years?

The Importance of Seabrook

A. The most important factor, by far, in determining the future costs of electricity will be the cost of Seabrook to PSNH shareholders. This cost is uncertain, depending upon construction costs, financing charges, completion dates, inflation rates, and ownership share, but it is certain that unless PSNH radically alters its ownership plans Seabrook will constitute the largest element in the PSNH cost structure at the end of the decade.

The commitment to Seabrook means that there will be no business as usual in the PSNH future. Seabrook in New Hampshire is a Giant in Lilliput. If Seabrook sneezes, the cost of electricity in New Hampshire will jump.

The present PSNH rate base is $500 million. On present plans, completing Seabrook I and II will raise the rate base to between two and three billion dollars, depending upon the outcome of various uncertainties.

The revenue charge on the rate base has already increased substantially because of high-cost borrowing to finance Seabrook. It will increase still more as this borrowing accumulates. Including taxes and depreciation, the charge against the rate base will exceed 30 percent per year when Seabrook I enters service.

The combination of a multiplied rate base and a high capital charge rate will transform the cost structure of PSNH from the present one, which is dominated by fuel costs, to one dominated by capital costs. Thus, trends in electricity costs in PSNH over the next decade will be determined largely by developments affecting the cost of the PSNH share of Seabrook.

The Influence of Price on Demand

PSNH electricity sales are significantly and quickly affected by changes in real (inflation-adjusted) electricity prices. This general finding should come as no surprise, since all economic investigations of electricity demand have found price to be an important factor. Analyses

of historical U.S. data indicate that the long-run elasticity of demand with respect to price is in the range of -0.8 to -1.2, with -1.0 being a reasonable median estimate.* This means that a 10 percent increase in the real price of electricity will, eventually, cause an approximate 10 percent decrease in electricity demand, and vice versa. What may be surprising is the extent of the short-run response to price found for PSNH electricity sales. Within 3 years of a 10 percent real price rise, sales were found to decrease by 8 percent, other things being unchanged (a price elasticity of -0.8).

Explaining Demand Changes

The determination of the price sensitivity of demand was based on an examination of the history of demand growth from 1960 to 1981. Each of four broad customer classes was analyzed separately. The influences of price and economic activity were studied using econometric and other techniques. This analysis produced four relatively simple equations, one for each customer class. These equations relate annual changes in demand to changes in electricity price and economic activity.

Except for the 1974-76 period, following the first oil shock, the quantitative response of demand to real price changes has been very consistent.** Since 1976, the relations between changes in sales, price, and economic activity have been very stable.

Table I (Exhibits, S-0, p.1) compares actual growth in electricity sales during 1977-81 with the growth estimated by the demand equations. Sales growth for a given year is estimated using actual changes in electricity price and economic activity for that year. Thus, Table I shows how well the demand equations would have predicted sales growth during the 1977-81 period if price and economic data were known accurately in advance. Under this assumption, the demand equations do an excellent job of tracking year to year changes in sales growth for each customer class as well as total sales growth. For the period as a whole, estimated total sales growth

---

* Lester Taylor "The Demand for Energy: A survey of Price and Income Elasticities," in International Studies of the Demand for Energy, William Nordhaus (Ed.), North-Holland Publishing Co., New York, 1977.

** In the post-embargo period, demand did not decrease as much as normal experience would have suggested, given the size of the real price increases that occurred. I hypothesize that this was because of the widespread confusion and uncertainty about whether the increases, which were the first in the history of electricity, were permanent or temporary.

of 2.76 percent per year is almost identical to actual growth of 2.72 percent per year.

Of course, equations such as these always are better at predicting the past than the future. But, the ability of the equations to track year to year changes closely within each customer category over the entire 5-year period gives more than the usual degree of confidence in their future usefulness.

Future Demand and Cost

The electricity demand equations were used to project Prime Sales for PSNH through 1991 for three different estimates of the cost of Seabrook. The present PSNH ownership share (35.6%) was assumed to be maintained. For all three cases, mid-range economic growth was assumed: growth in manufacturing of 4.7 percent per year (5.9 percent through 1986) and Personal Income growth of 4.4 percent per year. Real fuel prices were assumed to remain constant through 1985 and to increase at a few percent per year thereafter. Inflation was assumed constant at 8 percent per year. Results for the three cases are displayed in Figures I and II (Exhibits, S-O, pp.2 and 3).

1) Low Seabrook Cost: The first case uses the Company projection of non-fuel costs based on its estimate of Seabrook ($3.6 billion). Seabrook I comes on-line in February 1984 and Seabrook II in May 1988 (a two-year delay).

In this favorable cost scenario, demand for electricity falls below the 1981 level for the next 5 years, but begins to grow rapidly after 1986. Under the assumptions used by PSNH, declining equity costs, depreciation of Seabrook I, and continued rapid inflation combine to push down rapidly the Seabrook contribution to real electricity costs after Seabrook I enters the rate base. Costs per kWh decline even during the years when Seabrook II is phased into the rate base. Falling electricity prices cause growing demand in the last part of the decade. For the 10 years through 1991, Prime Sales increase by an average of 3.5 percent per year, with all of the increase occurring after 1986.

2) Mid-Range Seabrook Cost: In the second case, the costs of Seabrook are estimated at $5.5 billion, between the PSNH estimate ($3.6 billion) and the base-case estimate of Richard Rosen ($8.6 billion)

presented in this docket. In this case, electricity demand remains below the 1981 level for the entire 10-year forecast period. Average electricity prices (measured in 1981 dollars*) increase from 7.6¢/kWh in 1981 to about 13¢/kWh in 1988-89. The increase in price depresses demand approximately 20 percent below the 1981 level. Prices decline and demand grows after 1989, but demand is still approximately 10 percent below the 1981 level in 1991.

3) <u>High Seabrook Costs</u>: The highest cost considered for Seabrook is the base-case estimate of $8.6 billion presented by Richard Rosen in this docket. If this estimate, based on his analysis of industry-wide cost trends, proves accurate, New Hampshire ratepayers will experience an unprecedented rate explosion. Real electricity prices will nearly triple in the next eight years, reaching 22¢ per kWh. (By comparison, they increased by 92 percent between 1973 and 1981.) The demand equations predict that price increases of this magnitude would push down electricity demand by over 40 percent, although these increases are so far outside of the range of experience on which the equations were based that this result must be treated cautiously. On the other hand, because these price increases would not necessarily be shared by neighboring states, the assumed manufacturing growth that underlies these projections may fail to materialize, causing electricity demand to be lower than projected.

<u>Adequacy of Planned Generation</u>

Whether the generation plans of PSNH are appropriate depends critically on the cost of Seabrook. Planned generation capability was compared with projected required generation for the three estimates of Seabrook cost. Results for the three cases are presented in Figures III-V (Exhibits, S-0, pp.4-6).

1) <u>Low Seabrook Cost</u>: In this case, planned additions to generation are sufficient to eliminate net purchases of interchanged power** and almost all oil-fired generation for most of the 10 year planning period. Under the assumptions of PSNH, the substitution of nuclear power for interchanged and oil-fired generation would be economically beneficial to ratepayers.

---

* All electricity prices, unless stated otherwise, are expressed in 1981 dollars.

** Except for nuclear entitlements, which would continue to be purchased because of their low cost.

Projected demand and generation capability appear well matched, given the cost assumptions of PSNH.

2) Mid-Range Seabrook Cost: Seabrook raises prices and depresses demand sufficiently to result in excess coal and nuclear generating capacity by 1987. By 1989, when Seabrook II is operational for the whole year, excess coal and nuclear generation equal 75 percent of the PSNH share of Seabrook. PSNH cannot utilize even the capacity of Seabrook I. Excess generation remains high until the end of the planning period. For the mid-range Seabrook cost ($5.5 billion), projected generation is not sufficient to justify acquisition of the PSNH share of Seabrook II. All of the generation from Seabrook II (or equivalent coal generation) would need to be sold to other power companies. Under present NEPOOL policies, with the fuel prices assumed, PSNH would receive about 4¢ per kWh, significantly less than the cost of Seabrook II power.*

3) High Seabrook Cost: In this case, the entire generating capacity of Seabrook is in excess of PSNH needs from 1988 forward, emphasizing how excessive would be the PSNH commitment to Seabrook if the high estimate were to prove correct.

Cancellation of Seabrook II

If Seabrook costs equal or exceed the mid-range estimate, the outlook for demand and prices would be improved if PSNH were to divest itself of its share of Seabrook II. Efforts of PSNH to find buyers for Seabrook shares have been unsuccessful, suggesting skepticism on the part of potential buyers that investment in Seabrook provides an attractive alternative to continued dependence on oil-fired generation. If this continues, cancellation of Seabrook II may be the only means available to PSNH to reduce its share of Seabrook.

The projected demand and generation capability, assuming cancellation of Seabrook II and the mid-range cost for Seabrook I ($3.1 billion), are

---

* At $2.8 billion for Seabrook II, a levelized charge rate of 20 percent, a levelized capacity factor of 55 percent, and non-capital costs of 2¢ per kWh, the cost per kWh (in 1981 dollars) would be 7.8¢/kWh.

shown in Figure VI (Exhibits, S-0, p.7). As compared to the case including Seabrook II; there is a much better balance between demand and capability. Purchases and oil-fired generation are eliminated by Seabrook I, except for the last two years when some oil-fired generation is again required.*

The improved balance between supply and demand for generation when Seabrook II is cancelled occurs not only because generation capability is reduced but because demand levels in the latter part of the decade are raised (Figure VII, Exhibits, S-0, p.8). This occurs because cancellation results in significantly lower prices after 1977 (Figure VIII, Exhibits, S-0, p.9).

Uncertainties Other Than Seabrook

In addition to the major uncertainty about the cost of Seabrook, there are other significant uncertainties that affect projections of demand and cost.

1) Economic growth: Plausible variations in future economic growth could cause growth rate of sales to vary by plus or minus one percent per year about the values based on mid-range economic assumptions.

2) Inflation: The projections presented all assumed constant inflation of eight percent per year. If present government policies are continued and succeed (an uncertainty), inflation will trend downward over the decade. Real interest rates and rates of return on equity could also be expected to decline under this circumstance, developments that would be favorable to the cost of Seabrook. On the other hand, approximately 60 percent of Seabrook will be financed by debt, whose dollar cost is fixed at the time of issuance. Declining inflation will add to the real (inflation-adjusted) burden of this debt in the future.

At lower rates of inflation, real capital charges on Seabrook will not decline as rapidly over time, and the decline in real electricity prices projected for the end of the decade will be less steep. This will have an adverse affect on projected demand. Thus, the upturn in demand projected

---

* Under the assumed course of oil prices, the fuel cost of oil-fired generation is 7.4¢ per kWh in 1991, roughly comparable with the cost of power from Seabrook II in the mid-range case (see previous footnote); thus there is no economic advantage to building Seabrook II to replace oil.

to occur near the end of the planning period for the mid and high Seabrook costs would be less steep if inflation slows.

3) <u>Performance of Seabrook</u>: The projections presented assume that Seabrook performance will conform to a statistical norm (operation at 55 percent of capacity from age 3 forward), but individual reactors may perform far from the norm. Ten percentage points difference in the capacity factor will cause about a 5 percent difference in electricity costs when both units are in operation.

4) <u>Inaccuracies in the Demand Equations</u>: The coefficients of the equations used to project demand are themselves uncertain, being based on statistical analysis of data. In particular, there is substantial uncertainty about the rate at which the electricity intensity of buildings and factory processes adjusts to major shifts in electricity price trends, such as occurred in 1973. I believe it prudent to allow plus or minus one percent in the projected 10-year growth rates to reflect uncertainties in the equations.

In summary, there are numerous uncertainties, in addition to the uncertain cost of Seabrook, that affect our ability to project future demand accurately. If the estimated growth rate is consistently off by two-percent per year, the error will equal (about) 10 percent in 5 years and 20 percent in 10 years.

EXPLANATORY COMMENT ON THE SENSITIVITY OF DEMAND TO SEABROOK COSTS

Q. Would you like to provide further explanation for the sensitivity of future demand to the cost of Seabrook?

A. It may seem surprising to some that demand projections are so very sensitive to the estimated cost of Seabrook. In addition to the obvious effect of higher Seabrook costs on electricity price and, thereby, demand, there are several less obvious factors that contribute to this sensitivity:

High Proportion of Fixed Costs: When Seabrook II is in full operation, cost items unrelated to the level of sales (primarily capital charges and taxes associated with Seabrook) will constitute a high proportion of total costs of PSNH. If sales decrease, these fixed costs must be spread over fewer kWh, requiring that prices be higher. Higher prices cause demand to fall, which causes still higher prices. This interaction between sales and price multiplies the effect of changes in the cost of Seabrook.

The exact multiplier varies with the structure of costs and the selling price for surplus power. For the mid-range cost case, after Seabrook II comes on-line an initial rise in the total cost of electricity of 1.0 percent will lead to a final increase in price of about 1.6 percent; thus the multiplier is about 1.6. Sales will decrease by 1.25 percent, 1.6 times the decline that would have occurred in the absence of secondary sales-price interactions.

Real Seabrook Costs: The actual costs of Seabrook to ratepayers will be substantially higher than the estimates produced using the methodology approved by the Commission for rate purposes. This methodology, which uses embedded average rates on long-term debt to calculate AFUDC, was used by the Company and by Richard Rosen in preparing the estimates of Seabrook cost cited herein. Thus, the actual costs that will be borne by ratepayers (and that were implicitly used in the calculations of projected demand) will be much higher than these "accounting" estimates.

Based on the embedded cost methodology, future AFUDC was calculated at 11.5 percent by PSNH and 12.5 percent by Rosen. Actual borrowing to finance Seabrook had a cost to ratepayers of about 25 percent per year in 1981.*

---

* The weighted cost of new money, calculated using 18 percent for borrowing and a cost of equity of 17 percent plus taxes (for a total cost of equity of 33 percent).

Actual interest during construction will be more than double the accounting AFUDC.

Appendix B presents a detailed calculation of the cost of Seabrook II using all of Rosen's base-case assumptions <u>except</u> for the 12.5 percent AFUDC rate. Instead, Rosen's projected costs of equity and new borrowing were used to calculate interest during construction. The resulting estimate to ratepayers for the PSNH share of Seabrook II is $2413 million, 48 percent higher than Rosen's accounting estimate.

The actual cost to ratepayers is what will determine future electricity costs. Understating interest during construction, as does the method used in New Hampshire, can hide some of the true costs of Seabrook but it cannot avert the necessity of paying them.

What embedded-cost AFUDC does is to change the timing of payment for borrowing. A portion of new borrowing costs enter PSNH rates as they are incurred rather than being deferred until Seabrook enters commercial operation. The new borrowing does not enter the rate base, but the higher costs of new debt raise the average cost of the debt used in calculating the allowed return on the rate base. This was explicitly recognized by the Commission in a recent order:

> "Rolled-in with the embedded cost rate of debt and preferred stock, recent issues tend to increase the earnings rate required to service the senior capital. It is this fact coupled with upward movements in short-term debt costs that has profoundly impacted the overall return requirements of the Company. Whereas PSNH had an overall return rate of 12.29% in mid-1980 (DR 79-187), current estimates of the overall return shown in exhibits filed in this docket range from 14.00% to nearly 16%.*

The rise in rate of return noted by the Commission is a cost of the Seabrook construction program currently being paid by ratepayers.

In terms of the effect on future prices of electricity, the method mandated by the Commission causes electricity prices to rise before the completion of Seabrook, but to rise less at the time Seabrook enters the rate base than would be the case if true interest costs were booked to AFUDC.

The overall rise in electricity prices caused by Seabrook must reflect actual borrowing costs. The full impact of Seabrook on future prices, thus, will be substantially greater than the standard accounting estimates superficially suggest.

---

* Report and Order Nos. 15,24 and 15,425 (DR 81-87), NHPUC

ECONOMIC ANALYSIS OF ELECTRICITY DEMAND

Methodology

Q. Could you explain the methodology used by you to analyze growth in consumption of electricity?

A. The approach used was to develop models that related annual changes in kWh use to changes in economic variables, such as the price of electricity, manufacturing activity, the number of customers, per capita income, and the price of oil.

I deflated all data reported in current dollars by an appropriate price index; thus all price and income data used were in constant dollars. In economics, these deflated data are termed "real" income and "real" price data. By using such real data, the distorting effects of varying rates of general price inflation are eliminated from the analysis.

To develop a basis for projecting future demand for electricity, I examined the historical relations among electricity use and various economic variables. To assist in this examination, I used the econometric technique of multiple regression analysis, but I did not rely solely on it.

Q. Can you explain multiple regression analysis and why you did not rely solely upon it?

A. Multiple regression analysis is a technique for deriving the "best" statistical relation between one "dependent" variable (electricity consumption) and a number of "independent" variables (such as number of customers and per capita income). This technique involves many assumptions that are highly unlikely to hold exactly in any real world problem, especially one that ranges over as turbulent a period as the 1970's. Thus, while regression analysis can assist in providing quantitative measures of the relations among variables that held <u>historically</u>, an intelligent assessment of <u>future</u> behavior requires that additional information, analysis, and judgement be brought to bear on the problem.

Q. Are there advantages to the economic approach over "end-use" analysis, which breaks down electricity consumption into as many end-use categories as feasible?

A. Because electricity price and economic activity are explicitly incorporated in the economic approach to forecasting, one can explicitly and quantitatively explore uncertainties in these variables. This is impossible with end-use analysis, since price and income elasticities are not available for detailed end-use categories.

Q. What customer categories did you consider separately in your detailed analysis?

A. I examined growth in electricity use separately for the following customer classes:

A. Residential

B. General

C. Industrial

1. Manufacturing

2. Large Commercial and Service

These categories correspond to the major rate classes of PSNH customers. I have separated the sales to large users (termed somewhat misleadingly by PSNH "industrial" users) into two sub-categories because, although both

---

* See, for example, the testimony of Robert Camfield before the Public Utilities Commission of New Hampshire, DR 80-47, May 1981, pp.4-6.

pay the same rates, they are affected quite differently by fluctuations in economic activity.

Q. Please continue to explain your analysis.

A. As a basis for projecting into the future, I examined the historical period from 1960 through 1981. The latter part of this period, after 1973, differs substantially from the former part. Some aspects, though, of the experience of the earlier period may still be relevant for understanding the future. I have looked at both sub-periods separately in an attempt to discern which of the factors affecting electricity growth have operated more or less unchanged throughout the entire period (providing reasonable confidence that they will continue to do so in the future) and which have been altered substantially by the disruptions and uncertainties that have afflicted the economy (and the energy sector, especially) since 1973.

In conducting the analysis, I have consistently used annual rates of change (sometimes averaged over 3 years) of the variables of interest, calculated as differences in the natural logarithms of the variables in adjoining years.* It should be kept in mind that all growth rates cited in the text and tables refer to logarithmic rates.

Examining rates of change in electricity use in relation to rates of change in other variables greatly reduces a common problem in economic analysis: the problem of spurious correlation. Because many parts of the economy have grown together over time, time series for causally unrelated items will show a strong correlation. For example, cigarette sales and electricity sales have both expanded many times since the 1920's; thus a plot of annual electricity sales versus annual cigarette sales will

---

* For all practical purposes, these are equivalent to commonly used arithmetic growth rates, but there are minor quantitative differences for large growth rates (above 10 percent). Logarithmic rates are used because they have desirable properties for linear regression analysis.

show a strong positive correlation. It would obviously be an error to suggest that growth in cigarette sales <u>must</u> go hand in hand with growth in electricity sales.

The correlation between electricity and cigarette sales reflects, in part, the effects on both of growing population and income, but it also reflects very importantly shifts in taste toward cigarettes and changes in energy technology favorable to electricity that occurred more or less cotemporaneously. Because these shifts were not causally related, however, they did not take place in lock-step; thus a plot of annual <u>changes</u> in electricity sales versus annual <u>changes</u> in cigarette sales will show a much weaker (possibly zero) correlation.

Analysis of rates of change helps to distinguish meaningful from spurious correlations.

Historical Analysis of Electricity Demand

Residential

Q. Please present the details of your historical analysis of electricity use in the residential customer categories.

A. My analysis focuses on annual electricity consumption (use) per residential customer and the average real (inflation-adjusted) price of electricity to residential customers. I have found that most of the changes that have occurred since 1960 in electricity use per residential customer (use per customer, for short) can be explained by changes in electricity price over time (with the exception of the changes occurring in years 1974-1976, an exception that will be discussed later).

Figure 1 (S-1, p.1, Exhibits) shows a plot of annual <u>changes</u> in electricity use per customer versus 3-year average annual <u>changes</u> in the real price of residential electricity.* This plot covers the years 1963-1973.** Except for the two years 1967 and 1972, all of the data points lie remarkably close to the straight line (shown in the figure) with a slope of -1.0 and a zero price-change intercept of 0.015.

---

* The real price change for a single year is defined as ln(RPK(t)/CPI(t)) - ln(RPK(t-1)/CPI(t-1)), where RPK(t) is the revenue per kWh (for residential customers), CPI is the Consumer Price Index, and t indicates the year. The 3-year average price change is (1/3) [ln(RPK(t)/CPI(t) - ln(RPK(t-3)/CPI(t-3))].

** Price data go back to 1960, but the first year for which a 3-year average can be calculated is 1963.

The implication of Figure 1 is that almost all of the remarkable growth in use per customer that occurred during the 1960's and early 1970's was caused by the substantial, persistent decline in real electricity prices. From 1960 to 1973, use per customer increased 6.8 percent per year, for a total increase of 140 percent. In the absence of the price decreases that were experienced, Figure 1 implies that the increase would have been only 1.5 percent per year, for a total increase for 13 years of 21 percent.

The persistent price decreases that underlay rapid growth in demand came to an abrupt halt in 1972 (surprisingly, two years before the full impact of OPEC pricing actions), and the rest of the 1970's was characterized by price changes that fluctuated wildly between negative and positive values. What had been an apparently stable, predictable pattern of declining prices was replaced by a chaotic unpredictable one.

Figure 2 (S-1, p.2, Exhibits) plots annual <u>increases</u> in electricity consumption and annual <u>decreases</u> in real electricity prices. (Note that both these are annual as opposed to 3-year-average changes.) The contrast in price behavior between the early and more recent periods is apparent. Also apparent is the sharp reduction in electricity growth once prices stopped declining steadily and instead began to fluctuate erratically.

Not surprisingly, as shown in Figure 3 (S-1, p.3, Exhibits), the 3-year average of annual price changes lost its predictive power during the first years after the 1973 oil crisis, when confusion over future prices was predominant. In a time of confusion, past price behavior does not provide people with a reliable indicator of future behavior. Most decisions that affect current electricity consumption, such as, for example, whether to install electric heat, buy a freezer, install electric rather than gas or oil hot water heat, or buy a larger, frost-free refrigerator, will also affect consumption for a long time in the future. Thus, expectations about future prices are an important determinant of changes in current consumption.

After experiencing a few years of the oil crisis, people appear to have accepted that a new and different era was here to stay. The trend of changes in electricity price (as indicated by 3-year average changes) once again became a good predictor of changes in electricity use. For the years

1977-1981, the data points in Figure 3 all lie close to a line with a slope of -1.0, as did the data points preceding the oil crisis. The zero-price-change growth rate appears to have fallen from 1.5 percent per year to zero, implying that in the absence of future real price changes, per customer use would remain constant.

Based on the above analysis, I recommend that for purposes of estimating future growth in Residential electricity sales:

(1) $\hat{\dot{s}}_r = \dot{n}_r - 1.0\ \dot{p}_r\ (3)$, where

$\hat{\dot{s}}_r$ = estimated annual change in Residential electricity sales,

$\dot{n}_r$ = annual growth in number of Residential customers,

$\dot{p}_r$ = prior 3-year average of annual change in real average price of Residential electricity.

Based on the PSNH forecast of the number of residential customers,* the implication of Equation 1 is that total residential electricity use, in the absence of real price changes, will grow by 1.9 percent per year from 1981 to 1991. If real prices were to increase by 1.9 percent per year, the implied growth in total residential sales would be zero. Conversely, a real decline in price of a comparable amount would imply growth of 3.8 percent per year.

The future course of electricity prices, thus, is important to growth in electricity demand and the need for additional electrical generating capacity.

Q. Have you considered any factors that would influence future electricity prices?

A. Yes, but I would prefer to discuss this subject after completing my historical analysis of the factors that have influenced electricity consumption for the various customer categories.

General Service

Q. Please present the details of your historical analysis of electricity use by General Service customers.

A. My initial hypothesis was that changes in total sales of electricity to General Service customers could be largely explained by changes in real electricity prices to these customers and changes in demand for

---

* Public Service Company of New Hampshire, Ten Year Electric Load Forecast, 1982 Edition, Table 5-1

the services provided by the commercial businesses that constitute this customer class. As a proxy for demand for business services, I used real New Hampshire Personal Income. To obtain real electricity prices, I divided average revenue per kWh by an index of the GNP deflator.

I applied multiple regression analysis to data on annual changes in total electricity sales and real Personal Income and prior 3-year average changes in real electricity prices, for the period 1963-1980. The analysis indicated that annual changes in Personal Income were not reliable predictors of annual changes in General Service electricity sales, but that changes in real electricity prices were strongly associated (negatively) with such changes in electricity sales.

Income Effects: Common sense strongly suggests that growth in General Service electricity use will be affected by the rate of growth in real Personal Income. The greater the amount of real income, the greater will be the demand for the services provided by General Service customers (commercial businesses). The negative finding of the regression analysis does not mean that there is little or no relation between growth in General Service sales and growth in Personal Income, but rather that short-term changes in these are not closely related. If Personal Income growth were to fall to 2 percent per year from its 1977-1981 average of 4.9 percent pev year, and were to stay at this lower level for long enough for business to believe the change would be relatively permanent, I believe that the long-run growth in General Service sales would decline by a roughly comparable amount (aside from effects of changes

in electricity prices). Conversely, increased growth in income would lead, eventually, to higher growth in General Service sales, other things equal. It is the growth in personal income that supports the expansion of the businesses that account for General Service sales.

The idea that long-run changes in personal income and in General Service sales are closely related is supported by the data for the 1961-81 period taken as a whole. The average annual growth in General Service sales (adjusted for effects of changes in real electricity prices) was 5.3 percent per year, excluding 1974-76. The average growth in Personal Income for the same years was almost identical--4.9 percent per year.

Thus, I believe that for long-term forecasting it is reasonable to assume that General Service sales will be proportional to Personal Income. It needs to be emphasized, however, that, as the statistical analysis revealed, this proportionality does not hold strongly for short-run changes in Personal Income, such as those that reflect business cycle effects rather than changes in secular trends.

Price Effects: Figure 5 (S-2, p.2, Exhibits) shows the relation between annual changes in General Service electricity sales and the prior 3-year average of annual changes in real electricity prices for General Service customers. The straight line in Figure 5 is the best fit regression line for the period, excluding the years 1974-76. The zero price-change intercept is 5.3 percent per year, and the slope is -.57. This implies that a one percentage point increase in real price is associated with a .57 percentage point decrease in sales. This result is statistically highly significant.

A different view of the same data is provided by Figure 6 (S-2, p.3, Exhibits), which connects the dots sequentially in time (excluding 1974-76). This time path shows that the rate of price decline accelerated throughout the 1960's, reaching its peak 3-year average in 1970. Sales experienced a parallel and even sharper acceleration in growth (the slope of the line through the points for 1963-71 is about -1.5). The momentum

of this acceleration carried sales growth to its peak of almost 12 percent per year in 1972, two years after the year in which prices decreased the most.

The pattern of the 1960's reversed in the 1970's. Prices first declined more slowly and then began to increase. Sales growth moved down as prices moved upward. Notably, however, the downward movement did not retrace the path of the 1960's. The 1970's path lies well above the earlier one. What could explain this difference? Is it likely to persist?

At least three different factors could underly the higher 1970's path:

1) A higher rate of electricity-using innovation.

2) A higher rate of substitution of electricity for other fuels.

3) Faster expansion of the commercial business sector.

Consider each in turn.

Most innovation occurs in response to price changes; thus it seems reasonable that as prices declined in the 1960's, innovation occurred to allow greater use of electricity as a substitute for other, more expensive resources (such as labor and building materials). This is reflected in the rise in electricity growth as prices declined ever more rapidly in the 1960's. It does not, however, explain the higher 1970's price-growth path, because at zero-price change, electricity growth was higher in the 1970's than in the 1960's. Thus, something aside from price-induced innovation was at work. And, since the major focus of development after the oil crisis seems to have been on electricity-saving innovation, it seems unlikely that changes in the rate of innovation account for the higher path.

Because oil prices rose so much faster than electricity prices during the 1970's (even before 1973), it seems plausible that at least some of the upward shift reflects a greater rate of substitution of electricity for oil heating. But, although plausible, the data do not support this explanation. Indeed, the shift toward electric heat was high only in the early 1970's, before the oil embargo. In 1971 and 1972, the increase in electric heating accounted for 2.7 and 3.2 percentage points of General Service sales growth (out of totals of 10.1 and 11.9 percent, respectively). However, from 1972 through 1979, growth in electric heating use accounted

for an average of only .2 percentage points per year (out of total growth of 4.6 percent per year).*

Thus, we are left with the third explanation for a higher sales-growth path in the 1970's: faster expansion of the commercial business sector. To explore this third explanation, I constructed an Index of Commercial Activity in New Hampshire (Table 1, S-2, p.4, Exhibits).** Table 2 shows the growth rates of this Index (and also for real N.H. Personal Income) for 5-year periods from 1955 to 1970 and for various periods from 1970 through 1981.

The pattern of growth in business activity revealed in Table 2 appears to largely explain the higher 1970's time path shown in Figure 6. As argued previously, changes in the rate of expansion in business activity must eventually be reflected in the rate of growth of General Service sales. Starting from a low base in the last half of the 1950's, growth in business activity accelerated throughout the 1960's and remained high until the 1974-75 recession created by the oil embargo. Rapid growth resumed in 1976 and continued through 1979, the last year for which data on business activity were available. This upward move in business growth provides reasonable explanation for the higher level of the electricity-sales:electricity-price growth relation in the 1970's as compared to the 1960's (Figure 6). Underlying the higher level is a higher rate of business expansion.

Figure 7 (S-2, p.4, Exhibits) shows the best-fit line through the points in Figure 6 for 1977-81. This line also provides a good fit for 1972 and 1973. Accepting that, over the long run, growth in Personal Income will, other things equal, cause an equal percentage increase in General Service sales, the line shown in Figure 7 can be used to derive a relation for estimating future sales growth. Using the 1981 value of

---

* Data are from <u>Working Papers for the 1981 Ten-Year Load Forecast</u>, PSNH, undated, pp.295-96.

** The index equals the sum of Trade and Service components of New Hampshire GNP divided by the deflator for the Personal Consumption component of U.S. GNP. Because of approximations used in constructing the State GNP series and because only a national price deflator was available, the Index is only an approximate indicator of the level of commercial business activity in New Hampshire. It should, however provide a reasonably accurate indication of relative growth rates during various multi-year periods.

the prior 5-year average of growth in Personal Income (.049 per year*) to represent the long-run trend in income growth, the best fit line implies:

(2) $\hat{s}_c = .019 + \bar{y} - 1.0\ \dot{p}_c(3)$, where

$\hat{s}_c$ = estimated annual change in General Service electricity sales,

$\bar{y}$ = long-run annual growth in real Personal Income,

$\dot{p}_c(3)$ = prior 3-year average of annual changes in real average price of General Service electricity.

Equation 2 implies that unless the economy soon returns to its previous rate of expansion, the sales:price growth relation is likely to shift downward from that shown in Figure 7. Personal Income grew by only 3.0 percent per year in 1980-81, and 1982 growth will also be low. The longer the current economic slowdown continues, the greater will be the downward pressure on electricity sales growth. At some point, business must bring its rate of physical expansion in line with growth in demand.**

Adjustment Lags: The constant term (.019) in Equation 2 implies that electricity sales would continue to grow by 1.9% per year even if there were no change in either income or price. This does not seem reasonable long-run behavior; thus we need to consider the source of this coefficient further.

The most plausible explanation is that the constant term reflects the continuing effects on electricity growth of the very long history of declining real electricity prices.

Q. The period of declining electricity prices ended in 1974. How could the declines of that period still be contributing to electricity growth today?

A. A significant portion of electricity use by commercial businesses is determined by building design. The electricity intensity (electricity use per unit of sales) of business increased steadily throughout the sixties and early seventies, as lighting levels were increased, air conditioning became more widespread, and electric heating became more common.

---

* This also is the 1961-81 average.

** Although not too much weight should be given to results for any one year, 1981 may have signalled a beginning of the downward adjustment. Sales growth in this year (which had unusually cold heating-season months) was well below the 1977-1980 sales:price relation. (See Figure 7.)

These trends were strongly encouraged (if not caused) by declining real electricity prices.

When prices began to rise, business took immediate steps to conserve on electricity (as indicated by the significant, negative coefficient of $\dot{p}_c(3)$), but conservation measures associated with changes in building design (such as improved insulation, greater use of natural light, and more efficient air conditioning) could be expected to affect electricity growth trends much more slowly.

First, building designs reflect long-run expectations about price, and for a time after the oil embargo most experts were predicting that rapid growth of nuclear power would soon put real electricity prices back on their old downward course. Only by the late seventies was it widely accepted that the era of declining prices was over.

Second, there are lags in bringing more efficient buildings into operation. Suppliers of equipment must redesign and retool. Architects must make new designs, businesses must be convinced of their practicality, and the buildings must be built.

Third, and most importantly, even after the electricity-intensity of new commercial buildings begins to fall, the average intensity of all plants will continue to rise for some time.

Figure 8 (Exhibits, S-2, p.7) is helpful for understanding why this is so. This figure displays hypothetical but reasonable schedules of the electricity intensity of new buildings and the average intensity of all buildings. During the 1950's and 60's, when electricity prices were falling, the electricity intensity of new buildings was constantly rising. The average intensity also rose, but because the average reflects the mix of buildings, it necessarily stayed below the schedule for new plants (as shown in Figure 8).

By the late 1970's, the schedule for new buildings begins to decline, but as long as new buildings have higher intensity than the average building, the average will continue to rise. As Figure 8 shows, it may well take some time before the crossover occurs and average intensity begins to decline.

The rise in average intensity that continued after electricity prices reversed their declining trend will show up as a contribution to the constant term in Equation 2.

Note, however, that as the rise in intensity begins to slow, as it must if prices continue to rise, Equation 2 will begin to overestimate growth in electricity sales. The degree of overestimation will continue to increase over time, becoming very large by the time that average intensity begins to decline.

Q. Is there evidence that Equation 2 overestimates recent sales growth?

A. No significant evidence.

Q. What do you conclude from the above discussion and analysis?

A. The discussion provides a theoretical rationale for expecting the constant term in Equation 2 to diminish over time (and even to become negative if electricity prices continue to increase), but there is not yet and will not be for some time reliable empirical evidence on the rate at which this shift can be expected to take place. This is one of many elements of uncertainty in future electricity growth.

Q. How do you propose to handle this uncertainty?

A. I will treat it explicitly when I present my estimates of the range within which future electricity demand might reasonably be expected to fall.

Industrial -- Manufacturing

Q. Please present your historical analysis of electricity use by Industrial customers.

A. I have separately analyzed two subcategories that together make up Industrial sales: 1) Manufacturing and 2) Commercial and Service. Manufacturing sales constitute about two-thirds of Industrial sales. I will discuss them first.

I first used regression analysis to estimate how annual changes in Manufacturing sales were affected by changes in the real prices of electricity and residual fuel oil and changes in the level of manufacturing activity (as measured by GNP originating in manufacturing in New Hampshire). Changes in oil and electricity prices are very highly correlated (a coefficient of correlation of .92). In this circumstance regression results that include both variables are not reliable. I therefore concentrated on analyses that excluded the price of oil. For reasons explained previously, price changes in 1974-76 were poor indicators of future price trends, and I dropped these years from the analysis. Also, Manufacturing sales growth for 1968 (19 percent) was so much higher than in the surrounding years (an average growth of 6.4 percent for 1965-70, excluding 1968)

that I hypothesize that some special, non-recurring factor (such as an acquisition of new service territory or the start up of a large plant) was at work,* and so I omitted this year from the analysis also.

A regression was performed on data for the years 1963 through 1981, excluding the years mentioned above. This yielded the following:

(3) $\hat{\dot{s}}_{IM} = .029 - .62\dot{p}_{IM}(3) + .52\dot{g}_{IM}$, where

$\hat{\dot{s}}_{IM}$ = estimated annual change in sales to Manufacturing (Industrial) customers.

$\dot{p}_{IM}(3)$ = prior 3-year average of annual changes in the real price of electricity to Manufacturing customers (reported prices were deflated by the U.S. Producer Price Index).

$\dot{g}_{IM}$ = annual change in manufacturing activity, as measured by real Gross National Product (GNP) originating in Manufacturing.**

---

* I have queried PSNH on this. The reply was negative. (See response to request 6 in PSNH Responses to CLF Data Request Set No. 7, July 30, 1982). Company data show however, that 55 percent of the sales increase in Manufacturing occurred in Sales to Paper Industries (Working Papers, op. cit., pp.346 and 356), generally a relatively slow-growing sector.

** For years prior to 1969, real Mfg. GNP had to be estimated by using the U.S. Producer Price Index to deflate current aggregate dollar values of New Hampshire Manufacturing GNP. Real GNP data for 1969-80 were available that were calculated by applying sectoral U.S. price deflators to current dollar figures for each of 22 manufacturing (2-digit SIC) categories. (Source: Gross State Product of New England 1977-79 and 1969-80 (two separate issues), Federal Reserve Bank of Boston.) Because the mix of industry in New Hampshire differs significantly from the national average, the later-year figures are substantially more accurate indicators of real New Hampshire Manufacturing Activity.

Real Manufacturing GNP of New Hampshire for 1981 was unavailable. It was estimated using an analysis of the relation between U.S. and New Hampshire economic activity presented in Appendix A of my testimony.

There are significant differences between the estimates of Manufacturing GNP derived by the alternative (aggregate and sectoral) deflation procedures. These differences, which can be seen in Table 3 (Exhibits, S-3, p.1), raise questions about the accuracy of the data prior to 1969. A regression on only the later-period growth data (1970-81), however, produced the same coefficient for $\dot{g}_{IM}$ (0.5) as did the regression for the entire 1963-80 period. This suggests that, for the purposes of the present analysis, the deficiencies in the earlier-period data are not damaging.

The regression has high statistical significance, explaining over 70 percent of the variance. The t-values of both coefficients exceed 4.0.

The constant term in the regression equation (2.9 percent per year) measures growth in electricity sales that are not statistically "explained" by the variables considered. In the analysis here, the effects of long-run trends in price and manufacturing expansion are not fully captured by the short-run explanatory variables used.

The coefficient of manufacturing growth in Equation 3 is about one-half, meaning that only one-half of the long-run growth in manufacturing is thereby predicted to be translated into electricity sales growth. Over the long run, though, electricity sales and manufacturing activity should change proportionally, other things being equal. Part of the constant term certainly reflects the one-half of long-term manufacturing growth not captured by the coefficient of $\dot{g}_{IM}$. Manufacturing output increased by an average of 4.6 per year during 1963-81 (and also during 1970-81). Incorporating long-run manufacturing growth in the prediction equation reduces the constant term by one-half that amount. Equation 3 becomes (rounding the coefficients):

(3a) $\hat{s}_{IM} = .006 - .6\ \dot{p}_{IM}\ (3) + .5\ \dot{g}_{IM} + .5\ \bar{g}_{IM}$, where

$\bar{g}_{IM}$ = long-run rate of manufacturing growth

Only a small constant term remains. This is plausibly attributable to the lag phenomena that were discussed under General Service sales. Although new manufacturing plants seem likely to be decreasing in electricity intensity under the force of rising electricity prices, the average intensity for all plants may still be increasing. Figure 8 is as applicable to the manufacturing as the commercial sector (although the rates of adjustment will almost certainly differ in the two sectors).

If this lagged adjustment is important, Equation 3 will increasingly overestimate the growth of electricity sales to Manufacturing as the proportion of more electricity-efficient plants rises over time. Figure 9 shows actual and estimated sales growth. The estimating equation does a good job of tracking actual sales growth (even for most of the years omitted in the regression used to derive the equation). Actual growth did fall somewhat below estimated growth in both 1980 and 1981, but the variance in year to year estimates is too great to have confidence that

this constitutes a trend. For the present, the existence and rate of this downward adjustment in sales growth must be considered uncertain.

Q. Might not a portion of the constant term in the estimating equation reflect above-average expansion of electricity-intensive industries in New Hampshire?

A. It is true in theory that this could be the case. Rapid growth of very intensive users of electricity (per dollar of production) would raise the overall electricity intensity of manufacturing. This would be growth over and above that related to expansion in the size (as measured by Manufacturing GNP) of the manufacturing sector. A detailed calculation for the 13 Manufacturing subcategories used by PSNH shows that this was not the case for the period 1972 through 1979, the only period for which data were available to permit the calculation to be made. For this period as a whole, real Manufacturing GNP increased by 43%. If electricity-intensities (kWh's per dollar of GNP) for each subcategory had remained at the 1972 values, Manufacturing electricity use would have increased by 40 percent; thus differential growth within subsectors tended to lower the overall electricity-intensity of manufacturing.*

Q. Does this complete your historical analysis of Manufacturing sales?

A. Yes.

Industrial -- Commercial and Service

Q. Please present your findings for the Commercial and Service portion of Industrial sales.

A. Commercial and Service (C&S) represents sales to large stores (the largest subcategory), hotels and motels, banks and insurance companies, private schools, hospitals, sales to utilities and miscellaneous other enterprises. This has been historically the fastest growing major category of sales, increasing at an average rate of 11 percent per year during 1966-81.

In analyzing C&S sales, it is helpful to treat sales to Utilities separately, as it is a special, atypical category. As can be seen in Table 4 (Exhibits, S-3, p.3), year to year sales fluctuate widely and show no growth trend. Prior to 1977, a large part of this category represented sales to a gas pipeline, which then ceased business with PSNH.

---

* Calculation based on constant-dollar GNP originating in 2-digit SIC manufacturing industries (Gross State Product of New Hampshire, Federal Reserve Bank of Boston, various issues).

Growth in more recent years represents construction power for Seabrook. These sales will begin declining as Seabrook II nears completion. For purposes of forecasting, I will project Utility sales separately. The remainder of this section will consider C&S sales excluding the Utility category.

The most striking characteristic of historical growth in C&S sales is the distinct difference in growth before and after 1973. For 1966-73, growth averaged 19 percent per year. For 1974-81, it averaged 3.4 percent per year. Before 1974 there was only one year in which growth was below 14 percent per year. After 1973, there was no year in which growth exceeded 10 percent.

The full explanation for this sudden change in pattern is not apparent from the data considered here. The primary factor was undoubtedly the shift from declining to rising real electricity prices, but this alone does not seem sufficient to explain the entire difference.

Figure 10 shows annual changes in C&S sales versus the prior 3-year average of changes in the real price of electricity to C&S customers. As usual, the points for 1974-76 lie above the sales:price relation for other years. Excluding these atypical years, there are two distinct clusters of data points: 1966-73 (with 1971 being atypical within the cluster) and 1977-81. Drawing a single best-fit line through both clusters (excluding 1971) would produce a coefficient of sales growth with respect to price change (a price elasticity of sales growth) of almost -2.0. This is a far greater sensitivity to price than found for any other category of sales and does not seem reasonable. A more plausible interpretation is that there was a downward shift in the underlying growth rate* between the two periods. If we accept -1.0 as a reasonable approximation of the price elasticity of sales growth (the elasticity found for General Service), the underlying growth rates would be about 13 and 8.5 percent per year in the two periods. Figure 11 shows the implied price:sales growth relations for the two periods.

---

* The one that would occur in the absence of changes in price.

The sales:growth line based on an assumed price elasticity of -1.0 underestimates sales growth in 1980 and 1981. This is undesirable for projecting future sales. The best-fit line through the 1977-81 data points in Figure 10 has a slope of -.5 (a smaller price elasticity) and implies an underlying growth rate of 5.8 percent. This gives a much better estimation for 1980 and 1981 and is therefore preferred, although the price elasticity seems low based on the results for General Service. If so, the equation will overestimate sales growth when prices are rising rapidly.

The underlying growth rate for the recent period (5.8 percent) implied by this analysis exceeds the growth rate of the New Hampshire economy as a whole. This does not seem surprising for this category of sales, first, because it contains relatively rapidly growing sectors (banks and insurance, hospitals) and, second, because large businesses are undoubtedly growing faster than small ones (reflecting the national trend toward bigness).*

There is no empirical way to determine the sensitivity of C&S sales to changes in the size of the state economy. Sales are not sensitive to short-run changes in state income, and over the longer run income growth has been relatively stable compared to many other factors that influence sales. Thus, one can only appeal to reason. As argued above, it does seem reasonable that C&S sales expand more rapidly than the average rate of business expansion. An estimating equation that allows for this effect and conforms to the 1977-81 best-fit price:sales growth relation (using the 1977-81 average annual growth in personal income of 4.9 percent) is:

(4) $\hat{s}_{IC} = 1.2\bar{y} - 0.5\,\dot{p}_{IC}(3)$, where

$\hat{s}_{IC}$ = estimated annual change in (Industrial) Commercial and Service sales,

$\bar{y}$ = long-run annual growth in real Personal Income,

$\dot{p}_{IC}(3)$ = prior 3-year average of annual changes in the price of Industrial electricity, deflated by the U.S. GNP implicit price deflator.

---

* The more rapid growth of the early period may reflect in part the initial surge of larger businesses into New Hampshire. The slower present growth may, then, reflect a more mature economy in this respect.

The coefficients in this equation are more uncertain than in previous equations. It will be important to test the performance of the equation in the next few years.

Q. Do you believe that the lag phenomena discussed previously is important in C&S sales.

A. The major expansion in this sector occurred in the late sixties and early seventies, when electricity-intensities of buildings were already at high levels; thus the average intensity was probably close to the intensity for new construction in 1974, when the trend of electricity prices reversed. If this is correct, there should be less of a lag in this sector than in manufacturing and small commercial business. This may also account, in part, for the apparent downward shift in the underlying rate of sales growth between the earlier and later periods.

I have chosen coefficients that make the constant term in Equation 4 equal to zero. This implies that average and new-construction electricity intensities are equal. This is unlikely to be the case, but there are no good grounds for assuming one is higher than the other. Again, this is an area of uncertainty.

Q. Does this complete your historical analysis of growth in electricity consumption?

A. Yes.

Q. Could you please summarize the equations that will form the basis for your projections of future demand for electricity.

A. Residential

(1) $\hat{\dot{s}}_r = \dot{n}_r - 1.0\ \dot{p}_r(3)$

General Service

(2) $\hat{\dot{s}}_c = .019 + \bar{y} - 1.0\ \dot{p}_c\ (3)$

Industrial-Manufacturing

(3a) $\hat{\dot{s}}_{IM} = .006 - .6\ \dot{p}_{IM}(3) + .5\ \dot{g}_{IM} + .5\ \bar{g}_{IM}$

Industrial-Commercial and Service

(4) $\hat{\dot{s}}_{IC} = -0.5\ \dot{p}_{IC}(3) + 1.2\ \bar{y}$

PROJECTING FUTURE DEMAND FOR ELECTRICITY

Q. Please describe how you will use the demand equations to project future sales of electricity.

A. The electricity demand "model" described by the four equations makes future growth in electricity a function of future changes in electricity prices, economic activity, and population (households). Thus, given this model, the task of projecting electricity demand becomes one of specifying future changes in these underlying variables. There are significant uncertainties about the future course of the economy and future prices of electricity and these uncertainties will be reflected in the projections of electricity demand.* The result of the analysis will be a range of rates of electricity growth, with the values within this range explicitly linked to the values of the underlying variables.

Q. What are the most important uncertainties affecting future electricity growth?

A. Future economic growth and fossil fuel prices are both uncertain, but by far the most important uncertainties concern Seabrook. The cost, timing, and PSNH ownership share of Seabrook are the dominant sources of uncertainty about future electricity growth.

Q. How will you deal with these uncertainties?

A. Because Seabrook is the most important factor in determining future demand growth, I will make separate projections of growth under different assumptions about Seabrook cost and timing. I will consider the effect of cancelling Seabrook II as a means of reducing the PSNH commitment to Seabrook.

Underlying Assumptions

The projections under different assumptions about Seabrook cost are made using a fixed set of values for future economic and population growth, fuel prices, Seabrook performance, and parameters of the demand model. Values were used that I judged to be near the middle of the range of uncertainty.**

---

* Growth in the number of households (residential customers) is also uncertain, but to a much lesser degree.

** See Appendix A.

Uncertainties in the values specified are considered separately.

The Basic Economic Environment

The basic economic environment assumed is favorable to expansion of electricity demand. Manufacturing expands rapidly: 5.9 percent per year through 1985 and 4.7 percent per year through 1991. Real personal income continues to grow rapidly, averaging growth of 4.4 percent per year over the next 10 years. Fuel prices are constant in real terms through 1985 and rise only modestly thereafter (2 to 3 percent per year). If it were not for Seabrook, the basic environment would imply electricity growth of 2 to 3 percent per year throughout the next decade. Seabrook, however, will radically transform the cost structure and growth prospects of PSNH.

Projecting Future Electricity Costs

Determining the effects of Seabrook on PSNH costs is an extremely complex problem. The effects depend not only on the cost and timing of construction expenditures, but also on the costs of borrowing, regulatory lags, and tax effects. PSNH and Rosen have made projections of future revenue requirements under various assumptions about Seabrook cost and timing using computerized financial models. Their projections of non-production costs (primarily capital-related costs, but including costs of administration and transmission and distribution O&M) are used as the basis for determining future electricity costs under different assumptions about Seabrook. Fuel and O&M expenses were estimated separately, using the basic-environment assumptions and estimated levels of generation. These expenses were added to the estimates of non-production costs to obtain estimated total costs.* The cost projections were then combined with the demand equations to project future electricity sales. Appendix A describes and illustrates the methodology.

Alternative Seabrook Cases

Demand and electricity prices were projected for four different

---

* The computer projections, which ended in 1989, were extrapolated to 1991 to permit 10-year projections of demand to be made.

Seabrook cases.

1) Low Seabrook Cost is based on a financial forecast of PSNH.* Seabrook I is assumed to begin commercial operation on 2/28/84 and Seabrook II on 5/31/88. The projection reflects the basic PSNH cost estimates of $2472 and $1549 million for the two units. No information is provided on how the two-year delay for Seabrook II affects the estimated cost, but any changes are implicit in the cost figures projected by PSNH.

2) Mid-Range Seabrook Cost is based on Rosen's Scenario A-4. On-line dates for Seabrook I and II are July 1985 and 1988. Estimated costs are $3129 and 2413 million.

3) High Seabrook Cost is based on Rosen's Scenario A-1. On-line dates are the same as in A-4, but estimated costs are $4010 and $4561 for the two units. This is Rosen's "most probable" estimate.

4) Mid-Range/Cancel Seabrook Cost is based on Rosen's Scenario A-8. Seabrook II is assumed cancelled on July 1, 1982, and sunk costs as of that date are assumed written off over 10 years, with no rate of return on the unamortized balance. Seabrook I comes on-line in July 1985 and costs $3129.

In all of the cases, the current PSNH ownership share (35.6 percent) is assumed. Rosen uses the PSNH estimates for Administration and General Expenses and Transmission and Distribution O&M Expenses, so these are the same in all cases. Rosen's projected borrowing costs are generally higher than those assumed by the Company. The financial projections of PSNH and Rosen both assumed constant 8 percent inflation throughout.** Rosen's estimated nuclear O&M costs were used in his scenarios. The PSNH estimates of O&M were used in the Low-Cost case.

---

* Financial Forecast Computer Solution, Scenario Designation G&R 82-3, PSNH, 6/7/82, NHPUC Docket No. DF 82-141, Attachment Panel-4.

** In applying these cost data to the demand models, they were first converted to 1981 dollars so that results could be presented in constant dollars. But, this conversion does not eliminate the effect of the assumed inflation rate on the results. Inflation affects both the estimated real cost of Seabrook and the rate at which its real contribution to the rate base declines after entering operation.

Projected Sales and Prices

Projected electricity sales and prices for each of the four Seabrook cases are presented in Tables 5-8 (Exhibits, S-4, pp.1-4). For the 10 year period considered, the average rate of electricity growth ranges from -5.3 percent per year in the High Cost case to 3.5 percent per year in the Low Cost case. Electricity prices in 1991 range from 5.5¢ per kWh to 17.4¢ per kWh (in 1981 dollars) for Industrial customers; prices for other classes exhibit similar variation.

These results demonstrate the dependence of future electricity prices and sales growth on Seabrook costs.

Q. Does this complete your testimony?

A. Yes.

EXHIBITS

to Accompany the

Testimony of Vince Taylor

before the

Public Utilities Commission

of New Hampshire

Docket No. DE 81-381

October 8, 1982

Conservation Law Foundation

Table I

Estimated and Actual PSNH Electricity Sales
Growth for 1977-81[a]
(Percent per Year)

	1977	1978	1979	1980	1981
Residential					
Estimated	1.2	2.9	2.4	1.7	-0.7
Actual	2.6	3.2	2.2	0.8	-.1
General Service					
Estimated	5.1	6.5	5.9	3.6	3.2
Actual	5.0	6.5	5.7	4.7	2.5
Industrial					
Manufacturing					
Estimated	6.9	7.5	5.5	0.1	-1.0
Actual	2.4	6.8	4.5	2.2	0.1
General & Service[b]					
Estimated	4.5	5.6	4.1	1.5	0.4
Actual	2.4	6.8	4.5	2.2	0.1
Total[c]					
Estimated	3.9	5.2	3.8	1.5	-0.6
Actual	3.7	6.8	3.4	0.6	-.9

---

a. Estimated values are based on Equations 1, 2, 3a, and 4 of this testimony, using actual changes in real price and economic activity.

b. Excluding Sales to Utilities within this customer category.

c. Weighted by the fraction of sales in each customer class.

Figure I

Projected PSNH Prime Sales for Three Estimates of Seabrook Cost -- Present Ownership Share, Mid-Range Economic Growth

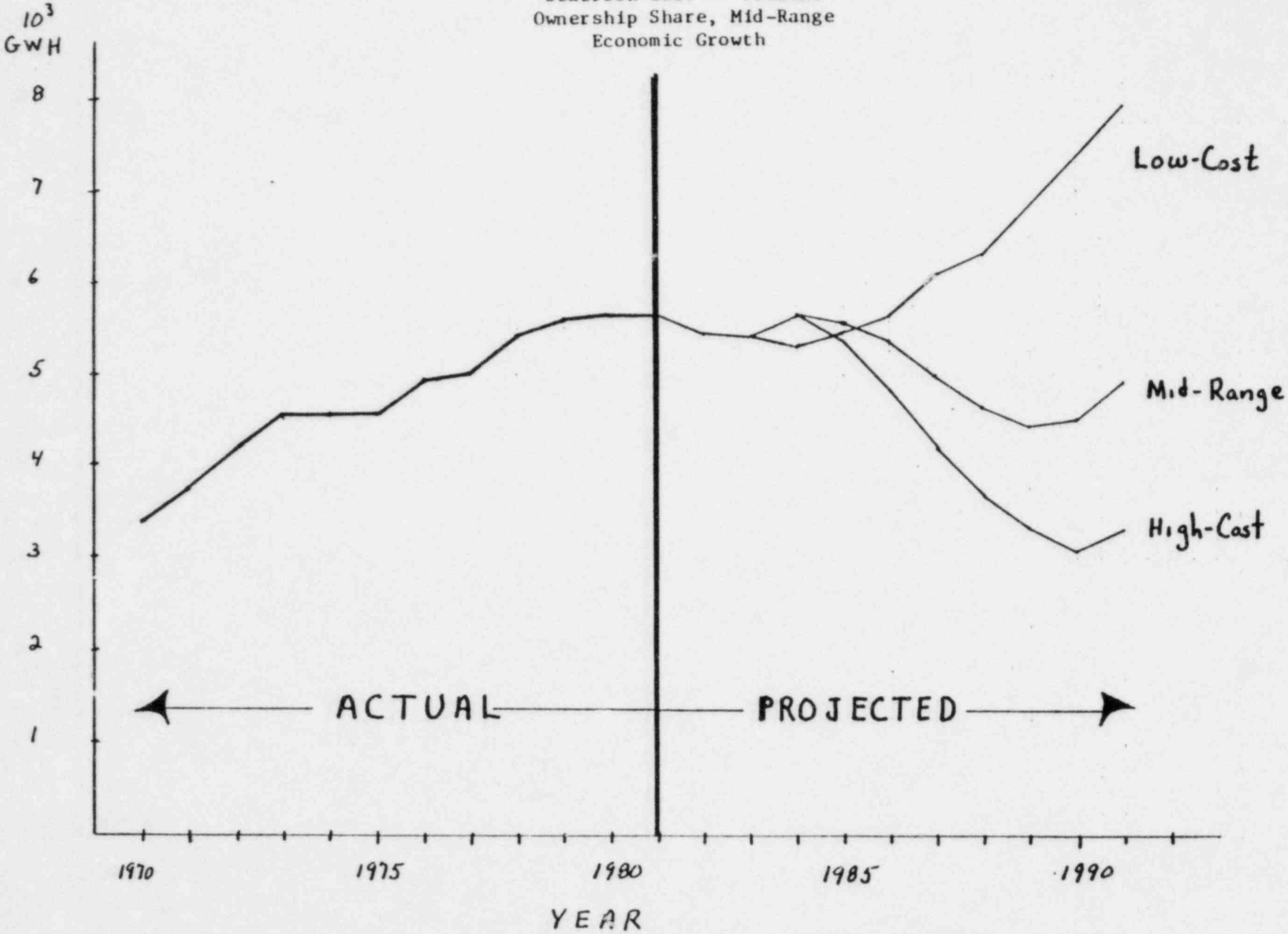


Figure II

Projected PSNH Real
Electricity Prices for
Three Estimates of
Seabrook Cost
(1981 Dollars)

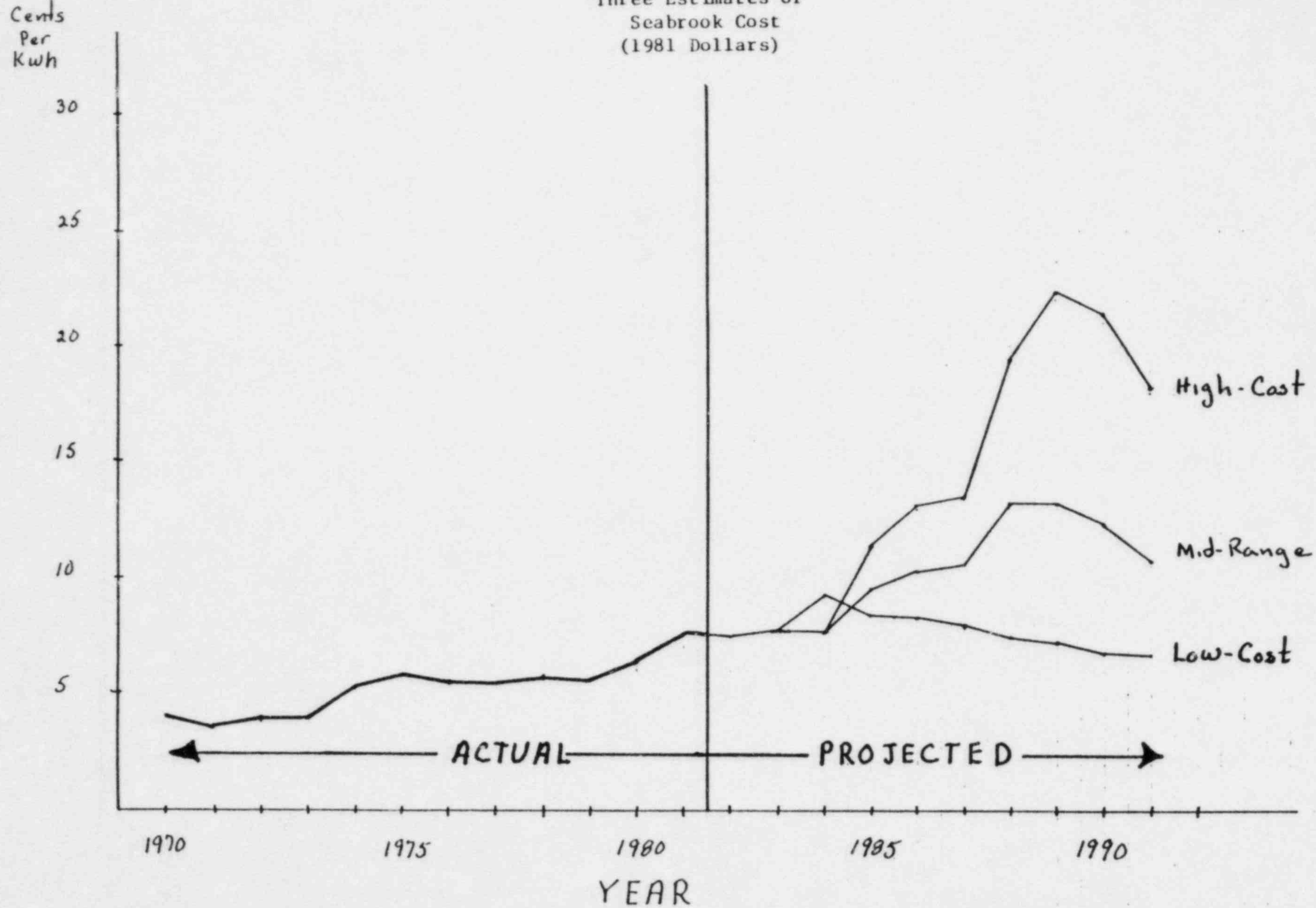


Figure III

PSNH Planned Generation Capability and Required Generation -- Low Seabrook Cost

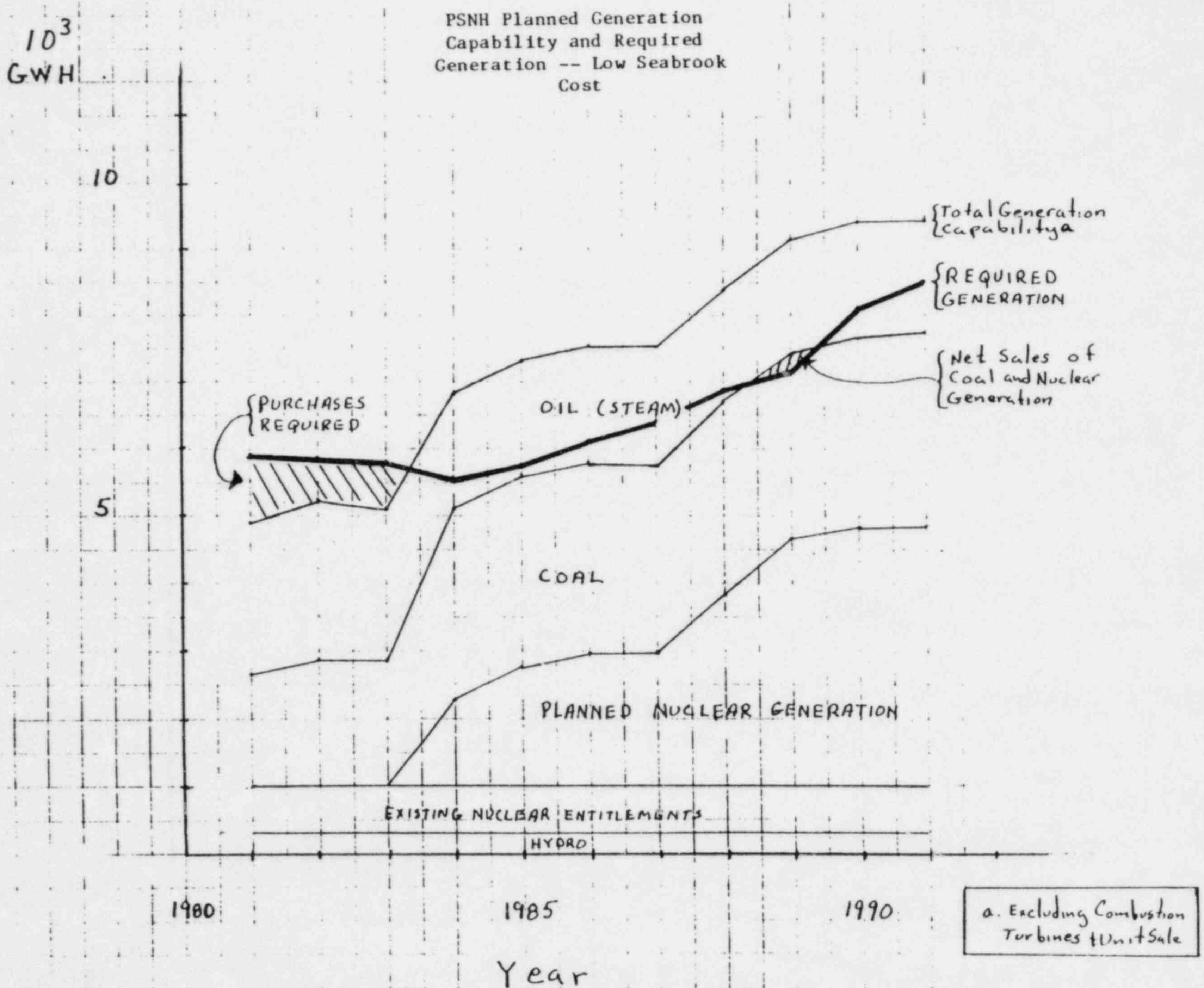
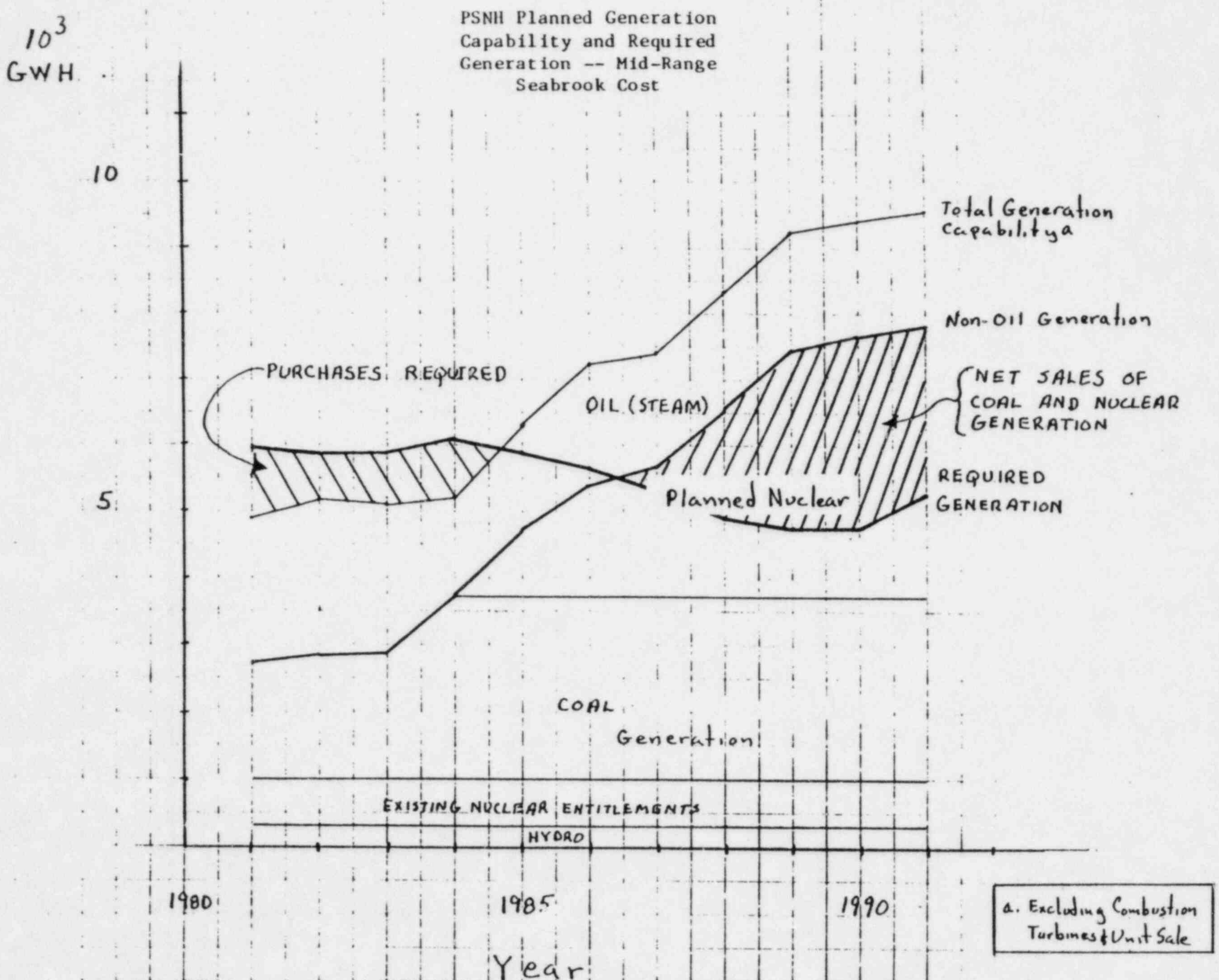


Figure IV

PSNH Planned Generation
Capability and Required
Generation -- Mid-Range
Seabrook Cost



S-O, p.5

Figure V

PSNH Planned Generation
Capability and Required
Generation -- High Seabrook
Cost

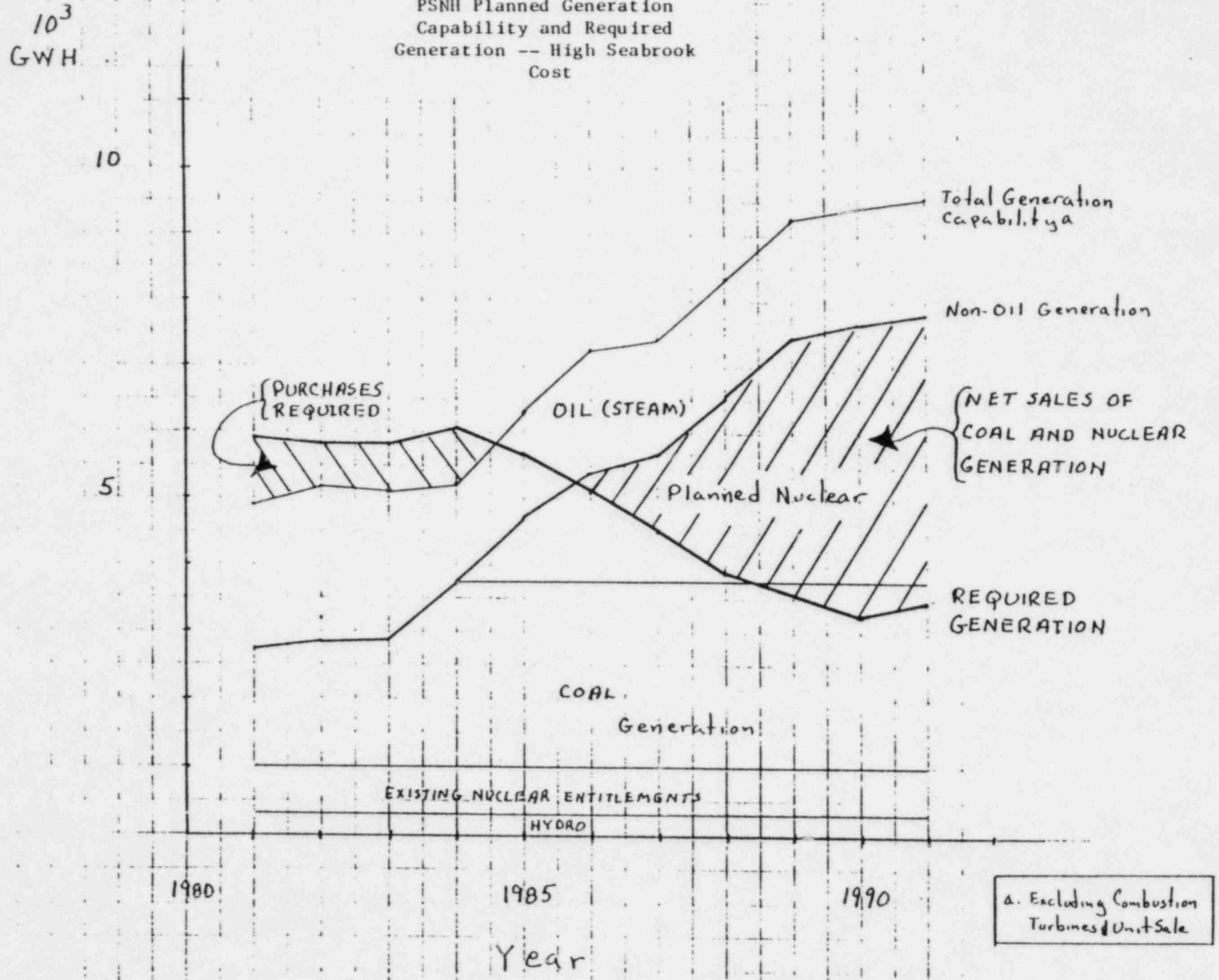


Figure VI

Cancellation of Seabrook II:
Generation Capability
And Requirements -- Mid-
Range Seabrook Cost

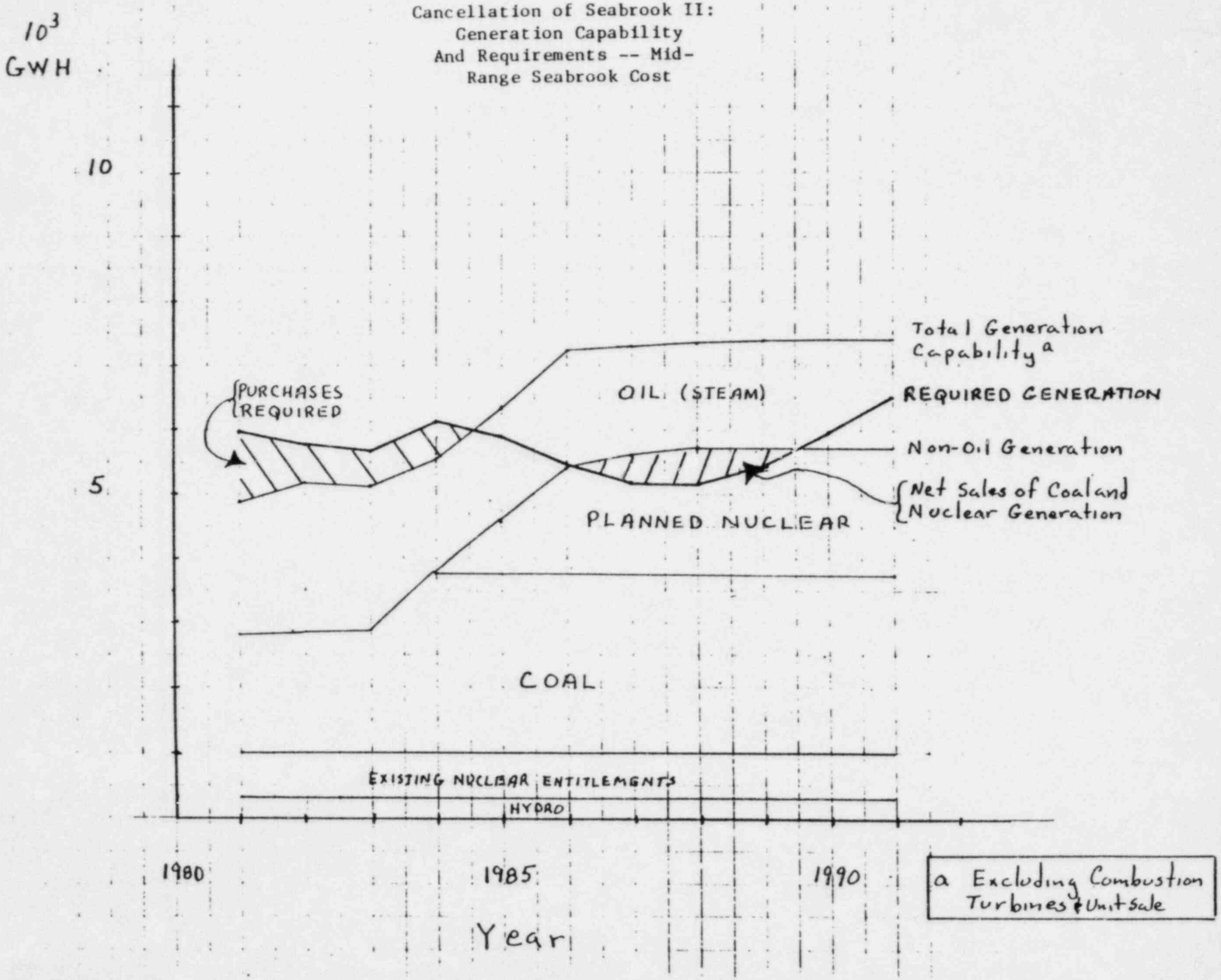
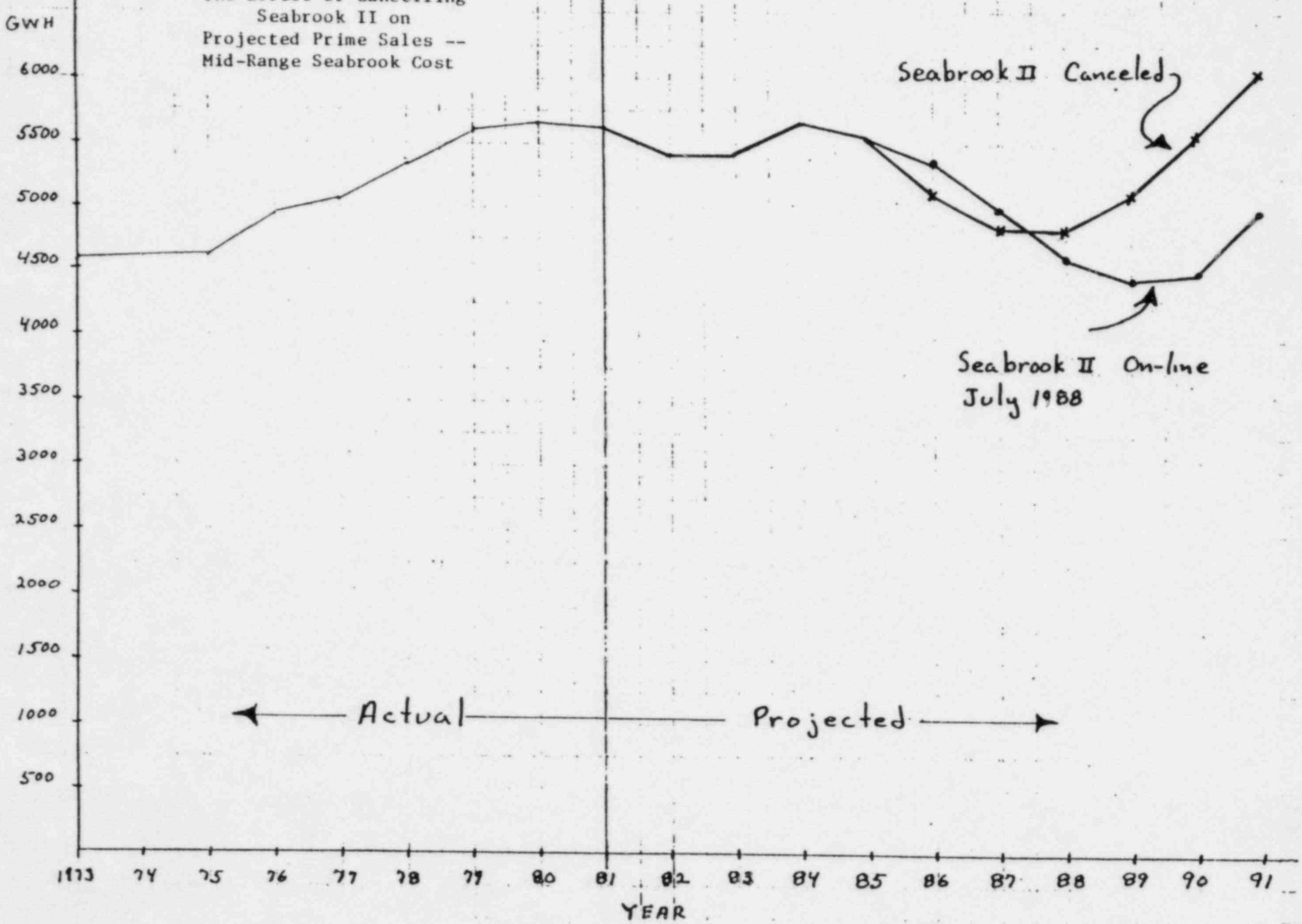


Figure VII

The Effect of Cancelling Seabrook II on Projected Prime Sales -- Mid-Range Seabrook Cost



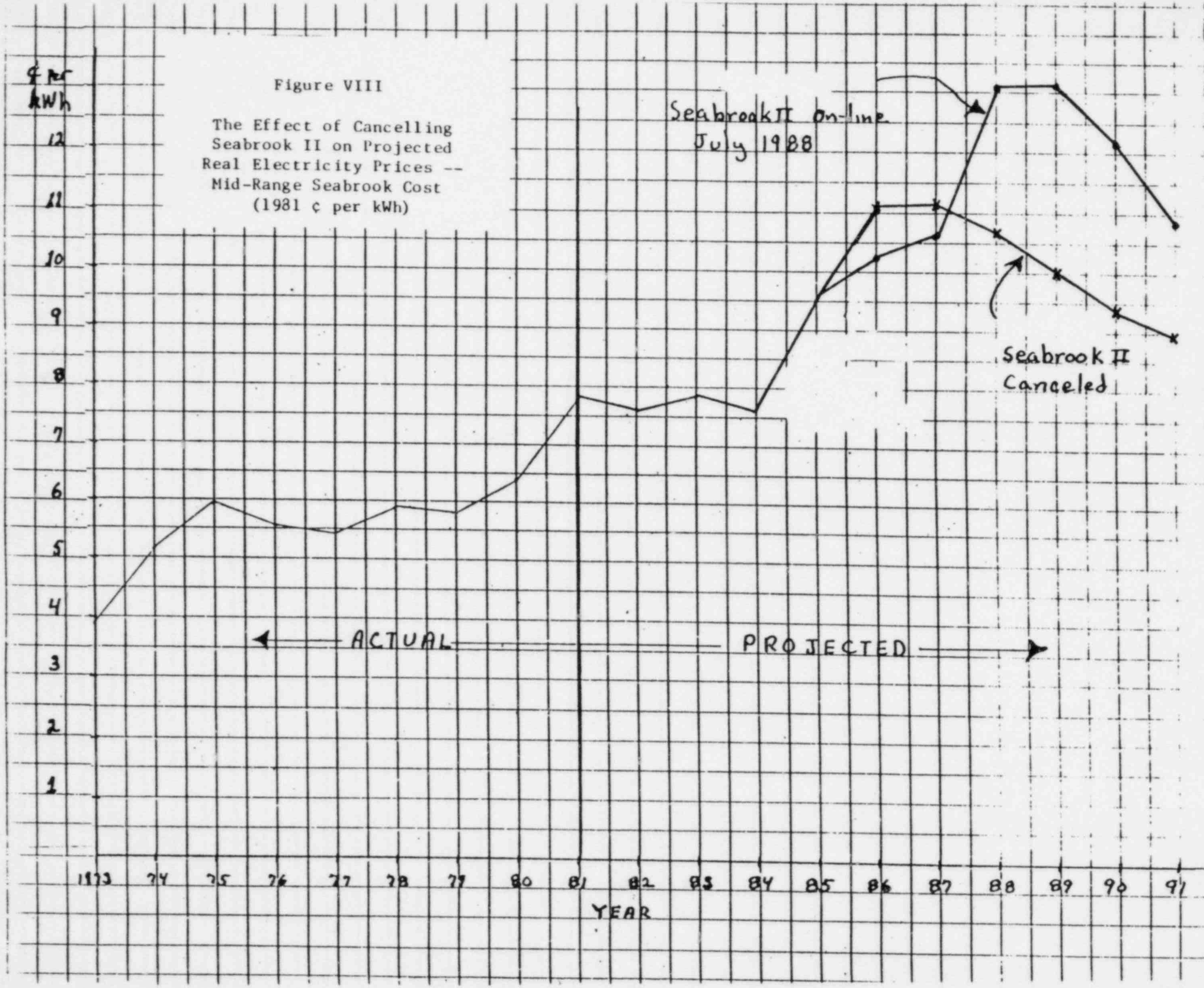
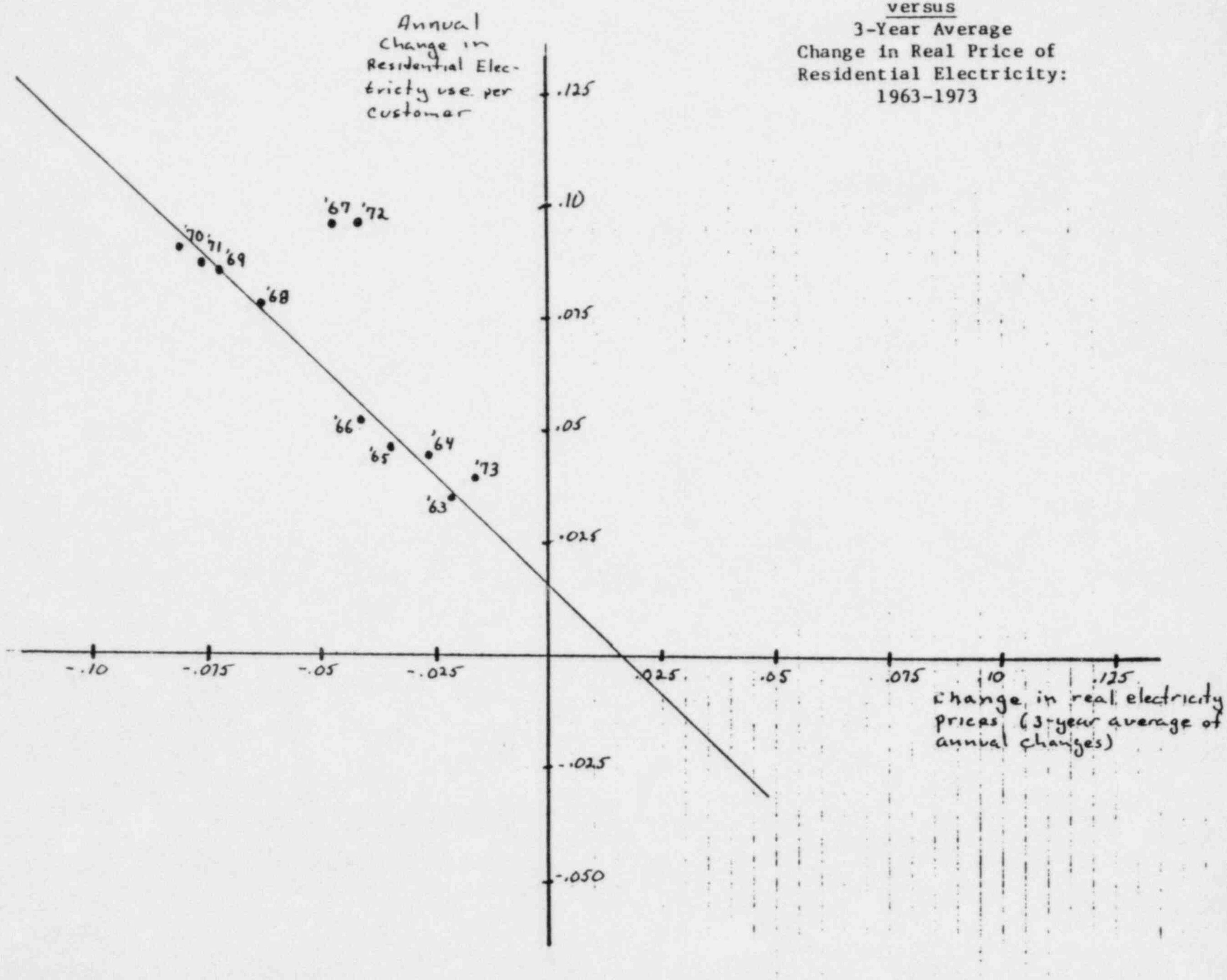


Figure VIII

The Effect of Cancelling Seabrook II on Projected Real Electricity Prices -- Mid-Range Seabrook Cost (1981 ¢ per kWh)

Figure 1

Annual change in Residential Electricity
Use per Customer
<u>versus</u>
3-Year Average
Change in Real Price of
Residential Electricity:
1963-1973



S-1, p.1

Figure 2

Annual Changes in Residential Electricity Use and Real Residential Electricity Prices

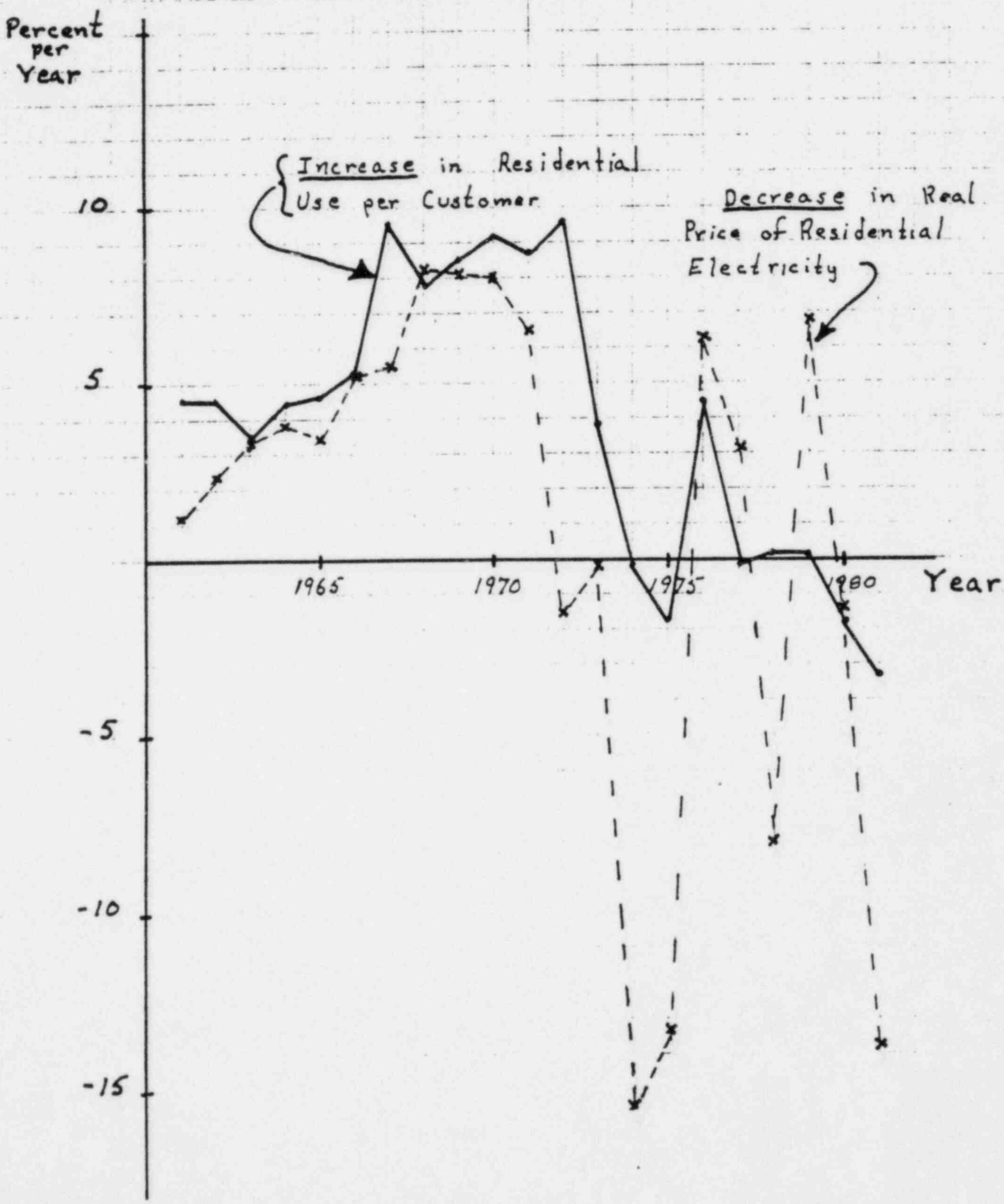
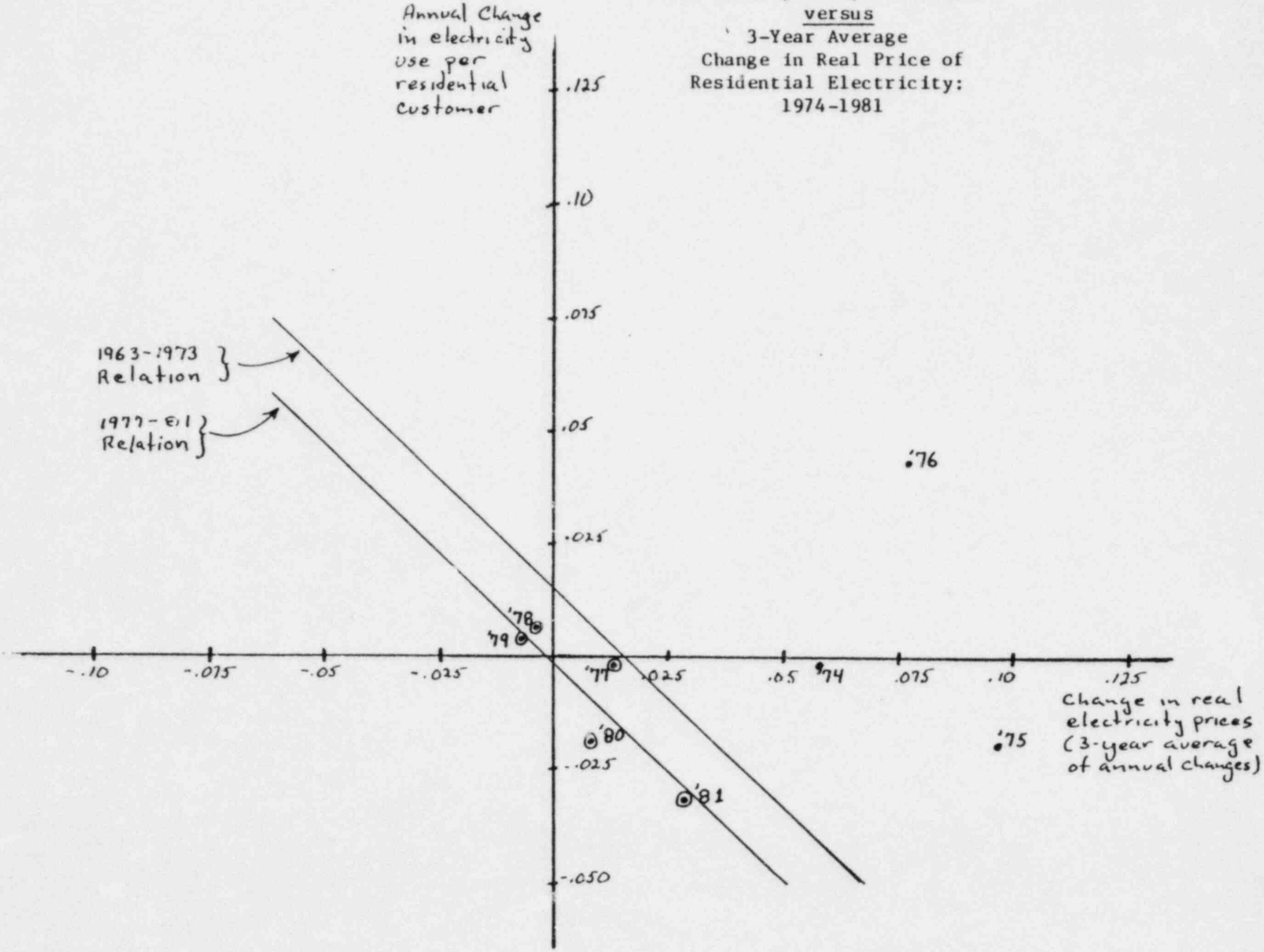


Figure 3

Annual change in Residential
Electricity Use per Customer
<u>versus</u>
3-Year Average
Change in Real Price of
Residential Electricity:
1974-1981



S-1, p.3

There is
no Figure 4

Figure 5

Annual Change in General Service Electricity Sales
versus
3-year Average Change in Real Price
of General Service Electricity:
Average 1963-81 Relation, Excluding 1974-76

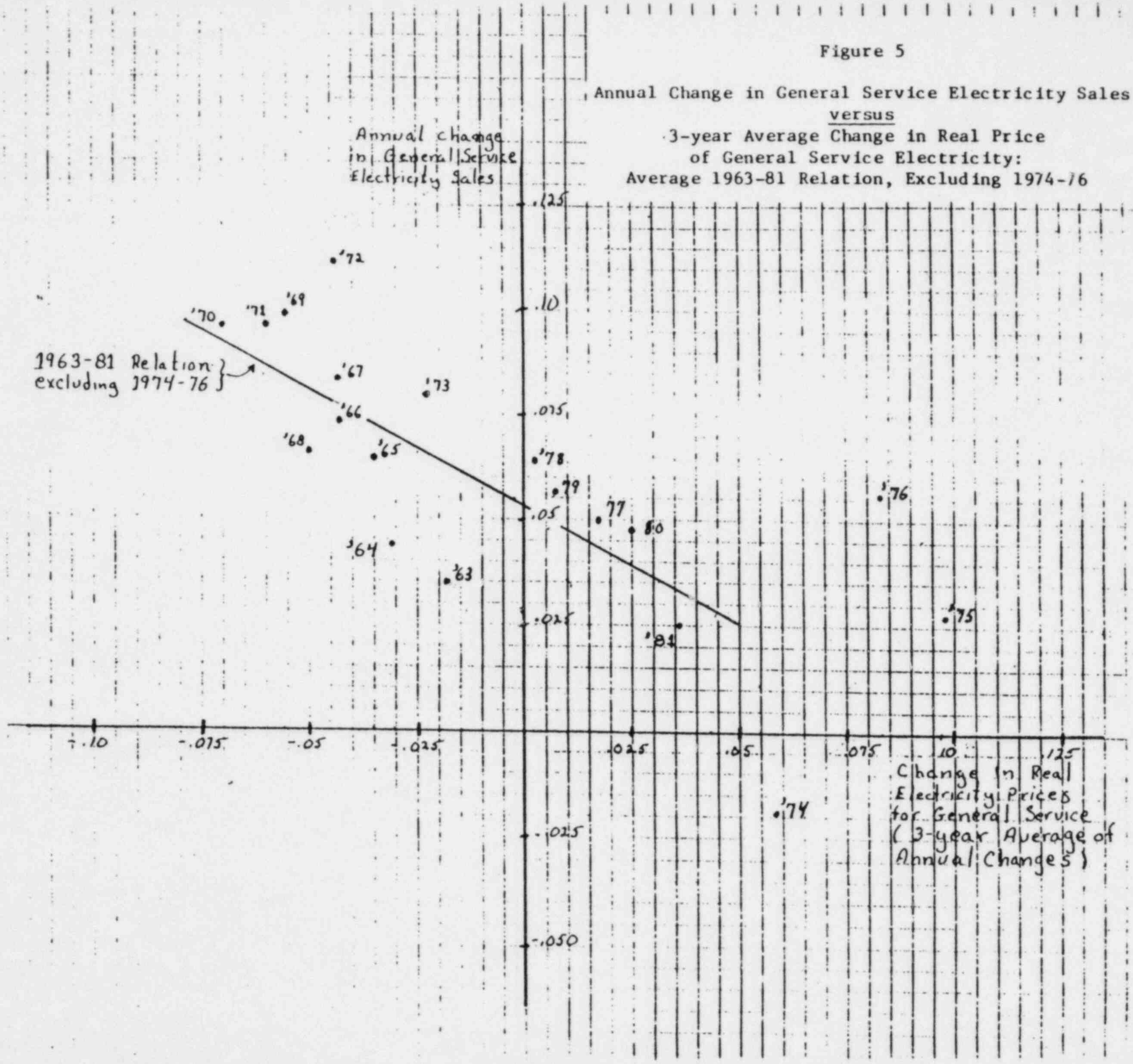


Figure 6

Annual Change in General Service Electricity Sales
versus
3-year Average Change in
Real Price of General Service Electricity:
1963-81 Sales-Change:Price-Change Path,
Excluding 1974-76

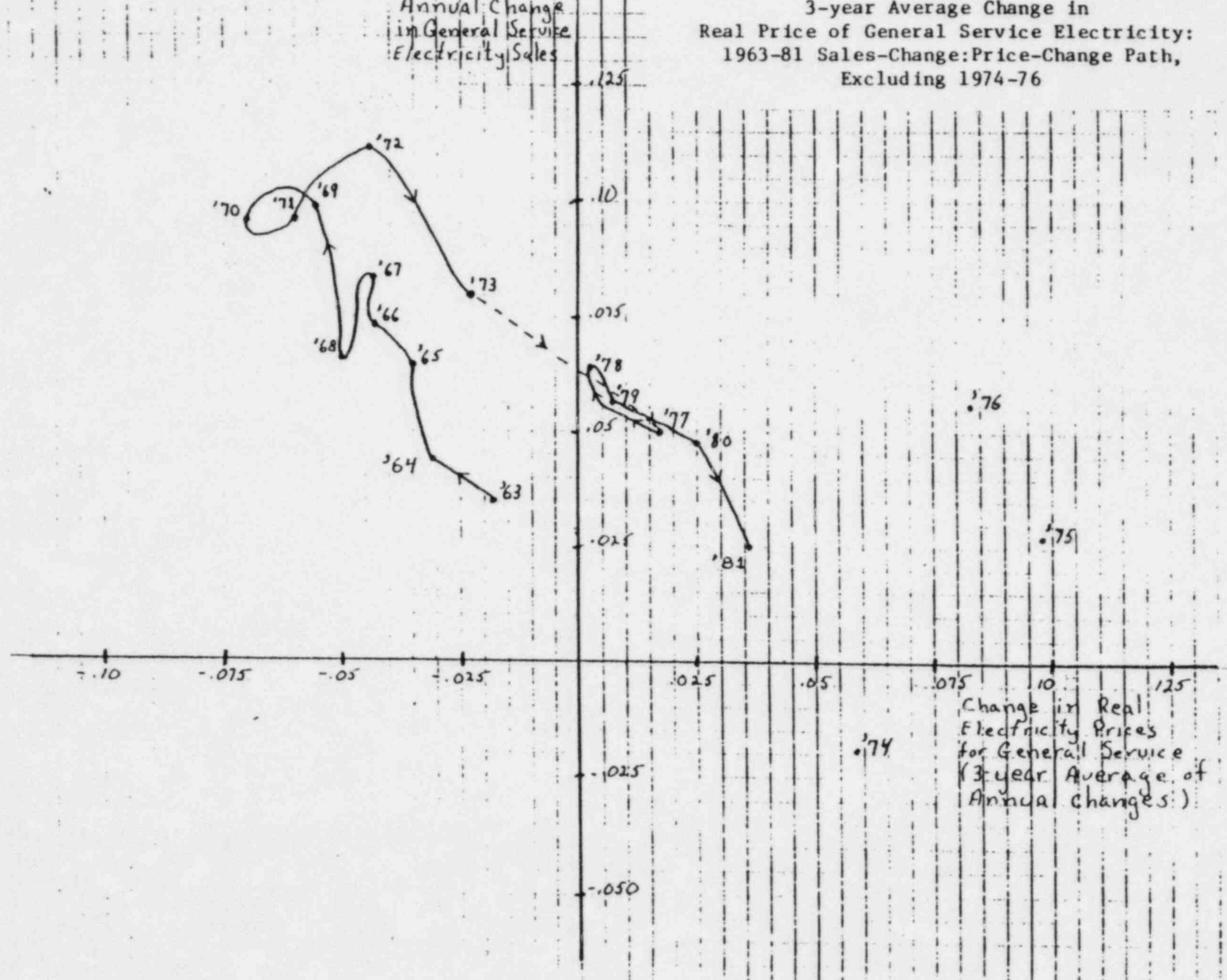


Figure 7

Illustrative Long-Run Relation between General Service Electricity Sales Growth and Changes in Real Price of General Service Electricity, Assuming 4.9 percent Annual Growth in Personal Income

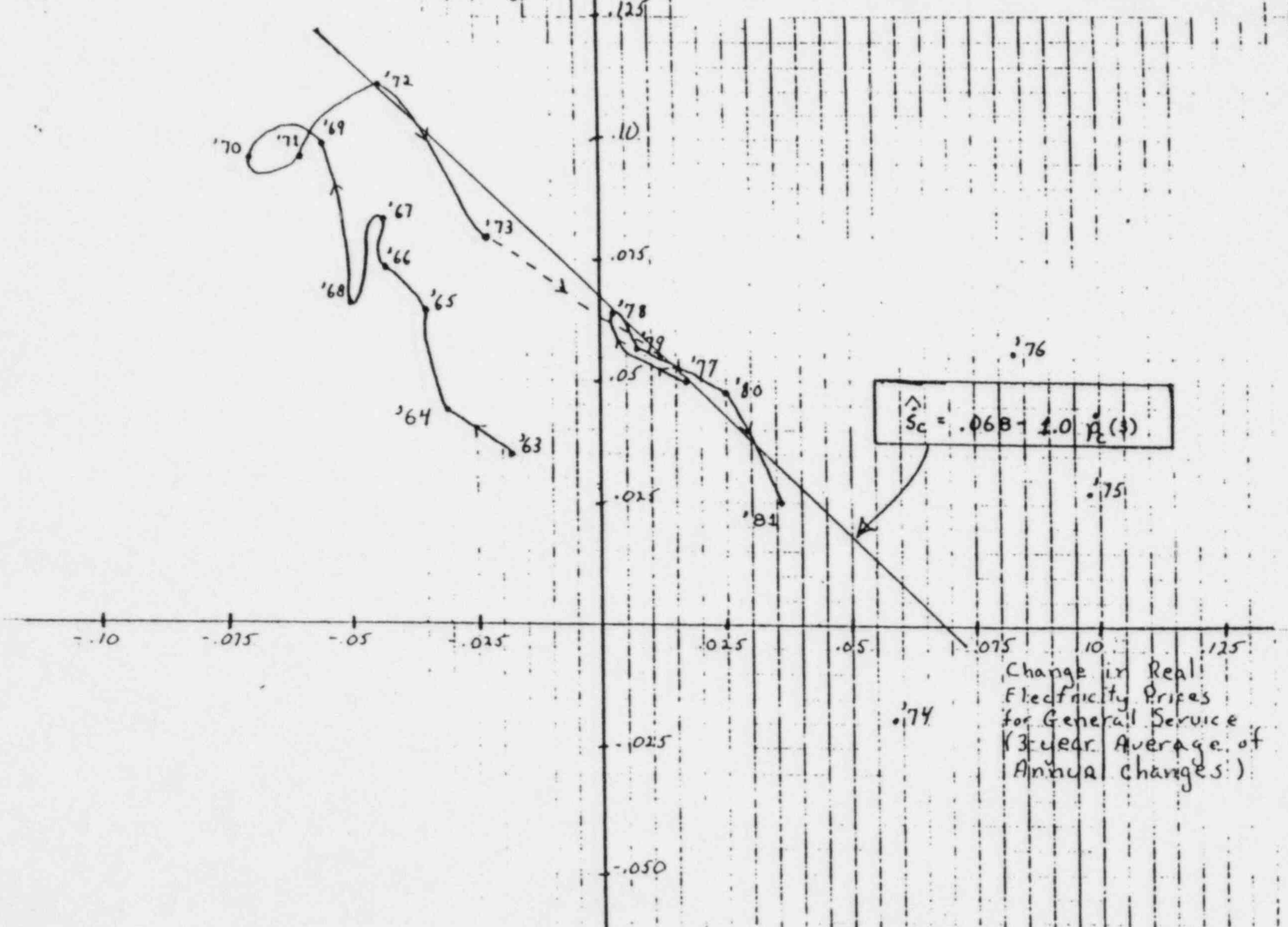


Table 1

Index of Commercial Activity
in the State of New Hampshire

Year	Value of Commercial Activities[a]	Price Deflator[b]	Index of Real Commercial Activities[c]
55	288	644	44.7
56	307	656	46.8
57	328	678	48.4
58	324	692	46.8
59	348	706	49.3
60	369	719	51.3
61	391	726	53.9
62	424	737	57.5
63	444	748	59.4
64	489	759	64.4
65	525	772	68.0
66	590	794	74.3
67	644	814	79.1
68	711	846	84.0
69	783	884	88.6
70	870	925	94.1
71	950	965	98.4
72	1023	1000	100.2
73	1243	1057	117.6
74	1384	1163	119.0
75	1463	1252	116.8
76	1683	1316	127.9
77	1898	1395	136.0
78	2169	1491	145.5
79	2427[d]	1623	149.5

Notes to Table 1

a. Equals the sum of Trade and Service components of New Hampshire GNP. Source: Gross State Product of New England 1977-79, Federal Reserve Bank of Boston, undated.

b. Deflator for Personal Consumption Expenditures component of U.S. GNP; 1972 equals 1000. Source: Economic Report of the President, Government Printing Office, Washington, D.C., February 1982, p.236.

c. Equals column 1 divided by column 2.

d. Latest year available.

Table 2

Growth Rates of Commercial Activity and Real Personal Income in the State of New Hampshire: 1955-1981 (percent per year)

Period	Index of Commercial Activity[a]	Real Personal Income[b]
1956-60	.028	.031
1961-65	.056	.044
1966-70	.067	.051
1971-75	.043	.029
1971-73	.074	.049
1974-75	-.003	-.002
1976-80	n.a.	.058
1976-79	.062	.064
1977-81	n.a.	.049
1977-79	.052	.061
1980-81	n.a.	.030

Notes to Table 2

a. From Table 1

b. Sources: Prior to 1960, Historical Statistics of the United States, Part 1, U.S. Department of Commerce, Bureau of the Census, Washington D.C., 1975, Series F297-348, p.244; 1960 to 1981, Survey of Current Business, U.S. Department of Commerce, Bureau of Economic Analysis, August 1979, July 1981, and April 1982. Deflation by the U.S. GNP implicit price deflator.

Figure 8

Illustrative Schedules of Electricity Intensity
In Commercial Buildings

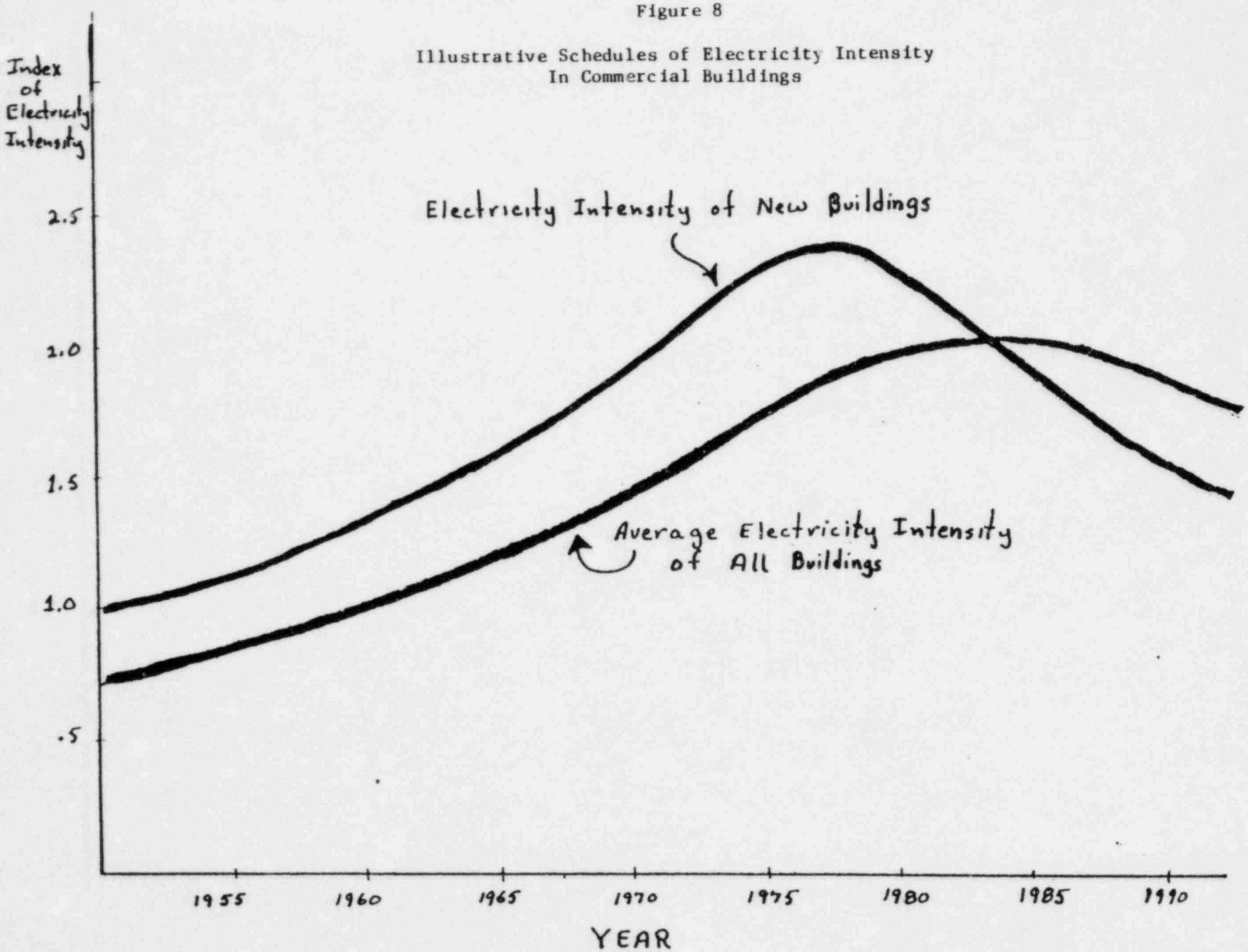


Table 3

Alternative Estimates of
Annual Changes in Constant
Dollar GNP Originating in Manufacturing
in New Hampshire

Year	Aggregate Deflation[a]	Sectoral Deflation
1970	-.057	-.064
71	-.003	.001
72	.031	.120
73	.060	.106
74	-.113	-.040
75	-.103	-.095
76	.144	.142
77	.110	.109
78	.093	.099
79	.043	.081
80	-.054[c]	.014
81	.028[c]	.050[d]
Average	.015	.046

Notes and Sources

a. Total current dollar GNP originating in Manufacturing (Gross State Product of New Hampshire 1977-79, Federal Reserve Bank of Boston, undated) deflated by the U.S. Producer Price Index (Economic Report of the President-1982, Government Printing Office, Washington, D.C., January 1982).

b. Constant dollar GNP originating in Manufacturing (Gross State Product of New England 1969-80, Federal Reserve Bank of Boston, undated), derived by applying U.S. sectoral deflators to current dollar values for each 2 digit SIC Manufacturing category.

c. Estimated by applying U.S. growth rates for the "Goods" component of GNP to 1979 data for New Hampshire Manufacturing GNP.

d. Estimated by applying U.S. real GNP growth in 1981 (.02) to the relation $\dot{g}_{IM}$ = .01 + 2.0 x (growth in U.S. real GNP); see Appendix A.

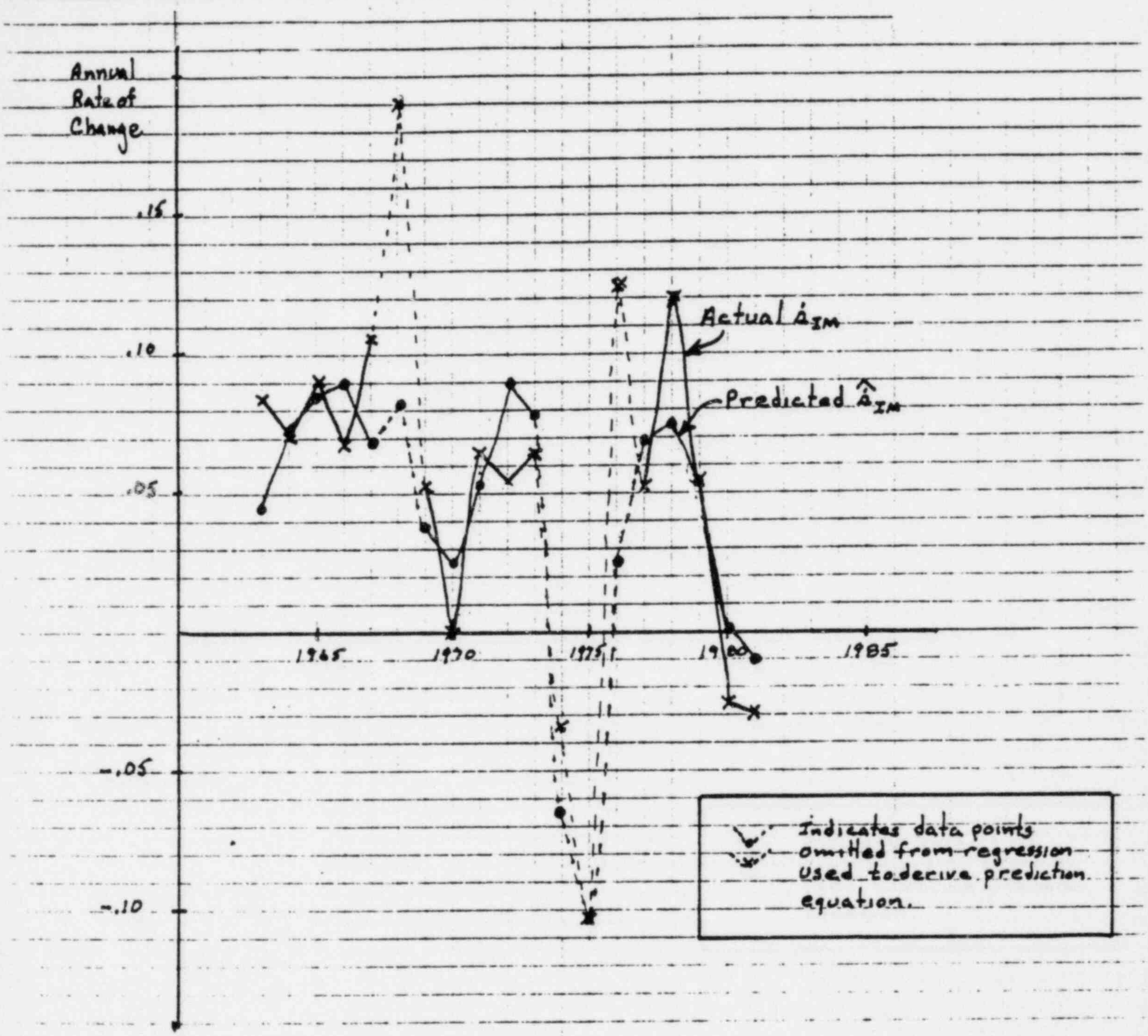


Figure 9

Actual and Predicted Changes
in Manufacturing Electricity Sales

Table 4

Public Service of New Hampshire
Sales to Utilities (within the
Commercial and Service Category)

Year	MWH Sales to Utilities
1965	62,300
1966	38,100
1967	41,600
1968	52,332
1969	57,835
1970	70,986
1971	79,606
1972	79,268
1973	87,642
1974	79,938
1975	75,904
1976	67,368
1977	31,049
1978	34,705
1979	43,403
1980	52,682
1981	81,447

Figure 10

Annual changes in Sales to Commercial and Service Customers
<u>versus</u>
3-Year Average Changes in Real Price of Commercial and Service Electricity

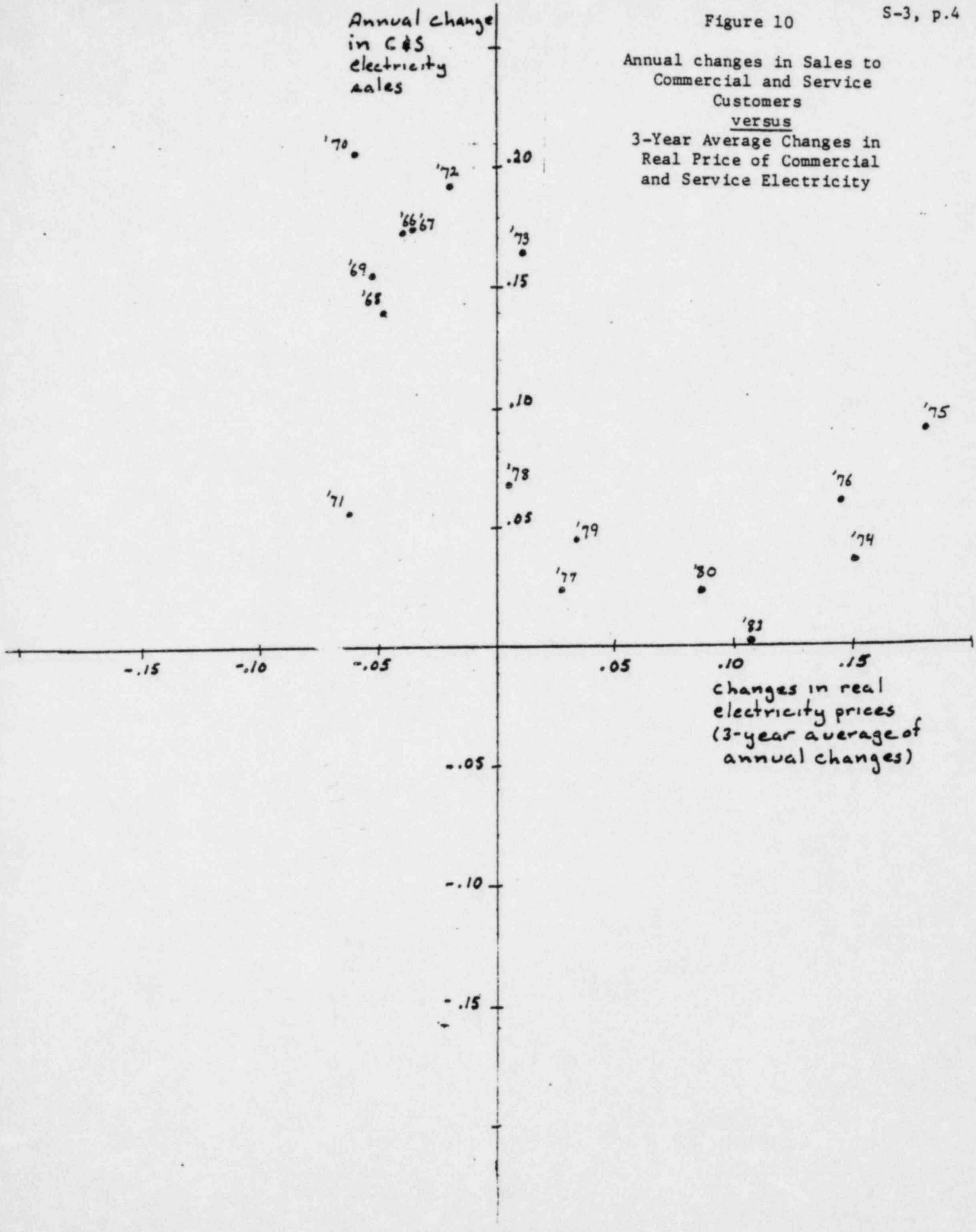


Figure 11

Relations between changes in Sales and Electricity Price for for (Industrial) Commercial & Service

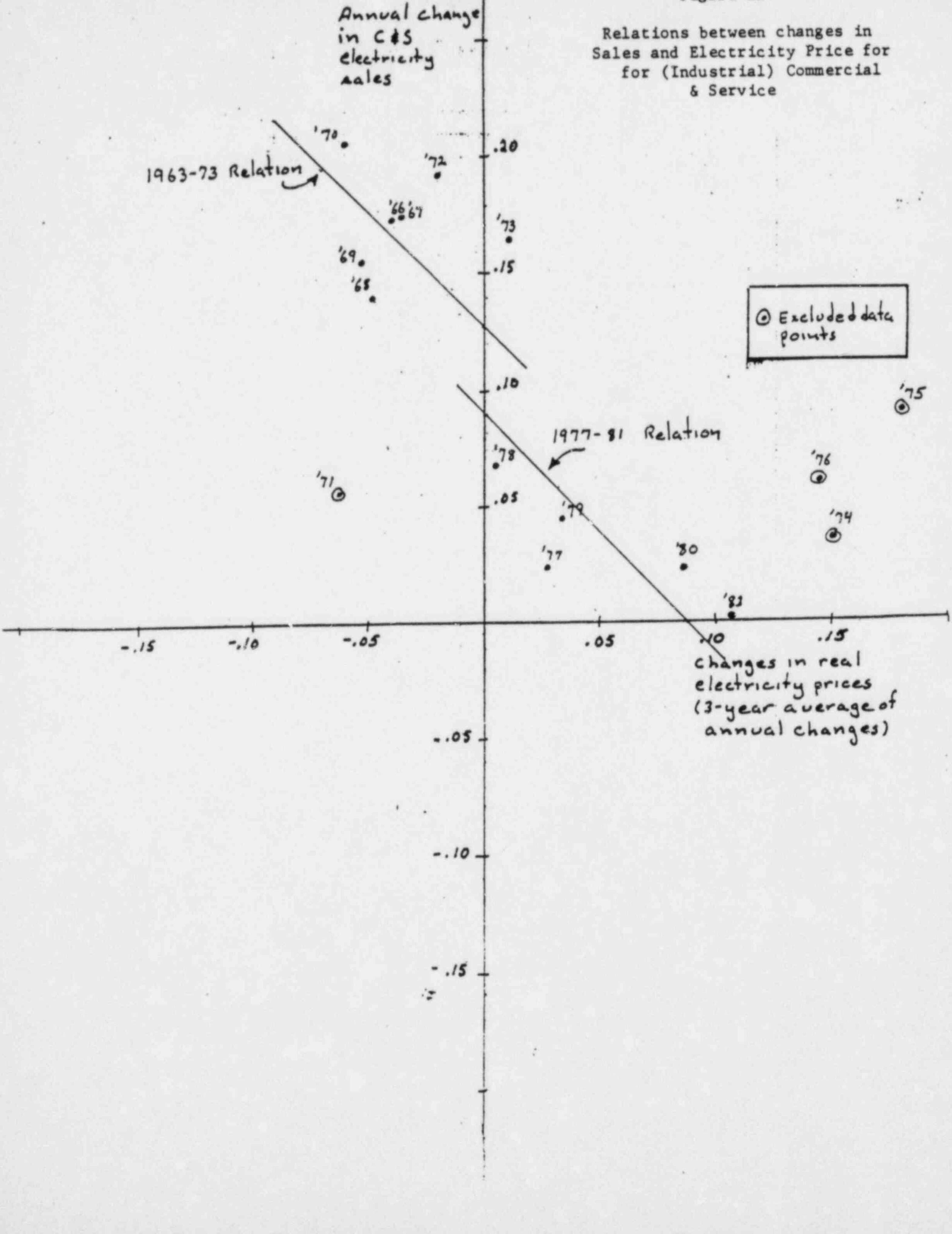


Table 5

Projected Electricity Sales and Prices -- Low Seabrook Cost
(Prices in 1981 dollars)

Year	Residential Price (¢/kWh)	Residential Sales (GWH)	General Service Price (¢/kWh)	General Service Sales (GWH)	Industrial Price (¢/kWh)	Industrial Mfg. Sales (GWH)	Industrial G&S Sales (GWH)	Retail Sales (GWH)	Other Sales (GWH)	Total Sales (GWH)
1981[a]	8.5	1794	8.9	619	6.9	1258	568	4239	1382	5621
1982	8.4	1696	8.8	630	6.8	1231	569	4139	1326	5465
1983	8.6	1645	9.0	640	7.0	1254	584	4123	1322	5445
1984	9.7	1582	10.1	641	8.1	1279	595	4043	1218	5261
1985	8.6	1606	9.0	663	7.0	1342	620	4231	1247	5478
1986	8.6	1629	9.0	691	7.0	1397	639	4356	1273	5630
1987	8.3	1759	8.7	764	6.7	1500	682	4706	1375	6082
1988	7.9	1848	8.4	822	6.3	1556	703	4929	1385	6314
1989	7.5	1972	8.0	965	5.9	1683	742	5363	1467	6830
1990	7.2	2106	7.7	1057	5.6	1843	804	5810	1589	7399
1991	7.1	2223	7.6	1144	5.5	1982	865	6212	1702	7915

Annual Growth in Total Sales, 1982-91: 3.5%

---

a. Actual values for 1981

Table 6

Projected Electricity Sales and Prices -- Mid-Range Seabrook Cost
(Prices in 1981 dollars)

Year	Residential Price (¢/kWh)	Residential Sales (GWH)	General Service Price (¢/kWh)	General Service Sales (GWH)	Industrial Price (¢/kWh)	Industrial Mfg. Sales (GWH)	Industrial G&S Sales (GWH)	Retail Sales (GWH)	Other Sales (GWH)	Total Sales (GWH)
1981[a]	8.5	1794	8.9	619	6.9	1258	568	4239	1382	5621
1982	8.4	1696	8.8	630	6.8	1231	569	4139	1326	5465
1983	8.6	1645	9.0	640	7.0	1240	584	4123	1322	5445
1984	8.4	1683	8.8	677	6.8	1349	613	4323	1381	5705
1985	10.7	1607	11.1	666	8.8	1361	620	4254	1312	5566
1986	11.3	1515	11.7	644	9.4	1344	622	4125	1221	5346
1987	11.7	1386	12.1	605	9.8	1279	592	3861	1137	4998
1988	14.2	1287	14.6	576	12.3	1213	558	3635	1013	4648
1989	14.2	1218	14.6	559	12.3	1210	564	3552	935	4486
1990	13.3	1190	13.7	561	11.4	1241	580	3571	930	4502
1991	11.4	1306	11.8	631	9.5	1369	636	3942	1035	4977

Annual Growth in Total Sales, 1982-91: 1.2%

---

a. Actual values for 1981

Table 7

Projected Electricity Sales and Prices -- High Seabrook Cost
(Prices in 1981 dollars)

Year	Residential Price (¢/kWh)	Residential Sales (GWH)	General Service Price (¢/kWh)	General Service Sales (GWH)	Industrial Price (¢/kWh)	Industrial Mfg. Sales (GWH)	Industrial G&S Sales (GWH)	Retail Sales (GWH)	Other Sales (GWH)	Total Sales (GWH)
1981[a]	8.5	1794	8.9	619	6.9	1258	568	4239	1382	5621
1982	8.4	1696	8.8	630	6.8	1231	569	4139	1326	5465
1983	8.6	1645	9.0	640	7.0	1254	584	4123	1322	5445
1984	8.4	1683	8.8	677	6.8	1394	613	4323	1381	5705
1985	12.2	1522	12.6	632	10.6	1312	604	4070	1258	5329
1986	13.9	1328	14.3	567	12.3	1228	584	3707	1095	4802
1987	14.4	1135	14.8	499	12.8	1111	535	3280	996	4236
1988	20.4	976	20.8	422	18.8	1007	485	2909	793	3702
1989	23.2	839	23.6	391	21.6	949	468	2646	662	3308
1990	22.3	763	22.7	354	20.7	913	457	2488	605	3093
1991	18.9	800	19.3	379	17.4	971	486	2632	642	3274

Annual Growth in Total Sales, 1982-91: -5.3%

a. Actual values for 1981

Table 8

Projected Electricity Sales and Prices -- Mid-Range/Cancel Seabrook Cost
(Prices in 1981 dollars)

	Residential		General Service		Industrial					
Year	Price (¢/kWh)	Sales (GWH)	Price (¢/kWh)	Sales (GWH)	Price (¢/kWh)	Mfg. Sales (GWH)	G&S Sales (GWH)	Retail Sales (GWH)	Other Sales (GWH)	Total Sales (GWH)
1981[a]	8.5	1794	8.9	619	6.9	1258	568	4239	1382	5621
1982	8.4	1696	8.8	630	6.8	1231	569	4139	1326	5465
1983	8.6	1645	9.0	640	7.0	1240	584	4123	1322	5445
1984	8.4	1683	8.8	677	6.8	1349	613	4323	1381	5705
1985	10.7	1607	11.1	666	8.8	1361	620	4254	1312	5566
1986	12.2	1479	12.6	629	10.3	1319	558	3985	1180	5165
1987	12.3	1347	12.7	586	10.4	1249	550	3729	1105	4834
1988	11.8	1331	12.2	594	9.9	1238	569	3732	1105	4837
1989	11.1	1386	11.5	641	9.2	1331	610	3968	1177	5145
1990	10.5	1491	10.9	708	8.6	1462	662	4324	1283	5608
1991	10.1	1601	10.5	779	8.2	1558	750	4718	1400	6118

Annual Growth in Total Sales, 1982-91: 0.9%

---

a. Actual values for 1981

APPENDICES

to the

Testimony of Vince Taylor
before the
New Hampshire Public Utilities Commission

Docket No. DE 81-381

October 8, 1982

Appendix A

PROJECTING ELECTRIC LOAD GROWTH FOR PSNH: ASSUMPTIONS AND METHODOLOGY

Appendix A describes how the demand equations developed in the body of the testimony can be used to project growth in electricity sales for PSNH. The underlying assumptions used i he projections for the four Seabrook-cost cases are specified. The demand equations are then applied to an illustrative case. Quantitative assumptions and illustrative results are presented in tables at the end of the Appendix.

Assumptions

Projected Basic Economic Environment

The U.S. is assumed to recover gradually from the current slowdown, enjoy several years of prosperou growth, and go through another normal business cycle in the last half of the decade. Real GNP growth averages 2.7 percent per year for 1982-91, significantly better than the 2.3 percent average of the post-embargo period.

The superior performance of New Hampshire economy relative to the U.S. average during 1976-80 continues throughout the 1980's, but the margin of superiority declines somewhat over time.

To project New Hampshire economic performance from the assumed course of U.S. GNP, historical data for 1970-1980 were analyzed. Using real (inflation-adjusted) growth rates, the following relations were found to hold:

(A-1) $\dot{g}(\text{Mfg, US}) = -.04 + 2\,\dot{g}(\text{GNP, US})$,

(A-2) $\dot{g}(\text{Mfg, NH}) = 1.2\,\dot{g}(\text{Mfg, US})$, for 1970-75,

(A-2b) $\dot{g}(\text{Mfg, NH}) = .05 + 1.0\,\dot{g}(\text{Mfg, US})$, 1976-80

(A-3) $\dot{g}(\text{PI, NH}) = .027 + .35\,\dot{g}(\text{Mfg, NH})$, where

$\dot{g}$ stands for a <u>real</u> annual growth rate, and the abbreviations in parentheses define whether it refers to GNP originating in Manufacturing (Mfg) or Personal Income (PI) for the United States (US) or New Hampshire (NH).*

---

* Deflation of Personal Income was by application of the U.S. GNP deflator for both N.H. and the U.S.

Manufacturing growth is based on Equation 2b, which is much more favorable to N.H. than 2a. The constant growth term is assumed to decrease by .005 per year through 1986 and to remain at .025 thereafter. This implies continued strong manufacturing growth in New Hampshire, with the size of the sector increasing by 58 percent between 1981 and 1991 (average growth of 4.7 percent per year). The average growth in real personal income is 4.4 percent per year, compared to an average of 4.2 percent for 1971-81, and 4.9 percent for 1977-81.

The year by year estimates are presented in Table A-1. To calculate the estimate of $\dot{g}$(Mfg, NH) from the assumed course of $\dot{g}$(GNP, US), Equation 1 was substituted in 2b to yield:

(A-2b′) $\dot{g}(\text{Mfg, NH}) = .01 + 2.0\,\dot{g}(\text{GNP, US})$.

Prices of Fuel and Interchanged Power

Real prices for fuel and net purchases of non-nuclear interchanged power are assumed to remain constant at the 1981 level (Table A-2) through 1985. After 1985, real oil prices are assumed to increase by 3 percent per year and real coal prices at 2 percent per year.* The real price of existing nuclear-entitlement purchases is assumed to remain at the 1981 level (Table A-2). Real nuclear fuel prices are assumed constant at 0.7¢ per kWh.

Net sales of coal or nuclear power made surplus by Seabrook are assumed to be at 90 percent of the fuel price of oil-fired generation.**

Generating Capability

Future generation capacity other than from planned nuclear additions was assumed equal to the prior 5-year averages (in 1981) of generation (by fuel type, including nuclear entitlements), modified to reflect the completion of Garvin and Eastman Falls Hydro projects and the conversion of the Schiller units to coal (assumed Jan. 1, 1984) (Table A-3). The PSNH

---

* No purchases of interchanged power are required after 1985 in any case considered.

** This is significantly more favorable to PSNH than would be the rate under present NEPOOL policies, which would pay energy costs plus 35 percent of the difference between this cost and the cost of the fuel displaced.

present 7.5 MW interest in Millstone III was assumed to be retained (in-service date of 6/1/88).

Seabrook Performance

Seabrook capacity factors are assumed to equal .45, .50, and .55 in years 1 through 3 and .55 thereafter.* This is between Rosen's estimated performance and the historical industry-wide average for all large units.

Lagged Response to Price Shifts

As discussed in the body of the testimony, there seems likely to exist lags not captured by the statistical analysis in adjustments of electricity intensity of new buildings and manufacturing. To account for these lags, the constant-growth terms of the demand equations for General Service (Equation 2) and Manufacturing (Equation 3a) are assumed to decrease linearly to zero over the next 5 years and to remain at zero thereafter. These adjustments lower the projected growth in total retail sales by 0.5 percent per year after 1985.

Methodology -- An Illustrative Example

The use of the demand equations to project future electricity sales is described below. The illustrative case described differs somewhat in the underlying assumptions from any of the cases considered in the body of the testimony, but the method of projection is identical.

Trial Values of Required Generation

To determine the production and purchase costs of power in a given year, the level of sales for the year must be known, but sales depend upon these costs (because they influence electricity prices). To get around this problem, a Trial Value of required generation is used to estimate production and purchase costs. This Trial Value is a "best guess," based on the previous year's value and anticipated cost trends.

---

* PSNH has a 7.5 MW interest in Millstone III. For simplicity, the capacity factor for this small increment of generating capacity is assumed constant at .55.

The Trial Values of required generation are obtained sequentially, year by year. The entire estimation procedure is carried through for one year before choosing the Trial Value for the next year. Actual generation will generally differ from the Trial Value, introducing an error in the estimating procedure, but the errors tend to correct themselves in the next year. They do not create a systematic bias, but a random element that is relatively small compared to other uncertainties.*

Projected Production and Purchase Costs

Using the Trial Value of required generation, production costs of electricity are calculated. The required generation is supplied from hydro, nuclear, coal, oil, and purchased generation, in that order. If more than sufficient generation is available, the highest-cost sources of generation are decreased until the required total is reached. Fuel and purchase power costs are applied to the generation figures and O&M costs are added to obtain the total production costs.

Non-Production Costs

Non-production costs are estimated independently.** These comprise transmission and distribution O&M, administration, and capital-related costs (interest, dividends, taxes, depreciation, and insurance).

Costs per KWH

The cost per kWh of Prime Sales is calculated by dividing total cost (production plus non-production cost) by the Trial Value of Prime Sales.*** Table A-4 presents the data for this calculation for the illustrative case.

---

* If this model were placed on a computer, it would be desirable to eliminate the error by iterating until the Trial Value equalled the estimated value. The present calculations were done by hand, and the gain in accuracy did not justify the additional labor.

** In the cases presented in the testimony, non-production costs were derived from the financial projections of PSNH and Rosen. Total revenue minus production cost equals non-production cost.

*** Equal to .938 times the Trial Value of required generation, allowing for losses and own use.

Price Changes by Customer Class

The yearly change in cost (¢ per kWh) of Prime Sales is calculated from Table A-4. The change is assumed to apply equally to all customer classes -- that is, if Prime costs increase .2¢ per kWh, all customer rates are assumed to increase by .2¢ per kWh. Table A-5 shows the resulting projected average prices (in constant dollars) of electricity by customer class, together with the (logarithmic) year to year price changes.

Projected Retail Sales

The price-change data (Table A-5) and economic growth data (Table A-1) are used with the sales estimating equations developed in the body of the testimony to project future sales. The equations*, data, and projections are presented in Table A-6 through A-9.

Projected Prime Sales

Sales for the retail classes of customer are added to yield Retail Prime Sales. The growth rate for Retail Sales is then used to estimate growth in Sales to Other Public Authorities and Firm Utility Sales.** Adding these plus Street Lighting Sales, as estimated by PSNH, yields Projected total Prime Sales. The components and the totals are presented in Table A-10. Trial Values of Prime Sales are also shown. Note the lack of any systematic error between Projected Sales and the Trial Values of Sales.

---

* The constant-growth term in the equation for General Service sales is assumed to decline at .004 (0.4 percent) per year and that for Manufacturing sales at .001 (0.1 percent) per year. This is similar to the assumption for the four Seabrook-cost cases, except that in the illustrative case the decline continues below zero.

** The PSNH projections for the three major customers within Other Public Authorities were accepted. The Retail Sales growth was applied to the remaining customers. Firm Utility Sales were adjusted downward to allow for the effect of the ownership purchase of 50 MW of Seabrook by the New Hampshire Electric Co-op.

Table A-1

Projected Economic Environment

Annual Real Growth Rates
(percent)

Year	1982	83	84	85	86	87	88	89	90	91	Avg.
U.S. GNP[a]	1.0	3.0	5.0	4.0	3.0	1.0	0.0	3.0	4.0	3.0	2.7
U.S. P.I.[b]	1.7	3.1	4.5	3.8	3.1	1.7	1.0	3.1	3.8	3.1	2.9
N.H. Mfg.	2.5	6.0	9.5	7.0	4.5	0.5	-1.5	5.5	6.5	4.5	4.7
N.H. P.I.	4.3	4.8	6.0	5.2	4.3	2.9	2.2	4.6	5.0	4.3	4.4

---

a. Assumed

b. Calculated from the historical relation: $\dot{g}$ (PI,US) = .01 + .7 $\dot{g}$ (GNP,US). This series is presented for comparison with projected N.H. Personal Income. It is not used in the base case analysis.

Table A-2

Cost of Fuel and Purchased Power - 1981[a]

Prime Sales

Generated Power	GWH	---Cost per kWh--- generated or purchased (¢/kWh)	sold	Percent of Prime Output
Coal	1.74	1.81	1.93	29
Oil	2.19	5.64	6.02	37
Hydro	.357	—	—	6
Subtotal - Generated	4.287	3.63		72
Subtotal - Sold[b]	4.019		3.87	
Purchased Power				
Nuclear Entitlements	627	2.55	2.72	10.5
Other Purchases } Net Purchases	1,410 }	5.82	6.20	17.5
Exchange Sales } Net Purchases	(338) }			
Subtotal - Purchased	1,698	4.63		28
Subtotal - Sold[b]	1,592		4.94	
Total - Generated or Purchased		3.91		
Total - Sold[b]			4.17	100%

Table A- 2 (continued)

Other Fuel Costs Used in Projections (1981 ¢/kWh)

Seabrook fuel cost	.7
Sales of Seabrook power	90% of the Fuel cost of oil-generated electricity

Seabrook O&M Costs -- Mid and High Cost Cases[c]
(Millions of 1981 dollars)

1985	86	87	88	89	90	91
49.7	53.1	55.7	104.1	112.6	119.3	124.2

---

a. Source: Statistical Supplement for the 1981 Annual Report, PSNH, pp. 12 and 14.

b. After losses estimated at 6.2% of generation.

c. Nuclear O&M costs are on a per year basis, including full year costs for the years in which the Seabrook Units come on line. Source: Richard Rosen testimony in this Docket.

Table A-3

Projected Generation Capability of PSNH, Excluding Planned Nuclear Additions (GWH)

Year	Oil	Coal	Hydro	Existing Nuclear Entitlements
1982	2320	1920	333	645
83	2193[a]	1920	348	645
84	1784[b]	2760[b]	348	645
85	1784	2760	348	645
86	1784	2760	348	645
87	1784	2760	348	645
88	1784	2760	348	645
89	1784	2760	348	645
90	1784	2760	348	645
91	1784	2760	348	645

a. Assumes loss of 136 GWH due to shutdown of Schiller plants for conversion to coal.

b. Gain of 840 GWH of coal generation (70 percent capacity factor) and loss of 546 GWH of oil generation from conversion of Schiller plants (assumes shift to base load).

Table A- 4

Projected Costs of Prime Sales - Illustrative Case

Year	Fuel	O&M	Other	Capital-Related	Total	Trial Value Prime Sales (GWH)	Cost per kWh	
	(millions of 1981 dollars)						1981 ¢	Current ¢
1981[a]	234.4	19.7	67.4	110.9	432.4	5620	7.7	7.7
82	213.9	19.2	66.2	110.9	410.2	5500	7.5	8.1
83	217.1	18.5	66.5	110.9	413.0	5530	7.5	8.7
84	217.7	20.3	72.5	110.9	421.4	6046	7.0	8.8
85	99.4	25.6	68.6	399.0[b]	592.6	5721	10.4	15.7
86	56.2	26.1	61.9	368.8	513.0	5159	9.9	14.6
87	67.5	25.1	66.1	341.5	500.2	5515	9.1	14.4
88	-37.8	35.8	59.6	575.9[c]	633.5	4971	12.7	21.8
89	-38.0	36.9	61.3	527.5	587.7	5110	11.5	21.3
90	-45.6	37.9	61.3	483.6	536.6	5110	10.5	20.9
91	-18.3	37.9	67.4	444.9	531.5	5621	9.5	20.4

a. Actual

b. Seabrook I enters commercial service on 1/1/85, at a cost to PSNH of $1308 million.

c. Seabrook II enters commercial service on 1/1/88, at a cost to PSNH of $1476 million

Table A- 5

Projected Electricity Prices
(1981 ¢/kWh)

	Residential		General Service		Industrial	
Year	Price	% change	Price	% change	Price	% change
1981[a]	8.5	13.8	8.9	12.0	6.9	22.4
82	8.3	-2.4	8.7	-2.3	6.7	-2.9
83	8.3	0.0	8.7	0.0	6.7	0.0
84	7.8	-6.2	8.2	-5.9	6.7	-7.8
85	11.3	37.0	11.5	34.0	9.7	45.0
86	10.5	-7.0	10.7	-7.0	8.9	-9.0
87	10.0	-5.0	10.2	-5.0	8.4	-6.0
88	13.5	30.0	13.7	30.0	11.9	36.0
89	12.3	-9.0	12.5	-9.0	10.7	-11.0
90	11.3	-8.5	11.5	-8.0	9.7	-10.0
91	10.3	-9.0	10.5	-9.0	8.7	-11.0

a. Actual (average) prices.

Table A-6

Projected Residential Sales

Year	$\dot{p}_r$	$\dot{p}_r(3)$	$\dot{n}_r$	$\hat{\dot{s}}_r$	Sales (GWH)
1980	.019				
81[a]	.138	.029		-.032	1794
82	.0[b]	.052	-.007[c]	-.045	1715
83	.0	.046	.020	-.026	1671
84	-.06	-.029	.023	.052	1760
85	.37	.103	.023	-.080	1642
86	-.07	.079	.022	-.057	1551
87	-.05	.083	.021	-.062	1457
88	.30	.060	.021	-.039	1401
89	-.09	.053	.020	-.033	1356
90	-.085	.042	.019	-.023	1325
91	-.09	-.088	.019	.107	1474

Estimating equation:

$$\hat{\dot{s}}_r = \dot{n}_r - 1.0\ \dot{p}_r(3)$$

a. Actual values for 1981.

b. The correct value (Table A-5) in -.024. The value listed was used inadvertently. The error in growth for 1982 is -.8 percent.

c. PSNH estimates of customer growth from 1982 Ten-Year Electric Load Forecast, January 1982.

Table A- 7

Projected General Service Sales

Year	$\dot{p}_c$	$\dot{p}_c(3)$	$\bar{y}$	$\hat{s}_c$	Sales
1980	.027				
81[a]	.120		.049	.025	619
82	.0[b]	.049	.049	.015	628
83	.0	.04	.049	.019	640
84	-.059	-.027	.050	.084	696
85	.34	.34	.050	-.041	676
86	-.07	-.07	.050	-.021	661
87	-.05	-.05	.050	-.028	643
88	.30	.30	.050	-.019	631
89	-.09	-.09	.050	-.016	621
90	-.08	-.08	.050	-.023	607
91	-.09	-.09	.050	.116	682

Estimating equation:

$$\hat{s}_c = .019 - .004\ (\text{Year} - 1981) + \bar{y} - 1.0\ \dot{p}_c(3)$$

a. Actual values for 1981

b. Correct value is -.023. See Note (b) to Table A-6.

Table A- 8

Projected Industrial - Manufacturing Sales

Year	$\dot{p}_{IM}$	$\dot{p}_{IM}(3)$	$\dot{g}_{IM}$	$\bar{g}_{IM}$	$\hat{s}_{IM}$	Sales
1980	.102					
81[a]	.224				-.028	1258
82	.0[b]	.109	.05	.048	-.011	1244
83	.0	.075	.07	.052	.020	1269
84	-.078	-.036	.11	.056	.107	1413
85	.45	.124	.09	.060	.003	1428
86	-.09	.094	.07	.060	.010	1441
87	-.06	.10	.03	.060	-.015	1419
88	.36	.07	.01	.064	-.006	1410
89	-.11	.06	.07	.064	.029	1451
90	-.10	.05	.09	.068	.046	1519
91	-.11	-.106	.07	.068	.129	1727

Estimating equation:

$$\hat{s}_{IM} = .006 - .001\ (\text{Year} - 1981) + .5\dot{g}_{IM} + .5\bar{g}_{IM} - .6\dot{p}_{IM}(3)$$

a. Actual values for 1981

b. Correct value is -.029. See Note (b) to Table A-6.

Table A-9

Projected Industrial - Commercial and Service

Year	$\dot{p}_{IC}$	$\dot{p}_{IC}(3)$	$\bar{y}$	$\hat{s}_{IM}$	Sales: Excluding Utilities	Sales: Utilities	Total
1980	.14						
81[a]	.224			.001	486.7	81	568
82	-.029	.117	.049	-.034	470.4	83	554
83	.0	.065	.049	.018	478.9	90	569
84	-.078	-.036	.050	.120	540.0	90	630
85	.45	.124	.050	-.039	519.3	89	624
86	.09	.094	.050	-.009	514.6	87	602
87	-.06	.10	.050	-.015	506.9	62	568
88	.36	.07	.050	.015	514.5	30	545
89	-.11	.06	.050	.025	527.5	30	557
90	-.10	.05	.050	.035	546	30	576
91	-.11	-.106	.050	.191	661	30	693

Estimating Equation: $\hat{s}_{IC} = 1.7\bar{y} - 1.0\ \dot{p}_{IC}$

* Estimating equation excludes C&S sales to Utilities, primarily to PSNH for construction of Seabrook. Projected sales to Utilities reflect estimated levels of effort on Seabrook construction.

a. Actual values for 1981.

b. Correct value is -.029. See Note b to Table A-6.

Table A-10

Projected Prime Sales
(GWH)

Year	Retail	Street Lighting	Other Public Authorities	Firm Utility	Total Projected	Trial Value
1981	4239	30	347	1004	5620	
82	4141	30	317	987	5475	5500
83	4148	31	318	992	5490	5530
84	4500	32	344	1088	5961	6046
85	4370	33	333	867[a]	5604	5721
86	4254	34	326	809	5424	5159
87	4087	35	318	707	5147	5515
88	3986	36	312	622	4957	4971
89	3986	37	312	622	4958	5110
90	4027	38	315	633	4967	5110
91	4578	38	349	765	5729	5621

a. Major decline from 1985-88 reflects phased replacement of PSNH electricity by self-owned generation (Seabrook I) by N.H. Electric Electric Cooperative.

Appendix B

Capital Cost of Seabrook II to PSNH Ratepayers
for Rosen's Base-Case

In his testimony in this docket, Richard Rosen presents a "base case" estimate of $1629 million for the PSNH share of Seabrook II. Of this total, $559 million represents AFUDC accumulated at 12.5 percent per year.

Table B-1 presents an alternative estimate based on the same direct construction costs, interest rates on new debt, and return on common equity. In the alternative, costs of financing construction are calculated using projected rates for new borrowing and for the cost of equity (including taxes) rather than at 12.5 percent per year. This is the only difference.

The alternative estimate of $2413 million is the cost that would be borne by PSNH ratepayers in constructing Seabrook II under Rosen's cost assumptions. This is 48 percent greater than Rosen's estimate of $1629 million. The amount attributable to financing charges is $1348 million, 2.4 times the accounting value of AFUDC in Rosen's estimate.

Table B-1

Capital Cost to Ratepayers of Seabrook II
for Rosen's Base Case[a]

Year	Cumulative Capital Cost: Debt & Preferred	Cumulative Capital Cost: Equity	Cumulative Capital Cost: Total	Cumulative Direct Construction Cost
≤1981	91.3	66.6	158.5	123
1982	111.9	81.1	193.0	123
1983	165.2	119.7	284.5	166
1984	339.4	245.8	585.3	373
1985	569.5	412.4	981.9	597
1986	887.2	642.6	1529.8	865
1987	1225.0	887.2	2112.2	1039
July 1988	1399.5	1013.5	2412.9	1071

a. Direct construction costs from testimony of Richard Rosen in this docket. Rosen's assumptions on financing cost were used: 18 percent on long-term debt and preferred (58 percent of financing) and return on equity of 18.5 percent, implying a cost of 36.2 percent (including tax) on common stock (42 percent of financing).

Interest, equity, and construction costs were calculated for each year. Financing to pay these costs was assumed to be divided between debt and equity at the 1981 ratio of 58:42.

Costs are in millions of mixed, current dollars and assume an inflation rate of 8 percent per year.

Appendix C

VINCENT D. TAYLOR
PROFESSIONAL QUALIFICATIONS

EDUCATION:

Bachelor of Science in Physics, California Institute of Technology, 1958.

Doctor of Philosophy in Economics, Massachusetts Institute of Technology, 1964.

PROFESSIONAL EXPERIENCE:

Economics Department, Rand Corporation, Santa Monica, California, 1961-1969; consultant to Capital Research, Inc., Los Angeles, on security selection, 1970-1973; senior staff member of Pan Heuristics, Los Angeles (a division of Science Application, Inc., La Jolla, California), 1974-1978; energy consultant to the Union of Concerned Scientists, 1979; senior staff of the Union of Concerned Scientists, 1980-82; economic consultant, 1982 to present.

PROFESSIONAL EXPERIENCE IN ENERGY-RELATED RESEARCH:

Beginning in 1974, my professional work has been exclusively on the economics of energy, with particular emphasis on the comparative economics of nuclear power and its alternatives. During the period 1974-1982, I performed research and wrote reports and articles on: the comparative economics of nuclear and coal generated electricity, forecasts of the future demand for energy, electricity, and nuclear electricity, the comparative economics of the use of uranium and plutonium on fuel for nuclear reactors, the economics of the uranium market, the economics of reprocessing of spent nuclear fuel, the comparative future energy potentials of nuclear power, synthetic fuels and improvements in the efficiency of energy use, the economic effects of the oil crisis, the contribution of electric utilities to oil consumption, and the economic implications of closing a nuclear power plant.

ENERGY-RELATED CONSULTING:

During the period 1974-1982, I have provided consulting services, research reports, or expert testimony for:

- The United States Arms Control and Disarmament Agency
- The Energy Research and Development Administration
- The California Energy Commission
- The Council on Environmental Quality
- The Nuclear Regulatory Commission
- The Pennsylvania Public Utility Commission
- The Vermont Public Service Board
- The Office of Technology Assessment

ENERGY-RELATED PUBLICATIONS:

The Uncertain Future of Nuclear Power, with Dennis Holliday, California Seminar on Arms Control and Foreign Policy, P.O. Box 925, Santa Monica, California, August 1975

Is Plutonium Really Necessary? Pan Heuristics, Los Angeles, Sept., 1976 (Revised)

The Myth of Uranium Scarcity, Pan Heuristics, Los Angeles, April 25, 1977.

How the U.S. Government Created the Uranium Crisis, Pan Heuristics, Los Angeles, June 1977 (Revised)

The Economics of Uranium and Plutonium, in "Moving Toward Life in a Nuclear Armed Crowd?", Minerva, Volume XV, Numbers 3 and 4 (combined issue), Autumn-Winter, 1977

Prepared Testimony of Dr. Vince Taylor in the Matter of GESMO, prepared for the California Energy Resources and Development Commission, Pan Heuristics, Los Angeles, March 4, 1977, Chapter A.

Energy: The Easy Path, prepared for the U.S. Arms Control and Disarmament Agency, January, 1979 (published by the Union of Concerned Scientists, Cambridge, Mass.)

The Easy Path Energy Plan, Union of Concerned Scientists, Cambridge, Massachusetts, May, 1979

"Science and Subjectivity," Technology Review, February, 1979.

"A Warning: E. F. Schumacher on the Energy Crisis," MANAS September 3, 1980.

"The End of the Oil Age," The Ecologist, October-November, 1980.

Swords from Plowshares, with Albert Wohlstetter, et. al., University of Chicago Press, Chicago and London, 1979.

Conservation, Equity, and Efficiency, testimony before the Vermont Public Service Board, Docket 4475, November 5, 1980

Electric Utilities: The Transition from Oil, testimony before the Subcommittee on Oversight and Investigations of the Committee on Interstate and Foreign Commerce Committee of the United States House of Representatives, December 9, 1980.

"Electric Utilities: A Time of Transition," Environment, Volume 23, No. 4, May 1981.

Testimony on the Economic Costs of Closing Indian Point, testimony before the Atomic Safety and Licensing Board of the Nuclear Regulatory Commission, Docket Nos. 50-247-SP and 50-286-SP (pending).

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the matter of CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. (Indian Point, Unit No. 2) POWER AUTHORITY OF THE STATE OF NEW YORK (Indian Point, Unit No. 3)	Docket Nos. 50-247 SP 50-286 SP 12 April 1983

CERTIFICATE OF SERVICE

I hereby certify that single copies of TESTIMONY ON THE ECONOMIC COSTS OF CLOSING INDIAN POINT, TESTIMONY OF VINCE TAYLOR was served upon the following by deposit in the U.S. mail, first class postage prepaid, this 12th day of April 1983, except where noted otherwise by asterisks.

Steven C. Sholly

Steven C. Sholly

Nunzio Palladino, Chairman
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

John Ahearne, Commissioner
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

James Asselstine, Commissioner
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Victor Gilinsky, Commissioner
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Thomas Roberts, Commissioner
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

James P. Gleason, Esq., Chairman
Adminstrative Judge
Atomic Safety and Licensing Board
513 Gilmoure Drive
Silver Spring, MD 20901

DS03

Dr. Oscar H. Paris
Administrative Judge
Atomic Safety and Licensing
Board
U.S. Nuclear Regulatory
Commission
Washington, DC 20555

David Lewis, Esq.
Atomic Safety and Licensing Board
U.S. Nuclear Regulatory Commission
Washington D.C. 20555

* Janice E. Moore, Esq.
Donald F. Hassell, Esq.
Henry J. McGurren, Esq.
Office of the Executive Legal
Director
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

**Bernard Sanoff, Esq.
Assistant General Counsel
Consolidated Edison Company of
New York, Inc.
4 Irving Place
New York, NY 10003

**Charles M. Pratt, Esq.
Stephen L. Baum, Esq.
Power Authority of the State
of New York
10 Columbus Circle
New York, NY 10019

Jonathon D. Feinberg
New York State Public Service
Commission
Three Empire State Plaza
Albany, NY 12223

Charles J. Maikish, Esq.
Litigation Division
The Port Authority of New
York and New Jersey
One World Trade Center
New York, NY 10048

Honorable Ruth Messinger
Member of the Council of the
City of New York
District #4
City Hall
New York, NY 10007

James A. Laurenson
Administrative Judge
Atomic Safety and Licensing
Board
U.S. Nuclear Regulatory
Commission
Washington, DC 20555

Docketing and Service Section
Office of the Secretary
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Atomic Safety and Licensing Board Panel
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Atomic Safety and Licensing Appeal
Board Panel
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Paul F. Colarulli, Esq.
Joseph J. Levin, Jr., Esq.
Pamela S. Horowitz, Esq.
Charles Morgan, Jr., Esq.
Morgan Associates, Chartered
1899 L Street, N.W.
Washington, D.C. 20036

Mayor F. Webster Pierce
Village of Buchanan
236 Tate Avenue
Buchanan, NY 10511

Stanley B. Klimberg, Esq.
General Counsel
New York State Energy Office
2 Rockefeller State Plaza
Albany, NY 12223

Marc L. Parris, Esq.
Eric Thorsen, Esq.
County Attorney
County of Rockland
11 New Hempstead Road
New City, NY 10956

Alfred B. Del Bello
Westchester County Executive
Laurie Vetere, Esq.
148 Martine Avenue
White Plains, NY 10601

Ezra I. Bialik, Esq.
Steve Leipsiz, Esq.
Environmental Protection Bureau
New York State Attorney
General's Office
Two World Trade Center
New York, NY 10047

Donald Davidoff, Director
New York State Radiological
Emergency Preparedness Group
Empire State Plaza
Tower Building, Room 1750
Albany, NY 12237

David H. Pikus, Esq.
Richard F. Czaja, Esq.
Shea and Gould
330 Madison Avenue
New York, NY 10017

Phyllis Rodriguez, Spokesperson
Parents Concerned About Indian Point
P.O. Box 125
Croton-on-Hudson, NY 10520

Richard M. Hartzman, Esq.
Lorna Salzman
Friends of the Earth, Inc.
208 West 13th Street
New York, NY 10011

Judith Kessler, Coordinator
Rockland Citizens for Safe Energy
300 New Hempstead Road
New City, NY 10956

Renee Schwartz, Esq.
Paul Chessin, Esq.
Laurens R. Schwartz, Esq.
Margaret Oppel, Esq.
Botein, Hays, Sklar & Hertzberg
200 Park Avenue
New York, NY 10166

David B. Duboff
Westchester People's Action
Coalition, Inc.
255 Grove Street
White Plains, NY 10601

Andrew S. Roffe, Esq.
New York State Assembly
Albany, NY 12248

Honorable Richard L. Brodsky
Member of the County Legislature
Westchester County
County Office Building
White Plains, NY 10601

Spence W. Perry, Esq.
Office of General Counsel
Federal Emergency Management Agency
500 C Street, S.W.
Washington, D.C. 20472

Stewart M. Glass, Esq.
Regional Counsel
Federal Emergency Management Agency
Room 1349
26 Federal Plaza
New York, NY 10278

Charles A. Scheiner, Co-Chairperson
Westchester People's Action
Coalition, Inc.
P.O. Box 488
White Plains, NY 10602

Alan Latman, Esq.
44 Sunset Drive
Croton-on-Hudson, NY 10520

Zipporah S. Fleisher
West Branch Conservation Association
443 Buena Vista Road
New City, NY 10956

Melvin Goldberg, Staff Attorney
Joan Holt, Project Director
New York Public Interest
Research Group, Inc.
9 Murray Street
New York, NY 10007

Craig Kaplan, Esq.
National Emergency Civil
Liberties Committee
175 Fifth Avenue, Suite 712
New York, NY 10010

Ms. Amanda Potterfield, Esq.
Johnston & George, Attys-at-Law
528 Iowa Avenue
Iowa City, IA 52240

Joan Miles
Indian Point Coordinator
New York City Audubon Society
71 West 23rd Street, Suite 1828
New York, NY 10010

Ellyn R. Weiss, Esq.
William S. Jordan, III, Esq.
Harmon and Weiss
1725 I Street, N.W., Suite 506
Washington, D.C. 20006

Jeffrey M. Blum, Esq.
New York University Law School
423 Vanderbilt Hall
40 Washington Square South
New York, NY 10012

Greater New York Council on Energy
c/o Dean R. Corren, Director
New York University
26 Stuyvesant Street
New York, NY 10003

Steven C. Sholly
Union of Concerned Scientists
1346 Connecticut Avenue, N.W., Suite 1101
Washington, D.C. 20036

* Served by Messenger to Maryland Nat'l.
Bank Bldg., 7735 Old Georgetown Rd.
Rm. 10708, Bethesda, MD

** Served by Fed'l. Express