ORIGINAL

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the matter of:

CONSOLIDATED EDISON COMPANY of NEW YORK

(Indian Point, Unit 2)

POWER AUTHORITY OF THE STATE OF NEW YORK

(Indian Point, Unit 3)

Docket No. 50-247 SP

50-286 SP

Location: White Plains, NY

Pages: 13777 - 14119

Date: Thursday, April 21, 1983

TAYLOE ASSOCIATES

Court Reporters
1625 I Street, N.W. Suite 1004
Washington, D.C. 20006
(202) 293-3950

ORIGINAL

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

---------------------------------------:

IN THE MATTER OF: : Docket Nos.

CONSOLIDATED EDISON COMPANY OF : 50-247 SP

NEW YORK (Indian Point Unit 2) :

POWER AUTHORITY OF THE STATE OF : 50-286 SP

NEW YORK)Indian Point Unit 3) :

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Westchester County Courthouse

111 Grove Street

White Plains, N.Y.

Thursday, April 21, 1983

The hearing in the above-entitled matter convened, pursuant to notice, at 9 a.m.

BEFORE:

JAMES GLEASON, Chairman

Administrative Judge

OSCAR H. PARIS

Administrative Judge

FREDERICK J. SHON

Administrative Judge

APPEARANCES:

On Behalf of Licensee, Consolidated Edison Company of New York

BRENT L. BRANDENBURG, ESQ.

Assistant General Counsel

THOMAS L. FARRELLY, ESQ.

Consolidated Edison Company of New York
4 Irving Place
New York, N.Y. 10003

BERNARD L. SANOFF, ESQ.

Kronish, Lieb, Shainswit, Weiner & Hellman
1345 AVenue of the Americas
New York, New York 10105

On Behalf of Licensee, The Power Authority of the State of New York

JOSEPH J. LEVIN, ESQ.

CHARLES M. PRATT, ESQ.

JENNIFER TOLSON, ESQ.

Morgan Associates, Chartered
1899 L Street
Washington, D.C. 20036

On Behalf of the Nuclear Regulatory Commission Staff

PATRICIA MOORE, ESQ.
HENRY J. McGURREN, ESQ.

On Behalf of the Intervenors

Council of the City of New York
CRAIG KAPLAN, ESQ.

NEW York University Law School
JEFFREY M. BLUM, ESQ.

West Branch Conservation Association
ZIPPORAH S. FLEISHER

Greater New York Council on Energy
DEAN R. CORREN, Director

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JUDGE GLEASON: If we could start,

please. We are going to have a brief bench conference here.

(There was a conference at the bench.)

MR. McGURREN: I would like to bring up a scheduling matter.

JUDGE GLEASON: All right. Is that all right with every one?

MR. McGURREN: I have a concern. Our panels have essentially been here all week long, and I know that the Board has ruled that Parents' witnesses will go at 3:30.

JUDGE GLEASON: That's tomorrow

MR. McGURREN: Correct. My concern is that our panels get on the stand before 3:30. And we would be willing to come a little earlier tomorrow.

JUDGE GLEASON: I presume we are going to be able to start your panels today.

MR. McGURREN: Well, we will be ready, Your Honor.

JUDGE GLEASON: I presume that we will finish them by 3:30.

MR. SANOFF: Your Honor, if they start today we have no chance to read their testimony. I have not read it, deliberately. I was planning on reading it tonight.

MR. PRATT: Your Honor, I think at a minimum we would request that we have break of an hour or so. There are people from the Power Authority who have been reviewing it. I join in spirit, if not exact detail, with Mr. Sanoff. But if we could have at least a short break before then.

JUDGE GLEASON: Let's stand in recess until the GNYC witness appears.

(The court recessed.)

MR. CORREN: Your Honor, the witness is now present.

JUDGE GLEASON: Mr. Rosen, if you will please stand, I will swear you in.

Whereupon,

RICHARD A. ROSEN,

having been sworn by the Administrative Law Judge, testified as follows:

DIRECT EXAMINATION BY MR. BLUM:

Q. Dr. Rosen, do you have in front of you a document entitled testimony of Richard Rosen on Commission question 6.3?

A. Yes, I do.

Q. And does this testimony include what

has come to be known as the NSRG study?

A. Yes, it does.

Q. Is this testimony complete and accurate to the best of your knowledge?

A. Yes. Basically, yes.

Q. Do you have any corrections you wish to make at this time?

A. No.

Q. Do you adopt this as your testimony in this proceeding?

A. Yes.

MR. BLUM: Your Honor, I would now move that this testimony be admitted into evidence and bound into the record.

JUDGE GLEASON: Is there objection?

MR. PRATT: Yes, Your Honor.

JUDGE GLEASON: Will you state it?

MR. PRATT: On behalf of the Power Authority, we believe that this testimony as it is presently formulated does not apply.

The purpose of this testimony, as revealed on page 4, is to look at the cost to downstate Power Authority and Con Edison rate payers, in looking at lines 3 and 4.

JUDGE GLEASON: Excuse me. Would you

say this again?

MR. PRATT: The purpose of this proposed testimony, and I am reading from page 4, is to look at the increased cost from the point of view of cost to the downstate Power Authority and Con Edison rate payers.

Now, in fact, the testimony does not do that. If you look at table 1 on page 5 of the testimony, it simply lumps together the Indian Point costs as respect to both the customers of Consolidated Edison and the Power Authority.

There is evidence in this record that the cost impacts are different on those two customers, and I think it is inappropriate to have the two put together.

I think as it is now formulated it is inapplicable at least to the Power Authority customers. It is possible that the witness could separate, I don't think it's a difficult procedure, but as it is presently formulated we don't think it's applicable to the Power Authority.

JUDGE GLEASON: Is it applicable to the question 6?

MR. PRATT: It may have some application generally, but in this case I have to find out whether it's applicable to the Power Authority in this case, and if it is not, on behalf of at least one of the two licensees I do object.

As respects us I would say no, it does not apply to question 6. I don't think it's formative or helpful in trying to assess what the rate impacts are going to be. So my answer is no.

MR. BLUM: Well, it's hard to tell what this objection is. I don't think it's a relevance objection. It may be something that goes to the weight of the testimony.

If Mr. Pratt believes a different way of presenting numbers is more helpful, he can bring that out on cross examination, but I don't think there is any serious issue on the relevance of this testimony.

JUDGE GLEASON: I gather your motion is to strike all of the testimony as it applies to the Power Authority?

MR. PRATT: That is correct.

JUDGE GLEASON: Would the staff care to express a view in this area? And would they?)

MR. McGURREN: May I have a moment?

(There was a brief pause.).

JUDGE GLEASON: Mr. Pratt, just as a bit of information, did you communicate to the other parties you intended to make this motion?

MR. PRATT: Did I communicate? Yes.

JUDGE GLEASON: When did you do that?

MR. PRATT: I certainly did to Mr. Pratt yesterday, and it could have been the day before, and I did to Mr. Lewis.

JUDGE GLEASON: How about Mr. Corren.

MR. PRATT: Mr. Corren has not been in the hearing room the last few days so I did not communicate it to him.

MR. BLUM: Mr. Corren was here day before yesterday. Mr. Pratt informed me of the motion yesterday.

JUDGE GLEASON: McGurren?

MR. McGURREN: Your Honor, we believe this testimony of Mr. Rosen is responsive to the commission question. We feel it is a broad question.

What the commission is concerned about is the broad economic effect of a shutdown at Indian Point. We think that Dr. Rosen's testimony responds to this.

We don't see, as I understand Mr.

Pratt arguing, that we are concerned just about the cost to rate payers of Con Ed.

JUDGE GLEASON: Well, we concur in that latter statement. The commission is interested in the overall economic impact of closing these plants within the State of New York.

And we don't think it's timely, either.

The motion is denied.

Is there other objection?

Hearing none, the testimony of the witness will be received into evidence and bound into the record as if read. That includes Appendix A, Mr. Blum? That does include Appendix A?

MR. BLUM: Yes, it does.

(Bound testimony follows:

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:
James P. Gleason, Chairman
Frederic J. Shon
Dr. Oscar H. Paris

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

TESTIMONY OF
GREATER NEW YORK COUNCIL ON ENERGY
WITNESS RICHARD A. ROSEN
ON COMMISSION QUESTION 6.3

April 12, 1983

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Richard A. Rosen. My business address is Energy Systems Research Group, Inc., 120 Milk Street, Boston, Massachusetts 02109.

Q. DR. ROSEN, PLEASE DESCRIBE YOUR BACKGROUND AND QUALIFICATIONS.

A. I am a senior research scientist at Energy Systems Research Group, Inc., as well as Executive Vice-President of the firm. ESRG is a non-profit organization specializing in research on energy-related issues, particularly research related to electric utilities. Among the issues addressed by ESRG research are demand forecasting, conservation program analysis, electric utility dispatch and reliability modeling, generation planning, avoided cost analysis, financial analysis, demand curtailment modeling, rate design, cost of capital analysis, and district heating.

In May, 1979, I completed directing my extensive critique of the New England Power Pool Electric Demand Forecasting Model under contract to the New England Conference of Public Utility Commissioners. I have also testified on demand forecasting in Case #19494 before the Massachusetts Department of Public Utilities, in Pennsylvania PUC v. Philadelphia Electric Company, RID #438 (the 1978 rate case), before the Pennsylvania Public Utility Commission, and before the Michigan Public Service Commission in Case #U-5979. During 1979, I was project director of a study that led to Dr. D. Shakow's testimony on behalf of our firm regarding "Generation Planning and Reliability" in Pennsylvania PUC v. Philadelphia Electric Company, R-79060865 (the

1979 rate case), before the Pennsylvania Public Utility Commission. During 1980 I was project director of a study that culminated in further testimony by Dr. D. Shakow regarding "Generation Planning and Reliability" in Case #EO-80-57 before the Missouri Public Service Commission.

I have submitted extensive direct and sur-rebuttal testimony in Case No. I-79070315 and 317 (CAPCO Investigation) before the Pennsylvania Public Utility Commission on generation planning and reliability, in Case No. I-80100341 (the Limerick Investigation), and on excess capacity in Case #R-822169. I have testified on "Generation Expansion Planning Re: Consumers Power Company" in Case No. U-6360 before the Michigan Public Service Commission, and on generation planning in cases before the Alabama Public Service Commission, Ohio Public Utility Commission (80-141-EL-AIR and 79-427-EL-AIR), and before the Maine PUC in Dockets #80-180 and #81-114. I have also testified before the North Carolina Utilities Commission in Docket No. E-100, Sub 47 on principles of risk sharing between ratepayers and utility investors as applied to the structure of fuel adjustment clauses and the role of power plant performance.

Other generation planning studies at ESRG that I have directed include analyses of proposed power plants in the American Electric Power system, and the Consolidated Edison service territory. That work, as well as prior research, led to the development of the ESRG Electric System Generation Planning Model (ESGEM) under Dr. Shakow's and my direction, and the introduction and revision of the SYSGEN electric system production costing

THE ECONOMICS OF CLOSING
THE INDIAN POINT NUCLEAR POWER PLANTS

The Direct Effects Upon Ratepayers of Early Retirement of Units 2 and 3

Prepared by

Energy Systems Research Group, Inc.
120 Milk Street
Boston, Massachusetts 02109

ESRG Study No. 82-40

Principal Investigators

Paul D. Raskin and Richard A. Rosen

Project Team

Thomas Austin, Stephen S. Bernow, Bruce Biewald,
Barry Feldman, and David Nichols

E S R G

For ordering information concerning this report,
see last page.

1. INTRODUCTION

1.1 The Issues

The research described in this report undertook to develop a systematic framework for assessing the direct economic effects upon ratepayers of a decision to retire a nuclear power plant that has already commenced commercial operation. This cost assessment system, consisting of conceptual analyses, computer models, and associated databases, has been applied to two case studies. The first case study was an assessment of the direct economic effects of retiring the Maine Yankee Atomic power plant in 1988. The second case study, reported on in detail here, was an assessment of the direct costs to ratepayers of retiring units 2 and 3 of the Indian Point nuclear generating station in New York in 1983. In both cases, these retirement years are well in advance of the retirement dates currently planned by the operators of the power plants.

Public concern about the health and safety implications of continued operation of existing nuclear power stations has increased in the aftermath of the Three Mile Island accident of 1979. One regulatory expression of this concern is the intensification of programs for safety-related plant modifications and post-accident emergency planning as promulgated by the U.S. Nuclear Regulatory Commission. However, recent regulatory pressures for upgraded plant operation measures have not comforted that segment of the public that has continued to advocate the closing of nuclear power plants.

Problems related to the aging of nuclear power plants, such as corrosion in steam generators, have begun to appear with increasing frequency. These problems have reinforced skepticism concerning the advisability of continuing to operate maturing nuclear plants.

One premise of the nuclear shutdown argument appears to be that avoiding the health and safety risks of continued nuclear plant operations, especially where such plants are in close proximity to population centers, is more important than securing whatever benefits can be derived from continued operation. But this premise is challenged by the proponents of continued nuclear plant operations, who have argued both that the risks of continued operation (while tangible) are relatively modest, and that the power system reliability impacts and the economic costs of premature retirement would be unacceptably severe.

On the one side of the debate, then, are those who emphasize the risks and uncertainties of the continued operation of nuclear power plants. But it is difficult to persuasively quantify both the probabilities of occurrence of, and the human and economic effects of, catastrophic events.

On the other side of the debate are those who emphasize the economic consequences of substituting more operation measures have not comforted that segment of the public that has continued to advocate the closing of nuclear power plants.

Problems related to the aging of nuclear power plants, such as corrosion in steam generators, have begun to appear with increasing frequency. These problems have reinforced skepticism concerning the advisability of continuing to operate maturing nuclear plants.

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On the other s' ' of the debate are those who emphasize the economic consequences of substituting more model at ESRG. I was also principal investigator for a project which expanded the capabilities of the ESGEM model, which was funded by the U.S. Department of Energy, Office of Utility Systems.

In a number of generation planning studies that I have conducted, the ESRG staff has applied the ELFIN electric utility corporate financial model to estimate the financial impacts of alternative construction programs.

I received my Bachelor of Science degree from M.I.T. in 1966 and my Master's degree and Ph.D. in physics from Columbia University in 1970 and 1974, respectively. Before joining ESRG, I did research at the National Center for the Analysis of Energy Systems at Brookhaven National Laboratory on industrial energy conservation. In that capacity, I served as Principal Investigator on two projects involving industrial process energy modeling for the U.S. Department of Energy.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY TODAY?

A. My testimony is comprised of seven pages of questions and answers and an 83-page document entitled, "The Economics of Closing the Indian Point Nuclear Power Plants," and the appendices thereto which together form a comprehensive study that Energy Systems Research Group, Inc. has performed with respect to contention 6.3 in these dockets. The basic motivation behind performing this study was to improve on the methodology and consistency of the earlier similar studies that had been performed by the General Accounting Office, the Congressional Research Service, and the Rand Corp. Further

The Mid-Range results are offered as our best estimates of the direct cost effects of early retirement of IP-2 and IP-3. The overall effect of closing the plants by 1983 is about $746 million (discounted 1981 dollars) or, on a percentage basis, approximately two percent. This is the cumulative impact for the entire 1983-1997 period. The annual impacts are relatively more severe in the early years and then moderate substantially over time, as will be discussed further below.

The results of our analysis for each of the three early retirement scenarios are summarized in Table 1. The results for each scenario are presented in terms of total additional revenues required from ratepayers during the period 1983-1997. The results are also expressed as a percentage increase or decrease from the revenues that would be required assuming continued plant operation during the period.

TABLE 1

REQUIRED REVENUE IMPACT OF INDIAN POINT RETIREMENTS: SUMMARY RESULTS FOR NEW YORK RATEPAYERS*, 1983-1997

Scenario	Cumulative Total (Millions of 1981 Discounted $)	Average Percentage Change in Discounted Revenue Requirements
1. High Impact	$3,656	9.2
2. Mid-Range	746	1.9
3. Low Impact	- 1,337	-3.5

*"New York ratepayers" are Con Ed's retail customers and PASNY's downstate customers.

A number of sensitivity tests were also performed to investigate the responsiveness of these results to changes in key variables. These results are detailed in Section 4.2. Relative to the Mid-Range average cumulative impact of 1.9 percent, we performed four sensitivity tests. First, increasing the length of the time period for analysis (from a final year of 1997 to one of 2000) decreases average impacts to 1.2 percent. Second, delaying the times of the retirement from 1983 to 1985 decreases average impacts to 0.8 percent. Third, increasing the assumed discount rate (from 12 to 14 percent) increases the impacts to 2.0 percent. Finally, assuming that capacity factors (a measure of plant availability at full capacity) do not deteriorate over time increases the net impacts to 3.9 percent.

The ratepayers cost impacts, then, are likely to average about two percent over the next fifteen years with the major effects in the earlier years. This small but measurable negative impact would have to be weighed against the perceived benefits in avoided nuclear risks in deliberating the fate of the Indian Point units.

Q. ARE THERE ANY IMPORTANT EVENTS THAT HAVE TAKEN PLACE SINCE OCTOBER, 1982 THAT WOULD TEND TO ALTER YOUR CONCLUSIONS?

A. Yes. The key change that has occurred since October, 1982 is that oil prices have fallen and not risen as we had projected. In fact in the study we find that by April, 1983 we had overpredicted oil prices by about 17 percent for Con Edison. If only this change were made for 1983 in our oil price assumptions (leaving the retirement of IP-2 and IP-3 are reported on next. Following this summary of major findings are sections of the report and appendices to the report designed to provide a full explication of methodology, data development, detailed results, and implications of the analysis.

The "ratepayers" with respect to whom this assessment was conducted are those located within the service area of the Consolidated Edison Company of New York. There are two sets of such electric ratepayers. First there are the retail customers of Con Ed itself. Second, there are the downstate customers of PASNY, such as the Metropolitan Transit Authority, the Triborough Bridge Authority, the New York City Housing Authority, and other public agencies.

1.3 Major Findings

Three "early retirement" scenarios for the fifteen year period 1983-1997 were developed and employed in this study. These are the High Impact scenario, the Low Impact scenario, and the Mid-Range scenario. The High and Low Impact scenarios are comprised of assumption sets which consistently bias the results of the analysis toward higher or lower cost effects from closing the units. As a group, the assumptions in either of these scenarios would therefore occur only if a set of conditions, each of which may individually be considered improbable, should prevail. Thus, the High Impact scenario assumes no deterioration in plant performance from nuclear plant closing upon ratepayers. Second, we have applied this assessment system to the case of a shutdown of Indian Point unit 2 (IP-2) and Indian Point unit 3 (IP-3) after 1982.

The cost assessment system is designed to simulate the increments in ratepayer costs -- or in utility finance parlance, the increased "required revenues" -- over a planning time frame. The streams of required revenues are disaggregated into the major categories of costs that would be affected by a nuclear plant closing. These include generation of replacement power; the recovery of, and return on, invested capital; nuclear fuel costs; nuclear operations and maintenance; plant decommissioning and radioactive waste disposal; and expenditures on power plant modifications.

There is considerable uncertainty with respect to the future behavior of the variables that influence future costs. Consequently, there is no substitute for developing scenarios comprised of clusters of variable assumptions to establish a range of plausible effects. Important variables included in our scenario analyses are: (1) the composition of make-up generation; (2) plant performance characteristics; (3) nuclear fuel and operation and maintenance (O&M) escalation rates; (4) electric energy conservation levels; and (5) decommissioning and waste disposal costs.

Once the scenarios were developed, the Cost Assessment of Nuclear Substitution (CANS) Model was run. The results of the application of the CANS system to the case of early price escalation assumptions as they were), the rate impact of early retirement in the Mid-Range case would be reduced from about 2 percent over the next 15 years, to about 0.2 percent. Thus we see that this single event has tended to almost completely eliminate any average 15 year impact on ratepayers of closing the Indian Point units now. I believe that this economic result, which is quite contrary to utility claims, is extremely important for the Licensing Board to take into account when deciding whether or not to order the closing of the Indian Point units.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

TABLE 1

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The ratepayers cost impacts, then, are likely to average about two percent over the next fifteen years with the major effects in the earlier years. This small but

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aging effects, no benefits from reductions in spent fuel and decommissioning costs, no readjustment of import power availability or system fuel mix in the absence of the plants, rapidly escalating make-up fuel costs, and so on. The Low Impact scenario is, by contrast, consistently pessimistic on nuclear plant performance and optimistic on make-up power economics. Each extreme may be considered unlikely. Together they place wide boundaries on plausible future conditions.

The Mid-Range results are offered as our best estimates of the direct cost effects of early retirement of IP-2 and IP-3. The overall effect of closing the plants by 1983 is about $746 million (discounted 1981 dollars) or, on a percentage basis, approximately two percent. This is the cumulative impact for the entire 1983-1997 period. The annual impacts are relatively more severe in the early years and then moderate substantially over time, as will be discussed further below.

The results of our analysis for each of the three early retirement scenarios are summarized in Table 1. The results for each scenario are presented in terms of total additional revenues required from ratepayers during the period 1983-1997. The results are also expressed as a percentage increase or decrease from the revenues that would be required assuming continued plant operation during the period.

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measurable negative impact would have to be weighed against the perceived benefits in avoided nuclear risks in deliberating the fate of the Indian Point units.

1.4 Report Plan

The remaining sections of this report explain and discuss the methodological strategy used to derive cost impacts (Section 2); the central components of the cost assessment model and the basis for quantitative input assumptions used (Section 3); the scenario specifications, basic findings, and related issues (Section 4); and the indirect impacts of a plant closing (Section 5). While a complete summary of methods and findings is presented in these sections, detailed technical explications of the computer models and databases have been deferred to a series of appendices for the more technically inclined reader.

2. METHOD OF ANALYSIS

The aim is to develop realistic estimates of the direct impacts on ratepayers of closing the two Indian Point nuclear units. Concretely, the analytical problem is to quantify the resulting changes in required revenues over a planning period. The required revenues consist of the amount utilities need to collect from their customers to cover operating expenses, taxes, capital amortization, and return on investment. As an appropriate overall measure of ratepayer costs, required revenues constitute the measure to be employed in the cost impact assessments performed here.

2.1 Impacts Considered

The required revenues for a given year are composed of many elements reflecting the operations of the entire electric system under consideration. However, the ratepayer impacts of a plant closing is the <u>difference</u> of two required revenue streams: one with the plant included and the other with it nonoperational. Consequently, costs common to both cases cancel in computing the incremental impacts of a plant closing and need not be considered further.

There remain seven significant components of the required revenue that would be affected by a plant retirement. These are:

<u>Make-up Generation</u>. In the absence of the nuclear plant, the electricity generation requirements must be

provided by the existing system, by purchased power, by new plant construction, or by conservation. The costs of these make-up power alternatives constitute the major penalty of early power plant retirement. To analyze them, it is necessary to carefully specify the possible economic system responses to the loss of the facility. Projections of nuclear plant generation (capacity factors) to determine how much generation must be replaced are an important ingredient in this analysis. Independent projections of possible future capacity factors for the Indian Point units have been performed for this study and will be detailed below.

Direct Capital Related Costs. These include recovery of the sunk capital, return on investment, taxes and insurance. In an early retirement scenario, a number of adjustments must be considered in, e.g., tax write-off schedules, insurance and property tax requirements, and regulatory treatment of customer responsibility for providing full capital recovery and return in the event the plant is no longer providing service.

Nuclear Fuel. This is an avoided cost (i.e., a benefit) of early retirement. As with make-up generation its value is dependent on assumptions on likely future plant capacity factors.

Nuclear Operation and Maintenance. This is another avoided cost of early retirement and, as we shall report, there is statistical evidence for projecting rapidly escalating nuclear O&M costs related in part to the aging-related equipment problem.

Radioactive Waste Storage and Disposal. In both cases, early and mature retirement, it is necessary to find temporary off-site storage for, and then, to finally dispose of highly radioactive spent fuel. However, the early retirement scenario has two advantages here. First, the storage ponds used for on-site storage until off-site temporary and permanent repositories become available will be filled to capacity in the next few years if the plants continue running, and this problem is ameliorated by early retirement. Second, the magnitude of waste requiring ultimate disposal is a direct function of cumulative plant generation, so early retirement reduces the total amount of waste that must be disposed of.

Decommissioning. In either case, expenses will be incurred in dismantling or encapsulating the radioactive facility after its useful life has ended. The relative costs may differ here primarily if the decommissioning expenses are greater for older, more irradiated units, as we discuss further below.

Other Expenses. Certain costs for major plant repairs and safety modifications are avoidable if the plant is to be closed. Furthermore, if the closing date is set for after the planned maintenance period during which these improvements will be made, then there is the extra benefit of having greater plant availability in the short run by not having to make these improvements.

2.2 Cost Accounting System

The complexity of these issues -- as well as the desire to have a flexible capability for developing scenarios, performing sensitivity analyses, and synthesizing results -- warranted the development of a computer-based costing model. The resultant model, the Cost Assessment of Nuclear Substitution (CANS) System used to compute the required revenue impact, is documented in Appendix A.

The CANS system is designed to simulate the required revenue impacts in both current and discounted dollars and over variable time periods. It provides a flexible framework for testing the effects for various scenarios and parameter ranges so that uncertainty in both technology variables (e.g., future plant performances) and policy or economic variables (e.g., conservation activity) may be adequately explored. In addition, several ancillary computer models were employed for developing inputs on make-up generation, capacity factors, and O&M costs. These will be identified and discussed in Section 3.

2.3 Scenario Design

Three scenarios were developed to estimate the ratepayer impacts of early retirement. In all three scenarios the retirement date is taken as January 1, 1983. In a separate sensitivity exercise, we report impacts based on a 1985 retirement date. The three scenarios incorporate a range of planning assumptions affecting the level of impact on ratepayers.

The High Impact scenario consistently incorporates those plausible assumptions on capital costing, load growth, make-up generation sources, nuclear O&M, capacity factors, waste disposal, and decommissioning that would be most unfavorable from the ratepayers' point of view. In the Low Impact scenario, on the other hand, the incremental costs are computed on the basis of inputs that are the most favorable to the ratepayer. The Mid-Range scenario reflects compromise assumptions between these extremes. Again, the High and Low Impact cases were developed to function as extreme and unlikely cases, based on the simultaneous bias of probablistic input variables in the same impact direction. In principle, the convolution of a number of stochastic, statistical, and uncertain policy variables should lead to a strong centering tendency around mid-range values. The Mid-Range scenario results therefore represent our best estimate figures. The other two scenarios' results and the supplemental sensitivity analyses serve to quantify the implications of alternative assumptions or sets of assumptions. A qualitative characterization of the scenarios is presented in Table 2. The details of the scenario analysis are the subject of the next section.

TABLE 2

QUALITATIVE SUMMARY OF SCENARIOS EMPLOYED

Scenario	Sunk Cost Treatment	Make-up Generation	Load Growth	Nuclear O&M	Nuclear Fuel	Nuclear Capacity Factors	Spent Fuel Disposal	Decommissioning
1. High Impact	Full Rate Base	Existing Systems High fossil fuel cost escalation, little additional imports	Base (0.5%/ year Growth Rate	Low	Low	High	Low	No aging effect/ Low Cost Escalation
2. Mid-Range	Full Rate Base	Additional coal conversion, additional hydro imports, lower fuel escalation, moderate additional imports	50% Conservation Target (no growth)	Mid	Mid	Mid	Mid	Mid
3. Low Impact	Full Capital Recovery	Additional conversion, low hydro, low fuel escalation, high additional imports.	Conservation Target (-0.7%/ year growth rate)	High	High	Low	High	Aging Effect/ High Cost Escalation

3. COSTS BY MAJOR CATEGORY

3.1 Introduction

This section describes our assumptions and results for each of the major cost categories considered. In all cases, the results are generated by the CANS system as documented in Appendix A. Supplementary modeling and analysis were performed in developing various input values. These efforts are identified below where reference is made to supporting technical appendices and documents.

The costs are consistently reported in discounted (or "present worth") 1981 dollars. This is the conventional approach to comparing dollar outlays (or savings) that occur at different points over a given time interval. A dollar today is worth more than a future dollar because of its earning power in the intervening years. Future impacts are brought back to a common year's currency in this study by discounting future nominal cost estimates ("current" dollars) at 12 percent per year. The average rate of inflation is taken at 8 percent per year, so the "real" discount rate is four percent above inflation. We analyze the effects of other discount rate assumptions in Section 4. It should be further noted that the dollar impact estimates consistently reflect an allowance for Con Ed revenue taxes taken at 4 percent overall (PASNY as a public authority pays no such taxes).

3.2 Make-Up Generation

3.2.1 Scenario Definitions

In the event of an early retirement, other power sources must supply the electrical energy that would have been produced by the Indian Point units. These sources could include running less economical units in the system more than they otherwise would have been run; importing more energy from outside the system; or investing in new generation facilities. In principle, it could also include utility investment in conservation and improved end-use equipment efficiency, though we have not considered this option for substitute power in the scenarios in the Indian Point case study. Make-up generation costs, then, are the costs of substitute power caused by the need to adjust and to re-dispatch the downstate Con Edison/PASNY generation system if the Indian Point units are not present. It is generally agreed that these costs are likely to be substantial in calculating the economic impact on utility ratepayers of an Indian Point closing.

3.2.2 Demand Growth

Demand growth scenarios were based upon our June, 1981, study for the New York City Energy Office.(7) This was a detailed study of the Con Ed and downstate PASNY generation system. The study developed a long-range Base Case forecast of electric energy and peak demand for the Con Ed region.

This long-range planning forecast is the one connoted by the term "Base Case" in Table 3 and used as the demand forecast in the High Impact scenario generation analyses.

Our June, 1981 study also developed a conservation scenario consisting of conservation measures and levels that were technically feasible and cost-effective compared to energy supply. A Conservation Case load forecast was prepared to calculate the year-by-year electric energy consumption and peak demand for the Con Ed region assuming implementation of the conservation scenario. In the Low Impact scenarios, we assumed full implementation of this conservation scenario, independently of whether or not the Indian Point units are retired early.

A systematic generation dispatch study was performed to develop make-up power cost scenarios for input to the CANS nuclear retirement cost assessment system. An economic dispatch model, SYGEN, was used to perform six generation system dispatch runs.* The six dispatch runs consist of High-Impact, Mid-Range, and Low-Impact Cases, each with and

*A dispatch model provides a computer simulation of the operation of an electric generation system as a function of demand, based on specified economic and operating characteristics for each available type of generating station. Plants with the lowest unit variable cost run first, with higher cost units being added as needed to meet demand. SYGEN documentation is provided in our June, 1981 study for the New York City Energy Office.

TABLE 3

MAKE-UP GENERATION SCENARIO DEFINITIONS

Scenario:	Demand Level	Ravenswood 1&2 Coal Conversion	Oil Price Escalation Rate (Real)*	Coal Price Escalation Rate (Real)	Availability of Canadian Imports to Con Ed Region**	Indian Point Capacity Factors
1. High-Impact						
a. Indian Point On	Base Case	No	4%	2%	42%	High
b. Indian Point Shut-down	Base Case	No	4%	2%	47%	--
2. Mid-Range						
a. Indian Point On	50% Conservation	No	2%	1%	42%	Mid-Range
b. Indian Point Shut-down	50% Conservation	Yes, in 1990,91	2%	1%	52%	--
3. Low-Impact						
a. Indian Point On	100% Conservation	No	0%	0%	42%	Low
b. Indian Point Shutdown	100% Conservation	Yes, in 1987	0%	0%	57%	--

* To these fuel prime escalation rates, 8 percent general inflation must be added.

** Measured as percentage of the non-firm Canadian power expected to come to the entire New York State Power Pool, which is 8,000 GWH for 1982-83, and 15,000 GWH for 1984-2000. Extra New York Power Pool imports are also available at higher cost according to dispatch requirements.

E S R G

without the Indian Point units.[10] The annual replacement power costs for any single scenario were then obtained by subtracting the dispatch for the results with Indian Point from the results without the units operating. The specific assumptions that were employed in creating the six generation system dispatch runs are detailed in Table 3. Let us review these assumptions -- on demand growth, coal conversion, fossil fuel escalation rates, the availability of Canadian power, and Indian Point capacity factors -- in turn.

In the Mid-Range scenario, fifty percent implementation of the conservation scenario was used. Thus, demand levels in the Mid-Range scenario are precisely halfway between the demand levels of the bracketing scenarios.

3.2.3 Coal Conversion

With regard to coal conversion, the Mid-Range scenario reflects the fact that an Indian Point shutdown should make the coal conversion options more attractive to NYS regulators and to Con Edison, so that the conversion of Ravenswood #1 and #2 is assumed to be added to their present conversion program. Such conversions would improve the downstate security of the transmission system. The 1990 and 1991 conversion dates for these units are Con Edison assumptions on the feasible conversion dates.[11] The conversion of these units was also included in the 1981 State Energy Master

Planning report "Full Implementation Scenario" for conversion, though not in the basic "Electricity Supply Plan".[12] This conversion is presently supported by the New York City Office as an important oil replacement option.

It is possible, though not likely, that these conversions would not occur in the event of an Indian Point shutdown. In the High Impact scenario, the conversions are assumed not to take place.

In our June, 1981 study we made independent estimates for cost and operating characteristics relevant to the conversion of Ravenswood 1 and 2. Our study found that even with scrubbers included in the cost of conversion to coal, it is cost-effective to convert the units from oil. Our analysis found that it was feasible to convert them by 1987.[7] These results informed development of our Low Impact scenario, where we assumed that early retirement would cause the Ravenswood conversions to occur in 1987, as shown in Table 3.

3.2.4 Fuel Cost Escalation

The scenario fuel price assumptions reflect the uncertainty surrounding likely future oil and coal prices. We have assumed that in real terms (above an overall 8 percent inflation rate) oil price escalation rates would range between 0 and 4 percent, and that real coal price escalation rates would range between 0 and 2 percent over the next 20 years. These price assumptions bracket the fuel price assumptions that Con Edison recently used to calculate the costs of replacement power for the Indian Point units.[14]

3.2.5 Canadian Power Availability

The three basic make-up generation scenarios are distinguished by differing assumptions on the future availability of Canadian power imports into the downstate Con Edison/PASNY system. Canadian imports are projected by the NYPP to come from both Hydro Quebec (HQ) and Ontario Hydro (ONHY) in the following amounts at the statewide level:[15]

NYPP Canadian Import Assumptions
(GWH)

Years	HQ	ONHY	Total Statewide
1982-83	8,000	3,000	11,000
1984-96	12,000	6,000	18,000

It was necessary to project the portion of these projected imports that would be available to the Con Ed and downstate PASNY systems. Based on a firm power contract of 780 MW, Con Ed is already entitled to some 3,000 GWH throughout the period. The question is thus what portion of the remaining 8,000 (1982-3) and 15,000 (1984-96) GWH to allocate the downstate systems in the various cases and scenarios. In the no-shutdown case, we assumed that 42 percent of the non-firm import power would be available. (This is approximately the portion of the non-firm power that went to Con Ed in 1981.)

In the shutdown scenario dispatch runs it was assumed that 5, 10, and 15 percent more Canadian power would be available downstate to both Con Edison and PASNY, in the High, Mid-Range, and Low Impact cases, respectively. These values derive from the assumption that some redistribution of PASNY Canadian power would occur throughout NYPP due to: (1) a reallocation of Canadian power between upstate and downstate, (2) the change in the dispatch of the NYS Power Pool and (3) the role of state regulators in allocating power to alleviate the impacts of an Indian Point shutdown. The average price for the Canadian imports in the base year 1981 was taken from Con Edison data to be $36.40 per MWH.(16)

In addition to Canadian power, higher priced NYPP power would be available to the downstate region if needed.(17) When Indian Point is assumed closed in 1983, then, some of the replacement generation comes from NYPP members, some from Con Edison's and PASNY's own plants, and some from Canadian imports. The more technically inclined reader may find it instructive to compare the sample Mid-Range Case dispatch model output given for 1990 for both the shutdown (MR1) and no shutdown (MKL) cases provided in Appendix F below.

One important consideration in modeling the costs of make-up generation is the extent to which transmission constraints exist from the upstate region (including Canada) to the downstate Con Edison/PASNY service territory. This is a complex subject with little published analytic material. However, several points can be made. First, transmission line improvements in 1984 and 1986 are currently scheduled. This will so significantly improve the capacity of the downstate interconnection, as well as the upstate NYPP interconnection to Canada, that after 1986 transmission constraints will be minimal. Second, if the Indian Point units are no longer operational, some additional capacity on the interconnection to upstate from New York City will be available prior to 1986. Indeed, Con Edison's dispatch analysis of the transmission constraints to the upstate region and their impact on the sources of energy to replace Indian Point indicates that there is considerable additional capability on these lines even in 1983.(19)

3.2.6 Power Plant Capacity Factor Assumptions

The quantity of replacement power required is directly proportional to the capacity factors of IP-2 and IP-3. The capacity factor scenario assumptions for the Indian Point units for each year of planned operation were developed on the basis of the units' historical experience, a review of the literature on nuclear plant capacity factors, and independent analyses conducted during the course of this investigation. The capacity factor represents the fraction of time a unit is available at equivalent full rated capacity. Three capacity factor scenarios were employed -- High Impact, Mid-Range, and Low Impact cases, embodying high, medium, and low predicted future performance of each of the two Indian Point units.

The multivariate regression analysis presented in Appendix C provides a model of nuclear power plant performance (capacity factor) as measured by a number of explanatory variables. Among these variables are the unit's size (maximum dependable capability), type [pressurized water reactor (PWR) or boiling water reactor (BWR)], age (years of commercial operation), and whether or not cooling towers or salt-water cooling are used.

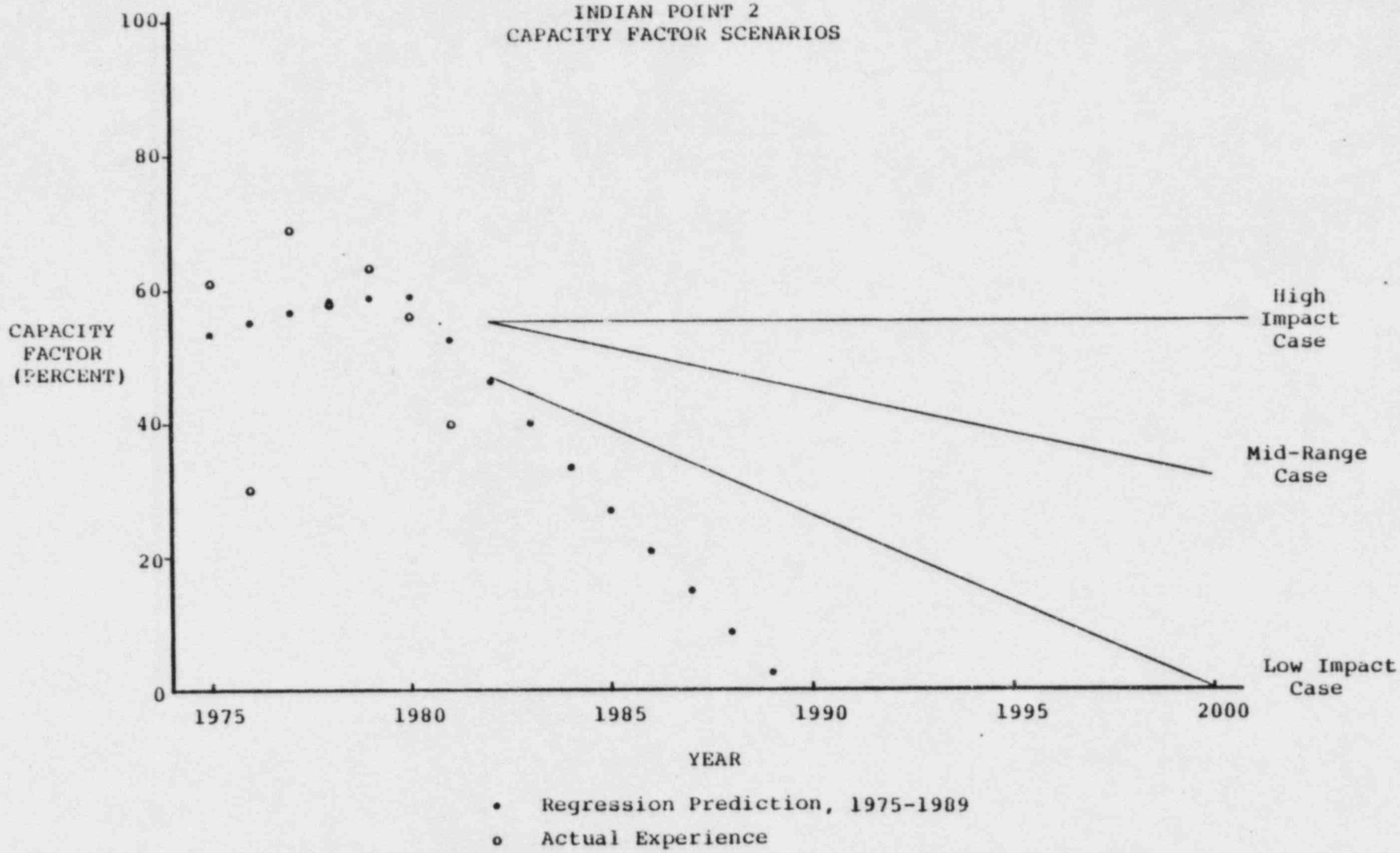
One significant implication of that analysis is that large salt-water cooled PWR nuclear units like the Indian Point units can be expected to exhibit strongly deteriorating performance after their first several years of operation. Application of the regression equation developed in our capacity factor analysis to the Indian Point units clearly shows this same general trend. We did not, however, directly apply the regression equation in developing our scenarios for future capacity factors, for the application of statistical results describing the historical experience of essentially all operating nuclear units in the U.S. to a particular unit must be made with caution. It is nonetheless obligatory, in an economic evaluation such as the present one or, for that matter, in any utility capacity planning analysis, to make estimates of the future capacity factors. The regression analysis presented in Appendix C certainly did provide an important guideline in our development of capacity factor scenarios for the Indian Point units.

Figures 1 and 2 show the High Impact, Mid-Range, and Low Impact capacity factor scenarios that were summarized in Table 3 for each of the Indian Point units. For comparison, the results of the regression equation as well as actual experienced capacity factors are also shown on the graph. All three of the scenarios chosen for this study assume better future performance than the regression analysis would indicate. Each scenario takes the actual operating experience for the units as a point of departure. The High Impact and Mid-Range cases assume that each unit's capacity factor for 1982 will be equal to its historic average, thus smoothing out the quite substantial fluctuations evidenced by the data points on the graphs. These initial values are 55 percent and 53 percent for IP-2 and IP-3, respectively. In the Low Impact case, the 1982 capacity factor values are those predicted for that year by the ESRG regression analysis. These results are 45 percent and 50 percent, respectively, for Indian Point units #2 and #3.*

*The 1980-81 average capacity factors for these units is 48 percent and 36 percent, respectively.

Figure 1

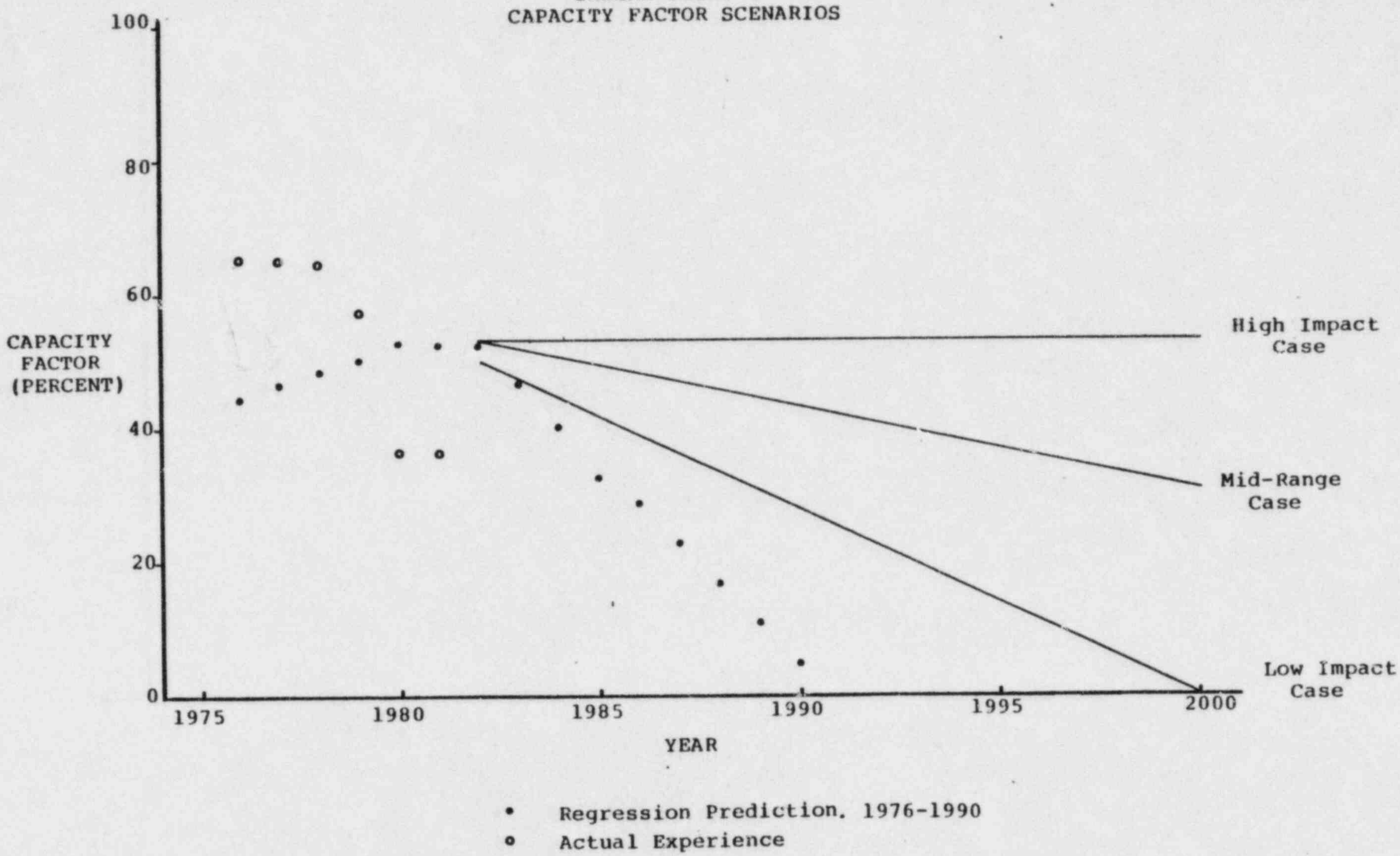
INDIAN POINT 2
CAPACITY FACTOR SCENARIOS



-28-

Figure 2

INDIAN POINT 3
CAPACITY FACTOR SCENARIOS



In the High Impact case no aging effect is assumed for either of the Indian Point units. The units are assumed to maintain their historic average capacity factors of 55 percent and 53 percent, respectively. Given our statistial results showing declining capacity factors for salt-water cooled PWRs, this scenario, while quite possible, does not appear to be likely. Con Edison and PASNY have assumed that both units will achieve 69 percent capacity factors for their remaining years of planned operation, but our studies lead to the conclusion that this assumption is too optimistic (even as a High Impact input).

In the Mid-Range case we have assumed that beginning in 1982 the capacity factors for the Indian Point units will decline linearly with age. Rather than the very rapid decline indicated by the results of our regression analysis of nuclear plant operating experience, we have assumed a more cautious rate of deterioration in performance, with capacity factors reaching 20 percent by the 35th year of operation.(21)

Finally, in the Low Impact case we have followed the regression analysis results somewhat more closely. We have assumed that the capacity factors will reach zero by the year 2000. This is less than half the rate of drop-off predicted by the regression equation. In the year 2000, the average age of the two Indian Point units will be twenty-five years. Of course, thus far there has been no experience of nuclear units remaining in operation for 25 years. In contrast, some reactors have been shut down before 15 years of operation. Given this history of actual early shutdowns and the strong results of the regression analysis, the capacity factor assumptions in the Low Impact case appear to be quite possible on an average basis (where some reactors may last for 30 to 35 years, while others may last only 15 to 20 years).

3.2.7 Make-Up Power Cost Summaries

The cost components of the make-up generation are presented in current dollars for the three scenarios in Tables 4, 5, and 6. The column labeled "Fuel Cost" represents the differential fuel costs for the Con Edison/PASNY system between the shutdown and no shutdown cases. The column labelled "O&M Cost" represents the differential variable O&M and purchased power costs again due to re-dispatch of the generation system in case of an Indian Point shutdown in 1983. The "Working Capital" values represent the additional working capital changes to ratepayers due to the increased level of fuel usage. The average rate appropriate to Con Edison and PASNY was assumed to be 2 percent of fuel costs annually. The "New Capital" column takes account of the annualized charges to ratepayers of the capital costs required to convert Ravenswood #1 and #2 to coal in the Mid-Range and Low Impact scenarios. The O&M cost column

TABLE 4

MAKE-UP POWER REPORT -- MID-RANGE
(Millions of Current Dollars)

Year	Fuel Cost	O&M* Cost	Working Capital	New** Capital	Total*** Cost
1983	359.365	174.969	7.187	0.0	541.520
1984	338.594	189.656	6.772	0.0	535.021
1985	356.177	211.021	7.124	0.0	574.321
1986	134.427	160.229	2.689	0.0	297.344
1987	349.594	285.760	6.992	0.0	642.345
1988	364.562	303.552	7.291	0.0	675.405
1989	391.146	329.104	7.823	0.0	728.073
1990	321.094	390.677	6.422	194.524	912.716
1991	-79.000	247.125	-1.580	217.777	384.322
1992	215.583	387.500	4.312	222.167	829.561
1993	210.052	413.917	4.201	226.945	855.114
1994	202.135	442.292	4.043	232.136	880.606
1995	199.594	476.625	3.992	237.843	918.053
1996	194.583	513.198	3.892	244.037	955.710
1997	184.417	554.510	3.688	250.842	993.456

*Includes purchased power.

**Composed of capital costs and incremental fixed O&M costs of coal conversion.

***All costs include revenue taxes at 4%.

TABLE 4

MAKE-UP POWER REPORT -- MID-RANGE
(Millions of Current Dollars)

Year	Fuel Cost	O&M* Cost	Working Capital	New Capital	Total Cost
1983	359.365	174.969	7.187	0.0	541.520
1984	338.594	189.656	6.772	0.0	535.021
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1996	194.583	513.198	3.892	244.037	955.710
1997	184.417	554.510	3.688	250.842	993.456

*Includes purchased power.

TABLE 5

MAKEUP POWER REPORT -- HIGH IMPACT
(Millions of Current Dollars)

Year	Fuel Cost	O&M* Cost	Working Capital	Total** Cost
1983	394.187	175.021	7.884	577.092
1984	412.844	190.573	8.257	611.673
1985	451.927	227.166	9.039	688.132
1986	437.281	315.510	8.746	761.537
1987	490.271	348.323	9.805	848.399
1988	539.104	392.406	10.782	942.292
1989	603.448	442.635	12.069	1,058.152
1990	675.219	498.072	13.504	1,186.795
1991	755.437	560.500	15.109	1,331.046
1992	845.156	630.771	16.903	1,492.829
1993	945.489	709.865	18.910	1,674.263
1994	1,057.604	797.865	21.152	1,876.620
1995	1,183.000	896.719	23.660	2,103.378
1996	1,323.532	1,007.469	26.471	2,357.471
1997	1,464.167	1,150.104	29.283	2,643.554

*Includes purchased power.

**All costs include revenue taxes at 4%.

TABLE 6

MAKEUP POWER REPORT -- LOW IMPACT
(Millions of Current Dollars)

Year	Fuel Cost	O&M* Cost	Working Capital	New** Capital	Total*** Cost
1983	275.240	158.938	5.505	0.0	439.682
1984	217.698	173.771	4.354	0.0	395.823
1985	214.604	182.552	4.292	0.0	401.448
1986	55.271	138.198	1.105	0.0	194.574
1987	97.208	235.198	1.944	167.647	501.997
1988	-111.604	96.562	-2.232	170.683	153.409
1989	22.615	184.979	0.452	174.033	382.078
1990	-6.656	184.667	-0.133	177.687	355.564
1991	-35.719	185.552	-0.714	181.672	330.791
1992	-75.146	182.000	-1.503	186.062	291.413
1993	-114.823	179.719	-2.296	190.840	253.439
1994	-159.781	175.990	-3.196	196.032	209.044
1995	-211.406	169.198	-4.228	201.738	155.301
1996	-278.083	155.281	-5.562	207.933	79.569
1997	-345.562	142.135	-6.911	214.737	4.399

*Includes purchased power.

**Composed of capital costs and fixed O&M costs of coal conversion.

***All costs include revenue taxes at 4%.

also includes the increase in fixed O&M that results from coal burning at Ravenswood when compared to oil burning.*

The total annual make-up generation costs from 1983-1997 in discounted 1981 dollars for all three scenarios are presented in Table 6. The sum for the Mid-Range Impact scenario is $3.91 billion, with the High Impact value at $6.49 billion and the Low Impact value at $1.95 billion. Thus these costs are both quite substantial and quite sensitive to the assumptions listed in Table 3.

3.3 Direct Capital-Related Costs

In this section, we will discuss the effect of past investments in the Indian Point units on future revenue requirements. As always, our attention will be focused on differential costs, that is, the change in costs that can be attributed to early retirements.

For PASNY, the primary capital cost component is the interest and principal payments on the bonds issued to finance IP-3. But because PASNY electric revenues will invariably be used to service the bonds, we assumed no differential costs or benefits from retirement. One differential cost factor considered was nuclear liability

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* We remind the reader that make-up generation costs generally reported in other studies subtract out the appropriate savings for nuclear fuel, nuclear O&M, and spent nuclear fuel disposal.(20) However, in this study these items (and their costs) are treated separately.

insurance, which we assumed was not to be incurred after the retirement date. Based on information supplied by PASNY, this insurance cost was taken to be $453,000 in 1981 and was assumed to increase at a rate of 9 percent per year.

The capital cost module described in Appendix A section A3 was employed in developing differential capital costs for Con Ed's IP-2. The major data items employed in this analysis are shown in Table 7. Estimates for original cost and tax credits were supplied by Con Ed. AFDC was assumed to be 20 percent of original cost.

Under retirement, it is assumed in the Mid-Range and High Impact cases that Con Ed will be allowed to amortize its remaining Indian Point investment over a twenty year period and to earn its average rate of return on the unamortized balance. In the Low Impact case, it is assumed that the plant will be more quickly amortized, over ten years, but that no return will be earned.

In Table 8, sample computer output of the capital cost module for Con Ed under "Keep" assumptions is shown. In Table 9, output of costs under retirement is shown. Table 10 displays the complete 1983-1997 time stream of relative impacts for the three scenarios in discounted dollars. Beyond the nuclear liability insurance adjustments, the major impacts result from the earlier tax write-off schedule of plant costs when a plant is retired.

TABLE 7

DATA USED IN DEVELOPING CAPITAL-RELATED COSTS
FOR CON ED INDIAN POINT 2

Data Item	Value
Original Cost (including AFDC)	\$363,741,000
AFDC	\$ 72,748,000
Tax Credits	\$ 15,657,000
Book Life	33 years
Tax Life	16 years
Tax Depreciation Method	Sum of Years' Digits
Income Tax Rate	46%
Other Annual Cost	\$2,619,000 in 1981 escalating at 9% per year

TABLE 8

CAPITAL COSTS OF CONTINUED OPERATION

CON ED

(MILLIONS OF DOLLARS)

YEARS ---	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
ANNUAL BOOK DEPR.	11.022	11.022	11.022	11.022	11.022	11.022	11.022	11.022	11.022	11.022
NET VALUE (BOOK DEPR.)	308.629	297.606	286.583	275.561	264.539	253.516	242.494	231.471	220.449	209.427
ANNUAL TAX DEPR.	23.536	21.397	19.257	17.117	14.978	12.838	10.698	8.559	6.419	4.279
NET VALUE (TAX DEPR.)	141.217	117.681	96.284	77.028	59.910	44.933	32.095	21.397	12.838	6.419
S.L. DEPR. FOR NORM. TA	8.818	8.818	8.818	8.818	8.818	8.818	8.818	8.818	8.818	8.818
OTHER COSTS	2.619	2.855	3.112	3.392	3.697	4.030	4.392	4.788	5.219	5.688
REVENUE TAX	2.428	2.333	2.244	2.157	2.075	2.002	1.934	1.871	1.816	1.767
TAX CREDIT ANN. AMORT.	0.474	0.474	0.474	0.474	0.474	0.474	0.474	0.474	0.474	0.474
TAX CREDIT RESERVE	13.285	12.810	12.336	11.861	11.387	10.912	10.438	9.964	9.489	9.015
DEFFERED TAXES	6.770	5.786	4.802	3.818	2.833	1.849	0.865	-0.119	-1.104	-2.088
AFDC-DEBT TAX AMORT.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DEFFERED TAX RESERVE	48.616	55.386	61.172	65.974	69.792	72.625	74.474	75.339	75.220	74.116
RATE BASE	251.117	233.816	217.499	202.167	187.819	174.456	162.076	150.681	140.270	130.843
RETURN TO EQUITY	18.080	16.835	15.660	14.556	13.523	12.561	11.669	10.849	10.099	9.421
RETURN TO PREFERRED	1.657	1.595	1.531	1.468	1.405	1.362	1.301	1.243	1.188	1.123
RETURN TO BONDS	7.071	6.996	6.890	6.672	6.446	6.218	5.990	5.702	5.431	5.181
TAXABLE INCOME	25.037	24.754	24.600	24.578	24.688	24.968	25.344	25.856	26.506	27.267
INCOME TAX	11.517	11.387	11.316	11.306	11.357	11.485	11.658	11.894	12.193	12.543
REQUIRED REVENUES	60.691	58.334	56.104	53.915	51.884	50.055	48.359	46.775	45.390	44.183
P.V. FACTOR TO 1981	1.000	0.893	0.797	0.712	0.636	0.567	0.507	0.452	0.404	0.361
P.V. OF REQ. REVENUES	60.691	52.084	44.725	38.376	32.973	28.403	24.500	21.159	18.332	15.933

TABLE 9

CAPITAL COSTS AFTER RETIREMENT

CON ED

(MILLIONS OF DOLLARS)

YEARS ---	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
ANNUAL BOOK DEPR.	8.439	8.439	8.439	8.439	8.439	8.439	8.439	8.439	8.439	8.439
NET VALUE (BOOK DEPR.)	168.785	160.346	151.906	143.467	135.028	126.589	118.149	109.710	101.271	92.832
ANNUAL TAX DEPR.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NET VALUE (TAX DEPR.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S.L. DEPR. FOR NORM. TA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OTHER COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
REVENUE TAX	1.872	1.821	1.768	1.715	1.660	1.602	1.542	1.481	1.420	1.359
TAX CREDIT ANN. AMORT.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TAX CREDIT RESERVE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DEFFERED TAXES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AFDC-DEBT TAX AMORT.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DEFFERED TAX RESERVE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RATE BASE	164.565	156.126	147.687	139.247	130.808	122.369	113.930	105.491	97.051	88.612
RETURN TO EQUITY	11.849	11.241	10.633	10.026	9.418	8.811	8.203	7.595	6.988	6.380
RETURN TO PREFERRED	1.159	1.133	1.105	1.088	1.050	1.010	0.965	0.905	0.854	0.790
RETURN TO BONDS	5.213	5.152	5.069	4.963	4.835	4.630	4.411	4.177	3.929	3.704
TAXABLE INCOME	39.716	38.544	37.365	36.208	35.014	33.814	32.606	31.370	30.150	28.905
INCOME TAX	18.269	17.730	17.188	16.656	16.107	15.554	14.959	14.430	13.869	13.296
REQUIRED REVENUES	46.801	45.517	44.202	42.887	41.509	40.046	38.560	37.028	35.499	33.968
P.V. FACTOR TO 1981	0.797	0.712	0.636	0.567	0.507	0.452	0.404	0.361	0.322	0.287
P.V. OF REQ. REVENUES	37.310	32.398	28.091	24.335	21.030	18.115	15.574	13.353	11.430	9.765

TABLE 10

CAPITAL COSTS IMPACTS
(Million 1981 Discounted Dollars)

	Scenario		
Year	High Impact	Mid-Range	Low Impact
1983	-7.8	-7.8	-19.2
1984	-6.4	-6.4	-15.6
1985	-5.3	-5.3	-12.7
1986	-4.5	-4.5	-10.3
1987	-3.9	-3.9	-8.4
1988	-3.4	-3.4	-6.8
1989	-3.2	-3.2	-5.6
1990	-3.0	-3.0	-4.5
1991	-2.9	-2.9	-3.7
1992	-2.9	-2.9	-3.2
1993	-2.7	-2.7	-11.1
1994	-2.7	-2.7	-9.8
1995	-2.7	-2.7	-8.7
1996	-2.6	-2.6	-7.7
1997	-2.6	-2.6	-6.8
TOTAL	-56.6	-56.6	-134.0

3.4 Nuclear Fuel

As described in Section 3.2, an early shutdown would incur the costs of substitute power. On the other hand, savings would result from avoiding expenditur for nuclear power production. One such avoided expenditure consists of nuclear fuel costs.

Nuclear fuel expenditures can be treated simply on a cost-per-KWH basis. The 1981 nuclear fuel costs were taken at 4.9 and 5.4 mills per KWH for IP-2 and IP-3, respectively. These are based on gross values provided by Con Ed and PASNY from which were deducted the costs collected for waste storage (about 2.1 mills per kwh). Waste storage costs were treated separately in this study.

For the High Impact, Mid-Range, and Low Impact scenarios, these 1981 nuclear fuel costs per KWH were increased by real escalation rates of 0 percent, 1 percent, and 2 percent, respectively.[23] In addition, a nuclear fuel "working capital" charge was included because nuclear fuel is capitalized by utilities. This capital charge amounts to 34 percent of the fuel costs so capitalized.[24] Table 11 shows the running costs for the Mid-Range case. Table 12 gives the discounted cost impacts for the three scenarios.

3.5 Operation and Maintenance Costs

Annual operation and maintenance (O&M) costs for the two Indian Point nuclear units were estimated for each of their

TABLE 11

NUCLEAR FUEL COST -- MID-RANGE CASE
(Current Dollars)

Year	Unit 1 Generation (GWH)	Unit 1 Unit Cost (Mils/KWH)	Unit 1 Total Cost ($ Millions)	Unit 2 Generation (GWH)	Unit 2 Unit Cost (Mills/KWH)	Unit 2 Total Cost ($ Millions)	Combined Total Cost ($ Millions)
1981	4,162.75	6.84	28.471	4,480.30	7.54	33.770	62.242
1982	4,162.75	7.46	31.034	4,480.30	8.22	36.810	67.843
1983	4,087.06	8.13	33.212	4,395.77	8.96	39.365	72.577
1984	3,935.69	8.86	34.860	4,311.23	9.76	42.083	76.943
1985	3,860.01	9.65	37.267	4,226.70	10.64	44.971	82.238
1986	3,784.32	10.52	39.824	0.0	11.60	0.0	39.824
1987	3,708.63	11.47	42.540	3,973.10	12.64	50.224	92.764
1988	3,557.26	12.50	44.476	3,888.56	13.78	53.579	98.056
1989	3,481.57	13.63	47.447	3,804.03	15.02	57.132	104.579
1990	3,405.89	14.85	50.593	3,719.49	16.37	60.890	111.483
1991	0,.0	16.19	0.0	3,634.96	17.84	64.861	64.861
1992	3,178.83	17.65	56.103	3,550.43	19.45	69.055	125.157
1993	3,103.14	19.24	59.696	3,381.36	21.20	71.685	131.381
1994	2,951.77	20.97	61.894	3,296.82	23.11	76.183	138.078
1995	2,376.08	22.86	65.735	3,212.29	25.19	80.911	146.646
1996	2,800.40	24.91	69.765	3,127.76	27.45	85.872	155.637
1997	2,724.71	27.15	73.989	3,043.22	29.93	91.070	165.059
1998	2,573.34	29.60	76.167	2,958.69	32.62	96.509	172.677
1999	2,497.65	32.26	80.580	2,874.15	35.55	102.189	182.770
2000	2,421.96	35.17	85.171	2,705.09	38.75	104.834	190.005
TOTAL	63,273.76		1,018.824	69,486.87		1,261.994	2280.819

E S R G

TABLE 12

NUCLEAR FUEL IMPACTS
(Million 1981 Discounted Dollars)

	Scenario		
Year	High Impact	Mid-Range	Low Impact
1983	-57.9	-57.9	-50.4
1984	-55.8	-54.8	-46.2
1985	-53.8	-52.3	-43.2
1986	-51.9	-22.6	-16.6
1987	-50.0	-47.0	-35.9
1988	-48.3	-44.4	-39.1
1989	-46.5	-42.2	-29.6
1990	-44.9	-40.2	-26.2
1991	-43.3	-20.9	-23.2
1992	-41.7	-36.0	-20.0
1993	-40.2	-33.7	-17.3
1994	-38.8	-31.6	-14.7
1995	-37.4	-30.0	-12.2
1996	-36.1	-28.4	-9.3
1997	-34.8	-26.9	-6.9
TOTAL	-681.3	-568.9	-370.7

future years of planned commercial operation. Historical data on the units' O&M cost experience were used in developing the estimates.

These data on IP-2 and IP-3 were complemented by an independent analysis of the O&M costs experienced by 49 commercially operating nuclear power plants during and before 1979 (described fully in Appendix B).

Actual experience shows that O&M costs for nuclear units have been increasing at rates generally far in excess of the rate of inflation. A simple exponential fit to the historical O&M cost experience of each of 49 nuclear units shows that more than 60 percent have incurred costs escalating at rates between 10 and 30 percent above inflation over their years of commercial operation (see Table B-19).

A regression analysis was performed to relate historical O&M costs for commercially operating nuclear generating stations to a number of explanatory variables. The explanatory factors include unit size, age, and in-service date, as well as several variables expressing the type of units (BWR or PWR) and whether they have cooling towers, use salt water for cooling, are located in the Northeast, are demonstration plants, or have two or more units at the station. This regression analysis is detailed in Appendix B.

In the regression analysis, two types of specification in the age (years of operation) variables were explored, linear and exponential. They were found to have comparable explanatory power for the historical data. Given these results one would expect that a plausible choice for nuclear O&M cost escalation would lie somewhere between the linear and exponential predictions. However, since the exponential form predicts a much more rapid escalation in the future, diverging strongly from the linear result, it was not used in the present study (as an exercise of caution).

The O&M cost scenarios developed for the present study begin with 1981 costs for the Indian Point generating station derived from a simple linear least squares fit to their historically experienced costs. This procedure ensures that any fluctuations in this experience are smoothed out so that a suitable starting point from which future escalation begins is established. The station 1981 O&M costs thus derived are $58.66 per KW or $107.3 million (in 1981 dollars). A similar estimate of the O&M costs based upon historical experience was made by the General Accounting Office (25). The GAO estimate, when corrected for inflation from 1979 to 1981, becomes about $71 million. By contrast, Con Edison has estimated 1983 O&M costs for the station to be about $41 million.

O&M costs for the remaining years of planned commercial operation of the Indian Point generating units were obtained by using the linear regression equation (Appendix B, Table B-11), applied to Indian Point, to obtain the ratios of future years' real-dollar O&M costs per KW to the base year (1981) value given above. These ratios provide real dollar O&M costs for all subsequent operating years. This procedure is employed in both the Mid-Range and Low Impact cases. For the High Impact case the real O&M cost escalation is taken to be 75 percent of that given by the linear regression equation. Thus, in the present study, three O&M cost scenarios are employed -- High Impact, Mid-Range, and Low Impact -- embodying low, medium, and high escalation rates, respectively.

The O&M cost projections for the Indian Point generating station are presented in Table 13 in constant dollars for the three scenarios. It can be seen in these tables that while per KW costs escalate smoothly, there are some years in which total station costs drop sharply. This occurs because in the Mid-Range and Low Impact cases, where it is assumed that steam generators are replaced once during each of the units' planned operating lives, no O&M costs are incurred during the period when replacement is being effected.

3.6 Radioactive Waste Disposal

The several year stay of nuclear fuel assemblies in the nuclear reactors themselves is but one phase in the "nuclear fuel cycle." The preparatory phases include mining and milling of uranium, conversion of uranium oxide into gaseous uranium hexafluoride, enrichment (increasing the concentra-

TABLE 13

NUCLEAR O&M IMPACTS
(Million 1981 Discounted Dollars)

Year	Scenario: High Impact	Mid-Range	Low Impact
1983	-109.9	-113.4	113.4
1984	-110.8	-115.9	-115.9
1985	-111.3	-118.1	-118.1
1986	-111.6	-56.6	-56.6
1987	-111.6	-121.4	-121.4
1988	-111.5	-122.6	-64.7
1989	-111.2	-123.6	-123.6
1990	-110.6	-124.3	-124.3
1991	-110.0	-65.8	-124.8
1992	-109.2	-125.1	-125.1
1993	-108.3	-125.2	-125.2
1994	-107.3	-125.1	-125.1
1995	-106.1	-124.8	-124.8
1996	-104.9	-124.4	-124.4
1997	-103.7	-123.9	-123.9

tion of the fissionable U-235 isotope of uranium), and fabrication of reactor-ready fuel elements consisting of zirconium tubes containing pellets of uranium dioxide. A portion of the "front-end" costs are reflected in rates through the nuclear fuel charges discussed in Section 3.4 above. Other social costs related to federal subsidies of nuclear fuel technologies and environmental impacts are beyond the scope of the quantitative analysis in this investigation. (See Section 5 for more discussion of indirect costs.)

In this subsection, costs associated with the "back-end" of the nuclear fuel cycle concern us. Until several years ago, it was assumed that spent fuel rods would, after several months in temporary storage to undergo initial radioactive decay, be reprocessed with uranium and plutonium extracted for re-use in conventional or breeder reactors. This "ideal" scheme is depicted in Figure 3(a). Spent fuel discharged from reactors contains substantial quantities of unburned uranium and plutonium. In the conventional judgment, it would be uneconomical not to recover these fuels. However, reprocessing of spent fuel has proved to be more technically complex and costly than anticipated by the nuclear industry. In addition, sensitivity to the dangers of nuclear weapons proliferation through use of reactor grade plutonium has raised further doubts about the reprocessing option and it has been indefinitely deferred.

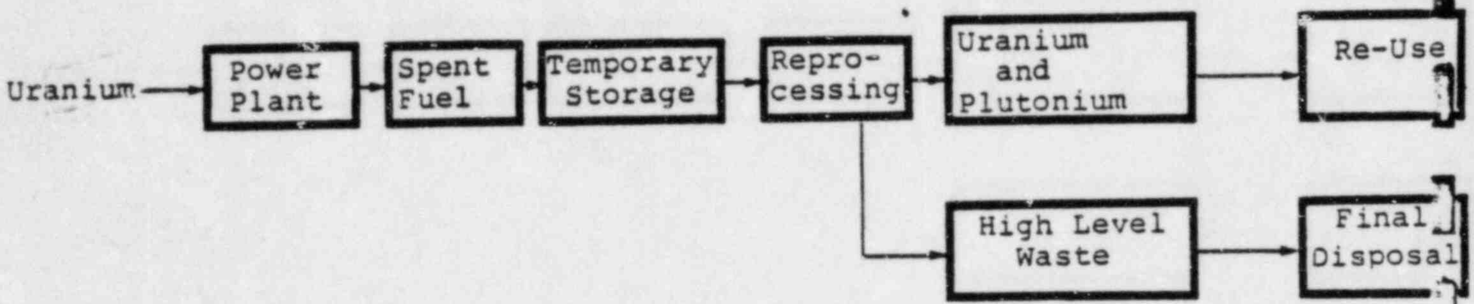
Until the last few years, research and development efforts assumed that highly radioactive wastes would be reprocessed. But in the absence of reprocessing, the spent fuel itself must be treated as the ultimate waste product. Not surprisingly, there is currently a good deal of uncertainty on the technologies, timing, and costs facing utilities over the next several decades as waste disposal burdens mount.

A detailed technical discussion on waste disposal alternatives is the subject of Appendix D. A schematic of the back-end of the nuclear fuel cycle that appears to be actually in the offing is presented in Figure 3(b). The temporary on-site storage pools have indefinitely become repositories for virtually all discharged fuel produced by commercial reactors. But the limited capacity of these pools allows them to accept only a fraction of spent fuel produced over the life of a reactor. The space available can be increased through fuel assembly "reracking" procedures, but this at best extends the time until existing pools are filled to capacity (until the late 1980's and early 1990's for most reactors).

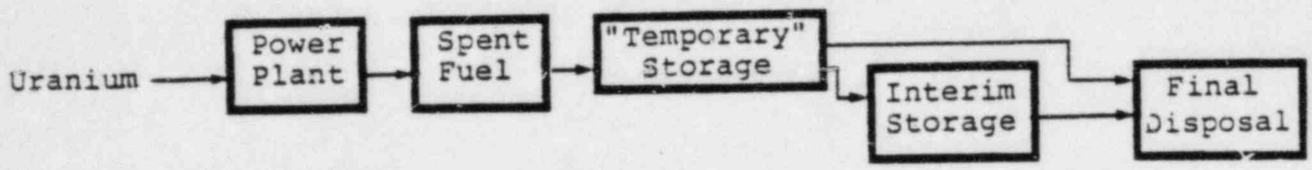
On the other hand, a workable solution to the "permanent" disposal of irradiated nuclear fuel is not in sight. Substantial problems remain regarding the selection of a viable storage technology which satisfactorily addresses environmental, social, and political concerns in an economi-

Figure 3

BACK-END OF NUCLEAR FUEL CYCLE



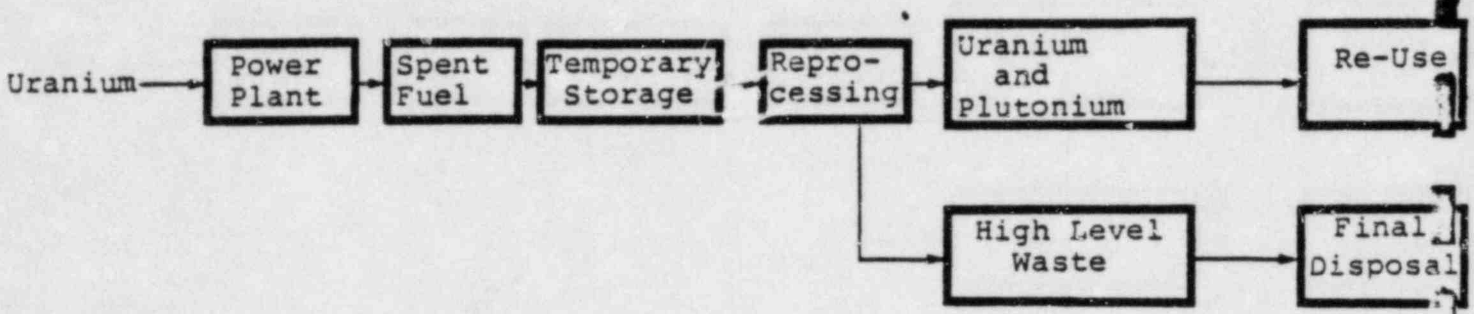
a) "Ideal"



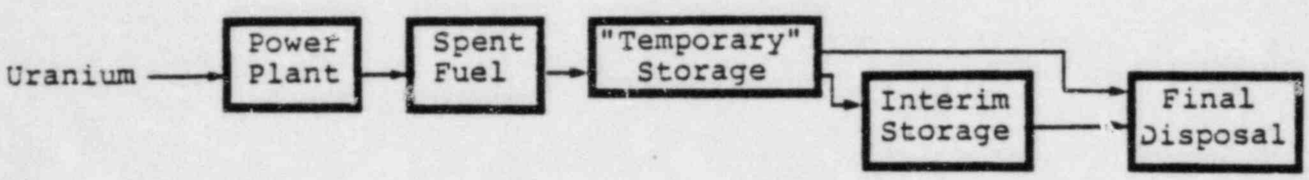
b) Actual

Figure 3

BACK-END OF NUCLEAR FUEL CYCLE



a) "Ideal"



b) Actual

cally acceptable manner. A federal disposal site cannot realistically be expected to be in operation until some time after the turn of the century.(26)

Therefore, a time gap can be anticipated between the filling of storage pools and the availability of an ultimate disposal facility. If a nuclear plant is to continue operating it must use some type of interim storage system. The costs for disposal are comprised of three components beyond temporary on-site storage: interim storage costs (either away from reactor or on-site), transportation costs, and permanent disposal fees.

The options, cost estimates, and methods for estimating waste disposal costs for Indian Point are detailed in Appendix D. A summary of total cost estimates, expressed in terms of 1981 dollars per kilogram of uranium waste, is presented in Table D-9. These costs can be converted to costs per KWH generated, as shown on page D-28, which led to the following estimates having been employed in the scenario analysis.

TABLE 14

SPENT FUEL DISPOSAL COSTS
(1981 Mills per KWH)

	Scenario		
	High Impact	Mid-Range	Low Impact
Planned Retirement	1.1	2.2	3.6
Early Retirement	0.9	1.7	2.8

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	Scenario		
	High Impact	Mid-Range	Low Impact
Planned Retirement	1.1	2.2	3.6
Early Retirement	0.9	1.7	2.8

Applying these figures to the lifetime generation in the respective scenarios yields incremental costs of $247, $322, and $222 million 1981 dollars for the Low Impact, Mid-Range, and High Impact scenarios. These are the estimated savings in fuel disposal resulting from a shutdown. In the planned retirement case, the extra costs are spread from 1985 to 2006.

3.7 Decommissioning

No large commercial nuclear power plant has yet been decommissioned in the United States. The largest nuclear reactor that has previously been decommissioned was the 22 MW experimental Elk River reactor in Minnesota, and that facility had only operated for 4 years. Decommissioning is the process whereby all components of the power plant and site are made secure from radiological contamination. Options include encasing the plant in an impermeable shell (entombment), and cutting up the plant, restoring the site, and shipping the radioactive parts of the plant to a permanent nuclear waste storage facility (dismantlement). A brief overview of decommissioning methods and their potential cost can be found in Appendix E.

There are two areas of concern in this study regarding the decommissioning of the Indian Point units. The first concerns the total ultimate cost of decommissioning. The second is the issue of the relationship between decommissioning costs for Indian Point and the length of time the units will have operated. The major fact relevant to this second issue is that the longer a nuclear reactor operates, the more highly radioactive it becomes, especially with respect to the longer lived radioisotopes induced in the plant structure itself. These radioactive parts become the major contributor to the radioactive inventory of the plant.[27]

However, the degree to which early retirement will affect decommissioning costs is difficult to estimate. Since there are currently no permanent nuclear waste storage sites we have assumed in this report that IP-2 and IP-3 will be decommissioned after their normal retirement dates in both the early shutdown or normal retirement scenarios. We also assume that the decommissioning technique used will be complete dismantlement and permanent disposal of the radioactive components. However, as Con Edison's own dismantlement cost analysis for Indian Point #2 indicates, "the costs to cut, remove, ship, and bury the reactor vessel and internals are dependent on the segment curie [measure of radioactivity] content and weight...." For reactors that operated for less than their design lifetime, there is a corresponding reduction in total curies, and a potential for reduction in disposal cost for segments that are curie limited.

Nuclear Energy Services, Inc. estimated that there would be 10 million curies in Indian Point #2 at the end of its normal lifetime.[28] To put this number in perspective, there is presently a 50 thousand curie per shipment burial limit at the Hanford burial site. Given this assumed level of radioactivity, NES estimates that it will cost about 90 million (1980 dollars) to dismantle the Indian Point Unit 2. For comparative purposes, in 1977, an even higher estimate of about $124 million (1980 dollars) was made for decommissioning Three Mile Island #1.[29]

While great uncertainty exists with respect to both total decommissioning costs and differential decommissioning costs as a function of plant lifetime, estimates must be made whenever an important public policy decision is pending, as one is at Indian Point. Inaccuracy in estimating the costs of constructing nuclear power plants has been widespread in the nuclear industry.. Actual costs have been as much as four or more times originally planned costs, even after inflation has been accounted for. We have assumed similar potential inaccuracy in designing our decommissioning cost scenarios. Much of the industry's inaccuracy in construction estimates was due to the changing regulatory environment as safety standards were upgraded, but we believe that similar regulatory changes are likely in the decommissioning area as well. This is especially so since it is an area that has not yet received as much attention at the Nuclear Regulatory Commission as other areas of nuclear regulation.

For our High Impact case we assumed that both IP-2 and IP-3 would cost Con Edison's estimate of $90 million in 1980 dollars to decommission. We further assumed that there would be no cost differential between early and normal retirement. This is a fairly extreme assumption. In the Mid-Range case we assumed that each Indian Point unit would cost two times the Con Edison estimate to decommission at the normal retirement date, and that early retirement would reduce this cost by 25 percent, resulting in a savings for both plants of $90 million out of $360 million (1980 dollars). Finally, in the Low Impact case we assume that allowing the radioactivity in the plant to decay for an extra 20 years or so prior to decommissioning in the early retirement situation would have a major impact on decommissioning costs and reduce them by 50 percent. The baseline cost for normal retirement was taken as four times the Con Edison estimate in the Low Impact case. This results in the early retirement savings for decommissioning in the Low Impact scenario being $360 million out of $720 million (1980 dollars). The annual scenario dependent required revenue impacts of these assumptions can be found in Tables 16, 17, and 18 below. Comparing these results with the aggregate scenario findings (Table 1), we see that even in the Low Impact case the differential discounted required revenue impact of decommissioning is only about $240 million out of a total scenario impact of about $1330 million, or less than 20 percent. In the Mid-Range case the differential decommissioning impact was only 8 percent of the total scenario impact. In the High Case, decommissioning has zero impact. Thus, decommissioning cost assumptions, while important, are not major determinants of the overall scenario results in this study.

The incremental costs of 0, \$90, and \$360 million (1981) dollars for the High, Mid-Range, and Low Impact cases, respectively, are assumed spread over the 1985-2006 time frame.

3.8 Costs of Capitalized Expenses

During the normal course of operating and maintaining a power station, various capital costs must be regularly incurred for replacement components and equipment as well as for new equipment required. These costs are in addition to the original capital investment in the plant (discussed in Section 3.3) and in addition to the expensed operations and maintenance costs (discussed above in Section 3.5). These expenditures have particularly affected nuclear stations because extensive retrofitting of many technological improvements has been required. These capital costs, which are added to the rate base and thus charged to ratepayers in the same manner as the original capital cost of the plant, can amount to a substantial economic deficit of trying to keep a nuclear station such as those at Indian Point functioning.

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Examining the record of capital cost increases for the Consolidated Edison portion of the Indian Point station (units #1 and #2), one finds that the total capital cost for these units has increased from about $335 million in 1973 to about $422 million in 1981.[30] This represents an average annual increase of about 3 percent per year. However, at the end of this period the increase for Indian Point #2 alone has been almost 11 percent from 1980 to 1981. Unfortunately, data for Indian Point #3, owned by PASNY, are not reported.

The key question in the current context is how can these additional capital costs for Indian Point #2 and #3 be reasonably projected. Con Edison anticipates that over the period 1983-1986 capital expenditures for Indian Point #2 will amount to $131 million.[31] This implies that from 1981 to 1986 the total capitalized cost for Indian Point #2 will increase by at least 6.8 percent per year. Con Edison lists a variety of items that these expenses will cover including: vendor retubing, NUREG-0737 modifications, cooling tower settlement modifications and "numerous other improvement projects." PASNY lists similar items in stating that Indian Point #3 will need $80 million worth of capital improvements in the foreseeable future.[32] These estimates do not cover the replacement of the steam generator, if this is needed.

In designing the three basic cost scenarios analyzed in this study, the following assumptions were made based on the information discussed above. For the <u>High Impact</u> case it is assumed that the rate of increase in the total capitalized costs for both Indian Point #2 and #3 returns for the period 1987-2000 to the lower rate of 3 percent per year that obtained from 1973-81 for Indian Point #2. In the <u>Low Impact</u> case we assume that the rate of increase in capitalized costs during 1987-2000 continues at 6.8 percent, the rate projected for IP-2 for the 1981-1986 period. For the Mid-Range case, an intermediate growth rate of 4.9 percent is used.

However, in addition, the GAO report states that serious corrosion problems were beginning to develop by 1979 in the IP-2 steam generators, and that similar problems have occurred at IP-3.[33] The report goes on to suggest that Con Edison will have to replace or retube the steam generator some time after 1983, requiring that IP-2 be out of service for up to one year. On the other hand, the Companies have stated that steam generator replacement will not be necessary at least until 1986.[34]

It appears that steam generator problems, as experienced in other aging nuclear units, are likely to occur at the Indian Point Station. However, recent experience indicates that the IP-3 unit has more severe problems with its steam generator than does IP-2.[35] In light of this, it is assumed in the Mid-Range scenario that replacement of this key component will be required during 1991 and 1986, for the IP-2 and IP-3 units, respectively. For comparison, the Rand

Report assumes that the IP-2 and IP-3 steam generator expenditures are made in 1985.[36] In this Mid-Range case the need for replacement of the steam generator is delayed for Indian Point #2, since its problems appear less severe to date. In contrast, in the Low Impact scenario it is assumed that the IP-2 steam generator will have to be replaced three years earlier, in 1988. Since both Con Edison and PASNY state that it is possible that steam generator replacement may not be necesary at all, this is assumed in the High Impact scenario. In all cases where the steam generator is replaced the cost is assumed to be capitalized at a level of $130 million and $132 million (in 1982 dollars), respectively, for IP-2 and IP-3, and depreciated over the remaining lifetime of the unit.[37] The replacement is assumed to take a period of one year to accomplish, during which the unit affected cannot operate. During this year, other expensed and capitalized operations and maintenance costs are not charged to those scenarios that assume Indian Point is not retired.

The resulting stream of these capitalized expenses from 1983 - 1997 can be found in Table 15 below for each of the three main scenarios.

TABLE 15

CAPITALIZED EXPENSES
(Million 1981 Discounted Dollars)

	Scenario		
Year	High Impact	Mid-Range	Low Impact
1983	-8.3	-8.3	-8.3
1984	-17.0	-17.0	-17.0
1985	-20.5	-20.5	-20.5
1986	-23.7	-34.8	-34.8
1987	-24.1	-35.8	-37.7
1988	-24.2	-36.5	-59.3
1989	-24.1	-36.8	-59.1
1990	-23.8	-36.9	-58.6
1991	-23.5	-55.3	-58.0
1992	-23.0	-53.0	-57.3
1993	-22.4	-50.8	-56.6
1994	-21.8	-48.7	-55.8
1995	-21.2	-46.7	-54.9
1996	-20.5	-44.8	-54.0
1997	-19.8	-43.0	-53.2
TOTAL	-317.9	-569.1	-685.0

4. IMPACT ON RATEPAYERS

4.1 Introduction

In the previous section, the findings for each of the major components of revenue impact were presented. Here, we synthesize these component results into integrated estimates of overall impacts on ratepayers.

The "basic results" for the three scenarios -- High Impact, Mid-Range, and Low Impact as described in Section 2.3 -- are the subject of the first subsection. Annual and cumulative cost impacts are reported over a fifteen year time frame. We then go on to explore the sensitivity of the results to variations in certain input assumptions such as the assumed year of retirement of the Indian Point units.

4.2 Basic Results

Summary results for the Mid-Range, High and Low Impact scenarios are given, respectively, in Table 16, 17, and 18. Each table shows the impact of closing the Indian Point facilities over our fifteen year horizon on both an annual and a cumulative basis. Also displayed is the annual percentage impact on required revenue.[38] This provides a measure of the relative magnitude of the repercussions on the price of power. In the lower right corner is the cumulative impact as a percentage of the cumulative required revenues, a useful figure in evaluating the overall impacts of closing the

Table 16

INDIAN POINT RETIREMENT STUDY -- MID-RANGE IMPACT

Differential Required Revenues by Cost Category

(millions of 1981 discounted dollars)

YEAR	CAPITAL CON ED	CAPITAL PASNY	NUCLEAR O&M	MAKEUP GENERATN	SPENT FUEL	DECOMMIS COST	NUCLEAR FUEL	OTHER COST	ANNUAL TOTAL	CUM. TOTAL	ANNUAL % IMPACT
1983	-7.4	-0.4	-113.4	431.7	0.0	0.0	-57.9	-8.3	244.2	244.2	7.1
1984	-6.0	-0.4	-115.9	380.8	0.0	0.0	-54.8	-17.0	186.7	430.9	5.7
1985	-4.9	-0.4	-118.1	365.0	-15.2	-4.6	-52.3	-20.5	149.1	580.0	4.7
1986	-4.1	-0.4	-56.6	168.7	-15.2	-4.6	-22.6	-34.8	30.4	610.3	1.0
1987	-3.5	-0.4	-121.4	325.4	-15.2	-4.6	-47.0	-35.8	97.5	707.9	3.4
1988	-3.0	-0.4	-122.6	305.5	-15.2	-4.6	-44.4	-36.5	78.8	786.6	2.9
1989	-2.8	-0.4	-123.6	294.1	-15.2	-4.6	-42.2	-36.8	68.4	855.1	2.6
1990	-2.6	-0.4	-124.3	329.1	-15.2	-4.6	-40.2	-39.9	104.9	960.0	4.2
1991	-2.5	-0.4	-65.8	123.7	-15.2	-4.6	-20.9	-55.3	-41.0	919.0	-1.6
1992	-2.5	-0.4	-125.1	238.5	-15.2	-4.6	-36.0	-53.0	1.8	920.8	0.1
1993	-2.4	-0.3	-125.2	219.5	-15.2	-4.6	-33.7	-50.8	-12.9	907.9	-0.5
1994	-2.4	-0.3	-125.1	201.8	-15.2	-4.6	-31.6	-48.7	-26.2	881.7	-1.2
1995	-2.4	-0.3	-124.8	187.9	-15.2	-4.6	-30.0	-46.7	-36.2	845.4	-1.7
1996	-2.3	-0.3	-124.4	174.6	-15.2	-4.6	-28.4	-44.8	-45.5	799.9	-2.3
1997	-2.3	-0.3	-123.9	162.1	-15.2	-4.6	-26.9	-43.0	-54.1	745.8	-2.9
TOTAL	-51.0	-5.6	-1710.1	3908.4	-198.2	-59.8	-568.9	-569.1	745.8	745.8	1.9

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Table 17

INDIAN POINT RETIREMENT STUDY -- HIGH IMPACT

Differential Required Revenues by Cost Category

(millions of 1981 discounted dollars)

YEAR	CAPITAL CON ED	CAPITAL PASNY	NUCLEAR O&M	MAKEUP GENERATN	SPENT FUEL	DECOMMIS COST	NUCLEAR FUEL	OTHER COST	ANNUAL TOTAL	CUM. TOTAL	ANNUAL % IMPACT
1983	-7.4	-0.4	-109.9	460.1	0.0	0.0	-57.9	-8.3	276.0	276.0	7.9
1984	-6.0	-0.4	-110.8	435.4	0.0	0.0	-55.8	-17.0	245.4	521.4	7.3
1985	-4.9	-0.4	-111.3	437.3	-10.5	0.0	-53.8	-20.5	235.9	757.3	7.4
1986	-4.1	-0.4	-111.6	432.1	-10.5	0.0	-51.9	-23.7	230.0	987.3	7.5
1987	-3.5	-0.4	-111.6	429.8	-10.5	0.0	-50.0	-24.1	229.7	1217.0	7.8
1988	-3.0	-0.4	-111.5	426.2	-10.5	0.0	-48.3	-24.2	228.4	1445.4	8.1
1989	-2.8	-0.4	-111.2	427.4	-10.5	0.0	-46.5	-24.1	232.0	1677.4	8.5
1990	-2.6	-0.4	-110.6	428.0	-10.5	0.0	-44.9	-23.8	235.1	1912.5	9.0
1991	-2.5	-0.4	-110.0	428.5	-10.5	0.0	-43.3	-23.5	238.5	2151.0	9.5
1992	-2.5	-0.4	-109.2	429.1	-10.5	0.0	-41.7	-23.0	241.9	2392.9	10.1
1993	-2.4	-0.3	-108.3	429.8	-10.5	0.0	-40.2	-22.4	245.5	2638.4	10.6
1994	-2.4	-0.3	-107.3	430.1	-10.5	0.0	-38.8	-21.8	248.9	2887.4	11.2
1995	-2.4	-0.3	-106.1	430.4	-10.5	0.0	-37.4	-21.2	252.3	3139.8	11.9
1996	-2.3	-0.3	-104.9	430.7	-10.5	0.0	-36.1	-20.5	256.0	3395.9	12.5
1997	-2.3	-0.3	-103.7	431.2	-10.5	0.0	-34.8	-19.8	259.9	3655.7	13.3
TOTAL	-51.0	-5.6	-1638.0	6486.2	-136.6	0.0	-681.3	-317.9	3655.7	3655.7	9.2

<u>Table 18</u>

INDIAN POINT RETIREMENT STUDY -- LOW IMPACT

<u>Differential Required Revenues by Cost Category</u>

(millions of 1981 discounted dollars)

YEAR	CAPITAL CON ED	CAPITAL PASNY	NUCLEAR O&M	MAKEUP GENERATN	SPENT FUEL	DECOMMIS COST	NUCLEAR FUEL	OTHER COST	ANNUAL TOTAL	CUM. TOTAL	ANNUAL % IMPACT
1983	-18.8	-0.4	-113.4	350.5	0.0	0.0	-50.4	-8.3	159.2	159.2	4.7
1984	-15.2	-0.4	-115.9	281.7	0.0	0.0	-46.2	-17.0	87.0	246.2	2.7
1985	-12.3	-0.4	-118.1	255.1	-11.7	-18.4	-43.2	-20.5	30.7	276.8	1.0
1986	-9.9	-0.4	-56.6	110.4	-11.7	-18.4	-16.6	-34.8	-38.0	238.9	-1.2
1987	-8.0	-0.4	-121.4	254.3	-11.7	-18.4	-35.9	-37.7	20.9	259.8	0.7
1988	-6.4	-0.4	-64.7	69.4	-11.7	-18.4	-19.1	-59.3	-110.5	149.2	-4.1
1989	-5.2	-0.4	-123.6	154.3	-11.7	-18.4	-29.6	-59.1	-93.6	55.7	-3.6
1990	-4.2	-0.3	-124.3	128.2	-11.7	-18.4	-26.2	-58.6	-115.5	-59.8	-4.7
1991	-3.4	-0.3	-124.8	106.5	-11.7	-18.4	-23.2	-58.0	-133.3	-193.1	-5.7
1992	-2.9	-0.3	-125.1	83.8	-11.7	-18.4	-20.0	-57.3	-151.8	-345.0	-6.9
1993	-10.8	-0.3	-125.2	65.1	-11.7	-18.4	-17.3	-56.6	-175.1	-520.0	-8.4
1994	-9.5	-0.3	-125.1	47.9	-11.7	-18.4	-14.7	-55.8	-187.5	-707.5	-9.4
1995	-8.4	-0.3	-124.8	31.8	-11.7	-18.4	-12.2	-54.9	-198.8	-906.3	-10.5
1996	-7.4	-0.3	-124.4	14.5	-11.7	-18.4	-9.3	-54.0	-210.9	-1117.2	-11.8
1997	-6.5	-0.3	-123.9	0.7	-11.7	-18.4	-6.9	-53.2	-220.1	-1337.3	-12.9
TOTAL	-128.8	-5.2	-1711.1	1954.3	-152.0	-238.8	-370.7	-685.0	-1337.3	-1337.3	-3.5

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plants. Cumulative results for the scenarios have been grouped in Table 1.

The High and Low Impact scenarios are, it will be recalled, developed by consistently biasing uncertain statistical and policy variables toward those future values which create the greatest and least ratepayer impact, respectively. The scenario likelihood is related in these cases to the joint probability of a set of unlikely events. For example, the High Impact scenario represents a case of no aging-related deterioration of capacity factors, no conservation effort beyond current levels, no electric system readjustment to the loss of the Indian Point units, high make-up fuel costs, no aging effect on decommissioning cost and so on. Likewise, the Low Impact scenario incorporates assumptions at the opposite end of the uncertainty band, those that are most pessimistic about the nuclear option. For these reasons, we consider the High and Low scenarios to bracket the range of plausible impact. Their average impact on electricity costs (9.2 percent and -3.5 percent, respectively) represent unlikely extreme cases.[39] We shall thus focus henceforth on the Mid-Range scenario.

Table 16 presents the breakdown by cost impact category as discussed in Section 3. The estimated average impact on required revenue over the period considered is 1.9 percent (a cumulative absolute total of $745.8 million discounted 1981 dollars). As expected the primary penalty of nuclear retirement is the cost of make-up power ($3.91 billion cumulatively). On the other hand, there are major benefits in avoiding the costs of nuclear O&M, fuel and additional capital investments. Additional savings result from decreased spent fuel disposal and decommissioning burdens. Minor savings result also from early tax write-offs and lower nuclear insurance costs. After 1990, the annual avoided costs (i.e., the benefits) of not having the units exceeds the extra costs incurred. These savings are reflected as negative annual impact in the output.

4.3 Sensitivity to Scenario Assumptions

Comparison of the disaggregated output across the scenarios reported earlier will reveal the variation of results with respect to the range of inputs characterizing each scenario. Here, we wish to explore the sensitivity of our basic results to four variables which cannot be gleaned from the earlier results. These are the length of the study period, the timing of the retirement of the Indian Point units, the discount rate, and nuclear capacity factors. These will be discussed in turn below. These sensivitity tests have been performed against Mid-Range scenario results.

Length of Period. The impacts were computed to the year 2000 or three years longer than in our basic runs. The effect is to decrease the impacts by $215 million discounted dollars and the average percent impact on required revenues from 1.9 percent to 1.2 percent. This is traced to the projection that nuclear related costs will escalate more rapidly than substitute power costs.

Timing of Retirement. Here, the Indian Point units are assumed to be retired in 1985 rather than in 1983 as was forecast in the basic runs, since impacts are most severe in the early years. Cumulative costs decrease from $746 million to $290 million 1981 discounted dollars while the percentage impact decreases from 1.9 percent to 0.8 percent.

Discount Rate. The impacts were recomputed using a 14-percent annual discount rate rather than the 12 percent employed in the basic results. This has the effect of weighting the early years more heavily in the cumulative impacts while decreasing the absolute levels of discounted costs. Specifically, the cumulative costs decrease by $70 million while the percentage impact increases to 2.0 percent from 1.9 percent.

Nuclear Capacity Factor. In this test the Mid-Range capacity factor assumptions were replaced by the High Impact case non-deteriorating capacity factor assumptions (see Section 3.1). Make-up generation costs were recomputed using the power plant dispatch model as described in Section 3.1. This raises the estimated impacts by $751 million (discounted to 1981) and the average percentage impact from 1.9 percent to 3.9 percent. This estimate does not reflect dollars and the average percent impact on required revenues from 1.9 percent to 1.2 percent. This is traced to the projection that nuclear related costs will escalate more rapidly than substitute power costs.

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Nuclear Capacity Factor. In this test the Mid-Range capacity factor assumptions were replaced by the High Impact case non-deteriorating capacity factor assumptions (see Section 3.1). Make-up generation costs were recomputed using the power plant dispatch model as described in Section 3.1. This raises the estimated impacts by $751 million (discounted to 1981) and the average percentage impact from 1.9 percent to 3.9 percent. This estimate does not reflect the increased fuel disposal costs which would result from additional generation.

5. INDIRECT REPERCUSSIONS OF PLANT CLOSINGS

5.1 The Limits of Direct Cost Impact Analysis

The foregoing discussion has developed the estimates of the impacts on ratepayers of the early retirement of the Indian Point facilities. The annual changes in required revenues (customer payments) were approximated over a future planning period for each of the major components of the cost structure likely to be reflected in electricity bills. These are the direct economic repercussions.

Such direct cost trade-offs do not, however, exhaust the impacts on society of a plant closing. There are a number of indirect consequences that are not incorporated into the required revenue analysis presented above. While there is at this time considerable controversy on methods and assumptions appropriate for quantifying indirect (or "external") costs and benefits of plant closings, there are four broad categories of indirect repercussions which deserve brief qualitative identification here. These are: health and safety issues, behavioral response to price increments, financial repercussions on utilities, and secondary impacts on economic activity. We shall discuss these below, in turn.

5.2 Health and Safety Issues

A full social cost/benefit treatment would attempt to monetarize and incorporate some measure of the health and safety trade-offs which would result from a nuclear plant closure. To date, there has been no attempt to include these in assessments of plant closing economic impacts. The reason is easily discovered: high-confidence techniques for estimating and costing the relevant factors do not currently exist. Of course, such methodological underdevelopment does not make the effects any less real.

What then are the main issues? On the nuclear side, the costs of continued operation would be identified with the extra risks incurred at all phases of the nuclear fuel cycle. The problems include (1) the mining and milling of uranium with danger of release of radioactive material (e.g., thorium, radium) from tailing heaps into soil and water systems, (2) low-level toxic releases during normal plant operations, (3) the risk of a major accident at a nuclear plant,[40] (4) protection against release of highly toxic spent fuel over unprecedented, long planning periods (say, ten half-lives or about 250,000 years for the case of Plutonium-239), and (5) avoiding proliferation of nuclear weapons fashioned from power plant plutonium. On the other side, the environmental cost of early closure would include increased air pollution from fossil fuel generated make-up power and perhaps increased dependency on uncertain foreign sources.

Full explication of these complex health and safety issues would, of course, require volumes. Some would argue that the risks are too serious to justify continued nuclear plant operation; others that they are comparatively negligible or easily manageable.(41) The exercise performed in this study -- the computation of required revenue under risk-free conditions -- can play a role here. It can help the public and their decision-makers in deciding whether the direct cost impacts are a tolerable investment for avoiding health and safety risks as they perceive them.

5.3 Behavioral Response to Price Increments

In theory, a change in electricity price will cause a change in the demand for electricity. This relationship is often expressed in the so-called "price elasticity of demand": the percentage change of consumption divided by the percentage change of price. Two time periods are generally distinguished. The "short run" elasticity represents the immediate response to price changes due presumably to adjustments in usage (e.g., changing thermostat settings), while the generaly larger "long run" elasticities should reflect the lagged response to price changes due to equipment choice (e.g., more efficient devices).

Clearly, these price elasticity effects would have a moderating influence on the direct cost impacts of a plant closing. This is shown mathematically in Table 19. The final equation presents a correction factor, which would scale down our earlier cost impacts. Indeed, if the elasti-

TABLE 19

PRICE ELASTICITY EFFECTS ON REQUIRED REVENUE IMPACTS

With the definitions:

	No Retirement	Retirement ($\varepsilon = 0$)	Retirement ($\varepsilon \neq 0$)
Required Revenue	R	$R + \Delta R_o$	$R + \Delta R$
Electricity Consumption	E	E	$E + \Delta E$
Average rate	r	-	$r + \Delta r$
Marginal generation cost	p		
Elasticity	$-\varepsilon$		
Correction factor	f		

We have:

$$\Delta R = \Delta R_o - p\Delta E$$

From $r \equiv R/E$, we have

$$\frac{\Delta r}{r} = \frac{\Delta R}{R} - \frac{\Delta E}{E}$$

Substituting $\frac{(\Delta E/E)}{(\Delta r/r)} \equiv \varepsilon$ yields:

$$\Delta E/E = \frac{\varepsilon}{1+\varepsilon} \left(\frac{\varepsilon}{1+\varepsilon}\right) \cdot \frac{\Delta R}{R} \text{ or } \quad \Delta E = \left[\frac{\varepsilon}{1+\varepsilon}\right] \cdot \frac{\Delta R}{r}$$

Substituting in defined equation and simplifying:

$$\Delta R = f \cdot \Delta R_o$$

Where the elasticity correction factor is

$$f = \left[1 + \frac{p}{r} \cdot \left(\frac{\varepsilon}{1-\varepsilon}\right) \right]^{-1}$$

city were minus one, the required revenue impact would be zero. The problem, however, is that in the words of a recent review monograph, there is a "startling lack of consensus on price elasticities."[42] Representative price elasticity spreads are shown in Table 20.

The uncertainty of these estimates makes specific applications problematic and we have not reported elasticity adjustments in our quantitative results. If, for the sake of illustration, one makes the not unreasonable assumption that marginal generation costs roughly equal average rates ($P/r \approx 1$) and the price elasticity is approximately -0.4, then the correction factor (f in Table 19) is 0.6. This would imply an overestimate in the earlier required revenue impacts of the order of 40 percent.

5.4 Financial Repercussions on Utilities

The central issue here is the possible impact on investor confidence in the event of a nuclear plant closing. The perception of risk by the financial community is reflected most directly in the level of return and annual cash flow required to attract an adequate level of investment. The determinants of that perception are multiple but probably include such factors as regulatory policy on rates and sunk cost recovery, market-to-book ratios, coverage ratios (earnings divided by debt service burdens), and, in the case at hand, confidence in nuclear plant performance.

TABLE 20

PRICE ELASTICITY ESTIMATES IN THE LITERATURE[43]

	Short-Run	Long-Run
Residential	-.08 to -.45	-.45 to -2.10
Commercial	-.17 to 1.18	-.56 to -1.60
Industrial	-.04 to -1.36	-.51 to -1.82

These, in turn, depend on utility management performance, construction plans, and on the performance of nuclear facilities over time.

Clearly, any quantification of investor response to a plant closing must first develop scenarios for these conditioning variables and then link them to estimated changes in the cost of capital and cash flow requirements. This is necessarily a complex and judgmental task.

However, the scenarios developed here assume full flow through of incremental costs of plant closing to the ratepayers (only the return portion of the unamortized part of the initial capital expenses is treated as a scenario variable). The working assumption for the High Impact and Mid-Range cases is that stockholders and investors will be "kept whole" in that the regulatory treatment will allow all utility costs to be reflected in rates. Under these conditions, there is no basis for assuming any additional expenses to maintain investor confidence. Furthermore, cash flow problems will not emerge with passthrough ratemaking as a result of a plant closing.(44)

There is, on the other hand, the possibility that performance by maturing nuclear power plants will not live up to industry expectations. In this event (our Mid-Range and Low Impact cases), investor confidence would presumably be sufficiently enhanced by the early retirement of such a facility that the loss of the return on the unamortized balance, as assumed in the Low-Impact case, will not negate this increased confidence. Additionally, in a full asessment, one would need to weight in the small probability of an unplanned plant shutdown (as occurred at Three Mile Island) which, of course, would be seriously detrimental to a utility's financial condition. These would be avoided costs -- that is, benefits -- to early retirement.

Each of the elements that constitute the indirect financial repercussions seems to satisfy at least one of these characteristics -- small, improbable, and speculative. Thus, we have not attempted to include them in our numerical results.

5.5 Secondary Economic Activity

The analysis of required revenue impacts is restricted to estimates of the direct out-of-pocket expenditures required to support an early plant closing. But will the ensuing change in business and household expenditure patterns -- more spending for electricity, less for other commodities in the case where the closing increases costs -- have significant indirect repercussions on employment, economic output, and household income?

The indirect impacts of changes in energy expenditure patterns are complex. Alternative patterns may alter the economic activity in the energy supply industry itself and in equipment supply sectors, in business costs and location decisions, in the suppliers of the suppliers, etc. There could be distributional impacts between household type and industrial sectors, between regions, and over time.[45] There have been no attempts to assess such secondary effects for a nuclear plant closing. In perhaps the most closely allied study, the impacts of a phase-out of nuclear power in California was analyzed with no significant secondary economic impacts found.[46]

One of the main complications, is that increases in electricity prices stimulate conservation and conservation dollar-for-dollar is thought to be more economically stimulative of a region than supply side alternatives. For example, a study of electric price increases in the Buffalo area concluded that the indirect effects actually were beneficial.[47] Similarly, two recent investigations of conservation impacts find substantial economic benefits in switching from energy investment to conservation investment.[48]

However, for the case of a plant closing the conservation induced is not easily specified (see the discussion of behavioral responses above). Against this effect will be the economically negative impact (if elasticities are less than one) of transferring household expenditures to electricity from other commodities. This is likely to decrease employment, especially in the case where the conservation expenditures stimulate local economic activitiy while the expenditures for make-up generation go in part to foreign coffers.

What are the changes in expenditures patterns implied by a plant closing? What are the economic repercussions locally and nationally? Will induced conservation and health and safety benefits counteract the negative repercussion of higher electricity costs? These are significant questions that cannot be answered today.

FOOTNOTES

1. The basic documents on the cost impacts of closing the Indian Point facility are listed in References 2 through 5 below. Together, they present a remarkable spectrum of assumptions, methods, and not surprisingly, results. None present a documented and systematic framework for scenario explication, sensitivity analysis, and output evaluation.

2. Economic Impact of Closing the Indian Point Nuclear Facility, Report by the Comptroller General of the United States, U.S. Government Accounting Office, EMD-81-3, Washington, D.C., November 7, 1980.

3. Costs of Closing the Indian Point Nuclear Power Plant, prepared for Power Authority of the State of New York, Rand Corporation, R-2857-NYO, Santa Monica, California, November, 1981.

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

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

6. The IP-1 unit has been shut down since 1974; the NRC revoked Con Ed's operating license in 1980. We shall not consider this unit further in this study.

7. An Analysis of the Need for and Alternatives to the Proposed Coal Plant at Arthur Kill, a report to the New York City Energy Office and the Corporation Counsel of New York, ESRG Study No. 81-21, June, 1981.

8. Referenced in Note 7. This study was also presented as part of testimony in the 1981 New York State Energy Master Planning hearings by Dr. Richard A. Rosen. The focus of the study was the economics of the proposed Arthur Kill plant, but the work has general applicability to generation planning and demand related issues in the region.

9. Documented in Note 7 reference.

FOOTNOTES
(Continued)

10. Note that neither the proposed 700-MW Arthur Kill unit on Staten Island nor the proposed Prattsville pumped storage facility has been included in these generation dispatch runs. Had they been, the replacement power for Indian Point would have derived from more efficient back-up units than we have assumed, thus lowering make-up power costs.

11. Con Edison response to NRC Staff interrogatory #24, NRC Docket #50-247SP, #50-286SP.

12. Vol. II, p. 433.

13. In the Low Impact case one could conceivably assume the additional coal conversions of the Astoria #3, #4, and #5 units, but due to unresolved controversy surrounding the feasibility of such conversions we did not.

14. Con Edison response to NRC Staff interrogatory #1, p. 7-8, NRC Docket #50-247SP, #50-286SP. Indeed, Con Edison's oil price assumptions are somewhat below the Mid-Range case assumption.

15. 1982 NYPP Report, p. 12.

16. Con Edison FERC Form #1, pp. 326-27.

17. The following amounts of power were assumed available for dispatch at the listed prices:

Power Line	Years	Megawattage Maximum	Cost (1981 $/MWH)
NYPP#1	1981-2000	300	49.60
LLLCO#1	1981-2000	500	65.00
NYPP#2	1981-2000	800	70.00
NYPP#3	1986-2000	1000	65.00

Generally these lines will dispatch only a fraction of the time.

18. Con Edison response to NRC Staff interrogatory #1, p. 9.

19. This analysis shows that about 36% or about 3000 GWH of the make-up power would come from upstate NYPP companies. This is the equivalent of about a 800 MW line with a capacity factor about 40%.

FOOTNOTES
(Continued)

20. In current dollars, in 1983, the make-up power costs for the Mid-Range scenario would be about $542 million. To compare with the Con Edison calculations provided on discovery for that year, however, the nuclear fuel, nuclear operations and maintenance costs (O&M) and nuclear spent fuel disposal costs would have to be subtracted, yielding a total Mid-Range impact of $327 million, or 3.8 cents per KWH. (See Table 2 referenced in note #14.) The comparable High-Impact value will be about $367 million, and the Low-Impact value is $235 million. In contrast, the RAND report claims that a reasonable upper and lower limit of $455 million and $425 million, respectively, is appropriate, which can be compared to the Con Edison value of $506 million. The largest single cost item that separates the Con Edison and Rand Estimates from the High-Impact or Mid-Range Impact cases here is a roughly $50-100 million differential for nuclear O&M. The justification for the ESRG assumptions on O&M can be found in Section 3.4 below. Secondly, different capacity factor assumptions among all parties account almost completely for the remainder of this cost differential.

21. The 20% figure was estimated by Dr. Lewis Perl of NERA, a consultant to Con Edison and other utility companies in Revised Direct Testimony, Pennsylvania Public Utility Commission Docket #I-80100341.

22. Response to Greater New York Council on Energy, interrogatory #23 (Con Ed), Table 6B, p.8, and #4 (PASNY).

23. The New York utilities appear to assume a 0% real escalation rate. Other observers assume rates above our High Impact case assumption (e.g., Lewis Perl, _op. cit._, Table 11 testified to over 5% real escalation rates).

24. Based on a reloading cycle of 18 months with one-third assembly replacement (implying an average age of 27 months) and a fixed charge rate of 15% (Con Ed & PASNY average): 27/12 x .15 = .34 .

25. Cited in Note 2.

26. See, _e.g._, App. D, Refs. D-4 and D-8.

27. NES, Inc., "Decommissioning Study of Prompt Dismantlement of Indian Point Unit 2", April, 1982, p. 9.

FOOTNOTES
(Continued)

28. Reference cited in Note 27.

29. Cited in California Energy Commission, "Nuclear Economics", November, 1980, p. 56.

30. Steam-Electric Plant Construction Cost and Annual Production Expenses, USDOE, various years esp. 1973 and 1979.

31. Con Ed response to interrogatory #2 of GNYCE's First Set.

32. PASNY response to interrogatory #2 of GNYCE's First Set.

33. Cited in Note 2, pp. 20-21.

34. Con Ed response to interrogatory #11 of GNYCE's First Set.

35. New York Times, March 31, 1982, p.A25. "Tubes at 40 A-Plants Assailed". Steam-generator replacement has already occurred at the Surry #1 and #2 units in Virginia. Similar replacements are underway or planned at Turkey Point and Palisades nuclear stations.

36. Cited in Note 3, Table 10.

37. PASNY response to interrogatory #11 of GNYCE's Furst Set.

38. Annual required revenue in constant dollars is assumed to decrease at an annual raate of -1.5%, -1.0%, and -0.5% for the Low, Mid, and High Impact scenarios, respectively, based on scenario load growth assumptions and a decrease in the unit cost of electricity in the Con Ed service area of 0.7%/year (Energy Master Plan II, State Energy Office of New York, August 1981, p. 170).

39. Indeed, in the later years of the Low Impact case the costs of generating power from the nuclear stations exceeds the make-up costs. In this case, on economic grounds, the plant would be voluntarily retired sometime after 1990.

FOOTNOTES
(Continued)

40. The required revenue simulation used in this study employs statistically estimated measures of normal plant operation. Abnormal events of low probability such as a catastrophic accident are, of course, not reflected. Cost estimates here would be related to such imponderables as the worth of human lives (a moral as well as economic concept), probability of losing lives, psychological costs, etc.

41. There is abundant popular literature on nuclear risks (see, e.g., Countdown to a Nuclear Moratorium, Environmental Action Foundation, 1976). On the other hand, most economic impact assessments are silent on the question of nuclear hazards (e.g., Refs. 2 and 3).

42. Bohi, Douglas R., Analyzing Demand Behavior: A Study of Energy Elasticities, John Hopkins, Baltimore, 1981, p. 1.

43. Ibid., p. 57 ff.

44. This is apparently confirmed in Ref. 2, Table 3-13, p.58, where satisfactory interest ratios are found under passthrough ratemaking. The caveat "apparently" is necessary due to a lack of documentation on data, assumptions, and methodology in that study. Ref. 3 refers to that exercise as a "black box" (p. 35) but nevertheless manipulates various Ref. 2 tables in an attempt to cull out "business costs" (everything but fuel-related cost it appears). This exercise cannot be considered scientifically interesting.

45. The issues are reviewed in Ref. 3 (pp. 38-45) and in J. Stutz and P. Raskin, Electricity Requirements in New York State. Volume III: Employment Impacts of the Conservation Policy Base Case Alternative, Energy Systems Research Group, Inc., ESRG 79-12/3, July, 1979. The latter offers a concrete quantitative assesment of the secondary effects of conservation in New York utilizing a regional model based on input/output techniques.

46. Martin L. Baughman et al., Direct and Indirect Economic, Social, and Environmental Impacts of the Passage of the California Nuclear Power Plant Initiative, Center for Energy Studies, University of Texas at Austin, FEA/G-7612661, April 1976. However, as pointed out in Ref. 3 (p.40), there are questions about the validity of this report and its relevance to an Indian Point closing.

FOOTNOTES
(Continued)

47. J.H. Savitt, Elec.ric Energy Usage and Regional Economic Redevelopment, Final Report, EPRI, ES-187, Palo Alto, California, August, 1976.

48. These are the ESRG study cited in Ref. 6 and the New York State Energy Office's State Energy Master Plan and Long-Range Electric and Gas Report, Albany, 1980.

APPENDIX A

COST ASSESSMENT OF NUCLEAR SUBSTITUTION (CANS) MODEL: A MATHEMATICAL DESCRIPTION

ESRG

August 1982

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LIST OF TABLES

In this appendix, the calculation procedures employed by the Cost Assessment of Nuclear Substitution (CANS) model are described. The appendix is divided into eleven sections. The first (section A-1) will describe the general organization of the CANS model and introduce seven modules used to calculate eight different components of costs.[1] Section A-2 describes the data requirements and conventions shared among the modules. Sections A-3 through A-10 describe the individual modules and the data requirements specific to each module. Finally, in Section A-11, we discuss the CANs report and comparison module.

A-1 An Overview of CANS

The CANS system consists of two separate FORTRAN programs. The first is the cost estimation program which estimates the required revenue impacts of a particular user defined scenario. The second is the report and comparison program which compares the revenue impacts of two scenarios.

The simulation program consists of seven independent modules that calculate the following cost impacts:

1. Nuclear plant capital costs , assuming the plant remains on line for its full expected lifetime.
2. Nuclear plant capital costs, assuming the plant is retired from service before its full lifetime.

[1] Since capital costs assuming the plant remains in service and capital costs assuming it is retired are separate modules, only seven modules are actually employed in any given simulation.

3. Nuclear plant operations and maintenance costs
4. Makeup power costs when the plant has been retired early
5. Spent nuclear fuel disposal costs
6. Nuclear plant decommissioning costs
7. Nuclear fuel costs
8. Extraordinary costs.

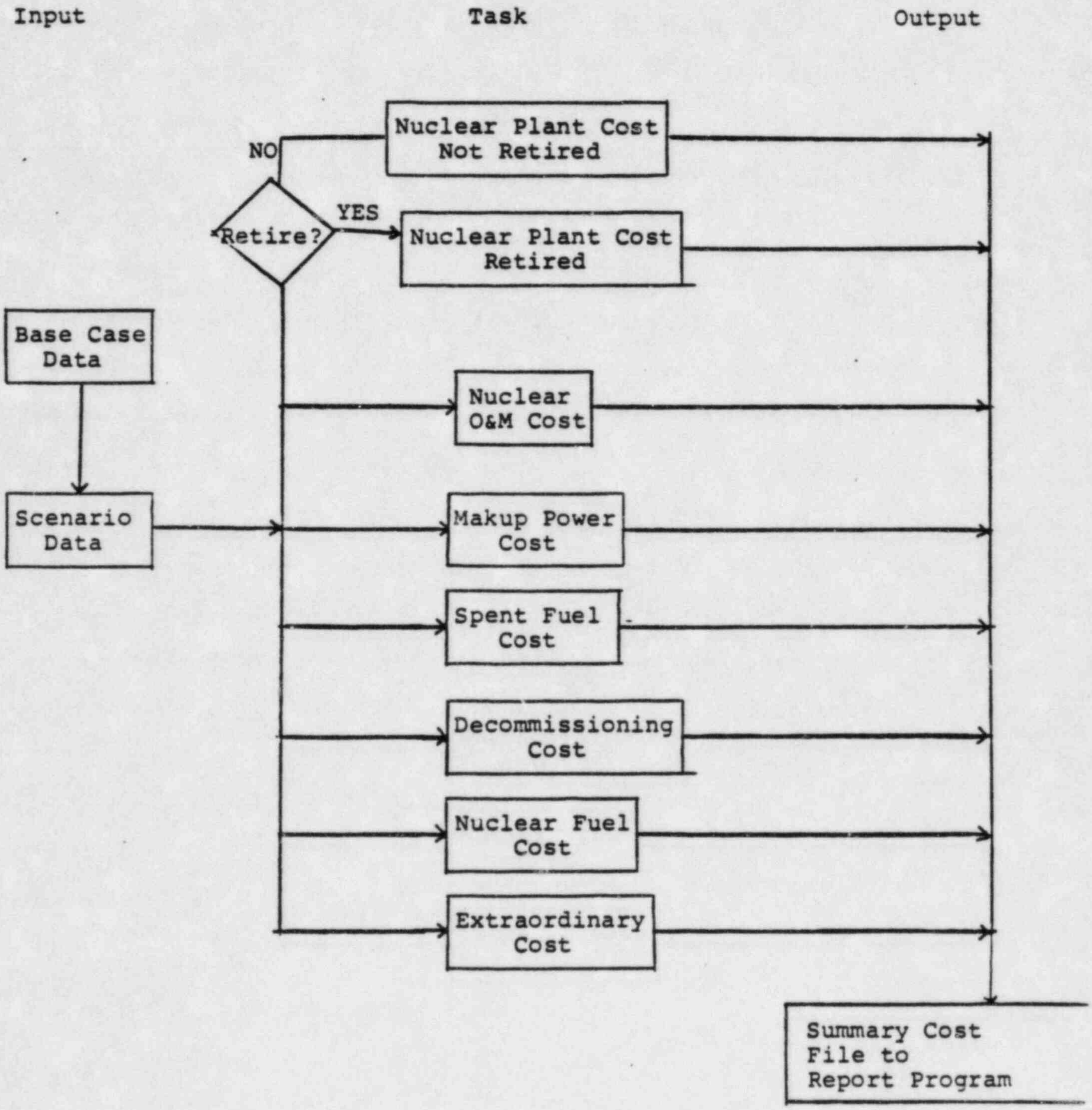
Since CANS was designed to estimate the costs of replacing nuclear plant with one or more alternatives, the modules were primarily designed to consider incremental required revenue impacts. For instance, the model makes no attempt to estimate the capital related costs of existing generators because these are independent of the decision on retiring nuclear plants. Similarly, no attempt is made to estimate the costs of current spent nuclear fuel.

An overview of CANS is provided in Figure A-1. The model reads the base case data, accepts or replaces values of inputs required for the particular scenario to be simulated, and calls the individual modules in turn. At this point it produces a file which summarizes the total revenue requirement impact as estimated by each module for the years in the study period. In addition, the user may request a more detailed report on the calculations performed by any of the individual modules.

When two scenarios have been simulated, the report program is used to generate a report comparing the results of the simulations.

Figure 1

Outline of the CANS Model



A-2. The Conventions of the CANS Model

In this section, we describe the handling of data common to more than one CANS module. In addition, we describe the conversion between cost estimates denominated in current dollars and present value estimates since this conversion is common to the reporting program (described in Section A-11) and the modules.

The data common to all CANs modules is entered through the BKGD data set. This data set is described in Table A-1. When CANS reports present values of various cost items, it does so based on the values of IPVYR and PVRATE from the BKGD data set. If PVRATE is not entered, present value calculations are based on the weighted cost of capital.

In the remainder of this appendix, we will make use of two conventions which the reader should note. First, variables which are inputs to CANS are denoted with an asterisk to distinguish them from variables which are internally calculated. Second, a number of variables are, in part, functions of time. These are denoted with the time subscript t. By convention, t is one in the base year; two in the second, and so on.

TABLE A-1

BKGD Data Set

Background Data Common to the CANS Program

$BNDCST_t$	Bond cost (as a fraction) in year t
$BNDSTR_t$	Bonds as a fraction of total capitalization in year t
CAPMW	Capacity of the nuclear generating unit in megawatts
COMP2	Logical variable. If true, the capital cost calculations are performed separately for two companies.
CONVRT	Factor to convert the dollars in which data is input to dollars of the base year of the study. Default value is 1.0.
$EQCST_t$	Common equity cost (as a fraction) in year t.
$EQSTR_r$	Common equity as a fraction of total capitalization in year t.
$ESCRAT_t$	The escalation rate to convert the year t-1 price level to the year t price level.
IBASE	Base year of the study
INDOL	Year in which input dollars are denominated
INYR	Year in which plant came on line
IPVYR	The year to which present values will be taken
IYRREP	The last year on which costs will be reported (Default value is LYSTUD)
LYSTUD	The last year of the study period
MECHO	Logical variable. If true the data sets are printed to a separate output file.
OWNSHR	The fraction of the nuclear generating unit owned by the utility being considered

$PRFCST_t$	Preferred stock cost (as a fraction) in year t
$PRFSTR_t$	Preferred stock as a fraction of total capitalization
PRTALL	If true, all modules print detailed reports on their estimations.
PVRATE	Rate for calculating present values (as a fraction). Default, weighted cost of capital is used.
REVTXR	Revenue tax rate, as a fraction
RRBAS	Total company required revenues in the base year
RRGR	Real escalation rate for required revenues.

A-3 Capital Costs of Nuclear Plant in Service

In this section, we describe the methodology employed to estimate the annual revenue requirement impact of the fixed charges associated with a nuclear plant. No allowance is made for fixed charges associated with nuclear fuel since these are estimated in the nuclear fuel cost module (see section A-6). The calculations described below are performed for every year in a "keep" scenario and for years prior to retirement in a "retire" scenario.

Like the other modules of CANS, this module employs both the background data set listed in Table A-1 and a module-specific data set, in this case CPTL. A description of the module specific data is presented in Table A-2.

As indicated in the table, the user can request employment of either normalized or flow-through accounting conventions. In the body of this section, we will assume normalized accounting. Subsequently, we describe the changes necessitated by a switch to the flow-through variant.

Required Revenues

The total annual revenue requirement impact is defined

$$REQREV_t = BKDEP_t + RETEQ_t + RETPRF_t + RETBND_t + TAX_t + DEFTAX_t - TXCRDA_t + OTHTOT_t - AFDCDA_t + REVTAX_t$$

TABLE A-2

CPTL Data Set

Used in Developing Annual Nuclear Capital Cost Estimates

Data Item	Description
AFDC	The allowance for funds used during construction (AFDC) component of original plant capital cost.
AFDCD	The income tax reduction resulting from the deduction of debt AFDC from taxable income which is flowed through to ratepayers.
BKLIFE	The total book life of the plant.
IDTXDP	Switch determining tax depreciation method if IDTXDP = 1, sum of the years' digits depreciation employed = 2, double declining balance depreciation employed If this variable is not specified, the default value is 1.
NRMDEP	Logical variable. If true, normalized accounting is employed. If false, flow-through accounting is used. The default value is true.
NYRDDB	When using the double declining balance method of calculating tax depreciation, NYRDDB controls the number of years during which that method will be used prior to switching over to straightline depreciation. The default value is one-half of the tax life.
OTHGRS	The fraction of original plant cost to be included as miscellaneous plant related expenses.
$OTHINP_t$	Annual miscellaneous expenses directly added to the revenue requirement.
OTHNET	Similar to OTHGRS except that the fraction is applied to the original cost net of book depreciation.
ORGCST	Original cost of the plant (in millions of dollars) including AFDC.
PRTFIX	Logical switch to prompt a report on the details of the fixed charge calculation. The default value is false.

where $REQREV_t$ - Required revenues in year t

$BKDEP_t$ - Book depreciation for revenue requirement purposes in year t

$RETEQ_t$ - Return to common stockholders in year t

$RETPRF_t$ - Return to preferred stockholders in year t

$RETBND_t$ - Return to bond holders in year t

TAX_t - Actual income taxes paid in year t

$DEFTAX_t$ - The difference between taxes charged to ratepayers and actual taxes (TAX_t) in year t

$TXCRDA_t$ - Amortization of the tax credit in year t

$OTHTOT_t$ - Other fixed charges in year t

$AFDCDA_t$ - Amortization of tax reduction from the interest component of AFDC in year t

$REVTAX_t$ - Revenue or gross receipts tax in year t

In the remainder of this section, each component of required revenues is described. An asterisk indicates those variables which are input items.

$\underline{BKDEP}_t$ - Annual book depreciation for rate purposes.

Unless explicitly input, book depreciation for rate purposes is calculated under straight line depreciation.

$$BKDEP_t = ORGCST^*/BKLIFE^*$$

where ORGCST - Value of asset, including AFDC, when it comes on line

BKLIFE - The book life of the asset.

TABLE A-2
(Continued)

RESCAP	The fraction of accumulated deferred taxes to be netted from the rate base. The default value is 1.
TXCRD	Total investment tax credit originally claimed for the plant.
TXLIFE	Tax life of the plant.
TXRATE	The composite (including federal and state) income tax rate.

$\underline{RETEQ}_t$, $\underline{RETPFR}_t$, $\underline{RETBND}_t$ - Return to capital

The return to each type of capital is calculated as

$$\text{Equity cost, year t} = EQCST^*_t \times EQSTR^*_t$$

$$\text{Preferred cost, year t} = PRFCST^*_t \times PRFSTR^*_t$$

$$\text{Bond cost, year t} = BNDCST^*_t \times BNDSTR^*_t$$

where $XXXCST_t$ - the cost of capital source XXX in year t (expressed as a decimal)

$XXXSTR_t$ - the proportion of capital source XXX as a fraction of total capital in year t.

Since returns to each type of capital are calculated symmetrically, only the derivation of RETEQ, the return to equity capital, will be described in detail

$$RETEQ_t = EQCST^*_t \times EQSTR^*_t \times RATBAS_t$$

where $RATBAS_t$ is the mid-year rate base in year t.

The rate base is defined as

$$RATBAS_t = ((BKVAL_t + BKVAL_{t+1})/2 - RESCAP^* \times (DTXRES_t + DTXRES_{c+1})/2)$$

where $BKVAL_t$ is the book value of the plant at the beginning of year t

RESCAP* is the fraction of the deferred tax reserve fund to be netted from the rate base

DTXRES is the deferred tax reserve balance in year t

RESCAP* is input data. $DTXRES_t$ is described below. The book value of the plant is

$$BKVAL_t = ORGCST - \sum_{i=1}^{t-1} BKDEP_i = ORGCST^* \frac{BKLIFE^* - t+1}{BKLIFE^*}$$

where ORGCST, $BKDEP_t$ and BKLIFE retain their definitions given above.

TAX_t - Actual Income taxes paid

CANS does not distinguish between Federal and state income taxes. Therefore

$$TAX_t = TAXINC_t \times TXRATE^*$$

where $TAXINC_t$ - taxable income for Federal tax purpose excluding any deductible state or local income taxes in year t

TXRATE - the composite state and Federal income tax rate

$TXCRD_t$ is described below. TXRATE is input data. When state taxes are deducted from income in determining taxes, the composite rate must be calculated as follows.

State Tax = State tax rate x Income

Federal Tax = Federal tax rate x (Income-State tax)

Total Income Tax = Federal Tax + State Tax

= Federal tax rate x (Income - State tax rate x Income)

+ State tax rate x Income

Therefore, the proper value of TXRATE for input is

TXRATE* = Federal rate + State rate - Federal rate x State rate

Taxable income must be calculated with reference to the fact that many components of income are after-tax

Unless input, accelerated tax depreciation is calculated by sum of the years' digits if IDTXDP = 1 or by double declining balance when IDTXDP = 2. Under sum of the years' digits,

$$TXDEP_t = (ORGCST^* - AFDC^*) \times (TXLIFE^* + 1-t)/SYD$$

$$SYD = \sum_{i=1}^{TXLIFE^*} i = TXLIFE^* \times (TXLIFE^*+1)/2$$

where $TXDEP_t$ - Accelerated depreciation for tax purposes in year 5

ORGCST - Cost of plant, including AFDC in rate base

AFDC - Total allowance for funds used during construction

SYD - Sum of the years' digits

Under double declining balance, tax depreciation in the early years is

$$TXDEP_t = (ORGCST^* - AFDC^*) \times (1-2/TXLIFE^*)^{t-1} \times (2/TXLIFE^*)$$

where all variables retain their previous definitions.

After one half of the tax life or at a user specified time the double declining depreciation method reverts to straight-line depreciation to allow a complete write-off.

Deferred taxes resulting from accelerated depreciation under normalized accounting are calculated as

$$DEFTAX_t = (TXDEP_t - BKDEP_t) \times TXRATE^*$$

For ease in understanding, the first terms in the taxable income equation can be rewritten requirements. Taxable income must be sufficient to fulfill these requirements.[1]

$$TAXINC_t = \frac{1}{1-TXRATE^*} (BKDEP_t - TXDEP_t + DEFTAX_t - TXCRDA_t + RETEQ_t + RETPRF_t - AFDCDA_t)$$

where $BKDEP_t$ - Straight line depreciation for book purposes in year t

$TXDEP_t$ - Accelerated depreciation for tax purposes in year t

$DEFTAX_t$ - Deferred taxes due to normalizing accelerated depreciation in year t

$TXCRDA_t$ - Investment tax credit amortized in year t

$RETEQ_t$ - Return to common stockholders in year t

$RETPRF_t$ - Return to preferred stockholders in year t

$AFDCDA_t$ - Amortization of tax savings from AFDC

The depreciation terms are conveniently considered together. Another depreciation item which requires introduction is $BKDEPT_t$, depreciation for book taxes. $BKDEPT_t$ is similar to $BKDEP_t$ with one significant difference. Since only direct construction expenditures can be depreciated for tax purposes, depreciation was calculated

$$BKDEPT_t = (ORGCST^* - AFDC^*)/BKLIFE^*$$

where AFDC* - total AFDC during construction.

Other variables are defined above.

---

[1]This equation is derived as follows

$$ATI_t = TAXINC_t - TXRATE \times TAXINC_t$$

where ATI - after tax income

rearranging terms yields:

$$TAXINC_t = \frac{1}{1-TXRATE} \cdot ATI_t$$

$$\frac{1}{1-TXRATE}(BKDEP_t - TXDEP_t + DEFTAX_t)$$

$$= \frac{BKDEP_t - TXDEP_t + (TXDEP_t - BKDEPT_t)TXRATE}{1 - TXRATE}$$

$$= \frac{BKDEP_t - TXRATE \times BKDEPT_t + (1-TXRATE)TXDEP_t}{1 - TXRATE}$$

$$= \frac{BKDEP_t - TXRATE \times BKDEPT_t}{1 - TXRATE} + TXDEP_t$$

<u>$TXCRDA_t$</u> - Investment tax credit amortization

Total investment tax credits taken during construction are entered as data. Once construction expenditures are over, no further tax credits are generated.

Credits are amortized over the book life so that

$$TXCRDA_t = TXCRD^*/BKLIFE^*$$

<u>$OTHTOT_t$</u> - Other Fixed Charges

Conceptually, these costs may represent insurance, property taxes or other miscellaneous items. To allow flexibility,

$$OTHTOT_t = OTHGR^* \times ORGCST^* + OTHNET^* \times BKVAL_t + OTHINP^*_t$$

where

OTHGR* - Other costs incurred as a fraction of original cost.

OTHNET* - Other costs incurred as a fraction of net plant

$OTHINP^*_t$ - Other costs in dollar terms exogenously supplied by the user.

$BKVAL_t$ is described above in the discussion of $RETEQ_t$.

$\underline{AFDCDA_t}$ - Amortization of deferred taxes from debt portion of AFDC.

When AFDC is partially debt related, the interest expense during the construction period results in a tax reduction during those years. Under normalized accounting, these are flowed through to ratepayers at a constant rate over the service life.

$\underline{DTXRES_t}$ - Deferred Tax Reserve

Deferred taxes result from two sources: 1) accelerated depreciation under normalized accounting, and 2) normalization of the tax savings from debt portion of AFDC. The investment tax credit component is not considered. The deferred tax reserve is the sum of these components not yet passed to ratepayers. In some jurisdictions, this account is netted against the rate base or, equivalently, considered as part of the capital structure at zero return.

$$DTXRES_t = \sum_{i=1}^{t} DEFTAX_i + (AFDCD^* - \sum_{i=1}^{t-1} AFDCDA_i)$$

where $DEFTAX_t$ - Current deferred taxes in year t

$AFDCD^*$ - Tax savings from debt portion of AFDC

AFDCDA - Amortization of AFDC tax savings in year t

$DEFTAX_t$, AFDCD and AFDCDA are described above.

$$AFDCDA_t = AFDCD^*/BKLIFE^*$$

where $AFDCD^*$ - Total tax reduction during contruction period

$BKLIFE^*$ - Asset life for book purposes.

Both $AFDCD^*$ and $BKLIFE^*$ are data inputs.

$\underline{REVTAX_t}$ - Revenue

Revenue taxes are calculated after all other components of required revenues have been computed. For didactic purposes, we will refer to this total revenue requirement, net of revenue taxes, as RR′.

Revenue taxes are then defined

$$REVTAX_t = \frac{REVTXR^* \times RR'}{1-REVTXR^*}$$

where REVTXR* is the revenue tax rate.

<u>Flow-Through Accounting</u>

Under flow-through accounting, various tax savings are used to reduce required revenues immediately. The computation is simpler since there is no need to differentiate between actual and book taxes. The required revenue function is

$$\begin{aligned} REQREV_t = \; & BKDEP_t - TXCRDA_t + RETEQ_t + RETPRF_t + RETBND_t \\ & + TAX_t + OTHTOT_t + TXCRD_t + REVTAX \end{aligned}$$

Variables retain their definitions from section 1. Note this formulation differs in that the elements relating to normalization of accelerated depreciation and the debt portion of AFDC do not appear. Other required changes are similarly straightforward. DTXRES, the deferred tax reserve fund, is no longer relevant. The taxable income calculation is the same, but some terms cancel.

$$\begin{aligned} TAXINC_t = \; & \frac{1}{TXRATE} (BKDEP_t - TXDEP_t + RETEQ_t + RETPRF_t \\ & - TXCRDA_t) \end{aligned}$$

Otherwise, the same equations employed under normalized accounting continue to apply.

A-4 Capital Cost Recovery for Retired Plant

In many respects, recovery of the capital of retired plants is similar to recovery of the costs of plants that remain in service. The most important change is that in the year of retirement, the focus shifts from the recovery of undepreciated plant costs to the recovery of that portion of plant costs charged to ratepayers. In a given situation, it is possible that these two items will be equal. A second potential difference is that the costs of retired plants may be amortized over a different time period. Finally, there is an important tax effect since upon retirement, the remaining value of the plant is written off for tax purposes rather than being recovered over the remaining tax life.

When estimating plant capital costs under a retirement scenario, CANS first calculates the capital costs of maintaining the plant in service during the years prior to retirement. This serves two purposes. First, the costs for those years are required directly. Second, the simulation serves to provide estimates of the levels of the reserve accounts, e.g. depreciation, deferred taxes, unamortized investment tax credits.

The module employs three data sets: the background data set, the capital cost data set (see Table A-2), and a new data set, CPRT, shown in Table A-3.

TABLE A-3

CPRT Data Set

Used In Developing the Annual Capital Costs

Of Retired or Cancelled Nuclear Plant

Data Item	Description
AMLIFE	Amortization period (in years) over which the ratepayers will be assessed for their share of retired or cancelled plant costs.
DEPNET	Fraction of deferred tax reserves which is credited to ratepayers in determining the value of plant to be recovered from ratepayers. The default value is 1.
OTHGRS	Fraction of original plant cost incurred as an annual miscellaneous expense (Values for OTHGRS, OTHINP, and OTHNET over-ride values in CPTL data set).
OTHINP	Input annual miscellaneous expense.
OTHNET	Fraction of unamortized unused plant incurred as an annual miscellaneous expense.
RETURN	Fraction of unamortized unused plant included in the rate base.
RPSHAR	Fraction of plant cost recovered from ratepayers.
TXCNET	Fraction of unamortized investment tax credit reserve credited to ratepayers in determining the value of plant to be recovered from ratepayers. Default value is 1.
TXWNET	Fraction of tax savings from write-off off plant costs which is credited to ratepayers in determining the value of plant. Default value is 1.

Required Revenues

The required revenues component is defined by the same equation described in Section A-3. The reader should note, however, that the definitions of individual items may change somewhat. In particular, $BKDEP_t$ refers to current book depreciation when referring to plant in service and current amortization of unused plant cost for plant not in service.

The total annual revenue requirement impact is defined

$$REQREV_t = BKDEP_t + RETEQ_t + RETPFR_t + RETBND_t + TAX_t + DEFTAX_t - TXCRDA_t + OTHTOT_t - AFDCDA_t + REVTAX_t$$

where $REQREV_t$ - Required revenues in year t

$BKDEP_t$ - Amortization of unused plant in year t

$RETEQ_t$ - Return to common stockholders in year t

$RETPRF_t$ - Return to preferred stockholders in year t

$RETBND_t$ - Return to bond holders in year t

TAX_t - Actual income taxes paid in year t

$DEFTAX_t$ - The difference between taxes charged to ratepayers and actual taxes (TAX_t) in year t

$TXCRDA_t$ - Amortization of the tax credit in year t

$OTHTOT_t$ - Other fixed charges in year t

$AFDCDA_t$ - Amortization of tax reduction from the interest component of AFDC in year t

$REVTAX_t$ - Revenue or gross receipts tax in year t

The methodology employed in calculating these elements is extremely similar to that described in the previous section. That earlier development will be redrawn here only to the extent that it is modified. The subscript r will refer to the year of retirement.

$\underline{BKDEP_t}$ - Amortization of unused plant

$$BKDEP_t = RPPLNT / AMLIFE^*$$

where RPPLNT - the value of the plant net of tax write-off charged to rate payers at time of retirement

$AMLIFE^*$ - the amortization period

The total plant cost to be recovered from ratepayers is developed from the net value of the plant prior to retirement. This can be adjusted to reflect

1) The tax reduction which results from writing the plant off as a loss for income tax purposes

2) (Optionally) The netting out of the value of the associated deferred tax accounts

3) (Optionally) A reduction of the ratepayers liability to some fraction of the original plant cost

Adopting the convention that the subscript r refers to a variable value on January first of the retirement year, RPPLNT is defined:

$$RPPLNT = BKVAL_r - TXRATE * BKVALT_r - DTXRES_r X\ DEPNET^*$$

$$- TXCRDR_r \times TXCNET^*) \times RPSHAR^*$$

where $BKVAL_r$ - Book value of plant immediately prior to retirement

$BKVALT_r$ - Tax value of plant immediately prior to retirement

TXRATE* - Composite income tax rate

$DTXRES_r$ - Deferred tax reserve from depreciation and AFDC sources prior to retirement

DEPNET* - Portion of DTXRES netted from rate payers liability for plant

$TXCRDR_r$ - Deferred tax reserve from investment tax credit

TXCNET* - Portion of $AFDCDR_r$ netted from ratepayers liability for plant

RPSHAR* - Fraction of original plant cost to be recovered from ratepayers

ORGCST* - Original plant cost (including AFDC).

<u>$RETEQ_t$</u>, <u>$RETPRF_t$</u>, <u>$RETBND_t$</u> - Return to capital

The changes outlined above affect the return on capital through its effect on the rate base. The rate base calculation must be modified to reflect both the new asset valuation and the possibility that the deferred tax reserve accounts may have been netted out.

$$RATBAS_t = ((BKVAL_t + BKVAL_{t+1})/2 - RESCAP^* \times (DTXRES_t + DTXRES_{t+1})/2) \times RETURN^*$$

where $RATBAS_t$ - mid-year rate base in year t

RESCAP* - Fraction of deferred tax reserve netted from rate base

$DTXRES_t$ - Deferred tax reserve at the beginning of year t

RETURN* - Fraction of plant allowed in the rate base

$DTXRES_t$ is calculated as shown in section A-3, but its components are reduced by the multiplication factor (1-DEPNET*) to reflect the possibility that the reserve has been wholly or partly netted against the plant value.

The returns to capital, $RETEQ_t$, $RETPRF_t$, and $RETBND_t$ are calculated as before by using the weighted cost of each capital component.

$\underline{TAX}_t$

Income taxes are calculated as before. The full remaining value of the plant is assumed written off for tax purposes in the first year.

$\underline{DEFTAX}_t$

Deferred tax expense is zero under flow-through accounting when the full tax benefits of write-off have not been immediately credited to ratepayers (e.g. TXWNET $\neq$ 1). In this case, deferred taxes are

$$DEFTAX_t = -TXRATE^* * (1-DEPNET) \times BKVALT_r/AMLIFE$$

$\underline{TXCRDA}_t$, $\underline{AFDCDA}_t$

Investment tax credits and the tax savings from debt AFDC are amortized over the amortization period with adjustments to recognize cases in which they have been netted against the ratepayer plant liability.

$\underline{OTHTOT}_t$

Other costs are calculated as shown in A-3. The reader should note, however, that new values of the inputs OTHGRS*, $OTHIMP_t$, and OTHNET* are read from the CPRT data set.

$\underline{REVTXR}_t$

Revenue taxes are calculated as before.

A-5 Calculation of Nuclear Plant Operation and Maintenance Costs

The development of the statistical forecasts for operation and maintenance expenses is described in detail in Appendix B. Here we will simply report the manner in which those forecasts are employed by CANS to produce required revenue impacts. In general, one of the two forecasting equations is employed in each simulation to derive an estimated real (net of general inflation) escalation rate for nuclear O+M costs for each year in the study period and prior to retirement. These escalation rates are then employed in concert with input values for base year nuclear O+M costs and a general inflation rate to produce estimated current dollar costs estimates for each year. In addition, the user is allowed to specify a scaling factor (OMSCAL) which is used to adjust the estimated real escalation rates.

This module requires the OM data set in addition to the general data. The OM data set is described in Table A-4.

Given the data inputs, nuclear O+M costs are calculated recurseively beginning in the first year.

$$OMCOST_t = OMNET_t + REVTX_t$$

where $OMCOST_t$ - Total O+M cost in year t including an allowance for revenue taxes.

$OMNET_t$ - O+M cost net of revenue taxes in year t

$REVTX_t$ - Revenue taxes associated with O+M costs in year t.

Revenue taxes are calculated in the manner described in A-3 and can be quickly dismissed.

$$REVTX_t = REVTXR^* \times OMNET_t / (1-REVTXR^*)$$

where REVTXR - revenue tax rate

TABLE A-4

O&M Data Set

Data Requirements for Calculating
Nuclear Operations and Maintenance Costs

Variable	Description
BASEOM	Nuclear operations and maintenance expense in the base year (millions of dollars)
$BIRTH_t$	Year unit first came on line relative to 1970. Since there may be if multiple units are at a site, this must be input as a vector of length 50 since other units on the site could be retired.
DEMO	A value of 1 indicates a demonstration unit. Otherwise zero.
LOG	Logical variable. If true, log-linear specification is employed. Otherwise, linear model used. Default value is false.
NEMASK	A value of one indicates the plant is in the Northeast. Otherwise zero.
OMSCAL	Scaling factor applied to the calcualted real escalation rate. See text. Default valve is one.
PRTOM	Logical variable. If true, a separate report on operations and maintenance costs is produced.
SALT	A value of one indicates a salt water cooling system. Otherwise zero.
SECOND	A value of one indicates unit is one of two or more at the site. For the reason noted in the discussion of BIRTH, above, this must be input as a vector.
TOWERS	A value of one indicates cooling towers are used. Otherwise zero.
TYPE	A value of one indicates unit is a pressurized water reactor (PWR). A value of zero indicates a boiling water reactor (BWR).

Operations and maintenance expenses net of revenue taxes is calculated

$$OMNET_t = BASEOM^* \text{ for } t = 1$$

$$= OMNET_{t-1} \left(1 + OMSCAL^* \left(\frac{OMEQ_t}{OMEQ_{t-1}} - 1\right) + ESCRAT^*_{t-1}\right)$$

$$\text{for } t > 1$$

where BASEOM* - Input operations and maintenance cost in the first year of the study (millions of dollars)

$OMEQ_t$ - Predicted operations and maintenance costs from linear or log-linear statistical model

OMSCAL* - Input scaling factor to adjust real escalation rate

$ESCRAT^*_{t-1}$ - General inflation rate from year t-1 to year t.

The values of $OMEQ_t$ are developed from either the linear or log-linear forecasting equation, depending on the value of the logical variable LOG*. If LOG is false the linear equation is employed. If true, the log-linear version is used. Using the linear equation,

$$\begin{aligned} OMEQ_t = & \ 23.1426 \\ & +4.000111 \times NEMASK^* \\ & +4.64958 \times SALT^* \\ & +2.75956 \times TOWERS^* \\ & +15.2714 \times DEMO^* \\ & +1.18159 \times TYPE^* \\ & -0.00372 \times CAPMW^* \\ & +1.94284 \times (IYEAR_t - 1980) \\ & +0.89526 \times DEMO^* \times (IYEAR_t - 1980) \\ & -3.17592 \times SECOND^*_t \\ & -0.38098 \times BIRTH^*_t \end{aligned}$$

where CAPMW - Plant capacity (in megawatts)

$IYEAR_t$ - Calendar year associated with year index t

All other variables as shown in Table A-5.

Using the log-linear specification,

$$
\begin{aligned}
OMEQ_t = \exp\,(3.01852 \\
&+0.270349 \times NEMASK^* \\
&-0.280196 \times SALT^* \\
&+0.109606 \times TOWERS^* \\
&+0.546909 \times DEMO^* \\
&+0.075949 \times (IYEAR_t - 1980) \\
&+0.000102 \times CAPMW^* (ITIME-1980) \\
&-0.201635 \times SECOND_t \\
&-0.013045 \times TYPE^* \times (ITIME-1980)
\end{aligned}
$$

where all variables retain their previous definitions.

A-6. Makeup Energy and Power Costs

The Makeup Energy and Power Costs module is employed to estimate the sources of energy which will replace nuclear generation and to calculate their costs. For this reason, it does not calculate costs when CANS is simulating a keep case.[1] Total makeup costs are calculated as the sum of five components:

1) Conservation costs when additional conservation is assumed to replace nuclear generation.
2) Energy costs (fuel and O&M) of replacement electricity
3) Capacity costs
4) Costs of fuel switching or similar investments
5) Revenue taxes.

As will be described below, energy costs can be developed in either of two ways. The total energy costs of a "KEEP" and a "RETIRE" case may be independently estimated (typically using a separate production costing model) or CANS will develop the cost estimate internally based on a user specified mix of replacement energy sources. Makeup power costs are calculated based upon data in the MKUP data set, described in Table A-5.

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[1]Strictly, the subroutine is called in such cases, but it assigns a zero cost.

TABLE A-5

MKUP Data Set

Data Used to Calculate Makeup Power Costs

Variable	Description
$CAPCST_j$	The capital cost of fuel switching investment j ($j \leq 50$) (in millions of IYRCAP dollars)
$CAPFCF_j$	The levelized fixed charge factor associated with investment j
CONB$	Base year capital cost of conservation (in dollars per killowatt hour)
CONFCF	Fixed charge factor to derive annualized cost of conservation
CONPEN	Ultimate conservation penetration ratio. Fraction of total energy demand met by conservation after the conservation plan is fully implemented
$FGWHKP_t$	When GWHINP is true, $FGWHKP_t$ is the total nonnuclear fuel cost in the reference case, year t. (Millions of current dollars)
$FGWHRT_t$	Counterpart of $FGWHKP_t$ current for the retirement case
$FSOM_t$	Differential operation and maintenance expenses resulting from fuel switching investment in year t
$FUEL_i$	Base year fuel cost of generation option i ($i \leq 5$) in dollars per million Btu
FWKCAP	Fuel working capital contribution to required revenues as a fraction of fuel expense
$GFRAC_{t,i}$	Fraction of replacement generation from source i in year t
GWHINP	Logical variable. If true, replacement energy costs are calculated based on the results of an independent analysis. The fault value is false
$HTRATE_i$	Average heat rate of generation option i, BTU per kilowatt hour

TABLE A-5

Continued

Variable	Description
$ICLIFE_j$	Book life of fuel switching investment j.
ILYCON	Year in which conservation achieves full penetration (CONPEN)
ISTCON	Year in which conservation program begins
$IYRCAP_j$	The year in which fuel switching investment j first is reflected in required revenues
$IYRNRG_j$	List of 3 future years in which forecast energy demand is available (See REFNRG)
NFUELS	Number of fuels used to provide replacement power ($NFUELS \leq 5$)
OMGEN	Operations and maintenance expense for replacement--power source λ ($\lambda \leq 5$)
$OGWHKP_t$	When GWHINP is true, $OTWHKP_t$ is the total non-nuclear operations and maintenance cost in the reference case, year t (millions of year t dollars).
$OGWHRT_t$	Counterpart of $OTWHKP_t$ for the retirement case.
PRTMUP	Logical variable. If true, a report on makeup power costs is printed.
RCESC	Real escalation rate for conservation costs
$REFNRG_j$	Forecast gigawatt hour demand for each of the three years specified by $IYRNRG_j$
$RFESC_j$	Real escalation rate for fuel costs of replacement power source j
$ROMESC_j$	Real escalation rate for operations and maintenance costs of replacement source j
RMWESC	Real escalation rate of peak capacity shortage costs

TABLE A-5

Continued

Variable	Description
$SHRTMW_t$	Megawatts of peak capacity shortage in year t
$MW	Base year peak capacity shortage cost (in dollars per megawatt)

Total makeup costs are calculated

$$TOTAL_t = \$CON_t + GWHDIF_t + \$SHRTP + TCAP_t + REVTAX_t$$

where $TOTAL_t$ - Total makeup costs (in millions of dollars) in year t

$\$CON_t$ - Total cost, as reflected in required revenues, of additional conservation

$GWHDIF_t$ - Total differential energy cost of generation and/or imports

$\$SHRTP_t$ - Total differential peak cost of generation and/or imports

$TCAP_t$ - Total cost of fuel conversion or similar investments

$REVTX_t$ - Annual revenue taxes associated with makeup power

Revenue taxes are calculated in the same manner described in section A-3. The other four components of makeup costs are discussed below.

$\$CON_t$ - Conservation Costs

If additional conservation efforts are undertaken in response to plant retirement, the resulting reduction in demand can be considered as a source of makeup power, de facto. Similarly, the costs of these efforts, to the extent they are reflected in required revenues, are a cost of makeup power. Conservation costs are calculated (in millions of dollars)

$$\$CON_t = CONB\$^* \times TCESC_t \times CONFCF^* \times CONGWH_t$$

where $CONB\$^*$ - Base year capital cost of conservation per KWH

$TCESC_t$ - Total escalation factor to convert base year conservation costs to costs in year t

$CONFCF^*$ - Fixed charge factor to annualize conservation capital costs

$CONGWH_t$ - Reduction in energy demand due to conservation

CONB$* and CONFLF* are input data items. Escalation factors similar to $TCEFC_t$ are also calculated for the other makeup costs. Discussion of these three elements is reserved for the end of the section. $CONGWH_t$ is calculated as a fraction of total systemwide energy demand, the fraction being determined by an ultimate conservation penetration and by a phase-in period for the conservation measures.

$$CONGWH_t = CONPEN^* \times FRCON_t \times DEMNRG_t$$

where CONPEN* - Conservation penetration fraction

$FRCON_t$ - Fraction representing the position of year t to the phase-in period

$DEMNRG_t$ - Base case customer energy demand in year t

CONPEN* is an input data item. $FRCON_t$ is determined by a user supplied phase-in period.

$$FRCON_t = 0 \quad \text{if } IYEAR_t < ISTCON^*$$

$$= \frac{IYEAR_t - ISTCON^* + 1}{ILYCON^* - ISTCON^* + 1} \quad \text{if } IYEAR_t \geq ISTCON^* \text{ and } IYEAR_t < ILYCON^*$$

$$= 1 \text{ if } IYEAR_t \geq ILYCON^*$$

where $IYEAR_t$ - Calendar year corresponding to year index t

ISTCON* - Year in which conservation effort produces its first effects

ILYCON* - Year in which conservation effort reaches full effect.

Base case energy demand, $DEMNRG_t$, is calculated based on forecasts of energy demands ($REFNRG^*_j$) in each of three years ($IYRNRG^*_t$). For other years, demand is assumed to be a piece-wise linear function of time.

$$DEMNRG_t = REFNRG_2 + \frac{REFNRG_2 - REFNRG_1}{IYRNRG_2 - IYRNRG_1} \times (IYEAR_t - IYRNRG_2)$$

For $IYEAR_t \leq IYRNRG_2$

$$= REFNRG_2 + \frac{REFNRG_3 - REFNRG_2}{IYRNRG_3 - IYRNRG_2} \times (IYEAR_t - IYRNRG_2)$$

For $IYEAR_t > IYRNRG_2$

where $IYRNRG^*_j$ - Is the calendar year of energy forecast j

$REFNRG^*_j$ - Energy demand (in GWH) of energy forecast j

<u>$GWHDIF_t$</u> - <u>Energy Cost of Makeup Power</u>

As noted earlier in this section, energy costs can be separately estimated or calculated by the CANS model. In the former case, energy costs are the difference between two vectors of annual costs.

$$GWHDIF_t = (1 + FWRKLP^*) (FGWHRT^*_t - FGWHRP^*_t) + (OGWHRT^*_t - OG$$

where * - Fractional working capital allowance

$FGWHRT_t$ - Non-nuclear fuel cost in the retirement case, year t

$FGWHKP_t$ - Non-nuclear fuel cost in the reference case, year t

$OGWHRT_t$ - Non-nuclear operations and maintenance cost in the retirement case, year t

$OGWHKP_t$ - Non-nuclear operations and maintenance cost in the reference case, year t.

If estimates of energy costs are not available from outside sources, they are calculated by CANS based upon the amount of energy required, the costs of energy from various sources, and user supplied estimates of the fraction of the total energy which will be provided by each source. Total costs are:

$$GWHDIF_t = \sum_{i=1}^{NFUELS} GWHSUP_{t,i} \times (HTRATE_i \times FUEL_i \times (1 + FWRKCP) TFESC_{t,i}/1{,}000{,}000) + OMGEN_i \times TOMESC_{t,i})$$

where $NFUELS^*$ - Number of sources of energy considered ($NFUELS \leq 5$)

$GWHSUP_{t,i}$ - Energy production (in GWH) from source i in year t

$FWRKCP^*$ - Working capital fractional allowance

$HTRATE_i^*$ - Heat rate of source i (in BTU per kilowatt hour)

$FUEL_i^*$ - Base year fuel cost of source i (in dollars per million BTU)

$TFESC_{i,t}$ - Total escalation factor for fuel i in time period t

$OMGEN_i^*$ - Base year variable operations and maintenance cost of source i

$TOMESC_{t,i}$ - Total escalation factor for fuel i in time period t.

As indicated, NFUELS, FWKLAP, $HTRATE_i$, $FUEL_i$, and $OMGEN_i$ are data items. The escalation factor derivation is at the end of this section. Energy production is calculated

$$GHWSUP_{t,i} = GFRAC^*_{t,i} \times (BSHWH1_t + BSGWH2_t) - (SCGWH1_t + SCGWH2_t) - CONGWH_t)$$

where $GFRAC^*_{t,i}$ - the fraction of energy supplied by source i in year t

$BSGWH1_t$ - Nuclear plant output (in GWH) from unit 1 in the reference case in year t

$SCGWH1_t$ - Nuclear plant output (in GWH) from unit 1 in the current scenario in year t

$CONGWH_t$ - Conservation makeup energy in year t

Conservation energy ($CONGWH_t$) is derived above. Nuclear output is calculated based on capacity factors input in the CPFC data set shown in Table A-6. Reference case nuclear output from generating unit one is

$$BASWH1_t = 8.760 \times UN1MW \times BCPFC1$$

where UN1MW* - unit one capacity (in MW)

$BCPFC1_t$ - Reference case capacity factor of unit one in year t.

Each of these items is input data. The other plant outputs are similarly calculated. $SCGWH1_t$ is defined to be zero after plant retirement.

The reader should note that energy makeup costs may be negative under some circumstances. In the years immediately prior to retirement, the user may wish to specify that an increased nuclear capacity factor, due perhaps to a modified refueling or maintenance schedule, or an early conservation program will cause a reduction in the energy supplied from non-nuclear sources. The Makeup module calcuates this as a credit using exactly the algorithms described above.

Peak Costs of Generation and/or Imports

Under retirement, peak costs may be incurred when construction of additional peaking units is necessary or when increased electricity importation requires a payment based upon the level of peak purchases. The revenue requirement impact of these costs is calculated

TABLE A-6

CPFL Data Set

Data Used to Determine Nuclear Generation

$BCPFC1_t$	-	Annual capacity factor of nuclear generating unit one in the reference case (year t)
$BCPFC2_t$	-	As above for unit 2
PRTFAC	-	Logical variable. If true, a report on capacity factors and nuclear generation is printed.
$SCPFC1_t$	-	Annual capacity factors of nuclear generating unit one in the retirement case (year t)
$SCPFC2_t$	-	As above for unit 2
UN1MW	-	Capacity (in megawatts) of unit one. (Default valve is CAPMW x OWNSHR from BKGD data set).
UN2MW	-	As above for unit 2.

$$\$SHRTP_t = SHRTMW_t^* \times \$MW^* \times TMWESC_t/1{,}000{,}000$$

where $SHRTMW_t^*$ - Number of megawatts of on-peak shortage

$\$MW^*$ - Base year cost of onpeak shortage (in dollars per megawatt)

$TMWESC_t$ - Total escalation factor for peak costs in time period t.

The items $SHRTMW_t$, and \$MW are from data. $TMWESC_t$ and the escalation factors employed earlier are described below.

TCAP--Fuel Switching Investments

The impact of fuel switching investments on required revenues is simulated through a fixed charge factor technique.

$$TCAP_t = FSOM_t + \sum_{i=1}^{50} \Psi_{Y,t} \times CAPCST_i \times CAPFLF_i$$

$$\Psi_{i,t} = 1 \quad \text{if } IYRCAP_i - IBASE + 1 \leq t \leq IYRCAP_i - IBASE + ICLIFE_i$$

$$= 0 \quad \text{Otherwise}$$

where $TCAP_t$ -- Revenue requirement impact of all fuel switching investments in year t

$FSOM_t^*$ -- O&M expenses of fuel switching investments in year

$CAPCST_i^*$ -- Current dollar cost of investment i

$CAPFLF_i^*$ -- Levelized fixed charge factor of investment i

$IYRCAP_i^*$ -- Year in which investment i is first reflected in required revenues

$ILLIFE_i^*$ - Book life of investment i

Escalation Factors

Individual escalation factors are employed for each of the components of makeup costs except for revenue taxes. The

A-7. Spent Fuel Costs

CANS does not produce an independent estimate of spent fuel costs. This analysis is separately performed and is described in Appendix D. CANS does, however, take the results of that analysis and estimate its impact on required revenues. This is done by spreading the costs over a user specified period of years under the assumption that recovery is equal in present value terms in each year.

The spent fuel module requires data set SFCT which is described in Table A-7. Using this data, it calculates the annual revenue requirement impacts in present value terms

$$SFRRPV_t = 0 \quad \text{if } IYEAR_t < IYRSTF^* \text{ or } IYEAR_t > IYRFNF^*$$

$$= \frac{TOTSF}{IYRFNF - IYRSTF + 1} \quad \text{if } IYRSTF^* \leq IYEAR_t \leq IYRFNF^*$$

where

- $SFRRPV_t$ - Spent fuel revenue requirement impact in present value terms in year t
- IYRSTF - First year in which spent fuel costs will be collected through the revenue requirement
- $IYEAR_t$ - Calendar year corresponding to index year t
- IYRFNF - Last year in which spent fuel costs will be collected through the revenue requirement

The revenue requirement impact in current dollar terms is then calculated through application of the present value multiplier (see section A-2).

$$SFRR_t = SFRRPV_t / PVVECT_t$$

method of calculation for all is very similar. For this reason, only $TCESC_t$, the escalation factor for conservation costs will be developed in detail.

$$TCESC_t = CONVRT^* \quad \text{when } t=1$$

$$TCESC_t = TCESC_{t-1} \times (1+ESCRAT^*_{t-1} + RCESC^*)$$

$$\text{when } t > 1$$

Where CONVRT* - conversion factors from input to base year dollars

$ESCRAT^*_{t-1}$ - nominal escalation factor to convert year t-1 dollars to year t dollars

RCESC* - Real escalation rate for conservation costs.

With the exception of the recursive term, $TCESC_{t-1}$, all elements are data items. (CONVRT and ESCRAT are from the BKGD data set.) It should be noted that when data is input in base year dollars, the value of CONVRT defaults to one.

TABLE A-7

SFCT Data Set

Data for Calculating Spent Fuel Costs

Variable	Description
IYRFNF	Last year in which spent fuel costs will be recovered through required revenues
IYRSTF	First year in which spent fuel costs will be recovered through required revenues
PRTSFC	Logical variable. If true, a report on spent fuel revenue requirement impacts is produced
TOTSF	Present value of total spent fuel costs (in millions of dollars).

where $SFRR_t$ - Spent fuel revenue requirement impacts in current dollar terms in year t

$PVVECT_t$ - Present value factor which, muliplicatively, converts current dollar costs to their present value equivalents in year t.

An allowance for revenue taxes is also made.

A-8 Decommissioning Costs

Like spent fuel costs described previously, an independent estimate of decommissioning costs is developed off line (see Appendix E) and the results are used by CANS to develop annual revenue requirements in the same manner used for spent fuel costs.

The decommissioning cost module uses the DCCT data set described in Table A-8. It calculates the annual revenue requirements in present value terms

$$DCRRPV_t = 0 \quad \text{if} \quad IYEAR_t < IYRSTD$$

$$\text{or} \quad IYEAR > IYRFND$$

$$= \frac{TOTDC}{IYRFND - IYRSTD + 1} \quad \text{If } IYRSTD \leq IYEAR_t \leq IYRFND$$

where $DCRRPV_t$ - Decommissioning revenue requirement impact in present value terms in year t

IYRSTD - First year in which decommissioning costs will be reflected through rates

IYEAR - Calendar year corresponding to index year t

IYRFND - Last year in which decommissioning costs will be reflected through rates.

The revenue requirement impact in current dollar terms is

$$DCRR_t = DCRRPV_t / PVVECT_t$$

where $DCRR_t$ - Decommissioning revenue requirement impacts in current dollar terms

$PVVECT_t$ - Present value factor which, multiplicatively, converts current dollar costs to their present value equivalents in year t.

An allowance for revenue taxes is also made.

TABLE A-8

DCCT Data Set

Data for Calculating Decommissioning Costs

Variable	Description
IYRFND	Last year in which decommissioning costs will be recovered through required revenues
IYRSTD	First year in which decommissioning costs will be recovered through required revenues
PRTDC	Logical variable. If true, a report on decommissioning revenue requirement impacts is produced.
TOTDC	Present value of total decommissioning costs (millions of dollars)

A-9. Nuclear Fuel Costs

Nuclear Fuel costs are calculated based upon user supplied data defining the capacity of each generating unit, its capacity factor, and its cost per kilowatt-hour of electricity generated. The first two items are described above in Section A-6 on makeup power costs. The last is calculated based upon data from the MFUL data set described in Table A-9. In the remainder of this Section, we describe the development of nuclear fuel costs for the first nuclear unit. When a second unit is also present, precisely symmetric calculations are performed for it.

The revenue requirement contribution of nuclear fuel by the first generating unit is

$$FLNRR_{1,t} = FLNKWH_{1,t} \times SCHWH1_{i}/1000.0$$

where $FLNRR_{1,t}$ - Revenue requirement of unit 1 Fuel in in year t (millions of dollars)

$FLNKWH_{1,t}$ - Fuel cost per kilowatt hour of unit 1 in year t (mils per kilowatt hour)

$SCLWH1_{t}$ - Generation of unit 1 in year t (gigawatt-hours).

$FLNKWH_{1,t}$ is the new element. It reflects allowances for return on nuclear fuel investment and revenue taxes.

$$FLNKWH_{1,t} = \frac{(1 + FULNWC^{*}) \times FULNBS_{1}^{*} \times TFESC_{t}}{(1 - REVTXR^{*})}$$

$TFESC_{t}$ is the nuclear fuel escalation factor in this module. It is calculated similarly to its counterparts in other modules.

$$TFESC_{t} = CONVRT^{*} \quad \text{when } t = 1$$

$$= TFESC_{t-1} \times (1 + ESCRAT_{t-1} + FULMGR^{*}) \quad \text{when } t > 1$$

TABLE A-9

NFUL Data Set

Data for Calculating Nuclear Fuel Costs

Variable	Description
$FULNBS_i$	Base year fuel cost of nuclear unit i ($i \leq 2$) in Mils per Kilowatt-hour.
FULNGR	Real escalation rate for nuclear fuel
FULNWC	Working capital multiplier for nuclear fuel
PRTNFL	Logical variable. If true, a report on nuclear fuel costs is generated.

A-10. Other Costs

As defined here, other costs represent one time costs required to maintain a nuclear plant in operation. CANS allows the user to separate these costs into those that will be capitalized and those that will be directly reflected in required revenues as expense items. In the former case, costs are reflected in required revenues by reference to a levelized fixed charge factor and an asset book life.

This module employs the XTRA data set detailed in Table A-10. The required revenue impact is the sum of the impacts of the expensed and the capitalized items.

$$XTRR_t = XEXPRR_t + XCAPRR_t$$

where $XTRR_t$ - Total revenue impact in year t

$XEXPRR_t$ - Revenue impact of capitalized items in year t

$XCAPRR_t$ - Revenue impact of capitalized items in year t

The revenue effect of expenses items is

$$XEXPRR_t = \sum_{i=1}^{50} \Psi_{i,t} \times XTLAP_i^* \times XTCFCF_i^*/(1-REVTXR^*)$$

$$\Psi_{i,t} = 1 \text{ if } IXTCAP_i^* - IBASE^{*+1} \leq t \leq IXTCAP_i^* + IXLIFE_i^* - IBASE^*$$

$$= 0 \text{ Otherwise}$$

TABLE A-10

XTRA Data Set

Data for Calculating Extraordinary Costs

Variable	Description
$IXLIFE_i$	Book life of capitalized expenditure i ($i \leq 50$)
$IXTCAP_i$	Year in which capitalized expenditure i is first reflected in required revenues
$IXTEXP_j$	Year in which non-capitalized expenditure j ($j \leq 50$) is made
PRTXTR	Logical variable. If true, a report on extraordinary costs is generated
$XTCAP_i$	Capitalized expenditure i (millions of $IXTCAP_i$ dollars)
$XTCFCF_i$	Levelized fixed charge factor associated with capitalized expenditure i
$XTEXP_j$	Non-capitalized expenditure i (millions of $IXTEXP_j$ dollars)

A-11. Cost Comparison Report

In addition to the cost estimation program, the CANS system includes a separate program (RETREP) which compares the costs of any two user specified scenarios. The logic of the program is very simple and intuitively straightforward. Each module of the cost estimation program writes an alpha-numeric identifier and the estimated annual costs to an intermediate file where it is saved. RETREP reads intermediate files for each of two cases and writes four reports.

1,2. For each case, a summary of the annual costs by component as well as aggregations over components and over years.

3. The differential cost of the second scenario relative to the first expressed in mixed current dollars.

4. The differential costs cited above but expressed in present value terms.

The RETREP program requires no new data, relying on the intermediate files just described and the BKGD data set described in Section A-2.

With one minor exception, the calculations performed by RETREP are limited to simple summing and subtracting and therefore will not be described in detail. The single exception is the column of the differential cost reports entitled "Annual % Impact." This column is calculated as the annual differential cost of scenario 2 as a percentage of total company required revenues. The latter is calculated as base year required revenues (RRBAS* in Table A-1) escalated according to both nominal and real inflation rates (ESCRAT* and RRGR*, respectively in the same table).

APPENDIX B

NUCLEAR POWER PLANT

OPERATION AND MAINTENANCE

COSTS

ESRG

August 1982

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B-1 NUCLEAR O&M DATABASE PREPARATION

O&M Costs

Operations and maintenance (O&M) cost data was collected from government documents and utility filings with government agencies. For the years preceeding 1978, the annual editions of the FERC survey of utility reports, "Steam Electric Plant Construction Costs and Annual Production Expenses" were utilized. For the year 1978 a proof of the 1978 edition of the steam survey was used in conjunction with the utilities' 1978 FERC Form 1 filings. The 1979 costs are based exclusively on Form 1 filings except for costs for the Cooper and Fort Calhoun stations which were obtained directly from the utilities.*

All data from the years 1970 through 1979 were included in this survey except the following: Humboldt station was not in operation during the years 1978 and 1979; the O&M costs for these years were excluded from this survey. Three Mile Island 2 was not included. Three Mile Island 1 was included, but data for the year 1979 was excluded because it was not in operation. Some further exclusions, mostly of abnormal partial years, will be described later.**

Table B-1 presents the annual O&M costs as reported. Table B-2 presents these costs in constant 1978 dollars by multiplying costs in Table B-1 by the GNP inflator, Table B-3.

Analysis of nuclear plant costs as presented in Tables B-1 or B-2 is difficult primarily because many stations are composed of more than one unit. Since utilities with multiple unit stations do not have to report O&M cost data on FERC forms separately by unit, the present analysis does not separate the cost data by unit.

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* Private communication, Verdel Goldberg at Omaha Public Power and Bob Buntain at Nebraska Public Power.

** In addition, Shippingport and LaCross were not included because data could not be obtained for years prior to 1978.

TABLE B-1

OPERATIONS AND MAINTENANCE COSTS IN MIXED CURRENT DOLLARS

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
DUANE ARNOLD	-	-	-	-	6.29	7.68	14.10	15.02	23.83	19.06
BEAVER VALLEY	-	-	-	-	-	-	8.80	18.36	28.35	28.63
BIG ROCK POINT	16.86	20.10	22.41	25.17	35.92	41.02	50.52	81.35	57.86	146.56
BROWNS FERRY	-	-	-	-	-	4.96	7.55	6.38	14.35	17.37
BRUNSWICK	-	-	-	-	-	35.50	13.31	17.96	16.86	21.65
CALVERT CLIFFS	-	-	-	-	-	8.06	11.09	13.75	15.52	21.73
DONALD C. COOK	-	-	-	-	-	4.44	6.71	9.54	9.68	12.44
COOPER	-	-	-	-	7.50	9.49	13.12	13.13	10.68	13.15
CONNECTICUT YANKEE	7.79	5.70	6.52	11.05	8.58	16.31	16.38	16.43	15.19	32.91
CRYSTAL RIVER	-	-	-	-	-	-	-	11.66	19.23	29.54
DAVIS BESSE	-	-	-	-	-	-	-	122.92	15.56	22.69
DRESDEN	4.58	3.31	5.09	5.04	9.32	18.33	16.76	15.04	18.90	24.84
JOSEPH M. FARLEY	-	-	-	-	-	-	-	7.11	15.45	28.53
JAMES A. FITZPATRICK	-	-	-	-	-	18.70	13.37	21.73	23.81	31.41
FORT CALHOUN	-	-	-	4.07	7.67	13.40	16.74	19.09	18.24	19.11
ROBERT E. GINNA	-	5.82	7.90	6.84	10.43	12.76	14.23	15.36	18.99	24.79
EDWIN I. HATCH	-	-	-	-	-	-	6.90	11.53	31.87	12.07
HUMBOLDT BAY	9.83	14.70	14.24	14.52	16.98	19.22	31.43	48.90	25.95	23.52
INDIAN POINT 1	13.20	14.95	26.23	-	-	-	-	-	-	-
INDIAN POINT 2	-	-	-	45.70	14.74	15.27	21.16	19.13	32.60	37.78
INDIAN POINT 3	-	-	-	-	-	-	7.50	13.11	24.16	29.93
KEWAUNEE	-	-	-	-	24.90	11.51	20.05	20.42	19.50	21.16
MAINE YANKEE	-	-	-	5.04	6.54	7.88	6.58	10.52	13.52	12.47
MILLSTONE 1	-	4.93	11.63	11.57	14.86	18.28	21.27	19.15	24.92	34.94
MILLSTONE 2	-	-	-	-	-	.54	13.46	21.40	27.45	27.01
MONTICELLO	-	5.56	4.61	8.99	9.30	15.67	11.87	19.94	16.40	19.00
NORTH ANNA	-	-	-	-	-	-	-	-	13.17	21.52
NUCLEAR ONE	-	-	-	-	-	4.92	7.19	10.02	14.50	22.64
NINE MILE POINT	2.81	4.52	5.86	7.42	10.25	9.52	8.74	15.97	11.20	19.12
OCONEE	-	-	-	2.91	6.85	4.83	6.49	9.70	11.47	15.57
OYSTER CREEK	3.00	4.76	5.96	9.71	16.43	18.94	16.00	22.82	24.46	20.08
PALISADES	-	-	-	4.27	15.92	12.97	13.31	8.88	20.80	35.60
PEACH BOTTOM	-	-	-	-	3.35	6.04	14.64	22.33	18.81	21.59
PILGRIM	-	-	2.85	7.16	14.22	10.96	24.83	22.87	21.17	27.44
POINT BEACH	-	-	9.22	3.68	5.28	6.22	6.66	8.09	7.47	12.59
PRARIE ISLAND	-	-	-	4.81	7.85	6.94	14.89	16.34	13.59	14.67
QUAD CITIES	-	-	3.46	3.99	5.84	9.36	10.60	11.25	14.05	19.79
RANCHO SECO	-	-	-	-	-	17.75	7.84	8.85	12.89	14.95
H.B. ROBINSON	-	3.44	2.54	6.58	6.83	9.09	8.43	9.41	20.51	21.63
ST. LUCIE	-	-	-	-	-	-	42.19	9.47	19.89	18.10
SALEM	-	-	-	-	-	-	-	23.15	20.49	43.63
SAN ONOFRE	5.13	5.53	8.07	13.39	12.75	19.88	24.06	18.63	33.30	26.76
SURRY	-	-	31.95	3.95	6.37	9.85	9.55	10.31	12.47	15.04
THREE MILE ISLAND 1	-	-	-	-	12.65	17.78	22.30	16.61	22.44	-
TROJAN	-	-	-	-	-	-	8.89	12.62	14.08	15.70
TURKEY POINT	-	-	4.84	4.44	6.94	10.41	13.36	10.85	13.36	16.17
VERMONT YANKEE	-	-	9.00	9.18	10.54	14.23	14.65	18.10	20.72	26.31
YANKEE ROWE	8.90	9.97	16.64	13.93	22.57	26.15	28.43	39.81	43.73	57.99
ZION	-	-	-	1.02	6.87	6.12	8.78	8.70	9.80	13.00

TABLE B-2

OPERATIONS AND MAINTENANCE COSTS IN CONSTANT 1978 DOLLARS

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
DUANE ARNOLD..........	-	-	-	-	8.25	9.18	16.03	16.11	23.83	17.80
BEAVER VALLEY.........	-	-	-	-	-	-	10.00	19.71	28.35	26.75
BIG ROCK POINT........	28.06	31.82	34.08	36.18	47.08	49.05	57.45	87.29	57.86	136.90
BROWNS FERRY..........	-	-	-	-	-	5.93	8.58	6.85	14.35	16.22
BRUNSWICK.............	-	-	-	-	-	42.45	15.14	19.27	16.86	20.22
CALVERT CLIFFS........	-	-	-	-	-	9.64	12.61	14.75	15.52	20.30
DONALD C. COOK........	-	-	-	-	-	5.31	7.63	10.23	9.68	11.62
COOPER................	-	-	-	-	9.82	11.35	14.92	14.09	10.68	12.29
CONNECTICUT YANKEE....	12.96	9.03	9.91	15.88	11.25	19.51	18.63	17.63	15.19	30.74
CRYSTAL RIVER.........	-	-	-	-	-	-	-	12.51	19.23	27.60
DAVIS BESSE...........	-	-	-	-	-	-	-	131.89	15.56	21.20
DRESDEN...............	7.62	5.23	7.74	7.25	12.22	21.91	19.06	16.14	18.90	23.20
JOSEPH M. FARLEY......	-	-	-	-	-	-	-	7.63	15.45	26.65
JAMES A. FITZPATRICK..	-	-	-	-	-	22.37	15.21	23.32	23.81	29.35
FORT CALHOUN..........	-	-	-	5.85	10.05	16.02	19.04	20.48	18.24	17.85
ROBERT E. GINNA.......	-	9.21	12.01	9.83	13.67	15.26	16.18	16.48	18.99	23.16
EDWIN I. HATCH........	-	-	-	-	-	-	7.85	12.37	31.87	11.27
HUMBOLDT BAY..........	16.35	23.28	21.65	20.87	22.26	22.99	35.74	52.48	25.95	21.97
INDIAN POINT 1........	21.97	23.68	39.88	-	-	-	-	-	-	-
INDIAN POINT 2........	-	-	-	65.68	19.32	18.26	24.07	20.52	32.60	35.29
INDIAN POINT 3........	-	-	-	-	-	-	8.53	14.07	24.16	27.96
KEWAUNEE..............	-	-	-	-	32.64	13.77	22.80	21.91	19.50	19.77
MAINE YANKEE..........	-	-	-	7.25	8.57	9.42	7.48	11.29	13.52	11.65
MILLSTONE 1...........	-	7.81	17.69	16.63	19.48	21.86	24.19	20.55	24.92	32.64
MILLSTONE 2...........	-	-	-	-	-	.64	15.31	22.96	27.45	25.23
MONTICELLO............	-	8.80	7.01	12.92	12.19	18.74	13.49	21.40	16.40	17.75
NORTH ANNA............	-	-	-	-	-	-	-	-	13.17	20.10
NUCLEAR ONE...........	-	-	-	-	-	5.88	8.18	10.75	14.50	21.15
NINE MILE POINT.......	4.68	7.16	8.91	10.66	13.43	11.39	9.94	17.14	11.20	17.86
OCONEE................	-	-	-	4.18	8.97	5.77	7.38	10.41	11.47	14.55
OYSTER CREEK..........	5.00	7.54	9.07	13.95	21.53	22.65	18.19	24.49	24.46	18.76
PALISADES.............	-	-	-	6.14	20.86	15.52	15.13	9.53	20.80	33.26
PEACH BOTTOM..........	-	-	-	-	4.39	7.22	16.65	23.96	18.81	20.17
PILGRIM...............	-	-	4.33	10.29	18.64	13.10	28.23	24.54	21.17	25.63
POINT BEACH...........	-	-	14.02	5.29	6.92	7.44	7.57	8.65	7.47	11.76
PRARIE ISLAND.........	-	-	-	6.91	10.29	8.30	16.93	17.53	13.59	13.70
QUAD CITIES...........	-	-	5.26	5.73	7.65	11.20	12.05	12.07	14.05	18.49
RANCHO SECO...........	-	-	-	-	-	21.22	8.91	9.49	12.89	13.96
H.B. ROBINSON.........	-	5.45	3.87	9.46	8.95	10.86	9.59	10.10	20.51	20.21
ST. LUCIE.............	-	-	-	-	-	-	47.98	10.16	19.89	16.91
SALEM.................	-	-	-	-	-	-	-	24.84	20.49	40.75
SAN ONOFRE............	8.54	8.76	12.27	19.25	16.71	23.77	27.36	19.99	33.30	25.00
SURRY.................	-	-	48.58	5.67	8.35	11.78	10.86	11.06	12.47	14.05
THREE MILE ISLAND 1...	-	-	-	-	16.57	21.26	25.36	17.82	22.44	-
TROJAN................	-	-	-	-	-	-	10.11	13.54	14.08	14.67
TURKEY POINT..........	-	-	7.36	6.38	3.09	12.45	15.20	11.65	13.36	15.11
VERMONT YANKEE........	-	-	13.68	13.19	13.81	17.01	16.66	19.42	20.72	24.58
YANKEE ROWE...........	14.82	15.79	25.30	20.01	29.58	31.28	32.33	42.71	43.73	54.17
ZION..................	-	-	-	1.46	9.00	7.32	9.99	9.34	9.80	12.15

TABLE B-3

GNP DEFLATORS
(Used to Compute 1978 Constant Dollars)

Years	Deflators
1970	1.66429
1971	1.58352
1972	1.5205
1973	1.43715
1974	1.31055
1975	1.19583
1976	1.13716
1977	1.07304
1978	1.
1979	0.918731

Based on 1980 Report of the President's Council of Economic Advisors

The present study deals with this problem by dividing total annual O&M costs by the station's capacity in megawatt-years for the respective year. This complication is necessary because new capacity does not materialize for commercial operation on the first day of the year. For example, we might have a 1000 MW unit on-line for a whole year, and another 1000 MW unit that comes into service at the same station on July 1st. The first unit contributes a full year of operation or 1000 MW-years, while the second one, only on-line for half a year, contributes 500 MW-years of capacity in that year. The station as a whole, then had 1500 MW-years of capacity for the year.

Standardizing costs on the basis of a unit of capacity per operating year basis also has the following advantages: it enables easy comparison of O&M costs on a cost per unit of capacity basis and it enables first years of operation of stations with single units to be included in the data base even when the unit went on-line during the calendar year.* Table B-4 presents the estimated megawatt-years of capacity for each station for each year of the survey. Each unit's in-service date was taken from the FERC steam station cost survey. In situations where only the first month of operation was reported, rather than an exact date, the in-service date was taken to be the mid-point of the month. A unit's capacity was taken to be its FERC reported net continuous capability.

As can be seen from Table B-4, operating time for units in their first year of operation was frequently very small. It was found that cost fluctuated widely for units with less than 10% of a year's operation. This may be a result of inaccurate reporting of the exact on-line data or possibly inaccurate expensing of O&M costs for the first year. At any rate, operation for less

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* Analysis of costs on a kilowatt-hour basis would have also eliminated these problems. This option was rejected because it is generally believed that nuclear O&M costs are not proportional, or even strongly related to a plant's capacity factor. Even so, uncertainty about future capacity factors would make cost projection difficult.

TABLE B-4

ANNUAL MEGAWATT-YEARS
OF CAPACITY FOR EACH STATION

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
DUANE ARNOLD	NA	NA	NA	NA	286.	380.	380.	380.	380.	500.
BEAVER VALLEY	NA	NA	NA	NA	NA	NA	262.	[illegible]	800.	900.
BIG ROCK	63.	63.	63.	63.	63.	63.	63.	63.	63.	63.
BROWNS FERRY	NA	NA	NA	NA	NA	1325.	2134.	3026.	3201.	3231.
BRUNSWICK	NA	NA	NA	NA	NA	826.	797.	1411.	1500.	1753.
CALVERT CLIFFS	NA	NA	NA	NA	NA	528.	660.	1066.	1675.	1675.
DONALD C COOK	NA	NA	NA	NA	NA	374.	1030.	1030.	1622.	2150.
COOPER	NA	NA	NA	NA	259.	778.	778.	778.	778.	778.
CONNECTICUT YANKEE	575.	575.	575.	575.	575.	575.	575.	575.	575.	575.
CRYSTAL RIVER	NA	NA	NA	NA	NA	NA	NA	652.	812.	812.
DAVIS BESSE	NA	NA	NA	NA	NA	NA	NA	2.4	906.	906.
DRESDEN	501.	1101.	1795.	1795.	1795.	1797.	1795.	1795.	1795.	1795.
JOSEPH M FARLEY	NA	NA	NA	NA	NA	NA	NA	63.	790.	790.
JAMES A FITZPATRICK	NA	NA	NA	NA	NA	369.	800.	800.	800.	360.
FORT CALHOUN	NA	NA	NA	130.	445.	445.	445.	445.	145.	445.
ROBERT E GINNA	NA	411.	517.	517.	517.	517.	517.	517.	517.	517.
HATCH	NA	NA	NA	NA	NA	2.	850.	850.	850.	850.
HUMBOLDT BAY	63.	63.	63.	63.	63.	63.	63.	63.	63.	63.
INDIAN POINT 1	265.	265.	265.	NA	NA	NA	NA	NA	NA	NA
INDIAN POINT 2	NA	NA	NA	325.	864.	864.	864.	864.	864.	864.
INDIAN POINT 3	NA	NA	NA	NA	NA	NA	128.	965.	965.	965.
KEWANEE	NA	NA	NA	NA	290.	535.	535.	535.	535.	535.
MAINE YANKEE	NA	NA	NA	800.	900.	830.	500.	310.	407.	309.
MILLSTONE 1	NA	660.	660.	660.	660.	660.	660.	660.	660.	660.
MILLSTONE 2	NA	NA	NA	NA	NA	12.	912.	812.	812.	812.
MONTICELLO	NA	257.	557.	557.	557.	557.	557.	557.	557.	557.
NORTH ANNA	NA	NA	NA	NA	NA	NA	NA	NA	495.	907.
NUCLEAR ONE	NA	NA	NA	NA	NA	820.	876.	836.	836.	836.
NINE MILE POINT	610.	610.	610.	610.	610.	610.	610.	870.	620.	620.
OCONEE	NA	NA	NA	313.	2000.	2500.	2500.	2586.	2580.	2530.
OYSTER CREEK	650.	650.	650.	650.	650.	650.	650.	650.	650.	650.
PALISADES	NA	NA	NA	740.	740.	749.	740.	740.	740.	740.
PEACH BOTTOM	NA	NA	NA	NA	535.	2093.	2094.	2090.	2090.	2090.
PILGRIM	NA	NA	40.	670.	670.	670.	670.	670.	670.	670.
POINT BEACH	NA	NA	250.	990.	990.	990.	990.	990.	990.	990.
PRARIE ISLAND	NA	NA	NA	21.	537.	1040.	1040.	1040.	1036.	1046.
QUAD CITIES	NA	NA	500.	1570.	1570.	1570.	1573.	1570.	1576.	1578.
RANCHO SECO	NA	NA	NA	NA	NA	650.	919.	918.	918.	919.
H B ROBINSON	NA	557.	700.	700.	700.	700.	700.	730.	700.	700.
ST LUCIE	NA	NA	NA	NA	NA	NA	795.	795.	795.	795.
SALEM	NA	[illegible]	NA	NA	NA	NA	NA	509.	1089.	1559.
SAN ONOFRE	436.	436.	436.	436.	430.	436.	436.	436.	436.	436.
SURRY	NA	NA	1..	1293.	1550.	1550.	1550.	1550.	1550.	1550.
THREE MILE ISLAND 1	NA	NA	NA	NA	265.	30.	800.	800.	800.	NA
TROJAN	NA	NA	NA	NA	NA	NA	600.	1080.	1080.	1080.
TURKEY POINT 3 AND 4	NA	NA	51.	715.	1392.	1392.	1392.	1392.	1392.	1392.
VERMONT YANKEE	NA	NA	46.	540.	540.	540.	540.	540.	540.	540.
YANKEE ROWE	175.	175.	175.	175.	175.	175.	175.	175.	175.	175.
ZION	NA	NA	NA	436.	1350.	2080.	2080.	2080.	2080.	2080.

than a month appeared to be highly unrepresentative of normal operation. Therefore, single units with less than 10% of a year's operation were dropped from analysis. Additionally, several years' costs were dropped because of other first-year abnormalities.* Table B-5 summarizes the excluded first year costs. Once abnormal first years of operation were excluded, the final data base could be prepared by dividing real annual costs (in constant 1978 dollars) by the station capacity for that year. Table B-6 presents the final data base used in this study. Table B-7 presents costs per kilowatt-year in mixed current dollars for reference. Kilowatt-years were found to be a more convenient unit of analysis than megawatt-years for the purposes of this report. O&M costs per kilowatt-year are megawatt-year costs divided by 1000.

Other Variables

Data on plant characteristics were used in addition to O&M costs. Tables B-8, B-9, and B-10 present these data in summary form. The column titles are the variable names used in the study. Plant characteristic data is taken from the NUS publication, "Commercial Nuclear Power Plants."

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* (1) Brunswick first year costs in 1975 were excluded because reported costs were more than twice the next year's costs on a per KW-year basis. (2) Cost data for Indian Point 2 was excluded for the years 1973 and 1974 because Indian Point 1 was in operation then and they were reported on the same account. Indian Point 1 was subsequently shut down. (3) Kewanee, Point Beach, and Rancho Seco also ad their first year's data excluded on the basis of having abnormally high reported costs. (4) Palisades was excluded for its first two years of operation because it was not in full power operation and had abnormally low reported costs compared to subsequent years. These data were excluded because the regression procedures would give them equal weight with other full year reported costs which have a much higher degree of certainty associated with them. Statistical weighting, called heteroskedastic correction could be attempted, but is beyond the scope of this study.

TABLE B-5

POWER PLANTS WITH FIRST YEAR OPERATION EXCLUDED FROM DATA BASE

			Fraction of Year	First Year Costs STAN(t)	Second Year Costs STAN(t+1)
#1	5:	Brunswick	.1589	35.5	13.31
#2	11:	Davis-Besse	.0027	122.91	16.45
#3	18:	Hatch	.0027	NR	
#4	21:	Indian Point 2	.3767	Indian Pt. #1 incl. in 1st 2 years	
#5	23:	Kewanee	.5425	24.90	11.51
#6	27:	Millstone 2	.01644	.523	13.46
#7	34:	Palisades*	1.00	1.0176	4.27
#8	36:	Pilgrim	.0603	2.85	7.1597
#9	37:	Point Beach	.2521	9.22	3.68
#10	38:	Prarie Island	.0411	4.8095	7.80
#11	40:	Rancho Seco	.7123	17.75	7.83
#12	42:	St. Lucie	.0968	42.19**	9.4
#13	46:	Surry	.0247	31.94	3.94
#14	50:	Turkey Point	.0739	5.04	4.63
#15	51:	Vt. Yankee	.0849	9.	9.1
#16	53:	Zion	.2096	1.01	4.44
#17	13:	Farley	.08		

TOTALS:

CAUSE ≡ {
NON STAN or FRAC RELATED: 2
FRAC TOO SMALL: 9
$STAN_{(t)}$ TOO HIGH: 4
$STAN_{(t)}$ TOO LOW: 2
}

COSTS HIGH: 8
COSTS LOW: 7
NA: 2

* Not in full power operation during 1st full year.

** Per KWH basis.

TABLE B-6

NUCLEAR STATION COSTS PER KILOWATT-YEAR
IN CONSTANT 1978 DOLLARS

[illegible]	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
DUANE ARNOLD	0.	0.	0.	0.	0.24	9.16	16.03	16.[illegible]	23.03	17.51
BEAVER VALLEY	0.	0.	0.	0.	0.	0.	10.	19.7	20.35	26.3
BIG ROCK	28.05	31.02	34.07	34.17	47.07	49.09	57.05	87.29	57.05	134.64
BROWNS FERRY	0.	0.	0.	0.	0.	3.93	8.50	4.09	14.34	15.95
BRUNSWICK	0.	0.	0.	0.	0.	0.	15.19	19.2[illegible]	14.85	19.00
CALVERT CLIFFS	0.	0.	0.	0.	0.	9.64	12.61	14.75	15.52	19.96
DONALD C COOK	0.	0.	0.	0.	0.	5.31	7.63	10.22	9.40	11.43
COOPER	0.	0.	0.	0.	9.02	11.35	14.92	14.09	10.67	12.00
CONNECTICUT YANKEE	12.96	9.03	9.91	15.07	11.24	19.5	18.62	17.62	15.19	30.23
CRYSTAL RIVER	0.	0.	0.	0.	0.	0.	0.	12.5	19.22	27.14
DAVIS BESSE	0.	0.	0.	0.	0.	0.	0.	0.	15.55	20.04
DRESDEN	7.62	5.23	7.76	7.24	12.21	21.91	19.06	16.12	10.9	22.01
JOSEPH M FARLEY	0.	0.	0.	0.	0.	0.	0.	0.	15.45	26.21
JAMES A FITZPATRICK	0.	0.	0.	0.	0.	0.	15.2	27.31	23.0	20.06
FORT CALHOUN	0.	0.	0.	5.04	10.05	14.02	19.03	20.4[illegible]	10.23	17.55
ROBERT E GINNA	0.	9.[illegible]	1[illegible].	9.82	13.66	15.25	16.17	16.40	10.99	22.77
HATCH	0.	[illegible]	[illegible]	0.	0.	0.	7.04	12.3[illegible]	14.43	14.6[illegible]
HUMBOLDT BAY	14.35	23.27	21.64	20.07	22.25	22.90	35.73	52.47	0.	0.
INDIAN POINT 1	21.96	23.6[illegible]	39.07	0.	0.	0.	0.	0.	0.	0.
INDIAN POINT 2	0.	0.	[illegible]	0.	0.	10.26	29.06	20.92	32.6	34.71
INDIAN POINT 3	0.	0.	0.	0.	0.	0.	8.52	14.07	24.16	27.5
KEWAUNEE	0.	0.	0.	0.	0.	13.78	22.0	20.91	19.49	19.40
MAINE YANKEE	0.	0.	0.	7.24	0.57	9.41	7.47	11.29	13.52	11.45
MILLSTONE 1	0.	7.91	17.60	14.62	19.47	21.06	24.19	29.34	24.92	32.09
MILLSTONE 2	0.	0.	0.	0.	0.	0.	15.3	27.96	27.44	24.01
MONTICELLO	0.	8.8	7.	12.91	12.10	10.74	13.49	21.4	14.4	17.45
NORTH ANNA	0.	0.	0.	0.	0.	0.	0.	0.	13.17	19.77
NUCLEAR ONE	0.	0.	0.	0.	0.	5.07	8.10	10.75	14.5	20.79
NINE MILE POINT	4.60	7.14	8.91	10.65	13.42	11.30	9.93	17.13	11.19	17.56
OCONEE	0.	0.	0.	4.10	0.97	5.77	7.37	10.41	11.47	14.3
OYSTER CREEK	0.	7.54	9.06	13.95	21.57	22.64	10.19	24.40	24.45	10.45
PALISADES	0.	0.	0.	4.19	20.05	15.51	15.13	9.52	20.0	32.7
PEACH BOTTOM	0.	0.	0.	0.	4.30	7.2[illegible]	16.49	23.96	10.0	19.0[illegible]
PILGRIM	0.	0.	0.	10.20	10.63	13.1	20.23	24.53	21.17	25.21
POINT BEACH	0.	0.	0.	5.2[illegible]	6.92	7.43	7.57	8.60	7.4[illegible]	11.56
PRAIRIE ISLAND	0.	0.	0.	0.	16.[illegible]0	8.3	16.[illegible]3	17.53	13.50	13.4[illegible]
QUAD CITIES	0.	0.	5.25	5.72	7.64	11.19	12.05	12.07	14.04	10.18
RANCHO SECO	0.	0.	0.	0.	0.	0.	8.91	9.49	12.0[illegible]	13.73
H B ROBINSON	0.	5.45	3.06	9.46	0.94	10.06	9.50	10.1	26.5	19.0[illegible]
ST LUCIE	0.	0.	0.	0.	0.	0.	0.	10.[illegible]5	19.09	16.63
SALEM	0.	0.	0.	0.	0.	0.	0.	24.03	20.48	40.06
SAN ONOFRE	8.53	8.78	12.26	19.20	16.	23.77	27.35	19.99	33.29	24.50
SURRY	0.	0.	0.	5.67	0.35	11.76	10.05	11.06	1[illegible].44	13.01
THREE MILE ISLAND 1	0.	0.	0.	0.	16.57	21.26	25.35	17.02	22.44	0.
TROJAN	0.	0.	0.	0.	0.	0.	10.[illegible]	13.54	14.07	14.42
TURKEY POINT 3 AND 4	0.	0.	0.	4.37	9.09	12.45	15.69	11.64	17.36	14.05
VERMONT YANKEE	0.	0.	0.	13.19	13.01	17.01	14.66	15.42	26.72	24.17
YANKEE ROWE	14.81	13.70	25.3	20.01	29.50	31.27	32.32	42.75	63.73	53.20
ZION	0.	0.	0.	0.	0.99	7.37	9.90	9.33	9.29	11.94

TABLE B-6

NUCLEAR STATION COSTS PER KILOWATT-HOUR
IN CONSTANT 1978 DOLLARS

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
DUANE ARNOLD	0.	0.	0.	0.	8.24	9.18	14.03	14.11	23.03	17.51
BEAVER VALLEY	0.	0.	0.	0.	0.	0.	16.	19.7	20.35	26.3
BIG ROCK	28.05	31.02	34.07	36.17	47.07	49.04	57.45	87.29	57.05	134.64
BROWNS FERRY	0.	0.	0.	0.	0.	5.93	8.50	6.04	14.34	15.95
BRUNSWICK	0.	0.	0.	0.	0.	0.	15.14	19.27	14.05	19.08
CALVERT CLIFFS	0.	0.	0.	0.	0.	9.64	12.41	14.75	15.52	19.96
DONALD C COOK	0.	0.	0.	0.	0.	5.31	7.63	10.27	9.60	11.43
COOPER	0.	0.	0.	0.	9.02	11.35	14.92	14.09	10.67	12.08
CONNECTICUT YANKEE	12.96	7.03	9.91	15.07	11.24	19.5	10.67	17.42	15.19	30.23
CRYSTAL RIVER	0.	0.	0.	0.	0.	0.	0.	12.5	19.22	27.14
DAVIS BESSE	0.	0.	0.	0.	0.	0.	0.	0.	15.55	20.04
DRESDEN	7.62	5.23	7.74	7.24	12.21	21.91	19.06	16.12	10.9	22.01
JOSEPH M FARLEY	0.	0.	0.	0.	0.	0.	0.	0.	15.45	26.21
JAMES A FITZPATRICK	0.	0.	0.	0.	0.	0.	15.2	23.31	23.0	20.06
FORT CALHOUN	0.	0.	0.	5.04	10.05	16.02	19.03	20.47	10.23	17.55
ROBERT E GINNA	0.	[illegible]	[illegible]	9.02	13.66	15.25	16.17	16.41	10.99	22.77
HATCH	0.	[illegible]	[illegible]	0.	0.	0.	7.04	12.31	14.43	14.47
HUMBOLDT BAY	16.35	23.27	21.64	26.07	22.25	22.90	35.73	52.47	0.	0.
INDIAN POINT 1	21.96	23.67	39.07	0.	0.	0.	0.	0.	0.	0.
INDIAN POINT 2	0.	0.	[illegible]	0.	0.	10.26	24.06	20.92	32.6	34.71
INDIAN POINT 3	0.	0.	0.	0.	0.	0.	8.52	14.07	24.16	27.5
KEWAUNEE	0.	0.	[illegible]	0.	0.	13.76	22.0	21.91	19.49	19.44
MAINE YANKEE	0.	0.	0.	7.24	8.57	9.41	7.47	11.29	13.52	11.45
MILLSTONE 1	0.	7.01	17.60	16.62	19.47	21.06	24.19	20.34	24.92	32.09
MILLSTONE 2	0.	0.	0.	0.	0.	0.	15.3	22.96	27.44	24.01
MONTICELLO	0.	8.8	7.	12.91	17.18	10.24	13.49	21.4	16.4	17.45
NORTH ANNA	0.	0.	0.	0.	0.	0.	0.	0.	13.17	19.77
NUCLEAR PPC	0.	0.	0.	0.	0.	5.07	8.10	19.75	14.5	20.79
NINE MILE POINT	4.60	7.14	8.91	10.65	13.42	11.30	9.93	17.13	11.19	17.26
OCONEE	0.	0.	0.	4.18	8.97	5.77	7.37	10.41	11.67	14.3
OYSTER CREEK	0.	7.54	9.06	13.95	21.52	22.64	18.19	24.40	24.45	18.45
PALISADES	0.	0.	0.	6.17	20.85	15.51	15.13	9.52	20.0	32.7
PEACH BOTTOM	0.	0.	0.	0.	4.30	7.22	16.64	23.96	18.0	19.02
PILGRIM	0.	0.	0.	10.20	10.63	13.1	20.23	24.53	21.17	25.21
POINT BEACH	0.	0.	0.	5.25	6.92	7.43	7.57	8.60	7.6	11.56
PRAIRIE ISLAND	0.	0.	0.	0.	16.0	8.3	14.93	17.53	13.50	13.42
QUAD CITIES	0	0.	5.25	5.72	7.64	11.19	12.05	12.07	14.04	10.18
RANCHO SECO	0.	0.	0.	0.	0.	0.	8.95	9.49	12.09	13.73
H B ROBINSON	0.	5.45	3.06	9.46	8.94	10.06	9.50	10.1	26.5	19.02
ST LUCIE	0.	0.	0.	0.	0.	0.	0.	10.16	19.09	16.43
SALEM	0.	0.	0.	0.	0.	0.	0.	34.03	20.46	40.06
SAN ONOFRE	8.53	8.76	12.26	19.24	16.	23.77	27.39	19.99	33.29	24.50
SURRY	0.	0.	0.	5.6	8.35	11.76	10.05	11.96	32.46	13.01
THREE MILE ISLAND 1	0.	0.	0.	0.	16.57	21.26	25.35	17.22	22.44	0.
TROJAN	0.	0.	0.	0.	0.	0.	10.1	13.54	14.07	16.42
TURKEY POINT 3 AND 4	0.	0.	0.	6.37	9.09	12.45	15.19	11.64	13.36	14.05
VERMONT YANKEE	0.	0.	0.	13.19	13.01	17.01	16.66	18.42	20.72	24.17
YANKEE ROWE	14.01	15.70	25.3	20.01	29.50	31.27	32.33	42.71	43.73	53.20
ZION	0.	0.	0.	0.	0.99	7.37	9.98	9.33	9.79	11.94

TABLE B-7

NUCLEAR STATION COSTS PER KILOWATT-YEAR
IN MIXED CURRENT DOLLAR

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
DUANE ARNOLD	0.	0.	0.	0.	6.7[illegible]	7.6[illegible]	14.09	15.01	23.83	11.0[illegible]
BEAVER VALLEY	0.	0.	0.	0.	0.	0.	8.79	11.3[illegible]	26.2[illegible]	28.[illegible]
BIG ROCK	16.85	20.09	22.41	25.17	35.9.	41.01	50.52	81.19	[illegible]	146.[illegible]
BROWNS FERRY	0.	0.	0.	0.	0.	4.95	7.54	6.3[illegible]	14.2	[illegible]
BRUNSWICK	0.	0.	0.	0.	0.	0.	13.31	17.9[illegible]	[illegible]	21.6[illegible]
CALVERT CLIFFS	0.	0.	0.	0.	0.	8.06	11.09	13.75	15.[illegible]	[illegible]
DONALD C COOK	0.	0.	0.	0.	0.	4.46	6.71	9.5[illegible]	9.68	[illegible]
COOPER	0.	0.	0.	0.	7.49	9.49	13.12	13.17	[illegible]	13.[illegible]
CONNECTICUT YANKEE	7.78	5.7	6.51	11.04	8.58	16.31	16.36	16.4[illegible]	15.1[illegible]	32.[illegible]
CRYSTAL RIVER	0.	0.	0.	0.	0.	0.	0.	11.65	19.2[illegible]	29.54
DAVIS BESSE 1	0.	0.	0.	0.	0.	0.	0.	0.	15.[illegible]	22.6[illegible]
DRESDEN	4.57	3.3	5.09	5.04	9.3[illegible]	10.32	16.76	15.04	16.[illegible]	24.8[illegible]
JOSEPH M FARLEY	0.	0.	0.	0.	0.	0.	0.	0.	15.45	28.53
JAMES A FITZPATRICK	0.	0.	0.	0.	0.	0.	11.37	21.72	23.[illegible]	31.4[illegible]
FORT CALHOUN	0.	0.	0.	4.06	7.66	13.39	16.73	19.0[illegible]	14.23	[illegible]
ROBERT E GINNA	0.	5.81	7.09	6.83	19.4[illegible]	[illegible]	14.2[illegible]	15.36	10.9[illegible]	[illegible]
HATCH	0.	0.	0.	0.	[illegible]	0.	4.[illegible]	11.5[illegible]	14.3[illegible]	15.[illegible]
HUMBOLDT BAY	9.8[illegible]	14.69	14.23	14.5.	16.58	19.22	31.42	4[illegible]	[illegible]	[illegible]
INDIAN POINT 1	13.15	14.95	26.2[illegible]	0.	[illegible]	0.	0.	0.	[illegible]	[illegible]
INDIAN POINT 2	0.	0.	0.	0.	0.	35.77	21.16	19.12	32.[illegible]	37.7[illegible]
INDIAN POINT 3	0.	0.	0.	0.	0.	0.	7.4[illegible]	13.11	24.16	29.93
KEWAUNEE	0.	0.	0.	[illegible]	[illegible]	11.51	20.05	20.41	19.4[illegible]	21.16
MAINE YANKEE	0.	0.	0.	5.04	6.[illegible]	[illegible]	4.[illegible]	10.5.	13.5[illegible]	12.96
MILLSTONE 1	0.	4.93	11.63	11.56	14.06	18.20	21.2[illegible]	27.18	24.5.	30.7[illegible]
MILLSTONE 2	0.	0.	0.	0	[illegible]	[illegible]	13.0[illegible]	21.4	27.04	[illegible]
MONTICELLO	0.	5.56	4.6	8.98	9.29	15.6[illegible]	11.87	19.94	16.6	11.
NORTH ANNA	0.	0.	0.	0	[illegible]	[illegible]	[illegible]	[illegible]	13.17	21.55
NUCLEAR ONE	0.	0.	0.	0.	[illegible]	6.[illegible]	7.1[illegible]	13.02	14.[illegible]	22.4[illegible]
NINE MILE POINT	2.83	4.52	5.06	7.41	11.[illegible]	5.5	6.[illegible]	15.9	11.19	19.12
OCONEE	0.	0.	0.	2.[illegible]	6.90	6.2[illegible]	6.4[illegible]	[illegible]	11.42	15.5[illegible]
OYSTER CREEK	3.	4.72	5.96	9.[illegible]	16.4.	16.[illegible]	15.5[illegible]	22.0[illegible]	24.45	20.06
PALISADES	0.	0.	0.	4.27	15.[illegible]	[illegible]	12.[illegible]	6.6[illegible]	20.8	35.[illegible]
PEACH BOTTOM	0.	0.	0.	0.	3.34	4.[illegible]	14.[illegible]	[illegible]	10.8	21.58
PILGRIM	0.	0.	0.	7.15	14.21	19.75	20.0[illegible]	[illegible]	21.17	27.4[illegible]
POINT BEACH	0.	0.	0.	3.0[illegible]	5.21	4.2[illegible]	6.4[illegible]	1.[illegible]	7.46	12.51
PRAIRIE ISLAND	0.	0.	0.	0.	7.0[illegible]	6.90	14.5.	16.23	13.58	14.[illegible]
QUAD CITIES	0.	0.	3.45	3.98	5.1[illegible]	9.[illegible]	10.5[illegible]	[illegible]	14.04	19.78
RANCHO SECO	0.	0.	0.	0.	[illegible]	[illegible]	[illegible].8	[illegible]	12.0[illegible]	14.5[illegible]
H B ROBINSON	0.	3.44	2.54	6.58	6.8	9.9[illegible]	6.4	9.[illegible]	20.5	21.63
ST LUCIE	0.	0.	0.	0	[illegible]	[illegible]	[illegible]	[illegible]	19.01	10.1
SALEM	0.	0.	0.	0.	[illegible]	[illegible]	[illegible]	22.14	20.48	43.62
SAN ONOFRE	5.12	5.53	8.06	13.39	[illegible].78	[illegible]	21.5[illegible]	12.67	33.25	26.74
SURRY	0.	0.	0.	3.94	[illegible]	[illegible]	9.[illegible]	[illegible]	12.46	15.04
THREE MILE ISLAND 1	0.	0.	0.	0.	12.4[illegible]	[illegible]	[illegible]	16.[illegible]	22.44	0.
TROJAN	0.	0.	0.	0.	[illegible]	[illegible]	8.8	12.6.	14.07	15.7
TURKEY POINT 3 AND 4	0.	0.	0.	4.43	[illegible].91	16.41	13.36	10.05	13.36	14.1[illegible]
VERMONT YANKEE	0.	0.	0.	9.17	15.[illegible]	15.2.	14.6[illegible]	18.1	20.72	26.3[illegible]
YANKEE ROWE	8.9	9.97	16.63	13.92	[illegible]	[illegible]	[illegible]	35.1	43.73	57.9[illegible]
ZION	0.	0.	0.	0.	6.6.	6.[illegible]	0.[illegible]	0.[illegible]	9.79	[illegible]

TABLE B-8

NUCLEAR UNIT CHARACTERISTICS

STATION	UNITSIZE (MW)	REACTOR TYPE (1 = PWR)	COOLING TOWERS (1 MEANS USED)	SALT WATER COOLING (1 MEANS USED)
DUANE ARNOLD	500.	0.	1.	0.
BEAVER VALLEY	800.	1.	1.	0.
BIG ROCK	63.	0.	0.	0.
BROWNS FERRY	1067.	0.	1.	0.
BRUNSWICK	790.	0.	0.	1.
CALVERT CLIFFS	840.	1.	0.	1.
DONALD C COOK	1060.	1.	0.	0.
COOPER	778.	0.	0.	0.
CONNECTICUT YANKEE	575.	1.	0.	0.
CRYSTAL RIVER	812.	1.	0.	1.
DAVIS BESSE	906.	1.	1.	0.
DRESDEN	800.	0.	0.	0.
JOSEPH M FARLEY	790.	1.	1.	0.
JAMES A FITZPATRICK	800.	0.	0.	0.
FORT CALHOUN	445.	1.	0.	0.
ROBERT E GINNA	517.	1.	0.	0.
HATCH	850.	0.	1.	0.
HUMBOLDT BAY	63.	0.	0.	1.
INDIAN POINT 1	265.	1.		
INDIAN POINT 2	864.	1.	0.	1.
INDIAN POINT 3	965.	1.	0.	1.
KEWANEE	535.	1.	0.	0.
MAINE YANKEE	800.	1.	0.	1.
MILLSTONE 1	660.	0.	0.	1.
MILLSTONE 2	812.	1.	0.	1.
MONTICELLO	557.	0.	1.	0.
NORTH ANNA	907.	1.	0.	0.
NUCLEAR ONE	836.	1.		
NINE MILE POINT	610.	0.	0.	0.
OCONEE	860.	1.	0.	0.
OYSTER CREEK	650.	0.	0.	1.
PALISADES	740.	1.	1.	0.
PEACH BOTTOM	1045.	0.	1.	0.
PILGRIM	670.	0.	0.	1.
POINT BEACH	445.	1.	0.	0.
PRARIE ISLAND	523.	1.	1.	0.
QUAD CITIES	789.	0.	0.	0.
RANCHO SECO	918.	1.	1.	0.
H B ROBINSON	700.	1.	0.	0.
ST LUCIE	795.	1.	0.	1.
SALEM	1089.	1.	0.	1.
SAN ONOFRE	436.	1.	0.	1.
SURRY	775.	1.	0.	1.
THREE MILE ISLAND I	800.	1.	1.	0.
TROJAN	1080.	1.	1.	0.
TURKEY POINT 3 AND 4	693.	1.	0.	1.
VERMONT YANKEE	540.	0.	1.	0.
YANKEE ROWE	175.	1.	0.	0.
ZION	1040.	1.	0.	0.

TABLE B-9

NUCLEAR UNIT CHARACTERISTICS

STATION	SECOND (1 IF MORE THAN ONE UNIT)	WESTING 1 IF WESTINGHOUSE DESIGN	CE 1 IF COMBUSTION ENGINEERING DESIGN
DUANE ARNOLD	0.	0.	0.
BEAVER VALLEY	0.	1.	0.
BIG ROCK	0.	0.	0.
BROWNS FERRY	1.	0.	0.
BRUNSWICK	1.	0.	0.
CALVERT CLIFFS	1.	0.	1.
DONALD C COOK	1.	1.	0.
COOPER	0.	0.	0.
CONNECTICUT YANKEE	0.	1.	0.
CRYSTAL RIVER	0.	0.	0.
DAVIS BESSE	0.	0.	0.
DRESDEN	1.	0.	0.
JOSEPH M FARLEY	0.	1.	0.
JAMES A FITZPATRICK	0.	0.	0.
FORT CALHOUN	0.	0.	1.
ROBERT E GINNA	0.	1.	0.
HATCH	0.	0.	0.
HUMBOLDT BAY	0.	0.	0.
INDIAN POINT 1	0.	1.	0.
INDIAN POINT 2	0.	1.	0.
INDIAN POINT 3	0.	1.	0.
KEWANEE	0.	1.	0.
MAINE YANKEE	0.	0.	1.
MILLSTONE 1	0.	0.	0.
MILLSTONE 2	0.	0.	1.
MONTICELLO	0.	0.	0.
NORTH ANNA	0.	1.	0.
NUCLEAR ONE	0.	0.	0.
NINE MILE POINT	0.	0.	0.
OCONEE	1.	0.	0.
OYSTER CREEK	0.	0.	0.
PALISADES	0.	0.	1.
PEACH BOTTOM	1.	0.	0.
PILGRIM	0.	0.	0.
POINT BEACH	1.	1.	0.
PRARIE ISLAND	1.	1.	0.
QUAD CITIES	1.	0.	0.
RANCHO SECO	0.	0.	0.
H B ROBINSON	0.	1.	0.
ST LUCIE	0.	0.	1.
SALEM	0.	1.	0.
SAN ONOFRE	0.	1.	0.
SURRY	1.	1.	0.
THREE MILE ISLAND I	0.	0.	0.
TROJAN	0.	1.	0.
TURKEY POINT 3 AND 4	1.	1.	0.
VERMONT YANKEE	0.	0.	0.
YANKEE ROWE	0.	1.	0.
ZION	1.	1.	0.

TABLE B-10

NUCLEAR UNIT CHARACTERISTICS

STATION	AVERAGE UNIT YEAR OF FIRST OPERATION (1970 = 0)	TURNKEY (1=TURNKEY)	DEMONSTRATION UNIT (1 = DEMO)	NE (1 = LOCATION IN THE NORTH EAST)
DUANE ARNOLD	4.474	0.	0.	0.
BEAVER VALLEY	6.74789	0.	0.	1.
BIG ROCK	-7.	0.	1.	0.
BROWNS FERRY	5.97079	0.	0.	0.
BRUNSWICK	6.18359	0.	0.	0.
CALVERT CLIFFS	6.3	0.	0.	0.
DONALD C COOK	6.9028	0.	0.	0.
COOPER	4.53841	0.	0.	0.
CONNECTICUT YANKEE	-2.	0.	0.	1.
CRYSTAL RIVER	7.1973	0.	0.	0.
DAVIS BESSE	7.9973	0.	0.	0.
DRESDEN	0.	0.	1.	0.
JOSEPH M FARLEY	7.9178	0.	0.	0.
JAMES A FITZPATRICK	5.5834	0.	0.	1.
FORT CALHOUN	3.7068	0.	0.	0.
ROBERT E GINNA	0.204102	1.	0.	1.
HATCH	5.9973	0.	0.	0.
HUMBOLDT BAY	-8.	0.	1.	0.
INDIAN POINT 1	-8.	0.	1.	1.
INDIAN POINT 2	3.62331	0.	0.	1.
INDIAN POINT 3	6.66029	0.	0.	1.
KEWANEE	4.4575	0.	0.	0.
MAINE YANKEE	3.	0.	0.	1.
MILLSTONE 1	1.	1.	0.	1.
MILLSTONE 2	5.98357	0.	0.	1.
MONTICELLO	1.53841	1.	0.	0.
NORTH ANNA	8.4548	0.	0.	0.
NUCLEAR ONE	4.96712	0.	0.	0.
NINE MILE POINT	0.	0.	0.	1.
OCONEE	4.3967	0.	0.	0.
OYSTER CREEK	0.	1.	0.	1.
PALISADES	1.9575	0.	0.	0.
PEACH BOTTOM	4.7438	0.	0.	1.
PILGRIM	2.9397	0.	0.	1.
POINT BEACH	2.25211	1.	0.	0.
PRARIE ISLAND	4.465	0.	0.	0.
QUAD CITIES	2.6274	1.	0.	0.
RANCHO SECO	5.2877	0.	0.	0.
H B ROBINSON	1.2041	1.	0.	0.
ST LUCIE	6.9032	0.	0.	0.
SALEM	6.4959	0.	0.	1.
SAN ONOFRE	-1.9575	1.	0.	0.
SURRY	3.1534	0.	0.	0.
THREE MILE ISLAND I	4.6685	0.	0.	1.
TROJAN	6.38361	0.	0.	0.
TURKEY POINT 3 AND 4	3.2849	0.	0.	0.
VERMONT YANKEE	2.9151	0.	0.	1.
YANKEE ROWE	-8.	0.	1.	1.
ZION	4.2487	0.	0.	0.

B-2 ANALYTIC METHOD

General Methodology

The data base for this study is substantial; included are 300 plant-years of power plant O&M cost observations cross-referenced with the characteristics of these plants. The problem is to draw meaningful conclusions regarding O&M cost trends on the basis of this data. To that end, the tools of statistical analysis are used. The principal approach and conclusions embodied in this appendix rely on the use of linear regression analysis, particularly the use of pooled regression and analysis of variance techniques. The aim of this section is twofold: to provide a general introduction to these techniques for those who are unfamiliar with them, and to describe their use in the analysis of nuclear plant O&M costs in particular.

Linear regression is generally used to build one kind of model of a particular process and to identify significant causal or associated factors that seem to explain the outcome of that process. The outcome of the process is represented by a so-called dependent variable and the causal factors are represented by the independent or explanatory variables. Statistical tests have been developed which give some idea of how important a given explanatory variable is and how precisely we can estimate its effect on the dependent variable. In our study, for example, annual nuclear plant O&M costs (represented as the dependent variable) can be considered to be the outcome of a process, and plant size and/or year of operation can be considered to be among the candidates for causal or associated factors (i.e. as independent or explanatory variables).

Regression works by assuming that the dependent variable to be analyzed, in this case annual O&M costs, is a linear function of other factors which we can measure, that is, that the effect of each factor is independent from the effects of other factors.* In this appendix we try to see how much we can learn by assuming that O&M costs are a function of intrinsic variables describing a power plant which are known before it is even built, such as whether it uses cooling towers, what its size is, and so forth. Thus, we are really concerned with examining the differences between O&M costs for different types of plants rather than developing a detailed model for any single unit.

Pooled analysis is a regression technique for simultaneously analyzing time related processes in different analytical units. In this study it will be used to study plant characteristics associated with different O&M cost levels or growth rates at different nuclear power stations.

When regression analysis is used to examine variation caused by qualitative explanatory variables it is called analysis of variance.** In this study we shall be interested in determining whether qualitative variables such as whether a given reactor is of boiling water or pressurized design has a significant impact on O&M costs for that unit.

The combined use of these techniques will enable determination of not only whether a variable is significantly associated with costs, but also what the form of that association is. For example, some variables may actually be associated with an increase of the rate of cost escalation while others might only be associated with the general level of costs.

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* Interactions between characteristics can themselves be identified as new characteristics. Several good texts about linear regression exist. The interested reader is directed to Kementa (1972) or Goldberg (1969).

** For a discussion of analysis of variance as a kind of linear regression analysis, see Hoel, et al. (1971), page 127, ff.

Description of Variables

The dependent variable in all cases is the annual non-fuel O&M costs for all plants in 1978 dollars and standardized on a per kilowatt-year basis, as presented in Table B-6. The natural logarithms of these costs were used when exponential growth rates were estimated. The name REALSTAN was chosen to represent O&M costs and REALPOOL was chosen to represent the logs of O&M costs.

The constant term used in all regressions has been called MASKS.* Time was represented by TIME, which was chosen as a sequentially increasing series of negative numbers which reached 0 in the year 1980. This particular way to represent time was chosen to facilitate comparison of expected 1980 costs and has no effect of the estimated costs in either the linear or log-linear models.

As discussed earlier, plant characteristics can affect the general level of costs uniformly or affect the rate of growth over time. For example, the variable SIZEM is the term which measures the uniform level effect of average unit size over time. The variable SIZET measures the effect of station unit size on the rate of cost escalation (SIZET is SIZEM x TIME). This pattern is repeated for other characteristics examined in this study. The suffix M refers to the variable's effect on costs uniformly and the suffix T refers to the effect on the rate of escalation. The following additional variables were tested or are in one of the final models:

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*This name evolved because of the procedure which had to be developed to cope with the fact that data for all plants was not available for all years of the survey and the computer routines used had no provision for the use of pooled data with missing observations.

variable	description
BIRTHM BIRTHT	The time a unit first came on line. Multiple unit stations have their birth dates averaged. Birth includes the actual date of commercial operation through the use of fractional years.
DEMOM DEMOT	It was found quickly that the earliest plants, which were built as demonstration projects, had normalized costs that were much higher than other stations and that other variables could not adequately account for this difference. Thus it was decided to add a dummy variable which could isolate the effect imputed to being early demonstration projects.
NEMASK NET	It was similarly found that units in the North East had abnormally higher costs, and this dummy variable was created to isolate the effect.
SALTM SALTT	SALT is 0 unless the station is cooled by salt water.
SECONDM SECONDT	SECOND is 0 unless there is two or more units at the station.
TOWERSM TOWERST	TOWERS is 0 unless the station is cooled with cooling towers, either mechanical or natural draft.
TURNKEYM TURNKEYT	TURNKEY is 0 unless the unit was completed as one of the original turnkey contracts.
TYPEM TYPET	TYPE is 0 unless the unit is a Pressurized Water Reactor design.

A complete listing of the values of these variables for every station can be found in Tables B-8 to B-10. In the actual computer runs an X will be found before all variables for cases when the Big Rock station is excluded.*

* In the original runs of the linear model, it was found that the Big Rock nuclear unit contributed almost a third of the total sum of squared errors. The reason for this is easy to locate in Table B-6 in which it can be seen that Big Rock's normalized costs were much higher than any other unit. This cost level was so much above the cost level for the other demonstration units that it proved impossible to adequately explain Big Rock's cost behavior through the fact that it was a demonstration unit, at least in the linear model. For these reasons, the work in this study was conducted without data for Big Rock station. There is an additional econometric reason for excluding Big Rock. Ordinary least square regression, described earlier, assumes that the size of the error term is randomly distributed. Therefore, the sum of squared error for any single plant should be within a certain range. If it is known that the sum of squared error of a given plant is outside of this normal distribution, then a heteroskedastic correction should be made to the data in order to normalize the effect that the abnormal data has on the regression process of minimizing the total sum of squared error (see for example, Kmenta (1972), p. 510). Heteroskedastic correction is difficult in this case because there are not enough observations of Big Rock's performance to accurately estimate the sample variance. The correction procedure then becomes totally arbitrary and it makes more sense to simply leave the unit out. Runs of the linear model with and without Big Rock can be found in the appendix. It can quickly be seen that the run without Big Rock had much more precision in its estimated coefficients (lower standard errors) and that the T-values were correspondingly higher. Most importantly, the standard error of the equation, which is the best overall indicator of the "resolving power" of the regression decreased from 7.76 to about 4.6, indicating a marked improvement in explanatory performance.

Other variables such as forced outage rate, capacity factor, reported radiation exposures, and person-hours of maintenance per year could also have been used in this study. They have not been included in the present research principally due to the limited time available. A more complete investigation would examine the correlations between such variables and O&M costs and thus give a more complete understanding of what is causing O&M cost increases. Instead of asking will O&M costs continue to rise, the question would be, will labor requirements, forced outage rates, and so forth continue to rise?

B-3 PRESENTATION OF RESULTS

Linear Models: Results

Table B-11 presents the basic linear model judged to best project future O&M costs. It shows an expected cost of 23.14 - (1000X.00372) = 19.42 dollars per KW (in 1978 dollars) for a non-duplicate 1000 MW reactor in 1980 (year 0) without cooling tower, etc. This cost is expected to grow at an average of $1.94 a year or just over 10% in real dollars in the first year. Other factors that would affect the base year (1980) cost include salt water cooling (+ $4.65), the use of cooling towers (+ $2.79) and PWR (TYPEM) design (+ $1.18). Co-location of the unit would reduce its expected 1980 cost by $3.18 and location in the North East is expected to add $4.00 to the costs. These figures can be read in millions of dollars if we consider a 1000 MW unit instead of a per KW cost.

TABLE B-11

REFERENCE LINEAR MODEL

Dependent Variable: REALSTAN

Independent Variable	Coefficient Value	Standard Error	t-Statistic	Confidence Level
TIME	1.94284	0.13734	14.14600	99.9%
MASKS	23.14260	1.58885	14.56560	99.9%
NEMASK	4.00011	0.66366	6.02732	99.9%
SIZEM	-0.00372	0.00220	-1.69181	97.5%
SALTM	4.64958	0.67700	6.86794	99.9%
TOWERSM	2.75956	0.76679	3.59883	99.5%
DEMOT	0.89526	0.32423	2.76116	99.5%
DEMOM	15.27140	2.38542	6.40196	99.9%
SECONDM	-3.17592	0.74950	-4.23739	99.9%
BIRTHM	-0.38098	0.17049	-2.23464	99.5%
TYPEM	1.18159	0.59233	-1.99481	99.5%

R^2 = .6802

Standard Error of the Equation: 4.5731

Sum of Squared Error: 5834.91

TABLE B-12

REFERENCE LINEAR CASE
BUT WITHOUT BIRTHM

Dependent Variable: REALSTAN

Independent Variable	Coefficient Value	Standard Error	t-Statistic	Confidence Level
TIME	1.85265	0.12995	14.25210	99.9%
MASKS	24.03200	1.53674	15.62830	99.9%
NEMASK	4.66269	0.62948	7.40723	99.9%
SIZEM	-0.00721	0.00158	-4.57198	99.9%
SALTM	4.42078	0.74543	5.93049	99.9%
TOWERSM	1.76842	0.72280	2.44661	97.5%
DEMOT	0.93647	0.32106	2.91684	99.9%
DEMOM	16.85320	2.17890	7.73472	99.9%
SECONDM	-2.95573	0.74865	-3.94805	99.9%
TYPEM	1.66645	0.61121	2.72649	99.5%

$R^2 = .6776$

Standard Error of the Regression: 4.5836

Sum of Squared Error: 5882.73

F-test for the significance of BIRTHM:

$$A(1,279) = \frac{5882.73 - 5834.91}{5834.91} \times \frac{290 - 11}{11 - 10} = 2.28654$$

The threshold value for 95% significance for F(1,200+) is 3.89, therefore BIRTHM is not statistically significant in the reference equation.

SIZET in the Linear Model

A natural question is whether the size of the units has any effect on the rate of cost increase in addition to its effect on the absolute level of costs. Using the linear model, a significant relationship between size of the units and a linear rate of cost increase was not found.* The details of this investigation will be presente' here because the use of the log-linear model results in very significant estimates for the effect of size on the escalation rate.

Table B-13 shows the results of a regression with SIZET added to the reference linear model. The coefficient of SIZET has a positive value of .00021, indicating that a 1000 MW unit increases in cost at a rate of 10¢ a year (per KW and in 1978 dollars) faster than a 500 MW unit. This corresponds to an additional rate of increase of $100,000 per year for the whole unit. This statistic, however, has a t-value below .5, and cannot be seriously considered as a significant variable in this equation. In order to examine this conclusion further, a F-test was performed, with the same result.

If, however, SIZET is used in the linear model without SIZEM, the results become quite significant. Table B-14 presents the results. The question might arise as to whether it might be preferable to use SIZET instead of SIZEM in the reference linear model. The answer is that statistical practice gives no absolute guidelines in such a situation--where one model is not a "subset" of another. However, in this case the reference run without SIZET but with SIZEM produced a lower sum of squared error, and absent any compelling reasons otherwise, such a model should be preferred. Thus, for the linear "equation specification" SIZEM has been chosen as the best measure of the effect of unit size on O&M costs. The use of the log-linear specification will lead to the opposite.

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*However, the linear model infers higher percentage escalation rates for larger plants because of lower base costs with the same annual cost increase (KW costs).

TABLE B-13

SIZET ADDED TO REFERENCE LINEAR MODEL

Dependent Variable: REALSTAN

Independent Variable	Coefficient Value	Standard Error	t-Statistic	Confidence Level
TIME	1.77361	.41431	4.2808	99.9%
MASKS	22.9578	1.28129	10.643327	99.9%
NEMASK	4.36153	.66142	6.59415	99.9%
SALTM	4.41715	.75306	5.86553	99.9%
TOWERSM	1.99068	.74436	2.67434	99.5%
DEMOT	.954623	.36916	2.58588	99.5%
DEMOM	15.6776	2.47989	6.32185	99.9%
SECONDM	12.91793	.75415	3.87059	99.9%
BIRTHM	-.249541	.16849	1.48103	90%
TYPEM	1.66079	.61813	2.68680	99.5%
SIZEM	-.004176	.00304	1.37412	90%
SIZET	.00021	.00057738	.362826	

$R^2 = .6804$

Standard Error of the Equation: 4.58027

Sum of Squared Error: 5832.14

TABLE B-14

SIZET REPLACING SIZEM IN REFERENCE LINEAR MODEL

Dependent Variable: REALSTAN

Independent Variable	Coefficient Value	Standard Error	t-Statistic	Confidence Level
TIME	1.40359	0.31538	4.45050	99.9%
MASKS	20.46110	1.16436	17.57270	99.9%
NEMASK	4.18621	0.65003	6.43999	99.9%
SALTM	4.40306	0.75420	5.83809	99.9%
TOWERSM	2.00292	0.74549	2.68671	99.5%
DEMOM	16.16540	2.45826	6.57597	99.9%
DEMOT	1.11972	0.34962	3.20265	99.9%
SECONDM	-3.04031	0.75007	-4.05335	99.9%
BIRTHM	-0.35213	0.15128	-2.32775	97.5%
TYPEM	1.60776	0.61791	2.60195	99.5%
SIZET	7.64203E-04	4.13596E-04	1.84770	95%

$R^2 = .6782$

Standard Error of Regression: 4.5876

Sum of Squared Error: 5871.76

The Log-Linear Model

The reference log-linear model results are presented in Table B-15. In this model SIZET is a significant term and so to compute estimated escalation rates, the size of the unit must also be known. Figure B-1 shows the estimated relationship between estimated escalation rate and size. The equation predicts that a 500 MW unit experienced, on the average a 13.5% escalation rate for O&M costs. in constant 1978 dollars. The value for a 1000 MW unit would be 19.48%.

In the log-linear model, constant terms enter into the costs in a uniformly multiplicative way rather than being uniformly additive. In order to derive the actual multiplier, the estimated coefficient must be exponentiated according to the formula:

$$\text{multiplier} = e^{[\text{log-linear coefficient}]}$$

Thus, from Table B-16 the multiplier for location in the North East can be constructed. It is $e^{.256199}$ which is equal to 1.29. Thus, location in the North East is expected to increase O&M costs by almost 30% over what they would be otherwise, for every year of operation. Table B-16 presents multipliers for all variables in the reference model, along with 95% confidence intervals.

If one compares these results with those of the reference linear model the general pattern is rougly similar in the near term. In the linear model a nonduplicate PWR with cooling tower would have (1978 dollar) O&M costs of $22.25 per KW in year 1980. Increasing at $1.91 per year, real O&M costs would reach $41.35 by the tenth year, and $60.45 by the 20th year. The log-linear model result would start at $22.61, reach $53.13 by the 10th year and $124.64 by the twentieth year. Clearly the log-linear model gives a more pronounced long-term cost escalation effect, although both model types have comparable explanatory power with respect to the historical experience.

TABLE B-15

REFERENCE LOG-LINEAR RESULTS

Dependent Variable: REALPOOL

Independent Variable	Coefficient Value	Standard Error	t-Statistic	Confidence Level
TIME	.075949	.0139914	5.42807	99.9%
MASKS	3.01852	.0434089	66.022425	99.9%
NEMASK	.270349	.0370223	7.30240	99.9%
SIZET	.000102	.00001937	5.28214	99.9%
SALTM	.280196	.045016	6.226224	99.9%
TOWERSM	.109606	.042258	2.5949963	99.5%
DEMOM	.546903	.067134	8.1524508	99.9%
SECONDM	-0.201635	.044147	4.56739	99.9%
TYPET	-0.013045	.0072153	1.75816	95%

R^2 = .6993

Sum of Squared Error: 20.8558

Standard Error of Regression: .2724

(e.g., 95% of estimates are within ± 70% of actual cost: $e^{(1.96 \times .2724)} = 1.70568$)

FIGURE B-1

LOG-LINEAR MODEL O&M COST ESCALATION RATE

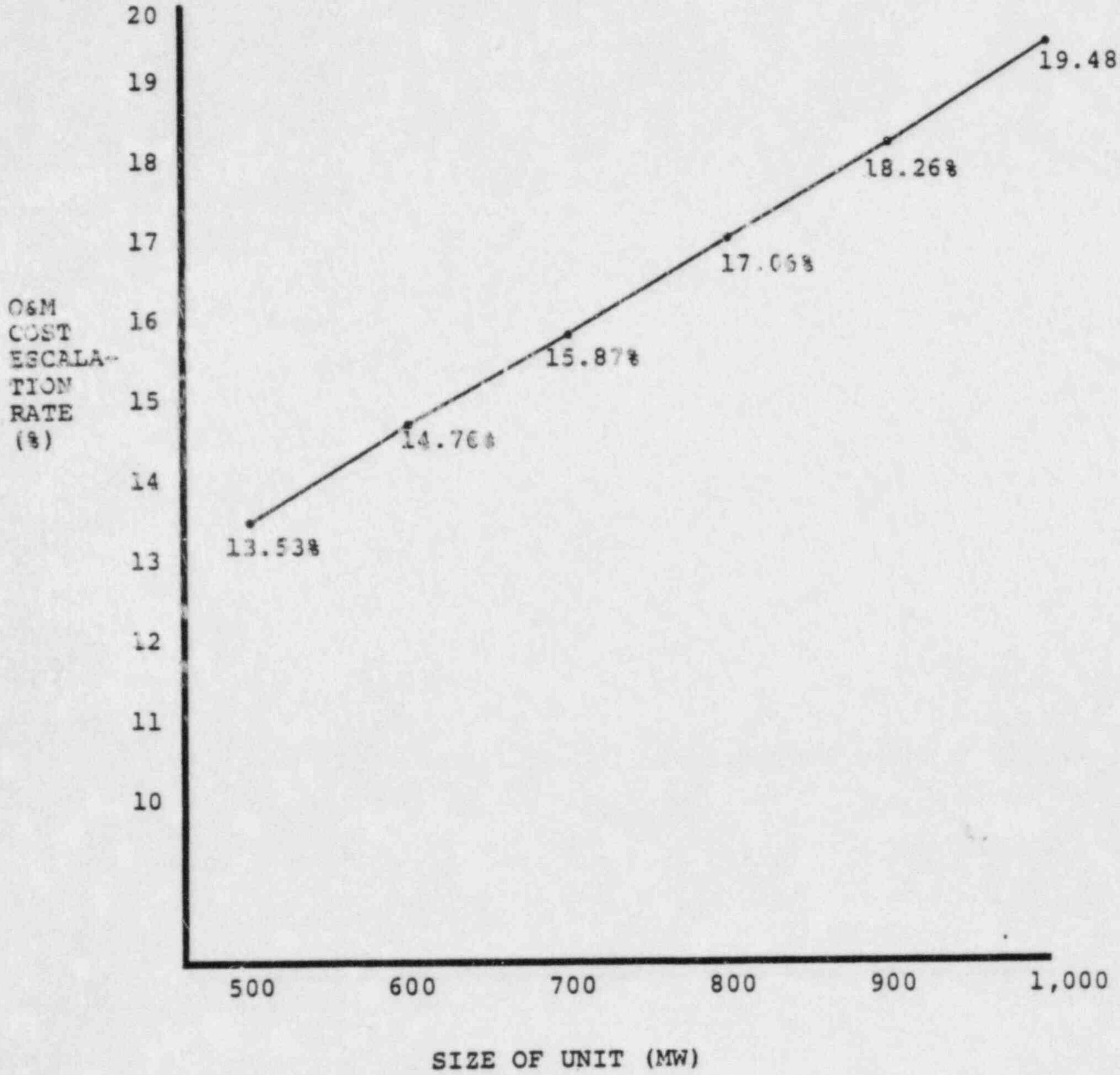

TABLE B-16

CONFIDENCE INTERVALS ON MULTIPLIERS
IN THE REFERENCE LOG-LINEAR
MODEL

		Confidence Interval*	
	Estimated	95% Lower Bound	95% Upper Bound
MASKS	20.46	18.79	22.28
NEMASK	1.31	1.22	1.41
SALTM	1.32	1.21	1.45
TOWERSM	1.12	1.03	1.21
DEMOM	1.73	1.51	1.97
SECONDM	.82	.75	.89
TYPET (differential escalation rate for PWRs)	.987	.973	1.001
TIME (base escalation rate above inflation)	7.89%	4.97%	10.89%
SIZET (incremental escalation rate per 1000 mw of capacity)	1.03%	.64%	1.41%

*95% probability that true coefficient value lies between lower and upper bounds.

SIZET in the Log-Linear Model

The log-linear model is different from the linear model in that it is more sensitive to quantities which behave exponentially, and "reacts" more strongly to such variables than does the linear model, which alternately is more sensitive to variables which increase in fixed absolute increments or in a fixed increment over the whole range of observations.

These factors must be kept in mind when examining why the SIZET term was chosen over SIZEM in the log-linear model. Consider Table B-17 where the SIZEM variable has been added to the reference log-linear model. The coefficient for SIZEM has a t-value of less than 1.3 while SIZET has a coefficient with a t-value of over 2.4 in this augmented model. The F-test shows that SIZEM does not approach contributing enough explanatory power to the regression to deserve inclusion. On the other hand, if one tests whether SIZET adds sufficient explanatory power to a model without it, but with SIZEM, the result is that SIZET is significant at the 95% level. Table B-18 shows the results of a regression on the log-linear model without SIZET and with SIZEM and the results of an F-test based on this regression and the regression presented in Table B-17.

This result thus supports the notion that larger units are associated with higher escalation rates in a stronger way than indicated by the linear reference model. Not only does it appear that larger units have higher escalation rates due to lower absolute costs, but the actual percentage annual increment of cost increase is identified as being larger for larger units by the log-linear model.

One might wonder why the "strength" of this interaction effect between size and escalation rate was not identified by the linear model. The simplest explanation is, of course, that the annual increase is not constant over time, but is itself increasing. The simplest approximation of this state of affairs is to assume that the annual increase itself increases a fixed amount every year, i.e., that the fractional or percentage increase is constant over time.

TABLE B-17

SIZEM ADDED TO REFERENCE LOG-LINEAR MODEL

Dependent Variable: REALPOOL

Independent Variable	Coefficient Value	Standard Error	t-Statistic	Confidence Level
TIME	0.09549	0.02112	4.52032	99.9%
MASKS	3.13857	0.10966	28.62530	99.9%
NEMASK	0.27287	0.03704	7.36612	99.9%
SIZEM	-1.80551E-04	1.46339E-04	-1.23379	90%
SALTM	0.28128	0.04490	6.26494	99.9%
TOWERSM	0.11535	0.04245	2.71695	99.5%
DEMOM	0.54261	0.05716	8.07905	99.9%
SECONDM	-0.19340	0.04461	-4.33546	99.9%
TYPET	-0.01374	0.00743	-1.84879	95%
SIZET	7.88549E-05	3.01396E-05	2.45043	97.5%

R^2 = .70053

Standard Error of the Regression: 0.2722

Sum of Squared Error: 20.743

F-test for significance of SIZEM:

$$F(1,280) = \frac{20.8588 - 20.743}{20.743} \times \frac{280}{1} = 1.52263$$

Critical value at 95% F(1,200+) = 3.89,
SIZEM "not significant."

TABLE B-18

SIZEM REPLACES SIZET IN REFERENCE LOG-LINEAR MODEL

Dependent Variable: REALPOOL

Independent Variable	Coefficient Value	Standard Error	t-Statistic	Confidence Level
TIME	0.14354	0.00793	18.10340	99.9%
MASKS	3.31636	0.08334	39.79200	99.9%
NEMASK	0.27044	0.03736	7.23882	99.9%
SIZEM	-4.55387E-04	9.48315E-05	-4.80207	99.9%
SALTM	0.29857	0.04473	6.67468	99.9%
TOWERSM	0.12622	0.04260	2.96309	99.9%
DEMOM	0.59802	0.06409	9.29956	99.9%
SECONDM	-0.20852	0.04457	-4.67838	99.9%
TYPET	-0.01735	0.00735	-2.35956	97.5%

$R^2 = .69411$

Standard Error of Regression: 0.2746

Sum of Squared Error: 21.188

F-test for the significance of SIZET:

$$F(1,280) = \frac{21.188 - 20.743}{20.743} \times \frac{280}{1} = 6.6068,$$

SIZET is a "significant at the 95% confidence level" addition to the reference log-linear model with SIZEM but without SIZET.

TURNKEYM and TURNKEYT were also statistically not significant in all tests, meaning that the study could not identify and O&M cost trends associated with the early turnkey construction projects.

Tests were also conducted to find out if significant O&M cost variations could be found between stations from different PWR reactor manufacturers. No significant variations could be identified.

In the future, more significant variables may be identified through the use of more years of plant data and through the study of particular components of O&M cost.

Existing Plants

For comparison, with the regression results, B-19, provides the results of a simple exponential regression fit to the historic real dollar O&M costs of each nuclear plant separately are presented. Similarly, Table B-20 provides the results of performing a simple linear fit to this data.

This is, in fact, the basic assumption of the log-linear model. The greater sensitivity to cost increases related to size in the log-linear model is also reflected in the greater precision of the SIZET variable in the log-linear model as opposed to SIZEM in the linear model (a higher t-statistic correlates with precision).

In other respects, the results of the log-linear model are similar to those of the linear model. Salt water cooling is expected to increase O&M costs about 33%, towers are expected to increase costs about 11%, co-location of units is expected to reduce costs about 22%, and PWR design is expected to reduce costs over time at the rate of about 1.31% a year relative to other designs.

The result that the linear model predicts uniformly higher costs for PWRs and the log-linear predicts a lower escalation rate is not necessarily contradictory for the same reason that lower uniform costs for larger units in the linear model are properly associated with higher escalation rates in the log-linear model, though the behavior of the TYPE variables is the converse of that of the SIZE variables. If linear base level costs are higher, the log-linear escalation rate associated with that cost can be expected to be lower.

Other Variables

Besides the variables considered here, others have been tested for significant association with O&M cost increases. These give however, negative results since these plant characteristics have not been found to have a significant association with O&M costs. They do not demonstrate that the characteristics under consideration have no impact on O&M costs, but merely that this impact cannot be identified as statistically significant at this time.

BIRTHM and BIRTHT were not found to be statistically significant under any conditions. This means that the in-service date of a nuclear station was not found to have a significant effect on the level of O&M costs or their rate of increase. This result creates the impression that new stations will start off being as expensive as those which have already been on-line for some time, a disconcerting possibility.

TABLE B-20

ESTIMATED SINGLE EQUATIONS LINEAR GROWTH

($ 1978 per KW)

STATION	ESTIMATED 1980 COST	ANNUAL ESCALATION (1978 DOLLARS)	R - SQUARED
DUANE ARNOLD	24.1682	2.58151	0.702003
BEAVER VALLEY	35.46.3	3.75575	0.809510
BIG ROCK	105.434	8.92981	0.33992
BROWNS FERRY	18.0754	2.55123	0.800415
BRUNSWICK	20.748	1.18333	0.430895
CALVERT CLIFFS	21.3800	2.35465	0.854334
DONALD C COOK	13.1443	1.42839	0.877058
COOPER	13.0023	0.240578	0.071303
CONNECTICUT YANKEE	24.479	1.33747	0.530002
CRYSTAL RIVER	34.2303	7.31715	0.027785
DAVIS BESSE	25..332	5.29723	1.
DRESDEN	24.5427	1.80389	0.773743
JOSEPH M FARLEY	36.9795	10.7333	1.
JAMES A FITZPATRICK	33.1803	4.14475	0.898104
FORT CALHOUN	23.3115	1.99803	0.330423
ROBERT E GINNA	22.5213	1.3173	0.914791
HATCH	17.8324	2.25008	0.843324
HUMBOLDT BAY	51.7809	3.81375	0.308032
INDIAN POINT 1	109.053	6.55429	0.920707
INDIAN POINT 2	38.4319	4.14009	0.80571
INDIAN POINT 3	35.3185	5.70059	0.937027
KEWANEE	21.8935	0.805041	0.130724
MAINE YANKEE	13.0389	0.87114	0.003875
MILLSTONE 1	21.5306	2.1902	0.611932
MILLSTONE 2	30.8839	3.30031	0.933334
MONTICELLO	21.0243	1.35131	0.823255
NORTH ANNA	23.3391	6.3977	1.
NUCLEAR ONE	22.8719	3.91321	0.952583
NINE MILE POINT	17.2464	1.02727	0.677753
OCONEE	14.6447	1.40017	0.788753
OYSTER CREEK	27.5433	2.00233	0.702232
PALISADES	27.7534	2.32997	0.425030
PEACH BOTTOM	27.0733	3.40830	0.931727
PILGRIM	28.8228	2.18808	0.513015
POINT BEACH	10.2718	0.733427	0.717010
PRARIE ISLAND	15.3547	0.223037	[illegible]
QUAD CITIES	18.3054	1.74043	0.844140
RANCHO SECO	15.7010	1.79780	[illegible]
H B ROBINSON	20.1327	1.80325	0.739402
ST LUCIE	28.0023	3.00335	0.420731
SALEM	42.7.3	7.303.1	0.9499.2
SAN ONOFRE	32.3271	2.34175	0.730038
SURRY	15.1330	1.14112	0.812799
THREE MILE ISLAND I	24.011	0.825742	0.13331
TROJAN	19.4057	1.24807	0.738-24
TURKEY POINT 3 AND 4	13.3047	1.1494	0.319870
VERMONT YANKEE	[illegible]	1.77318	0.57.80
YANKEE ROWE	[illegible]	4.06337	0.200774
ZION	[illegible]	.314830	0.570404

TABLE B-19

ESTIMATED SINGLE EQUATIONS EXPONENTIAL GROWTH

($ 1978 per KW)

STATION	ESTIMATED 1980 COST	ESCALATION RATE % = X100	R - SQUARED
DUANE ARNOLD	27.5414	0.208614	0.758553
BEAVER VALLEY	44.2886	0.386037	0.789055
BIG ROCK	113.081	0.159601	0.850822
BROWNS FERRY	20.191	0.283134	0.798695
BRUNSWICK	20.987	0.070865	0.491901
CALVERT CLIFFS	23.2092	0.18092	0.956787
DONALD C COOK	14.5562	0.193639	0.84417
COOPER	13.0195	0.022923	0.068849
CONNECTICUT YANKEE	25.0135	0.096313	0.596402
CRYSTAL RIVER	40.5553	0.473095	0.995978
DAVIS BESSE	27.9301	0.339837	1.
DRESDEN	29.2878	0.170795	0.78314
JOSEPH M FARLEY	44.476	0.696569	1.
JAMES A FITZPATRICK	36.1087	0.214414	0.860922
FORT CALHOUN	27.9667	0.184237	0.641283
ROBERT E GINNA	24.0944	0.108888	0.911037
HATCH	19.8936	0.22514	0.806661
HUMBOLDT BAY	57.1158	0.133829	0.708008
INDIAN POINT 1	401.872	0.347289	0.84244
INDIAN POINT 2	40.6132	0.172093	0.796063
INDIAN POINT 3	46.2901	0.499768	0.948436
KEWANEE	22.5322	0.054853	0.180298
MAINE YANKEE	13.6894	0.092073	0.659367
MILLSTONE 1	35.7053	0.129788	0.719221
MILLSTONE 2	33.228	0.17678	0.673199
MONTICELLO	23.0413	0.112589	0.451068
NORTH ANNA	29.6734	0.500823	1.
NUCLEAR ONE	27.7017	0.363408	0.997967
NINE MILE POINT	19.0889	0.114762	0.692972
OCONEE	16.4245	0.185799	0.756824
OYSTER CREEK	34.711	0.169225	0.722094
PALISADES	29.1781	0.17546	0.400511
PEACH BOTTOM	38.0517	0.360675	0.729415
PILGRIM	31.8214	0.136046	0.549913
POINT BEACH	11.1888	0.099317	0.751948
PRARIE ISLAND	17.1992	0.085258	0.280132
QUAD CITIES	21.7625	0.190023	0.940578
RANCHO SECO	16.5158	0.173879	0.916173
H B ROBINSON	23.052	0.188826	0.789214
ST LUCIE	24.5205	0.279402	0.501633
SALEM	44.094	0.270382	0.479566
SAN ONOFRE	37.894	0.147612	0.793882
SURRY	16.6132	0.129512	0.757544
THREE MILE ISLAND I	24.2832	0.043919	0.154385
TROJAN	17.0229	0.116889	0.746287
TURKEY POINT 3 AND 4	18.1482	0.122716	0.652427
VERMONT YANKEE	25.9601	0.103615	0.962388
YANKEE ROWE	60.85	0.147923	0.934457
ZION	11.8235	0.065612	0.556827

APPENDIX C

Nuclear Capacity Factors

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C-1 Introduction and Summary

The capacity factor of a power plant is the ratio of actual electricity generation to the maximum potential generation over some time period.* Annual capacity factors are a key measure of plant performance. The present study was a statistical analysis of the determinants of nuclear power plant capacity factors. Its data base consisted of operating information and data on other plant characteristics for 68 commercially operating nuclear units in the U.S., representing almost all such units.

The multiple regression analysis that was performed for this study focussed on the question of how and why capacity factors change over time. An equation was specified that explained historical capacity factors (and had test statistics sufficient to merit serious consideration to predicting nuclear power plant performance).

Among the variables found to have explanatory power were the size of the unit, its reactor type (pressurized water vs. boiling water), whether or not its cooling system used salt water or fresh water, and its age. Of the several interesting results obtained by applying the regression eqation, perhaps the most important was the effect upon

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* Capacity factors as reported in this text are defined as:

$$\frac{\text{Net electrical energy generated} \times 100}{\text{Period hours} \times \text{maximum dependable capacity}}$$

Maximum dependable capacity is defined in Table C-2 below.

capacity factors of a nuclear unit's using salt water for cooling. After a period of maturation during which capacity factors increase from their initial level, the capacity factors for units using salt water cooling decline significantly. The capacity factors of salt water cooled pressurized water reactor (PWR) units were found to decline much more rapidly than those of salt water cooled boiling water reactor (BWR) units. For non salt water cooled BWRs the general aging trend was a long term increase in adjusted capacity factors. For similar PWRs this was balanced by a long term trend towards declining performance, which was more pronounced for smaller units.

In the balance of this technical report, the present research is situated in the context of previous studies; the study methodology and data base are described, the modelling approach is discussed; the resulting analysis of capacity factors is detailed; and the use of the results in the Maine Yankee nuclear retirement study is described.

Statistical Analyses of Nuclear Capacity Factors

The several capacity factor studies that have been completed heretofore have attempted to provide an analytical basis for understanding nuclear power plant performance. Thus far, there have not been many years of capacity factor data for nuclear units. The investigations heretofore conducted on the subject of nuclear capacity factors have addressed the hypothesis of a "maturation" effect, a hypothesis which implies increasing capacity factors (after relatively low initial values) for the first few years of commercial operation. On the basis of the limited operating experience upon which previous studies have been carried out, there is some evidence for maturation.

The principal question left unanswered by these previous studies is whether nuclear units can be expected to perform at the levels they reach after approximately five years of capacity factor maturation for the remaining twenty five years of planned operating life, or whether shortly after attaining this "mature" level an aging effect will set in, causing capacity factors to decline. The available data base spans such a relatively short time that it is difficult to provide a conclusive answer to this question. It is obligatory, however, to provide analyses which may give indicative, if only tentative, results.

This study addresses the issue of nuclear power plant performance generally, the maturation effect, and capacity factor behavior after the maturation period. One conclusion that has been reached is that significantly decreased performance can be expected from pressurized water reactor (PWR) units and reactors cooled by salt water after a maturation period of about six years. These findings extend and are consistent with earlier analyses, and provide a basis for more extensive work in the future.

Charles Komanoff pioneered capacity factor analysis (Ref. C-1). His work revealed poor performance of large boiling water reactor (BWR) units and indicated that maturation effects for large PWRs were limited. Komanoff is continuing to perform research in this field.

Robert Easterling found a strong maturation effect for nuclear units up to the fifth year of operation; significantly poorer than average overall performance by large units; and differential levels of performance of PWR and BWR units over time (Ref. C-2). His predictions of large PWR unit performance -- an average capacity factor of 57 percent over the second to tenth years of operation -- were much lower than estimates generally made by the industry and government. Easterling considered age, size, and reactor type as independent or explanatory variables in his statistical analyses of nuclear plant capacity factors.

A more comprehensive study by Lucas and Hall (Ref. C-3), based upon an international cross-section of nuclear reactors, shows a probable decline in BWR capacity factors after the fourth year of operation.

Generally, previous work has indicated that industry expectations of post-maturation capacity factors of 70 percent or higher may be too optimistic. However, the question of long-term nuclear power plant performance has been left open, due to the limitations of this work. It is only in the last few years that significant numbers of nuclear power plants have entered what may prove to be their post-maturation phase. This may be one of the factors accounting for the low degree of explanatory power characteristically found in past statistical analyses of power plant capacity factors, which in turn made it difficult to predict long term trends with any degree of precision.

The present study attempts to go beyond previous work methodologically in two important ways. It includes more explanatory variables in the statistical analysis. Additionally it uses an adjusted capacicity factor as the measure of power plant performance to be investigated, explained, and predicted. The methodological innovation used to develop the adjusted capacity factor is conceptually straightforward. It was decided to subtract planned refueling outages and outages mandated by the Nuclear Regulatory Commission (NRC) from the total of planned and forced outages for each unit. This had not been done in previous capacity factor studies, but it permitted us to focus more narrowly on the issue of past and future technical performances *per se.*

Methodology and Data Base

The basic procedure employed in this study, as in the previous efforts referred to above, was multivariate regression analysis by the method of least squares. This statistical technique for the analysis of variance estimates coefficients in an equation in which several independent variables are believed to collectively "explain" the observer variation in the dependent variable. In this case the dependent variable is the key component of the capacity factor, namely, the adjusted capacity factor based on forced outages and scheduled equipment and maintenance. One can express the dependent variable as a linear combination of the independent or explanatory variables chosen. For the variable of primary interest, CF, a multiple regression equation is

$$CF = \sum_i a_i X_i$$

For a set of observations of CF and values of the explanatory variables (X_i) the values of the coefficients (a_i) are estimated. That is, the dependence of the dependent variable upon each of a set of explanatory variables (and the set as a whole) is statistically established.

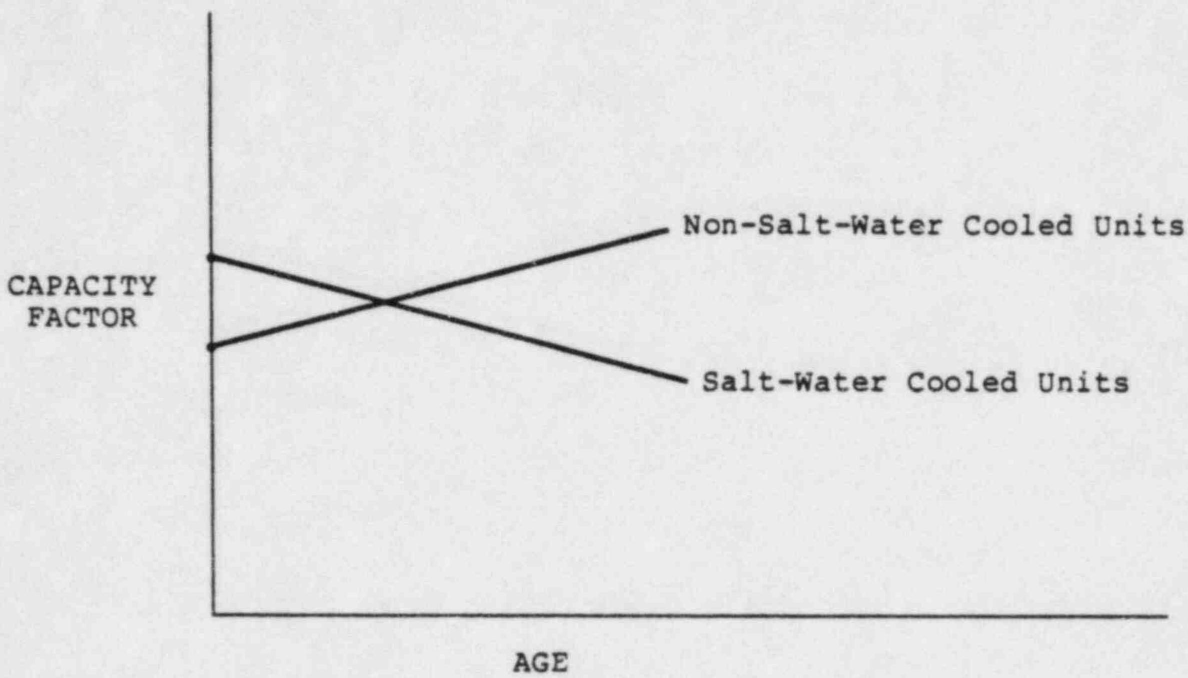
Regression analysis provides methods by which the accuracy of the estimated coefficient for each independent variable may be evaluated. Moreover, regression analysis provides means by which the explanatory power of a particular set of independent variables may be measured. Alternative equations or models, embodying different sets of independent variables, may be compared.

The basic set of independent variables (the X_i) used in the capacity factor analysis in this study are the unit's maximum dependable capacity (MDCU), use of cooling towers (TOWERSU=1 if they are used, 0 otherwise), use of salt water in the cooling system (SALTU=1 if it is used, 0 otherwise), the type of unit (PWRU=1 if it is a PWR, 0 otherwise), and a variable (AGE) which identifies the year of plant operation with which each capacity factor observation is associated. These are not an exhaustive set of potential explanatory variables, and indeed they do not prima facie provide significant explanatory power. Some of them, however, have already been used rather successfully in previous analyses, and the group as a whole represents a real expansion of the information considered to date.

Moreover, extensive use has been made of product terms, which entail new independent variables created as the product of two or more of the basic set of variables given above. The interpretation of these terms is straightforward. For example, if AGE, SALTU, and AGE x SALTU are among the variables in an equation (or model) under consideration, then a statistically significant value for the coefficient of the product term AGE x SALTU indicates differential capacity factor aging behavior for salt-water cooled nuclear power plants when compared with other types of plants. The coefficient of the SALTU term itself thus can be taken as providing an intercept value that estimates a baseline difference that is modified by the product term. These three terms together can characterize a general aging effect for all nuclear units (the AGE term) starting from a common baseline, a differential baseline effect for salt-water cooled units (the SALTU term), and a differential aging effect for salt-water cooled units (the SALTU x AGE term). Figure C-1 below illustrates this possibility.

Figure C-1

Hypothetical Effect of a Simple Product Term for Aging



The accuracy of regression analysis is predicated upon the assumption that all available information relevant to the explanation of the dependent variables (in this case the capacity factor) is incorporated into the model. Two sources of outage that contribute to the total outage data from which the capacity factor is formed are particularly troublesome in this regard. Plant outages for nuclear refueling and NRD-mandated shutdowns cause a significant and apparently random variation in observed capacity factors that has not been separately analyzed in previous research. If one is attempting principally to explain forced outage rates for nuclear units, inclusion of these outages in the capacity factor observation would in theory lead to biased results. This should thus be corrected if credibility is to be achieved for the regression analysis.

If refuelling and NRC mandated outages are not related to the independent variables selected for a model of equipment and maintenance related outages the explanatory power of a model for the total or unadjusted capacity factor (incorporating all outages) may be found to be unnecessarily poor. Removal of this "noise" could lead to statistical results which are much improved over those found for the unadjusted capacity factor. This is especially likely in the case of capacity factors calculated, as is usually done, on an annual basis, since refuelling cycles generally do not occur on a regular yearly basis, but often each 14 to 18 months, thus affecting plant outages in different calendar years quite differently. Randomness can also be introduced by NRC related outages. As a consequence, an adjusted capacity factor resulting from the subtraction of refuelling and NRC-mandated outages was chosen as the dependent variable in this study. Since training and licensing outages, while not lengthy, introduce similar randomness, they too were subtracted. Adjustment is according to the formula:

NCAPFAC2 = Electric Generation/[8760 x FRAC-OUTAGE] x MDC

where "MDC is the maximum dependable capacity of the plant, "FRAC" is the fraction of the year it was in commercial operation, and "OUTAGE" is the total outage hours for the categories for which adjustment is made.

This adjustment to the nuclear capacity factors analyzed is one of the important advances that the present study offers.

Data on nuclear unit outages for the years 1975 through 1981 were obtained from the NRC "grey book" data base on computer tape.* This data was processed by computer into outage hours for 16 categories of outage causes. The basic categories were equipment failure, maintenance, refueling, NRC mandated shutdown, training and examination, administrative causes, operator error, and "other" causes. Table C-1 provides capacity factors expressed as ratios and adjusted by subtracting outages due to refueling, NRC orders, and training and licensing.

Table C-2 provides some of the characteristics of the existing nuclear units whose operating experience has been used as the basis for the present study.

The use of adjusted capacity factors requires further correction of the regression analysis because the significance of each observation is no longer equal. For example, a 20 percent capacity factor for 600 hours of operation should not carry as much weight as one of 60 percent for a whole year (8760 hours). Also, the expected variance of observations on shorter periods is higher. The way to correct for this bias is to weight the estimates through the use of the generalized least squares (GLS) techniques. The weights are proportional to expected variance, which in this case was taken to be a linear function of the square of the inverse of the on-line hours (Ref. C-4).

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* The "grey book" is the Licensed Operating Reactors Status Summary Report (NUREG-0020) issued periodically by the NRC. The data base underlying this report was obtained on computer tape from NRC for use in this analysis.

TABLE C-1

ADJUSTED CAPACITY FACTORS

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981
1. ARKANSAS 1	-	-	-	-	-	0.669	0.531	0.854	0.849	0.546	0.579	0.842
2. ARKANSAS 2	-	-	-	-	-	0.	0.	0.	0.	0.	0.633	0.788
3. DUANE ARNOLD	-	-	-	-	-	0.453	0.664	0.785	0.306	0.643	0.778	0.668
4. BEAVER VALLEY 1	-	-	-	-	-	0.	0.173	0.405	0.35	0.528	0.372	0.657
5. BIG ROCK POINT	-	-	-	-	-	0.518	0.654	0.804	0.715	0.233	0.912	0.919
6. BROWNS FERRY 1	-	-	-	-	-	0.151	0.148	0.771	0.707	0.849	0.829	0.898
7. BROWNS FERRY 2	-	-	-	-	-	0.071	0.195	0.667	0.784	0.872	0.77	0.801
8. BROWNS FERRY 3	-	-	-	-	-	0.	0.	0.751	0.757	0.83	0.859	0.856
9. BRUNSWICK 1	-	-	-	-	-	0.	0.	0.461	0.753	0.704	0.757	0.369
10. BRUNSWICK 2	-	-	-	-	-	0.61	0.359	0.499	0.693	0.746	0.557	0.475
11. CALVERT CLIFFS 1	-	-	-	-	-	0.766	0.873	0.875	0.8	0.74	0.82	0.845
12. CALVERT CLIFFS 2	-	-	-	-	-	0.	0.	0.837	0.783	0.865	0.911	0.88[illegible]
13. CONNECTICUT YANKEE	-	-	-	-	-	0.967	0.953	0.899	0.968	0.994	0.955	0.961
14. D. C. COOK 1	-	-	-	-	-	0.626	0.761	0.646	0.878	0.73	0.918	0.821
15. D. C. COOK 2	-	-	-	-	-	0.	0.	0.	0.657	0.754	0.746	0.829
16. COOPER STATION	-	-	-	-	-	0.51	0.646	0.715	0.8	0.812	0.77	0.654
17. CRYSTAL RIVER 3	-	-	-	-	-	0.	0.	0.666	0.38	0.756	0.855	0.757
18. DAVIS-BESSE 1	-	-	-	-	-	0.	0.	0.	0.34	0.567	0.654	0.57
19. DRESDEN 1	-	-	-	-	-	-	-	-	-	-	-	-
20. DRESDEN 2	-	-	-	-	-	0.7	0.806	0.512	0.844	0.84	0.682	0.775
21. DRESDEN 3	-	-	-	-	-	0.547	0.691	0.766	0.674	0.513	0.778	0.769
22. FARLEY 1	-	-	-	-	-	0.	0.	0.684	0.841	0.703	0.807	0.482
23. J. A. FITZPATRICK	-	-	-	-	-	0.501	0.612	0.741	0.726	0.808	0.83	0.811
24. FORT CALHOUN	-	-	-	-	-	0.66	0.656	0.859	0.846	0.876	0.793	0.69
25. GINNA	-	-	-	-	-	0.805	0.618	0.819	0.928	0.84	0.887	0.977
26. HATCH 1	-	-	-	-	-	0.	0.624	0.624	0.729	0.779	0.722	0.695
27. HATCH 2	-	-	-	-	-	0.	0.	0.	0.	0.812	0.597	0.773
28. HUMBOLDT BAY	-	-	-	-	-	0.697	0.348	0.	0.	0.004	0.	0.
29. INDIAN POINT 2	-	-	-	-	-	0.614	0.598	0.76	0.8	0.846	0.[illegible]	0.663
30. INDIAN POINT 3	-	-	-	-	-	0.	0.657	0.653	0.826	0.806	0.41	0.359
31. KEWAUNEE	-	-	-	-	-	0.745	0.894	0.918	0.964	0.841	0.925	0.962
32. LA CROSS	-	-	-	-	-	0.821	0.779	0.534	0.52	0.542	0.597	0.626
33. MAINE YANKEE	-	-	-	-	-	0.751	0.835	0.875	0.857	0.923	0.747	0.845
34. MILLSTONE 1	-	-	-	-	-	0.721	0.786	0.841	0.902	0.885	0.782	0.564
35. MILLSTONE 2	-	-	-	-	-	0.	0.6	0.627	0.777	0.722	0.925	0.869
36. MONTICELLO	-	-	-	-	-	0.781	0.849	0.928	0.857	0.937	0.84	0.741
37. NINE MILE POINT	-	-	-	-	-	0.57	0.77	0.879	0.836	0.809	0.852	0.906
38. NORTH ANNA 1	-	-	-	-	-	0.	0.	0.	0.849	0.755	0.796	0.839
39. NORTH ANNA 2	-	-	-	-	-		0.	0.	0.	0.	1.024	0.725
40. OCONEE 1	-	-	-	-	-	0.703	0.632	0.595	0.78	0.77	0.791	0.61
41. OCONEE 2	-	-	-	-	-	0.66	0.633	0.588	0.73	0.836	0.681	0.695
42. OCONEE 3	-	-	-	-	-	0.669	0.713	0.77	0.902	0.847	0.741	0.793
43. OYSTER CREEK	-	-	-	-	-	0.676	0.774	0.836	0.826	0.84	0.767	0.526
44. PALISADES	-	-	-	-	-	0.451	0.792	0.914	0.66	0.9	0.718	0.946
45. PEACH BOTTOM 2	-	-	-	-	-	0.567	0.801	0.705	0.828	0.931	0.75	0.72
46. PEACH BOTTOM 3	-	-	-	-	-	0.586	0.682	0.734	0.891	0.787	0.799	0.712
47. PILGRIM	-	-	-	-	-	0.441	0.62	0.63	0.746	0.825	0.826	0.799
48. POINT BEACH 1	-	-	-	-	-	0.739	0.944	0.929	0.911	0.836	0.74	0.727
49. POINT BEACH 2	-	-	-	-	-	0.863	0.928	0.961	0.963	0.907	0.911	0.955
50. PRARIE ISLAND 1	-	-	-	-	-	0.838	0.815	0.927	0.924	0.72	0.827	0.972
51. PRARIE ISLAND 2	-	-	-	-	-	0.725	0.698	0.982	0.946	0.957	0.912	0.808
52. QUAD CITIES 1	-	-	-	-	-	0.634	0.627	0.611	0.71	0.767	0.734	0.85
53. QUAD CITIES 2	-	-	-	-	-	0.54	0.738	0.649	0.773	0.658	0.771	0.803
54. RANCHO SECO	-	-	-	-	-	0.245	0.288	0.977	0.724	0.904	0.859	0.472

TABLE C-1

ADJUSTED CAPACITY FACTORS

(Continued)

55. H. B. ROBINSON 2	-	-	-	-	-	0.804	1.059	0.711	0.801	0.886	0.7	0.649
56. SALEM 1	-	-	-	-	-	0.	0.	0.379	0.479	0.427	0.74	0.655
57. SAN ONOFRE 1	-	-	-	-	-	0.892	0.871	0.612	0.872	0.879	0.294	0.204
58. ST. LUCIE 1	-	-	-	-	-	0.	0.531	0.785	0.894	0.912	0.902	0.94
59. SURRY 1	-	-	-	-	-	0.786	0.678	0.875	0.893	0.871	0.483	0.35
60. SURRY 2	-	-	-	-	-	0.855	0.569	0.72	0.813	0.964	0.899	0.922
61. THREE MILE ISLAND 1	-	-	-	-	-	0.815	0.867	0.956	0.954	0.33	0.	0.
62. TROJAN	-	-	-	-	-	0.	0.345	0.689	0.79	0.714	0.88	0.837
63. TURKEY POINT 3	-	-	-	-	-	0.843	0.879	0.935	0.916	0.81	0.862	0.188
64. TURKEY POINT 4	-	-	-	-	-	0.915	0.782	0.786	0.774	0.863	0.797	0.968
65. VERMONT YANKEE	-	-	-	-	-	0.872	0.824	0.927	0.794	0.893	0.814	0.929
66. YANKEE ROWE	-	-	-	-	-	0.937	0.817	0.874	0.938	0.857	0.215	0.764
67. ZION 1	-	-	-	-	-	0.539	0.677	0.663	0.857	0.77	0.757	0.914
68. ZION 2	-	-	-	-	-	0.53	0.513	0.882	0.912	0.678	0.579	0.693

TABLE C-2

NUCLEAR UNIT CHARACTERISTICS

	PWR	SALT WATER	MDC	TOWERS	STEAM SYSTEM	C. O. DATE
1. ARKANSAS 1	1	0	836	0	1	74.97
2. ARKANSAS 2	1	0	858	1	2	80.23
3. DUANE ARNOLD	0	0	515	1	4	75.09
4. BEAVER VALLEY 1	1	0	810	1	3	76.75
5. BIG ROCK POINT	0	0	64	0	4	63.24
6. BROWNS FERRY 1	0	0	1065	1	4	74.58
7. BROWNS FERRY 2	0	0	1065	1	4	75.16
8. BROWNS FERRY 3	0	0	1065	1	4	77.16
9. BRUNSWICK 1	0	1	790	0	4	77.21
10. BRUNSWICK 2	0	1	790	0	4	75.84
11. CALVERT CLIFFS 1	1	1	825	0	2	75.35
12. CALVERT CLIFFS 2	1	1	825	0	2	77.25
13. CONNECTICUT YANKEE	1	0	555	0	3	38.00
14. D. C. COOK 1	1	0	1044	0	3	75.65
15. D. C. COOK 2	1	0	1082	0	3	78.50
16. COOPER STATION	0	0	764	0	4	74.50
17. CRYSTAL RIVER 3	1	1	782	0	1	77.12
18. DAVIS-BESSE 1	1	0	874	1	1	78.50
19. DRESDEN 1	0	0	200	0	4	60.00
20. DRESDEN 2	0	0	772	0	4	70.44
21. DRESDEN 3	0	0	773	0	4	71.88
22. FARLEY 1	1	0	804	1	3	77.92
23. J. A. FITZPATRICK	0	0	810	0	4	75.57
24. FORT CALHOUN	1	0	478	0	2	74.47
25. GINNA	1	0	470	0	3	70.46
26. HATCH 1	0	0	757	1	4	76.00
27. HATCH 2	0	0	771	1	4	79.68
28. HUMBOLDT BAY	0	1	65	0	4	60.00
29. INDIAN POINT 2	1	1	864	0	3	74.58
30. INDIAN POINT 3	1	1	965	0	3	76.66
31. KEWAUNEE	1	0	512	0	3	74.42
32. LA CROSS	0	0	48	0	-	69.84
33. MAINE YANKEE	1	1	810	0	2	74.99
34. MILLSTONE 1	0	1	654	0	4	71.16
35. MILLSTONE 2	1	1	864	0	2	75.99
36. MONTICELLO	0	0	536	1	4	71.41
37. NINE MILE POINT	0	0	610	0	4	69.92
38. NORTH ANNA 1	1	0	865	0	3	78.43
39. NORTH ANNA 2	1	0	890	0	3	80.96
40. OCONEE 1	1	0	860	0	1	73.54
41. OCONEE 2	1	0	860	0	1	74.69
42. OCONEE 3	1	0	860	0	1	74.96
43. OYSTER CREEK	0	1	620	0	4	69.92
44. PALISADES	1	0	635	1	2	71.92
45. PEACH BOTTOM 2	0	0	1051	1	4	74.51
46. PEACH BOTTOM 3	0	0	1035	1	4	74.99
47. PILGRIM	0	1	670	0	4	72.92
48. POINT BEACH 1	1	0	495	0	3	70.97
49. POINT BEACH 2	1	0	495	0	3	72.75
50. PRARIE ISLAND 1	1	0	503	1	3	73.96
51. PRARIE ISLAND 2	1	0	500	1	3	74.97
52. QUAD CITIES 1	0	0	769	0	4	73.13
53. QUAD CITIES 2	0	0	769	0	4	73.19
54. RANCHO SECO	1	0	873	1	1	75.29

TABLE C-2

NUCLEAR UNIT CHARACTERISTICS
(Continued)

55. H. B. ROBINSON 2......	1	0	665	0	3	71.18
56. SALEM 1...............	1	1	1079	0	3	77.4[illegible]
57. SAN ONOFRE 1..........	1	1	436	0	3	68.[illegible]
58. ST. LUCIE 1...........	1	1	777	0	2	76.[illegible]
59. SURRY 1...............	1	1	775	0	3	72.97
60. SURRY 2...............	1	1	775	0	3	73.33
61. THREE MILE ISLAND 1...	1	0	776	1	1	74.[illegible]
62. TROJAN................	1	0	1080	1	3	76.[illegible]
63. TURKEY POINT 3........	1	1	646	0	3	72.[illegible]
64. TURKEY POINT 4........	1	1	646	0	3	73.47
65. VERMONT YANKEE........	0	0	504	1	4	72.92
66. YANKEE ROWE...........	1	0	175	0	3	61.[illegible]
67. ZION 1................	1	0	1040	0	3	74.[illegible]
68. ZION 2................	1	0	1040	0	3	74.7[illegible]

Notes

PWR: PWR Unit if 1; BWR if 0

Salt Water: Salt water used for cooling if 1; fresh water if 0

MDC: Maximum dependable capacity net MW (maximum electrical output during the most restrictive seasonal conditions, less the normal station service loads)

Towers: Cooling towers if 1; none if 0

Steam System: Supplier of steam system (Babcock and Wilcox, 1; Combustion Engineering, 2; Westinghouse, 3; or General Electric, 4)

C.O. Date: Date of initial commercial operation (year, followed by the fraction of the year that had passed by the point of commercial opeation. Thus, Yankee Rowe started commercial operation at 61.50, or July 1, 1961).

First years of operation are included among the capacity factor observations, and thereby in these analyses, since the GLS estimation procedure weights their significance appropriately.

Outage data for the Dresden #1 unit is not presently available in the NRC data base, and hence this unit was not included in the analysis. Exclusion of this unit's experience tends to bias the capacity factor results of this study on the high side. Similarly, Three Mile Island #2 was excluded, as were Indian Point #1 and Humboldt Bay after 1978. Year 1980 data for Arkansas #2 was unintentionally excluded. Moreover, no operating experience prior to 1975 has been analyzed since the unit-specific (as opposed to station-specific) outage data were not available on the NRC tape.

Modelling Considerations

Simple linear regression using the basic set of independent variables -- MDCU, PWRU, SALTU, TOWERSU, and AGE -- produced rather weak results. The model employed and the regression results are given explicitly in Table C-3 below.

Note the only term here with strong statistical significance is the PWRU term, while the SALTU and AGE terms are only found to be significant at 90+ percent. Note, also, the poor R-SQUARED (.07).

Addition of various cross product terms to the regression equation (e.g. AGE x MDCU, AGE x SALTU, PWRU x MDCU, SALTU x PWRU) yielded significantly improved results, and this modelling direction was pursued on a systematic basis. Moreover, in an attempt to capture long term trends two methods were explored; the addition of quadratic age terms (e.g. AGE^2 x MDCU; etc.), and the use of broken linear terms. These approaches were taken in order to examine whether the

TABLE C-3

INITIAL REGRESSION ON BASIC SET OF VARIABLES

Term in Equation	Coefficient of Term	t-Statistic
1	.717	13.7
MDCU	-5.77×10^{-5}	-1.23
PWRU	.071	4.20
SALTU	-.034	-1.75
AGE	.005	1.76
TOWERSU	3.73×10^{-4}	.016

Number of Variables = 6
R-Squared = .069
Corrected R^2 = .058

Standard Error of Regression = .140
F(5/414) = 6.18
COND(X) = 15.5

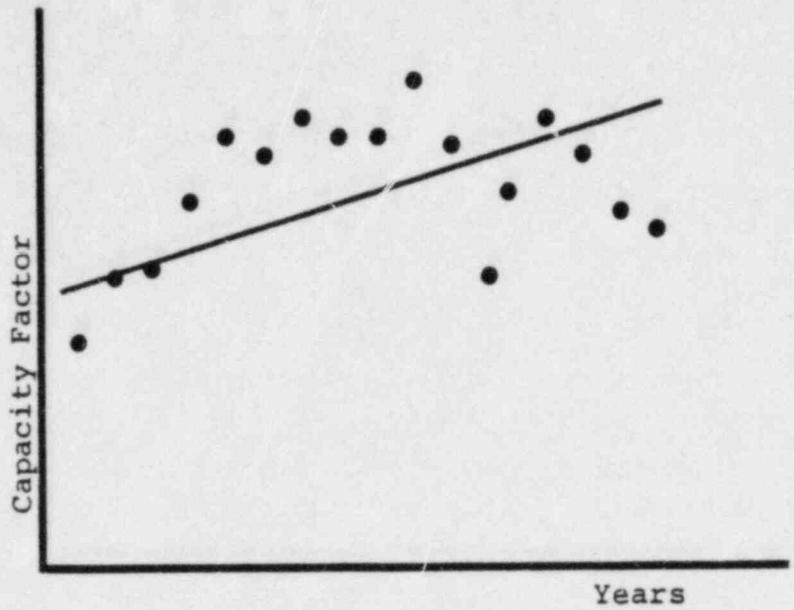
basic age results, for example maturation in early years, could be expected to continue beyond those years or whether a change in the capacity factor aging behavior would be found. If such additional (i.e. quadratic or broken linear age) terms proved to be statistically significant then the latter conclusion would be indicated.

Illustration of the use of quadratic and broken linear approaches can be found in Figures C-2, C-3, and C-4. Figure C-2 shows how a hypothetical set of observations could be explained by a simple linear term (e.g. in any one of the age variables; AGE or AGE x SALTU). Quadratic terms start out small and become rapidly larger. If a quadratic term is added to the linear and found to be statistically significant, it means that the long term behavior of the same set of observations (the dependent variable capacity factor) is better estimated by the sum of linear and quadratic terms than by the linear alone. This can be seen by comparing Figure C-3 to Figure C-2. In Figure C-3 the resulting estimation is the solid line which is the sum of the linear and quadratic (dashed) lines.

Broken linear age terms can be used to estimate the behavior of the capacity factors over limited segments of time within the operating experience of the nuclear units. Consider Figure C-4. In this illustration example line A (beginning as a broken line and continuing as solid) represents an overall long-term aging trend, while line B is added to account for early year (i.e. maturation) behavior. The actual estimate is the sum of these two lines, i.e. the solid line beginning with line segment C (early maturation). If the coefficients of both lines (A and B) are found to be statistically significant, it means that actual capacity factor behavior is better

FIGURE C-2

Illustration of a Simple Linear Specification



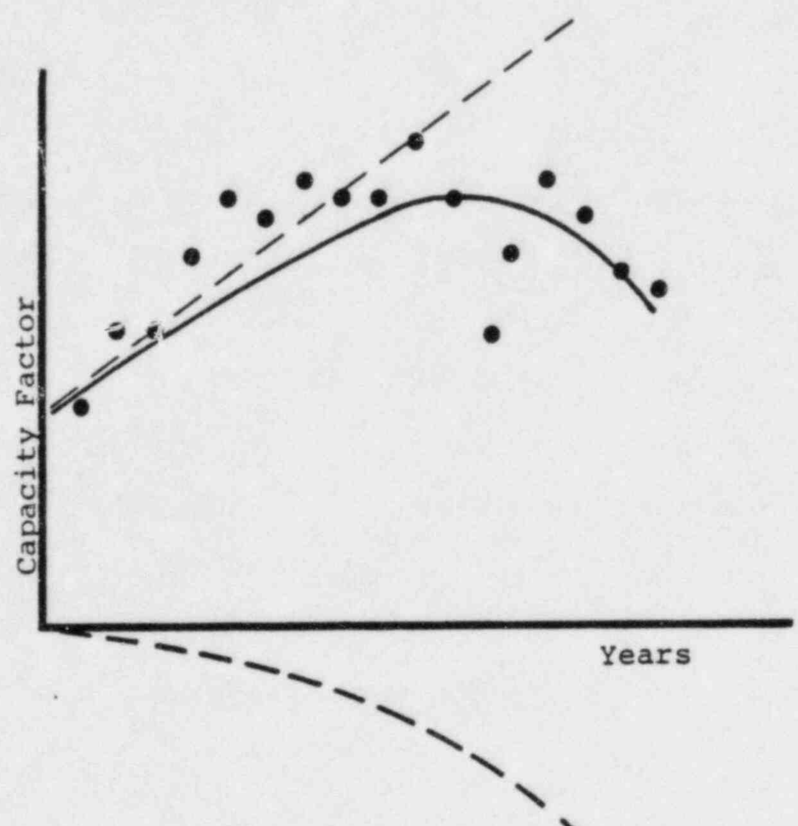


FIGURE C-3

Illustration of a Linear Plus Quadratic Specification

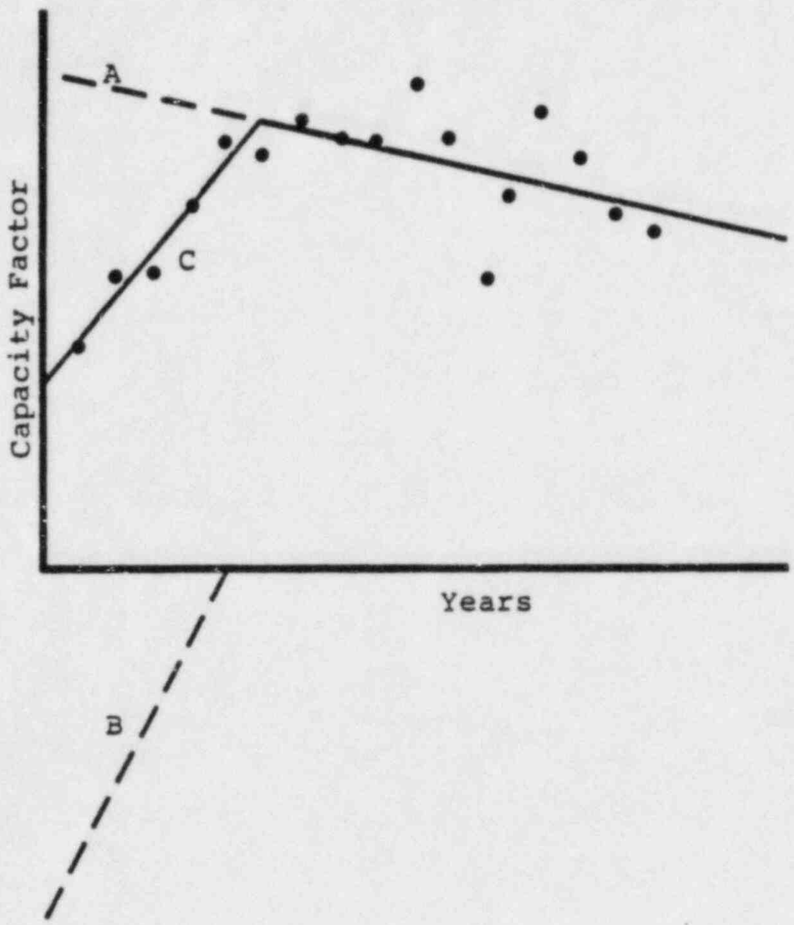


FIGURE C-4

Illustration of a Broken Linear Specification described by the broken linear than by a simple linear age term (compare Figures C-2 and C-4). Note, finally, that while both the quadratic (Figure C-3) and broken linear Figure C-4) estimations have comparable explanatory power with regard to the observations, they have quite different long term behavior. In either case statistically signficant results for this illustrative example would indicate that capacity factors experienced early maturation followed by long-term decline.

The broken linear method was ultimately selected over the quadratic approach. The basic reasons for this choice was that the results of the broken linear approach were easier to interpret, more conservative with regard to long term capacity factor prediction, and potentially much more accurate given the greater number of functions of age used (four). Given the limited number of operating years within the existing nuclear plant data base, a finding of a slow down or leveling of capacity factor maturation by use of a quadratic age term (i.e., a negative coefficient for this term) provide serious problems for prediction of long term behavior. While a leveling off of maturation could be embodied in the data base a quadratic term which explains this could misleadingly indicate an extremely rapid decline in just a few years thereafter. The long term aging effects could be further explored by adding higher order (e.g., cubic) terms. The introduction of such terms could have a moderating effect on the rapid capacity factor decline associated with the quadratic model, but would be difficult to justify statistically at this point.

While the broken linear approach was chosen here, it is interesting to note that the general results were similar for both broken linear and quadratic models. That is, they have comparable explanatory power with respect to the observations embodied in actual operating experience.

In addition to a general age term, four broken linear terms were tested for significance both alone and in product terms containing AGE. These were called AGE2, AGE4, AGE6, and AGE8. The values for these terms were established by subtraction of 2, 4, 6, and 8, respectively, from a nuclear unit's age in a given year of its operation and setting to zero all of the resulting values that were greater than zero. Each of these variables has a sequence of negative values whose absolute magnitude decreases by 1 each year until zero is reached.

This technique produces four line segments in the first eight years of operation, similar to the simple broken linear illustration discussed earlier. It is employed in an attempt to capture the shape and duration of early maturation effects, while the simple AGE terms capture long-term behavior. The procedure for choosing which broken linear age terms to include in the model was to begin by including all of them and to follow this by eliminating those which contributed insufficiently to the explanatory power of the equation. With this procedure AGE8 was not found to be significant in any of the models examined.

Analysis of Adjusted Capacity Factors

The model selected and the linear regression results are given in Table C-4. The terms in the equation for the adjusted nuclear capacity factor (NCAPFAC2) are defined in Table C-5. Some terms not introduced in the earlier discussion of the basic independent variables were incorporated in the model to explore additional relationships.

TABLE C-4

FINAL REGRESSION RESULTS FOR ADJUSTED CAPACITY FACTORS

Name of Coefficient	Term in Equation	Coefficient of Term	t-Statistic
A	1	.625	6.10
B	MDCU	-7.53×10^{-5}	- .528
Z	MDCU x PWRU	-3.44×10^{-4}	-3.73
C	PWRU	.527	5.01
G	SALTU	.723	4.33
E	AGE	1.35×10^{-4}	.013
X1	MDCU x SALTU	-5.35×10^{-4}	-3.73
K	PWRU x TOWERSU	- .143	-3.30
W	AGE x PWRU	- .021	-3.32
D	AGE x MDCU	3.29×10^{-5}	2.31
L	TOWERSU	.101	2.84
S	SALTU x AGE	-.050	-4.29
F	SALTU x PWRU	.133	1.78
H	SALTU x PWRU x AGE	-.028	-2.82
L3	AGE6	.036	1.52
M2	AGE4 x MDCU	1.07×10^{-4}	3.55
M3	AGE6 x MDCU	-7.75×10^{-5}	-1.95
N2	AGE4 x SALTU	-.079	-1.87
N3	AGE6 x SALTU	.105	3.24
X2	BWSTM	-.089	-2.30
X3	WESTM	-.035	-1.30
X4	TMI	.002	.131
X5	TMI x BWSTM	-.025	-.543

Number of Variables = 23
R-Squared = .362
Corrected R^2 = .327

Standard Error of Regression = .118
F(22/397) = 10.2
COND(X) = 81.4

TABLE C-5

INDEPENDENT VARIABLE DEFINITIONS

Variable Name	Definition
MDCU	Unit size in megawatts
PWRU	1 if unit is pwr 0 otherwise
SALTU	1 if unit is salt water cooled 0 if otherwise
AGE	Years of commercial operation according to calendar years. The first calendar year of operation averages only one-half a year of plant operation.
TOWERSU	1 if unit has cooling tower 0 otherwise
AGE4	AGE-4 for Age $\leq$ 4 0 otherwise
AGE6	Age-6 for Age $\leq$ 6 0 otherwise
BWSTM	Babcock and Wilcox Steam System
WESTM	Westinghouse Steam System
TMI	1 if year of operation is 1980, 1981 0 otherwise (This is to estimate the effect of the Three Mile Island event.)

The regression summarized in Table C-4 has an R-SQUARED of 0.36, which is much higher than the results heretofore reported in the literature. The standard error is about 0.12, which means that 68 percent of the adjusted capacity factors estimated by this equation will fall within 12 percent of the actual observations. Its value of 81 for COND(X) indicates that collinearity is not a serious problem.

The F-statistic indicates more than sufficient explanatory power for all 23 variables collectively at the 99%+ confidence level.

Table C-4 also presents the values, standard errors, and t-statistics for each of the coefficients in the regression. The interpretation of these results is straightforward. The estimated value for a coefficient is its most likely value. The standard error is a probability measure of the difference between actual and predicted values. There is a 68 percent probability that the estimate will be within one standard error of the actual value. The t-statistic measures the likelihood that the coefficient is significantly different from zero, that is, whether the independent variable is statistically significant. A t-statistic of absolute value equal to or greater than 1.645 indicates that the probability is 90 percent that the coefficient differs from zero. A value greater than 1.96 indicates a 95 percent probability, and one of 2.57 or greater indicates a 98 percent probability.

The most important terms in the regression are those related to capacity factor aging effects. The coefficients of these terms will be reviewed first. Reference can be made to Table C-4.

General aging effect: Coefficient E has the estimated value of .000135. If accurate this would mean that the average adjusted capacity factor for nuclear units increases almost not at all, other factors equal. In fact, the rather high standard error and near zero t-statistic found here indicate that there is no significant general aging effect. Rather one must look to other more complex terms in the regression equation (with AGE) to see whether they can capture or explain general aging behavior.

The only other general age term in the model is AGE6. Its coefficient L3 indicates an average general capacity factor maturation rate of 3.6 percent per year for the first six years of operation. However, this coefficient is found to be significant only at the 80 percent confidence level.

PWR aging effect: The value of coefficient W for the product term AGE x PWRU suggests a 2 percent annual decline in the adjusted capacity factor for PWR units after their 6th year of operation. Unlike the E coefficient for aging in general, W is estimated to be significant at the 99.8 percent level. Broken linear terms were not found to be significant in the case of PWR-specific aging effects.

Size related aging effects: The value of coefficient D for the product term AGE x MDCU estimates the effect of a nuclear unit's size on the general long-term variation of its capacity factor. In order to obtain the estimated annual effect this coefficient must be multiplied by the unit's size (MDCU). For a 1000 MW plant of any type this general long-term size related aging effect is estimated to embody a 3.2 percent annual increase, as opposed to 1.6 percent for a 500 MW unit. This coefficient is found to be significant at the 95 percent confidence level.

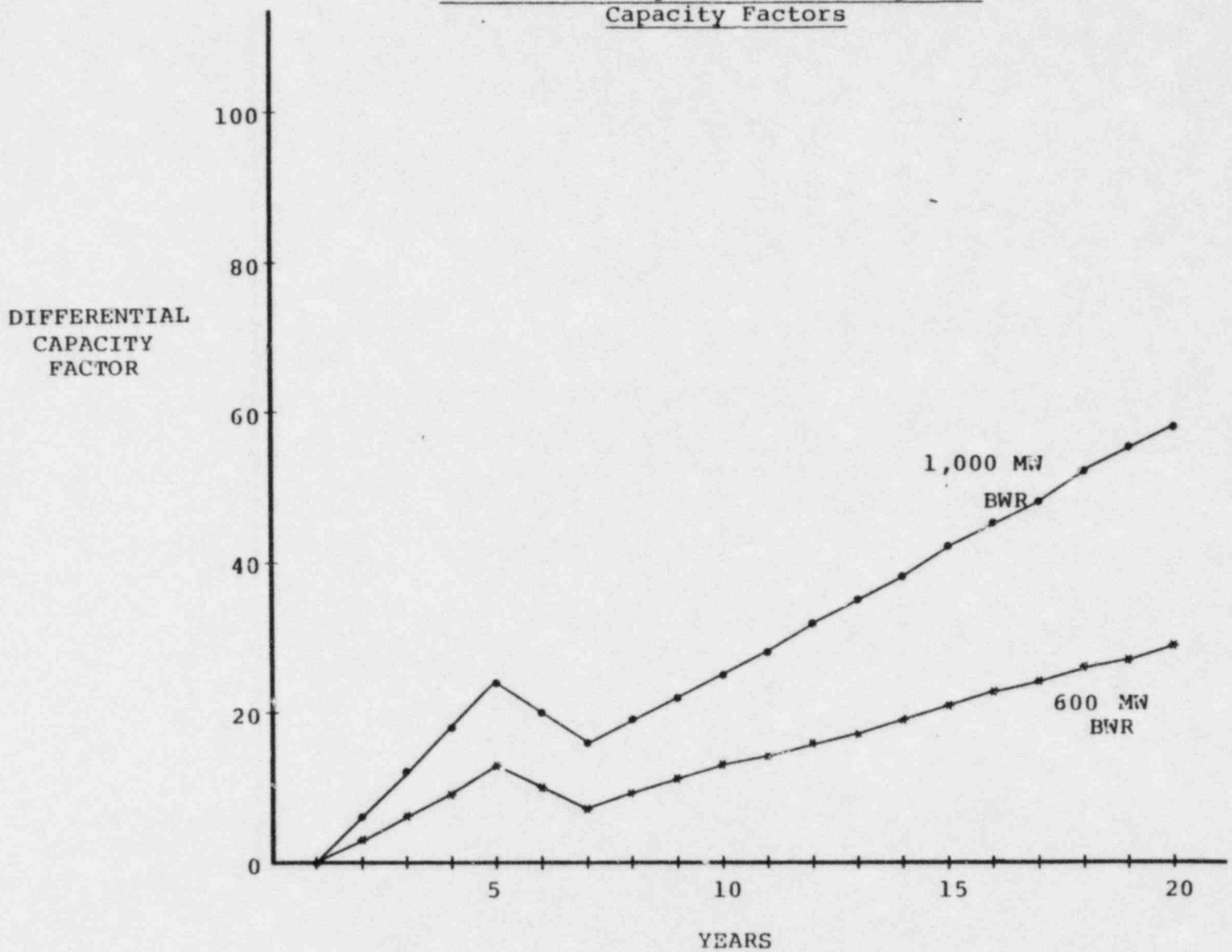
Since AGE, AGE x MDCU, and AGE x PWR are the only non salt-water cooling related age variables representing long-term adjusted factor behavior, it can be seen that a net long-term growth in capacity factors of BWR units which are not salt-water cooled has been estimated. This result will be reviewed later.

The broken linear age coefficients M2 and M3 for the variables AGE4 x MDCU and AGE6 x MDCU, respectively, are both found to be significant at the 95+ percent confidence level. These imply early maturation effects, which are greater for larger units, followed by a decline in the years 5-7, followed by continued maturation. The decline and subsequent maturation are both greater for larger units. Figure C-5 shows the estimated magnitude of these effects for 600 MW and 1000 MW BWR units not cooled by salt-water. The peak could be real, but sharpened by the regression specification, or it could be an artifact of the data base. Since performance data prior to 1975 were not available, the data base could be comprised mostly of units with data for the pre-maturity years and others for the post-maturity years but not the first 4-6 years.

<u>Salt-water cooling-related effects</u>: Salt or brackish water is used in the cooling systems of 20 nuclear units, 14 PWRs and 6 BWRs (see Table C-2). These are cooled by oceans, bays, or rivers with tidal flows. The regression analysis summarized in Table C-3 indicates that salt-water cooled nuclear plants have sharply reduced performance over time. The salt-water related aging effects are represented by the terms SALTU x AGE (a general long-term effect for these units), SALTU x AGE4 and SALTU x AGE6 (a general early year effect for these units), and SALTU x PWR x AGE (a differential long-term effect

FIGURE C.5

Size Related Age Trends for Adjusted Capacity Factors



for PWR units). In addition, a SALTU x MDCU term accounts for a differential effect for salt-water units related to their size. Finally, two other salt-water cooling terms, SALTU (general effect) and SALTU x PWR (PWR effect) provide the intercepts for the aging effect product terms given above. Two of these estimations (coefficients N2 and F) were found to be significant at about the 95 percent confidence level and the other five are significant at greater than the 99 percent level.

Coefficient S of the SALTU x AGE term measures the differential average annual long-term percentage decline of capacity factors associated with salt-water cooled nuclear units at about 5 percent per year. The coefficients of the broken linear terms AGE4 x SALTU and AGE6 x SALTU indicate a different behavior over the first six years for such units. Taken together, these coefficients (N2 and N3) imply aging behavior that is opposite to that reported earlier for the size related aging effects. In this case performance first declines, then improves sharply, and then declines again.

Coefficient H for the SALTU x PWRU x AGE term estimates a further negative age effect for salt-water cooled units of the PWR type, a decline of almost 3 percent per year. No significant early operating year effects were found. This effect is likely due to the well-noted faster deterioration of steam generators in salt-water cooling environments (Ref. C-5).

Coefficient X1 estimates an across-the-board decline in adjusted capacity factors of salt-water cooled plants with increasing size. This differential amounts to a 26 percent lower base line performance for a 600 MW unit.

Remaining terms in the equation: Coefficients X2 and X3 measure differential performance for reactors with Babcock & Wilcox and Westinghouse steam systems, respectively. It can be seen that Babcock & Wilcox reactors are expected to have a capacity factor 9 percent lower than other non-Westinghouse reactors. All other things equal, Westinghouse reactors are expected to have a 3.5 percent lower performance, but the low t-statistic for X3 indicates uncertainty regarding this estimate.

Coefficients X4 and X5 are present in the equation to capture any "post-TMI" effects on nuclear unit performance. "TMI" is a dummy variable which is 1 for the years 1979, 1980 and 1981. The near 0 t-statistic for coefficients X4 and X5 shows that all general post-TMI effects have been corrected for by the previously discussed adjustment of capacity factors for refueling and NRC mandated shut-downs.

The remaining coefficients are intercept terms for the various related coefficients. The exceptions are K and L which estimate the impact of cooling towers on plant performance. Coefficient L estimates that cooling towers improve reactor performance by an average of 10 percent for BWR units. Coefficient K estimates that PWR units with cooling towers show a differential negative performance of about 14 percent, for a net negative effect of about a 4 percent reduction in capacity factor.

Coefficient F is the salt-water cooled PWR intercept, G is the general salt-water plant intercept, C is the PWR unit intercept term, and Z is the size of PWR intercept term.

The model as a whole: The previous discussion has focused attention upon the specific effects of each term in the equation specified. Summary statistics, presented at the beginning of this section show that the specification has relatively good explanatory power for the observed variations in capacity factors. However, because of the rather complex nature of this equation, involving the superposition of many terms, it is difficult to see by cursory inspection how the various terms contribute together to estimate yearly capacity factors for nuclear units with various reactor tyupes, sizes, cooling systems, ages, etc. It is therefore useful to apply the equation to several generic cases to illustrate the overall results of the regression analysis.

Table C-6 shows the adjusted capacity factors expressed as ratios and estimated by the equation for each year of operation for each of eight composite nuclear power plant types: BWRs and PWRs of 600 and 1000 MW, with and without salt-water cooling systems. Figures C-6 through C-9 illustrate the general results graphically.

Inspection of these results shows that salt-water related effects dominate all others, causing adjusted capacity factors for both BWR and PWR units of either size to decline rapidly after several years of maturation. Capacity factors of salt-water cooled PWRs are found to decline much faster than those of salt-water cooled BWRs. Moreover, large salt-water cooled PWRs are found to have much poorer initial performance and even more rapid decline than smaller such units.

TABLE C - 6

Adjusted Capacity Factors
(BWR)

600 MW BWR
No Salt

Age*				
1	0.404022	0.478342	0.552662	0.626982
5	0.701301	0.710044	0.718787	0.73959
9	0.760394	0.781197	0.802	0.822804
13	0.843607	0.864411	0.885214	0.906017
17	0.926821	0.947624	0.968427	0.989231
21	1.01003	1.03084	1.05164	1.07244
25	1.09325	1.11405	1.13485	1.15566
29	1.17646	1.19726		

600 MW BWR
Salt

Age				
1	0.460154	0.510611	0.561067	0.611525
5	0.661982	0.727597	0.793214	0.763837
9	0.73446	0.705085	0.675708	0.646332
13	0.616956	0.58758	0.558204	0.528828
17	0.499452	0.470075	0.440699	0.411325
21	0.381948	0.352571	0.323195	0.293818
25	0.264442	0.235066	0.20569	0.176313
29	0.146938	0.117562		

1000 MW BWR
No Salt

Age				
	0.404613	0.503889	0.603166	0.702443
5	0.801719	0.791701	0.781683	0.815921
9	0.850158	0.884396	0.918633	0.952871
13	0.987109	1.02135	1.05558	1.08982
17	1.12406	1.1583	1.19253	1.22677
21	1.26101	1.29525	1.32948	1.36372
25	1.39796	1.4322	1.46644	1.50067
29	1.53491	1.56915		

1000 MW BWR
Salt

Age				
1	0.249287	0.3247	0.400113	0.475527
5	0.550941	0.597796	0.644651	0.628708
9	0.612766	0.596825	0.580883	0.564941
13	0.548998	0.533057	0.517116	0.501173
17	0.485232	0.469289	0.453347	0.437407
21	0.421465	0.405523	0.389581	0.373639
25	0.357697	0.341755	0.325813	0.309871
29	0.293929	0.277987		

* The capacity factors for each age category are to be read across in groups of four years beginning with the year indicated in the "Age" column.

TABLE C-6(cont.)

Adjusted Capacity Factors
(PWR)

600 MW PWR
No Salt

Age				
1	0.708445	0.760837	0.812829	0.865021
5	0.917213	0.903828	0.890444	0.889119
9	0.887795	0.886471	0.885147	0.883823
13	0.882498	0.881174	0.87985	0.878526
17	0.877201	0.875877	0.874553	0.873229
21	0.871905	0.87058	0.869256	0.867932
25	0.866608	0.865284	0.863959	0.862635
29	0.861311	0.859987		

600 MW PWR
Salt

Age				
1	0.86533	0.865767	0.866203	0.866643
5	0.867081	0.882679	0.898276	0.818881
9	0.739486	0.660092	0.580697	0.501301
13	0.421907	0.342511	0.263117	0.183721
17	0.104327	0.024931	-0.054464	-0.133857
21	-0.213253	-0.292648	-0.372044	-0.451439
25	-0.530834	-0.610229	-0.689624	-0.769019
29	-0.848414	-0.927809		

1000 MW PWR
No Salt

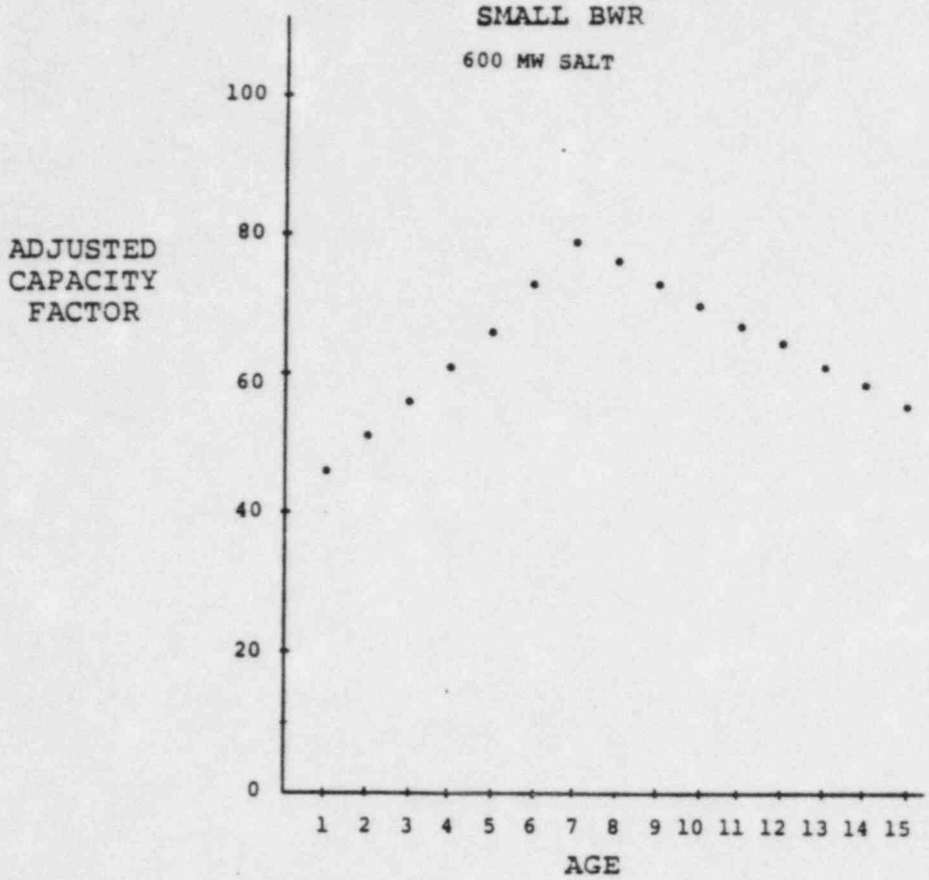
Age				
1	0.568561	0.64571	0.722859	0.800008
5	0.877157	0.845011	0.812865	0.824976
9	0.837086	0.849196	0.861306	0.873416
13	0.885526	0.897636	0.909746	0.921856
17	0.933966	0.946076	0.958186	0.970297
21	0.982407	0.994517	1.00663	1.01874
25	1.03085	1.04296	1.05507	1.06718
29	1.07929	1.0914		

1000 MW PWR
Salt

Age				
1	0.513989	0.539384	0.564779	0.590174
5	0.615569	0.612403	0.60924	0.543279
9	0.477318	0.411358	0.345397	0.279436
13	0.213474	0.147514	0.081554	0.015593
17	-0.050368	-0.116329	-0.182289	-0.248249
21	-0.314211	-0.380171	-0.446132	-0.512093
25	-0.578054	-0.644015	-0.709975	-0.775937
29	-0.841897	-0.907858		

Figure C-6

ADJUSTED CAPACITY FACTORS
SMALL BWR



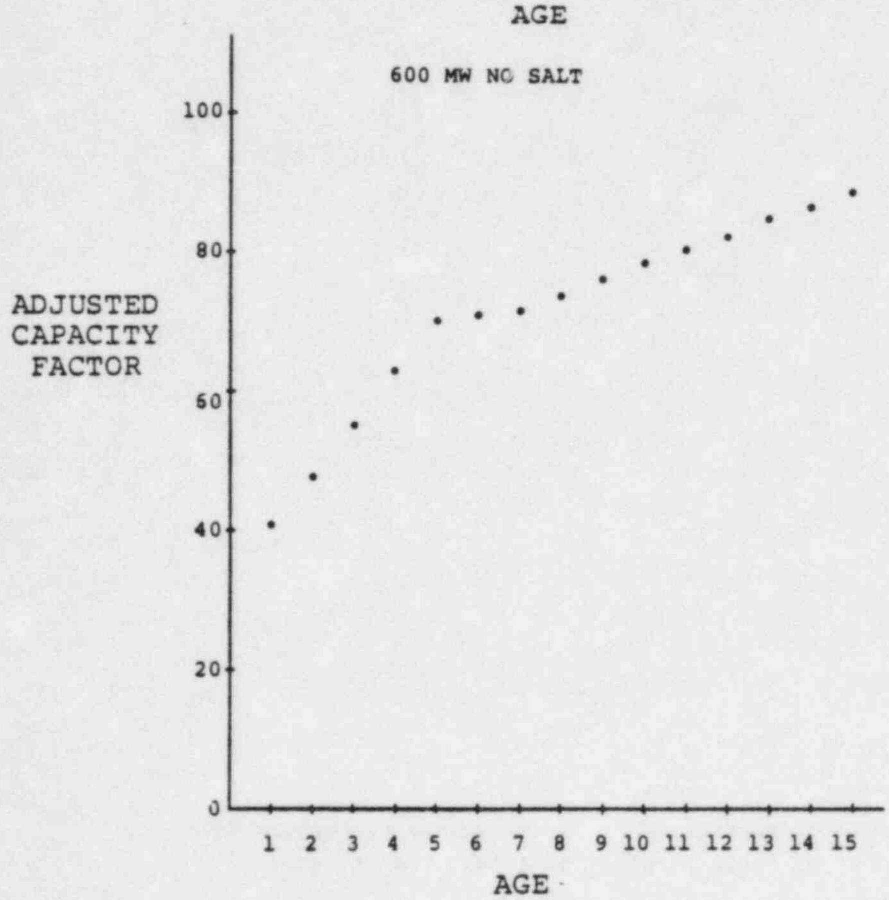


Figure C-7

ADJUSTED CAPACITY FACTORS

LARGE BWR

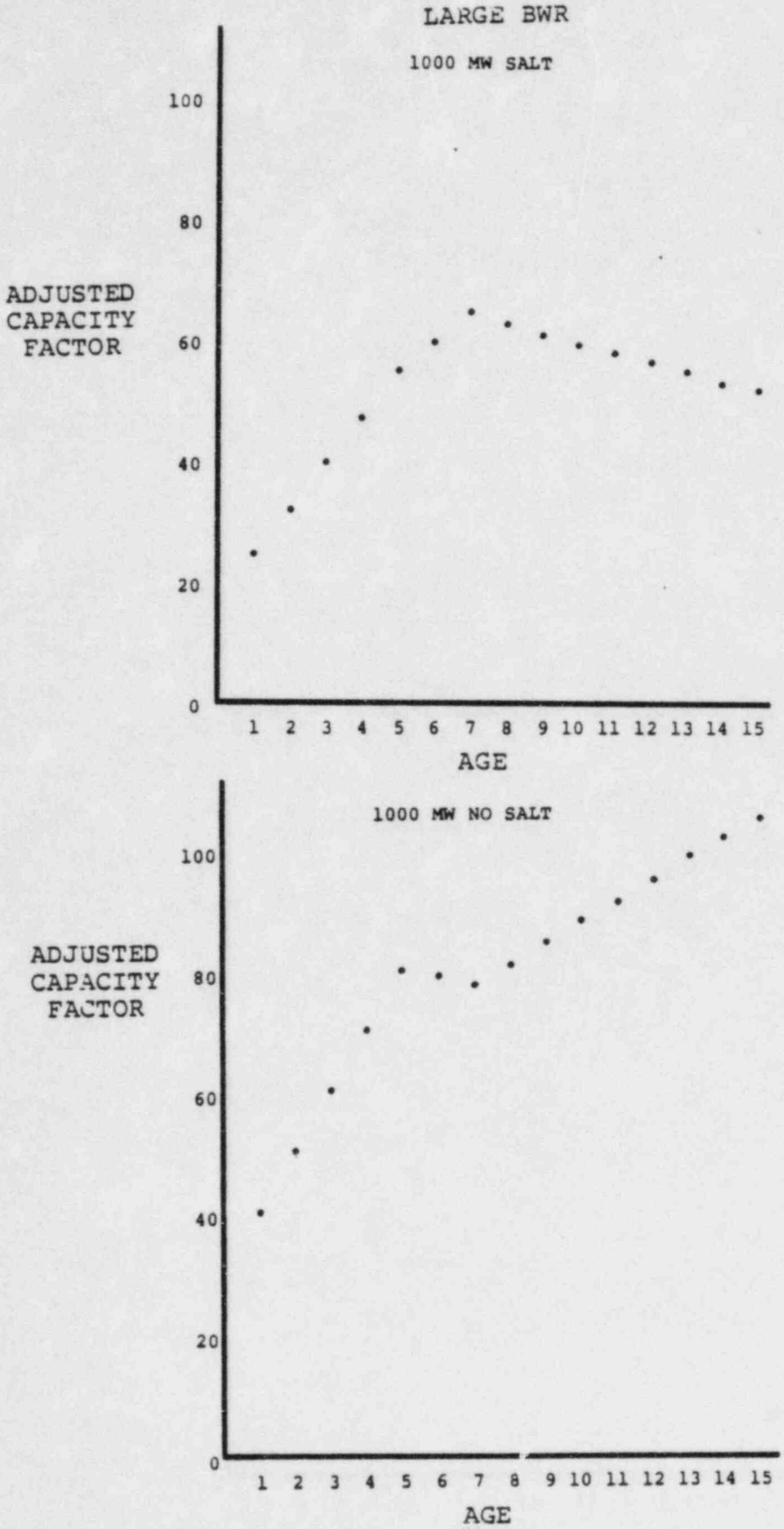
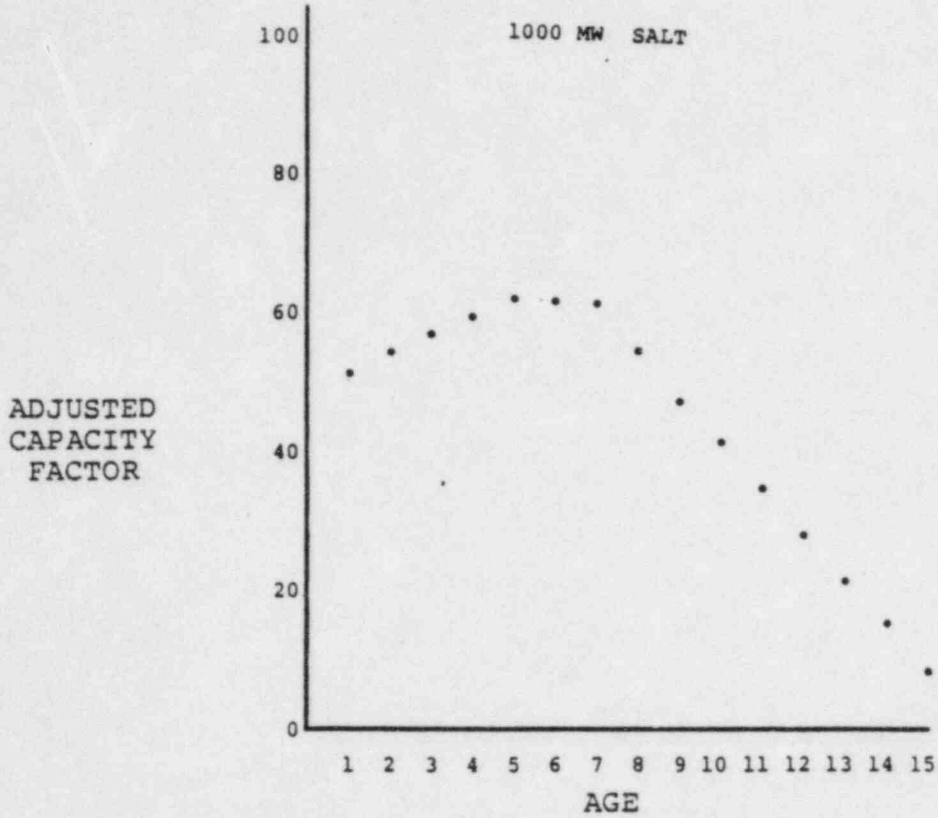


Figure C-9

ADJUSTED CAPACITY FACTORS
LARGE PWR



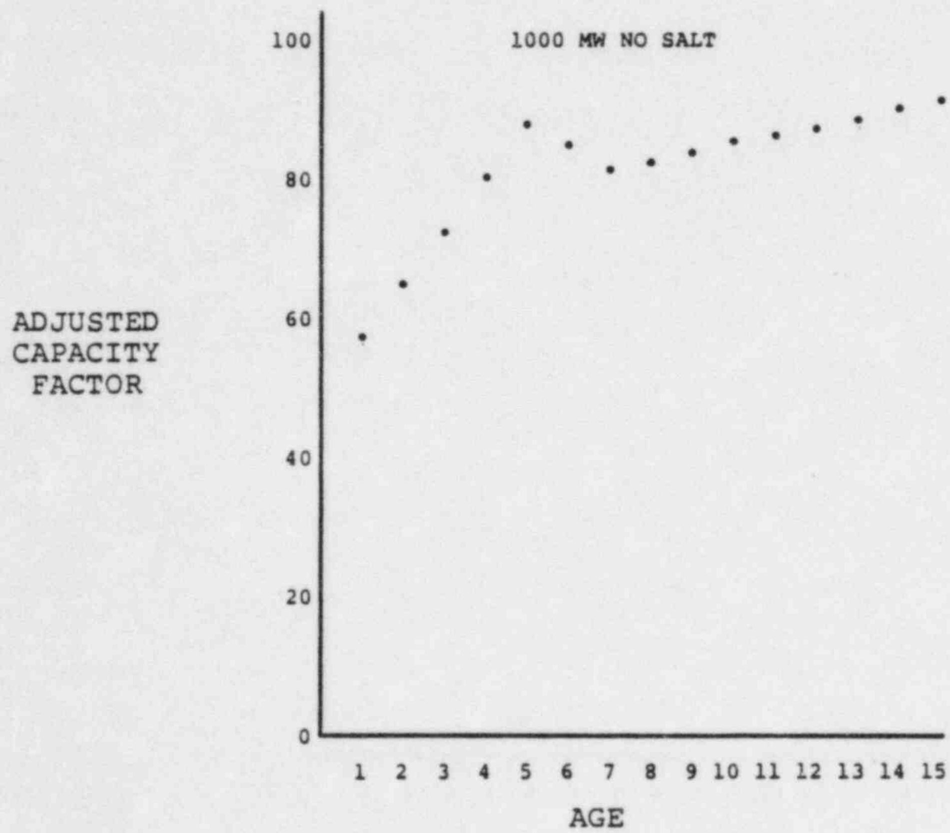
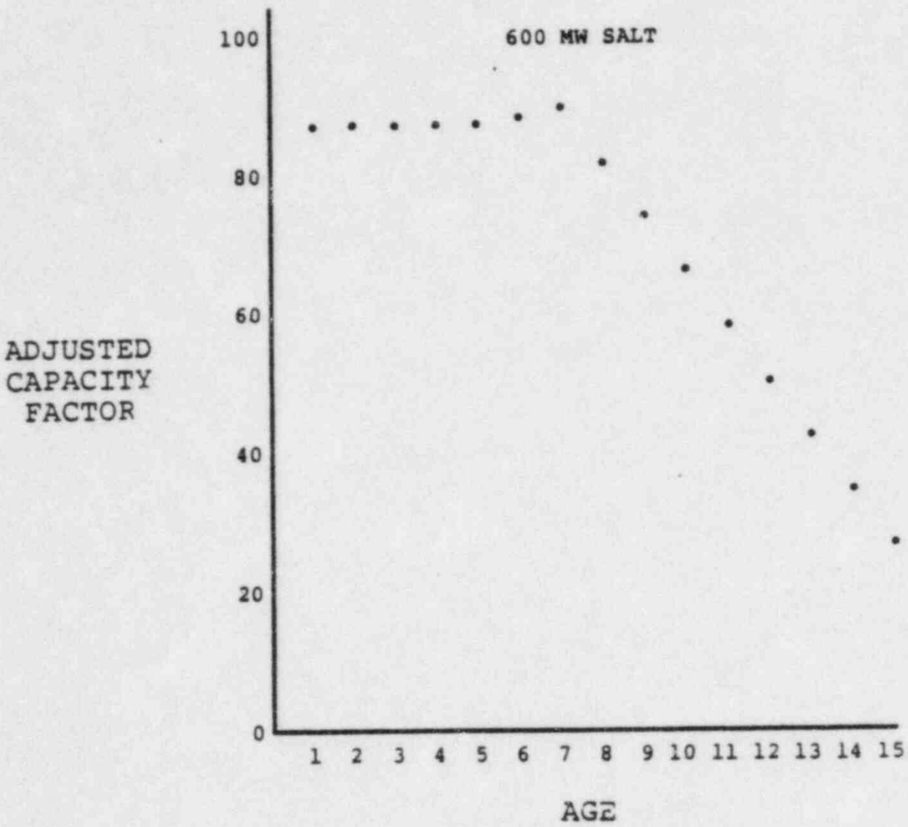
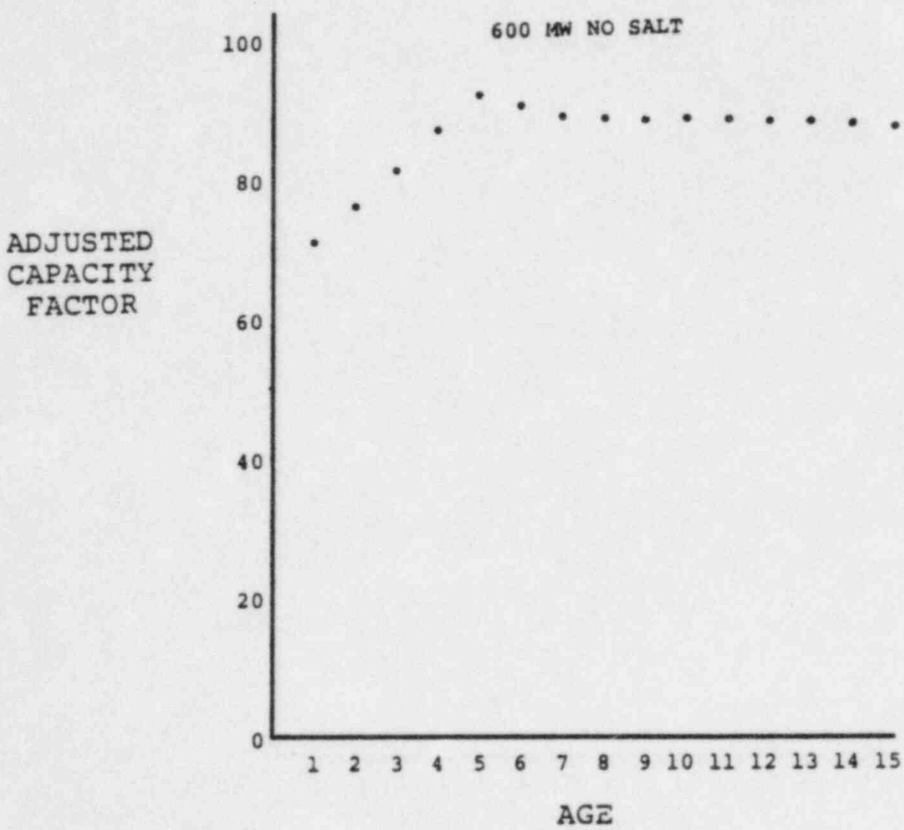


Figure C-8

ADJUSTED CAPACITY FACTORS
SMALL PWR





Among non-salt-water cooled units, BWRs are shown to have continued maturation (out to the limits of the data), with larger units approaching 100 percent adjusted capacity factor more rapidly than smaller units. For all but non-salt-water cooled BWRs larger units perform more poorly. PWR units that are not salt-water cooled show middle ground performance. For these PWRs smaller units perform somewhat better than larger ones in the early years, while the larger units "catch up" after maturation. On the other hand, PWRs of this type are found to perform better in their early years than their BWR counterparts. After maturation, however, PWR performance is overtaken by BWR performance.

The general aging trend for non-salt-water cooled BWRs shows a long term increase in adjusted capacity factors. For similar PWRs this is balanced by a long term trend towards declining performance, which is more pronounced for smaller units. Further exploration of these long term general aging effects is essential as more years of data become available. Even after taking account of refueling outages in preparing the data base, the above results would show total capacity factors of non-salt-water cooled BWRs approach 100 percent. This is not plausible, since refueling alone would keep these at about 85 percent as an upper limit. Further statistical analyses of an exploratory nature provided preliminary indications that this long term increase may abate within the time periods under investigation.

Given the limitations of the data base, the aging effects found in this study are more accurate for the first 10-12 years or so of unit operation. The key finding that emerges is that salt-water cooled reactors of all types may be running into serious operating problems as they age. We believe that this is the first time such a finding has been reported.

The graphs presented in Figures C-6 through C-9 illustrate the general results for adjusted capacity factors for the eight generic nuclear units. These results are in broad agreement with those reported in the less detailed earlier studies. For example, BWRs in general are found to achieve capacity factors of about 60 percent on average during their first 10 years of operation, with little difference between large and small units. Large PWRs have comparable performance, while small PWRs perform substantially better (capacity factors over 70 percent). The significant advance embodied in these results are the clear maturation effects and the differential aging trends for different types of units, especially the sharp decline found for salt-water cooled nuclear units.

Total or unadjusted capacity factors: In order to estimate values for the total or unadjusted nuclear capacity factors that are generally discussed in the literature, three alternative procedures could be followed. First, one could simply revert to explanation of the observed values of these capacity factors by regression analysis similar to that performed for the adjusted capacity factors. This would depart from one of the major methodological objectives of this study, the removal of bias or "noise" associated with refueling outages and NRC mandated outages (e.g. events like the post-TMI shutdowns of certain units) from unadjusted capacity factors.

To illustrate this first alternative we can examine a regression using the model, discussed earlier, that was developed for the adjusted capacity factors. Applying this to the unadjusted capacity factors (Table C-7) it is found that there is a general continuity of many of the results. However, the R-SQUARED for this equation is substantially lower and the standard error is higher, reflecting both greater variation in the data and lower explanatory power when refueling and NRC outages are included. This size maturation effect (coefficient D) is insignificant, and the general aging effect (coefficient E) is barely significant (at the 60 percent level). The post-TMI variables (coefficients X4 and X5), on the other hand, become significant in this regression whereas they were not in the case of the adjusted capacity factors. They reflect the shut-downs for NRC mandated modifications. It appears that the change in the significance of the age and age-size variables is due to the variations in refueling outages.

Second, regression analysis could be applied to the refueling and NRC outage observations alone. The results could then be used (in conjunction with the independently developed adjusted capacity factor estimations) to develop total capacity factor estimations. However, preliminary regression analyses of the refueling and NRC outages did not produce satisfactory results. It would be important to explore this approach further in future work.

The final, and at this time most straightforward, procedure for readjusting the adjusted capacity factor results to account for refueling outages is to obtain the average values of these outages for the two reactor types, PWRs and BWRs. The information in the data base yields:

BWR Refueling Outage Rate: 14%

PWR Refueling Outage Rate: 12.5%

TABLE C-7

FINAL REGRESSION MODEL APPLIED TO UNADJUSTED CAPACITY FACTORS

Name of Coefficient	Term in Equation	Coefficient of Term	t-Statistic
A	1	.413	4.04
B	MDCU	1.43×10^{-4}	.981
Z	MDCU x PWRU	-4.32×10^{-4}	-4.51
C	PWRU	.608	5.54
G	SALTU	.538	2.90
E	AGE	.010	1.23
X_1	MDCU x SALTU	-4.05×10^{-4}	-2.61
K	PWRU x TOWERSU	-.214	-4.65
W	AGE x PWRU	-.026	-3.80
D	AGE x MDCU	1.33	.878
L	TOWERSU	.132	3.49
S	SALTU x AGE	-.036	-2.78
F	SALTU x PWRU	.057	.686
H	SALTU x PWRU x AGE	-.020	-1.77
L3	AGE6	.019	.722
M2	AGE4 x MDCU	1.17	.361
M3	AGE6 x MDCU	2.00	.005
N2	AGE4 x SALTU	-.035	-.767
N3	AGE6 x SALTU	.054	1.56
X2	BWSTM	-.035	-.821
X3	WESTM	-.017	-.605
X4	TMI	-.045	-2.23
X5	TMI x BWSTM	-.074	-1.51

Number of Variables = 23
R-Squared = .263
Corrected R^2 = .222

Standard Error of Regression = .149
F(22/397) = 6.45
COND(X) = 77.0

or 1976 (for IP 3), we applied the following formula for estimated total capacity factor:

$$\frac{\text{Adjusted Capacity Factor} \times (100 - 12.5)}{100} = \text{Total Capacity Factor}$$

The resulting estimated total capacity factors were then used as guidance in establishing the scenarios, as described in the text of section 3.3 of the report. The total capacity factors are plotted in Figure 1 and 2 of the report for the years during which they are greater than zero.

While actual refueling outage time may be typically somewhat smaller than these averages, it should be borne in mind that refueling outages reported to the NRC can often contain outage hours for other of the outage modes since certain kinds of equipment, maintenance, and even NRC related outage activities may be performed while the plant is shut down for refueling.

The net or readjusted capacity factor can be obtained as:

$$\text{CAPFAC} = (1-\beta) \times \text{NCAPFAC2}$$

Where NCAPFAC2 is the adjusted capacity factor, and β is the average fraction of a year during which refueling outages occur.

Note here, that no adjustment is made for outages resulting from explicit NRC mandates. This tacitly assumes that, unlike past experience, no NRC-mandated outages will occur in the future. This assumption yields higher capacity factor estimates than would be obtained if average NRC related outages of the past were assumed for the future.

We developed total capacity factor estimations for the two Indian Point units for use as guidance in establishing the High Impact, Mid-Range, and Low-Impact scenarios for capacity factors. We began by applying the regression model described in Table C-4 to each Indian Point unit. We adjusted the resulting stream of adjusted capacity factor estimations to simulate total capacity factors according to the third method described in the preceding section. In other words, for each year from 1974 (for IP 2)

REFERENCES

C-1 Charles Komanoff, "Nuclear Plant Performance Update 2," Komanoff Energy Associates, 475 Park Avenue South, N.Y. 10016.

C-2 R.G. Easterling, "Statistical Analysis of Power Plant Capacity Factors Through 1979," NUREG CR-1881 (April 1981), Division 1223, Sandia National Laboratories, Alburquerque, NM 87185.

C-3 N.J.D. Lucas and P.J. Thompson, "Age, Size, and Learning Effects in Light Water Reactors," Dept. of Mech. Eng., Imperial College, London SW7 England.

C-4 See, for example, Elements of Econometrics, Jan Kementa, MacMillan, 1971, pp. 317-321 and 499-508.

C-5 See, for example, "Workshop Proceedings: Outage Planning & Maintenance Management," WS-78-94 EPRI, June 1979, especially section F-8.

APPENDIX D

Irradiated Fuel Storage Costs

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D-1 General Issues

With the exception of a small amount of irradiated fuel which was sent to reprocessing plants, all of the irradiated fuel discharged from commercial nuclear reactors is being stored in onsite storage pools. These pools, which were designed to serve as temporary, short-term storage, have limited capacity.

As the available space in existing storage pools decreases, reactor operators have taken steps to increase the capacity of their pools by packing the irradiated fuel rods closer together. The procedure generally used is called "reracking." The assemblies of spent fuel rods are moved close together and separated by boron metal plates. While there is some concern regarding the safety of storing increased quantities of fuel in existing pools (Ref. D-1), the NRC has approved the reracking of most storage pools (Ref. D-2). Even if reracking is used to the full extent allowable under current licensing requirements, the storage pools at most reactors will be filled to capacity by the late 1980's and early 1990's.

While the Federal government has shown fairly clearly its intent to take responsibility for the ultimate disposal of irradiated nuclear fuel, progress toward a detailed solution faces a "formidable array of social, economic, and political problems" (Ref. D-3). It is estimated that the opening of a federal "permanent" disposal facility will take place some time after 1997 (Refs. D-4 and D-8).

If a nuclear power plant is to continue operating between the time that its storage pool fills and the time that a permanent disposal facility becomes available, then some type of interim system must be used to store the irradiated fuel. Current possibilities for interim storage fall into two categories: federally operated away from reactor storage facilities (AFRs)* and onsite storage.

Federally operated AFRs, if available, are likely to be the preferred option from the point of view of the utility which would pay a one-time fee and then be free of responsibility for the irradiated fuel. The availability of AFRs is uncertain, however, so utilities must consider the options for on-site storage: water pools, storage casks, drywells, concrete silos, and air cooled vaults (Ref. D-5).

The total cost for the disposal of irradiated fuel can be considered in three parts:

1. interim storage cost (away from reactor or onsite)
2. transportation cost
3. permanent disposal fee

The next section of this appendix will discuss these costs in a general sense, then the derivation of the costs used in our analysis of Indian Point will be described.

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*These were previously referred to as Independent Spent Fuel Storage Facilities (ISFS).

D-2 Cask Storage Costs

Our cost estimates for onsite storage of irradiated fuel in casks are based on the procedure used in A Preliminary Assessment of Alternative Dry Storage Methods for the Storage of Commercial Spent Nuclear Fuel (Ref. D-5). In that study, a cost per kilogram of waste was calculated for Virginia Electric Power and Light Co.'s Surry Station by assuming normal plant operation until 2009. The 967 MTU* of irradiated fuel was assumed to require storage between 1985, when the onsite pool will run out of room, and 2009, the scheduled retirement date.

Based upon the above assumptions a unit cost of $117/KgU (1981) was calculated for the storage of unconsolidated fuel in casks. This cost is not much greater than the $110/KgU (1981) calculated for the storage of consolidated fuel in casks, the least expensive of the options for onsite storage (according to the study). Although consolidating the fuel results in a slightly lower cost, the procedure involves greater technical uncertainties.

The various components of the cost of storing unconsolidated irradiated fuel onsite in casks are listed in Table D-1. Note that the casks used for storage are larger than typical transportation casks. The cask assumed in our cost estimates is designed to hold up to 24 PWR assemblies, or about 10 MTU of irradiated fuel.

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* Metric tonne (1000 Kg.) uranium.

The tax and insurance costs are based upon $.45 per $100 of investment for taxes and $.48 per $100 of investment for insurance. At an investment of $600,000 per cask the annual taxes and insurance will be about $6000 per cask per year. The cost of constructing warehouse space for each cask was calculated by multiplying the cost per square foot ($75/sq. ft.) by the floorspace required for a cask (850 sq. ft./cask). The costs listed in the table for the operation of the cask storage facility were derived by plotting the costs listed in Reference D-5 as a function of the warehouse size in casks. This procedure resulted in a linear fit which implied the fixed and variable operating costs listed in the table.

The costs listed in Table D-1 can be expressed in units of $/cask-year by assuming that the cask purchase and warehouse construction costs are capitalized at a certain fixed charge rate, and by spreading the fixed operating costs over the average number of casks being stored. At a fixed charge rate of 18 percent and 50 casks on average per warehouse, the cost simplifies to $135,000/cask-year (1981). At a cask capacity of about 10 MTU this cost converts to $14/KgU-year (1981).

TABLE D-1

Cask Storage Costs[1]
(1981 $)

	Cost
Cask Purchase	600,000/cask
Maintenance Supplies	1,000/cask
Taxes and Insurance	6,000/cask-year
Warehouse Construction[2]	64,000/cask
Fixed Operating Cost[3]	190,000/year
Variable Operating Cost[3]	5,000/cask-year

1) Source: Reference D-5.

2) This includes the cost of the warehouse, pad, and approach roads.

3) The operating cost of the cask storage warehouse is broken into two components, the part which is attributable to operation of the facility itself (fixed), and the part which can be allocated to each cask (variable).

D-3 Costs of Other Onsite Storage Technologies

There are a variety of alternatives to storage casks for onsite storage of irradiated fuel. Unit cost estimates for these were developed by E.R. Johnson Associates for DOE (Ref. D-5). These estimates are expressed in dollars per kilogram.* In order to recast these estimates in dollars per kilogram per year to better represent the utilities' cash flow, (the costs of storing irradiated fuel onsite are likely to be capitalized), the cost relationships between the alternative technologies analyzed in Reference D-5 were applied to our cost estimate for casks of $14 per KgU-year to derive the costs listed in Table D-2.

Drywells are steel storage cylinders placed in the ground just below grade and covered with concrete plugs. Silos are similar to drywells, except that they are made of large amounts of concrete, and that they stand above grade on concrete pads. An air cooled vault is a massive two-level concrete structure in which the fuel would be stored in steel cavities on the lower level. Water pool storage is the method currently in use at reactor sites. Of these methods, casks, drywells, and silos can be built in increments, while air cooled vaults and water pools to be economical must be built in entirety. In this sense, the incremental methods offer less risk of unnecessary spending.

As the table shows, for the technologies which require canning, the costs are significantly less if the fuel can be canned in the existing storage pool rather than in a separate canning facility. At this point, it is not clear whether or not existing pools will be acceptable as the location for the canning process.

* Quantities of irradiated fuel are measured in kilograms of uranium (KgU) or kilograms of heavy metal (KgHM). The term heavy metal refers to all metals with atomic numbers of 90 or greater. Because nearly all of the heavy metal content of irradiated fuel is uranium, KgU and KgHM are considered to be equivalent for the purposes of this study.

TABLE D-2

Cost Estimates for Onsite Storage Technologies of Unconsolidated Fuel[1]

(1981 $ per KgU-year)

	Cost
Cask Storage	14
Drywell Storage	
Canned in Reactor Pool	16
Canned in Separate Facility	31
Silo Storage	
Canned in Reactor Pool	19
Canned in Separate Facility	30
Vault Storage	
Canned in Reactor Pool	50
Canned in Separate Facility	60
Water Pool Storage	41

1) Source: Reference D-5.

AFR Storage Costs

The total cost of storing irradiated fuel at an away from reactor storage facility includes the fee paid to the operator of the facility (the U.S. government) and the cost of transporting the fuel from the reactor site to the AFR site. A federally operated facility will presumably be run on a full cost recovery basis, that is, the utility will pay a one-time fee when the irradiated fuel is delivered to the AFR. The fee would be designed to totally recover the cost of constructing and operating the facility. The costs of transporting the irradiated fuel to the AFR will most likely be paid by the utility.

DOE estimates the unit cost for storage in a 3000 MTHM away from reactor storage pool at $117/KgHM(1978) (Ref. D-7, Volume 1, page 4.105). This cost will decrease for AFR pools with greater capacity. However, it will increase if the capacity is underutilized. For example, DOE estimates that using storage pools of 5000 MTHM capacity will reduce the unit cost by about 30%. They also state that "if a facility utilized only 50 percent of its capacity, unit costs would be almost doubled. In the study which reports these estimates (Ref. D-7) the cost of $117/KgHM(1978) is used in reference calculations.

A study by MHB Technical Associates (Ref. D-12) calculates a unit cost for disposal which includes AFR and permanent disposal costs. The MHB cost estimates which apply to AFR operation are listed in Table D-3. The unit costs at the bottom of the table are the costs to the government in constant 1978 dollars. They do not include the effects of possible real cost escalation (above or below inflation), the time value of money, and interest compensation for money spent by the government before the fee is collected. (These factors are apparently included in the DOE estimates referred to above, but it is not obvious how.) Depending upon the assumptions made for these financial parameters and the time schedule of costs and payments received, Table D-3 unit cost estimates will adjust accordingly. Generally, the fee will be significantly higher than the costs listed here because the Government must spend a great deal of money on construction before any fees are collected.

The basis for each of the "uncertainty factors" listed in the table is described in Reference D-12. These are included here as a reminder that there is a wide range of uncertainty in cost estimates for undeveloped technologies.

TABLE D-3

MHB AFR Cost Estimates[1]
(Millions of 1978 $)

Task	REFERENCE CASE COST	Uncertainty Factor	Cost	Uncertainty Factor	Cost
Research and Development	40	4	160	1/2	20
NEPA/Site	75	2	150	1	75
Licensing	75	2	150	1	75
Construction[2]	750	4	3000	1/3	250
AFR Operation	450	4	1800	1/3	150
Decommissioning of AFR	75	2	150	1/2	38
Totals	1465		5410		608
Unit Costs (1978 $/KgU)	98		361		41

1) Source: Reference D-12.

2) Cost is based upon construction of 3 5000 MTU AFRs.

D-5 Transportation Costs

The primary modes of transportation for irradiated nuclear fuel are truck and rail. In either case, some type of shipping cask must be used. The primary factors affecting transportation cost are the distance to be covered, the mode of transportation chosen, and the leasing rate paid for the casks.

As no site has been designated for away from reactor storage or permanent disposal of spent fuel, transporation cost estimates cannot be based upon a specific route. Also, it is unclear in many cases whether or not transportation by rail will be a viable option.

Furthermore, it is possible but far from certain that casks used to store spent fuel onsite will be acceptable for transportation. Cask leasing comprises about 73 percent of transportation cost (Ref. D-6, Vol. 4, p. II-15). Therefore, if casks which were purchased for onsite storage can be used for transportation, the transportation cost estimate will be dramatically reduced. In a preliminary assessment done for DOE (Ref. D-5) it is stated that "none of the casks currently under consideration as storage vessels are considered capable, under current regulations, of being licensed in the U.S. as a transportation cask, although at least one of them has been licensed in the Federal Republic of Germany."

DOE's Final Environmental Impact Statement Management of Commercially Generated Radioactive Waste estimates the transportation cost for a 1,500 mile delivery by truck to be $26.4/KgHM (1978) (Ref. D-7, Vol. 2, p. A.103). This figure adjusted by the GNP price deflators to 1981 dollars is about $34/KgHM. This is consistent with a range of $21 to $29 per KgHM (1978) for a 1,500 mile delivery by truck used in a slightly more recent DOE report (Ref. D-6, Volume 4, page II-14). In one of these reports (Ref. D-7) it appears that rail transportation would cost about 15 percent less than truck. This disagrees with the other report (Ref. D-6) and a recent telephone conversation with DOE (Ref. D-8), both of which indicate a higher cost for rail transportation.

The cost estimates reported above can be compared to a figure of $30/KgU (1980?) used in two recent studies of various aspects of the economics of nuclear fuel cycles (Refs. D-9 and D-10). They also fall generally within the range reported by the American Physical Society in 1978 (page S64, Ref. D-11) of $15 to $30 per KgHM (1976). Also notable is a 1978 report by MHB Technical Associates which uses a price of $30/KgU (1978). All of the cost estimates referred to above for transportation of irradiated fuel are listed in Table D-4.

TABLE D-4

Summary of Cost Estimates for Transportation

of Irradiated Nuclear Fuel

	Year in Which Cost Reported	Dollars in Which Cost Reported	Reported Cost ($/Kg)	Escalated[1] Cost (1981 $/kg)
DOE (Ref. D-6)[2]	1980	1978	21-29	27-37
DOE (Ref. D-7)[2]	1980	1978	26	34
DOE (Ref. D-6)[3]	1980	1978	10-45	13-58
DOE (Ref. D-7)	1980	1978	16-32	21-41
TRCF (Ref. D-9)	1980	1980?	30	33
GIT (Ref. D-10)	1981	1980?	30	33
APS (Ref. D-11)	1978	1976	15-30	22-44
MHB (Ref. D-12)	1978	1978	30	39

1) Escalated according to the GNP price deflators listed in the Economic Report of the President, February 1982.

2) These costs are explicitly for transportation 1,500 miles by truck. The other costs in this table are not as specific.

3) The range of costs here is especially wide due to a wide range of distance assumptions (500 miles to 1,500 miles) and lease rates.

Permanent Storage Costs

Whether the irradiated fuel is temporarily stored onsite or at AFRs, at some point the problem of long-term storage, or disposal, must be addressed. Many schemes have been proposed for the disposal of high level radioactive waste. These include placing the waste into space, into the ocean, into continental ice sheets, and into geologic formations of the earth's crust. Of these, the last seems to entail the least technical and political difficulty. Of the possibilities for geologic disposal, the only option which is based upon available technology is storage in the mined vaults of a deep geologic repository.

While the mined deep geologic repository is currently considered the most viable option for disposal of spent nuclear fuel, it is not without technical difficulties. Some of the uncertainties which could effect the cost and effectiveness of this technology are listed and discussed in a recent report of the Union of Concerned Scientists (Ref. D-3). These include uncertainties regarding the effects upon the geological stability of the host rock due to mechanical disturbances during mining, heat released by the radioactive wastes, changes in ground water flows, and possible future seismatic activity. Also, the chemical processes involved in the decay of the storage containers are not well understood. These are some of the issues which must be adequately addressed before the disposal of permanent high level waste in geologic formations can be considered safe.

The responsibility for the research and development of a viable waste disposal method and ultimately the construction and operation of waste disposal facility appears to rest upon the federal government. It is intended that any government operated facility for permanent waste disposal be run on a "full cost recovery" basis (Ref. D-13). The specific design of the fee remains to be worked out. The details which are of the most importance to this study are: 1) when is the fee paid by the utility and how is it collected from the utility's customers, and 2) does the fee distinguish between spent fuel which requires temporary (AFR) storage and that which goes directly to permanent storage?

We chose to assume a one-time fee for permanent storage which would be paid by the utility at the time of delivery to the permanent disposal site. This fee would be designed to recover the full cost of storage including regulation, research and development, licensing, and decommissioning as well as the costs of actually constructing and operating the facility. Utility costs are assumed to be collected from the utility's customers.

The fee assumed in this study corresponds to the "dual cost center pricing philosophy" used by DOE in their <u>Final Environmental Impact Statement U.S. Spent Fuel Policy</u> (Ref. D-6). That is, if AFRs are built and operated by the government, fuel sent to an AFR will be charged a higher fee than fuel sent directly to permanent storage. The higher fee would reflect the cost of supplying the interim storage.

DOE estimates the fee for disposal only (as opposed to interim storage and disposal) at $114/KgU (1978) for a case in which domestic and foreign irradiated fuel is stored in a geologic repository (Page II-5, Volume 4, Ref. D-6). This fee is listed in components as follows:

Encapsulation	$33/KgU
Geologic Repository (construction and operation)	$50/KgU
R&D and Gov't. Overhead	$31/KgU
Total	$114/KgU

The same DOE study estimates a slightly higher unit cost for a case in which foreign irradiated fuel is not stored in the U.S. Also, calculations for a "low demand case" yield a significantly higher unit cost of $234/KgU.

The above estimate of the fee for disposal in a geologic repository seems to agree with another DOE estimate of the unit cost for constructing, operating, and decommissioning a repository sited in salt of $52/KgHm (1978) (Ref. D-7, Vol. 1, p. 5.95). According to other estimates in the same report, salt is the least expensive media in which to situate a repository. However, technical uncertainties of salt disposal could force another, more expensive, geologic media (with its own technical uncertainties) to be used. A Union of Concerned Scientists report (Ref. D-3) cites the following technical uncertainties associated with repositories sited in salt:

1. problems of brine-induced corrosion
2. effects of heat on salt geologic integrity
3. problems due to plasticity of salt.

These (or other problems) could easily increase costs by requiring additional research on equipment, by necessitating the use of another disposal technology, or by requiring that the deposited fuel be recovered and shipped to another disposal site.

A recent GAO study, Economic Impact of Closing Zion Nuclear Facility (Ref. D-18), uses a fee of $339/kg (1981) for irradiated fuel disposal. While this figure is "based upon DOE estimates," it is significantly higher than the DOE estimates discussed above.

An MHB study of waste disposal costs (Ref. D-12) addresses the uncertainties necessarily present in cost estimates for untested technologies. We adjusted the MHB figures such that they apply to permanent disposal only (not AFR storage). The figures, thus derived, are listed in Table D-5. Note that, as for the MHB estimates for AFRs discussed earlier, the costs are in constant 1978 dollars -- unadjusted for real cost escalation, the time value of money, and interest compensation.

The range indicated by the uncertainty factors implies that in the reference and high cases the waste put into one of the two repositories must be retrieved and reburied. This is an expensive procedure, but given the uncertainties in the technology of deep geologic disposal, it is certainly possible if not likely.

TABLE D-5

Irradiated Fuel Permanent Disposal Costs[1]
(Millions of 1978 $)

TASK	REFERENCE CASE Cost	HIGH CASE Uncertainty Factor	HIGH CASE Cost	LOW CASE Uncertainty Factor[2]	LOW CASE Cost
I. FIXED COST					
1. Regulatory	285	3	858	1	286
2. APR R&D	-				
3. Repository R&D	660	2	1320	1	660
4. Alternative R&D	600	2	1200	0	0
II. VARIABLE COSTS					
1. NEPA/Site	571	2	1142	1	571
2. Licensing	371	4	1484	1/3	124
3. AFR Const.	-				
4. AFR Oper.	-				
5. Repos. Const.	3150	2	6300	1/3	1050
6. Transport	-				
7. Repos. Oper.	750	2	1500	1/3	250
8. Repos. Monit.	390	4	1560	1/2	195
9. Retrieval	1566	2	3132	0	
10. Alt. Const.	1575	2	3150	0	
11. Alt. Transp.	900	2	1800	0	
12. Alt. Oper.	375	2	750	0	
13. Alt. Monit.	125	2	250	0	
14. Decommissioning	70	2	140	1/2	35
TOTALS (10^6, 1978 $):	11,389		24,586		3,171
UNIT COSTS (1978$/KgU):	$190/KgU		$410/KgU		$53/KgU

1. This table is based upon Table 5-3 in Spent Fuel Disposal Costs (Ref. D-12).

2. An uncertainty factor of zero means that the task is not performed.

D-7 Summary of Cost Estimates

Table D-6 summarizes our unit cost assumptions for disposal of irradiated fuel. Low, reference, and high costs are listed. The range of uncertainty in current cost estimates is represented by, but in no way limited to the range of costs listed here. Note that the low disposal cost will later be applied in our High Impact case. Likewise, the high disposal cost listed here will be applied in our Low Impact case. This somewhat confusing procedure is necessary because higher disposal costs will result in lower costs for plant shutdown.

The low cost assumption of $15/KgU-yr. for onsite storage is based on the current estimate for casks. (See Table D-2.) The reference cost assumption of $30/KgU-yr. is roughly the estimate for storage in dry wells or silos of fuel canned at a separate facility. The high cost assumption of $50/KgU-yr. can be thought of as representing vault or water pool storage. Of course, even cask storage could cost as much as the reference or high cost figures if current estimates prove to be low.

The costs listed in the table for transportation, either to an AFR or to the permanent storage site, are all within the range of current estimates (see Table D-4). These could be decreased to about one-quarter of the prices listed here if one assumes that storage casks purchased for onsite storage can be used for transportation.

The low fee for AFR storage is based upon the DOE figure of $117/KgHM (1978) cited earlier (Ref. D-7, Vol. 1, page 4.105). This figure escalated by 29 percent for three years of inflation yields the low cost figure in the table.

The reference cost estimate for AFR storage, double the low cost estimate, is more likely than the current DOE estimate. It reflects a cost increase that could occur with the use of much smaller AFRs than those upon which the original cost estimates were made. At present it seems that if an AFR is built at all, it will be much smaller than originally planned. However, current cost estimates for AFR storage are not available. Also, some cost overrun is certainly likely given the preliminary nature of the DOE estimates, and the problems which have historically plagued the storage of other radioactive materials.

The high AFR fee of $500/KgU (1981) represents a case in which the relationship between the preliminary cost estimates and the actual implementation costs is similar to that seen historically for other untested technologies. The difference here of about a factor of three is roughly the difference between preliminary estimates and actual costs for the construction of nuclear plants. A recent study by the RAND Corporation (Ref. D-20) concludes that "significant underestimation of future costs by several orders of magnitude is a general rule for new technologies" (Ref. D-19, page 56). The storage of large quantities of irradiated fuel by any method other than the onsite storage pool is a problem with more than its share of unresolved details, and is certainly classifiable as a "new technology." There is at the very least, a significant probability that current cost estimates will prove to be low by a factor of three or more.

For permanent disposal, the low fee listed in the table is based upon the DOE figure of $114/KgU (1978) (Ref. D-6, Vol. 4, page III-5) escalated to 1981 dollars. The reference and high cost estimates are increased similarly to those for AFR storage, for basically the same reasons.

Here, there are also potential problems with geological instability and long term chemical corrosion which could require very expensive repairs or possibly the retrieval of deposited waste which would then have to be re-deposited. Problems of this magnitude could easily result in costs much greater than those assumed in our high case.

TABLE D-6

Low, Reference, and High Case Unit Cost Assumptions
(1981 $)

	Low Case	Ref. Case	High Case
Onsite Storage Cost ($/KgU-year)	15	30	50
Transport to AFR ($/KgU)	20	30	40
AFR Storage Fee[1] ($/KgU)	150	300	500
Transport to Permanent Storage ($/KgU)	20	30	40
Permanent Disposal Fee[1] ($/KgU)	150	300	500

1) Note that the AFR storage fee and permanent disposal fee are treated separately here. In some of the DOE cost estimates (consistent with stated DOE policy) it is assumed that utilities using the AFR storage pay a fee at the time of delivery to the AFR which covers the costs of AFR storage, transportation, and permanent disposal. Because the utility is prepaying many of the costs to the government, the fee is lower (in constant dollars), reflecting the time value of money over the prepayment period. In our analysis we assume the fees associated with permanent disposal are paid at the time of permanent disposal, even for fuel which is stored temporarily in an AFR. This allows comparison between options for interim storage.

D-8 Application to Indian Point

The storage pool at Indian Point 2 originally designed to hold 482 assemblies, has the potential, through reracking, to hold 980 (Ref. D-14). Work on reracking the pool is currently under way (Ref. D-15). With 344 assemblies scheduled to be in the pool during 1982, and 72 more at each refueling, the pool will require alternative storage in 1993 in order to maintain full core reserve (Ref. D-14). Table D-7 shows the scheduled storage requirements by year.

In addition to the technical uncertainties faced by federally operated AFRs, there is considerable political uncertainty. In fact the AFR concept was discarded by DOE in March 1981 because of "lower than projected requirements for AFR storage, and lack of Congressional authority to implement the establishment of federal spent fuel storage facilities" (Ref. D-5). Recently the Senate passed a bill (S.1662) which includes a provision for building a small AFR.* However, this bill (and especially the part supporting AFRs) is the target of significant political opposition (Refs. D-13 and D-16). The siting of radioactive waste storage facilities is particularly troublesome. Construction plans have a tendancy to be delayed. At this point we do not know whether or not away from reactor storage will be available by 1993.

In the absence of an AFR, Con Ed would have to consider onsite storage. The large storage casks described earlier are not a feasible option because the Indian Point 2 fuel pool crane was not designed for

* The small AFR would take up to 2800 MTU of irradiated fuel. This is a much smaller quantity than that proposed by the Carter administration for AFR storage. The cost estimates discussed above all assumed the larger AFRs and are probably significantly low. Studies of cost more recent than those discussed above are not currently available.

the 100 ton loads typical of storage casks (Ref. D-17). If storage casks cannot be used, then drywells or silos are likely to be the preferable technology. The cost of drywells or silos will be greater than casks, especially if the irradiated fuel cannot be canned in the reactor pool.

Table D-7 shows the annual costs for storage of irradiated fuel at Indian Point 2 assuming the fuel reloading schedule listed in Reference D-14, and that an AFR is available by 1993. The fuel discharged between 2000 and 2005 goes directly to permanent disposal. In 2010, after the most recently irradiated fuel has had five years to "cool," all of the fuel remaining in the pool and all of the fuel at the AFR goes to permanent disposal. The total cost of this scenario is about $430/KgU (1981).

Table D-8 is similar to Table D-7, but here onsite storage replaces the AFR. The total cost for this scenario is $480/KgU (1981), 12% higher than the AFR case price. Of course, the relative economics of onsite interim storage vs. AFR interim storage will vary depending upon what assumptions are made regarding the timing and quantities of waste storage requirements.

Note that our calculations of unit disposal costs are based upon Indian Point unit 2. For Indian Point unit 3 the onsite storage pool is expected to reach capacity earlier, therefore, the disposal costs can be expected to be higher due to the larger quantity of fuel requiring interim storage. This effect is not accounted for here.

TABLE D-7

Indian Point 2 Irradiated Fuel Disposal Costs with AFR Interim Storage[1]
(All costs in thousands of 1981 $)

	Cumulative[2] Irradiated Fuel Discharges (MTU)	Fuel[2] Requiring Interim Storage (MTU)	Transport to AFR Cost	AFR Fee	Transport To Permanent Disposal Cost	Permanent Disposal Fee	Total Cost
1980	91	0					
1981	124	0					
1982	157	0					
1983	157	0					
1984	190	0					
1985	233	0					
1986	233	0					
1987	255	0					
1988	288	0					
1989	288	0					
1990	321	0					
1991	354	0					
1992	354	0					
1993	387	28	840	8400			9240
1994	420	33	990	9900			10890
1995	420	0					
1996	452	33	990	9900			10890
1997	485	33	990	9900			10890
1998	485	0					
1999	518	33	990	9900			10890
2000	551	33	990	9900			10890
2001	551	0					
2002	584	33			990	9900	10890
2003	617	33			990	9900	10890
2004	617	0					
2005	650	33			990	9900	10890
2006	650	0					
2007	650	0					
2008	650	0					
2009	650	0					
2010[3]	650	0			16,530	165,300	181,830
Total	650	292	5790	57,900	19,500	195,000	278,190

1. Costs are based on reference case costs in Table D-6.
2. Source: Reference D-14.
3. In 2010, 551 MTU is shipped to permanent disposal, 193 MTU from the AFR and 358 MTU from the onsite pool.

TABLE D-8

Indian Point 2 Irradiated Fuel Disposal Costs
With Onsite Interim Storage[1]

	Cumulative Irradiated Fuel Discharges (MTU)[2]	Fuel Requiring Interim Storage (MTU)[2]	Cumulative Fuel Requiring Interim Storage	Onsite Storage Cost	Transport to Permanent Disposal Cost	Permanent Disposal Fee	Total Cost
1980	91	0	0				
1981	124	0	0				
1982	157	0	0				
1983	157	0	0				
1984	190	0	0				
1985	233	0	0				
1986	233	0	0				
1987	255	0	0				
1988	288	0	0				
1989	288	0	0				
1990	321	0	0				
1991	354	0	0				
1992	354	0	0				
1993	387	28	28	840			84[illegible]
1994	420	33	61	1830			1830
1995	420	0	61	1830			1830
1996	452	33	94	2820			[illegible]
1997	485	33	127	3810			3810
1998	485	0	127	3810			3810
1999	518	33	160	4800			480[illegible]
2000	551	33	193	5790			579[illegible]
2001	551	0	193	5790			5790
2002	584	33	226	6780			678[illegible]
2003	617	33	259	7770			77[illegible]
2004	617	0	259	7770			7770
2005	650	33	292	8760			8760
2006	650	0	292	8760			876[illegible]
2007	650	0	292	8760			876[illegible]
2008	650	0	292	8760			8760
2009	650	0	292	8760			876[illegible]
2010[3]	650	0	292	0	19,500	195,000	214,5[illegible]
Total	650	292	292	97,440	19,500	195,000	311,940

1. Same as 1 above.
2. Same as 2 above.
3. In 2010 all 650 MTU is shipped to permanent disposal.

Table D-9 shows total costs per unit of waste calculated according to the unit costs for interim storage, transportation, and disposal listed in Table D-6. For the AFR case the storage requirements assumed in Table D-7 are used. For the onsite interim storage case the storage requirements are taken from Table D-8. The lower of the two sets of costs, those which assume AFR storage is available, are used for our continuation scenario.

The costs in Table D-9 for "no interim storage required" include the permanent disposal fee and the cost of transportation. These are the disposal costs used in our early retirement scenario. The costs of interim storage are excluded becasue it is assumed that if the plant is shut down before the existing pool is full, then the irradiated fuel can remain in the existing pool until a permanent geologic repository is available. This may require that the plant not be dismantled until the next century. Actually, it is not likely that the plant would be dismantled any sooner anyway due to the inavailability of a disposal site for large quantities of low level waste, and the general tendency of utilities to avoid dismantling.

Also shown in Table D-9 are cost estimates for irradiated fuel disposal from two other sources. The first is a study by Lewis Perl of NERA (Ref. D-21). Note that these estimates, while lower than ours, show a wide margin of uncertainty and imply a significant increase beyond the initial DOE estimates. The other source is a California Energy Commission report (Ref. D-19) which

TABLE D-9

Sample Total Costs for Storage, Transportation, and Disposal of Irradiated Fuel[1]
(All costs in 1981 dollars per KgU)

Case	Low	Reference	High
ESRG[1]			
With AFR interim storage	220	428	700
With onsite interim storage	245	480	790
With no interim storage required (*i.e.*, early retirement scenario)	170	330	540
NERA/Lewis Perl[2]	170	294	434
CEC/Duane Chapman[3]	300	-	3000

1. ESRG cost estimates are based upon the low, reference, and high case prices in Table D-6, and the scenarios outlined in Table D-7 for the AFR case and in Table D-8 for the onsite storage case.

2. Table 12 of Lewis Perl's Revised Testimony, April 9, 1981 (Ref. D-21). Prices originally in 1979 dollars were escalated to 1981 by the GNP price deflators.

3. Page 73 of Nuclear Economics: Taxation, Fuel Cost, and Decommissioning by Duane Chapman for The California Energy Commission, November 1980 (Ref. D-19). Prices originally in 1979 dollars were escalated and rounded.

uses a price of about \$300/KgU in its reference calculations. This report goes on to state that a cost higher by a factor of 10 is "equally likely."

For our reference case model runs, a cost for fuel disposal of \$430/KgU (1981) was used in the continuation scenario and \$330/KgU (1981) was used in the retirement scenario. The total incremental cost difference between the two scenarios is attributable to two separate effects. The first is that in the retirement scenario much less waste is produced. The second effect is that because the capacity of the existing storage pool is never exceeded, costs of onsite or AFR interim storage are avoided.

Cost per KgU can be converted to cost per Kwh if the number of Kwh generated per unit of fuel is known. The conversion factor can be estimated as follows:

$$\text{Kwh/KgU} = \frac{B \times N \times 24 \text{ hrs/day} \times 1000 \text{ KW/MW}}{1000 \text{ KgU/MTU}}$$

where:

B = burnup (MWtd/MTU)

N = plant thermal efficiency.

Assuming a burnup of 25,000 MWtd/MTU and a thermal efficiency of .32 (Ref. D-12), we calculate a factor of 192,000 Kwh/KgU. Using this number, our cost estimates in Table D-9 translate to 1981 mills per kwh as follows:

	Low	Ref.	High
Continuation Scenario	1.1	2.2	3.6
Retirement Scenario	0.9	1.7	2.8

The costs per kwh listed above were used to calculate the total costs for disposal of irradiated fuel in our Low, Mid-Range and High Impact cases. The low disposal cost listed above was used in our High Impact case, because a lower disposal cost will result in a larger difference between the keep and retirement cases. Likewise, the high disposal cost was used in our Low Impact case.

The total lifetime energy generation from the Indian Point units were calculated based upon the Low, Mid-Range, and High Impact scenario capacity factors as discussed in the text. These energy totals were multiplied by the costs per kwh listed above to derive the total irradiated fuel disposal cost for each scenario. These are listed in Table D-10. Note that the different capacity factors used in the Low, Mid-Range and High Impact scenarios serve to offset most of the disposal price variation.

Table D-10

Total Irradiated Fuel Disposal Costs
for Indian Point Units 1 and 2
(millions of 1981 $)

Indian Point Retirement Scenario	Keep	Retire	Increment
Low Impact	422	175	247
Mid-Range Impact	429	107	322
High Impact	279	57	222

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APPENDIX E

Decommissioning Options

and Costs

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APPENDIX E

E-1 Decommissioning Options

Whether or not a nuclear reactor continues to operate until the date of its planned retirement, the problem of decommissioning must eventually be addressed. Cost estimates for the various decommissioning options vary widely, even within the nuclear industry. Critics outside of the industry predict that even the highest utility estimates are much too low.

The three decommissioning options generally considered are entombment, mothballing and immediate dismantlement. Entombment involves removing the fuel and radioactive liquids, and then encasing the radioactive components of the reactor within a concrete structure (entombment barrier).

Mothballing is essentially entombment with decreased physical barrier and greater security requirements. Mothballing is lower cost than entombment initially, but the increased annual cost of guarding the site will generally make entombment the less expensive option over a long time period.

Immediate dismantlement entails clearing the radioactive components to the extent that decontamination is practical, and then cutting the radioactive structures into pieces which can be transported to a permanent radioactive waste disposal site. This option requires the highest initial investment, but if the site can be restored to unrestricted use, thereafter, the land use benefits as well as the saving in the direct costs of guarding the site will generally make immediate dismantlement the most economically attractive option.

It was once believed that a retired reactor could simply be entombed until the radioactivity decayed to the point at which the structure could be demolished by the same methods used to demolish a conventional building. However, due to the discovery of some extremely longlived radioactive isotopes, ^{94}Nb and ^{59}Ni, which were originally overlooked, it is now believed that entombment is not a permanent solution. Design and construction of a structure which would survive the hundreds of thousands of years required for these isotopes to decay to acceptable levels is beyond present capabilities. Therefore, entombment and mothballing are now considered the only means of postponing dismantlement.

Delaying dismantlement would allow some of the radionuclides with short half-lives to decay, reducing the overall internal radioactivity level, thereby somewhat decreasing dismantling cost and worker exposure. In spite of this, immediate dismantlement, with its advantages of lower overall cost and allowing earlier use of the site, is currently the preferred option (Ref. E-1, p. 54, and Ref. E-2, p. 376). However, immediate dismantlement may not be a viable option for a reactor retired in the near future due to waste storage requirements:

"The large quantities of low-level wastes generaged in the decommissioning process may exceed the existing quantity limits on operating burial grounds and so cannot be buried. Because of the present waste disposal problem, it may not be possible to conduct a total decommissioning today." (page 4, ref. E-3)

It is not clear how or when storage of huge quantities of low-level radioactive waste will cease being a problem.

E-2 Cost Estimates

With nuclear reactor dismantling experience limited to a number of very small military or research reactors and one 22 MW demonstration plant, cost estimates are necessarily approximate.

The 22 MW Elk River reactor is hardly comparable to the large commercial reactors in operation today since Elk River was only in operation for about four years. Elk River was dismantled between June 1972 and November 1974 at a cost of over $6 million. This was roughly equal to the original construction cost (Ref E-4).

There may be some factors which lead to relatively higher costs for larger reactors:

"When dismantling larger reactors, workers would have to be protected with more effective--and isolating--shielding; the isolation will require both remote operation and monitoring of the cutting torches. In addition, the thicker, heavier fragments from commercial reactors will be more expensive to handle: additional manipulators will be needed, and current to the plasma torch would have to be higher to cut through the thicker metal. A particularly cumbersome problem would arise if the nuclear facility is a great distance away from a convenient nuclear waste disposal site. (Ref. E-5)

On the other hand, large scale dismantling projects would tend to enjoy certain economies of scale as they do at the construction phase.

The radioactive waste from Elk River was shipped from Minnesota to a burial site in Illinois. This distance is much shorter than can be expected on average for future decommissionings though the current shortage (indeed non-existance) of sites for the disposal of large quantities of radioactive waste makes detailed estimates impossible. The Elk River costs for dismantlement simply scaled by MW size, in 1982 dollars, the cost of dismantling a 1,000 MW power plant would be about $600 million. Further, if the decommissioning costs for a large reactor scaled from the Elk River costs according to MW years of operation, then the cost would be much higher. But clearly either scaling approach is too simplistic.

A recent survey of decommissioning cost estimates was done by Stone Webster Engineering Corp. for NESP (Ref. E-3). This survey selected and compared some of the current industry estimates of decommissioning costs for large reactors of approximately 1,000 MW. The conclusions of the survey are summarized briefly in Table E-1. Many of the studies surveyed estimated costs by adjusting the figures in a 1976 Atomic Industrial Forum/NESP study, An Engineering Evaluation of Nuclear Power Reactor Decommissioning Alternatives.

TABLE E-1

Summary of AIF/NESP Survey of Decommissioning Cost Estimates[1]

	Low	Average	High
Mothballing	3	6	13
Entombment	7	16	45
Immediate Dismantling	26	59	111
Annual Costs[3]	0.18	--	0.34

[1]Source: Reference E-3.

[2]Costs are escalated to 1981 $ according to the GNP price deflators.

[3]Components of annual cost include a full-time security guard force, surveillance, and radiological monitoring.

The wide range, to some extent, indicates differences in local labor rates and characteristics specific to individual plants. However, most of the disagreement is ultimately attributable to the judgement of the estimators. The low estimates are Arkansas Power and Light Co's estimates for the ANO-1 plant. These were made by scaling the original AIF/NESP estimates to account for the smaller size of ANO-1 and then reducing the estimate further to account for several factors which include the lack of cooling towers and an accelerated work schedule. The high estimates in Table E-1 were made in a 1977 study for TMI-1 by the Jersey Central Power and Light Co. and the Pennsylvania Electric Co. The judgement in the TMI-1 study is that "the NESP study estimated certain items too optimistically." These utilities then made estimates that more than doubled the total cost relative to the original AIF/NESP estimates.

A 1978 Battelle study done for the NRC (Ref. E-6) is the most detailed engineering analysis of decommissioning costs presently available. The Battelle estimates (which were included in the AIF/NESP survey) are just slightly higher than the original AIF/NESP estimates, and fall roughly in the middle of the range reported in the AIF/NESP survey. The final estimates from the Battelle report are summarized in Table E-2. A breakdown of the Battelle estimate for immediate dismantlement is listed in Table E-3.

TABLE E-2

Battelle Cost Estimates for PW. Decommissioning[1]

(All costs in millions of 1981 $)[2]

	Cost
Immediate Dismantlement	54
Safe Storage	
Initial Cost	16
Annual Cost (million $/yr)	0.10
Deferred Dismantlement	
10 years deferred	48
30 years deferred	48
50 years deferred	39
100 years deferred	39

[1]Source: Reference E-6

[2]Costs are escalated from 1978 dollars to 1981 using the factor of 1.29 indicated by the GNP price deflators.

TABLE E-3

Battelle Cost Estimate for Immediate Dismantlement of a Reference Pressurized Water Reactor[1]

(all costs in millions of 1981$)[2]

Category	Cost
Spent Fuel Disposal	3.2
Activated Materials Disposal	3.5
Containment Internals Disposal	1.2
Other Building Internals Disposal	5.4
Waste Disposal	0.9
Staff Labor	11.6
Electrical Power	4.5
Special Equipment	1.1
Miscellaneous Supplies	2.0
Facility Demolition (non-radioactive)	8.3
Specialty Contractors	0.5
Nuclear Insurance	1.0
Environmental Surveillance	0.2
SUBTOTAL	43.4
25% Contingency	10.9
TOTAL DISMANTLING COSTS (ROUNDED)	54.3

[1]Source: Reference E-6

[2]Costs are escalated from 1978 dollars to 1981 using the factor of 1.29 indicated by the GNP price deflators.

An alternative estimate for large reactor decommissioning costs has been made by a consultant to the California Energy Commission (Ref. E-1). Their report concludes that 24% of the original plant cost is a reasonable assumption.

The quantitative estimates in the decommissioning literature must be considered speculative. Indeed, if the comparison of initial industry estimates for nuclear power plant construction costs to final actual costs can be taken as any guide, then it will not be surprising if the NESP cost assumptions prove too low by factors of 4-5 or more. Such a possibility is also supported by a Rand Corp. report which concludes that "significant underestimation of future costs by several orders of magnitude is a general rule for new technologies." (Cited in Ref. E-1, p. 56)

References

E-1 Nuclear Economics: Taxation, Fuel Cost, and Decommissioning, P 300-80-038 by Duane Chapman of Cornell University for California Energy Commission, November 1980.

E-2 "A Long Term Problem for the Nuclear Industry," Colin Normin, Science, Volume 215, January 22, 1982.

E-3 Analysis of Nuclear Power Reactor Decommissioning Costs, AIF/NESP-021 SR, by Greenwood, Rymsha, Tondu, and Westfahl of Stone & Webster Engineering Corp. for the National Environmental Studies Project, Atomic Industrial Forum, Inc., May 1981.

E-4 "A Landscape of Nuclear Tombs," Alexis Parks, The Progressive, December 1977.

E-5 "Decommissioning Commercial Nuclear Reactors," Joseph Sefcik, Technology Review, Volume 81, Number 7, June 1979.

E-6 Technology, Safety and Costs of Decommissioning a Reference Pressurized Water Reactor Power Station, NUREG/CR-0130, Battelle Pacific Northwest Labs, June 1978.

E-7 A Review of Cost Estimation in New Technologies: Implications for Energy Process Plants, Ed Merrow, Rand Corporation, R-2481, July 1979.

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APPENDIX F

Sample Dispatch Runs

Output for Mid-Range Case

with and without

Indian Point

(1983, 1990, 1997)

Continued operation: Case MK1

Plant retirement: Case MR-2

UNIT TOTALS FOR 1983

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW %
1	INDPNT 2	NUC INTR	864.0	4087061.0	0.0	0.0	0.0	0.540			
3	INDPNT 3	NUC INTR	965.0	4395763.0	0.0	0.0	0.0	0.520			
4	INDPCT	DIST PEAK	72.0	0.8	0.0	0.0	0.0	0.000			
5	RVNSWD 1	RSID INTR	390.0	931328.4	56.1	0.9	57.0	0.273			
8	RVNSWD 2	RSID INTR	390.0	1304269.0	77.7	1.3	79.0	0.382			
11	RVNSWD 3	RSID INTR	928.0	377094.4	23.0	0.4	23.4	0.046			
12	RVNSWD 3	COL1 INTR	928.0	4396491.0	136.3	13.7	150.0	0.541			
14	RAVCT2	DIST PEAK	239.0	20.5	0.0	0.0	0.0	0.000			
15	RAVCT3	DIST PEAK	126.0	8.0	0.0	0.0	0.0	0.000			
16	RVCT4-11	DIST PEAK	142.0	6.9	0.0	0.0	0.0	0.000			
17	ASTORIA1	RSID INTR	149.0	67869.9	5.1	0.1	5.2	0.052			
18	ASTORIA2	RSID INTR	164.0	71338.7	5.4	0.1	5.5	0.050			
19	ASTORIA3	RSID INTR	387.0	473495.8	30.7	1.0	31.7	0.140			
22	ASTORIA4	RSID INTR	387.0	452537.7	29.5	0.9	30.4	0.133			
25	ASTORIA5	RSID INTR	395.0	331291.2	23.0	0.7	23.7	0.096			
28	ASTORIA6	RSID INTR	825.0	1291460.0	77.1	2.7	79.8	0.179			
29	ASTCT1	DIST PEAK	18.0	15.0	0.0	0.0	0.0	0.000			
30	ASTCT2	DIST PEAK	184.0	122.6	0.0	0.0	0.0	0.000			
31	ASTCT3	DIST PEAK	184.0	87.8	0.0	0.0	0.0	0.000			
32	ASTCT4	DIST PEAK	184.0	63.7	0.0	0.0	0.0	0.000			
33	ASCT5-13	DIST PEAK	172.0	38.7	0.0	0.0	0.0	0.000			
34	BOWLINE1	RSID INTR	401.0	1900675.0	102.8	0.9	103.7	0.541			
35	BOWLINE2	RSID INTR	400.0	2129195.0	115.1	1.0	116.1	0.608			
36	ROSETON1	RSD2 INTR	240.0	1423496.0	60.2	0.5	60.6	0.677			
37	ROSETON2	RSD2 INTR	237.0	1400688.0	59.3	0.4	59.8	0.675			
41	FITZPATK	NUC INTR	123.0	726900.3	0.0	8.4	8.4	0.675			
47	WATRSID4	RSID INTR	20.0	431.9	0.0	0.0	0.0	0.002			
49	WATRSID6	RSID INTR	14.0	296.6	0.0	0.0	0.0	0.002			
50	WATR5,7	RSID INTR	74.0	1552.2	0.2	0.0	0.2	0.002			
51	WTR8,9	RSID INTR	72.0	1305.4	0.1	0.0	0.1	0.002			
52	WTR14,15	RSID INTR	116.0	2540.9	0.2	0.0	0.3	0.003			
53	E RIV5	RSID INTR	134.0	4594.8	0.4	0.0	0.4	0.004			
54	E RIV6	RSID INTR	134.0	3991.7	0.4	0.0	0.4	0.003			
55	E RIV7	RSID INTR	170.0	82068.3	5.9	0.4	6.3	0.055			
56	NARROWS1	DIST PEAK	184.0	29.6	0.0	0.0	0.0	0.000			
57	NARROWS2	DIST PEAK	184.0	21.6	0.0	0.0	0.0	0.000			
58	GWNUSCT1	DIST PEAK	174.0	5.4	0.0	0.0	0.0	0.000			

UNIT TOTALS FOR 1983

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW %
59	GWNUSCT2	DIST PEAK	186.0	4.2	0.0	0.0	0.0	0.000			
60	GWNUSCT3	DIST PEAK	167.0	2.8	0.0	0.0	0.0	0.000			
61	GWNISCT4	DIST PEAK	142.0	1.8	0.0	0.0	0.0	0.000			
62	HUDCT1-5	DIST PEAK	83.0	0.8	0.0	0.0	0.0	0.000			
63	HUDSN2,3	RESD PEAK	34.0	0.2	0.0	0.0	0.0	0.000			
65	HUDSON6	RESD PEAK	17.0	0.1	0.0	0.0	0.0	0.000			
66	HUDSON7	RESD PEAK	101.0	0.0	0.0	0.0	0.0	0.000			
67	HUDSON7	RESD PEAK	126.0	0.6	0.0	0.0	0.0	0.000			
68	HUDSON8	RESD PEAK	151.0	0.6	0.0	0.0	0.0	0.000			
69	HUDSON10	RESD PEAK	40.0	0.2	0.0	0.0	0.0	0.000			
70	74TH-9	RSID INTR	58.0	63.1	0.0	0.0	0.0	0.000			
71	74TH-10	RSID INTR	58.0	55.5	0.0	0.0	0.0	0.000			
72	74TH-11	RSID INTR	31.0	29.6	0.0	0.0	0.0	0.000			
73	74TH CT	DIST PEAK	34.0	0.2	0.0	0.0	0.0	0.000			
74	59TH-13	RSID INTR	53.0	45.2	0.0	0.0	0.0	0.000			
75	59TH-14	RSID INTR	19.0	16.2	0.0	0.0	0.0	0.000			
76	59TH-15	RSID INTR	20.0	16.2	0.0	0.0	0.0	0.000			
77	59TH CT	DIST PEAK	40.0	0.4	0.0	0.0	0.0	0.000			
78	BUCHANAN	DIST PEAK	20.0	0.1	0.0	0.0	0.0	0.000			
79	KENT CT	DIST PEAK	12.0	0.1	0.0	0.0	0.0	0.000			
80	ARTKILL2	RSID INTR	350.0	1150794.0	67.5	1.6	69.2	0.375			
83	ARTKILL3	RSID INTR	501.0	1978568.0	112.4	2.8	115.2	0.451			
87	ARKLCT	DIST PEAK	18.0	0.9	0.0	0.0	0.0	0.000			
98	HYDQ1S	PRCH BASE	780.0	3003518.0	0.0	64.4	64.4	0.440			
99	HYDQ2S	PRCH INTR	168.0	747645.6	0.0	29.8	29.8	0.508			
100	HYDQ2W	PRCH INTR	343.0	1230600.0	0.0	49.0	49.0	0.410			
101	ONHY1	PRCH BASE	161.0	1150500.0	0.0	45.9	45.9	0.816			
104	NYPP1	PRCH INTR	300.0	1616547.0	0.0	88.2	88.2	0.615			
105	LILCO	PRCH INTR	500.0	493525.4	0.0	35.3	35.3	0.113			
106	NYPP2	PRCH INTR	800.0	182672.9	0.0	14.1	14.1	0.026			
108	PSEG1	PRCH INTR	600.0	10133.0	0.0	1.1	1.1	0.002			
109	PSEG2	PRCH INTR	800.0	2941.1	0.0	0.3	0.3	0.000			
SYSTEM TOTALS				37425744.0	988.7	366.1	1354.7	0.294			

UNIT TOTALS FOR 1990

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW	%
1	INDPNT 2	NUC INTR	864.0	3405883.0	0.0	0.0	0.0	0.450				
3	INDPNT 3	NUC INTR	965.0	3719492.0	0.0	0.0	0.0	0.440				
4	INDPCT	DIST PEAK	72.0	0.0	0.0	0.0	0.0	0.000				
5	RVNSWD 1	RSID INTR	390.0	898763.6	105.4	1.6	107.0	0.263				
8	RVNSWD 2	RSID INTR	390.0	1259707.0	146.3	2.2	148.5	0.369				
13	RVNSWD 3	COL2 INTR	922.0	4089910.0	203.2	17.4	220.7	0.506				
14	RAVCT2	DIST PEAK	239.0	0.2	0.0	0.0	0.0	0.000				
15	RAVCT3	DIST PEAK	126.0	0.1	0.0	0.0	0.0	0.000				
16	RVCT4-11	DIST PEAK	142.0	0.1	0.0	0.0	0.0	0.000				
17	ASTORIA1	RSID INTR	149.0	8139.9	1.2	0.0	1.2	0.006				
18	ASTORIA2	RSID INTR	164.0	7171.6	1.1	0.0	1.1	0.005				
19	ASTORIA3	RSID INTR	387.0	439552.2	55.6	1.6	57.2	0.130				
22	ASTORIA4	RSID INTR	387.0	474005.2	60.2	1.7	61.9	0.140				
25	ASTORIA5	RSID INTR	395.0	303024.1	41.0	1.1	42.1	0.088				
28	ASTORIA6	RSID INTR	825.0	1165089.0	135.7	4.2	139.8	0.161				
29	ASTCT1	DIST PEAK	18.0	0.3	0.0	0.0	0.0	0.000				
30	ASTCT2	DIST PEAK	184.0	2.0	0.0	0.0	0.0	0.000				
31	ASTCT3	DIST PEAK	184.0	1.3	0.0	0.0	0.0	0.000				
32	ASTCT4	DIST PEAK	184.0	0.9	0.0	0.0	0.0	0.000				
33	ASCT5-13	DIST PEAK	172.0	0.5	0.0	0.0	0.0	0.000				
34	BOWLINE1	RSID INTR	401.0	1465419.0	154.7	1.1	155.9	0.417				
35	BOWLINE2	RSID INTR	400.0	1702068.0	179.6	1.3	180.9	0.486				
36	ROSETON1	RSD2 INTR	240.0	124370[illegible].0	102.5	0.7	103.2	0.592				
37	ROSETON2	RSD2 INTR	237.0	1173616.0	97.0	0.6	97.6	0.565				
51	WTR8,9	RSID INTR	72.0	49.9	0.0	0.0	0.0	0.000				
52	WTR14,15	RSID INTR	116.0	89.8	0.0	0.0	0.0	0.000				
53	E RIV5	RSID INTR	134.0	171.0	0.0	0.0	0.0	0.000				
54	E RIV6	RSID INTR	134.0	141.1	0.0	0.0	0.0	0.000				
55	E RIV7	RSID INTR	170.0	11326.4	1.6	0.1	1.7	0.008				
56	NARROWS1	DIST PEAK	184.0	0.3	0.0	0.0	0.0	0.000				
57	NARROWS2	DIST PEAK	184.0	0.2	0.0	0.0	0.0	0.000				
58	GWNUSCT1	DIST PEAK	174.0	0.0	0.0	0.0	0.0	0.000				
59	GWNUSCT2	DIST PEAK	186.0	0.0	0.0	0.0	0.0	0.000				
60	GWNUSCT3	DIST PEAK	167.0	0.0	0.0	0.0	0.0	0.000				
61	GWNISCT4	DIST PEAK	142.0	0.0	0.0	0.0	0.0	0.000				
62	HUDCT1-5	DIST PEAK	83.0	0.0	0.0	0.0	0.0	0.000				
65	HUDSON6	RESD PEAK	17.0	0.0	0.0	0.0	0.0	0.000				

UNIT TOTALS FOR 1990

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW %
67	HUDSON7	RESD PEAK	126.0	0.0	0.0	0.0	0.0	0.000			
69	HUDSON10	RESD PEAK	40.0	0.0	0.0	0.0	0.0	0.000			
70	74TH-9	RSID INTR	58.0	1.2	0.0	0.0	0.0	0.000			
71	74TH-10	RSID INTR	58.0	1.0	0.0	0.0	0.0	0.000			
72	74TH-11	RSID INTR	31.0	0.5	0.0	0.0	0.0	0.000			
73	74TH CT	DIST PEAK	34.0	0.0	0.0	0.0	0.0	0.000			
74	59TH-13	RSID INTR	53.0	0.8	0.0	0.0	0.0	0.000			
75	59TH-14	RSID INTR	19.0	0.3	0.0	0.0	0.0	0.000			
76	59TH-15	RSID INTR	20.0	0.3	0.0	0.0	0.0	0.000			
77	59TH CT	DIST PEAK	40.0	0.0	0.0	0.0	0.0	0.000			
78	BUCHANAN	DIST PEAK	20.0	0.0	0.0	0.0	0.0	0.000			
79	KENT CT	DIST PEAK	12.0	0.0	0.0	0.0	0.0	0.000			
82	ARTKILL2	COL2 INTR	335.0	1663075.0	72.1	21.3	93.4	0.567			
85	ARTKILL3	COL2 INTR	461.0	2121399.0	89.1	27.1	116.3	0.525			
87	ARKLCT	DIST PEAK	18.0	0.0	0.0	0.0	0.0	0.000			
88	PEEKSKIL	SLWT INTR	50.0	315309.7	17.3	0.0	17.3	0.720			
98	HYDQ1S	PRCH BASE	780.0	3004559.0	0.0	125.6	125.6	0.440			
99	HYDQ2S	PRCH INTR	168.0	705865.4	0.0	53.1	53.1	0.480			
100	HYDQ2W	PRCH INTR	343.0	1227819.0	0.0	92.4	92.4	0.409			
101	ONHY1	PRCH BASE	161.0	1104748.0	0.0	83.1	83.1	0.783			
102	HYDQ3	PRCH BASE	194.0	1416482.0	0.0	106.6	106.6	0.833			
103	ONHY2	PRCH BASE	160.0	1019822.2	0.0	76.7	76.7	0.728			
104	NYPP1	PRCH INTR	300.0	1254184.0	0.0	133.3	133.3	0.477			
105	LILCO	PRCH INTR	500.0	513350.9	0.0	71.5	71.5	0.117			
106	NYPP2	PRCH INTR	800.0	12183.8	0.0	1.8	1.8	0.002			
107	NYPP3	PRCH INTR	1000.0	449272.7	0.0	62.6	62.6	0.051			
108	PSEG1	PRCH INTR	600.0	302.6	0.0	0.1	0.1	0.000			
109	PSEG2	PRCH INTR	800.0	59.8	0.0	0.0	0.0	0.000			
SYSTEM TOTALS				36175712.0	1463.8	888.8	2352.6	0.269			

UNIT TOTALS FOR 1997

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW %
1	INDPNT 2	NUC INTR	864.0	2724704.0	0.0	0.0	0.0	0.360			
3	INDPNT 3	NUC INTR	965.0	3043221.0	0.0	0.0	0.0	0.360			
4	INDPCT	DIST PEAK	72.0	0.0	0.0	0.0	0.0	0.000			
5	RVNSWD 1	RSID INTR	390.0	808328.2	184.8	2.4	187.2	0.237			
8	RVNSWD 2	RSID INTR	390.0	1417769.0	320.8	4.2	325.0	0.415			
13	RVNSWD 3	COL2 INTR	922.0	4152029.0	377.0	33.7	410.8	0.514			
14	RAVCT2	DIST PEAK	239.0	1.6	0.0	0.0	0.0	0.000			
15	RAVCT3	DIST PEAK	126.0	0.6	0.0	0.0	0.0	0.000			
16	RVCT4-11	DIST PEAK	142.0	0.5	0.0	0.0	0.0	0.000			
17	ASTORIA1	RSID INTR	149.0	19791.1	5.7	0.1	5.8	0.015			
18	ASTORIA2	RSID INTR	164.0	17802.2	5.1	0.1	5.2	0.012			
19	ASTORIA3	RSID INTR	387.0	546628.9	134.7	3.3	138.0	0.161			
22	ASTORIA4	RSID INTR	387.0	565764.1	139.9	3.4	143.3	0.167			
25	ASTORIA5	RSID INTR	395.0	391112.1	103.1	2.4	105.5	0.113			
28	ASTORIA6	RSID INTR	825.0	1631698.0	369.9	10.0	379.8	0.226			
29	ASTCT1	DIST PEAK	18.0	1.8	0.0	0.0	0.0	0.000			
30	ASTCT2	DIST PEAK	184.0	14.4	0.0	0.0	0.0	0.000			
31	ASTCT3	DIST PEAK	184.0	9.7	0.0	0.0	0.0	0.000			
32	ASTCT4	DIST PEAK	184.0	7.1	0.0	0.0	0.0	0.000			
33	ASCT5-13	DIST PEAK	172.0	3.7	0.0	0.0	0.0	0.000			
34	BOWLINE1	RSID INTR	401.0	1616393.0	332.4	2.2	334.6	0.460			
35	BOWLINE2	RSID INTR	400.0	1854351.0	381.1	2.5	383.6	0.529			
36	ROSETON1	RSD2 INTR	240.0	1317054.0	211.5	1.2	212.8	0.626			
37	ROSETON2	RSD2 INTR	237.0	1263161.0	203.3	1.2	204.5	0.608			
55	E RIV7	RSID INTR	170.0	26213.1	7.2	0.3	7.5	0.018			
56	NARROWS1	DIST PEAK	184.0	2.6	0.0	0.0	0.0	0.000			
57	NARROWS2	DIST PEAK	184.0	1.8	0.0	0.0	0.0	0.000			
58	GWNUSCT1	DIST PEAK	174.0	0.4	0.0	0.0	0.0	0.000			
59	GWNUSCT2	DIST PEAK	186.0	0.2	0.0	0.0	0.0	0.000			
60	GWNUSCT3	DIST PEAK	167.0	0.2	0.0	0.0	0.0	0.000			
61	GWNISCT4	DIST PEAK	142.0	0.1	0.0	0.0	0.0	0.000			
62	HUDCT1-5	DIST PEAK	83.0	0.0	0.0	0.0	0.0	0.000			
65	HUDSON6	RESD PEAK	17.0	0.0	0.0	0.0	0.0	0.000			
70	74TH-9	RSID INTR	58.0	285.3	0.1	0.0	0.1	0.001			
71	74TH-10	RSID INTR	58.0	189.4	0.1	0.0	0.1	0.000			
72	74TH-11	RSID INTR	31.0	132.9	0.0	0.0	0.1	0.000			
73	74TH CT	DIST PEAK	34.0	0.0	0.0	0.0	0.0	0.000			

UNIT TOTALS FOR 1997

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW	%
75	59TH-14	RSID INTR	19.0	2.1	0.0	0.0	0.0	0.000				
76	59TH-15	RSID INTR	20.0	1.9	0.0	0.0	0.0	0.000				
77	59TH CT	DIST PEAK	40.0	0.0	0.0	0.0	0.0	0.000				
78	BUCHANAN	DIST PEAK	20.0	0.0	0.0	0.0	0.0	0.000				
79	KENT CT	DIST PEAK	12.0	0.0	0.0	0.0	0.0	0.000				
82	ARTKILL2	COL2 INTR	335.0	1722357.0	136.5	42.0	178.5	0.587				
85	ARTKILL3	COL2 INTR	461.0	2124611.0	163.2	51.8	215.0	0.526				
87	ARKLCT	DIST PEAK	18.0	0.0	0.0	0.0	0.0	0.000				
88	PEEKSKIL	SLWT INTR	50.0	322446.8	32.3	0.0	32.3	0.736				
98	HYDQ1S	PRCH BASE	780.0	3004559.0	0.0	244.7	244.7	0.440				
99	HYDQ2S	PRCH INTR	168.0	745454.6	0.0	105.9	105.9	0.507				
100	HYDQ2W	PRCH INTR	343.0	1230597.0	0.0	174.8	174.8	0.410				
101	ONHY1	PRCH BASE	161.0	1147590.0	0.0	163.0	163.0	0.814				
102	HYDQ3	PRCH BASE	194.0	1480159.0	0.0	210.2	210.2	0.871				
103	ONHY2	PRCH BASE	160.0	1073177.0	0.0	152.4	152.4	0.766				
104	NYPP1	PRCH INTR	300.0	1389408.0	0.0	287.9	287.9	0.529				
105	LILCO	PRCH INTR	500.0	664194.0	0.0	180.3	180.3	0.152				
106	NYPP2	PRCH INTR	800.0	33162.6	0.0	9.7	9.7	0.005				
107	NYPP3	PRCH INTR	1000.0	715897.7	0.0	194.4	194.4	0.082				
108	PSEG1	PRCH INTR	600.0	1510.7	0.0	0.6	0.6	0.000				
109	PSEG2	PRCH INTR	800.0	302.5	0.0	0.1	0.1	0.000				
SYSTEM TOTALS				37052048.0	3108.8	1884.7	4993.5	0.289				

UNIT TOTALS FOR 1983

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW %
4	INDPCT	DIST PEAK	72.0	16.3	0.0	0.0	0.0	0.000			
5	RVNSWD 1	RSID INTR	390.0	1410518.0	84.9	1.4	86.3	0.413			
8	RVNSWD 2	RSID INTR	390.0	1801623.0	107.3	1.8	109.1	0.527			
11	RVNSWD 3	RSID INTR	928.0	544320.7	33.2	0.5	33.8	0.067			
12	RVNSWD 3	COL1 INTR	928.0	4634463.0	143.4	14.4	157.9	0.570			
14	RAVCT2	DIST PEAK	239.0	328.7	0.0	0.0	0.0	0.000			
15	RAVCT3	DIST PEAK	126.0	130.5	0.0	0.0	0.0	0.000			
16	RVCT4-11	DIST PEAK	142.0	116.3	0.0	0.0	0.0	0.000			
17	ASTORIA1	RSID INTR	149.0	182226.6	13.6	0.4	14.0	0.140			
18	ASTORIA2	RSID INTR	164.0	212130.6	15.9	0.4	16.3	0.148			
19	ASTORIA3	RSID INTR	387.0	838854.4	54.4	1.7	56.1	0.247			
22	ASTORIA4	RSID INTR	387.0	775952.7	50.5	1.6	52.1	0.229			
25	ASTORIA5	RSID INTR	395.0	643620.0	44.6	1.3	46.0	0.186			
28	ASTORIA6	RSID INTR	825.0	2127338.0	126.9	4.4	131.3	0.294			
29	ASTCT1	DIST PEAK	18.0	175.3	0.0	0.0	0.0	0.001			
30	ASTCT2	DIST PEAK	184.0	1490.3	0.2	0.0	0.2	0.001			
31	ASTCT3	DIST PEAK	184.0	1118.8	0.1	0.0	0.1	0.001			
32	ASTCT4	DIST PEAK	184.0	884.0	0.1	0.0	0.1	0.001			
33	ASCT5-13	DIST PEAK	172.0	538.9	0.1	0.0	0.1	0.000			
34	BOWLINE1	RSID INTR	401.0	2345132.0	126.6	1.1	127.7	0.668			
35	BOWLINE2	RSID INTR	400.0	2486442.0	134.2	1.1	135.3	0.710			
36	ROSETON1	RSD2 INTR	240.0	1580833.0	66.8	0.5	67.3	0.752			
37	ROSETON2	RSD2 INTR	237.0	1578535.0	66.8	0.5	67.3	0.760			
41	FITZPATK	NUC INTR	123.0	726900.2	0.0	8.4	8.4	0.675			
47	WATRSID4	RSID INTR	20.0	3786.2	0.4	0.0	0.4	0.022			
49	WATRSID6	RSID INTR	14.0	2617.4	0.3	0.0	0.3	0.021			
50	WATR5,7	RSID INTR	74.0	10916.3	1.1	0.1	1.1	0.017			
51	WTR8,9	RSID INTR	72.0	11969.	1.2	0.1	1.3	0.019			
52	WTR14,15	RSID INTR	116.0	21048.6	2.0	0.2	2.2	0.021			
53	E RIV5	RSID INTR	134.0	37537.7	3.5	0.2	3.6	0.032			
54	E RIV6	RSID INTR	134.0	34465.7	3.3	0.2	3.4	0.029			
55	E RIV7	RSID INTR	170.0	201323.2	14.5	0.9	15.4	0.135			
56	NARROWS1	DIST PEAK	184.0	426.7	0.1	0.0	0.1	0.000			
57	NARROWS2	DIST PEAK	184.0	323.7	0.0	0.0	0.0	0.000			
58	GWNUSCT1	DIST PEAK	174.0	95.0	0.0	0.0	0.0	0.000			
59	GWNUSCT2	DIST PEAK	186.0	74.6	0.0	0.0	0.0	0.000			
60	GWNUSCT3	DIST PEAK	167.0	52.2	0.0	0.0	0.0	0.000			

UNIT TOTALS FOR 1983

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW	%
61	GWNISCT4	DIST PEAK	142.0	34.8	0.0	0.0	0.0	0.000				
62	HUDCT1-5	DIST PEAK	83.0	16.6	0.0	0.0	0.0	0.000				
63	HUDSN2,3	RESD PEAK	34.0	4.1	0.0	0.0	0.0	0.000				
65	HUDSON6	RESD PEAK	17.0	2.0	0.0	0.0	0.0	0.000				
66	HUDSON7	RESD PEAK	101.0	0.2	0.0	0.0	0.0	0.000				
67	HUDSON7	RESD PEAK	126.0	12.6	0.0	0.0	0.0	0.000				
68	HUDSON8	RESD PEAK	151.0	13.2	0.0	0.0	0.0	0.000				
69	HUDSON10	RESD PEAK	40.0	3.4	0.0	0.0	0.0	0.000				
70	74TH-9	RSID INTR	58.0	729.4	0.1	0.0	0.1	0.001				
71	74TH-10	RSID INTR	58.0	590.5	0.1	0.0	0.1	0.001				
72	74TH-11	RSID INTR	31.0	348.2	0.0	0.0	0.0	0.001				
73	74TH CT	DIST PEAK	34.0	3.4	0.0	0.0	0.0	0.000				
74	59TH-13	RSID INTR	53.0	522.3	0.1	0.0	0.1	0.001				
75	59TH-14	RSID INTR	19.0	192.9	0.0	0.0	0.0	0.001				
76	59TH-15	RSID INTR	20.0	185.4	0.0	0.0	0.0	0.001				
77	59TH CT	DIST PEAK	40.0	7.4	0.0	0.0	0.0	0.000				
78	BUCHANAN	DIST PEAK	20.0	2.5	0.0	0.0	0.0	0.000				
79	KENT CT	DIST PEAK	12.0	1.3	0.0	0.0	0.0	0.000				
80	ARTKILL2	RSID INTR	350.0	1638229.0	96.0	2.3	98.4	0.534				
83	ARTKILL3	RSID INTR	501.0	2490674.0	141.4	3.6	144.9	0.568				
87	ARKLCT	DIST PEAK	18.0	14.0	0.0	0.0	0.0	0.000				
98	HYDO1S	PRCH BASE	780.0	3004558.0	0.0	64.4	64.4	0.440				
99	HYDO2S	PRCH INTR	208.0	1048942.0	0.0	41.8	41.8	0.576				
100	HYDO2W	PRCH INTR	424.0	1521208.0	0.0	60.6	60.6	0.410				
101	ONHY1	PRCH BASE	199.0	1540818.0	0.0	61.4	61.4	0.884				
104	NYPP1	PRCH INTR	300.0	2016284.0	0.0	110.0	110.0	0.767				
105	LILCO	PRCH INTR	500.0	1024525.7	0.0	73.3	73.3	0.234				
106	NYPP2	PRCH INTR	800.0	796510.7	0.0	61.3	61.3	0.114				
108	PSEG1	PRCH INTR	600.0	95112.7	0.0	10.4	10.4	0.018				
109	PSEG2	PRCH INTR	800.0	32048.0	0.0	3.5	3.5	0.005				
SYSTEM TOTALS				37429808.0	1333.7	534.0	1867.7	0.313				

CONED-PASNY (CASE MR2)

UNIT TOTALS FOR 1990

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALE (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW %
4	INDPCT	DIST PEAK	72.0	0.1	0.0	0.0	0.0	0.000			
7	RVNSWD 1	COL2 INTR	372.0	1272729.0	62.5	5.4	67.9	0.391			
8	RVNSWD 2	RSID INTR	390.0	1527786.0	177.3	2.6	180.0	0.447			
13	RVNSWD 3	COL2 INTR	922.0	4234113.0	210.1	18.1	228.2	0.524			
14	RAVCT2	DIST PEAK	239.0	5.4	0.0	0.0	0.0	0.000			
15	RAVCT3	DIST PEAK	126.0	1.9	0.0	0.0	0.0	0.000			
16	RVCT4-11	DIST PEAK	142.0	1.5	0.0	0.0	0.0	0.000			
17	ASTORIA1	RSID INTR	149.0	67397.0	9.9	0.2	10.1	0.052			
18	ASTORIA2	RSID INTR	164.0	66920.5	9.8	0.2	10.0	0.047			
19	ASTORIA3	RSID INTR	387.0	726628.6	91.9	2.6	94.4	0.214			
22	ASTORIA4	RSID INTR	387.0	795891.1	100.9	2.8	103.8	0.235			
25	ASTORIA5	RSID INTR	395.0	530539.1	71.8	1.9	73.6	0.153			
28	ASTORIA6	RSID INTR	825.0	1840569.0	214.1	6.6	220.6	0.255			
29	ASTCT1	DIST PEAK	18.0	5.4	0.0	0.0	0.0	0.000			
30	ASTCT2	DIST PEAK	184.0	42.6	0.0	0.0	0.0	0.000			
31	ASTCT3	DIST PEAK	184.0	29.2	0.0	0.0	0.0	0.000			
32	ASTCT4	DIST PEAK	184.0	22.9	0.0	0.0	0.0	0.000			
33	ASCT5-13	DIST PEAK	172.0	11.4	0.0	0.0	0.0	0.000			
34	BOWLINE1	RSID INTR	401.0	1758007.0	185.5	1.4	186.9	0.500			
35	BOWLINE2	RSID INTR	400.0	2006218.0	211.5	1.6	213.1	0.573			
36	ROSETON1	RSD2 INTR	240.0	1401928.0	115.5	0.8	116.3	0.667			
37	ROSETON2	RSD2 INTR	237.0	1349928.0	111.5	0.7	112.2	0.650			
51	WTR8,9	RSID INTR	72.0	1173.9	0.2	0.0	0.2	0.002			
52	WTR14,15	RSID INTR	116.0	1827.5	0.3	0.0	0.4	0.002			
53	E RIV5	RSID INTR	134.0	4063.7	0.7	0.0	0.8	0.003			
54	E RIV6	RSID INTR	134.0	3361.3	0.6	0.0	0.7	0.003			
55	E RIV7	RSID INTR	170.0	79173.4	11.1	0.6	11.7	0.053			
56	NARROWS1	DIST PEAK	184.0	8.3	0.0	0.0	0.0	0.000			
57	NARROWS2	DIST PEAK	184.0	5.7	0.0	0.0	0.0	0.000			
58	GWNUSCT1	DIST PEAK	174.0	1.1	0.0	0.0	0.0	0.000			
59	GWNUSCT2	DIST PEAK	186.0	0.7	0.0	0.0	0.0	0.000			
60	GWNUSCT3	DIST PEAK	167.0	0.5	0.0	0.0	0.0	0.000			
61	GWNISCT4	DIST PEAK	142.0	0.3	0.0	0.0	0.0	0.000			
62	HUDCT1-5	DIST PEAK	83.0	0.1	0.0	0.0	0.0	0.000			
65	HUDSON6	RESD PEAK	17.0	0.0	0.0	0.0	0.0	0.000			
67	HUDSON7	RESD PEAK	126.0	0.1	0.0	0.0	0.0	0.000			
69	HUDSON10	RESD PEAK	40.0	0.0	0.0	0.0	0.0	0.000			

UNIT TOTALS FOR 1990

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW %
70	74TH-9	RSID INTR	58.0	25.5	0.0	0.0	0.0	0.000			
71	74TH-10	RSID INTR	58.0	16.6	0.0	0.0	0.0	0.000			
72	74TH-11	RSID INTR	31.0	12.0	0.0	0.0	0.0	0.000			
73	74TH CT	DIST PEAK	34.0	0.0	0.0	0.0	0.0	0.000			
74	59TH-13	RSID INTR	53.0	16.1	0.0	0.0	0.0	0.000			
75	59TH-14	RSID INTR	19.0	6.3	0.0	0.0	0.0	0.000			
76	59TH-15	RSID INTR	20.0	5.6	0.0	0.0	0.0	0.000			
77	59TH CT	DIST PEAK	40.0	0.0	0.0	0.0	0.0	0.000			
78	BUCHANAN	DIST PEAK	20.0	0.0	0.0	0.0	0.0	0.000			
79	KENT CT	DIST PEAK	12.0	0.0	0.0	0.0	0.0	0.000			
82	ARTKILL2	COL2 INTR	335.0	1823639.0	79.0	23.3	102.4	0.621			
85	ARTKILL3	COL2 INTR	461.0	2124611.0	89.3	27.2	116.5	0.526			
87	ARKLCT	DIST PEAK	18.0	0.2	0.0	0.0	0.0	0.000			
88	PEEKSKIL	SLWT INTR	50.0	334682.6	18.3	0.0	18.3	0.764			
98	HYDQ1S	PRCH BASE	780.0	3004558.0	0.0	125.6	125.6	0.440			
99	HYDQ2S	PRCH INTR	208.0	1014827.1	0.0	76.3	76.3	0.557			
100	HYDQ2W	PRCH INTR	424.0	1521208.0	0.0	114.4	114.4	0.410			
101	ONHY1	PRCH BASE	199.0	1505893.0	0.0	113.3	113.3	0.864			
102	HYDQ3	PRCH BASE	240.0	1946839.0	0.0	146.5	146.5	0.926			
103	ONHY2	PRCH BASE	198.0	1406906.0	0.0	105.8	105.8	0.811			
104	NYPP1	PRCH INTR	300.0	1494829.0	0.0	158.9	158.9	0.569			
105	LILCO	PRCH INTR	500.0	925096.9	0.0	128.9	128.9	0.211			
106	NYPP2	PRCH INTR	800.0	166441.1	0.0	25.0	25.0	0.024			
107	NYPP3	PRCH INTR	1000.0	1230290.0	0.0	171.4	171.4	0.140			
108	PSEG1	PRCH INTR	600.0	6213.0	0.0	1.3	1.3	0.001			
109	PSEG2	PRCH INTR	800.0	1285.6	0.0	0.3	0.3	0.000			
SYSTEM TOTALS				36175712.0	1772.0	1263.9	3035.9	0.281			

UNIT TOTALS FOR 1997

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW %
4	INDPCT	DIST PEAK	72.0	0.4	0.0	0.0	0.0	0.000			
7	RVNSWD 1	COL2 INTR	372.0	1898660.0	170.5	15.4	185.9	0.583			
10	RVNSWD 2	COL2 INTR	370.0	1900571.0	168.7	15.4	184.1	0.586			
13	RVNSWD 3	COL2 INTR	922.0	4234187.0	384.1	34.4	418.5	0.524			
14	RAVCT2	DIST PEAK	239.0	15.8	0.0	0.0	0.0	0.000			
15	RAVCT3	DIST PEAK	126.0	5.7	0.0	0.0	0.0	0.000			
16	RVCT4-11	DIST PEAK	142.0	4.6	0.0	0.0	0.0	0.000			
17	ASTORIA1	RSID INTR	149.0	60520.0	17.3	0.4	17.6	0.046			
18	ASTORIA2	RSID INTR	164.0	60254.0	17.2	0.4	17.6	0.042			
19	ASTORIA3	RSID INTR	387.0	779403.8	192.0	4.7	196.7	0.230			
22	ASTORIA4	RSID INTR	387.0	805745.6	199.2	4.9	204.1	0.238			
25	ASTORIA5	RSID INTR	395.0	569335.7	150.1	3.4	153.5	0.165			
28	ASTORIA6	RSID INTR	825.0	1971437.0	446.7	12.0	458.8	0.273			
29	ASTCT1	DIST PEAK	18.0	13.7	0.0	0.0	0.0	0.000			
30	ASTCT2	DIST PEAK	184.0	110.7	0.1	0.0	0.1	0.000			
31	ASTCT3	DIST PEAK	184.0	77.3	0.0	0.0	0.0	0.000			
32	ASTCT4	DIST PEAK	184.0	61.1	0.0	0.0	0.0	0.000			
33	ASCT5-13	DIST PEAK	172.0	31.6	0.0	0.0	0.0	0.000			
34	BOWLINE1	RSID INTR	401.0	1689992.0	347.6	2.3	349.9	0.481			
35	BOWLINE2	RSID INTR	400.0	1938218.0	398.3	2.6	400.9	0.553			
36	ROSETON1	RSD2 INTR	240.0	1373668.0	220.6	1.3	221.9	0.653			
37	ROSETON2	RSD2 INTR	237.0	1312184.0	211.2	1.2	212.4	0.632			
55	E RIV7	RSID INTR	170.0	72456.1	19.8	1.0	20.8	0.049			
56	NARROWS1	DIST PEAK	184.0	23.5	0.0	0.0	0.0	0.000			
57	NARROWS2	DIST PEAK	184.0	16.4	0.0	0.0	0.0	0.000			
58	GWNUSCT1	DIST PEAK	174.0	3.5	0.0	0.0	0.0	0.000			
59	GWNUSCT2	DIST PEAK	186.0	2.4	0.0	0.0	0.0	0.000			
60	GWNUSCT3	DIST PEAK	167.0	1.6	0.0	0.0	0.0	0.000			
61	GWNISCT4	DIST PEAK	142.0	0.9	0.0	0.0	0.0	0.000			
62	HUDCT1-5	DIST PEAK	83.0	0.4	0.0	0.0	0.0	0.000			
65	HUDSON6	RESD PEAK	17.0	0.1	0.0	0.0	0.0	0.000			
70	74TH-9	RSID INTR	58.0	1758.8	0.7	0.1	0.7	0.003			
71	74TH-10	RSID INTR	58.0	1082.0	0.4	0.0	0.4	0.002			
72	74TH-11	RSID INTR	31.0	837.7	0.3	0.0	0.3	0.003			
73	74TH CT	DIST PEAK	34.0	0.1	0.0	0.0	0.0	0.000			
75	59TH-14	RSID INTR	19.0	16.3	0.0	0.0	0.0	0.000			
76	59TH-15	RSID INTR	20.0	14.4	0.0	0.0	0.0	0.000			

UNIT TOTALS FOR 1997

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW	%
77	59TH CT	DIST PEAK	40.0	0.2	0.0	0.0	0.0	0.000				
78	BUCHANAN	DIST PEAK	20.0	0.1	0.0	0.0	0.0	0.000				
79	KENT CT	DIST PEAK	12.0	0.0	0.0	0.0	0.0	0.000				
82	ARTKILL2	COL2 INTR	335.0	1821781.0	144.4	44.4	188.7	0.621				
85	ARTKILL3	COL2 INTR	461.0	2124385.0	163.2	51.8	215.0	0.526				
87	ARKLCT	DIST PEAK	18.0	0.1	0.0	0.0	0.0	0.000				
88	PEEKSKIL	SLWT INTR	50.0	334789.2	33.5	0.0	33.5	0.764				
98	HYDQ1S	PRCH BASE	780.0	3004558.0	0.0	244.7	244.7	0.440				
99	HYDQ2S	PRCH INTR	208.0	1008238.4	0.0	143.2	143.2	0.553				
100	HYDQ2W	PRCH INTR	424.0	1520918.0	0.0	216.0	216.0	0.409				
101	ONHY1	PRCH BASE	199.0	1494032.0	0.0	212.2	212.2	0.857				
102	HYDQ3	PRCH BASE	240.0	1923122.0	0.0	273.1	273.1	0.915				
103	ONHY2	PRCH BASE	198.0	1382249.0	0.0	196.3	196.3	0.797				
104	NYPP1	PRCH INTR	300.0	1426460.0	0.0	295.5	295.5	0.543				
105	LILCO	PRCH INTR	500.0	951112.1	0.0	258.2	258.2	0.217				
106	NYPP2	PRCH INTR	800.0	146672.1	0.0	42.9	42.9	0.021				
107	NYPP3	PRCH INTR	1000.0	1230142.0	0.0	334.0	334.0	0.140				
108	PSEG1	PRCH INTR	600.0	10306.4	0.0	4.3	4.3	0.002				
109	PSEG2	PRCH INTR	800.0	2302.0	0.0	1.0	1.0	0.000				
SYSTEM TOTALS				37051712.0	3285.9	2417.1	5702.9	0.296				

APPENDIX F

Sample Dispatch Runs

Output for Mid-Range Case

with and without

Indian Point

(1983, 1990, 1997)

Continued operation: Case MK1

Plant retirement: Case MR-2

UNIT TOTALS FOR 1983

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW	%
1	INDPNT 2	NUC INTR	864.0	4087061.0	0.0	0.0	0.0	0.540				
3	INDPNT 3	NUC INTR	965.0	4395763.0	0.0	0.0	0.0	0.520				
4	INDPCT	DIST PEAK	72.0	0.8	0.0	0.0	0.0	0.000				
5	RVNSWD 1	RSID INTR	390.0	931328.4	56.1	0.9	57.0	0.273				
8	RVNSWD 2	RSID INTR	390.0	1304269.0	77.7	1.3	79.0	0.382				
11	RVNSWD 3	RSID INTR	928.0	377094.4	23.0	0.4	23.4	0.046				
12	RVNSWD 3	COL1 INTR	928.0	4396491.0	136.3	13.7	150.0	0.541				
14	RAVCT2	DIST PEAK	239.0	20.5	0.0	0.0	0.0	0.000				
15	RAVCT3	DIST PEAK	126.0	8.0	0.0	0.0	0.0	0.000				
16	RVCT4-11	DIST PEAK	142.0	6.9	0.0	0.0	0.0	0.000				
17	ASTORIA1	RSID INTR	149.0	67869.9	5.1	0.1	5.2	0.052				
18	ASTORIA2	RSID INTR	164.0	71338.7	5.4	0.1	5.5	0.050				
19	ASTORIA3	RSID INTR	387.0	473495.8	30.7	1.0	31.7	0.140				
22	ASTORIA4	RSID INTR	387.0	452537.7	29.5	0.9	30.4	0.133				
25	ASTORIA5	RSID INTR	395.0	331291.2	23.0	0.7	23.7	0.096				
28	ASTORIA6	RSID INTR	825.0	1291460.0	77.1	2.7	79.8	0.179				
29	ASTCT1	DIST PEAK	18.0	15.0	0.0	0.0	0.0	0.000				
30	ASTCT2	DIST PEAK	184.0	122.6	0.0	0.0	0.0	0.000				
31	ASTCT3	DIST PEAK	184.0	87.8	0.0	0.0	0.0	0.000				
32	ASTCT4	DIST PEAK	184.0	63.7	0.0	0.0	0.0	0.000				
33	ASCT5-13	DIST PEAK	172.0	38.7	0.0	0.0	0.0	0.000				
34	BOWLINE1	RSID INTR	401.0	1900675.0	102.8	0.9	103.7	0.541				
35	BOWLINE2	RSID INTR	400.0	2129195.0	115.1	1.0	116.1	0.608				
36	ROSETON1	RSD2 INTR	240.0	1423496.0	60.2	0.5	60.6	0.677				
37	ROSETON2	RSD2 INTR	237.0	1400688.0	59.3	0.4	59.8	0.675				
41	FITZPATK	NUC INTR	123.0	726900.3	0.0	8.4	8.4	0.675				
47	WATRSID4	RSID INTR	20.0	431.9	0.0	0.0	0.0	0.002				
49	WATRSID6	RSID INTR	14.0	296.6	0.0	0.0	0.0	0.002				
50	WATR5,7	RSID INTR	74.0	1552.2	0.2	0.0	0.2	0.002				
51	WTR8,9	RSID INTR	72.0	1305.4	0.1	0.0	0.1	0.002				
52	WTR14,15	RSID INTR	116.0	2540.9	0.2	0.0	0.3	0.003				
53	E RIV5	RSID INTR	134.0	4594.8	0.4	0.0	0.4	0.004				
54	E RIV6	RSID INTR	134.0	3991.7	0.4	0.0	0.4	0.003				
55	E RIV7	RSID INTR	170.0	82068.3	5.9	0.4	6.3	0.055				
56	NARROWS1	DIST PEAK	184.0	29.6	0.0	0.0	0.0	0.000				
57	NARROWS2	DIST PEAK	184.0	21.6	0.0	0.0	0.0	0.000				
58	GWNUSCT1	DIST PEAK	174.0	5.4	0.0	0.0	0.0	0.000				

UNIT TOTALS FOR 1983

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW %
59	GWNUSCT2	DIST PEAK	186.0	4.2	0.0	0.0	0.0	0.000			
60	GWNUSCT3	DIST PEAK	167.0	2.8	0.0	0.0	0.0	0.000			
61	GWNISCT4	DIST PEAK	142.0	1.8	0.0	0.0	0.0	0.000			
62	HUDCT1-5	DIST PEAK	33.0	0.8	0.0	0.0	0.0	0.000			
63	HUDSN2,3	RESD PEAK	34.0	0.2	0.0	0.0	0.0	0.000			
65	HUDSON6	RESD PEAK	17.0	0.1	0.0	0.0	0.0	0.000			
66	HUDSON7	RESD PEAK	101.0	0.0	0.0	0.0	0.0	0.000			
67	HUDSON7	RESD PEAK	126.0	0.6	0.0	0.0	0.0	0.000			
68	HUDSON8	RESD PEAK	151.0	0.6	0.0	0.0	0.0	0.000			
69	HUDSON10	RESD PEAK	40.0	0.2	0.0	0.0	0.0	0.000			
70	74TH-9	RSID INTR	58.0	63.1	0.0	0.0	0.0	0.000			
71	74TH-10	RSID INTR	58.0	55.5	0.0	0.0	0.0	0.000			
72	74TH-11	RSID INTR	31.0	29.6	0.0	0.0	0.0	0.000			
73	74TH CT	DIST PEAK	34.0	0.2	0.0	0.0	0.0	0.000			
74	59TH-13	RSID INTR	53.0	45.2	0.0	0.0	0.0	0.000			
75	59TH-14	RSID INTR	19.0	16.2	0.0	0.0	0.0	0.000			
76	59TH-15	RSID INTR	20.0	16.2	0.0	0.0	0.0	0.000			
77	59TH CT	DIST PEAK	40.0	0.4	0.0	0.0	0.0	0.000			
78	BUCHANAN	DIST PEAK	20.0	0.1	0.0	0.0	0.0	0.000			
79	KENT CT	DIST PEAK	12.0	0.1	0.0	0.0	0.0	0.000			
80	ARTKILL2	RSID INTR	350.0	1150794.0	67.5	1.6	69.2	0.375			
83	ARTKILL3	RSID INTR	501.0	1978568.0	112.4	2.8	115.2	0.451			
87	ARKLCT	DIST PEAK	18.0	0.9	0.0	0.0	0.0	0.000			
98	HYDQ1S	PRCH BASE	780.0	3003518.0	0.0	64.4	64.4	0.440			
99	HYDQ2S	PRCH INTR	168.0	747645.6	0.0	29.8	29.8	0.508			
100	HYDQ2W	PRCH INTR	343.0	1230600.0	0.0	49.0	49.0	0.410			
101	ONHY1	PRCH BASE	161.0	1150500.0	0.0	45.9	45.9	0.816			
104	NYPP1	PRCH INTR	300.0	1616547.0	0.0	88.2	98.2	0.615			
105	LILCO	PRCH INTR	500.0	493525.4	0.0	35.3	35.3	0.113			
106	NYPP2	PRCH INTR	800.0	182672.9	0.0	14.1	14.1	0.026			
108	PSEG1	PRCH INTR	600.0	10133.0	0.0	1.1	1.1	0.002			
109	PSEG2	PRCH INTR	800.0	2941.1	0.0	0.3	0.3	0.000			
SYSTEM TOTALS				37425744.0	988.7	366.1	1354.7	0.294			

CONED-PASNY (CASE MK1)

UNIT TOTALS FOR 1990

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW	%
1	INDPNT 2	NUC INTR	864.0	3405883.0	0.0	0.0	0.0	0.450				
3	INDPNT 3	NUC INTR	965.0	3719492.0	0.0	0.0	0.0	0.440				
4	INDPCT	DIST PEAK	72.0	0.0	0.0	0.0	0.0	0.000				
5	RVNSWD 1	RSID INTR	390.0	898763.6	105.4	1.6	107.0	0.263				
8	RVNSWD 2	RSID INTR	390.0	1259707.0	146.3	2.2	148.5	0.369				
13	RVNSWD 3	COL2 INTR	922.0	4089910.0	203.2	17.4	220.7	0.506				
14	RAVCT2	DIST PEAK	239.0	0.2	0.0	0.0	0.0	0.000				
15	RAVCT3	DIST PEAK	126.0	0.1	0.0	0.0	0.0	0.000				
16	RVCT4-11	DIST PEAK	142.0	0.1	0.0	0.0	0.0	0.000				
17	ASTORIA1	RSID INTR	149.0	8139.9	1.2	0.0	1.2	0.006				
18	ASTORIA2	RSID INTR	164.0	7171.6	1.1	0.0	1.1	0.005				
19	ASTORIA3	RSID INTR	387.0	439552.2	55.6	1.6	57.2	0.130				
22	ASTORIA4	RSID INTR	387.0	474005.2	60.2	1.7	61.9	0.140				
25	ASTORIA5	RSID INTR	395.0	303024.1	41.0	1.1	42.1	0.088				
28	ASTORIA6	RSID INTR	825.0	1165089.0	135.7	4.2	139.8	0.161				
29	ASTCT1	DIST PEAK	18.0	0.3	0.0	0.0	0.0	0.000				
30	ASTCT2	DIST PEAK	184.0	2.0	0.0	0.0	0.0	0.000				
31	ASTCT3	DIST PEAK	184.0	1.3	0.0	0.0	0.0	0.000				
32	ASTCT4	DIST PEAK	184.0	0.9	0.0	0.0	0.0	0.000				
33	ASCT5-13	DIST PEAK	172.0	0.5	0.0	0.0	0.0	0.000				
34	BOWLINE1	RSID INTR	401.0	1465419.0	154.7	1.1	155.9	0.417				
35	BOWLINE2	RSID INTR	400.0	1702068.0	179.6	1.3	180.9	0.486				
36	ROSETON1	RSD2 INTR	240.0	1243701.0	102.5	0.7	103.2	0.592				
37	ROSETON2	RSD2 INTR	237.0	1173616.0	97.0	0.6	97.6	0.565				
51	WTR8,9	RSID INTR	72.0	49.9	0.0	0.0	0.0	0.000				
52	WTR14,15	RSID INTR	116.0	89.8	0.0	0.0	0.0	0.000				
53	E RIV5	RSID INTR	134.0	171.0	0.0	0.0	0.0	0.000				
54	E RIV6	RSID INTR	134.0	141.1	0.0	0.0	0.0	0.000				
55	E RIV7	RSID INTR	170.0	11326.4	1.6	0.1	1.7	0.008				
56	NARROWS1	DIST PEAK	184.0	0.3	0.0	0.0	0.0	0.000				
57	NARROWS2	DIST PEAK	184.0	0.2	0.0	0.0	0.0	0.000				
58	GWNUSCT1	DIST PEAK	174.0	0.0	0.0	0.0	0.0	0.000				
59	GWNUSCT2	DIST PEAK	186.0	0.0	0.0	0.0	0.0	0.000				
60	GWNUSCT3	DIST PEAK	167.0	0.0	0.0	0.0	0.0	0.000				
61	GWNISCT4	DIST PEAK	142.0	0.0	0.0	0.0	0.0	0.000				
62	HUDCT1-5	DIST PEAK	83.0	0.0	0.0	0.0	0.0	0.000				
65	HUDSON6	RESD PEAK	17.0	0.0	0.0	0.0	0.0	0.000				

CROSS EXAMINATION EXHIBIT

CANADIAN ENERGY IMPORTS ASSUMED

IN MID RANGE RUNS OF ESRG STUDY --

AS PER APPENDIX F

1990

Unit Index	Unit Name	Cost Mills/KWH	Energy With Indian Point	Energy Without Indian Point	% Increase
98	HYDQ15	42	3004.6	3004.6	0 %
99	HYDQ25	75	705.9	1014.8	44%
100	HYDQ2W	75	1227.8	1521.2	24%
101	ONHY1	75	1104.7	1505.9	36%
102	HYDQ3	75	1416.5	1946.8	37%
103	ONHY2	75	1019.8	1406.9	38%
Total Canadian Imports			8479.3	10400.2	23%

1) Source Appendix F, 1990 Page 2 of Run MK1.

2) Source Appendix F, 1990 Page 2 of Run MR2.

UNIT TOTALS FOR 1990

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW %
67	HUDSON7	RESD PEAK	126.0	0.0	0.0	0.0	0.0	0.000			
69	HUDSON10	RESD PEAK	40.0	0.0	0.0	0.0	0.0	0.000			
70	74TH-9	RSID INTR	58.0	1.2	0.0	0.0	0.0	0.000			
71	74TH-10	RSID INTR	58.0	1.0	0.0	0.0	0.0	0.000			
72	74TH-11	RSID INTR	31.0	0.5	0.0	0.0	0.0	0.000			
73	74TH CT	DIST PEAK	34.0	0.0	0.0	0.0	0.0	0.000			
74	59TH-13	RSID INTR	53.0	0.8	0.0	0.0	0.0	0.000			
75	59TH-14	RSID INTR	19.0	0.3	0.0	0.0	0.0	0.000			
76	59TH-15	RSID INTR	20.0	0.3	0.0	0.0	0.0	0.000			
77	59TH CT	DIST PEAK	40.0	0.0	0.0	0.0	0.0	0.000			
78	BUCHANAN	DIST PEAK	20.0	0.0	0.0	0.0	0.0	0.000			
79	KENT CT	DIST PEAK	12.0	0.0	0.0	0.0	0.0	0.000			
82	ARTKILL2	COL2 INTR	335.0	1663075.0	72.1	21.3	93.4	0.567			
85	ARTKILL3	COL2 INTR	461.0	2121399.0	89.1	27.1	116.3	0.525			
87	ARKLCT	DIST PEAK	18.0	0.0	0.0	0.0	0.0	0.000			
88	PEEKSKIL	SLWT INTR	50.0	315309.7	17.3	0.0	17.3	0.720			
98	HYDQ1S	PRCH BASE	780.0	3004559.0	0.0	125.6	125.6	0.440			
99	HYDQ2S	PRCH INTR	168.0	705865.4	0.0	53.1	53.1	0.480			
100	HYDQ2W	PRCH INTR	343.0	1227819.0	0.0	92.4	92.4	0.409			
101	ONHY1	PRCH BASE	161.0	1104748.0	0.0	83.1	83.1	0.783			
102	HYDQ3	PRCH BASE	194.0	1416482.0	0.0	106.6	106.6	0.833			
103	ONHY2	PRCH BASE	160.0	1019822.2	0.0	76.7	76.7	0.728			
104	NYPP1	PRCH INTR	300.0	1254184.0	0.0	133.3	133.3	0.477			
105	LILCO	PRCH INTR	500.0	513350.9	0.0	71.5	71.5	0.117			
106	NYPP2	PRCH INTR	800.0	12183.8	0.0	1.8	1.8	0.002			
107	NYPP3	PRCH INTR	1000.0	449272.7	0.0	62.6	62.6	0.051			
108	PSEG1	PRCH INTR	600.0	302.6	0.0	0.1	0.1	0.000			
109	PSEG2	PRCH INTR	800.0	59.8	0.0	0.0	0.0	0.000			
SYSTEM TOTALS				36175712.0	1463.8	888.8	2352.6	0.269			

UNIT TOTALS FOR 1997

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW	%
1	INDPNT 2	NUC INTR	864.0	2724704.0	0.0	0.0	0.0	0.360				
3	INDPNT 3	NUC INTR	965.0	3043221.0	0.0	0.0	0.0	0.360				
4	INDPCT	DIST PEAK	72.0	0.0	0.0	0.0	0.0	0.000				
5	RVNSWD 1	RSID INTR	390.0	808328.2	184.8	2.4	187.2	0.237				
8	RVNSWD 2	RSID INTR	390.0	1417769.0	320.8	4.2	325.0	0.415				
13	RVNSWD 3	COL2 INTR	922.0	4152029.0	377.0	33.7	410.8	0.514				
14	RAVCT2	DIST PEAK	239.0	1.6	0.0	0.0	0.0	0.000				
15	RAVCT3	DIST PEAK	126.0	0.6	0.0	0.0	0.0	0.000				
16	RVCT4-11	DIST PEAK	142.0	0.5	0.0	0.0	0.0	0.000				
17	ASTORIA1	RSID INTR	149.0	19791.1	5.7	0.1	5.8	0.015				
18	ASTORIA2	RSID INTR	164.0	17802.2	5.1	0.1	5.2	0.012				
19	ASTORIA3	RSID INTR	387.0	546628.9	134.7	3.3	138.0	0.161				
22	ASTORIA4	RSID INTR	387.0	565764.1	139.9	3.4	143.3	0.167				
25	ASTORIA5	RSID INTR	395.0	391112.1	103.1	2.4	105.5	0.113				
28	ASTORIA6	RSID INTR	825.0	1631698.0	369.9	10.0	379.8	0.226				
29	ASTCT1	DIST PEAK	18.0	1.8	0.0	0.0	0.0	0.000				
30	ASTCT2	DIST PEAK	184.0	14.4	0.0	0.0	0.0	0.000				
31	ASTCT3	DIST PEAK	184.0	9.7	0.0	0.0	0.0	0.000				
32	ASTCT4	DIST PEAK	184.0	7.1	0.0	0.0	0.0	0.000				
33	ASCT5-13	DIST PEAK	172.0	3.7	0.0	0.0	0.0	0.000				
34	BOWLINE1	RSID INTR	401.0	1616393.0	332.4	2.2	334.6	0.460				
35	BOWLINE2	RSID INTR	400.0	1854351.0	381.1	2.5	383.6	0.529				
36	ROSETON1	RSD2 INTR	240.0	1317054.0	211.5	1.2	212.8	0.626				
37	ROSETON2	RSD2 INTR	237.0	1263161.0	203.3	1.2	204.5	0.608				
55	E RIV7	RSID INTR	170.0	26213.1	7.2	0.3	7.5	0.018				
56	NARROWS1	DIST PEAK	184.0	2.6	0.0	0.0	0.0	0.000				
57	NARROWS2	DIST PEAK	184.0	1.8	0.0	0.0	0.0	0.000				
58	GWNUSCT1	DIST PEAK	174.0	0.4	0.0	0.0	0.0	0.000				
59	GWNUSCT2	DIST PEAK	186.0	0.2	0.0	0.0	0.0	0.000				
60	GWNUSCT3	DIST PEAK	167.0	0.2	0.0	0.0	0.0	0.000				
61	GWNISCT4	DIST PEAK	142.0	0.1	0.0	0.0	0.0	0.000				
62	HUDCT1-5	DIST PEAK	83.0	0.0	0.0	0.0	0.0	0.000				
65	HUDSON6	RESD PEAK	17.0	0.0	0.0	0.0	0.0	0.000				
70	74TH-9	RSID INTR	58.0	285.3	0.1	0.0	0.1	0.001				
71	74TH-10	RSID INTR	58.0	189.4	0.1	0.0	0.1	0.000				
72	74TH-11	RSID INTR	31.0	132.9	0.0	0.0	0.1	0.000				
73	74TH CT	DIST PEAK	34.0	0.0	0.0	0.0	0.0	0.000				

UNIT TOTALS FOR 1997

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW	EFFECTIVE CAPACITY %
75	59TH-14	RSID INTR	19.0	2.1	0.0	0.0	0.0	0.000				
76	59TH-15	RSID INTR	20.0	1.9	0.0	0.0	0.0	0.000				
77	59TH CT	DIST PEAK	40.0	0.0	0.0	0.0	0.0	0.000				
78	BUCHANAN	DIST PEAK	20.0	0.0	0.0	0.0	0.0	0.000				
79	KENT CT	DIST PEAK	12.0	0.0	0.0	0.0	0.0	0.000				
82	ARTKILL2	COL2 INTR	335.0	1722357.0	136.5	42.0	178.5	0.587				
85	ARTKILL3	COL2 INTR	461.0	2124611.0	163.2	51.8	215.0	0.526				
87	ARKLCT	DIST PEAK	18.0	0.0	0.0	0.0	0.0	0.000				
88	PEEKSKIL	SLWT INTR	50.0	322446.8	32.3	0.0	32.3	0.736				
98	HYDQ1S	PRCH BASE	780.0	3004559.0	0.0	244.7	244.7	0.440				
99	HYDQ2S	PRCH INTR	168.0	745454.6	0.0	105.9	105.9	0.507				
100	HYDQ2W	PRCH INTR	343.0	1230597.0	0.0	174.8	174.8	0.410				
101	ONHY1	PRCH BASE	161.0	1147590.0	0.0	163.0	163.0	0.814				
102	HYDQ3	PRCH BASE	194.0	1480159.0	0.0	210.2	210.2	0.871				
103	ONHY2	PRCH BASE	160.0	1073177.0	0.0	152.4	152.4	0.766				
104	NYPP1	PRCH INTR	300.0	1389408.0	0.0	287.9	287.9	0.529				
105	LILCO	PRCH INTR	500.0	664194.0	0.0	180.3	180.3	0.152				
106	NYPP2	PRCH INTR	800.0	33162.6	0.0	9.7	9.7	0.005				
107	NYPP3	PRCH INTR	1000.0	715897.7	0.0	194.4	194.4	0.082				
108	PSEG1	PRCH INTR	600.0	1510.7	0.0	0.6	0.6	0.000				
109	PSEG2	PRCH INTR	800.0	302.5	0.0	0.1	0.1	0.000				
SYSTEM TOTALS				37052048.0	3108.8	1884.7	4993.5	0.289				

UNIT TOTALS FOR 1983

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW	%
4	INDPCT	DIST PEAK	72.0	16.3	0.0	0.0	0.0	0.000				
5	RVNSWD 1	RSID INTR	390.0	1410518.0	84.9	1.4	86.3	0.413				
8	RVNSWD 2	RSID INTR	390.0	1801623.0	107.3	1.8	109.1	0.527				
11	RVNSWD 3	RSID INTR	928.0	544320.7	33.2	0.5	33.8	0.067				
12	RVNSWD 3	COL1 INTR	928.0	4634463.0	143.4	14.4	157.9	0.570				
14	RAVCT2	DIST PEAK	239.0	328.7	0.0	0.0	0.0	0.000				
15	RAVCT3	DIST PEAK	126.0	130.5	0.0	0.0	0.0	0.000				
16	RVCT4-11	DIST PEAK	142.0	116.3	0.0	0.0	0.0	0.000				
17	ASTORIA1	RSID INTR	149.0	182226.6	13.6	0.4	14.0	0.140				
18	ASTORIA2	RSID INTR	164.0	212130.6	15.9	0.4	16.3	0.148				
19	ASTORIA3	RSID INTR	387.0	838854.4	54.4	1.7	56.1	0.247				
22	ASTORIA4	RSID INTR	387.0	775952.7	50.5	1.6	52.1	0.229				
25	ASTORIA5	RSID INTR	395.0	643620.0	44.6	1.3	46.0	0.186				
28	ASTORIA6	RSID INTR	825.0	2127338.0	126.9	4.4	131.3	0.294				
29	ASTCT1	DIST PEAK	18.0	175.3	0.0	0.0	0.0	0.001				
30	ASTCT2	DIST PEAK	184.0	1490.3	0.2	0.0	0.2	0.001				
31	ASTCT3	DIST PEAK	184.0	1118.8	0.1	0.0	0.1	0.001				
32	ASTCT4	DIST PEAK	184.0	884.0	0.1	0.0	0.1	0.001				
33	ASCT5-13	DIST PEAK	172.0	538.9	0.1	0.0	0.1	0.000				
34	BOWLINE1	RSID INTR	401.0	2345132.0	126.6	1.1	127.7	0.668				
35	BOWLINE2	RSID INTR	400.0	2486442.0	134.2	1.1	135.3	0.710				
36	ROSETON1	RSD2 INTR	240.0	1580833.0	66.8	0.5	67.3	0.752				
37	ROSETON2	RSD2 INTR	237.0	1578535.0	66.8	0.5	67.3	0.760				
41	FITZPATK	NUC INTR	123.0	726900.2	0.0	8.4	8.4	0.675				
47	WATRSID4	RSID INTR	20.0	3786.2	0.4	0.0	0.4	0.022				
49	WATRSID6	RSID INTR	14.0	2617.4	0.3	0.0	0.3	0.021				
50	WATR5,7	RSID INTR	74.0	10916.3	1.1	0.1	1.1	0.017				
51	WTR8,9	RSID INTR	72.0	11969.6	1.2	0.1	1.3	0.019				
52	WTR14,15	RSID INTR	116.0	21048.6	2.0	0.2	2.2	0.021				
53	E RIV5	RSID INTR	134.0	37537.7	3.5	0.2	3.6	0.032				
54	E RIV6	RSID INTR	134.0	34465.7	3.3	0.2	3.4	0.029				
55	E RIV7	RSID INTR	170.0	201323.2	14.5	0.9	15.4	0.135				
56	NARROWS1	DIST PEAK	184.0	426.7	0.1	0.0	0.1	0.000				
57	NARROWS2	DIST PEAK	184.0	323.7	0.0	0.0	0.0	0.000				
58	GWNUSCT1	DIST PEAK	174.0	95.0	0.0	0.0	0.0	0.000				
59	GWNUSCT2	DIST PEAK	186.0	74.6	0.0	0.0	0.0	0.000				
60	GWNUSCT3	DIST PEAK	167.0	52.2	0.0	0.0	0.0	0.000				

UNIT TOTALS FOR 1983

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW %
61	GWNISCT4	DIST PEAK	142.0	34.8	0.0	0.0	0.0	0.000			
62	HUDCT1-5	DIST PEAK	83.0	16.6	0.0	0.0	0.0	0.000			
63	HUDSN2,3	RESD PEAK	34.0	4.1	0.0	0.0	0.0	0.000			
65	HUDSON6	RESD PEAK	17.0	2.0	0.0	0.0	0.0	0.000			
66	HUDSON7	RESD PEAK	101.0	0.2	0.0	0.0	0.0	0.000			
67	HUDSON7	RESD PEAK	126.0	12.6	0.0	0.0	0.0	0.000			
68	HUDSON8	RESD PEAK	151.0	13.2	0.0	0.0	0.0	0.000			
69	HUDSON10	RESD PEAK	[illegible]	3.4	0.0	0.0	0.0	0.000			
70	74TH-9	RSID INTR	58.0	729.4	0.1	0.0	0.1	0.001			
71	74TH-10	RSID INTR	58.0	590.5	0.1	0.0	0.1	0.001			
72	74TH-11	RSID INTR	31.0	348.2	0.0	0.0	0.0	0.001			
73	74TH CT	DIST PEAK	34.0	3.4	0.0	0.0	0.0	0.000			
74	59TH-13	RSID INTR	53.0	522.3	0.1	0.0	0.1	0.001			
75	59TH-14	RSID INTR	19.0	192.9	0.0	0.0	0.0	0.001			
76	59TH-15	RSID INTR	20.0	185.4	0.0	0.0	0.0	0.001			
77	59TH CT	DIST PEAK	40.0	7.4	0.0	0.0	0.0	0.000			
78	BUCHANAN	DIST PEAK	20.0	2.5	0.0	0.0	0.0	0.000			
79	KENT CT	DIST PEAK	12.0	1.3	0.0	0.0	0.0	0.000			
80	ARTKILL2	RSID INTR	350.0	1638229.0	96.0	2.3	98.4	0.534			
83	ARTKILL3	RSID INTR	501.0	2490674.0	141.4	3.6	144.9	0.568			
87	ARKLCT	DIST PEAK	18.0	14.0	0.0	0.0	0.0	0.000			
98	HYDQ1S	PRCH BASE	780.0	3004558.0	0.0	64.4	64.4	0.440			
99	HYDQ2S	PRCH INTR	208.0	1048942.0	0.0	41.8	41.8	0.576			
100	HYDQ2W	PRCH INTR	424.0	1521208.0	0.0	60.6	60.6	0.410			
101	ONHY1	PRCH BASE	199.0	1540818.0	0.0	61.4	61.4	0.884			
104	NYPP1	PRCH INTR	300.0	2016284.0	0.0	110.0	110.0	0.767			
105	LILCO	PRCH INTR	500.0	1024525.7	0.0	73.3	73.3	0.234			
106	NYPP2	PRCH INTR	800.0	796510.7	0.0	61.3	61.3	0.114			
108	PSEG1	PRCH INTR	600.0	95112.7	0.0	10.4	10.4	0.018			
109	PSEG2	PRCH INTR	800.0	32048.0	0.0	3.5	3.5	0.005			
SYSTEM TOTALS				37429808.0	1333.7	534.0	1867.7	0.313			

UNIT TOTALS FOR 1990

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW %
4	INDPCT	DIST PEAK	72.0	0.1	0.0	0.0	0.0	0.000			
7	RVNSWD 1	COL2 INTR	372.0	1272729.0	62.5	5.4	67.9	0.391			
8	RVNSWD 2	RSID INTR	390.0	1527786.0	177.3	2.6	180.0	0.447			
13	RVNSWD 3	COL2 INTR	922.0	4234113.0	210.1	18.1	228.2	0.524			
14	RAVCT2	DIST PEAK	239.0	5.4	0.0	0.0	0.0	0.000			
15	RAVCT3	DIST PEAK	126.0	1.9	0.0	0.0	0.0	0.000			
16	RVCT4-11	DIST PEAK	142.0	1.5	0.0	0.0	0.0	0.000			
17	ASTORIA1	RSID INTR	149.0	67397.0	9.9	0.2	10.1	0.052			
18	ASTORIA2	RSID INTR	164.0	66920.5	9.8	0.2	10.0	0.047			
19	ASTORIA3	RSID INTR	387.0	726628.6	91.9	2.6	94.4	0.214			
22	ASTORIA4	RSID INTR	387.0	795891.1	100.9	2.8	103.8	0.235			
25	ASTORIA5	RSID INTR	395.0	530539.1	71.8	1.9	73.6	0.153			
28	ASTORIA6	RSID INTR	825.0	1840569.0	214.1	6.6	220.6	0.255			
29	ASTCT1	DIST PEAK	18.0	5.4	0.0	0.0	0.0	0.000			
30	ASTCT2	DIST PEAK	184.0	42.6	0.0	0.0	0.0	0.000			
31	ASTCT3	DIST PEAK	184.0	29.2	0.0	0.0	0.0	0.000			
32	ASTCT4	DIST PEAK	184.0	22.9	0.0	0.0	0.0	0.000			
33	ASCT5-13	DIST PEAK	172.0	11.4	0.0	0.0	0.0	0.000			
34	BOWLINE1	RSID INTR	401.0	1758007.0	185.5	1.4	186.9	0.500			
35	BOWLINE2	RSID INTR	400.0	2006218.0	211.5	1.6	213.1	0.573			
36	ROSETON1	RSD2 INTR	240.0	1401928.0	115.5	0.8	116.3	0.667			
37	ROSETON2	RSD2 INTR	237.0	1349928.0	111.5	0.7	112.2	0.650			
51	WTR8,9	RSID INTR	72.0	1173.9	0.2	0.0	0.2	0.002			
52	WTR14,15	RSID INTR	116.0	1827.5	0.3	0.0	0.4	0.002			
53	E RIV5	RSID INTR	134.0	4063.7	0.7	0.0	0.8	0.003			
54	E RIV6	RSID INTR	134.0	3361.3	0.6	0.0	0.7	0.003			
55	E RIV7	RSID INTR	170.0	79173.4	11.1	0.6	11.7	0.053			
56	NARROWS1	DIST PEAK	184.0	8.3	0.0	0.0	0.0	0.000			
57	NARROWS2	DIST PEAK	184.0	5.7	0.0	0.0	0.0	0.000			
58	GWNUSCT1	DIST PEAK	174.0	1.1	0.0	0.0	0.0	0.000			
59	GWNUSCT2	DIST PEAK	186.0	0.7	0.0	0.0	0.0	0.000			
60	GWNUSCT3	DIST PEAK	167.0	0.5	0.0	0.0	0.0	0.000			
61	GWNISCT4	DIST PEAK	142.0	0.3	0.0	0.0	0.0	0.000			
62	HUDCT1-5	DIST PEAK	83.0	0.1	0.0	0.0	0.0	0.000			
65	HUDSON6	RESD PEAK	17.0	0.0	0.0	0.0	0.0	0.000			
67	HUDSON7	RESD PEAK	126.0	0.1	0.0	0.0	0.0	0.000			
69	HUDSON10	RESD PEAK	40.0	0.0	0.0	0.0	0.0	0.000			

UNIT TOTALS FOR 1990

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW %
70	74TH-9	RSID INTR	58.0	25.5	0.0	0.0	0.0	0.000			
71	74TH-10	RSID INTR	58.0	16.6	0.0	0.0	0.0	0.000			
72	74TH-11	RSID INTR	31.0	12.0	0.0	0.0	0.0	0.000			
73	74TH CT	DIST PEAK	34.0	0.0	0.0	0.0	0.0	0.000			
74	59TH-13	RSID INTR	53.0	16.1	0.0	0.0	0.0	0.000			
75	59TH-14	RSID INTR	19.0	6.3	0.0	0.0	0.0	0.000			
76	59TH-15	RSID INTR	20.0	5.6	0.0	0.0	0.0	0.000			
77	59TH CT	DIST PEAK	40.0	0.0	0.0	0.0	0.0	0.000			
78	BUCHANAN	DIST PEAK	20.0	0.0	0.0	0.0	0.0	0.000			
79	KENT CT	DIST PEAK	12.0	0.0	0.0	0.0	0.0	0.000			
82	ARTKILL2	COL2 INTR	335.0	1823639.0	79.0	23.3	102.4	0.621			
85	ARTKILL3	COL2 INTR	461.0	2124611.0	89.3	27.2	116.5	0.526			
87	ARKLCT	DIST PEAK	18.0	0.2	0.0	0.0	0.0	0.000			
88	PEEKSKIL	SLWT INTR	50.0	334682.6	18.3	0.0	18.3	0.764			
98	HYDQ1S	PRCH BASE	780.0	3004558.0	0.0	125.6	125.6	0.440			
99	HYDQ2S	PRCH INTR	208.0	1014827.1	0.0	76.3	76.3	0.557			
100	HYDQ2W	PRCH INTR	424.0	1521208.0	0.0	114.4	114.4	0.410			
101	ONHY1	PRCH BASE	199.0	1505893.0	0.0	113.3	113.3	0.864			
102	HYDQ3	PRCH BASE	240.0	1946839.0	0.0	146.5	146.5	0.926			
103	ONHY2	PRCH BASE	198.0	1406906.0	0.0	105.8	105.8	0.811			
104	NYPP1	PRCH INTR	300.0	1494829.0	0.0	158.9	158.9	0.569			
105	LILCO	PRCH INTR	500.0	925096.9	0.0	128.9	128.9	0.211			
106	NYPP2	PRCH INTR	800.0	166441.1	0.0	25.0	25.0	0.024			
107	NYPP3	PRCH INTR	1000.0	1230290.0	0.0	171.4	171.4	0.140			
108	PSEG1	PRCH INTR	600.0	6213.0	0.0	1.3	1.3	0.001			
109	PSEG2	PRCH INTR	800.0	1285.6	0.0	0.3	0.3	0.000			
SYSTEM TOTALS				36175712.0	1772.0	1263.9	3035.9	0.281			

UNIT TOTALS FOR 1997

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW %
4	INDPCT	DIST PEAK	72.0	0.4	0.0	0.0	0.0	0.000			
7	RVNSWD 1	COL2 INTR	372.0	1898660.0	170.5	15.4	185.9	0.583			
10	RVNSWD 2	COL2 INTR	370.0	1900571.0	168.7	15.4	184.1	0.586			
13	RVNSWD 3	COL2 INTR	922.0	4234187.0	384.1	34.4	418.5	0.524			
14	RAVCT2	DIST PEAK	239.0	15.8	0.0	0.0	0.0	0.000			
15	RAVCT3	DIST PEAK	126.0	5.7	0.0	0.0	0.0	0.000			
16	RVCT4-11	DIST PEAK	142.0	4.6	0.0	0.0	0.0	0.000			
17	ASTORIA1	RSID INTR	149.0	60520.0	17.3	0.4	17.6	0.046			
18	ASTORIA2	RSID INTR	164.0	60254.0	17.2	0.4	17.6	0.042			
19	ASTORIA3	RSID INTR	387.0	779403.8	192.0	4.7	196.7	0.230			
22	ASTORIA4	RSID INTR	387.0	805745.6	199.2	4.9	204.1	0.238			
25	ASTORIA5	RSID INTR	395.0	569335.7	150.1	3.4	153.5	0.165			
28	ASTORIA6	RSID INTR	825.0	1971437.0	446.7	12.0	458.8	0.273			
29	ASTCT1	DIST PEAK	18.0	13.7	0.0	0.0	0.0	0.000			
30	ASTCT2	DIST PEAK	184.0	110.7	0.1	0.0	0.1	0.000			
31	ASTCT3	DIST PEAK	184.0	77.3	0.0	0.0	0.0	0.000			
32	ASTCT4	DIST PEAK	184.0	61.1	0.0	0.0	0.0	0.000			
33	ASCT5-13	DIST PEAK	172.0	31.6	0.0	0.0	0.0	0.000			
34	BOWLINE1	RSID INTR	401.0	1689992.0	347.6	2.3	349.9	0.481			
35	BOWLINE2	RSID INTR	400.0	1938218.0	398.3	2.6	400.9	0.553			
36	ROSETON1	RSD2 INTR	240.0	1373668.0	220.6	1.3	221.9	0.653			
37	ROSETON2	RSD2 INTR	237.0	1312184.0	211.2	1.2	212.4	0.632			
55	E RIV7	RSID INTR	170.0	72456.1	19.8	1.0	20.8	0.049			
56	NARROWS1	DIST PEAK	184.0	23.5	0.0	0.0	0.0	0.000			
57	NARROWS2	DIST PEAK	184.0	16.4	0.0	0.0	0.0	0.000			
58	GWNUSCT1	DIST PEAK	174.0	3.5	0.0	0.0	0.0	0.000			
59	GWNUSCT2	DIST PEAK	186.0	2.4	0.0	0.0	0.0	0.000			
60	GWNUSCT3	DIST PEAK	167.0	1.6	0.0	0.0	0.0	0.000			
61	GWNISCT4	DIST PEAK	142.0	0.9	0.0	0.0	0.0	0.000			
62	HUDCT1-5	DIST PEAK	83.0	0.4	0.0	0.0	0.0	0.000			
65	HUDSON6	RESD PEAK	17.0	0.1	0.0	0.0	0.0	0.000			
70	74TH-9	RSID INTR	58.0	1758.8	0.7	0.1	0.7	0.003			
71	74TH-10	RSID INTR	58.0	1082.0	0.4	0.0	0.4	0.002			
72	74TH-11	RSID INTR	31.0	837.7	0.3	0.0	0.3	0.003			
73	74TH CT	DIST PEAK	34.0	0.1	0.0	0.0	0.0	0.000			
75	59TH-14	RSID INTR	19.0	16.3	0.0	0.0	0.0	0.000			
76	59TH-15	RSID INTR	20.0	14.4	0.0	0.0	0.0	0.000			

SYSGEN

CONED-PASNY (CASE MR2)

UNIT TOTALS FOR 1997

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW	%
77	59TH CT	DIST PEAK	40.0	0.2	0.0	0.0	0.0	0.000				
78	BUCHANAN	DIST PEAK	20.0	0.1	0.0	0.0	0.0	0.000				
79	KENT CT	DIST PEAK	12.0	0.0	0.0	0.0	0.0	0.000				
82	ARTKILL2	COL2 INTR	335.0	1821781.0	144.4	44.4	188.7	0.621				
85	ARTKILL3	COL2 INTR	461.0	2124385.0	163.2	51.8	215.0	0.526				
87	ARKLCT	DIST PEAK	18.0	0.1	0.0	0.0	0.0	0.000				
88	PEEKSKIL	SLWT INTR	50.0	334789.2	33.5	0.0	33.5	0.764				
98	HYDQ1S	PRCH BASE	780.0	3004558.0	0.0	244.7	244.7	0.440				
99	HYDQ2S	PRCH INTR	208.0	1008238.4	0.0	143.2	143.2	0.553				
100	HYDQ2W	PRCH INTR	424.0	1520918.0	0.0	216.0	216.0	0.409				
101	ONHY1	PRCH BASE	199.0	1494032.0	0.0	212.2	212.2	0.857				
102	HYDQ3	PRCH BASE	240.0	1923122.0	0.0	273.1	273.1	0.915				
103	ONHY2	PRCH BASE	198.0	1382249.0	0.0	196.3	196.3	0.797				
104	NYPP1	PRCH INTR	300.0	1426460.0	0.0	295.5	295.5	0.543				
105	LILCO	PRCH INTR	500.0	951112.1	0.0	258.2	258.2	0.217				
106	NYPP2	PRCH INTR	800.0	146672.1	0.0	42.9	42.9	0.021				
107	NYPP3	PRCH INTR	1000.0	1230142.0	0.0	334.0	334.0	0.140				
108	PSEG1	PRCH INTR	600.0	10306.4	0.0	4.3	4.3	0.002				
109	PSEG2	PRCH INTR	800.0	2302.0	0.0	1.0	1.0	0.000				
SYSTEM TOTALS				37051712.0	3285.9	2417.1	5702.9	0.296				

JUDGE GLEASON: All right. Proceed, please.

CROSS EXAMINATION BY MR. SANOFF:

Q. Dr. Rosen, at page 6 of your testimony you stated that by April, 1983, you had overpredicted oil prices by about 17 percent for Con Edison, and that if only this change were made for 1983 in your oil price assumptions, leaving your price escalation assumptions as they were, the rate impact of the shutdown in your mid range case would be reduced from 2 percent to 2 tenths of a percent. Do you recall that testimony?

A. Yes, I do.

Q. Would you explain for us as simply, but as completely as you can, how you derive that decrease from 2 percent to 2 tenths of a percent?

A. Yes. I just subtracted 17 percent, and this is a, you know, quick approximation. I subtracted 17 percent of the replacement power costs for the shutdown of the Indian Point plants from the total of the present required revenues.

Q. That's all you did?

A. That's correct. I assume that all the requested power costs would scale according to the correction in the base year of the oil prices.

Q. Isn't that kind of a broad assumption that you made, that everything would come down by 17 percent?

A. Well, certainly it would apply to all the oil in the replacement power. I believe it would apply basically to any of the Hydro Quebec or Canadian power that would replace the plants, because that would be priced roughly proportionally to the oil costs.

I think it was only intended as a rough calculation to indicate the order of magnitude of the change, but I believe that it's a reasonable approximation.

Q. In your original estimate of the cost of Canadian power you didn't base it, did you, on any split difference with the purchaser, split the difference between the cost of oil and the cost of the imported power?

A. The cost of the Canadian power was geared to roughly 80 percent of the power it replaced. That was the basic concept.

Q. But you didn't make any analysis to trace it through to see what the cost to the purchaser was, did you?

A. Well, as you are probably aware, we

utilize a single area dispatch model in modeling the downstate region, and we were forced to make approximations for the power of the Canadian power.

We geared it, as I said, to 80 percent of the cost. But because we did not have accessibility to the New York Power Pool multimodel, we could not do it precisely.

JUDGE SHON: Dr. Rosen, let me get this straight in my mind, the answer you just gave.

You say that when you found you had overpredicted oil price, and only oil price, by 17 percent, you then knocked 17 percent off the cost of all replacement power in that period. Is that right?

THE WITNESS: Well, most of the replacement power, by far the majority, is oil or Canadian imports that are priced on the basis of oil.

As I said, that figure in my cover testimony was only intended to give people a sense of the kind of change that the recent changes in oil price would lead to on our bottom line. Obviously I didn't go through and do it year by year. I just wanted to give people a sense of that single change in the base year.

Now, clearly, since we did this report last summer, and let up our assumptions, people generally are projecting lower escalation rates in the price of oil, as well, and I have not made any similar order of magnitude correction for that, either.

JUDGE SHON: I realize that, but it would seem that even for oil generating power the price is not entirely the cost of fuel. It involves --

THE WITNESS: Well, in the definition of make up generation, as we use it in this report, we are just talking about the variable costs of the generation. The O and M or anything else would be an extremely small fraction, and that's excluding the fixed cost of those oil plants. So the way we are using make up generation in this report is just the variable costs.

JUDGE SHON: And the Canadian power, you said something about 80 percent of the oil costs. Wouldn't that automatically make it increase 80 percent?

THE WITNESS: Well, 80 percent of the oil costs. If the oil costs were high by 17 percent, then you would have to adjust by 80 percent, which is also a 17 percent reduction. The fraction just flows through when you are multiplying.

JUDGE SHON: I see. All right.

Q. If you were really on a split the difference 50-50 basis it would be a substantially lower amount?

MR. BLUM: I object to the wording of that question a little bit, because it's not clear what is meant on a 50-50 basis

MR. SANOFF: Splitting on a 50-50 basis.

MR. BLUM: What?

MR. SANOFF: The cost to the seller and the detrimental cost to the purchaser.

MR. BLUM: The witness can answer, if he understands it.

A. To the extent that there would be some economy split savings power that was in the replacement power, then it would be reduced somewhat from the 17 percent figure, yes, but that's a small minority.

And, as I say, I was only intending to estimate the order of magnitude of the change of that one assumption alone.

Q. Would you look at your work paper for run MK 1 for the year 1983, and will you go to page 33 of that work paper?

A. What do you mean by the work paper?

Q. The computer runs that you supplied to us.

A. Yes.

MR. BLUM: Could counsel for Con Edison make this available?

A. I did not bring all the computer output from the runs.

MR. SANOFF: It will take us some time. I assumed the witness would have the work papers.

A. Are you referring to a work paper or the computer output?

Q. The computer run.

JUDGE GLEASON: Did you bring your computer with you?

THE WITNESS: No, I am afraid not.

Q. We will give you MK and MR.

MR. BLUM: Do you have an additional copy for counsel?

MR. SANOFF: No. We don't make copies of those things.

MR. BLUM: Would it be a large number of these outputs and work papers that you are questioning on?

MR. SANOFF: No.

Q. Now, for the fuel class, on page 33, Dr. Rosen, for the fuel class RSD 2-1 NTR, are the total MBTUs consumed, and you can take time to check it, 26,428,652?

A. That's correct.

Q. Now, if you turn to page 30 --

JUDGE GLEASON: What was that question?

MR. SANOFF: Are the total MBTUs consumed for that class RSD-2, 26,428,652?

JUDGE GLEASON: Thank you.

MR. SANOFF: Mr. Blum, you are supposed to just be watching over his shoulder and not consulting.

JUDGE GLEASON: Mr. Blum, please, you know better.

MR. BLUM: Well, the confusion --

MR. SANOFF: There is no confusion.

JUDGE GLEASON: Mr. Blum, if you are going to stand there you cannot talk to the witness. You can make objections.

MR. BLUM: Fine.

Q. If you turn to page 30, Dr. Rosen, are the total fuel costs for all units in the class RSD-2 INTR 119.5 million dollars?

A. I believe so. I see two entries.

Q. Are gross 1 and 2 the only units in that class?

A. That's correct, yes.

Q. Does that give you a fuel cost of $4.52 per million BTU, and I get that by dividing 119.5 million dollars by the previous figure that Judge Gleason asked me about, 26,428,652 MBTU?

A. Well, I could check that for you. I will accept it subject to check.

Q. All right. Fine.

Wouldn't a 17 percent reduction in that price result in a fuel price of $3.75 per million BTU?

A. I will accept that subject to check, yes.

Q. Do you think that was the price that was paid for the Rosten fuel on April, 1983?

A. I don't have that figure available.

Q. Well, I have the April 4, 1983 issue of <u>Electric Utility Week</u>, and I would show you and your counsel a copy of that.

Now, that shows for Rosten oil deliveries in September, 1982, Central Hudson, you realize Central Hudson is the utility which is the purchaser for Rosten, that they paid $4.14 and $4.24 per million BTU. Do you see that?

A. Yes, I do.

Q. We don't have here yet the figures for April, but you don't suppose that the April cost has come down from the figures I have just given you for December, these were December deliveries, to anything like $3.75, do you?

A. Well, I think it's important to note that the figures you have given me are for December.

My understanding from following the energy press generally is that yes, prices have come down since December, to March or April.

And just to clarify this, and perhaps speed the process, the 17 percent oil cost reduction that I used, as I say, as a rough overall figure, I derived from these figures for Ravenswood 2 and 3, Astoria, and Arthur Kill.

And again there may be some plants that had changed less than that, some more. I do not purport to have calculated for each plant separately. As I said, it was a rough overall approximation to give the order of magnitude of the change of recent oil price reductions. That's the basis on which I got the 17 percent. But I would --

Q. Do you realize that to get down to the $3.75 from the $4.14 and $4.24, you would have to have a 12 percent drop from the December to April deliveries?

A. Yes.

Q. Now, when you talk about falling prices of oil, have you been following world prices of crude oil or prices of residual oil?

A. Both.

Q. And you think that there has been a drop in the magnitude of residual oil prices that could approximate that magnitude between the December and April deliveries?

A. Well, again I don't maintain that the drop for Rosten is 17 percent. I calculated Ravenswood 2 and 3 which was 17.6 percent, Astoria which was 17.2 percent, and Arthur Kill which was 16.2 percent. And from those rough figures I used the 17 percent overall reduction.

Perhaps if you weighted overall plants it could be 14 or 15 percent, or 20 percent. I did not do it for every plant.

MR. BLUM: Mr. Sanoff, I am going to have to -- I believe you said the drop from $4 14 to $3.75 was a 12 percent reduction?

MR. SANOFF: $4.24. There were two prices.

MR. BLUM: All right. Thank you.

Q. Now, you say you checked the prices for the other units.

Did you check the price for Rosten?

A. No, I did not.

Q. Now, Dr. Rosen, you claim, don't you, that the shutdown Indian Point would make more attractive the conversion of Ravenswood 1 and 2 to coal, and you therefore included the conversion of those units by 1987 in your low impact case. Is that correct?

A. That's correct.

Q. And am I also correct that you also have the conversion of these two units in your reference case? I will call it reference, mid range.

A. Yes.

Q. But in the years 1990 and 1991. Is that correct?

A. Yes.

Q. Now, with Indian Point in operation you don't include the conversion of Ravenswood 1 and 2?

A. That is right.

Q. Now, it's only when you retire Indian Point 1 and 2 that you include those conversions. That's correct?

A. Yes. We explained the reasons for that in the report.

Q. Now, doesn't your data indicate to you that it would be cost beneficial to convert Ravenswood 1 and 2 even if Indian Point is operating?

A. That's certainly possible.

Q. Not possible. Doesn't it indicate it to be so?

A. I have not looked at specifically that with respect to the data in this report, although the earlier New York City Energy Office report on which it is based indicated that, yes.

Q. Do you have any question about what your data shows?

A. I am saying it's not data in the report that is part of my testimony here that would show that.

Q. Mr. Meehan tells me that he has computed that in 1991 your computed cost of shutting Indian Point would have been at least -- well, strike that question. Let me take you through this slowly.

Your Appendix F shows over ten billion kilowatt hours of oil generation in 1990 with Indian Point in service. Is that correct?

A. Again I will accept that subject to check. I certainly would have to add up the column.

Q. If you accept it subject to check, that's fine.

The cost of that generation at the Astoria station in 1990 is 127 mils per kilowatt hour, and the cost of coal fired generation in 1990 is 53 mils per kilowatt hour if Ravenswood is converted. Would you accept that subject to check?

A. Yes.

Q. If we take the difference between 127 mils and 53 mils we get 74 mils. Is that correct?

A. Yes.

Q. And if we escalate that at 7 percent

from 1990 to 1991 we get a cost difference of 79 mils. Is that correct?

A. Yes.

Q. Now, your work papers for your reference case without Indian Point show coal generation at Ravenswood 1 and 2 of 3 billion 799 million kilowatt hours in 1991. Is that correct?

A. Again I will accept that subject to check.

MR. BLUM: Could the page be identified for that, please?

MR. SANOFF: Well, can you make that page available to Dr. Rosen?

JUDGE GLEASON: It would be helpful to all parties if you could reference pages as you ask questions.

MR. SANOFF: All right. I appologize for not having it.

Q. Page 66 of case MR 1. I am sorry, page 62 of MR 1.

A. All right.

I just would like to remind you that upon discovery I informed your party that MR 2 is the correct case for the mid range.

Q. Is there a difference in that in 1991?

A. There may not be a difference in 1991, but we should just be careful.

Q. All right. We will try.

If we multiply 3 billion 799 million by 79 mils we get annual fuel saving of 300 million dollars. Is that correct? Will you accept that subject to check?

A. Okay. I have not done those calculations.

Q. Now, isn't it obvious from this that the conversion of Ravenswood 1 and 2 is economical whether or not Indian Point is in operation or out of operation?

A. Well, again you have illustrated the total cost of the fuel savings that would be involved and, you know, if your numbers are correct, you know, that would be the answer.

Of course, you have to trade that off with the increase in operation and maintenance costs when you convert the plant to coal, and the fixed costs over the long use term.

But I have not at all denied that it is probably economical in both cases.

Q. Now, haven't you estimated the increase in operation and maintenance costs on your table 4 in your basic report, and page 31 is the reference. And you have the capital electrical costs and incremental fixed costs of coal conversion, and that's 217 million dollars for 1991. Is that correct?

A. That's correct.

Q. So that am I correct that the 300 million dollars, the difference between the 300 million dollars and the 217 million dollars is the saving that we are referencing?

A. Yes. That is the reason.

Q. Now, if you had included the conversion of Ravenswood 1 and 2 in your case with Indian Point in, wouldn't the cost impact of shutting down Indian Point be greater than you showed it?

A. It would be, but we did not consider that a reasonable assumption for a mid range assumption.

MR. SANOFF: Your Honor, can I ask that the witness be directed to limit his answers to my questions without making speeches?

MR. BLUM: I would object to that. The witness said one sentence.

JUDGE GLEASON: I will direct the

witness to just respond to the questions. If the witness feels that he wants to add something, he should ask the attorney if he would mind him adding something, and get into it that way.

Q. And wouldn't that impact grow over the years, Dr. Rosen?

A. Yes, it would.

Q. Now, Mr. Meehan has computed for me, or he tells me that he has computed, that in 1991 your computed cost of shutting Indian Point would have been 70 million dollars greater than you showed it, and that in 1997 the increase would have been 200 million dollars greater. Would you accept those numbers, subject to check

MR. BLUM: I am going to object to this procedure because we have numbers that are being thrown out that we are not even being told how they have been derived.

Yesterday we ran into a problem with mistakes being made with spontaneous calculations confusing the witness, and therefore I am going to instruct the witness not to accept things subject to check unless he knows what calculation is being performed, how it is being performed, and is accepting subject to check the mathematics.

JUDGE GLEASON: Mr. Blum, please don't be instructing the witness. You can make your objections to the Board.

MR. BLUM: All right. I will make that objection to the board.

JUDGE GLEASON: All right. The objection is denied.

The witness will respond to the question.

Q. Before you respond, Dr. Rosen, didn't we just compute that --

JUDGE GLEASON: I say to the witness that I presume he understands that if he is uncertain about answers he should not answer. If he is uncertain about the origin of information he can express that concern.

I am not telling him to respond under all circumstances. I am telling him to attempt to give a factual answer to a question.

Q. Didn't we just establish, Dr. Rosen, that for the year 1991, if you had included the conversions of Ravenswood 1 and 2 in your reference case with Indian Point, that the penalty of retiring Indian Point would have been the difference between 300 million and 217 million?

A. Well, no. The answer is no. I don't think that's what we established.

We established the plausibility that it was economical to convert Ravenswood 1 and 2 to coal anyway.

Now, one very important thing we have to note here is that to do the calculations properly you would have to input the new assumptions into the dispatch model and run that to get the full system fuel cost changes.

So I think we have established a plausibility which I agreed with in the very beginning. But the precise numbers on the fuel saved would have to be derived through rerunning the dispatch model.

Q. I agree with you that the precise numbers are not what I am referring to, but you haven't shown such a regard for precise numbers, have you, when you talked about the magnitude of a 17 percent decrease in fuel. There you were willing, weren't you, to take what you thought was a ballpark estimate?

A. If you note, first of all, that 17 percent price reduction change was cited in the cover testimony as an indication of the type of change that would occur. It was not a part of the quantitative report that we prepared.

Q. But didn't you highlight that for the consideration of the panel, and urge them to take that very much into consideration in making their judgment?

A. My purpose was to indicate what a significant change the recent history of oil price changes would make.

If I were to do this report over again today, clearly there are other changes that I would make due to Energy Research Systems research done since the date of this report. But this report is to be considered here as it was compiled, as you know, as of last fall.

Q. Now, didn't you state at page 7 of your testimony, "I believe that this economic result," and your reference to economic result was to your change from 2 percent to 2 tenths of a percent, "which is quite contrary to utility claims is extremely important for the licensing board to take into account when deciding whether or not to close the Indian Point plant."?

A. Well, there are --

Q. Did you say that?

A. Yes, I certainly said that.

Q. Now, ballpark, have you not agreed with me that if you had included the conversion of Ravenswood 1 and 2 in your reference case with Indian Point in service, that there would have been a larger penalty than you showed for taking the plants out of service?

A. That's right. If you change that single assumption, yes.

Q. Now, on page 23 of your testimony, I keep referring to testimony, it's really 23 of your report, I guess it is

MR. SANOFF: Is it clear to the Board what I am referring to? I will call this the NSRG report. The testimony is really --

JUDGE PARIS: Is that the study NSRG study number 22-40?

MR. SANOFF: Yes, sir.

JUDGE PARIS: What page?

MR. SANOFF: I am referring to page 23 of that report.

Q. Now, you say that there, and I am quoting from the third line, "In the shutdown scenario of dispatch runs it was assumed that five, ten, and fifteen percent more Canadian power would be available downstate to both Con Edison and PASNY in the high, mid range, and low impact cases, respectively." Is that correct?

A. Yes.

Q. Am I correct in saying that in your mid range case you assume that there would be ten percent more Canadian energy available to Con Ed and PASNY, with apologies to Mr. Pratt for calling it PASNY, than would be available with the plants in operation. Is that correct?

A. Yes.

Q. Now, would you turn to Appendix F, case MK 1 for 1990, the second page? Do you have it?

A. Yes.

Q. Now, is it correct that unit index numbers 98, 99, 100, 101, 102, and 103, represent Canadian imports?

A. Yes.

Q. With the exception of unit 98, which represents the firm purchase by Con Ed from Hydro Quebec, and is priced in your run at 42 mils per kilowatt hour, are not all the other units priced identically at 75 mils per kilowatt hour?

JUDGE GLEASON: What page are you on,

Mr. Sanoff?

MR. SANOFF: I am on page -- it's called page 59 in the appendix. It's 4 pages back, Your Honor.

JUDGE GLEASON: All right.

MR. SANOFF: Now, Your Honor, I would like to have marked for identification an exhibit, and I only made ten copies, I am used to hearings that are not as widely attended as these, could I ask Your Honors to share a copy so I don't have to deprive the parties?

JUDGE GLEASON: All right.

MR. SANOFF: May we have this marked as the next Con Edison exhibit in order?

JUDGE GLEASON: This will be marked as Con Edison Exhibit number 11.

(Con Edison Exhibit 11 was marked for identification.)

Q. Dr. Rosen, would you review Exhibit 11 and tell us whether you agree that it was prepared directly from the data in your Appendix F?

MR. BLUM: Mr. Sanoff, may I ask what you mean by it's prepared?

MR. SANOFF: Well, it's taken from the numbers on the page except for the percentage increase on the righthand column, which Mr. Meehan was kind enough to compute for me.

MR. BLUM: From page 59

MR. SANOFF: Page 59 of MK 11 and NR 2.

A. Yes.

Q. Have you checked it, Dr. Rosen?

A. Yes. It's taken from Appendix F.

Q. And are these your runs for the mid range case?

A. Yes.

Q. And would you check or accept, subject to check, the computations, percentage increases on the right hand column?

A. Yes, they are correct.

Q. Would you agree that the 1997 results for the mid range case would show essentially similar results in terms of a percentage increase in Canadian imports?

A. Yes. Well, I think there seems to be some confusion about the percentage increase that I referred to in the text.

The percentage increase, the ten percent increase for the mid range case, was with respect to the total amount of Canadian energy.

That would be approximately 18 hundred gigiwatt hours. But I don't know if you were intending to compare these. It sounded like you were.

Q. Well, what did you count by the five, ten, and fifteen percent? What was your own reference by that five, ten, and fifteen percent increases that you referred to at page 23 of your NSRG report?

A. I think it stated in the text, I hope it is clear, and I will clarify it for you. I intended the five, ten, and fifteen percent increases to stand for increases relative to the total amount of Canadian imports.

Q. To Con Edison and PASNY?

A. That's correct.

Q. Are you saying that the 18 percent applies to the 18 thousand?

A. The five, ten, and fifteen percent applies to the 18 thousand.

Q. Did Con Ed and PASNY get that 18 thousand?

A. There is obviously some confusion which could be our fault in not stating it clearly in the text.

The five, ten, and fifteen percent

increase in the availability of Canadian power was with respect to the total amount of Canadian power coming into New York State. Now, the dispatch model won't give you precisely those round numbers, but those were the availabilities that were increased.

Q. I am puzzled. It says here that in the shutdown scenario of dispatch runs it was assumed that five, ten, and fifteen percent more Canadian power would be available downstate to both Con Ed and PASNY?

A. And there should have been a phrase that said five, ten, and fifteen percent of the total amount of Canadian power coming into New York State.

Q. That would be quite different, would it not?

A. Well, it's not different. I am just saying I apologize if it was not perfectly clear.

Q. Now, by what amount do you increase the price for Canadian energy in the runs without Indian Point?

A. I don't remember if we increased it at all. I would have to check.

Q. Would you check? My information is

that you did not increase it.

A. Did you say did, or --

Q. Did not.

A. Did not. Well, offhand that seems to be correct. That's my recollection.

Q. Now, are you aware of any contracts, arrangements, or interchange practices, between the New York Power Pool and the Canadian utilities on which the price is not plugged by either the New York Power Pool average fossil cost or the New York Power Pool costs voided by the Canadian purchase?

A. Generally the cost of Canadian power is dependent on both the average and the marginal voided cost of the fuel.

Q. Now, when you show zero price increase for this increase in the amount of Canadian energy attributable to the shutdown, how do you account for the increase in the price of Canadian energy that would result from the New York Power Pool average fossil on a voided generation costs attributable to the shutdown?

A. Well, on a pool level, which I think we are discussing, I think there would be a very small effect. We did not take that into account.

And we tried, because we knew we could not take that into account, not having a multiarea dispatch model available, we tried to estimate the cost of Canadian power on the high side. But we certainly did not take that into account. But I think it would be a very small effect.

Q. Well, by reference to what did you purport to say you estimate the price on the high side?

A. Well, I am just saying that obviously we knew we would be subject to criticism if we did not try to conservatively estimate the price of imported power.

Just as an illustration, on the table you just handed me for 1990, we have here a price, as you pointed out, of 75 mils per kilowatt hour for power from Ontario Hydro, and my understanding through information I have learned since I prepared this report is that that power is likely to be priced lower than some of the other power from Hydro Quebec. So we tried to be conservative.

Q. Well, would you answer my question, Dr. Rosen?

You tried to be conservative by

estimating the price in reference to what data point? How did you determine it to be conservative?

A. Well, we looked at the costs of power, the actual cost of power for 1981, we looked at any more recent information we had, which was somewhat scarce, obviously. We looked at the results of our dispatch runs from the New York City report. We looked at, you know, the latest information we could find on the pricing agreement with Hydro Quebec in the New York Power Pool 1982 report, and we, you know, arrived at a price estimate.

Again, the precise inputs, I would have to check work papers that I don't have here with me. But I am saying that generally we certainly tried to have a conservative price on the high side for Canadian imports.

Q. Do you think your use of 80 percent that we referred to before was in that conservative vein?

A. Well, for instance, we tried to estimate the price based on 80 percent of the voided costs of power to the pool.

But since then I have come to

understand that a substantial amount of power from Hydro Quebec will, in fact, be priced at 80 percent of the average cost of power to the New York Pool. So clearly that would have substantially overestimated the cost of that part of Canadian power. That's a for instance.

Q. Where do you learn these things?

A. Through various cases we are working on in New York State.

Q. Do you learn these from the Canadian authorities?

A. No, from interrogatories direct from the Power Authority.

Q. You have an answer to an Interrogatory from the Power Authority that says that?

A. Well, that would leave open several jokes, but yes.

Q. Could we get a copy of that?

A. We got a copy from the Power Authority a copy of the existing contract with Hydro Quebec.

Q. Well, you said you had an answer to an Interrogatory from the Power Authority?

A. Not in this docket, not in this

hearing.

Q. Could we have a copy of whatever it is you have?

A. Certainly you are welcome to it. It was part of the Power Authority's filings in the Marcy South transmission line hearings before the New York State Service Commission. I assume you have a copy, but we would certainly be happy to provide you with one.

Q. Thank you.

Now, on page 23 you mention state regulation which is going to produce this increase in Canadian power available. Do you recall that? State regulatory authorities?

A. That would be one avenue, yes.

Q. What regulatory agencies were you referring to?

A. The State Planning Board, the Public Service Commission, the Energy Office. Those would be the authorities potentially involved.

Q. What role do those agencies currently have in allocating Canadian power between utility companies?

A. Well, I believe some of the allocation is actually mandated by legislation in

New York.

I cannot tell you precisely to what extent the Public Service Commission has either informal or formal role over allocating power, but I would assume that if legislation were in place, or if the Public Service Commission had the motivation to influence the distribution of power, that that's certainly a possibility.

Q. Did you think that your assumption that there would be this legislation, and that the regulatory agencies would do all this, was equally in the same conservative vein?

A. Well, again, this is a mid range estimate. One can certainly imagine, again, legislation on the Master Planning Board, or what have you, acting to protect rate payers in the Con Ed franchise area from an action such as the shutdown of the Indian Point units which would bear on them more adversely than rate payers in the rest of the state.

So I can easily imagine a policy based on a more socially oriented decision that the Indian Point units should be shut, and that some of the costs of that should be distributed around the state, if not around the country.

Q. Are you saying, Dr. Rosen, that you thought it was a conservative approach to assume that if Indian Point were shut down that the other people who are getting Canadian power were going to be very considerate of the downstate rate payers and say, "We are going to give you more of this Canadian power."?

A. Well, we felt that was a reasonable assumption. You are free to make up your own scenarios. We offer 3 scenarios that we feel are representative of a high, middle, and low range case.

There can be great disagreement, but I think you should examine each of these scenarios on merit.

Q. My question, Dr. Rosen, is did you think that was a conservative assumption, namely that if Indian Point were shut down that the people up state who are now getting Canadian imports would make them available, or would permit legislation to be passed which would make greater percentages of that power available to the downstate?

A. We thought it was a reasonable assumption.

Q. Conservative?

A. Yes. We thought it was a reasonable assumption given the small extent of the redistribution of power that we assumed.

JUDGE GLEASON: Mr. Sanoff, does "reasonable" equate to "conservative"?

MR. SANOFF: No. I was asking him about a conservative. To me conservative is something more than reasonable.

JUDGE GLEASON: I guess I was concerned why you were using the word.

MR. SANOFF: He testified on my cross that all the assumptions were conservative.

JUDGE GLEASON: Well, he testified, I thought, with respect to cost.

MR. SANOFF: Well, I am asking him if he was proceeding in the same conservative vein.

JUDGE GLEASON: All right. Thank you.

Please proceed.

JUDGE SHON: By conservative in this case you mean tending to make the cost look larger. Is that right?

MR. SANOFF: Could I hear your question, judge?

JUDGE SHON: By conservative in this

case you mean tending to make the ultimate impact look larger?

MR. SANOFF: I assume that's the vein in which Dr. Rosen was using that.

JUDGE SHON: Sometimes people say it's a conservative estimate when it's smaller.

MR. SANOFF: But in this case, considering the people Dr. Rosen represents, when he uses the word conservative, I think he was making it as high as he reasonably could.

JUDGE GLEASON: I think we have done enough worrying about that.

MR. SANOFF: All right.

Q. Your analysis in terms of cost impacts was only related to the downstate Con Edison service area. That's correct?

A. That's correct.

Q. Now, if you had approached the cost impact on a state wide basis none of what we have been discussing would be applicable, would it, because what you took from upstate would go to downstate, but on a state wide basis it would have no impact. Is that correct?

A. I assume by "none of what we have been talking about" you mean just the redistribution of Canadian power.

Q. Yes, sir.

A. Well, again, as I said, I think it's reasonable to assume that this would occur in the mid range scenario. There would be a negative cost impact to upstate rate payers.

Q. But what I am saying is if you modeled the cost impact on a state wide basis reallocation wouldn't have any play, would it?

A. That's correct.

Q. Just an obvious question, Dr. Rosen.

If the reallocation doesn't take place, as you assume it would, would your replacement power be comprised of a larger amount of oil than you show?

A. Again, to follow up your own point, the charges to the Con Ed franchise area would be somewhat higher, but the distribution of power among the Power Pool would be the same.

Q. Now you want to use a state approach to answer me? Is that what you are doing? You are saying on a statewide base that would be true?

A. I thought we agreed that if there was no agreement on the release of Canadian power the cost --

Q. But I am talking about cost impacts. You have only provided cost impacts for the downstate area. Correct?

A. That's correct. Our whole study ignores, as we say very very clearly, all the larger social cost impact in the rest of New York, the country, the world, whatever.

Q. I am not talking about social impacts. I am talking about dollar costs impacts elsewhere in the state.

A. I am talking about dollar impacts, as well.

Q. Would you agree you can't have it both ways? You can't be presenting a downstate dollar cost impact estimate, and then rely on an upstate offset, which you are doing now in answering my question.

I am asking you wouldn't your estimate of downstate cost impact be increased if there were no reallocation of Canadian power?

A. And I said very clearly yes. I thought we had agreed on that.

Q. All right. I think if you had just said yes I wouldn't be having this debate with you.

Now, on table 4, page 31, of the NSRG

report, for the year 1991 you show a fuel cost decrease of 79 million dollars. Why does that happen?

A. That is due to one of the Indian Point units being out for steam generator repairs in the Indian Point in case.

Q. I am confused. Could you try to explain a little more for me?

Doesn't column 1 show the make up power, the cost of make up power with the Indian Point plants out?

A. Yes. The reason it's negative is that in that year, with the coal conversions of Ravenswood 1 and 2 occurring, the system fuel costs are lower when one of the Indian Point units is out due to steam generator repairs as it is in the case when Ravenswood 1 and 2 were not converted to coal, and both Indian Point units -- I am sorry. Could I start over?

Q. Please do. You still haven't caught me yet.

A. When the Indian Point units are retired we have agreed earlier that Ravenswood 1 and 2 is converted to coal. That produces lower fuel costs. That produces fuel costs that are even lower in the case where Ravenswood 1 and 2 are not converted to coal and one of the Indian Point generators is out for a replacement generator where you keep Indian Point and it's running.

JUDGE SHON: In effect, it's because when you took the Indian Point plants out you also converted Ravenswood to coal?

THE WITNESS: That's right.

JUDGE SHON: You made two changes.

THE WITNESS: That's right.

MR. SANOFF: Excuse me, Your Honor, I am trying to get some assistance on this.

Q. Now, am I correct that in Appendix F, case MK 1, which is your mid range case, you show 1983 kilowatt hour consumption for the service area of 37 billion 426 million kilowatt hours?

A. That's correct.

Q. For the year 1988 your work papers for the same case show kilowatt hour consumption of 35 billion 852 million kilowatt hours.

MR. BLUM: Can we have the page identified?

MR. SANOFF: I am trying to get that.

MR. BLUM: Could the witness be provided with a copy of the page?

MR. SANOFF: He has a copy of the MK 1.

Q. Page 51, Dr. Rosen. Total expected energy. Do you see that?

A. Yes, I do.

Q. Am I correct that that's a five year reduction in energy consumption of 4.2 percent?

A. Subject to check, yes

MR. SANOFF: Your Honor, I would like to have marked --

JUDGE GLEASON: What are these pages out of? We are a little bit confused.

MR. SANOFF: I am sorry, Your Honor. These are computer runs.

JUDGE GLEASON: I wish you would identify them as that in the future.

MR. SANOFF: Well, let me redo it so the numbers are correct. I apologize.

Q. In 1983 for the service area of Con Ed you showed kilowatt hour consumption of 37.4 billion kilowatt hours, and you would accept that. Correct?

A. Yes.

Q. And then for the year 1988 you have now accepted, subject to check, that the kilowatt hour consumption was 35.8, you estimated it to be 35.8 billion kilowatt hours?

A. Yes.

Q. And you have also accepted, subject to correction, that that's a five year reduction in energy consumption, namely the five years between 1983 and 1988 in the Con Edison service area, of 4.2 percent?

A. Correct.

Q. And that's your mid range case. Right?

A. That's correct. The reason for that --

Q. I didn't ask you for the reason.

A. But I want to explain.

Q. But you are under an admonition from the judge. Talk to your lawyer. I am not trying to prevent the record, but I have a right to have it flow the way I want it to.

MR. SANOFF: I would like to mark for identification table 16, page 105, of volume 1, of the 1983, section 5-12 report of the New York Power Pool.

JUDGE GLEASON: This will be marked as Con Ed number 12.

(Con Ed Exhibit 12 was marked for identification.)

Q. Now, would you look in the column marked total franchise area sales, Dr. Rosen?

Would you agree with me that that column shows that the total franchise area sales have increased continuously since 1977?

A. That is correct, yes.

Q. And would you accept, subject to check, that that same column shows that in the five year period 1977 to 1982 the franchise area sales have increased 4.1 percent?

A. Subject to check, yes

MR. SANOFF: Your Honor, may I have the Exhibits 11 and 12 incorporated into evidence in the record?

JUDGE GLEASON: Is there an objection?

Hearing none, the exhibits will be admitted into the record as evidence.

(Con Ed Exhibits 11 and 12 were received in evidence.)

JUDGE GLEASON: Mr. Sanoff, would you mind if we recessed?

MR. SANOFF: I would be delighted.

JUDGE GLEASON: Let's take a ten minute recess.

(There was a short recess.)

JUDGE GLEASON: All right. Shall we proceed, please?

Q. Dr. Rosen, you remember we referred to that 79 million negative figure, I think it was table 4?

A. Yes.

Q. Would that figure be negative if you had not assumed the Ravenswood conversions in the Indian Point shutdown case, but had included them in the Indian Point in case, as well?

A. No, it wouldn't.

Q. In your testimony you testified, you stated in your report, did you not, that you thought that the decommissioning costs would be less with the shutdown than they would be without the shutdown. Is that correct?

A. That's correct.

Q. Now, you purport to site Nuclear Energy Services in support of that conclusion, do you not?

A. Well, I cited a discussion they had of radiation levels in the plants, yes.

MR. SANOFF: Your Honor, I would like to have marked for identification a letter dated April 7, 1983, from Nuclear Energy Services, Inc., addressed to me.

JUDGE GLEASON: All right. The letter will be marked as Con Ed number 13.

(Con Ed Exhibit 13 was marked for identification.)

Q. Would you read that Exhibit 13 from beginning to end, including examining that chart, figure 1, at the back?

JUDGE GLEASON: We really don't want him to read the whole letter, Mr. Sanoff.

MR. SANOFF: All right.

Q. That letter states in the third paragraph that the initial premise stated on page 52 that, " The longer a nuclear power plant operates, the more highly radioactive it becomes, and that for reactors that operate for less than their design lifetime there is a corresponding reduction in total curies is a misconception indicating a misunderstanding of radionuclide production."

And it goes on to point out by reference to figure 1 that in terms of cobalt 60 and iron 55, which are the principal radioactive elements involved that cause a problem in decommissioning, that the build up on those occurs very rapidly in the early years, as may be seen on the chart in figure 1, and then levels out. And you notice that in the years ten to fifteen they practically reach their maximum level.

Would you agree that is scientifically so with respect to cobalt 60 and iron 55

MR. BLUM: Your Honor, I have to question here. Is Mr. Sanoff planning to introduce this as part of the record?

JUDGE GLEASON: Well, that is up to him.

MR. SANOFF: Well, I have no desire to tell him now. I am just asking the witness a question.

JUDGE GLEASON: All right. Go ahead.

A. Well, again, I cannot verify just from looking for a few minutes at this chart whether this is correct for the Indian t units or any other units.

Q. It's not correct for Indian Point units.

It talks about a scientific fact relating to the buildup of radioneucleides in two elements, cobalt 60 and iron 55, and it says that these build up very rapidly in the first few years of operation.

Now, do you know whether that's true or not?

A. I understand what you are telling me, but I am a physicist and I would have to know a lot more about the assumptions under which these curves were calculated before I would say anything about them.

Q. As a physicist are you saying you can't confirm to us that the buildup in these two elements is very rapid in the first few years, and then levels off?

Now, I am not trying to tell you that in the fifth or tenth or fifteenth year, but is it true that the build up --

A. I agree that qualitatively the build up is rapid.

When it levels off with respect to any given reactor, I would have to know a lot more about this. I cannot confirm the time schedule on this figure.

JUDGE GLEASON: Please keep the conversation quiet except for the cross examination.

Q. Now, would you agree with the statement in Exhibit 13 of Mr. Manion, who is the principal at Nuclear Energy Services, Inc., that "It is the short lived isotopes like cobalt 60 that control the manner in which various decommissioning alternatives are implemented by their massive quantities and accompanying high dose levels, and premature shutdown of reactor operation will not realize any cost savings in disposal of activated material, as implied in the NSRG study."

Do you agree with that?

A. Well, precisely one of the factors that we had in mind in saying that there would be cost savings was the fact that the short lived isotopes would have a chance to decay to lower levels due to earlier shutdown than due to later shutdown. That's a simple point.

So I would disagree with the statement that you have read there.

Q. In that connection would you turn to the second page and look at the next to last paragraph?

"Cost reductions from radioactive decay are not realized until long after twenty years. Cobalt 60, the predominant radionuclide in the plant's curie inventory has a half life of approximately five years. After twenty years the cobalt 60 levels will still require the same remote dismantling techniques to be employed in disposition of activated material and the same removal and disposal techniques of contaminated material as at shutdown."

Does that strike you as correct?

A. I don't agree with it, no.

Q. Do you disagree that cobalt 60 has a half life of approximately five years?

A. No. I would say that the lower the radioactivity levels in the unit generally, the lower the cost for dismantling would be.

Q. Well, if the radioactive level is lower, but still not low enough to permit you to do anything but remote dismantling, is there going to be a saving?

A. Well, that's accepting their premise that the exact same techniques would be required, which I would not accept without further study.

Q. Well, without further study of the issue you reached the conclusion that earlier decommissioning would lower decommissioning costs.

Correct?

A. That's correct.

Q. Now, on the third paragraph on the second page Mr. Manion says, "Dismantling, unlike construction, is a straightforward process. Once a dismantling order is received from the NRC there is no further licensing process."

Do you agree with that statement?

A. I am not familiar with the licensing process with respect to decommission.

Q. It goes on, "Very few plant systems are required during dismantling, allowing for rapid dismantlement of systems and structures. Dismantling activities do not require the sequencing and integration with numerous critical paths, as with construction projects. With over sixty-five experimental and demonstration reactors having been either mothballed, entombed, or dismantled, significant knowledge in decommissioning planning has been accumulated. The cost to dismantle the Elk River reactor was within ten percent of the cost projections."

And incidentally, might I ask if you realize that Mr. Manion was in charge of that Elk River dismantling?

A. No.

Q. "Certainly applying a factor of 4 to present cost projections, as done on page 54 by NSRG has absolutely no basis or precedent."

Does that give you pause about your use of the factor of 4?

A. No.

Q. None whatever?

A. No.

Q. And you have made no study, have you, of the -- have you studied the cost of the Elk River dismantlement in terms of what the estimate was?

A. My only recollection at the moment is that out of capacity the Elk River decommissioning project was extremely expensive, but I could check that.

Q. That's not what I asked you.

I asked you whether you had compared the actual cost of the dismantlement with the estimate?

A. No. I had no knowledge of the original estimate. I have looked at the actual cost.

Q. Do you think that the cost per

kilowatt of dismantling the Elk River reactor is a basis for estimating the cost per kilowatt of decommissioning Indian Point?

A. Well, I wouldn't translate it on a one for one basis, no, but it's relevant.

Q. What is its relevance? Wasn't Elk River the first reactor dismantled?

A. I don't know that. It may have been the first dismantled.

Q. Well, isn't there a learning curve in this decommissioning process?

A. I don't think there's any basis for speculation at this point on the learning curve. There have been no large commercial reactors decommissioned.

Q. You mean you can't learn from decommissioning small reactors?

A. I don't believe it's a simple process of extrapolation, no. Definitely not.

MR. SANOFF: Your Honor, I would like to have Exhibit 13 marked in evidence.

JUDGE GLEASON: Is there an objection?

MR. BLUM: Yes. I would object.

JUDGE GLEASON: The objection is granted.

MR. SANOFF: I figured that would be the answer.

Your Honor, I might note that without rebuttal, and we are not permitted rebuttal, that there should be some leeway in permitting a document like this in evidence. We just don't have the normal procedure where we can call Mr. Manion and put him on the stand and have him testify.

Now, this is a letter, I don't think anyone would dispute that this is Mr. Manion's letter, and he is the principal of NES, which is referred to in Dr. Rosen's testimony, and he has testified as to the cost of decommissioning, and has made a site estimate of the decommissioning of Indian Point.

Now, against that background. sir, I wonder if you would reconsider your ruling. It is difficult to cross --

JUDGE GLEASON: I think there is a rebuttal witness coming on that at least talks about Mr. Rosen's testimony.

MR. SANOFF: On decommissioning?

JUDGE GLEASON: No. About his testimony.

There is nothing to have prevented

you from presenting this witness.

I have reconsidered and still hold to the ruling.

Q. Now, what capacity factors, Dr. Rosen, did you assume in your mid range case? Tell us first for Indian Point 2 and then for Indian Point 3.

Let me see if I know them. Did you start for Indian Point 2 at 55 percent, and decline at a 1.3 percent per year to 20 percent by the 35th year?

A. That's correct.

Q. And did you start for Indian Point 3 at 53 percent, and decrease that by 1.14 percent per year, to 20 percent by the 35th year?

A. Yes, that's approximately correct, yes.

Q. Now, in your deposition, at page 98, --

JUDGE GLEASON: Do you have a copy of your deposition with you?

THE WITNESS: No, I do not.

Q. At page 98 I asked you, "What was the basis for your conclusion that the capacity factor in the mid range case is going to decline and it looks almost by balancing it like a linear --

straight line decline over the life of the plant?"

And your answer was, "Well, there are two factors involved as it states on page 29, one of which was an assumption by of NERA by Dr. Louis J. Pearl, a well known consulting firm, where we assumed the capacity factors he did reached 20 percent by the 35th year of operation."

Is that a fair reading?

A. Yes. That was one of the considerations.

MR. SANOFF: Now, since I only have one copy, Your Honor, may approach the witness and hand it to him and read over his shoulder?

JUDGE GLEASON: That's all right with me.

MR. SANOFF: Oh, wait. I do have another copy.

Q. I would like to hand you a copy of the transcript of the testimony of Louis J. Pearl before the Pennsylvania Public Utility Commission on behalf of Philadelphia Electric Company, dated April 9, 1981, and I am going to ask you to look at page 22 and 23.

I am sorry. Could you look at page 8 of that document I just handed you? I am going to ask you to look at line 18. I am going to read it.

"Based upon these data, the capacity factors for nuclear plants were estimated to rise from about 50 percent at the outset of operation to about 70 percent at the end of ten years of operation. Although little data exist on performance for nuclear units older than ten years, the capacity factor was assumed to remain constant at 70 percent for the next ten years, and to fall linearly from the 20th year to 20 percent at the end of book life."

Have I correctly read Dr. Pearl's testimony?

A. That's correct.

Q. Do you think that you have correctly invoked Dr. Pearl's testimony as a justification for starting this linear decline to 20 percent in the case of Indian Point 2 at this stage of its life, and in the case of Indian Point 3 at this stage of its life? I ask you have you correctly invoked the testimony of Dr. Pearl in support of that?

A. I never intended to invoke the testimony of Dr. Pearl to determine what would happen to the capacity factor in the early years of plant life.

In the case of these plants we had actual operating experience. It was merely invoked as one reason for setting the end point of the capacity factor at 20 percent at the 35th year.

Q. Well, would the reader who did not have the benefit of Dr. Pearl's testimony, in its actual content, would not the reader of your testimony conclude that you found support for what you did in the derivation of capacity factors for Indian Point 2 and 3 in the testimony of Dr. Pearl in that case?

A. Well, to quote from my deposition again, lines 23 to 25, I said, "Where we assume that the capacity factor, as he did, reached 20 percent by the 35th year of operation."

That's the only aspect of Dr. Pearl's testimony I invoked.

Q. Well, let us look at the item on page 19 of your report. You state, "In the mid range case..." Have you got that? I will wait for you.

A. Yes.

Q. You state, "In the mid range case we have assumed that beginning in 1982 the capacity factors for the Indian Point units will decline linearly with age rather than the very rapid decline indicated by the results of our regression analyses of nuclear plant operating experience we have assumed a more cautious rate of deterioration and performance with capacity factors reaching 20 percent by the 35th year of operation. Footnote 21."

And then in footnote 21 it says, "The 20 percent figure was estimated by Dr. Louis Pearl, of NERA, a consultant to Con Edison and other utility companies, from revised direct testimony."

Now, are you saying that that doesn't convey to the casual reader, or even the careful reader, that Dr. Pearl is supporting what you did in the derivation of the capacity factor?

A. Not in my mind.

Q. You are willing to accept Dr. Pearl's end point, but not his intermediate points?

A. His intermediate points were for a plant that had no operating experience, so they were deemed irrelevant.

We wanted to make a simple assumption about how the capacity factor for the Indian Point units would trend over time.

We are all aware of the fact that

there is very little operating experience for the years of operation beyond ten or twelve, so we thought that Dr. Pearl's assumption for an end point was a reasonable mid range assumption.

Q. Now, let me ask you this. Do you recall the document that you presented to the -- well, it was presented to the Robin M. Herzog, director of the New York Energy Office, and it's entitled NSRG 10-21, entitled An Analysis for the Need for and Alternatives to the Proposed Coal Plant at Arthur Kill, and was dated June 15, 1981?

A. Yes, I recall that document.

Q. Your name was on that as the principal investigator. Correct?

A. Correct.

Q. Now, do you remember what the Indian Point 3 projected capacity factor was that was used in that case?

A. Well, in that case, I don't know what the exact numbers are, although I could check them for you.

Q. Would you accept, subject to check, that it was.606?

A. Yes. Well, that was before we did our capacity factor study.

Q. Was there any bearing on the fact that in that case you were trying to show that a plant at Arthur Kill was not necessary, and the high capacity factor of Indian Point helped in proving that?

A. I don't think that's what we were trying to show by that report.

Q. Now, you have excluded refueling in your computed adjusted capacity factors, have you not?

A. The adjusted capacity factors are the capacity factors once refueling and NRC mandated averages are removed, yes.

Q. You are aware, are you not, that refueling outages cover many other things?

A. I am aware that sometimes the reporting is not very sharp, the divisions and the way outages are reported to the NRC, is not very sharp.

Q. That's not what I asked.

When you take a plant down for a refueling, isn't that a proper time to do operational maintenance, since the plant is down anyway?

A. I agree. Sometimes it is done when

there is an outage classified as a refueling outage.

Q. Let me ask you this. Would you be surprised if there was ever a refueling of a major nuclear unit accomplished without doing operation and maintenance?

A. I agree. Generally other maintenance is done. There's no question about it.

Q. Well, wouldn't you agree with me that a lot of operation and maintenance is down in this two or three month period that the plant has to be down, anyway?

A. I agree. I have agreed.

Q. Were you relying on your regression analyses which reflects your adjusted capacity factors in determining the predicted capacity factors for Indian Point 2 and 3?

A. No. The equation that is applied to the unadjusted capacity factors, that is also reported in our report, page C-39, gives the same qualitative result of the decline of capacity factor, so it doesn't matter if we use the adjusted or unadjusted.

We explain in the report why we use the adjusted, but the result is the same either way.

Q. Now would you turn to table C 4 in your NSRG report?

MR. SANOFF: That's on page C 21, Your Honor.

Q. Now, is this a regression analysis of adjusted capacity factors? It says so at the top, does it not?

A. Yes.

Q. Are the results given to typical units on table C 6 and figure C 6, C 8?

A. Yes.

Q. On page 33, C 33, you show the results of your analysis for a thousand megawatt PWR with fresh water cooling. Is that correct?

A. With fresh water cooling, yes, on the bottom.

Q. And does the graph show that the plant would achieve a hundred percent capacity factor by the fourteenth year?

A. The graph shows an increase from year seven on, and obviously you cannot extrapolate the curve beyond seven percent since it would not mean anything, but it shows an increase after year seven.

Q. On table C 6, which is on page C 31, does your projected capacity factors for a thousand megawatt B W R, with fresh water use, show a capacity factor of 157 percent by the 30th year.

JUDGE GLEASON: Mr. Sanoff --

JUDGE PARIS: Mr. Sanoff, C 6 on 31, mine says PWR.

MR. SANOFF: I am sorry. On page 30, Judge Paris.

Q. You will see --

A. As I just said, we let the table print out numbers above one. We could have stopped it after--

Q. You could also have answered me with one word, yes.

A. No.

Q. I asked you does your table on C 6 show a projected capacity factor with fresh water of 156 percent in the 29th year

MR. BLUM: I would object to Mr. Sanoff not giving the witness a chance to say even a single sentence.

JUDGE GLEASON: He has answered it, so let's go on.

Q. Does the table C 6, thousand megawatt BWR show in the 29th year 1.56915?

A. The number is there, but obviously it doesn't stand for a possible capacity factor since by definition you cannot have a number greater than 1.0. We could have stopped the printout sooner, but we let it go.

Q. Doesn't that sort of a number make you at all hesitant about your regression precision?

A. No. It says very clearly throughout the report that the regression results greater than years roughly ten of age are to be ignored because there is very little data.

The significant point is what is the trend from years six or seven to perhaps ten or twelve. Beyond twelve you claim no, you know, substantial veracity for the results.

Q. While you have nothing in your regression or data base for this period, you are predicting a decline in capacity factors right out to your assumed end of the life the plant?

A. Were you speaking of Indian Point?

Q. Indian Point 2 and 3.

A. Yes. And we state, I believe very

clearly, in the report that it's on the basis of the initial indications that after year seven, or so, that there is a dec' ne in salt water cooled units. And how that is to be projected out in the future, we know clearly that we are not assuming that the capacity factor will decline at the same rate that the equation predicted, in fact a much slower rate of decline. We predict much higher capacity factors.

Q. How many thousand megawatt salt water PWRs are there?

A. Well, we provide the data. I would have to go through table C-2 and count them.

Q. Would you accept, subject to check, that there are none, thousand megawatt?

A. Oh, thousand megawatt. Precisely a thousand?

Q. Thousand or more.

A. Oh, that's possible, sure.

Q. How many salt water PWRs are there other 8 hundred megawatts?

A. Again I would have to go through the data.

Q. Well, there's I P 2, which went in service 1973. There's Calvin Cliffs 1, which went into the service in 1975. There's Calvin Cliffs 2, which went into service in 1977. There's I P 3 which sent into service in 1976. There's Millstone 2, which went into service in 1975, and there's Salem 1 which went into service in 1977.

Would you accept, subject to check, that that is the universe of 8 hundred or more megawatt salt PWRs?

A. Certainly.

Q. And those are the years in which they were installed. Would you accept that subject to check?

A. Yes.

Q. The latest year of your data is 1981. That's correct?

A. Yes.

Q. And how old was the oldest of those unit in 1981? Would you accept, subject to check, that it was Indian Point at eight years?

A. Yes.

Q. So there is no data of these large units after eight years?

A. Of that specific type.

Q. Eight hundred megawatt salt water PWRs, 8 hundred megawatt or more?

A. Correct.

Q. Now, would you look at figure C 9, at page C 35 of your ESRG report?

A. Did you say page C-35?

Q. Page C-35, figure C 9.

First of all, that's labeled a thousand megawatts. We have agreed that there was none of a thousand, but I am not stressing that. By that category you are including all large salt water PWRs of 8 hundred or more. Right?

A. No. Let me explain what those figures are.

Those figures are the result of putting into the regression equation the data indicated. For instance, a thousand megawatts, salt water cooling, et cetera. It's just a generic printout to give the reader a feel for the way the regression equation behaves.

Q. Let me ask you what that generic printout, that's such a beautiful term, what does that mean in terms of data point? Isn't your last data point for eight years?

A. No. Let me explain, please.

As I said, we derived the regression equation that we have indicated on table C-4. If you plug certain values for a generic hypothetical unit into it you get the curves indicated in these figures.

The data that the regression equation is based on is based on all of the data for all units, including ages beyond eight.

Q. I thought it was thousand megawatt salt?

A. Yes. But again I sense a confusion in terms of what regression analysis accomplishes for you.

Q. Oh, there's great confusion between you and me on what regression analysis accomplishes.

A. Can I finish my answer?

Q. Yes. I am sorry.

A. It is, in a sense, a technique for pulling apart the impact on the data of various variables. And, as I say, in that sense you cannot identify any separate sub-section of data spanning a range of age, size, or what have you, with any particular type of units. The regression equation is based on amount data for all the units.

Q. Now, I am not a statistician, and I don't claim to be one, I have the barest smattering of knowledge in this area.

Would you agree with me that a regression analysis which can't be squared with some underlying theory or analysis is not worth the computer time that is spent on it?

A. Well, I really don't see exactly what you mean. It's hard to define, I think, what you mean.

Q. Well, if you put these numbers together, and all your independent variables, and I think in the various regression analyses you have as many as twenty independent variables, without trying to understand what is happening, without looking to see what the data signifies, whether the regression analysis is skewed because of a particular occurrence in a particular year, can't you reach ridiculously misleading results?

A. Well, I suppose it's possible if one doesn't have a theory.

Sure. You need to choose the variables that make sense, given the topic you are studying. Certainly.

Q. For example, you might be able to take some batting averages of baseball players, and I am not being facetious about that, and put them in as independent variables, and conceivably you might come up with some sort of an acceptable coefficient, and determine a capacity factor. But you would know, wouldn't you, that there is no relationship between the capacity factor and baseball batting averages. Correct?

A. Correct.

Q. And you would discard that regression analysis. You would laugh at whoever presented it. Is that correct?

A. That's correct.

Q. Now, is there, in your use of these regression analyses, the underlying attempt to look at the basic data and see what is happening in each year, and to see whether the data is skewed by a particular occurrence, or not?

A. When doing regression analysis one doesn't look at the raw data and say is this data skewed. You use the data consistently. You use the data available.

Q. Well, let me ask you this. You purport to project regression analyses which show age in large PWR salt water cooled reactors as being a very significant factor operating to decrease capacity factors. Is that correct?

A. Yes. And that's been shown by other people now, too.

Q. Now, if you look at that data, and you look at some of the points in that data, and you see that the data is very heavily affected, for example, by the fact that there were a couple of large units that had steam generators replaced in the years 1980 or 1981, and that if you take those two data points out you suddenly lose all correlation between age and capacity factor, shouldn't you take that into account in evaluating the significance of your regression analyses?

A. Absolutely not. I think you have several misconceptions.

Number one, steam generator replacements are not in any way distortions of the data. They are exactly the aspects of the data that we want in the data base, that anyone should want, to study the likely impact on aging of nuclear power plants, particularly salt water cooled.

And, number two, you don't look at the data on an ad hoc basis and say well, I like these, and don't like those. We will throw those out.

The regression techniaue becomes your eyes and ears. It is the thing that is most sensitive to pull out of the data the effects that you are looking at.

So I feel implicit in your question are several misconceptions.

Q. Assume with me that steam generators suffer problems that, for example, supposing a steam generator suffering a denting problem due to water chemistry that is soluble by changing the water chemistry.

Now, supposing plants that did not act in time had the steam generators replaced. Now, if that plant replaces the steam generator, and solves the problem that caused the problem with the steam generators, what does the outage that that plant incurred at the impaired capacity factor have to do in terms of its future capacity factor?

A. Would you like my response as a hypothetical?

Q. Any way you want.

A. Well, if you want to assume that all that you have assumed is correct, then I should say well, I should look at additional variables in order to see how that might be connected to other variables.

Again, you might find that it's water chemistry that accounts for the decline with age for certain PWRs, and you may find that doesn't work, and it's still the salt water cooling variable.

Now, that assumes there is no connection between the two, which I would not assume, and certainly to my knowledge has never been established in the literature.

JUDGE GLEASON: Mr. Sanoff, how much more do you have to go?

MR. SANOFF: I would say a half an hour, sir.

JUDGE GLEASON: All right. Go ahead, Mr. Sanoff.

Q. Now, in your report, the ESRG report, you suggested, didn't you, and I think it begins roughly at page 72 -- no, I am sorry. It begins at page 70. You suggested that your cost impacts might be overstated because of a price elasticity of demand?

A. Yes. We discussed that topic, yes.

Q. Now, were you stating that if the

customer reduces his consumption of electricity in response to the increase in the cost of fuel attributable to the shutdown, the cost impact of the shutdown is reduced by any reduction in fuel costs that he has to pay as a result of his using less electricity?

A. We were saying, yes, that if there is an increase in required revenues, not just due to fuel costs, but due to any consequence of the Indian Point shutdown, if there is an increase in required revenues, and therefore in the customer's rates, based on no change in consumption, that's going to have feedback effect, namely, the customer sees rates go up, and there will be some tendency, however slight, and we don't put a number on it, for the customer to reduce his usage of electricity.

Q. Now, Dr. Rosen, when I deposed you on this I thought that you agreed with me that on the assumptions you have stated on page 72, that given the fact that Con Edison's incremental or marginal cost is only half of its revenue requirements, that your impact of over 40 percent was overstated?

A. Well, we give you the formula. If you change P divided by R to a half instead of one, we can redo the calculation.

Q. In other words, you are saying it's still 40 percent if the formula is as you stated it, which is not recognized applicable to Con Ed?

A. No. The formula is applicable to Con Edison.

I said if, as we agreed, and I do agree that we agreed, that P over R is more nearly one half for Con Edison, and if the price elasticity were minus 0.4, then it would turn ought to be .75 instead of .6.

You can put in any numbers you want, but there will be an effect to reduce the revenue.

Q. I understand.

Do you recall that in your deposition I asked you whether in concluding that the cost impact of the shutdown would be reduced as a result of the price elasticity of demand, you necessarily were assuming that the reduction of consumption was a benefit to the rate payer?

And you agreed that that was a necessary assumption. And I will reference you to page 41, if you still have the deposition there.

A. I assume you are referring to lines 18 to 21?

Q. Yes. And your answer on 22, "Sure."?

A. Right. We were talking about what the general situation might be for rate payers if the cost went up.

And I was saying that there would be several ways, if I remember correctly, that the rate payer might reduce his electricity costs by responding to this "price elasticity." And one would be using less electricity, and one would be changing technologies that would be cost beneficial to the customer.

Q. I asked you you, in order for you to reach the conclusion that the customer's usage of less electricity could produce a reduction in the cost impact of the shutdown, you had to make an assumption that the price elasticity of demand and the customer's reaction to the price elasticity of demand, was a benefit to the customer?

A. Well, either way it would be a reduction in required revenues.

In terms of the total social cost it would be reduced if there was an even --

Q. Let me read the question and the answer.

"Now, isn't it a necessary assumption

or a necessary intermediate point in going from one point to the other," and the one point was that the cost impact could be reduced by price elasticity of demand, I have interpolated that, "going from one point to another in that conclusion, that there has to be a benefit to the rate payer in this?"

And you said sure?

A. And I am explaining the context for people that were in that position, what kind of benefit we are talking about, and what this reference from one point to another meant.

I am just saying that to be absolutely precise about it, whether there was a benefit or not, the required revenues would go down.

And whether there was a net social cost reduction is another issue, and that would require a benefit to the rate payer.

Q. You were contending in your testimony that the cost impacts that you estimated could very well be overstated because of the price elasticity of demand. Is that right?

A. In our study, since it is limited to required revenues, we were focusing on that quantity.

Q. Well, weren't you really saying that the customer gets a benefit which offsets the cost impact of the shutdown if he or she uses less electricity?

A. Correct.

Q. Now, let me see. Aren't you saying that if there were a 7 percent rate increase, and a customer reduced his consumption by 7 percent, to hold his bill constant, that the customer would be just as well off as he was before the increase?

A. Now, wait. I think that's going way beyond what we were discussing.

I say that by definition there would be a required revenue impact, right. And, as you point out, the required revenues would be lower than they would have been if the customer did not reduce his consumption.

Now, if you are looking at whether there would be a general cost reduction to the customer for his electric bills, plus his cost for any measures that he would have to implement to reduce his electric use, that's a separate issue, and I am willing to discuss that, too.

Q. Did you say at the bottom of page 70, "Indeed, if the elasticity were minus 1, the required revenue impact would be zero."?

A. Yes. Under the right assumption on P over R, yes.

Q. Weren't you trying to tell the people who read your report that your computation of cost impacts, 2 percent, 4 percent, 1 percent, that those could be overstated, those cost impacts could be overstated, because they did not take account of the effect of price elasticity of demand?

A. That's correct. That's correct. The whole thing is to say what the over statement might be in required revenue.

Q. Now, in order to make that statement didn't you have to make the assumption that the customer's cutting his consumption of electricity in response to price was a benefit to him which offset the cost impact of the shutdown?

A. No. Only if you are looking at total social cost, not just required revenues.

MR. SANOFF: Could you bear with me for just a few minutes? I may have asked my last question. I don't swear to it, but I may have.

JUDGE GLEASON: All right.

MR. SANOFF: Oh, I am sorry. I have one last subject.

Q. Now, on the subject of O and M expense and capital costs, you used a linear regression, a linear line to project future O and M and capital costs. Is that correct?

A. Well, you keep saying O an M and capital costs.

Q. O and M expenses?

A. For O and M expenses we used a linear fit.

Q. Now, let me ask you this. Supposing you made an examination of the data points to which you were applying the least squares line, and you found that there had been a large increase in O and M expenses for things like, let's say, the better security systems, better safety inspections on entry and exit from the container, and things of that sort, and they were large increases but they were the kind of increases that, while the amount that you spent would continue into the future, there would not be a future increase of that amount.

Would it be intelligent to apply a least squares line to O and M figures that included such nonrecurring percentage increases?

A. Certainly. The line should be fit to all the data for the total O and M expenses for all the nuclear plants.

There will be some components of those costs that will increase once and not again, and there will be some costs that will increase more rapidly in the future than they did in the past.

You have to look at the total data and, you know, look at what kind of extrapolation makes sense.

Q. Wait a second. The use of the least squares lines assumes, does it not, that the past is prologue? I don't mean to wax poetic.

JUDGE GLEASON: Sounds good.

JUDGE SHON: That's nice.

MR. SANOFF: Thanks. I heard it somewhere.

A. Would you define your question more completely?

Q. I was taken by the sound of my own words.

Doesn't the least squares line assume that the past will be replicated in the future, that the line will continue?

A. Well, it certainly seems the line will continue.

It does not say the past will be replicated in the future in the same way it occurred in the past. And the most important aspect that of that that is relevant here is that a straight line projection of real dollar costs indicates a decrease from what occurred in the past.

Q. Well, suppose you look at the most recent numbers in that data base, and you saw that for a brief period of years the O and M costs accelerated dramatically, and you concluded that those costs were related intimately to the TMI outage, that there were a lot of O and M work done as a result of that, that there were a lot of O and M incurred, which will continue to be incurred in the future, but it will not be increased in the future.

Wouldn't you say to yourself that it doesn't make sense to project a line?

A. Well, the first thing I would say to myself is is the hypothetical true, which we found it is not.

Second of all, I would say to myself that one reason for not using an exponential fit to the data, if you thought there was an acceleration of the expenses, is that you might overestimate the rate of growth of the expenses in the future.

You notice we discussed the exponential fit and we rejected.

Thus in using a straight lane which we feel is not biased in either an upward growth direction or downward growth direction, we are indicating slower growth rates in the future than in the past, and we feel it is the most unbiased manner of projecting.

Q. Are you suggesting by your testimony that you examined the items that entered into the O and M expense increases for Consolidated Edison and the Power Authority in the last three or four years of the data you were using?

A. As you know, the data bases for most all the commercially operating plants in the country, we definitely have examined the growth rates that the regression equation established for the preTMI period. And we have demonstrated that the growth rates in the post TMI period have not been substantially greater than the ones we are projecting to the future.

Q. Did you hear my question? I asked you did you try to break down the O and M figures from the particular companies involved and try to see what the particular cost items were that occasioned these large increases in O and M?

A. Yes. To some extent, since the form of the study as published here, we have done that. We have looked at the components of O and M, not just for Con Ed and PASNY.

However, your question also had embodied in it a hypothetical about the role of TMI related expenditures, and their relationship to growth rates, and I was trying to clarify the fact that we have, in fact, established that the implication of your hypothetical is not correct.

Q. Did you finish?

A. Yes.

Q. You in that answer said not only for Con Ed.

Were you intending by that language to suggest that you looked at the cost items that occasioned the total figures for Con Edison?

A. We have not looked specifically at

the Con Edison. We have looked generically across the industry.

Q. You have no idea, do you, of what the constituent components of those cost increases were for Con Edison and the Power Authority. Isn't that a statement of fact?

A. No. I didn't say I have no idea. I said I have not studied the components in detail for the Indian Point units.

If you notice, in the report we do not use the generic equation to predict the base year expenses for Con Ed. We only use the base year to get the growth rates starting with the actual base year for the Indian Point units.

Q. Are you suggesting by your testimony that you made any analysis of Con Ed, of PASNY, or any other utility company, to determine whether these increases in O and M were step increases which were not likely to be replicated in the future?

And when I say make an analysis, did you determine from the companies involved what the constituent components of their O and M figures were, and whether they were the kind of things that would see increases in the future?

A. I have stated that we did not do that analysis as part of this study.

However, your question implies that one can know, or even hypothesize, what the likely trend would be by component, and I am saying our study rests on the sum of all components, some of which, I grant you, will not increase in the future in real dollars, and some will.

It looks at the total of all components and looks at how they have grown for all nuclear plants.

Q. Did you think of applying your least squares fit, rule, to your oil prices to see what they would extrapolate into for the future?

A. We did not deem it proper to use that approach to projecting oil prices, no. We feel that would not be an appropriate way to study a different subject.

Q. In other words, would you agree that if you applied your least squares analysis to the price increases experienced in the oil fields in the last eight years, that you would have an extrapolation that would vastly exceed anything estimated by any party in this proceeding?

A. I have no idea. I haven't done that

analysis.

Q. Well, if I told you that the annual average increase in oil prices, in real oil prices, between 1970 and 1981 was 22.20 percent, would that surprise you?

A. No. But I don't see what relevance that that --

Q. If you applied your least squares line and projected that for oil prices, you would be projecting a 22.2 percent real price increase no oil, would you not?

A. Not if you use a linear extrapolation, no. Only if you use an exponential fit.

Q. Would you accept, subject to check, that if you applied your linear least squares fit you would get a ten percent increase per year in real price?

A. No.

Q. You wouldn't?

A. It's a more complicated calculation. I would want to do it myself.

Q. Well, so you suspect it would be much larger than the real price increase you allowed?

A. It may be. But, again, it's an inappropriate technique for forecasting oil prices.

Q. It's only good for O and M costs?

A. No. I have other subjects I think it's good for, too.

MR. SANOFF: Thank you.

JUDGE GLEASON: Mr. Pratt?

CROSS EXAMINATION BY MR. PRATT:

Q. Dr. Rosen, I would like to ask you first in connection with the point I made, what is the purpose of your testimony in this case?

A. The purpose of our testimony is to look at the economic impacts on the rate payers in the Con Ed franchise area of a shutdown of the Indian Point unit.

Q. And in particular it's the cost to the downstate Power Authority and Consolidated Edison rate payers. Is that right?

A. That's right.

Q. And did you attempt to set out that estimate in your table 1 in the testimony, and I mean the extra testimony, not the study?

A. The table 1?

Q. Table 1.

A. Yes.

Q. And your mid range estimate is 1.9 percent, if I understand it?

A. Well, expressed as a percentage, yes.
Q. Good.
Now, can you tell me, not in numbers, but in concept, just how that 1.9 percent is derived?
A. In concept it's derived by dividing the dollar amount of the impact, as presented in that table, by the total required revenues, and the sum of those two sets of rate payers.
Q. Would you give me at this time what the required revenues that you used in that calculation for the Power Authority were?
A. I would have to dig through my notes. I don't remember.
Q. Good. We will take time. Would you do it?
A. Well, if I have the number.
(There was a brief pause.)
A. I am afraid I do not have those figures with me.
Q. Maybe we can reconstruct it, at least in, as you say, an order of magnitude sense.
The impact, I gather, would be the number shown in table 16, would it?
A. That's correct.

Q. So to take a particular year, let's say 1984, the penalty would be in that year by your numbers 186.7 million for both companies. Is that correct?

A. Are you talking about mid range?

Q. That's right. I am just discussing your best estimate, which --

A. Yes. 707.9? Are you doing current dollars or discount?

Q. I am looking at the table 16.

A. Correct.

Q. Are you looking under cumulative total?

A. Under--

Q. No. 1984, annual total.

A. Oh. Sorry. 186.7. Correct.

Q. Now, it is my understanding that you cannot today break down that penalty, that impact, into the Power Authority share and the Con Edison share?

A. No. We have not done that analysis.

Q. You never did that analysis?

A. No. I mean, I have not disaggregated the numbers that way. It is certainly possible, based on what we did, but I have not done that.

Q. Would you agree that one way to do that is simply to take the megawatt output of the two units and use that as a ratio, and divide the impact in that fashion?

A. Well, no, I don't think that would accurately reflect the correct numbers.

Q. Well, I don't think it's accurate, either. I think it's conservative.

Do you understand anything about the relationships between Con Ed and the Power Authority with respect to the sale of power in this part of the state?

A. I understand some things, I am sure.

Q. Do you have any idea of where the make up costs, make up power, would come from if Indian Point 3 were shutdown?

A. Not precisely in terms of PASNY's bookkeeping, no.

Q. Would it be likely to be at the same marginal rate as Con Edison's make up power?

A. I do not know.

Q. You don't know.

Tell me what is wrong with using the megawatt output as a ratio to divide the impact?

A. Well, I grant it may be a reasonable

first order of approximation. I just think the pricing agreements are somewhat more complex.

Q. So it's at least one way to do it. There may be more detailed one?

A. Well, I would think corrections would be required.

Q. Have you examined the testimony of Messrs. Hochman, Rubin and Dean in which they set out certain revenues in the downstate area of the Power Authority and Con Edison?

A. No, I am afraid I haven't seen them.

Q. I would like to show you now Exhibit 1 which is in evidence to that testimony, Hochman, Rubin and Dean. It was admitted yesterday, and let me show it to you at this time.

Can you accept, subject to check, that the revenues shown on Exhibit 1, and I refer to the year 1984, revenues for Consolidated Edison and in a different column for the Power Authority, Con Ed is 46 hundred million, and in the case of the Power Authority it's 729 million? Would you accept those as accurate, subject to check?

A. Yes.

Q. Thank you.

Now, while we are on page 61 and

table 16, you have a series of annual totals for impact. Do you see what I am pointing at, the column entitled annual total?

A. Yes.

Q. And it's my understanding, and correct me if I am wrong, that the items 244.2 for the year 1983, 186.7 for the next year, those items that are positive indicate a cost impact if the Indian Point plants were shutdown. Is that correct?

A. That's correct.

Q. In other words, the shift to replacement power would cost something, and you have given your estimate of what it is in that column?

A. The shift in total cost.

Q. That's right. This is a net figure?

A. Yes.

Q. And then in the latter part of that column, take the year 1997, for example, you have a minus number, minus 54.1. Do you see that?

A. Yes.

Q. Now, at this point, if I understand, and correct me if I am wrong, there would be a saving in shifting to replacement power. Is that correct?

A. There would be a saving of the scenario as a whole. Yes.

Q. That's right.

Now, are you familiar with the concept of economic dispatch in this state?

A. Yes.

Q. Tell me what your understanding of that concept is?

A. Well, just in its broadest outlines economic dispatch means that subject to the constraints on transmission lines that the lowest cost power plants are always dispatched first before higher cost power plants.

Q. Are you aware of any plants in the State of New York that are being run at a loss, that is that the cost of running that plant, and I mean the total cost of running the plant, exceeds the cost of some alternative source of power?

A. No, certainly not. But that's not what that column shows.

Q. Well, just answer yes or no.

A. No.

Q. Isn't it true that the numbers in this column that are minus numbers are completely irrelevant, since they could never occur?

A. No. That's a misconception.

Q. Could you tell me under what circumstances the Indian Point plants would be run at a loss?

A. That's the misconception I want to clear up.

The reason those numbers are negative, and I have certainly anticipated this question, is that there are the incremental savings from the Ravenswood 1 and 2 coal conversion that we discussed earlier.

Q. I don't care where they come from. They can come from a variety of places.

Your testimony, as I understand it, is the incremental use of the Indian Point plants in 1997 is at a loss. That's what you just testified?

A. But that's why it's important to understand it's the scenario as a whole. It includes various fixed charges, various assumptions about decommissioning, and what have you. It's not just the variable cost of running the units.

Q. I understand that. We are talking about the scenario as a whole?

A. Right.

Q. And looking at the state as a whole, the scenario as a whole, however you want to look at it, you are projecting certain years when the plants will be run, even though there is more economic power available elsewhere?

A. No. That is not what it shows.

Q. Can you tell me why the Power Authority or Consolidated Edison would ever return the Indian Point units if it is producing a loss, given the entire scenario

MR. BLUM: Objection. There is no foundation. The witness has already testified that's not what the figures mean.

JUDGE GLEASON: Well, he can respond that he is misinterpreting the figures.

Answer the question, please. Did you understand the question?

THE WITNESS: Well, perhaps it would be better if the question were read back so I answer it precisely.

JUDGE GLEASON: Would you mind reading it question back?

(The reporter read the pending question.)

A. Well, again, the entire scenario is applied over a long period of time, not just year by year.

You would not run the Indian Point units in a given year if there were other units that could be run at lower variable costs.

But the scenario cannot be manipulated year by year. One could use the type of analysis we have done to show exactly in which year it becomes uneconomical to run the Indian Point units based on variable costs, but we have not done that.

Q. When you run your cost assessment model do you run it first for year number 1, we will say 1984, and then 1985, and so on?

A. Yes.

Q. So, in fact, you have done your analysis year by year by year. Correct?

A. Correct. But we have not defined the scenario year by year.

Q. Now, Dr. Rosen, one of the crucial components in any presentation such as the one you have made is the load growth, is that correct, the predictions by the utilities, or by anyone else, of what the demand for electricity is going to be?

A. Well, that's one of the assumptions. I don't know that it would have a very strong bearing here.

Q. We will leave the significance to a later point.

Is it one of your assumptions?

A. Yes.

Q. And isn't it a fact that your demand scenarios were based on the Arthur Kill report, the June, 981, study from the New York City Energy Office?

A. Yes.

Q. And I am referring to page 176 your testimony.

A. Yes.

Q. That document, again, is dated mid 1981. Is that correct?

A. Right.

Q. And when was the data concerning load growth taken on which that study was based?

Let me see if I can make my question more precise.

What is the age of the data underlying that 1981 report?

A. I would have to check with the people that did the forecast. I would assume either 1979 or 1980.

MR. PRATT: At this time I would like to have two documents which are selections of pages from the June, 1981, NSRG report, marked. I believe the next document is Power Authority 49, so I propose that we mark these two exhibits as Power Authority 49 and Power Authority 50, respectively.

In one case a three page document which I propose be 49, and in the other case a 4 page document that I propose be exhibit 50.

JUDGE GLEASON: How did you reference them?

MR. PRATT: They are selected pages from Dr. Rosen's study of the Arthur Kill plant.

JUDGE GLEASON: The documents will be marked as Power Authority Exhibit 49 and Power Authority Exhibit 50.

(Power Authority Exhibits 49 and 50 were marked for identification.)

Q. Dr. Rosen, focusing on the base case forecast, that's Power Authority 49, I believe table Roman 2.1.2 shows what NSRG in June of 1981 thought the peak load for the Consolidated Edison Company would be in the year 1982, the summer peak load. Do you see that table 2.1.2?

A. Yes.

Q. And, correct me if I am wrong, I read that to be 7,600 megawatts peak load summer?

A. Correct. That was the forecast.

Q. Now, would you at this time accept, subject to check, from the 1983, volume 1, of the New York Power Pool 5-12 statement, that, in fact, Consolidated Edison's load for 1982 was 7,326, a difference of just about 300 megawatt?

A. Would you repeat the figure again?

Q. 7326?

A. Yes.

Q. Approximately 275 megawatt difference?

A. Yes.

Q. Now take a look, if you will, at Power Authority 50, which is NSRG's conservation case?

A. Yes.

Q. On Power Authority 50, if you will look at table Roman 3.4.3, which is on 3-29.

If I read that table correctly, and which will require a little more computation than the prior example, again for the year 1982 the aggregate Power Authority and Con Ed franchise area load summer peak is predicted to be 8,259. Is that correct?

A. Yes.

Q. Now, if I wanted to get just the load for Consolidated Edison, what I have done is subtracted 1,210, which you show on Power Authority 49, on table 2.1.2 for the same year as 1210. Do you see that? In other words, I am trying to focus on the Summer load, so my subtraction says that the NSRG estimate for the summer load for 1982 in the conservation case, the conservation scenario, would be 7,069 again approximately 300 megawatts below the actual. Do you see that?

A. Yes.

Q. Good.

And I have read the numbers correctly?

A. Yes, you have.

Q. Now, the Arthur Kill report is not the only time that NSRG has been interested in conservation in this state, is it? It's not the only proceeding in which you have played a role in connection with conservation, is it?

A. No, it isn't.

Q. And, in fact, didn't the NSRG Company accident on behalf of certain parties in the State Energy Master Plan proceeding, Roman 2?

A. Yes, we did.

Q. And do you recall at that time that the SEMP II analysis about conservation was described in the following words?

"While the conservation scenario is not presented as a blueprint for immediate action, it does offer a first approximation measure of the merits of such a program."

That's a quote from the NSRG submission. Do you recall that?

A. Yes.

MR. PRATT: I have to correct the record at this time. Others who have a more mathematical bent than I do subtract 1210 from 8259 and produce 7049. I stand corrected.

Q. Now, are you asking this board to rely as the low forecast in this case on a low forecast that you, yourself, your company, described not sufficient for blueprint? Is that the position of NSRG?

A. No. What page are you referring to?

Q. We start with this case. Your mid range forecast, if I understand you, is based on a mid point between the conservation case from the Arthur Kill proceeding and your base estimate in the Arthur Kill proceeding

A. That's right. In both the Indian Point retirement and no retirement cases we assume 50 percent of the conservation scenario.

Q. The same conservation scenario that you described as not a blueprint for the future.

Now, let me ask you, if I can, exactly, I am still interested in the impacts on the customers in this case. Let me ask you, if I can, to tell me exactly how -- can you tell me how the impact in this case was calculated? And let me focus you on page 60 of the study, and section 4.2 of your study.

In that area you indicate that there is an annual percentage impact on required revenue. Do you see that sentence?

JUDGE GLEASON: Which study are you talking about?

MR. PRATT: We are now talking about just the testimony in this case.

JUDGE GLEASON: What page?

MR. PRATT: We are on page 60.
JUDGE GLEASON: All right.
Q. Do you see that reference, footnote 38?
A. Yes.
Q. When I turn to 38 I see that you rely, among other matters, on the cost and projection on the cost of unit cost of electricity in the Con Ed service territory. Do you see that on page 81, footnote 38?
A. Yes.
Q. And you indicate that the unit cost is going to decrease at 0.7 percent a year, and you cite a reference?
A. Yes.
Q. All right.
Now, what I need to know, what I would like to ask you, is where, in your study, does that decrease of 0.7 come into play? How is it factored in?
A. Okay. Well, again, to clarify, I think the 0.7 percent is a decrease in constant dollars.
How did it factor in? I am basically not as familiar with some of the submodules within

the demand module as others within NSRG. I would think it plays a minor role in looking at the penetration of various conservation scenarios, I am sorry, conservation technologies, and heating technologies. But I could check for you.

Q. Again let's focus on table 16.

If I Understand the burden of your testimony, it's table 16 that sets out most of your results. You have a column entitled make up generation. If I was trying to find on table 16 the right column where the minus .7 appeared, would it be in that make up generation table? In other words, is that column, make up generation, the one that is impacted?

A. Only to the extent that the assumption in footnote 38 has any substantial effect on the demand level, which I doubt that it does.

Q. Well, let's leave the size of the impact, and tell me which column on table 16 would this impact?

A. Well, as I say, if there is an impact, it would be in make up generation.

Q. All right. Fine. Thank you.

Now, the impact, if I understand it,

would be as you passed through the years from 1983, 1984, and so on, would be to tend to decrease the make up generation number, all other things being held constant?

A. Well, again I don't think -- yes, there would be a second order effect, keeping in mind the fact that the same demand level is used in both the Indian Point and in our scenario. Yes, there would be an impact on the make up generation.

Q. Isn't this, to put the matter in simple terms that I can understand, I am talking about the make up generation column. It's a quantity of electricity times a price of electricity? I am trying to simplify. In broad concept it's quantity times price?

A. Well, that strikes me as too broad to be of use.

It's the result of running the whole dispatch system.

Q. You are a great believer in the order of magnitude estimate and the qualitative estimate. I am trying to deal in your terms.

A. Well, with a slightly lower demand level, which is the case in the mid range scenario, you would get a slightly lower cost per hour in make up generation.

Q. Thank you.

MR. PRATT: I would like to have marked at this time a document which will be Power Authority 51.

JUDGE GLEASON: All right. How do you identify that?

MR. PRATT: This his page 170 from the 1981 State Energy Master Plan. It is, in fact, the reference cited by Dr. Rosen in footnote 38.

JUDGE GLEASON: All right. It will be marked as PA Exhibit 51.

(Power Authority Exhibit 51 was marked for identification.)

Q. Now, Dr. Rosen, do you have a copy of that in front of you yet?

A. Not yet.

Q. One is coming.

In this case we are talking about the Con Ed service territory, so let's focus on the second line, or second group of lines, entitled Con Ed.

Looking at table 16, your scope of interest is the years 1983 through 1997, and the best indication I see of that is the right hand column on PA 51 for the years 1980 through 1996. You tell me, is there a minus .7 in that set of three numbers which are positive .8, positive .6, and positive .8?

A. No, there isn't.

Q. Is this simply an error that should be corrected?

A. Well, I didn't make that calculation. It may be, but I think it would have negligible consequence.

Q. Well, independent whether it means nothing at all, or makes a great deal of difference, it appears to be an error?

A. At this moment it appears to be. I would have to check with the people that derived that number.

Q. In fact, this is in the nature of speculation, which you don't have to answer, but if you look above in the Central Hudson line, you have three numbers that are all minus .7. Do you think your colleagues may have taken the number from that?

A. Well, again it's speculation. Not knowing how they calculated it, I couldn't say.

Q. Now, this impact, the 0.7 number we

have been focusing on, applies in, to start with, 1983. Isn't that correct?

A. It applies in 1983.

Q. And then it will apply in each successive year?

A. Right. It will tend to need more electricity to be used.

Q. Now, in this case you assume, and I focus on page 24 of your testimony, the study which is a part of your testimony, you assume that transmission line improvements in 1984 and 1986 that are currently scheduled will be in place. Isn't that correct?

A. Yes.

Q. If, by reason of some licensing problem, financing problem, any of those transmission line improvements were not in place, it would change your results in this case, wouldn't it?

A. Well, it might. As I said, we didn't have a multiarea dispatch model available, so I could not tell you whether it would or not.

Q. Has New York State historically, and I am talking about the last twenty years, had transmission restraints from one part of the state to another part? I am just thinking generically at this point.

A. Yes, there have been.

Q. And such transmission restraints play a role, have an impact, on total production costs, either on a statewide basis or in a particular area?

A. Yes, in general.

Q. And if you were selecting a model to use, would you go to one that recognized transmission restraints, or would you pick one that was independent, did not have any account for transmission restraints?

A. Well, any modeling exercise you would want to include transmission restraints.

Q. Fine. It might be likely to produce a more accurate, more complete answers?

A. Yes. And the model we used did.

MR. PRATT: Thank you very much. I have no other questions.

JUDGE GLEASON: Mr. McGurren?

CROSS EXAMINATION BY MR. McGURREN:

Q. My name is Henry J. McGurren. I represent the Nuclear Regulatory Commission Staff.

We have spent a lot of time with

table 16, and just so that I am sure that I understand your testimony, I would first like to see if I can develop the relationship between table 16, which is on page 61 of your report, and table 1 of your testimony, page 5.

Am I correct that it is your testimony that you have taken numbers from table 16, for instance let's just take table 16, I think table 16 is your mid range scenario. Is that correct?

A. Yes.

Q. And under cumulative total you have. 745.8. Is that correct?

A. Yes.

Q. And if you look at table 1, under cumulative totals, you get 746, is that correct?

A. Yes.

Q. All right. I think I followed it that far.

Now, with respect to table 16, Mr. Pratt was asking you about the economics or the decision to continue to operate the Indian Point plants if you start to see a negative annual total. Do you remember that question?

A. Yes.

Q. And I think you indicated that -- what did you answer? What was your answer to his question?

A. Well, I said that you would not operate the Indian Point units once it got to be a point where the increase in the variable costs of operating them exceeded the variable costs of replacing that power with some other source, but that that was different from the numbers that appeared in table 16 under the annual total column, which involves total scenario effects and variable costs.

Q. Well, if I am trying to answer the commission's question here on the cost of shutdown at Indian Point, are you telling me that I can't look at table 16 and answer that question?

A. Well, you can answer the question in that table 16 shows you accurately the cost impact of shutting the units down in early 1983 through 1997.

I assume what you are getting at is one would have to -- one could double check --

Q. Don't assume what I am getting at.

Didn't you say in answer to Mr. Pratt that there is another factor, that when annual totals became negative that Ravenswood came in?

JUDGE GLEASON: What was that?

MR. McGURREN: That Ravenswood was a factor.

Q. Is that correct?

A. That's correct.

Q. And what did you say about Ravenswood?

A. I said that because Ravenswood, converted to coal, was assumed in the Indian Point shutdown scenario, that that would lead to negative numbers in that column, even though it was still economical to operate Indian Point in the Indian Point in operation scenario.

Q. Would the same be true if we looked at table 18? Table 18 reflects in your low impact scenario?

A. Yes.

Q. Are you saying wnere the numbers for annual total begin to be negative, that again Ravenswood would come in?

A. Yes. In the low impact scenario, however, given the size of the numbers at the end of the period, it may be that you would reach a point where it would no longer be worth running the Indian Point plants. That would not be the case in the mid range, but it's possible in the low range impact.

Q. And carrying these total numbers, then, from table 16 and 18 back to table 1, my question is does table 1 have a correct title? It states Required Revenue Impact on Indian Point REtirements, Summary Results for New York Rate Payers.

Are we, in fact, looking at Indian Point in and out or something else?

A. We looking at Indian Point in and out here as defined by the scenario comparisons that we have indicated.

Q. Would it more clearly be Required Revenue Impact of Indian Point and Impacts of Coal Conversion at Ravenswood?

A. I say the table is well defined in the text of the report. It's a matter not just of, you know, causation in terms of relations between Indian Point retirements and the dispatch of the NERA Power Pool.

It's a matter of a scenario definition that I think we have been perfectly candid about. We have provided several clear tables that define the range of actions that we believe are reasonable to assume for each of these scenarios.

Q. Would you please turn to table 3 on page 19 of your report?

Now, as I understand the term "scenario," it suggests that there is a certain consistency --

MR. SANOFF: I can't hear you, sir.

Q. As I understand the use of the term "scenario," it implies a certain consistency with respect to the set of assumptions concerning those parameters. Is that correct?

A. Well, I think there should generally be consistency, but the way we use "scenario" here is that it represents a nexus of assumptions that would have a similar impact on the cost impact. So that, for instance, in the extremes, the high and low impact case, we grouped assumptions that would have a, you know, respectively a high or low impact on the cost. Some of them are independent.

In other words, in so scenarios some things are independent of each other, so consistency is not a particular issue.

Q. Well, so that I understand your testimony, is it consistent, for instance, in your scenario 3 B, Indian Point shutdown, is it consistent that the demand level would be one hundred percent conservation, you would have Ravenswood 1 and 2 converted to coal, and at the same time that you would have an increase to 57 percent of power from Canada? Is that consistent?

A. As far as I know, all those assumptions are perfectly consistent, yes.

Q. Wouldn't you think it would be more consistent that there would be a higher need for power from Canada in the first scenario, that would be with 1 B, shutdown Indian Point, demand level base case, no conversion?

A. Well, there might be a higher need. But you asked me about consistency.

We have explained, I hope clearly, in the text, that the low impact scenario is the result of policy actions as well as, you know, dispatch of the Power Pool, that could be taken to mitigate cost impacts. That's the whole point of the scenario.

You know, people can do something to minimize the cost impact. It's not just letting the system go as if nothing happened.

So while I agree with you the need

would be greater in the high impact, we are postulating additional policy actions in the low scenario.

Q. Can you give me an example of the policy action that you are speaking of?

A. Well, that would be an example of where we discussed earlier where state officials or utility officials or a combination of the above would take action to mitigate the cost impact in the Con Ed franchise area by reallocating some of the Hydro Quebec power.

Q. And wouldn't that be reallocating away from the upstate users?

A. If the quantity is fixed yes.

Q. And wouldn't there be an increase in cost to the upstate users?

A. I already agreed to that.

Q. And would you think that would be a cost that should be considered by this board?

A. Well, we discussed two things. One are the set of revenues to these rate payers.

We also discussed all the other social costs, whether it's to people upstate, tax payers, people throughout the country, the world, for that matter. We have not quantified those, although clearly, for instance, the cost of waste disposal of continuing to operate the nuclear units could be quite negative, far beyond the confines of rate payers of New York State. We have not included those impacts.

Q. But the cost to the upstate rate payers, is it your testimony that the cost to the upstate rate payers should be included as a cost of the shutdown Indian Point 2 or 3?

A. It should be included in a study that looks at all the rest of the costs to the rest of the world. Yes

MR. McGURREN: Just a moment, Your Honor. With all the cross examination that has preceded me, I am checking off questions that have been asked.

JUDGE GLEASON: All right.

Q. Appendix C, is that the model that you used to develop your capacity factor?

A. Yes.

Q. Have you attempted to compare actual 1982 capacity factors for salt water PWRs with what your model predicts for 1982?

A. No. We have tried to get the data from NRC, and it hasn't been available quite yet on tape, so we will be doing that quite soon.

Q. When you do get that opportunity, what kind of errors would you tolerate before questioning the predictive powers?

A. Well, I don't think the question is so much what kind of errors would we tolerate.

What we would do with the data is put it into the data base and redo the regression equation based on the data. Obviously there will always be short term alterations about any average we predict for the future.

Q. Is it reasonable to expect from your model that it would predict in 1982, which is one year beyond your data base, that it would better predict for 1982, than for years further out in the future?

A. It would tend to better predict for 1982, yes.

Q. Would you please turn back to tables 16, 17, and 18, in your report?

MR. SANOFF: What page was that?

MR. McGURREN: This is pages 61, 62, and 63, of the report.

MR. SANOFF: Thank you, sir.

Q. There are columns for spent fuel and

decommissioning, and I notice in looking at these columns that the figure, table 16, 15.2 occurs all the way down from 1985 to 1997, and the figure under decommissioning 4.6 occurs, again, from '85 down to '97. The same number occurs, really, understand each column for the same years. Can you explain why that is?

A. Yes. We just set those costs up so they would be levelized on a discounted basis. It's explained in the appendices.

You could set them up, you know, to go in some other pattern if you wanted to. That was just the pattern we did.

Q. Would you please turn to page 22 of your report?

A. Yes.

Q. The very last sentence on that page, it reads, "Under no shutdown case we assume that 42 percent of the nonfirming core power would be available."

What would be that 42 percent of? I multiply 42 percent times 15 thousand G W H?

A. Yes. In the period '84 to '96.

Q. And tell me if my hand calculations are correct. Would that come out to be 99,300 G W

H, including the 3 thousand fixed? Is that correct? Please feel free to use your calculator.

A. Yes. Including the 3 thousand, that's correct.

Q. Now, if I wanted to compare what happens in the low impact case for Indian Point out, would I use the 57 percent figure?

A. That would be the power available, yes.

Q. And again I would multiply 57 percent times the 15 thousand G W H. Is that correct?

A. Yes. That, of course, helps clear up the confusion of the questions earlier.

Q. And adding the 3 thousand to that I would come up with 11,550 G W H. Is that correct?

A. That sound correct.

Q. And if I subtracted my earlier number of 9,300 G W H from the 11,550 G W H, what would that represent?

A. That would represent the differential power that was made available to the dispatch model.

Q. From Canada, is that correct?

A. Yes.

Q. How does this compare with the

kilowatt hours that Indian Point generates?

A. Well, the differential, it's a lot less. It's maybe about 20, 25 percent. I don't have the figures in front of me.

Q. What would happen in later years, just a general observation?

A. What would happen in later years?

Well, we gave on discovery the computer outputs for every year for every scenario.

Q. How about power coming in from Canada in the low impact case relative to the power generated from Indian Point 2 and 3 units?

A. In which scenario are you talking about?

Q. The low.

A. Oh, low impact. Well, as the capacity factor in Indian Point units decline, they would become a bigger and bigger percentage of the power.

Q. Taking it now in terms of looking down to future years, was the change in Canadian purchases ever greater than Indian Point generation?

A. In the low impact case that could happen, yes.

Q. Isn't this inconsistent?

A. Well, I have to check if it does happen, first of all.

And if you say there might be a few years at the end where there's a slight overlap, you know, one could make a very slight adjustment for that in the numbers. It's not going to change anything substantially.

MR. McGURREN: We have just a few seconds, Your Honor.

JUDGE GLEASON: Yes.

(There's a brief pause.)

MR. McGURREN: That's all we have, Your Honor.

JUDGE GLEASON: Any redirect?

MR. BLUM: Yes. I have about 25 or 30 minutes of redirect.

MR. PRATT: Judge, please, before we break, the NRC staff's cross examination seems to me to have allowed the witness to rehabilitate himself slightly. I would like to come back to a few of the items Mr. McGurren raised.

And, second, I don't want to leave the day without getting my exhibits into evidence.

MR. BLUM: Your Honor, in general we have been denying recross. I don't know if you want to change that.

JUDGE GLEASON: Pardon?

MR. BLUM: I said in general we have been denying recross. I don't know if we want to change that.

JUDGE GLEASON: Well, Mr. Blum, I don't know what it refers to. I feel now, with your request for twenty minutes for redirect, I can't believe that.

Do you have a couple of witnesses waiting, Mr. Kaplan? Are they here?

MR. KAPLAN: One just stepped out. I assume, a normal lunch break, he will be back at 1:30. One of them is here, but it's a panel.

JUDGE GLEASON: all right. Let's get your exhibits moved, please.

MR. PRATT: I move that Power Authority Exhibit 49, Power Authority 50, and Power Authority 51 be accepted into evidence.

JUDGE GLEASON: Is there an objection? Hearing none, the exhibits will be received into evidence.

MR. BLUM: Could they be identified, what these three things are, please?

JUDGE GLEASON: Don't you have them

marked? 49, 50, and 51.

MR. BLUM: Well, two of them are prior NSRG testimony in prior proceedings. Is that correct?

MR. PRATT: Not testimony, no. Submissions to a federal agency, presumably subject to the penalty of perjury.

MR. BLUM: The problem is, these were handed out. They are just pages, and it's difficult to say what they are.

MR. PRATT: I will let you look, over the lunch break, at the entire report.

MR. BLUM: Can we do this after we come back?

JUDGE GLEASON: All right. But he indicated at the time they were introduced, Mr. Blum. I suggest that you make little notes as we go along.

What else do you have?

MR. PRATT: I have not more than two minutes of questioning.

JUDGE GLEASON: What are the questions on?

MR. PRATT: On this table 16, and the questions about the conversion of Ravenswood 1 and

2.

JUDGE GLEASON: All right.

RECROSS EXAMINATION BY MR. PRATT:

Q. Dr. Rosen, you indicated to Mr. McGurren that your mid range impact study assumes the conversion of Ravenswood 1 and 2. Do you recall?

A. That's correct.

Q. And the conversion of those two plants is the reason why the annual total impact for certain years slips into the negative column?

A. Correct.

Q. On which column on table 16 does the Ravenswood conversion show up? Let me point it more directly. Is it in the make up generation column?

A. It would have an effect there, yes.

Q. Elsewhere also?

A. Correct.

Q. What other columns?

A. It would be in the, I think it's the other cost item. It's the capital and O and M would be reflected.

Q. What's the amount in the make up generation column that is saved, or is reduced, as a result of the conversion of Ravenswood 1 and 2?

A. I don't know.

Q. You can't tell the Board at this time what that number is. Is that correct?

A. Not at this moment, no.

Q. All right.

And in the other cost column I assume the capital would be shown as a positive number?

A. A cost of converting, yes.

MR. PRATT: Thank you. No further questions.

JUDGE GLEASON: All right. We will be back here at 1:45.

(There was a luncheon recess.)

JUDGE GLEASON: Let's get on the record.

Mr. Levin, you had an application.

MR. LEVIN: Yes, sir. With respect to the licensee's motion to require the depositions of the FEMA witnesses, we have entered into an agreement -- let me get my papers -- entered into an agreement that we will reduce to a written stipulation at a later point, but I wanted to inform the board and put on the record the terms of the agreement.

The two regional witnesses, Mr. Kowisky and Mr. McIntyre, will be deposed by stipulation and that will be at a time to be set between now and Monday.

The notice of deposition for what I will refer to as the national witness, Mr. Krimm, will be withdrawn. FEMA has agreed to answer interrogatories which would be served tomorrow morning directed to Mr. Krimm, and they will try to complete the answers by close of business Monday.

Now, they have retained the right to the normal objections that they would have to interrogatories, but they will stipulate to the admissibility of the interrogatories and the answers to interrogatories into evidence, subject to relevance and materiality objections.

They will not, during the course of this hearing -- FEMA will not during the course of this hearing -- attempt to introduce any of the verification evidence that was also the subject of our motion, but will rather provide that evidence in the regular administrative process, so that both the NRC staff and the commission will have an opportunity to have it before them, in the administrative side of the process rather than in the hearing side.

That is the disposition of the motion.

JUDGE GLEASON: Yes, Ms. Potterfield.

MS. POTTERFIELD: May we ask the other parties be informed as soon as possible of the date and time of the deposition of the witnesses.

JUDGE GLEASON: I was just going to tell Mr. Levin that he should make sure that all parties be communicated with.

MR. LEVIN: You can expect that it will be tomorrow afternoon or Saturday morning are the likely times. The exact time I don't know yet.

Take your seat again, Dr. Rosen.

Start your redirect, Mr. Blum. .

REDIRECT EXAMINATION

BY MR. BLUM:

Q. Dr. Rosen, you recall Mr. Sanoff asking you a number of questions about price elasticity, do you not?

A. Yes.

Q. What use of price elasticity did you make in your study?

A. In terms of the figures cited in the conclusions of the study remain; none. None with respect to the price elasticity discussion at the end of the volume.

Q. So you included a discussion at the end in an appendix, but as far as calculating for your reference case or your low scenario or your high scenario, you assumed a price of zero for price elasticity, is that correct?

A. Implicitly.

Q. In reality the price elasticity would be something higher than zero, would it not?

A. Yes, it would.

Q. And what effect would there be on your results if you had been able to calculate and include these price elasticities?

MR. SANOFF: I object to the question.

JUDGE GLEASON: What was the question?

MR. SANOFF: Mr. Blum has just elicited from Dr. Rosen, correctly so, that there was no adjustment made to his figures if price elasticity had been considered.

Now he is asking him what would the effect have been if he had included price elasticity, and I don't think that is proper.

JUDGE GLEASON: That is new evidence.

MR. SANOFF: New evidence and not proper.

JUDGE GLEASON: You are on redirect. You are rehabilitating a witness, Mr. Blum.

Q. Dr. Rosen, could you turn to figure four of your testimony.

MR. SANOFF: Could you give us the page, Mr. Blum?

MR.BLUM: Perhaps Dr. Rosen could.

A. Did you say figure 4?

Q. I didn't.

A. Do you mean table 4?

Q. This one (indicating).

JUDGE GLEASON: What does he mean?

THE WITNESS: Figure 4.

JUDGE GLEASON: While we are turning to that, just so I don't have any loose items, do you want to make an objection on the admission of exhibits 49 through 51?

MR.BLUM: No, on one condition: That the proper front pages identifying the testimony, that these are be appended to them. Otherwise it is quite confusing. It can look that this is part of the current ESRG testimony since it is on the same stationery.

That is the normal procedure in putting in pages.

JUDGE GLEASON: He has identified where they come from.

MR. PRATT: I don't object to adding a page. I don't go along with the idea of what is normal.

MR.BLUM: If you agree to add a page, we have no objection.

MR. PRATT: Should I do it with each of the two documents?

JUDGE GLEASON: I gather it is 49 and 50. Do you want 51 too, a page?

MR.BLUM: If we could, yes.

JUDGE GLEASON: All three.

MR. PRATT: We will do that.

JUDGE GLEASON: With that understanding the exhibits are received into evidence.

(Power Authority Exhibits 49, 50, 51 were received in evidence.)

MR. SANOFF: Do you have the page, Dr. Rosen?

THE WITNESS: I am afraid not.

JUDGE GLEASON: Do you have a page reference? Is it in the appendix, Mr. Blum?

THE WITNESS: Do you mean the capacity factor figures?

MR.BLUM: Yes, that's right; over time showing the regression line and the high, mid range and low impact.

THE WITNESS: That's figures 1 and 2.

MR. SANOFF: From where?

THE WITNESS: From the body of my report.

MR. SANOFF: What page?

THE WITNESS: Witness 27 and 28.

JUDGE GLEASON: All right, Mr. Blum.

Q. Dr. Rosen, you don't use the actual regression line in any of your three estimates, do you?

THE WITNESS: No. We did not use the actual regression equation prediction for any of the three impact cases.

Q. And in fact your high impact case shows no decline with age out to the year 2000, is that correct?

A. That's correct.

Q. And both the mid range and the low impact cases show a decline vastly smaller in rate than that which would come from the regression line, is that correct?

A. That's correct.

Q. Could you estimate what the difference in slope is for the mid range against the regression line and the low impact case against the regression line?

MR. SANOFF: I object to that.

JUDGE GLEASON: Let him answer that. I realize it is an extension but let him answer.

We ought to keep things on a confined basis, Mr. Blum.

A. I would say the ratio of the slopes is approximately one to two to three in the case of the mid range; the low impact and the actual regression line.

Q. Are you sure you calculated that correctly?

A. Yes. I think the slopes are in the range roughly of one, two to three.

Q. From the graph it seemed to be more like --

MR. SANOFF: I object to this. You can't cross-examine your witness.

JUDGE GLEASON: All right, Mr. Blum.

MR.BLUM: The testimony will speak for itself.

MR. SANOFF: You can't evoke that against your own witness, Mr. Blum.

Q. Why did you not simply extend out the regression line? What did you do to choose these other approaches instead?

A. The main reason we did not extend the regression line is because we believed that while the basic trend towards poor performace of plans is a realistic one, we felt that further data would moderate the effect somewhat and that it was not reasonable to expect the capacity factors to fall that quickly.

So we put in more moderate

assumptions.

Q. Now, under cross-examination you mentioned that the need to replace steam generators is one of the factors that's been involved in calculating declining capacity factors, is that correct?

A. Yes.

Q. Is it conceivable that steam generators would have to be replaced more than once during the natural lifetime of a plant?

A. That's certainly possible, yes.

Q. Is there anything in the existing experience of plants that you are aware of that would suggest that possibility?

A. Well, yes. Just the fact that steam generators have sometimes been been replaced well before ten years of age for a plant. If a plant actually were to last 30 or 40 years one might expect the steam generators to have to be replaced again before the lifetime ended.

Q. With regard to the letter submitted from William man I don't know, I believe it was pointed out that that letter contradicted something of his that you had quoted in your testimony, is that correct?

A. I don't believe it contradicted it, no.

Q. Well, the letter contradicts a position you take with regard to the cost of decommissioning; that's true, is it not?

A. Yes. The letter expresses the opinion that the extra amount of radioactivity present in the reactor as a function of how long it runs or when it is retired would not impact the cost.

Q. What is your basis for believing that a reactor shut-down now and then decommissioned 20 years later will be much cheaper to decommission than one that runs for 20 years and then is decommissioned right at the end of its 20 years?

A. Well, the basis for that, even according to the figures in the letter, is that there will be something of the order of a 16 fold reduction of radioactivity in the reactor from the two components, cobalt 60 and the other that we discussed earlier, after an initial 20 years of operation.

Now, that's relative to a twenty-year earlier shut down.

As far as I can see, the letter cites

no basis or studies or reports for its conclusion that there would be no impact on cost.

My experience with cost estimates from the nuclear industry is that they tend to consistently be well below actual cost experience and they tend to underestimate the realism of complex procedures.

So if the degree of radioactivity is going to be considerably higher if you dismantle the plant soon after retirement rather than 20 years after retirement, it seems to me that the 25 percent cost reduction that we assumed in the mid range scenario would be quite reasonable.

MR. PRATT: I object to the last part of that answer about what he expects generally from the nuclear industry, and move that that part of the answer be stricken. It is irrelevant, speculative and inappropriate.

I move to strike it.

JUDGE GLEASON: We will leave it and accord it the weight which is appropriate.

MR. SANOFF: Your Honor, I would like to move again the admission of that letter. There is a concept of the law called opening the door, and if I ever saw a door opened, it has been opened now by my opponent.

I think the letter now has been clearly made admissible by Mr. Blum's redirect.

MR.BLUM: That's absolutely incorrect as an application of the idea of opening the door. If Mr. Sanoff is going to cross-examine a witness on unreliable hearsay evidence, it is certainly possible to do redirect on an area of confusion without then allowing the evidence in without cross-examination itself.

JUDGE GLEASON: The motion is denied. Continue your redirect.

Q. Dr. Rosen, in your low impact and mid range impact cases you have a scenario by which the Ravenswood plant is not converted to coal except in the event of shut-down of the Indian Point plants, and in the mid range case it is converted in 1991 and in the low impact case in 1987, is that correct?

A. Yes. More precisely in the mid range case 1990 and 1991, yes.

Q. Thank you. What justification do you have for assuming that the Ravenswood plants will not be converted to coal generation in any event, regardless of shut-down of Indian Point?

A. Well, the reason we assumed that in the mid range case and the low impact case Ravenswood 1 and 2 were not converted to coal, is that it is not in the New York Power Pool plan currently and that my understanding is that Con Ed presently oppose is the conversion of those two units to coal.

But we did cause them to be converted to coal in the case where the Indian Point units were retired early precisely because we felt that people, poly-makers, would realize it was in the interest to mitigate the impact of that early retirement on the rate pairs by having the coal conversion go forward.

That is certainly a decision I believe that is within the realm of jurisdiction of the Energy Master Planning Board.

Q. When projecting a scenario to calculate net cost to society, there is nothing unreasonable, is there, about assuming that certain logical compensating measures will be taken by the society, is there?

A. No. That's the basis for our definition of these scenarios. As I say, I think we describe it clearly in the report that the scenario is not something that is just a matter of what might be left up to the utilities themselves to decide to do under different conditions, but is something that is a composite of what the utilities might themselves choose to do as well as state policy makers.

Q. There is nothing intrinsically more correct about an approach which assumes that society behaves exactly the same regardless of shut-down, is there?

MR. SANOFF: I object. These are leading questions. They are objectionable as to form, your Honor.

JUDGE GLEASON: Rephrase the question.

MR. SANOFF: You are asking a question that can take a yes or no answer. That's not the way to redirect.

Q. What is the basis for your previous answer that it is reasonable to use an approach which takes into account compensating measures by the society?

A. Well, it was our view that society's actions would not be the same in the case where the Indian Point units were shut down versus when they were not shut down. We thought that some mitigating actions should be taken.

Q. Do you recall Mr. McGurren's suggestion that there was something a little bit uneven in doing an approach that way?

A. Yes.

Q. Do you agree with that suggestion?

A. No. As I said in my response earlier, it is unrealistic to expect the same exact composition of the power supply plants for the downstate region of New York if the Indian Point plants are shut down. We feel that the degree to which we have introduced mitigating effects is quite reasonable.

Q. In Power Authority exhibits 50 and 51 there was an effort to compare some earlier projections you had made about peak demand for electricity with your current peak projections.

Is peak demand a statistic that we are going to be very interested in?

A. Well, for the purposes of doing an economic analysis of the shut-down of Indian Point, the more important factor is not the peak forecast but the energy forecast, because we are basically concerned with the energy that is required to economicly replace the energy produced by Indian

Point.

The peak is taken up with more expensive peaking units, and there is plenty of reserve capacity for that purpose.

Q. Are there anyplaces where you project total energy requirement that can be compared with exhibits from the Power Authority or from Con Edison?

A. Yes. In the appendix F to my testimony, and I believe this figure was cited earlier, we show for 1983 a net generation required of about 37.4 billion kilowatt hours.

If you compare that to the exhibit that was handed out earlier -- I am afraid I don't have the number marked on it, but it was table 16 from this year's New York Power Pool report -- it shows that for 1982 the total energy required in the last column on the right, was 37.2 billion kilowatt hours.

So you are comparing 37.2 actual in 1982 with our projection made two years ago for 1983, which is 37.4.

So that allows for a slight growth, and I would say it is an excellent forecast for energy.

Q. At one point do you recall Mr. Pratt saying or asking you whether you relied upon the forecast which you earlier had set was not a blueprint for energy in the state?

A. Yes. The forecast he was referring to was when we had introduced 50 percent of our conservation scenario in the mid range case to get a somewhat lower than base case demand in both the Indian Point retired and nonretired scenarios.

Q. What justification do you have for using that, if you don't believe it is a blueprint?

A. Well, what we meant by blueprint was really something quite minor. We had not mapped out a sort of year-by-year schedule or plan for the state to implement that scenario.

However, we did introduce on a year-by-year basis the details of our conservation scenario. So we didn't want people to take it as sort of the final word or a complete plan, but it is clearly a realistic conservation scenario in our view, and the fact that we only used one half of its implementation in the mid range case to me signifies that it is quite a reasonable basis for calculating a demand growth, if it were deemed appropriate, to move in the conservation direction.

Q. Do you recall Mr. Pratt questioning you about some figures where you had made a projection of negative 0.7 for the years 1983 through 1997, and Mr. Pratt provided evidence that for the years 1980 through 1996 figures projections were positive 0.8 and positive 0.6.

Do you recall that interchange?

A. Yes.

Q. And do you recall your stating that this was unimportant?

A. Yes, sir. In my judgment this was an extremely minor--it would involve an extremely minor correction in our forecast, if any.

Q. Could you give us some quantitative sense of what you mean by "extremely minor"?

A. Well, I think it would affect the forecast by much less than a tenth of a percent per year.

Q. Do you wish to briefly explain why that is so, or would it take too long?

A. No. It is a long story because it only affects a couple of the submodules within our demand forecasting model. That is my estimate of the effect.

Q. Do you recall being questioned by Mr.

Sanoff that you had projected a decline in total franchise area sales for Con Edison service territory, when in fact between 1977 and 1982 there had been a slight rise; do you recall that question?

MR. SANOFF: I object to that question. It was not a slight rise. It was a 4.1 percent rise.

JUDGE GLEASON: Rephrase the question.

Q. For the six-year period listed here, it was a 4.1 percent rise.

MR. SANOFF: It was a five-year period for a 4.1 percent rise. It is a five-year period of rise.

MR.BLUM: Thank you.

Q. Do you recall that?

A. Yes, I do.

Q. Is there anything you wish to say by way of further clarification of that issue?

A. Yes. Well, if you turn to the exhibit, which I believe has been marked Exhibit 49, the base case forecast, one will see that our base case forecast for Con Ed in fact has demand going up over time in the future.

The reason the demand in the mid

range case went down is, as I said, that in the mid range case consistently we used 50 percent of the conservation scenario, which is what accounts for the fact that in the late 1980s demand is declining slightly. It was less than 1 percent a year. That's the impact of 50 percent of the conversation scenario.

Q. In your mid range case did you apply that reduction equally to the Indian Point retired and Indian Point continuing cases?

A. Yes, we did.

Q. How do you characterize the various assumptions that are made in your study overall?

A. Well, the idea of the assumptions that went into each scenario, and I think this is the important point, is that while any party to this case, or any other person might disagree with any particular assumption in any particular case, such as the mid range case which seems to have been getting the most attention, we felt that it was a reasonable set or mix of assumptions, in terms of the impact that those assumptions would have on the cost impact of early retirement.

Clearly other assumptions could have been made. We could have testified on 36 different scenarios. We limited it to three because we thought that would be sufficient to illustrate the range of cost impacts.

Of course, the world is always changing. As I indicated in my cover study, since we did the study oil prices have dropped. Other things may change as well that would impact on our bottom line.

I would say, all in all from everything I know at the moment, the mid range impact case I believe is a fair representation of the likely economic impact of an early retirement.

MR.BLUM: I have no further questions.

JUDGE GLEASON: The witness is excused. Thank you.

MR. KAPLAN: Members of the New York City council call Dr. Commoner and MR. Schrader.

WHEREUPON,

BARRY COMMONER and RICHARD SCHRADER, were duly sworn by the administrative trial judge and testified as follows:

DIRECT EXAMINATION

BY MR. KAPLAN:

Q. Gentlemen, will you please state your full name;s and addresses.

A. (Witness Commoner) My name is Barry Commoner. My address is 352 Remson Street, Brooklyn, New York.

A. (Witness Schrader) My name is Richard Schrader. My address is 636 Tenth Street, Brooklyn, New York.

Q. Do you have before you a copy of the document entitled "Testimony submitted on behalf of New York City Council intervenors by Mr. Barry Commoner and Mr. Richard Schrader"?

A. (Witness Schrader) Yes.

Q. Was that document prepared by you or under your supervision?

A. (Witness Schrader) Yes, it was.

Q. Are the contents of that document, to the best of your knowledge, true to the best of your information and belief?

A. (Witness Commoner) Yes.

Q. Are there any corrections you wish to make to that statement?

A. (Witness Commoner) Yes, we have several corrections.

Q. Please state them.

A. (Witness Schrader) On the coversheet, the title "Testimony submitted," instead of "of" that should be stricken and replaced with "on."

Page 2, the first paragraph, six lines down, the sentence should end after "bulbs." The rest of that sentence should be struck.

MR. PRATT: Can you do that once again?

THE WITNESS: (Witness Schrader) On page 2, the first paragraph, six lines down, the sentence is completed after "bulbs." The rest is struck.

On page 3, underneath the third paragraph next to number one, the number "3.154," the "4" should be struck.

Page 6 --

MR. PRATT: I am sorry --

JUDGE GLEASON: You said 3.154 should be what?

THE WITNESS: (Witness Schrader) The "4" should be struck. The last digit.

On page 6, the second line, 2.0 should be struck, the number 2.0. Inserted should be 1.95.

Again on page 6, two lines down, after the word "eliminate," there should be an insertion "97 percent of." And after Indian

Point 2 the word "power" should be inserted into that sentence.

In that same paragraph, after the phrase "as a third alternative," the rest of that sentence should be struck, as well as the sentence after that, so that a new sentence is formed, "As a third alternative, Canadian authorities," which is the fifth line after "as a third alternative."

Is that clear?

MR. SANOFF: No. Could you read that again, Mr. Schrader? It now reads what?

THE WITNESS: (Witness Schrader) The rest is struck and "Canadian authorities" begins the rest of that sentence.

MR. SANOFF: Thank you.

THE WITNESS: (Witness Schrader) On page 8, the third paragraph, the second line, the word "to" should be inserted before the word "years." It is t[illegible] second line in the third paragraph.

MR. PRATT: I am sorry, I am not following you.

MR. SANOFF: Is this page 7?

THE WITNESS: (Witness Schrader) Page 8.

JUDGE PARIS: Second full paragraph on the page?

THE WITNESS: (Witness Schrader) Third full paragraph, it begins with "the time frame." The second line of the third paragraph, at the end of that sentence, the word "to" should be inserted after "next" and before "years."

Q. Why don't you read the way it is goes going to be read now.

A. "The time frame for the appliance replacement plan should be streamlined to five years and begun within the next two years."

On page 9, the first paragraph, the word "increase" should be struck; the word "increases" inserted.

MR. PRATT: This is line 2?

THE WITNESS: (Witness Schrader) Line 2 in the first paragraph, page 9.

MR. PRATT: Line 2 on the page?

THE WITNESS: (Witness Schrader) Line 2 on the page.

MR. PRATT: You are striking the word "increase"?

THE WITNESS: (Witness Schrader) And changing it to "increases." The phrase after that, "Over the 1985 to 1989 time period."

MR. SANOFF: Now I have lost it.

You are striking the five-year savings?

THE WITNESS: (Witness Schrader) No. I will read the sentence. The first sentence on that page will read this way, "For a typical unit using 300 kilowatt hours or less energy a year, with Con Edison's projected rate increases over the 1985835 to 1989 time period a five year savings would be begun in 1985."

On page 10, three lines from the bottom of the page, the number "380 million" should be struck; the number "996 million" replacing it.

In reference is, footnote 10 has been struck.

That's it.

Q. Now, with the corrections that you have just articulated is the document that we are discussing true and accurate to the best of your knowledge, information and belief?

A. (Witness Commoner) Yes.

MR. KAPLAN: We moved the admission of that document and bound into the record as if read.

JUDGE GLEASON: Is there objection?

MR. SANOFF: Yes, sir. This one I notified both the attorney and your assistant, sir.

I move to strike, on page 4, the testimony beginning on the seventh line down, the word "according," through the bottom of the page, and the footnote would become academic.

The reason is obviously hearsay. It is all related to a telephone conversation with a representative of the Carrier Corporation. That's just beyond our ability to cross-examine, verify or confirm.

JUDGE GLEASON: Excuse me, Mr. Sanoff, what are you striking?

MR. SANOFF: The entire paragraph -- the entire page beginning on the seventh line down with the word "according" --

JUDGE GLEASON: The whole page thereon?

MR. SANOFF: Yes. It is predicated on a telephone conversation with a representative of the Carrier Corporation, as is indicated in footnote 5, it says, "Carrier Corporation Company representative telephone interview, 4-11-83."

JUDGE GLEASON: All right.

MR. SANOFF: I also move to strike, on

page 6 as now amended, the sentence beginning, "As a third alternative Canadian authorities have indicated that additional power is available and the purchase by Con Edison can be authorized by the New York State Power Pool and state regulators," and the source for that is footnote 11 of Mr. Peter Holmes 'Peddling Canadian Power,' September 1982," again that is the rankest sort of hearsay that is beyond our power to verify and cross-examine. Even in an administrative hearing this sort of hearsay should not be permitted.

There is a footnote, sir, I am sorry, on page 6 that is similarly hearsay. It refers to a telephone interview with a Mr. Cliff Aarons of Business Energy Investments that I think should be stricken.

JUDGE SHON: Don't you also want to strike the 50 percent figure on the first line of that page?

MR. SANOFF: Pardon, sir?

JUDGE SHON: The information that was contained in this telephone call was in the first line.

MR. SANOFF: I am sorry, thank you very much, Judge.

JUDGE GLEASON: Let's get back to what you are trying to strike, please on that page.

MR. SANOFF: I want to strike on page 4 the matter beginning on the seventh line with the word "according" and running down to the end of the page.

I want to strike on page 6 the correction noted by judge shown. The sentence that begins, "if these savings were 50 percent, a figure which could be reasonably achieved," and continuing to the end of that sentence, because it is based on a footnote which is the rankest sort of hearsay, namely, a telephone conversation with a gentleman from an organization called Business Energy Investments.

I also want to strike --

JUDGE GLEASON: Just hold it, please. So you strike down to the word "power"?

MR. SANOFF: I didn't hear you, sir.

JUDGE GLEASON: I said so that would strike down to the words "Indian Point 2 power"?

MR. SANOFF: Yes, sir.

Now, the last point I want to strike, sir, is the sentence that begins, "as a third alternative, Canadian authorities have indicated that additional power is available," and the rest of the sentence, and I weren't to strike with it that footnote 11.

I might indicate that in making the motion to strike footnote 5 and the material on page 4, that the footnote 5 purports to be based on a telephone conversation of 4-11-83 supporting testimony dated April 8, 1983.

My associate here, Mr. Farrelly, reminds me that my motion should be amended to include page 9, two items on page 9, beginning from page 8 over to 9, the sentence beginning, "The energy efficient model is currently priced at 637 and continues, which now sells for 545," that being based on footnote 14, which is another telephone interview with an ELS Refrigeration Company, dated 4-9-83, again a date which is after the date of the testimony.

And then the last full paragraph on page 9, which reads, "A residential room air conditioner," and is based on the statement, "According to local retailers," unnamed -- well, they are named, J and L Air Conditioning Refrigeration Company telephone interview."

JUDGE PARIS: You are moving to strike

that whole paragraph?

MR. SANOFF: Yes, sir. I don't have to move to strike the figures there because they fall on their head if you take out the stuff that comes before it.

JUDGE PARIS: But continuing over into page 10?

MR. SANOFF: Yes, your Honor, because footnote 16 refers back to footnote 15, which is similarly a hearsay telephone interview.

JUDGE GLEASON: I would suggest, Mr. Kaplan, that we take these up one at a time.

MR. KAPLAN: If I might, I will do it if you prefer, but I think there is one response to the totality of the objections, because all of them rest on the same kind of hearsay argument. So I think if the court buys the argument then there may be words that we will leave in and out. If you buy the argument that Mr. Sanoff is right. But I think the argument is specious.

Do you want to do it that way?

JUDGE GLEASON: Any way you want. A

MR. KAPLAN: First thing I would like to say is Mr. Sanoff is correct on the dates. The reason for that is the cover sheets were provided to Mr. Commoner, in defference to getting the stuff out as quickly as possible, the date of April 8 indicates my best hope that we would have gotten the testimony to him at that time. Obviously we failed that and it was prepared.

That explains the telephone contacts on the 10th and the 11th and the date of the 8th on there the testimony.

I have move the date of the testimony be corrected. The date could be the 12th and it would fit within the confines expressed by the board.

JUDGE GLEASON: We will take your explanation for it under advisement.

MR. KAPLAN: To the specifics, each of Mr. Sanoff's objections rest on the assertion of hearsay. Yesterday, just taking yesterday's testimony, repeatedly the board allowed Mr. Meehan and Ms. Streiter to testify that we got this stuff from the engineers. The board precluded cross-examination in response to the questions "we didn't do the work, we were given the material."

Mr. Stewart testified yesterday and he referred to information he received from the Con Ed General Planning Department. I asked him how the figures were derived, where he got them from. Each time he said he didn't know.

I have moved to strike that testimony on the basis that it was predicated on hearsay information that was not cross examinable in this hearing because of the structure of testimony. He didn't cite anybody by name. He just asserted it.

We have had that consistent leave. There were references to contacts with people who worked for the Power Authority.

Judge Paris elicited information based on these conversations with the MTA yesterday. We didn't make motions to strike. We wanted the board to have the most complete record as possible.

The hearsay objection in this proceeding can appropriately be used, as the Federal Rules recognize, should be applied to the weight of the evidence, not its admissibility.

The court and this board can choose to credit that information or credit some information more than others, based on the information that a witness before it can provide as to its derivation, as to its computional base.

To argue at this point, based on

weeks and weeks of hearing that we have had, different standards have applied, even over objection, it seems to me begins to look -- I won't characterize it.

I would point out I asked for a document that was provided to us so kindly by Mr. Pratt that was footnoted in Mrs. Streiter's testimony. Well, nobody moved to strike her conclusions drawn on the Power Authority document because the people who put the document together were not present.

We couldn't discuss or delve into how the report on Indian Point 3 was analyzed, and we chose not to. The board has that obligation.

Therefore, I would ask the board ab initio to deny the motion to strike. If the board wishes I would like, rather than go through them specifically, there are a few specific things where I think the motion is over-brought.

JUDGE GLEASON: Are you asking us to deny the motion before you argue specifically the motion?

MR. KAPLAN: I just argued in general terms. If you want me to go through each thing specifically, I will do that. What I am suggesting to the board is the motion, in its motivation, scope and intent deviates from the standards set by this board. To apply that to one party and not to the another, especially when yesterday I made the point that Mr. Stewart's questions and answers, all of which were predicated on information not cross examinable that it was hearsay, the board denied it and said it would weigh it in its fact-finding.

I am asking the same standard, and only that standard, that applied to the licensee's witnesses, be applied to the witnesses of the New York City Council.

That's why I don't want to go into the specifics because it may not be necessary.

JUDGE GLEASON: It is that kind of thing that bothers me, Mr. Kaplan. As long as you don't ask us to go into motivation on the part of the parties making motions --

MR. KAPLAN: I didn't ask you to go into their motivations. I just ask that it be rejected.

I would add one more thing, that had the testimony been written without, just asserted blindly without any reference, this motion would not have even come forward.

It seems to me that there is sort of a boot strapping going on here. Had the source not been cited but merely asserted there wouldn't have been an objection.

If the court wishes we can strike the sources, strike the reference to the telephone conversation, strike the footnote and Mr. Commoner will tell you why we did it.

JUDGE GLEASON: Does that finish your comments, Mr. Kaplan?

MR. KAPLAN: Yes.

(There was a pause in the proceeding.)

JUDGE GLEASON: The motion is denied. There is enough credibility to the testimony that is submitted here that it gets by the kind of concerns someone would generally have in hearing hearsay testimony.

Proceed with your examination.

MR. KAPLAN: The witnesses are available for cross-examination.

CROSS-EXAMINATION

BY MR. PRATT:

Q. Good afternoon, gentlemen.

I would like to start, Mr. Commoner,

by asking you as a general matter. In your prior writings you have warned against the --

JUDGE GLEASON: Excuse me, Mr. Pratt, Judge Paris reminds that the testimony is not in evidence yet.

The testimony of the witnesses will be received into evidence and bound into the record as if read.

(The bound testimony follows)

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD
Before Administrative Judges
James P. Gleason, Chair
Frederick J. Shon
Dr. Oscar H. Paris

In the Matter of:	
CONSOLIDATED EDISON COMPANY OF NEW YORK INC. (Indian Point, Unit No. 2),	Docket Nos. 50-247 SP
POWER AUTHORITY OF THE STATE OF NEW YORK (Indian Point, Unit No. 3)	50-286 SP
	April 8, 1983

Testimony Submitted of Behalf of
"New York City Council" Intervenors

By

Dr. Barry Commoner and Mr. Richard Schrader

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CRAIG KAPLAN
SPECIAL COUNSEL

1.0 INTRODUCTION

These Hearings are concerned with a petition to close Indian Point nuclear power units II and III. One of the issues raised by this petition is whether the demand for electricity-powered services normally met by these units can be met in some other ways if they are shut down. This testimony is concerned with this issue. In what follows, we propose specific steps which can be taken to eliminate the need for the power produced by Indian Point units II and III.

It is our proposal that instead of operating Indian Point II and III, Con Edison and PASNY institute a program of energy conservation, based on accelerated replacement of present appliances with energy-efficient ones and on the introduction of decentralized power production by small-scale cogenerators. We propose to show that these measures can eliminate the need for the power that Indian Point II and III are expected to supply and that they are economically advantageous as well. We contend that Con Ed and PASNY can make better use of their financial capabilities by supporting such a program of energy conservation than by operating Indian Point II and III.

2.0 ELIMINATION OF THE NEED FOR POWER FROM INDIAN POINT II

2.1 The Problem

Indian Point II represents a nominal capacity of 873 MW. Over its life it has operated at an average capacity factor of 50 percent[1]; this performance level may be expected to continue.

Table 1

	Average Power Consumption (kwh/year)	Saturation	Average Power Consumption Per Household (kwh/year)
Refrigerator	900	102%	918
Air conditioner (room)	419	98%	408
Lighting	609	100%	609
		TOTAL	1935

Long Range Plan, Vol. 1 (1981)
New York Power Pool

2.4 Residential Air Conditioners

As indicated in Table 1, in 1985 room air conditioner units are expected to use, on average, 419 kwh/year. Given the 98% saturation level for room air conditioners, the 3,067,000 households within the Company's service area operate a total of 3.01 million residential room air conditioners. However, higher electric rates and New York State's promulgation of efficiency standards have broadened the market for high-efficiency units. According to Carrier Corporation,[5] the average EER* for the current stock of residential air conditioners in New York State is 7.75. However, according to a City Energy Office report,[6] models with an EER of 10 are available. Accordingly, if 75% of the residential room air conditioners currently attaining an EER of 7.75 were replaced by units with an EER of 10, the resulting power savings can be computed as follows:

(1) $.75 \times 3.01 \times 10^6$ units = 2.26×10^6 units (number of potential high efficiency units)

(2) 419 kwh x .225 = 94.3 kwh (saving/unit)

(3) $2.26 \times 10^6 \times 94.3 = 213 \times 10^6$ kwh (total saved)

The replacement of 2.26 million air conditioners with units of efficiency measured at 10 EER will result in a savings of 213.2 million kwh. Room air conditioners will contribute 1330 MW to summer peak demand in 1985, or 58.8 percent of a residential peak of 2260 MW. A 22.5% decrease in peak would create a reduction of 300 MW of peak demand.

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*EER is defined as the ratio of the number of BTU's of heat removed per hour by the air conditioner to the number of watts used per hour.

Table 2

Appliance	% Replaced	Total KWH Saved
Refrigerator	75	700×10^6 kwh
Residential A/C	75	213.2×10^6 kwh
Residential Lighting	75	841×10^6 kwh

2.7 Meeting the Costs of Power-saving Measures

The Home Insulation Energy Conservation Act (HIECA) has sought to create a financing mechanism in which homeowners of up to four-family buildings can obtain low-interest loans from utilities to invest in a variety of conservation measures. Rather than providing a direct loan to property owners, investor-owned utilities guarantee a portion or all of a loan made by a local financial institution. Utilities first perform energy audits on buildings whose owners request them. If a homeowner wishes to make conservation investments, the utility will subcontract the work out and provide a loan up to $4500 for a four-family house at roughly 11.5 to 12% interest. The utility therefore subsidizes a portion of the loan to homeowners, leveraging its credit to back up the bank loan by providing an interest rate tied to its rate of return. Currently, multi-family buildings and commercial units are unable to borrow through HIECA. An amendment to the original legislation was introduced in the last session of the state legislature to expand the purview of the program to both these large groups of building owners.

HIECA can provide the financing vehicle for a five-year program of accelerated appliance replacement. Two further additions to the existing law would facilitate financing the replacement strategy:

1) The Power Authority should be included on some level of financing. Legislation has been introduced in the state

which now sells for $545.[14] For a typical unit using 300 kwh less energy a year, with Con Edison's projected rate increase, a five-year savings would be, if begun in 1985,

	Con Ed Rates ¢/kwh	Consumer $ Savings
1985	18.19	54.60
1986	19.67	59.01
1987	21.15	63.45
1988	22.63	67.89
1989	24.11	72.33

for a five-year $320 total savings. If we assume that each unit carries an embedded value equalling two-thirds of its original cost, and if the purchase price of the unit is discounted by 10% to account for inflation, then the salvage value of that unit would be $335 ($500 x .67). The total cost of the change is then $435, which represents a payback of seven years, taking into account the expected increase in Con Ed rates after 1990.

A residential room air conditioner unit, with a mean lifetime of 12 years, would experience half its life cycle during the five-year replacement schedule. According to local retailers, the difference in cost between a unit with an EER of 7.5 to 7.75 and an EER of 10 is approximately $100.[15] A five-year schedule of savings at 22.5% less usage would achieve annually

	Con Ed Rates ¢/kwh	Consumer $ Savings
1985	18.19	17.15
1986	19.67	18.54
1987	21.15	20.00
1988	22.63	21.34
1989	24.11	22.73

for a $100 savings in five years. The unit will have an embedded cost of half its total life cycle on a purchase price of $350.[16]

RICHARD SCHRADER
636 10th Street
Brooklyn, New York 11215
(212) 965-3862 (h)

EDUCATION

Boston University Graduate School of Public Communications
M.S. in Journalism; Minor in Economics - 1976

Fordham University
B.A. (Magna Cum Laude) - 1973

EMPLOYMENT

May 1982 - Present
Research Associate, Center for the Biology of Natural Systems, Queens College

* Authored report on financing options for building owners who will invest in energy conservation measures.

* Co-authored report on building tracts and thermal characteristics of New York City's housing stock.

* Participated in project to design a cogeneration system for the Bronx Zoo, responsible primarily for environmental impacts and legal implications of the technology.

* Director of the CBNS education program, which involved monthly workshops with community organizations throughout New York City; the workshops used a computer program to provide detailed savings schedule for a variety of conservation measures as well as a seminar on financing strategies.

September 1979 - April 1982
Energy Director, New York Statewide Senior Action Council

* Intervened in Consolidated Edison rate cases before the Public Service Commission (PSC); prepared testimony and briefs on capital structure, fuel procurement and excess generating capacity.

* Presented evidence before Environmertal Protection Agency (EPA) during Con Ed coal conversion proceedings in coordination with Queens Community Planning Boards 1, 2, and 3.

* Participated formally in the New York State Master Energy Plan on the feasibility of hydropower and resource recovery as available fuel options.

* Organized outreach project to 125 senior cetners in 8 counties, describing federal and state energy assistance programs and cold weather utility regulations.

MR.BLUM: Excuse me, your Honor, it is fine with me if the licensees go first with their cross-examination, but I did want to make sure the board was aware that with these witnesses I would be doing some cross-examination on behalf of the New York City Council.

JUDGE GLEASON: I am going to insist it is adversarial.

MR.BLUM: I can explain the economic basis of the adversarialism.

MR. PRATT: We don't care if he goes first. We grant his request.

MR. SANOFF: That will get rid of any question whether it is cross or redirect.

JUDGE GLEASON: Do you want to go first?

MR.BLUM: No, I would prefer the licensees.

MR. SANOFF: I would rather he go first.

JUDGE GLEASON: Proceed, Mr. Pratt.

Q. Mr. Commoner, in your prior writings you have argued, warned against the inefficient waste of resources as a general matter, isn't that correct?

A. (Witness Commoner) Yes. Particularly with respect to nuclear power.

Q. Well, with particular respect to central station generating units?

A. (Witness Commoner) Yes, I find them very wasteful of capital, generally.

Q. So independent of the merits or demerits of nuclear power, you are concerned about wasting of society's capital assets?

A. (Witness Commoner) Oh, yes, absolutely.

Q. Could you sum this theme up simply by saying you are opposed to the destruction of capital as a general policy?

A. (Witness Commoner) No. What I am opposed to is the wasteful use of capital by central power stations. This comes about because of the fact that demand rise is gradually, while the building of a central power station imposes a sudden increase in capacity, which is inevitably beyond the demand.

MR. PRATT: I am going to move to strike all of that answer. In this case we are not trying to build any new power plants. We have some already built and you are talking about a different case.

My question to you is are you opposed to the waste of resources?

MR. KAPLAN: I owe pose the motion to strike. Mr. Pratt asked the question, if he didn't like the answer he can ask another question. He can't move to strike an answer he doesn't like.

MR. PRATT: I can move to strike unresponsive answers.

A. I thought it was being responsive to your question about capital.

JUDGE GLEASON: I am going to deny the motion on this answer, but I would caution you to try to restrain from answering anything other than what the question asks.

If you feel you would like to expand on your answer, ask the permission of the attorney if he will permit you to do so.

Thank you.

Q. Now, gentlemen, I note from page 2 of your direct testimony that you have used information from the 1981 5112 statement, is that correct?

A. (Witness Commoner) Which reference are you referring to?

Yes, right.

Q. Do you agree, middle of the page?

(Witness Commoner) Yes.

Q. Are you aware that there have been since then two additional 5112 statements filed by the New York Power Pool members?

A. (Witness Schrader) Yes, we are. WeReceived the 1983.

Q. Now, a good bit of your testimony in this case refers to the possibility of substituting conservation for the output of power of the Indian Point plants, is that correct?

A. (Witness Commoner) Yes.

Q. Did you make in your consideration, your analysis, did you make any adjustment for or did you take account of the conservation reductions that are already forecast by the utilities in this area?

A. (Witness Schrader) We did not.

Q. No?

A. (Witness Schrader) We did not.

Q. So to the extent that there was some conservation implicit or included in, for example, the Consolidated Edison forecast, that component of the forecast might very well duplicate the conservation savings that you propose here?

A. (Witness Schrader) Yes. We have the percentages.

Q. We will get to that in just a moment.

Now, let's focus on each of the components of your conservation portion of your testimony. I will start first with refrigerators since that's the item taken up by you first.

You assume, do you not, that 75 percent of the residential appliances generally will be replaced with more efficient ones over a five-year period?

A. (Witness Commoner) Our calculation is based on that assumption, not on the assumption that that will happen.

Q. Have you made any consideration of the impact on production, the manufacture of these appliances outside of New York City or wherever they are manufactured; have you taken that into consideration at all?

A. (Witness Commoner) Not in a specific way. It would generally improve the economy of the relevant manufacturers.

Q. What basis do you have for saying that?

A. (Witness Commoner) It would increase their sales of the appliances.

Q. You are making some assumptions in saying that, aren't you, such as they have the existing plant that they could use?

A. (Witness Commoner) Generally speaking, industrial capacity is now, oh, I think, averaging 70 percent of capacity, and I assume that most manufacturers would be happy to receive new orders.

Q. Well, we are not talking about generally speaking or most manufacturers. We are talking about refrigerators.

A. (Witness Commoner) I have no specific information on refrigerator manufacturers. We can find that out for you.

Q. Let me ask you specifically about your proposed refrigerator, that's the Amana 14 cubic foot refrigerator. Do they have 30 percent spare capacity?

A. (Witness Commoner) I don't know.

Q. Speaking of that refrigerator, in fact do you have any idea how many have been sold in this country since 1981?

A. (Witness Commoner) No.

Q. Your proposal for changing on an

expedited crash basis the refrigerators in the Consolidated Edison service territory focuses on a typical lifetime of appliance, is that accurate?

A. (Witness Commoner) Yes.

Q. Is there a difference in your mind between the actual appliance lifetime, on the one hand, and the likely replacement life on another? In other words, to put it another way, how long the machine actually lasts and how long it lasts in the hands of the first owner before it is replaced?

A. (Witness Commoner) Obviously, the replacement time will always be shorter than the life time.

Q. Which of these two values was used by you in making your calculations?

A. (Witness Schrader) On page 147 of the 1981 5112, we used the numbers under table 26 under the column "mean lifetime." That's page 147.

For air conditioners, refrigerator, those two items.

Q. So this was the total lifetime of the refrigerator or the replacement time?

A. (Witness Schrader) Mean lifetime.

Q. Now, are you familiar with the appliance efficiency standards that were set in 1980?

A. (Witness Commoner) Yes.

Q. Were you aware that those are adopted, have been adopted by Consolidatedd Edison in their forecasting procedure and if fact were done so in 1980?

A. (Witness Schrader) Yes, we are.

Q. And what is the efficiency target for the refrigerators?

A. (Witness Commoner) The target is as indicated in table 26, 23 and 33 for air conditioners and refrigerators.

Q. That means an improvement of 33 percent from what?

A. (Witness Commoner) Well, whatever the base line of this table is. 1980. These are targets for 1980. It is calculated against 1975.

Q. Since you are relying on the 1981 5112 statement, using that as one of of the bases of your testimony, you are aware of the standards, will you accept subject to check -- in fact you can look here in the book if you like -- that the Consolidatedd Edison forecasts adopt this 33 percent 1980 FDA target? Will you accept that?

A. (Witness Commoner) Yes, sure.

Q. Now, in your testimony -- I am looking at page 3 -- you rely on a typical refrigerator, you focus on a typical refrigerator that Consolidatedd Edison service territory of 900 KW H per unit; do you see that on page 3?

A. Yes.

Q. What sides refrigerator do you have in mind in that context, what size in terms of cubic feet?

A. (Witness Schrader) We are simply using the use per unit of kilowatt hour. They are in the same year table 8, 5112, page 29, under "refrigerator" for "system average." The column that says "use per unit, KWH."

Q. So this is a mean number? There are some refrigerators bigger and some that are smaller?

A. (Witness Commoner) Certainly.

Q. What is your idea of a reasonable range in cubic feet of the refrigerators covered by this 900 KWH?

A. (Witness Schrader) 14 to 16 cubic feet.

Q. Now, in considering whether homeowners and owners of refrigerators are likely to change to a new refrigerator according to your proposal, have you given any consideration to such things as brand name loyalty or to any consumer preferences generally?

A. (Witness Commoner) No. We generally assumed that the economic considerations would dominate the choice; that is, the savings.

Q. I didn't hear of the last part of your sentence. It is that savings would dominate the choice?

A. (Witness Commoner) Yes, rather than brand loyalty.

Q. Do refrigerators have particular unique features -- are you familiar with unique features, such features an as cold water taps, ice makers, things of that sort?

A. (Witness Commoner) I have seen them, Yes.

Q. Would you give those unique features and customer preferences for them any consideration?

A. (Witness Commoner) I think they enter into a decision to purchase, yes.

Q. What consideration were they given if your analysis?

A. (Witness Commoner) None. I know of no hard numbers that would enable us to determine the degree to which these special features would condition a customer's choice of an energy-saving refrigerator.

JUDGE SHON: Just in that regard, Dr. Commoner, do you know whether this Amana standard 14 cubic foot energy saver is a self-defrosting refrigerator or not?

THE WITNESS: (Witness Schrader) I believe it is.

JUDGE SHON: I just wondered.

THE WITNESS: (Witness Commoner) I think they took some special pains to take care of that point.

JUDGE SHON: I am sorry, Mr. Pratt. Please go ahead.

THE WITNESS: (Witness Schrader) If I might respond --

MR. PRATT: I don't think there is a question pending. I will ask the questions and you can put your answers in response.

Q. Now, the average life span of a

refrigerator in the Consolidated Edison territory is 16 years, isn't that correct?

A. (Witness Schrader) Yes, it is.

Q. Now, let me ask you if you will accept the following mathematics, and I have demonstrated this morning that my subtraction ability is not perfect, but as I understand it, since Consolidatedd Edison has since 1980 been using the FEA targets of higher efficiency, of the 33 percent improvement in efficiency of refrigerators, isn't it true that by 1985, the time of the start of your program, that at least 5/16 of the refrigerators in the Con Ed service territory are going to be replaced with ones that are 33 percent more efficient?

A. (Witness Commoner) That depends on whether the customers follow Con Ed's target.

Q. Let me ask you first about the forecast. We are not at this point really talking about actually is going to happen, we are talking about the forecast.

As far as the Con Ed forecast is concerned and their need to have adequate capacity, isn't it true that in their forecast they will have taken account of 5/16 of the conversions that might happen with more efficient refrigerators?

A. (Witness Commoner) Yes. What we are saying is that conversion can take place more rapidly than their forecast, thereby bring about the savings we are talking about.

Our results include theirs.

Q. Well, by the time your program starts, won't you agree that one-third of the potential market has already been eaten up, already converted before your program starts, isn't that correct?

A. (Witness Commoner) Yes. One-third of the reduction in demand will have been achieved.

Q. By the time your program in 1989 will be coming to an end, even independent of your proposed conversion program, won't approximately 9/16, or almost 60 percent of the total number of refrigerators, be replaced at least as far as the Con Ed forecast is concerned?

A. (Witness Commoner) Yes. Assuming that your calculations are correct, what you are saying is that there is a process underway which is gradually reducing the need for the power produced by Indian Point 2.

Our testimony is that by speeding

that up somewhat, we can eliminate the need for Indian Point 2 completely.

Q. Now, I asked you a few minutes ago if you would tell me what the standard today -- what you thought the range of size is of refrigerators in this part of the state is, and I think you said 14 to 16 cubic feet?

A. (Witness Schrader) Yes, that's approximately right.

Q. To make your proposal work, as I understand it, every one of the people who convert from their current refrigerator would have to take a 14 foot cubic refrigerator, is that correct?

A. (Witness Commoner) No, not at all. Our calculations are simply based on that mean value. If a person with a twelve-foot refrigerator made a comparable shift, it would have an effect on the reduction in demand just as well.

The number 14 was taken simply to give us a mean value that would simplify the calculations.

One could take the entire range -- get a distribution curve for the different sizes of refrigerators in place and do a more complicated calculation. I don't think it would change the end result very much.

Q. Well, did you make that more complicated calculation in this case?

A. (Witness Commoner) No.

Q. You did not cus on different sizes of refrigerators, such as the 16 foot --

A. (Witness Commoner) No.

Q. Let me give the full question. The 16 foot size, possibly the 18 foot size that some people in single family homes have gotten?

MR. KAPLAN: Objection. This has been asked and answered.

JUDGE GLEASON: Let him answer the question.

A. (Witness Commoner) We took a mean value.

Q. What basis, what analysis did you make to determine that that was the mean?

A. (Witness Schrader) We simply were using the descriptions and characteristics of this unit that we had found from the Amana Corporation, and tried to give some range of what that particular unit would look like.

Q. So you started with an ideal

refrigerator, a good refrigerator, this Amana model, and are now using that as a model, is that correct? Is that what you said?

A. (Witness Schrader) We took what would be the most energy efficient refrigerator that we thought would be marketable.

JUDGE PARIS: That's not really a mean side size refrigerator; that's the size of the reference model you used in your calculation?

THE WITNESS: (Witness Schrader) I would say that's correct.

JUDGE SHON: In other words, you actually characterized the present energy consumption by a mean or an average which you obtained, and that was an average in energy consumption and then you selected a refrigerator that might or might not have a mean size as far as storage capacity is concerned? They don't necessarily correspond one to the other?

THE WITNESS: (Witness Commoner) That's correct. Basically what we were doing was showing how that refrigerator could be used to reduce the overall consumption.

JUDGE SHON: Presuming enough people would find it suitable to their means, is that right?

THE WITNESS: (Witness Commoner) Right.

Q. I would like to follow up on that question and just find out what this Amana 14 cubic foot refrigerator is that you have been talking about. I have, and I am going to show you at this time, the 1982 Directory of Certified Refrigerators and Freezers --

MR. KAPLAN: Certified by whom?

MR. PRATT: It is published by the Association of Home Appliance Manufacturers, North Wacker Drive, Chicago.

Let me give you a copy at this time. Judge Gleason, maybe a more proper procedure would be simply to ask that it be marked for identification at this time and then I will give it to the board.

I have lost track exactly of our number. I believe it is 52.

JUDGE GLEASON: This will be marked Power Authority Exhibit 52.

(Power Authority Exhibit 52 was marked for identification)

Q. Now, gentlemen, on page 5 of Power

Authority 52 for identification, there is a certain number of model numbers which I take to be the Amana refrigerator model number; do you see that?

A. (Witness Schrader) Yes, I do.

Q. And it is a mass of numbers but apparently they sell a number of different sizes of refrigerators, some of which appear to be 14 cubic feet in size, is that correct?

A. (Witness Commoner) Yes.

Q. Now we are looking for not just a mere 14 cubic foot refrigerator but one that has a 600kilowatt hour per year consumption, isn't that correct? Because that's the one you are talking about.

A. (Witness Commoner) We can specify it in that list if you would like.

Q. Yes.

A. (Witness Commoner) Model ESR-14 E.

Q. I would ask you now if you will take subject to check that that does not have a 600 KWH consumption but rather has a 644 KWH per year consumption.

A. (Witness Commoner) Okay, fine.

Q. Can we agree that there isn't such a

thing as the Amana 600 KWH per year refrigerator?

MR. KAPLAN: Excuse me, what was the number you said it had?

MR. PRATT: 644.

A. (Witness Schrader) The number 600 was cited from two sources. The first being the New York City Energy Office study done in 1981, in which they describe the Amana model and the quote is 600 kilowatt hours as its annual usage; and the second was the phone conversation with the company. This is the model that we discussed.

But we will accept, subject to check, what you say.

Q. Now, Mr. Commoner and Mr. Schrader, it is my understanding, and I am going to see if I can master the cost factor of this in very few questions. You indicate on pages 8 and 9 --

A. (Witness Schrader) Excuse me, Mr. Pratt, I am looking for my testimony.

(There was a pause in the proceeding.)

Q. You indicate on pages 8 and 9 of your testimony that your proposed energy efficient refrigerator is currently priced at $637, is that correct?

A. (Witness Schrader) That's correct.

Q. Since everything else that you have been relying on, almost everything else that you rely on is 1981 calculations, is this in 1981 dollars or is it in 1983 dollars?

A. (Witness Schrader) 1983 dollars.

Q. First let me ask you, you indicate there would be a salvage value. If I understand that correctly, and correct me if I am wrong, what you have in mind is that a certain portion of the refrigerators that are replaced would be thrown away or be discarded before their 16-year life span was complete, is that correct?

A. (Witness Schrader) Yes, there is an imbedded value to that.

Q. You assigned a value of approximately two-thirds of the original cost of the discarded refrigerator?

A. (Witness Schrader) Yes.

Q. Are those refrigerators simply discarded forever and they go out of circulation or to some other household?

A. (Witness Schrader) That was beyond the scope of our study. We didn't factor that.

Q. Avenues far as you are concerned,

they are a cost, however? You treat them as a lost item, item of no further value?

A. (Witness Schrader) We treat the cost of the new unit as the difference between the two units, plus the salvage value of the unit discarded, which is two-thirds of the original cost.

Q. Now, I live in an apartment in New York City and this idea seems a little strange to me, but I understand that some people live in single family homes, and they may even basements. Did you give any consideration to the fact that a person with a basement might not discard their old refrigerator but might simply keep it?

A. (Witness Schrader) We relied on the saturation values that were given in 5112, and the saturation values were not high enough for us to factor that in as a component.

Q. The saturation factor is 102, isn't it?

A. Yes.

JUDGE PARIS: What is a saturation value?

THE WITNESS: (Witness Schrader) How many units in a franchise area are utilizing that particular appliance. 102 percent would mean 2 percent over the full unit would be utilizing the refrigerators, they have more than one.

Q. But that 102 percent is based on Consolidated Edison's traditional best estimates of what would happen before they heard about your program, isn't it?

A. (Witness Schrader) That's correct.

Q. Would the saturation rates be expected to go up if your program is adopted?

A. (Witness Schrader) We didn't factor that into the study.

Q. Do you have an opinion today, yes or no?

A. (Witness Schrader) I could only give a speculative response to that.

Q. Well, I would like your best informed opinion, if you have one.

A. (Witness Schrader) I would speculate that there would be some rise in the saturation level.

Q. Now, who pays for the salvage value, that part of the cost?

A. (Witness Schrader) The entire cost will be borne by whatever program would be designed to accelerate the replacement and turn over of this appliance stock.

Q. So it is part of the 1 plus billion dollar cost of your proposal?

A. (Witness Schrader) That's correct. We define a financial program.

Q. Now, you say that the cost of the refrigerator is 637 and yet you are treating as the cost, if I understand it, 435. Now, that 435 is, by my understanding, based on two components: A 335 salvage value and 100 differential?

A. (Witness Schrader) Yes, between the two units.

Q. Even in my mathematics, $200 got lost there; that is, the figure cost 637 and you say the cost of the program is only 435. Where is the $200?

A. Well, in terms of the economics, you don't take the entire cost of the system. You have a refrigerator, and in our program in looking for a replacement, an overall replacement scheme, so what we are looking for in terms of designing a kind of financing plan for this would be what the value of the existing unit is, plus the difference in cost that the consumer will unlikely be willing to bear.

The economics is not a wholesale new purchasing on the part of the financial plan, but a description of what the cost of this unit should be given the fact that it is being turned over in an accelerated form.

Q. If I understand you correctly, some portion of the cost of this program then is going to be borne by the consumer, is that correct?

A. (Witness Schrader) That would be correct, as would be any typical turn over scenario.

Q. You indicate a total financing cost, a total -- let me correct that -- a total cost to this program, and I don't have the figure at the tip of my finger but my recollection is it is slightly over a billion dollars, is that correct?

A. 1.03 billion.

Q. Was that figure based on the 637 price or some different number?

A. (Witness Schrader) That figure is based on the cost of the unit, the additional cost, the difference of the two units, plus the salvage value of the unit, for the 2.36 million replacement units.

Q. Have you given any consideration to the mechanism by which these cash flows are going to be handled?

A. (Witness Schrader) Yes. We describe that particular scenario under the HIECHA co-generation plan in the testimony.

Q. Let me take a very simple-minded approach to this. If the Power Authority, Consolidatedd Edison is asked to do this program, aren't they obligated to come up with at least for one unit, at least $637 so they can go to the manufacturer and buy it?

A. (Witness Schrader) Our plan would be, under the existing HEICHA program, to design a system of loans, preferably at zero interest, which would allow the company to include in their rate base the money that is invested on the new units, air conditioners, refrigerators, et cetera, thereby earning a rate of return.

We ascribe through HIECHA the need, then, to expand the purchase view of the existing program to include PASNY and Con Ed.

The company, whatever moneys they would be spending on the appliance retrofit, would be returning into their rate base, thereby creating a rate of return of what they are getting in that rate case.

Q. Let's take an example of one refrigerator. Wouldn't that company have to have at least the value, the purchase price of that refrigerator?

A. (Witness Schrader) That's correct.

Q. To that extent the total cost, at least as far as the utility, is understated substantially in your estimate?

A. (Witness Schrader) The total cost in terms of the immediate cash flow would be higher than the 1 billion by a certain amount, but the actual economics is that the salvage value of the unit is a crucial and critical item in calculating what the real cost analysis is; in other words, what the life cycle cost of that system would be.

What is important in these units is to recognize when you build a plant or buy an appliance it doesn't really matter a great deal of difference in terms of the money on the very shear economic model of it.

It matters in terms of cash flow. People look at life cycle cost, what the value of that investment will be.

What we are saying is the value of that investment is $435 given the difference between the two units, and of course there are savings associated with this.

Q. An utility company, when it has an increase in rate base, is usually able to gain more revenues. The rates, when they are set in the final analysis, go up when the rate base goes up.

A. (Witness Schrader) That's correct.

Q. Now, can you tell me what happens to an individual, a person, a family who does not get one of your refrigerators but still is in the service territory?

A. (Witness Schrader) Clearly there would be, under any kind of subsidy program, there is a series of skewed signals. One of those signals is that someone who does not purchase a new appliance or insulation or what have you, and doesn't participate in the loan program, will then be paying for that out of their rates.

Q. Now, I would like to move on to air conditioners, if I could, residential air conditioners.

I believe there is a standard in New

York State for window air conditioners; are you familiar with that?

A. (Witness Schrader) We are familiar with the estimate given to us by the Carrier Corporation, which is of the average EER, which is standard in air conditioning efficiency.

Q. And that's 7.5 EER, is that correct?

A. (Witness Schrader) No, we used 7.75. Carrier Corporation gave us a range between roughly 7.5 to 7.8.

Q. Now, there is a standard lifetime, at least according to the best estimates we have, of the life span of a room air conditioner, isn't that correct?

A. (Witness Schrader) Yes.

Q. That's twelve years according to the 1981 5112?

A. (Witness Schrader) Yes.

Q. In general 250,000 air conditioners a year are replaced on a normal basis?

A. (Witness Schrader) Subject to check, I will accept that.

Q. So your scenario would increase the number of annual replacements from that base?

A. (Witness Schrader) That's correct.

Q. Now, are you aware that the Consolidated Edison company, with respect to air conditioners, also has made some assumptions in their energy forecast, the demand forecast, for more efficient air conditioners?

A. (Witness Schrader) We relied upon those numbers in the 1985 residential kilowatt hour consumption by end use table, table 8, which is on page 129, and that's the 5112, 1981. The air conditioner number for use per unit kilowatt hour is 419.

Q. Now, I asked you a series of questions about refrigerators and the fraction of your estimate that would be duplicative of the Con Ed estimate.

I would like to see if we can establish the same idea in this area, in the air-conditioning area.

Isn't it true that by the end of your five year scenario, which I have taken to be 1989, through 1989, isn't it true that approximately three-quarters or 75 percent of the refrigerators would have turned over during that period, from 1980 --

MR. KAPLAN: Excuse me, you said

refrigerators. Do you mean air conditioners?

MR. PRATT: I mean air conditioners.

Q. -- that as far as the Con Ed forecast is concerned, three-quarters of the stock of refrigerators by the end of your period would have already turned over -- of air conditioners?

A. (Witness Commoner) Yes. Our program is intended to accelerate that and to increase the savings of energy.

Q. Do you have any idea how much your program is in addition to the already existing natural turn over of inefficient air conditioners for more efficient ones?

A. (Witness Schrader) We do have, from the current 1983, 5112, the current estimates of the use per unit kilowatt hour, which, in air-conditioning, from 1985 to 1990, that study projects a 10 percent increase in efficiencies per unit.

Q. Does the efficiency of air-conditioning units vary depending on the size of the unit, small one, a large one?

A. (Witness Schrader) Yes.

Q. Did you make any segregation in your analysis of different efficiencies?

A. (Witness Schrader) No, we did not.

Q. Let me ask you a few questions about lighting. Do you propose to replace florescent fixtures with your proposed more efficient bulbs?

A. (Witness Schrader) Our proposal is a proposal which would replace existing stock over a five-year period with the Durotest unit, regardless of florescent or incandescent.

Q. So you would replace, at least in part, florescent bulbs as well?

A. (Witness Schrader) We have not in this study broken down the numbers of incandescent and opposed florescent units that would be replaced.

Q. Do you have any cost estimate of how much it costs to take out a florescent fixture?

A. (Witness Schrader) We did not do any projections like that for this study.

Q. Thinking about the practical costs of that sort, did you may any estimate to deliver, install the room air conditioners we were talking about a moment ago?

A. (Witness Schrader) We did not make one for this study.

Q. Will the Durotest bulb fit into every kind of lighting fixture?

A. (Witness Schrader) The Durotest company, in telephone interviews, suggested that some 80, 85 percent of the fixtures they were familiar with in New York City would be applicable to their unit.

Q. Now, when you are proposing switching bulbs from a less efficient to a more efficient one, is part of the cost of that proposal that there be reduced lighting levels; in other words, that the lumen level come down, or are you holding that constant?

A. (Witness Schrader) In the interviews with the Durotest company, their description would be there would be a minimal amount of loss

Q. Would you accept, subject to check, that the lumen output of Durotest is about 1160?

A. (Witness Schrader) Have you broken that down in terms of the difference?

Q. 1160 lumens for your proposed bulb.

A. (Witness Schrader) Subject to check.

JUDGE PARIS: This is for a 100 watt?

MR. PRATT: 90.

Q. Do you know the lumen level for a garden variety 75 watt bulb?

A. (Witness Schrader) I do not.

MR. PRATT: I have here a package of bulbs, general electric, and I would ask you to take that the average lumens are 1170 for a 75 watt bulb.

MR. KAPLAN: You are asking him to take subject to check that that is what appears on the package.

MR.BLUM: Has a copy of that been prepared for all of the parties?

JUDGE SHON: Perhaps I can shed some light on this. I am rather bothered by two things. One is your footnote 8, which says, "In a new light, Durotest's' longer lasting bulbs." Now, I am not a light bulb engineer but if I remember some of the basic principles here, longer lasting bulbs generally give less light per kilowatt hour consumed.

That seems to be exactly what Mr. Pratt suggested here, that the number of lumens per kilowatt is less in the bulbs you are suggesting. So that it would seem that one could achieve the same thing by just going through the house and putting in 25 watt bulbs everywhere where you had 50 or 60 watt bulbs, couldn't you?

THE WITNESS: (Witness Commoner) I don't think that the economic result would be the same. I think that the design of the Durotest is to see to it that the lamp lasts longer, albeit at some sacrifice in light emission.

I should point out, too, that here, too, I think that the controling factor is going to be the economic result and no customer is ordinarily going to put a foot candle meter up and check to see what they are paying per lumen of light.

What they are going to be interested in is getting adequate lighting at the cheapest possible cost.

JUDGE SHON: I guess I just don't understand what that means, adequate lighting, if you don't care how much light there is how much is adequate lighting?

THE WITNESS: (Witness Commoner) Adequate lighting is a subjective factors. It means that it suffices for you to see what it is that you want to see.

JUDGE SHON: I would think that were would bear some relation to the total number of foot candles or lumens or something at that surface that you want to look at.

THE WITNESS: (Witness Commoner) It does, but it also bears some relationship to the nature of the task. I think the main point to make is that the standards of what light emission ought to be in various places, like schools, are inordinantly high at this time.

JUDGE SHON: So what you are talking about is reducing light levels, is that right?

THE WITNESS: (Witness Commoner) We are talking about two things. We are talking about extending the economic life of the lamp at some sacrifice in lumenocity.

JUDGE SHON: I am sorry, Mr. Pratt, I didn't mean to interrupt. Go ahead.

Q. Dr. Commoner, if I understand your testimony, you are saying that for equivalent lighting levels, your conservation scenario would actually increase the usage by 15 watts per hour per bulb, isn't that correct?

A. (Witness Commoner) I don't know where the number 15 watts per hour comes in.

Q. Well, it is of the difference between 75 and 90.

JUDGE SHON: I sort of resent watts

per hour. Just because either Dr. Commoner or Mr. Schrader seems to have performed this slight lapse on page 4, the watt per hour is not a recognized unit of anything. There are watts and there are watt hours, but there are no watts per hour.

Q. Let me make the point more generally. For the same lumen, for the same equivalent lighting level, aren't you using 15 -- I don't know how to phrase it -- I am comparing a 75 watt to 90 watt bulb -- for bulbs of different sizes aren't you simply using more electricity to get the same lighting level?

A. (Witness Commoner) No. The Durotest reduces the amount of electricity per lighting level but it doesn't reduce it by the amount of the increase in duration.

Q. Please explain to me, how is a 90 watt bulb uses less electricity than a 75 watt bulb?

A. (Witness Commoner) What you say would be true if the way in which the longevity was achieved --

Q. I didn't mean to interrupt you.

A. (Witness Commoner) -- simply by reducing the output of the bulb.

The Durotest bulb, and I am not a light bulb engineer -- there are factors built into the design of the bulb which increase its longevity more than by the reduction in output of light.

Q. Let's just talk about at one moment in time. Let's not think about the longevity. Just as a slice of time, a second, if you will, is the lighting level -- if the lighting level is held even for both bulbs, isn't the Durotest bulb more expensive in electricity usage than just a competing general electric bulb?

A. (Witness Commoner) I can't answer that question because, as you have already pointed out, of the Durotest bulb is not equal in light output to the conventional one. It puts out less.

Q. Let's go back.

JUDGE PARIS: Dr. Commoner, I don't understand the emphasis you are putting on the longevity of the Durotest bulb. What we are concerned with is current usage, isn't it?

JUDGE SHON: Precisely, Dr. Commoner. It makes no difference how long the bulb lasts. Economically it makes very little difference since the cost of the light bulb itself is small compared to the electricity it uses.

I know that sounds like I am testifying, but I want to know what does longevity have to do with light level and electrical power consumption, just as Dr. Paris asked? What has longevity to do with it?

THE WITNESS: (Witness Commoner) I think that longevity influences the consumer decision. The point is that the Durotest bulb, bulbs of that type, achieves two changes. One is in longevity and the second is in power consumption.

It does it at a cost or reduction in light output, but the reduction in light output is not equivalent to the savings in power. It is smaller.

JUDGE SHON: But according to the figures that Mr. Pratt just read, two bulbs, one Durotest and one GE that gave out the same amount of light, would have power consumptions in which the Durotest bulb was higher than the GE.

Is that not correct, Mr. Pratt?

MR. PRATT: That's exactly correct, Judge Shon.

JUDGE SHON: How can substituting the

one for the other for the same amount of light decrease the amount of energy used, when the bulb uses it at a higher rate?

THE WITNESS: (Witness Commoner) We took as the factor involved the evidence provided in the New York City Energy Office report which dealt with the savings in power.

JUDGE SHON: Thank you. I am still as confused as ever.

JUDGE GLEASON: All right, Mr. Pratt, let's continue and wind up.

Q. Now, I would like to focus on a different area briefly, if I may. As a basic matter of economics, when the price of an item goes down it is often considered that the usage consumption goes up, is that correct?

A. (Witness Schrader) That is often the case.

Q. Price elasticity is one way of determining this or calculating this, isn't that right?

A. (Witness Schrader) That's correct.

Q. In fact if we assume a price elasticity value of one, does not that mean that when the price rises by 10 percent, that the demand is going to drop by 10 percent, assuming a value of one or minus one?

A. (Witness Schrader) Theoretically, that's correct.

Q. In fact, doesn't it also also work in the other direction as well, assuming we have as an item as a discreet part of the curve, the elasticity value is known, if the price drops by 10 percent, the usage will also go back up?

A. (Witness Schrader) Again, theoretically that can also happen.

Q. If I have a refrigerator at home, one of your more efficient Amana refrigerators, won't I be given the price signal that I am getting cheaper refrigeration services; that is to say, for the same amount of electricity I am getting more refrigeration, isn't that correct?

A. (Witness Schrader) On any appliance that becomes more efficient and therefore uses less kilowatt hours, and therefore saves money, one could argue that there is a signal being sent.

Q. And the same thing is true, as you say not just for the refrigerator but for any of the electric appliances that get more efficient?

A. (Witness Schrader) Again,

theoretically the economic theory up holds that.

Q. Thank you. Now, on page 5 of your testimony you again rely on the 1981 Energy Office record to state that conservation measures could reduce power consumption in the commercial sector by a minimum of 31 percent; do you see that testimony?

A. (Witness Commoner) Yes.

Q. What analysis did you perform of that figure in filing this testimony?

A. (Witness Commoner) We accepted that figure from the city energy office report.

Q. Do you have any idea of the breakdown between the use of electricity for cooling and lighting the commercial sector that underlay that analysis?

A. (Witness Schrader) Yes, I do.

Q. What is that?

A. (Witness Schrader) Subject to check, the lighting represented something on the order of 10 trillion BTUs and the cooling something in the order of 2.35, perhaps a slightly higher fraction, as the breakdown of their chart of the entire residential city and commercial usage. That's subject to check.

Q. On page 6 of your testimony you indicate that these savings could reach reasonably 50 percent, on the top two lines of the testimony on that page.

A. (Witness Commoner) Yes.

Q. What basis do you have, if any, other than Mr. Aaron's telephone call to support that statement?

A. (Witness Commoner) To begin with, the energy office estimate is a minimum. So that we felt that there was the opportunity to have it larger.

We have discussed this with Mr. Aarons and discussed it with other people as well. The 50 percent figure is our best estimate of a figure which could reasonably be achieved.

Q. Let me focus now on the sentence that you have changed, which you amended when you came onto the stand. That deals with the importation of power from Canada.

If I understand it, that sentence as it now reads, you rely on Canadian authorities to the effect, one, there is additional power available; and secondly, that Con Ed can be authorized by New York State to purchase it; and third, that Con Ed can be authorized by state regulators to purchase it.

Three separate things, all of which you relied on, is that correct?

A. (Witness Schrader) We have only recently received the 1983 Power Pool authority, which describes 12 billion kilowatt hours that are available from Canadian systems. We received that from Con Edison after the testimony was filed.

Q. And the actual basis, if I understand your testimony, the actual basis for these three statements, is not so much the Canadian authorities as is Mr. Peter Holmes' article which you cite in footnote 11?

A. (Witness Schrader) Footnote 11 is Mr. Holmes' article. The 1983 report, which I just cited, has more up-to-date numbers, on the order of 12 billion kilowatt hours.

Q. Did you make any estimates in the analysis of transmission capability when you stated that additional power could be imported and used in the Con Ed service territory?

A. (Witness Schrader) In terms of the overall potential for Canadian hydro power, there is ongoing litigation and a series of lawsuits the

Power Authority is engaged in, and it is a difficult item to have a fine-tuned number for.

However, the 1983 number I quoted gives a broad ballpark number. We could not calculate transmissions losses in there because of the complexities and other numbers it related to.

Q. Did you make any analysis of other purchasers, competing purchasers for the Canadian power?

A. (Witness Schrader) Our analysis did not give in this current form a hard number as to how much hydro power would be available to Con Edison. That 12 billion kilowatt hours that I just cited would be available to the entire state, and that's an annual number.

Q. Now, the cost of this program, if I understand it, in your testimony on page 10, is approximately 1.6 $1 billion, is that correct?

A. (Witness Schrader) That's correct.

Q. Now, there is a certain amount of capital already invested in the Indian Point units; do you agree with that?

A. (Witness Schrader) Yes, we do.

Q. Have you included that capital in your estimate of 1.61?

A. (Witness Commoner) No. That's sunk capital, if I may use that word.

Q. Sunk beneath the waves, as it were?

A. (Witness Commoner) Yes.

Q. Have you given any consideration to the federal tax code in making the assertion that the Power Authority could dramatically expand or expand its authority in the way that you propose?

A. (Witness Schrader) We have suggested that there be changes in the HIECHA program where we began looking at the prospects of that change of existing state legislation that is pending. There is a piece of legislation pending in that regard.

Q. I am very familiar with that legislation, but I am asking you are you familiar with the industrial development bond provisions of the IRS code?

A. (Witness Schrader) I am somewhat familiar with them. We did not calculate or factor them into these discussions.

Q. Any limitations on tax exempt financing that are in the federal tax code you didn't consider?

A. (Witness Schrader) No, we did not

consider that.

Q. Now, this 1.61 billion dollar number, what did you assume for the cost of the money, what interest rate did you assume?

A. (Witness Schrader) We were attempting to suggest a zero interest loan program on the order of the California zero interest plan, TVA plan, et cetera, which is why we included the capability or suggested that there be an allowance for the capability of Con Edison to include investments in these appliances in their rate base.

Q. Let me ask you about the Power Authority which has to sell bonds to raise money. What interest rate did you assume for the bonds that the Power Authority would raise to finance this program?

A. (Witness Schrader) We made no interest rate adjustment for this.

Q. You didn't consider interest at all?

A. (Witness Schrader) No, we didn't.

JUDGE GLEASON: Are you about finished?

MR. PRATT: I have about 15 minutes. Not more than 15 minutes.

JUDGE GLEASON: It is only eleven pages of testimony, but go ahead.

Q. Let me ask you generally about your proposals for co-generation. This is a subject that various governmental agencies have looked into in detail and Consolidated Edison & Company, among others, is very acutely aware of.

Have you made any specific analyses of the viability of your proposal or is your plan a more conceptual proposal?

A. (Witness Commoner) Our plan is based on a series of very specific data regarding the availability of co-generation equipment, its efficiency and reliability which, as it happened, we prepared as part of our work in the contract with the New York State Energy Research and Development Authority.

We have gone through all of the applicable forms of co-generators for residential buildings in this area and have a complete tabulation of their relevant engineering characteristics.

Q. Well, I didn't ask you about the data so much as your proposal. Is it a specific detailed proposal or is it more conceptual in nature, something that might be described as a possibility?

MR. KAPLAN: I object to that. I am not sure what he means and maybe he can break that down in a way the witnesses can answer it.

JUDGE GLEASON: Does the witnesses understand the question?

THE WITNESS: (Witness Commoner) Yes, I do.

JUDGE GLEASON: Respond to It.

A. (Witness Commoner) Every activity we carry out is, in part, conceptual. I have no way of distinguishing between any two acts, as to one being conceptual and the other not.

The question is to what detail has the concept been carried out, and what I am saying is that with respect to the applicability of co-generation to New York City residences, we are in fact engaged in a very detailed study which describes the available co-generators, their reliability, the cost figures, the pay-back terms, so that we have a very detailed knowledge of the applicability of co-generation to New York City residential buildings.

Q. Your proposal relies on the totem model of co-generators?

A. It does not rely on the totem. It

uses the totem solely to give a single set of numbers.

We have figures on, as I say, a whole series of co-generators, of which the totem is only one.

Q. Do you list any other type of co-generation mechanism in your testimony other than the totem?

A. (Witness Commoner) No. We use the totem as an example of the engineering characteristics of a co-generator that is applicable to residential buildings.

There are, in fact, and if you will bear with me for a moment I will give you a count of the number of other models that are available for the same purpose. We have has list of 17 models of co-generators, all, except the totem, manufactured in the United States, which would be equally applicable to the purpose that we describe.

Q. Any deficiencies in the totem model would also be applicable to these others?

A. (Witness Commoner) No, sir. The characteristics of each of these models is somewhat different.

For example, the totem happens to be

a high-speed engine; therefore, in some respect less reliable than low-speed engines. Some of these models operate at half the speed of the totem.

JUDGE PARIS: What kind of fuels do these other models use?

THE WITNESS: (Witness Commoner) All of these models are designed to run on methane, natural gas.

Q. I have a limited amount of time left. Let me just ask a few questions about your testimony, which does mention and indicates the totem as an example.

I believe I have read that there are several different models of totem, some of which have voltage controls, some of which do not; do you agree with that?

A. (Witness Commoner) Yes. In Italy they are produced in different ways.

Q. Is the one with voltage control available in this country today?

A. (Witness Commoner) To my knowledge, any totem bought in this country would have to be bought directly from Italy. So that all models that they produce are available to that extent.

A. (Witness Schrader) Fiat Corporation is the manufacturer.

Q. You assume they will run at a 95 percent capacity factor, is that correct?

A. (Witness Commoner) Yes. That's a typical figure for most of the co-generator equipment. You leave 5 percent for down time and overhaul. That's a general figure. It is quite applicable to the totem.

Q. Now, I believe that you calculate that the maintenance would be in the order of 40 cents an hour?

A. (Witness Commoner) That's a figure only for the totem, as an example.

Q. For the totem I have done some calculations that indicate it would be, at that rate, approximately -- maintenance figure of about $3,328 a year. Will you accept that, subject to change?

MR. KAPLAN: Can Mr. Pratt tell us how he made his calculations?

MR. PRATT: 40 cents times 24 hours times 365 days times .95.

MR. KAPLAN: You didn't take out vacation time and things like that?

MR. PRATT: I did take out whatever vacation time has been taken out, 5 percent.

Q. Will you accept that figure?

A. (Witness Commoner) Yes.

A. (Witness Schrader) Subject to check.

Q. Now, if you look at the hours for down time, now we are switching from money to hours, doing the same kind of calculation, using that 95 percent capacity factor, I calculate that to be about 437, 438 hours. Doing the division again, that's about $7.60 spent per hour of maintenance, is that correct?

A. (Witness Schrader) Would you go through that calculation again?

Q. 365 times 24 times 5 percent.

A. (Witness Schrader) And your number was?

Q. 438.

A. (Witness Schrader) We will accept that.

Q. You end up with about $7.60 per per hour maintenance cost, which pays, if I can add to that question, which pays for the manpower and any investments in of a hardware nature in maintenance? You consider that to be a reasonable figure?

A. (Witness Commoner) Subject to check.

Q. Have you given any consideration, have you accounted in your proposal for the costs of joining the totem systems heat output to the present heating systems in the buildings that it would be installed in?

A. (Witness Commoner) Yes. The figures that we have are for installed capacity.

Q. Mr. Schrader, let me focus this question to you, and I think it may be my last subject, subject to one last check with my colleagues.

These measures that you are proposing, conservation and co-generation measures you are proposing, aren't they valuable to society independent of the closing of Indian Point?

A. (Witness Schrader) It is a question that I think requires much more engagement than just a simple yes or no answer, but, of course, yes, they are.

Q. Couldn't you value it in a monetary sense, the benefit of these measures by what they are displacing?

A. (Witness Schrader) If I follow your logic, I think that the issue there is that one could make that evaluation. One would also have to make an evaluation as to the continuation of the existing source or the existing alternative and what that's effects may be on society at large as well.

MR. PRATT: No further questions.

JUDGE GLEASON: Do you have cross-examination?

MR. SANOFF: I sure do. ly

JUDGE GLEASON: Let's take a five-minute recess, please.

(there was a short recess.)

JUDGE GLEASON: Let's proceed, please.

CROSS-EXAMINATION

BY MR. SANOFF:

Q. Mr. Schrader, do you recall that judge shown asked you about the Amana refrigerator, whether it was automatic or manual in terms of defrost, and you answered that it was automatic?

A. (Witness Schrader) Yes, subject to check I answered that.

Q. Let's check it. Exhibit 52 that's now part of the record, the Power Authority's Exhibit 52 --

MR. KAPLAN: I don't think that was

part of the record. It was marked for identification.

MR. SANOFF: I will mark again for identification and introduce it in evidence.

Q. Would you turn to the page 5 which has the Amana refrigerator on it and, Dr. Commoner, you said that of the one you were referring to was ESR 14 E, is that correct?

A. (Witness Schrader) That's correct, sir.

Q. Do you see the line next to that, it says TFP?

A. (Witness Schrader) Yes.

Q. Would you turn to the page 4 and look at the directory signals. Do you see TF is the top freezer? And you see P as partial automatic?

A. (Witness Schrader) Yes, I do.

Q. So it is not automatic, it is partially automatic?

A. (Witness Schrader) Partial automatic defrost.

Q. Do you know which part is automatic? The defrosting action for the refrigerator surfaces in the freezer is initiated manually. In other words, the thing that annoys everybody is the part that you have to defrost manually, correct?

A. (Witness Schrader) It has never annoyed me.

Q. Is that the part that most house wives are bothered with?

MR. KAPLAN: Object. Nothing in the record as to what housewives want.

MR. SANOFF: He gave an incorrect answer when he said it was automatic.

MR. KAPLAN: He said subject to check.

MR. SANOFF: He didn't say subject to check. It said it was automatic.

Let's go on. I am under a sharp tie time limit and I am going to move like gangbusters.

MR. KAPLAN: He is just being adversarial, Judge.

Q. Do you recall, gentlemen, Mr. Pratt and I deposed you on March 24?

A. (Witness Commoner) Yes.

Q. Didn't you say that it was a mistake for the country to get involved in nuclear power and that the best thing the country could do was to phase out nuclear power as rapidly as possible? I am referring to page 76, Dr. Commoner.

A. (Witness Commoner) I said it and I am hope to note that I am getting some support from the Supreme Court.

Q. Good. Didn't you then answer that it was your view that the plants were not now necessary?

A. (Witness Commoner) That's right.

Q. And do you recall that at page 77 of the transcript I asked the following questions and you gave the following answer --

MR. KAPLAN: Can you show the deposition to Dr. Commoner? He does not have a copy.

THE WITNESS: (Witness Commoner) I think I do.

Page what?

Q. 77, Dr. Commoner. Got it?

A. (Witness Commoner) Yes.

Q. "Mr. Sanoff: To have reached the end conclusion that you had, would it be logical that you would have some pretty good ideas where that power is going to come from?

"Dr. Commoner: Yes, we are working on that and we will, in our testimony, propose where the power will come from.

"Mr. Sanoff: You reached the conclusion first and now you are filling in the steps that lead up to the conclusion?

"Dr. Commoner: Yes."

Have I read that faithfully?

MR. KAPLAN: I object to this line of questioning. The purpose of a deposition is to impeach a witness. Mr. Sanoff has laid no foundation to impeach the witness with those questions. I am not arguing that the use of a deposition is inappropriate but this is.

JUDGE GLEASON: He doesn't have to lay a foundation to impeach a witness.

MR. KAPLAN: No basis to read in questions and answers. A prior statement is used when there is an inconsistency.

MR. SANOFF: I want to get something in the record.

JUDGE GLEASON: The objection is denied. Go ahead.

Q. Now, do you recall that on your deposition you, Dr. Commoner, stated that "while the incentive for residential consumers to conserve is very high they can't find the initial capital to make what is a very worthwhile investment." My frame of reference is 104 of the transcript.

A. (Witness Commoner) Yes.

Q. You also stated that banks "fail to understand the economic value of conservation when a customer comes to them," 104 is the frame of reference, "That you are not going to base your estimate of potential conservation on any utility subsidies." 105, "And that you "assumed that the banks could be induced to make these loans simply by educating them as to their attractiveness," page 106.

Do you recall that testimony?

A. (Witness Commoner) Let me read it.

Q. Go ahead.

(There was a pause in the proceeding.)

A. (Witness Commoner) You are referring to what page?

Q. 104 for the one you said yes to, for 105 to the statement --

A. (Witness Commoner) Just a minute. I said yes to what on page 104?

Q. That the banks --

A. (Witness Commoner) I see no word "yes" on page 104.

Q. You said yes here when I quoted you from page 104 that "banks failed to understand the economic value of conservation when a customers comes to them."

A. (Witness Commoner) Give me the line.

Q. The third line from the bottom of the page, 23, "For example, banks fail to understand the economic value" --

A. (Witness Commoner) Just a moment. Let's read the whole thing.

"Mr. Sanoff: Is it an economic determinant?

And I said, "No, it is a social determinant. Banks fail to understand the economic value of energy conservation when a customer comes to them."

Q. And did you testify on the next page that you were not going to -- I said to you, "You are not going to be purporting to provide this conservation in this territory by the big daddy providing the wherewithal," and big daddy you understand I was referring to Con Edison and the Power Authority, didn't you?

A. (Witness Commoner) I had no idea who you were referring to when you said, "Big daddy."

MR. KAPLAN: He is referring to whom he considered to be the big daddy.

Q. Did you say "I will stipulate that we are assuming that the economic system that operates in southern New York State will continue"?

A. I certainly did say that.

Q. Weren't you suggesting that you were not going to look for utility company subsidies to support this conservation?

A. (Witness Commoner) I have to tell you what my interpretation of "big daddy" was. I thought you were referring to the United States government and that you were referring to a social mechanism that would change our economic system, and my answer was designed to assure you and calm you down so that you know that we accept the existence of the present economic system in its present form.

Q. When you were testifying on deposition were you thinking that this conservation was going to be subsidized by Con Edison and the Power Authority?

A. (Witness Commoner) No.

Q. Now, is that your testimony now, though?

A. (Witness Commoner) We are proposing a social mechanism to undue the social damage resulting from the building of those two nuclear power plants.

You have placed, by building those plants, a heavy burden, has been placed on the people of New York. We are proposing a social mechanism whereby the people of New York, using certain existing financial mechanisms available to them, could finance a series of changes which will make it unnecessary to continue the operation of those two nuclear power plants.

A. (Witness Schrader) On line 21 of that page Mr. Sanoff is quoted as responding to me saying, "you mentioned HIECHA." I would suggest that apparently the program had been mentioned during the deposition and you were responding to that.

Q. Does HIECHA presently provide for Con Edison to put up the money for buying appliances?

A. (Witness Commoner) No, and we specifically propose that the HIECHA legislation be expanded to include that and that also PASNY be included in it.

We are proposing a new social

mechanism which is required because this society is now suffering under the burden created by the existence of those two nuclear power plants.

Q. I want to look at the financial mechanism that you are talking about.

You talked about replacing 2.36 million refrigerators, did you not?

A. (Witness Commoner) Yes.

Q. And the cost of those refrigerators was $637 apiece, is that correct?

A.. (Witness Commoner) The initial cost.

Q. Whose going to put up the money to buy those 2.36 million refrigerators at $637?

Before I ask who is going to put it up, would you accept subject to check that $2.36 million times $637 is $1 billion 500 million dollars?

A. (Witness Commoner) Yes.

Q. Who is going to put up that amount of money to buy these 2.36 million refrigerators? No speeches, just tell me specifically who is going to do it.

A. (Witness Commoner) I will answer you in my own way if you don't mind.

Q. Your buddy there has tickets to the

Knick game and I am trying to help him out.

A. (Witness Schrader) Would you like to come with me, Mr. Sanoff?

JUDGE GLEASON: Please.

Mr. Kaplan, if you want to make comments address the chairman.

MR. KAPLAN: I will address the chairman right now. I suggest the comments of Mr. Sanoff about the Knick game should be stricken from the record.

JUDGE GLEASON: You want that stricken from the record?

THE WITNESS: (Witness Schrader) It doesn't bother me in the least.

A. (Witness Commoner) We are proposing a social mechanism to undertake the financing needed to undertake these conservation measures. We think that the HIECHA approach will suffice. And with the addition of the part of the money handled by Con Ed entered into their rate base.

Q. I want to know who is going to put up -- however many people put it up, however many agencies -- who is going to put up 1 billion 500 million dollars?

Somebody has to pay for these 2.36

million refrigerators.

A. (Witness Commoner) Part of it through public funds, through PASNY.

Q. How many from public funds through PASNY?

A. (Witness Commoner) We have not calculated it because the obvious reason the mechanism doesn't exist. We say the mechanism ought to be created and that there are pathways for moving money into that program.

Q. You know, I thought you included all of this testimony on the Con Ed -- replacement of the Con Ed Indian Point 2. I was wondering why you separated the testimony out, but the refrigerators and the air conditioners were designed to replace the generation lost by Indian Point 2.

A. (Witness Commoner) You misconstrue our testimony. The financial program that we propose is applicable generally to both Indian Point 2 and Indian Point 3.

Q. So you have part of this money is going to be put up by PASNY, in some undetermined amount, and through some as yet unpassed legislation amending the Internal Revenue Service code which will allow them to do it without loosing their tax exemption for bonds, is that correct?

MR. KAPLAN: That is not a question, it is a speech.

JUDGE GLEASON: It is a question. Objection denied.

Answer the question.

A. (Witness Commoner) We propose that there are reasonable legislative means for providing the funds necessary to undo the damage created by the existence of those two nuclear power plants.

It is going to cost money, of course it will.

Q. I understand. I am trying to find out where the money is going to come from.

A. We propose partly from Con Ed --

Q. How much from Con Ed?

A. We don't know.

Q. Give me a for instance. A billion dollars? How much?

A. (Witness Commoner) The answer to your question is we don't know.

Q. You see, it is very difficult for me

to focus on the cost of this program unless I know how much is going to go into Con Ed's rate base and get the equity return that Mr. Schrader talked about.

Suppose it is a billion dollars, do you know what Con Ed's present equity return is allowed by the commission?

A. (Witness Schrader) 16 percent roughly.

Q. 15.2. I wish it were 16. Let's say 15. Do you know what the pretax requirement is to earn a 15 percent equity return?

A. (Witness Commoner) You tell me.

Q. 30 percent. It is a 46 percent tax rate.

Now, if Con Ed has to put up a billion dollars, we would have to earn, to get an equity return on that, we would have to earn 15 percent on that after tax dollars, 30 percent before. That's $300 million a year. Is that the kind of thing you are thinking of?

A. (Witness Commoner) If you are asking me my personal opinion I wouldn't worry even if Con Ed had to pay it out of its profits.

Q. Now you have said it. You wouldn't worry about the Constitution either, whether that permits it?

MR. KAPLAN: Objection.

A. (Witness Commoner) Just a moment. Don't say that to me.

MR. KAPLAN: I have an objection pending.

JUDGE GLEASON: We will strike that question from the record.

Q. Now, the air-conditioning units of 2.26 million air conditioners, correct?

A. (Witness Commoner) Yes.

Q. Now, I had trouble figuring out what the cost of those are. I think it is $450, is that correct? Because it is 350 for the ordinary air conditioner and 100 premium for the more efficient one, is that correct?

A. (Witness Commoner) Yes.

Q. My arithematic tells me that's a billion dollars. Now, do you have the same sort of social program that you haven't resolved, how much PASNY is going to pick up and how much Con Ed is going to pick up?

A. (Witness Commoner) Exactly.

Q. You don't care if the Con Ed stockholders have to pay for that either?

MR. KAPLAN: Objection to the form.

JUDGE GLEASON: Objection denied.

A. (Witness Commoner) You are asking for my personal opinion?

Q. Yes.

A. I think Con Ed has made enough profits and has caused enough social damage that I wouldn't mind seeing their profits cut.

Q. Are you an expert on rate of return of utility companies?

A. (Witness Commoner) No, but I am a citizen that has some sense of social responsibility.

Q. Is this your citizen's approach as distinguished from your expert approach?

A. (Witness Commoner) Yes.

Q. But do you have any idea what cost of capital is or what Con Ed had been earning on cost of capital?

A. (Witness Commoner) Yes, we have just been through that.

Q. Do you know what Con Ed had earned on its allowed returns?

Have you any idea of that?

A. (Witness Commoner) No, tell me.

Q. Do you think they have earned their allowed return in the last ten years?

A. (Witness Commoner) I don't know.

Q. But you are reaching the conclusion that they are making more than they should be, right?

A. (Witness Commoner) I am counting their profits, whatever they are, against the damage to our society by having, in my view, wrecklessly built the nuclear power plant.

Q. When you talked about a seven-year payout in your testimony and a 16-year payback, what was your frame of reference there? Do you recall what I am talking about?

A. (Witness Commoner) I don't know what you are talking about.

Q. It is a shame you don't.

On page 9, and this is your frame of reference here, the refrigerators, and you say, "And that represents a payback of seven years."

Where does the consent of payback enter into it if you are talking about Con Edison and the Power Authority putting up the money for this accelerated replacement of appliances?

A. (Witness Commoner) That refers to the consumers' interest in it.

Q. How are the consumers going to get paid back -- first of all, what are they going to get paid an how are they going to get paid back that in seven years?

A. (Witness Commoner) If you will look above we point out there is a 320 total savings to the consumer over a five-year period. That's the source of the payback.

Q. Dr. Commoner, isn't it possible that you have two completely different concepts involved here? One you seem to be talking in this testimony, and I have prepared my cross-examination on the basis of it, like the customer was going to be induced to go to the bank and pay for this accelerated replacement of appliances, and you were talking about a seven-year payback for refrigerators and a 16-year payback for air conditioners, and I prepared to cross-examine you on that.

But this morning I hear, and on my cross-examination, that you are now talking about Con Edison and the Power Authority putting up the cash for these. Now, if they put up the cash, how does the concept of payback to the customers take place?

A. (Witness Commoner) We refer there to the savings to the customers. Nowhere do we say that we propose to induce the customers to carry this out. We are proposing a social program in which the state and Con Ed, in collaboration, work out an effective fiscal mechanism for carrying through this energy saving program, which we regard as worth the overall investment.

Q. When you talked about a seven-year payback on page 9 and you talked about a 10 to 123 year payback for the air conditioners on page 10, who was going to get paid back? You were referring to a payback. Somebody had to be getting paid back.

A. (Witness Commoner) There are various ways of doing it. For example, one could pass legislation that took the consumers' savings and used them to pay back the loans required to acquire the new appliances.

In other words, the point we are making is very simple. If the capital investment is available, the savings through power consumption are able to pay back that investment to a certain extent. Obviously a mechanism then has to be created to effectuate the flow of the savings back to the investors.

We are proposing that the mechanism could be created.

Q. I am exploring it with you, Dr. Commoner.

A. (Witness Commoner) Good.

Q. If the customers are the ones who are going to be getting paid back, they have to be the ones who made the initial investment?

A. (Witness Commoner) Necessarily.

Q. You aren't going to pay them back if they didn't pay for the appliances to begin with, are you?

A. (Witness Commoner) The payback is the measure of the financial savings resulting from the investment. I think the equitable thing to do perhaps would be to direct the payback to the investors, who may be PASNY, may be Con Ed, it may be the customer himself.

We are showing what the overall fiscal balance is. The mechanism has to be created, and I think there are various options for doing that.

Q. Now, on one of your conclusory pages

you talked about a cost --

A. (Witness Commoner) What page?

Q. Page 10. You talked about a cost of 1.61 billion dollars. Now, Mr. Pratt covered this point but I want to drive it home again because I want to make sure that everybody understands it. That 1.61 was derived by applying figures less than 637 dollars for refrigerators and less than $435 in air conditioners, is that correct?

A. (Witness Commoner) Yes, taking into account the salvage value.

Q. Who is going to pay the salvage? Are we going to develop a used market in refrigerators and air conditioners?

A. (Witness Schrader) Interesting idea.

Q. Wait a second. If Con Ed pays $637 apiece for however many refrigerators you assigned to them, what are you going to do, pay them in used refrigerators and decrease their investment that way?

A. (Witness Commoner) I think that this is an issue which can be resolved in a series of different ways.

One might be to increase the availability of low cost appliances that might be used, for example, in other countries. You know, a good deal of the turn over in our automobile industry involves shipping out used cars.

I think it might be very interesting to see whether we could develop a way of recovering some of that salvage money by developing an international market in used air conditioners.

Q. You don't want that to come out of our rate of return, do you?

A. (Witness Commoner) The people in New York are facing a problem that has been imposed on them by Con Ed.

Q. Why do you keep saying Con Ed?

Isn't it con Ed and the Power Authority?

A. (Witness Commoner) You built the plants.

Q. They own one of them, too.

A. (Witness Commoner) I don't think it was a voluntary purchase.

In the beginning there was Con Ed, let's face it.

Q. That's a good line, that's a good line.

A. (Witness Commoner) Well, you haven't heard the end of it.
Q. Go ahead.
A. (Witness Commoner) In the end there may not be Con Ed.
Q. That's what your devout hope is, isn't it?
A. (Witness Commoner) No. We will discuss that at some other time.
Q. Let me ask you this: To the extent that you might contemplate that the customers would make this investment, did you ever think of the varying types of customer groups that you have? I am not talking about anything except the type of service they take, residential customers.
Do you know the varying types of categories of customers that there are?
A. (Witness Commoner) We have some ideas.
Q. Tell me what they are.
A. (Witness Commoner) Just a moment. That's a very wide question. Within what scope?
Q. For example, there are rent included customers. Do you know what that is?
A. (Witness Commoner) I suppose by that you mean people who get the refrigerator in the

rent.

Q. That's right, they get the electricity in the rent.

A. (Witness Commoner) All right.

Q. In those cases the landlord owns the refrigerator, right?

A. (Witness Commoner) Yes.

Q. The tenant gets the electricity charged to him in the rent. You think that the landlord is going to be interested in replacing refrigerators in that sort of situation?

A. (Witness Commoner) Possibly not. It might be that Con Ed would have to give them some kind of special deal, which it often does, when it is interested in getting people to use more electricity.

Q. You are interested in promotional rates.

A. (Witness Commoner) Giving them a promotional rate.

Q. Absent some subsidy you couldn't get the landlord to make an investment of that sort, could you?

A. (Witness Commoner) Probably not. It is going to cost money.

Q. Let's take the many and condominiums in the City of New York, and unfortunately I have just had to buy one, and I own a refrigerator but there is a master meter in the building. Do you think I am ever going to be interested in replacing that refrigerator and lowering the master meter reading every month?

A. (Witness Commoner) I thought that your social conscience might allow you to overcome that.

Q. It doesn't extend that far. Never fear. Yours may, not mine.

JUDGE GLEASON: Let's get back to the subject matter.

Q. Let's get on to totems -- I am moving very quickly.

JUDGE GLEASON: It is where you are moving.

Q. You talked about totems and you also talked in your deposition, you said that you are both familiar with the co-generation proceeding, correct?

A. (Witness Commoner) Yes.

Q. You read the decision of the commission in that case?

A. (Witness Commoner) I haven't but my friend has.

Q. Let me ask you, what kind of distribution systems does Con Edison have?

A. (Witness Commoner) You mean the network?

Q. Yes, it has a network system, correct?

A. (Witness Commoner) Yes.

Q. What's the other distribution system, radio, right?

A. (Witness Commoner) Yes.

Q. Do you know of any problem of put -- the totem you talked about would have to be connected in parallel, wouldn't it?

A. (Witness Commoner) No.

Q. Doesn't it require Con Ed energy to run, it needs Con Ed energy to be started and it needs it --

A. (Witness Commoner) Again, the totem was mentioned for the only purpose of providing an example of the engineering characteristics. Yes, the totem that Brooklyn Union Gas is testing right now has the original model, needed outside power to start. But it is a very simple procedure to avoid that and there are other devices that don't need it.

So I want to make it very clear that our testimony does not hang on the uniqueness of the totem.

Q. But all of your co-generation systems would be interconnected with Con Ed or would they stand alone?

A. (Witness Commoner) It varies. There is an advantage, an economic and social advantage, to being interconnected with Con Ed but it is possible that they can stand alone if Con Ed is pretty sticky about it.

Q. Well, you always think it is Con Ed that's sticky. The commission thought there was a good, sound safety reason for being careful about interconnections. Do you know what that would be?

A. (Witness Commoner) Absolutely. I think that all safety precautions have to be involved.

Q. What's the danger in interconnecting one of these co-generation units with a secondary system?

A. (Witness Commoner) There is a danger of backfeed into the if he network.

Q. Did the commission express great

concern in its decision about backfeed?

A. (Witness Commoner) I don't know about the adjective but they expressed some concern about it.

Q. Didn't they write and say that there will be no interconnections permitted with the secondary system unless the possibility of backfeed was expressly excluded because you could wreck the secondary system and kill people who might be working in the secondary system; didn't they say that?

A. (Witness Commoner) I don't recall that particular statement.

Q. You seem to have an engineering background --

A. (Witness Commoner) I do not have an engineering background.

Q. You know about the secondary system and you know you don't want backfeed into it, correct?

A. (Witness Commoner) Absolutely.

Q. How do you provide against backfeed?

A. (Witness Commoner) I have no engineering knowledge on the technique but there are techniques.

Q. Have you heard of a network protector?

A. (Witness Commoner) I have.

Q. Those are pretty expensive devices, aren't they?

A. (Witness Commoner) Yes.

Q. For every co-generator that you would interconnect to Con Edison system you would have to put a network protector to insure that that co-generator could never backfeed into the secondary system, is that correct?

A. (Witness Commoner) Providing that a primary circuit were not available.

Q. You are going to hook a 15 KV into a primary circuit?

A. (Witness Commoner) We are not talking about 15 KV. The buildings may require multiples of 15 KV co-generators.

Q. Aren't all these buildings interconnected to the secondary distribution system?

A. (Witness Commoner) Not always.

Q. For those who are located on a radial system, they would be on a radial system?

A. (Witness Commoner) Yes.

Q. What portion is radial of Con Ed's

system

Q. (Witness Commoner) I don't know.

Q. Small portion, isn't it?

A. (Witness Commoner) I don't have the figure.

Q. In your deposition, you, Dr. Commoner, I questioned you about potential environmental problems that might be occasioned by co-generation. You stated, didn't you, that in your opinion "diesel co-generators were not acceptable in urban areas." Is that correct?

A. (Witness Commoner) Yes.

Q. And I then asked you whether there weren't environmental problems associated with natural gas-fired co-generation and you answered that there was an environmental problem, is that correct?

A. (Witness Commoner) That's correct.

Q. I then asked you whether environmental regulations in place were adequate to deal with a large proliferation of natural gas-fired co-generation; your answer was, "it depends on how large it is." I then said, "Large enough to fill the gaps occasioned by the shut-down."

Your answer was, page 88 of your deposition, "That's a calculation we will have to look at."

Did you say that?

A. (Witness Commoner) I guess so, yes.

MR. SANOFF: No further questions.

JUDGE GLEASON: Mr. Blum, I want you to know that I have serious reservations about allowing you to cross examine these witnesses because I do not consider their position as adverse to your own. Unless your questions are adversarial they are going to be stricken. If you do it twice I am going to take your time away from you, do you understand?

MR.BLUM: Yes.

CROSS-EXAMINATION

BY MR. BLUM:

Q. Gentlemen, I am Jeffrcy Blum, I am an attorney for the Union of Concerned Scientists. I will be asking you questions on behalf of the Greater New York Council on Energy, which has a position with regard to co-generation somewhat different from that of the City Council.

Gentlemen, in your testimony on behalf of the city council you state, on the last two lines of page 11, running over to the top of page 12, "It is our contention that the power supplied by Indian Point 3 can be replaced by installing cost effective co-generators in residential buildings."

You are aware, are you not, that using the figures projected forth by the licensees, the greater rate increases due to shutting down Indian Point will not be to Con Edison's residential customers but rather to PASNY's customers in the Con Edison service territory; you are aware of that, are you not?

A. (Witness Commoner) Yes.

Q. In fact, the proposed PASNY increases in rates are on the order of five or six times as high as the proposed Con Edison increases?

A. (Witness Commoner) We have no direct knowledge of that.

MR. SANOFF: Talking about percentages.

MR.BLUM: In terms of percentages, yes.

Q. Isn't it true that substantial progress in the use of co-generation could be made in the use of governmental buildings as opposed to residential ones?

MR. SANOFF: Your Honor, that is not cross-examination.

JUDGE GLEASON: That is not cross-examination.

MR.BLUM: That is cross-examination.

JUDGE GLEASON: It is not and I do not consider. That's an effort to get direct testimony in and I am going to tell the witness not to answer.

That's number one, Mr. Blum.

MR.BLUM: I object to that, your Honor.

JUDGE GLEASON: You can have your objections but I made my statement at the beginning, that you are going to have to be adversarial. You are not going to use these witnesses to get in direct testimony. That is clear.

We are behind schedule and this kind of ruling should have been put in at the start of these hearings rather than when we started to impose it in connection with questions 3 and 4.

Q. Gentlemen, why did you put the term residential buildings and specificallyly exclude mention of buildings owned by the city council?

A. (Witness Commoner) Simply because they represent the bulk of New York City housing.

Q. But it is true that the city council could do much more than it has done to spread co-generation in the city?

MR. PRATT: Objection.

JUDGE GLEASON: That's twice, Mr. Blum. I am going to allow you one more time.

MR.BLUM: I take strong exception to this.

JUDGE GLEASON: Mr. Blum, your time is taken away from you and we are going to the staff for their cross.

MR.BLUM: May I be heard on the objection?

JUDGE GLEASON: Very briefly because you have already objected.

MR.BLUM: For parties to be

adversarial does not mean they have to be hostile with each on every issue. There must merely be a material issue before the board on which they have a separate interest where they disagree. The extent to which the city council has thus far failed to adequately push co-generation as an alternative in public buildings, in the buildings it owns, is a direct area of clash between the greater New York Council on Energy and the city council.

That was precisely the area that I had spoken about earlier today.

MR. PRATT: I am not aware that the city council owns any buildings and the city council, moreover, is not here. Certain members of it are here.

MR.BLUM: The city government of New York.

JUDGE GLEASON: That is testimony that you could have put if you wanted to put it on.

I have insisted, and I am insisting as I told you in the beginning, that your questions have to be adversarial. Your time has been taken away.

MR. KAPLAN: We didn't put anything

like that on because we didn't think that was the position we wanted to advance. Just for some clarity, Mr. Blum had no input into the creation of this direct testimony.

JUDGE GLEASON: I am not saying that. I am saying that this record has been rife with sweetheart cross-examination. It is now stopped permanently. We are going to maintain this schedule and I really don't want to hear anything more.

MR.BLUM: I am sympathetic with the schedule but I wish to lodge a due process objection.

There were other areas that were adversarial and I did not ask on those because I didn't realize this one wasn't. Thus it becomes a vehicle of arbitrariness.

JUDGE GLEASON: It is a little difficult to define it in advance, we can only define it in terms of the context of the questions you ask.

I told you at the beginning that the the only way I can evaluate is the way you start, and then two misses and you are out of the ball game.

You are out.

CROSS-EXAMINATION

BY Mr. McGURREN:

Q. I have one question. When Mr. Pratt was asking you about the totem co-generator you indicated that there were 15 other American-made systems, is that correct?

A. (Witness Commoner) Yes.

Q. Why is it in your testimony that you happen to pick totem above the 15 American-made systems?

A. (Witness Commoner) It so happens that we have had longer experience with the characteristics of the totem because, in fact, the totem was available before many of these American systems.

MR. McGURREN: Thank you. That's all I have.

JUDGE GLEASON: Any redirect?

MR. KAPLAN: Yes.

REDIRECT EXAMINATION

BY MR. KAPLAN:

Q. I think in one of the first questions Mr. Pratt asked you regarding the Con Ed program of conservation and at one point Mr. Pratt asked you about percentages that will overlap.

Do you remember that testimony?

A. (Witness Commoner) Yes.

Q. Have you prepared or have you done an analysis which would show that portion of your program and compare that percentage of overlap in terms of forecasted conservation vis-a-vis that program put forth by the Con Edison company?

A. (Witness Schrader) Yes. The numbers, in terms of the changes in use per unit, kilowatt hours, were not available in 1981, 5112, between the years 19835 to 1990 for the appliances is we have been discussing.

In the 1983 5112 they are available and I have the percentages of what the varying efficiencies will translate into by way of lesser consumption.

For refrigeration there will be roughly a 6 percent decrease from 1985 to 1990, which means a drop in use per unit of 916 kilowatt hours over the year to 856 kilowatt hours over the year.

For air-conditioning it will be a drop of 10 percent in efficiency performance, that's a drop from 417 to 378 kilowatt hours. For lighting it would be a drop of 1.5 percent, which is 3571 kilowatt hours per household down to 4561 kilowatt hours per household by 1990.

Q. Mr. Pratt, I think, raised some suggestion about brand name loyalty. I think that's the phrase he used.

In your analysis did you consider -- I am sure there is a term of art for this but I don't know it -- did you consider the possibilities of other companies beyond Amana manufacturing -- I think we did this in terms of refrigerators -- refrigerators which replicated that of Amana? Was that a normal occurrence of the marketplace, in your analysis?

A. (Witness Commoner) Yes. Amana has a tendency to be a technological leader in the field. I would expect that the appearance of the Amana refrigerator with this rather high energy efficiency will result in other companies getting into competition and producing, others perhaps trying to exceed the efficient seats of the Amana model.

Q. So in your judgment, the question of brand name loyalty would not necessarily militate against the achievement of your projected figures?

A. (Witness Commoner) No, I don't think so. Because, as I say, my experience is, and I have owned an Amana refrigerator, my experience is that they turn up first with the useful technological invasions.

Q. Let me go back to the previous question. In terms of the discussion you had with Mr. Pratt regarding the conservation that would happen in any case, that he cited from the Con Ed forecasts. To your knowledge, does Con Ed now perform any sort of funding program similar to the one that you are proposing with zero interest loans which would implement their forecasts?

A. (Witness Commoner) No, not to my knowledge.

MR. KAPLAN: I have only two or three more questions, Judge.

Q. Mr. Sanoff referred to environmental problems and your consideration of them. I believe he you indicated you were aware of environmental problems that would result from the utilization of co-generators.

A. (Witness Commoner) Yes.

Q. Could you tell the board whether or not in your judgment it is possible that those problems be dealt with as they were projected?

(Question read)

A. That's the environmental problems. Yes, the chief problems that were referred to was the fact that an engine driven by methane may produce nitrogen oxides. That problem can be dealt with in at least two different ways that I know of.

For example, since this is a problem which has occurred in the automotive pollution field, there is a good deal of evidence about it. There were hearings held in 1973 by the Committee on Public Works in the United States Senate, and in those hearings there is the description of an engine made by Honda, which is a so-called charge stratification engine, which results in a 69 percent reduction in NOX.

In this case they compared it with a Vega, I think it was, model car with and ordinary engine and with the Honda charge stratified engine.

That means that a charge stratified engine used to drive a co-generator, which is a perfectly straightforward application, would result in a very appreciable reduction in NOX emission.

Another approach which can be used is in the case of a co-generator driven by a gas turbine. In that case the NOX can be appreciably reduced by putting an after burner on the exhaust, an additional stream of methane is introduced and that tends to reduce the NOX emissions.

I might add that there is a way of building a co-generator which has zero environmental pollution, and that has already been constructed by the Sanyo company. What it is is a series of amorphous photovolteic cells bathed in a stream of water, about 5.6 percent of the solar energy is converted to electricity and most of the rest of it is converted to heat. That is a co-generator. It produces no environmental pollution.

The reason why it is worth talking about is that Sanyo has now built an automated factory to produce these amorphous cells and has reduced the cost of these cells to the point where I think New York City may become the first point where it is applied.

The rates of electricity in New York City are so high that the Sanyo photovolteic cell, and therefore the Sanyo co-generator, will be economically applicable first in New York City in this country.

There, I think, is another opportunity to take up the slack created by closing down the Indian Point plants and doing it to great economic, and, I dare say, social advantage.

Q. Mr. Sanoff asked you about the difficulty of interconnection, interconnecting co-generators with grid systems or Con Ed's system. Are there examples, such as Big Six, in Queens where there have been connections or have not been connections?

A. (Witness Commoner) Big Six is not connected. In fact, to my knowledge, the gas-driven co-generators in New York City are not connected to Con Ed.

Starrett City, I think, I think is stand alone.

JUDGE PARIS: Dr. Commoner, what is Big Six?

THE WITNESS: (Witness Commoner) Big Six towers is a large housing complex in Queens which is supplied by natural gas-driven co-generators.

The reason why it comes up is that it is the most recent example of a residential co-generator system.

Q. Do you have any information regarding reliability of this free-standing, meaning non connected, co-generator or any information regarding its capacity factor, up time, down time?

A. (Witness Commoner) I know more about the Starrett City operation because we happen to be particularly interested in it. It seems to have an excellent record of reliability and is, in fact, now funded by New York City to undertake a very interesting energy conservation -- further energy conservation step by exchanging heat and methane with a sewage treatment plant that's right across the street.

The city was very careful in examining this project, which I think cost several million dollars, and was satisfied, I believe, that the reliability of the system warranted this kind of interconnection.

Q. Given Mr. Sanoff's concern about the interconnection capabilities are you aware of or are there any policies or mechanisms by which Con Edison company either has retarded or advanced the ease of interconnection?

MR. SANOFF: I object to that. I don't understand how that a redirect.

JUDGE GLEASON: Say it again.

MR. KAPLAN: The question was, given Mr. Sanoff's concern about the inability or difficulty of connection, I am trying to find out whether the witnesses are aware of any policies or practices of the Con Edison corporation itself which militates against, which retards, which makes it payable those interconnections that he was so interested in.

THE WITNESS: (Witness Commoner) I have no direct knowledge.

THE WITNESS: (Witness Schrader) I have no to knowledge.

Q. Mr. Pratt, or Mr. Sanoff, the attorneys for the licensees, suggested that approach you took in your testimony was somehow inappropriate because it required the dispersion of the cost of the mechanisms that you are suggesting over a broad range of people.

Do you have a judgment regarding the appropriateness or lack thereof of spreading out the cost, or is it your belief -- withdraw the "or."

What I am asking is given the suggestion by the licensee's attorneys that your testimony required the disbursal of costs, the societal bearing of the burden here, that that was somehow a contradiction in your testimony. Would you comment on that?

A. (Witness Commoner) No. In fact, I think that is the basic philosophical justification for what we are proposing.

The fact of the matter is, and this is certainly, I think, a position I hold very strongly, the existence of the two nuclear power plants is a burden imposed by the operators and the builders of those plants on all of society. That is a burden which is spread across the population. It is unfortunate that it has happened.

We are faced with the social problem of undoing that burden, and I think it is appropriate that society has a whole should contribute to releaving that burden. This is a social problem.

I know, I realize that it was created as a private investment, but it has emerged clearly as a social problem and I think it makes perfectly good sense, in fact it is the only way to go about it, to turn to society as a whole and say that this is our problem and how are we going to solve it.

I think it is fair to disburse the cost of solving it in some socially equitable way.

MR. KAPLAN: Nothing else.

JUDGE PARIS: Dr. Commoner and Mr. Schrader, you say according to a city energy report there are available air conditioners, room air conditioners with an EER of ten. I just wonder how available room air conditioners with this kind of EER are available? Do you know?

THE WITNESS: (Witness Commoner) This is simply the result of a report that they worked on and they are available. I think there are some manufacturers here in New York that produce them.

JUDGE PARIS: I could go to down and buy one today if I wanted to?

THE WITNESS: (Witness Commoner) I think so. I am not sure about this but I think there is a Friedrich air conditioner.

MR. PRATT: If I could respond to that, we had, in addition --

MR. KAPLAN: I object.

JUDGE GLEASON: Is this going to be testimony?

MR. PRATT: I am just identifying a document which responds exactly to Judge Paris' question.

MR. KAPLAN: Maybe we should do it privately in that it hasn't been entered into evidence.

MR. SANOFF: It would be ex parte then.

MR. PRATT: I will make it available as an exhibit. I want to offer, when the time is appropriate, the one we have identified already.

JUDGE GLEASON: How do you want it marked? PA Exhibit 53?

MR. PRATT: I believe it would be 53.

(Port Authority Exhibit 53 was marked for identification.)

MR. GLEASON: I am not sure who this should be addressed, but is the totem type co-generators utilizeable, can be utilized in what you would consider energy intensive industries? You just talked about residential properties, but how about higher users of energy?

THE WITNESS: (Witness Commoner) You

mean like the steal industry, for example?

JUDGE GLEASON: You were talking about New York. Let's take the Empire State building.

THE WITNESS: (Witness Commoner) I don't understand the question. You mean could it be used in a commercial building?

JUDGE GLEASON: Yes.

THE WITNESS: (Witness Commoner) Yes.

JUDGE GLEASON: Has it been?

THE WITNESS: (Witness Commoner) No, the only applications of that particular co-generator, very few in the United States, but co-generators have been used in, for example, Starrett city, a 5000 unit apartment building. It has certainly been used, co-generators, in industry. In fact, the problem is not how large you can go, because it turns out that large co-generators are more readily available than smaller ones. The real problem in getting into the residential market is the existence of relatively small co-generators, and that's a recent development.

Big ones have been available for a long time because they have been used in industry.

JUDGE GLEASON: Your social solution

to this problem I presume is a universal solution or a national solution, in your view?

THE WITNESS: (Witness Commoner) Do you mean --

JUDGE GLEASON: Does that apply to every nuclear plant in the country?

THE WITNESS: (Witness Commoner) The calculations would have to be made. The only other nuclear power plant with which I am familiar is the Calloway plant -- in this regard, is the Calloway plant in Missouri. During the NRC hearings about licensing that plant, I did a calculation which showed that if the money was spent to simply buy efficient air conditioners and give them to the customers in the area, it would eliminate the need for the Calloway nuclear power plant.

So that I think the generic approach that we have developed is probably applicable.

Again, you have to take into account climb mat particular -- I think that in Missouri the pure air conditioner approach is probably more effective than it is here. So you would have to look at the climb plat particular, and indeed economic conditions in each nuclear power plant area.

But my impression is, and certainly with the applicability of co-generators, my impression is that the approach that we have developed here could probably apply equally well to most of the nuclear power plants in the United States.

JUDGE GLEASON: Thank you.

You are excused gentlemen. Thank you very much for your testimony.

MR. PRATT: Judge Gleason, I would like at this time to formally offer PA exhibits 52 and 53 in evidence.

JUDGE GLEASON: Objection to the admission of those documents in evidence?

MR. KAPLAN: No objection to 52, but I do object to 53. I don't know what it stands for. Since it was not referred to in the course of testimony, no witness was asked a question about it,. I have no objection to 52 but I do as to the other.

JUDGE GLEASON: What is the document?

MR. PRATT: 53 is an analog to 52. It is a Directory of Certified Room Air Conditioners, April 1982. I believe what we have done is copied the pages of a document that's a little bit larger. We have copied all the pages that deal with room air-conditioning units.

JUDGE GLEASON: One is April 1982 and the other is June 1982?

MR. PRATT: The June 1982 refers to refrigerators and freezers.

JUDGE GLEASON: It is just a Directory of Certified Room Air Conditioners. Do you object to that?

MR. KAPLAN: The difficulty, the argument here is --

JUDGE GLEASON: All it is going to do is respond to Judge Paris' question. That's the only purpose it was used.

MR. KAPLAN: One is 1982, over a year-old, so it doesn't reflect what is currently available. It is being offered in order to dispute, I gather, to either raise questions about the availability of the carrier or the air conditioner that Dr. Commoner spoke about. So I don't think it does that. I think it leaves a false impression. I object it to it being bound in the record as a piece of evidence.

JUDGE PARIS: Mr. Kaplan, it provides

an answer, albeit a dated one, to my question.

MR. KAPLAN: If everyone recognizes there may be new information with a change in figures, then I have no problem. Take it for what it is worth.

MR. PRATT: I am informed it is the the most recent document extant.

JUDGE GLEASON: April 1982 is pretty recent for a directory of this type.

MR. KAPLAN: I object to its relevance to what is available.

JUDGE GLEASON: For the limited purpose of answering the specific point of inquiry of Judge Paris it will be admitted into the record and so will document PA Exhibit 52.

MR. PRATT: At this time I would make one additional request. There have been references during the cross-examination to saturation levels and various numbers, all of which have come from with respect the 1983 document, that comes from tables 9-1 through 9-5 of the 1983, 5112 statement. The title of this table is the "residential KWH by end use." Then they give it for 1980, 1985, 1990 and 1995.

MR. KAPLAN: 51112, is that what you

are referring to?

MR. PRATT: For 1983.

I would at this time ask that these five pages be identified as PA 54 and I would move them into evidence as well.

JUDGE GLEASON: Without objection -- dash

MR. KAPLAN: I was under the impression the whole 5112 had gone in.

MR. PRATT: No.

JUDGE GLEASON: PA 54 will be admitted into the record.

(Exhibits received.)

MR. PRATT: I have the original document. I don't have the appropriate copies but will have them in here tomorrow.

JUDGE GLEASON: The reporter has to have them today.

MS. POTTERFIELD: Judge Gleason, we were going to argue UCS NYPIRC and the city council's motion. I understand witnesses are waiting but if the argument won't be too long, I wonder if we can take it now.

JUDGE GLEASON: I don't think the cross is going to be very long on these witnesses, so we don't mind waiting. Mr. Fleisher has been here for sometime back and forth.

MS. FLEISHER: We wouldn't mind waiting because we would want to hear the argument on that one, too. In any event, we will be the latest out.

JUDGE GLEASON: If that's agreeable with you, we will hear Mr. Wang, the argument, and then Mr. Fleisher.

MS. FLEISHER: I didn't understand Mr. Wang was in that. I thought it was just between the two of them. I think were would rather ;o now. Mr. Fleisher is getting tired.

JUDGE GLEASON: Mr. Wang is going now.

It doesn't look like there be much more cross-examination.

Whereupon

GEORGE C. S. WANG, being duly sworn by the administrative judge, testified as follows:

DIRECT EXAMINATION

BY MR. SANOFF:

Q. State your name and business address for the record.

A. My name is George C. S. Wang. My address is Consolidated Edison Company of New York, 4 Irving Place, New York, New York 10003.

Q. Mr. Wang, could you please turn that microphone around so that it faces you and talk into it.

A. Okay.

Q. Do you have before you a copy of a document entitled "Licensee's testimony of George C. S. Wang on commission question 6"?

A. Yes, I do.

Q. Do you have any changes or corrections?

A. No.

Q. Does the document have before it, annexed to it a table entitled "Table 1"?

A. Yes.

Q. Now, was this testimony and table 1 prepared by you or under your direct supervision?

A. Yes, it was.

Q. Is it true and accurate to the best of your knowledge and belief?

A. Yes.

Q. And do you adopt it as your sworn testimony in this proceeding?

A. Yes, I do.

MR. SANOFF: Chairman Gleason, I move

that the testimony of this witness be admitted into offered and bound into the record as if orally presented.

JUDGE GLEASON: All right. Any objection?

Hearing none, the testimony of the witness will be received in evidence and bound into the record as if read.

(The bound testimony follows)

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:
James P. Gleason, Chairman
Frederick J. Shon
Dr. Oscar H. Paris

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 April 12, 1983

LICENSEES' TESTIMONY
OF GEORGE C. S. WANG ON COMMISSION QUESTION 6

ATTORNEYS FILING THIS DOCUMENT:

Brent L. Brandenburg

CONSOLIDATED EDISON COMPANY
OF NEW YORK, INC.
4 Irving Place
New York, New York 10003
(212) 460-4600

Charles M. Pratt

POWER AUTHORITY OF THE STATE
OF NEW YORK
10 Columbus Circle
New York, New York 10019
(212) 397-6200

TESTIMONY OF
GEORGE WANG

Q. Please state your name and business address.

A. George C. S. Wang, 4 Irving Place, New York, New York.

Q. Please state your education and experience.

A. I received a Bachelor of Arts degree in Economics from National Taiwan University in 1958. From New York University, I received an M.B.A. degree in 1965, and a Ph.D. degree in 1972, majoring in statistics and economics. I am a member of the American Statistical Association. Prior to joining Con Edison, I was employed by CBS, Marketing Division as a statistician, 1968-69. During my employment with CBS, my responsibilities involved market research utilizing statistical sampling technique, regression analysis and experimental design. In 1970, I was employed by Con Edison. Presently, I am Forecast Development Manager in the Electric Forecast Section of the Forecasting and Economic Analysis Department. My responsibilities are in the areas of statistical and economic analysis, econometric modeling for electric sendout, sales and revenue forecasts, interdepartmental consultations on statistical matters, and evaluation of computer applications in the forecasting area.

Q. What is the purpose of this testimony?

A. The report on "The Economics of Closing the Indian Point Nuclear Power Plants" prepared by the Energy Systems Research Group, Inc. appears to suggest that a price elasticity of -0.4 for the Con Edison service area would not be unreasonable (p. 72). The purpose of this testimony is to show that -0.4 is a gross overstatement of the price elasticity of demand for electricity in the Company's service area.

Q. Have you ever testified in legal proceedings on forecasting models which include estimates of price elasticities?

A. Yes, I have. In the Public Service Commission electric rate case No. 28211, I testified with respect to Con Edison's econometric model used to forecast electric sendout. The model includes estimates of the short-term and long-term price elasticities of demand for electricity in the Con Edison service area.

Q. Would you briefly define "price elasticity"?

A. Price elasticity is a measure of change in consumption of a certain good in response to a change in its price. The measure is simply the ratio of the percentage change in consumption and the percentage change in price. The value of price elasticity is usually negative, i.e., when the price of a good increases, the demand for the good decreases. There are generally two time periods for the price elasticity. The short-term price elasticity measures the immediate response to a price change, and the long-term price elasticity reflects consumers' gradual adjustment to price changes over time. If the short-term price elasticity equals - .10, a 10% increase in price will result in a decrease in consumption by 1%.

Q. What are the estimated values of the short-term and long-term price elasticities included in Con Edison's sendout forecast model presented in the Public Service Commission Case No. 28211?

A. The estimated short-term price elasticity was -.10 and the estimated long-term price elasticity was -.25.

Q. Other things being equal, does the magnitude of price elasticity affect Con Edison's revenue requirement in a rate case proceeding?

A. Yes, it does. For example, other things being equal, had the estimated short-term price elasticity been -.40 instead of -.10, Con Edison's net revenue forecast presented in the Public Service Commission Case No. 28211 would have been 11% or $270 million less, and the revenue requirement would have been $270 million more than the Company's request.

Q. Besides the other independent variables in Con Edison's econometric model, how was the price variable structured into the model in order to estimate the short-term and long-term price elasticities?

A. By the definitions for price elasticities described before, the short-term price elasticity and its long-term "steady state" value can be represented by a power series which asymptotically approaches to a constant. Let the short-term price elasticity be a1 and the initial value of the power series be d, then the long-term price elasticity equals a1/(1-d). This expression is demonstrated in Table 1.

Q. Would you describe the historic data used to estimate the model?

A. The model presented in the Public Service Commission Case No. 28211 used quarterly data from the first quarter of 1972 through the fourth quarter of 1981 for electric sendout which is the dependent variable and used quarterly data from the first quarter of 1973 through the fourth quarter of 1981 for the price variable which is one of the independent variables. All other independent variables included in the model have the same historic modeling period as the sendout data. These historic modeling data have been updated through the fourth quarter of 1982. The estimated price elasticities using this extended historic period did not change significantly from the values mentioned before.

Q. Were the results of Con Edison's econometric model for electric sendout forecast used in the decision of Public Service Commission Case No. 28211?

A. Yes.

TABLE 1

Formula for the Estimation of
Short-Term and Long-Term Price Elasticities

Let the short-term elasticity be a1 and the long-term adjustment process be represented by the following power series:

$$1+d+d^2+...+d^n$$

which asymptotically approaches $1/(1-d)$, for $0 \leq d < 1$. The long-term price elasticity is, then,

$$a1(1+d+d^2+...+d^n)=a1/(1-d).$$

The model for estimating a1 and d can be structured as follows:

$$Y_t=a_o+a1(1+dL+d^2L^2...+d^t\ L^t\ )P_t+\sum_{i=2}^{K} a_iX_{it}$$

$$=a_o+[a1/(1-dL)]P_t+\sum_{i=2}^{K} a_iX_{it}$$

Where Y_t, P_t and X_{it} are in logarithm, and L is the backward shift operator.

Y_t = Electric sendout in quarter t.

P_t = Real electric price in quarter t.

X_{it} = Other independent variables.

The estimated values for a1 and d are -.1 and .6 respectively. The long-term price elasticity is,

$$a1/(1-d) = -.1/(1 - .6) = -.25.$$

MR. SANOFF: The witness is available for cross-examination.

JUDGE GLEASON: Mr. Blum.

CROSS-EXAMINATION

BY MR. BLUM:

Q. Dr. Wang, it is your belief that price elasticity of for the purchase of electricity by customers of the Power Authority would be rather small, is that correct?

A. In New York City, yes.

Q. But you don't believe it would be zero, do you?

A. If not zero it will be very close to zero.

Q. So a study which assumed zero price elasticity for Power Authority customers would thereby exaggerate the costs of shutting down Indian Point slightly, is that correct?

MR. SANOFF: Your Honor, I am going to object to this question. Dr. Wang was not offered as any witness to get into the debate as to whether price elasticity is a proper offset to the cost impact of the shut down of the plants. He was offered for one discrete purpose: To testify as to the price elasticity of demand in the Con

Edison franchise territory. His knowledge, his expertise and his testimony does not extend one whit beyond that point.

MR.BLUM: That's absurd.

MR. SANOFF: You turn a beautiful phrase.

JUDGE GLEASON: Please. His testimony can be examined, his expertise can be examined on price elasticity.

Objection denied. If he doesn't know, all he says is I don't know. That's all.

Proceed.

Do you understand the question?

THE WITNESS: Yes.

Well, from what I understand during the proceeding it appears that most of the calculations assumed zero elasticity. I think that the record should say what was calculated to cause whatever they believed. I don't know what impact they would be. You have to recalculate them.

Q. You have done studies of price elasticity of Con Edison's customers for the period 1972 to 1982, have you not?

A. Yes.

Q. Now, during that time, in real terms, that is, constant dollars, the price of electricity for Con Edison customers went up 60 percent, did it not?

A. Yes.

Q. And you found, notwithstanding such a large increase in price, that the elasticity was very low, is that correct?

A. That's correct.

Q. So the customers were able to keep on purchasing essentially the same amount of electricity, notwithstanding the price rise, is that correct?

A. I will give you a couple of numbers to compare with, see how much they have conserved over the last ten years.

Since 1972, was the first year I started with my model and study, I will give you the 1972 number first. In 1972 total Con Edison sent out, including PASNY -- at that time PASNY customers were still Con Edison's customers -- was 36 billion 810 million kilowatt hours.

In 1982 the total was 36 billion 907. It is slightly higher than 1972.

So the conservation, you can see how

much they have done.

The price increase was 60 percent, but the 1982 consumption is slightly higher than 1972.

Q. You said this includes a different group of customers?

A. No, its same group of customers. The 1982 number includes the PASNY customers. The sales to customer, PASNY customers was included.

Q. I see. So it is true that for both Con Edison and PASNY customers combined, that a 60 percent increase in price during this period resulted in know reduction in their usage of electricity, is that correct?

A. As far as these two numbers are concerned, they speak for themselves.

Q. Now, I want to break down what kinds of things could go into producing a reduction in use of electricity. One thing that could do it is if a business stayed where it was but simply used less electricity, that would reduce consumption, would it not?

A. Yes.

Q. Secondly, if a business ceased operating altogether and used zero electricity, that would produce a reduction in consumption, would it not?

A. Supposedly.

Q. If if a business moved away so it was no longer in Con Edison service territory, that would produce a reduction in use of electricity, is that correct?

A. Yes.

Q. And finally, if residential, if people living in residences, as residential customers, either moved away or used less electricity, that would produce a reduction?

A. You chase them away, yes.

Q. So it is your testimony that considering all four of those things, businesses moving away, businesses shutting down, businesses using less electricity, residential customers moving away and residential customers using electricity; all five of those things combined produced no reduction in consumption of electricity during the period of 1972 to 1982, notwithstanding the 60 percent price rides, is that correct?

MR. PRATT: I am going to object to that question. It suggests that those are the only factors that are happening during that period and I object to that.

MR.BLUM: You can do it on redirect, Mr. Pratt.

MR. PRATT: He is not my witness.

Excuse me, that's not true.

JUDGE GLEASON: Answer the question.

A. I don't think I have ever said that business has moved away. There are residential customers that have moved out of the city. I have not said anything in the area. That's your assumption. I said if they do, if that happened, it would reduce consumption.

Q. But I am saying that among all of those things, and whatever else that could produce a reduction in the consumption of electricity, your testimony is that for all the causes combined there has been no reduction in the consumption of electricity?

A. I simply gave you two numbers to compare with. I read a number out of my records. Those were the actual numbers in our book.

You asked me to compare the conservation. I gave you two numbers to compare with. That's all I did.

Q. I understand, but I am simply trying to clarify that taking into account all possible causes of reduction in consumption of electricity, the 60 percent increase in rates for both Con Edison and PASNY customers combined during this ten-year period has produced no reduction in consumption of electricity; that's correct, is it not?

A. I would put it this way --

Q. Could you first answer yes or no and then give additional explanation?

JUDGE GLEASON: Mr. Wang, you already indicated there has been an increase. Why don't you just answer his question yes.

MR. SANOFF: He said he wants to qualify it, explain it.

THE WITNESS: I would like to qualify it. I can't give you a simple yes. We have to recognize that as time goes by, even that we have experienced tremendous price increases, coupled with the recession. I believe the living standard in 1982 is higher than in 1972. In that respect we sho[illegible] expect some increase in electricity consumption, but it didn't go up. That is conservation also.

Therefore, I cannot just say yes. There is conservation but the conservation we are talking about is that we have given up the growth.

Q. So you are saying that the price elasticities are really quite a bit higher than what your data show; is that your belief?

A. The elasticity is just what I calculated. I calculated the price elasticity of minus.1. The data just tells me that's the number I will get if I do any kind of econometric analysis. If anybody else would do it using the same kind of data I would think he would get similar number.

Q. Similar number to what?

A. Similar to what I got.

Q. To the negative .1?

A. Yes.

Q. And that's for both Con Edison and PASNY customers?

A. Yes, for the service area.

Q. And what do you get in the long run for both Con Edison and PASNY customers combined?

A. Well, the service area include PASNY and Con Ed.

Q. What is your long run elasticity?

A. Long term elasticity?

Q. Yes.

A. Minus .25.

Q. But you would characterize these elasticities as rather low, is that correct?

A. No. I don't think this at all. It is proper.

Q. No, I didn't low in the sense of incorrect, but I meant low in the sense as price elasticities goes foreelectricity nationally, there is a very low pricing elasticity?

A. I don't understand why you said it is low nationally.

Q. Aren't there other locations that have elasticity significantly higher than what you came up?

A. There are other regions which have higher elasticities but there are others that could have elasticities lower than ours.

Q. But it is fair to say that it does not look like the 60 percent price increases forced the customers into substantial reductions in their use of electricity? That's apparent from your data, is it not?

A. No, it did not produce a lot of

reduction in consumption.

Q. I am sorry, you are agreeing that there were no substantial reductions in consumption, is that correct?

MR. PRATT: I object to that question.

MR.BLUM: I didn't understand him and I was simply trying to clarify what he had said before.

MR. PRATT: I object because you are changing the subject from one particular customer or particular customers to looking at the system as a whole.

JUDGE GLEASON: Clarify your question.

MR.BLUM: I would like the reporter to read back the answer.

(Answer read.)

MR. BLUM: We wanted the previous question and previous answer.

(Question and answer read).

Q. So you would agree that the empirical data of the last ten years does not show customers having to forego large amounts of electricity as a result of the 60 percent price increase; you would agree with that, would you not?

A. Yes.

Q. And that 60 percent price increase does not take into consideration major economic dislocations, has it?

A. The 60 percent increase, as I said before, that to the extent we lost the sales in growth, we don't have any growth. If you compared those two numbers I gave you before, you can see you don't have any growth at all. You do lose some sales. If there were not a price increase like that, you probably would have higher sales.

Q. You are talking about Con Edison sales?

A. I am talking about Con Edison electric sales. If price didn't increase by 60 percent, 9 sales would probably be higher.

Q. That's what you mean by price elasticity?

A. Yes.

Q. By major dislocation I mean something broader than that. I mean the Con Edison price increases have not, for example, significantly hindered the economic growth or well being of New York City, have they?

MR. SANOFF: I object to that. I think it is beyond the scope of this witness' testimony.

JUDGE GLEASON: It is.

Mr. Blum, what are you trying to prove with this witness anyway? What are you trying to extract from him?

MR.BLUM: What I am trying to show is that implicit in this figure of very low price elasticity is empirical evidence supporting the proposition that electrical rate increases do not produce dramatic hindrances to the society's economy.

Otherwise it would show up in terms of higher price elasticities along with these other allegedly dramatic effects.

JUDGE GLEASON: That seems to me to be beyond the scope of his testimony.

MR.BLUM: Dr. Wang supposedly must know about the processes by which behavorial responses to electrical price increases occur. I assume he is just not punching numbers into a computer.

JUDGE GLEASON: It seems to me you can restrict your questions to challenging the accuracy of his figures more directly by asking him implicit questions or questions that affect the marketplace and affect the growth and everything else. I am sure he has some knowledge about those things.

I think you ought to make your questions more direct and let's get out of here because his testimony is not that complicated.

Q. What do you see as the major effects of that 60 percent increase in electrical rates?

MR. SANOFF: I object to that. I think Mr. Blum is trying to extend Dr. Wang's testimony into areas that they don't belong. He is trying to make him his witness. Dr. Wang has testified to a price elasticity. If he agrees with it, then he ought to accept it. If he disagrees with it, he ought to cross-examine him as to its accuracy.

MR.BLUM: What price elasticity is, it is one measure of behavorial responses to changes in the price of electricity. That doesn't occur in a vacuum. It occurs as a combination of behavorial responses. I am trying to examine on the significance of his data for those responses.

MR. SANOFF: He hasn't defined price elasticity in that basket of terms Mr. Blum used.

JUDGE GLEASON: His testimony is not

in the terms or implications of all this. All he is doing is reporting what happened in terms of price elasticity.

MR. SANOFF: Of demand. That's all he has testified to.

Q. Dr. Wang, do you know of any circumstances where there have been major economic dislocations due to rate increases in electricity but no very substantial price elasticity?

MR. SANOFF: Mr. Blum, all that question proves is your ingenuity in trying to circumvent a ruling. I object.

MR.BLUM: The licensees can't have it both ways unless there is something very remarkable about price elasticities as a phenomenon that I am simply not understanding, in which case perhaps Dr. Wang could explain it to me.

MR. SANOFF: We put this testimony on to rebut a statement in ESRG's report that the price elasticity of demand was minus .4. We put on testimony to show that Dr. Wang's twelve-year or ten-year computation, his econometric model which he uses to forecast sendout and sales shows a short run price elasticity of minus .1. That's all his testimony is designed to do.

MR.BLUM: That's correct but it is not my fault if along the way it happens to knock out the testimony of three of your witnesses, but if that is the central implication of it I am entitled to bring that out.

JUDGE GLEASON: Proceed, Mr. Blum. We can't deny you that that opportunity. I do think you can get it more directly.

MR.BLUM: I don't anticipate this going on much longer.

Q. Dr. Wang, it is true, is it not, that the 60 percent increases in electrical rates for Con Edison have not produced major economic dislocations for New York?

A. If we look at the recent recession, everybody is talking now that we are getting out of the recession. The reason the recession started in 1980, that every part of the nation was hit so hard but not New York City. It is clear that the 60 percent increase hurt the customer, hurt everybody.

I think the other parts of the country have also experienced the high prices of electricity. But if you look at the recent recession, New York City was not hit that hard.

Q. What you are saying is the experience with the recent recession shows that Con Ed's rate increases did not have the significant dislocation effect on the New York economy; that's what you mean, is it not?

A. If anything at all, Con Edison is not responsible.

Q. And that 60 percent increase in rates is not responsible?

A. No, did not cause any major dislocation or cause anything that would hurt New York City.

Q. And it has not caused a very significant number of workers to lose their jobs, has it?

A. I don't know of any significant damage because of the 60 percent increase in rates. I don't know any.

MR.BLUM: Thank you very much, Dr. Wang.

MR. McGURREN: No questions

MR. SANOFF: No redirect.

JUDGE GLEASON: Thank you, Dr. Wang. We appreciate your testimony.

Mr. Fleisher.

MS. FLEISHER: Your Honor, I did ask one licensee if he would let us put it in an affidavit but he said no.

WHEREUPON

WALTER FLEISHER, previously sworn, resumed and testified as follows:

DIRECT EXAMINATION

BY MS. FLEISHER.

Q. Mr. Fleisher, you have before you a four-page document entitled "Testimony of Walter L. Fleisher"?

A. Yes, I do.

Q. If you were to be asked the same questions as appear on that testimony today, would your answers be the same?

A. Yes, they would.

Q. Did you prepare this testimony yourself?

A. Yes.

Q. And have you any corrections to pages 1, 2, 3 and 4?

A. Yes, there are a few minor corrections. On page 1, line 10, after "B," where it says "appendix B," after that insert, "Is a listing of 20," and then it goes on.

On page 1, line 18, the word "section," third word from the end of the line, has two S's in it and one should be stricken.

On page 2, line 1, last word is "constant." The C should be an S in that.

Also inadvertently the title was left off of appendix B, which should say, "Proceedings at which Walter Fleisher appeared as an intervenor and/or witness."

That's the sum of my corrections.

MS. FLEISHER: I move that the testimony of Walter Fleisher and appendix B be bound not record as if read.

JUDGE GLEASON: Is there objection?

Hearing none, the testimony will be received in evidence and bound into the record as if read.

(The bound testimony follows)

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

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

April 12, 1983

TESTIMONY OF

WALTER L. FLEISHER

Contention 6.1

WEST BRANCH CONSERVATION ASSOCIATION

443 Buena Vista Road
New City, N.Y. 10956
914/634-2327

WALTER FLEISHER

Q. Please state your name and address.

A. Walter L. Fleisher, Vice-President of the West Branch Conservation Association, 443 Buena Vista Road, New City, N.Y. 10956

Q. Have you previously testified in thie proceeding?

A. Yes, on contention #2.2(a) and 2.2.1 on January 25. With my prior testimony I provided a resumé and expanded on it in the first two pages of testimony. I wish to supply additional background as Appendix B, listing is a of 20 17 before the New York State Public Service Commission and 3 before the New York State Energy Office, proceedings in which I participated as an intervenor, and in many as a witness.

Q. What is the purpose of your testimony?

A. My testimony will assess the economic benefits that will accrue to Rockland County if Indian Point Units 2 and 3 are shut down. Incidently, the same benefits will accrue to Orange County and the ~~s~~section of New Jersey served by Rockland Electric Company (a wholly owned subsidiary of O&RU.)

Q. What is the basis for the benefit to Rockland County?

A. Since 1973 or 1974, when Bowline Unit #2 came on line, Orange and Rockland Utilities (ORU) has had excess capacity of about 300 mW. The excess capacity, which was ruled prudent at the time by the New York

State Public Service Commission, has been a constant tax on ORU's customers.

Summer peak demand has varied between 662 and 717 mW between 1977 and 1982, and winter peak demand between 509 and 536 mW. (Vol. 1, Exh. 1, Sect. 5-112 New York Power Pool (NYPP) Report 1983). O&RU's generating capacity is 987 mW summer and 999 mW winter, (Vol. 2, Exh. 1, ibid.) Average load calculates below 400 mW. Therefore, there is, on average, over 500 mW of excess capacity, and on peak 270 to 325 mW of excess capacity.

During this period O&RU's customers have not received any of the "cheap" nuclear generated power from ConEd or PASNY.

During 12 months ending March 31, 1982, O&RU sold for resale 510,371 mWh of electricity for $26,194,000 excluding sales to O&RU's subsidiaries. (PSC Case #28278 O&RU Exh. E-4, Schedules 1 and 4). The average capacity calculates at 58 mW. The net value of the sales is about $1,800,000 per year, (PSC Case #28278 Recommended Decision p. 15), or $31,000/mW year

Q. What is the benefit to Rockland County?

A. If ConEd did no more than make use of its share of Bowline Units 1 and 2 it would reduce the capital and operating costs per kWh and improve the heat rate which in turn would reduce the fuel cost.

However, the loss of 5874 gWh of energy produced by Indian Point Units 2 and 3 in 1982, down from 7321 gWh in 1980 (Vol. 2, Exh. 1 1980, 1981 and 1982), which is equivalent to 670 mW years of generator capacity and would call on the NYPP grid. If 10%, or 67 mW years was alotted to O&RU, which I consider reasonable, on average, Rockland County would benefit by (67 X $31,000) $2,077,000 per year. 10% is probably a minimum and it could well be higher in which case the benefit could be two or three times $2,077,000 per year.

Q. Did you consider the effects of the increased fuel cost due to the shutting down of Indian Point Units 2 and 3 and the possible side effect on the economy of Rockland County?

A. The magnitude of the added fuel cost due to shutting down the units is not significant when compared to the recent drop in oil prices of about $5/bbl, or about 16%; the ongoing rise in natural gas price which has varied between 25 and 35% this year and is still going up, the drop in the rate of inflation and consequent drop in interest rates.

It is pure fantasy to think that the effect of one small item of change can be evaluated against the tremendous economic chaos in the United States and world wide.

Q. Does that complete your testimony?

A. Yes.

PROCEEDINGS AT WHICH WALTER FLEISHER APPEARED AS AN INTERVENOR AND/OR WITNESS.

APPENDIX B

Spring Valley Water Co.	1975	PSC #26781
	1978	27260
	1980	27567
	1981	27936
	1983	28253
Orange & Rockland Utilities	1977	27094
	1979	27554
	1981	27909
	1983	28278
Article VIII PSC Law, 149b	1974	26368
(After 1978 became State Energy Office)	1975	26829
	1976	26985
	1977	27154
	1978	27319
N Y State Energy Office 5-112	1980	
	1981	
	1982	
Generic PSC		
Nuclear vs Fossil	1976-8	26974
Site Survey	1978-82	27282
Sterling Abandonment	1980-1	27794

MS. FLEISHER: The witness is ready for cross-examination.

JUDGE GLEASON: Who wishes to proceed?

CROSS-EXAMINATION

BY MR. FARRELLY:

Q. On page 2 of your testimony, line 15, you set out the sales by O & R for resale. Do you see that?

A. That's correct.

Q. Do you have any information about the level of purchases by O & R of utilities for the same period of time?

A. Yes, I know of it. It was about 50 percent of that.

Q. Your testimony is that that O & R purchased --

A. About 250,000 megawatt hours.

Q. Can you give us some idea of what the cost of that power was?

A. No, I don't know that.

Q. Would you accept, subject to check, that the same period of time O & R purchased 27 million 747 thousand dollars worth of power?

A. I don't believe that's correct but I am not positive of it.

It may take me a little while to locate that because this is a long, drawn-out process.

(There was a pause in the proceeding.)

A. Do you have the reference?

Q. Unfortunately I don't. I believe it is from an O & R document in their rate case which I can supply to you.

A. I have the rate case here but I don't remember where the sales for resales and the purchased power occur.

I am sorry, I have it. It is 27,000 647 thousand dollars.

Q. That's 27 million?

A. 27 million rather, that's correct.

Q. Now, on page 1, line 24 of your testimony, you testify to the fact that O & R or orange and Rockland utility has had excess capacity of 300 megawatts.

A. That's correct.

Q. Do you have the most recent 5112 filing of the New York Power Pool before you?

A. Yes, I do.

Q. Please turn to page 37, volume 2 of that do you mean.

MS. FLEISHER: Mr. Farrelly, one more time, no book for the judges?

JUDGE GLEASON: We are used to being without things by now.

Q. Do you see the portion of that table that says excess DEF?

A. Yes.

Q. Isn't it true that for both the summer and winter periods, that the excess capacity in each of the years indicated, which is from 1983 to 1999, in no case exceeds, I believe, 188 megawatts?

A. That's not the excess capacity I am talking about.

Q. When you use excess capacity are you counting for the required 18 percent reserve?

A. There is nothing that says that they can't sell it. They only have to it above their peak load requirement under the Power Pool agreement but it didn't say they can't sell that 18 percent if it is available for sale.

Q. You are not suggesting that they would be able to sell the capacity, are you?

A. The excess capacity is available for sale, yes.

Q. If that is so, if you were selling all of that capacity, wouldn't you be violating the required 18 percent reserve margin for the pool?

A. Not if it is being sold on an interruptable basis. If they were selling it to their own customers, yes. But if it is something which is going out over the Power Pool grid as surplus, I don't see any reason why not.

Q. Are you suggesting there is a market for such interruptable power, capacity?

A. That's what it is. It is based on the cost and availability under the program, the computer program of the Power Pool. It calls on it, whatever is available at the lowest price at that time, is what is dispatched. So it is certainly available.

Q. I believe you have just raised or discussed the concept of economic dispatch. Did you, in formulating your testimony, perform an analysis utilizing economic dispatch?

A. I didn't make the analysis. I didn't have to, really, for my testimony. I depended on the fact that the power was dispatched over the year, and has over the years under the Power Pool agreement, and assumed that the only basis for that -- because this was not contact sales but came out of the fact that at the particular times that that power was the cheapest power available.

Q. I am still a little confused. It seems as if you are talking about, in answering my question, sales of energy and not actually sales of capacity, is that true?

A. Energy, we are talking about energy.

I also might say I think you ought to refer to the rest of the testimony, that these sales doesn't only have to go on under peak load conditions. Much of the sales may not be under peak load conditions.

MR. FARRELLY: No further questions.

MR. PRATT: Could I take a moment? I gave away my volume 2.

JUDGE GLEASON: All right.

(In was a pause in the proceeding.)

CROSS-EXAMINATION

BY MR. PRATT:

Q. Mr. Fleisher, you testified -- you gave a number of approximately 250,000 megawatt hours for the year ending March 31, 1982; do you recall that?

A. Yes, I do.

Q. Now, the numbers I have gotten from orange and Rockland are the calendar years and I am going to give you the numbers I have received for 1981 and then for 1982 and ask you if you will accept those subject to check. These are for purchases by Orange and Rockland. 1981, 775,451 megawatt hours; for 1982, 995,493 megawatt hours.

Do you accept those numbers, sir?

A. Yes.

MR. PRATT: No further questions.

MR. GLEASON: Any redirect?

MR. McGURREN: The staff has a few questions.

CROSS-EXAMINATION

BY mR. MCgURREN:

Q. Would you please turn to page 2, line 15. You state that during "twelve months ending March 31, 1982, Orange and Rockland sold for resale 510,371 megawatts of electricity for $26,194."

Then you go on in the next sentence and you say, "The net value of sales is about 1.8 million dollars." Is that correct?

A. Yes.

Q. Who made that 1.8 million, do you know?

A. Whoever purchased that power.

Q. You don't know who purchased that power?

A. I don't believe it could be anybody within the Power Pool. I don't know that it goes directly to any customer. Maybe it does.

It is unimportant to me where it went particularly.

Q. Does this 1.8 million, is that what you see as the benefit to Orange and Rockland?

A. Yes. That is the bottom-line, that's a bottom line number that they recovered, which is added to their revenue and, therefore, is a benefit. It is power that they would not have sold otherwise.

Q. If power were sold in the future to Con Ed customers, is that the same benefit that Orange and Rockland would see?

A. Orange and Rockland, if it sells power that it cannot sell otherwise, which utilizes equipment that that is not otherwise fully utilized, then it is a benefit to the Orange and Rockland customers.

Q. Isn't it a cost to some customer?

A. In our society everybody simply pays for everything they buy.

MR. McGURREN: That's all.

JUDGE GLEASON: Any redirect?

MS. FLEISHER: Your Honor, it isn't really redirect. I am afraid Mr. Fleisher forgot a correction. It is a quotation from the Power Pool book, and he can give you the citation, where it refers to line 21, page 3, and line 22 he omitted to tell what proportion of natural gas orange and Rockland burns for fuel as against oil.

I wonder if we could accept that now, only if he quotes directly from the Power Pool book?

JUDGE GLEASON: Is there objection to making that change in Mr. Fleisher's testimony?

MR. PRATT: I am sorry, Mrs. Fleisher, could you say it one more time?

MS. FLEISHER: Mr. Fleisher will read it and you can see whether or not you will object. It is a quotation from volume 2, I believe, of the 1983 book and he will give you the page reference.

It refers to lines 22 and 23 on page 3.

The witness forget to tell how much Orange and Rockland used of oil versus gas as fuel, and I think it is important to this case, when it is so often said --

JUDGE GLEASON: All right, you may read it.

THE WITNESS: I haven't got it. I know it is in the power book but I am not prepared at the moment to go right to it.

(There was a pause in the proceeding)

MS. FLEISHER: Your Honor, maybe we can bring it in tomorrow.

THE WITNESS: I know what the information is but I can't quite put my hands on it.

JUDGE GLEASON: Thank you for your testimony.

MR. PRATT: Let me note that we are distributing now a copy Power Authority 54, which we had referred to earlier. We will be giving copies to the board, the parties and to the court reporter.

JUDGE GLEASON: I would like to say before we get into the motion that the other day the Parents organization delivered a motion for approval and stipulation that had been agreed to sometime ago which had not been submitted to the director.

This was the one that related to the preservation, production of documents which related to the exercise of March 9. I just want to say the board approved that.

Do you have a copy of this? It apparently was not submitted. It was in the record and approved at that time according to Ms. Posner.

MR. LEVIN: I am familiar with the motion being filed. I assume it is correct. I believe that involves primarily FEMA.

JUDGE GLEASON: That's right, you are right. It was signed by the staff and by Feinberg and it related to FEMA and Ms. Potterfield.

M[illegible] Hassel isn't here, so I guess we had better [illegible] it until next week.

MS. MOORE: I remember the motion and I have seen it and I know that the stipulation was signed.

JUDGE GLEASON: Why don't we put it in the record as approved by the board. If there is any problem with it we can refer it to Mr. Hassel.

(The stipulation is inserted as follows:

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	
	)	
CONSOLIDATED EDISON COMPANY OF NEW YORK	)	Docket Nos. 50-247 SP
(Indian Point Unit 2)	)	50-286 SP
	)	
POWER AUTHORITY OF THE STATE OF NEW YORK	)	April 12, 1983
(Indian Point Unit 3)	)	

PARENTS CONCERNED ABOUT INDIAN POINT
MOTION FOR APPROVAL OF STIPULATION

In order to complete the record, Parents Concerned About Indian Point hereby respecfully moves the Board to approve the attached stipulations regarding the Intervenors' Observation of the March 9 radiological emergency preparedness exercise for Indian Point Unit 2.

These stipulations represent an agreed upon resolution of certain of Intervenors' requests in NYPIRG Motion for Preservation and Production of Certain Documents Relevant to the Exercise of March 9, 1983, dated February 22, 1983, and should be accepted by the Board.

Parents apologizes for the delay in submitting the signed stipulation for approval by this Board, and trusts that no party has been inconvenienced since all the agreed upon actions have been carried out by the respective parties.

Pat Posner

Pat Posner
Parents Concerned About Indian Point
P.O. Box 125
Croton-on-Hudson, New York 10520

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of	x	
CONSOLIDATED EDISON COMPANY OF NEW YORK (Indian Point, Unit 2)	.	Docket Nos. 50-247-SP 50-286-SP
POWER AUTHORITY OF THE STATE OF NEW YORK (Indian Point, Unit 3)	x	March 31, 1983

STIPULATION OF NRC STAFF, FEMA, NEW YORK STATE REGARDING NYPIRG'S MOTION FOR PRESERVATION AND PRODUCTION OF CERTAIN DOCUMENTS RELEVANT TO THE EXERCISE OF MARCH 9, 1983

It is stipulated between Petitioner New York Public Interest Group (NYPIRG), the Westerchester Peoples' Action Coalition (WESPAC), Parent Concerned About Indian Point (Parents), Greater New York Council on Energy (GNYCE), Friends of the Earth (FOE), the New York City Audubon Society (NYC Audubon), West Branch Conservation Association (WBCA) and Rockland Citizens for Safe Energy (RCSE)[1/], and the New York State Energy Office representing the Executive Branch of New York State (New York State) and the Staff of the Nuclear Regulatory Commission (NRC Staff) with the agreement of the Federal Emergency Management Agency (FEMA)[2/] as follows:

1) Petitioners withdraw their Motion of February 22, 1983.

1/ Amanda Potterfield, counsel for NYPIRG, has been authorized by the above-named Petitioners to sign this stipulation on their behalf.

2/ Although FEMA is not a party to the above-captioned proceeding, it is the Federal agnecy primarily responsible for observing the off-site portion of the Indian Point emergency planning exercise. As such, FEMA voluntarily participated in the negotiation of this stipulation, and has made certain commitments reflected in this stipulation.

2) In exchange for this withdrawal FEMA, with the agreement of the Staff, agrees to provide information to representatives of Petitioners who may be present in the County Emergency Operations Center on the day of the exercise, but no sooner than the time at which the participants are informed, as to the location of exercise activities. FEMA, with the agreement of the Staff, agrees to notify the persons who control these locations that FEMA and the Staff have no objection to the presence of no more than two (2) Petitioner representatives at these locations. However, it is understood that the Staff and FEMA have no authority to require the parties who control these locations to permit the presence of Petitioner representatives. Petitioners agree that their representatives will merely audit the activities and will in no manner hinder or attempt to participate in the activities or discussions.

3) The Staff further agrees to preserve the following items and documents prepared in connection with the exercise until the Commission has rendered its decision in the above-captioned proceeding:

   a) All draft reports prepared by the NRC team leader

   b) Written reports, if any, submitted to the NRC team leader.

4) FEMA further agrees to preserve the following items and documents prepared in connection with the exercise:

   a) The FEMA team leaders' reports and any drafts of those reports if they are materially different.

   b) The reports submitted by the observers for FEMA to the FEMA team leaders.

5) FEMA, with the agreement of the Staff, also agrees that Petitioners shall be permitted to make a tape recording of the public post-exercise meeting scheduled for March 10, 1983.

6) FEMA agrees to preserve survey instruments and the information gathered therein pursuant to the verification effort undertaken by Argonne National Laboratories.

7) The State of New York, Radiological Emergency Preparedness Group, agrees to preserve a copy of the scenario and the individual evaluation sheets from the March 9, 1983 exercise and to produce a copy of the scenario used at the exercise in Westchester County on February 24, 1983.

8) Intervenors agree to preserve any and all observer reports generated by the intervenor observers during the exercise.

9) It is agreed that the custodian for the NRC Staff will be Edythe Becker.

10) It is agreed that the custodian for FEMA will be Stewart Glass.

11) It is agreed that the custodian for NYS will be Stephen Clemente.

12) It is agreed that the custodian for Intervenors will be Joan Holt.

13) It is further agreed that Intervenors reserve their right to reassert their Motion for Production of documents and that the NRC, FEMA and New York State reserve their rights to object to the Production of their documents.

Donald F. Hassell

Donald Hassell
Counsel for NRC Staff

Stewart M. Glass

Stewart M. Glass
Regional Counsel
Federal Emergency Management Agency

Amanda Potterfield

Amanda Potterfield
Counsel
New York Public Interest Research Group

Jonathan Feinberg

Jonathan Feinberg
Staff Counsel
New York State Department of Public Service
Appearing for New York State Energy Office
Representing the Executive Branch of
New York State

Dated:

JUDGE GLEASON: We will now consider the motion made by UCS NYPIRC, members of the New York City Council, which is a motion for permission to present rebuttal witnesses on two subjects: The subjects of prevailing winds and the subject of sample surveys, et cetera.

I think the motion is fairly clear as to its intent, what it is designed to confront.

So I will turn to Mr. Levin and to whoever else wishes to talk in opposition to it or in its favor.

Proceed, Mr. Levin.

MR. LEVIN: The Power Authority opposes the motion, your Honor. It starts from the premises 10 CFR 2.743 B requires that all pre filed testimony be served at least 15 days prior to the witnesses' appearance.

It seems that the effort by USC NYPIRC and the New York City Council members to include what they refer to as rebuttal testimony is premised upon the concept of surprise -- at least that that's the way I read their motion.

I would like to say in advance of addressing the specific areas that they wish to -- as they phrase it -- rebut, that they do state they had difficulties in locating witnesses, but it seems to me that under these circumstances, and particularly when I refer the board back to some of the prefiled testimony where these topics were discussed, that at a minimum, at a bare minimum, we could have been told, the board could have been told at a much earlier date that the intervenors would seek to present rebuttal testimony and they could have at that time sought the board's permission to do so and we would have had an opportunity to argue this at something other than the eleventh hour.

We had no hint that any of this was in the works, and the first time that the power tort, and I am sure Con Edison, had any knowledge that there was going to be such testimony offered was when Ms. Potterfield handed us a copy of the document, which I believe was yesterday afternoon.

Now, it is clear, in just reviewing, particularly the Holt document, which is about 14 pages long, and obviously took a great deal of thought and consideration, that this is not something that they put together at the last minute. They were clearly very much aware of exactly what they wanted to cover, and yet the board and all the rest of the parties were left in the dark as to what that might be.

Moreover, the court clearly stated, and I am referencing now the transcript, page 13076, and this was in reference to the April 26 to 29 hearing period, that, "We are not going to be hearing other witnesses on emergency planning and the witnesses that are going to have to testify are going to be testifying completely on the matters that relate to the exercise."

"So this is not an open, you know, open door to pick up testimony that should have been delivered in the previous days as has been allocated for that purpose."

This is exactly what the intervenors are attempting to do in this case. Any concession on this point is going to open up the door for all the parties, and I can assure you that the Power Authority has matters that came up on cross-examination and also by questions to the board that it could justify in the same way that the intervenors have sought to justify their rebuttal witnesses, where we could justify rebuttal witnesses.

It is an interminable process if we

began down that path.

It is axiomatic when you have cross-examination of witnesses that matters are going to come up which aren't covered in detail in the direct examination. Otherwise what's the point in having cross-examination? It is always going to be that way.

Let's go specifically -- I am going to pass over the prevailing winds issue because that is peculiarly one to Mr. Cohen, who is a Con Ed witness, and go directly to the survey testimony and the bystander testimony --

MS. FLEISHER: This is what I was just going to bring up. Couldn't we take it up item-by-item?

MR. LEVIN: I am on the items.

JUDGE GLEASON: There are just two items.

I want to proceed the way the parties want to proceed. If he wants to proceed this way, I think we ought to let him proceed this way.

MR. LEVIN: Let's go directly to the survey testimony and the bystander testimony. Again, I remind the board the whole premise of getting this in and for the late filing and notice appears to be surprise.

The entire first part of Mr. Holt's testimony, and I am now looking at most of pages up to about 1 through 8, all of that appears to be attempting to justify the reliability of self-prediction in surveys. Now, that is no surprise to the intervenors that that was to be a topic covered by Mr. Lecher. I would refer the board to page 10 of the Lecher testimony, and now I am talking about the prefiled testimony, where he states --

JUDGE GLEASON: What date did Dr. Lecher and Dr. Dynes appear?

MR. LEVIN: I have the transcript right here, Judge.

(There was a pause in the proceeding.)

MR. LEVIN: This was March 30, 1983.

At page 10 of the testimony Dr. Lecher says, "An important point regarding both the public and emergency workers is that their own predictions as to how they would respond to radiological emergency are of limited value. I assign little credence to predictions that bus drivers will not slow up or people will ignore the plan even when such predictions are made by the individuals themselves."

Well, if that is not notice of the fact that self-prediction was an issue in that testimony, I don't know how much more clearly it could have been stated.

The intervenors had the opportunity for discovery, where they could have ferret the out as much informations on that as they wished, in addition to have the prefiled testimony, and a suggestion that during the cross-examination or during examination by the board they were surprised by that line of testimony is simply not a suggestion that will hold water.

A similar problem exists with respect to the bystander testimony that they claim to have been surprised by.

If one were to look at page 4 of the prefiled testimony of Dr. Lecher you will find the following passage, "Particularly in the initial phases of a reaction to disaster they" -- talking about people -- "they become responsive to authority."

That is is exactly what this late-filed testimony attempts to address and it was in the prefiled testimony, it was no surprise to the intervenors it was going to be part of this hearing and that it supported the position taken by Dr. Lecher.

In fact, careful analysis, and if I were to do a line-by-line analysis I am sure I could pin it down more specifically, looking at pages 8 through 14 of this proposed testimony of Mr. Holt, one finds that the it is exactly the kind of testimony that could have been provided much, much earlier than the date we are confronted with now.

It is obvious, although the intervenors attempt to characterize this testimony as narrow in scope, that the extent, the amount of time necessary to prepare and cross-examine Mr. Holt in particular, and to deal with some of the assertions and allegations that he made will be extensive, not to mention the amount of cross-examination time that would be necessary to deal with him during the hearing process itself.

It is too little, it is too late, the arguments of surprise are simply incorrect and unfounded.

JUDGE GLEASON: Mr. Levin, what do you say with respect to the argument that a certain element of unfairness has been visited upon these parties supporting the motion because of the fact that on the first issue they had stipulated the testimony but that the new information really was promulgated as a result of board questions to those witnesses?

MR. LEVIN: It seems to me that the most extensive testimony that was drawn out by the board, in other words where more detail occurred than was in the original filed testimony, was probably in the case of Mr. Cohen on prevailing winds.

My position on that is that we also oppose any additional testimony on that and I think that Mr. Farrelly will be able to address this with moe specificity than I. Certainly in Mr. Cohen's prefiled testimony he references the various studies that appeared to hve been the basis for the more detailed discussion that occured, I think as a result of Judge Paris's questions when he was on the stand.

JUDGE PARIS: What was that study?

MR. LEVIN: I don't know the name off the top of my head. I believe those are the studies which formed the basis for his responses, and probably initiated your questions in the first place, and form the basis of the responses he gave. It was in the prefiled testimony, depositions of Mr. Cohen. I don't recall if intervenors took depositions. Questions addressed to him would have elicited the same amount of detail that you secured on cross-examination.

Again I might say if there has been an unfairness visited on the intervenors, It has been visited equally. We have had the same situations arise with respect to our witnesses where testimony has been brough out on cross examination by the board, which is not testimony that we -- that is, by the intervenors -- where it was not in the prefiled testimony, it was not anything that we had seen at that level of detail, and if we are going to start down this path of rebuttal we can find areas where we believe we are entitled to rebuttal aslo.

JUDGE GLEASON: I don't thing you have answered my specific point because I do think it is kind of crucial to my position of this; that is, ordinarily when you have a stipulation of parties, ordinarily the board accepts the stipulation, approved it and then that puts an end to it.

In this case we had some questions emanated from the board, with no one having an opportunity to complete that or having an opportunity to meet it, does that visit a degree of unfairness that you think should be addressed?

MR. LEVIN: I don't think my response would be any different. I think apparently the board, or someone, conceded that this might go beyond the scope of the direct testimony. There have been many other occasions when the board has asked questions of witnesses where I would argue it went beyond the scope of the direct testimony. So I don't see them being in any different position than the licensees in that regard.

We also the point I initially made, which is why is this the first we have heard of this?

JUDGE GLEASON: I understand the lateness argument, but there is an element here that once you have stipulated you kind of waive your right to ask any questions or ask if you have ask questions, that kind of thing. It is that kind of issue.

Mr. Farrelly.

MR. FARRELLY: Con Ed joins the Power Authority in opposing the motion. I would like to emphasize the extreme prejudice that granting the motion would place on the licensees and other parties in this proceeding. We are at this point faced with an impossible schedule. To add further to that is imposing a further burden.

I would also like to to emphasize the prejudice to licensees of getting rebuttal testimony on this one issue and being precluded from filing rebuttal testimony on a whole host of issues that we would like to file rebuttal testimony on if we could.

We realize that the proceeding has to come to an end, and the end is in sight. I think granting the motion should open the door for other parties to put in rebuttal testimony to address issues that did come up on cross, came up during questioning by the board.

I can recall Tuesday morning the board asking some questions of a licensee witness, and the licensee wanting to have some follow-up questions and was precluded. The board precluded further questioning in that area.

On the question of the Cohen testimony, the areas that Judge Paris explored were in his direct testimony. The testimony of Mr. Cohen and the other members of the panel was filed on June 7, 1982. Intervenors had more than adequate time to pursue discovery, interrogatories or depositions if they wished, and they didn't.

JUDGE PARIS: Can you refresh my memory and tell me in case I have never been told this, was the the research of Mr. Cohen in his testimony reported in the meteorological update to the FSAR, dated 1981?

MR. FARRELLY: I am at a disadvantage. I cannot answer that question yes or or no.

MS. POTTERFIELD: May I be heard?

JUDGE GLEASON: Yes.

MS. POTTERFIELD: With regard to the lack of notice, we are aware that it is some hardship on the other parties and apologize for that. On the other hand, the issues are very narrow. Next week coming up is not nearly as heavy as other weeks have been and the issues are quite capable of being explored. We know that the licensees have a consultant already on the issue of sample surveys. I am sure they would be able to prepare themselves.

We did, however, talk to Mr. Brandenburg about our wish to present a rebuttal witness on the prevailing winds issue. When we attempted to get from the licensees a copy of the FSAR, which is the subject of Mr. Gutten's testimony, it goes without saying that we were refused that by the licensees and so had to get a copy in the public document room -- I am sorry, by Con Edison.

So there was at least that amount of notice about that issue.

There is a problem here in talking about fairness among the parties given the order of testimony, which is an order that we wanted to have, we wanted to present our case first.

Since we did, that of course made our positions very clear and I believe it is fair to say that our positions were clear that the board asked those questions that it asked of the witnesses that we are talking about.

The board's question to Mr. Cohen -- rather first to Ms. Lamonica on page 11681 of the transcript, went directly, as I read it, to the testimony that was presented by intervenors and the state Attorney General by Dr. Beahy.

We didn't know and we were unfairly surprised because we hadn't understood that it would be an issue, the question of how far the winds would get, the winds from Indian Point, hadn't yet been made into an issue. It had been included in part of Dr. Beahy's testimony. As Judge Gleason said when he first asked the question, he imagined that the information was in the safety analysis report but since that report wasn't in the record he wished to have the information in the record.

That was our first notice that that information about meteorological conditions and the prevailing winds might become an issue.

With regard to the human response testimony about which we are offering Dr. Cole as a rebuttal witness, what has come up in this proceeding has been the question of what is competent and material testimony on the question of human response and behavior. As everyone is aware, we had hoped to present a case that was not a case of experts but a case of community people who wanted to talk about their own particular responses and how they would behave in the event of an emergency within the ten mile-zone, which is the place where they live.

We were precluded from doing that. We were limited, therefore, in our case to the hypothetical and scientific evidence presented by social scientists and also by evidence presented by sample surveys.

Those sample surveys become important to our case in a way that they weren't before because our case was built around the community and we had hoped that the board would hear from the community itself about what they expected they would do and have to do in the event of an emergency.

When it became so critical, of course, that sample surveys might be the only way we could present our case, it then became important for the board to inquire of the licensees' experts in the social science area about their opinion on the utility of sample surveys.

For the first time the issue became whether or not even sample surveys were good evidence. We have had already been told that the evidence from the community was not going to be considered by the board and now suddenly we are confronted with the possibility that the board could discount even the sample survey evidence. We felt unfairly surprised and want to present the testimony of Dr. Holt about that.

The same thing is true of bystander behavior. True enough, the word bystander appears in Dr. Lecher's testimony but it is used in his testimony in the way we understood it to be used by social scientist, as bystanders. Suddenly, in response to the board's questions, he uses bystander to mean also people who are being evacuated, people that we had always understood to be referred to as victims or evacuees or potential victims. Because he used that theory and Dr. Holt discusses the research and bystander behavior, he suddenly uses that to buttress his whole other argument about people responding in a particular way in an emergency.

It is critical to this case. It is the intervenor's case that you cannot depend on basic uniformed obedient responses, at least not in this community, at least not to this emergency, at least not under these emergency plans.

It was a new use of a theory and we want to rebut it. We will make every concession that we can to make it easier on the licensees. We will be glad to present these witnesses on Friday rather than Tuesday. We will do what we can but we feel in order to have a complete and full and accurate record on these very critical issues to the intervenors, that the commission's regulation of fundemental fairness requires that we be allowed to present these two witnesses.

MR.BLUM: If I may be heard on one area.

JUDGE GLEASON: Please make it brief because I think the issues have been joined.

MR.BLUM: I think all of Ms. Potterfield's arguments are well taken. I am only going to address Mr. Cohen's testimony about New York City, since my role as UCS NYPIRC attorney on questions of risk. This was principally a risk issue which cropped up in a very unforeseen way during the on site emergency planning part of the hearings. I am not sure whether the licensees are focused on the same question specifically.

I have the transcript here, which has Judge Gleason's questions on pages 11731 through 11733 that elicited the testimony of the likelihood of a radiation plume traveling to New

York City.

I read through the testimony very carefully of these witnesses and there was nothing on the face of that testimony that would make it at all foreseeable that this kind of issue could come up in that context. If it had been at all foreseeable, I never0have concurred in a decision to forego cross-examination on that, since it is a rather central issue on the risk question.

MR. KAPLAN: I just want to make two comments. I had a discussion it was with Mr. Pratt on Monday, the 11th, indicating to him the intent to make this motion. He indicated to me he was going to have to speak the people at Shea & Gould, who were dealing with the questions 3 and 4 for the Power Authority. There was some notice to them an as of 4-11 and I know there were prior discussions where representatives of NYPIRC tried to seek out the information.

So although the motion papers appeared yesterday, there was earlier notice.

Obviously there is difficulty in knowing what the witness would say until they could look at the documentation that Mr. Cohen relied on.

Second of all, the problem of opening the door would be in the broad sense a difficult one. As the board recognize is, given the stipulated nature of his testimony this would set no precedent to any other rebuttal issue. It really is different from any other situation.

I only want to add in a different fashion, I represent the members of the New York City Council. What is at issue here is whether or not we are talking about the same case that Mr. Beahy and the same one he has put in order. There is a small issue of fact which I suggest that the board, in order to be responsible to its mandate, must consider, which is the validity and accuracy of Mr. Cohen's testimony. We are offering it very narrowly to do it. We won't take very much time on this board's schedule.

MS. MOORE: Your Honor, may I make a few points?

JUDGE GLEASON: Go ahead.

MS. MOORE: I don't want to repeat any of the arguments that have been made. There are just a few things I would like to raise and that is on the question of the sample surveys particularly, in the motion I believe it was stated that this was brought up by the board on redirect. In fact it was also brought up by the intervenors themselves on cross-examination. That's on page 11984 and 11990, where Doctors Lecher and Dynes were specifically asked about whether their public opinion polls had been conducted around Indian Point.

As a matter of fact it was the intervenors that used the words "public opinion polls." So there is some cross-examination that was conducted in that area. I don't believe that that particular issue was first brought up on redirect.

The second point I would like to raise is that Ms. Potterfield just mentioned the theory concerning victims in the bystander theory. I would note for the board on page 8 of Dr. Dynes' testimony he makes a statement about victims aiding in emergencies. So that that subject was in fact covered in the direct testimony.

I think these issues are somewhat distinct from the issue of meteorology, although the staff does believe that even the meteorological testimony and the motion is untimely.

MR. KAPLAN: Just one more sentence that I did leave out.

JUDGE GLEASON: One sentence?

MR. KAPLAN: Yes.

JUDGE GLEASON: I will let you to see whether you can do it.

MR. KAPLAN: One sentence. That at the time the board questioned Dr. Cohen, Ms. Potterfield was precluded by the board, upon a request she made to this board, to ask Dr. Cohen questions regarding the specific issue that we are now addressing, on the basis that we stipulated to the testimony.

JUDGE GLEASON: Is that true?

MR. KAPLAN: Unfortunately I am told it did not appear in the record but I will go on oath and swear to it.

JUDGE GLEASON: Ms. Fleisher, did you want to get in this with something?

MS. FLEISHER: I will just say that I thought the bleeding hearts business about the dates when they would get the testimony and reading to us something about 15 days, should we need to be reminded, therefore, that all the witnesses that the Power Authority and Con Ed brought before us this week, their testimony is dated April 12 and today is the 20th and I received mine on the 15th and I worked very hard all weekend.

So I think that they have no argument whatsoever about preparation time, so forth. We are all working very hard on this case and trying to complete it.

As far as the other parties is concerned, West Branch Conservation Association joins in the motion, for plenty of reasons, if you need to hear them and if you have run out of them I will come back on.

JUDGE GLEASON: That won't be necessary.

MR. LEVIN: I wanted to point out one other thing to the board, which is that a significant portion of this testimony bootstraps in the erosion of public faith and authority figures, which is justified in some convoluted fashion as somehow supporting, I suppose, perhaps the survey aspect of their contention. That's at page 10 and it runs in and out throughout.

I was not aware that one of the grounds for this motion was somehow what I know

Ms. Potterfield views as the exclusion of members of the community from testifying in this hearing. I have not this afternoon sat down and counted up the numbers of the members of community who have testified on behalf of the intervenors, but I can assure you that that there has been several weeks worth of that testimony.

JUDGE GLEASON: Give the board a couple of minutes here to get our heads together.

(There was a pause in the proceeding.)

JUDGE GLEASON: The board, after due deliberation, finds itself in somewhat of quandary with respect to the motion, at least part of it. The quandary is essentially this: We believe that there has been adequate notice with respect to the second issue that has been raised, the issue of surveys and the bystander issue and there has been adequate opportunity to put in testimony.

In fact, there is testimony still to come in on that issue. Mr. Cesawine is still to come in, which I presume he is.

Therefore, we do not think that that argument has validity and, therefore, we rule that witnesses in that area would not be permitted.

With respect to the meteorological

issue, in the restricted area we talk about, we find ourselves in a little bit more of a problem because we recognize that these questions were asked in an area which is an area that New York City had expressed quite an interest in the past. It is one that perhaps there should have been some testimony on, presented by them.

Nevertheless it was an issue in which the board questioned on. Because it has that kind of importance, we feel that somehow some method ought to be worked out, if fairness can be assured, to allow this witness to come in in that limited area because we believe it is our basic responsibility to assure fairness in these proceedings.

Obviously, the board can authorize rebuttal testimony if it feels that it is necessary to complete the record, and we kind of feel that in this instance.

However, we also feel in order to do that two things have to take place. First of all, the opposition of the licensees and the staff should have an opportunity to depose the individual.

Secondly, they should have an

opportunity to present a rebuttal witness with respect to that testimony. Because otherwise they could only do it on cross and that has a limited purpose.

So I guess what we are ruling is that we would like to hear that witness in that area next week, within the time period we have left, and we only have four days next week, and we would like the parties to work out the best method of doing it.

MR. LEVIN: I take it if he is to appear, we are entitled to a deposition.

JUDGE GLEASON: We are entitled to a deposition.

MR. KAPLAN: We have no objection.

MS. POTTERFIELD: The only clarification I wanted to make is that if the board were willing to hear Mr. Gut man on Friday, that would be the best day for him. We can arrange a time I think in the city for a deposition.

JUDGE GLEASON: As far as the board is concerned, you work out the schedule between you. We already have I think one of the licensees witnesses coming within the first of two days and maybe you can get your witness in the last two days.

JUDGE PARIS: Friday gives the licensees maximum time.

MR. KAPLAN: There may be no other way to do it if they want to hear him on Tuesday.

MR. LEVIN: We will work it out.

I don't think anyone has told the board yet that we reached agreement that Dr. Cohen, Bernard Cohen, will be first up Tuesday morning.

JUDGE GLEASON: That's what I was referring to because Mr. Lewis had advised me of that.

All right, so that is the ruling of its board and with that we will see you tomorrow.

MR. McGURREN: Before you close the record I would like to express a concern that I have expressed twice this week.

JUDGE GLEASON: Express that again. I know what it is about but I guess it hasn't been sinking in because you keep bringing it back.

MR. McGURREN: We have two separate panels that have been here essentially all week. As a matter of fact, you indicated we might even get to one of those panels tonight. I am concerned about tomorrow. You did indicate that Parents were would go at 3:30. We urge this board to allow us to put both of our panels on and precede Parents tomorrow. We are also concerned about the amount of time we have tomorrow. We would not mind starting a little earlier.

JUDGE GLEASON: That's a good idea.

MR. KAPLAN: I am scheduled first tomorrow with a witness. I am not sure they can get here any earlier. They are coming from Albany.

JUDGE GLEASON: If they are coming that far they can stay awhile.

Why don't we schedule your panels to start, at least the first one, and see how you go. Let's start at 8:30.

MR. McGURREN: That sounds fine.

JUDGE GLEASON: Any earlier than that will be tough.

Is that all right because I know you have studying and review?

MR. LEVIN: I don't think a half hour -- it makes a lot of difference in getting organized in here but it doesn't make an a hill of beans in finishing testimony. A half hour is not much at the end of the day.

JUDGE GLEASON: We will see you all tomorrow at 8:30 a.m.

(Hearing recessed at 6:45 p.m.)

NUCLEAR REGULATORY COMMISSION

This is to certify that the attached proceedings before

THE ATOMIC SAFETY AND LICENSING BOARD

in the matter of: CONSOLIDATED EDISON COMPANY OF NEW YORK (Indian Point Unit 2) - POWER AUTHORITY OF THE STATE OF NEW YORK (Indian Point Unit 3)

Date of Proceeding: Thursday April 21, 1983

Docket Number: 50-247 SP and 50-286 SP

Place of Proceeding: White Plains, New York

were held as herein appears, and that this is the original transcript thereof for the file of the Commission.

Raymond DeSimone

Official Reporter

Ruth Bennett

Official Reporter