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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)	)	Docket Nos. 50-247 SP 50-286 SP
POWER AUTHORITY OF THE STATE OF NEW YORK (Indian Point, Unit No. 3)	)	April 12, 1983

LICENSEES' TESTIMONY OF SALLY HUNT STREITER ON COMMISSION QUESTION 6

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THE DIRECT COSTS

OF CLOSING INDIAN POINT

TABLE OF CONTENTS

INDEX OF TABLES

INDEX OF APPENDICES

My name is Sally Hunt Streiter. My business address is 123 Main Street, White Plains, New York. I am a vice president of National Economic Research Associates, an economic consulting firm, where I have been employed for the past nine years, mainly in analyzing different aspects of the electric industry.

My education and experience are attached as Exhibit 1.

The purpose of my testimony is to make estimates of the direct cost to customers of permanently closing the Indian Point Units 2 and 3.

I. INTRODUCTION AND SUMMARY

The Indian Point Plants, located in Buchanan, New York consist of three units. Unit 1, owned by Con Edison, operated from 1962 to 1974. It has not yet been decommissioned, but can be ignored for the purposes of this study. Indian Point 2, owned by Con Edison, cost $216 million to build; it began operation in 1973. It is a pressurized water reactor (PWR) built by Westinghouse with a net maximum dependable capacity of 849 MW in the summer and 864 MW in the winter. Indian Point 3 owned by the Power Authority cost $435 million to build; it is also a Westinghouse PWR, rated at 965 MW. It began operation in 1976. The units are not identical, and are separately operated and administered by the two companies. The licenses for Units 2 and 3 expire in 2006 and 2009, respectively.

The two plants, running at a 63 percent capacity factor, produce approximately 10,000 Gwh (10 billion kwh) per year. If Indian Point were to be closed, the energy normally generated by the units would have to be replaced from other sources. The sources of replacement power and the estimates of cost have been presented by Mr. Meehan. At some point, replacement capacity would be

required to maintain minimum reserve margins. On the other hand, some fuel, operation and maintenance (O&M) and capital expenditures associated with continued operation of Indian Point could be avoided. This testimony makes projections of the costs and savings resulting from closing the units in 1984.

As with all projections, there are areas of uncertainty, and results vary widely according to the assumptions made. Therefore I present a reference case which gives a comprehensive exposition of the direct costs to consumers of closing Indian Point. The reference case projection is that the costs associated with closing both Indian Point units would amount to about $400 million per year, rising to over $2 billion a year by the end of the century. The present discounted value of the reference case shows a total cost to consumers of some $9 billion dollars. The details of this estimate are discussed below.

Estimates are by their nature more uncertain as the period increases. Even between now and 1990, there is uncertainty as to oil prices, the schedule for coal conversions, the construction of new units and the growth in demand for electricity. In most instances the numbers presented are predicated on the plans and forecasts of the member companies of the New York Power Pool (NYPP), or on detailed studies done for the Pool members.

After 1990, estimates, including mine, become subject to the tyranny of projected growth rates. However, in considering the economic impact of closing Indian Point it is not necessary to rely on assumptions about the distant future and on discounted present values, since we are not estimating the lifetime benefits of constructing a new plant, where an all or nothing choice has to be made about a multi-million dollar expenditure. In this case, the investment has already been made, and each year of saving is a real saving which will be lost if the plant is closed.

Some general observations about the form of my analysis are in order. The reference case is discussed in Section II. Summary reference case tables are presented in three forms: current (nominal) dollars, constant 1982 dollars and dollars discounted to 1983. The inflation rate assumed is 7 percent annually. The discount rate is 10 percent, or 3 percent real. Summary tables are presented for New York State, Con Edison and the Power Authority separately.

Some individual components of the reference case are discussed in Section III. Because of the uncertainties, I have examined the sensitivity of the estimates to individual assumptions, and show the effect of changing these assumptions on the time path of costs, and on the total dollar impact of closing the plants. Individual components are shown in constant 1982 dollars in sensitivity tables and charts.

Section IV discusses alternatives to Indian Point. Section V discusses the allocation of capital costs of Indian Point 3. Section VI puts the shutdown costs in perspective.

II. THE REFERENCE CASE

A forced closing of the Indian Point plants would require additional generation and purchased power to replace the 10,000 gwh of annual generation. Mr. Meehan has projected these costs, in the reference case as growing from $459 million per year in 1984 to $2,190 million per year in 1999. I have projected the per kwh cost from 1999 to 2009 as rising at 2 percent annually in real dollars, which is conservative, given the rate of increase projected by Mr. Meehan in the late 1990s. Mr. Meehan's projections take account of nuclear fuel savings from closing Indian Point, and additional O&M costs required by the fossil replacement units. His estimates do not include the following items, for which separate

adjustments must be made: working capital and inventory costs, taxes, loss of fuel core, decommissioning costs and costs of additional capacity, which all tend to increase the replacement cost; and nuclear operation and maintenance costs and capital additions at the Indian Point plants, which reducc the replacement cost.

The estimated annual current dollar costs of the production penalty to New York State, assuming a 7 percent inflation rate, are shown in Table 1. This table identifies fuel replacement costs specifically in column 1 with all other costs shown consolidated in column 2. Savings of O&M costs, and capital additions are shown in columns 3 and 4; the final column shows the net annual total.

In Table 1.1 the same data are shown in constant 1982 dollars,[1] and in Table 1.2 the costs are shown discounted[2] at 10 percent per year. The sum of the discounted values are given on Table 1.2. The present value of the cost of closing Indian Point in the reference case is $9.0 billion.

This total is not easily translated into customer rates. First, not all the costs are borne in the Con Edison Service Area in New York City and Westchester County. This is primarily because the pricing of Canadian purchases by NYPP is tied to the NYPP decremental operating cost, which will rise if Indian Point is closed. Hence the price paid for Canadian energy will rise, and all purchasing utilities will bear some of that increase.

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1. Constant dollars remove the effects of assumed inflation after 1982.

2. Discounted dollars take into account the time value of money and assign a lower weight to costs in the future than to costs today. The sum of the discounted stream of annual costs is called the "Present Value" (PV). This is the conventional means of comparing streams of costs occurring at different times in the future.

Second, the systems of the Power Authority and Con Edison are very dissimilar and the closing of Indian Point would affect the systems differently. In contrast to the typical utility pattern reflected by Con Edison, the Power Authority has an unusual system. Its customers in the Southeast New York region, which is roughly equivalent to the Con Edison service territory, are served by two plants, Indian Point 3 and Charles Polleti, an oil and gas-fired plant in New York City. In addition, certain limited additional power and energy is brought to this area from the Power Authority's upstate plants for the public customers. That transfer is subject to changes in water levels at the Power Authority's hydroelectric plants, to legislation, to con' :t provisions with Con Edison and litigation by competing customers. In any event, it is not likely that it could be increased, absent legal changes and continued high water in the Great Lakes, if Indian Point 3 were closed.

To show the impact in the Con Edison service territory on both Con Edison's customers and the Power Authority's southeast New York customers, Mr. Meehan has calculated the fuel replacement costs to the franchise area and for Con Edison. They are given in Tables 4.2 and 4.3 of his testimony. I have used these data to calculate the net impacts on Con Edison and the Power Authority separately. Table 2 shows the Con Edison impacts only, in current dollars; Table 2.1 shows the same data in constant 1982 dollars, and Table 2.2 in discounted dollars. These are comparable to Tables 1, 1.1 and 1.2 which cover the whole of New York State. Tables 3, 3.1 and 3.2 give similar data for the Power Authority.

Table 4 then shows the rate impact on each of the companies through 1990. The expected level of revenues with Indian Point open is shown for Con Edison and for the downstate portion of the Power Authority, and the company

increases and percentage increases are shown. The increased costs reflect increase over existing revenues. Because the Authority has a relatively greater reliance on Indian Point as a source of energy for its downstate customers, the percentage effect on these customers is considerably greater than the effect on Con Edison's customers. Dr. Dunbar will discuss the effect of this magnitude of rate increase on the Power Authority's largest customer, the MTA. Other witnesses will discuss the other impacts of the Power Authority's resulting rate increase.

III. DISCUSSION OF IMPORTANT ASSUMPTIONS IN THE REFERENCE CASE

a. Oil Prices

Oil represents 92 percent of total replacement fuel in 1984, or 13.9 million barrels of oil annually. This percentage will drop in later years if the coal conversions and transmission reinforcements presently scheduled take place. It will then rise with load growth to reach 99 percent of replacement fuel by 1999. Accordingly the production cost results presented are very sensitive to the oil price assumptions used in the projection of replacement power penalties.

The reference case employs forecasts prepared by ICF Inc. for the NYPP in November 1982. These forecasts were used in NYPPs April 1983 submission to the State Energy Office. This forecast assumes 6.7 percent decline from the then current world price of $34 a barrel during 1983, a return to the real 1982 price by 1985 and a 2 percent annual increase in real terms thereafter.

From this world oil price base, the product prices were derived by ICF for oil delivered to New York Harbor and upstate New York. A 7 percent annual inflation rate was assumed.

It is notoriously difficult to forecast the price of oil. In recent years a number of fairly sophisticated models have been developed. Their common thread is that they view the power of OPEC to set prices as being dependent on world demand for oil; if OPEC is operating at a high percentage of its capacity, it will be able to reach agreement on restricting production and keeping the price high. But higher prices induce conservation and fuel substitution, and also induce recession in the Western economies, thereby reducing demand and reducing OPEC's power. High prices also lead to more exploration for alternative sources of oil. Major political events which reduce supply (such as the Iraq-Iran war of 1979) or increase the cohesiveness of OPEC (such as the Yom Kippur war) induce much higher prices, but these are generally viewed as short term shocks on an underlying price path, which in turn depends on world economic growth assumptions and assumptions about the ultimate availability of as yet undiscovered reserves. See the testimony of Melvin A. Conant for additional detail on these matters.

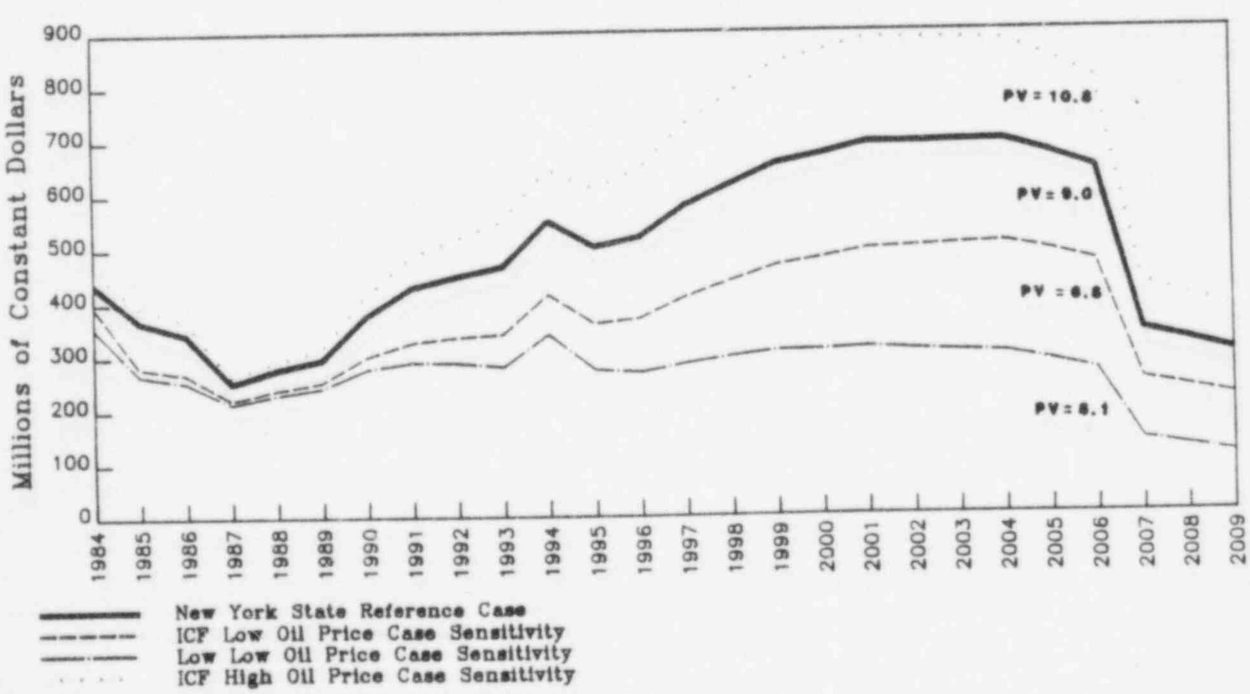
All estimates of future oil prices are subject to wide variations. Appendix 1 shows the recent reference case projections of 18 different analysts; the more recent the projection the lower the short-run price increase projected. ICF's predictions in the reference case were reduced about 10 percent from the previous (February 1982) forecast for NYPP. ICF's high and low cases were similarly reduced in the November 1982 forecast, and represent alternative assumptions about the course of the major variables.

The consensus of experts that oil prices will be flat or declining to 1985 is based on the excess oil production capacity currently available, and in pessimism about quick recovery from the world recession. But it is noticeable how much expert opinions have changed in just 12 months.

In 1978, following four years of stable real prices, many analysts were predicting declining real prices: the following year the price doubled, following a 4 million barrel per day reduction in supply from Iran. Similar upheavals are quite possible but not specifically predictable and are not generally considered in reference case forecasts. ICF estimated the effect of a shock in world supplies corresponding to a revolution in Saudi Arabia and a consequent reduction of world production by 7 million barrels per day in 1990. The estimated effect in a world where western economic growth had resumed, was a 63 percent increase in price in one year. This is not the largest conceivable shock, but gives some idea, if any is needed after 1974 and 1979, of the magnitude of shock-induced increases which could occur despite the general consensus on lower oil prices in the absence of shocks. Nevertheless people are talking about oil prices even lower than the low ICF case: a $28 real oil price in 1986 is perceived by some analysts as a distinct possibility.

OIL PRICE SENSITIVITIES

1984 – 2009



Source: Table 6.

It is this aspect of vulnerability and uncertainty which has the greatest impact on the projections of the cost of closing Indian Point. The sensitivity of direct cost estimates to the ICF alternative oil prices are shown in Figure 1 and also Table 5. Figure 1 also shows the low low case of $28 real oil prices throughout the 1980s and thereafter.

b. <u>Capacity Factors</u>

A second major item in estimating the replacement cost for Indian Point is the expected output of the units, which is directly related to the capacity factor. The major difficulty in projecting Indian Point capacity factors beyond the age of 10 years is that no large unit, of the size of Indian Point, is over 10 years old. So any estimate, including my own, must be based on informed judgment.

The companies' own capacity factors have averaged 53 percent and 51 percent at Indian Point 2 and Indian Point 3 respectively to the end of 1981. Both units have had serious problems with major components. In projecting a 63 percent capacity factor in the reference case, I have assumed that these problems can be solved. There is support in the national data for this assessment.

Analysis of the U.S. data on unit annual capacity factors is particularly complicated. [In all data analysis subsequently referred to, I have eliminated the data on the very small old units (Big Rock Point, Humboldt Bay, Yankee 1, Dresden 1, Indian Point 1, Fort St. Vrain and LaCrosse) since I consider any experience with those units to be irrelevant to expectations about the subsequent generations of units. Annual data from 1968-1981 are used.]

The remaining 62 units have been in service for up to 14 years, although only six units and only two PWRs have been in service for longer than ten years. The annual average performance of these units is shown in Table 7. The standard

deviation of the mean values in the annual data is close to 17 percentage points, which is due partly to the refueling cycle. However, since refueling outages are used to perform many types of maintenance, the exclusion of reported refueling outages from the data is almost certain to introduce more errors in any statistical analysis than it corrects, and I have not attempted to adjust the data in this way.

What is immediately apparent from the annual averages is the sharp drop between 1978 and 1980. Some analysts have ascribed this to outages following the Three Mile Island accident and no doubt it was due to this, at least in part. There was however a major outage at Surry 2 for steam generator replacement in 1979-80, and San Onofre, one of the two oldest of the PWRs, had very low capacity factors in 1980 and 1981 due to steam generator problems quite unrelated to the Three Mile Island accident. Indian Point 3 also had low capacity factors in this period, again due to steam generator problems.

The changes in the data from year to year, and the heavy weight that a few units can exert on the averages, make it very difficult to analyze the data adequately, particularly for small subsets of the data. The small subset of salt water cooled PWRs, for example has only 14 units, and the three units mentioned above, which are all salt water PWRs, pulled down the average for these units in 1980 from 63.8 to 56.6 percent and in 1981 from 63.2 to 58.2 percent. Prior to that, this subset had performed similarly to other subsets. There are undoubtedly problems associated with steam generators. Con Edison and the Power Authority have faced these problems and are spending considerable sums to ameliorate them.

The effect of age after the initial maturation is very ambiguous in the data. Some analysts have claimed to discover a very substantial decline with age in salt water cooled PWRs. I have examined the data using regression analysis techniques, and find that in the data to 1981 an "age" decline in salt water PWRs

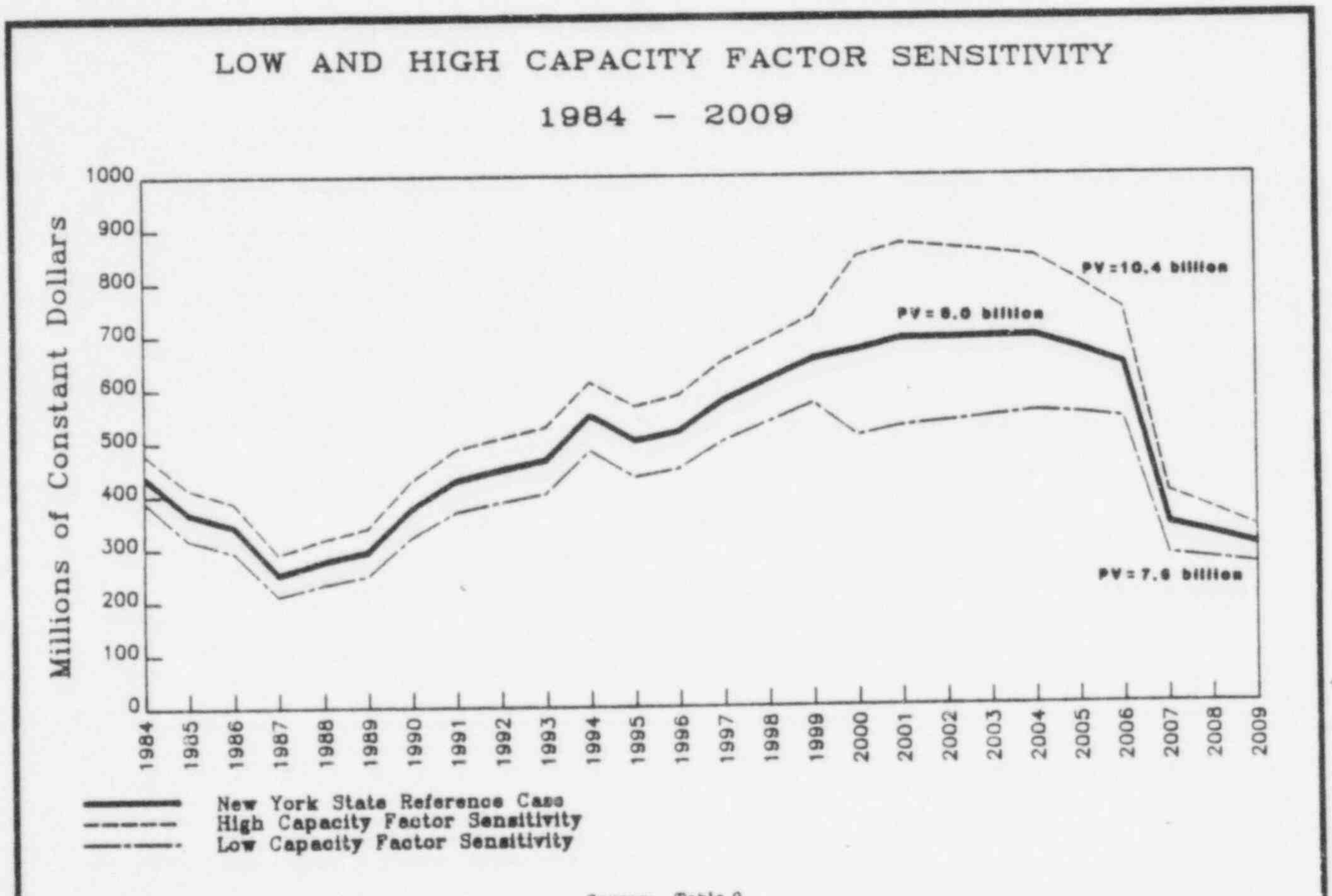
does indeed show up in the data. However, on the data to 1980 only, the effect is smaller and less significant, and on the data to 1979 it is much smaller and not significant. Therefore it is fair to assert that this "effect" has only shown up in 1980 and 1981. [The regression analyses are given in Appendix 2 of the testimony.] And in fact, by careful inspection, it appears that the "age effect" is almost entirely due to the recent steam generator problems discussed above at Surry, San Onofre and Indian Point 3. Removing these six data points removes the statistical significance of "age." In fact the San Onofre data alone impart most of the statistical significance of the age "effect": since this is the only salt water cooled PWR unit with an age greater than 10 years, inclusion of two very low capacity factors in the 13th and 14th years is comparable to putting two heavy weights on the very end of a seesaw when all the other weights are close to the middle. Exclusion of only these two points removes half the statistical significance from the "age" effect in the 1980 and 1981 data.

My own view is that there have been widespread problems with steam generators, but that this cannot be taken to indicate monotonic decline for the next 20 years in capacity factors. It is an identified problem, and to assume that it cannot and will not be solved suggests a certain technological helplessness in the face of known difficulties. In fact Con Edison achieved a 62 percent capacity factor in the last refueling cycle from May 1981 to January 1983.

In the reference case, I have used 63 percent as the projected capacity factor over the lives of the units. This reflects some optimism about the industry's ability to recover from the relatively poor performance in recent years; the nuclear industry has made great efforts to improve response time to technical problems, through sharing of data and thorough pre-outage technical analyses. The reference case also reflects the companies' extensive expenditures on repairs and capital replacements, which are expected to continue; these are

included in the estimates of O&M and capital expenditure discussed below. After the 25th year of life the capacity factors in the reference case are reduced to reflect reduced capital expenditures towards the end of the life.

The low capacity factor in the sensitivity case is set at 57 percent, which is more in line with recent industry experience. The high case is set at 69 percent, which has been used by the NYPP in its projections of nuclear output, and which was the industry experience in the early 1970s. Table 8 shows the capacity factors assumed for each year in the base and reference cases. Table 9 and Figure 2 show sensitivity to capacity factor assumptions.



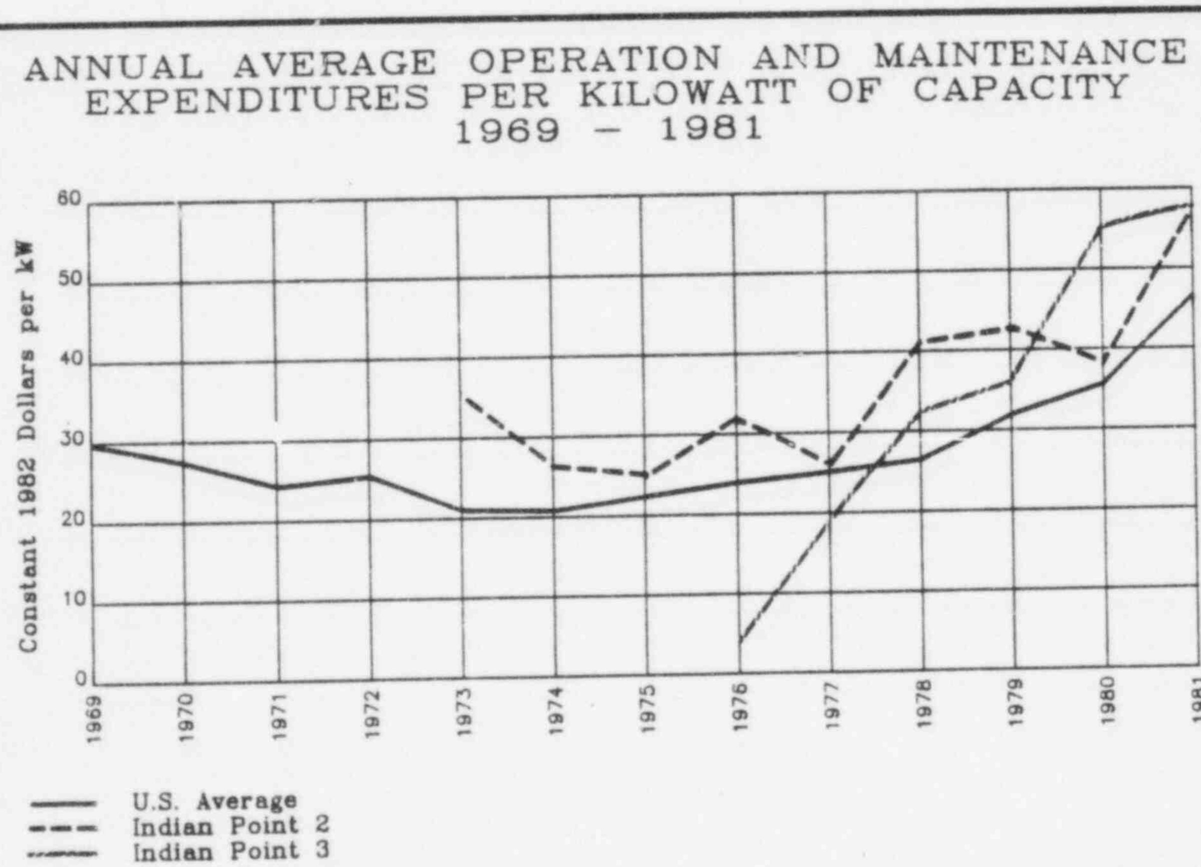
Source: Table 9.

c. Operation and Maintenance Costs

In the reference case, I have used the companies' own detailed estimates of operation and maintenance costs through 1986 together with their estimates of required capital additions to 1986 annualized over the remaining life of the units.

The companies' estimates assume that the level of required base staffing will not increase beyond present levels. I have assumed that if economic growth resumes, after 1986 the real costs will increase at 1 percent per year, due to real increases in wages, partially offset by productivity improvements and turnover of employees. Historic and projected costs are given in Table 10.

Expenditures on nuclear operation and maintenance have risen sharply all over the U.S. since 1978. It appears that a large part of the change is due to a step increase caused by increased NRC requirements which rose very rapidly following the Three Mile Island accident. The annual average O&M expenditure per kilowatt in constant 1982 dollars for the U.S. is given in Figure 3 and Table 11, and the actual expenditure for Indian Point 2 and 3 in the same units.



Source: Table 11.

The companies have provided me with analyses of their O&M expenditures, which suggest that there are two major regulatory elements to the sharp recent increase over the 1972-77 levels: first, there were step increases in basic staffing levels, including guards, training and operating personnel, and in security and other contracts, which are expected to continue, but not grow in the future; these annual expenditures have been estimated by Con Edison at some \$14 million in 1983;[3] second, there was a series of one time expenditures related to regulatory requirements, which are expected to decline gradually. These represent some \$6 million of increase in 1983 over the 1976 levels for the Power Authority.[4] If Con Edison and the Power Authority's experience were valid for all utilities, these numbers would explain a large part of the average United States increase in O&M, from about \$21 per kilowatt (in 1982 dollars) in 1973-74, to about \$47 per kilowatt in 1981.

Some support for this view is provided by analysis of the Commission annual reports and summations of the number of bulletins, orders and generic letters issued by the Commission. While it is true that every utterance of the Commission does not require a new round of expenditures, and while the expenditures required are not uniform per publication, the increase in output from 1976-1980 was nonetheless truly staggering. (See Figure 4 and Table 12.) The Commission's 1981 Annual Report,[5] noting the substantial reduction in

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3. Con Edison, "Indian Point 2 Cost Data," Internal Memorandum (April 1983).

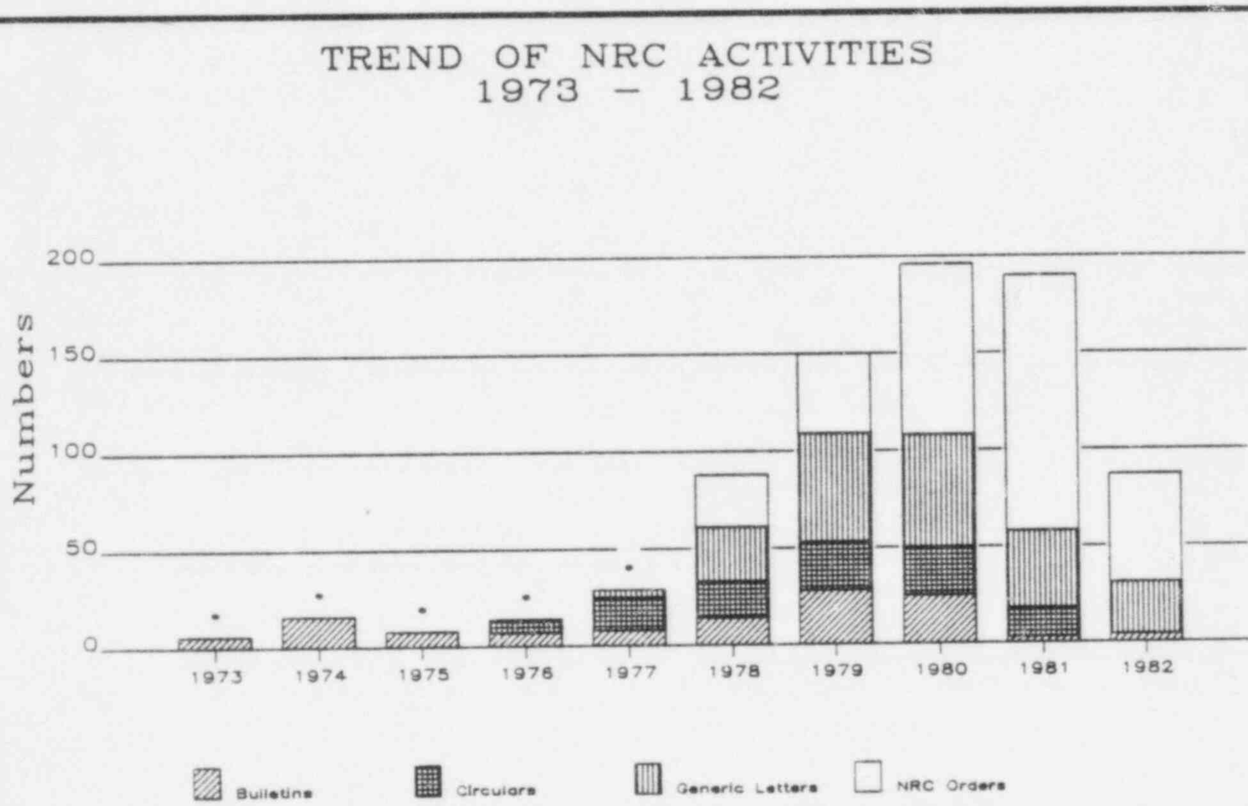
4. Determining the Portion of Regulatory Burden on Indian Point Unit 3, Capital and O&M Expenditures, 1976-1986, Budget Division, Power Authority of New York, April 1983.

5. U.S. Nuclear Regulatory Commission, 1981 Annual Report, p. 92.

bulletins, circulars and generic letters that year, said:

> These reduced numbers reflect more stringent criteria in determining whether an issue is significant enough to merit industry-wide communication, and recognition that the NRC may have been overburdening licensees and construction permit holders with requirements of marginal safety impact. The same philosophy led to the formation, late in 1981, of the Committee for Review of Generic Requirements.

The number of orders however did not decrease until 1982. Consideration of both the costs and benefits of each action has already reduced the amount of output, and may hold level or even reduce O&M expenditure.



*Data on NRC Orders are incomplete before 1978. 1978 figure is estimated from 3 quarters data.

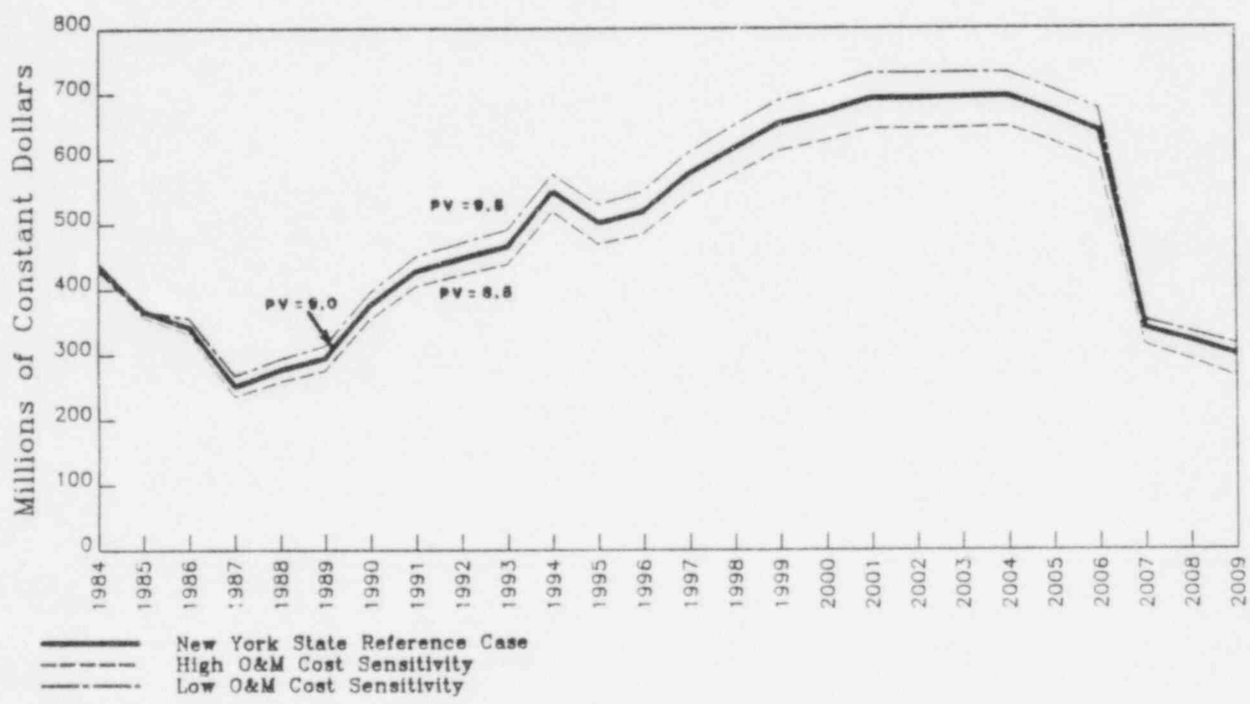
Source: Table 12.

A third item of the licensees' increase in O&M is attributable to specific repairs and changes, particularly maintenance work associated with the extended

outage for the fan coolers at Indian Point 2 and the steam generator sleeving program at Indian Point 3. Projections for 1983 continue at this high level for Unit 3, for completion of the sleeving program, and are expected to decline slightly in 1984. Con Edison estimates 1983 expenditures of $48 million, in a non-refuelling year, with an additional $20 million in refueling years. I have normalized the $20 million based on a 16 month refueling cycle to $14 million for an average year for projections.

LOW AND HIGH O&M COST SENSITIVITY

1984 – 2009



Source: Table 14.

The sensitivity cases are estimated as follows. NERA's analysis of national O&M data suggests that if the reduced volume of NRC regulation lead to a stabilization of expenditures at the 1980-81 level, the companies could be expected to achieve O&M levels somewhat below their own projections by the

mid-1980s. This analysis also suggests that the cumulative experience of a utility in running nuclear units tends to offset other time related effects on the required O&M expenditures. Therefore, the low O&M case assume that after 1987 the companies O&M costs drop to \$40/Kw real dollars, the mean of the U.S. average 1980 and 1981 costs per Kw, rising at inflation. The high O&M sensitivity case assumes the companies own (higher) estimates, an additional step increase in regulatory burden of 10 percent, and 2 percent real growth. These cases are shown in Figure 5 and Table 14.

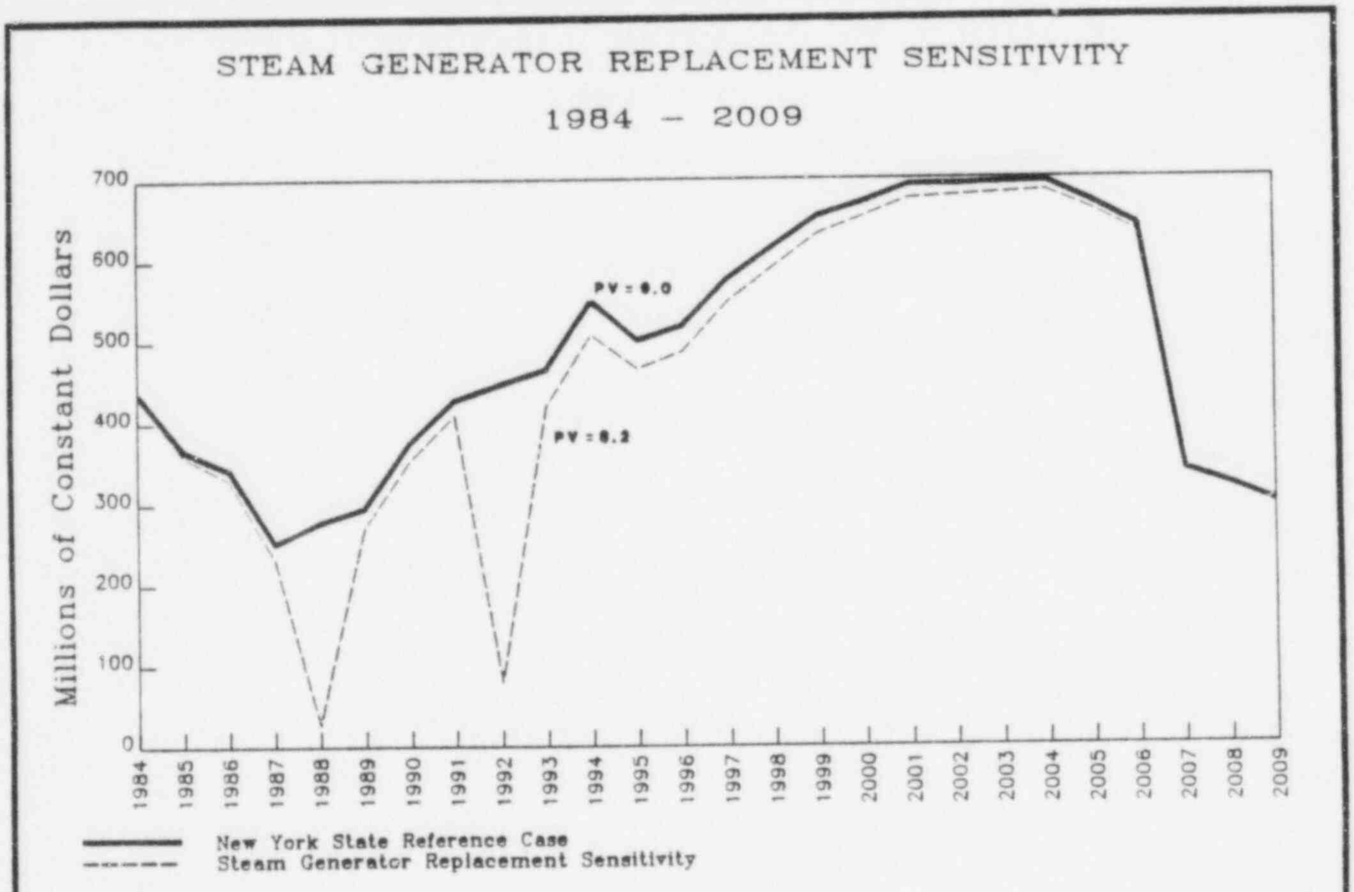
d. Capital Expenditures at Indian Point

Additional capital expenditures needed for the units were estimated by the companies after detailed review. The historic and annual expected capital expenditures to 1990 were given in Table 10. They include major repairs, regulatory requirements and productivity modifications which are anticipated through 1986, and estimates thereafter. In the summary tables, capital expenditures are annualized, and the costs are presented as the annualized value of each year's expenditure cumulated over time.

The main source of uncertainty is the possibility of a steam generator replacement. Both companies have been experiencing problems with the steam generators.

At Indian Point 3, a program of plugging and sleeving the steam generator tubes has been undertaken, and will be continued. \$20 million of O&M were spent last year (1982) on this project. Future costs of this program are included in total O&M estimates. The Power Authority hopes to avoid the need for replacement by the sleeving program. It has however made contingency plans, which would involve replacing the steam generator in 1987 or 1989. Costs for this are estimated at \$200 million dollars in that year, exclusive of replacement power costs.

Indian Point 2 has also been subject to steam generator problems. Contingency plans for replacement of the steam generators are under discussion, but no decision as to the need for replacement has been made. I have not included estimates in the base case for replacement at either Unit 2 or Unit 3.



Source: Table 16.

The sensitivity of the estimates of net cost to the steam generator replacement are shown in Figure 6 and Table 15. The reference case includes no steam generator replacement. The high sensitivity case includes replacements at Unit 3 in 1988 and at Unit 2 in 1991. Fuel savings are netted out, representing 12 months of outage in each case. The difference in present value between the

reference case and the steam generator replacement case is $800 million. With capital cost projections, as with O&M, the companies' near term estimates of capital expenditures are higher than NERAs projections from national data would suggest, even leaving aside the steam generator replacement.

e. Load Growth, Capacity Additions and Conversion

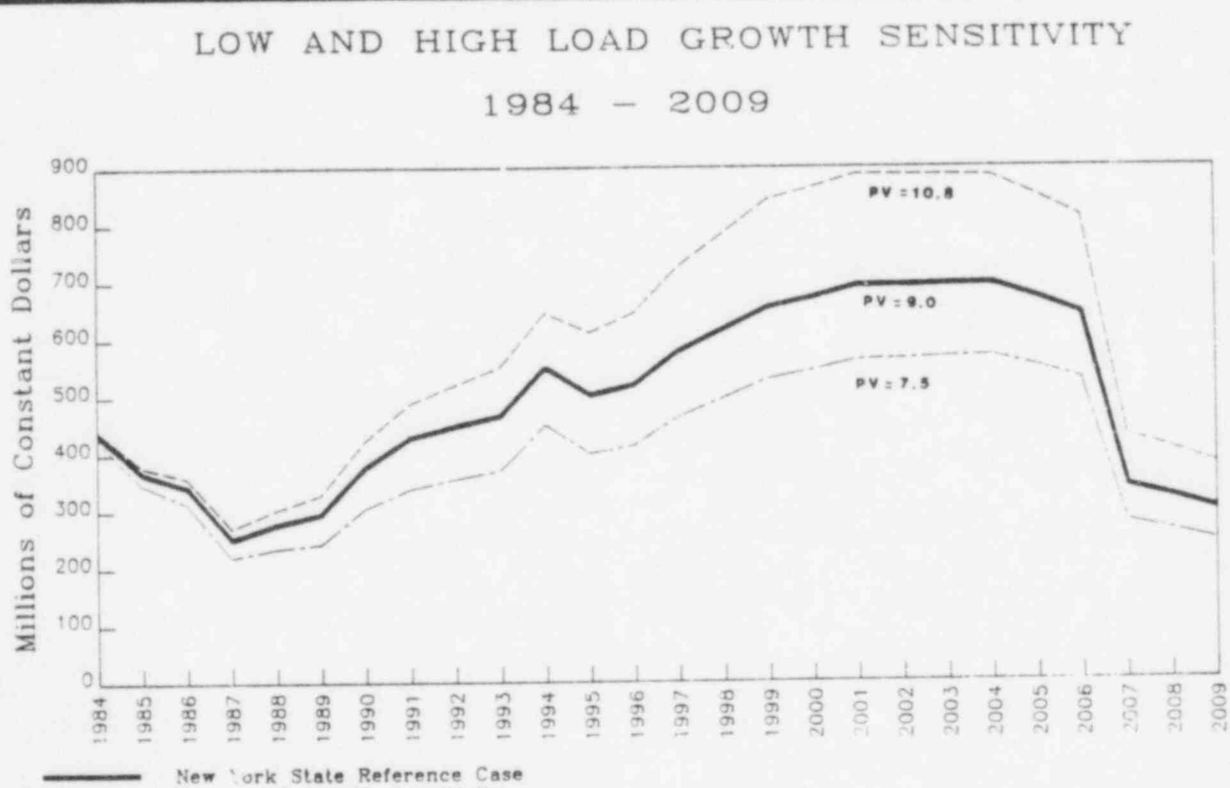
(i) Load Growth

In the period to 2000, load growth (growth in energy consumption) in New York State is estimated by the NYPP members to be at an average annual level of 1.4 percent. This projection is the sum of individual NYPP members' projections and includes a growth projection of 1.3 percent annually in Con Edison's franchise area. The importance of the base growth projection is that if the construction schedule is unchanged, lower growth leads to less expensive units on the margin and hence lower replacement costs. Higher growth on the other hand leads to higher cost units on the margin and higher replacement costs given the same construction schedule.

But of course if projected growth falls, the construction schedule may also change. For example, NYPP's energy growth projections have dropped from 1.8 percent overall growth in 1982 to 1.4 percent this year, reflecting closings of upstate manufacturing facilities. The units planned for Erie, Jamesport and Arthur Kill have been cancelled or indefinitely deferred and coal conversion has been indefinitely deferred at the Albany units.

However, if growth were projected to increase from 1.4 percent, licensing and regulatory constraints make it impossible to plan with confidence for a prompt quickening of the construction schedule if that should be needed. Hence, the sensitivity to growth alone should be viewed with some perspective. Lower growth can be adjusted to and may not lead to lower replacement costs for Indian Point power. But higher growth would pose real problems of adjustment.

Mr. Meehan ran sensitivity analyses for 1991 and 1999 on alternative growth scenarios of 0.7 percent overall, and 2.1 percent overall. The low and high growth sensitivity is shown in Table 17. Unfortunately Mr. Meehan's sensitivity analyses incorporate the old expansion plan, and are therefore not sensitivities about the reference case. I have recomputed the sensitivity of the reference case to load growth after consultation with Mr. Meehan. The results of this sensitivity analysis are shown in Figure 7 and Table 18.



Source: Table 18

(ii) Capacity Additions

At the time of the last NYPP submission pursuant to Section 5-112,[6] there were plans for constructing four new generating units in addition to the plants at Somerset, Nine Mile Point, and Shoreham, which are under construction. One of these new units, Prattsville, is now scheduled for a later in-service date (1989), and three others, Erie, Jamesport and Arthur Kill have been cancelled or indefinitely postponed.

(iii) Coal Conversion

Ten NYPP oil burning units, totalling over 2900 MW, are currently scheduled to be converted to coal-burning. The schedule for conversions is set out in the 1983 Section 5-112 submission, and reflects a number of deferrals from previous 5-112 submissions. The schedule has been slipping since 1979. In fact no unit in New York State has yet converted to coal. Mr. Meehan's reference case assumes the current proposed conversion schedule will be met. The likelihood of conversion on any scale approaching this figure is doubtful, and his alternate case where none of the units are converted is quite conceivable.

f. Canadian Imports

Large amounts of energy are expected to be available from Canada at reasonable prices, and some 6,000-12,000 Gwh/year expected to be purchased whether or not Indian Point is closed. This amount of energy is not, therefore an alternative to operation of Indian Point, as it will be imported independent of any decision concerning Indian Point. The availability of this Canadian power, on the schedule proposed, requires state and federal authorities to license promptly the Marcy-South line. The existence of opposition to the project, and the tight

6. Report of Member Electric Systems of the New York Power Pool and the Empire State Electric Energy Research Corporation pursuant to Section 5-112 of the Energy Law of New York State.

licensing and construction schedule assumed, make it possible that the line will not be in service when it is now planned. The reference case projection of the costs of closing Indian Point assumes that the line will go into service on schedule and additional imports will be available. The costs of closing Indian Point would be higher if this construction did not take place.

g. Replacement Capacity

NYPP member companies keep a gross reserve margin of generating capacity above peak requirements of 22 percent on a state-wide basis, and each company within NYPP is required to keep 18 percent above its own peak requirements.

NYPP has a substantial reserve margin over its peak requirements. As shown in Table 14, if the units currently under construction plus Prattsville are completed and put into service, and if the load growth averages 1.2 percent per year, there will be a sufficiently large margin over peak requirements that the closing of Indian Point would not of itself leave NYPP as a whole short of capacity (that is, below its 22 percent margin requirement) in the 15 year planning period.

However, if Prattsville is deferred or cancelled, NYPP would run below its reserve margin in 1999 without Indian Point, as shown in Table 19. Such an eventuality would probably lead to a rescheduling of one of the deferred units. Hence, closing Indian Point may indeed involve new construction, most likely of a coal fired plant. Coal units are currently estimated by the NYPP Economic Parameters Report to cost $1,715 per KW. This is also the estimated cost of Somerset, due to go on line in 1984. Building a coal unit in or near New York City would probably cost more. Replacing Indian Point units 2 and 3 (which cost about $360 per kilowatt when they were built) with coal units of equivalent capacity would cost at least $3 billion today.

If peak growth is higher than predicted, the NYPP reserve margin will become inadequate even with the new units in the early 1990s. In this case, the closing of Indian Point would also require additional capacity.

However, the Con Edison franchise area (including the Power Authority's downstate customers as well as Con Edison's customers) would run short of capacity in the 1990s if Prattsville were not built and if Indian Point were closed. The franchise area would require the equivalent of Indian Point's capacity by the turn of the century either in new construction or firm contracts.

h. The Discount Rate

The present value of a future stream of costs is customarily calculated by applying a market discount rate to current dollar costs, or a "real" discount rate to constant dollar cost. I have discounted the current dollar stream at 10 percent, which represents a 3 percent real discount rate above inflation of 7 percent. Discounting at 12 percent or 14 percent would of course produce lower present value estimates. The sensitivity of the present value to the discount rate is shown in Table 20.

i. Decommissioning Costs

If Indian Point Unit No. 2 were to close permanently, the plant would presumably be decommissioned, but not necessarily immediately.

Although no large plant of this size has ever been decommissioned, several studies have estimated the decommissioning cost. A recent site specific study for Con Edison estimated the cost for dismantling Units 1 and 2 to be \$138.5 million (1980) but the PSC has allowed only \$92.7 million. The additional cost of closing the plant early depends on assumptions as to what would be done if the plant remained open as compared with what would be done if the plant were to be closed. In the reference case I have assumed that if the plant

were to be ordered closed today, the companies would not undertake decommissioning before 1994 and that the real costs would be the same as those estimated for decommissioning at the end of life; this means that additional cost would have to be incurred to prepare the unit 2 for safestorage and its continual care until the unit is dismantled. It is estimated that it would cost \$6.3 million (1980) to prepare the unit for mothballing and would cost \$6.9 million per year for continuing care of the unit, while the spent fuel is at site. After the spent fuel has been shipped, the unit continuing care cost would drop down to \$2.3 million per year. For simplicity I have estimated these costs to average \$5 million per year to 1994. To this must be added the present value of moving forward the decommissioning from 2010 to 1994, or the time value of making the expenditures earlier. This cost is calculated as follows:

Estimated Cost of Dismantlement: (1980 Dollars per unit)	\$90 million.
Nominal Cost in 2010: (Assuming 5 percent savings for simultaneous dismantlement)	\$1,302 million.
Present Value, in 1983:	\$99 million.
Nominal Cost in 1994: (Assuming 5 percent savings for simultaneous dismantlement)	\$441 million.
Present Value, in 1983:	\$155 million.
Difference: (Present Value in 1983 of Cost of Early Decommissioning)	\$55 million.

This difference in present value has been added to the 1994 costs.

There is some possibility that early closing would reduce the cost by reducing the cumulative amount of radiation. On the other hand, early closing and decommissioning would mean being among the first to do it, and would

probably involve a learning premium. Since the plant will have to be decommissioned under either an early closing or full life scenario, the difference in costs due to decommissioning is a small part of the total, and I have not performed sensitivity analyses on it.

j. Disposal Costs

Disposal and storage costs of spent nuclear fuel were included in Mr. Meehan's estimates of nuclear fuel costs.

k. Loss of Fuel Core

The cost per kwh of nuclear fuel, which has been estimated as 7 mills/kwh in 1984, was used in Mr. Meehan's runs to determine the net production penalty. However, if the plant were to be closed, the value of the fuel core already installed would be lost. The core consists of three "regions," one of which is replaced at each refueling. Each region is one-third used up between refuelings. Hence, if the unit were closed immediately after a refueling, the loss would be all of the most recent region, two-thirds of the previous region and one-third of the oldest region. If the plant were closed before a refueling, the loss would be two-thirds of one region plus one-third of another. Assuming the plant would be closed before a refueling, the loss would be a total of one fuel region, which costs about $50 million.

l. Tax Changes and Working Capital

If Indian Point were closed, it may be anticipated that Con Edison would write off Indian Point 2 for tax purposes. The impact is very small because the tax benefits would be accrued whether or not the unit were closed: the only difference would be in the timing. It is unlikely to make any difference to customers, who get rate base credit for timing differences in any event.

Sales taxes at 8-1/4 percent and taxes on gross revenues have been included for Con Edison, at 4 percent.

The Power Authority, as a tax exempt entity has not such tax savings or penalties.

Working capital and inventory costs are calculated as prescribed by the New York Public Service Commission. These changes are all shown in Table 21.

IV. ALTERNATIVES TO INDIAN POINT

a. Price Induced Conservation

A price increase such as that projected in the reference case would induce some additional conservation. This effect would be spread over several years. The effect on the Power Authority's customers is discussed in the testimony of Dr. Dunbar and Mr. Dean.

Adding 4 percent to Con Edison's prices every year after 1983 could be expected to reduce energy sales in the long run (by 1995) by about 1.0 percent or 350 GWH. (Long run elasticity for Con Edison's customers is estimated by Con Edison at -.25.) Since only half the revenue from these 350 GWH represents fuel savings, and fixed costs still have to be recovered, an additional $26 million (1982 dollars) would have to be added to the base rates, raising prices a further .4 percent. After a second round of elasticity, and increased prices, the final price impact would be about 4.5 percent, and the final GWH reduction about 400 GWH. This would not come close to offsetting the generation from Indian Point, which is 10,000 GWH a year.

This reduction in consumption is not an <u>economic</u> benefit, however, unless it reflects a commensurate increase in safety. (People who give up beef because it is too expensive do not feel better off eating bologna than they did eating cheaper beef.) The reduced demand consequent on the price increase saves production costs, but there is an offsetting reduction in consumer satisfaction,

since consumers are giving up the use of electricity which they have demonstrated, by buying it, is worth the original (pre-Indian Point closing) price.

ESRG has asserted[7] that the reduction in sales, which leads to a reduction in revenues, can be viewed as a benefit to consumers, partially offsetting the increased costs. They even assert that if the elasticity of demand were equal to minus one, and if marginal fuel costs were equal to average price, that there would be no impact at all from the closing, as customers would reduce demand to keep total bills constant. This latter assertion fully demonstrates the fallacy of the conclusion: if customers were paying exactly the same bill for 7 percent less electricity, they would clearly be 7 percent worse off. Their choice to do without electricity rather than pay the additional price imposed because of an Indian Point closing comes to virtually the same impact as paying 7 percent more money for the same amount of electricity. [Indeed, under ESRG's scenario, if demand were elastic, consumers could always be benefitted by raising the price of any good so that they would spend less on it in total. Presumably, in this case, no consumption at all would confer the greatest benefits of all.]

The small grain of truth in ESRG's absurd assertion is demonstrated in Appendix 3 where I calculate the appropriate correction factor to be under 1 percent. Since it is so small, I have ignored it.

b. Alternative Technologies for Generation

NYPP members aim to minimize total production costs subject to financial, regulatory and technological constraints.

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7. Raskin, Paul D. and Rosen, Richard A., The Economics of Closing the Indian Point Nuclear Power Plants. The direct effect upon rate payers of early retirement of units 2 and 3. ESRG Study 82-40, ESRG Boston, Mass. (no date) p. 70.

If Indian Point were closed, the NYPP might review its construction plan. But any dramatic changes in the economics of that plan would depend on changes in the marginal costs of fuel consequent on closing Indian Point. I asked Mr. Meehan to compute the change in marginal cost for 1991, a typical year, for a change in load of 100 MW. With Indian Point open the mean marginal cost is 102 mills per kilowatt-hour. With Indian Point closed it is 113 mills. This 11 percent increase in marginal costs due to the closing of Indian Point might make some generation alternatives more economic. But it is unlikely that any new technology such as solar electric generation or windmills will become dramatically more likely to be adopted if Indian Point were closed.

V. THE ALLOCATION OF THE CAPITAL COST OF INDIAN POINT

Mr. Meehan's projection focuses on production costs, not the embedded capital cost of the existing Indian Point plants. Indian Point 2 is presently included in Con Edison's rate base. If that unit were closed prematurely by order of the Commission, the company expects that the unrecovered investment would be treated as an extraordinary loss, and the unamortized balance would continue in the rate base.

Indian Point 3 presents a different situation. The Power Authority now sells power from Indian Point 3 and the Poletti Plant on a melded basis, in which the rates charged its customers in Southeast New York pay for variable and fixed costs of both plants.

The Power Authority does not have any shareholders. It is required to pass on to its customers all costs of its plants, including amortization of its investment and the cost of purchasing replacement power. The customers have entered into power supply contracts with the Power Authority that specify the

terms of the individual relationships. The rates charged by the Authority for power vary substantially depending on, among other things, the source of power supplied to the particular customer. Because the power supply contracts give the customers the right to switch to a supplier other than the Power Authority, they would be expected to exercise that option if the rates of the local investor-owned utility were more attractive.

A shutdown of Indian Point would inevitably require sharp rate increases for the Power Authority's Southeast New York customers. To the extent that increases would raise rate levels above those of an alternative supplier, the possibility exists that the Power Authority's downstate customers would seek another supply source. This would threaten the Power Authority's ability to meet required payments under its bond resolution and thereby would have a substantial, direct and adverse impact on the Power Authority, its future projects and other governmental entities in New York State.

The Power Authority now expects that the embedded costs of Indian Point 3 might have to be recovered from the customers of the Authority's remaining revenue producing facilities in proportion to the ability of each of these facilities to carry such costs and still produce (and/or transmit) power at competitive rates. The major remaining facilities include:

(1) the Hydroelectric Projects--Niagara and St. Lawrence-FDR generating projects and related transmission facilities,

(2) the James A. FitzPatrick nuclear power plant,

(3) the Blenheim-Gilboa pumped storage power project, and

(4) the Gov. Charles Poletti oil and gas fueled power project.

The Power Authority has indicated to me that it is quite possible that none of the anticipated closing costs could be recovered from ratepayers served from

the Poletti plant, assuming the Power Authority would continue to operate this facility as an isolated unit. This is because on a stand-alone basis it is estimated that Poletti rates at point of delivery to ultimate customers would just barely be competitive when compared to the local retail rates for electricity produced by Con Edison.

Furthermore, based on a similar analysis of the effect on current rates and competitive position of allocating a portion of the closing costs to the FitzPatrick nuclear plant and the Blenheim-Gilboa pumped storage power project, the Power Authority has concluded that only a relatively small portion of such costs could reasonably be allocated to these facilities.

Therefore, the effect of recovering the closing costs from the Authority's remaining revenue producing facilities, after competitive considerations are taken into account, could be that the customers bearing the bill would be located almost exclusively in Upstate New York, as distinguished from the Con Edison service territory, and for the most part such consumers would be customers of the Hydroelectric Projects.

It is estimated by the Power Authority that the Hydroelectric Project rates would have to be increased immediately by about $70 million annually, or by about 45 percent over current levels, to ensure that the costs of closing Indian Point could be met by the Authority.

To the extent other Authority customers' rates increased as a result of shutdown, it would offset the increase to SENY customers by a corresponding amount. Every dollar of Indian Point 3 costs which is allocated to plants other than Poletti results in a dollar reduction in the amount of the increase to the downstate public customers.

VI. SHUTDOWN COSTS IN PERSPECTIVE

How might this Commission determine whether the benefits of closing Indian Point are in any way commensurate with the costs? The risks attached to Indian Point operating are expressed by the Indian Point Probabalistic Safety Study in terms of probabilities of occurrence of certain accidents. If Indian Point were closed the benefits would be expressed in terms of avoidance of those risks. On the other hand, the direct costs of closing Indian Point are expressed here in terms of dollars, although I have not attempted to estimate environmental costs, or risks of war consequent on increased dependence on oil, or the effect on the financial well being of the electric utility industry. These are real costs nonetheless.

I would suggest, though, that looking only at the direct costs as I have measured them, one might reasonably frame the question as "what am I buying for $4-600 million a year?" Clearly, those arguing for closing Indian Point would characterize the costs of the closing as a purchase of safety. Independent of the merits of that suggestion, we should ask ourselves what the citizens of the region typically buy for $4-600 million a year, and how much they have shown themselves willing to tax themselves to purchase public goods. By way of example, the public makes comparably large payments for what are undeniably safety expenditures: the New York City Police Department budget for the fiscal year 1983 is $838 million: the Corrections Department's budget is $211 million: the Fire Department's $419 million: the department of Environmental Protection's $199 million. These are basic safety expenditures made by New York City.

For the penalty is like a tax--it is money taken from the citizens to purchase a public good. If it were levied as a tax, instead of through the electric

rates, $400 million would be roughly equivalent to raising the sales tax from 8-1/4 percent to 9 percent. Or to an 8 percent increase in the property tax. It is a substantial amount even in the context of a multibillion dollar city.

Testimony of

Sally Hunt Streiter

TABLES, APPENDICES & EXHIBITS

REFERENCE CASE
SUMMARY OF COSTS
OF CLOSING INDIAN POINT

New York State

	Costs		Savings		
Year	Production Cost Penalty	Total Other Costs	Avoided O&M Costs	Avoided Capital Charges	Net Cost
	(Millions of Nominal Dollars)				
	(1)	(2)	(3)	(4)	(5)
1984	$ 463	$ 176	$ 131	$ 27	$ 482
1985	533	87	144	43	433
1986	549	88	150	56	431
1987	503	76	165	75	340
1988	576	87	178	86	400
1989	650	98	192	99	456
1990	819	125	207	114	622
1991	965	148	224	130	760
1992	1,073	165	242	146	850
1993	1,188	184	261	164	947
1994	1,306	350	282	182	1,192
1995	1,438	213	305	183	1,164
1996	1,604	238	329	222	1,291
1997	1,859	276	355	244	1,537
1998	2,090	310	384	262	1,754
1999	2,339	347	414	277	1,994
2000	2,550	378	448	289	2,191
2001	2,779	412	483	293	2,415
2002	2,943	436	508	284	2,586
2003	3,113	462	534	268	2,772
2004	3,290	488	561	247	2,971
2005	3,362	499	573	223	3,065
2006	3,421	507	591	200	3,137
2007	1,931	286	332	117	1,768
2008	1,959	291	361	105	1,784
2009	1,978	293	398	94	1,779
Present Value	$10,736	$1,768	$2,313	$1,190	$9,001

REFERENCE CASE
SUMMARY OF COSTS
OF CLOSING INDIAN POINT

New York State

	Costs		Savings		
Year	Production Cost Penalty	Total Other Costs	Avoided O&M Costs	Avoided Capital Charges	Net Cost
	(Millions of Mid 1982 Constant Dollars)				
	(1)	(2)	(3)	(4)	(5)
1984	$ 418	$ 159	$ 118	$ 24	$ 435
1985	450	73	122	36	365
1986	433	69	118	45	340
1987	371	56	121	56	250
1988	397	60	123	59	276
1989	419	63	124	64	294
1990	493	75	125	69	375
1991	543	83	126	73	427
1992	564	87	127	77	447
1993	584	91	128	81	465
1994	600	161	130	84	548
1995	617	91	131	78	500
1996	643	95	132	89	518
1997	697	104	133	91	576
1998	732	109	134	92	615
1999	766	114	136	91	653
2000	780	116	137	89	670
2001	795	118	138	84	691
2002	787	117	136	76	691
2003	778	115	133	67	693
2004	768	114	131	58	694
2005	734	109	125	49	669
2006	698	103	121	41	640
2007	368	55	63	22	337
2008	349	52	64	19	318
2009	329	49	66	16	296
Present Value	$10,736	$1,768	$2,313	$1,190	$9,001

REFERENCE CASE
SUMMARY OF COSTS
OF CLOSING INDIAN POINT

New York State

	Costs		Savings		
Year	Production Cost Penalty	Total Other Costs	Avoided O&M Costs	Avoided Capital Charges	Net Cost
	(Millions of 1983 Discounted Dollars)				
	(1)	(2)	(3)	(4)	(5)
1984	$ 421	$ 160	$ 119	$ 24	$ 438
1985	440	72	119	36	357
1986	412	66	112	42	324
1987	344	52	112	51	232
1988	358	54	110	53	248
1989	367	55	108	56	258
1990	420	64	106	59	319
1991	450	69	104	61	354
1992	455	70	103	62	360
1993	458	71	101	63	365
1994	458	123	99	64	418
1995	458	68	97	58	371
1996	465	69	95	64	374
1997	490	73	94	64	405
1998	500	74	92	63	420
1999	509	75	90	60	434
2000	504	75	89	57	433
2001	500	74	87	53	434
2002	481	71	83	46	423
2003	463	69	79	40	412
2004	445	66	76	33	401
2005	413	61	70	27	377
2006	382	57	66	22	350
2007	196	29	34	12	180
2008	181	27	33	10	165
2009	166	25	33	8	149
Present Value	$10,736	$1,768	$2,313	$1,190	$9,001

Table 2

REFERENCE CASE
SUMMARY OF COSTS
OF CLOSING INDIAN POINT

Con Edison

Year	Costs: Production Cost Penalty	Costs: Total Other Costs	Savings: Avoided O&M Costs	Savings: Avoided Capital Charges	Net Cost
	(Millions of Nominal Dollars)				
	(1)	(2)	(3)	(4)	(5)
1984	$ 200	$ 91	$ 69	$ 12	$ 210
1985	227	47	74	16	184
1986	211	43	80	23	150
1987	227	44	87	38	146
1988	271	52	94	45	184
1989	312	59	101	53	217
1990	347	67	109	62	243
1991	404	79	118	71	294
1992	446	87	128	81	325
1993	502	99	138	90	373
1994	572	186	149	100	509
1995	639	121	161	111	488
1996	728	138	174	122	570
1997	692	131	187	133	503
1998	798	151	202	140	607
1999	918	173	219	142	730
2000	1,001	189	236	141	813
2001	1,091	206	255	134	908
2002	1,155	218	262	120	991
2003	1,222	231	268	108	1,077
2004	1,291	244	273	95	1,167
2005	1,320	249	278	83	1,208
2006	1,343	253	281	71	1,244
Present Value	$4,216	$884	$1,154	$583	$3,362

REFERENCE CASE
SUMMARY OF COSTS
OF CLOSING INDIAN POINT

Con Edison

	Costs		Savings		
Year	Production Cost Penalty	Total Other Costs	Avoided O&M Costs	Avoided Capital Charges	Net Cost
	----------(Millions of Mid 1982 Constant Dollars)----------				
	(1)	(2)	(3)	(4)	(5)
1984	$ 181	$ 83	$ 62	$ 1[illegible]	$ 190
1985	192	39	63	13	155
1986	167	34	63	18	119
1987	167	32	64	28	108
1988	187	36	65	31	127
1989	201	38	65	34	139
1990	209	40	66	37	146
1991	227	44	66	40	165
1992	235	46	67	42	171
1993	247	49	68	44	183
1994	263	86	68	46	234
1995	274	52	69	48	209
1996	292	55	70	49	229
1997	259	49	70	50	189
1998	280	53	71	49	213
1999	301	57	72	47	239
2000	306	58	72	43	249
2001	312	59	73	38	260
2002	309	58	70	32	265
2003	305	58	67	27	269
2004	302	57	64	22	272
2005	288	54	61	18	264
2006	274	52	57	15	254
Present Value	$4,216	$884	$1,154	$583	$3,362

REFERENCE CASE
SUMMARY OF COSTS
OF CLOSING INDIAN POINT

Con Edison

	Costs		Savings		
Year	Production Cost Penalty	Total Other Costs	Avoided O&M Costs	Avoided Capital Charges	Net Cost
	(Millions of 1983 Discounted Dollars)				
	(1)	(2)	(3)	(4)	(5)
1984	$ 182	$ 83	$ 63	$ 11	$ 191
1985	188	39	62	13	152
1986	159	32	60	17	113
1987	155	30	59	26	100
1988	168	32	58	28	114
1989	176	33	57	30	122
1990	178	34	56	32	125
1991	188	37	55	33	137
1992	189	37	54	34	138
1993	194	38	53	35	144
1994	200	65	52	35	178
1995	204	38	51	35	155
1996	211	40	50	35	165
1997	182	34	49	35	132
1998	191	36	48	33	145
1999	200	38	48	31	159
2000	198	37	47	28	161
2001	196	37	46	24	163
2002	189	36	43	20	162
2003	182	34	40	16	160
2004	175	33	37	13	158
2005	162	31	34	10	148
2006	150	28	31	8	139
Present Value	$4,216	$884	$1,154	$583	$3,362

REFERENCE CASE
SUMMARY OF COSTS
OF CLOSING INDIAN POINT

Power Authority

Year	Costs: Production Cost Penalty	Costs: Total Other Costs	Savings: Avoided O&M Costs	Savings: Avoided Capital Charges	Net Cost
	(Millions of Nominal Dollars)				
	(1)	(2)	(3)	(4)	(5)
1984	$ 255	$ 64	$ 62	$ 15	$ 243
1985	302	16	70	27	221
1986	299	16	69	33	213
1987	262	13	78	38	159
1988	293	14	84	40	183
1989	329	15	91	46	208
1990	384	20	98	52	253
1991	432	23	106	59	290
1992	485	26	114	66	331
1993	541	29	123	74	373
1994	598	106	133	82	489
1995	665	30	144	72	479
1996	741	33	155	100	518
1997	878	42	168	111	641
1998	983	46	181	122	726
1999	1,091	51	196	135	811
2000	1,549	72	212	149	1,261
2001	1,688	79	228	159	1,379
2002	1,788	83	247	164	1,461
2003	1,891	88	266	160	1,553
2004	1,999	93	288	151	1,653
2005	2,043	95	295	140	1,703
2006	2,078	97	310	128	1,737
2007	1,931	90	332	117	1,572
2008	1,959	91	361	105	1,584
2009	1,978	92	398	94	1,578
Present Value	$5,885	$358	$1,159	$606	$4,478

REFERENCE CASE
SUMMARY OF COSTS
OF CLOSING INDIAN POINT

Power Authority

	Costs		Savings		
Year	Production Cost Penalty	Total Other Costs	Avoided O&M Costs	Avoided Capital Charges	Net Cost
	----------(Millions of Mid		1982 Constant Dollars)----------		
	(1)	(2)	(3)	(4)	(5)
1984	$ 230	$ 58	$ 56	$ 13	$ 220
1985	255	14	59	23	187
1986	236	13	55	26	168
1987	193	9	57	28	117
1988	202	10	58	28	126
1989	212	10	58	30	134
1990	231	12	59	31	153
1991	243	13	60	33	163
1992	255	14	60	35	174
1993	266	14	61	36	183
1994	275	49	61	38	224
1995	285	13	62	31	206
1996	297	13	62	40	208
1997	329	16	63	42	240
1998	344	16	64	43	254
1999	357	17	64	44	266
2000	474	22	65	46	386
2001	483	23	65	46	395
2002	478	22	66	44	390
2003	472	22	67	40	388
2004	467	22	67	35	386
2005	446	21	64	31	372
2006	424	20	63	26	354
2007	368	17	63	22	300
2008	349	16	64	19	282
2009	329	15	66	16	263
Present Value	$5,885	$358	$1,159	$606	$4,478

REFERENCE CASE
SUMMARY OF COSTS
OF CLOSING INDIAN POINT

Power Authority

Year	Costs: Production Cost Penalty	Costs: Total Other Costs	Savings: Avoided O&M Costs	Savings: Avoided Capital Charges	Net Cost
	(Millions of 1983 Discounted Dollars)				
	(1)	(2)	(3)	(4)	(5)
1984	$ 232	$ 58	$ 56	$ 13	$ 221
1985	250	13	57	23	183
1986	225	12	52	25	160
1987	179	9	53	26	109
1988	182	9	52	25	113
1989	186	9	51	26	117
1990	197	10	50	27	130
1991	202	11	49	27	136
1992	206	11	48	28	140
1993	209	11	48	28	144
1994	210	37	47	29	171
1995	212	10	46	23	153
1996	215	10	45	29	150
1997	231	11	44	29	169
1998	235	11	43	29	174
1999	237	11	43	29	177
2000	306	14	42	29	249
2001	304	14	41	29	248
2002	292	14	40	27	239
2003	281	13	40	24	231
2004	270	13	39	20	223
2005	251	12	36	17	209
2006	232	11	35	14	194
2007	196	9	34	12	160
2008	181	8	33	10	146
2009	166	8	33	8	132
Present Value	$5,885	$358	$1,159	$606	$4,478

RATE IMPACT ON DOWN-STATE CUSTOMERS RESULTING FROM INDIAN POINT CLOSING

Year	Estimated Con Edison Revenues --($M)-- (1)	Rate Increase --(%)-- (2)	Estimated Power Authority Revenues --($M)-- (3)	Rate Increase --(%)-- (4)
1984	$4,600	4.6%	$ 729	33.3%
1985	5,000	3.7	782	28.3
1986	5,300	2.8	839	25.4
1987	5,600	2.6	901	17.6
1988	5,900	3.1	967	18.9
1989	6,200	3.5	1,038	20.0
1990	6,500	3.7	1,114	22.7

Sources: Col. (1): Con Edison Projection.
Col. (2): Table 2, Col. (5) / Col. (1) x 100.
Col. (3): Power Authority Projection.
Col. (4): Table 3, Col. (5) / Col. (1) x 100.

SENSITIVITY CASE WORLD OIL PRICE ASSUMPTIONS

Year	Reference Case	ICF High Oil Prices	ICF Low Oil Prices	Low Low Oil Prices
	(Millions of Mid 1982 Constant Dollars per Barrel)			
	(1)	(2)	(3)	(4)
1984	$32.9	$35.0	$30.0	$27.0
1985	34.0	36.1	28.0	27.0
1986	34.7	37.2	28.3	27.0
1987	35.4	38.3	28.6	27.0
1988	36.1	39.4	28.8	27.0
1989	36.8	40.6	29.1	27.0
1990	37.5	41.8	29.4	27.0
1991	38.3	43.1	30.0	27.0
1992	39.1	44.4	30.6	27.0
1993	39.8	45.7	31.2	27.0
1994	40.6	47.1	31.9	27.0
1995	41.4	48.5	32.5	27.0
1996	42.3	49.9	33.1	27.0
1997	43.1	51.4	33.8	27.0
1998	44.0	53.0	34.5	27.0
1999	44.9	54.6	35.2	27.0
2000	45.8	56.2	35.9	27.0
2001	46.7	57.9	36.6	27.0
2002	47.6	59.6	37.3	27.0
2003	48.6	61.4	38.1	27.0
2004	49.5	63.2	38.8	27.0
2005	50.5	65.1	39.6	27.0
2006	51.5	67.1	40.4	27.0
2007	52.6	69.1	41.2	27.0
2008	53.6	71.2	42.0	27.0
2009	54.7	73.3	42.9	27.0

Sources: Cols. (1) - (3): ICF Incorporated, Forecast of Fuel Markets and Prices in New York State, Volume 1, Oil and Gas Markets and Prices, Presented to New York Power Pool, November 1982, page I-1.

SENSITIVITY OF NYS REFERENCE CASE NET COST TO OIL PRICES

	Net Cost of Closing			
Year	Reference Case	ICF High Oil Prices	ICF Low Oil Prices	Low Low Oil Prices
	(Millions of Mid 1982 Constant Dollars)			
	(1)	(2)	(3)	(4)
1984	$435	$464	$396	$355
1985	365	394	281	267
1986	340	368	268	253
1987	250	263	220	213
1988	276	292	239	230
1989	294	314	253	242
1990	375	414	300	277
1991	427	486	326	289
1992	447	518	335	287
1993	465	550	340	279
1994	548	646	413	339
1995	500	610	358	272
1996	518	644	368	267
1997	576	727	407	283
1998	615	783	437	296
1999	653	841	465	306
2000	670	862	479	307
2001	691	886	495	311
2002	691	885	498	306
2003	693	884	502	302
2004	694	882	505	299
2005	669	849	489	283
2006	640	811	468	265
2007	337	427	247	135
2008	318	403	232	122
2009	296	377	215	108

Sources: Col. (1): Table 1.1, Col. (5).
Col. (2): Table 1.1 adjusted for ICF High Oil Prices from Table 5.
Col. (3): Table 1.1 adjusted for ICF Low Oil Prices from Table 5.
Col. (4): Table 1.1 adjusted for Low Low Oil Prices from Table 5.

ANNUAL AVERAGE CAPACITY FACTORS FOR U.S. NUCLEAR UNITS, 1970 - 1981

	All Units		All PWRs		Salt PWRs		Salt PWRs Excluding Six Observations	
	Capacity Factor (Percent)	Obs.	Capacity Factor (Percent)	Obs.	Capacity Factor (Percent)	Obs.	Capacity Factor (Percent)	Obs.
1970	62.01	4	76.43	2	80.09	1	80.09	1
1971	73.20	6	78.45	4	86.48	1	86.48	1
1972	67.89	11	66.96	6	73.62	1	73.62	1
1973	60.62	20	58.90	10	54.10	4	54.10	4
1974	56.12	26	56.14	16	57.74	7	57.74	7
1975	62.89	38	69.12	24	70.41	7	70.41	7
1976	60.65	47	63.37	28	64.73	9	64.73	9
1977	65.87	51	69.30	32	68.60	11	68.60	11
1978	68.51	58	68.53	37	65.61	14	65.61	14
1979	63.08	59	60.27	38	55.21	14	58.76	13
1980	59.80	60	59.52	38	56.62	14	63.81	11
1981	61.44	62	62.79	40	58.18	14	63.19	12

Table 7

SENSITIVITY CASE CAPACITY FACTOR ASSUMPTIONS

Year	Reference Case	Higher Capacity Factor	Lower Capacity Factor
	(Percent)		
	(1)	(2)	(3)
1984	63.0%	69.0%	57.0%
1985	63.0	69.0	57.0
1986	63.0	69.0	57.0
1987	63.0	69.0	57.0
1988	63.0	69.0	57.0
1989	63.0	69.0	57.0
1990	63.0	69.0	57.0
1991	63.0	69.0	57.0
1992	63.0	69.0	57.0
1993	63.0	69.0	57.0
1994	63.0	69.0	57.0
1995	63.0	69.0	57.0
1996	63.0	69.0	57.0
1997	63.0	69.0	57.0
1998	63.0	69.0	57.0
1999	63.0	69.0	57.0
2000	63.0	69.0	57.0
2001	63.0	69.0	57.0
2002	61.2	66.6	55.8
2003	59.4	64.2	54.6
2004	57.6	61.8	53.4
2005	54.0	57.0	51.0
2006	50.4	52.2	48.6
2007	52.2	54.6	49.8
2008	48.6	49.8	47.4
2009	45.0	45.0	45.0

SENSITIVITY OF NYS REFERENCE CASE NET COST TO CAPACITY FACTORS

Year	Reference Case	Higher Capacity Factor	Lower Capacity Factor
	Net Cost of Closing (Millions of Mid 1982 Constant Dollars)		
	(1)	(2)	(3)
1984	$435	$480	$390
1985	365	413	317
1986	340	386	293
1987	250	290	211
1988	276	318	233
1989	294	339	249
1990	375	428	322
1991	427	486	369
1992	447	507	387
1993	465	528	403
1994	548	612	483
1995	500	566	433
1996	518	587	449
1997	576	651	501
1998	615	693	536
1999	653	735	571
2000	670	847	509
2001	691	871	527
2002	691	863	535
2003	693	855	544
2004	694	846	553
2005	669	799	548
2006	640	746	539
2007	337	398	280
2008	318	366	271
2009	296	331	261

Sources: Col (1): Table 1.1, Col. (5).
Col. (2): Table 1.1 adjusted for higher capacity factors from Table 8.
Col. (3): Table 1.1 adjusted for lower capacity factors from Table 8.

HISTORICAL AND PROJECTED O & M AND CAPITAL EXPENDITURES AT INDIAN POINT

Year	Indian Point 2 O & M Expense	Indian Point 2 Capital Expense	Indian Point 3 O & M Expense	Indian Point 3 Capital Expense
	----------(Millions of	Current Dollars)----------		
	(1)	(2)	(3)	(4)
1973	$ 17	$11	na	na
1974	14	5	na	na
1975	14	3	na	na
1976	19	8	$ 3	na
1977	17	6	13	$26
1978	28	8	23	15
1979	33	14	29	30
1980	33	24	50	30
1981	55	77	58	34
1982	69	59	83	16
1983	50	46	69	38
1984	69	46	62	82
1985	74	14	70	74
1986	80	31	69	36
1987	87	57	78	30
1988	94	35	84	21
1989	101	38	91	38
1990	109	41	98	41

na -- not applicable.

Source: Actual Expenditures from FERC Form 1. Projected Expenditures by Companies to 1986; Rising at 8% per year to 1990.

U.S. AND INDIAN POINT O & M EXPENDITURES IN CONSTANT 1982 DOLLARS PER KW

Year	In Current Dollars: U.S. Average (1)	In Current Dollars: Indian Point 2 (2)	In Current Dollars: Indian Point 3 (3)	In Constant Dollars: U.S. Average (4)	In Constant Dollars: Indian Point 2 (5)	In Constant Dollars: Indian Point 3 (6)
	(Dollars per KW)			(Mid 1982 Dollars per KW)		
1970	$11	na	na	$27	na	na
1971	10	na	na	24	na	na
1972	11	na	na	25	na	na
1973	10	$ 16	na	21	$36	na
1974	11	13	na	21	26	na
1975	12	14	na	22	25	na
1976	14	19	$ 2	24	32	$ 4
1977	16	16	12	25	26	19
1978	18	28	22	26	41	32
1979	24	32	27	32	43	36
1980	30	33	47	36	38	55
1981	44	54	54	47	57	58
1982	NA	68	77	NA	68	77
1983	43	49	64	40	46	60
1984	46	68	58	40	59	50
1985	49	73	65	40	60	53
1986	52	79	65	40	61	50
1987	56	86	73	40	61	52
1988	60	93	79	40	62	52
1989	64	100	85	40	62	53
1990	68	108	92	40	63	53

na -- not applicable.

NA -- not available.

Note: O&M Expenditures are per KW of Nameplate Capacity.
Indian Point 2 is 1013 MW;
Indian Point 3 is 1068 MW.

Source: Actual Expenditures from FERC Form 1.
Col. (1) Projections: NERA Projections.
Cols. (2) and (3) Projections: Projected by Companies to 1986; Rising at 8% per year to 1990.

NUMBER OF ORDERS, BULLETINS, GENERIC LETTERS AND CIRCULARS ISSUED BY THE NRC 1973 - 1982

Year	Bulletins	Circulars	Generic Letters	NRC Orders	Total
			(Number)		
	(1)	(2)	(3)	(4)	(5)
1973	6	na	na	na	6
1974	16	na	na	na	16
1975	8	na	na	na	8
1976	7	7	na	na	14
1977	8	17	4	na	29
1978	14	19	28	37	98
1979	28	25	56	41	150
1980	25	25	58	88	196
1981	3	15	40	132	190
1982	4	0	27	56	87

na -- not applicable.

Note: Data on NRC orders are incomplete before 1978. 1978 figure is estimated from 3 quarters' data.

Source: LIS Corporation document sent to the Power Authority.

SENSITIVITY CASE
O & M ASSUMPTIONS

Year	Reference Case	Lower O&M Costs	Higher O&M Costs
	----------Annual O&M Costs----------		
	---(Millions of Nominal Dollars)---		
	(1)	(2)	(3)
1984	131	131	138
1985	144	144	153
1986	149	129	159
1987	165	142	184
1988	178	152	200
1989	192	163	219
1990	207	174	238
1991	224	186	260
1992	242	199	283
1993	261	213	308
1994	282	228	335
1995	305	244	366
1996	329	261	399
1997	355	279	435
1998	383	299	474
1999	415	320	517
2000	448	342	563
2001	483	367	614
2002	509	383	652
2003	534	401	691
2004	561	418	731
2005	573	424	753
2006	591	431	789
2007	332	268	451
2008	361	281	510
2009	398	296	588

Sources: Col. (1): Company Projections
Col. (2): See Text
Col. (3): See Text

SENSITIVITY OF NYS REFERENCE CASE NET COST TO O & M

Year	Reference Case (1)	Lower O&M Costs (2)	Higher O&M Costs (3)
	Net Cost of Closing (Millions of Mid 1982 Constant Dollars)		
1984	$435	$435	$429
1985	365	366	358
1986	340	356	332
1987	250	268	236
1988	276	294	259
1989	294	314	276
1990	375	396	355
1991	427	451	405
1992	447	472	423
1993	465	492	439
1994	548	576	519
1995	500	530	469
1996	518	550	485
1997	576	610	540
1998	615	651	576
1999	653	690	612
2000	670	709	628
2001	691	731	646
2002	691	731	646
2003	693	732	647
2004	694	732	649
2005	669	705	625
2006	640	676	596
2007	337	351	313
2008	318	333	290
2009	296	314	263

Sources: Col. (1): Table 1.1, Col. (5).
Col. (2): Col. (1) adjusted for lower O & M Expenditures from Table 13.
Col. (3): Col. (1) adjusted for higher O & M Expenditures from Table 13.

SENSITIVITY CASE
STEAM GENERATOR ASSUMPTIONS

Year	Reference Case	With Two Steam Generator Replacements
	-----Capital Expenditures----- (Millions of Nominal Dollars)	
	(1)	(2)
1984	128	137
1985	88	120
1986	67	99
1987	87	155
1988	56	124
1989	76	76
1990	82	82
1991	88	88
1992	96	316
1993	102	102
1994	109	109
1995	115	115
1996	123	123
1997	131	131
1998	127	127
1999	121	121
2000	116	116
2001	91	91
2002	54	54
2003	27	27
2004	7	7
2005	0	0
2006	0	0
2007	0	0
2008	0	0
2009	0	0

Sources: Col. (1): Company Projection of Capital Expenditures without replacement of Steam Generators.
Col. (2): Company Projection of Capital Expenditures with replacement of Steam Generators.

Table 16

SENSITIVITY OF NYS REFERENCE CASE NET COST TO STEAM GENERATOR REPLACEMENT

Year	Reference Case	With Two Steam Generator Replacements
	——Net Cost of Closing——	
	(Millions of Mid 1982 Constant Dollars)	
	(1)	(2)
1984	$435	$434
1985	365	359
1986	340	330
1987	250	232
1988	276	27
1989	294	271
1990	375	354
1991	427	409
1992	447	79
1993	465	420
1994	548	508
1995	500	466
1996	518	487
1997	576	549
1998	615	591
1999	653	632
2000	670	653
2001	691	675
2002	691	678
2003	693	681
2004	694	684
2005	669	661
2006	640	633
2007	337	335
2008	318	316
2009	296	294

Sources: Col. (1): Table 1.1, Col. (5).
Col. (2): Col. (1) adjusted for steam generator replacements in 1988 and 1992.

SENSITIVITY CASE
LOAD GROWTH ASSUMPTIONS

Year	Reference Case	Higher Load Growth	Lower Load Growth
	---------(Annual	NYS GWH)--------	
	(1)	(2)	(3)
1984	120,068	119,108	117,467
1985	121,891	121,880	118,545
1986	123,609	124,715	119,632
1987	125,311	127,617	120,729
1988	126,909	130,586	121,836
1989	128,636	133,625	122,954
1990	130,370	136,734	124,081
1991	132,287	139,915	125,219
1992	134,295	143,070	126,134
1993	136,178	146,297	127,056
1994	138,195	149,596	127,984
1995	140,260	152,969	128,919
1996	142,427	156,419	129,861
1997	144,472	159,947	130,810
1998	146,617	163,554	131,766
1999	148,818	167,242	132,729

Source: Testimony of Eugene Meehan.

SENSITIVITY OF NYS REFERENCE CASE NET COST TO LOAD GROWTH

	———Net Cost of Closing———		
Year	Reference Case	Higher Load Growth	Lower Load Growth
	(Millions of Mid 1982 Constant Dollars)		
	(1)	(2)	(3)
1984	$435	$441	$427
1985	365	378	347
1986	340	358	314
1987	250	271	220
1988	276	303	235
1989	294	329	243
1990	375	423	305
1991	427	488	339
1992	447	520	356
1993	465	551	371
1994	548	645	450
1995	500	611	400
1996	518	645	414
1997	576	725	463
1998	615	784	496
1999	653	843	529
2000	670	864	544
2001	691	887	562
2002	691	886	564
2003	693	885	567
2004	694	884	569
2005	669	850	550
2006	640	812	527
2007	337	428	277
2008	318	404	261
2009	296	378	243

Sources: Col. (1): Table 1.1, Col. (5).
Col. (2): Col. (1) adjusted for higher load growth from Table 17.
Col. (3): Col. (1) adjusted for lower load growth from Table 17.

Table 19

NEW YORK POWER POOL RESERVE MARGINS

Year	Annual Peak	Capacity, Purchcase & Sales	Reserve Margin	IP 2 & IP 3	Capacity Less IP 2 & IP3	Reserve Margin	Prattsville	Capacity Less IP 2, IP 3 & Prattsville	Reserve Margin
	(MW)	(MW)	(Percent)	(MW)	(MW)	(Percent)	(MW)	(MW)	(Percent)
			(2)-(1) /(1)		(2)-(4)	(5)-(1) /(1)		(5)-(7)	(8)-(1) /(1)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1984	21620	31570	46.0	1829	29741	37.6	0	29741	37.6
1985	21750	32258	48.3	1829	30429	39.9	0	30429	39.9
1986	21990	32288	46.8	1829	30459	38.5	0	30459	38.5
1987	22180	32232	45.3	1829	30403	37.1	0	30403	37.1
1988	22610	33327	47.4	1829	31498	39.3	0	31498	39.3
1989	22870	34295	50.0	1829	32466	42.0	990	31476	37.6
1990	23150	34207	47.8	1829	32378	39.9	990	31388	35.6
1991	23430	34207	46.0	1829	32378	38.2	990	31388	34.0
1992	23750	34207	44.0	1829	32378	36.3	990	31388	32.2
1993	24060	34232	42.3	1829	32403	34.7	990	31413	30.6
1994	24410	34228	40.2	1829	32399	32.7	990	31409	28.7
1995	24720	34228	38.5	1829	32399	31.1	990	31409	27.1
1996	25050	34180	36.4	1829	32351	29.1	990	31361	25.2
1997	25350	34174	34.8	1829	32345	27.6	990	31355	23.7
1998	25660	34174	33.2	1829	32345	26.1	990	31355	22.2
1999	25980	34174	31.5	1829	32345	24.5	990	31355	20.7

Source: Col.(1): Testimony of Eugene Meehan.
Col.(2): Report of Member Electric Systems of the New York Power Pool and the Empire State Electric Research Corporation Pursuant to Section 5-112 of the Energy Law of New York State, 1982, Vol. 1, pp. 12 and 23, revised to reflect cancellations (see text).

Table 20

SENSITIVITY OF NYS REFERENCE CASE NET COST TO DISCOUNT RATE

Present Value

Discount Rate	NYS	Con Edison	Power Authority
	(Millions	of Discounted	1983 Dollars)
10%	$9,001	$3,362	$4,478
12%	7,148	2,711	3,498
14%	5,788	2,225	2,794

OTHER CHANGES IN TAXES AND WORKING CAPITAL
REFERENCE CASE

New York State

Year	Working Capital Addition	Oil Inventory Expense	Gross Receipts and Sales Taxes	Lost Fuel Core and Additional Decomm. Cost
	--------(millions of current dollars)--------			
	(1)	(2)	(3)	(4)
1984	$10	$12	$ 49	$105
1985	12	13	56	6
1986	12	12	57	6
1987	11	6	52	7
1988	13	7	60	7
1989	15	8	67	8
1990	18	13	85	8
1991	22	17	100	9
1992	24	20	112	9
1993	27	24	124	10
1994	29	27	136	158
1995	32	31	150	
1996	36	34	167	
1997	42	40	194	
1998	47	45	218	
1999	53	50	244	
2000	57	55	266	
2001	63	59	290	
2002	66	63	307	
2003	70	67	325	
2004	74	70	343	
2005	76	72	351	
2006	77	73	357	
2007	43	41	202	
2008	44	42	205	
2009	44	42	206	

Appendix 1

AVERAGE IMPORTED CRUDE OIL PRICE FORECASTS

Base Price[1]	1980	1981	1982
	(1982 Dollars per Barrel)		
	39.30	39.27	33.55

Source	Date Published	Forecasts (1982 Dollars per Barrel) 1985	1990	2000	Average Annual Growth Rate (Percent) 1982-1985	1982-1990	1990-2000
MIT (World Oil Project)[2]	Dec. 1981	41.40	44.70		7.3	3.7	
MIT (Jacoby/Paddock)[3]	Dec. 1981		47.83			4.5	
DOE/EIA (Midprice)[4]	Feb. 1982	38.27	56.82	86.97	4.5	6.8	4.3
Gately[5]	Feb. 1982		56.07	76.00		6.6	3.1
IEES-OMS[6]	Feb. 1982		48.87			4.8	
IPE[7]	Feb. 1982		39.43	57.88		2.0	3.9
Salant-ICF[8]	Feb. 1982		58.83	75.58		7.3	2.5
ETA-MACRO[9]	Feb. 1982		53.64	85.01		6.0	4.7
WOIL[10]	Feb. 1982		50.67	73.78		5.3	3.8
Kennedy-Nehring[11]	Feb. 1982		60.21	82.15		7.6	3.2
OILTANK[12]	Feb. 1982		66.78	97.63		9.0	3.9
Opeconomics[13]	Feb. 1982		42.08	43.99		2.9	0.4
OILMAR[14]	Feb. 1982		67.84	92.01		9.2	3.1
Bankers Trust[15]	May 1982	33.92			0.4		
Stanford[16]	Sep. 1982	37.81			4.1		
IEA[17]	Oct. 1982	33.92			0.4		
DRI[18]	Oct. 1982	32.15	38.62	53.47	-1.4	1.8	3.3
ICF[19] Base	Nov. 1982	34.00	37.54	45.76	0.4	1.4	2.0
Low	Nov. 1982	28.00	29.43	35.87	-5.8	-1.6	2.0
High	Nov. 1982	36.07	41.82	56.19	2.4	2.8	3.0
DOE/EIA (Preliminary)[20]	Feb. 1983	25.44	37.10	58.30	-8.8	1.3	4.6

Sources and Notes

1 U.S. Department of Energy, Energy Information Administration, Monthly Energy Review, February 1983, p. 82. 1982 data from telephone conversation with Mr. Charles Riner, March 24, 1983. These prices reflect the average refiner acquisition cost of crude oils imported into the U.S. from various suppliers. Prices were adjusted to 1982 dollars with the GNP implicit price deflator. (1980 = 9.3 percent, 1981 = 9.4 percent, 1982 = 6.0 percent. Source: 1983 Economic Report of the President, Table B-3.)

2 J. Carson, W. Christain and G. Ward, "The MIT World Oil Model," (MIT-EL 81-027WP), December 1981, p. 9. Prices were adjusted from 1979 dollars to 1982 dollars with the GNP implicit price deflator.

3 H. D. Jacoby and J. L. Paddock, "World Oil Prices and Economic Growth in the 1980's," (MIT-EL 81-060WP), December 1981, p. 39. The authors discuss a window of oil prices considered "not likely" for a smoothly changing world. A range of likely 1990 Saudi marker crude Persian Gulf prices (in 1980 dollars) from $27/bbl to $50/bbl is forecast. To obtain a specific point forecast the mid-range of the Jacoby/Paddock forecast was assumed. This forecast was adjusted to 1982 dollars using the GNP implicit price deflator. The resulting price was then adjusted by $3.18/bbl (1982 dollars) to reflect transportation and insurance costs.

4 U.S. Department of Energy, Energy Information Administration, 1981 Annual Report to Congress, February 1982, Vol. 3, p. 6. Midprice case is displayed. Prices were adjusted from 1980 dollars to 1982 dollars with the GNP implicit price deflator.

5 Energy Modeling Forum, World Oil: Summary Report, EMF Report 6, Stanford, CA, February 1982, Tables A-6, A-7. Prices were adjusted from 1981 dollars to 1982 dollars with the GNP implicit price deflator. Model designed by D. Gately, New York University and J. Kyle, Imperial Oil Ltd.

6 Ibid. Model designed by C. Kilgore, U.S. Department of Energy.

7 Ibid. Model designed by N. Choucri, Massachusetts Institute of Technology.

8 Ibid. Model designed by S. Salant, U.S. Federal Trade Commission and W. Stitt, ICF Incorporated.

9 Ibid. Model designed by A. Manne, Stanford University.

10 Ibid. Model designed by J. Stanley-Miller, U.S. Department of Energy/Energy and Environmental Analysis, Incorporated.

11 Ibid. Model designed by M. Kennedy, University of Texas and R. Nehring, Rand Corporation.

12 Ibid. Model designed by L. Ervik, Chr. Michelsen Institute.

[13] Ibid. Model designed by J. Mitchell, British Petroleum Co. Ltd.

[14] Ibid. Model designed by F. Pott , Energy and Power Subcommittee, U.S. House of Representatives.

[15] Bankers Trust Company, Energy Viewpoint, May 1982, Vol. III, No. 2. The report discusses the Saudi marker price. The FOB price given was adjusted by $3/bbl to reflect transportation and insurance costs to the U.S., then adjusted from 1981 dollars to 1982 dollars with the GNP implicit price deflator.

[16] B. G. Hickman and H. G. Huntington, "EMF 7 Study Design," (EMF WP 7.1, revised) Energy Modeling Forum, Stanford, CA, September 1982. Nominal 1985 price was deflated to 1982 dollars assuming 6.0 percent escalation per year. The FOB price given was adjusted by $3.18/bbl (1982 dollars) to reflect transportation and insurance costs.

[17] Platt's Oilgram News, October 12, 1982, p. 2. The $29/bbl price quoted in the article was adjusted by $3/bbl to reflect transportation and insurance costs, then adjusted from 1981 dollars to 1982 dollars with the GNP implicit price deflator.

[18] Data Resources, Inc. Energy Review, Autumn 1982.

[19] ICF Incorporated, Forecast of Fuel Markets and Prices in New York State, Volume 1: Oil and Gas Markets and Prices, Presented to New York Power Pool, November 1982, p. I-1.

[20] U.S. Department of Energy, Energy Information Administration. Preliminary forecasts from telephone conversation with Mr. Daniel Butler, March 23, 1983.

REGRESSION RELATING CAPACITY FACTOR TO SELECTED UNIT CHARACTERISTICS

PWRs Only To 1978

Variable	Variable Mean (1)	Regression Coefficient (2)	t-Statistic (3)
Constant	-	81.89	-
Size 6-800 MW [1]	0.147	-3.45	-0.91
Size 800MW and Up [1]	0.479	-12.69	-4.37
One - Three Years [1]	0.595	-10.12	-3.87
Cooling Towers [1]	0.178	-6.85	-2.11
Salt Water Cooling [1]	0.350	-0.44	-0.10
Salt x Age [2]	1.196	-0.43	-0.47
SG Replacement [1]	0.067	-0.66	-0.13
Turnkey [1]	0.276	-4.47	-1.51
TMI [3]	-	-	-

Number of Observations	163
R-Squared	0.290
Adjusted R-Squared	0.253
Standard Error of Estimate	13.906

[1] Equals 1 if the unit has the characteristic named, and 0 otherwise.
[2] Equals age if unit is salt water cooled, and 0 otherwise.
[3] Equals 1 in calendar years 1979, 1980 and 1981, and 0 otherwise.

REGRESSION RELATING CAPACITY FACTOR TO SELECTED UNIT CHARACTERISTICS

PWRs Only To 1979

Variable	Variable Mean (1)	Regression Coefficient (2)	t-Statistic (3)
Constant	-	82.89	-
Size 6-800 MW [1]	0.139	-5.91	-1.66
Size 800MW and Up [1]	0.512	-14.10	-5.16
One - Three Years [1]	0.537	-10.33	-4.22
Cooling Towers [1]	0.184	-6.33	-2.14
Salt Water Cooling [1]	0.353	1.82	0.45
Salt x Age [2]	1.323	-0.77	-0.97
SG Replacement [1]	0.065	-6.89	-1.47
Turnkey [1]	0.254	-4.02	-1.43
TMI [3]	0.189	-6.63	-2.40
Number of Observations		201	
R-Squared		0.319	
Adjusted R-Squared		0.287	
Standard Error of Estimate		14.282	

[1] Equals 1 if the unit has the characteristic named, and 0 otherwise.
[2] Equals age if unit is salt water cooled, and 0 otherwise.
[3] Equals 1 in calendar years 1979, 1980 and 1981, and 0 otherwise.

REGRESSION RELATING CAPACITY FACTOR TO SELECTED UNIT CHARACTERISTICS

PWRs Only To 1980

Variable	Variable Mean (1)	Regression Coefficient (2)	t-Statistic (3)
Constant	-	82.69	-
Size 6-800 MW [1]	0.134	-5.76	-1.68
Size 800MW and Up [1]	0.536	-13.88	-5.32
One - Three Years [1]	0.481	-9.39	-4.01
Cooling Towers [1]	0.188	-7.79	-2.81
Salt Water Cooling [1]	0.356	4.18	1.09
Salt x Age [2]	1.469	-1.37	-1.96
SG Replacement [1]	0.063	-9.29	-2.08
Turnkey [1]	0.238	-4.68	-1.72
TMI [3]	0.318	-6.70	-2.89
Number of Observations		239	
R-Squared		0.296	
Adjusted R-Squared		0.268	
Standard Error of Estimate		14.722	

[1] Equals 1 if the unit has the characteristic named, and 0 otherwise.
[2] Equals age if unit is salt water cooled, and 0 otherwise.
[3] Equals 1 in calendar years 1979, 1980 and 1981, and 0 otherwise.

REGRESSION RELATING CAPACITY FACTOR TO SELECTED UNIT CHARACTERISTICS

PWRs Only To 1981

Variable	Variable Mean (1)	Regression Coefficient (2)	t-Statistic (3)
Constant	-	82.91	-
Size 6-800 MW [1]	0.129	-6.30	-1.91
Size 800MW and Up [1]	0.556	-13.68	-5.51
One - Three Years [1]	0.427	-9.66	-4.31
Cooling Towers [1]	0.194	-7.95	-3.08
Salt Water Cooling [1]	0.355	6.03	1.66
Salt x Age [2]	1.613	-1.89	-3.10
SG Replacement [1]	0.061	-8.19	-1.93
Turnkey [1]	0.226	-5.18	-1.98
TMI [3]	0.416	-5.53	-2.56
Number of Observations		279	
R-Squared		0.272	
Adjusted R-Squared		0.247	
Standard Error of Estimate		15.018	

[1]Equals 1 if the unit has the characteristic named, and 0 otherwise.
[2]Equals age if unit is salt water cooled, and 0 otherwise.
[3]Equals 1 in calendar years 1979, 1980 and 1981, and 0 otherwise.

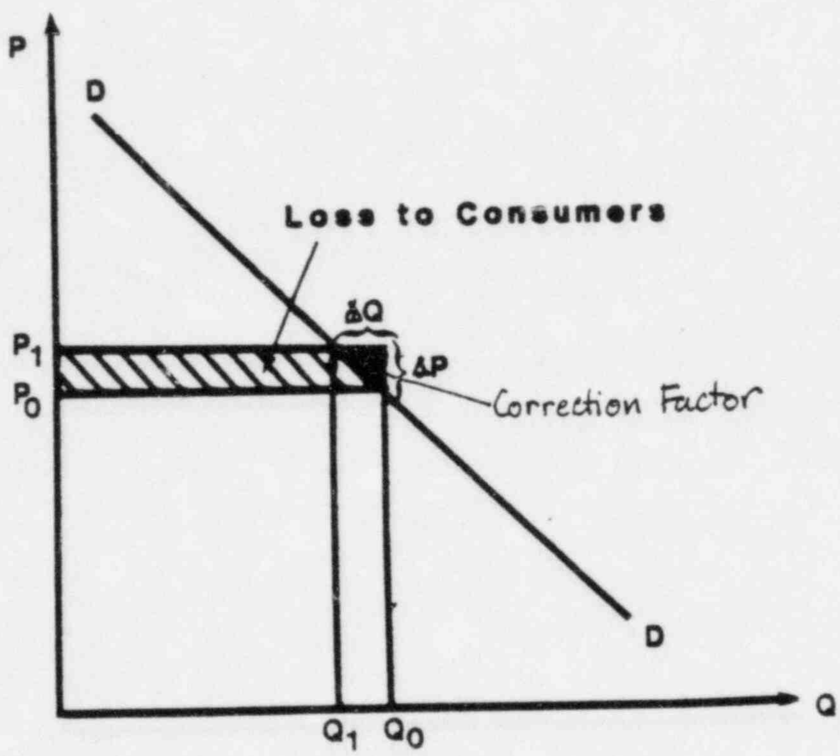
CORRECTION FACTOR FOR DEMAND ELASTICITY

If demand elasticity equals ε, a rise of Δp in price will cause a reduction of Δq in demand.

The loss to consumers is given by

$$\text{Loss} = \Delta p \,.\, Q_o - \frac{\Delta p \,.\, \Delta q}{2} \quad (1)$$

In Diagram 1



In the diagram, DD is the demand curve for electricity, P_o is the intial price, Q_o is the initial quantity, P_1 is the final price, Q_1 is the final quantity and Δp, Δq are the changes in price and quantity.

The loss to consumers is given by the heavy shaded trapezoid, which is equal to the rectangle $\Delta p \,.\, Q_o$ <u>less</u> the small triangle, whose area is half $\Delta p \,.\, \Delta q$. (See the equation above.)

Since $\frac{\Delta q}{Q_o} = \frac{\Delta p}{P_o} \cdot \varepsilon$

Where ε is the elasticity of demand

Then $\Delta q = \frac{\Delta p}{P_o} \cdot Q_o \cdot \varepsilon$

And the equation (1) becomes

$$\text{Loss} = \Delta p \cdot Q - \Delta p \cdot Q \left(\frac{\Delta p}{P_o} \cdot \frac{\varepsilon}{2}\right)$$

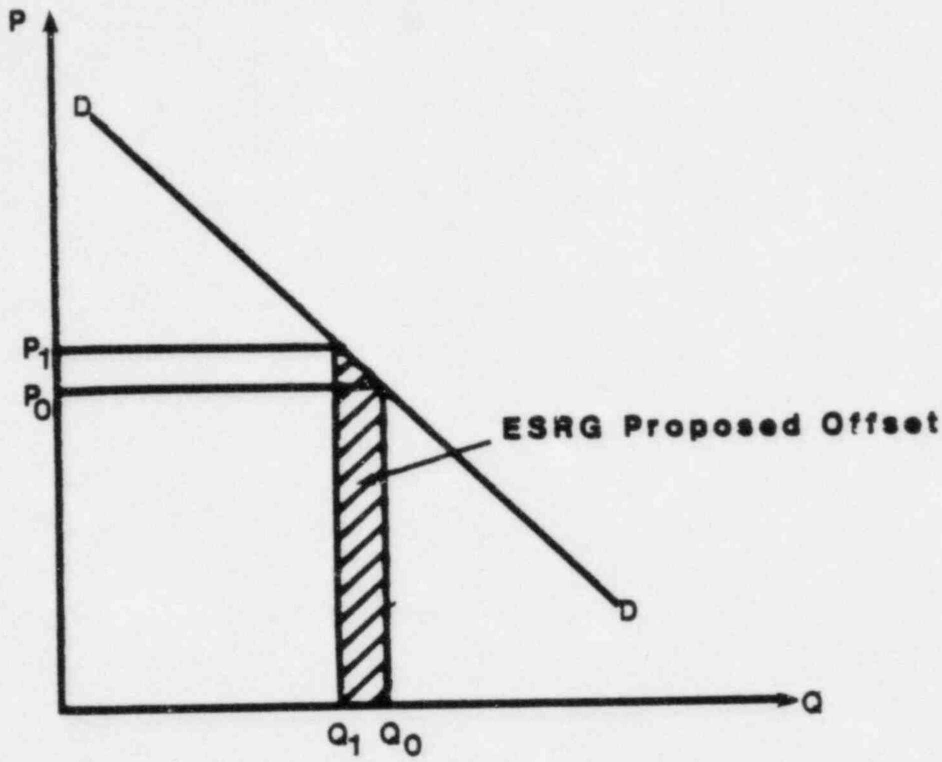
$$= \Delta p \cdot Q \left(1 - \frac{\Delta p}{P_o} \cdot \frac{\varepsilon}{2}\right)$$

The correction factor is equal to half the percentage change in price times the elasticity of demand. After correction, the loss to consumers in the present case amounts to over 99 percent of the calculated amount. Various combinations of price change and elasticity are given below.

Final Impact After Elasticity
As a Percentage of Calculated Dollar Impact

	Elasticity		
ε=	- .1	- .5	- 1.0
Price Increase $\frac{\Delta p}{p}$			
5%	.997	.987	.975
10%	.995	.975	.95
15%	.992	.962	.925

What ESRG has done is to estimate the correction factor as $\Delta q \cdot P_o$ rather than $\Delta q \cdot \Delta p/2$.



$\Delta q \cdot P_0$ is the change in revenues, but it represents foregone electricity. This electricity was obviously worth the original price to the customers, because they were prepared to pay that much for it before the price rise. Losing it because it is too expensive is in no way a benefit.

Exhibit 1

SALLY HUNT STREITER

I was an open scholar of Somerville College, Oxford, England, where I studied economics and philosophy, and graduated with honors. I also received my M.A. degree from Oxford. As a research assistant at the London School of Economics, I took part in a large econometric study of educational productivity.

After emigrating to the United States, I joined Consad Research Corporation, and assisted in a study of the oil depletion allowance. I was chief investigator for an econometric study of the effects of economic development policies on unemployment in Appalachia.

In 1969 I joined the New York City Budget Bureau as a planner on education, and developed a model of the effects of different policy variables on reading levels of school children. I also developed a simulation model to distribute funds to school districts in the City in accordance with the new education law. I was promoted to head of the Environmental Protection section of the Budget Bureau planning staff, where I performed and directed analyses of air pollution control strategies, water pollution control strategies and refuse disposal options.

In 1972 I became Assistant Commissioner in the New York City Department of Air Resources, the agency with regulatory responsibility for fuel burning in New York. In this capacity I became familiar with the disruptions in the fuel markets in the early 1970s. In late 1973, when the OPEC embargo threatened New York, I was assigned to analyse requests for variances from the Air Pollution Control laws, and negotiated with State and Federal Officials and with fuel users, in particular Con Edison, to determine prudent solutions to the

impending crisis. I sat as an examiner in a public hearing, and presented testimony on behalf of the city in PSC hearings on Con Edison's request to convert to coal. I was named Deputy Director of the City Energy Office at its inception.

In late 1974, I joined NERA, where I have worked since then. Initially I was assigned to the task of rate structure revision, and developed a simplified model of marginal cost pricing which drew heavily on the planning process of utilities. This became the basis for the NERA costing methodology, on which I testified in many States. I also performed many studies of the energy situation in general, and the electric industry in particular; I analyzed the economics of coal versus nuclear units for new construction in a 1976 study, and prepared an analysis of Amory Lovins' proposals for alternatives to conventional generation in 1977. I was chief investigator for the plaintiffs in a case brought by Commonwealth Edison and others against the Montana Coal Severance Tax, which involved extensive studies of coal markets. I was project director of a large econometric study of the availability of large coal-fired units, and of another study of the economics of conversion of oil-fired units to coal. This latter involved an analysis of the course of oil and coal prices. I have given speeches and testified on most of these subjects.

I have also published articles on the feasibility of trending the rate base to avoid rate shock when new nuclear units come on line, and have testified in three recent cases on criteria for evaluating proposed efficiency clauses in electric ratemaking.