UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	
	)	
CONSOLIDATED EDISON COMPANY	)	Docket No. 50-247
OF NEW YORK, INC.	)	(Extension of Interim
	)	Operation Period)
(Indian Point Station, Unit No. 2)	)	

77Ø249

TESTIMONY OF NRC STAFF ON THE RELATIVE BENEFITS AND COSTS ASSOCIATED WITH APPLICANT'S REQUEST FOR EXTENSION OF OPERATION WITH ONCE-THROUGH COOLING AT INDIAN POINT UNIT NO. 2

(undated)

Dr. Robert Spore
and
Dr. Webster Van Winkle

During the course of hearings on the request by Consolidated Edison Company of New York (Applicant) for extension of the date for termination of operation of Indian Point Unit 2 with once-through cooling, Chairman Jensch requested that the Staff file supplemental testimony on the subject of the cost/benefit balance of the proposed amendment.[1] The Staff understands this request to seek greater detail and fuller quantification to support the Staff's conclusion that the benefits do not outweigh the costs of the proposed action. The testimony contained herein attempts to address that request and represents the Staff's fuller analysis and quantification of positions earlier articulated, including the considerations expressed in earlier testimony in this proceeding.[2]

8110240045 770209
PDR ADOCK 05000247
G PDR

247
H 4

This testimony is organized as follows. Part I analyses the potential benefits of the proposed delay, emphasizing the economic savings to the Applicant if the construction and subsequent operation of a natural draft cooling tower are delayed one year. Part II presents the Staff's analysis of the costs of the proposed delay, emphasizing an economic evaluation of the impact on the Hudson River striped bass population. Because of data limitations (primarily the non-availability of analyses of the impact on the striped bass population of a single year's operation with once-through cooling), the costs presented in this testimony are those associated with the originally-proposed two-year extension, even though a one-year extension already has been obtained under provisions of the facility operating license. For the purposes of discussion, however, the costs of an additional one-year extension (to May 1, 1981) can be taken as approximately one-half those associated with a two-year delay. Part III summarizes the overall benefits and costs of the proposed delay. The Staff's position continues to be that an additional one-year extension in the period of operation with once-through-cooling is not warranted.

I. Benefits

1. Savings if the Wet Natural Draft Cooling Tower is Delayed Two Years

The Staff's method of computing the savings that would accrue as a result of the proposed action is to calculate the difference between the incremental generating costs corresponding to construction and operation of a natural draft cooling tower under two cases. Case I encompasses the current revised licensing schedule with the cessation of OTC in May 1980 and cooling system tie-in completed in December 1980. Case II analyzes the proposed amended schedule with cessation of OTC in May 1981 and cooling system tie-in completed in December 1981. The costs to be considered in each case consist of four components: (1) capital costs, (2) annual operating costs, (3) cost of replacing loss of peak generating capability and average annual loss of generating capability, and (4) downtime costs for cooling system tie-in. Since the two cases consist of varying time streams of future costs, the Staff's policy is to discount the above costs to a present worth on a common date (January 1, 1976) using a discount factor of 10% per year,[3] and compute their sum. In addition, each cost as well as their total is expressed as an annualized value representing a constant stream of revenue requirements over the estimated useful life of the facility. The economic life of the cooling tower is measured from the time it becomes operational to the end of the total economic service of the plant, i.e., 23 years (Dec. 1980 - Dec. 2003) in Case I, and 22 years (Dec. 1981 - Dec. 2003) in Case II.

Except as noted, the Staff's analysis is based primarily on information provided by the Applicant in the Environmental Report accompanying the original application for license amendment and on the cost analysis of natural draft cooling towers presented in the Staff's Final Environmental Statement on Closed Cycle Cooling.[4] Since the cost information provided in the ER assessed the originally proposed two year delay, the Staff's approach involved the adjustment of that data to reflect the revised cases analyzed here. This approach was successful except that a calculation of revised annual levelized carrying charges for the cooling towers and gas turbines was not possible. In this case, the original data presented in the ER was used. The errors thereby introduced are considered to be minor.

Capital Cost

Tables 1 and 2 present estimates of the capital costs of a natural draft cooling tower for Case I and II, respectively. These estimates correspond to those of the Applicant (ER, Tables 4.2 and 4.3) with the exception that, in accordance with Staff policy, real estate taxes during

TABLE 1

CAPITAL COST ESTIMATE SUMMARY OF CLOSED CYCLE NATURAL DRAFT WET COOLING TOWER FOR CASE I SCHEDULE

DESCRIPTION	INSTALLATION COMPANY	INSTALLATION CONTRACTOR	MATERIAL	TOTAL
Install cooling tower		10,372,000		$10,372,000
Amertap clean system		3,112,000		3,112,000
Furn. install piping (mech. sys.)	$17,600	2,652,400	4,973,400	7,643,400
Struct., excavation, tunnels, tower, etc.	20,700	13,778,500		13,799,200
Struct., excav., roads, sump pits, etc.		1,020,000		1,020,000
Struct., excav., for elect. work & assoc.		86,100		86,100
Elect. work assoc. w/tower		620,500	370,300	990,800
Elec. work assoc. w/substa.		362,200	815,900	1,178,100
Elec. work lighting power		23,600	140,000	163,600
Project Management & Inspection	1,136,800			1,136,800
Other Direct Cost	82,100		110,100	192,200
Total Direct Cost	1,257,200	32,027,300	6,409,700	$39,694,200
Engineering & Supervision				4,763,300
Administration & Supervision				1,222,600
Payroll Taxes & Pensions				1,565,300
Interest During Construction				7,441,200
Total Project Cost				$54,686,600
Escalation				18,484,100
Contingency				13,829,300
Total Estimated Cost				87,000,000

Source: ER, Table 4.2.

TABLE 2

CAPITAL COST ESTIMATE SUMMARY OF CLOSED CYCLE NATURAL DRAFT WET COOLING TOWER FOR CASE II SCHEDULE

DESCRIPTION	INSTALLATION COMPANY	INSTALLATION CONTRACTOR	MATERIAL	TOTAL
Install cooling tower		10,372,000		$10,372,000
Amertap clean system		3,112,000		3,112,000
Furnish install piping (mech. systems)	$17,600	2,652,400	4,973,400	7,643,400
Struct., excavation, tunnels, tower, etc.	20,700	13,778,500		13,799,200
Struct., excav., roads, sump pits, etc.		1,020,000		1,020,000
Struct., excav., for elect. work & assoc.		86,100		86,000
Elect. work assoc. w/tower		620,500	370,300	990,800
Elec. work assoc. w/substa.		362,200	815,900	1,178,000
Elec. work lighting power		23,600	140,000	163,600
Project Management & Inspection	1,136,800			1,136,800
Other Direct Cost	82,100		110,100	192,200
Total Direct Cost	1,257,200	32,027,300	6,409,700	39,694,200
Engineering & Supervision				4,763,300
Administration & Supervision				1,222,600
Payroll Taxes & Pensions				1,565,300
Interest During Construction				7,441,200
Total Project Cost				$54,686,600
Escalation				21,054,300
Contingency				15,259,100
Total Estimated Cost				91,000,000

Source: ER, Table 4.3.

construction are not included. The estimates are based on an implied escalation rate for the period 1974 to the predicted end of construction (33.8% in Case I, 39.5% in Case II).

Annual carrying charges as a percent of capital costs as estimated by the Applicant (ER, Tables 4-7 and 4-8) are itemized in Tables 3 and 4 for Cases I and II, respectively. Again, however, as in the estimates of capital costs, taxes are considered simply to be a means of distributing benefits and are not included in fixed charges. Using these annual carrying charges, the calculated present value (1976) capital cost for a natural draft cooling tower is:

Case I $$e^{-0.10(5)} \int_0^{23} (\$87,000,000 \times 0.1483)e^{-0.10t}dt = \$70,409,400$$

Case II $$e^{-0.10(6)} \int_0^{22} (\$91,000,000 \times 0.1495)e^{-0.10t}dt = \$66,390,200$$

The corresponding annualized cost is:

Case I $$\$70,409,400 \left(\int_0^{28} e^{-0.10t}dt\right)^{-1} = \$7,496,800$$

Case II $$\$66,390,200 \left(\int_0^{28} e^{-0.10t}dt\right)^{-1} = \$7,068,900$$

TABLE 3

ANNUAL LEVELIZED CARRYING CHARGES
OF A COOLING TOWER AND GAS TURBINES AT INDIAN POINT
(AS A PERCENT OF CAPITAL COST)

CASE I

	COOLING TOWER (1)	GAS TURBINE (2)
Return	9.861	9.921
Depreciation	4.167	4.000
Allowance for Replacements	0.500	0.500
Insurance	0.300	0.100
Total Fixed Charges	14.828	14.521
Total Fixed Charges Rounded	14.83	14.52

NOTES:

(1) 24 Year Recovery Period to allow recovery coincident with 30 Year Economic Service Life of Indian Point No. 2.

(2) 25 Year Recovery Period to allow recovery coincident with 30 Year Economic Service Life of Indian Point No. 2.

SOURCE: ER, Table 4-7.

TABLE 4

ANNUAL LEVELIZED CARRYING CHARGES
OF A COOLING TOWER AND GAS TURBINES AT INDIAN POINT
(AS A PERCENT OF CAPITAL COST)

CASE II

	COOLING TOWER (1)	GAS TURBINE (1)
Return	9.803	9.803
Depreciation	4.348	4.348
Allowance for Replacements	0.500	0.500
Insurance	0.300	0.100
Total Fixed Charges	14.951	14.751
Total Fixed Charges Rounded	14.95	14.75

NOTE:

(1) 23 Year Recovery Period to allow recovery coincident with 30 Year Economic Service Life of Indian Point No. 2

SOURCE: ER, Table 4-8.

Annual Operating Cost

Once the cooling tower is operational, annual operating costs are incurred to maintain efficient system operation. Based on information presented by the Applicant (ER, p. 4-14 and Table 4-4), these costs were estimated to be $150,000 per year in 1974. Escalated at 5% per year continuous compounding, annual operating costs are calculated by the Staff to be $211,100 for Case I and $221,600 for Case II. The discounted present value of the annual operating costs is calculated as:

$$\text{Case I} \qquad e^{-0.10(5)} \int_0^{23} \frac{\$211{,}100\ e^{0.05t}}{e^{0.10t}}\, dt = \$1{,}749{,}900$$

$$\text{Case II} \qquad e^{-0.10(6)} \int_0^{22} \frac{\$221{,}600\ e^{0.05t}}{e^{0.10t}}\, dt = \$1{,}622{,}700$$

The annualized cost of these operating expenditures is:

$$\text{Case I} \qquad \$1{,}749{,}900 \left(\int_0^{28} e^{-0.10t} dt \right)^{-1} = \$186{,}300$$

$$\text{Case II} \qquad \$1{,}622{,}700 \left(\int_0^{28} e^{-0.10t} dt \right)^{-1} = \$172{,}800$$

Cost of Replacing Loss of Peak Generating Capability and Energy from Plant Derating

The installation of a natural draft cooling tower at Unit No. 2 will result in reduction of peak generating capability of approximately 63 MWe.[5] According to the Applicant, this loss of peak generating capability poses a potentially adverse effect on system reliability at peak load and should be replaced with supplementary power. Given the uncertainties associated with the long-run availability of purchased power, the Staff agrees with the Applicant's proposed installation of gas turbines for maintaining system reliability. Assuming the purchase and installation of the turbines is timed to correspond to the dates of plant shutdown for cooling system tie-in (May 1980 in Case I, May 1981 in Case II), the capital cost of gas turbines, based on the Applicant's data (ER, p. 4-18), is estimated to be \$300 per kW and \$315 per kW, respectively. Thus, the cost of replacing 63 MWe peak generating capability is \$18,900,000 for Case I and \$19,845,000 for Case II.

Using the carrying charges for gas turbines reported in Tables 3 and 4, the total present value (1976) of the capital cost of replacing peak generating capability is calculated by the Staff to be:

$$\text{Case I} \quad e^{-0.10(4.5)} \int_0^{23.5} (\$18{,}900{,}000 \times 0.1452)\, e^{-0.10t} dt = \$15{,}829{,}500$$

$$\text{Case II} \quad e^{-0.10(5.5)} \int_0^{22.5} (\$19{,}845{,}000 \times 0.1475)\, e^{-0.10t} dt = \$15{,}108{,}100$$

Alternatively, the annualized cost is:

$$\text{Case I} \quad \$15,829,500 \left(\int_0^{28} e^{-0.10t} dt\right)^{-1} = \$1,685,400$$

$$\text{Case II} \quad \$15,108,100 \left(\int_0^{28} e^{-0.10t} dt\right)^{-1} = \$1,608,600$$

In addition to the loss of peak generating capability, the closed cycle cooling system will cause an average annual loss of generating capability estimated by the Applicant to be 25 MWe.[6] Replacement energy for this loss is available from within the Applicant's system through additional operation of a combination of oil-fired steam generators and gas turbines. The incremental cost of this energy is estimated to be 29 mills per KWhr in 1979 (ER, p. 4-17). In addition, the Applicant estimates that the cost of number 6 oil will rise at an average annual rate of approximately 5% between 1975 and 1980.[7] This rate is used to calculate 1980 incremental energy costs of 30.45 mills per kWhr for case I, 31.97 mills per kWhr for Case II, and for estimating annual incremental energy costs for each year thereafter.

The discounted present value (1976) of energy to replace the average annual loss of generating capability is calculated below. A plant capacity factor of 76.2% was used based on 8 weeks scheduled maintenance and a mature outage of 10%.

$$\text{Case I} \quad e^{-0.10(4.5)} \int_0^{23.5} (25000\text{kW} \times \$0.03045/\text{kWhr} \times 8760 \text{ hrs} \times 0.762) \frac{e^{0.05t}}{e^{0.10t}} dt =$$

$$\$44,789,400$$

$$\text{Case II} \quad e^{-0.10(5.5)} \int_0^{22.5} (25000\text{kW} \times \$0.03197/\text{kWhr} \times 8760 \text{ hrs} \times 0.762) \frac{e^{0.05t}}{e^{0.10t}} dt =$$

$$\$41,575,500$$

The corresponding annualized cost is:

$$\text{Case I} \quad \$44,789,400 \left(\int_0^{28} e^{-0.10t} dt \right)^{-1} = \$4,768,900$$

$$\text{Case II} \quad \$41,575,500 \left(\int_0^{28} e^{-0.10t} dt \right)^{-1} = \$4,426,700$$

<u>Downtime Costs for Cooling System Tie-in</u>

The Applicant anticipates a seven month outage of Unit No. 2 from May 1, 1980 to December 1, 1980 for Case I and from May 1, 1981 to December 1, 1981 for Case II, as a result of the tie-in for closed cycle cooling. Since Unit No. 2 requires two months annually for refueling, the Staff concludes that by utilizing the tie-in period for refueling, the outage could effectively be reduced to five months, or 3672 operating hours. Unit No. 2 is currently rated at 873 MWe. Since 25 MWe already has been accounted for above when the cost of replacement energy from plant de-rating was computed, then the maximum loss of energy due to the five month outage is approximately:

$$848\text{MW} \times 3672 \text{ hrs} = 3114 \times 10^6 \text{ kWhr.}$$

As in the case of the average annual loss of generating capability due to derating, replacement for the outage loss is assumed to come from the additional operation of other plants on the Applicant's system together with some increase in firm purchases from other utilities. Taking into account the savings resulting from the fact that Unit No. 2 will not be in operation, the resulting incremental production costs are calculated as follows:

	Case I	Case II
Average cost of replacement energy ($kWhr)	$0.03034	$0.03197
Unit No. 2 production costs ($/kWhr)	0.00273	0.00273
incremental cost ($/kWhr rounded)	0.0277	0.0292

Thus, the discounted present value (1976) of the loss of energy due to downtime for tower tie-in is calculated by the Staff to be:

Case I $e^{-0.10(4.5)}[(3114 \times 10^6 \text{kWhr}) \times \$0.0277/\text{kWhr}] = \$55,000,400$

Case II $e^{-0.10(5.5)}[(3114 \times 10^6 \text{kWhr}) \times \$0.0292/\text{kWhr}] - \$52,461,400$

The corresponding annualized values are:

Case I $\$55,000,400 \left(\int_0^{28} e^{-0.10t} dt\right)^{-1} = \$5,856,200$

Case II $\$52,461,400 \left(\int_0^{28} e^{-0.10t} dt\right)^{-1} = \$5,585,800$

In addition to the cost of energy to replace the loss of generating capacity due to downtime for cooling system tie-in, the 5-month outage of Unit No. 2 causes a temporary reduction in the reserve generating capacity available to meet peak load. Table 5 presents the Applicant's ten year planned capacity, load, and reserve margin for summer peaks. In the summers of 1980 and 1981, with Unit No. 2 removed from service for cooling tower tie-in to 26.8% and 21.3% respectively, the Applicant's reserves as a percentage of peak load are reduced. Table 6, in turn, presents the planned capability, load, and reserves for the New York Power Pool (NYPP), of which the Applicant is a member. The NYPP's determination of an adequate reserve is based on the reliability standards

TABLE 5

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

PLANNED CAPACITY, LOAD, AND RESERVE - SUMMER

MAXIMUM INSTALLED NET CAPABILITY	SUMMER MEGAWATTS									
	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
THERMAL (OIL FIRED)	7001	7001	6936	6747	6747	6693	6693	6573	6573	6210
THERMAL (COAL FIRED)	0	0	0	0	0	0	0	0	0	0
THERMAL (OTHER)	0	0	0	0	0	0	0	0	0	0
THERMAL (GAS TURBINES)	2165	2224	2234	2255	2255	2255	2255	2255	2255	2255
THERMAL (DIESEL)	0	0	0	0	0	0	0	0	0	0
THERMAL (NUCLEAR)	873	873	873	1033	1033	1033	1033	1033	1033	1033
HYDRO (CONVENTIONAL)	0	0	0	0	0	0	0	0	0	0
HYDRO (PUMPED STORAGE)	0	0	0	0	0	0	0	0	0	0
TOTAL CONTROLLED SOURCES	10039	10098	10043	10035	10035	9981	9981	9861	9861	9498
*NET CAPACITY TRANSACTIONS	607	407	1025	993	981	965	1554	1796	1619	2508
TOTAL CAP. FOR LOAD OF AREA	10646	10505	11068	11028	11016	10946	11535	11657	11480	12006
COINCIDENT PEAK LOAD	7845	7440	7560	7785	8050	8355	8665	8675	8900	9125
GROSS MARGIN	2801	3065	3508	3243	2966	2591	2870	2982	2580	2881
GROSS MARIN -% OF LOAD	35.7	41.2	46.4	41.7	36.8	31.0	33.1	34.4	29.0	31.6
GROSS MARGIN WITH IP-2 REMOVED FROM SERVICE					2156	1781				
GROSS MARGIN -% OF LOAD					26.8	21.3				

Source: 1976 Report of Member Electric Systems of the New York Power Pool and the Empire State Electric Energy Research Corporation pursuant to Article VIII, Section 149-b of the Public Service Law, Volume 2, Appendix D, (April 1, 1976)

TABLE 6

NEW YORK STATE INTERCONNECTED SYSTEMS

PLANNING CAPABILITY, LOAD, AND RESERVE, SUMMER

MAXIMUM INSTALLED NET CAPABILITY	SUMMER MEGAWATTS 1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
THERMAL(OIL FIRED)	13360	14147	14468	15249	15249	15112	15062	15029	14967	14378	14178	13978	13778	13578	13370	13178
THERMAL(COAL FIRED)	3263	3253	3570	3570	3570	3561	3556	5103	5088	4988	5738	5638	6388	6288	6189	6088
THERMAL(OTHER)	0	0	0	32	32	32	32	32	32	32	32	32	32	32	32	32
THERMAL(GAS TURBINES)	3777	3836	3846	3867	3867	3867	3867	3867	3867	3867	3867	3867	3867	3867	3867	3867
THERMAL(DIESEL)	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
THERMAL(NUCLEAR)	2774	3547	3739	4719	4787	4755	4736	6920	8037	10354	10354	10354	10354	12836	15319	17842
HYDRO(CONVENTIONAL)	4025	4025	4025	4025	4025	4025	4025	4025	4025	4025	4025	4025	4025	4025	4025	4025
HYDRO(PUMPED STORAGE)	1000	1000	1000	1000	1000	1000	2000	2000	2000	2000	2000	3000	4000	4000	4000	4000
UNDETERMINED INTERMEDIATE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL CONTROLLED SOURCES	28273	29992	30722	32536	32604	32426	33352	37050	38090	39718	40268	40968	42518	44700	46882	49106
CAPACITY PURCHASES	83	11	807	803	800	800	800	800	800	800	800	800	800	800	800	800
CAPACITY SALES	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
TOTAL CAP.FOR LOAD OF AREA	28206	29853	31379	33189	33254	33076	34002	37700	38740	40368	40918	41618	43168	45350	47532	49756
COINCIDENT PEAK LOAD	21000	21920	22770	23650	24610	25600	26600	27600	28640	29760	30890	32060	33280	34450	35700	36950
GROSS MARGIN	7206	7933	8609	9539	8644	7476	7402	10100	10100	10608	10028	9558	9888	10900	11832	12806
GROSS MARGIN-% OF LOAD	34.3	36.2	37.8	40.3	35.1	29.2	27.8	36.6	35.3	35.6	32.5	29.8	29.7	31.6	33.1	34.7

Source: 1976 Report of Member Electric Systems of the New York Power Pool and the Empire State Electric Energy Research Corporation pursuant to Article VIII, Section 149-b of the Public Service Law, Volume 2, Appendix C (April 1, 1976).

of the Northeast Power Coordinating Council (NPCC), which specify that generating capacity should be installed and located in such a manner that after due allowance for required maintenance and expected forced outages, each area's generating supply will equal or exceed area load at least 99.9615% of the time; this is equivalent of a loss of load probability of one day in ten years.[8] To meet this criterion, the NYPP has determined that the reserve margin responsibility of each member after 1975 will be 18% of peak load.[9] Due to diversity, this results in reserves of approximately 20% over peak load for the state.

Thus, even with Unit No. 2 removed from service, the Applicant is able to meet it's NYPP reserve margin responsibility in the summers of 1980 and 1981. In addition, relatively high reserve margins during summer peaks indicate the NYPP is prepared to maintain a reliable supply of electricity during individual system peak loads, as well as coincident peak loads (see Table 6). Given, therefore, that the absence of Unit No. 2's peak generating capacity does not lower reserves to an unacceptable level, it is the Staff's conclusion that the Applicant's proposed installation of gas turbines to temporarily replace peak generating capability would be an unnecessary commitment of resources and should not be included as a cost in either Case I or Case II.

Finally, Table 7 summarizes the incremental generating costs associated with each case and presents the total savings if the cooling tower is delayed two years as the difference between Case I and Case II.

TABLE 7

COST ANALYSIS SUMMARY: INCREMENTAL GENERATING COSTS FOR A NATURAL DRAFT COOLING TOWER CASE I, CASE II, AND CASE I - CASE II

	CASE I		CASE II		CASE I-CASE II	
	Present Value ($)	Annulized Value ($)	Present Value ($)	Annualized Value ($)	Present Value ($)	Annualized Value ($)
1) Capital Cost	70,409,400	7,496,800	66,390,200	7,068,900	4,019,200	427,900
2) Operating Cost	1,749,900	186,300	1,622,700	172,800	127,200	13,500
3) Derating Cost						
a) Replacement Capacity	15,829,500	1,685,400	15,108,100	1,608,600	721,400	76,800
b) Replacement energy	44,789,400	4,768,900	41,575,500	4,426,700	3,213,900	342,200
4) Downtime Cost (Replacement energy)	55,000,400	5,856,200	52,461,400	5,585,800	2,539,000	270,400
Total	187,778,600	19,993,600	177,157,900	18,862,800	10,620,700	1,130,800

2. <u>The benefits associated with further study and evaluation of environmental impacts of once-through cooling prior to "irretrievable commitment" of resources to a closed-cycle system.</u>

The Applicant claims, as a primary benefit of the extension of time for operation with once-through cooling, that the collection and presentation of further data about the environmental effects of once-through cooling will permit a period for assessment which has some (unspecified) probability of leading to a decision which would permit the avoidance of a commitment of substantial resources to a closed-cycle-cooling system, specifically the construction of natural draft cooling towers. The Staff concludes that, in the time expected to be gained for further study and evaluation, virtually no probability exists of an event occurring which prevents the Applicant from being required, if it wishes to continue operation of Unit 2 after May 1, 1980, to commit resources to the cooling tower. The reasons for this are set forth below.

A. Less than one year remains before the letting of contracts for construction to meet a May 1, 1981 termination date would be called for, according to construction schedules submitted by the Applicant. Only slightly more than a year remains before construction must begin in order to meet the 1981 date.

B. In the event that newly collected and submitted data do not appear to present significant new or different information, this one-year time period is probably adequate for the Staff to complete its independent review of the submittals. However, in those circumstances, the failure of the Applicant to offer substantial new information would lead to no real probability that a different outcome could be expected on the question of whether closed-cycle cooling will be required for Indian Point , Unit No. 2.

C. Should the submittals of further information appear to contain significantly new or different information, the Staff will perform a full independent assessment or re-analysis of the subject area. This process is a substantially more complex and time-consuming one than that conducted for submittals which may be corroborative of earlier work done by the Applicant's consultants or by the Staff. For example, in the testimony of Campbell et al. of December 7, 1976, at least five areas appear to warrant such an independent assessment. They include 1) relative contribution of Hudson River striped bass to the Atlantic coastal fishery; (2) estimates of entrainment mortality, including corrections for differential net mortality and larval-table data; (3) compensation in the Hudson

River striped bass population; (4) the method of equilibrium reduction for impact assessment; and (5) consideration of a more comprehensive assessment of the impact of power plant operation on the Hudson River white perch and tomcod populations. In the course of a full Staff assessment of any of Applicant's submittals which raise the possibility of significantly new and different information, any gaps in information submitted result in our requesting further information from Applicant. For example, our questions and requests relating to the Texas Instruments First Multiplant Report (July, 1975) were formulated and transmitted to Applicant by March 28, 1976. The Applicant then responded in three parts on July 8, 1976; August 6, 1976 and September 23, 1976. (14 months after the original submittal) It is only after satisfying ourselves that these responses are sufficient that we can then complete our assessment. It is already clear from a preliminary review of the December 7 testimony that we will require answers to several inquiries. A copy of the questions relating to the Report on Relative Contribution of Hudson River Striped Bass to the Atlantic Coastal Fishery is attached as Appendix A. Although presumably the Applicant's "January 1977 Report" will contain further information on the five subject areas covered by the December 7 testimony which appear to require independent Staff analysis, it is reasonable to assume that the report will not be fully responsive to all our questions, and it is probably reasonable to assume that the report will raise other subject areas on which the Staff may wish to perform independent assessments. Further, there may be a need for certain important data which are not immediately available, e.g., larval-table data for 1976 and larval-table data at Indian Point. A cursory overview of the nature and scope of the material available and expected to become available makes it clear that the Staff cannot, during the time period available before "irretrievable commitment", complete an assessment and reach any new conclusion with respect to the basic proposition of whether closed-cycle cooling is warranted for Indian Point Unit No. 2.

D. Even in the unlikely event that the Staff could complete an independent assessment of data which would lead it to conclude that a closed-cycle-cooling system is not warranted for Indian Point Unit No. 2, the Staff does not understand that its conclusion would be the end of the matter. Presumably there would be a hearing on the question of whether an amendment should be issued permitting the Applicant to continue operation with once-through cooling. Therefore, the Staff concludes that the time required for drafting of the necessary impact statement and for the conduct of a full hearing should also be included in assessing the probability that a decision can be reached which allows the Applicant to avoid irretrievable commitment of resources.

In light of the foregoing, the Staff believes that no measureable benefit, in terms of probability of avoiding an irretrievable commitment of resources, can be expected.

3. <u>Prevention of Non-Water Quality Impacts during Period of Delay</u>

The Staff agrees with the Applicant that the construction and operation of a wet natural draft cooling tower could result in some adverse environmental impacts, including damage to aesthetically valuable trees and the possible deterioration of scenic views. These impacts are discussed in the Staff's Final Environmental Statement for Selection of the Preferred Closed Cycle Cooling System At Indian Point Unit No. 2.[10] While such damages cannot be readily quantified, it is the Staff's position that they are small and that postponement of these impacts for two years is a minor benefit of the proposed action.

II. Costs

In accordance with economic theory, the Staff accepts the proposition that the value to society of damages resulting from environmental impacts is that amount society would be willing to pay to avoid such losses.[11] It is the Staff's position that the economic loss to society which would result from the extinction or irreversible reduction in size of a fish species from all or parts of its habitat or range is unlikely ever to be completely measureable. In particular, the dollar values of a given yield to the sport fishery, such as those estimated by the Applicant, are not acceptable as measures of the full economic loss in the case of irreversible effects since these values represent only what one segment of society might be willing to pay to prevent such a loss.* Other segments of society may treasure other attributes of a fish species.[12]

Nevertheless, the legislative and judicial branches of government, acting in the interests of society, are obliged to make and regularly do make decisions regarding the protection of environmental values based on an implicit valuation of the relative costs and benefits of such decisions. The adoption of air- and water-quality

---

* For example, the Applicant's analysis fails to attach any value to the risks of irreversible impacts on the striped bass yields, to the impacts on the commercial fishery, or to the impacts on other species and on the river ecosystem. This nonexhaustive list illustrates the inadequacy of attempts to value the ecological impacts of once-through cooling employing Applicant's methodology.

standards is a common example. One result of such decisions, moreover, is that estimates of environmental values can be inferred indirectly. For example, the cost of installing and operating air-pollution control equipment can be taken as one measure of what society is willing to pay to avoid the damages from air pollution. It can be inferred, therefore, that from the point of view of society as a whole, the economic value of damages prevented must at least be equal to the costs of control.[13]

A similar case is at hand. The Staff has concluded, and the Licensing Board, Appeal Board, and Commission have agreed, that the impacts of entrainment and impingement resulting from the long-term operation of IP-2 with once-through-cooling (OTC), in combination with IP-3, Bowline, Lovett, Roseton, and Danskammer, will expose the Hudson River striped bass population to a risk or probability of irreversible damage that is unacceptable. Further, the Applicant has proposed and the Staff and Licensing Board have concurred that a natural draft cooling tower (NDCT) be installed as the preferred method to reduce this exposure to risk.

The economic implications of these decisions can best be developed algebraically.

Let $E(V_L) = V_{L1} \cdot P_{L1} + V_{L2} \cdot P_{L2}$

where $E(V_L)$ = the expected value of loss,

V_{L1} = the economic loss associated with event L1: irreversible damage to the striped bass population does occur,

V_{L2} = the economic loss associated with event L2: irreversible damage to the striped bass population does not occur,

P_{L1}, P_{L2} = the probabilities that L1 and L2, respectively, will occur.

By definition, $V_{L2} = O$, i.e., economic loss is not incurred if there are no irreversible effects since any economic losses associated with reversible damages are not relevant in this analysis. Therefore, $E(V_L) = V_{L1} \cdot P_{L1}$. Similarly, $\Delta E(V_L) = V_{L1} \cdot \Delta P_{L1}$, i.e., changes in the expected value of a loss are directly related to changes in the probability that irreversible damages will occur. The Licensing Board concluded, in essence, that

$$V_{L1} \cdot \Delta P_{L1} \geq PVCT$$

where PVCT = the discounted present value (1976) of constructing and operating a NDCT, which the Staff (Table 7, above) estimates to be \$187,778,600.

In other words, the Licensing Board concluded that the Hudson River striped bass population was of sufficient worth (V_{L1}) and that the probability of irreversible damage sufficiently high that incurring the cost of constructing and operating a NDCT in order to reduce the probability of a loss (ΔP_{L1}) was justified. *

The reduction in the probability of irreversible damage, ΔP_{L1}, resulting from the installation of a NDCT is not known. However, a proxy measure of ΔP_{L1} can be estimated as follows. The installation of a NDCT reduces the exposure of the Hudson River striped bass to the risk of irreversible damage. Reducing the exposure to risk, in effect, reduces the probability that an irreversible loss will occur. One measure of the risk of irreversible damage adopted by the Staff is the number of years that some index of relative population size is less than some specified level (e.g., relative yield less than 0.5, Table 3.2, FES). A second measure of the risk of irreversible damage, which is used in this testimony, is the sum of the annual differences in some index of relative population size with and without the NDCT in place for all years in which the index falls below some

* More accurately, the Licensing Board and Appeal Board concluded that the probability of irreversible damage was sufficiently high that incurring the economic cost of constructing and operating a closed-cycle cooling system (NDCT) and the environmental costs of constructing and operating the system (e.g. aesthetic disadvantages), was justified. Because of an inability to fully quantify the environmental costs of constructing and operating the tower (as explained in FES for Selection of Preferred Closed Cycle Cooling System) and because of the complexities associated with examining such costs on a year-to-year basis, that portion of the value assigned by the decision-makers is ignored here. However, in considering this testimony, one should remember that whatever value is reported as that which is less than or equal to the value of the impact on the fishery is conservative because of its failure to reflect any environmental costs associated with cooling tower construction and operation.

specified value. This second measure of risk takes into account not only the number of years the index of relative population size is below the specified level but also how far below.

Figure 1 reproduces Figure 3-1 from the FES which displays the relevant relative-yield curves from the Staff's life-cycle population model. The reduction in the exposure to risk resulting from the installation of a NDCT can be calculated as:

$$\sum_{t=1}^{80} \frac{[RY_x(t)-RY_y(t)]}{(1+i)^t}$$

subject to the condition that $RY_x(t)$, $RY_y(t) < 0.50$, and where

$RY_x(t)$ = the relative yield in year t associated with cessation of OTC in May, 1979 (represented by curve x in Figure 1),

$RYy(t)$ = the relative yield in year t associated with the base design of OTC for 35 years (represented by curve y in Figure 1), and

i = the rate of discount (=0.10).

The use of discounting of the measure of risk reflects the Staff's assumption that society in making its decisions exhibits a time preference toward risk and discounts future exposure to risk just as it discounts future exposure to dollar costs.

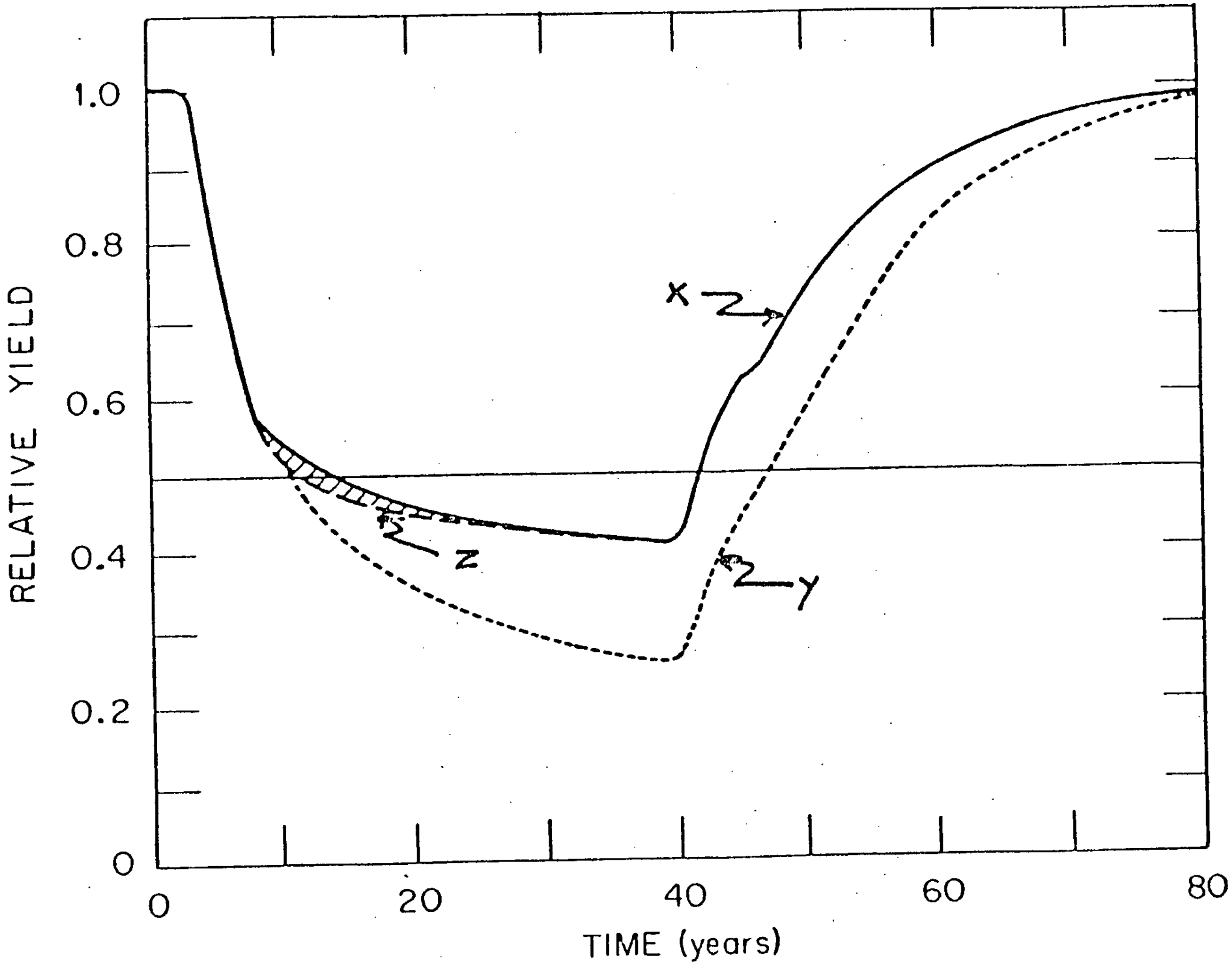

Fig. 1. Curves for relative yield versus time. The three curves are for cessation of once-through cooling at Indian Point Unit No. 2 on May 1, 1979 (solid line) and on May 1, 1981 (dashed line) and for the base design of once-through cooling for 35 years at both Unit Nos. 2 and 3 (dotted line).

The estimate obtained from using this method to calculate the reduction in exposure to risk is adopted as a proxy measure of the decrease in probability of incurring an irreversible loss as a result of installing a NDCT (ΔP_{L1}). Solving, now, for V_{L1}:

$$V_{L1} \geqq \frac{PVCT}{\Delta P_{L1}} \geqq \frac{\$187,778,600}{0.4417} \geqq \$425,127,000$$

The above result can now be employed to estimate the increase in expected loss to society, $\Delta E(V_L)$, from the proposed two-year delay in cessation of operation with OTC. The significance of the dalay is to increase the probability of irreversible damage (ΔP_{L1}) by increasing the exposure of the striped bass population to the risk of irreversible damage. The increase in probability, as measured by the increase in risk, can be calculated as:

$$\sum_{t=1}^{80} \frac{[RY_x(t)-RY_z(t)]}{(1+i)^t} = 0.0520$$

where $RY_z(t)$ = the relative yield in year t associated with the cessation of OTC in May, 1981 (represented by curve z in Figure 1).

The increase in expected loss as a result of the delay, $\Delta E(V_L)$, can then be estimated as follows:

$$\Delta E(V_L) \geqq V_{L1} \cdot \Delta P_{L1}$$
$$\geqq \$425,127,00 \cdot 0.0520 \geqq \$22,107,000$$

Thus, assuming one-half of this amount approximates the costs of a one-year extension, then the costs associated with the delay exceed the anticipated economic benefits (see Table 7, above), thereby supporting the Staff's position that no further extension in the period of operation of IP-2 with OTC be granted.*

It is appropriate to emphasize that the above results are offered only as an example of a reasonable approach to estimating the costs of the proposed delay. The particular results obtained are dependent upon several assumptions. First, the selection of 0.50 as the relative yield value below which the risk of irreversible effects is incurred is a somewhat arbitrary choice. A more conservative figure of 0.75 was also used in the FES. However, there exists no body of knowledge which can be appealed to in defense of using a particular figure. The use of 0.50 is based on the judgement of the Staff and the desire to use a reasonable figure. Second, the particular set of relative yield curves presented in Figure 1 is just one of a number of sets that might have been employed, depending upon the parameters specified for the Staff's life-cycle population model as well as for the Staff's young-of-the-year striped bass population model. Again, no criteria other

* If the Licensing and Appeal Board actually perceived the benefits of closed-cycle cooling to <u>significantly</u> outweigh the costs, the dollar figure for this example would be much higher and many more examples of model runs would yield a figure which supports a conclusion that the costs of extension outweigh the benefits of extension.

than the analyst's judgement exist for selecting a "most likely" set of curves. It is appropriate to note, however, that the relative yield curves presented in Figure 1 represent a fairly severe case in terms of the assumed impact of OTC on the striped bass population. Third, it is assumed that the incremental risk for year t, $RY_x(t) - RY_y(t)$ or $RY_x(t) - RY_z(t)$, is of the same importance as an incremental risk of equal magnitude for any other year. An alternative assumption to this equal weighting of incremental risks through time would be to give progressively greater weight to the incremental risks incurred later in time. This second assumption would reflect that there may be a threshold for the cumulative risks and that incremental risks in later years may have a greater effect in reducing the margin of safety than would incremental risks in earlier years.

The results presented above do not contradict the Staff's conclusion in the FES "... that the incremental long-term impact [of entrainment] on the striped bass population due to the requested extension of time is negligible" or "...that the incremental long-term impact from these losses [from impingement] is not expected to be large and has essentially no risk of being irreversible." (FES, p. 3-6) The incremental impact is small, as indicated above: an increased exposure to risk of 0.0520 compared, say, to the risk associated with OTC over the plant's lifetime of 0.4417. So also would the impact of a second, third, etc., two-year extension be small if analyzed in the same manner. The conclusion of negligible impact in the biological sense follows from the incremental or piece-meal procedure employed and poses the danger that non-negligible cumulatiive impacts, as a result of a series of discrete successive extensions, might be overlooked. In addition, of course, a finding of negligible biological impact does not necessarily imply a negligible economic impact. The significance of an economic cost can only be determined in relation to the size of the corresponding economic benefit. The value of the analysis presented above is to illustrate that a situation does exist where the costs of the proposed delay exceed the benefits.

III. Summary

Sections I and II above have reviewed the relative costs and benefits of the proposed extension in operation of IP-2 with once-through cooling, emphasizing the quantification of what the Staff considers to be the principal elements. The costs of the originally-proposed two-year extension are analyzed, reflecting limitations in available data which prevent a review of a one-year's delay.

On the benefit side, the Staff estimates a cost savings from delay in construction and operation of a NDCT of $10,620,700. This is approximately comparable to the Applicant's estimate for a one-year delay of $6,797,000. Other benefits of the delay cannot be quantified, but are considered by the Staff to be small.

The Applicant and Staff disagree considerably in their respective estimates of the costs of the delay. The Applicant, concerned only with the economic losses associated with estimated reductions in the yield to the striped bass sport fishery, estimates a cost of $112,000 for a one-year delay. The Staff recognizes that such economic losses will occur, but considers them only a minor addition to that cost element of principal concern, i.e., the expected loss associated with exposing the Hudson River spawned striped bass population to an increased risk of irreversible damage.

In its previous decisions, the Licensing Board and Appeal Board have concluded that the Hudson River striped bass population was of sufficient worth and that the probability of irreversible damage (from operation of IP-2 with once-through cooling for 35 years) sufficiently high that incurring the costs (including environmental costs) of constructing and operating a NDCT in order to reduce the probability of a loss was justified. By inference, the Staff estimates that the expected loss associated with the increased probability of irreversible damage due to a one-year extension of operation with once-through cooling to be at least $11,053,500. Thus, under the assumptions and conditions stated in that analysis, a situation does exist where the costs of the proposed delay exceed the benefits.

REFERENCES

1. Tr. 869.

2. See, for example, FES, §6.4; Tr. 143-45, 732.

3. United States Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Final Environmental Statement Related to Operation of Indian Point Nuclear Generating Plant Unit No. 3, Docket No. 50-286, NUREG-75/002, February, 1975, p. xi-60.

4. United States Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Final Environmental Statement for Selection of the Preferred Closed-Cycle Cooling System at Indian Point Unit No. 2, Docket No. 50-247, NUREG-0038, August, 1976.

5. Consolidated Edison Company of New York, Inc., Economic and Environmental Impacts of Alternative Closed-Cycle Cooling Systems for Indian Point Unit No. 2, Volume No. 1, December 1, 1974, Table 3.2.

6. Ref. 3, Table 3.3.

7. Telephone conversation between Dr. M. B. Spangler, NRC, and Mr. M. Scott, Consolidated Edison Company of New York, Inc., on August 5, 1975.

8. Northeast Power Coordinating Council, Basic Criteria for Design and Operation of Interconnected Power Systems, July, 1970.

9. New York Power Pool, Generation Reliability and Reserve Requirements, November, 1972.

10. Ref. 4, Chapter 5.

11. A. Myrick Freeman, III, The Economics of Pollution Control and Environmental Quality, (New York: General Learning Press, 1971), p. 5.

12. John V. Krutilla, "Some Environmental Effects of Economic Development," Daedalus, 96(4), pp. 1058-1070; see also, John V. Krutilla, "Conservation Reconsidered," American Economic Review, September, 1967.

13. Larry E. Ruff, "The Economic Common Sense of Pollution," The Public Interest, No. 19 (Spring, 1970), pp. 81-82; see also, Ref. 11, p. 16.

Appendix A

1. Provide punched computer cards or magnetic tape and a listing of cards for the following:

   A. The 15 characters for each fish in the discriminate analysis of 1974 source-river data (Table B-1).

   B. The 8 characters for each fish in the discriminate analysis of 1975 source-river data (Table B-2 and B-3).

   C. The 5 characters for the 2,737 fish in the discriminate analysis of 1975 Atlantic coastal data (Table III-3).

In each of the above three cases, include values for fork length, age, sex, time period, stratum, and substratum, method of collection and any other information TI found to be useful. For item 1-C above, include for each fish the values obtained for F_{HUD}, F_{CHES}, F_{Roan}, F_{BHUD} (Appendix D, equations 1-4, respectively).

2. Provide the four discriminate functions related to Table B-6.

3. Provide the two discriminate functions related to Table B-7. Were both the 1974 and 1975 Hudson data and Chesapeake data used for Table B-7?

4. Were any striped bass less than 406.5 mm fork length found in any strata other than 4, 5, 6, and 7 (i.e., New York waters) (see Table III-2)? If so, provide numbers of fish by time period and substrata.

5. On page II-1, the statement is made that "Most of the misclassifications occurred between Hudson and Chesapeake stock, as indicated by overlaps of 24.06, 4.44, and 10.94% obtained for the Hudson-Chesapeake, Hudson-Roanoke, and Chesapeake-Roanoke spawning stock pairs, respectively." For each of the three stocks, provide values for the number and fraction of fish from that stock that were misclassified into each of the other two stocks.

6. To continue analysis of the LMS one-dimensional, tidal-averaged model for the Hudson River, we need LMS estimates for 1974 and 1975 for each parameter in the model that has a value different from that in 1973. Examples are values for fraction egg production by week and river segment, values for fresh-water flow and dispersion coefficient by flow period and river segment, and values for migration preference for each of the three juvenile life stages.

PROFESSIONAL QUALIFICATIONS
ROBERT L. SPORE
OAK RIDGE NATIONAL LABORATORY

I am Robert L. Spore, Cost-Benefit Group Leader with the Environmental Impact Section, Energy Division, Oak Ridge National Laboratory. I have served in this position since November 1975. I am responsible for reviewing and coordinating the activities of the members of the Cost-Benefit Group in the preparation of cost-benefit sections for environmental statements for the U. S. Nuclear Regulatory Commission and other agencies. I also supervise and conduct generic research on topics related to the social and economic impacts of energy-producing facilities as well as the development of methodologies for performing cost-benefit assessments. My recent activities also have included direct participation in the preparation of cost-benefit sections of environmental statements for several nuclear power stations.

I received a B.A. degree in Economics from the University of Nebraska in 1967, and a M.A. and Ph.D. in Economics from the Pennsylvania State University in 1968 and 1972, respectively. My graduate program specialized in the following areas: economic theory, regional economics, public finance, and environmental economics. My graduate research encompassed the development and application of techniques for the measurement of the economic costs of air pollution.

In May 1972 I joined the staff of the Oak Ridge National Laboratory, serving as an economist with the ORNL-NSF Environmental Program. In this capacity I conducted research developing and applying methodologies for assessing the environmental impacts of coal surface mining. From May 1974 to November 1975 I served as Group Leader for an NSF-sponsored program entitled "Sytems Studies of Coal Production" which encompassed the development of a related set of detailed engineering/economic models capable of predicting the impacts on coal production and consumption of alternative national energy policies. The principal application of these models was an evaluation of the impact of surface mining regulations on the Appalachian coal surface mining industry. I have authored and co-authored several reports on this research for publication in professional journals or for presentation at professional meetings, including the preparation of testimony for Congressional hearings.