UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board

In the Matter of CAROLINA POWER & LIGHT COMPANY (H.B. Robinson Steam Electric Plant, Unit 2)	)))))	Docket No. 50-261 OLA January 20, 1984

TESTIMONY OF

PAUL D. RASKIN

On behalf of:

The Hartsville Group
P.O. Box 1089
Hartsville, S.C. 29550

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Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Paul D. Raskin. I am the President of Energy Systems Research Group, Inc., 120 Milk Street, Boston, Massachusetts 02109.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND QUALIFICATIONS.

A. Subsequent to receiving my Ph.D. in physics from Columbia University in 1969, I served on the faculties of City College of New York and the State University of New York at Albany. At the latter, in addition to completing research in physics, I chaired the faculty at an interdisciplinary college on contemporary social institutions, and expanded my research activities to include energy and environmental issues.

Since 1976, I have been with ESRG, where I have authored or co-authored over forty energy studies and have advised many state and federal governmental agencies, private organizations, and international bodies and governments. These studies cover a variety of energy-related issues, including utility system planning, demand forecasting, conservation policy, and cost-benefit analysis. I have testified on these issues before the New York State Public Service Commission in Case Nos. 27136, 27154, 27319, and 28233; the New York Siting Board in Case No. 80003; the Energy Board in the 1979 and 1981 Energy Master Planning Proceedings; the Federal Energy Regulatory Commission in Project No. 2729; the Connecticut Power

Facility Siting Council in Case No. F-80; the Connecticut PUCA in Docket Nos. 800302, 810602 and 810604; and the Massachusetts Department of Public Utilities in Docket No. 20248.

My background is described more fully in the resume attached as Exhibit ___(PDR-1).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY TODAY?

A. The purpose of my testimony is to introduce the report Electric Rate Consequences of Retiring the Robinson 2 Nuclear Power Plant, prepared under my supervision. It is appended as Exhibit ___(PDR-2).

Q. PLEASE DESCRIBE THAT REPORT.

A. I will restrict myself here to a very brief summary since the report is designed to explicate the issues, findings, and methods used in examining the likely cost impacts of retiring the Robinson facility.

Q. PLEASE GIVE THE BACKGROUND TO YOUR INVESTIGATION.

A. The H.B. Robinson Steam Electric Plant Unit No. 2 is a pressurized water reactor (PWR) located at Hartsville, South Carolina. It is owned and operated by the Carolina Power and Light Company, a utility serving about 800,000 customers in both North (85 percent) and South (15 percent) Carolina. The Robinson plant, manufactured by the Westinghouse Corporation, began commercial operation in March, 1971.

Beginning in 1980, corroding tubes in the steam generators at the plant began cracking at a rapid rate. Operations at the plant have been restudied in an effort to reduce the rate of corrosion cracking.

CP&L, in anticipation of continued steam generator degradation, determined in 1982 that the three generators at the plant should be replaced. CP&L submitted its final proposal in early 1983 to the Nuclear Regulatory Commission pursuant to the present hearing. Consequently, this is a propitious moment to explore the economic justification of continued operation at the unit.

The proposed steam generator replacement project raises a number of issues with respect to proper engineering methods, health and safety ramifications, and, the issue addressed by my testimony, economic justification. But the steam generator problem is not the only major area of uncertainty clouding Robinson's future. In a recent study, the NRC staff concluded that a number of PWR facilities suffer from prematurely embrittled reactor vessels. The plant identified as highest priority concern is the Robinson unit. It is likely that hardware and procedural modifications will be required within five years.

Another problem requiring timely solution is the disposal of radioactive spent fuel should the plant remain in operation. The "temporary" on-site storage pools will

reach capacity in about four years. An acceptable solution to the permanent off-site disposal of the irradiated fuel does not yet exist. For Robinson to continue in operation, interim storage arrangements will be required by the late 1980s with associated environmental impacts, cost consequences and plant availability repercussions which are, at this time, difficult to quantify.

It is within this broad context of long-term uncertainty that the more narrowly defined economic question is addressed. Is it cost-effective to replace the steam generators at the H.B. Robinson 2 facility or should the plant be retired?

Q. WHAT APPROACH WAS USED IN ANSWERING THIS QUESTION?

A. The objective is to simulate the flow of revenues CP&L will receive from its ratepayers ("required revenue") under two future scenarios, one with Robinson assumed to continue in operation and a second in which the plant is assumed to be retired. The difference in required revenue streams between these two scenarios is the "bottom line" measure of the cost impacts of retiring the facility.

The revenue streams are developed for the major cost categories that would be affected by a decision to retire Robinson. These include operations and maintenance costs (O&M), levels of additional capital expenditures on plant and equipment, nuclear fuel costs, decommissioning costs,

and waste disposal costs for the Robinson unit. Additionally, the costs of the steam generator replacement must be accounted for, as must be the make-up power and energy costs required to substitute for Robinson.

Wherever possible, statistically based techniques have been used to estimate key parameters. This has been particularly useful for projections of Robinson O&M, capital additions, and capacity factors (a measure of plant availability). Computer models have been employed to develop these inputs and to produce the scenario cost comparisons. Descriptions of methods, assumptions and results are provided in Exhibit ___(PDR-2).

In this investigation, the quantification of the impacts of retiring Robinson are limited to those costs which are directly incurred by ratepayers. A host of other consequences -- environmental trade-offs, public and occupational health and safety, nuclear risk, employment impacts -- are not included. Consensual "social" cost/benefit analyses on these elusive issues, depending as they do on normative judgment and incomplete information, are not possible at present. Debate on these critical "external" impacts will be enhanced by a careful assessment of the direct economic repercussions of retiring Robinson, the aim of my study.

Q. PLEASE SUMMARIZE YOUR FINDINGS.

A. The detailed findings on cost impacts are presented in Section 2 of Exhibit ___(PDR-2). below. The basic conclusion is that rates in the CP&L service area are likely to be somewhat higher if the steam generator is replaced and Robinson continues to operate than if Robinson is closed. The results for the Baseline scenario -- defined by mid-range assumptions which are neither optimistic nor pessimistic with respect to the plant's prospects -- is that approximately $50 million in 1983 present value will be saved if the plant is retired early.

Additionally, in a number of sensitivity tests, the effects of a range of variation in key inputs have been examined. In most instances, the economics of continued operation are not favorable. The results are summarized in Table 1.1 of Exhibit ___(PDR-2), where both the cumulative cost impact and the average percent change in rates are given for selected scenarios.

The average rate impact of early retirement is small in all scenarios, with a reduction of only 0.2 percent in the Baseline case. Nevertheless, some savings are probable under retirement. The results indicate that there is no economic case for the Robinson steam generation expenditure at this time. Through a detailed comparison and critique (Section 8 of Exhibit ___(PDR-2)), we conclude that CP&L could make such a case only by

systematically adopting optimistic assumptions on future nuclear plant performance and costs, which are not validated by statistical analysis of the actual experience and trends.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

Exhibit ___ (PDR-1)

PAUL D. RASKIN

Research Scientist
President
Energy Systems Research Group

Dr. Raskin performs resource policy evaluations for domestic and international governments and a variety of private organizations. He provides quantitative analyses of the economic, environmental and social tradeoffs resulting from alternative energy and resource development strategies, technologies, and programs. He has supervised the development of a number of computer-based planning models to assist such efforts including the widely-used ESRG electric utility forecasting model, a model for the evaluation of conservation-oriented programs (CONCOST), the Water Availability and Demand Evaluation System (WADES), and the LDC Energy Alternatives Planning (LEAP) system.

Education

Ph.D.	Theoretical Physics, Columbia University, 1970.
B.A.:	Physics, University of California at Berkeley, 1964.

Experience

1976 - Present:	Energy Systems Research Group, Inc. President with overall executive responsibility since the incorporation of ESRG in December, 1976. Principle responsibility for energy and resource planning research projects for a variety of international, state, local, and private agencies; development of computer-based modeling systems for the analysis of the physical, economic, and environmental implications of alternative energy policy strategies.
1976 - 1978:	Associate Professor, Empire State College, State University of New York. Instruction in physics, energy/environment, and science/society.
1973 - 1976:	Assistant Professor, State University of New York at Albany. Chairman of the Faculty, The Allen Center, 1974 - 1976.
1969 - 1973:	Instructor, Department of Physics, City College of New York, CUNY.

Selected Reports and Publications

Energy Development in Kenya: Problems and Opportunities, Scandinavian Institute of African Studies, Uppsala, 1984 (forthcoming).

Power Planning in Kentucky: Assessing Issues and Choices, A Report to the Kentucky Public Service Commission, Co-author, October, 1983.

Long Island Without the Shoreham Power Plant: Elecricity Cost and System Planning Consequences, Prepared for the County of Suffolk, N.Y., July, 1983 (5 volumes).

LEAP, LDC Energy Alternatives Planning System, Volume 1 - Overview, Volume 2 - User Guide, Volume 3 - Reference Manual, A Report to the Beijer Institute of the Royal Swedish Academy of Sciences, 1983.

Issues in SADCC Energy Planning: Usage Patterns, Resource Potential and Regional Possibilities, A Report for a seminar convened by Angola and hosted by Zimbabwe with cooperation from the Swedish International Development Agency, November, 1982.

Review of the Kentucky-American Water Company Capacity Expansion Program, A Report to the Kentucky Public Service Commission, ESRG Study 82-45, Co-author, October, 1982.

The Economics of Closing the Indian Point Nuclear Power Plants, ESRG Study 82-40, October, 1982.

The Impacts of Early Retirement of Nuclear Power Plants: The Case of Maine Yankee, ESRG Report 82-91, August, 1982.

Energy Planning for Small Developing Islands, A Report to Ocean Economics and Technology Branch, D.I.E.S.A., The United Nations, ESRG Study No. 81-28, Co-author, February, 1982.

Energy Development in Kenya: Problems and Opportunities. A Report to the Kenya Ministry of Energy, ESRG Study No. 80-24, Principal investigator, January, 1982.

A Conservation Scenario for the Northeast Utilities Connecticut Service Area, ESRG Study No. 81-12, October, 1981.

Implementing Conservation in New York State, ESRG Study 81-9, Co-author, September, 1981.

Utility Promotion of Customer Energy Conservation, ESRG Study No. 81-18, A Report to the New Jersey Department of the Public Advocate, August, 1981.

LDC Energy Alternatives Planning Model (LEAP), Report on Model Developed for Energy Analysis of Kenya, July, 1981.

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

The Conservation Investment Alternatives for New York State, ESRG Study No. 80-42, January, 1981.

Long Range Forecast of Appalachian Power Company Electrical Loads, ESRG Study 80-8, January, 1981.

The Conservation Alternative to the Power Plant at Shoreham Long Island, ESRG Study No. 80-31, Co-author, November, 1980.

The ESRG Electrical Systems Generation Model: Incorporating Social Costs in Generation Planning, ESRG Study No. 80-12, Co-author, October, 1980.

Base Case Forecasts for Seven Ohio Utilities, ESRG Study No. 79-14, A Report to the Consumers' Counsel of Ohio, Co-author, October, 1980.

Curtailment Planning Model, ESRG Study No. 79-21, A Report to Brookhaven National Laboratory, Co-author, September, 1980.

District Heating Strategy Model, Report to Argonne National Laboratory, Report No. 79-20, September, 1980.

The Potential Impact of Conservation and Alternative Supply Sources on Connecticut's Electric Energy Balance, ESRG Study No. 80-09, A Report to the Connecticut Power Facility Evaluation Council, July, 1980.

The Employment Impact of Energy Conservation, ESRG Study No. 79-29/5, A Report to the U.S. General Accounting Office, Co-author, July, 1980.

Long Range Forecast of the Massachusetts Municipal Wholesale Electric Company Electricity Requirements, ESRG Study No. 80-07, Principal investigator, June, 1980.

Long Range Forecast of Eastern Wisconsin Utilities'and Western Wisconsin Utilities' Electric Energy Requirements and Peak Demands, ESRG Study No. 79-28, A Report to the Wisconsin Public Service Commission, February, 1980.

Duquesne Light Company Forecast, ESRG Study No. 79-26/1, Co-author, February, 1980.

Pennsylvania Power Company Forecast, ESRG Study No. 79-26/2, Co-author, January, 1980.

Public Service Company of Oklahoma System Forecast, Volume I: The Base Case Forecast; Volume II: The State Conservation Policy Case, ESRG Study No. 79-23, January, 1980.

Philadelphia Electric Company System Forecast, Volume I: The Base Case Forecast; Volume II: The State Conservation Policy Case, ESRG Study No. 79-25, November, 1979.

Electricity Requirements in New York State, ESRG Study No. 79-12. Three volumes: Base Case Forecast, State Conservation Policy Case Forecast, and Employment Impacts of the Conservation Policy Case Alternative, Principal investig[illegible], July, 1979.

Long Range Forecast of Electric Energy and Demand in the Service Area of the Duquesne Light Co., ESRG Study No. 79-17, Co-author, June, 1979.

Assessment of the New England Power Pool - Battelle Long Range Electric Demand Forecasting Model, ESRG Study No. 79-06, A Report to the New England Conference of Public Utility Commissioners, Co-author, May, 1979.

Electric Backup of Residential Solar System: A Utility Demand Model for Use in Cost Assessments, ESRG Study No. 79-05, Principal investigator, May, 1979.

Demand Curtailment Planning Methodology, ESRG Study No. 78-18, Chapter submitted to Brookhaven National Laboratory and the Department of Energy for the Electric Demand Curtailment Planning Study, Co-author, May, 1979.

Long Range Forecast of Electric Energy and Demand in New Hampshire, ESRG Study No. 79-03, Principal investigator, March, 1979.

Long Range Forecasting Model: Electric Energy and Demand in New York State, ESRG Study No. 78-06, Three volumes, Principal investigator, September 1978

"Short-Time Stochastic Electron," Foundations of Physics, vol. 8, February, 1978.

Industrial Cogeneration in New York State: Identifying and Overcoming Barriers, ESRG Study No. 78-01, A Report to the N.Y. State Energy Office, Co-principal investigator, January, 1978.

The Effect of Conservation on Environmental Emissions - Utility, Residential, and Commercial Sectors, ESRG Study No. 77-06, Principal investigator, September, 1977.

The Effect on Air and Water Emissions of Energy Conservation in Industry, ESRG Study No. 77-04, Principal investigator, July, 1977.

Toward an Energy Plan for New York, ESRG Study No. 77-03, A Report to the Legislative Commission on Energy Systems, Co-author, June, 1977.

Assessing Demand, Alternative Generating Strategies, and Utility Economics in the Service Territory of Orange and Rockland Utilities, ESRG Study No. 77-01, April, 1977.

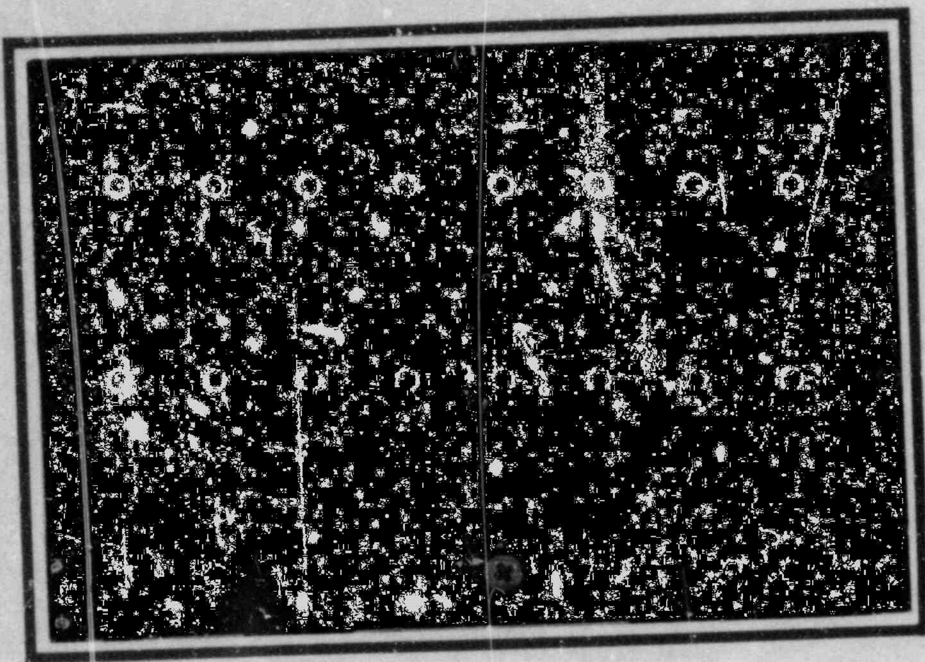
Testimony

Agency	Case or Docket No.	Date	Topic
Special Governor's Commission on Shoreham		July, 1983	Cost/benefit trade-offs of the Shoreham power plant
New York Public Service Commission	28233	Nov., 1982	Conservation program design
Connecticut Public Utility Control Authority	810602 and 810604	Oct., 1981	Costs and benefits and program design of utility customer conservation program
New York Energy Master Planning Board		Sept., 1981	The New York State Energy Master Planning and Long Range Electric and Gas System Proceeding
New York Public Service Commission	27811	Feb., 1981	LILCO's request for recovery of expenditures on cancelled nuclear power plant project
New York Public Service Commisson	27774	Nov., 1980	Conservation Alternative to Shoreham
Connecticut Power Facility Evaluation Council	F-80	July, 1980	Utility Demand and Supply Planning

Agency	Case or Docket No.	Date	Topic
Massachusetts Department of Public Utilities	20248	June, 1980	Load forecasting and conservation investment opportunities in New York State
Federal Energy Regulatory Commission	2729	May, 1980	Load forecasting
New York State Energy Office		Sept., 1980	Long-range electric demand and conservation and generation alternatives
New York Public Service Commission	27319	Sept., 1980	Forecast critique and results of independent long-range demand forecast
New York Public Service Commisson	27154	Sept., 1977	Forecast critique and assessment of customer and utility level management options
New York Public Service Commission	27136	Apr., 1977	Cost-benefit analysis of alternative generation scenarios

Exhibit_____(PDR-2)

ESRG



Energy Systems Research Group

Boston, Massachusetts

ELECTRIC RATE CONSEQUENCES OF RETIRING THE ROBINSON 2 NUCLEAR POWER PLANT

Submitted as Testimony Before the
Nuclear Regulatory Commission
(Docket No. 50-261 OLA)

January 20, 1984

By

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1. OVERVIEW

1.1 Background

This report addresses a fundamental question which will increasingly face ratepayers and regulators throughout the country: is it economically justified to make substantial investments to keep aging nuclear power plants in operation? The response surely depends on the circumstances particular to a specific facility. The economic trade-offs of continued operation versus retirement are analyzed here for the case of the H.B. Robinson Unit 2 nuclear plant in South Carolina.

The very fact that there is an issue of continued operation for a twelve year old plant such as Robinson, is itself noteworthy. At the inception of the commercial nuclear power program, there was wide engineering consensus that nuclear generating facilities would operate for several decades with high reliability and at extremely low cost. The initial prognosis proved to be overly optimistic. The experience of nuclear power plant operations over the past twenty years has contrasted with the earlier promise of unprecedented economic efficiency. At each phase of the process from initial construction to operations and radioactive waste handling, the technology has proved to be more intractable and costly than anticipated by the nuclear industry and its regulators.

In recent years, a new dimension of the problem has begun to come into focus: the first generation of nuclear power plants are exhibiting premature component deterioration. Such early aging phenomena as leaking steam generator tubes and embrittled reactor vessels have caused concern over the reliability, safety, and economic viability of future operations at certain nuclear stations.

Indeed, periodic reconsideration of the advisability of continuing to generate at aging facilities is the prudent course given the mounting costs required to ensure adequate plant performance. Reviewing alternatives to escalating expenditures on deteriorating power plants is as sound for power planning as it is for the automobile owner faced with costly decisions on whether to try to keep an old car on the road. The economic impacts of early retirement of problem-prone nuclear units is the subject of the present case study.

1.2 The Issue at Robinson

The H.B. Robinson Steam Electric Plant Unit No. 2* is a pressurized water reactor (PWR) located at Hartsville, South Carolina. It is owned and operated by the Carolina Power and Light Company, a utility serving about 800,000 customers in both North (85 percent) and South (15 percent) Carolina. The Robinson plant, manufactured by the Westinghouse Corporation, began commercial operation in March, 1971.

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*Referred to below as "Robinson" or "the plant."

Beginning in 1980, corroding tubes in the steam generators* at the plant began cracking at a rapid rate. Over the past three years well over a thousand tubes have been repaired. Operations at the plant have been restricted in an effort to reduce the rate of corrosion cracking.

CP&L, in anticipation of continued steam generator degradation, determined in 1982 that the three generators at the plant should be replaced. The Nuclear Regulatory Commission (NRC) initiated hearings to determine whether a licensing amendment should be granted for the steam generator repairs (Docket No. 50-261). CP&L submitted its final proposal in early 1983 (Ref. 1). A decision on this issue is expected in 1984. Consequently, this is a propitious moment to explore the economic justification of continued operation at the unit.

The proposed steam generator replacement project raises a number of issues with respect to proper engineering methods, health and safety ramifications, and, the issue addressed here, economic justification. But the steam generator is not the only major area of uncertainty clouding Robinson's future. In a recent study, the NRC staff concluded that a number of PWR facilities suffer from prematurely embrittled reactor vessels

*In a PWR, the heat from the reactor core is carried by water under high pressure (the "primary cooling cycle") to the steam generator. There it travels through thousands of tubes, transferring heat to water circulating outside the tubes (the "secondary cooling cycle") which, once raised to steam, drives the turbine generator.

(Ref. 2).* The plant identified as highest priority concern is the Robinson unit. It is likely that hardware and procedural modifications will be required within five years (Ref. 3).

Another problem requiring timely solution is the disposal of radioactive spent fuel should the plant remain in operation. The "temporary" on-site storage pools will reach capacity in about four years (Ref. 4). In the original nuclear "fuel cycle" scheme, spent fuel from the industry was to be transferred after several months to a reprocessing facility where uranium and plutonium would be extracted for re-use. However, due to unexpected technical complications, soaring costs, and concern over nuclear weapons proliferation, the reprocessing option has been indefinitely deferred. At the same time, an acceptable solution to the permanent off-site disposal of the irradiated fuel does not yet exist. For Robinson to continue in operation, interim storage arrangements will be required by the late 1980s with associated environmental impacts, cost consequences and plant availability repercussions which are, at this time, difficult to quantify.

Within this broad context of long-term uncertainty, we wish to pose and address a narrowly defined question. Is it cost-effective to replace the steam generators at the H.B. Robinson 2 facility or should the plant be retired?

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*The steel walls of the reactor vessel, under high pressure conditions, are progressively weakened by absorption of neutron radiation from the fission process. If there is a sudden drop in temperature, as would occur for example if the emergency core cooling system is activated during an accident, the embrittled reactor is susceptible to "pressurized thermal shock" and could rupture.

1.3 Study Approach

The objective of this study is to simulate the flow of revenues CP&L will receive from its ratepayers ("required revenue") under two future scenarios, one with Robinson assumed to continue in operation and a second in which the plant is assumed to be retired. The difference in required revenue streams between these two scenarios is the "bottom line" measure of the cost impacts of retiring the facility.*

The revenue streams are developed for the major cost categories that would be affected by a decision to retire Robinson. These include operations and maintenance costs (O&M), levels of additional capital expenditures on plant and equipment, nuclear fuel costs, decommissioning costs, and waste disposal costs for the Robinson unit. Additionally, the costs of the steam generator replacement must be accounted for, as must be the make-up power and energy costs required to substitute for Robinson.

Wherever possible, statistically based techniques have been used to estimate key parameters. This has been particularly useful for projections of Robinson O&M, capital additions, and capacity factors (a measure of plant availability). Computer models have been employed to develop these inputs and to produce the scenario cost comparisons. Descriptions of methods, assumptions and results are provided in subsequent sections of this report.

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*Formally stated, the cumulative present value of required revenues under alternative scenarios have been computed and compared. Present value calculations are commonly used in comparing costs and benefits which occur at different points in time. The procedure "discounts" future costs and benefits to reflect the time value of money and underlying inflation.

In this investigation, the quantification of the impacts of retiring Robinson are limited to those costs which are directly incurred by ratepayers. A host of other consequences -- environmental trade-offs, public and occupational health and safety, nuclear risk, employment impacts -- are not included. Consensual "social" cost/benefit analyses on these elusive issues, depending as they do on normative judgment and incomplete information, are not possible at present. Debate on these critical "external" impacts will be enhanced by a careful assessment of the direct economic repercussions of retiring Robinson, the aim of this study.

1.4 Summary of Findings

The detailed findings on cost impacts are presented in Section 2 below. The basic conclusion is that rates in the CP&L service area are likely to be somewhat higher if the steam generator is replaced than if Robinson is closed. The results for the Baseline scenario -- defined by mid-range assumptions which are neither optimistic nor pessimistic with respect to the plant's prospects -- is that approximately $50 million in 1983 present value will be saved if the plant is retired early.

Additionally, in a number of sensitivity tests, the effects of a range of variation in key inputs have been examined. In most instances, the economics of continued operation are not favorable. The results are summarized in Table 1.1 where both the cumulative cost impact and the average percent change in rates are given for selected scenarios.

The average rate impact of early retirement is small in all scenarios, with a reduction of only 0.2 percent in the Baseline case. Nevertheless, some savings are probable under retirement. The results indicate that there is no economic case for the Robinson steam generation expenditure at this time. Through a detailed comparison and critique (Section 8), we conclude that CP&L could make such a case (Ref. 5) only by systematically adopting optimistic assumptions on future nuclear plant performance and costs which are not validated by statistical analysis of the actual experience and trends.

TABLE 1.1

RATE IMPACTS OF ROBINSON 2 RETIREMENT UNDER ALTERNATIVE SCENARIOS

Scenario	Description	Cost Impact of Retirement: Cumulative Change in Required Revenue (1983 present value dollars in millions)	Cost Impact of Retirement: Average Percent Change in Rates
Baseline	(See Text)	-50	- 0.2
Baseline with 20 year plant life	Retirement in 1994 with steam generator replacement	-120	- 0.5
Baseline with Conservation	Pursue conservation investment to partially replace Robinson generation	-160	- 0.7
Nuclear O&M Costs			
- High	Double projected real increases (Sec. 4)	-180	-0.8
- Low	No real increases	40	0.2
Future Robinson 2 Investments			
- High	Double projected real increases (Sec. 3)	- 90	- 0.4
- Low	No real increases	- 20	- 0.1
Robinson 2 Capacity Factor			
- High	5% higher than Baseline (Sec. 3)	0	0.0
- Low	5% lower than Baseline	-120	-0.5
Fuel Price Escalation			
- High	Coal at 2% real (from 1%, Sec. 7)	10	0.1
- Low	Coal at 0% real	-120	-0.5
Load Growth			
- High	2.6%/year peak growth (from 2.2%)	20	0.1
- Low	1.7%/year	-240	-1.1
Period of Analysis			
- Long	25 years, 1984-2008	- 90	-0.4
- Short	10 years, 1984-1993	- 90	-0.4

2. COST IMPACTS OF RETIRING ROBINSON 2

The objective of this study is to quantify the changes in the costs to ratepayers resulting from not operating the Robinson facility, relative to the option of extending the lifetime of the plant via the steam generator investment. This was achieved by considering CP&L's annual required revenues under various scenarios. Required revenues are the funds utilities need to collect from their customers to cover operating expenses, taxes, capital, amortization, and return on investment. As an overall measure of ratepayer expenditures, required revenues are an appropriate indicator of cost impacts.

2.1 Cost Components

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

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

Make-up Generation. In the absence of the nuclear plant, the electricity generation requirements must be provided by the existing system, by purchased power, by new plant construction, or by conservation. The costs of these make-up power alternatives constitute the major penalty of early power plant retirement. To analyze them, it is necessary to specify the system responses to the loss of the facility (discussed in Section 7). Projections of nuclear plant generation (capacity factors) to determine how much generation must be replaced are an important ingredient in this analysis (discussed in Section 3).

Direct Capital Related Costs. These include recovery of capital, return on investment, and taxes related to the steam generator investment, recovery of the unamortized part of the Robinson investment, and insurance. The amount and method of recovery is to some extent a regulatory policy issue. In this investigation, capital related costs have been computed using a financial model to simulate CP&L characteristics and practices. Assumptions are discussed in Section 6.

Nuclear Fuel. This is an avoided cost (i.e., a benefit) of not running the plant. As with make-up generation, its value is dependent on assumptions on likely future plant capacity factors. Nuclear fuel cost projections are presented in Section 6.

Nuclear Operations and Maintenance. This is another avoided cost. As discussed in Section 4, there is statistical evidence for projecting escalating nuclear O&M costs related in part to aging-related equipment problems.

Radioactive Waste Storage and Disposal. In the case where the plant operates, it is necessary to store and to finally dispose of additional highly radioactive spent fuel. Analysis is given in Section 6.

Decommissioning. Expenses will be incurred in dismantling or encapsulating the radioactive facility in either case. However, the retirement dates may effect the timing of dismantlement and the level of facility irradiation and, thereby, costs. These issues are addressed in Section 6.

Capital Additions. Certain costs for major plant repairs and modifications are avoided if the plant is not operated. In Section 5, statistical estimates of these costs are developed based on actual experience with nuclear facilities.

2.2 Cost Accounting System

The complexity of these issues -- as well as the desire to have a flexible capability for developing scenarios, performing sensitivity analyses, and synthesizing results -- warranted the use of a computer-based costing model. The model is designed to simulate the required revenue impacts in both current and discounted dollars and over alternative time periods. It provides a flexible framework for testing the results over various scenarios and parameter ranges, so that the consequence of uncertainty in both technology variables (e.g., future plant performance) and policy or economic variables (e.g., fuel prices) may be adequately explored. In addition, as described earlier, several ancillary models were used in developing inputs on make-up generation, capacity factors, O&M costs, and capital additions.

2.3 Scenario Definitions

The benchmark comparison - the Baseline scenario -- is defined by the input assumptions described in Sections 3 through 7. The retirement date, should the steam generator not be replaced, is December 31, 1984, as assumed by CP&L (Ref. 5). The Baseline time period for analysis is the fifteen-year period 1984-1998. This period is selected for ease of comparison to the Company results which were computed for this period. Sensitivity results for alternative time periods -- 25 years and 10 years -- were reported in Table 1.1.

2.4 Baseline Results

The revenue impacts of retirement are given in Table 2.1. They are disaggregated for each year by cost category.* The cost streams are discounted to common 1983 present value dollars.**

The first column of Table 2.1 shows projections of CP&L's revenue requirements (i.e., ratepayer payments), assuming that the steam generator replacement takes place and Robinson continues in operation throughout the time period considered. No further extraordinary plant outages are assumed in this Robinson "in" case. It is worth underscoring here, however, that if additional

*More details on the results by category are given in subsequent sections.

**The discount rate, a measure of the time value of money, is taken at 11.75%, the Company's average cost of capital. From the ratepayer point of view, the discount rate is related to borrowing costs (or lost earnings on savings) plus whatever premium is placed on short-term cash. The figure used here, based on a conventional approach, is a reasonable proxy for such a "social" discount rate. The underlying general rate of inflation is taken at 6% per year throughout the study.

major operational problems occur, related to continuing embrittlement or other severe difficulties of the reactor vessel at Robinson, the case for the steam generator replacement deteriorates substantially. Since this possibility is not included in the Baseline analysis, the finding of modest economic benefits to retirement must be considered conservative. For example, if one assumes that the plant lifetime is limited, even with the steam generator replacement, to, say, ten additional years, the benefits of retirement jumps from $50 to $120 million (see Table 1.1).

The next eight columns in Table 2.1 are "adjustments" to the revenue requirements that are projected to result from a decision to retire the plant rather than to replace the steam generators. Detailed discussions of each of these adjustments will be found in Sections 3 through 7.

The adjustment in column (2) is for differences in capital-related costs in the two cases, primarily for amortization, return and associated taxes on the Robinson facility including the steam generator investment. A financial model is used to simulate these revenue flows. It will be noted that there is a cumulative benefit here to retirement of some $122 million, half of it associated with initial tax write-offs of sunk investment. Column (3) displays an additional benefit to retirement of some $49 million cumulatively in avoided property tax, nuclear insurance, and miscellaneous expenditures that would otherwise be required were the plant in operation.

The adjustment for the avoided costs of operations and maintenance ("Nuclear O&M") at Robinson are given in Column (4). This is a major benefit of early retirement at $397 million. Column (5), labelled "net capital additions," summarizes the projections for revenues associated with continued capital expenditures at the Robinson plant were it to remain in operation. The cumulative benefit here to retirement is estimated at $157 million.

Column (6) gives the projected cost stream for the nuclear fuel costs avoided by retiring Robinson. The positive value for 1984 is related to the lower fuel requirements associated with reduced operation during the steam generation replacement. The net benefit to early retirement is estimated at $240 million. Columns (7) and (8) give, respectively, estimates of reduced expenditures under retirement for disposing of radioactive spent fuel and for ultimately decommissioning the plant itself. These benefits amount to $108 million -- $84 million for spent fuel and $24 million for decommissioning.

The total benefit to retirement from the seven adjustment categories described above is some $1,072 million (1983 present value). The offsetting cost to early retirement is shown in Column (9), labelled "make-up generation." With Robinson not in operation, the electricity that it would have generated must be compensated for. Make-up energy could come from additional generation from existing facilities, purchases from outside the CP&L system, and from the possible construction and operation of

additional power sources. An important opportunity for both make-up energy and capacity would also come from increased efforts to promote and finance cost-effective conservation and load management initiatives. Such a conservation investment emphasis has not been included in Baseline assumptions.*

Beyond the need to make-up the energy lost from Robinson if it retires, additional expenses would be incurred to keep the generating capacity of the system sufficient to service a growing load (i.e., peak demands) with adequate reliability. Loads and resources projections, make-up energy sources and costs, and make-up capacity costs are discussed in Section 7. Column (9) summarizes the result, a $1,017 million penalty to retirement. Note that in 1984 alone there is a benefit to retirement related to the extra downtime required for the steam generation replacement.

Combining the benefits and the penalties of retirement, we arrive at the total adjustment in Column (10) and the total required revenues "without Robinson" (that is, with Robinson retired in 1985) in Column (11). The cumulative benefit of retirement is shown to be $54 million.

It will be noted that the annual cost impacts fluctuate due to a combination of first-year effects, pattern of power plant availability, and a variety of other factors. The "Revenue Impact Summary" shown in Table 2.2 gives a summary of the

*Were conservation considered the preferred policy response, the benefits of retirement would improve substantially as shown in the sensitivity test reported in Table 1.1.

adjustment stream from Table 2.1 as well as the cost impacts expressed as a percentage change in electricity rates. The cumulative percentage impact of retirement is negative throughout the period.

From Table 2.2 it will be seen that, over the long run, the economic consequences of either continuing to operate or retiring Robinson are not large on a relative basis (about 0.2% average rate savings if the plant is retired). Beyond such ratepayer impacts, a prudent decision on the fate of Robinson would need to rely on assessments of environmental and safety tradeoffs, future risks attendent on each option, and employment and other indirect impacts -- factors beyond the scope of the direct cost analysis presented here. However, given the results of this analysis, there must be an affirmative demonstration that continued operation would indeed provide sufficient "external" benefits. Absent such a showing, the plant should be retired.

TABLE 2.1

CP&L REVENUE REQUIREMENTS WITH ROBINSON NOT OPERATING
(Millions of Dollars — 1983 Present Value)

Year	Total With Robinson (1)	Capital Cost (2)	Prop. Tax Ins. Misc. (3)	Nuclear O&M (4)	Net Cap. Addition (5)	Nuclear Fuel (6)	Spent Fuel (7)	Decom. Cost (8)	Make-up Generation (9)	Total Adjust. (10)	Total Without Robinson (11)
1984	1,677	-62	- 1	0	- 2	7	2	0	- 55	-112	1,566
1985	1,657	-12	- 6	-31	- 4	-11	- 4	0	93	25	1,682
1986	1,636	- 9	- 6	-31	- 6	-17	- 4	0	99	27	1,663
1987	1,616	- 7	- 5	-31	- 7	-17	- 4	- 1	67	- 5	1,612
1988	1,597	- 5	- 5	-30	- 8	-20	- 4	- 1	68	- 5	1,592
1989	1,577	- 3	- 4	-30	-10	-21	- 5	- 1	88	16	1,593
1990	1,558	- 2	- 4	-29	-11	-18	- 5	- 1	68	- 2	1,556
1991	1,539	- 1	- 3	-29	-12	-19	- 6	- 1	53	-17	1,522
1992	1,520	- 0	- 3	-28	-12	-16	- 6	- 1	57	-10	1,510
1993	1,501	- 1	- 3	-28	-13	-20	- 7	- 2	64	- 7	1,494
1994	1,483	- 3	- 2	-27	-14	-18	- 7	- 2	64	-10	1,473
1995	1,465	- 6	- 2	-27	-14	-19	- 8	- 2	75	- 2	1,463
1996	1,447	- 5	- 2	-26	-15	-19	- 8	- 4	106	28	1,474
1997	1,429	- 4	- 2	-26	-15	-16	- 9	- 4	87	11	1,440
1998	1,411	- 4	- 2	-25	-15	-17	-10	- 4	84	9	1,420
Totals	23,112	-122	-49	-397	-157	-240	-84	-24	1,017	-54	23,057

Figures may not sum due to rounding.

TABLE 2.2

REVENUE IMPACT SUMMARY
(Millions of Dollars)

YEAR	PRESENT VALUE REVENUE WITH ROBINSON	PRESENT VALUE TOTAL ADJUST.	PRESENT VALUE REVENUE WITHOUT ROBINSON	ANNUAL PERCENT IMPACT	CUMULATIVE PERCENT IMPACT
1984	1,677	-112	1,566	- 6.6	- 6.6
1985	1,657	25	1,682	- 1.5	- 2.6
1986	1,636	27	1,663	1.6	- 1.2
1987	1,616	- 5	1,612	- 0.3	- 1.0
1988	1,597	- 5	1,592	- 0.3	- 0.8
1989	1,577	16	1,593	1.0	- 0.5
1990	1,558	- 2	1,556	- 0.1	- 0.5
1991	1,539	- 17	1,522	- 1.1	- 0.6
1992	1,520	- 10	1,510	- 0.7	- 0.6
1993	1,501	- 7	1,494	- 0.5	- 0.6
1994	1,483	- 10	1,473	- 0.7	- 0.6
1995	1,465	- 2	1,463	- 0.1	- 0.5
1996	1,447	28	1,474	1.9	- 0.4
1997	1,429	11	1,440	0.8	- 0.3
1998	1,411	9	1,420	0.6	- 0.2
TOTALS	23,112	- 54	23,057	N.A.	-0.2

Figures may not sum due to rounding.
N.A. = Not Applicable

2.5 Sensitivity Analysis

The sensitivity of results to alternative sets of assumptions has been examined in a series of additional cost comparisons. A range of values for key variables which bracket the mid-range Baseline inputs have been considered. Sensitivity scenario definitions and corresponding cost impact estimates are presented below. A summary of results was already reported in Section 1 as Table 1.1.

Baseline With 20-year Plant Life

One of the major uncertainties in the cost comparison exercise is the long-term prospects for the Robinson Unit even if the steam generators are replaced. The Baseline impact of about $50 million savings attributed to early retirement assumes that the plant is in service throughout the study time frame, 1984-1998, once the replacement occurs. However, this will understate the benefits of early retirement if this assumption proves to be too optimistic.

Due to such contingencies as a moratorium on nuclear operations, further containment vessel embrittlement problems, or the absence of a radioactive spent fuel disposal system, operations may be curtailed earlier than hoped. The implications of this possibility were tested with a sensitivity run that assumes that Robinson lasts only ten years, through 1993, even with the steam generator replacement. With this assumption, the benefits of preemptive retirement rise to $120 million.

Baseline With Conservation

If Robinson 2 is retired, there will be greater incentive for CP&L to promote and invest in additional conservation and load management programs. No such extra conservation is included in the Baseline comparison. Conservation is a means of replacing both energy and power. Without Robinson, the case for further conservation effort is stronger in two respects. First, such an effort can reduce the need for any additional power that would be required. Second, the economics of conservation investments improve since the benefits of such investments are governed by the savings in avoided energy and capacity cost which could be achieved through demand-side initiatives. In the case in which Robinson is retired, avoided costs are higher since marginal generation is from more costly sources and marginal capacity costs are greater.

In the sensitivity case, it is assumed that a heightened conservation effort leads to a phase-in of load reduction beginning in 1985 and reaching 300 MW (about half of Robinson's capacity) by the end of the study period. Incremental conservation investments are costed out at an average 2.8¢ per saved KW (1983 price) and included as a revenue requirement of retirement. The effect is to increase the Baseline estimates of retirement savings from $50 million to $160 million.

Nuclear O&M Costs

A range of future O&M costs are developed around the statistically-based Baseline projections (see Sec. 4).

Specifically, the real escalation rate is doubled in the high O&M case and eliminated altogether in the low O&M case. The impacts, under the circumstances, range from a penalty of $40 million for retirement to a benefit of $180 million.

Future Robinson 2 Investments

This refers to projections of additional capital investment that will be required over the life of the Robinson unit (excluding steam generator costs which are treated separately here). The statistical analysis employed to develop Baseline estimates is discussed in Section 5. A technique similar to that used for the O&M sensitivity runs is used here, that is, defining a range by doubling and zeroing Baseline real escalation rates. The results are a spread of retirement benefits from $20 to $90 million.

Robinson 2 Capacity Factor

Again, the Baseline case relies on statistically derived projections for plant availability (Sec. 3). In these tests, those capacity factor projections, averaging 60.3 percent over the study time frame, are increased and decreased by 5 percent in the high and low case, respectively. The corresponding retirement benefits range from zero to $120 million.

Fuel Prices

For reasons discussed in Sec. 7, Baseline coal escalation rates are assumed to be 1 percent per year real (7 percent overall) over the 1984-1998 period. In sensitivity runs, that rate was varied to 2 percent and 0 percent, respectively, in

separate runs. The corresponding retirement impacts range under these assumptions from a penalty of $10 million to a benefit of $120 million.

Load Growth

The Baseline case includes a mid-range estimate of load growth of 2.2 percent/year averaged over 1984-1998 (see Sec. 7). In these tests, a high growth case of 2.6 percent/year (CP&L's December 1983 forecast) was employed and a low growth case of 1.7 percent/year (recent Carolina Commission staff estimate) is used. The forecast assumption is important in determining the amount of additional capacity required over time. The high growth rate case would require substantial make-up power late in the study period. It is assumed that part of this is made up by conservation and load management efforts along the lines discussed above, as the case for demand-side initiatives would be particularly compelling under conditions of high load growth if Robinson were unavailable. Under these forecast ranges the ratepayer impact of retirement ranges from a benefit of $240 million to a penalty of $20 million under low and high load growth assumptions, respectively.

Period of Analysis

The Baseline study period is 15 years from 1984-1998. To explore the dependency of cumulative cost impacts, the study time frame was altered to 25 years (1984-2008) and 10 years (1984-1993). The Baseline finding of a $50 million benefit to retirement, increases to about $90 million for both the longer and the shorter time frame.

3. CAPACITY FACTORS

3.1 Introduction

The maximum output of a power plant over the course of a full year of operation is the product of the total number of hours in a year (8,760) and net full rated capacity of the unit. Thus, for a 1,000 MW plant it would be 8,760 GWH.* This output is never achieved for a number of reasons. First, power plants require outages for scheduled maintenance and equipment repair. Second, there are unscheduled (or "forced") outages in which unplanned maintenance and equipment repair occur. Finally, some power plants are dispatched intermittently to follow load and are consequently brought on-line (off-line) as system loads experience upward (downward) swings. Peaking units, for example, generate power for only a small fraction of their available hours.

Nuclear units experience forced and scheduled outages whose magnitude and character are specific to this technology. Nuclear units are rarely operated to load follow. The relatively high initial construction costs and technical characteristics of nuclear units dictate that they be operated in the baseload mode, generating electricity at the maximum number of hours that they are available, while coming off-line only when necessary.

*A GWH (gigawatt-hour) is one million kilowatt-hours or one thousand megawatt-hours.

For nuclear plants, however, there is downtime beyond the imperatives of forced and scheduled maintenance and equipment outages. Nuclear units require rather long down times for refueling, typically on a twelve to eighteen month cycle. Moreover, Nuclear Regulatory Commission mandated outages for inspection, safety, training and licensing can also temporarily remove nuclear units from service.

Capacity factors are defined as the net electrical generation divided by the maximum possible generation over the course of a year (or any other time period). In effect, the capacity factor is the fraction of time (e.g., a year) a unit is generating electricity at full rated capacity.

Nuclear power plants' capacity factors have been far below the expectations of the industry. A simple compilation of this industry-wide experience from 1973 to 1982, provided by the U.S. Department of Energy (Ref. 44, 4/83) indicates a ten-year average industry-wide capacity factor of 57 percent. This average falls far below industry expectations, which have ranged between 65 percent and 80 percent. Furthermore, there is no evidence in the DOE data of an industry-wide learning process, that is, no general improvement over time.

There has been, however, a wide variation around the industry-wide average depending on the particular plant and year considered. In order to understand the basis for this

variation, further detailed analysis has been performed here. First, outages were divided into two sets. One set consists of outages for refueling, regulatory restriction (i.e., NRC mandated), and operator training and licensing (hereafter referred to as "refueling and NRC" outages). The other set consists of all other outages, including those associated with equipment failure and maintenance (hereinafter referred to as "maintenance and repair" outages).

To explain the maintenance and repair outages, statistical procedures were employed in the present study. The result of these procedures -- multivariate regression analysis -- shows the magnitude of contributions to observed capacity factors (adjusted to exclude refueling and NRC outages) from each of several explanatory variables associated with the characteristics of the nuclear power plants in the data base. Once these magnitudes are established they can be applied to any specific nuclear plant (such as Robinson) whose characteristics are known, as one tool to predict future maintenance and repair outages. The results and methods are described below.

3.2 Findings

The results of the statistical analyses are presented in Table 3.1 below, where the regression results, modified to incorporate a four percent annual NRC outage rate, and CP&L's anticipated refueling schedule, are detailed for the years 1985

to 1998.* The results have been modified upward by incorporating an average improvement factor derived from industry-wide data on the magnitude of steam-generator-related maintenance and repair outages. In essence, it is assumed that the steam generator replacement will initially obviate the need for outages dedicated to steam generator repair. Over time this advantage is assumed to diminish as the new steam generators will themselves be subject to possible corrosion and degradation problems. Table 3.1 also indicates CP&L's assumptions concerning Robinson capacity factors, as well as the assumptions employed in the present study.

The NRC-mandated outages were analyzed separately. Year-by-year data was collected on such outages and a weighted average was developed for the years 1975 to 1981. This average outage factor, expressed as a percentage of total industry-wide reactor hours, was then included with CP&L's planned outage schedule, to derive annual capacity factor projections for the Robinson plant. While there are statistical indications of continued long-term decline in Robinson capacity factors (adjusted to exclude refueling and NRC outages) after 1990, the assumption used here for conservatism is that the adjusted capacity factor remains constant after 1990.

*For 1984, the capacity factor in the steam generator replacement scenario is assumed to be about 15 percent. In the case where Robinson is retired at year end of 1984, the plant's capacity factor in 1984 is assumed to be 52.8 percent. The assumptions are consistent with those of CP&L assumptions (Ref. 5, App. H and Interrogatory Response).

TABLE 3.1

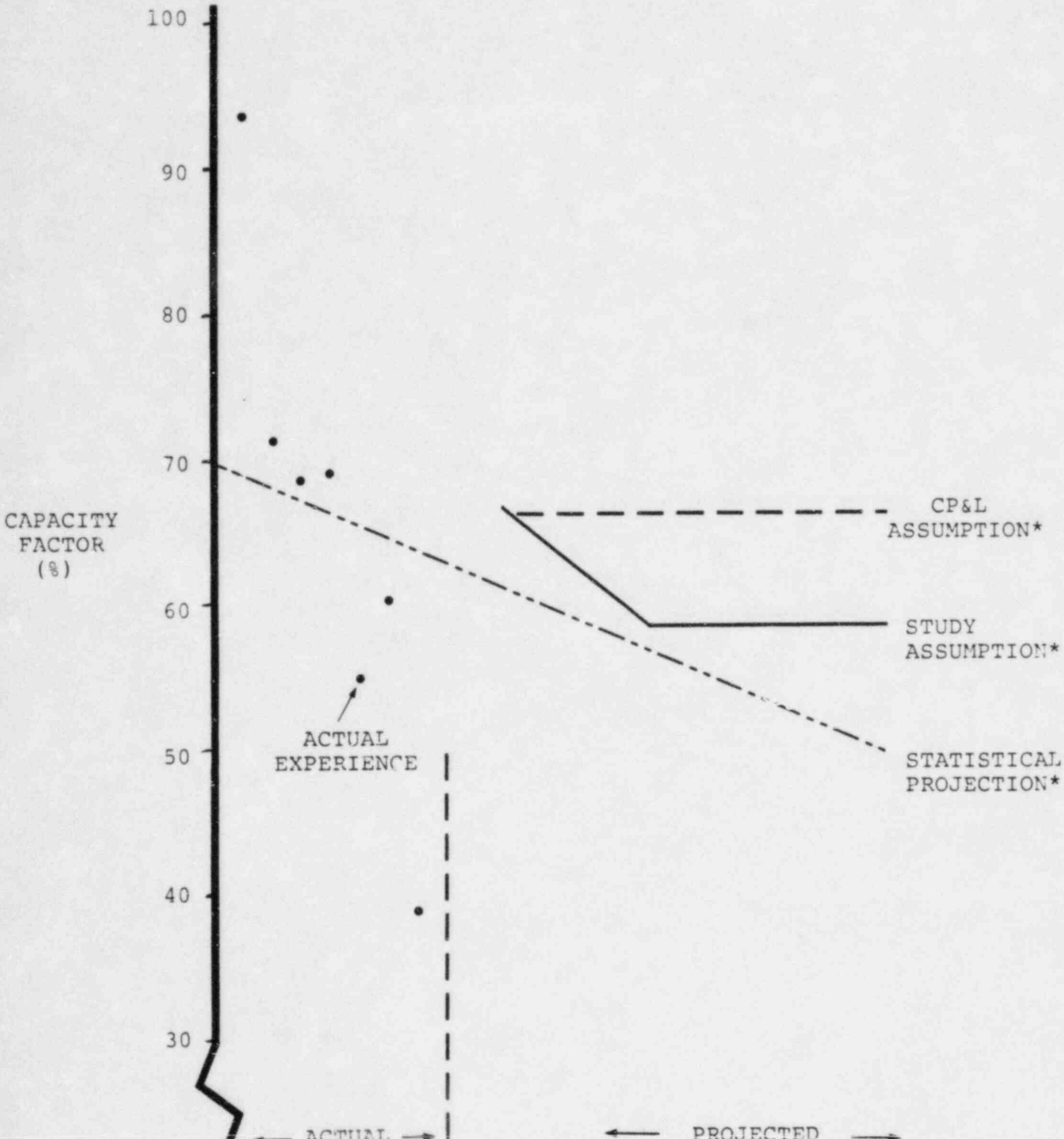
CAPACITY FACTOR PROJECTIONS FOR THE ROBINSON NUCLEAR UNIT: 1985-1998
(Percent)

Year	Regression Analysis Projected Capacity Factor	Study Assumptions	CP&L Assumptions
1985	60.1	65.1	69.0
1986	68.2	73.1	80.0
1987	51.8	54.9	62.0
1988	51.1	53.5	63.0
1989	71.5	77.1	88.0
1990	52.4	53.4	65.0
1991	51.7	53.6	66.0
1992	56.9	59.9	73.0
1993	61.2	65.6	80.0
1993	48.3	52.6	66.0
1995	48.3	53.4	66.0
1996	63.9	74.9	88.0
1997	46.7	53.4	65.0
1998	45.9	53.4	66.0

The results of the regression analysis, as well as CP&L and study assumptions, are depicted graphically in Figure 3.1. In this figure the results and assumptions are recast; for purposes of clarity, the estimates are smoothed over time by substituting an average annual refueling rate for the planned refueling schedule wherein downtimes fluctuate from year to year. Figure 3.1 also provides the actual experienced and statistically predicted capacity factors from 1975 to 1982.

FIGURE 3.1

ROBINSON CAPACITY FACTORS
HISTORICAL AND PROJECTED



*For clarity of display, projections are based on average annual values for scheduled outages (see Table 3.1 for precise yearly projections).

3.3 Statistical Analysis

The statistical analysis of nuclear plant capacity factor experience involved three areas of study:

1. Multivariate regression analysis of capacity factors (adjusted to exclude refueling and NRC-mandated outages).
2. Assessment of the magnitude of steam generator-related maintenance and repair outages.
3. Estimates of the magnitude of NRC outages.

These areas of analysis are discussed in turn in the sub-sections that follow. The application of the results of the statistical analysis to the Robinson nuclear plant is discussed in Section 3.4

Regression Analysis: Introduction

The data base used in the regression analysis consists of the electricity production and outage experience of 72 US. nuclear power plants (essentially all commercially operating units) from 1975 through 1982. The source of this data is the Nuclear Regulatory Commission (NRC) "Grey Books" (Ref. 6). The analytical technique applied is multivariate regression analysis, which explains the observations (experienced annual capacity factors) in terms of a linear combination of independent variables selected because they are believed to have a causal or associative relationship to the observations. The variables explored in the regression analysis included unit

size, reactor type, unit age, presence or absence of cooling towers, salt-water cooling or not, steam system supplier, and commercial operation date.

The age (years of operation) variable is interesting in two respects. First, it can express a maturation effect, i.e., improvement after the first few years ("shakedown" period) of operation. Second, it can express aging phenomena, i.e., deterioration of performance with age, after mature levels have been reached. In order to test for such phenomena it is necessary to use broken linear, rather than a single linear age variable. In addition, to examine whether aging effects differ with plant characteristics, i.e., reactor type, size, salt-water cooling, product terms of age times these variables have been employed.

A further discussion of the data base used for regression analysis deserves attention here. Since NRC mandated outages occur somewhat episodically or randomly over the data base period, these outage hours have been removed from the analysis. Similarly, refueling outage hours have been removed, since these too add a degree of scatter or randomness because they sometimes overlap calendar years and the cycle itself can vary rather widely. While regression could readily be performed on the raw or unadjusted capacity factors, here we have applied it to adjusted capacity factors in order to obtain a better analysis of the factors which contribute to forced and scheduled maintenance and equipment outages. The adjusted capacity factor is:

$$\text{Adj. Cap. Fac.} = \frac{\text{Net Electrical Generation}}{\text{Net Design Electrical Rating} \times (8{,}760 - \text{Refueling and NRC Outage Hours})}$$

Regression Analysis: Discussion

The independent variables selected in the multivariate regression specification for adjusted capacity factors are defined below in Table 3.2.

The results of the multivariate regression analysis are provided below in Table 3.3. The first two columns provide the form of the equation, a sum of coefficients times independent variables, with the second column designating the independent variable, defined in Table 3.2. The third column provides the value of the regression coefficient, the fourth column gives the T-statistic, and the fifth column gives the confidence level. The regression coefficient is the measure of the magnitude of a variable's contribution to the observed result (here, adjusted capacity factor). Thus, for example, the value -.090 for the BWSTM coefficient shows that on average nuclear units with a Babcock and Wilcox steam system have experienced 9.0 percent lower adjusted capacity factors than other units. The T-statistic is the measure of the significance of the variable in explaining the observed variation in adjusted capacity factors. The confidence level indicates the probability that the coefficient of the independent variable has an absolute value greater than zero.

TABLE 3.2

INDEPENDENT VARIABLES SELECTED FOR REGRESSION SPECIFICATION FOR NUCLEAR POWER PLANT ADJUSTED CAPACITY FACTORS

Variable Name	Definition
DERU	Unit net design electrical rating in megawatts
PWRU	1 if unit is PWR 0 otherwise
SALTU	1 if unit is salt-water cooled 0 otherwise
AGE	Years of commercial operation (through the end of the calendar year of the capacity factor observation)
TOWERSU	1 if unit has cooling tower 0 otherwise
AGE4	AGE-4 for Age $\leq$ 4 0 otherwise
AGE6	AGE-6 for Age $\leq$ 6 0 otherwise
AGE10	AGE-10 for Age $\leq$ 10 0 otherwise
BWSTM	Babcock and Wilcox Steam System
WESTM	Westinghouse Steam System

TABLE 3.3

REGRESSION RESULTS FOR NUCLEAR POWER PLANT ADJUSTED CAPACITY FACTORS 1975 Through 1982

Equation Coefficient		Independent Variable	Value of Coefficient	T-Statistic	Confidence Level
	A		.704	8.73	> 99.8%
+	B x	DERU	-5.39×10^{-5}	- .444	> 20.0%
+	Z x	DERU x PWRU	-2.86×10^{-4}	-3.84	> 99.8%
+	C x	PWRU	.450	5.41	> 99.8%
+	G x	SALTU	1.23	4.51	> 99.8%
+	E x	AGE	-.005	-.820	> 50.0%
+	X1 x	SALTU x DERU	-2.35×10^{-4}	-1.99	> 95.0%
+	K x	PWRU x TOWERSU	-.136	-3.81	> 99.8%
+	W x	AGE x PWRU	-.016	-3.14	> 99.0%
+	D x	AGE x DERU	1.55×10^{-5}	1.25	> 50.0%
+	L x	TOWERSU	.053	1.95	> 90.0%
+	S x	SALTU x AGE	-.102	-4.68	> 99.8%
+	F x	SALTU x PWRU	.112	1.56	> 80.0%
+	H x	SALTU x PWRU x AGE	-.022	-2.36	> 98.0%
+	L3 x	AGE6	.030	1.28	> 50.0%
+	M2 x	AGE4 x DERU	6.34×10^{-5}	2.39	> 98.0%
+	M3 x	AGE6 x DERU	-3.54×10^{-5}	- .961	> 50.0%
+	N2 x	AGE4 x SALTU	-.040	- .997	> 50.0%
+	N3 x	AGE6 x SALTU	.017	.454	> 20.0%
+	N4 x	AGE10 x SALTU	.112	3.83	> 99.8%
+	X2 x	BWSTM	-.090	-2.96	> 99.0%
+	X3 x	WESTM	-.018	-.739	> 50.0%

Number of Variables = 22
R-Squared = .296
Corrected R^2 = .265

Standard Error of Regression = .145
$F(21/470) = 9.41$
COND(X) = 90.65

Finally, summary statistics, including the corrected R-SQUARED and F-ratio which are measures of the goodness-of-fit of the entire equation, are also provided in Table 3.3.

Average Steam Generator-Related Maintenance and Repair Outages

In order to track the initial improvement in operating performance resulting from replacement of a plant's steam generators, the result of the regression equation has been modified to incorporate an improvement factor. This factor was derived from industry-wide data compiled by the NRC (Ref. 7) that indicates that steam generator-related maintenance and repairs account for 23 percent of all non-refueling outage time. It is assumed that the initial impact of steam generator replacement will be to reduce to zero the outage time dedicated to steam-generator replacement and, therefore, that the statistically predicted outage time will be reduced by the industry-wide average figure of 23 percent.

In the years that follow, it is expected that steam generator tube corrosion resulting from secondary coolant impurity deposition will lead to a gradual increase in steam generator repair and maintenance efforts.

Average Regulatory Outages

Once results are obtained for the adjusted capacity factors, refueling and NRC-related outages must be reincorporated to obtain the net result, i.e., experienced capacity factor. For the purposes of this study, CP&L's projected refueling schedule is adopted.

In contrast to the regular refueling cycles, NRC-mandated outages occur more unpredictably. They result from a perceived need by the NRC for back-fit or other safety-related modifications and activities. In order to assess the magnitude of these outages, industry-wide data for the years 1975 to 1981 was analyzed and average outage rates for PWR's, BWR's, and all reactor types were developed. The average NRC-mandated outage rates for this period are presented in Table 3.4.

TABLE 3.4

NUCLEAR POWER PLANT NRC-RELATED OUTAGE RATES: 1975 TO 1981

	Outage Rate*
PWR	.04
BWR	.01
All Reactors	.03

*Expressed as a fraction of total annual reactor-hours.

3.4 Application to Robinson

The regression equation for adjusted capacity factor, given earlier in Table 3.3, can be applied to any nuclear facility once its characteristics (i.e. values of the independent variables) are established. For the Robinson facility these characteristics are provided below in Table 3.5.

TABLE 3.5

ROBINSON PLANT CHARACTERISTICS
(Values of Independent Variables)

DERU	712 MW
PWRU	1
SALTU	0
TOWERSU	0
AGE	0.82 in 1971, incremented by 1 thereafter
AGE4	-3.18 in 1971, incremented by 1 through 1975 and 0 thereafter
AGE6	-5.18 in 1971, incremented by 1 through 1977 and 0 thereafter
AGE10	-9.18 in 1971, incremented by 1 through 1981 and 0 thereafter
WESTM	1

The results are given below in Table 3.6. The adjusted capacity factor regression predictions are based upon the assumption of a 712 MW design electrical rating. The first column of this table recasts the predicted capacity factors in terms of CP&L's 665 MW capacity assumption for Robinson. The equation predicts an adjusted capacity factor (on a 665 MW basis) of 79 percent in 1985, dropping at a rate of 1.6 percent to an adjusted capacity factor of about 64 percent in 1998.

The assumptions used for this study concerning adjusted capacity factors are presented in the second column of Table 3.6. For the present analysis, the regression results have been modified to incorporate an improvement factor in 1985

corresponding to the replacement of Robinson's steam generators (see discussion in Section 6.4). The results have been further modified to incorporate the assumption that renewed steam generator corrosion, as well as possible problems related, for example, to containment vessel embrittlement, will force Robinson's adjusted capacity factor to drop from its high point in 1985 of about 86 percent to a value of 75 percent in 1990. Because of the uncertainty in assessing the long-term impacts of steam generator performance and embrittlement, it is conservatively assumed that no further age-related deline in operating performance will take place after 1990.

The third column of Table 3.6 gives the assumptions used for the present study for Robinson's experienced capacity factor. This column simply incorporates CP&L's planning schedule for refueling outages and an average figure for NRC-mandated outages into the adjusted capacity factor assumptions in the second column.

Finally, CP&L's assumptions for Robinson capacity factors from 1985 to 1998 are given in the fourth column of Table 3.6. It can be seen that over the fourteen-year period, CP&L's estimate of capacity factor averages almost 11 percentage points higher than the capacity factor assumptions used in the present study.

TABLE 3.6

ROBINSON NUCLEAR PLANT PREDICTED CAPACITY FACTORS
(Percent)

Years	Regression Result Adjusted Capacity Factor	Study Assumptions Adjusted Capacity Factor	Study Assumptions Capacity Factor
1985	79.0	85.7	65.1
1986	77.9	83.5	73.1
1987	76.8	81.4	54.9
1988	75.7	79.2	53.5
1989	74.5	77.1	77.1
1990	73.4	74.9	53.4
1991	72.3	74.9	53.6
1992	71.2	74.9	59.9
1993	70.0	74.9	65.6
1994	68.8	74.9	52.6
1995	67.8	74.9	53.4
1996	66.6	74.9	74.9
1997	65.5	74.9	53.4
1998	64.3	74.9	53.4
Fourteen-Year Average	71.7	77.2	60.3

4. OPERATIONS AND MAINTENANCE

4.1 Introduction

The operations and maintenance (O&M) costs of nuclear generating stations together with nuclear fuel expenses comprise the electricity production costs at these facilties. These costs are passed on to electricity consumers as direct expense items in required revenues. Other costs associated with nuclear power include the capital costs of the facilities (including capital additions) which enter required revenues through their inclusion in the rate base, upon which interest or a rate of return can be earned. In addition, the costs of decommissioning and spent fuel disposal can impact required revenues insofar as funds for their implementation are collected during the operating years of the nuclear station. Discussions of capital additions, steam generator replacement, spent fuel disposal, and decommissioning costs and their required revenue impacts follow in Sections 5 and 6.

Nuclear power plant operations and maintenance costs fall into 13 broad subcategories, as reported by utilities to the Federal Energy Regulatory Commission (FERC) in annual Form 1 submissions and to the U.S. Department of Energy (Ref. 8). These are listed below in Table 4.1. Data on these O&M costs have been collected for nuclear generating stations for the years 1970 through 1980. A total of 49 nuclear stations, including virtually all commercial units that have operated in the U.S.*, are included in this data base.

*Station sites may contain more than one power plant "unit."

TABLE 4.1

NUCLEAR O&M SUBCATEGORIES

Operations	Maintenance
Supervision and Engineering Coolants and Water Steam Expenses Steam from Other Sources Steam Transferred Electric Expenses Miscellaneous Nuclear Power Expenses Rents	Supervision and Engineering Maintenance of Structures Maintenance of Reactor Plant Maintenance of Electric Plant Maintenance of Miscellaneous Nuclear Plant

Some of the salient features of nuclear power plant O&M cost experience are revealed by direct examination of industry-wide averages. In the industry as a whole, nuclear O&M costs have increased from about one-half of nuclear fuel costs in 1970 and 1971 to about twenty percent greater than nuclear fuel costs in 1979 and 1980. Thus, these costs have begun to dominate the production costs for nuclear facilities. Within the O&M costs themselves the split has remained rather stable at about 55 percent for operations and 45 percent for maintenance throughout the 1970-1980 period. Of the 13 subcategories, the two largest are miscellaneous nuclear power expenses (23.5 percent in 1980) and maintenance of miscellaneous reactor plant (20.5 percent in 1980). These two subcategories plus maintenance of miscellaneous nuclear plant have increased their share of total O&M costs from about 39 percent in 1970/71 to over 50 percent in 1979/80.

Table 4.2 shows the industry-wide annual O&M costs for nuclear stations from 1970 through 1980 on a per-kilowatt installed capacity basis, in both nominal and constant (1983) dollars. The second column, nuclear O&M costs in 1983 dollars per kilowatt, shows the growth trend in real costs during this period, thus correcting for both inflation and the increasing size of the industry. The increase was from about $12.5 per kilowatt in 1970 to about $35.9 per kilowatt in 1980. The average annual growth rate in real (i.e. above inflation) O&M costs per kilowatt for nuclear stations in the U.S. was 9.3 percent per year from 1970 through 1978 (the last full year before the TMI reactor accident) and 11.0 percent per year from 1970 through 1980.

TABLE 4.2

OPERATIONS AND MAINTENANCE COSTS FOR NUCLEAR STATIONS IN THE U.S. 1970-1980

Year	Average Industry Dollar per Kilowatt	Average Industry 1983 Dollars Per Kilowatt
1970	5.25	12.53
1971	5.02	11.40
1972	6.91	15.08
1973	6.38	13.16
1974	8.73	16.58
1975	9.94	17.27
1976	11.98	19.78
1977	13.65	21.29
1978	16.78	24.39
1979	20.93	28.04
1980	29.21	35.93
Average Annual Growth Rate (Percent)		
1970-1978	16.6	9.3
1970-1980	18.6	11.0

4.2 Findings

Linear regression techniques have been used to explain the variation in operations and maintenance costs throughout the industry in terms of independent variables expressing the characteristics of nuclear stations. The results of this analysis have been applied to the Robinson plant to predict operations and maintenance costs for the years 1984 to 1998. These costs, in millions of constant 1983 dollars, are presented in Table 4.3.* Table 4.3 also displays CP&L's assumptions.

The results of the regression analysis, as well as CP&L's assumptions, are depicted graphically in Figure 4.1. Historical O&M expenditures for the Robinson plant are also provided in Figure 4.1 for the 1971 to 1980 period, along with the stream of expenditures predicted by the regression analysis for those years. It is apparent upon examination of Figure 4.1 that the regression analysis predictions for 1971 to 1980 closely track actual experienced costs during that period.

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*For the Robinson retirement case it is assumed that expenses incurred in 1984 are equal to the value predicted by the regression analysis ($33 million 1983 dollars).

TABLE 4.3

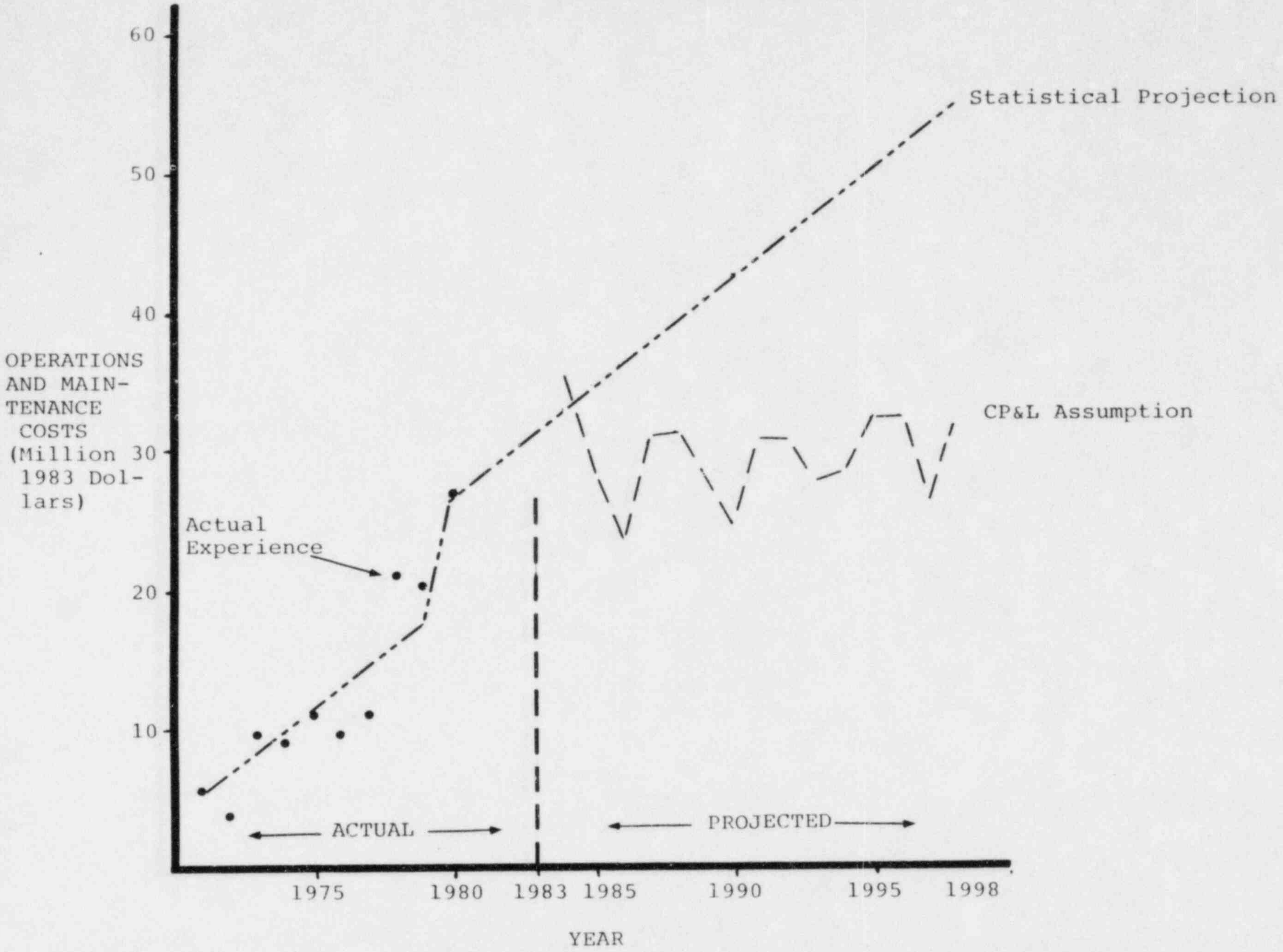
ROBINSON NUCLEAR PLANT OPERATIONS AND MAINTENANCE COSTS
(Millions of 1983 Dollars)

Year	Regression Analysis Projected Operations and Maintenance Costs	CP&L Assumptions
1984	33.0	35.6
1985	34.6	29.3
1986	36.1	24.1
1987	37.7	30.5
1988	39.2	31.4
1989	40.8	29.1
1990	42.4	24.7
1991	43.9	30.8
1992	45.5	31.2
1993	47.1	27.7
1994	48.6	28.6
1995	50.2	32.3
1996	51.8	32.6
1997	53.3	26.7
1998	54.9	32.2

FIGURE 4.1

ROBINSON OPERATIONS AND MAINTENANCE COSTS

HISTORICAL AND PROJECTED



4.3 Statistical Analysis

Nuclear generating station operations and maintenance costs have varied widely by facility and year of operation. In the present analysis, linear regression techniques have been used to explain this variation in terms of independent variables expressing the characteristics of the nuclear stations. Various models or equations were selected for analysis. These equations expressed the dependent variable (O&M costs in 1980 dollars per kilowatt) as a linear combination of several independent or explanatory variables.

Numerous independent variables were explored in various combinations with each other. These included plant size (in Megawatts) and age, chosen to test whether economies of scale and cost increases associated with aging have been occurring. Other variables which were explored for statistical significance in explaining the variation in O&M costs were plant vintage (date of initial commercial operation), geographic location, demonstration unit status, salt-water cooling, multiple unit siting, 1980 operation, reactor manufacturer, cooling towers, turbine manufacturer, utility size, and utility experience with nuclear plant operation. The last five variables were not found to have statistical significance. Definitions of the variables for which statistical significance was found are provided in Table 4.4.

The model chosen, including the values found for the coefficients and the measures of statistical significance and goodness of fit (t-statistics, R-Squared, etc.) is given in Table 4.5. All of the variables in the model show strong statistical significance.

TABLE 4.4

DEFINITIONS OF INDEPENDENT VARIABLES USED IN NUCLEAR O&M COST REGRESSION MODEL

Variable	Definition
AGESTEP	Cumulative years of commercial operation to the end of the year for which the O&M cost observation is made. For multiple unit stations, AGESTEP equals the age of the first unit until the second unit comes on-line. With multiple units in operation the variable will equal the average age of all units.
NEMASK	1 if station located in the Northeast 0 if otherwise
DERSTEP	The station's net design electrical rating (DER) in megawatts. For multiple unit stations, DERSTEP equals the first unit's capacity until the second unit commences operation. With multiple units operating the variable will equal the average (DER).
SALT	1 if station is salt-water cooled. 0 if otherwise
DEMO	1 if station was built as a demonstration project 0 if otherwise
MULTSTEP	For multiple unit stations MULTSTEP is 0 until the year the second unit begins commercial operation. With multiple units operating MULTSTEP will equal 1. 0 at all times for single unit stations.
BIRTHSTP	Date of commercial operation. BIRTHSTP includes the actual calendar on-line date through the use of fractional years. For multiple unit stations, BIRTHSTP equals the birth date of the first unit prior to commercial operation of the second unit, after which BIRTHSTP equals the average birth date if both units are operating.
TMI	1 if year of operation is 1980 0 if otherwise

TABLE 4.5

NUCLEAR STATION O&M COST REGRESSION MODEL+

Equation Coefficient		Independent Variable	Value of Co-efficient	T-Statistic	Confidence Level
A			-139.21	-8.45	> 99.8%
+ B	x	AGESTEP	3.19	7.00	> 99.8%
+ C	x	NEMASK	5.15	5.75	> 99.8%
+ G	x	DEMOX AGESTEP	3.24	4.78	> 99.8%
+ H	x	DEMO	-31.71	-3.87	> 99.8%
+ J	x	MULTSTEP	-2.98	-3.21	> 99.8%
+ K	x	BIRTHSTP	2.02	9.28	> 99.8%
+ M	x	DERSTEP X AGESTEP	-.002	-3.28	> 99.8%
+ Q	x	SALT x AGESTEP	.915	5.65	> 99.8%
+ N	x	TMI	8.59	6.25	> 99.8%

Number of Variables = 10	Standard Error of Regression = 7.16
R-Squared = .675	F(9/317) = 73.21
Corrected R^2 = .666	COND(X) = 131.98

+Dependent variable is nuclear station O&M costs in 1980 dollars per kilowatt.

Several of the variables are time related. The result for general age term (AGESTEP) indicates that real (1980 dollars) O&M costs have been increasing at over $3/KW per year for every additional year of operation of nuclear stations. The aging effect of operating salt-water cooled plants, (SALT x AGESTEP) is found to be an additional $.92/KW per year, probably the result of the corrosive impacts of salt-water in the cooling systems and steam generators of these units. Economies of scale were found to be significant. The value for the coefficient for the size times age term (DERSTEP x AGESTEP) implies that for a 1200 MW plant O&M costs would be $.40/KW lower than for a 800 MW in the first year of operation. These effects increase with age. For a 1000 MW plant the two terms together imply O&M cost increases of about $1.20/KW per year, while for a 800 MW the increases would be about $1.60/KW per year.

Two other time related variables proved significant. The variable TMI was found to have a coefficient of 8.59, implying that on average an additional $8.59/KW was experienced by nuclear stations in the year 1980 (the first full year of operation after the TMI accident). There has been a large upward shift in the level of nuclear O&M costs since 1979. This is probably due to costs associated with increased safety related requirements related to the TMI accident and greater NRC scrutiny generally. It is too early to tell whether this represents an acceleration of the trend in real cost increases or a permanent shift.

Preliminary analysis based on the inclusion of 1981 data confirm the regression results given above. The upward shift of about \$8/KW occurs in 1981 as well as 1980. It is appropriate at this time to conclude that this shift will persist.

The variable BIRTHSTP is also time related. It measures the calendar year (and fractions thereof) of initial commercial operation. The finding of an additional \$2/KW for each year later of commercial operation indicates that there are higher costs for maintaining a kilowatt of capacity which is built later. This may be a result of greater complexity and more safety features embodied in later vintage plants.

4.4 Application to Robinson

The regression equation given in Table 4.5 was applied to the Robinson facility for the years 1984 to 1998. Table 4.6 below, gives the values of the independent variables for Robinson, which were used in the regression equation. Table 4.7 gives the results in 1980 dollars/KW, nominal dollars/KW and total required revenues impact in nominal dollars.

TABLE 4.6

ROBINSON PLANT CHARACTERISTICS
(Values of Independent Variables)

AGESTEP	0.82 in 1971, incremented by 1 thereafter
NEMASK	0
DERSTEP	712 MW
SALT	0
DEMO	0
MULTSTEP	0
BIRTHSTP	71.18
TMI	1

TABLE 4.7

ROBINSON NUCLEAR PLANT OPERATIONS AND MAINTENANCE COSTS

	$/KW (1980)	$/KW (Nominal)	Total (Millions Nominal)*
1984	37.43	49.16	35.0
1985	39.20	54.58	38.9
1986	40.98	60.48	43.1
1987	42.75	66.88	47.6
1988	44.52	73.83	52.6
1989	46.30	81.38	57.9
1990	48.07	89.57	63.8
1991	49.84	98.45	70.1
1992	51.62	108.07	76.9
1993	53.39	118.49	84.4
1994	55.16	129.77	92.4
1995	56.94	141.98	101.1
1996	58.71	155.19	110.5
1997	60.48	169.47	120.7
1998	62.26	184.90	131.7

*The regression analysis prediction is based on a capacity rating for Robinson of 712 MW. The data in this column is therefore derived by multiplying the second column by 712 x 10^3.

5. CAPITAL ADDITIONS

5.1 Introduction

Capital expenditures on nuclear generating stations do not end upon completion of construction, fuel loading, and the commencement of commercial operation. Additional capital costs are incurred in the years following the in-service date. Indeed, the rather large capital additions associated with replacement of the three steam generators at the Robinson plant are a striking example of these continued expenditures. The steam generator replacement costs for Robinson are treated separately in Section 6. Independent of steam generator replacement costs, however, nuclear stations have incurred annual capital additions in the millions and sometimes tens of millions of dollars throughout the 1970s.

Capital costs for nuclear generating stations, and therefore capital additions as well, fall into three broad categories -- land, structures, and equipment -- as reported in the annual Form 1 submissions of electric utilities to the Federal Energy Regulatory Commission (FERC) and by the U.S. Department of Energy (Ref. 8). These data are reported for nuclear generating stations on a cumulative basis. Thus, the difference between cumulative station costs in two successive years is the net capital addition in the last year. It is the net result of both additions to and retirements of nuclear plant. In the present treatment only these net capital additions are examined.*

*The result of this is to somewhat under-estimate the additional required revenues which derive from capital additions. This is because the reported retirements in the net additions are in original rather than depreciated cost in the FERC Form 1 documents. Furthermore, retired plant can still influence revenue requirements through continued amortization or as expensed items after removal from the rate base.

Data on forty-nine nuclear generating station net annual capital additions for the years 1970 through 1980 have been collected from utility FERC Form 1 reports and the U.S. Department of Energy documents. Simple inspection of some industry-wide averages reveals some interesting patterns. Over this period as a whole, the mix between the net additions in the three categories has been about 30 percent for structures and 70 percent for equipment (with less than one-half percent for land). The overall net annual capital additions in the industry increased from about $2.6 million in 1970 to about $840 million in 1980, over three-hundred-fold. Table 5.1 shows the annual industry-wide expenditures in both nominal and constant (1983) dollars per kilowatt of installed capacity.

The last column of Table 5.1 industry-wide costs in 1983 dollars per kilowatt, shows the broad temporal trend when corrected for both inflation and the growing size of the nuclear power sector. These costs increased from about $3.50 per kilowatt in 1970 to about $24.70 per kilowatt in 1980. The growth rate in industry-wide nuclear station net capital additions was 17.5 percent per year above inflation from 1970 to 1978 (the last full year before the TMI reactor accident) and 15.9 percent per year above inflation from 1970 to 1980. Just as the initial real capital costs per kilowatt of nuclear power plants have increased over this period, so too have the real costs of capital additions. It is much more costly to both construct and maintain a kilowatt of nuclear capacity today than it was a decade ago.

TABLE 5.1

NET CAPITAL ADDITIONS FOR NUCLEAR STATIONS IN THE U.S.: 1970-1980

Year	Cost ($/KW)	Cost (1983 $/KW)
1970	1.46	3.49
1971	1.84	4.18
1972	3.96	8.65
1973	5.30	10.93
1974	4.74	8.99
1975	4.72	8.20
1976	6.51	10.75
1977	10.63	16.58
1978	9.24	13.43
1979	8.65	11.59
1980	20.08	24.70
Average Annual Growth Rate (Percent)		
1970-1978	25.3	17.5
1970-1980	23.9	15.9

5.2 Findings

Industry-wide variations in net capital additions have been analyzed with the use of multivariate linear regression techniques. Applying the results of this analysis to the Robinson nuclear plant yields predictions of net capital additions for the years 1984 to 1998, net of anticipated steam generator replacement costs. These predicted costs (in millions of constant 1983 dollars) are summarized in Table 5.2.* Also detailed in Table 5.2 are CP&L's assumptions concerning future net capital additions.

*The projected net capital addition costs listed in Table 5.2 assume continued operation of the Robinson plant following steam generator replacement. For the Robinson retirement case no further capital additions are assumed between 1984 and 1998.

The projections provided in Table 5.2 have been depicted graphically in Figure 5.1. Included in this figure are the actual historical expenditures incurred at the Robinson plant for the period 1972 to 1980. An examination of the historical data indicates both the episodic nature of annual net capital additions costs, as well as the general trend towards increasing costs during this period. Despite fluctuations, the experience at Robinson has been broadly consistent with the results of the regression analysis.

TABLE 5.2

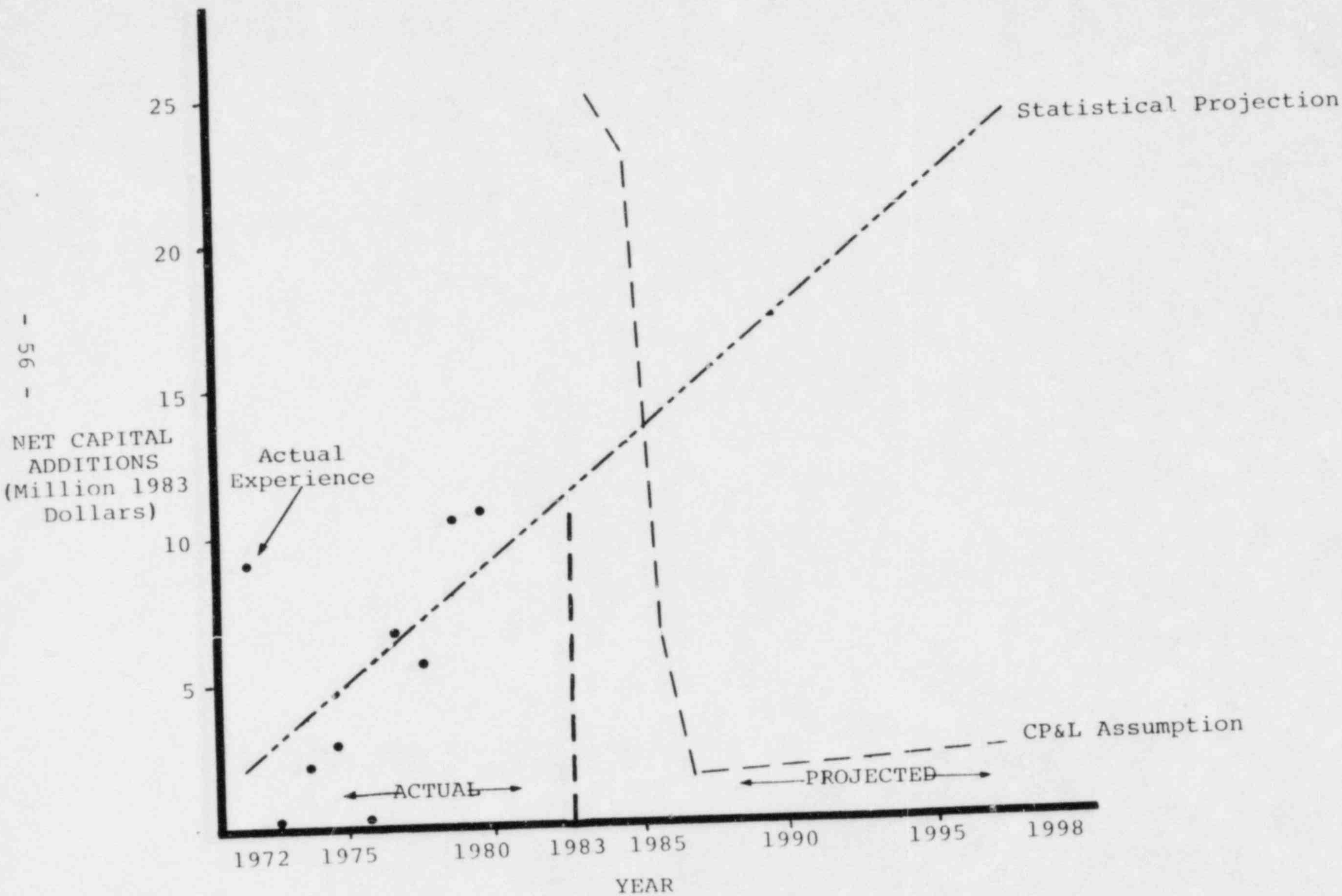
ROBINSON NUCLEAR PLANT NET CAPITAL ADDITIONS COSTS
(Million 1983 Dollars)

Year	Regression Analysis Projected Net Capital Additions Costs	CP&L Assumptions
1984	12.2	24.8*
1985	13.1	23.2
1986	13.9	6.7
1987	14.7	1.7
1988	15.5	1.8
1989	16.4	1.8
1990	17.2	1.9
1991	18.1	1.9
1992	18.9	2.0
1993	19.8	2.0
1994	20.6	2.1
1995	21.5	2.2
1996	22.3	2.2
1997	23.1	2.3
1998	24.0	2.4

*Net of steam generator replacement costs.

ROBINSON NET CAPITAL ADDITIONS COSTS

HISTORICAL AND PROJECTED



5.3 Statistical Analysis

Various models (or equations), expressing observed nuclear station net capital additions costs as a linear function of sets of explanatory variables (representing the nuclear station characteristics), were explored in regression analyses.* Most of the variables discussed and defined earlier in the sections on capacity factors and O&M costs were examined. The four that were found to have strong significance were the station's age (years of commercial operation, represented by the variable AGESTEP), the date of initial commercial operation (represented by the variable BIRTHSTP), whether multiple units are sited (represented by the variable MULTSTEP), and whether the plant is salt-water cooled (represented by the variable SALT). These variables are more precisely defined in Table 5.3 below.

Table 5.4 provides the statistical results. The rather low R-Squared is the result of very wide plant-by-plant and year-by-year variation in the historical net capital additions data base that is not explained by the equation. Strong results are obtained, however, for the independent variables, all of which were found to be significant at confidence levels above 99 percent. Thus the equation gives the average net capital additions costs of nuclear plants with different characteristics, around which there is substantial variation.

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*So as not to double count the cost impacts of steam generator replacement (discussed independently in Section 6), the net capital additions for the years of steam generator replacement at the Surry nuclear plant were excluded from the regression analysis.

TABLE 5.3

DEFINITION OF VARIABLES IN NET CAPITAL ADDITIONS COST REGRESSION EQUATION

Variable	Definition
AGESTEP	Cumulative years of commercial operation through the end of the year for which the net capital additions cost observation is made. AGESTEP equals the age of the first unit until the second unit comes on-line. With multiple units in operation the variable will equal the average age of all units.
MULTSTEP	For multiple unit stations MULTSTEP is 0 until the year the second unit begins commercial operation. With multiple units operating, MULTSTEP will equal 1. For single unit stations MULTSTEP equals 0 at all times.
BIRTHSTP	Date of commercial operation. BIRTHSTP includes the actual calendar on-line date through the use of fractional years. For multiple unit stations, BIRTHSTP equals the first unit's birth date prior to commercial operation of the second unit. With multiple units operating, BIRTHSTP equals the average birth date.
SALT	1 if station is salt-water cooled. 0 if otherwise.

TABLE 5.4

NUCLEAR STATION NET CAPITAL ADDITIONS COST REGRESSION MODEL+

Equation: Coefficient	Equation: Independent Variable	Value of Coefficient	T-Statistic	Confidence Level
A		-121.18	-3.24	> 99.8%
+ B x	AGESTEP	1.70	3.23	> 99.8%
+ J x	MULTSTEP	-7.59	-2.92	> 99.0%
+ K x	BIRTHSTP	1.72	3.51	> 99.8%
+ Q x	SALT x AGESTEP	1.59	3.76	> 99.8%

Number of Variables = 5	Standard Error of Regression = 19.46
R-Squared = .118	F(4/263) = 8.76
Corrected R^2 = .104	COND(X) = 81.22

+Dependent variable is expressed in 1980 dollars per kilowatt.

The first term, AGESTEP, shows an increase in costs of \$1.70/KW (1980 dollars) per year as the plant ages. The BIRTHSTP term shows a \$1.72/KW per year increase for each year later of commercial operation. The first temporal term is designed to capture the increased costs associated with plant aging and the need for repair and replacement of equipment. The second temporal term is designed to express and capture the quantitative effects of the nuclear plant's vintage.

Plants completed (and entering service) at a later date have generally cost more to construct (per KW of capacity) due to increased regulatory impacts on reactor safety and design. For similar reasons, it is expected that the cost of repairing and replacing equipment would be more costly per KW since both the amount and cost of this equipment per KW has increased over the years of the data base (1970-1980). Together, the AGESTEP and BIRTHSTP terms can be interpreted as expressing the effects of physical deterioration and regulatory impacts on the costs of capital additions to nuclear power plants.

Another temporal term, SALT x AGESTEP, gives an additional increase of \$1.59/KW per year for salt-water cooled plants. That is, salt-water cooled plants' net capital additions increase at \$3.29/KW per year (in 1980 dollars), as compared to the \$1.70/KW annual increase of non-salt-water cooled plants. Finally, the term MULTSTEP gives an economy of common siting of \$7.59/KW. Thus, two units at the same site have lower average costs because certain equipment, structural and land additions can be shared.

Preliminary analysis of capital additions in 1981 confirms the regression results reported above. The results now embody twelve years of data.

5.4 Application to Robinson

The regression model for net capital additions, shown in Table 5.4, can be applied to the Robinson facility once its characteristics (values for the independent variables) are specified. These are given in Table 5.5.

TABLE 5.5

ROBINSON PLANT CHARACTERISTICS
(Values of Independent Variables)

AGESTEP	0.82 in 1971, incremented by 1 thereafter
MULTSTEP	0
BIRTHSTP	71.18
SALT	0

The regression model has been calibrated to the experience at the Robinson plant for the years 1972 to 1980. An annual overall adjustment factor of 56 percent has been applied.

The modified regression equation is used to predict Robinson net capital additions costs (in 1980 dollars). These costs are converted to nominal dollars by applying annual inflation rate estimates for the 1980-1983 period and a percent rate thereafter. For each annual net capital addition, a fixed charge rate is applied for every year including and following the year the addition is made. This fixed charge rate (17.37 percent*) gives the required revenues impact of each investment.

*Based on CP&L estimates.

These results are provided in Table 5.6. The first column gives the 1980 dollar cost per KW of net capital additions predicted for the Robinson facility. The second column gives these annual investments in nominal dollars per kilowatt and the third gives them in millions of nominal dollars (column two times .712). The fourth column gives the increment to that year's required revenues due to that year's net capital addition investment (column three times the fixed charge rate of .1737). Finally, the last column gives the impact in each year of that year's and all previous years' capital additions investments on required revenues (i.e. the running sum of column four entries).

TABLE 5.6

NET CAPITAL ADDITIONS COST AND REQUIRED REVENUE IMPACTS FOR THE ROBINSON NUCLEAR PLANT

Year	Cost Per KW (1980$)	Cost Per KW (Nominal $)	Total Cost (Million Nominal $)	Annual Required Revenue Increment (Million Nominal $)	Annual Required Revenue (Million Nominal $)
1984	13.86	18.12	12.9	2.2	2.2
1985	14.81	20.65	14.7	2.5	4.8
1986	15.76	23.17	16.5	2.9	7.7
1987	16.72	26.12	18.6	3.2	10.9
1988	16.67	29.21	20.8	3.6	14.5
1989	18.63	32.72	23.3	4.0	18.6
1990	19.58	36.38	25.9	4.5	23.1
1991	20.53	40.45	28.8	5.0	28.1
1992	21.49	44.94	32.0	5.6	33.6
1993	22.44	49.72	35.4	6.1	39.8
1994	23.39	54.92	39.1	6.8	46.6
1995	24.35	60.53	43.1	7.5	54.1
1996	25.30	66.71	47.5	8.3	62.3
1997	26.25	73.46	52.3	9.1	71.4
1998	27.20	80.62	57.4	10.0	81.4
Total	--	--	468.5	81.4	499.0

6. ADDITIONAL ROBINSON RELATED COSTS

The previous three sections discussed the methods and assumptions employed in performing capacity factor, O&M, and capital additions projections. In this section, other costs related to operation of the Robinson plant are discussed. The categories of cost addressed sequentially below are: nuclear fuel, spent fuel disposal, plant decommissioning, the steam generator replacement, recovery of sunk investment, and miscellaneous items.

6.1 Nuclear Fuel

The costs of nuclear fuel can be divided into three components: the direct cost of the fuel itself, the cost of financing the nuclear fuel inventory, and the cost of disposing of the fuel after its use. The first two components are discussed in this subsection. The costs of spent fuel disposal are discussed in subsection 6.2.

The direct cost of nuclear fuel was estimated to be 3.6 mills per KWH in 1984, and was assumed to escalate thereafter at 4.43 percent per year above the general rate of inflation (itself 6 percent per year). Both the initial value and the escalation rate were based on CP&L estimates (Ref. 5, App. D). These figures exclude revenues earmarked for spent fuel disposal. Estimates of the cost of financing nuclear fuel inventories were also based upon CP&L projections, suitably diminished to reflect the lower level of generation and hence, nuclear fuel expense, assumed for future plant generation (see capacity factor analysis in Section 3.)

In Table 6.1, the revenue requirements associated with these components of nuclear fuel costs are reported for the scenario in which Robinson operates. If Robinson is retired at the end of 1984, the cost of the nuclear fuel inventory at that time will be written off. The cost of that write-off, assumed to be collected over six years and summing to $12.7 million (present value) was charged to scenarios in which Robinson is retired.

6.2 Disposal of Spent Nuclear Fuel

6.2.1 Introduction

The Nuclear Waste Policy Act ("NWPA") of 1982 (Ref. 9) provides for "the development of repositories for the disposal of high-level radioactive waste and spent nuclear fuel." Utilities which operate commercial nuclear power plants must pay a fee, currently set at 1 mill per kilowatt hour of nuclear generation, to the "Nuclear Waste Fund" established by the Act. The Department of Energy ("DOE") is given responsibility for using this fund to establish a nuclear waste disposal program, the full cost of which is to be recovered through fees paid by the electric utilities supplying the fuel for disposal. The costs to be recovered include the costs of regulation, research and development, licensing, and decommissioning, as well as the costs of actually constructing and operating the disposal facility.

TABLE 6.1

NUCLEAR FUEL COSTS IF ROBINSON OPERATES
(Current Dollars)

Year	Robinson Generation (GWH)	Direct Unit Cost (Mills/KWH)	Total Direct Cost ($ Millions)	Finance Costs ($ Millions)	Total ($ Millions)
1984	862.16	3.60	3.102	0.000*	3.102
1985	3,792.33	3.98	15.103	6.451	21.554
1986	4,258.37	4.41	18.772	10.889	29.661
1987	3.198.14	4.88	15.606	14.447	30.053
1988	3,116.59	5.40	16.835	18.715	35.550
1989	4,491,38	5.98	26.856	13.653	40.509
1990	3,110.76	6.62	20.590	17.967	38.557
1991	3,122.41	7.33	22.878	23.654	46.532
1992	3,489.41	8.11	28.301	16.150	44.451
1993	3,821.46	8.98	34.310	24.924	59.234
1994	3,064.16	9.94	30.453	31.107	61.560
1995	3,110.76	11.00	34.223	36.882	71.105
1996	4,363.22	12.18	53.136	26.934	80.070
1997	3,110.76	13.48	41.935	34.774	76.709
1998	3,110.76	14.92	46.420	40.746	87.166
TOTAL:	50,022.68	N.A.	408.519	317.293	725.812

The costs of financing nuclear fuel inventory in 1984 is unaffected by whether the plant is retired, and, consequently, is not considered in either scenario.

N.A. = Not Applicable

The NWPA offers utilities relief from responsibility (but not the cost) for the ultimate disposal of spent fuel. However, with federal permanent storage facilities not scheduled to open until 1998, many utilities, including CP&L, must face the problem of insufficient capacity of on-site reactor storage pools. At a number of nuclear sites, including Robinson 2, storage pool capacity has been expanded by "reracking" the spent fuel assemblies (i.e., storing the fuel at a higher density). Some plants, again including Robinson 2, have shipped spent fuel to the on-site storage pools of other reactors. These are, however, limited solutions to the problem of storing spent fuel until permanent storage is available.

The following subsections will discuss the costs of interim storage, the costs of disposal, and, finally, the application of these costs to Robinson.

6.2.2 Interim Storage of Spent Nuclear Fuel

Interim storage of spent fuel is necessary until permanent repositories become available. The NWPA establishes a separate fund for interim storage and authorizes the DOE to establish facilities for temporary storage. However, there are several reasons for utilities to opt to use on-site facilities for interim storage.

First, the intention of Congress in establishing the Interim Storage Program is not to transfer responsibility for interim storage from the utilities to the federal government. Rather,

the objective is to provide an option for utilities which cannot provide for interim storage on their own. Specifically, "the persons owning and operating civilian nuclear power reactors have the primary responsibility for providing interim storage..." (Ref. 9, 2229). Also, the DOE is authorized to provide interim storage capacity of only 1,900 metric tons -- a small fraction of the interim storage capacity projected to be required prior to the targeted opening of a permanent disposal facility in 1998.

Furthermore, governmentally provided interim storage is not likely to represent a cost savings relative to on-site utility operated interim storage. The full cost of federal storage is to be recovered from the utilities utilizing the service, while the storage methods under consideration are the same for the governmental or direct utility options. The cost to the utility is likely to be comparable, with the economics of centralized federally operated option benefitting from possible economies of scale while being burdened with additional transportation costs.

The costs of on-site utility operated interim storage facilities were estimated in a recent report prepared for the DOE (Ref. 10). Cost estimates, stated in 1981 dollars, range from a low of about $120/KgU for cask storage to $410/KgU for vault storage.*

*The cost estimates presented here are for interim storage options involving "unconsolidated" spent fuel. Costs for "consolidated" (more closely packed) options may be slightly lower, but more uncertain technologically and less likely to achieve licensing approval (Ref. 10, p. 2).

Many technical and regulatory uncertainties exist regarding interim storage of spent fuel. It is not yet clear which of the options will ultimately be favored, or whether the current cost estimates will prove to be accurate. At the present time, a figure of $200/KgU (1983 constant $) can be considered to be a reasonable mid-range estimate for planning purposes. This is comparable to current high case estimates for silo or drywell storage and is well below the current estimates for vault storage.

This cost can be compared to the fee which DOE expects to charge for federal interim storage. The DOE fee estimates, shown in Table 6.2, vary widely depending on the mode of storage chosen and the amount of spent fuel to be stored at the interim storage facility. The estimate here, of $200/KgU for storage at the reactor, falls within the range of currently projected costs for federal interim storage which are expressed in terms of total costs per KgU deposited. Additionally, costs would be incurred for transporting the spent fuel from the plant to the federal facility.

There may be some possibility of providing interim storage at the on-site storage pools of other nuclear units. Shipments of spent fuel from Robinson to the storage pools at CP&L's Brunswick nuclear station began in 1977. Utilizing a portion of the existing storage capacity at Brunswick has allowed the continued operation of Robinson which is currently forecast to have adequate on-site pool capacity until 1987 (Ref. 19). Transshipment of fuel to Brunswick is no longer a reasonable option, however, as the storage pools of the Brunswick units themselves are expected to be filled soon after.

Assuming Harris Unit #1 is not cancelled or substantially delayed, trans-shipments from Robinson to the Harris spent fuel storage pool may be possible. But in addition to the question of the timely completion of Harris, the usefulness of the storage pool at Harris is likely to be limited given the extent of CP&L's interim storage problem (three units scheduled to lose full core reserve between 1987 and 1990). The cost of transporting spent fuel from Robinson to Harris would be on the order of $20/KgU in 1983 dollars (based upon Ref. 11). At present, all plans for spent fuel interim storage must be considered uncertain.

TABLE 6.2

ESTIMATE OF THE TOTAL UNIT COST FOR FEDERAL INTERIM STORAGE SERVICES AT VARIOUS CAPACITY LEVELS FOR EACH OF THE ALTERNATIVE MODES OF STORAGE*

Capacity of FIS Facility (MTU)	Total FIS Fees (1983 $/KgU)					
	At Site Without Existing Transfer Facilities			At Site With Existing Transfer Facilities		
	Storage Cask	Drywell	Silo	Storage Cask	Drywell	Silo
50	$1,041	$1,145	$1,082	$ 594	$ 782	$ 718
100	598	632	613	368	450	429
300	280	280	277	206	219	216
800	180	168	176	151	144	151
1500	150	139	144	134	124	129
1900	142	130	136	130	118	124

*Source: DOE (Ref. 11)

6.2.3 Permanent Disposal of Spent Nuclear Fuel

Interim storage, whether at reactor site or FIS facility, is a temporary measure to allow nuclear reactors to continue operating until a permanent storage (or "disposal") facility is ready to receive spent fuel for burial in a geologic repository.

DOE's current estimate of the total cost of permanently storing approximately 140,000 metric tons (1 Metric ton = 1000 kg) of spent fuel is between $20 and $30 billion in 1982 dollars (Refs. 12 and 17). Assuming a cost in the middle of this range and full utilization of the storage capacity, the price per unit of spent fuel stored is $179/kgU in 1982 dollars. This is, in some sense, the basis for the 1 mill/KWH fee established by Congress.

It should be noted that the DOE figures cited above do not account for inflation. The system of cost collection involves a review of the cost estimate by DOE each year, at which time an increase or decrease can be recommended. It appears that the intention is to account for cost increases due to inflation (and other factors) through these yearly revisions. Thus, even if the current DOE total cost estimate for disposal in 1982 dollars proves to be accurate, increases in the 1 mill per KWH fee corresponding to the general inflation rate, can be expected. This is recognized in CP&L's cost figures which put the fee at 1.1 mills per KWH in 1984.

Other estimates have put the cost for disposal of spent fuel well above the $179/KgU price. Some of these are listed in Table 6.3. The first listing in the table is a cost estimate from a study done for the California Energy Commission (Ref. 13). This study employs a price of $250/KgU (1979) in most of the analysis, but in sensitivity calculations a cost of $2500/KgU (1979) is used. The study states that the second price estimate, higher than the first price by a factor of 10, is "equally likely," citing "problems of technological optimism" for the lower figure. Specifically, reference is made to pre-construction estimates

of the construction cost of nuclear power plants, which were low by a factor of about 3 and the original estimate of the cost of the Alaskan oil pipeline which proved to be low by a factor of 10.

Also listed in Table 6.3 is a price estimate based upon a study by MHB Technical Associates (Ref. 14), in which the tasks of disposing of spent fuel were allocated to 18 categories, and a cost estimated separately for each. The MHB study included costs for interim storage which we excluded from the figure listed here. The cost estimate in the table attributed to National Economic Research Associates, Inc. (NERA) is from Lewis Perl's testimony before the Pennsylvania Public Utility Commission regarding the Limerick Nuclear Station (Ref. 15). A study by the General Accounting Office (Ref. 16) estimates the cost for disposal of spent fuel from the Zion plant to be $339/kgU (1981$) "based on Department of Energy estimates."

At the present time, it appears that the costs of disposal can reasonably be expected to fall between $300 and $400 per KgU (1983 $). As was the case for interim storage costs, current estimates of permanent disposal costs are, of course, necessarily uncertain. If previous cost escalation patterns are a guide, the ultimate costs could greatly exceed the high end of this range. Another indication that the initial fee of 1 mill/KWH may prove ultimately to be insufficient is that at least one utility (Commonwealth Edison) had, prior to the NWPA, arranged for funds to be collected for spent fuel disposal at a rate of 2 mills/KWH (Ref. 18).

In this study it was assumed that payment for nuclear fuel disposal begins in 1984 near the figure of 1 mill/KWH prescribed by the NWPA. For the following reasons, however, future revisions to the fee are likely to outpace the general inflation rate.

TABLE 6.3

COST ESTIMATES FOR DISPOSAL OF SPENT NUCLEAR FUEL[1]

	1983 $/kgU	
CEC/Duane Chapman[2]	336-3360	(250-2500 in 1979 $/kgU)
GAO[3]	381	(339 in 1981 $/kgU)
NERA/Lewis Perl[4]	333	(248 in 1979 $/kgU)
MHB[5]	321	(220 in 1978 $/kgU)
DOE Current Estimate[6]	190	(179 in 1982 $/KgU)

Notes:

1. Note that these cost estimates do not include the cost of interim storage.
2. Source: Ref. 13, pg. 73.
3. Source: Ref. 16, pg. 11.
4. Source: Ref. 15, Table 12.
5. Based upon Table 5-3 of Ref. 14. The costs associated with away from reactor (interim) storage were subtracted from the MHB estimates.
6. Based on Refs. 12 and 17. The price listed here is derived by dividing the mid-range cost estimate for the entire waste disposal program ($25 billion) by the total storage capacity to be constructed (140,000 MTU).

First, as discussed above, the initial fee is based on cost assumptions at the low end of the range of the available estimates. Apparently this is due at least in part to a desire by Congress to keep the technical aspects of the Act as simple and understandable as possible. That is, 1 mill/KWH was chosen as an initial expedient and is not intended to be an accurate estimate of the final cost.

Second, the nuclear industry has a track record of underestimating the costs of large projects, often by factors of 3 or more.

Third, preliminary cost estimates for projects involving a great deal of technological uncertainty (such as the disposal of spent nuclear fuel) are optimistic as a general rule.

Fourth, the current DOE estimates ignore not only inflation, but real price increases as well. Generally, costs of construction escalate more rapidly than the general inflation rate. Even quite small annual increases in real cost will result in large increases in the cost of a facility to be constructed in the late 1990s.

Given that cost increases are likely as a Federally operated disposal site materializes, there is also the problem of subsidization of disposal costs for previously burned fuel. That is, according to the current plan the approximately 9300 metric tons of nuclear fuel burned prior to April 1983 will be charged a one-time fee which is "equivalent" to 1 mill per KWH. While the plan provides for revaluation of the fee for fuel burned after

April 1983 to provide for increases in DOE's cost estimate for the entire waste disposal program, no provision is made for previously burned fuel to share in future cost increases. Thus, as cost increases materialize, the fee for fuel burned in the future will be adjusted to reflect the disposal cost increases for all fuel, including fuel which has already been burned. This subsidization of the disposal cost of previously burned fuel will result in the magnification of any future cost increases.

6.2.4 Robinson Spent Fuel Interim Storage and Disposal Costs

As discussed in the preceding sections, the cost of interim storage for Robinson's spent fuel can be expected to fall between $20 and $200 per KgU, while permanent disposal costs can be expected in the range of $300 to $400 per KgU. Considering these cost ranges and the high degree of uncertainty, a total price of $500/KgU (in 1983$) is a reasonable estimate for disposal spent fuel from Robinson.

At this price, the total disposal cost for the spent fuel discharged between 1984 and 1998 will be about $145 million (1983$). This assumption has been incorporated into the analysis of required revenues in the following manner. A fee of 1.1 mill per KWH was charged to fuel burned in 1984. This is the fee assumed by CP&L based upon DOE's proposed fee of 1.0 mills per KWH escsalated for one year to 1984. In 1985 the fee

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*Based on Ref. 19.

is assumed to be simply the 1984 fee escalated with the general inflation rate (6 percent). In the following years, costs are assumed to escalate such that the full incremental cost of $145 million (in constant 1983 dollars), incurred if Robinson is not active, is recovered by 1998. The resulting flow of projected costs is presented in Table 6.4.

The negative impact in 1984 results because for that year Robinson is assumed to operate more in the retirement case than in the case of continued operation.

TABLE 6.4

ROBINSON SPENT FUEL DISPOSAL COSTS
(Millions of Dollars)

Year	Required Revenue Impacts (Current Dollars)	Required Revenue Impacts (1983 Dollars)
1984	-2.4	-2.2
1985	4.3	3.8
1986	5.2	4.4
1987	6.3	5.0
1988	7.7	5.7
1989	9.3	6.6
1990	11.3	7.5
1991	13.6	8.6
1992	16.5	9.8
1993	20.0	11.2
1994	24.2	12.8
1995	29.3	14.6
1996	35.5	16.6
1997	43.0	19.0
1998	52.1	21.7
Total	276.0	145.0

6.3 Decommissioning

6.3.1 Introduction

In the past, it was thought that permanent entombment of retired commercial nuclear reactors would be a viable decommissioning option. However, it is no longer considered to be a reasonable option due to the problems associated with maintaining security for the centuries required for radiation to decay to acceptable levels. Hence, it is expected that at some point all existing nuclear units will be dismantled and disposed of. That is, the radioactive structures will be cut into pieces which can be put into containers and transported to a site for permanent underground storage.

Dismantlement can take place soon after plant retirement or it can be deferred for a number of years. Immediate dismantlement has the advantage of returning the site to unrestricted use at an earlier date. Delayed dismantlement can decrease worker exposure to radiation, and hence the cost of dismantlement, but has the added cost of maintaining security at the site during the interim period. When the costs of security are considered, immediate dismantlement is generally thought to be the least expensive option, even in present value terms (Ref. 20, p. 3).

6.3.2 Cost Estimates for Dismantlement

Nuclear reactor dismantling experience is limited to very small military or research reactors and one 22 MW demonstration plant. Cost estimates for modern commercial nuclear power plants are therefore extremely speculative.

The 22 MW Elk River reactor, which was dismantled between June 1972 and November 1974, serves as the basis for some recent decommissioning cost estimates. It is, however, hardly comparable to a modern nuclear plant. Elk River operated commercially for only four years, generating approximately 420 GWH over its lifetime (Ref. 21, p. 53). This can be contrasted to the more than 100,000 GWH expected to be generated during the operating lifetime of a typical commercial nuclear power plant. The buildup of radionuclides at a plant such as Robinson will be much greater than that faced by the dismantlers of Elk River. Higher levels of radiation, along with other problems associated with dismantling a large reactor, would lead to relatively higher costs:

> "When dismantling larger reactors, workers would have to be protected with more effective -- and isolating -- shielding; the isolation will require both remote operation and monitoring of the cutting torches. In addition, the thicker, heavier fragments from commercial reactors will be more expensive to handle: additional manipulators will be needed, and current to the plasma torch would have to be higher to cut through the thicker metal. A particularly cumbersome problem would arise if the nuclear facility is a great distance away from a convenient nuclear waste disposal site." (Ref. 22)

On the other hand, large scale dismantling projects would tend to enjoy certain economies of scale as have been experienced in the construction phase of nuclear power plants.

The radioactive waste from Elk River was shipped from Minnesota to a burial site in Illinois. This distance is much shorter than can be expected on average for future

decommissionings, though the current shortage (indeed non-existence) of sites for the disposal of large quantities of radioactive waste makes detailed estimates of shipping distance and cost impossible.

Dismantling the Elk River plant cost $6.15 million (Ref. 23). Simply scaling this cost by MW size, in 1982 dollars, results in cost for dismantling a 1000 MW power plant of about $600 million. Further, if the decommissioning costs for a large reactor scaled from the Elk River costs according to MW years of operation, then the cost would be much higher. But such scaling is too simplistic.

Some cost estimates for immediate dismantlement are presented in Table 6.5. These give some indication of the range of the estimates and also show a trend within the utility industry toward higher estimates over time. The first engineering analysis of the decommissioning cost of a large nuclear power plant was published in 1976 by The Atomic Industrial Forum's National Environmental Studies Project (AIF/NESP, Ref. 24). The cost at that time was estimated at $26.9 million (in 1975 dollars) for immediate dismantlement of a 1,160 MW pressurized water reactor (PWR).

An engineering study done for the NRC in 1978 by Battelle Pacific Northwest Laboratory (Ref. 20) estimated a higher cost, $42 million (in 1978 dollars), for immediate dismantlement of a reference 1,175 MW PWR.

TABLE 6.5

COST ESTIMATES FOR DECOMMISSIONING BY IMMEDIATE DISMANTLEMENT

Estimator	Year Original Estimate Published	Type of Plant	Capacity of Unit (MW)	Original Estimate (in Millions of $)	Estimate[8] Converted to Millions of 1983 $
AIF/NESP[1]	1976	PWR	1160	26.9 (1975$)	47
Battelle:[2]	1978	PWR	1175	42.1 (1978$)	61
LaGuardia for RG&E3	1979	PWR	470	37 (1979$)	50
AIF/NESP Survey[4]	1981	PWR	Avg.	54.5 (1980$)	66
LaGuardia for RG&E[5]	1982	PWR	470	120 (1982$)	127
Weinstein for PP&L[6]	1983	BWR	1050	123 (1983$)	123
CEC[7]	1980	PWR	1000	269 (1990$)	162

Notes:

1. Source: Ref. 24
2. Source: Ref. 25.
3. Source: Ref. 27, p. 8.
4. Source: Ref. 20. Cost estimate listed is an average of a number of industry estimates performed during or prior to 1981.
5. Source: Ref. 27, p. 6.
6. Source: Ref. 28
7. Source: Ref. 21, p. 55.
8. Conversion to 1983 dollars is based upon the implicit price deflators for the gross national product listed in the Economic Report of the President.

A survey of decommissioning cost estimates was made in 1981 by Stone & Webster Engineering Corp. for the AIF/NESP (Ref. 20). In this survey, various industry estimates of decommissioning costs were presented and compared. The Battelle estimate noted above was included in the survey. However, most of the cost estimates were made by utilities, generally based upon the 1976 AIF/NESP study. The average of the available industry cost estimates for immediate dismantlement of PWRs was found to be $54.5 million (in 1980 dollars).

Thomas LaGuardia's 1979 estimate of $37 million (in 1979 dollars) for the decommissioning cost of Rochester Gas and Electric's Ginna nuclear unit is typical of utility estimates at that time. It is, like many of the others, based upon the 1976 AIF/NESP study. Recently, LaGuardia estimated the decommissioning cost of the Ginna unit to be $120 million (in 1982 dollars). This represents an annual escalation rate of 48 percent over the three-year period for the estimated costs.

LaGuardia points to several specific categories of cost as the major forces driving the escalation of his cost estimate for decommissioning:

> National average labor rates have increased approximately 21% since 1979. Shipping costs have increased about 50% per mile since 1979, reflecting the economic impact of the fuel cost increases. Furthermore, the current estimate assumes shipments are made to Hanford, WA (2600 miles) as compared to a 500 mile trip in the NUREG and AIF/NESP studies. Burial costs have increased by 350% since 1979, which accounts for a major portion of the current $120 million Ginna estimate compared to prior estimates (Ref. 27, p. 8).

Albert Weinstein recently estimated the cost of decommissioning PP&L's Susquehanna Unit #1 to be $123 million (in

1983 dollars). This is another indication of the trend toward higher decommissioning cost estimates.

Estimates from outside of the industry have been predicting much higher costs for a number of years. Particularly notable is a report prepared for the California Energy Commission in 1980 in which it was concluded that because of the "apparent systematic understatement of engineering cost estimates of complex technological systems" the then current estimates of decommissioning costs were "inadequate for planning purposes" (Ref. 21, p. 56). The report went on to estimate a cost of $162 million (in 1983 dollars) to decommission a 1000 MW nuclear unit. The basis for this estimate is the assumption that the decommissioning cost will be 10 percent of the construction cost, or specifically, that the decommissioning cost in constant on-line year dollars will be ten percent of the construction cost in current dollars, excluding AFUDC.

Another analyst has estimated that decommissioning costs will be as much as 24 percent of the cost of construction (Ref. 26). This figure is based upon the relationship between construction cost and decommissioning cost for the Elk River reactor and the Sodium Reactor experiment.

All of the quantitative estimates in the decommissioning literature must of course be considered highly speculative.

6.3.3 Robinson Decommissioning Cost

CP&L's most recent estimate for Robinson decommissioning is $44.8 million (in 1979 dollars) for dismantlement after a 30 year delay (Ref. 29, p. 5). This was prepared by Thomas LaGuardia in

1979. While immediate dismantlement is expected to be somewhat less expensive at an estimated $34.7 million (in 1979 dollars), CP&L has adopted decommissioning with a 30-year delay before dismantlement as the preferable option (Ref. 30, p.3).

As discussed above, any estimate of decommissioning cost made in 1979 must be updated for the dramatic increases in cost estimates which have occurred between that time and the present. LaGuardia's cost estimate for RG&E's Ginna unit increased by a factor of 3.2 between 1979 and 1982. This factor was applied to LaGuardia's 1979 estimate for Robinson to yield a decommissioning cost estimate of $143 million in 1982 dollars, or about $150 million in 1983 dollars. This can be considered a "current" industry estimate for Robinson.

There are reasons to expect the cost to be much higher. First, the nuclear industry has a track record of estimating the costs of nuclear projects optimistically. If the comparison of initial industry estimates of nuclear power plant construction costs can be taken as a guide, then it will not be surprising if preliminary engineering estimates of decommissioning cost prove too low by factors of 4 or more.

Second, "overnight" engineering estimates in general are often low. As projects materialize, costs which were not anticipated are realized and costs which were anticipated often turn out to be far greater than originally expected, resulting in "adjustments" to the original estimates. This is particularly true for new technologies such as decommissioning.

Third, as prices for labor and materials increase, escalation of the costs of construction in general have tended to outpace inflation. For example, between 1972 and 1982 the GNP price deflator increased at an annual rate of 7.6 percent while the price deflator for fixed investment in nonresidential structures increased at an annual rate of 10.3 percent. Continuation of this trend until the time of dismantlement would have a tremendous impact on costs.

Fourth, waste disposal costs represent a large portion of the total cost of dismantlement. The cost of radioactive waste disposal is highly uncertain and subject to rapid cost escalation such as that experienced over the past few years. There are no obvious reasons to expect waste disposal costs to escalate at more reasonable rates in the future, particularly with the existing shortage of disposal facilities aggrevated by the need to store the tremendous quantities of waste associated with decommissioning.

And finally, there are the impacts of regulation. Much of the industry's inaccuracy in construction estimates was due to the changing regulatory environment as safety standards were upgraded, and thereby engineering and construction requirements and costs were increased. Similar regulatory changes are likely in the decommissioning area as well. This is especially so since it is an area that has not yet received as much attention at the Nuclear Regulatory Commission as other areas of nuclear regulation.

For these reasons, current cost projections such as the $150 million estimate for decommissioning Robinson at the end of its planned lifetime must be considered optimistic.

6.3.4 Cost Savings Due to Early Retirement

Decommissioning costs are largely a function of the amount of radiation present at the time of plant shutdown. The longer a nuclear reactor operates, the more highly radioactive it becomes, and correspondingly, the more decommissioning will cost. However, the degree to which early retirement will affect decommissioning cost is difficult to determine.

A recent study of decommissioning cost states that "the costs to cut, remove, ship, and bury the reactor vessel and internals are dependent upon the segment curie (measure of radiation) content and weight..." (Ref. 31). Thus, for reactors that are operated for less than their design lifetime, there is a corresponding reduction in total curies, and a potential for reduction in disposal cost for segments that are curie limited. Millions of curies of radiation will be present at the shutdown of a plant such as Robinson. To put this in perspective, the existing burial sites have limits of about 60 thousand curies per shipment (Ref. 32).

The longer lived radionuclides such as ^{63}Ni, ^{59}Ni, ^{14}C, and ^{94}Nb, which contribute significantly to the difficulty (and cost) of long term disposal, build up in the reactor in proportion to the cumulative operation time. Thus, the inventory of these radionuclides will more than double if Robinson is allowed to operate through the end of its expected useful life.

Cobalt-60 is the primary isotope of concern in terms of dose rates to workers during decommissioning processes. This radionuclide has a shorter half-life (about 5 years) and therefore builds up more rapidly during the early years of a reactor's operation, the quantity leveling off after approximately 20 effective full power years of operation. If allowed to operate to the end of its expected life, Robinson will have about 30 percent more ^{60}Co present at the time of shutdown than would be present at a shutdown in 1984.

Roughly two-thirds of decommissioning costs are directly related to the removal of radioactive structures and equipment, or about \$100 million of the \$150 million decommissioning cost estimate. Of this, about 25 percent, or \$25 million, is avoidable by shutting down the unit at the end of 1984, based on the variation in radioactivity as discussed above. Key factors influencing ultimate decommissioning costs are dependent on radiation levels. These include shipping and disposal of radioactive material and costs associated with more difficulty in meeting occupational health and safety requirements. Lower radiation levels, and thereby lower costs, are attributed to early retirement.

There is also a cost savings in the case of Robinson's early retirement in that the need to ship and dispose of a second set of steam generators is avoided. At current prices, the estimated cost of shipping and burial will be on the order of \$1 million. Such additional savings are not included in this analysis.

6.3.5 Decommissioning Cost Collection

The cost of decommissioning in the case in which Robinson continues operating is estimated to be $25 million (in 1983 dollars) more than the cost of decommissioning Robinson were it retired at the end of 1984. At the 6 percent annual inflation rate assumed in this study, the incremental cost becomes $60 million in 1998, the year by which Robinson's decommissioning costs are to be collected.

Thus, an incremental total of $60 million (in 1998 dollars) is assumed to be collected over the fifteen year period 1984-98 and put into a decommissioning fund ("sinking fund"). It was assumed that the incremental cost of decommissioning was re-estimated every three years, with each revision more nearly approximating the estimated ultimate cost differential of $60 million in the year 1998. For the first three years, (1984-1986) no extra funds were collected.

It was assumed that the fund would be used to support the Company's rate base, prior to decommissioning, and therefore would be credited with interest at the Company's average rate of return, 11.757 percent. Income taxes were charged both on the annual contribution and on a portion of the interest credit.*

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*The need to pay income tax on a portion of interest can be seen as follows. Prior to decommissioning, the decommissioning fund is a source of capital which earns a cash return and which offsets Company issues of both debt and equity. To the extent that equity is offset, no additional tax is incurred since both the fund balance and equity returns are taxable. When bonds are offset, however, tax deductible bond interest costs are replaced by the non-deductible fund interest. Here, additional income taxes are incurred.

In Table 6.6, the status of the fund and the annual rate impacts are shown. On the left of the table, increases in the fund from rate payer contributions and interest accruals are shown. On the right, we show the annual impact on required revenues, disaggregated into the direct contribution and tax effects.

TABLE 6.6

ROBINSON DECOMMISSIONING COSTS
(Millions of Dollars)

	DECOMMISSIONING FUND				ANNUAL REQURED REVENUE IMPACT		
Year	Previous Balance	Annual Contrib.	Annual Interest	New Balance	Annual Contrib.	Income Tax	Total
1984	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1985	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1986	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1987	0.0	0.5	0.0	0.5	0.5	0.5	1.0
1988	0.5	0.5	0.1	1.1	0.5	0.5	1.0
1989	1.1	0.5	0.1	1.7	0.5	1.6	1.1
1990	1.7	1.4	0.2	3.3	1.4	1.5	2.9
1991	3.3	1.5	0.4	5.2	1.5	1.6	3.1
1992	5.2	1.6	0.6	7.4	1.6	1.8	3.4
1993	7.3	3.3	0.9	11.6	3.3	3.6	6.9
1994	11.6	3.5	1.4	16.5	3.5	3.9	7.5
1995	16.5	3.7	1.9	22.2	3.7	4.4	8.1
1996	22.2	8.2	2.6	32.9	8.2	8.9	17.1
1997	32.9	8.7	3.9	45.5	8.7	9.9	18.6
1998	45.5	9.2	5.3	60.0	9.2	11.0	20.2
TOTALS		42.6	17.4		42.6	48.1	90.7

Interest Rate: 12.757%
Inflation Rate: 6.000%

N.A. = Not Applicable

6.4 Steam Generator Replacement Costs

CP&L is planning to repair the three Westinghouse steam generators at its Robinson nuclear plant by replacing the lower assembly and refurbishing components of the upper assembly of each steam generator. This method of repair has been chosen over several other options because of its technical feasibility and perceived cost-effectiveness. The alternatives include: 1) entirely replacing the steam generators, 2) retubing the steam generators, or 3) sleeving the steam generators.

The first alternative to the current repair plan -- replacing the steam generator as a whole -- was rejected due to several engineering constraints. These included insufficient space to maneuver the steam generators within the containment structure, as well as the necessity for breaching the containment dome in order to remove the generators.

Retubing and sleeving of the existing steam generators were rejected as repair options because it was assumed that these repairs would be short-lived and would, therefore, necessitate further repair efforts in the near future. CP&L assumes that the degradation problems they are currently experiencing require implementation of a wide range of design modifictions which could not be incorporated in a retubing or resleeving program.

The current repair program involves several modifications in the design of the new steam generators, including the use of thermally treated Inconel 600 tubing, full depth expansion of tubes in the tubesheets, and redesign of the tube sheet and

support plates. In addition, CP&L is planning to switch from phosphate chemistry control to all-volatile-treatment in the secondary system.

Substantial expenditures for the steam generator repair have already been made. However, the overall level of expenditures and the treatment of those expenditures for ratemaking purposes are dependent on whether the steam generator replacement is completed.

In the case of continued operations at Robinson, the steam generator replacement project is assumed to be completed, at a total investment of some $105,673,000 (Ref. 33, p. 49). This investment would be recovered through rates. A utility financial model was employed to simulate the flow of required revenues associated with this investment. The results are shown in Table 6.7. The annual revenue requirements include recovery of the initial investment (based on a twenty-five year life), return on the investment*, income taxes, and deferred income taxes.

In the case where Robinson is assumed to be retired, the steam generator replacement is not performed but recognition must be made of the $66,854,000 in steam generator costs which CP&L will have committed itself to by the end of 1983 (Ref. 33, p. 49). In a recent CP&L rate case, the North Carolina Utilities Commission determined that the Company should be allowed to

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*A rate of return weighted over the projected capital structure of 11.757 percent was employed (Ref. 5, p. 5).

TABLE 6.7

CAPITAL-RELATED COSTS OF STEAM GENERATOR REPLACEMENT

YEARS ---	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
ANNUAL BOOK DEPR.	4.225	4.225	4.225	4.225	4.225	4.225	4.225	4.225	4.225	4.225	4.225	4.225	4.225	4.225	4.225
NET VALUE (BOOK DEPR.)	105.630	101.405	97.180	92.954	88.729	84.504	80.279	76.054	71.828	67.603	63.378	59.153	54.928	50.702	46.477
ANNUAL TAX DEPR.	7.730	13.527	11.574	9.662	9.662	9.662	8.696	8.696	8.696	8.696	0.000	0.000	0.000	0.000	0.000
NET VALUE (TAX DEPR.)	96.620	88.890	75.364	63.769	54.107	44.445	34.783	26.087	17.392	8.696	-0.000	-0.000	-0.000	-0.000	-0.000
S.L. DEPR. FOR NORM. TAX	3.865	3.865	3.865	3.865	3.865	3.865	3.865	3.865	3.865	3.865	3.865	3.865	3.865	3.865	3.865
OTHER COSTS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
REVENUE TAX	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TAX CREDIT ANN. AMORT.	0.387	0.387	0.387	0.387	0.387	0.387	0.387	0.387	0.387	0.387	0.387	0.387	0.387	0.387	0.387
TAX CREDIT RESERVE	9.663	9.276	8.890	8.503	8.117	7.730	7.344	6.757	6.571	6.184	5.798	5.411	5.025	4.638	4.252
DEFFERED TAXES	1.903	4.758	3.806	2.855	2.855	2.855	2.379	2.379	2.379	2.379	-1.903	-1.903	-1.903	-1.903	-1.903
AFDC-DEBT TAX AMORT.	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DEFFERED TAX RESERVE	9.663	11.180	15.551	18.970	21.438	23.906	26.374	28.366	30.359	32.351	34.343	32.054	29.764	27.475	25.185
RATE BASE	93.096	85.927	77.807	70.638	63.944	57.251	50.796	44.578	38.361	32.144	28.067	26.131	24.196	22.260	20.324
RETURN TO EQUITY	5.483	5.061	4.583	4.161	3.766	3.372	2.992	2.626	2.259	1.893	1.653	1.539	1.425	1.311	1.197
RETURN TO PREFERRED	1.043	0.962	0.871	0.791	0.716	0.641	0.569	0.499	0.430	0.360	0.314	0.293	0.271	0.249	0.228
RETURN TO BONDS	4.419	4.079	3.694	3.353	3.035	2.718	2.411	2.116	1.821	1.526	1.332	1.240	1.149	1.057	0.965
TAXABLE INCOME	8.940	2.153	2.964	3.906	2.982	2.058	2.133	1.274	0.415	-0.443	7.689	7.422	7.155	6.887	6.626
INCOME TAX	4.402	1.060	1.460	1.924	1.468	1.013	1.050	0.627	0.204	-0.218	3.786	3.655	3.523	3.391	3.260
REQUIRED REVENUES	21.089	19.759	18.252	16.922	15.680	14.438	13.240	12.086	10.932	9.778	9.022	8.663	8.303	7.944	7.585
P.V. FACTOR TO 1983	0.895	0.801	0.716	0.641	0.574	0.513	0.459	0.411	0.368	0.329	0.294	0.263	0.236	0.211	0.189
P.V. OF REQ. REVENUES	18.871	15.820	13.076	10.848	8.994	7.410	6.081	4.967	4.020	3.217	2.656	2.282	1.957	1.676	1.432

recover an investment in abandoned plant over ten years but should not be allowed to earn a return on that investment (Ref. 34, pp. 66-67). This approach was applied to the currently committed investment in the new steam generator, again using the financial model. Included are income tax implications of write-off of the steam generator investment. It may be deducted from taxable income, reducing income taxes in the year in which the deduction is taken.

The difference between the required revenue streams assuming steam-generation completion as reflected in Table 6.7, on the one hand, and a write-off of the sunk costs, on the other hand, is the net benefit credited to the retirement scenario. The cumulative savings over the 1984-1998 period is computed to be about $83 million (1983 present value). This is reflected under the column labelled "capital cost" in Table 2.1.

6.5 Recovery of Sunk Investments

There are additional consequences for capital-related required revenues, beyond those for the steam generator replacement discussed above, that are likely to be experienced in the event Robinson is retired. These relate to the unamortized capital investment in Robinson 2 itself.

CP&L has invested over $125 million in the Robinson nuclear plant, excluding the costs of steam generator replacement. Over time, this investment has been depreciated so that net investment was $84 mllion at the end of 1982 (Ref. 35, pp. 67-68). If

Robinson continues to operate, CP&L rate payers will continue to be charged for depreciation, return, and the associated income taxes on this investment. If the plant is no longer operating, the ratemaking treatment of this investment is somewhat less certain.

In the Robinson operating case, depreciation, return, and the income taxes associated with the sunk investment were included as a component of revenue requirements and projected using the financial simulation model. For the retirement case, the treatment embodied in the recent North Carolina decision cited above (ten year amortization with no return) was employed beginning in 1985, and the associated revenue impact was included in revenue requirements.* The net benefit to retirement is computed to be $38 million (1983 present value).

6.6 Miscellaneous Costs of Robinson

In addition to the various costs related to the operation of Robinson discussed above, several more minor items were also considered. These are grouped under the column "Prop. Tax, Ins., Misc." in Table 2.1. Included are nuclear liability insurance, property insurance, property taxes, and general and administrative costs.

In each case, the estimates of these costs were developed from CP&L projections. Nuclear liability insurance estimates

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*The analysis does not attempt to reflect the likelihood that the sunk investments could be written off for income tax purposes more quickly if the plant is retired . This retirement case underestimates the benefit to the retirement case since earlier tax deductions imply savings in present value terms.

were employed directly*. For the other items, estimates of the ratio of these costs to plant investment were employed to develop revenue requirement impacts.

In particular, property tax was estimated to be 0.629 percent of gross investment while property insurance and general and administrative costs were estimated at 0.323 and 2.327 percent, respectively (Ref. 33, p. 49).

*In December 1983, the NRC recommended to Congress that the $570 million limit on utility liability for damages related to a nuclear accident be removed. This controversial limitation, dating to the Price-Anderson Act of the late 1950s, was designed to encourage the growth of the nuclear power industry. Its removal would increase the insurance-related costs of nuclear operation above the historically-based estimates employed here.

7. SUPPLY PLANNING WITHOUT ROBINSON

In earlier sections, the operations and cost projections associated with continued service at Robinson have been analyzed. As already discussed in Section 2, the key cost penalty of early retirement, results from the need to supply the energy that Robinson would have provided, and additional generating capacity to ensure adequate service reliability. This section summarizes the supply planning picture in the CP&L service area, the implications of a Robinson retirement, and the assumptions employed in estimating make-up power expenses.

7.1 Loads and Resources

Currently, almost all of CP&L's generation is from coal- and nuclear-fired plants. In 1982, coal plants provided about 73 percent of CP&L's energy requirements, while nuclear provided about 22 percent. Of the remainder, hydro electric generation and interchange purchases were the most important sources. Less than one-tenth of one percent of the energy requirement was supplied from the Company's gas turbine plants.

Installed capacity is more evenly divided among coal, nuclear, and gas turbines. Including Mayo 1 which began commercial operation in March, 1983, coal-fired plants account for about 60 percent of installed capacity, while nuclear plants represent about 24 percent and gas turbines account for some 14 percent.

Current CP&L plans call for two new generating plants by 1991.* The Company is constructing a 900 MW nuclear unit, Harris 1, which will be operational in 1986. In addition, a 720 MW coal-fired plant, Mayo 2, is due in-service in 1991. In order to identify the power planning implications of retirement, Baseline case capacity requirements for the period 1984 to 1998 were analyzed assuming that the Robinson steam generators were replaced and the plant operates throughout the study period.** Similarly, capacity requirements were computed assuming that the plant was retired at the beginning of 1985.

7.1.1 Load Forecast

The first step in developing a supply plan is to estimate the long-term growth in the demand for electricity in the area. In order to establish a plausible range, forecasts of peak load were reviewed.

Two recent load forecasts are available, one performed by the Company*** and the second by the Public Staff of the North Carolina Utilities Commission (Ref. 37). CP&L forecasts that peak load will increase at an average annual rate of about 2.8 percent from 1984 to 1998. The Public Staff report forecasts that peak load will grow at an average annual rate of about 1.7 percent over the same period. The two forecasts are shown

*CP&L announced in December 1983, that it was cancelling Harris 2, a second 900 MW nuclear unit, and advancing the in-service date of Mayo 2 by one year.

**Recall that a separate cost comparison explored the implications of Robinson not lasting this long even with the steam generator repair (see Table 1.1).

***The CP&L forecast (Ref. 36) was updated in December 1983 (private communication with CP&L personnel). The updated figures are used throughout this study.

graphically in Figure 7.1. The deviation between them is traced largely to differing assumptions on the future market penetration of demand moderating technologies at the end-use, e.g., more efficient appliances and motors, tighter buildings, better energy "housekeeping," and load management initiatives.

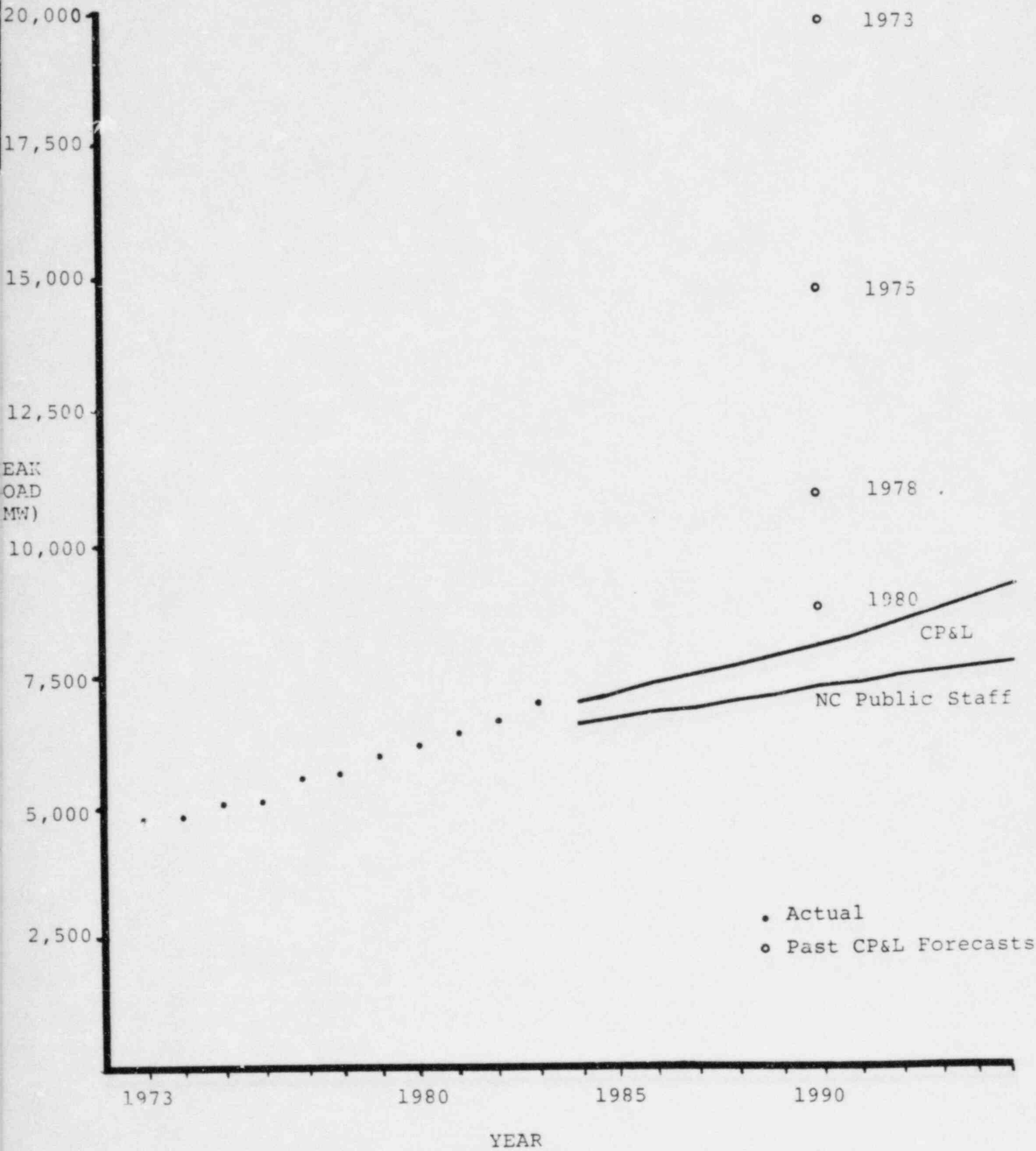
The first energy crisis of 1973 ushered in some striking shifts in the patterns of electricity consumption. Prompted by the combined effects of higher prices, regulatory and policy initiatives, the growing saturation of certain end-uses, a levelling in demographic growth trends, and heightened conservation awareness, the rapid post-war growth in demand dropped precipitously throughout the nation. Over time, utilities and planners have grown to appreciate the irreversible character of this transition and began factoring these effects into their long-term system planning perspective.

The result has been a near universal drop in long-range load forecasts over the last ten years. CP&L is no exception, as illustrated in Figure 7.1 where its forecast of peak demand for the year 1990 is shown to decline over the past ten years. The CP&L forecast of the 1990 peak was almost 29,000 MW, dropping to 8,200 MW in the latest revision.

An independent load forecast was beyond the scope of this investigation. The forecasts employed in the Baseline cost comparison is mid-range between those of CP&L and the North Carolina Public Staff. Review of the CP&L forecast suggests that

FIGURE 7.1

LOAD FORECASTS FOR THE CP&L SERVICE AREA



the process of downward revision may not be complete. In particular, the forecasting methods are insufficiently detailed to adequately incorporate continuing evolution toward more efficient equipment and structures at the point of consumption. A more disaggregated "end-use/engineering" emphasis in model construction and data development would lead to higher confidence and, in all likelihood, more modest forecasts.

On the other hand, the Public Staff forecast which incorporates substantially higher levels of conservation and load management, does not provide uncontroversial, sharply argued justification for the particular set of assumptions. In light of the current absence of a consensual state-of-the-art forecast, the mid-range forecast is adopted as the most reasonable choice at this time.

7.1.2 Generating Capacity Requirements

The next step is to determine the amount of capacity which will be necessary to reliably service the forecast demand. Like all electric utilities, CP&L must maintain capacity reserves over and above the level of peak demand. This reserve serves as insurance against equipment breakdown and other outages. In general, most utilities try to maintain a reserve margin (the percentage by which capacity exceeds peak demand) of fifteen to twenty percent. CP&L's planning criteria is to maintain a twenty percent reserve margin.

A convenient form for considering the adequacy of reserves is the loads and resources table. This table shows the forecast peak load and the generating resources available over a period of

years. In Table 7.1, the loads and resources for CP&L during the study period are shown. The loads are mid-range between the CP&L and staff forecasts, as discussed above. The resources shown include the two new plants currently under construction as well as a small amount of purchased power which CP&L expects to receive regardless of the status of Robinson. The Robinson plant is assumed to be removed as of 1985.

The table indicates under "Additional Resources Required", the capacity required above the current plan if Robinson were retired. In two near-term years (1985 and 1990) CP&L will likely have modest capacity shortfalls. Thereafter, capacity shortages are unlikely to be a problem until the mid 1990s.

There are substantial quantities of power available for purchase in the region. The Southeastern Regional Electric Reliability Council (SERC) currently has resources which are about 45 percent in excess of peak demand, about 40,000 MW. In the near term, likely sources are the Southern, TVA, and South Carolina Electric and Gas System (Ref. 5, App. F). It is likely that regional capacity will be available well into the 1990s. A recent summary of the situation in the SERC area projected that capacity will be in excess of that required to meet projected demands (plus a 20 percent reserve margin) by some 10 percent, or about 10,000 MW, into the early 1990s (Ref. 38, pp. 9 and 25).

This projection is based on planned resource additions and a compendium of utility-supplied load forecasts, averaging about 3.4 percent growth per year. The pattern of continuing downward adjustments described earlier for CP&L applies to the other SERC

numbers as well. It is likely that demand projections will drop further with time. For example, if load growth is taken at a 2 percent average annual rate*, computed overcapacity in the SERC area is huge, over 25,000 MW in 1991 under current resource plans. Similar conditions pertain in neighboring regions which could offer further sources of power.

However, neither new plant construction nor external purchases may ultimately prove to be the optimal replacement power chosen. Toward the end of the century, when the most additional capacity will be required, a number of alternatives to conventional coal plants may be available. Among the alternatives are advanced conservation technologies, wind generated power, prefabricated modular units (fuel cells, batteries, integrated gasification-combined cycle coal units, pressurized fluidized bed combustion), and solar power. These non-conventional approaches to planning are at various stages in the research, development, and demonstration process.

*This level of load growth is similar to that found by independent load forecasts of area utilities (e.g., Refs. 37 and 39).

TABLE 7.1

LOADS AND RESOURCES

Year	Peak Load (MW)	Resources Required Under Current Plan (MW)	Capacity in Excess of Required Reserves (MW)	Additional Resources Required Without Robinson 2 (MW)	Resources Without Robinson 2 (MW)	Reserve Margin (%)
1984	6,758	8,800	690	0	8,800	30
1985	6,919	8,800	498	167	8,302	20
1986	7,066	9,700	1,221	0	9,035	28
1987	7,187	9,700	1,076	0	9,035	26
1988	7,312	9,700	926	0	9,035	24
1989	7,460	9,700	749	0	9,035	21
1990	7,648	9,700	523	142	9,177	20
1991	7,791	10,420	1,071	0	9,755	25
1992	7,965	10,420	863	0	9,755	23
1993	8,135	10,420	659	6	9,761	20
1994	8,299	10,420	461	204	9,958	20
1995	8,481	10,420	243	422	10,177	20
1996	8,686	10,423	0	665	10,423	20
1997	8,896	10,675	0	665	10,674	20
1998	9,115	10,938	0	665	10,938	20

7.2 Sources of Replacement Energy

There remains the issue of how the available generating plants will be utilized to serve customers' energy requirements. The objective of power plant dispatching is to fulfill these requirements from the available generating plants at the lowest cost. The principles of economic plant loading indicate that the plants with low running costs, particularly nuclear plants, be used first. These plants are followed in the loading order by generating plants with increasingly greater running costs. Costs are minimized when plants are dispatched (subject to their availability) in this order on an hour-by-hour basis until the current customer requirements are met.

Over the past several years, a number of computer models have been developed which simulate this process of hour-by-hour dispatch to meet customers' requirements. CP&L employed one such model (PROMOD) to determine what plants would replace the Robinson plant if it is retired (Ref. 5, p. 4). Their effort consisted of running the model twice, once assuming that the steam generators were replaced and once assuming that the Robinson plant was retired. By comparing these two runs, one can estimate which plants would replace the lost generation at Robinson.

The runs indicate that about ninety percent of the Robinson generation would be replaced by the Company's own coal-fired generation. The remainder was divided between increased purchases from other utilities and increased use of CP&L's own

gas turbine plants. Each of these sources is significantly more expensive than coal-fired generation.

For the purposes of this study, these dispatch runs were relied upon to determine the source of replacement energy. Several adjustments were made, however. The most important stems from the adoption of a lower load forecast. Based on its relatively large projected growth in future demand, CP&L assumed that coal plants which are not explicitly identified in its current plan would be constructed beginning in 1994. Because such plants would not be required under the lower forecast adopted here, the percentage of replacement power from coal was reduced in the later years of the study. The sources of make-up generation over the study time frame are presented in Table 7.2.

TABLE 7.2

SOURCES OF REPLACEMENT ENERGY
(GWH)

Year	Coal	Gas Turbine	Purchases	Total
1984	-1,957	-102	-155	-2,214
1985	3,352	110	330	3,792
1986	3,739	221	298	4,258
1987	2,930	102	166	3,198
1988	2,743	215	159	3,117
1989	4,038	180	274	4,491
1990	2,812	87	211	3,111
1991	2,894	72	156	3,122
1992	3,235	80	174	3,489
1993	3,420	138	264	3,821
1994	2,666	92	307	3,064
1995	2,706	31	373	3,111
1996	3,796	44	523	4,363
1997	2,706	31	373	3,111
1998	2,706	31	373	3,111
Total	41,787	1,332	3,828	46,947

7.3 The Costs of Replacement Power and Energy

Once replacement capacity requirements and the sources which supply the replacement energy have been established, the next step is to develop estimates of the associated costs. These costs can be conveniently broken into three groups: the cost of replacement capacity in the two years it will be required through 1990, the costs of replacement capacity in the last years of the study, and the costs of each of the various sources of replacement energy.

As described in subsection 7.1, three categories of make-up power sources are available to replace that portion of Robinson power needed to meet the reliability criterion. These are the construction of a new facility, purchases from neighboring utility systems, and nonconventional sources.* As we have seen, abundant purchased power sources are available in the region, a condition that will in all likelihood persist well into the 1990s. Cost projections based on this option (or new construction if that is necessary), as presented in Table 7.3, are used to estimate make-up capacity charges. They are taken to increase from current levels based on the embedded costs of existing facilities to the projected costs of new coal plants with scrubbers in the 1990s.

*A fourth, the most cost-effective, is additional effort to promote efficiency and load management at the end-use. This option would have top priority under the real-world Robinson retirement scenario. For conservatism, it has not been included in Baseline results.

Because uncertainties concerning availability, engineering, and cost remain at this time for the non-conventional generating technologies, these alternatives have not been included in this analysis. Should the remaining uncertainties concerning these alternatives to coal be resolved favorably over the period before make-up capacity is required, then the costs of substitute power may well be less than calculated here.

TABLE 7.3

CAPACITY CHARGE ASSUMPTIONS

Year	\$/KW/MONTH
1985	8.00
1986	8.50
1987	9.00
1988	10.00
1989	20.00
1990	30.00
1991	33.00
1992	36.00
1993	39.00
1994	42.00
1995	46.00
1996	50.00
1997	55.00
1998	60.00

Source: Ref. 5, App. F

The third cost category is the cost of replacement energy. Here, 1984 average fuel costs for coal and gas turbine generation of 22.3 and 87.2 mills/KWH, respectively, were developed based on the dispatch runs. In addition, carrying costs for the additional fuel inventories required when Robinson is not in operation were included. Costs for purchased energy were similarly developed, based on CP&L estimates.

Turning to the cost of replacement energy in future years, it is useful to review the costs of energy production, particularly the cost of coal, in recent years. In the years following the OPEC embargo in 1973, there was a dramatic rise in the price of coal as well as other fuels. Rising oil prices led to a number of government and private initiatives to expand coal use in the U.S. The subsequent upturn in demand resulted in an increase in new mine contracts, many of which tied coal price escalation to the cost escalation of various elements of the mining process (labor, equipment, freight, etc.). These new contracts, combined with a shift toward the use of more expensive low-sulfur coal during this period, generated rapid increases in the average contract price of coal. The magnitude of this rise is apparent in Table 7.4, which presents the average cost of coal to utilities from 1973 to 1983 as compiled by the DOE.

As shown in the table, the 1973-1983 period can be conveniently divided into three sub-periods. Between 1973 and 1974, the price of coal increased dramatically, at a real rate (net of inflation) of sixty percent. From 1974 to 1978, the price of coal continued to increase, though less rapidly, at about five points above inflation. Since 1978, the price has been more stable, rising at an average annual real rate of one percent.

During the past few years, the worldwide glut of oil and consequent drop in oil price has slowed the rapid growth in demand for coal. With supply overtaking demand, the trend in new

contracts is toward existing mine supply and away from the escalation indices attached to new mine contracts. Furthermore, utilities are re-negotiating existing contractual obligations in order to moderate or remove these cost escalation clauses. The end result has been a down-turn in the growth rate of average contract coal prices. From 1980 to 1981 the real growth rate in average coal prices was 3.6 percent. From 1981 to 1982 this dropped to 1.5 percent, and from 1982 to mid-year 1983 coal prices actually declined by 2.4 percent.

TABLE 7.4

AVERAGE COST OF COAL DELIVERED TO STEAM-ELECTRIC UTILITY PLANTS (¢/MILLION BTU)

Year	Current Dollars	1983 Constant Dollars
1973	40.5	81.8
1974	71.0	131.9
1975	81.4	138.4
1976	84.8	137.1
1977	94.7	144.6
1978	111.6	158.8
1979	122.4	160.6
1980	135.1	162.7
1981	153.2	168.5
1982	164.7	171.0
1983*	166.9	166.9

*Data is for the first seven months.

Source: Ref. 40, p. 92.

There is a growing consensus today that this turn-around will continue through the next decade. For example, at a recent fuel supply seminar sponsored by the Electric Power Research Institute (EPRI) the price of coal was projected to remain constant in real terms through 1990 (Ref. 41). Similarly, in a recent long-term energy analysis, state planners in New York assumed a coal price forecast of zero percent real escalation (Ref. 42). At the same time, there are recent indications that world oil prices are soon likely to undergo further substantial real price decreases, with inevitable cross-over effects of controlling coal demand and coal prices (Ref. 43). Given these outlooks, fuel escalation rate assumptions of from zero to two percent real are suggested. An assumption of a one percent price escalation rate (seven percent nominal) was adopted for the Baseline case.

Summary estimates of the make-up energy and power costs likely to be incurred if Robinson is retired in 1985 are presented in Table 7.5. The negative figures in 1984 reflect the extra plant down-time required for the steam generator repair. The total cost of retirement, suitably discounted to present value dollars, was reported under the column "make-up generation" in Table 2.1. At $1017 million (1983 present value), the price of replacement power and energy for Robinson 2 would indeed be substantial. However, as discussed in Section 2, the costs of running the facility are likely to more than offset this cost penalty of retirement; that is, the benefits of retirement are projected to exceed the expense of substitute power.

TABLE 7.5

COST OF ENERGY AND CAPACITY TO REPLACE ROBINSON
(Millions of Nominal Dollars)

Year	Capacity Cost	Energy Cost*			Total
		Coal	Gas Turbine	Purchases	
1984	0	-45	-9	-8	-62
1985	8	82	10	16	116
1986	0	98	22	18	138
1987	0	82	11	11	104
1988	0	82	25	11	118
1989	0	129	22	20	172
1990	26	97	12	14	148
1991	0	106	10	13	130
1992	0	127	12	16	155
1993	1	144	22	25	193
1994	51	120	16	28	216
1995	116	131	6	33	286
1996	200	196	9	46	451
1997	219	150	7	36	412
1998	239	160	7	38	445
Total	861	1,660	183	318	3,023

*Working capital calculated as 2.3 percent of fuel costs.

8. COMPARISON TO CP&L FINDINGS

The analysis presented in the preceding sections indicates that ratepayers are likely to benefit from retiring the Robinson 2 nuclear facility in 1985, as opposed to replacing the plant's steam generators in 1984 with continued operation thereafter. The cumulative benefits would not be large, about $50 million (1983 present value) in the mid-range Baseline comparison. Recast in a more familiar form, this benefit amounts to an average reduction in rates of 0.1 percent over the next fifteen years. Sensitivity tests designed to encompass uncertainty in key parameters, showed that the range of rate impacts lies perhaps a half percentage point on either side of the Baseline result.

In short, it has been found that the ratepayer impact of retiring Robinson is likely to be favorable or, at worst, cause tiny rate increases. This contrasts with CP&L's basic finding (Ref. 5) that, rather than a $50 million benefit to retirement, there would be a penalty of about $350 million.

While CP&L's result represents a rather small impact (about one percent on rates), it is nevertheless of interest to identify the reasons for the difference between the two cost comparisons. Through backup materials supplied by CP&L and informal clarifying discussion with responsible personnel, it has been possible to identify the main points of difference between CP&L's results and those presented here.

How then does one get from CP&L's $350 million cost penalty of retirement to the Baseline result of a $50 million benefit? The steps are laid out in Table 8.1 in the form of adjustments by the major categories of disagreement. These will be discussed in turn below. It will be argued that CP&L's study judgements are unjustifiably optimistic about future Robinson operations, reliability and costs. The Baseline comparison better balances the range of conceivable outcomes, and is recommended as the more suitable result for planning purposes at this time.

The adjustment estimates were developed by changing CP&L's assumptions to those in the Baseline case performed in the sequence shown in Table 8.1. Each adjustment entry is thereby the incremental effect beyond the cumulative effects of those preceding it.

The first entry refers to the value used in discounting future costs and moving to common (1983) dollars. The CP&L study uses a discount rate of 9.4 percent based on the Company's projected overall rate of return, net of tax. This figure is too low. As discussed earlier, the discount rate is a measure of the time value of money to the impacted actors. Long-range planning requires the adoption of an appropriate "social" discount rate. If Company return is used as the proxy for this rate, then the pre-tax figure is the proper measure for society-as-a-whole (investors and taxpayers). This is a common approach.

If the ratepayers are considered the appropriate group in this case, the discount rate could be related to borrowing interest rates or lost earnings. However, it is well known that

individual implicit discount rates are much higher than this, often well over 20 percent, reflecting a premium on more certain, near-term savings (e.g., see Ref. 44). At the least, CP&L's full projected rate of return, about 11.8 percent, should be used. It is in the Baseline comparison.

The bulk of the difference, some $380 million, between the impact of ESRG Baseline and CP&L assumptions lies in the second category of adjustments listed in Table 8.1 labelled "Robinson Operations Costs." The major issues have already been discussed with respect to capacity factors, O&M, and additional capital expenditures at Robinson 2, in Sections 3, 4 and 5, respectively. In each case, the current study relied on detailed explanatory models in attempting to establish the important determinants of these variables and the likely trends in their future behavior at Robinson. CP&L's estimates appear to be based on in-house judgements. If systematic mathematical models and data analyses were employed they have not been publicly documented or alluded to. These estimates are far too optimistic, as illustrated graphically in Figures 3.1, 4.1, and 5.1, which contrast the CP&L projections with those derived from the statistically analyzed trends based on actual experience.

Two other Robinson 2 operations costs that CP&L has likely underestimated are also indicated in Table 8.1. First, spent fuel costs in the Baseline scenario reflect both an allowance for interim storage expenses until a final depository is available

and likely escalation of cost estimates for ultimate disposal (see Sec. 6.2). CP&L's do not include these costs, accounting for $50 million of the overall variation. Second, incremental decommissioning costs related to additional component irradiation, estimated at $10 million, have been charged, perhaps conservatively, to continued Robinson operation under Baseline assumptions (see Sec. 6.3). CP&L has not considered this phenomenon.

The third adjustment category in Table 8.1 refers to the different methods and assumptions used in estimating costs associated with the additional energy and capacity required if Robinson were retired in 1985. Here, CP&L underestimated the costs of substitute power by about $60 million. The breakdowns by three subcategories are shown in the table. First, the Baseline comparison uses a somewhat lower electricity demand forecast than CP&L, reflecting a mid-range of current estimates as discussed in Section 7.1. Employing the lower forecast would decrease CP&L estimates of retirement cost impacts by $60 million. Second, the CP&L study does not appear to assign capacity charges to the additional power needed in the 1990s in the absence of Robinson 2. This translates into an additional $180 million charge to retiring Robinson. The Baseline case incorporates this cost penalty to retirement. The third subcomponent under "Make-up Generation Costs" refers to a variety of effects leading to different results for make-up fuel costs. These include variations in fuel price escalation rates and alternative supply plans.*

*CP&L's study was performed before the decision was made to cancel Harris 2 in December 1983. Part of the make-up energy is achieved by advancing the Mayo 2 plant when Robinson 2 is not running. This credit is not taken in the Baseline comparison.

It is impossible to pinpoint the contrasting results with precision in the absence of detailed breakdowns of CP&L results, but the aggregate effect is to overcharge the Robinson make-up fuel costs by some $60 million.

The fourth and final category listed in Table 8.1 refers to differing assumptions about the likely rate treatment for recovering past Robinson investments in the event the plant is retired -- unamortized original investment, additional capital expenditures up to this time, and the already committed payments on the steam generator replacement. The Baseline scenario assumes only the return of the investment, the CP&L study assumes both return of and return on that capital (Ref. 45). That is, in CP&L 's accounting, the ratepayers pay for the capital investment of the abandoned facility and interest on that investment. For reasons indicated in Section 6.5, the Baseline recovery treatment of sharing the costs between ratepayers and stockholders appears consistent with recent regulatory policy. If so, CP&L has overestimated retirement impacts by some $20 million.

There is inherent uncertainty in the type of long-range cost comparison undertaken here. However, the Baseline case attempts to incorporate middle range assumptions in simulating the probable effects of abandoning Robinson 2. The results strongly suggest that while the impacts are not large, there are likely to be benefits to an early retirement. The primary deviation with CP&L findings concerns the degree of optimism brought to characterizing

the future reliability and costs at Robinson 2. In light of past experience, we see no scientific evidence for the rosy picture CP&L paints. The Baseline results are recommended as the more reliable estimate of the cost repercussions of an early retirement of the Robinson 2 facility.

TABLE 8.1

RECONCILIATION OF ESRG AND CP&L RATE IMPACT ESTIMATES
(Million 1983 PV $)

CP&L Estimate		350
Adjustments		
1. Increase Discount Rate		- 60
2. Robinson Operations Costs		-380
- Use Statistical Projection of O&M	(-130)	
- Use Statistical Projections of Capital Additions	(- 90)	
- Decrease CP&L Capacity Factors	(-100)	
- Reflect Spent Fuel Interim Storage Costs and Cost Escalation	(- 50)	
- Account for Incremental Decommissioning Costs	(- 10)	
3. Make-up Generation Costs		+ 60
- Use Mid-range Load Forecast	(- 60)	
- Include All Capacity Charges	(+180)	
- Adjust Fuel Costs	(- 60)	
4. Capital Recovery Treatment		- 20
Total Adjustment		-400
ESRG Baseline Estimate		- 50

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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING LOARD

In the Matter of)
CAROLINA POWER & LIGHT COMPANY) Docket No. 50-261-OLA
(H.B. Robinson Steam Electric) January 20, 1984
Plant, Unit 2))

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Appeared before me Paul D. Raskin who does affirm that he did this day cause to be placed in the United States mail, Express Mail or First Class postage prepaid, copies of the attached TESTIMONY AND EXHIBITS addressed to the below named persons:

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AFFIRMED and subscribed before me
this 20th day of January, 1984.

David R. McAnulty
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My Commission Expires: November 12, 1987

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