MASTER

"POWERPLANT PRODUCTIVITY IMPROVEMENTS
AND REGULATORY INCENTIVES"

A Report Prepared for

U.S. Department of Energy
Economic Regulatory Administration
Division of Powerplant Supply and Reliability

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Table of Contents

Executive Summary	i
Chapter I. Introduction.	1
I.1 The Problem	2
I.2 Scope of the Study.	4
Chapter II. Long-Term Savings Associated with Reductions in Forced Outages	6
II.1 Introduction	7
II.2 Methodology.	7
II.3 Description of Cases Considered.	7
II.3.1 The Fixed Expansion Plan.	8
II.3.2 The Variable Expansion Plan	8
II.4 Data Base for the Long-Term Cost Benefit Analysis.	8
II.5 Results.	9
II.5.1 Case 1 5 Percentage Point Reduction in Coal Plant Forced Outage Rates.	9
II.5.1.1 Case 1 Assuming a Fixed Expansion Plan.	9
II.5.1.2 Case 1 Assuming a Variable Expansion Plan	14
II.5.2 Case 2 5 Percentage Point Reduction in Nuclear Plant Forced Outage Rates	18
II.5.2.1 Case 2 Assuming a Fixed Expansion Plan.	18
II.5.2.2 Case 2 Assuming a Variable Expansion Plan	21
II.5.3 Case 3 5 Percentage Point Reduction in Coal and Nuclear Plant Forced Outage Rates	21
II.5.3.1 Case 3 Assuming a Fixed Expansion Plan.	21
II.5.3.2 Case 3 Assuming a Variable Expansion Plan	24
II.5.4 Case 4 7 Percentage Point Reduction in Coal Plant Forced Outage Rates	33
II.5.4.1 Case 4 Assuming a Fixed Expansion Plan.	33
II.5.4.2 Case 4 Assuming a Variable Expansion Plan	34
II.5.5 Case 5 3 Percentage Point Reduction in Coal Plant Forced Outage Rates	37
II.5.5.1 Case 5 Assuming a Fixed Expansion Plan.	37
II.5.5.2 Case 5 Assuming a Variable Expansion Plan	37
II.6 Summary of Long-Term Cost Benefits	41
Chapter III. Regulation and Powerplant Productivity.	43
III.1 Introduction.	44
III.2 System Efficiency, Powerplant Productivity, and Incentive Programs.	45
III.3 Powerplant Productivity Improvements: Cost-Effective Possibilities.	49
III.4 Summary	50

Table of Contents (cont.)

Chapter IV. Implementing an Incentive Plan.	.54
IV.1 Introduction.	.55
IV.2 An Incentive Plan for Existing Powerplants: The Decisionmaking Process.	.55
IV.3 Phase 1: Initiating an Incentive Program for Existing Powerplants and the Splitting of Net Cost Savings Between the Utility and Its Customers.	.56
IV.4 Phase 2: Establishing Performance Standards for Existing Powerplants.	.58
IV.5 Overview of the Incentive Program for Existing Powerplants.	.59
IV.6 An Incentive Plan for new Powerplants	.60
IV.7 Procedure for Determining Net Cost Savings.	.61
IV.8 Improvement Scenario.	.62
 APPENDICES - VOLUME I.	.66
 Appendix A. Unit Performance Characteristics for the ERCOT Region.	.67
A.1 Introduction	.68
A.2 EEI Data	.68
A.2.1 Tabular Presentation.	.68
A.2.2 Graphical Presentation.	.68
A.3 Additional ERCOT Data.	.78
A.3.1 Unit Performance Data	.78
A.3.2 Outage Cause Data	.82
A.4 Lignite-Fired Units.	.86
A.4.1 Unit Performance Data	.86
A.5 Conclusions.	.90
A.5.1 EEI Data.	.90
A.5.2 Additional ERCOT Data	.90
A.5.3 Lignite-Fired Units	.91
A.5.4 Outage Cause Data	.91
 Appendix B. Short-Term Savings Associated with Reductions in Outages	.92
B.1 Introduction	.93
B.2 Methodology.	.94
B.2.1 The PRODCOST Program.	.95
B.2.2 The TESCO Program	.96
B.2.3 Significant Program Differences	.98
B.3 Results of the Short-Term Savings Analysis	.98
B.3.1 Results for the Base Case	.98
B.3.2 Results for a 5/8 Percentage Point Reduction in Forced Outage Rates.	.99

Table of Contents (cont.)

B.3.3	Results for a Range of Percentage Point Reductions in Forced Outage Rates	99
B.3.4	Results for Specified Reductions in Planned Outage Rates	100
B.4	Conclusions.	100
Appendix C.	Powerplant Performance Data	103
Appendix D.	Sample Simulation Results for the TESCO Program (Base Case)	136
Appendix E.	Sample Simulation Results for the PRODCOST Program (Base Case).	140
Appendix F.	Modeling Tool - REM	145
F.1.	Introduction	145
F.2	Data Base.	147
F.3	Operation Simulation	147
F.4	Financial Simulation	151
F.4.1	Price Regulation.	151
Appendix G.	Increased Productivity Given the Typical Regulatory Environment and the Role of Incentives	153
G.1	Introduction	154
G.2	Rate of Return Regulation and Profit	154
G.3	The Utilization of Incentives.	157
G.4	Alternative Actions and Possibilities.	160
G.4.1	The Michigan Incentive Plan	160
G.4.2	A Comparison of the General Incentive Format of this Study and the Michigan Program.	162
G.4.3	Fuel Adjustment Mechanism.	164
G.5	Summary.	165

List of Illustrations

CHAPTER II

Figure II-1	Elimination of Coal Plants for Case 1 Variable Expansion.	12
Figure II-2	Comparison of Gas Saving for Case 1 Alternatives.	15
Figure II-3	Elimination of Coal Plants for Case 2 Variable Expansion.	19
Figure II-4	Comparison of Gas Saving for Case 2 Alternatives.	20
Figure II-5	Elimination of Coal Plants for Case 3 Variable Expansion.	25
Figure II-6	Comparison of Gas Saving for Case 3 Alternatives.	27
Figure II-7	Elimination of Coal Plants for Case 4 Variable Expansion.	28
Figure II-8	Comparison of Gas Saving for Case 4 Alternatives.	32
Figure II-9	Elimination of Coal Plants for Case 5 Variable Expansion.	38
Figure II-10	Comparison of Gas Saving for Case 5 Alternatives.	40

APPENDICES - VOLUME I

APPENDIX A

Figures A-1 - A-15	Powerplant Performance Data.	70-77
Figures A-16 - A-21	Powerplant Performance Data.	79-81
Figures A-22 - A-27	Powerplant Performance Data.	87-89

APPENDIX B

Figure B-1	Percentage Reduction in Fuel Costs vs. Percentage Reduction in Forced Outage Rates.	101
Figure B-2	Percentage Reduction in Fuel Costs vs. Total Number of Weeks Reduction in Planned Outages of Lignite Units.	102

List of Illustrations (cont.)

APPENDIX F

Figure F-1	National Electric Reliability Council (NERC) Regions	.146
Figure F-2	Construction Cash Flows	.149
Figure F-3	REM Sub-Models.	.150

APPENDIX G

Figure G-1	Profit under Rate of Return Regulation.	.156
Figure G-2	A Comparison of Alternatives.	.163

List of Tables

CHAPTER II

Table II-1	Assumed Forced Outage Rates for Case 1.	10
Table II-2	Long-Term Savings for Case 1, Fixed Expansion Plan. . . .	11
Table II-3	Long-Term Savings for Case 1, Variable Expansion Plan . .	13
Table II-4	Assumed Forced Outage Rates for Case 2.	16
Table II-5	Long-Term Savings for Case 2, Fixed Expansion Plan. . . .	17
Table II-6	Assumed Forced Outage Rates for Case 3.	22
Table II-7	Long-Term Savings for Case 3, Fixed Expansion Plan. . . .	23
Table II-8	Long-Term Savings for Case 3, Variable Expansion Plan . .	26
Table II-9	Assumed Forced Outage Rates for Case 4.	29
Table II-10	Long-Term Savings for Case 4, Fixed Expansion Plan. . . .	30
Table II-11	Long-Term Savings for Case 4, Variable Expansion Plan . .	31
Table II-12	Assumed Forced Outage Rates for Case 5.	35
Table II-13	Long-Term Savings for Case 5, Fixed Expansion Plan. . . .	36
Table II-14	Long-Term Savings for Case 5, Variable Expansion Plan . .	39

CHAPTER IV

Table IV-1	Incentive Schedule.	58
Table IV-2	Physical and Financial Factors.	63

APPENDICES - VOLUME I

APPENDIX A

Table A.1	Dallas Power and Light Forced Outage Cause.	82

List of Tables (cont.)

Table A.2	Central Power and Light Forced Outage Cause 1976.	83
Table A.3	Central Power and Light Forced Outage Cause 1977.	83
Table A.4	Central Power and Light Forced Outage Cause 1978.	84
Table A.5	Texas Electric Service Forced Outage Cause 1976	84
Table A.6	Texas Electric Service Forced Outage Cause 1977	84
Table A.7	Texas Electric Service Forced Outage Cause 1978	85

APPENDIX B

Table B-1	Texas Utilities Lignite Units	93
Table B-2	Simulation Results for the Base Case.	99
Table B-3	Simulation Results for a 5/8 Percentage Point Reduction in Forced Outage Rates of the Lignite Units.	99

APPENDIX C

Tables 1 - 66	Powerplant Performance Data	104-135

APPENDIX D

Tables 1 - 3	Sample Simulation Results for the TESCO Program (Base Case).	137-139

APPENDIX E

Tables 1 - 3	Sample Simulation Results for the PRODCOST Program (Base Case).	141-143

APPENDIX F

Table F-1	Plant Types and Their Licensing and Construction Lead Times	148

List of Tables (cont.)

APPENDIX G

Table G-1	Proposed Expanded Scale of Availability Adjustment	.161
Table G-2	Proposed Expanded Scale of Availability Adjustment Including Periodic Maintenance Factor	.161

EXECUTIVE SUMMARY

In recent years, the precipitous increase in electric utility capital and fuel costs has focused much attention on powerplant productivity. During the decade of the 1970s, the electric utility industry's struggles with these increasing costs were amplified by the greater effort required to maintain powerplant performance. This can be attributed partially to the gradual transition from cleaner burning fuels, oil and gas, to environmentally less desirable fuels, coal and nuclear power. In addition, there is a growing consensus among State and Federal regulators that the typical mechanisms of regulation could be geared to better motivate electric utilities to increase the productivity of their base load generating capacity.

Once a problem--such as the presence of financial disincentives facing utilities which seek to increase powerplant productivity levels--is recognized and a policy decision is made to take corrective action, there are two basic initial tasks that must be undertaken. First, the underlying causes of the problem must be identified, and second, a solution (or solutions) to the problem must be developed and considered for implementation. Far too often, especially in government related activities, it suffices to identify the underlying causes and not search for solutions. However, when the benefits of solving the problem substantially outweigh implementation costs, electrical producers and consumers become more aware of productivity problems and begin to search for constructive solutions.

In the case of powerplant productivity, the problem was recognized by engineers many years ago, and as far back as the early 1960s the economics profession was examining the underlying causes. But, because the decade of the 1960s was a period of decreasing costs for electrical generation (including both capital and fuel costs), the deadweight loss of inefficient capital utilization was relatively small. As indicated earlier, however, since the early to mid-1970s, both capital and fuel costs have risen sharply, accompanied by an increased interest in finding ways to improve powerplant productivity.

The purpose of this study is to examine the benefits to be gained from increased powerplant productivity and to validate and demonstrate the use of incentives within the regulatory process to promote the improvement of powerplant productivity. In the first section of this study (Chapter II and Appendices A - B), system-wide costs savings to be gained from given productivity improvement scenarios are estimated in both the short and long term. At the present time, there exist numerous reports and studies which indicate that productivity improvements at the powerplant level are feasible and cost effective. The efforts of this study widen this focus and relate system-wide productivity improvements with system-wide cost savings. The initial thrust of the regulatory section of this study (Chapters III - IV) is to validate the existence of reasonable incentive procedures which would enable regulatory agencies to better motivate electric utilities to improve productivity on both the powerplant and system levels. The voluntary incentive format

developed in this study was designed to facilitate the link between profit and efficiency which is typically not clear in most regulated market environments.

In the following section, Chapters II - IV and Appendices A - B are summarized. Specifically, the purpose of these chapters and the conclusions to be drawn from each are outlined. The Appendices C - G and Appendix Volume II expand upon the subject material in the text and are referred to in each relevant chapter.

Long-Term Savings Associated with Reductions in Forced Outages

Chapter II presents an analysis of long-term savings associated with reductions in forced or planned outage rates. The time frame of this analysis covers 1980 through 1996, and the relevant level of aggregation is the Electric Reliability Council of Texas (ERCOT) as a whole. Reductions in future installed capacity requirements are considered as well as potential savings due to reduced gas consumption. Generally speaking, when a longer time frame is considered a reduction in future installed capacity may be possible for a sufficiently large reduction in forced outages of base load units. In order to assess these potential benefits as well as fuel savings, five cases were considered. In each case, forced outage rates are reduced by a specified percentage point reduction uniformly realized over an eight-year period (1980-1987). During the time frame 1988 to 1996 the outage rate remains fixed. Cases considered are:

- A. Case 1 - 5 percentage point reduction in coal plant forced outage rate;
- B. Case 2 - 5 percentage point reduction in nuclear plant forced outage rate;
- C. Case 3 - 5 percentage point reduction in coal and nuclear plant forced outage rate;
- D. Case 4 - 7 percentage point reduction in coal plant forced outage rate; and
- E. Case 5 - 3 percentage point reduction in coal plant forced outage rate.

As an example of the outage rate assumption, consider Case 1 which is a 5 percentage point reduction in coal plant forced outage rate. We assume an outage rate reduction of 5/8% for each of the years 1980 to 1987. The outage rate is then held fixed at a total reduction of 5 percentage points for the remaining years 1988 to 1996. For each case considered, a variable expansion plan and a fixed expansion plan are analyzed. The fixed expansion plan assumes no change in the base case expansion plan and in the variable expansion plan future generation additions are reduced in a reasonable way. Gross benefits for all cases are quantified in terms of changes in gas and coal consumption, reductions in production expenses, benefits to consumers

and reductions in capital expenditures. The simulation tool used in the analysis is the Regionalized Electricity Model (REM) developed at M.I.T. and the University of Texas at Austin. Appendix F describes this model.

In all cases considered, reductions in forced outage rates result in the major portions of benefits going to the consumer. This is true whether a variable expansion plan or fixed expansion plan is made. In general, an improvement in the forced outage rates for coal units results in significant gas savings but relatively low reductions in production expenses. Improvement in nuclear plant forced outage rates results in much lower gas savings but relatively high reductions in production expenses. This is a result of the relatively high operating and maintenance costs associated with coal plants and the low percentage of nuclear generation in the ERCOT region for the relevant time period. It is further shown that if gas savings alone are the most important consideration, the base case expansion plan should not be altered as outage rates are improved since going from a fixed to a variable expansion plan generally cuts gas savings in half. Minimization of the cost of service to consumers generally requires that future installed coal plant capacity be cut back as much as possible as outage rates are improved. Under current regulatory practices, this results in a drop in utility net revenue. In this manner, the typical rate of return mechanism utilized for years by a majority of regulatory agencies impedes efforts to increase powerplant productivity.

Regulation and Powerplant Productivity

The primary task performed in Chapter III is to present a general incentive format that can introduce into rate of return regulation a strong connection between profit and efficiency both in the short run and the long run. The general incentive format simply states that if a utility undertakes an identifiable system efficiency improvement program which results in lower KWH costs, then the utility will be allowed to keep a portion of the associated net savings (over and above its allowed revenues). The fraction kept by the utility would be directly related to some performance measure of its base load units.

Three basic conclusions can be drawn from this chapter. First, the typical rate of return mechanism utilized by most state regulatory agencies and the practice of passing through all legitimate short-run variable costs (e.g., fuel and labor) together have clouded the connection between profit and efficiency which is the incentive that encourages cost-minimal production in a functioning competitive environment. Second, experience shows that improvements in powerplant productivity are feasible, cost effective, and beneficial. Third, a voluntary incentive plan which conforms to the basic framework of the general incentive format presented in this chapter can guarantee a clear positive tie between profit and efficiency and still conform to basic rate of return regulation.

Implementing an Incentive Plan

The purpose of Chapter IV is to trace the steps that would be taken both by the utility considering the incentive plan and the regulatory

agency offering the incentive. The basic framework of the chapter is two-fold: first, an outline and a detailed examination of the ground rules for both existing and new plant incentive programs are presented and second, a reasonable improvement scenario is considered to illustrate the salient calculations that must be made by the regulated utility and the regulatory agency.

The general incentive plan presented in Chapter IV can be briefly described by the following outline:

- o Existing Powerplants, Phase 1: Regulatory Commission will allow a return consisting of a benchmark profit plus a percentage of net cost savings from a productivity improvement.
- o Existing Powerplants, Phase 2: This is an alternative form for the incentive format where standards are set up. The utility will increase its return by exceeding the standards.
- o New Powerplants: Performance standards are established for each prospective plant. Similar to Phase 2.

Unit Performance Characteristics for the ERCOT Region

In Appendix A, operating and performance data are analyzed for five major utilities in the ERCOT region. The utilities chosen represent roughly 78% of the total generation capacity in the region. Thus, a significant sample of utilities in the state is taken. EEI data is used for the period 1965 through 1975. Additional data was obtained directly from the utilities for the years 1976 to the present. These additions included data on lignite units and also outage cause data.

An examination of actual reported performance data shows that when fuel type is considered, the electric utility industry in Texas has historically exhibited a higher equivalent availability factor and a lower forced outage rate than the national average. The tabulations of the capacity factor, however, show mixed results, with half of the reported utilities above and half below the national average. The basic implication of this observed disparity between the average equivalent availability factor and the average capacity factor in Texas is that for some utilities there exists sufficient generating capacity to permit the removal of base load plants from the grid for substantial periods of time for economic reasons. The strong base load capacity that has been established in ERCOT should prove to be a tremendous long run benefit as the rapidly inflating cost of construction forces up the cost of new base load generating units.

Short Term Savings Associated with Reduction in Outage

In Appendix B, an analysis of short term savings associated with reductions in forced and planned outage rates is presented. Short term savings are defined to be those savings in fuel costs which would be realized if a specified reduction in forced or planned outage rates occurred. Generally speaking, in the short term a reduction in outage rates for base load units

reduces the amount of demand which must be satisfied by burning more expensive peaking unit fuel. An in-depth analysis was made of the Texas Utilities System for the year 1980. This system consists of three major utilities serving approximately one-third of the population of Texas in 87 counties of North Central, East and West Texas. The system includes eight lignite units and forty-nine natural gas units. Sufficient data was provided by the member utilities to permit detailed computer simulation of the hour-by-hour operation of the Texas Utilities System for the year 1980. Computer simulations were run at the University of Texas and results were compared to the results of a production simulation program developed and owned by one of the member utilities. Thus, results were validated by comparing computer outputs from the two models. Since the difference between the levels of fuel savings estimated by the two models was exceedingly small, the results are quite credible.

Savings were computed for a $5/8$ percentage point reduction in lignite unit forced outage rates, a range of percentage point reductions in lignite unit forced outage rates, and for specified reductions in lignite unit planned outage rates. The $5/8$ percentage point reduction was chosen to estimate annual savings under the assumption of a 5 percentage point reduction in forced outage rates uniformly realized over an eight-year period. A $5/8$ percentage point reduction in forced outage rates for the lignite units would realize (approximately) a $1/4$ of one percent savings in fuel costs. This result is extended to show that a 1.0 percentage point reduction in outage rates for the lignite units increases the fuel cost savings (approximately) to $1/2$ of one percent. Reductions in planned outage rates result in somewhat smaller increases in fuel cost savings. These results are summarized in Appendix B.

Concluding Comments

It was not the purpose of this study to develop a single hard and fast rule to achieve greater powerplant productivity, but rather to demonstrate that there exist numerous incentive plans that can encourage productivity improvements. The one point that is clear is that one of the necessary conditions for a successful incentive plan is that the link between profit and efficiency must be maintained.

Also, it should be noted that the purpose of instituting and maintaining a powerplant productivity incentive program as proposed in this study is not to cut back the absolute level of electricity generating capital. The ultimate goal and logical outcome of such a program is the efficient utilization of capital at all output levels. If a system is undercapitalized then a properly designed incentive program would encourage an increase in capital per unit of output, whereas if a system is overcapitalized it will encourage a decrease in capital per unit of output.

At the present time, many electric utilities in this country could significantly increase the productivity of their base load units, and the adoption of an incentive program of the general type recommended in this study

would add to rate of return regulation the needed financial incentives to enable utilities to make such improvements without losing long-run profit. In light of the upcoming oil import target levels and mandatory cutbacks of oil and gas as boiler fuels for electric utilities, the use of incentive programs to encourage more efficient utilization of coal and nuclear base load capacity will become far more inviting over the next two decades. The imminent mandatory backout of oil as a boiler fuel for electric utilities will exert a substantial upward pressure on capital requirements, and the benefits to be gained from the maximum utilization of existing and planned coal and nuclear base load capital will increase dramatically.

CHAPTER I. INTRODUCTION

I. INTRODUCTION

I.1 The Problem

Beginning with the Arab Oil Embargo in the early 1970s, the cost of fuel to the electric utility industry has increased precipitously. In addition to unprecedented increases in the cost of variable inputs, the utility industry has also been facing a steady rise in capital costs. As a consequence, the interest of utilities as well as regulators in increasing overall system efficiency has noticeably expanded. One of the more promising areas of improvement that offers substantial possible savings is powerplant performance. During those periods when fuel and capital costs are low and decreasing, the gains to be derived from increases in powerplant performance do not present a highly visible issue. Now that the electric utility industry has entered an era of rapidly rising fuel and capital costs, however, the effort by both utilities and regulatory agencies to facilitate increases in system efficiency has increased significantly.

During this past decade of the 1970s, the electric utility industry's struggles with these increasing costs have not been accompanied by increasing levels of powerplant productivity. There are numerous reasons for this situation. As the utility industry moves from the cleaner burning fossil fuels (oil and gas) to coal and nuclear it is inevitable that the incidence of both forced and planned outages will increase. This can be partially attributed to the need for maintaining EPA mandated equipment (e.g., scrubbers) which exhibits high outage rates, and to the need for longer planned outage periods for nuclear plants for required maintenance and safety checks. Also, in the case of coal-fired plants, the decreasing quality of coal supplies has taken its toll on powerplant productivity (e.g., outage rate) and efficiency (e.g., heat rate).¹

In addition to concern about this general type of performance damaging factor, there is a growing interest on both the Federal and State levels to identify regulatory mechanisms which would encourage electric utilities to increase the productivity of their base load generating capacity in a cost-effective manner.

Attention has been drawn to the improvement of powerplant productivity, not only because of fuel cost increases attributable to the price setting activities of the OPEC cartel, but also because of the threat of nonmarket related supply disruptions which have become a reality, and which will loom even larger as the U.S. grows more dependent on foreign oil. This dependency and its accompanying threat of supply disruption can be diminished through reductions of oil and gas consumption by electric utilities. Productivity improvements in coal and nuclear base load plants would be a significant step in the direction of reducing crude oil imports.

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¹ The use of scrubbers and the decreasing quality of coal are but two examples of outage causes, and should not be interpreted as the only causes.

The Department of Energy (DOE) is the Federal agency that bears the ultimate responsibility for implementing energy related programs and policies such as oil import quotas and the mandates of the Fuel Use Act (and future amendments). Electric utilities as well as industrial sector firms must start to cut back the use of oil and gas as a boiler fuel. And, one of the most immediate steps that can be taken to aid such a cutback is to encourage greater productivity of base load plants which utilize alternative fuels. It was the recognition of this situation that led the Economic Regulatory Administration of DOE to commission this study, and to contribute to its funding (68% by DOE, 32% by the State of Texas). DOE and the predecessor Federal Energy Administration have been actively engaged in encouraging increased productivity to save scarce capital and fuels since 1974.

The present instability of the money market coupled with high interest rates and the generally poor financial condition of the electric utility industry has made it difficult for most utilities to obtain funds for long term investment at reasonable rates. Given the scarcity of investment funds at this time and the regulatory environment in which electric utilities must operate, increased demand or changes in State or Federal regulations which impose heavy capital expenditure requirements on electric utilities cannot realistically be assigned a high probability of success.

Due to its pivotal position in any attempt to attain national energy independence, the electric utility industry has been identified through Federal legislation as one of the primary sources for oil displacement. One way to insure that the existing regulatory structure does not hinder the national effort to displace oil and gas as boiler fuels is to introduce incentive mechanisms into the regulatory process which motivate electric utilities to maximize the utilization of base load units. One general incentive format which addresses this problem is based on a very simple concept; if a utility can demonstrate that it has instituted a program that has lowered its average total cost of supplying electricity, then the utility is permitted to retain a fraction of the associated net saving, based on the performance level of its base load units. In this manner, the utility is encouraged to implement any program that lowers average total cost and increases the efficient utilization of its base load generating capacity.

In essence, this study highlights the benefits to be gained from increased system efficiency and validates and demonstrates the use of incentives within the regulatory process to promote improved performance levels. Concentrating on the ERCOT (Electric Reliability Council of Texas), regional powerplant performances are first tabulated and then analyzed. System-wide gross cost savings to be gained from given productivity improvement scenarios are estimated in both the short and long term. At the present time, there exist numerous reports and studies, national in scope, which indicate that productivity improvements at the powerplant level are feasible and cost effective. The current study widens this focus and relates system-wide productivity improvements with system-wide cost savings.

An examination is made of the typical regulatory format in order to assess the capacity of the regulatory environment to motivate utilities to increase the productivity of their generating capacity. The basis of our approach to possible regulatory action rests on the argument that there

are reasonable incentive procedures available to regulatory agencies which would motivate electric utilities to improve productivity on both the powerplant and system level. The primary effort of the regulatory section of the study follows this line of argument, and a fairly detailed discussion (analysis in the Appendix) is made of one general type of regulatory incentive which could be helpful in attaining the goals of lower system costs and higher powerplant productivity. Utilizing this general incentive format as a basis, a number of alternative incentive programs are then compared (in the Appendix). The incentive mechanisms scrutinized in this study, however, do have one basic facet in common: they have been designed to establish a strong positive relationship between profit and efficiency while remaining within a rate of return regulatory structure. Ultimately, we are exploring methods of introducing some of the beneficial aspects of the free market into the regulatory environment without compromising needed safeguards.

I.2 Scope of the Study

More efficient utilization of the existing generating capacity of electric utilities can be facilitated in a number of ways. Basically, however, there are two general categories of possible actions: those which are demand related and those which are supply related. Until recently, virtually all efforts by State and Federal agencies to promote greater productivity (efficient use of capital) were demand oriented. Even though the bulk of the research and the regulatory programs are still concentrated upon demand modification, supply problems are receiving increasingly more attention. The scope of this study encompasses the efficient supply of electricity through the productivity of capital. Though demand criteria are not directly treated in this study, one must be reminded that demand-related programs can and do facilitate the more efficient use of capital.

Demand-oriented regulatory programs which seek to improve the overall system productivity of a given electric utility are typically geared toward lessening demand load fluctuations. Load control can be facilitated either in the form of load shifting (from on-peak to off-peak) or in the form of total load shedding. Time of day pricing is a representative form of load shifting and the use of interruptible rates is the most common form of load shedding. Direct control of water heaters can be utilized both as a load shifting and a load shedding technique. Load shifting techniques help limit the use of peaking units (which use expensive fuel) and increase the off-peak utilization of base and intermediate load units (which use less expensive fuel). Load shedding is effectively an addition to spinning reserve and helps minimize the use of peaking units; this procedure aids in the economic dispatch of generating capacity.

Supply-oriented regulatory programs, directed at promoting the more efficient makeup and utilization of the capital base of electric utilities, can be grouped into two basic categories: existing plant performance and new plant performance. Those projects which address existing plant performance are long term in nature. Both short-run and long-run cost savings can result from increased powerplant productivity or from other cost-

effective system improvements. The short-run savings which result from improved outage rates (or other performance standards) for existing powerplants commonly occur in the form of lower fuel and purchased power expenditures. As the productivity of coal and nuclear base load plants increases, the consumption of expensive fuels needed to operate intermediate and peaking units decreases. Greater productivity of these existing base load units can be facilitated in many ways. The improvement strategy could be as sophisticated as adding to or modifying existing capital equipment (e.g., more pulverizers in a coal plant) or as simple as the alteration of a maintenance procedure. In other words, one can improve productivity through better management of operations and maintenance and in engineering capital plant improvements.

In the long run, an improvement in powerplant performance can be utilized to lower the level of generating capital required to meet demand. Whenever an improvement plan results in increased powerplant performance, the resulting total savings is subject to a trade off between fuel and capital savings, which would be set at the discretion of the utility and the regulatory agency. Long-run costs are also influenced by the efficiency (e.g., heat rate) of new plant design and the productivity (e.g., outage rates) of that plant once construction is completed. In any estimation of long-run cost savings that result from increased powerplant productivity, new plant as well as existing plant improvements should be considered.

As discussed earlier in this chapter, probably the most effective tactic for encouraging cost minimal system operation (including improvements in powerplant productivity) would be to introduce some form of financial incentive into the regulatory arena similar to those forces which naturally exist in a free market environment. By facilitating a carefully constructed link between profit and efficiency within the format described earlier, a regulatory agency can create a self-enforcing procedure which promotes increased system efficiency. And, such an incentive format can be implemented within the existing framework of rate of return regulation.

CHAPTER II. LONG-TERM SAVINGS ASSOCIATED
WITH REDUCTIONS IN FORCED OUTAGES

II. LONG-TERM SAVINGS ASSOCIATED WITH REDUCTIONS IN FORCED OUTAGES

II.1 Introduction

Long-term savings associated with reduced powerplant forced outage rates are presented in this chapter. These benefits include savings in fuel consumption and in reduced installed capacity requirements. The benefits presented are quantified in terms of changes in gas and coal consumption, reductions in production expenses, benefits to consumers and reductions in capital expenditures. Short-term savings presented in Appendix B consider potential fuel savings due to reduced outage rates for the Texas Utilities System for the year 1980. The long-term savings presented in this chapter extend the analysis in several ways. First, the time frame is extended to cover 1980 through 1996. Second, the entire Electric Reliability Council of Texas region is analyzed. Third, reductions in future installed capacity requirements are considered as well as potential savings due to reduced gas consumption. The results of this analysis indicate two basic points. First, the major portion of the benefits that arise from a decrease in powerplant forced outage rates passes on to the customer. Second, the utility will actually experience a drop in net revenues in the long run as outage rates decrease.

II.2 Methodology

The approach taken in this study is to run a base case with present forced outage rates and then compare the results with cases run with improved forced outage rates incorporated in them. This comparison yields the potential benefits that can be obtained if the improved forced outage rates were to be realized. It should be noted that neither the cost nor the technical feasibility of achieving such improved outage rates is evaluated in this chapter.

The simulation tool used in this study is the Regionalized Electricity Model (REM) developed at M.I.T. and The University of Texas at Austin. This version of REM operates on Electric Reliability Council regions. These regions are aggregates of interconnected electric utilities. Appendix F contains a brief description of REM and the way it operates.

II.3 Description of Cases Considered

In each case considered, forced outage rates are reduced by a specified percentage reduction uniformly realized over an eight-year period (1980-1987). For example if the specified reduction is 5%, it is assumed that in each year during the time frame 1980 to 1987 there is a reduction in forced outage rates of 5/8%. During the time frame 1988 to 1996 the outage rates remain fixed. The cases considered are:

- A. Case 1 5 percentage point reduction in coal plant forced outage rate.
- B. Case 2 5 percentage point reduction in nuclear plant forced outage rate.

- C. Case 3 5 percentage point reduction in coal and nuclear plant forced outage rate.
- D. Case 4 7 percentage point reduction in coal plant forced outage rate.
- E. Case 5 3 percentage point reduction in coal plant forced outage rate.

Note that cases 4 and 5 permit consideration of a slight increase or decrease over the 5% reduction in forced outage rates considered in case 1. Each of the above cases are analyzed twice. First a fixed expansion plan is assumed, then a variable expansion plan is assumed. Note that the purpose of these cases is to examine the cost (and profit) impacts of outage rate improvements. No attempt has been made to relate resulting outage levels to the outage performances of all regions (especially since the impacts examined in this study are more closely related to percentage improvements in outage rates than to absolute outage rates).

II.3.1 The Fixed Expansion Plan

In the fixed expansion plan the future generation expansion remains the same as in the base case study. The benefits obtained under this plan are in the form of savings in expensive fuel (oil & gas). Reduction in consumption of expensive and scarce oil and gas benefits the consumer and the utilities. The benefits to the consumer are in the form of lower electricity costs. Utilities benefit by being in a better position in the event of a shortage or price increase in these fuels.

II.3.2 The Variable Expansion Plan

As the forced outage rate of powerplants is improved, the availability increases. This increased availability permits a reduction in future installed capacity. In the variable expansion plan, future additions of generation are reduced in such a way that quality of service is maintained. This will be described in detail as each case is developed. Benefits are mainly in the form of capital savings.

II.4 Data Base for the Long-Term Cost Benefit Analysis

The region selected for this study is the ERCOT region which is one of the nine regions of the National Electric Reliability Council (NERC). Data on existing generation capacity and future expansion plans have been obtained from the ERCOT reports and used as input to REM. Other data inputs such as operating and maintenance expenses, forced outage rates for the base case and fuel costs have been taken from the report "An Assessment of the Effect of Uncertainty on the Adequacy of the Electric Utility Industry's Expansion Plans, 1983-1990" by Martin L. Baughman and Dilip P. Kamat. That report was prepared under EPRI contract RP 1153-1, "Integrated Regional Electric Power Planning and R&D Analysis."

The fuel prices used in REM are:

- A. Gas prices are assumed to vary from 186.43 cents/MCF in 1980 to 499.55 cents/MCF in 1996.
- B. Coal prices are assumed to vary from 29.92 \$/s. ton in 1980 to 85.492 \$/s. ton in 1996.
- C. Nuclear fuel prices are assumed to vary from 4.22 mills/KWHR in 1980 to 16.554 mills/KWHR in 1996.

The operating and maintenance costs that are used in REM are:

- A. Gas-fired plant operation and maintenance expenses are assumed to vary from 1.314 mills/KWH in 1980 to 3.096 mills/KWH in 1996.
- B. Coal-fired plant operating and maintenance expenses are assumed to vary from 3.556 mills/KWH in 1980 to 8.34 mills/KWH in 1996.
- C. Nuclear plant operating and maintenance costs are assumed to vary from 2.43 mills/KWHR in 1980 to 6.19 mills/KWHR in 1996.

As can be seen, the operating and maintenance costs for coal-fired plants are about three times those of the gas-fired units and about one-and-one-half times those of the nuclear plants.

II.5 Results

II.5.1 Case 1 5 Percentage Point Reduction in Coal Plant Forced Outage Rates

In this part of the study productivity improvement is analyzed for a 5 percentage point improvement in coal plant forced outage rates uniformly realized over the eight year period 1980 to 1987. From 1987 on the outage rate is held constant. The forced outage rate in the base case is assumed to remain constant at 8.3 percent. In Case 1, the forced outage rate decreases by 5/8 of a percentage point every year starting in 1980, achieving a total reduction of 5 percentage points by the year 1987. The new coal plants coming on line after 1987 are assumed to have the improved forced outage rate incorporated in them. This is illustrated in Table II-1.

II.5.1.1 Case 1 Assuming a Fixed Expansion Plan

In this case the future generation expansion is kept the same as that used in the base case while the forced outage rates of the coal plants are improved. The benefits are basically in the form of expensive and scarce fuel (oil and gas) savings. Since this study is for the ERCOT region and this region has no significant oil-fired units, the major fuel saving is that of gas. If the same study is performed for regions rich in oil-fired plants the savings could be much higher.

TABLE II-1
Assumed Forced Outage Rates for Case 1

Year	Base Case Forced Outage Rate	Improved Forced Outage Rate
1980	8.3	7.675
1981	8.3	7.050
1982	8.3	6.425
1983	8.3	5.800
1984	8.3	5.175
1985	8.3	4.550
1986	8.3	3.925
1987	8.3	3.300
1988-96	8.3	3.300

Table II-2 summarizes results obtained using REM. The results compare the base case with the improved forced outage rate case. Column 2 shows the reduction in gas consumption. As the productivity of coal plants is improved there is a shift in generation from gas-fired units to coal-fired plants. This shift in generation takes place because it is more economical to burn coal than gas. This reduction starts in 1980, the first year that improvement begins, and increases until 1987. After 1987, the reduction in gas consumption remains almost constant since there is no further improvement in forced outage rates and no new gas plants come on line.

Column 3 shows the increase in coal consumption. Column 4 shows the reduction in production expenses. Production expenses include fuel costs and operating and maintenance costs.

A shift in generation from gas to coal-fired units results in lower fuel costs. REM calculates operating and maintenance costs per KWH generated and since these costs are about three times higher for coal-fired units than for gas-fired units, a shift in generation from gas to coal results in significantly higher operating and maintenance costs. Thus fuel costs go down and operating and maintenance costs go up. The difference between these two costs is the reduction in production expenses. Were it not for the high operating and maintenance costs associated with the coal plants, the reduction in production expenses would be much higher. Column 5 shows the percentage reduction in production expenses.

The cumulative gas saving from 1980 to 1996 is 121.2 million equivalent bbl. Since production costs are paid by the consumer, reductions in these costs flow directly to the consumer. Since this is the major portion of the overall benefits, it can be concluded that the consumers would benefit the most under current regulatory mechanisms.

Table II-2

Long-Term Savings for Case 1

Fixed Expansion Plan

Coal Plant Forced Outage Rate Improved by 5 Percentage Points Over the Eight-Year Period 1980-1987

(1)	(2)	(3)	(4)	(5)
Year	Reduction in gas consumption Million MCF	Increase in coal consumption Million s. Tons	Reduction in Production expenses 10 ⁶ \$	Percentage reduction in production expenses
1980	4.81	0.23	1.0	0.03
1982	15.70	0.75	2.5	0.06
1984	30.60	1.46	3.5	0.07
1986	46.16	2.21	3.1	0.05
1988	52.00	2.48	3.9	0.05
1990	53.42	2.55	7.0	0.07
1992	55.81	2.76	10.5	0.09
1994	49.61	2.37	14.6	0.1
1996	43.17	2.1	17.5	0.1

Cumulative gas saving from 1980 to 1996 is 121.2 Million Equivalent bbl. (assume 5.8 MBTU/bbl)

II.5.1.2 Case 1 Assuming a Variable Expansion Plan

As the coal plant forced outage rate is improved, coal plant availability increases. This extra availability of the coal plants reduces the requirement for future installed capacity. In the variable expansion plan new capacity expected to come on line in the future is reduced in such a way that the base case reserve margin is maintained. Figure II-1 shows the installed capacity of powerplants in the ERCOT region for the period 1980 to 1996. There is a maximum effective capacity for the base case forced outage rate and a higher maximum effective capacity when the forced outage rate is improved. As can be seen in Figure II-1, the improvement in forced outage rate of the coal plants causes an increase in maximum effective capacity and in the availability of the coal plants. Since REM operates on an aggregate regional basis, the individual units that are expected to come on line are not specified. Therefore, in order to investigate alternative expansion plans, fixed minimum plant sizes of 350, 400 and 450 MW are assumed. For example, in the year 1985 the extra capacity due to the forced outage rate improvement is 416 MW, therefore, a coal unit of 400MW is eliminated. A second coal plant of 450 MW is eliminated in the year 1988, since at that time there is 851 MW extra generating capacity, 400 MW of which was eliminated in 1985. In the year 1994, a third coal plant of 400 MW can be eliminated because of extra generating capacity available. Thus the variable expansion plan is simulated by eliminating coal plant units at certain points in time while still maintaining the base case reserve margin.

Table II-3 summarizes the results for the variable expansion plan. Column 2 presents the reduction in gas consumption. This gas saving is much smaller than for the fixed expansion plan shown in Table II-2 because eliminating the coal plants at certain points in time cuts down the coal plant generating capability and the generation shift from gas to coal-fired units is correspondingly less.

Column 3 shows the increase in coal consumption. This increase in coal consumption is due to the shift in generation from gas to coal. This increase is smaller than for the fixed expansion plan since some coal units that were expected to come on line have been eliminated.

Column 4 shows the reduction in production expenses. As was explained earlier, production expenses include fuel costs and operating and maintenance expenses.

Column 6 shows the reduction in construction expenses. This reduction obviously takes place because of the coal units that would not be constructed, and consequently there would be a drop in capital investment.

Column 7 is the benefit to consumers. This is much higher than for the fixed expansion plan where consumer benefits essentially consist of the reduction in production expenses. As can be noted, there is a loss to the consumers in 1982. This is due to the fact that certain plants are eliminated. This causes interest during construction (IDC) to drop and since the rate of return (r) remains constant the gross revenue to the utilities

† Maximum Effective Capacity for the Base Case

|+ New Maximum Effective Capacity for Improved Case

Figure II-1

Elimination of Coal Plants for Case 1 Variable Expansion

Table II-3

Long-Term Savings for Case 1

Variable Expansion Plan

Coal Plant Forced Outage Rate Improved by 5 Percentage Points Over the Eight Year Period 1980-1987

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Year	Reduction in gas consumption Million MCF	Increase in coal consumption Million s. Tons	Reduction in production expenses 10 ⁶ \$	Percentage reduction in production expenses	Reduction in construction expenses 10 ⁶ \$	Benefit to consumers 10 ⁶ \$	Drop in net revenue 10 ⁶ \$
1980	4.81	0.23	1.0	0.03	1.4	1.0	0.0
1982	15.70	0.75	2.5	0.06	54.6	-6.6	-0.1
1984	30.60	1.46	3.6	0.07	86.9	26.7	26.3
1986	23.92	1.13	2.2	0.03	151.6	15.1	24.5
1988	17.53	0.82	2.3	0.03	0.0	106.3	59.8
1990	23.10	1.10	4.0	0.04	34.8	100.0	53.9
1992	27.30	1.34	6.1	0.05	205.3	53.0	47.6
1994	18.68	0.88	7.0	0.05	0.0	171.7	92.2
1996	20.63	0.97	9.6	0.06	0.0	164.7	82.3

Cumulative gas saving from 1980 to 1996 is 63.37 Million Equivalent bbl. (assume 5.8 MBTU/bbl)

goes up temporarily. Appendix F describes regulatory practices for price regulation that makes this point clear.

Column 8 is the drop in net revenue to utilities. As can be seen, there is a disincentive for the utilities to be more productive.

Cumulative gas savings from 1980 to 1996 are 63.37 million equivalent bbl. which is about half as much as for the fixed expansion plan.

Figure II-2 is a comparison of gas savings for the fixed expansion plan versus the variable expansion plan. The sudden drops in gas savings in 1985, 1988 and 1994 occur because of coal units that are eliminated in those years. Although the variable expansion plan yields a much greater benefit to the consumer, the high savings in gas consumption for the fixed expansion plan coupled with a tight and unpredictable gas supply market could make the fixed expansion plan a better choice.

II.5.2 Case 2 5 Percentage Point Reduction in Nuclear Plant Forced Outage Rates

In this part of the study productivity improvement is analyzed for a 5 percentage point improvement in nuclear plant forced outage rates uniformly realized over the eight-year period 1980 to 1987. The base case forced outage rate for nuclear plants (17.8%) is assumed to remain constant over the years and is an input to the program. For Case 2, improvement in this outage rate starts in 1980 and the 5 percentage point reduction is realized by the year 1987. Table II-4 shows the way the improvement in forced outage rate is realized. By the year 1987 the forced outage rates for nuclear plants that are already installed or for the plants coming on line is 12.8 percent.

II.5.2.1 Case 2 Assuming a Fixed Expansion Plan

In this case the future generation expansion is kept the same as that used in the base case. The benefits are reductions in the consumption of relatively expensive gas and coal as generation shifts to nuclear. Table II-5 summarizes results obtained using REM.

Column 2 shows the reduction in gas consumption. Comparing this with Case 1 in which the productivity improvement is applied to coal units, it is seen that the gas saving is much lower. This occurs because there is also a shift in generation from the coal units to nuclear units and some of the fuel savings results from reduced consumption of coal.

Column 3 shows this reduction in coal consumption and column 4 shows the increase in nuclear fuel usage.

Column 5 shows the reduction in production expenses. Production expenses include fuel costs and operating and maintenance costs. REM calculates operating and maintenance costs per KWH generated. It should be noted that despite the fact that gas savings for case 2 are significantly less than gas savings for case 1, the reduction in production expenses in

Figure II - 2

Comparison of Gas Saving for Case 1 Alternatives

Table II-4
Assumed Forced Outage Rates for Case 2

Year	Base Case Forced Outage Rate	Improved Forced Outage Rate
1980	17.8	17.175
1981	17.8	16.550
1982	17.8	15.925
1983	17.8	15.300
1984	17.8	14.675
1985	17.8	14.050
1986	17.8	13.425
1987	17.8	12.800
1988-1996	17.8	12.800

Table II-5

Long-Term Savings for Case 2

Fixed Expansion Plan

Nuclear Plant Forced Outage Rate Improved by 5 Percentage Points Over the Eight-Year Period 1980-1987

(1) Year	(2) Reduction in gas consumption Million MCF	(3) Reduction in coal consumption Million s. Tons	(4) Increase in nuclear fuel consumption Mil. Equiv. bbl	(5) Reduction in production expenses 10 ⁶ \$	(6) Percentage reduction in production expenses
1980	0.66	0.001	0.13	1.2	0.04
1982	4.77	0.02	0.97	8.1	0.20
1984	7.52	0.06	1.62	14.8	0.29
1986	12.30	0.16	2.92	29.0	0.45
1988	13.40	0.47	4.31	44.7	0.57
1990	14.11	0.63	5.07	58.0	0.60
1992	14.95	0.73	5.69	70.4	0.60
1994	13.80	1.13	6.93	95.0	0.66
1996	12.50	1.51	8.18	121.3	0.70

Cumulative gas saving from 1980 to 1996 is 32.49 Million Equivalent bbl. (assume 5.8 MBTU/bbl)

Case 2 is substantial. This occurs because of the reduction in high operating and maintenance costs for the coal plants as coal generation is shifted to nuclear. Note that the reduction in production expenses (column 5 of Table II-5) compares favorably with the benefit to consumers in the variable expansion for Case 1 (column 7 of Table II-3). The major portion of the benefits obtained from productivity improvements in this instance goes to the consumer since production costs are paid by the consumer.

II.5.2.2 Case 2 Assuming a Variable Expansion Plan

As nuclear plant forced outage rates are improved, effective installed capacity increases. Overall future generation expansion can therefore be reduced. In all variable expansion plan cases it is assumed that where reduction in installed capacity is feasible, coal plants should be eliminated. This assumption is made because of the higher long-term benefits associated with nuclear units such as reduced fuel and operating and maintenance costs compared to the coal units.

The fixed minimum sizes of coal units that may be eliminated were assumed to be 350, 400 and 450 MW. Figure II-3 shows the installed capacity of generating units in the ERCOT region. Maximum effective capacity for the base case and for Case 2 is shown on Figure II-3. As can be seen there is a gradual increase in maximum effective capacity for Case 2 but since nuclear generation is not a substantial percentage of overall generation in ERCOT this extra effective capacity is not significant. The only coal unit that can be eliminated is a 350 MW unit in 1994. Therefore the results obtained before the year 1994 would be the same as for the fixed expansion plan. The only difference would be a sudden drop in gas savings in 1994 and the following years. There is a reduction in capital investment due to elimination of the one coal unit in 1994.

Fig. II-4 shows a comparison of gas savings for the fixed expansion plan versus the variable expansion plan. As can be seen, until 1994 there is no difference in the gas savings between the two cases, but due to elimination of a coal unit in 1994 gas savings drop.

II.5.3 Case 3 5 Percentage Point Reduction in Coal and Nuclear Plant Forced Outage Rates

In Case 3, benefits are analyzed for a 5 percentage point improvement in coal and nuclear plant forced outage rates uniformly realized over the eight-year period 1980 to 1987. From 1987 on, the outage rate is held constant. In the base case the forced outage rates of nuclear and coal plants are assumed to remain constant over the years. In Case 3 forced outage rates of the nuclear and coal plants decrease by 5/8 of a percentage point every year starting in 1980 achieving a total reduction of 5 percentage points by the year 1987. New plants coming on line after 1987 are assumed to have the improved outage rate incorporated in them. This is illustrated in Table II-6.

II.5.3.1 Case 3 Assuming a Fixed Expansion Plan

In this case the future generation expansion is kept the same as that

$\overline{+}$ Maximum Effective Capacity for the Base Case
 $|+ \Delta$ New Maximum Effective Capacity for Improved Case

Figure II-3

Elimination of Coal Plants for Case 2 Variable Expansion

_____ Fixed Expansion
----- Variable Expansion

Figure II - 4

Comparsion of Gas Saving for Case 2 Alternatives

Table II-6
Assumed Forced Outage Rates for Case 3

Year	Base Case Coal Plant Forced Outage Rate	Improved Coal Plant Forced Outage Rate	Base Case Nuclear Plant Forced Outage Rate	Improved Nuclear Plant Forced Outage Rate
1980	8.3	7.675	17.8	17.175
1981	8.3	7.050	17.8	16.550
1982	8.3	6.425	17.8	15.925
1983	8.3	5.800	17.8	15.300
1984	8.3	5.175	17.8	14.675
1985	8.3	4.550	17.8	14.050
1986	8.3	3.925	17.8	13.425
1987	8.3	3.300	17.8	12.800
1988-1996	8.3	3.300	17.8	12.800

used in the base case while forced outage rates of coal and nuclear plants are improved. The potential benefits obtained are in the form of reduced gas consumption. Table II-7 summarizes the results obtained by comparing the base case with Case 3. Column 2 is the reduction in gas consumption. It is higher than in the previous two cases since both nuclear and coal plant forced outage rates are improved.

Columns 3 and 4 show the increases in coal and nuclear fuel consumption since a shift in generation from gas to coal and nuclear has taken place. This is to be expected as it is more economical to generate electricity using these two fuels than it is to generate electricity using gas.

Column 5 shows the reduction in production expenses. Production expenses include fuel costs and operating and maintenance expenses. REM calculates the operating and maintenance expenses per KWH generated, therefore as there is a shift in generation from gas to coal and nuclear, there is a change in operating and maintenance expenses as well. If operating and maintenance expenses are neglected the reduction in production expenses would be higher.

Cumulative gas savings from 1980 to 1996 are 150.64 million equivalent bbl. Since production costs are paid by the consumer, reductions in these costs flow directly to the consumer. Thus, again the consumer benefits the most.

II.5.3.2 Case 3 Assuming a Variable Expansion Plan

In the variable expansion plan the future generation additions are reduced in such a way that the base case margin is maintained. Reduction in future generation expansion is possible because of the extra availability of the improved coal and nuclear powerplants.

Figure II-5 shows the future generation expansion in the ERCOT region. Maximum effective capacity for the base case and for Case 3 are shown. There is a gradual increase in maximum effective capacity for Case 3 starting in 1980. Since REM operates on a regional basis, the individual units are not specified. Therefore in order to simulate the variable expansion case, fixed minimum coal plant sizes of 350, 400 and 450 MW are assumed. Figure II-5 shows that by the year 1984 there is enough extra capacity to be able to eliminate a coal plant of 400 MW. By the year 1988 another coal unit of 450 MW is eliminated. The third plant to be eliminated is a coal plant of 400 MW in 1994.

Table II-8 shows the results of the comparison between the base case and the variable expansion case. Column 2 shows the reduction in gas consumption. This is smaller than for the fixed expansion case, as would be expected. Column 3 is the change in coal consumption. There is an increase in coal consumption until 1992 due to the fact that some generation shifts from gas to coal. But after 1992, there is a reduction in coal consumption, because at this point in time less expensive nuclear generation can replace some of the coal generation.

Table II-7

Long-term Savings for Case 3

Fixed Expansion Plan

Coal and Nuclear Forced Outage Rate Improved by 5 Percentage Points Over the Eight-Year Period 1980-1987

(1) Year	(2) Reduction in gas consumption Million MCF	(3) Increase in coal consumption Million s. Tons	(4) Increase in nuclear fuel consumption Mil. Equiv. bbl	(5) Reduction in production expenses 10 ⁶ \$	(6) Percentage reduction in production expenses
1980	5.47	0.23	0.13	2.2	0.06
1982	20.43	0.73	0.97	10.7	0.26
1984	37.97	1.39	1.60	18.3	0.35
1986	57.89	2.02	2.92	32.1	0.5
1988	64.25	1.96	4.30	48.5	0.61
1990	66.10	1.85	5.07	64.8	0.67
1992	69.15	1.95	5.69	80.6	0.68
1994	61.28	1.14	6.93	109.0	0.76
1996	52.90	0.41	8.18	137.8	0.80

Cumulative gas saving from 1980 to 1996 is 150.64 Million Equivalent bbl.

$\overline{\uparrow}$ Maximum Effective Capacity for the Base Case
 $\uparrow$ New Maximum Effective Capacity for Improved Case

Figure II-5
 Elimination of Coal Plants for Case 3 Variable Expansion

Table II-8
Long-Term Savings for Case 3
Variable Expansion Plan

Nuclear and Coal Forced Outage Rates Improved by 5 Percentage Points Over the Eight-Year Period 1980-1987

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Reduction in gas consumption Million MCF	Change in coal consumption Million s. tons	Increase in nuclear fuel consumption Million Equiv. bbl.	Reduction in production expenses 10 ⁶ \$	Percentage reduction in production expense	Reduction in construction expenses 10 ⁶ \$	Benefit to consumer 10 ⁶ \$	Drop in net revenue 10 ⁶ \$
1980	5.47	+0.23	0.13	2.2	0.06	18.3	0	-0.1
1982	20.43	+0.73	0.97	10.7	0.26	106.4	12.3	-0.5
1984	13.43	+0.21	1.63	16.1	0.31	26.2	55.5	25.3
1986	35.93	+0.96	2.92	27.5	0.43	151.6	38.1	20.6
1988	30.55	+0.34	4.31	46.9	0.60	0.0	141.2	53.2
1990	36.61	+0.43	5.07	61.9	0.64	34.8	142.6	44.2
1992	41.50	+0.57	5.69	76.3	0.65	205.3	103.0	34.1
1994	31.74	-0.28	6.93	101.6	0.71	0.0	238.1	73.3
1996	31.97	-0.59	8.18	130.4	0.75	0.0	246.9	56.6

Cumulative gas saving from 1980 to 1996 is 90.22 Million Equivalent bbl.

Column 4 shows the increase in nuclear fuel consumption. As nuclear plant forced outage rates are improved they are able to generate more electricity.

From this point in time onward nuclear generation is used to its maximum capability. Column 5 shows the reduction in production expenses. Production expenses include fuel and operating and maintenance expenses.

Column 7 shows the reduction in construction expenses. As the plants are eliminated there is a reduction in construction expenses and therefore less capital is required.

Column 8 shows the benefit to the consumer. It is observed that almost all the benefits go to the consumer.

Column 9 shows the drop in net revenue to utilities; therefore it can be concluded that there is no incentive for them to incorporate the improvement.

Cumulative gas savings from 1980 to 1996 are 90.22 million equivalent bbl.

Figure II-6 is a comparison of gas savings for the fixed expansion plan versus the variable expansion plan. The savings drop in 1984, 1988 and 1994. These are the years in which coal plants are eliminated.

II-5-4 Case 4 7 Percentage Point Reduction in Coal Plant Forced Outage Rates

In this part of the study productivity improvement is analyzed for a 7 percentage point improvement in coal plant forced outage rates uniformly realized over the eight-year period 1980 to 1987. From 1987 on, the outage rate is held constant and any new plants coming on line are assumed to have the improved outage rate incorporated in them. The forced outage rate in the base case is assumed to remain constant at 8.3 percent. Table II-9 shows the assumed forced outage rates for this case. Note that Case 4 is a direct extension of analysis presented in Case 1 but it assumes a larger reduction in coal plant forced outage rates (7% vs. 5% over the eight year period 1980 to 1987).

II.5.4.1 Case 4 Assuming a Fixed Expansion Plan

In this case the future generation expansion is kept the same as that used in the base case while forced outage rates of the coal plants are improved. The benefits are in the form of savings in gas consumption. Table II-10 summarizes results obtained using REM. Results compare the base case with the improved forced outage rate case (Case 4).

Column 2 shows the reduction in gas consumption and column 3 shows the increase in coal consumption as generation shifts from gas to coal. Column 4 shows the reduction in production expenses. Production expenses include fuel costs and operating and maintenance costs. A shift in generation from gas to coal-fired units results in lower fuel costs. REM calculated operating and maintenance costs per KWH generated and since these costs are about three

Figure II - 6

Comparison of Gas Saving for Case 3 Alternatives

Table II-9
Assumed Forced Outage Rates for Case 4

<u>Year</u>	<u>Base Case Forced Outage Rate Percentage</u>	<u>Improved Forced Outage Rate Percentage</u>
1980	8.3	7.425
1981	8.3	6.550
1982	8.3	5.675
1983	8.3	4.800
1984	8.3	3.925
1985	8.3	3.050
1986	8.3	2.175
1987	8.3	1.300
1988-1996	8.3	1.300

Table II-10
Long-Term Savings for Case 4
Fixed Expansion Plan

Coal Plant Forced Outage Rates Improved by 7 Percentage Points over the Eight-Year Period 1980-1987.

(1)	(2)	(3)	(4)	(5)
Year	Reduction in gas consumption Million MCF	Increase in coal consumption Million S. tons	Reduction in production expenses 10 ⁶ \$	Percentage reduction in pro- duction expenses
1980	6.73	0.32	1.5	0.04
1982	21.94	1.05	3.5	0.08
1984	42.66	2.04	4.9	0.09
1986	64.01	3.06	4.3	0.07
1988	71.50	3.42	5.4	0.07
1990	73.20	3.50	9.7	0.10
1992	76.36	3.78	14.4	0.12
1994	67.13	3.20	19.8	0.14
1996	56.45	2.74	23.4	0.14

Cumulative gas saving from 1980 to 1996 is 166.39 million equivalent bbl.

times higher for coal-fired units than for gas units, a shift in generation from gas to coal results in significantly higher operating and maintenance costs. Thus fuel costs go down and operating and maintenance costs go up. The difference in these two costs is the reduction in production expenses. Were it not for the high operating and maintenance costs associated with the coal plants, the reduction in production expenses would be much higher. Column 5 shows the percentage reduction in production expenses. Cumulative gas savings are 166.3 million equivalent bbl. from 1980 to 1996. This is the highest gas saving observed in any of the cases.

II.5.4.2 Case 4 Assuming a Variable Expansion Plan

In the variable expansion plan future generation expansion can be reduced due to improved availability of the installed coal plants. This reduction is achieved in such a way that the base case reserve margin is maintained.

REM operates on an aggregate regional basis. That is, the units have not been specified. Therefore, in order to simulate the variable expansion case, fixed minimum coal plant sizes of 350, 400 and 450 MW are assumed.

Figure II-7 shows the future planned installed capacity and respective base case maximum effective capacity. New maximum effective capacity after improvement has also been shown. As can be seen there is a gradual increase in maximum effective capacity as improvement is applied to the coal plants.

In the year 1984 there is 460 MW of capacity available. At this point in time a coal unit of 400 MW is eliminated. By the year 1987 we have enough extra capacity available to eliminate a second coal unit of 400 MW.

In the following year we are in a position to eliminate a third coal unit of 400 MW. Two more coal units of 400 MW each are eliminated in the years 1994 and 1996.

Table II-11 summarizes the results obtained by comparing the base case with Case 4. Columns 2 and 3 show the reduction in gas consumption and the increase in coal consumption respectively. The reduction in gas consumption is much smaller than for the fixed expansion plan. This is expected as the elimination of coal units results in a small shift in generation from gas to coal.

Column 6 shows the reduction in construction expenses. Elimination of five coal units results in the greatest reduction in construction expenses which in turn causes the greatest drop in capital investment for all the cases investigated.

Column 7 shows benefits to the consumer. There is a loss to consumers in the years 1980 and 1982. This is due to the fact that Interest During Construction (IDC) drops as the plants are eliminated and with a fixed rate of return there would be a temporary increase in gross revenue to utilities.

$\uparrow$ Maximum Effective Capacity for the Base Case
 $\leftarrow$ New Maximum Effective Capacity for Improved Case

Figure II-7

Elimination of Coal Plants for Case 4 Variable Expansion

Table II-11
Long-Term Savings for Case 4
Variable Expansion Plan

Coal Plant Forced Outage Rates Improved by 7 Percentage Points over the Eight-Year Period 1980-1987

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Year	Reduction in gas consumption million MCF	Increase in coal consumption million s. tons	Reduction in production expenses 10 ⁶ \$	Percentage reduction in production expenses	Reduction in construction expenses 10 ⁶ \$	Benefit to consumers 10 ⁶ \$	Drop in net revenue 10 ⁶ \$
1980	6.73	0.32	1.5	0.04	18.3	-0.8	-0.1
1982	21.94	1.05	3.6	0.09	108.0	-19.2	-0.2
1984	17.89	0.84	2.7	0.05	85.1	32.8	25.7
1986	41.80	1.99	3.4	0.05	202.8	46.0	52.2
1988	22.97	1.08	3.2	0.04	0.0	148.5	82.2
1990	30.79	1.45	5.4	0.06	34.8	139.0	74.7
1992	36.67	1.78	8.3	0.07	245.0	85.4	66.1
1994	28.83	1.36	10.2	0.07	237.0	155.0	107.0
1996	22.82	1.07	11.4	0.07	0.0	289.1	152.7

Cumulative gas saving form 1980 to 1996 is 83.13 million equivalent bbl.

Column 8 shows the drop in net revenue to utilities. So there is no incentive for them to be more productive.

Figure II-8 shows gas savings for the fixed expansion plan versus the variable expansion plan. There are sudden drops in gas savings in the variable expansion plan whenever a coal unit is eliminated.

Cumulative gas savings are 83.13 million equivalent bbl.

II.5.5 Case 5 3 Percentage Point Reduction in Coal Plant Forced Outage Rates

In this part of the study productivity improvement is analyzed for a 3 percentage point improvement in coal plant forced outage rates uniformly realized over the eight-year period 1980 to 1987. From 1987 on, the outage rate is held constant and any new plants coming on line are assumed to have the improved forced outage rate incorporated in them. The forced outage rate in the base case is assumed to remain constant at 8.3 percent. Table II-12 shows the assumed forced outage rates for Case 5. Note that Case 5 is a direct extension of the analyses presented in Cases 1 and 4. These three cases considered together permit examination of the effects of reducing coal plant forced outage rates over a range of improvement scenarios.

II.5.5.1 Case 5 Assuming a Fixed Expansion Plan

In this case the future generation expansion is kept the same as that used in the base case while forced outage rates of the coal plants are improved by 3 percentage points over an eight-year period (1980-1987). Benefits are in the form of reduced gas consumption. Table II-13 summarizes results using REM. Results compare the base case with the improved forced outage rate case (Case 5).

Column 2 shows the reduction in gas consumption and column 3 shows the increase in coal usage. Note the shift in generation from gas to coal. Column 4 shows the reduction in production expenses. Production expenses include fuel costs and operating and maintenance costs. REM calculates operating and maintenance costs per KWH generated and since these costs are about three times those of gas units, a shift in generation from gas to coal results in significantly higher operating and maintenance costs. Thus fuel costs go down and operating and maintenance costs go up. The difference in these two costs is the reduction in production expenses. Were it not for the higher operating and maintenance costs associated with the coal plants, the reduction in production expenses would be much higher. Column 5 shows the percentage reduction in production expenses. Cumulative gas savings are 74.34 million equivalent bbl. from 1980 to 1996.

II.5.5.2 Case 5 Assuming a Variable Expansion Plan

As powerplant productivity is improved, plant availability is increased. In the variable expansion plan, future planned generation is reduced in such a way that the base case reserve margin is maintained.

Figure II - 8

Comparison of Gas Saving for Case 4 Alternatives

Table II-12
Assumed Forced Outage Rates for Case 5

<u>Year</u>	<u>Base Case Forced Outage Rate Percentage</u>	<u>Improved Forced Outage Rate Percentage</u>
1980	8.3	7.925
1981	8.3	7.550
1982	8.3	7.175
1983	8.3	6.800
1984	8.3	6.425
1985	8.3	6.050
1986	8.3	5.675
1987	8.3	5.300
1988-1996	8.3	5.300

Table II-13

Long-Term Savings for Case 5

Fixed Expansion Plan

Coal Plant Forced Outage Rates Improved by 3 Percentage Points over the Eight-Year Period 1980-1987.

(1)	(2)	(3)	(4)	(5)
Year	Reduction in gas consumption Million MCF	Increase in coal consumption Million S. Tons	Reduction in production expenses 10 ⁶ \$	Percentage reduction in pro- duction expenses
1980	2.89	0.14	0.6	0.02
1982	9.44	0.45	1.5	0.04
1984	18.43	0.88	2.1	0.04
1986	27.95	1.34	1.9	0.03
1988	31.76	1.52	2.4	0.03
1990	32.73	1.56	4.3	0.04
1992	34.24	1.69	6.4	0.05
1994	30.76	1.47	9.0	0.06
1996	27.20	1.30	11.0	0.06

Cumulative gas savings are 74.34 million equivalent bbl.

Figure II-9 shows the future planned generation. The maximum effective capacity increases as the improvement is realized. Since REM operates on an aggregate regional basis, individual units have not been specified. Therefore, to simulate the variable expansion case fixed minimum plant sizes of 350, 400 and 450 MW are assumed.

As shown in Figure II-9, by the year 1988 there is enough extra capacity so that a coal unit of 400 MW can be eliminated. A second coal unit of 400 MW is eliminated in 1995.

Table II-14 shows the results obtained by comparing the base case with Case 5. Column 2 shows the reduction in gas consumption and column 3 shows the increase in coal usage. Compared to the fixed expansion there is a smaller reduction in gas usage. This is due to the fact that two coal units have been eliminated.

The reduction in production expenses is shown in Column 4. This includes fuel costs as well as operating and maintenance costs.

Column 6 shows the reduction in construction expenses. This is due to the elimination of the coal units which causes the capital investment to drop.

Column 7 shows the benefit to the consumers. The major portion of the benefits go to the consumers. As can be seen, there is a loss to the consumers in the years 1984 and 1986. This is because Interest During Construction (IDC) drops as the plants are eliminated, and with a constant rate of return there would be a temporary increase in revenue to utilities. The regulatory process that would make this clear has been described in Appendix F.

Column 8 shows the drop in net revenue to utilities. The utilities lose their revenue for being more productive so there is no incentive.

Figure II-10 shows gas savings for the fixed expansion plan versus the variable expansion plan. There is a sudden drop in gas savings in the year 1988 and 1995. This is due to the elimination of coal plants in those years. Cumulative gas savings are 51.93 million equivalent bbl.

II.6 Summary of Long-Term Cost Benefits

In all of the five cases considered, reductions in forced outage rates result in the major portion of the benefits going to the consumer. In the variable expansion plan situations, the reduction in capital investment would result in a negative benefit to utilities under current regulatory mechanisms in that the rate base would be reduced. In the fixed expansion plan situations, the benefits are in the form of fuel savings, namely gas savings for the ERCOT region.

Improvement in forced outage rates of coal units alone produces significantly different results than improvements in forced outage rates of nuclear units alone. Improvement in coal unit forced outage rates alone results in

$\overline{+}$ Maximum Effective Capacity for the Base Case
 $|+ \overline{+}$ New Maximum Effective Capacity for Improved Case

Figure II-9

Elimination of Coal Plants for Case 5 Variable Expansion

Table II-14

Long-Term Savings for Case 5

Variable Expansion Plan

Coal Plant Forced Outage Rates Improved by 3 Percentage Points Over the Eight-Year Period 1980-1987

(1) Year	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Reduction in gas consumption million MCF	Increase in coal consumption million s. tons	Reduction in production expenses 10 ⁶ \$	Percentage reduction in production expenses	Reduction in construction expenses 10 ⁶ \$	Benefit to consumers 10 ⁶ \$	Drop in net revenue 10 ⁶ \$
40 1980	2.89	0.14	0.6	0.02	0.0	0.6	0.0
1982	9.44	0.45	1.5	0.04	0.0	1.7	0.1
1984	18.44	0.88	2.1	0.04	23.3	-0.7	0.0
1986	27.95	1.34	1.9	0.03	134.8	-27.6	-0.8
1988	15.56	0.74	1.7	0.02	0.0	55.0	31.8
1990	18.39	0.87	2.9	0.03	2.4	54.4	28.4
1992	20.72	1.02	4.4	0.04	94.8	35.5	25.1
1994	20.77	0.99	6.5	0.05	107.6	96.2	69.4
1996	12.74	0.60	6.0	0.03	0.0	124.2	64.0

Cumulative gas saving 1980 to 1996 is 51.93 million equivalent bbl.

Figure II - 10

Comparison of Gas Saving for Case 5 Alternatives

relatively high gas savings and relatively low reductions in production expenses. Improvement in nuclear unit forced outage rates alone results in relatively low gas savings and relatively high reductions in production expenses. This is a direct result of the relatively high operating and maintenance costs associated with the coal plants and the low percentage of nuclear generation in the ERCOT region for the time period considered. This suggests that if gas savings are of primary concern, efforts should be concentrated on improving coal plant forced outage rates. Moreover, the expansion plan should not be significantly changed if the gas savings are to be realized since it has been shown that going from a fixed to a variable expansion plan generally cuts gas savings in half. If reductions in production expenses are of primary concern, efforts should be concentrated on improving nuclear plant forced outage rates. If maximization of benefits to consumers is of primary concern, a 5 percentage point reduction in coal and nuclear plant outage rates (Case 3) produces consumer benefits comparable to a 7 percentage point reduction in coal plant forced outage rates alone (Case 4) provided that future coal plants are eliminated to the maximum extent possible (i.e. the variable expansion plan). Unfortunately, as has been shown, the variable expansion plans produce a drop in net revenue under current regulatory practices.

CHAPTER III. REGULATION AND POWERPLANT PRODUCTIVITY

III. REGULATION AND POWERPLANT PRODUCTIVITY

III.1 Introduction

The basic purpose of Chapters III and IV is to introduce and discuss a general incentive format that would add to rate of return regulation a clear and positive relationship between profit and efficiency in the long run as well as the short run. The general incentive format developed in this chapter and briefly illustrated in the next chapter is designed to reward increased system efficiency and encourage cost-effective powerplant productivity improvements. In general terms, the incentive format presented in this study states that if the utility voluntarily demonstrates that a specified system efficiency improvement program results in a net savings, then the utility is to receive (over and above its allowed return) a fraction of that net savings. The fraction that goes to the utility depends upon the present performance level of its base load capacity.

During the 1950s and the 1960s, electric utilities in general faced relatively low capital and variable costs (e.g., fuel and labor). In fact, most utilities operated under a decreasing cost structure. In other words, average total cost was decreasing as output increased. Consequently, during that period of time, in the case of most electric utilities, powerplant productivity improvements did not offer sufficiently high total system cost savings to raise a highly visible issue.

The decade of the 1970s, in contrast, witnessed a drastic change in the cost structures of electric utilities. In the past 10 years, electric utilities have experienced sharp upturns in the cost of capital as well as the cost of variable inputs (e.g., fuel). As a result, the electric utility industry, as a whole, shifted from a decreasing cost structure to an increasing cost structure. During periods of increasing average total cost (i.e., as output increases), the value of powerplant productivity (and/or system efficiency) improvements increases. It is during those time periods, therefore, that the issue of powerplant productivity and system efficiency improvement becomes more highly visible.

On the whole, the electric utility industry is presently in a weak financial condition. Although there are a few electric utilities which are still fairly strong financially, all utilities are having at least some difficulty acquiring the funds to pursue necessary capital expansion. Prior to 1970, when capital costs were relatively low (and perhaps decreasing on the average as output increased), the selling price of virtually all electric utilities' common stock exceeded their book value, and from 1958 to 1969 the annual increase in stock price was 4.4%. During the 1970s, however, this trend was reversed and by 1978 a vast number of utility stocks sold for less than their book value. For all electric utilities between 1970 and 1978, stock price actually decreased at an average annual rate of 5%. This situation can be attributed at least to some extent to inadequate revenues (and, therefore, returns) allowed in the regulatory process. When excessive downward pressure on customer

charges due to public pressure (or other reasons) persists beyond the short run, the financial health of the utility is jeopardized. This hurts their bond rating in the money market and lowers the market value of their common stock. Raising funds for new plant construction under those circumstances becomes a difficult and expensive undertaking. Before proceeding, it should be emphasized that the existing financial condition of a utility affects its ability to participate effectively in a voluntary incentive program. The impact of a utility's financial stability on its ability to take full advantage of a financial incentive program will be clarified later in this chapter.

The remainder of this chapter presents and discusses the general incentive format. The text of this chapter does not contain highly technical material and, therefore, the reader can obtain an overall view of how voluntary financial incentives can operate within a rate of return regulatory environment without having to deal with the highly technical details of the regulatory process. A more technical discussion and theoretical defense of voluntary incentive plans such as the general format established in this study can be found in the Appendix (as footnoted in later sections of this chapter).

While reading through the following discussion of the general incentive format, the reader should keep in mind that voluntary incentive plans which promote increased powerplant productivity and system efficiency can impact both short and long-run costs. Whenever a cost-effective powerplant productivity improvement is implemented, there are associated fuel and capital savings. The fuel savings are enjoyed immediately and the capital savings occur over a longer time horizon in the form of lower base load capacity requirements to meet demand expansion (e.g., the timetable of future plant construction may be backed off a finite period). Also, the implementation of many possible cost-effective powerplant productivity improvement projects may require at least a moderate capital investment.

III.2 System Efficiency, Powerplant Productivity, and Incentive Programs

Ultimately, the purpose of the type of voluntary incentive format proposed in this study is to encourage electric utilities to seek all means of increasing system efficiency. More precisely, under the general incentive format, a utility is rewarded for any identifiable system efficiency improvement program that leads to a decrease in average total cost of system operation. One of the more promising areas of system efficiency improvement is powerplant productivity (e.g., as measured by system availability, outage rates, etc.). Due to the precipitous increase in the cost of new plant construction that has occurred over the past 10 years, even a small percentage increase in powerplant productivity can represent a substantial total dollar savings. In effect, the increased utilization of older, less costly existing generating units decreases the present and/or future level of required expenditures on more costly replacement units.

As the cost of new base load generating capacity increases, the dollar savings associated with a given percentage improvement in powerplant performance increase. As a consequence, given the present trend in construction

costs, productivity improvements can work. Such improvements can be cost effective (as discussed in the next section of this chapter). And, under the general incentive format, it is clear that all parties can benefit from cost-effective powerplant productivity improvements. A voluntary incentive program which successfully encourages cost-effective powerplant productivity improvements is good for the regulatory commission and the customers it represents since the resulting short and long-run cost reductions translate into lower rates for customers than would otherwise occur. From the viewpoint of the utility, it will be able to earn greater profit than would otherwise be allowed. The only reason why all parties can benefit from a voluntary incentive program that falls within the framework of the general incentive format is that the utility will only choose productivity improvement projects (or other system efficiency plans) that are cost effective. Essentially, all cost-effective efficiency improvement projects are similar, in a financial context, to windfall gains (i.e., the benefits from the improvement projects exceed the cost of implementation).

As stated in Section III.1, the primary driving force behind the general incentive format proposed in this study is created by offering utilities a portion of any net saving resulting from an identifiable program designed to lower average total cost (per Kwh consumed). The fraction of that net savings retained by the utility is tied to the existing performance level of its base load capacity (e.g., outage rate, availability factor, etc.). The general incentive format, therefore, establishes a reward which is based on two factors. The first of these factors is the net savings that arise from a given productivity improvement plan. In simple notation this could be written as follows:

$$\text{Net savings or benefit} = (S_i - C_i)$$

Where:

S_i is the total capital and fuel savings attributed to completion of the i th system efficiency improvement project. For example, this could refer to the savings created by operating a given plant (categorized by fuel type and outage) at productivity levels higher than last period's levels or by implementing a rate structure that facilitates a redistribution of the peak load.

C_i is the cost of implementing the i th system efficiency improvement project.

The second factor, σ_i , is the fraction of the net capital and fuel savings to be retained by the utility after the successful completion of the i th improvement project. As discussed earlier, the fraction of the net savings retained by the utility, σ_i , is related to the present performance level of its base load generating capacity. Multiplying net savings $(S_i - C_i)$ by σ_i gives us the increase in utility profits attributable to the i th improvement project (i.e., $\sigma_i(S_i - C_i)$ where $i = 1, \dots, n$ projects). The total increase in profit attributable to the voluntary incentive program is the sum of the partial profits of all individual improvement projects.

The portion of net savings returned to customers through the rate structure is $(1 - \sigma_i)(S_i - C_i)$.

$$\text{Total increase in profit} = \sum_{i=1}^n \sigma_i (S_i - C_i) = \text{Incentive Profit.}$$

The incentive program should be voluntary to be truly effective; and under a voluntary format, the sign of $(S_i - C_i)$ is expected to be positive. The utility will order its timetable of chosen projects according to their relative degree of cost effectiveness (i.e., the projects which exhibit the greatest positive value for $(S_i - C_i)$ will be undertaken first), except in those cases where the necessary capital investment to facilitate the project is excessive.

Due to the basic framework of the general incentive format as described above, system-wide cost savings are encouraged with emphasis placed on cost-effective increases in powerplant productivity. As the cost effectiveness of an improvement project increases (i.e., as $(S_i - C_i)$ increases), the incentive profit also increases. But if the present level of the utility's powerplant productivity is low relative to a reasonable standard (for its given mix of base load units), then the share of the net savings retained by that utility, σ_i , will also be low. If, on the other hand, the performance level of the utility's base load units is high, its retained share of net savings would be higher.

The positive correlation between base load unit performance levels and σ_i is necessary to insure that all participating utilities have equal opportunities to participate in a voluntary incentive program. The utility whose present base load performance level is low relative to a reasonable standard for its mix of base load units has a greater number of cost-effective powerplant productivity improvement projects to choose from than the utility with a higher performance level. Also, since many of the more cost-effective projects require added capital expenditures, the utility with the higher powerplant performance history has probably exhausted most of the low-cost projects and can expect to experience higher investment requirements for the cost-effective projects available to them.¹

A utility which is consistently constrained to a level of total revenue inadequate to cover existing debt service, new debt service, all other operating costs, and an adequate return to common stock (to maintain price above book value), however, may not be able to finance many of the cost-effective improvement plans requiring added capital expenditures. The utility in that financial condition has difficulty acquiring any level of funding in the money market, at reasonable rates, for needed capital expansion. Rather than add new capital at a loss, the utility in this financial situation would first pursue the lowest cost strategies for keeping base load units on line longer and then turn to intermediate

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¹ For a more detailed discussion of this topic and a sample schedule relating powerplant performance levels, see Table IV-1 in Chapter IV and the relevant sections of Appendix G (Volume I) and Appendices A - D (Volume II).

units to cover base load expansion. Given that demand increases over time and that fuel adjustment clauses exist, the utility will be induced to burn more expensive fuel rather than expand base load capacity at a loss.

The utility in this situation is most in need of rate relief and the benefits offered by an incentive program, yet it is this utility that may be least able to take advantage of an incentive program. Most powerplant productivity improvements that are highly cost effective can be expected to entail at least a moderate additional capital expenditure. A utility in relatively good financial condition can pursue a number of improvement projects at one time even if relatively large expenditures are necessary. On the other hand, the financially weak utility will be limited to a few projects at most, and perhaps will be unable to finance many of the more cost-effective plans which require additional capital expenditures.

Although in the short run a voluntary incentive plan may be able to soften the financial burden a utility faces due to inadequate rate relief, in the long run this financial condition should be handled more directly in a rate hearing. In order to take full advantage of a voluntary incentive plan, the utility should not be in a persistently weak financial position. An adequate return and a voluntary incentive plan together can tend to lower costs for the utility in the long run and, consequently, lower rates for its customers. Excessively low rates in the short run that result in inadequate revenues to maintain the financial stability of the utility end up costing the customer more in the long run. An incentive plan, therefore, should not be viewed as a long-run correction for financial instability created by consistently low levels of allowed rate of return (or inadequate customer charges to earn that allowed rate of return).

Regulation of natural monopolies such as electric utilities is essential from society's viewpoint. The technology of electrical generation--yielding large economies of scale--forces public utilities to positions of substantial market power if not outright monopoly. Allowing many firms to compete within that industry would sacrifice the cost savings offered by a single firm. In exchange for exclusive franchise, public supervision and scrutiny have been used to control prices, profit, quality and reliability.

Stated in a different manner, the purpose of public utility regulation is to retain for consumers the benefits offered by a single firm operation without incurring the burden of monopoly prices and profits. The operating efficiency associated with the (competitive) free market is the logical target for regulation, and the long-run minimization of electrical costs is society's reward for success. The reader should keep in mind that, in a free market, a firm will adopt the lowest cost-productive arrangement of capital, fuel, labor, etc. available, because profits can always be improved through cost reductions. This unquestionable link between profit

and efficiency drives the competitive free market, but is unclear in the long run in a rate of return regulated environment.²

III.3 Powerplant Productivity Improvements: Cost-Effective Possibilities

As discussed earlier in this chapter and detailed in the Appendix, economic theory indicates that current rate of return regulatory policies adopted by most State regulatory bodies are not sufficiently flexible to guarantee utilities higher long-run profits for increases in total system efficiency, especially in the area of powerplant productivity. Since it is imprudent to make policy recommendations and encourage regulatory changes strictly upon the basis of theoretical findings, experience must be considered before proceeding. As discussed in Chapter I, however, there does exist a multitude of reports and studies that indicate the agreement of experience and theory on two basic points: first, that improved productivity at the powerplant level can yield significant benefits (which could then be split between utility stockholders and electricity customers), and second, that there are steps which can be taken to increase the presence of financial incentives for improving powerplant efficiency within the typical regulatory environment (1-19).

Some of the findings of studies, performed on behalf of the U.S. Department of Energy (and its predecessor, the Federal Energy Administration), by Mechanics Research, Inc. (MRI), Nuclear Service Corporation (NSC), and Trident Engineering Association (TEA) highlight the first of these points quite adequately. Their interest, and ours, focuses on base load plants (primarily coal and nuclear). And, as a whole, they agree that for a great number of productivity improvement plans the resulting benefits far exceed the cost of implementation. In one extreme case, MRI found that the cost of replacing the feedwater control valve in a specific nuclear plant (\$21,000) was dwarfed by the value of the projected benefits (\$20,000,000). All three studies agree that the major factors influencing efficiency at the powerplant level include the following: coal quality (for coal-fired plants), maintenance practices, system demand, personnel experience, regulatory requirements, and vintage (novelty) of the design (11-13). And there is general agreement that each of these areas offers the possibility of significant improvements in powerplant productivity. These findings are further supported by the 1978 General Electric Study which examined in detail the benefits to be derived from improved powerplant reliability and productivity (17).

The second point, concerning the lack of financial incentives for improving powerplant productivity, has been examined not only in economic literature, but also by Federal and State level agencies (i.e., NARUS and FEA, now DOE). One Federal Energy Administration report found that the

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² For a theoretical defense of this statement, see Appendix G (Volume I) and Appendices A - D (Volume II).

effective operation of financial incentives for improving powerplant productivity appears, at best, uncertain (1).

III.4 Summary

The most salient quality of a voluntary incentive program such as presented in this study is that if implemented in the proper setting it will encourage and financially facilitate the rapid adoption of all identifiable cost-effective system efficiency improvements. Utility executives and personnel tend to respond to public pressure as much as possible within the bounds created by the financial constraints inherent in rate of return regulation. Many of the capital investment choices and operational procedures selected by management are good for the consumers, but unfavorable for stockholders. Even though utility management may choose to implement a certain number of efficiency improvement plans that lower total system costs but have uncertain impacts upon long-run total profit, many cost-effective plans must be passed over because of the financial burden they impose on the utility in the form of added capital expenditure in the present.

The strong positive correlation between profit and efficiency that is created by an effective voluntary financial incentive plan would enable participating utilities to increase the pace at which they can undertake system efficiency improvement projects and know with certainty that both the immediate and future financial stability of the utility will be strengthened. Ultimately, the electricity consumer benefits the most from a voluntary incentive plan. Every time a cost-effective productivity improvement is implemented under a voluntary incentive format, cost per kilowatt hour consumed is decreased both in the short and long term. And just as cost increases are reflected in higher customer charges, cost savings lead to lower charges.

It is evident that increases in powerplant performance levels can lead to significant savings of both capital and fuel. Appendix A and Chapter II discuss the findings of a number of simulated improvements in powerplant productivity. Three different models were utilized and compared, and the outputs of all three verify the position that powerplant improvements lead to both capital and fuel savings. Section III.3 in this chapter references studies which indicate that there exist numerous areas of productivity improvement that are notably cost effective.

Due to the publicity that has been given to the rapid increase in the cost of petroleum products since the early 1973 oil embargo, consumers tend to be more aware of possible fuel savings than capital savings. Yet, due to the regulatory process, the precipitous increase in the cost of new construction has had a substantially greater impact upon the financial health of electric utilities.³ In contrast to fuel savings, capital

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³ The increased utilization of automatic fuel adjustment clauses has shifted most of the risk of regulatory lag as far as escalating fuel costs are concerned on to the consumer. Construction work in progress, however, has not typically been handled in this manner; escalating construction costs are not as expeditiously shifted from the consumer.

savings are enjoyed mostly in the long run. Considering the length of time new plant construction now requires and the high cost of that construction, the benefits to be gained from cost-effectively increasing the performance characteristics of existing base load units warrant greater financial encouragement than typical rate of return regulation presently offers. A voluntary incentive program such as the general incentive format can fill that gap in the existing framework of utility regulation.

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CHAPTER IV. IMPLEMENTING AN INCENTIVE PLAN

IV. IMPLEMENTING AN INCENTIVE PLAN

IV.1 Introduction

In the last chapter a general type of voluntary incentive format was developed which increased the capability of rate of return regulation to encourage cost-effective powerplant productivity improvement plans (and other system-wide efficiency programs). This favorable addition to regulatory environment is created by the establishment of a clear link between profit and efficiency, a quality which is not present in typical rate of return regulation. The task which remains is to trace the steps that would actually be taken both by the utility considering the incentive program and the regulatory agency offering the initiative. The basic framework of this chapter is twofold: first, an outline and a detailed examination of the ground rules for both existing and new plant incentive plans are presented, and second, a reasonable improvement scenario is considered in order to illustrate the salient calculations that must be made by the regulated utility and the regulatory agency.

A total incentive plan must have provisions to deal both with existing capital stock as well as proposed capital expansion. In actuality, the general proof in Appendix G, which shows that a properly designed incentive program would encourage increasingly efficient capital choices, makes no distinction between existing and new capital (expanded in Volume II, Appendix C for variable quantity). For practical application, however, it is necessary at first to isolate new and existing plant productivity incentives into two separate programs.

For the convenience of the reader, before proceeding into the details of the incentive program, we have included the following outline and brief description of the upcoming sections of this chapter.

- o Existing Powerplants, Phase 1: Regulatory Commission will allow a return consisting of a benchmark profit plus a percentage of net cost savings from a productivity improvement.
- o Existing Powerplants, Phase 2: Standards can be utilized as an alternative to benchmark profit levels. Benchmark profit level will be phased out and standards will be set up. The utility will increase its return by exceeding the standards.
- o New Powerplants: Performance standards are established for each prospective plant. Similar to Phase 2.
- o Net Cost Savings: Both fuel and cost savings occur when cost-effective system improvement programs are implemented. Procedures for determining these savings are outlined.

IV.2 An Incentive Plan for Existing Powerplants: The Decisionmaking Process

Before an electric utility can make a decision to participate in an incentive program for existing powerplants, it must first determine that,

in its judgment, the stockholders and the company as a whole would benefit from that move. In effect, utility personnel would have to project an increase in future profits under the incentive plan before such a project would be considered. A determination that an increase (or no decrease) in future profits would occur requires that the regulated utility know the values for the following variables: the present benchmark level of total profit, the allowable profit that would be expected in the next regulatory round without an incentive program, the projected net benefit that would result from a planned improvement program (cost saving over and above the cost of implementing the improvement), and the fraction of the net benefit cost savings retained by the utility.

The utility should know last period's profit from the most recent rate proceedings, as well as capital, and should have a good idea of the magnitude of the spread between allowed rate of return and market cost of capital. The two remaining figures are: the project cost savings which would result from the proposed productivity improvement plan, and the fraction of the net savings to be retained by the utility. The first will be elaborated in Section IV.7.

IV.3 Phase 1: Initiating an Incentive Program for Existing Powerplants and the Splitting of Net Cost Savings between the Utility and Its Customers

In reference to an incentive program for existing powerplants, the total profit allotted to the utility has so far in this analysis been defined as the sum of the usual regulated profit plus the utility's portion of net benefit or total cost savings.¹ A more facile application of this same incentive principle in the start-up phase of the program would entail guaranteeing the utility a target level of profit, A , based on last period's profit, given that the utility can demonstrate that a net savings does result from a productivity improvement program, plus some portion, σ , of that net cost savings. The calculation of profit (or net revenue) would then be made as follows:

$$\text{Total profit} = A + \sigma_i (S_i - C_i)$$

Where:

A is last period's profit.

S_i is the total capital and fuel savings attributed to operating the i th powerplant (categorized by fuel type and vintage) above last period's levels.

C_i is the cost of implementing performance improvements in the i th powerplant that creates the capital and fuel savings.

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¹ See Appendix C (Volume II) for the derivation of net savings.

σ is the fraction of the net capital and fuel savings to be retained by the utility for the i th powerplant category.

The establishment of a σ greater than zero guarantees that the corresponding incentive is sufficiently high to induce the utility to implement a cost-effective productivity improvement plan. For purposes of identification, this form of the incentive plan is referred to as Phase 1.

Prior to the offering of an incentive program, the regulatory agency would be responsible for establishing a set of σ schedules for different plant types. The level of σ in each schedule should be set to increase as the level of base load plant performance increases. In this manner, as demonstrated in the last section of this chapter, the utility will be continually induced to move actual capitalization closer to the cost minimal level. This positive correlation between σ and powerplant productivity also satisfies an equity consideration. Those utilities that exhibit higher levels of powerplant performance for their base load units at any point in the incentive program should receive a greater portion of the cost savings they may achieve. As the system-wide performance level (e.g., outage rate, availability factor, etc.) of any given utility improves, each consecutive cost savings becomes more difficult and less cost effective. Yet to approach the cost-minimal mix of fixed and variable inputs over time, the utility must be encouraged to seek all cost-effective improvements regardless of magnitude. Logically, the utility will choose to undertake the most cost-effective improvements first since they will yield the highest incentive reward, and then proceed to undertake improvements that yield lesser rewards in descending order of cost savings.

For the purposes of this study, Table IV-1 established the relationship between σ and equivalent availability and forced outage rate (as performance measures) for the different plant types as indicated.²

A composite σ schedule for an individual utility could be determined by the relative mix of the plant types in that system. The composite schedule would be a weighted average of the individual schedules, the weights being determined by the percentages of system base load attributable to each fuel type. It would be easier, however, to treat each fuel type separately and aggregate the incentive rewards (or penalties) due each category.

In the following schedule, σ approaches zero when equivalent availability approaches a level for each plant type, deemed by the regulatory agency to be a reasonable minimum requirement (i.e., a level below which there would be no realized cost savings). Whether or not it is on an incentive program, if the utility operates below that level, the regulatory agency (if it judges the poor performance to be due to negligence on the

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² Equivalent availability has been allocated as a representative measure of powerplant productivity. In practice, there are a number of possible measures or combination of measures that will be utilized.

Table IV -1
Incentive Schedule

OLD COAL			NUCLEAR			NEW COAL & LIGNITE		
σ	E.A.	F.O.R.	σ	E.A.	F.O.R.	σ	E.A.	F.O.R.
.30	88-100	1-4	.25	88-100	1-5	.35	88-100	1-5
.25	85-87	5-6	.20	85-87	6-7	.30	85-87	6-7
.20	81-85	7-9	.15	81-84	8-9	.25	81-85	8-9
.15	76-80	10-14	.10	76-80	10-14	.20	76-80	10-14
.10	71-75	15-20	.07	71-75	15-20	.15	71-75	15-20
.07	66-70	21-25	.05	66-70	21-25	.10	66-70	21-25
.05	61-65	26-30	.03	61-65	26-30	.07	61-65	26-30
.03	56-60	31-40	.01	56-60	31-40	.05	56-60	31-40

part of the utility) may remove from profit (net revenue) all or part of the additional cost that the lower performance level causes, i.e., costs above the minimum performance level.

The levels of σ in Table IV-1 have been arbitrarily set at levels above zero. A regulatory agency that offers an incentive program of this nature would establish a schedule that provides adequate incentive for the utility to implement all cost-effective productivity improvements while insuring that a fair portion of the savings is passed on to the customers. The actual computation of profit under a Phase 1 incentive plan would occur as follows:

$$\text{Total profit} = A + \sum \sigma_i (S_i - C_i)$$

IV.4 Phase 2: Establishing Performance Standards for Existing Powerplants

It should be noted that the utilization of $A + \sum \sigma_i (S_i - C_i)$ as the rule for determining Phase 1 profit has been proposed in order to utilize the observable level of profit, A. It would be unrealistic to expect a utility to embark on an incentive plan which would result in a drop in total profit in the long run. A variation of this general incentive format would be to set the base line profit as would be determined in a current rate hearing. Then, after experience is gained under an incentive program and patterns

are established for reasonable minimum performance standards (and the utilities are in agreement), the regulatory agency could adopt the following format for computing profit (Phase 2):

$$\text{Total profit} = B + \sum \rho_i (S_i^* - C_i)$$

Where:

B is the usual profit allowed under rate of return regulation.

S_i^* is the plant (categorized by fuel type and vintage) above a minimum performance standard.

C_i is the cost of implementing the improvements that create the capital and fuel savings in the i th powerplant category.

ρ_i is the fraction of the net capital and fuel savings to be retained by the utility for the i th powerplant category.

Schedules for ρ would be established as discussed earlier in Appendix E (Volume I) except that instead of the ρ schedule being associated with performance levels that generate profit level A, it is now associated with the minimum performance levels. In Appendix G (Volume I), it is shown that there is a minimum level of ρ that must be exceeded in order to maintain utility participation in the incentive program after Phase 1 is completed.

IV.5 Overview of the Incentive Program for Existing Powerplants

It should be noted that Phase 1 was introduced as a mechanism to initiate an incentive program for existing units. Its advantage over the alternative incentive plans is strictly one of perception. Under all of the incentive plans the starting position of the utility is known (levels of capitalization and profit). It is only under the Phase 1 plan, however, that we have a reasonable ex ante perception of the sign and direction of the profit change created by the incentive program along with a built-in guarantee that cost-effective performance improvements will be adopted. If an incentive plan such as Phase 2 were to be adopted from the start, the regulatory agency would have to set ρ sufficiently high to insure that the profit lost concomitant to the capital reduction does not exceed the incentive reward.

The Phase 2 plan is just an additional way of designing a permanent voluntary incentive program. The primary recommendation for a Phase 2 plan is that a new plant incentive program could adopt a format similar to Phase 2. The type of program adopted by the Michigan Public Service Commission which relates system availability and return to equity would be a workable plan. Under a plan which directly relates system availability to return-to-equity, however, the regulatory agency offering such an incentive program must be extremely diligent in overseeing that program

to insure that only cost-effective outage improvements are adopted (as did the Michigan Commission).³

Looking back at the total profit calculations for the Phase 1 and Phase 2 incentive plans, it should be reemphasized that the utility's share of net savings, $\sum \sigma_i (S_i - C_i)$ or $\sum \rho_i (S_i^* - C_i)$, could be substantially different in magnitude for total profit under the different phases to be equal. As stated earlier, Phase 1 is one way to facilitate the introduction of an incentive program and should be set up in a manner to be compatible with the Phase 2 format which is a more appropriate format for new plants coming on line. Therefore, it would be informative as an exercise to equate the total profit calculations for Phase 1 and Phase 2 as follows:

$$\text{Total profit} = A + \sum \sigma_i (S_i - C_i) - B + \sum \rho_i (S_i^* - C_i).$$

We know that $A > B$ after a powerplant performance improvement is experienced, and that in the situation where the performance improvement is substantial, the difference between A and B may become quite significant. For Phase 1 and Phase 2 to be equivalent, therefore, $\sum \rho_i (S_i^* - C_i)$ must exceed $\sum \sigma_i (S_i - C_i)$ by $A - B$. However, only under specific extreme improvement scenarios would ρ have to approach unity or even exceed unity.

It has been the explicit policy of the general incentive framework presented in this study that the utility's share of the net cost savings is $\sigma (S_i - C_i)$ and the remainder, $(1 - \sigma)(S_i - C_i)$, will be passed on to the utility's customers in the form of lower rates or a less rapid rise in rates. Since any incentive program must be voluntary to be truly effective, the share of net cost savings retained by the utility should be set sufficiently high to attract the utility into the program. The movement from a Phase 1 to a Phase 2 program should not be undertaken without utility agreement. Excessively high standards can have the same financial impacts as directly setting the rate of return below the cost of capital.

IV.6 An Incentive Plan for New Powerplants

The format of an incentive plan for new plants would resemble the Phase 2 plan except that there would be an individual incentive schedule for each plant (or plant type if appropriate) as it comes on line. In this manner, the incentive program becomes an ongoing institution that continually encourages the utility to choose the cost-minimal mix of fixed and variable inputs required to meet demand.

If the utility is on the incentive program for existing plants (Phase 2) and finds itself building new plants, total profit would be calculated as follows:

$$\text{Total profit} = B + \sum \rho_i (S_i^* - C_i) + \sum \sigma_j (S_j - C_j)$$

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³ The type of plan utilized by Michigan is described and analyzed in Appendix G (Volume I).

Where:

S_j is the total capital and fuel savings attributed to operating j th new plant above a minimum performance level judged to represent satisfactory operation of that facility.

C_j is the extra cost incurred in operating the j th new plant above the established minimum performance level.

ρ_j is the fraction of the net capital and fuel savings attributed to the j th new plant to be retained by the utility.

IV.7 Procedure for Determining Net Cost Savings

The purpose of this section is to identify some procedures to measure the cost savings that may result from a productivity improvement plan. In the next section hypothetical data will be used to illustrate these procedures. The incentive reward will be included in the revenue requirements only after prior notification is given to the regulatory agency by the electric utility of the nature and costs of the planned productivity improvements. In addition, these cost savings must be realized before the incentive reward can be retained by the utility.

In the initial phase, the utility outlines the prospective costs of raising baseload availability by some target amount. Added maintenance, redesign of plant, increased inventories of defect-prone parts and installation of more reliable parts are some of the possible components of this calculation. Some will be ongoing, such as additional maintenance workers, while others will be nonrecurring, such as installation of more reliable parts.

The utility must then demonstrate that these outlays are cost effective by computing the savings brought about by outage reductions. These savings come about in at least two ways, short run and long run. Savings related to fuel, labor, and other variable inputs are short run in nature, and savings related to capital are long run in nature.

Fuel savings will be the most immediate impact. With higher baseload availability, intermediate and/or peaking plant operation can be reduced. This would increase utilization of the baseload's lower cost fuel. The exact savings can be computed from information on changes in base plant availability, decreased usage of intermediate plants, and costs of nonbase-load fuels.

Simplifying the problem somewhat will allow computation of the fuel savings. Let F and f_I be actual fuel costs/KwH of the base and intermediate units, respectively; N_B and N_I be capacities of the base and intermediate units, multiplied by the number of hours in a year. If T is the outage rate (planned and forced) of the base load plant (i.e., fraction of year base load unit is down), then the intermediate plant must operate T percent of the time. Assuming $N_B = N_I$, total fuel bill is $F = f_B N_B (1 - T) + f_I N_I (T)$.

For a given outage improvement, ΔT , the fuel savings, $\Delta F = f_B N_B \Delta T + f_I N_I \Delta T$, is positive if f_B is less than f_I .

The second sort of cost savings associated with productivity improvement is in capital savings. In a simplified sense, this is merely the amount of capital saved multiplied by the cost of capital. This simplification, however, belies the complexity of the utility's capital decisions. Greater base load availability obviates or postpones the need for additional base load capacity. To be more precise, secular growth in electric load requires periodic additions to base load capacity. Higher productivity allows postponement of the construction and completion of such additions since it extends the available capacity of the existing electricity generation.

There are at least two ways to calculate such effects. The discounted costs of construction scenarios under two time frames (one status quo, one to reflect the greater availability of existing base load units) could be compared. Alternately, the additional available base load capacity created by increased productivity of existing units could be computed as a fraction of total availability (which would give us the kilowatt capacity needed to produce that number of kilowatt hours in the span of a year):

$$h = \frac{\text{Added KWH/year due to outage improvement}}{(\text{hours/yr.})(\text{target availability factor})}$$

Then h could be multiplied by what a new base load unit of that size would cost (or typical new base load unit cost). Since a new unit would not come on line for some years, it would be correct to use the discounted costs of a future plant.

IV.8 Improvement Scenario

As a demonstration, the fuel and capital savings from a 5% improvement in the availability of a 650 Mw coal plant can be calculated using the hypothetical data in Table IV-1.

First, the additional megawatt hours available over the year are computed by multiplying number of hours in a year times capacity times the increment the unit is on line:

$$(.05)(650 \text{ Mw})(8640 \text{ hrs}) = 280,800 \text{ MWh}$$

If a gas-fired plant operates when the base load unit is down, 280,000 MWh of fuel is saved. Translating this to dollars,

$$\frac{(280,000 \text{ Mw})(12,000,000 \text{ Btu}^1/\text{Mw})}{1,000,000 \text{ Btu/MCF}} \times (\$1.8643/\text{MCF}) = \$6,281,942$$

To calculate net fuel savings, this figure must be reduced by the increased expenditure on coal used in the base load plant. This expense is calculated utilizing similar format:

TABLE IV-2

Physical and Financial Factors

Intermediate
Gas Plant

Heat Rate (Btu/Kwh)	12,000
Btu/MCF gas	1,000,000
Gas Price \$/MCF	\$1.8643

Base Load
Coal Plant

Heat Rate (Btu/Kwh)	12,000
Btu/lb. Coal	11,000
Coal Price \$/ton	\$29.

$$\frac{(280,000 \text{ Mw})(12,000,000 \text{ Btu/Mw})}{11,000 \text{ Btu/lb.}} \times (\$.0145/\text{lb.}) = \$4,441,745.40$$

Capital savings could be computed in terms of backing off a hypothetical plant. For example, the size of a plant with 80% availability could be calculated as follows:

$$\frac{280,800 \text{ Mwh}}{(.80)(8640)} = 40.625 \text{ Mw.}$$

That is, a 40 Mw coal plant with 80% availability could be eliminated by reducing outage rates 5%.

Note that, currently, the capital cost of a coal facility falling within a 500-700 Mw capacity range runs in the neighborhood of \$600/Kwh. The current dollar value of a 40.625 Mw capital savings is \$24,375,000.

The composite savings from the outage reduction is the sum of fuel and capital savings. Since a coal plant has a life of 30 years, the utility would use the depreciation of the plant as the relevant expense when

computing capital savings for a year. One-thirtieth of \$24,375,000 (or \$812,500) would be the capital savings added to a net fuel savings of \$1,840,196 (savings in gas less extra expense of coal) to give a gross savings of \$2,652,696.

The expense of increasing availability must then be deducted to yield net savings. This latter figure is multiplied by the relevant σ from Table IV-1, 15% in this case. This will give the amount going to utility, with $(1 - \sigma)$ times net savings as customer's share.

Those readers interested in more detailed calculations of the fuel and capital cost savings resulting from a powerplant productivity improvement are referred to Sections 4.2.2-4.2.5, in the "Powerplant Productivity Improvement Study" (1), and page 95 in the "Summary Report of the FEA Regional Meetings on Improving Powerplant Productivity" (2).

References

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APPENDICES

VOLUME I

APPENDIX A

A. UNIT PERFORMANCE CHARACTERISTICS FOR THE ERCOT REGION

A.1 Introduction

Operating and performance data for the period 1965 through 1975 obtained from Edison Electric Institute (EEI) are analyzed for five utilities in the Electric Reliability Council of Texas (ERCOT) region. These utilities are Central Power and Light, Dallas Power and Light, Houston Lighting and Power, Texas Electric Service, and Texas Power and Light. These utilities are chosen simply because they represent over 78% of the total generation capacity in the ERCOT region. EEI data represent units fueled by gas. Additional data were received from some of the utilities in the ERCOT region for the years 1976 to the present, including data on lignite-fired units from Texas Utilities.

Data are tabulated and Equivalent Availability Factor, Capacity Factor and Forced Outage Rates are shown and compared to national averages. In addition, causes of forced outages for some of the utilities were obtained for the years 1976 to the present. These data are also presented.

A.2 EEI Data

A.2.1 Tabular Presentation

The EEI data have been rearranged into a tabular format for all five utilities. This format lists the equivalent availability factor, capacity factor and forced outage rate for each unit above 100 Mw in size. A complete listing of all these data is shown in Appendix C.

It should be noted that there are errors in some of the data from EEI. Data listed as greater than 100% (see Appendix C) were considered in error and are not used in any conclusions or analysis. Errors in the EEI data are also noted and discussed in the Oak Ridge National Laboratory report, "An Assessment of Anomalies in the EEI Data Base on Powerplant Performance," February 1979. Subsequent review by Texas Electric Service Company and Dallas Power and Light revealed further anomalies in the EEI data base. Since the data base was preprocessed by EEI, there is no means of determining the source of these errors short of getting a complete raw data base from EEI (or the utilities) and searching for errors from that point. Therefore, except for the errors already discussed, the data are assumed to be representative.

A.2.2 Graphical Presentation

A graphical presentation of the data has been made and is shown in Figures A.1 through A.15. Again, these graphs do not show the erroneous data previously mentioned. Each of the graphs represents one of three factors: the equivalent availability factor, the capacity factor or the forced outage rate. The vertical axis of each graph represents one of the three factors on a percentage basis. The horizontal axis represents

the year that the utility had one or more units in operation. Also, the number in parentheses shown below the year of operation represents the number of units the utility had in operation for that year. Where there are no numbers in parentheses, there were no units (in the size range listed) in operation for that utility. The data points listed on the graphs show the average value of all the units in that year for that size range. For the years where there was more than one unit in operation, the maximum and minimum values are shown as end points on a vertical bar with the average value shown somewhere between the maximum and minimum points. Finally, the national average for that size range is shown as a horizontal dotted line for comparison. The value for the national average is taken from the EEI publication, "Report on Equipment Availability for the Ten-Year Period--1967-1976," December 1977.

Since the primary area of interest is those machines that are 400 Mw and larger in size, most of the graphs represent machines in that range. With the exception of Central Power and Light, all the graphs represent machines in the range of 400-599 Mw. This range was chosen because the same range of machines was chosen by EEI in their previously mentioned report. Central Power and Light was represented with machines in the range of 300-399 Mw because there were no machines in the 400-599 Mw range for that utility.

CENTRAL POWER & LIGHT
EQUIVALENT AVAILABILITY FACTOR
300 - 399 MW

Figure A-1

CENTRAL POWER & LIGHT
CAPACITY FACTOR
300 - 399 MW

Figure A-2

CENTRAL POWER & LIGHT

FORCED OUTAGE RATE

300 - 399 MW

NATIONAL
AVERAGE
= 7.9%

Figure A-3

DALLAS POWER & LIGHT

EQUIVALENT AVAILABILITY FACTOR

400 - 599 MW

NATIONAL
AVERAGE

Figure A-4

DALLAS POWER & LIGHT
CAPACITY FACTOR
400 - 599 MW

Figure A-5

DALLAS POWER & LIGHT
FORCED OUTAGE RATE
400 - 599 MW

Figure A-6

HOUSTON LIGHTING & POWER
EQUIVALENT AVAILABILITY FACTOR
400 - 599 MW

Figure A-7

HOUSTON LIGHTING & POWER
CAPACITY FACTOR
400 - 599 MW

Figure A-8

HOUSTON LIGHTING & POWER

FORCED OUTAGE RATE

400 - 599 MW

Figure A-9

TEXAS ELECTRIC SERVICE

EQUIVALENT AVAILABILITY

400 - 599 MW

Figure A-10

TEXAS ELECTRIC SERVICE
CAPACITY FACTOR
400 - 599 MW

Figure A-11

TEXAS ELECTRIC SERVICE
FORCED OUTAGE RATE
400 - 599 MW

Figure A-12

TEXAS POWER & LIGHT
EQUIVALENT AVAILABILITY FACTOR
400 - 599 MW

Figure A-13

TEXAS POWER & LIGHT
CAPACITY FACTOR
400 - 599 MW

Figure A-14

TEXAS POWER & LIGHT

FORCED OUTAGE RATE

400 - 599 MW

Figure A-15

A.3 Additional ERCOT Data

A.3.1 Unit Performance Data

Additional unit data were obtained from Dallas Power and Light, Texas Electric Service Company, and Central Power and Light. The data provided by these three utilities are for gas generation. A graphical and tabular format for this data is presented as in section A.2. The tables are listed in Appendix C.

Dallas Power and Light provided data for three units ranging in size from 350-550 Mw for the years 1976-1978. Figures A.16-A.18 show the equivalent availability factor, capacity factor and the forced outage rate.

Central Power and Light provided data only for the year 1976 for units ranging in size from 108-350 Mw. No graph is presented because the data provided are for only one year.

Texas Electric Service Company provided data for the three-year period (1976-1978) for units with a generating capacity ranging from 375-550 Mw. Figures A.12-A.21 show the equivalent availability factor, capacity factor and forced outage rates for Texas Electric Service.

DALLAS POWER & LIGHT
EQUIVALENT AVAILABILITY FACTOR

Figure A-16

DALLAS POWER & LIGHT
CAPACITY FACTOR

Figure A-17

DALLAS POWER & LIGHT
FORCED OUTAGE RATE

Figure A-18

TEXAS ELECTRIC SERVICE
EQUIVALENT AVAILABILITY FACTOR

Figure A-19

TEXAS ELECTRIC SERVICE

CAPACITY FACTOR

Figure A-20

TEXAS ELECTRIC SERVICE

FORCED OUTAGE RATE

Figure A-21

A.3.2 Outage Cause Data

The outage cause data provided by Dallas Power and Light listed the number of times a unit was forced out for a particular cause but did not indicate the amount of time the unit was down due to that cause. They reported a total of 112 forced outages for the years 1974-1978. Table A.1 lists the different equipment causes and the number of times a unit was forced out because of a particular cause and the percent outage, which is the number of times a unit was forced out due to a specific cause divided by the total number of outages.

DALLAS POWER AND LIGHT
FORCED OUTAGE CAUSE
350-550 MW

Equipment Cause	No. of Outages	Percent Outage
Boiler	49	43.75
Turbine	19	16.96
Generator	6	5.36
Condenser	3	2.68
Other	35	31.25
Total Outages	112	100.00

TABLE A.1

The outage cause data supplied by Central Power and Light and Texas Electric Service Company reported the number of hours a unit was down and the cause of the outage. The causes were reported in the standard form used by EEI and they were broken up into five main causes: (1) boiler, (2) turbine, (3) generator, (4) condenser, and (5) other. The last cause, "other," includes every other cause besides anything related to the first four, including human error.

These data are presented in Tables A.2-A.7. The hours listed for a particular cause are total hours for the full year and the percent outage is the total outage hours for a specific cause divided by the total outage hours for the full year.

CENTRAL POWER AND LIGHT
FORCED OUTAGE CAUSE
1976

Equipment Cause	Outage Hours	Percent Outage
Boiler	747.00	44.22
Turbine	479.00	28.35
Generator	9.00	0.53
Condenser	409.00	24.22
Other	45.00	2.68
Total Outage	1,689.00	100.00

TABLE A.2

CENTRAL POWER AND LIGHT
FORCED OUTAGE CAUSE
1977

Equipment Cause	Outage Hours	Percent Outage
Boiler	11,278.00	30.85
Turbine	8,271.00	22.62
Generator	7,284.00	19.92
Condenser	6,861.00	18.77
Other	2,867.00	7.84
Total Outage	36,561.00	100.00

TABLE A.3

CENTRAL POWER AND LIGHT
FORCED OUTAGE CAUSE
1978

Equipment Cause	Outage Hours	Percent Outage
Boiler	7,259.00	26.00
Turbine	7,707.00	27.56
Generator	3,947.00	14.13
Condenser	5,563.00	19.91
Other	3,465.00	12.40
Total Outage	27,941.00	100.00

TABLE A.4

TEXAS ELECTRIC SERVICE
FORCED OUTAGE CAUSE
1976

Equipment Cause	Outage Hours	Percent Outage
Boiler	5,795.00	88.45
Turbine	588.00	8.97
Generator	14.00	0.21
Condenser	61.00	0.93
Other	94.00	1.44
Total Outage	6,552.00	100.00

TABLE A.5

TEXAS ELECTRIC SERVICE
FORCED OUTAGE CAUSE
1977

Equipment Cause	Outage Hours	Percent Outage
Boiler	885.00	33.13
Turbine	14.00	0.52
Generator	16.00	0.62
Condenser	1,753.00	65.63
Other	3.00	0.12
Total Outage	2,671.00	100.00

TABLE A.6

TEXAS ELECTRIC SERVICE
FORCED OUTAGE CAUSE
1978

Equipment Cause	Outage Hours	Percent Outage
Boiler	2,265.00	51.97
Turbine	412.00	9.50
Generator	1,510.00	34.66
Condenser	76.00	1.74
Other	93.00	2.13
Total Outage	4,356.00	100.00

TABLE   A.7

A.4 Lignite-Fired Units

A.4.1 Unit Performance Data

Data were obtained from Texas Utilities on lignite-fired units ranging in size from 525-750 Mw for the years 1976-1978. These units are jointly owned by Dallas Power and Light, Texas Electric Service Company, and Texas Power and Light. They are used as base load units.

A graphical and tabular format for these data is presented as in section A.2. The tables are listed in Appendix C. Figures A.22-A.27 show the equivalent availability factor, capacity factor and the forced outage rate.

TEXAS UTILITIES LIGNITE UNITS
400-599 MW
Equivalent Availability Factor

Figure A-22

TEXAS UTILITIES LIGNITE UNITS
400-599 MW
Capacity Factor

Figure A-23

TEXAS UTILITIES LIGNITE UNITS
400-599 MW
Forced Outage Rate

Figure A-24

TEXAS UTILITIES LIGNITE UNITS
600-799 MW
Equivalent Availability

Figure A-25

TEXAS UTILITIES LIGNITE UNITS
600-799 MW
Capacity Factor

Figure A-26

TEXAS UTILITIES LIGNITE UNITS
600-799 MW
Forced Outage Rate

Figure A-27

A.5 Conclusions

With the exception of the lignite-fired units treated in this appendix, all Texas data are for gas-fired units. This fact must be kept in mind in evaluating the data. It is also important to note that national averages shown for comparison purposes reflect either gas-fired or coal-fired unit national averages. Thus, it is not surprising to see Texas lignite units showing forced outage rates somewhat higher than national average data based on coal units.

A.5.1 EEI Data

Figures A.1-A.15 are presented primarily for comparison purposes. From the graphs it is clearly evident how each particular utility compared to the EEI national averages. Also, it is possible to compare the representative utilities from Texas as a group to the national averages.

By comparing the graphs of the various utilities, some definite trends can be observed. In general, the representative utilities of Texas had an equivalent availability factor that was greater than the national average. The only utility that averaged less than the national average for the equivalent availability factor was Dallas Power and Light as shown in Figure A.4. Similarly, all the utilities investigated had a lower (or better) forced outage rate than the national average. However, the utilities capacity factor did not compare quite as well to the national average as the equivalent availability factor or the forced outage rate. Only two of the utilities averaged as high or higher than the national average for capacity factor. Figure A.8 shows that Houston Lighting and Power had an average capacity factor about 10% higher than the national average for the same period of years. Texas Electric Service showed a similar average over the same period, although not as high as Houston Lighting and Power. The other utilities all averaged below the national average, some significantly. Central Power and Light, as shown in Figure A.2, averaged 10-15% lower than the national average.

A.5.2 Additional ERCOT Data

Figure A.16-A.18 for Dallas Power and Light show that the equivalent availability factor and capacity factor are decreasing while the forced outage rate is increasing for the years 1976-1978. Comparing the graphs of Dallas Power and Light for 1976-1978 to the graphs for 1965-1975, it is observed that the trend for the equivalent availability factor is more or less the same from 1965-1977 but decreases drastically for the year 1978. It is also observed that the capacity factor deteriorated for the years 1976-1978 and the forced outage rate increased for the years 1977-1978. The drastic change in 1978 was caused because a 550 Mw unit was forced out for the entire year.

Comparing the Central Power and Light units (ranging from 300-399 Mw) to the national average, it is observed that the equivalent availability factor and the capacity factor are lower than the forced outage rate is

higher. The table in Appendix C lists the averages and the national average. It should be noted that the national averages listed are for the years 1965-1975.

Comparing the graphs of Texas Electric Service for the years 1976-1978 to the graphs for 1965-1975, it is observed that the equivalent availability factor is greater and the capacity factor is slightly less than the national average. The important thing to note is that the trend of the equivalent availability factor and the capacity factor remains more or less the same over the years. The forced outage rate is very low compared to the national average.

A.5.3 Lignite-Fired Units

Figures A.22-A.24 show the equivalent availability factor, capacity factor and forced outage rates for unit sizes 400-599 Mw, and Figures A.25-A.27 correspond to unit sizes 600-799 Mw.

It is observed from the graphs that equivalent availability factor and capacity factor are greater than the national average. The forced outage rate is greater (or worse) than the national average.

The national averages are obtained from the EEI publication, "Report on Equipment Availability for the Ten-Year Period--1967-1976," December 1977.

A.5.4 Outage Cause Data

From Table A.1, which lists the outage cause data for Dallas Power and Light, it can be concluded that the boiler is the chief cause of forced outages while the forced outage rate due to a generator or condenser is very minimal. The 550 Mw unit that was forced out for the entire year of 1978 was incapacitated by some malfunction in the turbine. Because of this observation it can be concluded that it is not only the number of times a unit is forced out due to a particular cause which is important, but also the amount of time that it is forced out due to a specific cause.

Looking at the outage cause data for Central Power and Light and Texas Electric Service in Tables A.2-A.7, it is observed that most outages are due to some malfunction in the boiler.

B. SHORT-TERM SAVINGS ASSOCIATED WITH REDUCTIONS IN OUTAGES

B.1 Introduction

An analysis of short-term savings associated with reductions in forced and planned outage rates is presented in this appendix. For purposes of this study, short-term savings are defined to be those savings in fuel costs which would occur over a one-year period due to a reduction in either forced or planned outage rates. It is important to realize that savings described in this appendix are fuel cost savings only and do not reflect costs which might be incurred to realize the particular outage reduction. In order to assess these savings, an in depth investigation of the Texas Utilities System is made for the year 1980.

The Texas Utilities System is ideally suited for an analysis of short-term fuel savings. It is a major electric utility system serving approximately one-third of the population of Texas in 87 counties of North Central, East, and West Texas. It consists of three utilities: Dallas Power and Light, Texas Electric Service Company, and Texas Power and Light. These member utilities share ownership of eight lignite units in three separate locations. Data on the lignite units are shown in Table B-1.

Table B-1
Texas Utilities Lignite Units

Unit	Capacity (Megawatts)
Big Brown 1	575
Big Brown 2	575
Monticello 1	575
Monticello 2	750
Monticello 3	750
Martin Lake 1	750
Martin Lake 2	750
Martin Lake 3	750

Remaining generation consists of 49 natural gas units ranging in size from 13 megawatts to 777 megawatts. These natural gas units are individually owned and operated by the three member utilities. Data on all generating units within the system as well as load data for the system were made available by the Texas Utilities System for this study. In particular, sufficient data were available to permit detailed computer simulation of the hour-by-hour operation of the Texas Utilities System for the year 1980.

Long-term savings are presented in Chapter II, where the time frame 1980 to 1996 is investigated. Essentially the short-term savings presented in this appendix consider the first year of the longer time frame considered in Chapter II. Short-term savings are due to reduced gas consumption. Long-term savings include not only benefits due to reduced gas consumption but also benefits due to reduced requirements for future installed baseload capacity. Finally, the long-term savings presented in Chapter II are estimates for the entire Electric Reliability Council of Texas (ERCOT) region.

B.2 Methodology

Short-term savings are determined by simulating the hour-to-hour operation of the Texas Utility System for the year 1980 using a production simulation program. This program simulates the behavior of a power system on an hourly basis for a specified period of time. Running totals reflecting megawatt hours generated, fuel costs, number of unit start-ups, etc., can be accumulated and expressed as output on a daily, weekly, monthly or annual basis at the discretion of the program user. The program essentially accomplishes the functions of unit commitment and economic dispatch in response to a randomly varying system load. Typical input data to the program consist of system peak load data and powerplant data such as heat rate curve coefficients, minimum and maximum plant outputs, minimum down hours, maintenance schedules, start-up costs, fuel costs and outage rates. Forecasted hourly load data for the year 1980 were furnished by Texas Electric Service Company for the entire Texas Utilities System. These load data were input directly into the production simulation program and that feature of the program normally used to generate a randomly varied load was bypassed.

The actual determination of short-term savings is accomplished by running the program for the entire year for a base case study using a set of assumed outage rates. The program is then run again with outage rates adjusted and results are compared to results for the base case. Reductions in both forced and planned outage rates are treated in this way.

The reduction in forced outage rate is initially based on the assumption of a 5 percentage point reduction uniformly realized over an eight-year period. This is similar to the scenario considered in the General Electric Company report "Study of Benefits of Improved Powerplant Reliability and Productivity, Phase 3 Report, National Analysis," December 30, 1977. Thus for the year 1980, we assume a 5/8 percentage point reduction in forced outage rates. In order to investigate a range of possible percentage point

reductions in forced outage rates, reductions slightly higher and slightly lower than 5/8 of a percentage point are then examined.

Reductions in planned outage rates are treated by subtracting specified integral numbers of weeks from the maintenance schedule of certain lignite units. This will be described in detail as results are presented.

The production cost simulation program used in the short-term savings analysis is the Philadelphia Electric Company Program entitled PRODCOST. This program was procured and adapted to the University of Texas CDC system to facilitate its use locally. In order to validate results from this program, selected runs were made using a production simulation program belonging to Texas Electric Service Company. This latter program, referred to hereafter as the TESCO program, was specifically written for the Texas Utilities System and takes into account area import/export constraints as well as the more typical production cost program features described earlier. Because the TESCO program simulates in greater detail than the PRODCOST program, the time per computer run is somewhat longer than that required for the PRODCOST program. It is therefore used only to demonstrate that for purposes of this study the simpler PRODCOST program, which can be run locally at the University of Texas, produces consistent results. It should be noted that the TESCO program has been shown to produce results which are in good agreement with actual operating experience. Thus the analysis presented herein yields realistic results.

B.2.1 The PRODCOST Program

The PRODCOST program is described in considerable detail in a Master's Thesis by S. T. Matraszek submitted in May 1972 at the University of Pennsylvania. The thesis is entitled "Computer Simulation of the Operation of an Electric Power System." What follows is a discussion of the important characteristics of the program and also modifications made to the program for the analysis of the Texas Utilities System.

Load modelling for the program is on a bihourly basis. An average value of load for every two-hour period for the entire year 1980 is required as program input. These load data are used to determine the unit commitment and load dispatch simulation. This load modelling is a modification of that used in the original PRODCOST program because complete forecasted hourly load data for the year 1980 were provided by Texas Electric Service Company for the Texas Utilities System.

Generation is modelled by specifying the no-load heat rate, the start-up cost, and heat rate data for each unit. Knowing this information and the cost per MBtu of fuel, we can determine the fuel costs for each unit. These fuel costs plus the estimated costs of operation and maintenance give the total operating costs for each unit in the system. Thus accurate day-to-day costs of operation can be determined for the entire system.

The maintenance schedule for each unit is an input to the program. The PRODCOST program requires that all maintenance for a particular unit be performed during one specified maintenance period for the whole year.

Essentially, a starting week and ending week for maintenance are input for each unit. The actual maintenance for the Texas Utilities units does not occur this way, therefore the maintenance schedule of each unit was simplified so that it could be an input to the PRODCOST program. However, the total number of weeks required for maintenance for each unit was not changed.

Forced outages are simulated by generating a uniformly distributed random number between 0 and 1 for a given unit at the beginning of each week in the simulation. If the number is between 0 and the forced outage rate of the unit, the unit is forced off line for a one-week period. Otherwise, the unit is assumed to be available for the entire one-week period.

Unit commitment is done on the basis of a priority list. Each unit in the system is ranked in order of its cost of operation in \$/Mwh at maximum output and unit commitment is based on this ranking. At the start of each week in simulation, the initial load for the system is observed and a complete, new unit commitment is made. After this initial unit commitment is made, the units are economically dispatched to meet the load requirements. As the week progresses, additional units are either added or deleted from the system so that load plus spinning reserve requirements are satisfied. Economic dispatch of the units to meet the actual load is then accomplished in the following manner. The loading of each unit in the system is broken up into "blocks" of secondary generation. These blocks have an associated incremental cost and are listed in ascending order of incremental cost. Whenever additional power is required, it is taken from the available block of generation that is lowest in incremental cost. When the load is decreased, the block previously dispatched that is highest on the list is removed first. This method of dispatching is consistent with the concept of equal incremental cost dispatch. If the load is such that all generators are backed down to their minimum generation and a generator should be shut down, the program "looks ahead" at the load for the next eight hours and determines if the unit would need to be brought back on line within that period. If the unit would need to be recommitted, then it is left on line and operates at no load.

B.2.2 The TESCO Program

The TESCO program is described in considerable detail in the paper entitled "A Practical Approach to Unit Commitment, Economic Dispatch and Savings Allocation for Multiple-Area Pool Operation with Import/Export Constraints" by R. R. Shoults, S. K. Chang, S. Helmick and W. Mack Grady. This paper (F 79 673-5) was presented at the IEEE PES Summer Meeting in Vancouver BC July 15-20, 1979. What follows is a discussion of important characteristics of the program insofar as this analysis is concerned.

The TESCO program directly uses the previously described forecasted hourly load data. Generation data includes heat rate data, start-up costs, and generator size. Operating, maintenance, and fuel costs are given as inputs to the program.

Forced outages in the TESCO program are also handled on the basis of an internally generated random number but the total base load generation (lignite generation) is adjusted. This differs from the PRODCOST program where individual units are actually forced off line for certain outcomes of the random variable. More specifically, the TESCO program accomplishes this function using the following formula:

$$AC = TC \left[1.0 - \frac{\frac{C}{100.0}}{0.375} R \right] \quad \text{For } R \geq 0.5$$

$$= TC \quad \text{For } R < 0.5$$

where:

R is a uniformly distributed random number between 0 and 1 generated for each day of the simulation.

TC is the total installed capacity of the specified base load units to be outaged, reduced to take into account spinning reserve requirements and maintenance requirements.

C is an input capacity factor adjusted to reflect outage rates of the lignite units.

AC is the actual lignite capacity available for a particular day in the simulation.

It is not difficult to show that the average value of AC over a yearly period is equal to the product of C and TC.

Unit commitment in the TESCO program is done on an hourly basis whenever additional capacity is needed. Each unit in the system is put on a priority list based on its operating cost at maximum efficiency and on its start-up costs. Certain units are designated as "swing" units. These units are listed as such because of their fast start-up time. The program looks at the load each hour of the year and when the load increases enough such that an additional unit must be committed, the program chooses first from the "swing unit" list of generators. When these swing units are no longer available, units are committed based on the priority list.

The maintenance schedule for the TESCO program is a program input. This schedule, specified by starting and ending dates, designates which units will be on maintenance and for how long. The maintenance periods need not be consecutive weeks. Units scheduled for maintenance are considered unavailable in the commitment and economic dispatch simulation.

Economic dispatch of the committed units is in accordance with the concept of operation at equal incremental cost. Before a unit is shut down, the program looks ahead at the load for a period of hours equal to the start-up time of the unit in question. If the unit will be needed

before that period is up, the unit remains on line as spinning reserve. Since Texas Electric Service Company is tied together in a power pool with two other utilities, there is a provision in the program for area constraints. These constraints take into account each area's generation plus the import/export limits between adjacent areas.

B.2.3 Significant Program Differences

The differences between the two simulation programs are basically in the implementation of algorithms rather than in the theory of operation. While the PRODCOST and TESCO programs both use an internally generated random number to simulate outages, the outages are implemented in different methods. PRODCOST forces specific units out on a weekly basis whereas the TESCO program reduces the total base load generation capacity on an hourly basis. It should be noted that only the base load generation (lignite generation) is affected by the forced outage simulation. The TESCO program does not simulate forced outages for other units. In the PRODCOST program a zero forced outage rate was assumed for all units other than the lignite units. Since the outage rates of these other units (natural gas) are low compared to the outage rates of the lignite units, little error is introduced by this assumption.

The unit commitment is quite different for the two programs. The TESCO program always commits available swing units regardless of their position in the economic priority list. PRODCOST makes a complete new unit commitment at the start of each week while TESCO does commitment on an hour-to-hour basis. The method used to shut down units is also different for the two programs. PRODCOST looks ahead for eight hours before shutting down a unit and TESCO looks ahead by a number of hours equal to the start-up time of the unit that is to be shut down. The differences in the method of commitment and shut down are quite evident upon comparing the number of unit starts for a particular unit as estimated by the two programs.

The differences in unit commitment and forced outage rate simulation are the major differences between the two programs. It will be shown in the next section that these simulation differences do not significantly affect the estimated total annual fuel costs.

B.3 Results of the Short-Term Savings Analysis

B.3.1 Results for the Base Case

Based on estimated load data provided by Texas Electric Service Company for the year 1980, a production simulation of the Texas Utilities System was performed by the PRODCOST and TESCO programs. Samples of the simulation results for both the TESCO program and the PRODCOST program are shown in Appendices D and E. The base case simulation results, including fuel costs and a breakout of the estimated lignite and natural gas generation, are shown in Table B-2. The fuel cost figure reflects both lignite generation and natural gas generation costs. Note that total fuel cost estimates from both programs differ by less than 1.5%.

Table B-2
Simulation Results for the Base Case

	<u>TESCO Program</u>	<u>PRODCOST Program</u>
Lignite Generation (Million Mwh)	31.79	31.44
Natural Gas Generation (Million Mwh)	30.74	30.71
Total Generation (Million Mwh)	62.53	62.15
Total Fuel Cost (Millions of Dollars)	501.68	508.93

B.3.2 Results for a 5/8 Percentage Point Reduction in Forced Outage Rates

Outage rates of the lignite units were reduced by 5/8 of a percentage point and the simulations were repeated. The reduced forced outage rate simulation results are shown in Table B-3. Note that again total fuel cost estimates from both programs differ by less than 1.5%. In comparing tables B-2 and B-3, it can be seen that a reduction in forced outage rates results in a savings in fuel costs. This savings is estimated to be 0.28% of the fuel costs in the base case if we consider the PRODCOST program results. The savings is estimated to be 0.27% of the fuel costs in the base case if we consider the TESCO program results. Thus percentage reductions estimated using either program are essentially the same.

Table B-3
Simulation Results for a 5/8 Percentage Point Reduction
in Forced Outage Rates of the Lignite Units

	<u>TESCO Program</u>	<u>PRODCOST Program</u>
Lignite Generation (Million Mwh)	32.08	31.74
Natural Gas Generation (Million Mwh)	30.51	30.41
Total Generation (Million Mwh)	62.59	62.15
Total Fuel Cost (Millions of Dollars)	500.23	507.50

It should be noted that even though the two simulators differ in the way they simulate the daily operation of the utility, they are in close agreement for the annual savings to be expected due to a reduction in forced outage rates. Because of the somewhat simpler simulation procedure and simpler set of constraints that the PRODCOST program runs under, it requires significantly less computer time than the TESCO program.

B.3.3 Results for a Range of Percentage Point Reductions in Forced Outage Rates

In order to assess the potential savings over a range of possible percentage point reductions in forced outage rates, additional runs were

made with the percentage point reduction in forced outage rates for the lignite units set at $3/8$ and $7/8$ of a percentage point. These runs were made using the PRODCOST program because of its ready availability and close agreement with the TESCO program. These runs indicate an increase in the percentage reduction in fuel costs as the percentage reduction in outage rates is increased. Results are shown in Figure B-1. As can be seen from this figure, a 1% reduction in forced outage rates would produce an approximate 0.50% reduction in fuel costs.

B.3.4 Results for Specified Reductions in Planned Outage Rates

In order to assess the potential savings due to reductions in planned outages of the lignite units, the maintenance schedule for some of the lignite units was modified and runs were repeated using the base case forced outage rate. The base case run had the lignite units scheduled for a total of 56 weeks of maintenance. This schedule was reduced by two, three and four weeks in three separate runs using the PRODCOST program. In each case, this was accomplished by subtracting one week at a time from the maintenance schedule prior to the subtraction. The percentage reduction in fuel costs is seen to increase as the number of weeks subtracted from the base case maintenance schedule is increased. This is shown in Figure B-2.

B.4 Conclusions

Short-term savings associated with reductions in forced and planned outage rates have been investigated for the Texas Utilities System for the year 1980. Reductions in outage rates of the base load (lignite) units result primarily in fuel cost savings. A $5/8$ percentage point reduction in forced outage rates for the lignite units would realize an approximate 0.25% savings in fuel costs. If a 1.0 percentage point reduction in outage rates could be achieved, fuel cost savings would increase to 0.50% (1.25 and 2.5 million dollar savings for reductions in forced outage rates of $5/8$ and 1 percentage points, respectively). Percentage reductions in fuel costs for decreases in the planned outage rates are somewhat lower. All of the savings presented in this appendix are for a single year (1980) and such savings must be considered in the light of a long-term investigation. This was presented in Chapter II.

Figure B-1: Percentage Reduction in Fuel Costs vs. Percentage Reduction in Forced Outage Rates

Figure B -2: Percentage Reduction in Fuel Costs
vs. Total Number of Weeks Reduction
in Planned Outages of Lignite Units

APPENDIX C

C. POWERPLANT PERFORMANCE DATA

C.1 CENTRAL POWER & LIGHT

1965

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
114	96.1	92.8	0.0
169	74.4	72.8	25.5
170	96.4	92.4	0.0

C.2 CENTRAL POWER & LIGHT

1966

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
114	93.3	90.3	0.2
169	98.6	96.5	0.0
170	93.9	90.1	0.0
180	86.3	86.6	0.3

C.3 CENTRAL POWER & LIGHT

1967

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
114	89.1	86.1	0.0
169	93.2	91.7	0.0
170	86.4	83.8	0.3
180	93.3	93.5	0.7

C.4 CENTRAL POWER & LIGHT

1968

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
110	68.1	68.3	0.0
168	96.1	64.1	0.0
176	85.6	72.3	0.0
178	98.2	82.5	0.2
266	107.8*	77.0	0.2

C.5 CENTRAL POWER & LIGHT

1969

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
110	94.2	41.6	0.0
168	87.2	58.1	0.1
176	94.7	64.9	0.0
178	90.7	75.2	2.1
266	84.2	62.0	0.1
268	81.8	51.9	12.1

C.6 CENTRAL POWER & LIGHT

1970

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
110	82.2	56.9	0.3
176	100.0	68.8	0.0
178	87.6	61.4	0.0
266	94.5	70.9	0.0

*Error in data

C.7 CENTRAL POWER & LIGHT

1971

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
110	74.7	56.7	0.0
176	81.4	47.7	0.0
178	94.0	67.0	0.1
265	85.9	53.9	3.1
266	94.3	67.1	1.1

C.8 CENTRAL POWER & LIGHT

1972

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
110	94.3	71.4	0.2
170	88.4	45.0	0.0
176	94.3	45.4	0.0
178	79.5	54.4	0.1
260	95.0	64.3	0.0
260	80.2	53.1	23.2
266	83.4	57.6	2.5
350	84.0	50.2	0.2

C.9 CENTRAL POWER & LIGHT

1973

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
110	93.1	68.8	0.0
155	87.2	73.2	1.0
155	88.0	73.2	0.0
170	81.5	49.3	1.7
176	99.9	49.9	0.0
260	81.5	54.0	2.2
260	84.0	56.6	1.0
266	94.1	61.2	1.2
350	69.7	45.6	0.1

C.10 CENTRAL POWER & LIGHT

1974

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
110	89.0	59.6	0.0
155	92.7	65.8	0.0
160	82.2	33.4	0.5
170	96.2	49.7	3.7
176	94.7	42.2	0.1
260	82.6	51.0	0.0
260	87.9	50.6	0.0
266	71.5	48.6	0.5
335	86.1	48.9	0.6
350	79.8	53.6	0.2

C.11 CENTRAL POWER & LIGHT

1975

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
53	2.2	1.8	27.3
109	72.8	46.8	11.0
110	99.4	54.2	0.0
155	0.9	0.1	2.6
170	82.9	17.3	0.0
170	91.2	25.3	0.0
176	81.1	24.2	0.0
260	91.6	56.7	0.0
260	82.3	48.8	0.0
266	95.7	59.1	0.0
335	67.2	33.7	4.0
350	87.5	55.2	0.0

C.12 CENTRAL POWER & LIGHT

1976

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
260	33.00	46.86	0.41
266	58.00	53.01	0.23
350	68.00	47.99	7.90
260	99.00	61.04	0.19
335	69.00	39.90	2.72
340	66.00	38.94	24.54
150	100.00	71.42	0.00
108	79.00	45.78	3.36
109	74.00	47.72	1.17

C.13 CENTRAL POWER & LIGHT

Comparison To National Averages

300-399 MW

	1976 Average	National Average
Equivalent Availability Factor	67.67	75.80
Capacity Factor	42.28	60.94
Forced Outage Rate	11.72	7.90

C.14 DALLAS POWER & LIGHT

1965

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
122	54.6	54.6	0.0
131	98.3	98.3	0.1
132	94.4	94.4	0.2
181	76.8	76.8	0.0
181	89.8	89.8	0.5
362	66.4	66.4	0.1

C.15 DALLAS POWER & LIGHT

1966

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
131	95.6	95.7	2.7
132	99.6	99.7	0.0
181	93.2	93.2	0.0
181	82.5	82.6	0.0
362	83.3	89.3	0.1

C.16 DALLAS POWER & LIGHT

1967

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
131	79.7	79.7	0.0
181	99.3	99.3	0.0
181	99.4	99.4	0.0
362	98.6	98.6	0.0

C.17 DALLAS POWER & LIGHT

1968

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
75	97.2	45.5	0.5
75	95.3	38.1	0.0
115	53.1	17.1	0.0
125	98.2	37.0	0.0
125	74.2	18.7	0.0
175	88.5	49.5	0.0
175	60.0	30.7	0.1
550	76.5	49.3	3.1

C.18 DALLAS POWER & LIGHT

1969

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
75	85.4	39.6	0.5
115	86.4	34.3	0.0
115	85.1	26.9	3.9
125	77.8	28.4	0.3
125	89.3	33.8	1.1
175	97.2	52.4	0.0
175	101.3*	47.8	3.2
350	85.2	50.1	8.2
550	68.9	47.8	0.5

*Error in data

C.19 DALLAS POWER & LIGHT

1970

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
115	98.1	32.9	0.0
115	67.0	16.2	0.0
125	99.5	38.5	0.0
125	96.5	38.3	1.0
175	72.8	43.7	0.9
175	93.4	57.7	0.1
350	82.1	49.5	1.7
375	54.0	26.7	16.6
550	71.4	53.8	1.4

C.20 DALLAS POWER & LIGHT

1971

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
115	83.6	31.6	0.0
115	61.2	17.2	0.1
125	88.8	33.0	0.0
125	68.3	22.0	0.0
175	92.9	49.6	0.0
175	96.7	48.4	0.0
350	79.5	46.2	3.0
375	42.2	24.8	3.5
550	92.5	72.5	2.3

C.21 DALLAS POWER & LIGHT

1972

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
115	88.4	22.1	0.3
115	96.5	30.3	1.0
125	74.3	32.6	0.1
125	99.5	37.6	0.1
175	95.0	51.7	0.0
175	92.2	49.5	1.8
350	81.1	51.5	1.3
375	71.8	42.6	2.7
550	70.8	59.1	4.2

C.22 DALLAS POWER & LIGHT

1973

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
115	73.1	20.1	0.1
115	91.2	36.9	2.2
125	88.3	34.4	0.0
125	85.5	36.6	0.0
175	81.5	42.6	0.0
175	68.9	44.8	0.0
350	67.8	39.4	2.2
375	96.8	25.2	2.7
515	25.3	12.4	45.0
550	87.7	64.5	2.1

C.23 DALLAS POWER & LIGHT

1974

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
115	90.6	9.3	0.2
115	84.1	9.3	18.1
125	96.2	17.3	1.5
125	88.3	17.2	0.0
175	90.7	35.5	2.7
175	82.1	36.9	0.5
350	75.3	42.9	0.4
375	71.9	19.2	1.2
515	57.4	36.7	11.5
550	63.5	42.4	1.0

C.24 DALLAS POWER & LIGHT

1975

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
115	80.5	7.9	0.0
115	92.0	10.9	8.5
125	96.0	13.6	1.3
125	5.3	0.5	98.4
175	63.5	20.1	0.0
175	86.0	28.1	2.7
350	88.6	46.9	1.0
375	57.3	5.8	2.7
515	87.9	60.5	7.0
550	63.5	42.4	1.0

C.25 DALLAS POWER & LIGHT

1976

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
550	58.4	41.2	3.0
515	83.7	50.8	0.7
350	75.8	43.5	1.3

C.26 DALLAS POWER & LIGHT

1977

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
550	58.3	40.6	24.7
515	75.4	46.2	1.3
350	63.7	36.9	0.2

C.27 DALLAS POWER & LIGHT

1978

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
550	0.0	0.0	100.0
515	76.4	51.0	1.1
350	86.0	48.3	1.0

C.28 HOUSTON LIGHTING & POWER

1965

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
175	92.7	93.0	0.2
175	99.4	99.2	0.1
175	94.2	93.5	0.0
175	93.2	91.8	0.1
240	92.8	93.4	0.0
240	95.2	95.3	0.1
240	86.9	86.9	0.0
300	91.3	91.3	0.3

C.29 HOUSTON LIGHTING & POWER

1966

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
175	93.7	94.1	4.0
175	95.2	94.5	0.0
175	96.7	96.2	0.0
240	78.1	78.9	14.9
240	82.2	82.6	0.5
240	94.9	94.1	0.0
300	84.5	85.1	0.0
350	78.5	78.2	0.2

C.30 HOUSTON LIGHTING & POWER

1967

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
175	97.0	96.0	0.0
175	99.5	96.2	0.0
175	99.7	97.6	0.0
240	93.7	94.1	0.3
240	97.9	97.9	0.1
240	96.1	95.8	0.6
300	98.6	98.6	0.5
350	91.5	91.4	0.0
450	79.3	80.2	1.7

C.31 HOUSTON LIGHTING & POWER

1968

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
112	81.8	31.4	0.0
112	46.0	16.3	0.0
112	69.5	25.6	0.0
112	69.2	29.4	0.0
177	95.9	61.1	0.4
177	84.7	60.6	0.0
177	91.3	64.5	0.3
177	96.7	68.9	0.0
177	92.1	67.5	0.0
234	81.9	65.5	0.5
235	91.1	70.5	0.0
235	88.5	68.6	0.0
278	90.1	70.0	1.6
375	88.6	66.9	1.5
481	92.5	74.6	0.2
481	94.9	75.9	0.3
565	91.7	72.4	1.2
565	27.9	13.3	69.2

C.32 HOUSTON LIGHTING & POWER

1969

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
112	72.8	14.2	0.1
112	98.9	16.4	0.0
112	97.6	16.0	4.6
112	59.7	14.9	0.2
172	88.1	64.0	1.7
172	84.8	48.9	0.0
172	84.7	51.8	0.0
172	91.3	60.9	0.0
183	90.0	54.7	0.5
230	93.0	71.6	0.0
230	97.4	75.8	0.0
230	92.4	70.8	0.1
297	87.9	61.7	0.1
375	89.9	64.2	0.8
481	82.1	67.3	1.5
481	87.0	70.4	0.4
565	90.7	76.5	1.5
565	88.5	75.3	1.6

C.33 HOUSTON LIGHTING & POWER

1970

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
112	90.4	27.8	1.1
112	94.6	28.9	1.7
112	94.9	31.8	0.0
112	92.3	31.5	0.0
177	90.8	55.9	0.0
177	97.1	64.9	0.0
177	95.5	67.7	0.2
177	99.2	72.8	0.0
177	99.6	73.4	0.0
234	82.1	69.3	1.7
235	81.8	62.9	0.0
235	76.5	60.0	0.0
278	87.9	69.5	0.6
375	73.3	55.7	0.6
481	89.0	74.9	0.5
481	84.1	70.6	3.0
565	93.5	82.1	1.6
565	81.6	69.8	4.4
750	91.8	47.1	0.0

C.34 HOUSTON LIGHTING & POWER

1971

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
112	89.6	32.6	1.3
112	85.7	31.1	1.8
112	118.0*	33.9	0.0
112	92.6	36.0	0.0
177	90.6	55.2	0.4
177	83.0	66.6	0.0
177	91.8	61.1	0.5
177	93.2	66.3	0.0
177	92.6	65.0	0.2
234	95.4	69.6	0.2
235	92.7	67.9	0.0
235	81.9	60.4	0.1
278	84.7	66.3	0.0
375	89.8	66.5	0.0
481	87.8	70.3	0.1
481	94.2	78.0	4.4
565	90.2	78.6	0.1
565	78.8	70.3	0.6
775	55.8	39.9	36.1

*Error in data

C.35 HOUSTON LIGHTING & POWER

1972

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
112	81.9	23.0	2.4
112	97.3	22.3	0.6
112	93.3	22.0	0.0
112	92.5	25.4	1.4
177	93.3	55.4	0.5
177	90.4	52.7	0.6
177	91.1	53.8	0.2
177	94.2	61.1	0.2
177	101.2*	59.5	0.1
234	98.7	79.8	0.0
235	92.7	76.5	0.2
235	96.9	79.2	0.3
278	92.6	72.9	1.5
375	89.3	71.9	3.0
481	77.3	62.7	0.5
481	85.6	68.3	0.0
565	82.8	66.0	0.0
565	89.0	70.9	3.2
750	67.5	58.5	1.6
750	104.1*	82.4	3.1

*Error in data

C.36 HOUSTON LIGHTING & POWER

1973

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
112	84.1	23.5	3.8
112	92.8	26.6	0.0
112	86.7	27.6	0.0
112	76.5	23.3	0.0
175	100.2*	58.0	0.8
175	94.9	56.9	0.7
177	97.3	61.8	1.0
177	84.4	48.6	0.4
177	89.5	53.7	0.0
234	78.2	67.2	1.0
235	89.1	68.7	1.8
235	90.3	67.5	1.8
278	90.4	65.1	1.4
335	97.6	79.3	1.1
409	90.5	70.5	0.0
481	93.4	76.2	6.1
481	88.3	70.2	0.2
565	83.2	67.5	0.2
565	82.3	66.4	0.0
750	73.4	68.3	6.0
750	80.9	71.7	3.3
750	155.1*	130.5*	0.0

*Error in data

C.37 HOUSTON LIGHTING & POWER

1974

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
112	95.8	10.6	0.0
112	105.3*	9.6	1.6
112	106.1*	9.3	0.0
112	87.7	11.3	0.1
175	64.6	34.5	0.1
175	80.7	42.3	0.1
177	72.8	43.4	0.0
177	91.9	40.8	0.4
177	96.6	37.8	1.1
234	85.7	68.8	0.2
245	95.0	67.0	3.6
245	73.6	54.9	5.5
278	93.7	62.9	0.2
375	76.7	50.5	0.8
409	69.7	44.4	29.4
481	97.0	76.9	0.1
481	93.4	72.8	0.2
550	79.5	59.9	1.4
565	88.1	66.8	0.6
700	84.9	76.5	0.0
750	92.6	74.7	1.6
775	66.0	54.7	0.9
775	100.0	72.6	0.0

*Error in data

C.38 HOUSTON LIGHTING & POWER

1975

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
112	92.6	14.9	2.6
112	77.5	10.8	16.2
112	94.5	15.9	0.0
112	94.5	15.4	0.0
175	99.1	51.9	0.0
175	66.9	36.2	3.2
177	89.8	63.9	1.0
177	93.3	51.9	1.2
177	92.3	50.0	0.7
234	97.2	73.8	0.0
245	54.7	43.6	0.2
245	61.1	51.4	0.0
278	71.8	47.6	0.0
375	79.2	59.9	0.3
409	60.2	41.4	0.1
481	71.2	57.4	2.7
481	87.6	72.9	0.1
565	87.1	70.8	1.9
565	95.4	73.4	1.6
725	68.7	50.8	0.1
775	61.7	50.3	5.7
775	63.8	50.1	3.3
775	84.8	65.6	7.4

C.39 TEXAS ELECTRIC SERVICE

1965

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
118	91.4	91.5	2.9
180	92.4	92.5	0.8
180	93.2	93.2	0.0
240	92.0	92.0	0.0
410	91.5	91.5	0.7

C.40 TEXAS ELECTRIC SERVICE

1966

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
118	99.6	99.9	0.1
180	72.7	72.7	0.0
240	73.4	73.4	1.7
410	89.9	91.1	0.5

C.41 TEXAS ELECTRIC SERVICE

1967

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
118	95.4	95.4	0.0
240	90.7	90.7	0.4
410	84.8	85.4	0.5
500	79.7	80.3	2.0

C.42 TEXAS ELECTRIC SERVICE

1968

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
115	91.5	87.5	0.5
120	87.1	42.4	0.0
175	93.2	61.6	0.0
180	56.9	40.9	0.6
262	97.9	71.6	1.8
411	93.6	72.7	0.8
500	87.1	58.4	0.8

C.43 TEXAS ELECTRIC SERVICE

1969

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
115	99.5	94.5	0.5
120	99.4	34.0	0.5
175	85.6	69.8	0.0
180	95.2	60.7	0.3
262	91.3	57.7	1.0
400	63.7	40.3	3.6
411	85.5	61.8	0.0
500	80.6	68.5	1.2

C.44 TEXAS ELECTRIC SERVICE

1970

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
115	96.4	89.4	0.0
120	85.3	33.9	0.0
175	94.9	82.9	0.0
180	78.0	51.1	0.0
262	89.4	54.3	0.7
382	82.7	53.4	0.2
411	92.7	65.4	0.3
500	78.0	74.3	1.8

C.45 TEXAS ELECTRIC SERVICE

1971

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
115	89.4	73.5	0.4
120	67.5	29.7	1.0
175	92.6	76.5	0.0
180	93.8	58.7	1.2
258	85.5	51.0	0.1
375	70.2	34.3	6.2
400	82.8	54.7	3.6
411	91.8	63.7	0.6
500	86.1	75.6	0.9

C.46 TEXAS ELECTRIC SERVICE

1972

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
115	90.4	80.1	0.5
120	88.9	50.1	4.2
175	84.7	72.8	0.0
180	88.6	68.1	1.5
258	86.2	54.0	1.4
375	81.8	19.7	0.9
400	96.1	66.0	2.7
411	62.6	47.3	11.6
500	83.4	68.8	7.1

C.47 TEXAS ELECTRIC SERVICE

1973

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
115	98.4	38.5	0.4
115	78.7	73.5	4.0
175	89.0	68.6	0.2
180	86.6	51.1	0.0
258	81.4	46.2	1.7
375	98.8	12.3	0.0
400	85.3	47.2	1.0
411	95.2	63.9	1.0
500	83.3	65.0	0.5

C.48 TEXAS ELECTRIC SERVICE

1974

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
115	93.7	75.1	1.4
115	100.0	57.3	0.0
175	82.3	65.4	0.6
180	95.0	43.9	0.4
258	87.9	52.3	1.4
375	113.1*	11.3	2.4
400	91.2	52.1	1.1
411	62.7	45.3	2.6
500	85.7	71.1	0.8
540	46.2	30.0	36.1

*Error in data

C.49 TEXAS ELECTRIC SERVICE

1975

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
115	86.9	26.7	1.2
129	98.5	17.5	0.0
172	91.6	49.5	0.0
175	64.3	54.0	0.0
240	65.0	50.3	3.8
375	54.5	44.1	0.0
390	83.9	14.3	3.1
411	66.9	45.4	1.1
500	72.9	57.6	2.7
540	93.4	60.5	0.4

C.50 TEXAS ELECTRIC SERVICE

1976

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
400	83.2	61.1	6.1
375	71.7	45.0	0.0
500	83.1	61.2	0.5
540	80.8	48.3	5.3

C.51 TEXAS ELECTRIC SERVICE

1977

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
400	71.1	49.9	1.1
375	81.9	52.4	2.9
500	79.4	59.8	0.7
540	68.6	42.3	2.2

C.52 TEXAS ELECTRIC SERVICE

1978

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
400	92.6	67.6	0.9
375	71.0	47.9	3.1
500	98.2	74.9	0.9
540	74.7	48.8	0.2

C.53 TEXAS POWER & LIGHT

1965

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
175	92.9	92.9	0.0
175	98.1	98.2	1.0
230	87.4	92.9	1.9

C.54 TEXAS POWER & LIGHT

1966

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
175	94.4	76.3	0.0
175	95.2	95.6	0.4
230	89.5	89.5	0.1
240	74.2	74.2	1.2
530	60.0	60.0	13.9

C.55 TEXAS POWER & LIGHT

1967

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
175	96.7	85.3	0.1
175	93.6	90.4	0.0
230	90.1	90.2	0.1
240	97.1	97.1	0.6
530	71.5	71.5	6.6

C.56 TEXAS POWER & LIGHT

1968

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
120	58.4	19.5	18.6
161	89.2	46.6	2.3
187	76.7	40.1	2.0
194	85.9	39.0	1.9
220	89.8	78.3	0.1
230	79.0	58.7	2.0
516	89.2	51.8	1.6
550	68.4	37.4	6.8

C.57 TEXAS POWER & LIGHT

1969

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
161	89.6	52.8	0.0
187	96.2	55.0	0.8
194	96.3	64.8	0.0
220	100.0	0.1	0.0
230	83.7	10.0	0.8
516	90.9	20.0	11.2
550	60.8	22.9	3.5

C.58 TEXAS POWER & LIGHT

1970

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
110	76.5	28.9	0.0
161	94.5	58.4	0.5
187	93.6	61.2	0.8
194	86.4	46.4	0.0
220	62.6	55.1	0.0
230	95.9	77.3	2.4
516	78.2	71.3	1.4
550	59.7	37.0	1.6
565	86.7	67.9	9.2

C.59 TEXAS POWER & LIGHT

1971

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
160	80.7	61.1	1.1
187	103.5*	52.2	0.0
187	87.6	49.0	8.2
220	79.4	66.1	1.4
230	98.6	82.1	0.0
375	93.6	11.3	1.8
516	83.8	58.3	3.4
550	72.3	43.9	1.1
560	77.8	64.7	1.1

*Error in data

C.60 TEXAS POWER & LIGHT

1972

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
110	73.3	13.6	0.0
160	80.6	52.1	2.1
187	79.0	48.4	4.1
187	94.1	44.0	5.5
220	95.1	74.5	1.2
230	76.1	49.8	0.8
375	65.2	10.5	23.6
516	126.0*	47.5	0.9
550	88.5	48.4	1.4
570	93.9	70.8	0.4
730	81.3	48.8	14.0

C.61 TEXAS POWER & LIGHT

1973

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
110	74.6	14.1	21.0
160	97.0	50.0	1.1
187	91.2	51.3	0.0
187	87.5	52.7	0.9
210	89.3	63.7	1.5
220	94.9	75.6	0.0
375	107.3*	22.1	17.2
516	86.6	51.5	0.7
550	60.2	35.6	30.4
570	64.3	48.9	34.2
730	49.9	35.2	30.3

*Error in data

C.62 TEXAS POWER & LIGHT

1974

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
110	91.1	44.4	0.0
174	71.9	39.9	0.0
175	101.3*	25.0	7.3
210	84.9	63.9	0.8
220	88.9	61.4	0.1
375	50.3	24.1	10.4
525	96.4	59.2	1.3
550	80.2	43.5	16.3
565	90.1	66.6	8.5
780	67.0	43.1	31.8

C.63 TEXAS POWER & LIGHT

1975

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
110	75.7	20.0	0.7
160	55.6	15.1	8.1
175	70.4	25.9	13.9
178	86.1	49.6	0.5
200	77.0	36.2	1.1
220	99.0	56.2	0.4
375	56.0	9.4	28.3
518	81.7	55.1	1.3
550	81.7	43.5	4.7
565	57.4	31.2	1.6
730	83.2	32.7	4.9
775	78.2	47.3	10.4

*Error in data

C.64 TEXAS UTILITIES

1976

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
540	85.1	79.8	3.3
540	69.3	64.5	26.6
525	78.3	72.8	6.6
525	85.0	80.6	2.6

C.65 TEXAS UTILITIES

1977

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
540	74.4	68.6	11.3
540	71.3	67.2	25.2
525	72.5	67.3	6.2
525	73.7	68.6	15.2
750	79.9	77.1	17.2

C.66 TEXAS UTILITIES

1978

Unit Size (MW)	Equivalent Availability Factor	Capacity Factor	Forced Outage Rate
540	70.6	65.1	23.0
540	85.0	79.9	4.1
525	74.6	68.9	6.5
525	66.3	63.8	7.9
750	56.3	52.6	33.3
750	63.5	59.7	24.1
750	85.5	83.4	6.2

APPENDIX D. SAMPLE SIMULATION RESULTS
FOR THE TESCO PROGRAM
(Base Case)

D-1

*****
 *
 * SUMMARY FOR CASE 1 *
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 *****

*****
 * TEXAS ELECTRIC SERVICE COMPANY *
 * MULTIPLE AREA *
 * UNIT COMMITMENT *
 *****

1980 TEST YEAR - DOE STUDY BASE CASE

UNIT	MWH	FACTOR		HRS SRV	FUEL PRICE			NUMBER OF START-UPS	START-UP COSTS \$	UNIT CHANGES			MAINTENANCE			
		CAP.	OUT.		\$/MMBTU	TYP	COST \$			MIN	MAX	MAX NET	START MONTH DAY	END MONTH DAY		
HAN 1	0	0.0	0.0	0	1.00	1	0	0	0							
HAN 2	617	0.09	62.70	12	1.00	1	7878	1	1020							
HAN 3	2441440	70.01	70.01	8784	1.00	1	24932917	0	0							
HAN 4	396695	9.97	57.05	1535	1.00	1	4975228	112	339696				10	5	12	13
HAN 5	753042	18.92	47.96	3466	1.00	1	9552228	134	406422				3	16	5	24
NM 4	1049	0.14	48.79	25	1.00	1	13440	1	1020							
EAG 1	3161	0.29	74.98	34	1.00	1	36302	2	2536							
EAG 2	602	0.04	92.90	4	1.00	1	6728	1	1673				2	3	3	15
EAG 3	571083	16.89	42.06	3527	1.00	1	7326929	217	391251				1	1	2	2
													12	14	12	31
GRA 1	55029	2.55	88.77	252	1.00	1	564833	31	65224				1	1	2	16
GRA 2	915946	26.81	68.33	3446	1.00	1	9396231	17	52870				2	17	3	22
MC 2	0	0.0	0.0	0	1.00	1	0	0	0							
MC 3	0	0.0	0.0	0	1.00	1	0	0	0							
MC 4	772	0.13	93.24	12	1.00	1	8972	1	928							
MC 5	6483	0.43	89.22	42	1.00	1	67653	3	4818				11	30	12	27
MC 6	2724365	62.40	73.68	7440	1.00	1	27663038	1	7860				10	5	11	29
PB 1	0	0.0	0.0	0	1.00	1	0	0	0							
PB 2	0	0.0	0.0	0	1.00	1	0	0	0							
PB 3	0	0.0	0.0	0	1.00	1	0	0	0							
PB 4	0	0.0	0.0	0	1.00	1	0	0	0							
PB 5	2615	0.29	80.91	32	1.00	1	28990	2	2402							
PB 6	2662571	56.24	63.53	7776	1.00	1	27775438	1	3150				2	24	4	5
VAL 1	51199	3.33	75.02	390	1.00	2	569550	60	100380				1	27	3	22
													9	7	11	8
VAL 2	2201516	45.57	56.67	7063	1.00	2	23005634	16	137248				11	16	12	31
VAL 3	52013	1.58	38.42	361	1.00	2	707001	42	75726				1	1	1	19
COL 1	67339	5.01	70.87	621	1.00	2	736349	95	140125							
TRN 5	2414	0.39	78.38	44	1.00	2	29535	10	9280							
TRN 6	195213	9.26	68.24	1192	1.00	2	2130264	118	234466				4	27	5	24
LCK 1	3465	0.45	64.24	62	1.00	2	43752	15	15285							
LCK 2	405014	20.05	40.88	4308	1.00	2	4893667	26	49894				4	20	5	17
THS 1	1786705	36.00	55.91	5656	1.00	2	19234319	32	559680				1	30	12	31
THS 2	4220064	61.99	67.26	8096	1.00	2	43440287	2	41970				3	16	4	12
DECVA	3171400	46.59	59.16	6917	1.00	2	33292409	2	27866				1	1	2	2
													9	14	10	25

D-2

*****
 * SUMMARY FOR CASE 1 *
 *****

*****
 * TEXAS ELECTRIC SERVICE COMPANY *
 * MULTIPLE AREA *
 * UNIT COMMITMENT *
 *****

1980 TEST YEAR - DOE STUDY BASE CASE

UNIT	MWH	FACTOR		HRS SRV	FUEL PRICE			NUMBER OF START-UPS	START-UP COSTS \$	UNIT CHANGES			MAINTENANCE			
		CAP.	OUT.		\$/MMBTU	TYP	COST \$			MIN	MAX	MAX NET	START MONTH DAY	END MONTH DAY		
STR 1	37266	2.42	64.33	331	1.00	2	28930	61	97966				11	2	11	29
STR 2	2175365	49.53	53.63	8112	1.00	2	23084073	1	4170				4	13	5	10
RVC 1	9552	0.99	92.38	94	1.00	2	116521	20	24020							
NLK 1	97685	6.35	51.26	1089	1.00	3	1093468	125	200750				1	6	2	2
												9	21	10	18	
NLK 2	273481	17.79	66.13	2363	1.00	3	2973794	152	244112				3	9	4	12
NLK 3	1392049	45.28	66.74	5959	1.00	3	14558085	35	97860				1	1	1	5
												10	19	12	31	
PKD 1	0	0.0	0.0	0	1.00	3	0	0	0							
PKD 2	0	0.0	0.0	0	1.00	3	0	0	0							
PKD 3	339	0.03	22.60	12	1.00	3	4395	2	2536							
MCK 6	2969	0.29	57.37	45	1.00	3	35148	10	12010							
MCK 7	7475	0.63	48.23	124	1.00	3	89246	24	30432							
MCK 8	1820971	37.69	64.87	5104	1.00	3	19606227	1	3410				1	1	5	31
DAL 3	0	0.0	0.0	0	1.00	3	0	0	0							
DAL 9	0	0.0	0.0	0	1.00	3	0	0	0							
LKH 1	196158	5.96	37.23	1405	1.00	3	2574215	99	178497							
LKH 2	2031095	44.90	44.90	8784	1.00	3	22817194	0	0							

851
138

*****
 + SUMMARY FOR CASE 1 +
 +*****+

*****
 + TEXAS ELECTRIC SERVICE COMPANY +
 + MULTIPLE AREA +
 + UNIT COMMITMENT +
 *****

1980 TEST YEAR - DOE STUDY BASE CASE

STUDY SUMMARY

TOTAL NET GEN	62522384 MWH	TOTAL COST	\$ 501584313	FIXED INTERCHANGE	0 MWH
DISPATCHED GEN	30736960 MWH	GEN COST	\$ 327815424	ECONOMY INTERCHANGE	8 MWH
BASEGEN	31785424 MWH	START-UP COST	\$ 3568553	BASEGEN INTERCHANGE	387303 MWH
BASEGEN BACKDOWN	397886 MWH	BASEGEN COST	\$ 170200336	EMERGENCY SALES	0 MWH
				EMERGENCY PURCHASES	1718 MWH

AREA SUMMARY

AREA	GENERATION NORMAL MWH	BASEGEN MWH	BASEGEN BACKDOWN MWH	SYSTEM LOAD MWH	GEN COST \$	START-UP COST \$	BASEGEN COST \$	TOTAL COST \$
TEXAS ELECTRIC SERVICE COMPANY	10535776	10462709	62654	21221408	112354816	1280870	56141408	169778864
TEXAS POWER AND LIGHT	14378844	14646410	274372	28751568	151710656	1518076	79997104	233227856
DALLAS POWER AND LIGHT	5822357	6676324	60860	12549495	63750016	769607	34061824	98582528

INTERCHANGE SUMMARY

*-----SALES-----**-----PURCHASES-----*

AREA 1	TO AREA 2	TO AREA 3	EMERGENCY FROM AREA 2	FROM AREA 3	EMERGENCY
FIXED	0	0	0	0	
ECON	0	0	0	5	
BASEGEN	4714	8859	190220	46817	
EMERG			0		0
AREA 2	TO AREA 1	TO AREA 3	EMERGENCY FROM AREA 1	FROM AREA 3	EMERGENCY
FIXED	0	0	0	0	
ECON	0	0	0	0	
BASEGEN	190220	112743	4714	23950	
EMERG			0		1718
AREA 3	TO AREA 1	TO AREA 2	EMERGENCY FROM AREA 1	FROM AREA 2	EMERGENCY
FIXED	0	0	0	0	
ECON	5	0	0	0	
BASEGEN	46817	23950	8859	112743	
EMERG			0		0

APPENDIX E. SAMPLE SIMULATION RESULTS

FOR THE PRODCOST PROGRAM

(Base Case)

OUTAGE RATE REDUCTION STUDY
1980 LOAD DATA 17500 MW SYSTEM CAPACITY
BASE CASE

----- AREA 1 YEARLY OUTPUT FOR 1980 -----

MACHINE NO.	MACHINE NAME	MW CAPACITY	CAPACITY FACTOR	MW-HRS GENERATED	HOURS RUN	MAINT. FROM TO	F.O. RATE	WEEKS F.O.	NUM. STARTS	FUEL COST IN \$K	TOTAL COST IN \$K
1	HAY 1	44.	222.2	0.	0	0 0	0.2222	0	0	0.	0.
2	HAY 2	78.	222.2	0.	0	0 0	0.2222	0	0	0.	0.
3	HAY 3	373.	75.5	2452448.	8736	0 0	0.2222	0	0	24123.	24123.
4	HAY 4	426.	3.5	132678.	334	41 50	0.2222	0	43	1348.	1348.
5	HAY 5	426.	222.2	0.	0	12 21	0.2222	0	0	0.	0.
6	VM 4	91.	222.2	0.	0	0 0	0.2222	0	0	0.	0.
7	EAG 1	115.	1.4	14694.	142	0 0	0.2222	0	23	133.	133.
8	EAG 2	152.	3.7	39535.	232	5 11	0.2222	0	34	474.	474.
9	EAG 3	352.	.1	3755.	12	1 7	0.2222	0	2	48.	48.
10	GRA 1	232.	43.3	895914.	3398	31 37	0.2222	0	227	9143.	9143.
11	GRA 2	356.	28.2	922495.	2730	3 12	0.2222	0	182	9350.	9350.
12	MC 2	22.	222.2	0.	0	0 0	0.2222	0	0	0.	0.
13	MC 3	45.	222.2	0.	0	0 0	0.2222	0	0	0.	0.
14	MC 4	55.	.5	2880.	48	0 0	0.2222	0	7	39.	39.
15	MC 5	153.	16.3	239582.	1244	49 61	0.2222	0	127	2547.	2547.
16	MC 6	457.	59.7	2844436.	7392	41 48	0.2222	0	1	28027.	28027.
17	PS 1	12.	222.2	0.	0	0 0	0.2222	0	0	0.	0.
18	PS 2	12.	222.2	0.	0	0 0	0.2222	0	0	0.	0.
19	PS 3	12.	222.2	0.	0	0 0	0.2222	0	0	0.	0.
20	PS 4	12.	222.2	0.	0	0 0	0.2222	0	0	0.	0.
21	PS 5	95.	7.1	59114.	642	0 0	0.2222	0	72	705.	705.
22	PS 6	547.	59.2	2579539.	7728	9 14	0.2222	0	1	25999.	25999.
23	VAL 1	155.	4.2	57105.	379	7 23	0.2222	0	48	717.	717.
24	VAL 2	517.	48.7	2158735.	4522	47 52	0.2222	0	173	22844.	22844.
25	VAL 3	353.	.2	7512.	26	1 4	0.2222	0	4	99.	99.
26	CUL 1	144.	5.5	59329.	578	0 0	0.2222	0	57	805.	805.
27	TRV 5	56.	222.2	0.	0	0 0	0.2222	0	0	0.	0.
28	TRV 6	225.	9.5	139056.	792	15 21	0.2222	0	84	2086.	2086.
29	LCK 1	82.	222.2	0.	0	0 0	0.2222	0	0	0.	0.
30	LCK 2	216.	6.0	113105.	454	17 20	0.2222	0	54	1273.	1273.
31	THS 1	531.	40.3	1892505.	3554	47 52	0.2222	0	178	21775.	21775.
32	THS 2	729.	73.1	4537590.	3562	42 45	0.2222	0	112	47554.	47554.
33	DEC VA	729.	22.9	1459294.	1792	5 15	0.2222	0	149	15373.	15373.
34	SIR 1	155.	1.7	27502.	190	45 48	0.2222	0	29	345.	345.
35	SIR 2	478.	85.3	3524352.	5736	0 0	0.2222	0	0	34337.	34337.
36	RVC 1	103.	.4	3988.	42	0 0	0.2222	0	7	54.	54.
37	VLK 1	155.	6.3	97435.	602	0 0	0.2222	0	55	1035.	1035.
38	VLK 2	155.	26.1	375890.	2140	0 0	0.2222	0	193	4020.	4020.
39	VLK 3	325.	70.3	2809165.	5794	0 0	0.2222	0	159	17850.	17850.
40	PAD 1	82.	222.2	0.	0	0 0	0.2222	0	0	0.	0.

OUTAGE RATE REDUCTION STUDY
1980 LOAD DATA 17500 MW SYSTEM CAPACITY
BASE CASE

---- AREA 1 YEARLY OUTPUT FOR 1980 ----

MACHINE NO.	NAME	MW CAPACITY	CAPACITY FACTOR	MWHR GENERATED	HOURS RUN	MAINT. FROM TO	F.O. RATE	WEEKS F.O.	NUM. STARTS	FUEL COST IN \$K	TOTAL COST IN \$K
41	PXD 2	139.	.3	2940.	34	0 0	0.3000	0	6	42.	42.
42	PXD 3	119.	1.1	11050.	130	0 0	0.3000	0	21	151.	151.
43	MCX 5	108.	.5	4520.	46	0 0	0.3000	0	7	50.	50.
44	MCX 7	118.	.4	4590.	44	0 0	0.3000	0	7	51.	51.
45	MCX 8	517.	18.4	831114.	1192	0 0	0.3000	0	118	8395.	8395.
46	DAL 3	71.	200.0	0.	0	0 0	0.3000	0	0	0.	0.
47	DAL 9	66.	200.0	0.	0	0 0	0.3000	0	0	0.	0.
48	LK1 1	353.	1.1	35315.	102	0 0	0.3000	0	17	422.	422.
49	LK1 2	430.	71.7	3030459.	9736	0 0	0.3000	0	0	30572.	30572.
100	BBRY 1	541.	75.0	3544532.	6552	13 19	.1304	5	5	15573.	15573.
101	BBRY 2	541.	65.4	3090192.	5712	4 16	.1304	5	5	14447.	14447.
102	MOVI 1	541.	73.1	3453744.	6334	45 48	.1304	10	10	19951.	19951.
103	MOVI 2	541.	78.8	3726299.	6899	2 5	.1304	7	6	21352.	21352.
104	MOVI 3	705.	75.5	4711729.	5720	45 50	.1800	7	5	32454.	32454.
105	MVLK 1	705.	69.8	4238182.	6048	1 11	.1457	5	4	29275.	29275.
106	MVLK 2	705.	72.4	4451039.	5394	12 17	.1900	9	8	30355.	30355.
107	MVLK 3	705.	68.5	4217544.	6002	1 6	.2067	10	6	29150.	29150.
TOTALS		16230.		62155485.						503929.	503929.

TOTAL ENERGY REQUIREMENT FOR YEAR WAS

62155486. MWH (EXCLUDING PUMPING LOAD IF ANY)

OUTAGE RATE REDUCTION STUDY
 1980 LOAD DATA 17500 MW SYSTEM CAPACITY
 BASE CASE

***** COST SUMMARY BY FUEL TYPE FOR 1980 *****

NO.	TYPE OF FUEL	\$/MBTU	-----AREA 1-----			-----AREA 2-----		
			MW GENERATED	FUEL COST \$K	AVG. \$/MWH	MW GENERATED	FUEL COST \$K	AVG. \$/MWH
1	NATURAL GAS	1.20	30711728.	314952.	14.26	0.	0.	0.00
2	LIGNITE A	.45	6634824.	31020.	4.58	0.	0.	0.00
3	LIGNITE B	.55	7190042.	41203.	5.74	0.	0.	0.00
4	LIGNITE C	.62	4711728.	32454.	5.99	0.	0.	0.00
5	LIGNITE D	.65	12917154.	99299.	6.91	0.	0.	0.00

APPENDIX F

F. MODELING TOOL - REM

F.1 Introduction

The simulation model used is a modified version of the Regionalized Electric Model (REM) that was originally developed at MIT and at the University of Texas at Austin. REM is a regionalized engineering economic simulation model of U.S. electricity supply and demand.

The level of regional aggregation used in REM is regional reliability council level. The regional reliability councils are aggregates of interconnected electric utilities that have coordinated already existing bulk power supply programs. Some of these utilities actually operate as power pools and even coordinate their planning. Figure F-1 is a map of the North American continent showing the geographical boundaries of each of the nine regions constituting the National Electric Reliability Council (NERC).

REM is an analytical tool that can be utilized to examine the effects of major national energy policy proposals on electricity price and fuel utilization by the electric utility industry.

In summary, whenever details of specific plant and equipment load, or geographic characteristics of the service area, are important, REM will be of little use. Issues of regional or national policy are more appropriate to its scale and aggregation. REM is, in effect, an aggregate version of the individual utility decision process.

The novelty of the model stems not so much from the way in which any of the individual portions of the model are structured, but rather from the scope and breadth of consistency maintainable from the integration of submodels of distinct but interrelated elements of the industry. With the interconnection of these components, we obtain a very robust, yet consistent, analytical device.

Analytical planning and policy analysis models are not new. Indeed, since the imposition of the oil embargo in the fall of 1973, models with applications in the energy area have proliferated. The Regionalized Electricity Model is nothing more than a mathematical analog of an explicit set of behavioral, accounting, and optimization rules. The model does not include all possible forces or constraints that might influence future development in the electricity utility sector. The complexities of real world social, political, environmental, institutional, and economic interactions preclude this possibility. By integrating the more important elements of the system, however, a tool is obtained that can be used to facilitate quantitative analyses, though the results have to be interpreted in light of considerations that are not explicitly factored into the model structure.

Figure F-1

National Electric Reliability Council (NERC) Regions

Source: NERC

F.2 Data Base

Data on existing generation capacity and future expansion plans that are readily available in the reports that each region submits to the Department of Energy each year are an input to REM.

The original version of REM included a generation expansion submodel that exogenously determined capacity expansion paths for each region. In the modified version, the internal computation of capacity expansion has been replaced by endogenously specified expansion plans that correspond to actual electric utility plans.

Each year the nine reliability council regions submit to the Federal Energy Regulatory Commission (FERC) reports on their existing capacity and future expansion plans. These reports list all existing powerplants, their location, the fuels they use, and the methods of transporting the fuel. The future expansion plans are listed in similar detail, along with the current status and expected completion dates for individual units. The data on existing and future electric powerplants have been computerized and set up in the form of a data base. The primary purpose of the data base for this project was to provide the REM with tabulations of future and existing generating capacity, aggregated for each region by plant type for every year from 1977 to 1987. Estimates of resources for the eleven to twenty-year period, as reported by NERC by each of the nine reliability council regions, were used to tabulate capacity levels beyond 1987.

F.3 Operation Simulation

The Regionalized Electricity Model provides a very detailed simulation of capacity expansion and investment. Four different time horizons are used to simulate the licensing and construction of the alternative plant types listed in Table F-1. For example, if a capacity expansion scenario calls for a nuclear plant to come on line in 1990, the licensing and construction time table is initiated in 1980, i.e., ten years prior to the target completion date. By utilizing widely accepted cash flow patterns, construction cash flows (Figure F-2) are computed on a half-yearly basis and are accumulated in "construction work in progress (CWIP)" accounts. During the period of construction, interest on CWIP is recorded in other accounts. When the plant is complete and begins operation, the accumulated construction and interest expense, which is the total initial capital cost, is entered into the rate base.

One other feature of REM is a set of cost and material balance relationships for the nuclear fuel cycle, encompassing the calculation of raw uranium ore requirements, fuel processing, enrichment, fabrication and reprocessing needs and costs.

Figure F-3 shows a block diagram of different submodels and the major paths of information flow in REM.

TABLE F-1

PLANT TYPES AND THEIR LICENSING AND
CONSTRUCTION LEAD TIMES

Plant Type	Lead Time (years)
1. Nuclear - LWR	10
2. Coal (existing)	5
3. Coal (new with flue gas desulfurization)	5
4. Coal (new without flue gas desulfurization)	5
5. Gas	5
6. Oil	5
7. Combined cycle	5
8. Combined cycle	2.5
9. Combustion turbines	2.5
10. Pumped storage	6
11. Hydro	6
12. Geothermal	6
13. Other	5

FIGURE F-2
Construction Cash Flows

FIGURE F-3
REM Sub-models

F.4 Financial Simulation

One of the important submodels is the Financial-Regulatory submodel. It applies the tax, accounting and regulatory rules of the industry to investment and operating costs of the supply system to determine the price of electricity. It also simulates the financing of future expansion within the normal guidelines of prudent financial management while maintaining consistency with the income and cash flow accounts and the endogenously supplied costs of alternative forms of capital. It computes balance sheet and income statement items for electric utilities aggregated by regions.

F.4.1 Price Regulation

The process of price regulation and regulatory practices has been simulated in the following manner.

The accounting net revenue R_n is expressed as:

$$R_n = R_g - C_p - d_B - PT - IT + IDC$$

Where:

R_g = gross revenue,

C_p = production costs,

d_B = book depreciation expenses,

PT = property taxes,

IT = income taxes, and

IDC = allowance for interest during construction.

The net revenue allowed by the regulatory commission R_n^* is:

$$R_n^* = r(K - D + W)$$

Where:

r = allowed rate of return on the rate base,

K = value of plant and equipment at original cost,

D = accumulated book depreciation, and

W = allowance for working capital.

Income taxes are given by the relation:

$$IT = T_y(R_g - C_p - d_T - I - PT) - ITC$$

Where:

T_y = income tax rate,

d_T = depreciation using accelerated method for tax purposes,

I = income expenses, and

ITC = investment tax credit.

The process of price regulation is simulated by equating allowed net revenue (R_n^*) to the accounting net revenue (R_n). Solving for R_g , we get:

$$R_g = \frac{r(K - D + W) + d_B - T_y d_T - T_y I - IDC - ITC}{I - T_y} + C_p + PT$$

This is the gross revenue that the utilities could earn, which is constrained by the net revenue allowed by the regulatory commission.

APPENDIX G

G. INCREASED PRODUCTIVITY GIVEN THE TYPICAL REGULATORY ENVIRONMENT AND THE ROLE OF INCENTIVES

G.1 Introduction

Chapter V presented a discussion of benefits to be gained from instituting a general incentive format within rate of return regulation. For the purpose of that discussion, it was implicitly assumed that once an electric utility has chosen and fixed its level of capitalization, the company will then work with its mix of variable inputs in the most efficient manner possible. When a utility is overcapitalized, for whatever reason, any improvement in the productivity of existing capital results in a drop in future capital requirements. As will be demonstrated in section 2 of this appendix, any such improvements will seriously diminish the net revenue posture of the electric utility. The converse situation, where undercapitalization occurs (due to insufficient return to capital or regulatory delay coupled with unanticipated load growth), is also discussed in that section. Note that runs of the Regional Electricity Model (reported in Chapter II) indicate that even with a minor increase in powerplant performance, large drops in the cost of electricity to consumers and profit to the utility are experienced. When the cost of implementing an efficiency improvement project is included, the cost saving to consumers would be diminished somewhat (assuming that only cost-effective projects are pursued), but the drop in utility profits would not be altered. Since anticipated demand levels as well as capitalization plans and fuel requirements are inputs into the Regional Electricity Model (as reported by electric utilities themselves), the relationship between the mix of inputs (including capital) and demand levels is indicative of the market and regulatory forces that drive electric utilities.

G.2 Rate of Return Regulation and Profit

In those situations where the utility experiences a rate of return that exceeds the cost of capital in an expanding market environment, constant rate of return regulation places monetary impediments in front of a utility if it chooses to back off capital expansion plans.¹ Rather than encourage efficient capital utilization, existing incentives give contrary signals. This is due to a change in the utility's profit situation when it cuts back capital. As we have argued before, overcapitalization may be selected when the utility commission allows a rate of return above current costs of capital of a hypothetical utility. Electricity consumption remains fixed in this model. A firm examines various capitalization levels to locate the point of highest profit.

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¹ Note that either average rate of return should be compared to average cost of capital, or marginal rate of return should be compared to marginal cost of capital.

This model of utility behavior proposes that a company first determine the demand it is required to fill under a certain rate structure and then choose the production strategy which serves that level of consumption. Figure G-1 illustrates the latter decision.

The profit possibility curve, $\pi(K)$, relates net revenue to different levels of capitalization. Labor, fuel, and other variables adjust to cost-efficient levels for each capital stock. The straight line, $(s-r)K$, is the excess of the regulated rate of return over the current cost of capital, multiplied by the rate base.

The graph conveniently illustrates the capital selection process under rate of return regulation. The electric utility behaves as if it is maximizing profit within the confines of a regulatory profit constraint. The straight line is the constraint, and the curved line is unconstrained profits. The curved line reflects the firm's production function. With output and rates constant, it is basically changes in cost which give rise to the shape of the curve. A utility moves along the constraint line until it reaches the highest profit level, in this case $\pi(K_1)$. Effective regulation forces the rate of return below the nonregulated return. This implies that the line $(s-r)K$ cuts $\pi(K)$ below the peak of the hill since the return at the peak is the unregulated return.

This graph demonstrates the consequences of an attempt to reduce capital below K_1 . Clearly, the company desires to make this change since unregulated profits will rise along the profit hill above point A. But rate of return regulation restricts net earnings to a certain fraction of capital. Any attempt to back down capital lowers allowed profits along with the straight line. The difference between the profit-maximizing behavior and rate of return regulation-induced behavior is never more striking. A regulated rate of return lowers a capital-intensive firm's profit level when it adopts productivity improvements. Tables II-3, II-8, II-11, and II-18 in Chapter II report the results of Regional Electric Model runs which were designed to simulate the effects of outage rates improvements. Since the financial section of this model simulates rate of return regulation, these findings verify the theoretical argument that increases in powerplant performance will lead to decreases in profit.

An incentive scheme must be designed in such a way that utilities find it to their advantage to more efficiently utilize capital (whether they are over- or undercapitalized at the start). This requires post-incentive profits to be no lower than $\pi(K_1)$. Otherwise, a company will opt out of the program and stay with its current capital structure.

In the case where the allowed return is below the market cost of capital, the logical capital investment choice is zero. Utilizing Figure G-1 as a format, this would rotate the straight constraint line below the K-axis, and the origin would become the maximum profit point, i.e., no capital would be used since the return on capital would be less than its purchase price. A utility would not take such a drastic step, but it is clear that allowing the rate of return to fall below the market rate discourages acquisition of capital.

Profit
\$

FIGURE G-1

Profit under Rate of Return Regulation

If the utility experiences a rate of return below its cost of capital, even for a short period of time, its borrowing capabilities will be compromised. It will be assigned a high risk rating in the bond market, and its cost of capital will be higher than for firms exhibiting a higher rate of return. Under these circumstances, even if in the long run the utility in question is able to equate its average rate of return and its average cost of capital, its long-run total cost cannot be minimized. Besides, even in the short run, when the rate of return and the cost of capital are equal, there exists no financial incentive under constant rate of return regulation for utilities to choose the cost-minimal stock of capital. Referring to Figure G-1, the utility is encouraged to choose the point to the right of K_0 , where the profit possibility curve $\pi(K)$ crosses the $(s-r)K$ line. In spite of the financial disincentives to undertake capital improvement projects, utility managements often choose to undertake projects that would lower total system cost. However, they are limited in the scope of these activities by the financial burdens imposed on the utility and the present instability in the money market.

Unforeseen regulatory delays during the siting and construction of new powerplants are another source of future undercapitalization. Delays that occur after the setting of target completion dates of individual powerplants place the timetable for future capacity in peril and could cause a loss of reliability or even a capacity shortfall at a future date, especially if those unforeseen regulatory delays are coupled with an underestimation of future demand growth. As discussed in the conclusions of Chapter III, any increased utilization of existing capital resulting from an incentive program might prove to be an effective hedge against such a combination of events. As will be demonstrated later in this appendix, a properly designed program which promotes improvements in existing powerplant performance can encourage the firm to select the cost-minimal stock of future capital required to satisfy demand when injected into a typical rate of return regulatory format. Starting from a position of undercapitalization, this same incentive program can encourage the utility to move to a lower operating cost position. The utility will choose to make such a move if it is allowed to retain a sufficient amount of the savings that result from a cost-effective capital addition such that, on the margin, its rate of return equals or exceeds its market cost of capital.

G.3 The Utilization of Incentives

Section 2 demonstrates that any improvement in powerplant productivity, under typical rate of return regulation, ultimately leads to a significant drop in utility profits. If the utility is overcapitalized and faces rates of return which exceed cost of capital on the margin, then projects which lower average KWh costs will typically be associated with long-run decreases in required capital per KWh sold and, therefore, a drop in profits. On the other hand, if the utility is undercapitalized and faces rates of return below the cost of capital on the margin, then projects which lower average KWh costs typically require increases in capital investment per KWh sold. Therefore, the utility would experience a drop in profits (since the utility's cost of capital would exceed the return to that capital for each unit of investment). And due to this breach between profit and

efficiency, utility management also faces the dilemma of trying to serve the interests of both the customer and the stockholder; unfortunately, utility management cannot serve both parties. To best serve the interest of electricity customers, management must compromise the stockholder's position, whereas to best serve the stockholder's position, management must choose to operate at a point where the cost of electricity to customers is not minimal. Also, it should not be forgotten that if the financial health of the utility is compromised in the short run, the customer will pay for it in the long run. Utility decisionmakers have exhibited a high level of attentiveness to the needs of the consumer, and typically choose the good of the consumer over the good of the stockholder. As mentioned in Section G.2, however, often the short-run burden of increased capital expenditures on electric utilities curtails projects which could lower long-run costs.

In the competitive free market environment, this dilemma does not exist since maximum profits are attained when costs are minimized; consequently, the drive for greater productivity serves both the customer and the stockholder. The lesson to be learned from the competitive free market is that one of the necessary conditions for assuring the selection of the cost-minimal mix of inputs is that efficiency and profit should be positively correlated.

The basic purpose of the general incentive program proposed in this study is to clearly establish the link between profit and efficiency. Typical rate of return regulation does not clearly make this link. And such a linkage between profit and efficiency can be facilitated with only minor modifications of the existing structure of utility regulation.

The first task of this section is to identify the set of alternative capital-profit choices that are possible under an incentive plan which rewards the utility for implementing programs that lower the cost of electricity service (per KWh sold). Assume the utility in question is operating at profit level A under a constant rate of return format. Since any incentive program should be voluntary, the rational profit-maximizing utility will reject the incentive plan if that plan results in a profit level lower than A. For utilities which are overcapitalized (where rate of return exceeds cost of capital on the margin), the set of possible capital-profit choices includes all combinations of capital choices between the present level and the unconstrained level (as identified by $\pi(K)$ in Figure G-1). For utilities which are undercapitalized (where rate of return is under cost of capital on the margin), the set of possible capital-profit choices is defined as above for the overcapitalized firm except that both present profit and present capitalization levels are lower in the undercapitalized case. It will be helpful for the reader to keep in mind that increases in profit are directly related to decreases in total cost, and that decreases in cost reflect increases in the productivity of capital.

In the case of an overcapitalized utility, when its rate of return exceeds the cost of capital, or the cost of other inputs, total cost decreases as the productivity of capital increases and the needed stock of capital per KWh sold decreases. Without an effective incentive program, increased productivity leads to a decrease in total profits (i.e., as the utility decreases capital from K_1 toward K_0 , in Figure G-1, the regulatory constraint line $(s-r)K$,

specifies a drop in profit). As documented earlier, the net revenue (profit) figures for the variable expansion cases reported in Tables II-3, II-8, II-11, and II-18 in Chapter II demonstrate the negative effects of a productivity increase upon profit levels for the ERCOT region as a whole.

In the case of an undercapitalized utility, when its rate of return falls beneath the cost of capital, total cost decreases as capital stock is increased relative to other inputs. However, under these circumstances utility profits decrease with each additional unit of capital investment. An incentive system can be utilized to ameliorate the impact of this problem.

An effective general incentive format would have to be sufficiently flexible to handle both the undercapitalization and the overcapitalization cases under a single basic framework. The incentive format proposed in this study is operative in both circumstances. As described in Chapter III, the basic strategy of the incentive format proposed in this study is to offer utilities a portion of any net saving resulting from a program designed to lower average total cost (per KWh consumed). The fraction of that net savings retained by the utility is related to the existing performance level of that utility (e.g., outage rate, availability factor, etc.). In this manner, the general incentive format encourages all measures that lead to lower KWh costs and rewards utilities for achieving high powerplant performance levels (for baseload units).

Typically, regulatory agencies utilize the market cost of capital as the target for the utility's rate of return. In Appendices C and D (Volume II), it is demonstrated in graphic and notational form that when it is assumed that a utility's rate of return exceeds the cost of capital on the margin, the more successful the regulatory agency is at equating rate of return and cost of capital, the greater will be the inducement for that utility to overcapitalize. In the reverse situation, where the utility's rate of return falls below the cost of capital on the margin, the utility resists all new investment regardless of how close the regulated rate of return approximates the cost of capital. The incentive format proposed in this study corrects both situations in that the closer the regulatory commission sets a utility's rate of return to its cost of capital, the greater is the incentive for that utility to choose the cost-minimal level of capital.¹ These results are logical since the utility under the incentive system clearly receives increasingly higher profit levels when average total costs are lowered. It must be reemphasized, however, that it is financially unhealthy for a utility to consistently face a rate of return which, on the margin, lies beneath the current cost of capital. Also, an incentive plan is not a cure for that malady. A properly designed and implemented plan would be capable of correcting a short-run occurrence where the rate of return lies slightly beneath the cost of capital, but large and/or consistent negative differentials must be treated more directly.

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¹ See Appendices C and D (Volume II) for a more detailed statement and rigorous proof of this assertion.

G.4 Alternative Actions and Possibilities

There are two topics included in this section. First, the Michigan incentive plan is outlined, and second, a comparison is made between the general incentive format proposed in this study and the type of incentive plan represented by the Michigan program. Third, the limitations of using the fuel adjustment clause as an incentive mechanism are discussed.

G.4.1 The Michigan Incentive Plan

In 1977 and 1978, the Michigan Public Service Commission set up a system-level availability incentive program for Detroit Edison Company and Consumers Power Company respectively. In December 1977, the Michigan Commission established a Task Force to trace the causes of the decline in powerplant availability within the electric utility industry, and to identify those regulatory mechanisms that are contributory to the low availability situation. In essence, the overall purpose of this staff-level effort is to fine-tune the existing incentive mechanisms and develop new ones to achieve higher levels of availability.

One of the specific projects of the Task Force is the development of a regulatory environment that is conducive to improved powerplant availability. This project seeks to accomplish the following: (1) establish baseline data on the performance of powerplants in Michigan, (2) evaluate the current production maintenance process for Detroit Edison and Consumers Power, (3) evaluate the Michigan Public Service Commission's present regulatory policies and techniques as they impact powerplant productivity, (4) analyze the impact of major productivity improvement projects for large baseload powerplants in Michigan, and (5) develop recommendations for improvement in present regulatory policies and techniques, and develop new regulatory policies and techniques that could be implemented by the Michigan Public Service Commission to improve powerplant availability.

The Michigan incentive program creates a direct link between system availability and return on equity. In this manner, the Michigan Commission is attacking the basic regulatory disincentive to powerplant efficiency--the breach between profit and efficiency created by the typical rate of return mechanism utilized to determine revenue requirements. This format of a direct link between return to equity and system availability does not in itself guarantee either that the availability improvement actually create a net benefit (above cost savings), or, given a positive net benefit, that the incentive reward not exceed net benefit. The viability of the Michigan incentive system hinges on the careful determination of equity return incentive levels by the Commission staff, and the first round of incentive rewards appears to have been successful. Tables G-1 and G-2 indicate the levels of system availability that are required to earn the associated increase in allowed equity return. Table G-2 accounts for a reasonable periodic maintenance program. In this manner, the Michigan Commission negates the manipulation of scheduled maintenance periods to earn the incentive reward.

TABLE G-1

Proposed Expanded Scale of Availability Adjustment

<u>System Availability</u>	<u>Equity Return Incentive</u>
100.00% - 85.01%	+.50%
85.00% - 83.76%	+.40%
83.76% - 82.51%	+.30%
82.50% - 81.26%	+.20%
81.25% - 80.01%	+.10%
80.00% - 74.01%	-0-
74.00% - 73.01%	-.05%
73.00% - 72.01%	-.10%
72.00% - 71.01%	-.15%
71.00% - 70.01%	-.20%
70.00% - 0	-.25%

TABLE G-2

Proposed Expanded Scale of Availability Adjustment

Including Periodic Maintenance Factor

<u>System Availability Plus Periodic Factor</u>	<u>Equity Return Incentive</u>
100.00% - 92.01%	+.50%
92.00% - 90.76%	+.40%
90.75% - 89.51%	+.30%
89.50% - 88.26%	+.20%
88.25% - 87.01%	+.10%
87.00% - 81.01%	-0-
81.00% - 80.01%	-.05%
80.00% - 79.01%	-.10%
79.00% - 78.01%	-.15%
78.00% - 77.01%	-.20%
77.00% - 0	-.25%

G.4.2 A Comparison of the General Incentive Format of this Study and the Michigan Program

Utilizing the same graphic presentation as in Figure G-1, we can represent the Michigan incentive plan, in Figure G-2, as the movement of $(s-r)K$ to $(s^*-r)K$ where:

$$s^* = s + s_I, \text{ and}$$

s_I = the incentive increase in the allowed rate of return.

The Michigan incentive plan permits the allowed rate of return to increase according to a preestablished schedule as baseload powerplant availability increases (Table E-2). This type of incentive plan implicitly recognizes the perverse nature of an accurate match between the allowed rate of return and the market cost of capital in a rate of return environment; this perverse relationship is discussed further in Appendix C (Volume II). By increasing the spread between the allowed rate of return and the cost of capital, the Michigan incentive plan encourages the utility to move along the $\pi(K)$ curve from point A toward point D. Point G represents the position that a utility would select if the incentive schedule effects a change in the allowed return from s to s^* . However, since the increased rate of return is associated with a prescribed increase in powerplant performance, the utility is not able to choose point G, but rather a point such as H, somewhere to the left of G on line $(s^*-r)K$. The exact position of H would be determined by the preestablished schedule relating increased performance and increased rate of return and the actual performance increase of the utility.

The incentive program recommended in this study encourages the utility to move along the constrained profit possibility curve from point A toward the cost-minimal level of capital. Both the Michigan plan and the plan recommended in this study are capable of moving the capitalization of regulated utilities toward the cost-minimal level (K_0), but they do so along different paths.

Assuming that an electric utility is a profit maximizer, its rational first move under an incentive program, as depicted in Figure G-2, will fall within area ADF. Such a profit assumption implies that the utility, given the type of incentive program offered, would prefer to move to a constrained profit maximum, such as point A_1 or point H.

Utility management, however, may not adhere strictly to the profit maximization motive under an incentive plan. Imperfect knowledge of the exact position of the profit curves and the regulatory constraint lines would lead to some degree of deviation from points A^* or G, given the implementation of their respective incentive programs. Also, as a hedge against adverse public opinion, utility management may choose to move slightly away from the constrained profit maximums (A_1 or H). In the case of the Michigan incentive plan, the utility must stay on line $(s^*-r)K$, so management may decide to operate slightly below and to the left of G on the incentive rate of return line. In the case of the incentive format

FIGURE G-2

A Comparison of Alternatives

Note that the constrained profit possibility curve does not have to intersect the K_0 line at profit level A as depicted at Point D . Also, for a more detailed derivation of this graphic presentation, see Appendix C (Vol. II).

proposed in this study, a similar shift would move the utility along the constrained profit possibility curve from A_1 toward D or back toward A. In the case of both plans, however, the utility is not likely to choose to operate below profit level $\pi = A$ or significantly to the left of K_0 (as constrained by reliability limits which are based on established loss of load probabilities). This means that utilities will tend to operate within the area bound by the endpoints ADF.²

In the case of the Michigan plan, the task of assuring that an increase in powerplant performance results in a net cost savings must be undertaken by the commission staff. In contrast, the small incentive format developed in this study places the primary responsibility of proof and planning on the utility. The commission staff's responsibilities would basically consist of oversight duties. Long-term capital decisionmaking as well as the development and modification of short-run operational procedures should be undertaken by the utility.

G.4.3 Fuel Adjustment Mechanism

The fuel adjustment clause is another candidate mechanism to encourage improvements in powerplant productivity. During the interim between full rate cases, adjustment clauses allow price increases to reflect escalating energy costs. We have suggested that much of the short-term cost savings from productivity improvements will manifest themselves as fuel savings. Thus, a link between outage rates and fuel savings is a means to implement productivity incentives. For example, some fraction of the fuel savings resulting from an outage reduction could be added to the revenue requirements of the utility. This is superficially similar to the incentive plan discussed earlier in the chapter since part of the cost savings consists of fuel savings.

However, several problems exist with a fuel adjustment mechanism. First, this approach ignores the capital savings that are possible when productivity is improved. While fuel savings result immediately, reductions in future additions to baseload capacity take longer. Productivity and average total cost improvements entail fuel and capital savings. The broader incentive strategy suggested in the first section of this appendix focuses on total cost reductions, and it should be noted that whether the utility is overcapitalized (with rate of return above cost of capital) or undercapitalized (with rate of return below cost of capital), the exclusion of capital savings from a general incentive format is counterproductive.

In order to overcome any possible capital disincentive and induce compliance when capital savings are ignored, the fraction of fuel savings returned to the firm as an incentive may have to be quite high. This is due to the drop in net revenue (profit) experienced by the overcapitalized utility facing a rate of return above the cost of capital when capital is

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² For a detailed graphic description of the dynamics of the general incentive format proposed in this study and the Michigan plan, see section 2 in Appendix C (Volume II).

reduced and earnings are reduced proportionately. To prevent profits from falling, the fuel adjustment incentive must be large enough to compensate for the losses associated with capital reductions. For the undercapitalized firm facing a rate of return below the cost of capital, in order to experience significant fuel savings, it must add base load capacity. Under the circumstances, however, the firm loses with each additional unit of investment.

Furthermore, utilizing a fuel adjustment mechanism as the source of reward for outage reduction may actually create inefficiencies by encouraging outage reductions that are not cost efficient. Suppose an outage improvement costs \$50,000 and reduces total costs (capital, fuel, labor, etc.) by \$40,000, three-fourths of which is fuel savings. Although the outage improvement is inadvisable, a fuel adjustment that rewarded 150% of any fuel reductions would turn a profit for the company despite the fact that the outage change yields no social savings. The fuel adjustment, therefore, could induce inefficient capital changes. In contrast, the general incentive mechanism described in this appendix requires demonstration of net cost savings.

G.5 Summary

The primary purposes of this appendix have been twofold. First, it is demonstrated that a rate of return regulating mechanism does not adequately encourage programs aimed at lowering average cost per kilowatt hour both for overcapitalized and undercapitalized utilities. Second, it is shown that there exists a general type of incentive plan which rewards utilities for implementing programs which lower average KWH costs and increase power-plant productivity. And it does so while maintaining the general framework of rate of return regulation.

Without an incentive program such as described in this study (or comparable alternative), constant rate of return regulation does not adequately encourage improvements in productivity. The lack of an incentive program also creates an environment in which a utility facing a rate of return higher than its cost of capital (on the margin) is encouraged to adopt a capital stock level which increasingly departs from the cost-minimal level as the regulatory agency more accurately matches allowed rate of return to equity with the market cost of capital. The incentive plan described in this section not only encourages higher productivity, it also induces the utility to choose levels of capitalization closer to the cost-minimal level when the agency closely approximates the allowed and market cost of capital.

Basically, the incentive plan links profit and efficiency in such a manner that the ultimate level of profit is allowed to vary with respect to average total cost and powerplant productivity within a given range. This concept is a return to the fundamental principal that a strong positive correlation between profit and efficiency is one of the necessary conditions for cost-minimal operation in the pure competitive state. In the regulatory environment, however, achieving that link is complicated by the rate of return mechanism. In effect, we have proposed a compromise between traditional rate of return regulation and free market forces. This compromise maintains the needed oversight that rate of return regulation affords utility operation while closely approximating many of the cost-minimal attributes observed in firms operating in a competitive market.