RATE INCENTIVE PROVISIONS:

A FRAMEWORK FOR ANALYSIS AND A SURVEY OF ACTIVITIES

William P. Pollard
Senior Research Associate

THE NATIONAL REGULATORY RESEARCH INSTITUTE
2130 Neil Avenue
Columbus, Ohio 43210

with contributions by the
Pennsylvania Public Utility Commission Staff

Conrad Six, Director
John J. Reilly
David M. Boonin
Bureau of Conservation, Economics and Energy Planning
John L. Dial, Director
Bureau of Audits

prepared for the
Pennsylvania Public Utility Commission

under the sponsorship of the

U.S. Department of Energy
Economic Regulatory Administration
Division of Regulatory Assistance

in partial fulfillment of

Grant No. DE-FG01-80-RG10268
Modification A003

November 1981

FOREWORD

This report was prepared by The National Regulatory Research Institute (NRRI) under Grant No. DE-FG-01-80RG10268 from the U.S. Department of Energy (DOE), Economic Regulatory Administration, Division of Regulatory Assistance. The opinions expressed herein are solely those of the authors and do not reflect the opinions nor the policies of either the NRRI or the DOE.

The NRRI is making this report available to those concerned with state utility regulatory issues since the subject matter presented here is believed to be of timely interest to regulatory agencies and to others concerned with utility regulation.

Douglas N. Jones
Director

EXECUTIVE SUMMARY

The Pennsylvania Public Utility Commission's Bureau of Conservation, Economics and Energy Planning is investigating ways in which it can improve power plant productivity and a utility's control of construction cost overruns through rate incentive provisions. Rate incentives are financial arrangements that reward or penalize a utility according to preestablished performance standards. The goal of incentive provisions is to lower the cost of service to consumers by not incorporating substandard performance in rates they pay.

Several states have implemented or are investigating rate incentive provisions. A review of these provisions discloses several recurring and unifying ideas central to rate incentive provisions. These ideas are summarized as nine criteria for a desirable rate incentive provision. They are listed below:

1. The incentive should be directed toward the interests that motivate the utility's behavior.
2. The incentive should address those aspects of a utility's performance under the control of its management.
3. To the extent feasible, the utility should be given a clear expectation as to how its performance under the incentive provision will be evaluated and rewards or penalties conferred.
4. Application of the incentive provision should result in a positive net benefit to the utility's consumers and society as a whole.
5. The information necessary to evaluate the desired behavior should be free from tampering and ambiguity.
6. The goal and method of application should stand in a clear and logical relationship to one another.
7. The goal and method of application should be neutral in their effects and have no unintended consequences.
8. The incentive should be consistent with other goals and incentives embodied in current regulatory practices.
9. The incentive should address and eliminate disincentives that currently exist in present regulatory practices.

The purpose of these criteria is to aid a commission in evaluating its present regulatory practices and in designing rate incentives to improve performance.

ACKNOWLEDGMENTS

Many individuals helped bring this study to fruition. Both Drs. Kevin A. Kelly and Daniel Z. Czamanski of the NRRI provided valuable guidance and helpful suggestions. Pennsylvania Public Utility Commission staff members, who sat through long interviews, gave insight into the problems they face in regulating electric utilities in their state. I would like to give particular thanks to John J. Reilly of the Pennsylvania Public Utility Commission's Bureau of Conservation, Economics and Energy Planning whose help was invaluable. Public utility staff members involved with the rate incentive programs covered in this report were most helpful. I thank them for answering my questions and providing necessary material. Finally, Debbie Kidikas and Gayle Swinger are to be commended for their patience and perseverance in typing this report.

TABLE OF CONTENTS

CHAPTER 1
INTRODUCTION

In this report, the material presented during a seminar on rate incentive provisions held at the Pennsylvania Public Utility Commission on August 10, 1981 is summarized. This seminar was the culmination of a six-week project undertaken by The National Regulatory Research Institute (NRRI) and the Pennsylvania Public Utility Commission's Bureau of Conservation, Economics and Energy Planning (CEEP). This project was funded as part of a United States Department of Energy grant to the NRRI. This project had two major objectives. The first objective was to identify possible rate incentive provisions for improving power plant productivity. The second was to suggest the type of studies and considerations necessary to plan and implement a rate incentive provision. However, after discussions about the type of possible rate incentives with the commission's staff and CEEP staff members in particular, the first objective was amended to include rate incentives designed to control cost overruns in nuclear power plant construction.

The work plan for this NRRI project was discussed and agreed to at the offices of the Pennsylvania Public Utility Commission (PAPUC) on June 29, 1981. The work plan was formally submitted to the PAPUC on July 1, 1981. During the preliminary work leading up to the seminar, several trips were taken to the PAPUC offices. The purpose of these trips was to discuss the concept of rate incentive provisions with PAPUC staff members from the various bureaus of the commission and to plan the seminar.

This project extended a CEEP study, <u>Electric Power Plant Productivity Related to Plant Availability: Assessment of Potential Benefits</u>, by John J. Reilly and Alvaro V. Domingos. This earlier study examined the potential savings to electric utility customers by improving the equivalent availability of plants on the Pennsylvania, New Jersey, Maryland Interconnection. The CEEP staff was concerned with how to achieve these potential benefits through rate incentive provisions. To this end, incentive programs of 10 states and 2 electric utilities were examined by the study team and discussed in the August 10 seminar. These activities are reported here.

Discussions with the Pennsylvania staff disclosed a concern about cost overruns on nuclear power plant construction and their effect on a utility's ability to maintain its existing system. In order to address this concern, two rate incentive programs--one developed by the Illinois Commerce Commission and another developed by the Federal Energy Regulatory Commission (FERC)--were included in the seminar.

In chapter 2, the cost control problem and managerial incentives are discussed. Chapter 3 contains a survey of rate incentive provisions that are either currently in place or under consideration in seven states and by two electric utilities to improve productivity. Chapter 4 is a more in-depth analysis of activities in three states and of a program designed by FERC staff. Two of the states, Virginia and Florida, have implemented rate incentive provisions to improve power plant productivity. Illinois is currently implementing an incentive provision to control cost overruns on nuclear power plant construction. The FERC program is designed to control cost overruns on the construction of the Alaskan Natural Gas Transmission System. In chapter 5, nine criteria for a desirable rate incentive provision are presented and discussed. These criteria provide a framework with which to think about planning a rate incentive provision. Chapter 6 is a compendium of material presented by the staff of the Pennsylvania Public Utility Commission and discussed at the August 10 seminar. John Reilly summarized the results of the study on the benefits of improved power plant productivity. David Boonin discussed the problems of energy clause designs and presented a proposed energy clause. John Dial presented some recommendations for cost controls at nuclear construction sites. These staff members are only responsible for the views contained in their specific presentations in chapter 6. In chapter 7, some possible extensions of the Pennsylvania Public Utility Commission's work in the rate incentive area are suggested.

CHAPTER 2

COST CONTROL AND INCENTIVES*

The current practice of public utility regulation with its frequent rate cases and automatic adjustment clauses is often cited as a contributing cause to escalating utility bills. This criticism is typically framed in very general terms such as the absence of a ceiling on increases. Such criticism obscures the fundamental problem and serves to focus public attention on cost control issues only during periods of inflation. The cost control problem, which rate incentive provisions are designed to correct, is not limited to periods of inflation but is said to be a direct manifestation of incentives created by the current practice of rate-of-return regulation. These incentives are alleged to motivate utility decision makers to make socially undesirable choices in three ways:

1. Inputs such as fuel, labor, equipment, and structures may not be combined in a manner that minimizes the annual cost of production given the existing technology and input prices.
2. Inputs may be paid for in excess of the amounts necessary to retain their services in the employment of the utility.
3. Technological advances and organizational changes are not developed nor adopted in such a way as to assure that output will be produced in the future at the lowest feasible cost.

These three outcomes tend to raise the cost of service to the consumer. These decisions are assumed to be under the control of the utility. At times, they may find it advantageous to stockholders or management to make suboptimal decisions for ratepayers because of regulatory practices.

---

*Most of this chapter is based on <u>Regulation as a System of Incentives</u>, chap. 1 [4].

It is important to begin consideration of this cost control problem by recognizing that the extent to which it occurs and the cost that society bears as its consequence are not fully known. Equally important is the recognition that changes in regulatory practice may lead to other, and perhaps more serious, manifestations of this problem. Thus, the design of rate incentive provisions to correct this cost control problem must be carefully considered.

Regulation and the Principal-Agent Relationship

While it is true that economic regulation has been introduced sometimes in response to an industry's desire to protect itself from competitive pressures, public intervention through regulation is historically justified by a need for a mechanism to protect consumers in cases where the existence of monopoly is inevitable or desirable. The inevitability, or desirability, of monopoly is attributed to the technological, or natural, circumstances where the costs incurred by a single producer of any quantity of output are less than the costs that would be incurred by two or more producers. Thus, a natural monopoly is justified by reference to cost reductions. Yet, once a firm establishes itself as a monopoly, there is a need for regulation to control it from exercising excessive power in the absence of disciplinary forces associated with competition.

To posit the existence of a cost control problem, however, is not equivalent to a criticism of the effectiveness of the current practice of regulation. It is plausible that little can be done to reduce the effects of the cost control problem. Nevertheless, examination of the incentives that the current practice of regulation provides and probing into the potential for rate incentive provisions are useful endeavors.

Incentives, or forces that motivate individuals to action, can be couched in terms of a highly stylized model of the relationship between a principal and the agent who is hired to perform actions on behalf of the principal. As in all such relationships, it is presumed that the agent is predisposed to limit his activity on behalf of the principal and that he is self-interested. All contracts that specify principal-agent relationships are faced with the problem of ensuring that the agent does in fact perform in the principal's interest. The problem arises due to the informational asymmetry that characterizes all such relationships. In particular, the principal is not able to observe the activity of the agent in its entirety. All attempts to monitor the activity of the agent are costly. At the same time, it is an assumption of this model that it is in the interest of the agent to obscure the information that the principal's monitoring is intended to uncover.

The current regulatory practice represents a contract between society and the utility. As society's agent, the utility is expected to provide its services to all who demand it at the least possible cost. The regulatory contract specifies that in return for its services the utility will be allowed to earn with mimimum risk a certain level of revenues that is consistent with that risk. To ensure that the contract's requirements are met, society through its representatives, the regulatory commission, "controls" the activity of the agent. There are two instruments that are typically employed by the principal: (1) the principal engages in monitoring to ensure that the utility does not pass onto the principal costs that should not have been experienced in the process of producing the utility's services, and (2) the principal sets an upper limit on the profits that the utility can earn.

Alternate contracts between principals and agents, or alternate regulatory practices, have the potential of generating different behavior on the part of the agent or utility. Rate incentive provisions are one alternative. These are financial arrangements designed to correct the cost control problem by motivating a desired behavior by the agent. Because the principal-agent model assumes the agent acts in its self-interest, this interest must be carefully identified. The specification of the profit motive may not be an adequate characterization of the interests of the utility's management. A utility under this model can be viewed as a heterogeneous, complex organization that does not harbor institutional motives, but whose behavior can be understood in a large part by direct reference to the self-interest of the individuals who manage it.

Managerial Self-Interest and the Discipline of Markets

The validity of viewing utilities in terms of the self-interest of their managers is associated with the character of the environment within which they operate. The single motive of profit maximization that is generally ascribed to firms may not be appropriate for describing utilities' behavior.

The basic reason for the use of profit motive as the sole driving mechanism in attempts to explain the behavior of unregulated firms is the presumption that the environment within which such firms must operate provides a number of forces that discipline them to behave as if they were maximizing profits. These forces arise from a variety of directions. Several have been identified very early in the history of economics by Adam Smith. For example, product market competition prevents firms from controlling the prices that are charged for products. Furthermore, firms that succeed in bringing down the price at which they can offer products are rewarded by increased sales and are soon emulated by other firms in the industry.

If product-market competition were the only disciplining force, it would be unreasonable to expect that profit maximization is a sufficient description of the behavior of modern enterprises. Dissatisfaction with the profit motive as the full explanation of firm behavior arises out of recognition that in modern enterprises the interest of managers may be different from that of security holders. Management's interest in perquisites and shirking is satisfied and occurs at the expense of profits that otherwise would accrue to holders of the residual claims on firms.

In addition to product market competition, three forces are presumed to discipline managers from making decisions that deviate from those consistent with profit maximization. One is the current prominence of the market for corporate control and the frequency with which the managements of industrial concerns are replaced by outside managers. This suggests that non-profit-maximizing behavior by management leads to deviation of the book value of corporate assets from their market value. Such deviations are sufficient to invite takeover bids.

A somewhat different, and yet related, disciplining force arises out of the market for managerial labor. Managerial mobility is circumscribed by the fact that a manager who has permitted several successful takeover bids in his lifetime will experience a decrease in the present value of his human capital. There is no reason to assume that managers are not self-interested and not rational and therefore that they do not attempt to maximize the value of their human capital.

Still another disciplining force is associated with a market for financial capital. The basic cost of capital is determined through the interaction of the demand for, and the supply of, investable funds. The cost of capital to specific firms, however, is also a function of the past and current performance of those firms in terms of profits. Inasmuch as management perquisites are bought out of profits, the ability to raise capital in the capital market is also in the interest of management and serves as another disciplining force.

The extent to which these various forces discipline managements and permit the retention of the profit motive as the sole driving characteristic of firms depends crucially on the information that is available in the various markets. Such information is, to a large extent, supplied by managements. There may be strong incentives for managements to withhold information and to provide misinformation. Particularly in the case of regulated utilities, some of the external forces that are typically presumed to discipline the management of firms are altogether absent. The introduction of regulation as a control mechanism introduces a new set of incentives that requires examination. Rate incentive provisions designed to motivate superior performance must take account of these considerations and use the proper conduit to assure they achieve the desired goal.

CHAPTER 3

A REVIEW OF INCENTIVE PROVISIONS

There are 10 states and 2 electric utilities that have implemented or are in varying stages of implementing incentive programs to improve various aspects of utility performance. This survey may not represent an exhaustive list of states working in the rate incentives area. The activities in 7 states and of 2 electric utilities are reviewed in this chapter. They are given below in order of presentation:

Michigan
North Carolina
Massachusetts
New York
Ohio
California
Utah
New England Electric Systems
Consumers Power Company

This review does not purport to be a thorough examination of each activity. Rather, the discussion centers on the goal and method of the program. Some states have had an instructive history in dealing with incentive mechanisms. When feasible, these programs will be discussed in more depth.

Commission Implemented Incentives

One should not expect each state to have an explicit formal incentive provision. The rate incentive is implicit in some states. Instead of having a specific system of rewards and penalties, the allowance or disallowance of specific costs is linked to some aspect of the utility's performance. In these cases, performance criteria or benchmarks become a basis for judging a utility's prudence or imprudence in incurring expenses. The utility is motivated to meet these criteria to avoid having these costs charged to the stockholders. Here, the incentive is to prevent a penalty, not to earn a reward.

Michigan

The Michigan rate incentive program for electric utilities is called the Availability Incentive Provision. It was instituted by the Michigan Public Service Commission in rate cases during 1977 and 1978. The incentive provision is designed to increase system availability by adjusting the rate of return on common equity. The total annual availability is calculated with adjustments being made for planned maintenance. System availability is the number of hours the system is available during the year divided by the number of hours in the year. Testimony is filed with this computation along with any supporting evidence and exhibits.

The system of rewards and penalties links an adjustment to the return on common equity to a specific range of values for system availability. The scale of adjustments is presented below.

TABLE 3-1

NEW SCALE OF AVAILABILITY ADJUSTMENT INCLUDING
PERIODIC MAINTENANCE FACTOR

System Availability (ECAR) Plus Periodic Maintenance Factor	Equity Return Incentive
100% - 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%

Source: Laughlin MacGregor, Report on Power Plant Availability, Michigan Public Service Commission, March 1979

This scale of adjustments for a given level of availability was expanded during the past year. The old scale was believed not to provide a utility sufficient incentive to increase availability. Utilities in Michigan are just filing under this new expanded scale of adjustment.

The rate incentive program in Michigan raises the question of whether there is a positive net benefit from the program. Stated succinctly, an increase in system availability does not necessarily imply the cost of service is lower. The increase in availability could have resulted from a capital improvement program, the cost of which was passed through to consumers. This cost, along with the costs of filing testimony and regulatory costs, must be balanced against the cost savings achieved by improving the system's availability. When the cost saving exceeds the cost of improving availability, a program like the Michigan availability incentive provision is desirable.

North Carolina

The North Carolina Utilities Commission tried to introduce issues of power plant productivity into their fuel adjustment hearing. This attempt was struck down by the State Appeals Court in May of 1981. The court ruled that the fuel adjustment hearing was not the proper arena in which to address questions concerning the prudence or imprudence of the fuel costs. In rendering this decision, the court stated that the hearing was to adjust rates for changes in fuel costs to the utility, not to the consumer. The commission currently is trying to consider the power plant performance in its regular rate cases. North Carolina's baseload power plant review plan is outlined below.

The North Carolina Utilities Commission set a minimum capacity factor for a utility's baseload nuclear plants. If a 4-month or 12-month rolling average of the capacity factor for all baseload nuclear plants fell below 60 percent, the commission or other interested party could initiate a review of baseload unit performance in the next fuel adjustment hearing. The commission could allow or disallow some of the fuel costs due to substandard performance.

As previously explained, these considerations are now being introduced into rate cases. This procedure may raise a potentially troublesome problem. It is possible that fuel costs to the consumer and the rate for fuel per kWh, as decided in the regular rate case and adjusted according to performance criteria, can be altered in a subsequent fuel adjustment hearing. Since the State Appeals Court has ruled that performance criteria are not a basis for deciding prudence in the fuel adjustment hearing, the costs disallowed in the base rate case on these grounds could be placed back in rates during this hearing.

The performance review is based on the baseload power plant performance report. This report is filed monthly for both nuclear and fossil-fired units. The utility must list each outage, its cause, its duration, an explanation of the cause, and the remedial action taken by the utility. Furthermore, the utility is required to report detailed information that the commission needs to calculate the capacity factor.

Massachusetts

The governor of Massachusetts signed a new fuel adjustment clause bill on August 6, 1981. This legislation sets up funds for a Fuel Clause Bureau in the Massachusetts Department of Public Utilities (DPU), establishes an annual efficiency hearing, introduces efficiency considerations into the quarterly fuel adjustment clause hearing, and funds the Attorney General's Office as an intervenor in electric utility hearings. The total funding was $475,000, with $400,000 for the DPU and $75,000 for the Attorney General's Office. The provisions of this legislation are quite specific.

Once a year an efficiency hearing will be held. In this hearing, targets will be set for operating availability, heat rate, equivalent availability, capacity factor, and forced outage rates. This information is to be used in the quarterly fuel adjustment clause hearing. In this hearing, the DPU reviews and sets a three-month prospective fuel cost. This fuel cost is used as a basis for an adjustment to rates. As part of these hearings, the targets set in the efficiency hearing are to be reviewed to see whether they were met. This review provides a basis for evaluating the reasonableness of the fuel costs the utility incurs.

The incentive to improve power plant performance in this legislation centers on the use of the target as a measure of prudence. The utility may be unable to recover some of its fuel costs for substandard performance. The utility's incentive is to meet the target so as to assure it will be allowed to recover all of the costs it incurs. Thus, the incentive is to avoid a penalty.

There is a special provision for the recovery of the costs of fuel-saving capital improvements. This provision is handled in a special intermediate hearing. It is not known whether a cost-benefit analysis of the capital improvement will be undertaken.

The uncertainty with this piece of legislation is whether it will yield benefits to consumers at least equal to the cost of the program ($475,000). One of the criteria for a desirable rate incentive mechanism is a positive net benefit to the consumers.

New York

The New York Department of Public Service (DPS) is engaged in an effort to improve power plant productivity. It formed, and after two years disbanded, a working group for this purpose. At present, the DPS with the help of DOE funding is investigating the feasibility of introducing power plant productivity issues into fuel clause hearings. Each of these efforts is described below.

The working group was made up of individuals from the Department of Public Service, New York utilities, and outside consultants. This group served as a conduit for obtaining information about a utility's procedures to improve productivity. They discussed and evaluated the information the group obtained and made suggestions to improve productivity and procedures in the future. The primary tool of the working group was peer group pressure. They engaged in "attaboys" and "finger pointing." There seems to be a consensus among both regulators and utilities in New York that this working group had some impact on power plant productivity.

At the present time, the New York Department of Public Service is trying to institute a more formal rate incentive program to improve power plant productivity. The staff is investigating how to integrate power plant productivity considerations into its fuel adjustment clause hearings. The perceived benefit of doing this is the potential displacement of high-cost oil-fired generation. It is anticipated that it will be early 1982 before any definitive action will be taken.

Ohio

On February 25, 1981, the Public Utilities Commission of Ohio eliminated its target thermal efficiency mechanism. The commission directed the staff to develop a cost-effective approach for improving power plant productivity. For purposes of this report, the discussion focuses on the problems with the target thermal efficiency mechanism. It was eliminated because it encouraged electric utilities to dispatch their plants in a manner that did not minimize fuel costs. This is an example of a rate incentive provision that had unintended consequences. A brief discussion of this problem is instructive.

The target mechanism was adopted in October of 1975. The target was calculated as a 12-month rolling average of heat rates for units dispatched to the system. The lowest expected thermal efficiency in 12 months was projected 12 months into the future. Also, extreme 12-month values were calculated. This information was used in the fuel clause hearing.

When utilities installed equipment and altered fuel-use practices to meet EPA environmental standards, the relationship between the cost per kWh and heat rates was changed for some plants on the system. This change led to a contradictory situation. Attempts by utilities to meet the target thermal efficiency measure dictated one dispatch of the system, while economic dispatch to minimize fuel costs dictated another. This set of circumstances meant the target mechanism was not a cost-effective standard by which to evaluate a utility's performance. The potential for this kind of unintended consequence needs to be carefully evaluated.

California

In a decision dated July 22, 1981, the California Public Utilities Commission instituted a rate incentive mechanism in its energy adjustment clause hearing. The incentive mechanism sets a band for the capacity factor and heat rate for two major baseload units owned by the Southern California Edison Company. When the capacity factor or heat rate falls above or below its band for either one or both, the utility is rewarded or penalized. The primary use of this mechanism is to assure that subpar performance is not included in the utility's energy expense.

The benchmarks are set for the capacity factor and heat rate averages. The capacity factor target for each unit is a four-year average of its historical capacity factor. The heat rate target is an annual average for the unit. The null zone for each target is the band in which there is no reward or penalty. This zone is determined by examining the standard deviation associated with each of the foregoing averages. The reward and penalty are based on the change in energy costs when actual performance lies outside the null zone. Up to some point, the utility is allowed to retain the energy cost savings from superior performance as its reward. When performance is substandard, additional energy costs are not charged to consumers.

A difficulty with this approach is that improved capacity factors and heat rates do not necessarily imply that the overall cost of service is falling. It could be that the improvements are achieved with capital improvements and/or maintenance programs that are not offset by the fuel savings. This is a question of the compatibility of methods with goals. There is no guarantee this program has a positive net benefit. It assumes this criterion is met.

Utah

The Utah Public Service Commission is developing a variant of the total factor productivity approach to rate incentive provision. In October of 1979, the commission received a PURPA Incentive Rate grant from the Department of Energy. With this grant, the commission staff and individuals from Utah's utilities investigated methods by which to encourage increased productivity. A four-part regression model was developed.

Four cost categories were defined and investigated. The first category is power production operating and maintenance expenses. Service cost operating and maintenance expense is the second category. This category consists of transmission, distribution, and general expenses. The third and fourth categories are investment costs: the third consists of investment in generation, and the fourth is made up of transmission, distribution, and general investment costs. Regressions are performed against these categories and one explanatory variable for each regression picked on the basis of goodness of fit (R^2). The findings for these categories are given below:

1. Number of kilowatt-hours explained the power production operating and maintenance expenses.
2. Number of customers explained the service cost operating and maintenance expenses.
3. Megawatts of installed capacity explained the investment cost in generation plant.
4. Number of customers explained the investment cost in transmission, distribution, and general plant.

These regression equations are generated with a 13-year history for each electric utility in Utah. In order to check the reasonableness of these results, similar regressions were performed using national averages.

The goodness of fit for this regression compared favorably with that for each of the utilities in Utah.

The regression equations for each of the categories provide the basis for the performance evaluation for the utility. Each utility is judged relative to its historical performance. This is done by using the actual data for a year in the equations and getting an expected cost for each category. This expected cost per category is compared with the actual cost the utility realized in that period. When the cost is lower, it is inferred that the utility's performance has improved. A reward is bestowed in these circumstances. When the actual cost is higher than expected for the utility, no action is taken.

The reward is based on the cost savings. This saving is to be discussed in testimony about the utility's performance. The commission staff is proposing that this saving should be divided equally between consumers and stockholders.

To date, the Utah commission has not established a track record with this incentive mechanism. There is a public hearing scheduled at present, soon after which time the mechanism is to be implemented. It should be noted, however, that there is significant interaction among categories. Measures in some categories could increase relative to historical performance to bring other measures down. Furthermore, the method of evaluation does not specify the source of the change in performance.

Utility Wage and Salary Incentives

Two electric utilities that have instituted in-house executive incentive programs are Consumers Power Company of Jackson, Michigan, and New England Electrical Systems based in Massachusetts. These programs supplement base salaries with an annual bonus based on performance goals for the utility and the executive. This kind of program weds the interest of upper management to that of the stockholder by allowing management to share in the utility's earnings directly. These two programs use a different conduit to motivate superior performance. The incentive mechanisms instituted by the state commissions are based on the assumption that management responds to the interest of the stockholder. For programs at the utilities, it is assumed that management responds to its own self-interest or its spheres of interest.

These programs are presented to offer additional alternatives to improve performance. Commissions could persuade utilities in their jurisdiction to adopt similar programs. Two programs are described below.

New England Electric Systems (NEES)

The NEES incentive program is based on a goal for earnings per share and goals for executive performance. A pool of funds is created from below-the-line earnings. These funds are computed as a percentage of the base salaries earned by executives participating in the program. A target is set for earnings per share. If actual earnings per share are above the target, participating executives are eligible to earn a bonus. If creating the bonus fund lowers earnings per share below this target, no bonuses are paid out.

Each executive earns a bonus according to how well he met his individual goals. The goals for each executive are established by the Compensations Committee. NEES prides itself in setting what it labels quantitative goals for each executive. According to spokesmen for NEES, these goals go beyond earnings into areas of customer relations and operating efficiency. Each year, the entire pool of funds is paid out to participating executives. Each executive's bonus varies as a percent of the pot according to his performance. This incentive program is believed to keep executives diligent in their work by eliminating merit raises and instituting this system of bonuses.

Consumers Power Company

The Consumers Power Executive Compensation program is based on a net income goal, a rate comparison, and a set of executive performance goals.

This incentive program is designed to enable Consumers Power to attract and retain competent executive talent. Executive compensation consists of a base salary, a merit raise, and an incentive bonus. Merit raises are based on individual performance, while the incentive bonus is based on corporate performance. Consumers Power sets the base salary for the participating executives lower than that for competitive positions. The bonus program is a supplement to the base salary.

The program establishes a bonus fund as a percentage of the salaries of the eligible executives. This fund is subject to adjustment based on the degree to which two goals are met. First, a net income goal is established by the Executive Committee of the Board of Directors. This goal is the initial test to determine whether there will be any participation in the program. The bonus fund is adjusted upward if the net income goal is exceeded, and downward if it is not reached. Lackluster performance can eliminate the bonus fund rather quickly.

After the fund is adjusted for the net income goal, it is divided equally between Consumers Power's gas and electric divisions for purposes of the rate comparison. A second test is performed for each division to ensure the net income goal was not met at the customers' expense. The most recent five-year average trend of rates per Mcf or kWh for Consumers Power is compared to the same average rate for similar large utilities around the country. The 10 largest electric or 10 largest gas utilities are used for this comparison. If Consumers Power's rates are lower, the bonus fund is enhanced; if higher, dollars are taken from the fund. Substantially higher rates for Consumers Power can eliminate the bonus fund.

If funds are left in the pot after this comparison, they are allocated to executives at the general manager's level or above. Performance goals are set for each executive. The actual allocation process, however, is judgmental. This allocation process may not exhaust the entire pot but will never allocate more than the funds available. This allocation supplements the executive's base salary with the bonus to provide a fully competitive compensation package.

CHAPTER 4
SELECTED RATE INCENTIVE PROVISIONS

The state public utility commissions of Virginia, Florida, Illinois, and the Federal Energy Regulatory Commission (FERC) have been active in the rate incentive area. Virginia and Florida have developed rate incentive programs that link power plant productivity to their fuel adjustment procedures. Illinois and the FERC have developed incentive programs designed to control cost overruns on major construction programs. It is appropriate to classify the Virginia and Florida programs as dealing with the productivity of existing plants, while the Illinois and FERC programs deal with productivity in the construction of prospective units.

This chapter is divided into two sections. The first section is a discussion of cost control when fuel recovery clauses are based on prospective fuel costs. It contains reviews of the Virginia and Florida programs. The second section is an overview of the general issues of construction cost overruns. It contains reviews of the Illinois and FERC programs.

Control of Prospective Fuel Costs

The use of prospective fuel costs in determining revenue requirements offers an opportunity to regulatory authorities to create incentives for efficient operation of the utility's system. These incentives can be introduced in the form of utilization targets for various aspects of the utility's operation and an evaluation of anticipated fuel prices. This information can be used in conferring explicit rewards and penalties on the utility, or as a guide in classifying the expenses to be incurred as prudent or imprudent. In either case, the rate of return to the common stockholders is linked to the commission's evaluation of what constitutes a reasonably efficient operation.

The total cost of fuel depends on the following factors:

1. The total kWh output expected for the future period.
2. The expected time pattern of customer demands.
3. The procured fuel cost.
4. The generation mix (reflects plant availability).
5. The efficiency of the utility's units (usually measured by heat rate).

In considering these five factors that determine the cost of fuel to the utility's customers, it is useful to delineate them in terms of the cost control problem. The proposition is that costs outside of the utility's control should be borne by the utility's customers, while those under the utility's control should be charged to stockholders.

The degree to which the total kWh output and the time pattern of demand for electricity are under a utility's control raises an important and complex set of issues. Load management through the installation of equipment, curtailment of interruptible customers during peak hours, and application of time-of-use rates can have a substantial effect on a utility's total cost of fuel. The time pattern of demand is of primary importance because of its effect on the optimal mix of generating capacity. To see this, assume two utilities in the same geographical area and both generating the same kWh output. The utility serving the load curve with substantial peaks and valleys typically will experience higher fuel costs than the one serving a flatter load curve with the same kWh output. The load factor is a measure of this variation in demand. A utility's planning staff faces a trade-off between fuel cost and capacity costs. As the load factor declines, the utility can minimize the cost of serving the peak by installing less efficient, lower cost plants and incurring a higher fuel cost per kWh. In doing this, the utility minimizes the investment cost that lies idle during the off-peak and only incurs the higher fuel cost when the plant is used to serve the peak. As a result, higher fuel costs per kWh become more cost effective if it is offset by a reduced annual cost of investment in plant and equipment. However, if a utility does not have an optimal configuration of generating units to serve the expected time pattern of demand, it can reduce both its fuel cost and total cost by increasing its load factor through load-management investments.

Two questions are important for the discussion at hand. To what extent should a commission expect a utility to manage its load curve? More important, is the consideration of prospective fuel costs the proper arena in which to address this question? These questions are only raised in this report. The incentive provisions covered in the next two subsections do not introduce explicit load-management incentives into their incentive provisions.

The procured fuel costs are a very important element of the cost control problem. Regulatory authorities must be assured that the prices paid to obtain fuel are not excessive. To do this, there is a consideration of whether arms-length bargaining is present. When it is not, the commission should be concerned whether fuels were obtained at competitive prices. When it is present, the focus of inquiry should shift to other aspects of the utility's procurement practices. These considerations differ from the traditional approach to fuel costs because the reasonableness of anticipated fuel prices is being evaluated. The commission should pass through increased fuel prices due to the effects of anticipated inflation. At the same time, however, the utility should be given a sufficient incentive to bargain strenuously for fuel.

The questions of generation mix and unit efficiency are important aspects of the cost control problem. The extent to which a given unit is utilized in meeting a utility's load affects the fuel cost per kWh. The availability of low-cost units is paramount when examining the fuel cost control problem. For instance, anytime a utility has to replace coal with oil because a coal plant is unavailable, fuel costs per kWh rise. Higher utilization of economic units with low overall heat rates tends to lower fuel cost per kWh. In order to ensure that estimates of prospective fuel costs are based on all reasonably expected economies of utilization, the commission should develop benchmarks for measures of a unit's utilization. Potential measures are the following:

Availability
Equivalent availability
Capacity factor
Forced outage rates
Partial forced outage rates
Heat rate

Targets or ranges of values could be set for these measures. The effect of this approach is to focus the commission's attention on issues of the levels of power plant productivity assumed in the estimates of prospective fuel costs. Stated differently, the benchmarks provide a means by which the commission can evaluate the prudence of the estimated fuel costs in terms of the proper input mix. Furthermore, it creates an explicit set of expectations about how the utility will be evaluated in future rate proceedings. Thus, an incentive for efficient operation is fostered.

In addition, there is a question of what costs to include in the fuel expense, particularly purchased power. Power is generally purchased from a grid by a utility for two reasons: first, for economy; second, for emergency. An economy purchase refers to the purchase of power that is entered into because the power can be purchased cheaper than the utility can generate it. This type of transaction should be encouraged because it results in the lowest possible operating cost. A question is whether to include the capacity cost that the purchasing utility pays to the seller in the calculation of prospective fuel cost. Emergency purchases of power refer to purchases made necessary because inadequate capacity is available to meet the utility's load. This type of purchased power cost is incurred usually when a utility experiences a forced outage. The inclusion of some of this type of purchase power cost may be desirable if the expense included is in line with an acceptable forced outage rate. Costs over and above this should be disallowed. Otherwise, the commission would create a disincentive to assure adequate availability of a utility's generating units.

In the foregoing discussion, the five factors determining prospective fuel costs were examined briefly. In evaluating the reasonableness of this expense, attention must be given to those factors under the utility's control. A rate incentive plan that links fuel cost to productivity measures should reward or penalize the utility on the basis of expenses under its control. The uncontrollable expenses may be passed through to the consumer, while those imprudently incurred are disallowed. Implementation of this type of rate incentive program requires that the commission develop benchmarks for each of the five cost categories above.

Virginia

In January of 1979, the Virginia State Corporations Commission instituted a fuel recovery clause based on generating unit performance criteria and a fuel price index. The purpose of this new clause and annual fuel clause hearing was to allow utilities in its jurisdiction to recover their fuel costs, but not allow utilities to incorporate low levels of performance in the projected fuel expense. The program has two parts. First is a fuel price index by which the reasonableness of procured fuel costs is evaluated. The second part is a set of targets for equivalent availability and a review of unit heat rates. This program has no explicit set of rewards and penalties but integrates performance criteria into its deliberations on the reasonableness of the projected fuel cost.

The fuel price index compares the cost per Btu for a certain type of fuel that is purchased by a utility with the same cost for the Mid-Atlantic and South Atlantic regions of the country. This comparison provides necessary, but not sufficient, information for determining the reasonableness of delivered fuel prices. The delivered fuel price is not a replacement cost, but a weighted average of actual prices paid for each fuel group. Thus, the duration of the contracts each utility has at a given price distorts the comparison somewhat. The computation of this index is briefly reviewed below.

FERC monthly fuel price data (Form 423 data) are the basis for the computation of the regional delivered fuel price index. The quantity delivered and the delivered fuel price for utilities in the Mid-Atlantic and South Atlantic regions are divided into several groups. The coal prices are categorized by ash content and sulfur content. The oil prices are categorized by type of oil (light or heavy), sulfur content, and whether the oil was acquired by a spot purchase or under contract. These data are summarized into a 12-month weighted average cost per Btu for each group. This cost per Btu is the benchmark against which the Virginia utilities are judged.

The cost per Btu for each utility is compiled from monthly fuel price data reported to the commission (SCC Form 220). These data are categorized in the same manner as the regional data. They are used to compute a 13-month weighted average cost per Btu for each group. This figure for each category is divided by the cost per Btu for the corresponding category of the regional data. If this ratio is significantly greater than one, there is cause for a further investigation into the utility's procurement practices.

In order to evaluate the projected fuel expense, the State Corporation Commission's staff sets a reasonable range for equivalent availability for comparison groups. Each comparison group is delineated by fuel type, size of unit, vintage, and design. The benchmark figure is approximately 75 percent equivalent availability. The heat rate of a unit is compared to its historical performance as well as to other units in its comparison group. The staff, however, does not develop a target for this efficiency measure because the heat rate depends on the economic dispatch of the unit. The review is an examination of the reasonableness of the unit's heat rate.

The staff then performs a computer simulation of the economic dispatch of the utility's system. The projected fuel prices, the utility's expected load curve, and the range of equivalent availabilities are inputs into this simulation. This enables the staff to derive an estimate of the fuel expense for a given value of equivalent availability. With this estimate, the reasonableness of the estimated fuel expense can be evaluated.

The annual hearing, in which the projected fuel expense is formally set, is also an opportunity to settle the utility's fuel account for overrecovery or underrecovery of the fuel expense for the previous 12 months. This is done in the annual hearing if the actual underrecovery is no more than 7.5 percent less than the estimated expense, or the overrecovery is no more than 5 percent more than the estimated expense. Otherwise, a special interim hearing may be required. If underrecovery is the result of substandard performance by one or more units and if this is due to factors within the utility's control, complete recovery of this cost is not guaranteed to the utility. The benefit to the utility from this procedure is a reduction in the time lag of the recovery. In other words, if actual performance is on target, the utility experiences no lag in the recovery of its fuel expense.

Florida

In February 1980, the Florida Public Service Commission instituted a rate incentive provision called the Generating Performance Incentive Factor (GPIF). The GPIF is a formula approach to incentives that links the rate of return on common equity to the equivalent availability and heat rate of a utility's units. The explicit set of rewards and penalties, which can be as much as .25 percent of the return on common, is conferred in the semiannual fuel and purchased power clause hearing. In this hearing, the fuel and purchased power costs are projected for the coming six months. The GPIF is used in conjunction with this procedure to assure the utilities in its jurisdiction have a clear incentive to minimize fuel and purchase power costs.

The GPIF is expressed as follows

$$\text{GPIF}(\$) = \text{MAX}(\$) \left\{ \sum_{i=1}^{n} a_i \left[\frac{EA_i(\text{actual}) - EA_i(\text{target})}{EA_i(\text{max}) - EA_i(\text{target})} \right] + e_i \left[\frac{AHR_i(\text{actual}) - AHR_i(\text{target})}{AHR_i(\text{min}) - AHR_i(\text{target})} \right] \right\}$$

where:

i	- the index for the n units in the utility's system
n	- number of units in the utility's system
GPIF($)	- incentive dollars awarded or deducted
MAX($)	- the maximum allowed incentive dollars
EA_i(target)	- the equivalent availability target set for unit i during the period
EA_i(max)	- the actual equivalent availability experiences by unit i during the period
AHR_i(target)	- the average heat rate target set for unit i during the period
AHR_i(min)	- the minimum reasonably attainable average heat rate for unit i during the period
AHR_i(actual)	- the actual average heat rate experienced by unit i during the period
a_i	- the percentage of the total system fuel cost savings attributed to the maximum reasonably attainable equivalent availability of unit i during the period
e_i	- the percentage of the total system fuel cost savings attributed to the minimum reasonably attainable average heat rate of unit i during the period

The calculation of the incentive dollars and the determination of the targets and the formula's coefficients require several computer simulations of the economic dispatch for the utility's system. The issues surrounding each element in the formula are addressed below. Following this discussion, the procedures involved with the GPIF are covered.

The maximum allowed incentive dollars (MAX$) are based on a seven-month rolling average of the book value of a utility's common stock. This dollar figure undergoes three adjustments. The first two adjustments are straightforward. The first adjustment is to multiply the seven-month average of the book value of the utility common stock by .25 percent (that is, 25 basis points). This adjusted dollar figure is cut in half for the second adjustment. Thus, .125 percent of the seven-month average of the book value of common equity is the outcome of the first two adjustments. The third adjustment is to divide the adjusted dollar figure by a revenue expansion factor. This factor is the percentage of utility revenues left after the gross receipts tax, the regulatory assessment fee, and income taxes are deducted. The factor is approximately 50.5 percent of gross revenues. Thus, the final adjusted dollar figure is a little less than .25 percent of the seven-month rolling average of a utility's common equity. This calculation has one important qualification: the maximum dollars cannot exceed the gross amount of any fuel saving or additional fuel cost the utility might experience during the period as the result of performance deviating from targeted performance. This provision clearly shows the GPIF is designed to allow a sharing of change in fuel costs between stockholders and consumers as the performance of the utility's generating units varies from targeted performance.

The targets for equivalent availability are determined from the historical performance record for each unit. Planned outage hours are taken from the latest system maintenance schedule. Target hours for unplanned outages are formulated by examining historical trends for the forced outage rate, maintenance outage rate, equivalent forced rate, and equivalent maintenance outage rate. These historical figures are adjusted for any improvements to the unit that reduce these outages and for any subpar performance that should not be incorporated into the target. A target for equivalent availability is set in this manner for each unit in the utility's system.

The maximum reasonably attainable equivalent availability for each unit is set by considering the quality of past performance. A unit with consistently low or high outage rates will have its maximum reasonably attainable equivalent availability set quite close to its target value. This is done to reflect the past consistency of performance. A unit with erratic past performance will have its maximum and minimum reasonably attainable equivalent availability set relatively far from its target value. As is noted below, this formulation of the maximum reasonably attainable equivalent availability rewards or penalizes the utility according to its potential for improving the equivalent availability of its units. As a result, a single unit or plant with a history of consistently good performance will not weigh heavily in the reward structure. At the same time, degradation from this high level of performance will be penalized.

The average heat rate target is set by examining a unit's monthly historical heat rate data. The monthly data are used to capture the variation in a unit's heat rate resulting from its utilization. Thus, a unit's ordering in the economic dispatch of the utility's system is considered. Adjustments are made to the historical data for any modification to the unit, changes in fuel burned, or changes in environmental regulations that might affect its heat rate. A target heat rate is set for each month of the year. The average heat rate target for the prospective six month period is a weighted average of the respective monthly targets.

The minimum reasonably attainable average heat rate is set with reference to the historical variation in monthly heat rates. A confidence interval about the six-month average heat rate is set such that it contains the monthly heat rates 90 percent of the time. The lower limit of this confidence interval establishes the minimum reasonably attainable heat rate. This calculation provides an incentive for a utility to reduce the variation in the heat rate for units that have experienced a wide fluctuation in their heat rate.

The calculation of the coefficients, a_i and e_i, requires several computer simulations of the economic dispatch of the utility's system. The a_i is the percentage of total system fuel cost savings that can be attributed to moving from the target equivalent availability for a unit to the maximum reasonably attainable equivalent availability for that unit. The e_i is the percentage of total system fuel cost savings that can be attributed to moving from the target heat rate for a unit to the minimum reasonably attainable average heat rate. The base case, from which all fuel saving are calculated, is determined by a computer simulation of economic dispatch for the six-month period with the equivalent availability and average heat rate set at target levels for all units in the utility's system. This simulation provides the commission with a working estimate of the fuel expense to be prudently incurred for this six-month period. This estimate is used in the fuel and purchased power clause hearing.

Following the calculation of the fuel cost for the base case, a number of computer simulations are run. A fuel cost is obtained for the utility's system by setting the equivalent availability at its maximum reasonably attainable level for each unit taken separately. The same is done for the average heat rate of a unit. This procedure enables one to calculate the fuel cost saving associated with operating a unit at its maximum reasonably attainable equivalent availability with average heat rate at its target level, or at its minimum reasonably attainable average heat rate with equivalent availability at its target level. The fuel cost saving for each run of the computer simulation is calculated by subtracting the base-case fuel cost from the fuel cost for each run. The total system fuel cost saving is the sum of these separate fuel cost savings. The percentage is calculated by dividing the total systems fuel cost saving into each run's fuel cost savings. This yields the coefficients a_i and e_i for each unit.

The reward or penalty the utility earns is determined by comparing actual value of a unit's equivalent availability and average heat rate to its target levels. When the utility just meets its target values, no reward or penalty is earned. Above average performance for both indicators confers a reward, while below average performance results in a penalty. Only when equivalent availability is at the maximum reasonably attainable level and average heat rate is at the minimum reasonably attainable level for all of the utility's units, does the utility earn the maximum allowed incentive dollars (MAX$). Thus, the monetary incentive is designed to encourage utilities to achieve these levels of unit performance.

The Florida Public Service Commission implements the GPIF in a series of four annual hearings, two for each semiannual period. These hearings are held for their fuel and purchased power recovery clause. One hearing is held in the month prior to the six-month fuel recovery period. This hearing is used to set targets for the performance indicators and establish the projected fuel expense for the coming six-month period. The second hearing is held two months into this six-month period. During this hearing, the commission accomplishes several tasks. First, the utility's fuel expense accounts are reconciled for overrecovery or underrecovery of the fuel expense from the previous six-month period. This amount with interest is factored into rates. Second, the actual performance of the utility for the previous six-month period is reviewed. Target values for equivalent availability and average heat rate for this previous period are adjusted for extenuating circumstances outside the utility's control. After this adjustment, the GPIF reward or penalty is calculated and factored into rates. Finally, the projected fuel expense for the current six-month period is reviewed. If circumstances since the initial hearing have changed significantly, an adjustment is made to this projected expense and rates are adjusted accordingly. This cycle is repeated every six months.

The Florida rate incentive provision does not take explicit account of procured fuel costs. They enter indirectly in the calculation of the coefficients a_i and e_i. The price differentials among fuels used in different units affects the magnitude of the fuel cost saving achieved by improving performance. This fact, however, does not guarantee fuel is purchased at competitive prices. The commission's fuel procurement section has an ongoing audit of each utility's procurement practices and procedures. The staff for this section verifies the assumptions concerning projected fuel prices that are used in the computer simulation.

Several questions about the GPIF can be raised. The information necessary for the provision is filed with the commission by the utility.

An assessment of these data is undertaken by the commission. There might be, however, some hidden nuances in the information requirements and reporting system. This report has not addressed any of these problems if they exist at all. Since the provision focuses on fuel cost savings resulting from improving specific performance indicators, other areas of the utility's performance could be biased unfavorably. For instance, the rewards and penalty system could be viewed by investors as increasing the risks of investment. This would occur because they are exposed to an additional risk of operating performance heretofore borne by customers. This statement is not to imply that such a shift in risk is not justified, but only to indicate a possible unforeseen consequence of the GPIF. The rate incentive mechanism is the only explicit incentive program in Florida. In terms of consistency among regulatory goals, it would seem the program encourages a utility to minimize the fuel cost it incurs. The important question centers on whether such a program encourages the utility to minimize the overall cost of operation. This consistency is not readily apparent, and as previously noted, it could have some unintended consequence contrary to this goal. Finally, cost-benefit analysis of the provision may have an uncertain outcome. The reporting requirements and the staff involvement in both analysis of the data and four annual hearings are a substantial commitment of manpower. The fuel savings resulting from this program is an uncertain outcome as is the reward or penalty. Thus, there may not be a clear net benefit accruing to the utility's consumers. As more operating experience is obtained with the GPIF rate incentive provision, its value for use in other states should become more apparent.

Control of Major Construction Costs

The cost control problem for major construction projects undertaken by electric utilities has been particularly acute in the past decade. Nuclear plants have entered the rate base at up to 5 times their initial estimates and coal plants at up to 1.9 their initial estimates. The costs of transmission and distribution facilities, on the other hand, have been relatively stable. The performance record for nuclear plants may reflect to a degree the fact that utilities have entered the frontiers of generation technology with nuclear construction. The problem, however, extends beyond this simplistic view of the cost control problem. In this section of this chapter, the sources of the cost control problem for major construction projects are reviewed. These causes suggest, in part, certain features for an incentive program to control the costs of construction. For purposes of this discussion, the cost control problem is called the cost overrun problem.

There are five possible sources of the cost overrun problem:

1. Initial cost estimates tend to be inaccurate.
2. The scope of the project is inadequately defined.
3. Unanticipated inflation drives up the cost of construction.
4. Management organization may be inadequate in several respects.
5. Projects are too large and too complex for the utility to handle with its available resources.

Each of these five causes of the cost overrun problem is discussed below. They are classified according to the degree of control the utility can exercise over the problem. This distinction is important when considering rate incentive programs to help bring the problem under control.

Initial estimates tend to be low for a couple of reasons. First, the design on which the initial estimate is based may be inadequate. A utility wants the approval of the project by regulators early in the planning and procurement stage to avoid sinking too many resources into a dead-end project. This particular behavior can account for some of the inadequate definitions of the scope of the project. The upshot is, however, that the estimates taken to authorities may be incomplete and too low. There exists another reason that tends to bias the initial estimate downward. Approval of a project by regulatory authorities generally requires the utility to promote the project in an adversary proceeding. The utility must justify its plan as being competitive with alternative sources of power as well as not being an undue burden on consumers.

This behavior on the part of a utility is under its control. Any rate incentive provision a commission might contemplate should foster an environment that encourages utilities to submit realistic estimates of the construction cost for a complete plan.

A complete plan for a construction project incorporates an adequate definition of the project's scope. An adequate definition of scope should ideally anticipate any changes in safety, environment, and legal requirements. Changes in these requirements, however, are one of the major reasons most projects have an inadequate definition of scope. This is particularly true of nuclear plant construction.

Changes in safety requirements and environmental standards drive up the cost of the project and the future cost of electric service in three primary ways. First is a delay for the redesign of the system. In addition to the direct costs associated with the redesign, interest and other capital costs are incurred on funds already sunk in the project during the period of delay. Redesign often requires the retrofit of equipment to a partially completed project. This retrofit procedure is often very expensive. This second source of cost overruns tends to drive up the cost relative to what would have been incurred had the redesign problem been incorporated into the initial plan. Finally, redesign and retrofit delay the in-service date of the plant that may increase the cost of service to consumers in the future if capacity is not available for generation when required. Then, electric power must be obtained from higher cost sources for the period between the initial in-service date and the new completion date.

The degree to which utilities can control changes in scope and their impact on construction costs is questionable. This is particularly true for nuclear plant construction. Much of the problem may center on the fact that the utility and the regulators may be dealing with a project that is on the frontiers of the technology. The utility confronts novel construction problems, while the regulators address unanticipated safety and environmental concerns. In developing a rate incentive plan to control cost overruns, account must be taken of both the utility's and the regulator's inability reasonably to control changes in scope. In many cases, this may mean that an incentive program would be designed to pass these costs through to consumers.

Unanticipated inflation is a particularly thorny problem that has pervasive effects on a construction project. Cost inflationary trends have been quite unpredictable and promise to stay that way for the near future. Anticipated inflation can be fully incorporated into initial estimates of the costs of construction. Unanticipated inflation, however, cannot. Unpredictability of inflation is the key to understanding this problem. The long lead times and construction delays for nuclear plants exacerbate the problems of formulating an accurate estimate. As the time period over which an estimate is made lengthens, unknown variables that affect inflation have a greater opportunity to enter the picture. As a result, inflation may escalate and the cost of labor, materials, and equipment as well as interest charges and other capital costs go up. To expect reasonably accurate estimates of actual inflation to enter the utility's initial estimate is often to ask a good deal of forecasting. A rate incentive provision to control cost overruns should recognize the limited control a utility has over its initial accuracy.

The organization of the project's management is an area in which the utility can exercise a reasonable degree of control. This aspect of the project includes cost control programs in the contracts it negotiates with suppliers and construction firms, efficient work schedule controls, and adequate work-force utilization incentives. Adequate controls require the utility to develop or use information systems that keep it (and the commission) up to date on all phases of the work in progress and pinpoint particular areas of cost overrun problems. Any rate incentive program should encourage a utility to adopt efficient project management practices. In theory, an incentive could require the utility's stockholders to bear the cost overruns resulting from a project's mismanagement. However, tracing cost overruns to mismanagement is quite difficult in practice. An adequate information reporting and problem tracking system could overcome many of these difficulties. Thus, the commission could scrutinize a project's management plan and management practices to assure that they are the best possible. In this way, both the utility's stockholders and consumers are spared an additional cost burden.

The expanding frontiers of technology, the growth in the demand for electric energy, and the limited number of adequate plant sites have led utilities to undertake larger and more complex construction projects. This expanded scope of the project has had two effects leading to cost overruns. First, it saps both the utility's management talent and the pool of talent from which it draws employees. Qualified personnel in the field of nuclear plant construction are a scarce labor resource. Numerous, large ongoing construction projects tend to spread this pool of talent thin and make it difficult and costly to retain qualified personnel. As the number of tasks any qualified manager has to manage increases, his ability to address and correct problems declines, thereby impairing his efficiency. Second, the financial burden a large ongoing project places on a utility may have a tendency to divert funds from maintenance and capital improvements on existing generating units. This lag in maintenance and improvements then may reduce the reliability of the existing system (that is, the equivalent availability of units declines). As a result, the cost of meeting current demand has a high probability of increasing and the projected need for new capacity goes up as well. Thus, the initial scope of the construction project has a synergistic effect on the cost control problem for these projects and the cost of day-to-day operations for the existing system.

In summary, the sources of the cost control problem for construction projects can be broken down into those factors under the utility's control and those which lie outside it. They are listed below:

Sources of cost overruns <u>under</u> the utility's control

1. Provide accurate estimates for a complete construction plan irrespective of promotional considerations.
2. Management organization.
3. Lags on maintenance and capital improvements.

Sources of cost overruns <u>outside</u> the utility's control

1. Safety, environmental, and legal changes in the scope of the project.
2. Unanticipated inflation.

A rate incentive plan designed to control construction cost overruns should address those aspects of the problem under the utility's control. At the same time, it should encourage the utility to anticipate better the aspects out of its control. However, it should not be held accountable for circumstances no reasonable person could conceivably anticipate. Striking this balance is, of course, a difficult problem in the design of rate incentive programs.

Illinois

The Illinois Commerce Commission has developed a three-part strategy for controlling cost overruns on nuclear power plant construction. The three parts are a statistical analysis of the relative cost of construction, an on-site monitoring program, and a rate incentive program. This last feature of the strategy involves the inclusion of construction work in progress (CWIP) in the rate base at a return lower than that allowed on the operational rate base. It is called the Variable Rate of Return to Construction Work in Progress. This program in conjunction with the other two parts is asserted to provide the utility with an enhanced cash flow, which enables it to complete the project in a timely fashion while providing incentives to control costs.

This three-part strategy is the outgrowth of a rate incentives grant from the United States Department of Energy. This grant partially funded the Illinois commission's study of rate incentives. As part of this grant, the commission was required to select a mechanism and apply it. The commission is currently working toward this goal with the program outlined in this report. This section briefly reviews all three parts of this integrated strategy for controlling cost overruns on nuclear power plant construction in Illinois.

The Statistical Analysis This part of the Illinois commission's strategy is designed to compare the cost and other aspects of constructing a nuclear plant to all other nuclear plants under construction. This analysis allows the commission to evaluate the reasonableness of the costs already incurred in constant dollars, the estimate of cost at completion in constant dollars, the estimated period of construction, and the estimated period of delay. The procedure for this statistical analysis and some particularly interesting results for the Pennsylvania circumstance are covered below.

The first step of the statistical analysis is to segregate nuclear plant construction projects throughout the country into four groups. First, they are divided into either boiling water or pressurized water reactors. Each of these groups is segregated according to whether there are multiple units or single units at the plant site. This grouping of construction data provides the basis for the subsequent analysis.

For each group, an estimate of the constant dollar annual addition to the cost of construction is made for each project. These annual costs are summed for each plant in a group to yield an estimate of the cost of construction in constant dollars for the period between the order of the nuclear steam supply system and the scheduled in-service operation date. These estimated data are used to compute averages and standard deviations for the cost of construction for all plants taken together and by group. These statistics allow the comparison of the cost of a nuclear plant per kW of rated capacity to all other projects or similar projects. As part of this analysis, averages and standard deviations are also computed for estimates of the construction period and for any delay that occurred or is anticipated. These statistics allow the commission to compare a given project to all other projects or similar projects. This comparison provides a basis by which a utility's prudence in controlling the costs of construction can be evaluated.

The variation in the cost per kW of rated capacity is also a focus of statistical analysis. This analysis allows the commission to compute the cost of a plant under construction given certain characteristics of the project. This analysis is performed by running a regression with the cost estimate from the analysis above. The following factors are found to explain the variation in construction costs among projects:

1. Reactors that have two units experience a cost savings.
2. Utilities that currently have reactors operating are able to hold down cost due to their previous experience with nuclear construction.
3. Utilities assuming the role of architect--engineer and constructor are able to hold down costs.
4. Length of construction and testing have an upward effect on costs.
5. Date the construction permit was issued influences costs.
6. Geographic location affects the cost of construction. The North Atlantic region experiences higher costs, while the South Atlantic and South Central regions experience lower costs.

These considerations are factored into the commission's analysis of the relative cost of construction for a plant. This comparison is necessary, but not sufficient, information by which to assess the cost the utility incurs in the construction of a nuclear plant.

For Pennsylvania, the Illinois Commerce Commission's analysis of the relative costs of construction and delay times discloses some results of interest to the commission staff. The Susquehanna 1 and 2 units fare nicely relatively to the estimated cost of construction for other projects. The estimated cost per kW of rated capacity is $1,845 per kW in constant dollars. This is slightly below the national average for all nuclear plants under construction, which is $1,917 per kW. The estimated period from the date the construction permit was issued to completion is 103 months, which is 18 months below the national average of 121 months. The estimated delay for these units is 23 months against a national average of 57 months. For Limerick 1 and 2, the results are not significantly different from the national averages. These estimated costs for these units are somewhat above the national average of $1,917 per kW at $2,068 per kW of rated capacity. The estimated delay for this project is 54 months, 3 months below the national average of 57 months. The estimated time period from the date the construction permit was issued to completion is 131 months compared to the national average of 121 months. From this, it would appear that Pennsylvania's utilities are doing an adequate job relative to other projects around the country.

On-Site Monitoring Program This program places a commission staff member or consultant at the construction site. This individual deals with construction problems directly and helps correct them as problems arise. This aspect of the monitoring program eliminates after-the-fact arguments to some extent.

The monitor interacts with both the utility and the construction firm. He is able to participate in the management of the project. For instance, he can help with and encourage the development of materials control models, work-crew scheduling procedures, equipment repair and allocation procedures, and many other cost control and planning measures. This type of direct contact enables the commission to evaluate the prudence of the utility and construction company's overall handling of the project. To this end, the monitor files periodic reports with the commission and the utility.

The monitoring program has several benefits. Among these are that it increases the commission's knowledge of the project and cost control activities, and it deals with problems as they arise. The attempt by the commission to keep informed about the project facilitates subsequent deliberation on including a particular cost in the rate base for the plant. Furthermore, the monitor's information does not come from an individual or company that has a direct financial interest in the final cost of construction. Thus, this information may be less biased than information received from the utility or the construction firm.

This on-site monitoring program is not without difficulties, however. Disadvantages include the additional cost of the monitor and the negative reaction of the construction firm to the presence of the monitor. The additional costs for the monitor can be either borne by the commission, if he is a staff member, or by the utility if a third party is the monitor. These disadvantages do not seem to weigh heavily against the potential benefits. However, an uncooperative construction firm could potentially limit the monitor's effectiveness.

The Variable Rate of Return to Construction Work in Progress (CWIP) The third part of the Illinois program is the inclusion of CWIP in the utility's rate base, which is asserted by the Illinois staff to create incentives for the utility to control cost overruns and complete the project in a timely fashion. As previously mentioned, this rate incentive includes CWIP in the rate base at a lower return than that allowed on its operational rate base. In order to evaluate the potential benefits of this program, the advantages and disadvantages of CWIP are compared to the alternative common practice of the allowance for funds used during construction (AFUDC). Following this comparison, the results of comparative simulation of the utility's financial performance under each treatment are presented.

The AFUDC method gives the utility a promise of a future cash flow. Under this treatment, interest and other capital costs associated with the construction project are accrued in a special account. This account enters the rate base, when the project is completed, as a legitimate cost of construction. By denying a current cash flow to the utility, AFUDC is argued to create an incentive to control the cost of construction. This incentive arises from the vulnerability of the utility's earnings to a cost overrun, and the need for rate relief to correct this vulnerability.

The likely effectiveness of this incentive, however, is also the basis for criticism of it. The costs of present nuclear construction projects weigh heavily in a utility's financial strategy. These projects are a sizable portion of a utility's rate base; typically, its inclusion will double the rate base. This sheer size can easily strain the financial viability of the healthiest of utilities. Thus, the ability of any utility's net operating revenues to support the cost of financing this type of project is continually called into question.

This point is cogent when most cost overruns are outside of the utility's control. Both changes in the scope of the project and unanticipated inflation account for a large portion of cost overruns. These overruns adversely affect the utility's cash flow and require rate relief. In the interim, there are two serious consequences. First, the cost of construction has increased. Second, the utility's cost of capital may have increased with the uncertainty of earnings. Coupling these consequences with the necessity of rate relief, consumers can potentially bear the burden of higher rates both now and in the future.

It is argued that CWIP corrects the problems associated with AFDUC by trading the future cash flow for a current cash flow as construction work is placed in the rate base and augments the net operating revenues the utility can potentially earn. This treatment of construction work, of course, increases rates to consumers in the present time period. These higher rates to consumers in the present period are a disadvantage of this treatment of construction costs. The Illinois Commerce Commission's staff, however, argues that consumers theoretically could pay the same amount under either treatment. The major difference between the two approaches is the timing of the cash flows to the utility. The incentive for cost control under CWIP and its advantages are now recounted.

First, proponents of CWIP say that CWIP forces a utility to earn the interest and other capital costs. Under AFUDC, a utility automatically earns these costs. In exchange for a cash flow, it gets a certain asset equal to this amount. CWIP, on the other hand, requires a utility to earn the cash flow to cover these costs through the relative efficiency of its current operations. This provides the utility with an incentive to organize both current operations and construction efficiently.

Second, the rate of return on CWIP in the Illinois program is lower than that allowed on the utility's operational rate base. This lower return creates an incentive to avoid delays in construction. By not completing construction in a timely fashion, the utility forgoes the incremental return associated with the plant entering the rate case at the full allowed return. This leads the utility to weigh the cost of delay against this enhanced return. Thus, cost-effective measures presumably will be undertaken to facilitate timely completion of the project.

Third is the familiar incentive associated with regulatory lag. The value of CWIP enters the rate base on a delayed basis (although not as "delayed" as when CWIP is not allowed). This regulatory lag creates an incentive to control cost overruns and also meet current demand efficiently. Otherwise, it would experience a deterioration of its enhanced cash flow. To this end, the commission should let it be known that rate relief under CWIP for these circumstances would be very difficult to obtain. In this way, the incentive for efficient management is reinforced.

Fourth, an enhanced cash flow enables a utility to maintain adequate financial ratios. This reduces the uncertainty of earnings relative to the uncertainty under the AFUDC treatment. Thus, consumers are alleged to benefit through a lower cost of capital in both the present and the future.

Finally, an improved cash flow allows a utility to undertake capital improvements and maintenance programs on existing units heretofore ruled out. These cost-effective capital improvements and maintenance programs increase the equivalent availability of units to the system, thereby increasing the system's reliability. Thus, current demand can be met at the lowest feasible cost.

The alleged benefits of this program are numerous. CWIP, however, has not been an accepted practice in many states. Among the arguments against CWIP is one that questions the basic premise of the Illinois program. The disadvantages of this approach to construction work are listed below.

The first criticism of CWIP focuses on the intertemporal subsidies associated with its use. By including the cost of a plant prior to its completion in the rate base, present consumers are forced to bear the cost of a plant from which they receive no benefit. This type of situation is antithetical to the traditional cost theory that hinges on "used and useful" plant and equipment in the rate base. Thus, it is argued, present ratepayers subsidize the cost of serving future consumers using electricity generated by the plant under construction.

Second, CWIP often requires legislative action. Such changes in the commission's enabling statute can be politically difficult to enact. This resistance is a source of hesitancy in adopting CWIP or advocating its adoption.

Finally, the inclusion of CWIP in the rate base at any positive rate of return is asserted to weaken the incentive to control cost overruns on the construction project. Improved cash flows enable the utility to absorb inefficiencies it would otherwise be unable to handle. In this view, CWIP is seemingly an abdication of the commission's responsibility to create incentives for the utility to control costs.

This last criticism of CWIP may be a particularly troublesome problem for the Illinois rate incentive plan. The commission staff specifically addresses this criticism. They state that they do not advocate the inclusion of all the costs of construction in their CWIP measure. The CWIP measure is built into a plant account that ultimately becomes the rate base entry for the reasonably incurred costs of used and useful plant and equipment. To this end, only those costs of construction reasonably incurred should be included in the CWIP rate base. The commission has created two bases for evaluating the reasonableness of the costs it is willing to include in CWIP. First, the statistical analysis provides necessary information by which to evaluate the relative cost of construction. Second, the on-site monitoring provides information about the project to the commission. Both of these programs, of course, can be supplemented with a management audit of the construction work in progress.

Thus, the commission staff asserts that one must view the program as an integrated approach to cost control.

In order to evaluate the financial performance of a utility under the CWIP approach relative to the AFUDC treatment, the commission staff ran some computer simulations of the utility's operation. Several scenarios were run, and one conclusion emerged--the present value of revenues paid by consumers is lower under the Variable Return to CWIP program than under the traditional AFUDC treatment. From these simulations, they concluded that rates paid by consumers over the life of the plant under construction are lower with the CWIP method than with AFUDC. In this particular demonstration, it was found that rates would be higher only during the first two years of the program and lower thereafter.

The commission's arguments in favor of this approach may be particularly cogent where a major portion of cost overruns on nuclear power plant construction is due to factors outside of the utility's control, that is, changes in the scope of the project due to regulatory changes and unanticipated inflation.

FERC

The Federal Energy Regulatory Commission (FERC) has designed a rate incentive provision intended to control construction cost problems for the Alaskan Natural Gas Transmission System. This project will transport natural gas from the northern slopes of Alaska to the upper tier of the lower 48 states. It has been under consideration off and on for the past eight years. Its expected cost is over $13 billion in current (1981) dollars. FERC, which has jurisdiction over the project, has developed a four-part incentive return program to deal with cost overruns on this project.

The FERC incentive return program is especially adapted to deal with a project after its design, but prior to its procurement and construction. The Illinois program covered in the previous section is readily adaptable to an ongoing project, as well as capable of application to a new project. No such flexibility exists for the FERC program. This important difference is discussed below.

The incentive return plan consists of the following:

1. A final estimate of construction costs.
2. A method for adjusting actual construction costs for inflation and certain changes in the scope of the project.
3. A center rate of return earnable if actual costs bear the expected relationship to estimated costs.
4. A schedule for adjusting the return on rate base for overruns or underruns.

The final estimate of the cost of the project is the key to the incentive return plan. This cost estimate should reflect a detailed design of the completed project. The costs of obtaining all state and federal permits, of meeting all safety requirements, of meeting all environmental standards, and other considerations should be fully integrated into this estimate. Any changes in scope required to meet standards that are in place prior to the time the cost estimate is submitted are charged to investors, not to consumers. Thus, the program is designed to encourage a realistic estimate of the cost of construction.

One might assert this program would encourage overestimates. However, two aspects of the project are supposed to discourage this behavior. First, the project must deliver gas at a cost competitive with other sources. This fact puts an upper bound on an acceptable estimate. Second, a formal bidding procedure for the construction contract inhibits overestimating the costs of construction.

At the same time, the way the cost estimate is used in the incentive program discourages underestimates of the cost of construction. Once the initial estimate is made, the constructing firm is held to this cost with certain allowances for unanticipated inflation and changes in scope. It becomes the benchmark by which performance is evaluated. If a firm were to gamble in the bidding process, it would most likely pad its bid, but cautiously so. Thus, the firm's estimation of the risks of cost overruns would be built into this estimate.

This cost estimate is adjusted periodically for uncontrollable cost overruns. Inflation and changes in scope are the primary sources of uncontrollable cost overruns. Quarterly inflation adjustments are made to the initial cost estimate. Specialized public and private indices of construction cost components are used for this adjustment. Changes in scope, however, are not so straightforward.

The key questions about this type of adjustment center on what kind of design changes may be charged to consumers and who judges the appropriate amount of this adjustment. FERC has left some uncertainty surrounding this type of adjustment to give the constructing firm some incentive to bargain with the authorities affecting the change. The intent is, however, to allow cost overruns due to (1) changes in laws or regulation after the final estimate is made, but none in effect prior to this estimate, and (2) changes in the project's route as required by federal and state authorities. Both these types of adjustments for inflation and scope changes are judged necessary for a fair contract. However, liberal application of these adjustments must be guarded against to avoid diluting the incentive return plan.

The center rate of return is that rate of return allowed when the actual cost of construction bears the expected relationship to the final cost estimate. The issues raised in setting this return pose many of the familiar issues faced by a commission in setting an allowed rate of return. FERC has examined setting two rates of return, one for the construction phase and another for the operational phase. The rationale for this differential return focuses on the risks of construction versus the risks associated with operating the completed transmission system. The essential point to be grasped is that the center rate of return links the return to the final cost estimate and therefore the constructing firm's performance.

This basis provides the means for setting up a schedule of allowable returns based on cost overruns or underruns.

The reward and penalty system in this incentive return plan is the linking of the company's overall return to its cost performance. This linkage mechanism can be expressed as a formula. It is

$$IROR = (1/A)\,(17.5) + [1 - (1/A)]\,(8)$$

where

IROR - the incentive rate of return (%)

A - The ratio of the actual cost of construction to the adjusted final estimate of cost.

The 17.5 and 8 are rates of return found to be appropriate by FERC for calculating a reward or penalty, respectively. As pointed out above, the center return is based on actual costs bearing the expected relationship to the final cost estimate. For this ratio, FERC chose 1.3. The center return, therefore, is 15.31 percent. The lowest return is given to the company when the project becomes noncompetitive with other sources.

Table 4-1 presents the rate of return (column 2) or the adjusted rate base (column 3) based on the company's performance in controlling costs as determined by the IROR formula. The rate base adjustments are predicated on the theory that FERC's commissioners cannot be expected to award an incentive return consistently over the life of the project (potentially 30 to 40 years). Thus, a one-time adjustment to the rate base is made. This, of course, introduces "funny money" into the company's plant accounts or requires that a special account be created. The adjustments in table 4-1 are computed using a 14 percent cost of capital. These rate base adjustments affect the return to common equity. Given the underlying premise of this adjustment, and the funny money issue aside, it seems a wise course of action.

TABLE 4-1

THE FERC INCENTIVE RETURN SCHEDULE BASED ON ACTUAL COST TO THE ADJUSTED FINAL COST ESTIMATE

A (1)	IROR (2)	Adjusted Rate Base (3)
.6	23.8	50.7
.8	19.9	30.5
1.0	17.5	18.1
1.2	15.9	9.8
1.4	14.8	4.1
1.6	13.9	-0.5
1.8	13.3	-3.6
2.0	12.8	-6.2
3.0	11.2	-14.5
4.0	10.4	-18.6
5.0	9.9	-21.2

Source: Robert E. Anderson, deputy director, Office of Regulatory Analysis, Federal Energy Regulatory Commission, Handout at NRRI's Workshop on Electric Utility Construction Cost Overruns: Regulatory Options, held August 13 and 14, 1981, at The Ohio State University

Thus, the FERC program takes the final cost estimate with certain adjustments for unanticipated inflation and scope changes as a benchmark against which performance is judged. The firm sponsoring the construction of the transmission system is held to this estimate. The firm must depend on its ability to cost out a large project correctly. The incentive return schedule creates a set of expectations about how the firm will be treated, given its ability to control costs.

A Comparison of the Illinois and FERC Programs

A comparison of the FERC and Illinois programs may be instructive. The net operating revenues a utility is allowed to earn to cover its interest and other capital costs for a new plant coming on-line or under construction is a product of two things: (1) the CWIP amount, and (2) the allowed rate of return.

The FERC program sets the CWIP amount with the final cost estimate and varies the allowed rate of return. This is possible because it deals with a new project after its detailed design and plans are completed, but prior to procurement and construction. Most commissions, however, may not have this luxury. Typically, commissions are dealing with ongoing nuclear construction programs.

The Illinois program is adapted to dealing with an ongoing project. This program sets the allowed rate of return and varies the CWIP measure according to a judgment about the prudence of costs incurred. The Illinois program, however, does not explicitly address the difficulties of unanticipated inflation and scope changes. Carefully tracking the cost increases associated with these difficulties for nuclear construction under both programs would require an information system currently not in existence.

Ideally, in a program like the one in Illinois, one should develop a benchmark against which to judge performance. However, with an ongoing project, designing this benchmark is nearly impossible, or at best, arbitrary. The Illinois commission relies on the statistical analysis and the on-site monitor for this performance evaluation.

CHAPTER 5

CRITERIA FOR A DESIRABLE RATE INCENTIVE PROVISION

The foregoing survey of rate incentive provisions has disclosed several recurring and unifying ideas central to rate incentive provisions. In this chapter, these considerations are summarized in nine criteria for a desirable rate incentive provision. The purpose of these criteria is twofold. First, the criteria can be used as a framework with which to evaluate current regulatory practices. Second and more important, these criteria can aid a commission in designing a rate incentive provision.

As previously mentioned, rate incentive provisions are financial arrangements designed to correct the cost control problem. The Oxford English Dictionary defines an incentive as something that "incites to action." Thus, a rate incentive must be designed in such a way that it uses the proper conduit to motivate the desired behavior. This behavior can be stated in either broad terms or be quite specific. The desired action is rewarded, while the wrong action or inaction is penalized. In order to evaluate the quality of the utility's response and confer rewards or penalties, a benchmark for performance must be set and a system of rewards and penalties instituted. The purpose is to lower the cost of rendering service to consumers through superior performance. Designing an incentive provision to accomplish this goal raises many complex, technical, and logistically difficult issues for a commission. The nine criteria for a desirable rate incentive provision help a commission address these issues.

The nine criteria are listed below:

1. The incentive should be directed toward the interests that motivate the utility's behavior.
2. The incentive should address those aspects of a utility's performance under the control of its management.
3. To the extent feasible, the utility should be given a clear expectation as to how its performance under the incentive provision will be evaluated and rewards or penalties conferred.
4. Application of the incentive provision should result in a positive net benefit to the utility's consumers and society as a whole.
5. The information necessary to evaluate the desired behavior should be free from tampering and ambiguity.
6. The goal and method of application should stand in a clear and logical relationship to one another.
7. The goal and method of application should be neutral in their effects and have no unintended consequences.
8. The incentive should be consistent with other goals and incentives embodied in current regulatory practices.
9. The incentive should address and eliminate disincentives that currently exist in present regulatory practices.

Each of these criteria is discussed below. The particular concern it addresses is elaborated, and when possible, examples are given using the rate incentive provisions covered in the previous two chapters. Many of these criteria are interrelated. These interrelationships are pointed out in the discussion below.

Discussion of the Nine Criteria

(1) The incentive should be directed toward the interests that motivate the utility's behavior.

In the first criterion, the basic premise of the rate incentive concept is addressed. A utility is typically personified as a profit-maximizing entrepreneur single-mindedly working in the interest of the utility's common stockholders. This view of the utility's organization however, is not entirely correct. The separation of ownership and management raises some substantive questions about the traditional assumptions concerning corporate motives.

A utility can be viewed as a complex organizational structure consisting of several "spheres of interest" within its corporate bounds. This heterogeneous structure does not necessarily harbor any well-understood motives. Instead, individual managers and various spheres of interest are motivated by reference to their own self-interest. To the extent this characterization is valid, incentives directed toward the stockholder's interests may have a diluted effect on performance, if any at all. In this case, the incentive provision should seek to wed the interests of management to those of the stockholder.

One can classify incentive provisions as either profit incentives or wage incentives. The profit incentive motivates superior performance by adjusting the return to common equity. The wage incentive bases a system of salary bonuses on the utility's performance. An example of a profit incentive is the Michigan Availability Incentive Provision. Under this program, the commission adjusts the return to common equity according to the availability of the utility's generating system to the grid. An example of a wage incentive is Consumers Power Company's Executive Compensation Program. This in-house program provides salary bonuses for executives at the general manager's level and above. Participation in this program is based on meeting a net income goal for the utility, a comparison of the utility's gas and electric rates to the rates of the 10 largest gas and electric utilities in the country, and specific performance goals of individual executives. Both of these programs make specific assumptions about what motivates superior performance. To date, all rate incentive provisions in use or under consideration by state commission are profit incentives. The wage incentive approach probably merits more attention by state commissions.

(2) The incentive should address those aspects of a utility's performance under the control of its management.

According to the second criterion, the cost control problem should be broken down into elements under the utility's control and those which lie outside of it. Furthermore, information must be available to adjust any performance standard to reflect uncontrollable changes in the utility's performance (criterion 5). These features are necessary if the rate incentive provision is to treat the utility's management, stockholders, and ratepayers fairly.

An example of an uncontrollable increase in the cost of service is the effect of both anticipated and unanticipated inflation on an electric utility's fuel or energy expense. As discussed in the previous chapter, fuel costs depend on the total kWh output, the time pattern of demand, the procured fuel cost, the generation mix, and the efficiency of the utility's units. Inflation enters this expense through the procured fuel cost. Increases in the cost of procuring fuel, however, can be broken down into those attributable to inflation and those due to improper or laxed procurement practices. While those due to inflation are outside the utility's control, the increased cost of fuel associated with its procurement practices are under its control. Thus, an integral part of a well-designed incentive provision that operates in conjunction with a fuel clause is an information system that allows the commission to assess the reasonableness of the fuel costs a utility incurs. With this feature, the commission can assure it is not incorporating subpar performance into this expense item.

The Virginia incentive provision covered in the previous chapter has developed a fuel price index that provides necessary, but not sufficient, information to assess the reasonableness of prices paid for fuel by a utility. This program is an exception. Most incentive plans, Florida for instance, rely on their ongoing management audits of fuel procurement to validate the fuel prices used in determining the fuel expense. Either one of these sources is adequate so long as it allows the commission to differentiate controllable cost increases from those outside the utility's control.

(3) To the extent feasible, the utility should be given a clear expectation as to how its performance under the incentive provision will be evaluated and rewards or penalties conferred.

The incentive plan's target(s) and system of rewards and penalties should be clearly articulated by the commission. The commission should announce prior to its application how the performance targets are used to confer rewards and penalties, and what the dollar amounts of these rewards and penalties would be. In doing this, the utility is able to formulate a cost-effective strategy to meet the incentive plan's goal. This criterion is closely related to criteria (5) and (6).

As an example of this criterion, the Virginia and Florida rate incentive provisions to improve power plant productivity can be compared. The Virginia program sets targets for equivalent availability of baseload units and reviews the heat rates of these units. This information is used to evaluate the prudence of a utility's projected fuel expense for the coming year. At year's end, actual performance is compared to the targets. Substandard performance is a basis for disallowing some of the fuel expenses already incurred. Above targeted performance, on the other hand, is considered when the commission sets the allowed rate of return for the utility. In an August 24, 1981 rate case that allowed Virginia Electric Power Company a 15 percent return on equity, the State Corporation Commission said a reasonable range would be 15 percent to 15.5 percent and that "if the company can make a satisfactory showing. . .that its performance has improved, we shall consider adjusting the allowed equity return within [that] range" (Electrical Week, September 14, 1981).

Compare this approach to Florida's formula approach to a system of rewards and penalties. As previously mentioned, this rate incentive provision is called the Generating Performance Incentive Factor (GPIF). Every six months the Florida Public Service Commission sets targets for equivalent availability and heat rate for each of a utility's generating units. These targets are used to determine the projected fuel expense for the coming six months. Both the targeted performance and the maximum changes performance that can be reasonably expected are used to calculate the rewards and penalties the utility can earn. At the end of the six-month period, actual values for equivalent availability and heat rate are plugged into the GPIF formula to determine the utility's reward or penalty.

This formula approach gives Florida utilities a clear expectation of how they will be evaluated and rewarded or penalized. The Virginia program, on the other hand, has no explicit set of rewards or penalties and conducts the performance evaluation in the context of an adversary proceeding. As a result, the utilities operating in Virginia may not have as clear an expectation as do utilities operating in Florida. If so, rate incentive provisions like Virginia's may have a somewhat diluted impact on performance.

(4) Applications of the incentive provision should result in a positive net benefit to the utility's consumers and society as a whole.

The purpose of a rate incentive mechanism is to lower the cost of rendering service to consumers through improved peformance. To accomplish this, the costs of designing and implementing the rate incentive, as well as the cost of improving the utility's performance, should be exceeded by the benefits it generates. The analysis of the costs and benefits should encompass impacts beyond the utility, its consumers, and regulators to society as a whole. It should be recognized, however, that quantifying many of the secondary and tertiary effects may be quite difficult.

Benefits of a rate incentive program could be measured in terms of the dollars saved by consumers through superior performance or in terms of costs not borne by consumers but that are charged to stockholders. Beyond these direct benefits, one could examine the indirect benefits of more reliable, low cost service. For instance, an increase in the availability of generating units would reduce the probability that interruptible customers would have power curtailed. The increase in annual production of goods and services by these interruptible customers is a benefit of the increased reliability of the system. Even if a commission cannot assign dollar amounts to these indirect benefits, they should be recognized.

The costs associated with a rate incentive provision are numerous. First is the man hours attributable to the design of the incentive plan. These costs are incurred not only by the commission but by the utility and other groups as well. Once designed, a system for the filing of, and the processing of, data to evaluate the utility's performance must be implemented. The costs to the commission, the utility, and other groups must be considered. Third, the performance evaluation requires a hearing to confer rewards or penalties and to allow for any extenuating circumstances the utility may have confronted that affected its performance during the relevant period. The cost of the reward when conferred must also be considered. There could be many other costs that are attributable to the program. One, in particular, is the costs the utility incurs to improve its performance (see the discussion for criterion 6).

This discussion of the costs and benefits is intended to suggest the kinds of considerations that must be integrated into any incentive analysis. The upshot however, is straightforward. Any incentive plan that does not result in a positive net benefit should not be implemented. The commission must try to anticipate this outcome.

(5) The information necessary to evaluate the desired behavior should be free from tampering and ambiguity.

The fifth criterion is probably the most difficult to satisfy. This difficulty is a manifestation of a situation endemic to public utility regulation. In most cases, the utility holds the information regulators need to assess performance and confer a reward or penalty. A rate incentive should be based on information that is clear, concise, readily available, and free from manipulation and contradiction as to proper interpretation. Since the utility generates most of this information, several problems are created. First, regulators may have concerns different from those of the utility. As a result, the information necessary to monitor the utility's behavior may not be available in a usable form or at all. Second, if the information is available, the utility may not want to disclose it in a usable form. Third, the utility can selectively use and disclose the information to its advantage. This information problem affects the degree to which all other criteria can be met. Thus, the aspects of performance the commission wishes to improve should be quantifiable and data available in a clear and concise form. If not, the rate incentive's impact will be only as robust as the information on which it is based.

Incentive provisions to control cost overruns on nuclear power plant construction are a good example of programs encountering a severe information problem. At present, there exists no information system with which to trace cost overruns to their root cause, and associate man hours and quantities of material and equipment with a cause. As a result, it is difficult, if not impossible, to assign dollar amounts to cost overruns due to controllable or uncontrollable causes. This kind of information problem inhibits a commission's ability to develop a meaningful benchmark with which to evaluate the utility's performance.

The Illinois Commerce Commission is presently considering a rate incentive provision to control cost overruns for nuclear power plant construction. The incentive feature of this three-part program involves the inclusion of construction work in progress (CWIP) in the rate base at a lower return than that allowed on the utility's operational rate base. Many complex issues are raised in determining the CWIP amount that enters the rate base periodically. By criterion (2), the commission should allow cost increases resulting from uncontrollable sources such as inflation and required changes in the scope of the project, while disallowing those resulting from controllable causes such as an inadequate initial design and management practices. As earlier mentioned, the Illinois commission has developed two methods of obtaining necessary, but not sufficient, information on the cost of construction. First is a statistical analysis of the relative cost of construction. This analysis allows the Illinois commission to compare estimates of the constant dollar cost of a nuclear plant to estimates of the constant dollar cost of similar projects throughout the country. While not conclusive, this comparison provides useful information to the commission about the reasonableness of the costs incurred. The second source of information is from an on-site monitor. The monitor continually interacts with the utility and its construction firm. He files reports with the commission that keep it apprised of problems, steps taken to correct the problems, and other useful information. This information, along with the statistical analysis, is presented as testimony with regard to the reasonableness of the CWIP entry in the rate base.

This program under consideration in Illinois provides the commission with two independent sources of information with which to evaluate the utility's performance. Beyond this information problem inherent with nuclear construction, one must question the extent to which a utility would publicly admit a cost overrun was avoidable. By using sources of information independent of the utility's interest, the commission is able to assess its performance with more confidence. It is this kind of consideration that is suggestive of the fifth criterion's purpose.

(6) The goal and method of application should stand in a clear and logical relationship to one another.

According to the sixth criterion, the means must be capable of achieving the desired end. Furthermore, the method of applying the incentive should relate in a direct way to the desired goal. This clear and logical relationship between ends and means creates an environment in which the utility can formulate a cost-effective strategy on a clear set of expectations (criterion 3) and help achieve a positive net benefit (criterion 4).

The ostensible goal of rate incentive provisions is to lower the cost of rendering service to consumers. Two general approaches to incentives can be used to accomplish this goal. One approach is based on total factor productivity. This approach develops a performance benchmark for the productivity of all inputs that are necessary to render service. The system of rewards and penalties is based on improvements and degradation in the average productivity of all inputs. The other approach is to aim the incentive provision at a specific area of the production process--a "rifle" approach to incentives. Under this approach, benchmarks are based on parameters of one or more aspects of the utility's operation. Rewards and penalties are then dependent on changes in these parameters.

While the total factor productivity approach raises many substantive issues, the "rifle" approach to incentives can create problems relevant to criterion 6. For instance, a rate incentive that rewards a utility for improvements in equivalent availability and heat rates of its baseload units or increased availability of the system to the grid is based on the assumption that the resulting fuel savings lowers the cost of service. This outcome, however, is uncertain. Improvements in the selected parameters of the utility's operation are achieved by undertaking either capital improvements, extensive maintenance, or both. The cost of these improvement programs should be scrutinized to assure they are cost-effective programs. If the commission were to allow them to enter revenue requirements without ascertaining their cost-effectiveness, the cost of rendering service to the consumer could increase while the utility earns a reward. This negative net benefit (criterion 4) could result from an uncertain relationship between improvements in power plant productivity and a lower cost of service. In circumstances like these, the commission, as part of the design of the rate incentive provision, should develop a strategy for dealing with the costs that are incurred to improve the parameters of the utility's operation.

(7) The goal and method of application should be neutral in their effects and have no unintended consequences.

According to the seventh criterion, the overall impact of the rate incentive on the utility's operation should be carefully evaluated. It implies, in particular, that the goals and methods of the incentive should be clearly and logically related (criterion 6), and that it should result in a positive net benefit (criterion 4).

The Public Utilities Commission of Ohio's experience with its target thermal efficiency mechanism is a good example. This incentive mechanism had an unintended consequence, and as a result, was eliminated in May of 1981. The target thermal efficiency measure was calculated as a rolling average of heat rates for units dispatched to the system. With the imposition of EPA standards, higher cost coal with a lower sulfur content was used in more efficient units to meet air-quality standards. As a result, the target thermal efficiency mechanism dictated one dispatch of the system, while economic dispatch dictated another. Thus, in meeting the target, a utility would fail to minimize its operating costs. Clearly, this is an unintended consequence of the incentive provision's design.

(8) The incentive should be consistent with other goals and incentives embodied in current regulatory practices.

In the eighth criterion, it is suggested that a rate incentive should not work at cross-purposes with other regulatory goals. Part of this consideration is a recognition of any legal constraints placed on the implementation of a rate incentive. Any precise statement of the goals of regulation would be inexact and arbitrary because they depend on the industry being regulated and other extenuating circumstances in a commission's jurisdictional area. However, the broadly conceived goals of regulation are to control potential monopoly profits, to be fair to both the utility and its consumers, to achieve safe and reliable service, and to promote both technical and economic efficiency. The concept of rate incentive provisions is fully compatible with these broad goals. However, a specific rate incentive provision designed to achieve particular goals can raise questions of its compatibility with other goals the commission is seeking to accomplish. In these circumstances, a commission should carefully weigh the trade-offs it confronts.

The Public Utilities Commission of Ohio recognized the problem of inconsistent goals in the operation of its target thermal efficiency mechanism. Confronting the trade-off between minimizing the costs of generation and meeting the target, the commission required the utilities to meet the target to the extent it allowed them to dispatch the system economically. This interim solution assured the incentive provision would be consistent with the goal of minimizing the cost rendering service.

(9) The incentive should address and eliminate disincentives that currently exist in present regulatory practices.

In the ninth criterion, an early step in designing a rate incentive program is suggested. The current framework of regulatory practices should be surveyed to identify potential areas for improvements. An integral part of this survey is the identification of any disincentives that exist. Of course, it should be recognized that to have an incentive provision eliminate disincentives that currently exist might be too much to ask of it. Thus, in implementing an incentive provision, it might be best to adopt new rules and change statutory provisions to address many of these problems. No matter what the course of action, the survey of current practices allows potential "targets of opportunity" to be identified for further consideration. Rate incentive provisions is a method to achieve the benefits the survey has identified.

Conclusion

Thinking of public utility regulation as a system of rate incentives provides a useful framework by which to evaluate the efficiency of present regulatory practices. The cost control problem to the extent it exists can be the consequence of undesirable incentives given to utilities by current regulatory practices. These practices can be evaluated in terms of the nine criteria outlined above. Once targets of opportunity are identified, effective rate incentive programs can be instituted to supplement or supplant current practices.

CHAPTER 6

SOME OF PENNSYLVANIA'S ACTIVITIES

This chapter is a compendium of material presented by the staff of the Pennsylvania Public Utility Commission at the seminar on August 10, 1981. This material summarizes some of the commission's activities in the rate incentives and cost control areas. The first section is a summary of the study on electric power plant productivity by John J. Reilly and Alvaro V. Domingos of the Pennsylvania Public Utility Commission's Bureau of Conservation, Economics and Energy Planning (CEEP). This summary, presented by John Reilly, points out "targets of opportunity" for a rate incentive. The second section is a review of how energy clauses create disincentives for adequate power plant productivity. The third section presents a proposed energy clause for Pennsylvania. This clause, developed by CEEP, is labeled the Energy Price Adjustment Clause. The second section is based on some material presented by David Boonin, and Boonin wrote the third section. The fourth section is a set of recommendations for cost controls at nuclear construction sites. These recommendations were presented at the seminar by John Dial, director of the Bureau of Audits.

Recent Cost Control Activities at the Pennsylvania Public Utility Commission: Electric Power Plant Productivity

CEEP studied, with the utilities, the potential for electric power plant productivity benefits from improved power plant availability associated with improved forced outage rates (FOR). CEEP was assisted by the four Pennsylvania utilities in the Pennsylvania, New Jersey, Maryland Interconnection (PA/PJM): Pennsylvania Power and Light Company (PP&L), Philadelphia Electric Company (PECO), and subsidiaries of General Public Utilities (GPU) which are Metropolitan Edison Company (Met-Ed) and Pennsylvania Electric Company (Penelec).

The study addressed the following for 14 coal units over 300 MW that are fully or partially owned by PA/PJM utilities:

1. The cause of lost output (MWh) and determination of possible improvement actions.
2. The costs of improvement programs.
3. The potential gross savings in generation costs and oil consumption from improvement programs.
4. Evaluation of the benefit/costs associated with improvement programs.

Figure 6-1 shows the study organization with the basic analytical steps. Based on the preliminary assessments in phase I of the potential gross savings and on the overall performance of large coal units, the 14 PA/PJM coal-fired units over 300 MW were selected for a detailed study in the second phase. The forced outage rates of these units ranged from a low of 13 percent to a high of 38 percent.

In phase II of the study, improvement programs that were expected to eliminate or reduce performance problems of the studied units were defined based on the analysis of the causes of productivity losses. In addition, both the costs and potential improvements in forced outage rates (FOR) associated with each unit and with improvement programs were estimated.

The chief analytical tool used in this study to estimate benefits was the PP&L Production Cost Simulation Program (Prod Cost). Prod Cost was used to simulate the economic dispatch of generating units on the PJM system to serve the energy demand at the lowest cost. PP&L Prod Cost has two-area capability, so the PJM system was divided into Pennsylvania companies of PJM (PA/PJM) and non-Pennsylvania companies of PJM (Non PA/PJM).

The basic study approach was to simulate PJM operations, using the production cost program with current unit availability forecasts for 1982 and 1987 base cases. Then, two improvement scenarios in FORs were

FIGURE I

STUDY ORGANIZATION

BASIC ANALYTICAL STEPS

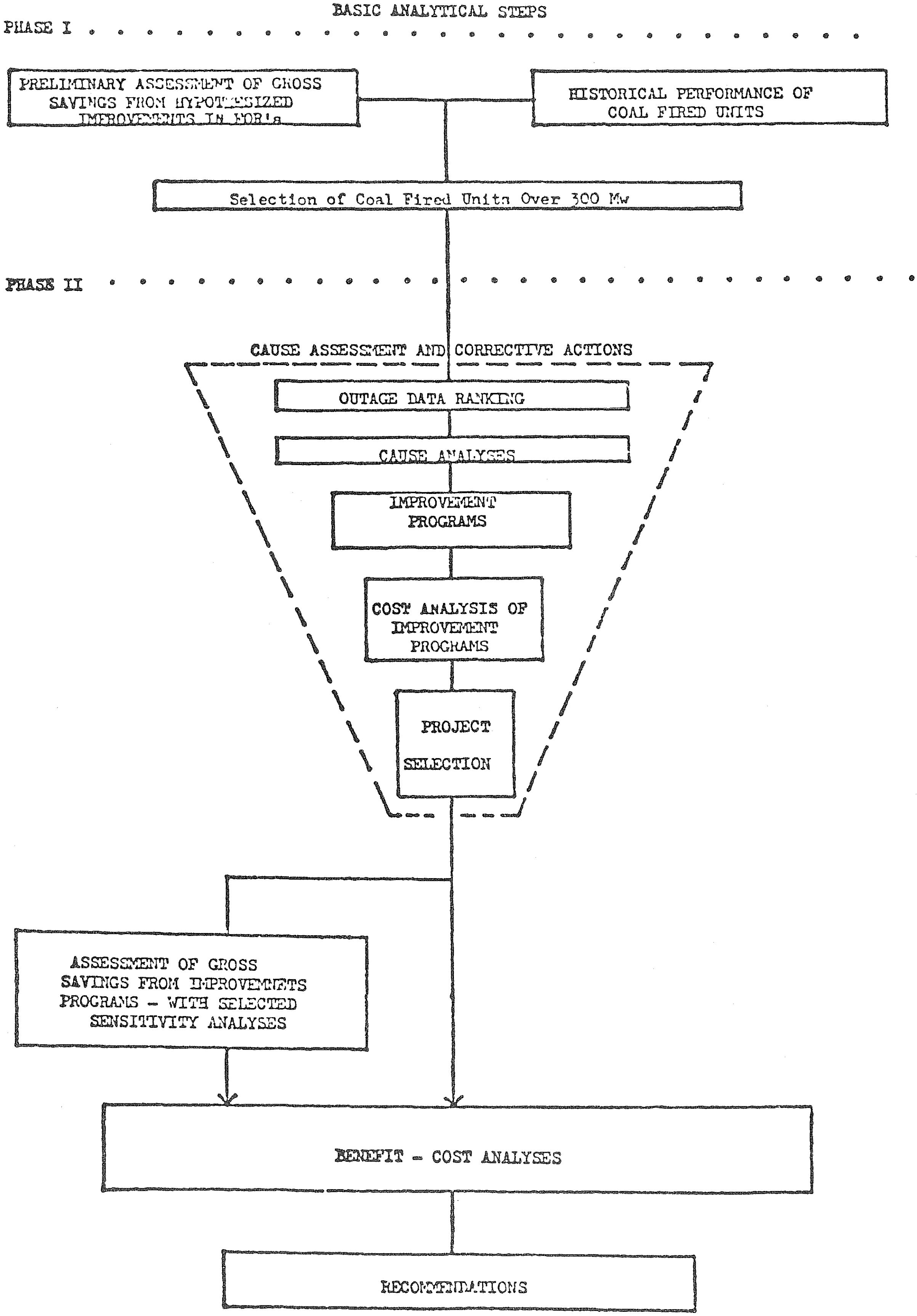

Fig. 6-1 Organization chart for Pennsylvania's study of power plant productivity

estimated for PA/PJM coal units over 300 MW, the operations simulated, and the results compared with the base cases to estimate potential fuel consumption and fuel cost savings. Also, the sensitivity of fuel cost savings to fuel prices was estimated for selected cases.

The following conclusions were developed in the study:

1. The estimated potential PJM pool net benefits in 1980 constant dollars for the six year period 1982 through 1987 range from $428* million to $704** million for a given improvement program aggregate. The estimated benefits consist of $160* million to $260** million for PA/PJM and $268* to $443* for NONPA/PJM. Also, the selection of the 1982 through 1987 period, though representative, does not cover the entire time period over which benefits would accrue. The benefits of a productivity program would be expected to continue beyond the 1987 study period.
2. There would be about 2.8* to 4.4** million barrels per year estimated reduction in the PJM pool oil consumption. Associated with the decrease in oil consumption would be 560* to 880** thousand tons increase in PJM coal consumption. Similarly, this would include about .8* to 1.3** million barrels per year reduction in PA/PJM companies' oil consumption.
3. The potential energy cost savings from improvements of the study units were very sensitive to the difference between coal and oil prices. For example, in a hypothetical example presented in the study, an increase in Steam Electric Plants fuel oil prices of about 63 percent between November 1978 and November 1979 reflects a 152 percent increase in potential benefits from availability improvement in a baseload coal unit on the hypothetical system when oil can be displaced 70 percent of the time.

---

*Represents the "Most Likely" estimated improvement from this program.

**Represents the "High" estimated improvement from the program.

4. The potential savings were sensitive to the percent composition of oil generation in the system because the latter determine the percent of time that oil is being burned and hence can be displaced.
5. Under the present regulatory climate (such as the Energy Adjustment Clause), the estimated cost savings would not accrue to the PA/PJM utilities. They would be passed along to their customers, without necessarily reflecting the offsetting changes in utility expenditures required to achieve the power plant productivity improvements.
6. The implementation of improvement programs is the responsibility of the PA/PJM utilities. However, the PUC has the responsibility of providing a regulatory climate conducive to power plant productivity improvements. Therefore, to establish the ground work for the development of candidate policies that may promote power plant productivity improvements, it was recommended that the commission consider holding generic hearings or establishing a regulatory/utility study group to develop candidate policies to promote power plant productivity improvements. The commission created an ad hoc staff committee to develop candidate incentive policies.

It cannot be overemphasized that the commitment of large dollar outlays is of great significance to the utilities. In effect, from the utilities' perspective, the capital costs and operating/maintenance (O&M) expenditures associated with the improvements program are viewed among other costs in the production of electricity. That is, economics of input substitution are such that to achieve fuel cost savings through implementation of improvement programs generally involves increased capital and O&M costs. Similarly, the use of higher fuel costs in the production of electricity reflects savings in other input factors. Thus, it can be a strong economic incentive for utilities to minimize generation cost by economizing on higher fuel cost inputs if the recovery of expenditures associated with the benefits in fuel costs is allowed.

Under the present regulatory climate, a utility generally has its capital and O&M costs estimated and set prospectively within its base rates. Once the revenue requirement associated with these costs has been established, any reduction the utility achieves in actual O&M expense may result in an increase in return to the utility. Any cost increase is fully borne by the utility until rates are adjusted to reflect the increase in revenue requirement. Conversely, any increase or decrease in total energy costs the utility achieves, however that energy cost change may occur, is passed along to its customers through the present Energy Adjustment Clause (EAC). As such, the present fuel and purchased power cost adjustment procedure both weakens and distorts management incentive for cost minimization planning. With this type of energy adjustment procedure, a utility has little financial incentive to economize on the use of fuel, when to do so would require increased expenditures of money on other input factors. The reason is that fuel costs can be recovered quickly, whereas variations in expenditures on other costs are not automatically recovered and possibly will not be recovered at all.

As a result, some of the improvement programs may not be implemented. Without appropriate incentives for cost minimization, utilities (individually) may opt for higher energy cost solutions and/or usage because the resulting higher fuel costs can be quickly recovered. Thus, the CEEP staff concluded that utilities that minimize generation costs by full-range trade-offs of higher capital and/or O&M costs to reduce total costs and economize on the use and purchase of high fuel cost should be compensated in some form. That is, cost minimization should ideally go along with maximum return to the utility.

Energy Clauses as a Disincentive to Power Plant Productivity

The concept of total recovery of energy expenses profoundly affects the incentives present in energy cost recovery clauses. As noted in the previous chapter, energy expenses fluctuate through the following five elements:

1. The total kWh output expected for the future period.
2. The expected time pattern of customer demands.
3. The procured fuel cost.
4. The generation mix (reflects plant availability).
5. The efficiency of the utility's units (usually measured by heat rate).

In an unpublished study by CEEP's Economic Division, Regression Analysis of Factors Contributing to Changes in Energy Costs, regression analysis indicated that changes in unit availability and customer load explained the change in energy cost better than changes in energy prices. Generation mix was used as a proxy for unit availability and customer loads in this study. The study by Reilly and Domingos, covered in the previous section, suggested that Pennsylvania's Energy Cost Rate (ECR), which allows total recovery of energy cost, may provide a disincentive to improving or maintaining the productivity of units in a utility's system. Thus, Pennsylvania has accumulated some evidence that suggests needed changes in its energy cost recovery clause. This section is a discussion of the disincentives that may be present in these types of clauses.

In order to highlight the incentives and disincentives in energy clause designs, two extreme examples of energy clauses are presented. The first clause permits a utility totally to recover all of the energy expense it incurs. At the other extreme is a clause that allows the utility to recover only a preestablished energy expense. These two extreme designs illustrate the way the financial risks of operation can be shifted to either the utility or the consumer. This risk shifting has a substantive effect on the incentives present in the clause.

An energy clause that allows total recovery of all energy expenses incurred by the utility places most of the financial risks of operation on the ratepayer. To illustrate this point, suppose a major baseload unit experiences a higher than normal forced outage rate. Under this type of clause, the utility is able to recover the costs of replacement energy associated with the above normal outages. This lack of the utility's financial exposure to above normal outages does not provide financial incentive to correct the unit's problem. In fact, the cost associated with the cost-effective capital improvements and maintenance expenses would not be recovered until the next rate case. The costs of replacement energy, on the other hand, are passed through to the consumer with a much shorter lag.

An energy clause designed to recover a preestablished energy expense shifts the financial risks of operation to the utility. To illustrate this point, the same baseload unit is assumed to experience an above normal outage rate. In this case, the higher costs of replacement cost energy are eventually borne by the utility's stockholders. The energy expense the utility actually incurred exceeds the preestablished expense. As a result, the bottom-line earnings are reduced. This set of circumstances provides the utility with a financial incentive to undertake cost-effective capital improvements and maintenance to reduce the unit's outages. Therefore, cost effective programs to improve power plant productivity would enhance a utility's earnings under this type of energy clause.

The Pennsylvania Energy Cost Rate is similar to the clause that allows total recovery of all energy expenses. The ECR sets the energy expense to be recovered each year according to the utility's projection of its energy costs. The reconciliation that occurs annually to adjust the rate for overrecovery and underrecovery does not necessarily protect the ratepayer from paying for energy cost associated with inferior performance. It also does not provide a utility with a reward for superior performance. Thus, an opportunity exists for a rate incentive provision in Pennsylvania's energy adjustment clause.

The Energy Price Adjustment Clause: A Proposal for Pennsylvania

The CEEP staff is developing an energy clause to correct the known deficiencies of the current ECR. The purpose of the Energy Price

Adjustment Clause (EPAC) is to provide a rate incentive to a utility to use an economically efficient generation mix. This is accomplished by allowing for the automatic reconciliation of annual energy costs directly attributable only to changes in energy prices. For a more detailed presentation of this clause, see appendix A. This distinction between procured fuel prices and energy costs will hold the utility responsible for changes in energy costs resulting from changes in the generation mix, the heat rate, and the time pattern of demand. In doing this, EPAC allows for a sharing of the financial risks of operation between ratepayers and the utility.

The EPAC would allow a utility to keep all gains from improved system efficiency, no matter how they were achieved. (The Pennsylvania staff is reviewing the possibility of limiting the extent of sharing the losses or gains.) The utility would therefore have a monetary incentive to undertake cost-effective programs to improve power plant availability, heat rate, or customer load. If the utility suffered degradation of any of these components, it would probably experience a financial loss.

Once a year it would be necessary to determine each utility's total projected energy cost. The contribution from each mode of supply (e.g., coal, oil, steam, nuclear, net interchange, combustion turbines) would be determined in megawatt hours. Projected average energy and fuel prices would also be set in $/MWh. Energy costs are determined by multiplying energy prices ($/MWh) by each mode's supply contribution (MWh). Implicit in these determinations are many productivity and load criteria. All of these criteria can be manipulated or determined through a production cost simulation model.

At the end of the EPAC year, overrecoveries or underrecoveries would be determined by inserting the actual average fuel and energy prices in place of the projected prices. The utility would be entitled to collect or required to refund the difference caused by changed fuel and energy prices. This would only be adjusted to reflect changes in total annual sales, but not the time pattern of sales. The utility would be responsible for both improvements and degradation in system efficiency. All energy cost changes, whether caused by changes in plant availability, heat rate, and/or load, would not be a cause for an automatic adjustment. These changes would rather be absorbed by this utility like O&M expenses that are handled in a rate case. Utilities would be permitted to petition for further cost recovery.

The hearings for setting and reconciling the EPAC would be an adversary proceeding. It might be possible to execute this process in tandem with a rate case, especially if a fully future test year was used. If the EPAC was set in tandem with a rate case, it may also be possible to include the nonenergy costs of a particular efficiency improvement program in the base revenue allowance while adjusting the EPAC for the anticipated energy cost benefits.

In comparing EPAC to the Virginia and Florida programs covered in the last chapter, several similarities and differences emerge. Each of the incentive provisions differs in its definitions of productivity, incentive target areas, and the risk and reward exposure. Only EPAC includes an explicit load-management incentive. Florida includes heat rates in its productivity measure, while Virginia does not explicitly set heat rate targets. Virginia's program is used only as a benchmark to evaluate the utility's prudence in incurring its energy expenses. Florida and the EPAC proposal, on the other hand, set up a specific system of rewards and penalties.

Although these three approaches differ to some degree, they do share many characteristics:

1. All make a utility more responsible for changes in energy cost, especially those caused by changes in power plant productivity, than under an energy clause alone.
2. All hold a utility less responsible for changes in energy costs than it would be if the energy rates were set in base rate case.
3. All allow for adjustments when energy cost changes due to changes in energy and/or fuel prices.

4. All of these productivity incentive programs require that a utility's fuel procurement practices still be monitored.
5. All are cost based and not based solely on engineering criteria (e.g., Ohio's heat rate targets and Michigan's availability rate targets).
6. All require a sophisticated production cost simulation model to be effective and executable. (This model need not be uniform for all utilities in the state.)

Recommendations for Cost Controls at Nuclear Construction Sites

This section of the chapter contains some recommendations presented by John L. Dial.

Drawn from the Bureau of Audits brief involvement with the Management Analysis Consultants' studies and the Susquehanna Project in general, a few suggestions with regard to improving regulatory oversight on such projects were made by John Dial. These recommendations are presented below.

1. The PUC should consider the establishment of construction contract guidelines. Present construction contracts appear to be typically "cost plus" with little or no risk to the contractors. There appears to be a need to balance risk among the contractors, the utility, and the ratepayers. Such guidelines could be prepared after completing a study of various contracting methods utilized throughout the country.
2. The PUC should monitor major construction projects in an effort to ensure that proper cost control procedures exist and are effective. It is suggested that the utility and contractors' cost control mechanisms be reviewed as opposed to a detailed analysis of individual cost components that would be excessively time consuming and beyond the commission's realistic man power capabilities. Also, it may be possible to establish guidelines for such cost control procedures.
3. At the present time, there are no gathering methodologies or other

cost center accounting procedures that would allow cost overruns to be identified by their root cause. Although an admittedly difficult undertaking, the identification of cost overruns is so important that regulators and utilities should make every effort to develop such a cost center accounting system.

CHAPTER 7
POSSIBLE EXTENSIONS

In the previous chapter, members of the Pennsylvania Public Utility Commission staff identified potential targets for rate incentive provisions and made certain proposals. Several possible extensions of their previous work are suggested in this chapter. In the area of power plant productivity, possible extensions are as follows:

1. Assess the financial and rate impact of at least two energy clauses with rate incentive provisions using historical operating data.
2. Analyze the prospective financial and rate impact of at least two energy clauses with rate incentive provisions. This includes conducting a sensitivity analysis.
3. Assess the legality for the Pennsylvania regulatory jurisdiction of two or more energy clauses with rate incentive provisions.
4. Assess the staffing and data requirements associated with implementing selected energy clauses with rate incentive provisions.
5. Review the potential for a wage and salary incentive program to be instituted by the utilities at the commissions' behest.
6. Have the utilities in the Pennsylvania regulatory jurisdiction conduct a root cause analyses of inferior power plant performance and develop a cost-effective improvement proposal.

The possible extensions in the area of cost control for major construction programs are the following:

1. Consider the establishment of construction contract guidelines.
2. Monitor major construction projects.
3. Develop or adopt an information system that would allow the root causes of construction cost overruns to be identified.

APPENDIX A

PROPOSED ENERGY PRICE ADJUSTMENT CLAUSE

This appendix contains a more detailed description of the proposed Energy Price Adjustment Clause for Pennsylvania. This is a working draft. Among the modifications being considered by commission staff are a ceiling and floor for the potential rewards and penalties the utility may incur.

ENERGY PRICE ADJUSTMENT CLAUSE

An Energy Price Adjustment Clause (EPAC) factor will be applied to each kilowatt-hour supplied under this tariff. The EPAC will be determined to the nearest one-thousandth or one mill per kilowatt-hour and will be levelized for 12 months and subjected to an annual review. The purpose of the EPAC, in accordance with the formulas set forth below, is to provide incentives for a utility to use an economically efficient generation mix, by allowing for the automatic recovery of only those costs directly attributable to changes in energy prices:

$$\mathrm{EPAC} = \left(\frac{F_{b+1}}{S_{b+1}} \qquad A_{+1} \right) \frac{1}{1 - T}$$

Where EPAC = Energy Price Adjustment Clause Factor in mills per kilowatt-hour to be applied to each kilowatt-hour supplied under this tariff.

F = The cost of fossil and nuclear fuels, plus the costs of purchased power and interchange purchases less the revenues from firm sales and interchange in the base (b) and current (c) computations.

Fossil Generation

The base period cost will be determined by multiplying the estimated unit cost of fuel consumed, in cents per million Btu by the product of an average heat rate approved for each station, in Btu per kilowatt-hour, and a fixed quantity of total kilowatt-hour for each station and then aggregated to arrive at a dollar cost of fossil fuel. These factors will be fixed for each station in an annual review that may be consolidated in a rate case. Current costs shall vary only due to changes in unit fuel price, with total generation contribution by each station and the heat rate for each station remaining fixed. The allowable contributions to fuel prices shall include the cost of fuel charged to Accounts 501 and 547 that are computed on the bases of fuel delivered to the generating site at which it is consumed, plus the cost of disposing of solid waste from sulfur oxide removal devices.

Nuclear Generation

The method for calculating base and current fuel costs is identical to that described under fossil generation. The allowable contributions to fuel price are the costs charged to fuel Accounts 518 and 521 that are computed on the bases of the costs of such fuel delivered at the generating station at which it is consumed after deducting these from the present salvage of reuse value of such fuel.

Energy Purchases (Firm)

A base cost shall be calculated by multiplying an estimated base price, in mills per kilowatt-hour, by a fixed quantity of total kilowatt-hours of firm purchased power. These factors will be determined in the annual review (see fossil generation). Current costs will be calculated by multiplying the average current cost (price) of purchased power (in mills per kilowatt-hour) by the fixed quantity of kilowatt-hours determined in the annual review. Allowable contributions to the price of purchased power shall include costs associated with those purchases charged to Account 555.

Energy Sales (Firm)

Revenues from firm sales of energy shall be calculated in an identical fashion as cost of firm purchases.

Interchange Purchases

Costs of interchange purchases shall be calculated in an identical fashion as costs of firm purchases, excepting that charges for non-energy related demand costs shall be excluded.

Interchange Sales

Revenues from interchange sales shall be calculated in an identical fashion as costs of interchange purchases.

Fb or Fb + 1 = The base cost of energy that was estimated in the utility's most recent rate case or in a subsequent annual review by the Public Utility Commission. The costs include the costs of fossil generation nuclear generation, energy purchases, interchange purchases less revenues from energy, and interchange sales, as defined above. Fb + 1 is the base cost for the prospective year. Fb is the base cost for a year just completed, undergoing annual review.

Fc = The current cost calculated by applying current fuel and energy prices for each source of energy to the predetermined heat rates and generation mix. Current fuel and energy prices are the average fuel and energy prices incurred during the EPAC year, as limited herein. That is, Fc is determined by using exactly the same quantities of fuels and energy purchases, energy sales, and interchange purchases and interchange sales that were determined in the base period that serves as the basis for the fuel price adjustment factor. This calculation isolates and separates the fuel/energy price effect from changes in generation mix or in the heat rates.

A or A + 1 = A factor expressed in mills per kilowatt-hour to adjust for any overcollection or undercollection of fuel costs caused by changes in fuel price alone during a 12-month period as prescribed by this commission. This shall be calculated by the formula given below:

$$A_{+1} = \left[\frac{(F_c - F_b)}{S_b} S_c + A\,(S_b - S_c) \right] \Big/ S_{b+1}$$

S = The company's total kilowatt-hour sale to customers as determined for the base (b) periods and actual kilowatt-hours sales in the current (c) period, excluding energy produced by facilities undergoing operational tests prior to being placed into commercial operation.

T = The Pennsylvania receipts tax rate in effect during the billing month expressed in decimal form.

Minimum bills shall not be reduced by reason of this EPAC factor. This rate shall be applied to all kilowatt-hours supplied, and such charge shall be in addition to any minimum applicable.

The company shall file quarterly reports within thirty (30) days following the conclusion of each computation year quarter. These reports will be in such form as the commission shall have prescribed. The third-quarter report shall be accompanied by a tentative estimate of the EPAC factor for the next computation year.

The application of the EPAC factor shall be subject to continuous review and to audit by the commission at such intervals as the commission shall determine. The commission shall continuously review the reasonableness and lawfulness of the amounts of the charges produced by the EPAC factor and the charges included herein.

If, from such an audit it shall be determined, by final order entered after notice and hearing, that this EAPC factor has been erroneously or improperly utilized, the company will rectify such error or impropriety, and in accordance with the terms of the order, apply credits against future EPAC factors for such revenues as shall have been erroneously or improperly collected. The commission's order shall be subject to the right of appeal.

The company will not be restricted from applying for a modification to the levelized rate set by this clause during the EPAC year. In the case of rate increase requests, the company will have to show that the cause of the increase was abnormal, unanticipated, and beyond the potential control of the company.

APPENDIX B

PARTICIPANTS AT THE RATE INCENTIVES SEMINAR

This appendix lists the participants at the Rate Incentive Seminar, held August 10, 1981, at the Pennsylvania Public Utility Commission.

List of Participants for the Rate Incentive Seminar,
Held August 10, 1981, at the Pennsylvania Public Utility Commission

Dan Czamanski	National Regulatory Research Institute (NRRI)
William Pollard	National Regulatory Research Institute (NRRI)
	<u>Pa. Public Utility Commission</u>
Conrad Six	Bureau of Conservation, Economics & Energy Planning (CEEP)
John Reilly	CEEP
David Boonin	CEEP
Thomas Clift	CEEP
Sue McBride	CEEP
Rich Sandusky	CEEP
William Townsend	CEEP
Blaine Loper	CEEP
Robert Packard	Bureau of Rates
John Steslow	Rates
Charles Smetak	Rates
Donald Birx	Rates
Errol Wagner	Rates
Donald Muth	Rates
James Giordano	Rates
John Dial	Bureau of Audits
Glenn Bartron	Audits
David Rolka	Commissioner Johnson's Office
Thomas Diana	Commissioner Johnson's Office
Billie Ramsey	Commissioner Johnson's Office
Paul Aleva	Commissioner Cawley's Office
Zabairu Kaloko	Commissioner Taliaferro's Office
Robert Bennett	Commissioner Taliaferro's Office
Gustav Gillert	Director of Operations' Office
Edward Casey	Administrative Law Judge
Jan H. Freeman	Governor's Energy Council
Bob Irvin	Duquesne Light Company
Ray Williams	Philadelphia Electric Company
Joe Pazak	Pennsylvania Power Company
Robert Geneczko	Pennsylvania Power and Light Company
Anton Stevens	West Penn Power Company
Phillip S. Thompson	Metropolitan Edison Company
Eugene F. Carter	GPU Service Corporation
Ronald P. Lantzy	Pennsylvania Electric Company

BIBLIOGRAPHY

1. California Utilities Commission. In the Matter of the Application of Southern California Edison Company for Authority to Modify Its Energy Cost Adjustment Billing Factors in Accordance with the Energy Adjustment Clause as Modified by Interm Decision 91277. Decision 93363, July 22, 1981.

2. Canaday, Henry T. Construction Cost Overruns in Electric Utilities: Some Trends and Implications. Occasional Paper #3. Columbus, Ohio: The National Regulatory Research Institute, November 1980.

3. ________________. "Rate of Return Incentive System." Speech to the National Regulatory Research Institute's Workshop on Electric Utility Construction Cost Overruns: Regulatory Options, August 14, 1981.

4. Czamanski, Daniel Z.; Henderson, J. Stephan; Odle, Curtis J.; and Witkind, Vivian. Regulation as a System of Incentives. Columbus, Ohio: The National Regulatory Research Institute, December 1980.

5. Florida Public Service Commission. "Generating Performance Incentive Factor: Implementation Manual" (Preliminary Draft).

6. ________________. Investigation of the Fuel Cost Recovery Clause. June 18, 1981.

7. ________________. "Generating Performance Incentive Factor Based on Computerized Production Costing Simulation." Speech by Robert L. Trapp before the 58th National Conference of Regulatory Utility Commission Engineers, June 16, 1980.

8. Illinois Commerce Commission. Testimony of Karl A. McDermott, Docket 80-0167.

9. ________________. Testimony of Karl A. McDermott, Docket 80-0544.

10. ________________. Testimony of J.L. Pappas, Docket 80-0544.

11. Kelly, Kevin A.; Pryor, Timothy; and Simons, Nat. Electric Fuel Adjustment Clause Design. Columbus, Ohio: The National Regulatory Research Institute, December 1979.

12. Kendrick, John W. "Efficiency Incentives and Cost Factors in Public Utility Automatic Adjustment Clauses." Bell Journal of Economics, Spring 1975.

13. Massachusetts Department of Public Utilities and Theodore Barry and Associates. Rate Incentives for Utility Efficiency in Massachusetts (Interim Report), October 1980.

14. ____________. On-going Cooperative Goal Setting Program. Summer 1981.

15. Michigan Public Service Commission. Report on Power Plant Productivity (Staff Report), Lauchlin MacGregor, Chair of Report Staff, March 1979.

16. New York State Department of Public Service. Power Plant Productivity Improvement in New York, March 1981.

17. Public Utilities Commission of Ohio. In the Matter of the Promulgation of Rules to Implement the Electric Fuel Component Requirements of Chapters 4905 and 4909 of the Revised Code. Case No. 80-928-EL-ORD, February 25, 1981.

18. _______________. A Regulatory Program for the Improvement of Power Plant Productivity in Ohio, Task II -- Development of Regulatory Procedures. July 1981.

19. Pennsylvania Public Utility Commission. Electric Power Plant Productivity Related to Plant Availability (Staff Report), John J. Reilly and Aluaro Domingos, December 1980.

20. Schmidt, Michael. Automatic Adjustment Clauses: Theory and Application, MSU Public Utility Studies, 1981.

21. Smith, George L. State Regulation and Power Plant Productivity. Columbus, Ohio: The National Regulatory Research Institute, September 1980.

22. TRW Energy Engineering Division. Powerplant Productivity Regulatory Elements for Ohio, Task 1 -- Determination of the Methodology. Prepared for the Public Utilities Commission of Ohio, March 1981.

23. Utah Division of Public Utilities, "Regulatory Incentives for Utility Efficiency." Speech by Kenneth B. Powell and James H. Reedy before the 1981 Reliability Conference for the Electric Power Industry.

24. Virginia State Corporation Commission. Testimony of James R. Wittine, Case No. 19960.

25. _______________. Testimony of James R. Wittine, Case No. PUE810025.