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Incentive Regulation of Investor-Owned Nuclear Power Plants by Public Utility Regulators

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Abstract

The U.S. Nuclear Regulatory Commission (NRC) periodically surveys the Federal Energy Regulatory Commission (FERC) and state regulatory commissions that regulate utility owners of nuclear power plants. The NRC is interested in identifying states that have established economic or performance incentive programs applicable to nuclear power plants, how the programs are being implemented, and in determining the financial impact of the programs on the utilities. The NRC interest stems from the fact that such programs have the potential to adversely affect the safety of nuclear power plants.

The current report is an update of NUREG/CR-5975, *Incentive Regulation of Investor-Owned Nuclear Power Plants by Public Utility Regulators*, published in January 1993. The information in this report was obtained from interviews conducted with each state regulatory agency that administers an incentive program and each utility that owns at least 10% of an affected nuclear power plant. The agreements, orders, and settlements that form the basis for each incentive program were reviewed as required. The interviews and supporting documentation form the basis for the individual state reports describing the structure and financial impact of each incentive program.

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1 Introduction

1.1 Purpose

This report continues the series of reports which provide information on the methodology and potential financial impacts of incentive programs applicable to commercial nuclear power plants. The U.S. Nuclear Regulatory Commission (NRC) staff reported to the Commission of its effort to track nuclear performance incentive programs in SECY-85-260 (July 26, 1985). Following this notice, several reports, tracking incentive regulation of nuclear power plants, have been published: NUREG-1256, *Incentive Regulation of Nuclear Power Plants by State Public Utility Commissions*, published in December 1987; NUREG/CR-5509, *Incentive Regulation of Nuclear Power Plants by State Public Utility Commissions*, published in December 1989; NUREG/CR-4911, *Incentive Regulation of Nuclear Power Plants by State Regulators*, published in February 1991; and the previous version of this report, NUREG/CR-5975, *Incentive Regulation of Investor-Owned Nuclear Power Plants by Public Utility Regulators*, published in January 1993. The primary purpose of this report and the previous reports is to describe how specific nuclear performance incentive programs work and to provide background information for use in evaluating the possible safety implications of the programs. In addition, these reports distinguish among various classes of incentive programs and summarize discontinued programs.

1.2 Incentive Regulation in the Nuclear Industry

The use of incentive regulation and forms of incentive programs are classified and explained in the following sections.

1.2.1 Use of Incentive Regulation

Incentive programs implemented by state regulatory agencies (most often termed public utility [or service] commissions) are used to measure a utility's efficiency in operating generating units and to financially reward or penalize the utility for performance above or below established levels. The objectives of an incentive program are generally to encourage sustained or improved performance and to achieve better economic performance with less regulation. Frequently, an incentive program establishes a standard to be used in fuel clause proceedings to determine the recovery of costs, including costs resulting from nuclear unit outages. The programs are intended to avoid the uncertainty and complexity inherent in case-by-case prudence proceedings (see Section 1.2.3.). In addition, an incentive program is a mechanism by which the state regulator allocates an appropriate share of the costs associated with nuclear unit outages between utility investors and the ratepayers. Various techniques have been used by the states to adjust utility revenues through an incentive program; thus, it is necessary to develop and apply a classification system for differentiating among types of programs.

1.2.2 Classification of Incentive Programs

Incentive programs use an objective, predetermined formula for determining the size of any financial reward or penalty based on performance. Incentive programs may be classified into one of two broad categories: "nuclear performance incentive programs" and "utility performance standard programs." Many utility regulatory agencies apply incentive programs to utilities with fossil-fuel-fired plants as well as nuclear power plants. These programs are not discussed in this report except to the extent that they relate to utility-wide performance standards. All forms of nuclear performance incentive programs use specific nuclear performance standards and are discussed in great detail in this report.

A key aspect of "nuclear performance incentive programs" is the correlation between revenue adjustments and established levels of nuclear plant(s) performance. Nuclear performance incentive programs vary widely in the criteria used to measure performance. The criteria may include heat rate, capacity factor, or availability factor of a single plant or a composite of multiple plants. Programs may be based on only one measure of performance; however, a number of programs employ more than one measure. The revenue adjustments applied also vary from program to program. The majority of programs reward good performance and penalize poor performance. The revenue adjustments can be substantial, potentially involving millions of dollars. Some programs include a "deadband," a zone of performance in which neither rewards nor penalties accrue. Nuclear performance incentive programs are often quite complex and may exert effects in indirect and different ways.

"Utility performance standard programs" are distinct from nuclear performance standard programs. These programs exhibit a wide variety of requirements, but generally emphasize either utility-wide performance or economic efficiency standards. The utility performance standard programs often emulate the established state regulatory practice of subjectively reviewing operating costs, including those costs associated with a nuclear unit. The programs often use performance standards, characteristic of nuclear performance standard programs, as indicators of efficiency. However the standards are used by the state regulator to subjectively determine the prudence or reasonableness of operations. In other words, these programs can have a set performance standard/goal. However, the economic reward or penalty is not based upon a corresponding predetermined amount, but rather is subjectively determined.

Performance standards in these programs are indirectly and subjectively used to implement economic incentive provisions upon a utility. In some cases, the programs may not be directly linked to generating asset performance, but provide for revenue adjustments based on a utility efficiency parameter such as total fuel costs (across all modes of production). These programs are based upon a utility's performance and can include either subjective or objective determinations by the state regulatory agency.

1.2.3 Incentive Regulation vs. Prudence Reviews/Hearings

It is frequently difficult to distinguish nuclear performance incentive programs from the various mechanisms state regulators use to adjust utility revenues since they share many of the same features. Generally, incentive programs function in lieu of routine "prudence" reviews. Prudence proceedings are conducted by the state regulatory commissions to review the propriety of a utility's operations. The result of this review determines the appropriate rate of return the utility will be allowed to recover from the ratepayers.

The revenue adjustments of incentive programs generally take the form of a reward or penalty, usually based on fuel costs. There are revenue adjustment mechanisms associated with fuel cost recovery procedures where the state regulator subjectively examines performance without the use of specified criteria such as capacity factor or availability. Such mechanisms generally are not included in this report as "incentive programs." Some revenue adjustment mechanisms also establish performance standards that are characteristic of incentive programs; however, the mechanisms are only one of many factors considered in fuel cost recovery and are infrequently associated with a prescribed penalty or reward. These programs are also not termed incentive programs for the purposes of this report. Alternatively, a number of state regulators adjust revenues as a function of a utility's management of the generating system's total fuel costs rather than the performance of the units.

The primary distinction between an incentive program and other fuel adjustment mechanisms is that an incentive program will have an established, predetermined standard upon which revenue adjustments are made. Other fuel adjustment mechanisms do not have these predetermined standards, but merely identify issues upon which subjective prudence determinations will be made. The extent of the revenue adjustment from application of an incentive program may be partially subjective or could be predetermined. The revenue adjustment may vary in amount with the difference between the target performance level and the actual performance of the units.

One program that appears similar to an incentive regulation is administered by the New England Power Pool, in which membership is voluntary. Under its Performance Incentive Plan (PIP), the pool's objective capability is established using several inputs, including load forecasts and target unit availabilities. The capability responsibility of each participant is determined on a pro rate basis. Failure to meet target availabilities results in an increase in capability responsibility. Although this program includes targets and outlines consequences for deficiencies, no revenue adjustments result. Responsibility for allocation of costs between producers and consumers rests with the local public utility commissions who adjust revenues, using either the programs reported here or other fuel adjustment mechanisms. Plans such as the PIP do not fit into our definition of incentive regulation and therefore are not included here.

1.3 The Potential Influence of Nuclear Performance Incentive Programs

There is considerable debate within and among the regulated utilities and their trade groups, the state regulators, the National Association of Regulatory Utility Commissioners, and various public interest groups as to the soundness and fairness of incentive programs. It is a difficult task to develop an incentive program for a utility that faithfully models the public interest with respect to a utility's reliability and efficient operation. Questions have been raised about whether an imperfect incentive program causes a utility to unknowingly act against the public interest or adversely affect public health and safety. The NRC has been studying state economic incentive programs for a number of years, and it, along with other groups, is concerned that nuclear performance incentive programs have the potential to influence a number of issues. These issues include operational decisions, the financial status of a utility, and the safe operation of a nuclear unit.

Initial findings from using industry data over the period 1986 to 1990 suggest that there is little systematic effect of state economic incentive programs on plant safety performance. The same multivariate analysis also found little support for a relationship between such programs and the owner/operator's financial status. Another concurrent study using econometric methods on the same data to analyze plant fixed O&M expenditure behavior did find evidence of a persistent, positive association of financial condition and O&M outlays. The link between such outlays and plant safety performance has been statistically rejected so far in the research.

1.3.1 Impact on Utility Financial Status

The utility and state regulatory personnel contacted in the survey usually were knowledgeable about the potential influence of incentive programs applicable to the affected nuclear units. Utilities, for the most part, have indicated that nuclear performance standards have not had an appreciable impact on the management of nuclear units. However, in some cases, the standards have been in effect for a relatively brief period of time, and this time period may not have been long enough to determine the operational impact.

State regulators frequently conduct periodic, routine reviews of utility operating costs, including those associated with nuclear units. State regulators may subject a utility to disallowances on the basis of imprudently incurred fuel costs. The primary disadvantage of routine reviews is the retrospective, subjective examination of performance and utility management. The financial consequences of poor unit performance or reduced system generation are, to a great extent, unknown and therefore difficult to predict. The structured revenue adjustments associated with performance that are used in incentive programs have been cited by both utilities and state regulators as an advantage of incentive programs.

The rewards and penalties associated with incentive programs may be small with respect to utility net revenues (on average less than 2%). Nevertheless, the revenue adjustments imposed by the nuclear performance incentive programs clearly result in an impact on ratepayers and utility investors. Disallowance of replacement fuel costs results in savings for the ratepayers and a measurable cost to the utilities. The impact of performance standards on the financial health of utilities, however, has been characterized as small (NUREG-1256, *Incentive Regulation of Nuclear Power Plants by State Public Utility Commissions, Vol. 1*, 1987). Incentive programs are not necessarily intended to be extremely punitive; programs usually provide for a detailed review of performance in extraordinary circumstances, such as an annual capacity factor of less than 50%. In these circumstances, the application of a specified penalty would also be examined for appropriateness.

In many cases, incentive programs may not significantly affect the budgets of utilities because the programs are intended to function as an alternative to routine individual outage reviews and fuel cost disallowances. However, the visibility of the penalties and the resulting decrease in revenues are frequently viewed by the utility as equally undesirable. Ratepayers and utility stockholders may view penalties as an indication of deficient management. The imposition of nuclear performance standards on utilities has, in some cases, impacted investments in utilities' generating assets. In addition, financial rating agencies have reacted unfavorably, in some cases, to the imposition of incentive programs.

1.3.2 Impact on Operation and Safety

An important question concerning incentive regulation of nuclear power plants is whether such programs affect unit safety. While the NRC has not conducted a detailed safety impact analysis regarding the effects of implemented incentive programs, the influence of such programs on reactor safety is believed to be small. Irrespective of whether a utility is affected by the application of incentive programs, the Atomic Energy Act requires a utility that operates a nuclear unit to comply with NRC regulations and requirements. NRC regulations, together with licensee conditions concerning operations and maintenance, require acceptable safety designs and safe operation of nuclear units. Furthermore, the NRC, through its licensing and inspection activities, verifies that licensees are adhering to safe practices. Nevertheless, economic regulation and, specifically, nuclear performance incentive programs, may have the potential to indirectly influence a licensee's approach to reactor safety issues in situations not addressed in license conditions. This influence may be positive as well as potentially negative.

Selected incentive programs indirectly reward a utility for correcting recurrent or predictable failures, or degradations that could lead to unit outage or derating. Even though incentive programs may have these effects, utilities have indicated that the operation of nuclear units involves more important factors than potential revenue adjustments tied to an incentive program. Incentive programs may encourage high morale and a quest for excellence in a utility's operation, which may improve both safety and economic performance. An incentive program could increase management's attention to preventative maintenance and safe operations.

The potential also exists that, in the interest of real or perceived short-term economies, a utility may delay necessary repairs, maintenance, and upgrades, or reduce the length of required outages in order to meet an incentive criterion. Because such decisions do not allow for adequate attention to be devoted to the units, it is possible that the safety of operations could be compromised. Although an incentive program may directly or indirectly foster decisions that would maximize measured performance at the potential expense of plant safety, such practices would ultimately work against a utility. A unit operating in less than optimal condition may have an increased number of unplanned outages and, thereby, effectively increase penalties. The effect of incentive programs on nuclear safety will hinge on utility managements' reaction to the program; that is, how management will address operational plans, operating instructions, and other measures that may evolve in response to the incentive program's provisions. The NRC's policy on incentive program implementation is discussed in the next section.

1.4 The Nuclear Regulatory Commission and Nuclear Performance Incentive Programs

The NRC staff continues to review the possible effects that incentive programs could have on nuclear industry. The structure of incentive programs may affect the balance between practices conducive to safe operations and practices that, in the short run, could increase revenues. In response to this concern the NRC issued a final policy statement in July 1991 (56 FR 33945). The statement established the NRC's policy on incentive regulation and discusses certain features of economic incentive plans the NRC either believes are desirable or undesirable.

1.4.1 Desirable and Undesirable Impacts of Incentive Programs

The NRC believes that economic performance programs, which provide utilities incentives "to make reasonable improvement in operations and maintenance that result in long-term improvement in the reliability of the reactor, the main generator, and their support systems" are desirable (56 FR 33946). In addition, an economic incentive program considered desirable by the NRC would reward a utility for having "sound operations and maintenance programs and for correcting recurrent or predictable failures...." Incentive programs that have these impacts enhance plant safety. Economic performance programs that either provide an incentive to a utility to operate a nuclear power facility with possible safety problems or incentives which encourage premature startup are considered extremely undesirable.

In addition to stating general desired effects of an economic performance program, the NRC suggested that State Public Utility Commissions consider including certain specific features in their programs. The Commission believes these features both promote safety as well as economic efficiency. The features enumerated by the NRC include "(1) capacity factor targets based upon industry's average performance to account for problems throughout the industry, (2) equal opportunities for rewards and penalties, (3) the "banking" of superior performance to offset lower performance, and (4) using performance measures of the entire system instead of those for a specific unit" (56 FR 33947). The NRC believes the influence of incentive plans on reactor safety is currently small (56 FR 33946). However, with new and innovative incentive plans being proposed, adopted, and current plans amended, the NRC has a continuing interest in monitoring incentive plan impacts. In particular, the NRC is concerned that "in the interest of real or perceived short-term economic benefit, the utility might hurry work, take short cuts, or delay a shutdown for maintenance in order to meet a deadline, a cost limitation, or other incentive factor" (56 FR 33946).

1.4.2 Incentive Plan Features Possibly Affecting Public Health and Safety

In its 1991 Policy Statement, the NRC identified two features of economic incentive plans currently used by various states that could adversely affect public health and safety. The Commission first identified plans that have "sharp thresholds" between rewards and penalties. A sharp threshold is a feature that causes a licensee to incur a large portion (or all) of the resulting replacement power costs for narrowly missing a target capacity factor. In place of sharp thresholds, the NRC recommends states incorporate "a reasonably broad null zone of acceptable performance in which no rewards or penalties are imposed" (56 FR 33947).

The NRC is also concerned about plans that have performance measurements for short time intervals. Plans with these features could encourage a utility to "focus on a short-term target or performance goal(s)...." and as a result lose sight of long-term goals of reliability and operational safety. The Commission is concerned that these short-term performance measurements have the tendency to make economic and safety goals conflict with each other, while long-term goals actually complement each other (56 FR 33947).

1.4.3 Use of SALP Ratings in Economic Incentive Programs

The prospect of financial rewards or penalties for a utility based on systematic assessment of licensee performance (SALP) ratings is another issue that concerns the NRC, because the focus of the SALP process may shift from the underlying issues to the numerical ratings. The NRC's SALP program was primarily developed to assist the NRC in determining the best allocation of its inspection resources. Based on the NRC's perception of licensee performance, the SALP program identifies nuclear units and program areas that need the most attention. In any particular SALP report, specific areas may be added or deleted based on site-specific considerations. The NRC staff focuses on the issues identified in the SALP report and apparent root causes of problems. The NRC is concerned that the safety of the unit could be adversely affected if the issues identified in SALP reports are obscured because of concerns over the financial consequences incurred as a result of specific SALP ratings.

The NRC is also concerned about the potential effects of SALP-based programs on the NRC's interaction with licensee staff. The NRC's effectiveness in inspecting nuclear units depends, to a significant degree, on having an open relationship with the operating staff and management at the nuclear unit. The operating staff report problems to NRC inspectors that may not otherwise be revealed in the course of the NRC's routine inspection program. The NRC encourages such a relationship and is careful to see that plant staff are not reprimanded for disclosing problems of possible safety-related significance. The NRC perceives a program that employs SALP ratings as one that could inhibit the operating staff and management from disclosing safety-significant information, which is cause for major concern. In addition, the NRC is concerned that an incentive program that uses SALP ratings could impose a large economic penalty on a licensee for minimally satisfactory performance. Such a penalty could reduce resources that might otherwise be available to improve safety performance.

In view of these concerns, the NRC does not support use of SALP ratings or enforcement history to arrive at financial rewards and penalties. Incentive programs that focus on nuclear safety rather than the economic operation of nuclear units have one more drawback--they may interfere with the exclusive Federal regulatory authority under the Atomic Energy Act over safety matters at nuclear power plants (56 FR 33947).

1.5 Methodology

The utilities selected for inclusion in the current report are investor-owned (publicly-owned systems have been excluded). Utilities must have a minimum investment of 10% in an individual nuclear unit to be included in the report. Information was primarily obtained in telephone interviews conducted with state regulators and utility personnel. In many cases, following each interview, a copy of the applicable 1993 individual incentive program report (from NUREG/CR-5975) was sent to the utility or state regulator for comments. In addition to interviews, agreements, orders, and settlements that implement each nuclear performance incentive program were reviewed as required.

Information was collected from the following sources: all utilities reported in NUREG/CR-5975 to be subject to an incentive program, all utilities potentially subject to an existing incentive program, and all state regulatory agencies that have implemented an incentive program.

In addition, state regulators were contacted in states where a utility either operated or made a significant investment (greater than 10%) in a nuclear unit and, consequently, was a candidate for incentive program application. If a state regulator indicated in the initial interview that there were no proposed or established programs, further interviews within that state were not conducted. The interviews and supporting documentation provided by the utilities and the state regulatory agencies form the basis for the individual incentive program narratives that describe the structure of each incentive program and discuss the financial effects of the programs on the utilities.

2 Individual Reports Grouped by State Regulatory Authority

The individual program narratives discuss each incentive program implemented by state regulatory agencies and the affected utilities. The narratives are organized alphabetically by state. As with previous versions of this report, the individual narratives identify the state regulator, applicable utilities, program status, performance criterion, type of incentive program, and a detailed description of the program and any available financial impact data.

The incentive program classification specifies the class of program or identifies programs with unique characteristics. The identification of the utilities includes a list of each utility's nuclear units that are affected by the program and the percentage of the utility's ownership in each unit. Program status indicates the effective date of a program's implementation, i.e., the date measurement of performance actually began. Type of incentive program refers to how revenue adjustments are made; for example, the use of rewards or penalties for nuclear performance incentive programs.

Program descriptions address the specific provisions of each program including the program's goal or purpose, the development of the program, the jurisdictional authority of a state, the applicable units, and any minor owners. The measure of performance, performance periods, target performance, and specified revenue adjustments are discussed in this section. This section also includes a description of unique program characteristics and any recent activity regarding the incentive program. The financial impact data sections are primarily devoted to reporting the revenue adjustments a utility has experienced as a result of performance and may include information regarding current or projected performance.

A number of terms or features are referenced within an individual program summary that are common to many programs. Capacity factor, a frequent measure of performance, refers to the actual dependable capacity as compared to availability unless otherwise stated. Revenue adjustments refer to rewards, penalties, disallowances, or other economic sanctions. There are programs that use an escalating technique to calculate rewards or penalties. In other words, the greater the variance from the target, the greater the reward or penalty. These programs specify different rewards or penalties for performance ranges above or below a certain value. For example, a program may have a relatively low penalty for the first 10% range below target capacity; the second 10% range below capacity may have a higher penalty. Total revenue adjustment is calculated by determining the penalties associated with performance within each range and adding these values together.

A change implemented in the previous version of this report has been continued in this revision. Each state program summary contains a section entitled, 1994 Update/Changes. This information provides the reader with a brief description of any changes in the incentive program since the first publication of NUREG/CR-5975 as well as the most recent penalty or reward. A detailed description of the incentive program and discussion of the financial impact of the program on the various utilities follows the synopsis. The goal of these changes is to provide easy access to the various types of information needed by the reader.

2.1 State: Arkansas

Program Effective: January 1980; revised January 1983

Regulatory Authority: Arkansas Public Service Commission

Utilities Affected: Arkansas Power and Light: Arkansas Nuclear Units 1 and 2, 100%

Program Status: Program in Operation

Performance Criterion: Capacity Factor

Type of Incentive Program: Nuclear Performance Incentive

1994 Update/Changes: Program was unchanged. The utility earned a $20.6 million reward in 1993.

Description: In June 1980, the Arkansas Public Service Commission established a nuclear performance incentive program to partially insulate ratepayers from replacement fuel costs that could result from unplanned outages of Arkansas Nuclear Units 1 and 2. The program was modified in 1983. The program's initial target capacity factor (approximately 79%) was adjusted within the first few months to consider downtime for post-Three Mile Island improvements. The target capacity factors ($\pm$ 2.5%) were reset at 72.92% for Unit 1 and 71.55% for Unit 2. The revised targets were reported to be based on industry data for similar units and are currently in use.

Prior to the 1983 modification, there was a 100% disallowance for each consecutive 30 days of outage (other than for refueling). The program was revised to apply a 100% penalty for such an outage only once during any 12-month period. Before the program was modified, Arkansas Power and Light incurred large penalties. The utility viewed the program as weighted toward penalties with little chance of earning rewards.

The 1983 revisions to the program also provide for penalties if a nuclear unit falls below the target capacity factor. Replacement fuel costs are limited to what the nuclear fuel costs would have been had the capacity factors been met. Also, for the first cumulative 30 days (rather than consecutive) of an outage (due to reasons other than refueling) during the 12-month period of performance, the net replacement fuel costs are limited to imputed nuclear fuel costs at the targeted capacity factors for each unit. The imputed nuclear fuel costs are reduced by an additional 10% penalty for all subsequent days of non-refueling outages during the same 12-month period. Rewards equal to the fuel cost savings are accrued when a nuclear unit exceeds the target capacity factor. The Arkansas nuclear units recently have been earning rewards under this program.

Implementation Results: Rewards and penalties are calculated monthly, based on nuclear performance for the 12-month period ending with the current month. Potential penalties range from limitation of the recovery of the net replacement costs to the imputed cost of nuclear fuel for the first 30 days of outage, and an additional 10% reduction in the imputed cost of nuclear fuel costs thereafter. Rewards are equal to fuel savings earned from higher than required capacity factors. The annual rewards, penalties, and total company revenues since 1980 are shown in Table 2.1. The annual capacity factors for each of the units are shown in Table 2.2.

Table 2.1 Arkansas Power and Light's revenues and adjustments: 1980-1993

Period	Total revenues (millions of $)	Nuclear incentive (millions of $)
1980	563.7	-17.9
1981	670.4	8.0
1982	688.8	-20.7
1983	763.2	-6.7
1984	871.4	18.4
1985	884.9	8.9
1986	911.4	.9
1987	923.6	4.3
1988	963.2	4.4
1989	1,022.4	.9
1990	1,120.8	8.8
1991	1,143.9	13.3
1992	1,111.8	11.3
1993	1,189.0	20.6

Table 2.2 Capacity factors for Units 1 and 2

Period	Unit 1	Unit 2
1990	56%	94%
1991	89%	81%
1992	82%	84%
1993	93%	98%

2.2 State: California

Program Effective: July 1988

Regulatory Authority: California Public Utility Commission

Utilities Affected: Pacific Gas and Electric: Diablo Canyon 1 and 2, 100%

Program Status: Program in Operation

Performance Criteria: Generation and Expenses

Type of Incentive Program: Nuclear Performance Incentive

1994 Update/Changes: A Cost Management Plan was implemented in 1994 to help control the variable costs of production. Diablo Canyon 1 and 2 received revenues of $1,033 and $900 million, respectively, in 1993.

Description: Revenues from the Diablo Canyon units are a function of generation and are based on a price per kilowatt determined by the California Public Utility Commission (CPUC). This program is referred to as Performance-Based Revenues (Pricing). Although Pacific Gas and Electric (PG&E) owns Diablo Canyon, Diablo Canyon's revenues are considered to be distinct from PG&E: the units are not in the rate base or regulated as are other California nuclear units. PG&E is also perceived to be the consumer of Diablo Canyon's generation, generation that is purchased at specified rates per kilowatt hour. The rate per kilowatt hour increased each year through 1994 according to a specified, escalating price. Subsequent rate increases are currently tied to the Consumer Price Index (CPI) according to the following formula: .5CPI + 1.25%. The performance of Diablo Canyon is not a factor in the CPUC's authorized rate of return for PG&E.

California does not permit a utility to recover capital construction costs through rates until a plant is operational. However, if requested, the Major Addition Adjustment Clause permits the revenue required to recover capital costs to be treated as a deferred debit until the completion of the project.

The utility has observed that the Performance-Based Revenues program has been a strong incentive for operating safely and efficiently. The program is believed to be a positive change and is expected to favorably impact the industry, utility, and customers. The program is intended to provide the ratepayer protection from nuclear units that fail to generate, and from escalating costs of operation and capital improvements. In return, PG&E has the opportunity to recover the full cost of the facility should the Diablo Canyon units perform at capacity factors in excess of the national average.

With respect to the conduct of operations at Diablo Canyon, the units' preventative maintenance and inventory of spare parts are a high priority with utility management. The risks of poor management are high enough to preclude ineffective operations. Since the utility's revenues depend purely on production, it claims that it does not want to risk long shutdowns. As a result, it is willing to spend money on preventative maintenance, which under this program is far less costly than long periods of downtime. PG&E now has a Cost Management Plan in place to ensure that the plants' variable costs of production (including capital addition) remain below the costs of competitive resources. In a 1991-1993 comparison with ten similar nuclear facilities, the Diablo Canyon units ranked the second highest spenders in terms of total production costs. However, in terms of production costs per kWh, Diablo Canyon was fairly competitive at 18.61 mills/kWh, due to its high capacity factor.

Implementation Results: Those responding to the survey indicate that recent Diablo Canyon performance has been good. The potential revenue from each plant is $3.1 million per day. Actual annual revenues and performance to date is shown in Table 2.3.

Table 2.3 Diablo Canyon performance and revenues, 1989 - 1993

Unit	Period	Capacity factor	Revenues
Diablo Canyon 1	1989	76.6%	$624 million
	1990	92.7%	$803 million
	1991	78.3%	$731 million
	1992	79.1%	$795 million
	1993	96.1%	$1,033 million
Diablo Canyon 2	1989	90.5%	$749 million
	1990	79.4%	$706 million
	1991	81.0%	$777 million
	1992	96.9%	$987 million
	1993	81.8%	$900 million

2.3 State: California

Program Effective: SONGS 1 terminated November 1992.
SONGS 2 effective September 1983.
SONGS 3 effective April 1984.
Palo Verde 1 effective February 1986.
Palo Verde 2 effective September 1986.
Palo Verde 3 effective January 1988.

Regulatory Authority: California Public Utility Commission

Utilities Affected: Southern California Edison: SONGS 2 and 3, 75.05%
Palo Verde 1, 2, and 3, 15.8%

San Diego Gas and Electric: San Onofre (SONGS) 2 and 3, 20%

Program Status: Program in Operation

Performance Criterion: Capacity Factor

Type of Incentive Program: Nuclear Performance Incentive

1994 Update/Changes: Beginning in 1993, capacity factors have been based upon weighted averages measured over two fuel cycles. In addition, the calculation of capacity factor was changed slightly to clear up some perceived ambiguities. (This is not expected to change the results very much.) SONGS 1 was permanently shut down on November 30, 1992, following completion of fuel cycle 11. The most recent financial impacts follow:

SCE: SONGS 1, $940,000 reward
SONGS 2, $0
SONGS 3, $5,030,000 reward
Palo Verde 1, $0
Palo Verde 2, $0
Palo Verde 3, $0
SDG&E: SONGS 1, $570,060 reward
SONGS 2, $0
SONGS 3, $2,670,000

Description: The Target Capacity Factor Incentive Program is applied to Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E). Designed to be a risk-sharing mechanism for the utility and the ratepayer, the program also serves to encourage efficient utility management. Performance, in terms of capacity factor, is measured over the unit's fuel cycle (approximately 18 months). The established deadband for SONGS 2 and 3, and the Palo Verde units, is from 55% to 80% (SONGS 1, which was permanently shut down November 30, 1992, had a deadband from 55% to 75%). At capacity factors above the deadband, the utility reward is equal to 50% of the fuel cost savings; at capacity factors below 55%, the utility incurs a penalty equal to 50% of the replacement fuel costs. The capacity factor is calculated separately for each utility as are rewards and penalties. The corresponding reward or penalty is based on each utility's replacement power costs and implemented through the Energy Cost Adjustment Clause (ECAC). In addition, the program provides for economic modifiers that would mitigate a penalty for operating at reduced capacity when in the interests of the ratepayer. Economic modifiers may be applied when a utility can purchase power at a lower rate or extend the operating period in order to continue to supply ratepayers in peak periods. The calculation of the capacity factor has recently changed slightly to clear up some ambiguities. Beginning in 1993, capacity factors were calculated by weighted averages measured over two fuel cycles, reducing the variation between cycles.

While the program functions, for the most part, in lieu of routine prudency reviews, the reasonableness of operations is always subject to review through the ECAC. The Division of Ratepayer Advocates (DRA) has the authority to conduct a prudency review of utility nuclear operations for the CPUC in the event of a forced outage and may, as it has in the past, deny recovery of replacement fuel costs associated with an outage. Further, the DRA is obligated by California law to review any outage that extends more than 9 months. However, once a penalty is imposed upon a utility for a nuclear unit's performance within a given period, a review of an outage occurring in that period is not usually conducted.

Implementation Results at Southern California Edison: SCE reports that while the incentive program receives attention from the public, its financial effect is small. However, SCE management is attentive to nuclear unit performance because of management's responsibility to the ratepayer and to the utility shareholder. It is in the best interest of SCE to have the highest capacity factor possible while operating the nuclear units such that the health and safety of the public is assured. Table 2.4 shows the performance and corresponding revenue impact of each of SCE's nuclear units subject to the program.

Implementation Results at San Diego Gas and Electric: SDG&E's reported capacity factor Cycle 1 at SONGS 3 (59.2%) was higher than that reported for SCE (54.6%). Late in Cycle 1, SCE continued to operate SONGS 3 at a reduced capacity rather that shut down as scheduled in order to support peak summer power demands. However, SCE continued to supply SDG&E with its generation requirements, resulting in a capacity factor higher than that reported for SCE. According to SDG&E, which has approximately $2.0 billion in annual revenues, the impacts of the rewards or penalties are quite small. The performance and corresponding revenue adjustment of each of SDG&E's nuclear units subject to the Target Capacity Factor Incentive Program is shown in Table 2.5.

Table 2.4 Southern California Edison's revenue adjustments as determined by capacity factor

Unit/effective date	Fuel cycle	Capacity factor	Nuclear incentive
SONGS 1			
July 1986	9	55.1%	0
	10	46.1%	-$1,680,000
	11	80.9%	+$940,000[1]
SONGS 2			
Sept. 1983	1	55.5%	0
	2	57.0%	0
	3	81.7%	+$1,290,000
	4	72.3%	0
	5	73.0%	0
	6	84.6%	0[2]
SONGS 3			
April 1984	1	54.6%	-$570,000
	2	56.2%	0
	3	80.6%	+$440,000
	4	78.4%	0
	5	86.7%	+$5,030,000
	6	81.4%	0[2]
Palo Verde 1			
Feb. 1986	1	55.4%	0
	2	37.3%	-$5,340,000
	3	62.2%	0
	4	78.3%	0[2]
Palo Verde 2			
Sept. 1986	1	67.0%	0
	2	54.9%	-$40,000
	3	77.6%	0
	4	67.5%	0[2]
Palo Verde 3			
Jan. 1988	1	58.3%	0
	2	71.1%	0
	3	77.5%	0
	4	77.3%	0[2]
			2.000

Note 1: San Onofre 1 was permanently shut down and removed from the Nuclear Unit Incentive Procedure upon completion of Fuel Cycle 11.
Note 2: Capacity Factor for San Onofre 2 and 3 will be averaged over Cycles 6 and 7. Palo Verde 1, 2, and 3 will be averaged over Cycles 4 and 5.

Table 2.5 San Diego Gas and Electric's revenue adjustments as determined by capacity factor

Unit/effective date	Fuel cycle	Capacity factor	Nuclear incentive
SONGS 1 July 1986	9	55.1%	0
	10	46.1%	-$1,680,000
	11	80.9%	+$940,000
SONGS 2 Sept. 1983	1	55.5%	0
	2	57.0%	0
	3	81.7%	+$1,290,000
	4	72.3%	0
	5	73.0%	0
	6	84.6%	0[2]
SONGS 3 April 1984	1	54.6%	-$570,000
	2	56.2%	0
	3	80.6%	+$440,000
	4	78.4%	0
	5	86.7%	+5,030,000
	6	81.4%	0[2]

[1] Note: Cycle 6 results will be averaged with Cycle 7 to calculate reward or penalty.

2.4 State: Connecticut

Program Effective: July 1979

Regulatory Authority: Connecticut Department of Public Utility Control

Utility Affected: Connecticut Light and Power: (A subsidiary of Northeast Utilities)
Millstone 1 and 2, 81%
Millstone 3, 53%
Connecticut Yankee, 33%

Program Status: Program in Operation

Performance Criterion: Capacity Factor

Type of Incentive Program: Utility Performance Standard

1994 Update/Changes: Program unchanged. $49 million in deferred fuel costs for the Generation Utilization Adjustment Clause year 1992/1993 were disallowed as a result of a Connecticut Department of Public Utility Control (DPUC) decision to require Connecticut Light & Power to recalculate the GUAC using actual rather than base case fuel costs.

Description: Connecticut Light and Power's (CL&P's) investment in Connecticut nuclear units is subject to the provisions of the Generation Utilization Adjustment Clause (GUAC) and the regulatory authority of the Connecticut Department of Public Utility Control (DPUC). However, while CL&P's investments in Vermont Yankee (9.5%), Maine Yankee (12%), and Seabrook (4.1%) are not subject to the Connecticut DPUC's regulation, these ownership interests contribute to the composite capacity measured by the GUAC. Seabrook became a component of CL&P's composite capacity factor in December 1990. GUAC treatment and application of performance standards to the nuclear units occur at the request of the utility. United Illuminating, a Connecticut utility with investments in Seabrook (New Hampshire), Connecticut Yankee (Connecticut), and Millstone 3 (Connecticut), is not affected.

The purpose of the GUAC is to recover or refund differences in fuel costs resulting from changes in the operation of nuclear units from that assumed in base rates. Base rates are currently set with an assumed nuclear plant performance of 72% capacity factor. If the composite nuclear capacity factor is greater than 72%, ratepayers receive a credit through the GUAC in order to reflect the lower fuel costs due the displacement of fossil fuel generation with lower cost nuclear generation. If the capacity factor is between 55% and 72%, ratepayers receive a charge to reflect the costs associated with the higher proportion of fossil fuel generation. If the capacity factor is less than 55%, the GUAC is calculated based on a 55% capacity factor and the utility must obtain approval from the PUC to recover the increased fuel costs resulting from nuclear operation below 55%. It is advantageous to the utility to avoid nuclear composite capacity factors below the deadband since the PUC may not allow full recovery of fuel cost.

The GUAC charges, or credits, are applied during each successive year to amortize the change in fuel expense from that included in base rates for the prior year. This results in an incentive to maintain good nuclear performance because there is a one-year delay in recovery of additional fuel expense associated with poor performance. Conversely, the utility benefits from high nuclear performance because GUAC credits for reduced fuel expense are not returned to ratepayers until the following year. Additionally, GUAC charges are subject to Connecticut gross receipts tax which must be paid by the utility but are not allowed to be recovered in the GUAC charge. Conversely, the utility benefits from high nuclear performance because GUAC credits lower the gross receipts tax below that recovered in base rates, which the utility is allowed to retain.

The nuclear capacity factor assumed for base rates and the GUAC may be adjusted periodically to reflect recent performance of the nuclear units, but this adjustment can only be done in conjunction with a rate case. At a capacity factor below 55%, the utility possibly may not recover replacement costs. However, criterion performance does not preclude disallowance for replacement fuel costs due to individual unit outages.

Implementation Results: Since the program's implementation, replacement fuel costs have not been denied due to the difference between the assumed capacity factor of the GUAC and the actual composite capacity factor achieved by the nuclear units. Rather, the GUAC functions as a fuel adjustment clause. Disallowances of replacement fuel costs have been the result of a prudency review and were not directly determined by the GUAC.

Furthermore, in a recent decision, the Connecticut DPUC ordered CL&P to recalculate the GUAC using actual rather than base-level fuel costs. As a result of this change, the DPUC subsequently disallowed $49 million in deferred fuel costs for GUAC year 1992/1993. The DPUC also required the company to implement a zero GUAC rate for August 1993-July 1994 and delayed implementation of a GUAC rate for August 1994 through July 1994.

The composite performance for the CL&P nuclear units since the GUAC became effective is shown in Table 2.6.

Table 2.6 Composite performance of Connecticut Light and Power's nuclear units

Period	Composite capacity factor	Reward/(penalty)
Aug. '84 - July '85	73.7%	0
Aug. '85 - July '86	74.1%	0
Aug. '86 - July '87	74.5%	0
Aug. '87 - July '88	72.1%	0
Aug. '88 - July '89	75.7%	0
Aug. '89 - July '90	74.8%	0
Aug. '90 - July '91	64.3%	0
Aug. '91 - July '92	45.8%	0
Aug. '92 - July '93	72.6%	(49,000,000)
Aug. '93 - July '94	68.2%	0

2.5 State: Florida

Program Effective: September 1980

Regulatory Authority: Florida Public Service Commission

Utilities Affected: Florida Power: Crystal River 3, 90%

Florida Power and Light: St. Lucie 1, 100%
St. Lucie 2, 85.1%
Turkey Point 3 and 4, 100%

Program Status: Program in Operation

Performance Criteria: Equivalent Availability and Heat Rate

Type of Incentive Program: Nuclear Performance Incentive

1994 Update/Changes: The incentive program remains unchanged. Florida Power received a $871,416 reward and Florida Power and Light (FP&L) received a total reward of $1,925,691 in the Winter 1993/1994 period. Results for the Summer 1994 period were not available by the date of publication.

Description: The Generating Performance Incentive Factors (GPIF) program goal is to minimize fuel costs and purchased power costs, and to provide an incentive for the efficient operation of base load generating units (both nuclear and fossil). The GPIF program calculates performance over six-month fuel adjustment periods. The generating units included in a utility's GPIF calculation are those units that contribute at least 80% of the estimated total system net generation for the performance period. During any given period, however, one or more generating units may need to be omitted from the GPIF calculation even though the units may meet the general selection criteria. The Florida Public Service Commission (PSC) has the authority to determine, on a case-by-case basis, whether a unit should be excluded from the calculation of the GPIF.

Six-month equivalent availability and average heat rate performance targets are set for each unit. Equivalent availability and heat rate for each unit are averaged on a three-year rolling basis. These averages form the basis for the PSC to evaluate the reasonableness of proposed GPIF performance targets. Target values for the most recent periods of performance for each nuclear unit are indicated in Table 2.7.

At the conclusion of the six-month fuel adjustment periods, actual unit equivalent availability and average heat rates are compared to the pre-established targets. Based on this comparison, a monetary reward is awarded for performance above the targets; a monetary penalty is incurred for performance below the targets. A production cost modeling program is used to determine replacement power costs or savings. Penalties or rewards incurred as a function of unit performance are implemented through the fuel and purchased power cost recovery clause. The maximum reward or penalty for a utility's period of performance is 50% of the maximum allowed incentive dollars. The maximum allowed incentive dollars are determined according to the following formula:

(Average month balance of common equity for the period) (25 basis points)/(Revenue expansion factor)

An adjustment is made to the value obtained from this formula for jurisdictional sales. The maximum allowed incentive dollars are not to exceed the gross amount of any fuel savings or costs experienced during the period under evaluation.

Implementation Results at Florida Power: This utility has received rewards in the last eight periods. However, Florida Power said that these rewards are minor in terms of the impact on operations.

Implementation Results at Florida Power and Light: Turkey Point 3 and 4 were not included in the program for the Summer 91 period due to planned outages to upgrade emergency diesel generators. Over the last three periods, all of FP&L's nuclear units have received net rewards except for St. Lucie 2 which has received a net penalty of $1,631,083.

Table 2.7 Generating Performance Incentive Factors (GPIF) program: 1989-1994 target and actual indicators, and incentive values

		Equivalent availability		Heat rate		
Unit	**Period**	**Target**	**Actual**	**Target**	**Actual**	**Incentive values**
Crystal River 3	Summer 90	49.7%	65.1%	10,592	10,652	+$998,778
	Winter 90/91	75.5%	83.6%	10,373	10,381	+$874,762
	Summer 91	76.5%	88.4%	10,678	10,622	+$1,107,607
	Winter 91/92	62.0%	66.7%	10,390	10,378	+$558,631
	Summer 92	51.2%	61.4%	10,637	10,549	+$975,832
	Winter 92/93	80.0%	93.1%	10,334	10,400	+$1,048,108
	Summer 93	72.0%	82.9%	10,461	10,582	+$1,005,230
	Winter 93/94	88.7%	99.0%	10,334	10,414	+$871,416
Turkey Point 3	Summer 90	43.5%	61.7%	11,110	11,206	+$950,795
	Winter 90/91	31.9%	38.5%	10,868	11,078	+$353,928
	Summer 91	N/A	N/A	N/A	N/A	N/A
	Winter 91/92	77.4%	89.0%	11,047	10,896	+$1,428,918
	Summer 92	62.7%	70.8%	11,305	10,217	+$1,101,557
	Winter 92/93	79.1%	77.6%	10,943	10,782	-$212,315
	Summer 93	90.7%	98.4%	11,258	11,090	+$1,118,800
	Winter 93/94	83.6%	87.7%	10,882	10,887	+$1,152,235
Turkey Point 4	Summer 90	74.4%	77.5%	11,104	11,221	-$64,469

Table 2.7 (Continued)

Unit	Period	Equivalent availability Target	Equivalent availability Actual	Heat Rate Target	Heat Rate Actual	Incentive values
	Winter 90/91	18.1%	25.0%	10,873	11,095	+$19,713
	Summer 91	N/A	N/A	N/A	N/A	N/A
	Winter 91/92	60.0%	69.2%	10,936	10,951	+$1,137,162
	Summer 92	76.2%	97.0%	11,230	10,206	+$603,437
	Winter 92/93	69.2%	81.2%	10,965	10,995	+$1,063,387
	Summer 93	60.1%	56.2%	11,216	11,121	-$363,659
	Winter 93/94	93.5%	93.4%	10,931	10,858	-$27,149
St. Lucie 1	Summer 90	85.9%	62.8%	10,760	10,816	-$823,183
	Winter 90/91	92.5	98.6%	10,671	10,696	+$1,610,664
	Summer 91	87.0%	93.9%	10,805	10,885	+$1,655,000
	Winter 91/92	54.4%	64.2%	10,689	10,666	+$779,317
	Summer 92	90.5%	91.3%	10,806	11,808	+$308,763
	Winter 92/93	88.3%	96.1%	10,718	10,822	+$1,273,058
	Summer 93	62.5%	66.2%	10,813	10,791	+$646,885
	Winter 93/94	93.1%	95.8%	10,742	10,894	+$1,159,980
St. Lucie 2	Summer 90	79.5%	72.5%	10,835	10,859	-$764,954
	Winter 90/91	77.2%	81.4%	10,734	10,600	+$809,057
	Summer 91	90.1%	98.0%	10,836	10,762	+$841,355
	Winter 91/92	90.0%	97.9%	10,740	10,663	+$1,086,109
	Summer 92	58.7%	59.0%	10,805	10,718	+$99,553
	Winter 92/93	93.6%	47.1%	10,702	10,821	-$1,348,739
	Summer 93	93.6%	88.4%	10,795	10,911	-$1,082,949
	Winter 93/94	60.9%	73.4%	11,151	11,579	+$800,605

2.6 State: Georgia

Program Effective: January 1990

Regulatory Authority: Georgia Public Service Commission

Utility Affected: Georgia Power: Hatch 1 and 2, 50.1%
Vogtle 1, 52.91%
Vogtle 2, 59.13%

Program Status: Program in Operation

Performance Criterion: Capacity Factor

Type of Incentive Program: Nuclear Performance Incentive

1994 Update/Changes: Program remained unchanged. Georgia Power received a reward of $8,496,029 in the last period, 1990-1992. The next period ends in 1995.

Description: The purpose of the Georgia Public Service Commission's (PSC's) nuclear performance incentive program is to provide equitable sharing between ratepayers and Georgia Power. Ratepayers and the utility are intended to share either the benefits derived from efficient operation or the excess costs associated with inefficient operation of nuclear generating assets. The PSC's position is that a nuclear performance incentive program is a reasonable means of providing some assurance to ratepayers that the utility will be held accountable for its fair share of any additional future costs resulting from poor performance of the Hatch and Vogtle units.

The measure of performance for the Georgia Power nuclear units is the composite, three-year capacity factor. Performance evaluations will be conducted at the conclusion of a three-year period. The target capacity factor chosen for each unit will be based on an average capacity factor for all comparable U.S. units that operated at an average capacity of 50% or higher during the three-year period. The deadband will be equal to target capacity factor $\pm$4%. Rewards or penalties will be equal to 50% of the savings (or costs) determined by the difference between actual performance and target performance, adjusted for the deadband. The standards specify that the maximum potential penalty is not to exceed the maximum potential reward. Revenue adjustments (rewards or penalties) will be implemented as required through the fuel cost recovery mechanism.

The standards are to function in lieu of routine, individual outage reviews that currently address replacement fuel costs. However, the order establishing the nuclear performance standards provides the Georgia PSC with flexibility, so that in the appropriate circumstances, any unit may be excluded from consideration under the performance incentive program for the purpose of performing a separate prudence evaluation. A unit that operates with an average capacity factor below 50% for the period of performance will be excluded from the program and considered for a detailed operating prudence review by the PSC. Georgia Power may also request that the PSC exclude a unit from the program in the case of unusual, or extraordinary circumstances.

Implementation Results: Georgia Power received a reward of $8,496,029 for the last filing period which ended in 1992. This has been the only financial impact of the program to date. The next period will end in 1995. Performance of the Georgia Power units since 1985 is shown in the Table 2.8.

Table 2.8 Georgia Power's nuclear unit performance: 1985-1993

Unit	Period	Capacity factor
Hatch 1	1985	72.20%
	1986	53.94%
	1987	77.27%
	1988	61.85%
	1989	97.71%
	1990	61.80%
	1991	72.40%
	1992	94.6%
	1993	76.7%
Hatch 2	1985	82.05%
	1986	53.06%
	1987	86.34%
	1988	63.02%
	1989	61.52%
	1990	97.30%
	1991	73.80%
	1992	69.8%
	1993	75.4%
Vogtle 1	1987	71.61%
	1988	71.65%
	1989	91.80%
	1990	77.70%
	1991	77.80%
	1992	96.7%
	1993	85.7%
Vogtle 2	1989	94.59%
	1990	70.50%
	1991	92.60%
	1992	79.7%
	1993	87.1%

2.7 State: Maryland

Program Effective: January 1988

Regulatory Authority: Maryland Public Service Commission

Utility Affected: Baltimore Gas and Electric: Calvert Cliffs 1 and 2, 100%

Program Status: Program in Operation

Performance Criterion: Capacity Factor

Type of Incentive Program: Utility Performance Standard. Subjective denial of replacement fuel costs.

1994 Update/Changes: Program unchanged since last report. No penalties have been issued to date.

Description: The Maryland Public Service Commission (PSC) permits recovery of increased fuel costs through the fuel rate only to the extent that the utility has maintained a reasonable production level at all of its generating assets. The Commission determined that the Generating Unit Performance Program (GUPP), a system-wide measure, constitutes an initial analysis of the reasonableness of a utility's performance. A utility that demonstrates that its actual system-wide performance meets or exceeds the determined target is considered to have maintained a reasonable production level at all of its assets. If the utility's system-wide performance falls short of the target, each plant's target and actual performance are examined and the utility is required to demonstrate that the outages associated with the poor performance were not due to utility imprudence. Even though meeting both the system-wide target and each plant's target is considered reasonable performance, individual outage reviews may still be conducted. Outage and poor performance reviews are consistent with the subjective reviews conducted in prior fuel rate proceedings that denied the utility replacement fuel costs incurred at Calvert Cliffs.

A more precise and restrictive definition of planned outages was implemented after 1990. In previous years, the adjusted actual capacity factor had been over 70% when the actual capacity factor was zero, leading to controversies over outage classification. This change is expected to remedy that situation.

The GUPP provides the basis to determine a reasonable production level. The annual target capacity factor, for individual nuclear units and the generating system as a whole, is based on a statistical analysis of the performance of similar nuclear units and of the generating systems as a whole. Performance is measured each calendar year. The actual capacity factor is then adjusted for planned outages. Utility performance for the past calendar year is reviewed in a fuel rate proceeding. The performance targets for the next two years are determined in a biannual January proceeding.

Implementation Results: Recovery of replacement fuel costs is not determined by performance standards but is addressed in the course of an individual outage review. Historically, approximately 50% of replacement fuel costs incurred due to imprudency on the part of the utility has been disallowed. Although no penalties have been issued under the current program for Calvert Cliffs, only the 1988 and 1992 cases have been resolved. The 1989-1991 case is still unresolved. Performance of the Calvert Cliffs units since the GUPP was implemented is shown in Table 2.9.

Table 2.9 Target and adjusted actual capacity factor of Baltimore Gas and Electric's nuclear units

Unit	Period	Capacity factor	
		Target	Adjusted actual
Calvert Cliffs 1	1988	52.71%	81.55%
	1989	60.69%	14.31%
	1990	62.26%	46.61%
	1991	62.85%	75.50%
	1992	58.10%	69.94%
	1993	63.00%	86.58%
	1994	62.25%	
Calvert Cliffs 2	1988	58.36%	85.33%
	1989	66.79%	85.81%
	1990	68.09%	74.36%
	1991	68.70%	49.47%
	1992	63.72%	81.09%
	1993	70.00%	90.00%
	1994	69.50%	

2.8 State: Massachusetts

Program Effective: November 1989, with revisions Fall 1992

Regulatory Authority: Massachusetts Department of Public Utilities

Utility Affected: Boston Edison: Pilgrim, 100%

Program Status: Program in Operation

Performance Criteria: Capacity Factor, Performance Indicators, and Systematic Assessment of Licensee Performance (SALP) Rating

Type of Incentive Program: Nuclear Performance Incentive

1994 Update/Changes: As of November 1, 1992, the base component and capacity factor was no longer part of the program. One-third of outage capital additions are excluded from the rate base, with the rest remaining in the rate base. The settlement agreement for new performance adjustment charges extend from November 1, 1992 - October 31, 2000. Boston Edison received a $8,792,000 reward for the November 1992 - October 1993 period under the most current performance adjustment formula.

Description: The settlement agreement of November 1989 resolved three cases before the Massachusetts Department of Public Utilities (DPU): the rate case filed by Boston Edison, a petition to remove Pilgrim from rate base, and $250 million in replacement fuel costs. The settlement was proposed and agreed to by Boston Edison and the various interveners. The Massachusetts DPU accepted the settlement, as it was consistent with the interests of the ratepayers. Under the terms of the settlement, Boston Edison withdrew a request for an 8.4% ($86 million) rate increase and wrote off $101 million in operating and maintenance expenses incurred during Pilgrim's 33-month outage. Boston Edison was precluded from filing a new rate case until 1992; however, the utility's rates changed in the interim in accordance with the performance adjustment factor.

The settlement imposed an incentive program upon Pilgrim adjusts the utility's revenues up or down based on Pilgrim's performance. The performance measures of the incentive program consist of the annual capacity factor, a set of performance indicators, and the unit's latest Systematic Assessment of Licensee Performance (SALP) rating. Boston Edison can be penalized $1 million for each 1% that Pilgrim operates below a 60% capacity factor. The utility will be awarded $1 million for each 1% above a 76% capacity factor, up to $15 million annually. For each of five performance indicators (safety system failures, collective radiation exposure, automatic scrams while critical, safety system actuations, and maintenance backlog over three months old), the utility could earn as much as $300,000 or be penalized up to $600,000. Criterion performance for automatic scrams while critical, safety system failures, and safety system actuations is defined by the NRC average. The collective radiation exposure criteria is defined as the Institute of Nuclear Power Operations (INPO) median boiling water reactor value of man-rems/unit/year $\pm$ 25.0; maintenance backlog criteria are equal to the INPO average number of work orders $\pm$ 5%. In addition, based on Pilgrim's SALP rating, the utility will earn $500,000 for each one-tenth of a point below 1.6, for a maximum reward of $3 million. It will be penalized $500,000 for each one tenth of a point above 1.8, for a maximum penalty of $6 million. The performance adjustment charge for Pilgrim is factored into the quarterly fuel charge for all Boston Edison generating assets. The fuel charge is passed on to ratepayers; thus, should Pilgrim incur a penalty, the loss of revenues to Boston Edison would be reflected in a reduced fuel charge.

In addition to these incentives, there is also a base component to the program. The annual base component element of the performance adjustment factor incrementally increased company revenues by $20 million and $22.5 million in 1990 and 1991, respectively. For 1992, the base component value will be $25 million.

The overall performance adjustment is calculated by the formula, $PA_i = (B_{py} + CF_{py} + SALP_{py} + PIT_{py})$,

where PA_i is the amount of performance adjustment in the quarter $_i$
B_{py} is the base component amount described in the previous paragraph during the three consecutive 12-month periods ($_{py}$ = 1, 2, and 3)
CF_{py} is determined by the capacity factor achieved by the Pilgrim plant
$SALP_{py}$ is an adjustment to the base rate determined an average score achieved by Boston Edison by the SALP, issued by the NRC
PIT_{py} is an adjustment to the base amount determined by Pilgrim's most recent ranking relative to other U.S. nuclear power plants on the following five performance indicators:
- automatic scrams while critical
- safety system failures
- safety system actuations
- collective radiation exposure (boiling water reactor [BWR])
- maintenance backlog greater than three months old.

Beginning November 1, 1992, several changes were made to the above program. The base component has been replaced with retail rates and charges. One-third of Boston Edison's retail base rate cost of service is excluded after this date. The other two-thirds will remain in the rate base. Costs of service include depreciation, return, income taxes, operations and maintenance expenses. After April 15, 1992, a new tariff has provided and governed a new performance adjustment charge which applies to all kilowatt hours sold by Boston Edison Company. The new performance adjustment charge is calculated quarterly, and described by the formula, $NPA_i = (POUT_{npy} * PRAT_{npy} + SALP_{npy} + PIT_{npy})$,

where NPA_i is the amount of the new performance adjustment charge in the quarter $_i$
$POUT_{npy}$ is one-third of Boston Edison Company's retail share of the kilowatt hours of net electric power generated by pilgrim, in each of the eight performance years beginning November 1, 1992 through October 31, 2000 ($_{npy}$ = 1, 2, 3 - 8)
$PRAT_{npy}$ is the Pilgrim cent per kilowatt hour rate based on Pilgrim's annual capacity factor
$SALP_{npy}$ is essentially the same as $SALP_{py}$, but calculated over $_{npy}$
PIT_{npy} is essentially the same as PIT_{py}, but calculated over $_{npy}$.

Implementation Results: Table 2.10 shows neutral bands for each of the seven criteria, Pilgrim's performance during the first year of the program, and the revenue adjustment figure. In addition to the $20 million base component, the utility earned a $470,800 reward for the November 1989 - October 1990 period. Table 2.11 shows the revenue recovery from 1989-1992.

Table 2.10 Pilgrim performance indicators, capacity factor, SALP rating, and nuclear incentive, November 1989 - October 1990

Criteria	Neutral band	Pilgrim performance	Nuclear incentive
Automatic Scrams While Critical	1 - 3	2	0
Safety System Failures	2 - 4	3	0
Safety System Actuations	1 - 2	0	+$100,000
Collective Radiation Exposure (man-rems)	345 - 575	221.1	+$247,800
Maintenance Backlog Over 3 Months Old (work orders)	49.4 - 59.4	41.2	+123,000
Capacity Factor	60% - 76%	68.3%	0
SALP Rating	1.6 - 1.8	1.7	0
Totals			+$470,800

Table 2.11 Generating Unit performance adjustment charge: 1989-1992 Pilgrim revenue recovery

Time Period	Performance	Revenue Recovery
November 1, 1989 - October 31, 1990	68.3%	$470,000
November 1, 1990 - October 31, 1991	64.0%	-$375,300
November 1, 1991 - October 31, 1992	84.2%	$8,792,000

2.9 State: Massachusetts

Program Effective: 1981, with revisions in 1983, 1985, and 1991

Regulatory Authority: Massachusetts Department of Public Utilities

Utilities Affected:		
	Boston Edison:	Pilgrim, 100%
	Western Massachusetts Electric:	Millstone 1 and 2, 19%
	(A subsidiary of Northeast Utilities)	Millstone 3, 12.24%

Program Status: Program in Operation

Performance Criteria: Equivalent Availability Factor (primary measure)

Type of Incentive Program: Utility Performance Standard. Subjective denial of replacement fuel costs.

1994 Update/Changes: Program remains unchanged since 1991.

Description: The Massachusetts Fuel Act gives the Massachusetts Department of Public Utilities (DPU) the authority to require utilities to meet performance goals. Each generating unit under DPU jurisdiction is required to meet the Generating Unit Performance Program goals established for that unit. Massachusetts performance standards are applied to Connecticut units when a Massachusetts utility has an investment in those units. In addition to Pilgrim, Boston Edison is a minor investor in Connecticut Yankee (9.5%) and Yankee-Rowe (9.5%). Boston Edison, therefore, is subject to the provisions of the Generating Unit Performance Program for these units. Similarly, Western Massachusetts Electric, which has a 9.5% investment in Connecticut Yankee in addition to the three Millstone units, is subject to Massachusetts performance standards. However, as the DPU distinguished between major and minor units, Western Massachusetts Electric's investments in Yankee-Rowe (7%), Maine Yankee (3%), and Vermont Yankee (2.5%) are generally excluded.

Goals are determined and performance is measured over a 12-month period (June 1 - May 31 for Western Massachusetts and November 1 - October 31 for Boston Edison). Goals and performance are based on a unit's equivalent availability factor (EAF) and its three-year performance averages for availability and capacity factors, and forced outage and heat rates. The DPU views the EAF as the best measure of performance and places primary emphasis on it. Performance goals for Western Massachusetts are determined using the target unit availability (TUA) goals set for each member utility unit under its performance incentive program.

The DPU conducts two proceedings each year. The first determines the performance goals as described above. The second analyzes the past year's performance relative to that year's goals. Targets for plant efficiency are compared to the monthly plant statistics submitted by the utility to assist the DPU in determining the prudency of utility fuel expenditures. Failure of a unit to meet a performance goal results in a review of the unit's replacement fuel costs. These reviews place the utility at risk for the denial of replacement fuel costs determined by the DPU to be imprudently incurred.

Implementation Results at Boston Edison: Boston Edison has incurred three penalties since the Generating Unit Performance Program was established in 1981. A \$5.2 million penalty incurred in 1981 was due to scheduling difficulties that extended the refueling outage during structural modification to Pilgrim. In 1984, a \$4.2 million penalty was related to an outage for pipe replacement and chemical decontamination. A \$3 million penalty in 1986 was associated with an outage because of valve misalignment and foreign material in the standby liquid control system. The replacement fuel costs incurred in the April 12, 1986 - December 1, 1988 outage were addressed in the 1989 Pilgrim settlement. No additional penalties have been assessed since then. Table 2.12, Generating Unit Performance Program: 1985 - 1992 Pilgrim Goals and Actual Values, includes goals and actual performance since the program's 1985 revisions. Results for the latest period were not available by the date of publication.

Implementation Results at Western Massachusetts Electric: Fuel cost disallowances were imposed upon the utility first in 1985 and again in 1986 due to the performance of the Connecticut Yankee unit. However, the Massachusetts DPU has not imposed a penalty upon Western Massachusetts for operation of the Millstone units to date. Table 2.13 includes the goals and actual performance since the program's 1985 revisions.

Table 2.12 Generating Unit Performance Program: 1985-1994 Pilgrim goals and actual values

			Average three-year performance			
Period		**Equivalent availability factor**	**Availability factor**	**Capacity factor**	**Forced outage rate**	**Heat rate**
Nov. 1985 - Oct. 1986	Actual:	33.2%	35.4%	33.2%	50.8%	10,276
	Goal:	67.6%	72.8%	67.6%	6.5%	10,275
Nov. 1986 - Oct. 1987	Actual:	0%	0%	0%	0%	0
	Goal:	67.6%	73.2%	67.6%	8.0%	10,275
Nov. 1987 - Oct. 1988	Actual:	0%	0%	0%	0%	0
	Goal:	69.4%	74.7%	69.4%	18.2%	10,278
Nov. 1988 - Oct. 1989	Actual:	32.4%	50.2%	17.1%	28.0%	11,384
	Goal:	79.2%	83.1%	79.2%	16.7%	10,278
Nov. 1989 - Oct. 1990	Actual:	68.3%	74.1%	68.3%	12.5%	10,346
	Goal:	71.9%	75.8%	71.9%	18.0%	10,278
Nov. 1990 - Oct. 1991	Actual:	64.2%	69.7%	64.0%	2.2%	10,333
	Goal:	78.2%	82.1%	78.2%	16.9%	10,278
Nov. 1991 - Oct. 1992	Actual:	84.2%	87.1%	84.2%	11.0%	10,282
	Goal:	70.6%	74.5%	70.6%	18.8%	10,278
Nov. 1992 - Oct. 1993	Actual:	66.0%	71.0%	66.0%	7.4%	10,334
	Goal:	73.9%	77.8%	73.9%	18.8%	10,282
Nov. 1993 - Oct. 1994	Actual:					
	Goal:	73.9%	78.6%	73.9%	8.9%	10,295

Table 2.13 Generating Unit Performance Program: 1986-1994 Millstone 1, 2, and 3 goals and actual values

Period		Equivalent availability factor	Average three-year performance: Availability factor	Capacity factor	Forced outage rate	Heat rate
MILLSTONE 1						
June 1986 - May 1987	Actual:	92.9%	95.6%	92.9%	4.4%	10,518
	Goal:	64.6%	68.9%	64.6%	8.0%	10,510
June 1987 - May 1988	Actual:	75.9%	77.9%	75.9%	2.4%	10,455
	Goal:	68.1%	73.2%	68.1%	3.9%	10,513
June 1988 - May 1989	Actual:	81.8%	84.2%	81.9%	2.7%	10,481
	Goal:	68.7%	72.0%	68.7%	3.6%	10,463
June 1989 - May 1990	Actual:	92.7%	95.8%	92.9%	3.4%	10,431
	Goal:	67.2%	70.5%	67.2%	3.6%	10,463
June 1990 - May 1991	Actual:	72.3%	74.9%	72.4%	11.9%	10,487
	Goal:	71.3%	73.8%	71.3%	2.8%	10,450
June 1991 - May 1992	Actual:	24.9%	28.9%	24.9%	63.5%	10,843
	Goal:	76.5%	79.0%	76.5%	5.7%	10,448
June 1992 - May 1993	Actual :	83.5%	87.0%	83.5%	13.0%	10,694
	Goal:	70.6%	73.0%	70.6%	16.5%	10,488
June 1993 - May 1994	Actual:	59.1%	62.8%	59.1%	4.2%	18,882
	Goal:	73.9%	76.9%	73.9%	24.2%	10,448
MILLSTONE 2						
June 1986 - May 1987	Actual:	64.3%	67.9%	64.5%	9.8%	10,878
	Goal:	76.8%	80.9%	76.8%	9.0%	10,944
June 1987 - May 1988	Actual:	75.6%	78.9%	75.6%	8.0%	10,818
	Goal:	79.6%	84.3%	79.6%	9.9%	10,951
June 1988 - May 1989	Actual:	71.9%	73.8%	71.9%	3.4%	10,767
	Goal:	70.1%	74.5%	70.1%	9.0%	10,800
June 1989 - May 1990	Actual:	81.8%	84.1%	81.8%	1.0%	10,825
	Goal:	81.9%	86.3%	81.9%	7.9%	10,800
June 1990 - May 1991	Actual:	66.5%	69.5%	66.9%	14.1%	10,778
	Goal:	76.7%	79.2%	76.7%	5.9%	10,763
June 1991 - May 1992	Actual :	57.2%	60.2%	57.7%	39.5%	10,744
	Goal:	76.5%	79.0%	76.5%	4.3%	10,763
June 1992 - May 1993	Actual:	34.8%	36.7%	34.8%	3.1%	10,624
	Goal:	70.6%	73.4%	70.6%	17.6%	10,781
June 1993 - May 1994	Actual:	77.9%	79.2%	77.9%	11.2%	10,600
	Goal:	73.9%	76.1%	73.9%	18.4%	10,653
MILLSTONE 3						
June 1986 - May 1987	Actual:	78.7%	83.1%	78.7%	9.8%	10,348
	Goal:	65.4%	75.4%	65.4%	24.6%	10,365
June 1987 - May 1988	Actual:	62.8%	66.0%	62.7%	8.6%	10,342
	Goal:	63.2%	67.4%	63.2%	14.9%	10,328
June 1988 - May 1989	Actual:	79.9%	84.1%	79.8%	11.0%	10,421
	Goal:	70.1%	74.7%	70.1%	9.7%	10,355
June 1989 - May 1990	Actual:	69.2%	75.8%	69.2%	14.3%	10,455
	Goal:	68.9%	73.5%	68.9%	9.9%	10,355
June 1990 - May 1991	Actual:	69.5%	76.8%	69.5%	3.6%	10,485
	Goal:	76.7%	81.0%	76.7%	8.1%	10,355
June 1991 - May 1992	Actual:	36.5%	39.0%	36.5%	59.3%	10,410
	Goal:	76.5%	81.9%	76.5%	10.2%	10,335
June 1992 - May 1993	Actual:	78.0%	85.1%	78.0%	14.1%	10,489
	Goal:	70.6%	76.2%	70.6%	22.3%	10,448
June 1993 - May 1994	Actual:	68.8%	72.4%	68.8%	0.5%	10,396
	Goal:	73.9%	79.8%	73.9%	18.4%	10,437

2.10 State: Michigan

Program Effective: January 1991

Regulatory Authority: Michigan Public Service Commission

Utility Affected: Detroit Edison: Fermi 2, 100%

Program Status: Program in Operation

Performance Criterion: Capacity Factor

Type of Incentive Program: Nuclear Performance Incentive

1994 Update/Changes: In 1994, Detroit Edison filled its first performance standards calculation.

Description: The nuclear performance standard compares the unit's 3-year, rolling capacity factor (first years are 1991-1993) to the greater of two criteria: either a 50% capacity factor or the average capacity factor of the top 50% of the nation's BWRs. Required revenue adjustments are to occur at the conclusion of each 12-month performance period. A disallowance will be imposed on the utility based on the net incremental cost of replacement power for a capacity factor below the minimum standard. Rewards are not directly applied when the performance standard is exceeded; however, rewards that might have accrued for these periods may be used to offset penalties in subsequent years when performance is below the standard. Thus, the rate order provides for a banking mechanism that can be used to offset penalties but does not provide for actual rewards. Under the terms of the 1988 settlement agreement, the performance standard runs to December 31, 2003.

Implementation Results: For the first performance standards case (capacity factor for years 1991, 1992, 1993) Fermi 2 had a capacity factor of 75.9% compared to the average of the top 50% of BWR of 76.1%. The .2% difference resulted in a $146,861 disallowance. Fermi 2 has been in an outage situation since December 1994. The financial effects of the prolonged outage will not be known until 1996.

2.11 State: New Jersey

Program Effective: For Public Service Electric and Gas: January 1987; revisions January 1990
For Jersey Central Power and Light: March 1987; revisions March 1990

Regulatory Authority: New Jersey Board of Public Utilities

Utilities Affected: Public Service Electric and Gas: Peach Bottom 2 and 3, 42.5%
Salem 1 and 2, 42.5%
Hope Creek, 95%

Jersey Central Power and Light: Oyster Creek, 100%
Three Mile Island 1, 25%

Program Status: Program in Operation

Performance Criterion: Capacity Factor

Type of Incentive Program: Nuclear Performance Incentive

1994 Update/Changes: Programs remain unchanged since 1990. Public Service Electric and Gas received a $3,900,000 reward for the year 1993, in which its units obtained an overall capacity factor of 77.2%. Jersey Central Power and Light received a $7.8 million reward for the March 1993 - February 1994 period.

Description: The New Jersey Board of Public Utilities (NJBPU) adopted performance standards in lieu of the previous case-by-case investigations that had determined whether or not a particular outage called for a monetary disallowance. The program is intended to shift the risks of poor nuclear performance from the ratepayer to the utility. The performance standard program is applied to each of the three utilities that operate or invest in New Jersey nuclear units: Atlantic City Electric, Jersey Central Power and Light (JCP&L), and Public Service Electric and Gas (PSE&G). Atlantic City Electric is a minor investor in Salem 1 and 2 (7.4%), Peach Bottom 2 and 3 (7.5%), and Hope Creek (5%); therefore, a detailed survey of the program's impact on this utility was not conducted.

Performance standards were established in 1987 and modified in 1989. The performance standard established in 1987 measured the composite capacity factor (of each utility's plants) over a 12-month performance period. The provisions of the program established a target capacity factor of 70% and a deadband of 60% to 80%. The deadband was established to allow for variations due to refueling outages scheduled during performance periods. An average capacity factor between 80% and 90% for a utility's nuclear units yielded a reward equal to 20% of the fuel cost savings (recovery of 120% of the fuel costs). For performance greater than 90%, the reward was equal to 25% of the fuel cost savings. For capacity factors between 50% and 60%, the utility's recovery of replacement fuel costs was limited to 80%, resulting in a 20% penalty (disallowance). The penalty for capacity factors between 40% and 50% was 25%. Penalties for capacity factors below 40% were to be based on a special review of the circumstances by NJBPU; these reviews included the utility's explanation of causes. All revenue adjustments were calculated from the target capacity factor at the rate corresponding to the capacity factor achieved.

Hearings were begun in October 1989 to review the nuclear performance standards. Provisions for these hearings were made when the original standards were established. The review of the original program specifications and the subsequent revisions were intended to address aspects of the program that were controversial. The impact of performance standards on the management of the nuclear units and on ratepayers and investors was discussed in the course of the hearings. Specific attributes of the standards were also examined and, in a number of instances, revised.

The consensus of the utilities at the 1989 hearings was that the performance standards have not had an appreciable impact on the management of the nuclear units. The utilities indicated that the operation of the units involves consideration of factors more important than the economic rewards or penalties of the standards, such as the NRC's requirements and general safety considerations. The utilities testified that the existence of performance standards have not had any measurable adverse impact on the safe operation of the nuclear units.

The revenue adjustments imposed by the standards clearly impacted the ratepayers and utility investors. The disallowance of certain replacement fuel costs has resulted in savings to the ratepayers and measurable costs to the utilities. The utilities expressed concern about the effect the imposition of nuclear performance standards has had on the financial community's perception of the utilities. They have pointed out that the major rating agencies have downgraded a number of utility securities. The NJBPU indicated that the investment risk of one utility versus another would include, among other factors, the aggregate investment in nuclear units owned or operated by a utility, a phenomenon which should be recognized by the market.

The 1989 revisions to the incentive program limited both the deadband range, where neither a penalty nor a reward accrues, and the percentage of replacement fuel costs the utility may collect from ratepayers. The percentage of fuel cost savings that accrue to the utility was adjusted, and the method of calculation of plant capacities and the cost basis against which the penalty and reward percentages are applied were revised.

The 1989 revised nuclear performance standards reduced the deadband range to a 65% to 75% "zone of reasonableness" and increased replacement fuel cost penalties (disallowances) for nuclear unit performance below 65%. At capacity factors ranging from 55% to 65%, the utility's recovery of replacement fuel costs is limited to 70%, resulting in a 30% penalty. The penalty for capacity factors between 45% and 55% equals 40% of the replacement fuel costs; between 40% and 45% the penalty equals 50%. The revised standards also allow for rewards when performance reaches 75%; at this point, 30% of the fuel cost savings accrues to the utility. Unit capacity is now calculated according to the unit's average summer/winter maximum dependable capacity (MDC) rating. MDC measures the output that the unit is realistically capable of reaching when operating at full capacity. Previously, unit capacity was calculated on the basis of the unit's design electrical rating (DER), a slightly higher rating than MDC.

According to the old standard, a utility would be penalized at the rate corresponding to the unit's actual capacity for each percentage point below the 70% target, even if the actual capacity fell into a more expensive range by only 1%. The revised program specifies that revenue adjustments are to be determined from the edges of the zone of reasonableness, eliminating the hard shoulder effect of the deadband. For example, with a capacity factor of 54%, 1% below the 55% to 65% range, the utility would incur a penalty of 30% of the replacement fuel costs for the 10% within the 55% to 65% range and a penalty of 40% for the 1% within the 45% to 55% range.

Table 2.14 summarizes the programs in terms of the percentage of fuel costs the utility is permitted to recover from ratepayers. A cost recovery level of 130% is equivalent to a reward of 30% of the fuel cost savings. Similarly, a cost recovery level of 70% is equivalent to a penalty or disallowance of 30% of the replacement fuel costs. At capacity factor levels below 40%, the NJBPU intervenes to review the circumstances associated with poor performance; these reviews include the utility's explanation of causes.

The 1989 program revisions were ordered in July 1990 and were applied in the 1990 performance period. The levelized energy adjustment clause (LEAC) year (the period of performance) for PSE&G is from January 1 through December 31. For JCP&L, the LEAC year is from March 1 through February 28.

Table 2.14 New Jersey's original and revised performance standards and revenue adjustments

Original program		Revised program	
Composite capacity factor	**Cost recovery**	**Composite capacity factor**	**Cost recovery**
90% and above	125%	75% and above	130%
80% - 90%	120%	65% - 75%	0%
60% - 80%	0%	55% - 65%	70%
50% - 60%	80%	45% - 55%	60%
40% - 50%	75%	40% - 45%	50%

Implementation Results: PSE&G regards the revised performance standard as marginally more equitable than the original standard. JCP&L reports that the revised performance standard may increase its opportunity to earn a reward. It has also been suggested that the program's impact on the utilities' potential losses or gains will be minimal, except in cases of extremely poor performance. Furthermore, large fluctuations in the composite performance of a utility's nuclear units are not anticipated. The impact of a single unit's poor performance would be offset by adequate performance of the utility's other nuclear units. However, JCP&L may be at greater risk than PSE&G for incurring a penalty, as its composite capacity factor is based on the performance of only two nuclear units.

The maximum penalty that can be attributed to the performance standards is 50% of the replacement fuel costs for a composite nuclear capacity factor of 40%. At capacity factors below 40%, the NJBPU would intervene. In these cases, the NJBPU could take actions, such as removing the poorly performing unit(s) from rate base or removing the unit(s) from the performance program and disallowing recovery of a portion of replacement fuel costs. NJBPU intervention is intended as a review of the circumstances that caused a particular unit's poor performance and is not necessarily intended to be extremely punitive.

Implementation Results at Public Service Electric and Gas: The performance of PSE&G's nuclear units and the associated rewards or penalties since the program's inception in 1987 are shown in Table 2.15. The 1987 and 1988 data were reported in the July 1990 Decision and Order of the NJBPU. PSE&G's composite DER capacity factor for 1989 includes Peach Bottom Unit 2 for the six months July through December, and excludes Peach Bottom Unit 3 for the entire year.

Implementation Results at Jersey Central Power and Light: The performance of JCP&L's nuclear units and the associated rewards or penalties are shown in Table 2.16. Data regarding the LEAC years concluding February 1988 and 1989 were reported in the July 1990 Decision and Order of the NJBPU. For the period ending February 1989, the scheduled refueling outages of both Oyster Creek and Three Mile Island were extended, reducing the capacity factor for the performance period.

Table 2.15 Public Service Electric and Gas' revenue adjustments as determined by composite capacity factor

Period	Composite capacity factor	Incentive values
1987	54.8%	-$19,500,000
1988	49.0%	-$22,500,000
1989	70.0%	0
1990	74.8%	0
1991	70.1%	0
1992	66.1%	0
1993	77.2%	+$3,900,000

Table 2.16 Jersey Central Power and Light's revenue adjustments as determined by composite capacity factor

Period	Composite capacity factor	Incentive values
March 1987 - Feb. 1988	69.0%	0
March 1988 - Feb. 1989	53.2%	-$4,800,000
March 1989 - Feb. 1990	56.4%	-$3,900,000
March 1990 - Feb. 1991	75.2%	+$2,700,000
March 1991 - Feb. 1992	64.0%	-$500,000
March 1992 - Feb. 1993	77.6%	+$700,000
March 1993 - Feb. 1994	95.5%	+$7,800,000

2.12 State: New Mexico

Program Effective: January 1986

Regulatory Authority: New Mexico Public Service Commission

Utility Affected: El Paso Electric: Palo Verde 1 and 2, 15.8%

Program Status: Program in Operation

Performance Criterion: Capacity Factor

Type of Incentive Program: Nuclear Performance Incentive

1994 Update/Changes: Program unchanged since 1986. El Paso Electric received a $61,524 reward in 1992.

Description: The New Mexico Public Service Commission's (PSC's) jurisdiction over El Paso Electric is due to the utility's New Mexico service area. The revenue adjustments determined by the nuclear performance standards are applied to two-thirds of El Paso Electric's output entitlement in the Palo Verde units. (Palo Verde 3 is excluded from rate base.)

The measure of performance is the annual composite capacity factor for Palo Verde 1, 2, and 3. The performance periods are calendar years; corresponding revenue adjustments are made each year. The established deadband ranges from 60% to 75%. For a capacity factor between 75% and 85%, the utility incurs a reward equal to 50% of the fuel cost savings; above 85%, the utility's reward equals 100% of the fuel cost savings. For a capacity factor between 50% and 60%, the utility incurs a penalty equal to 50% of the replacement fuel costs; below 50%, the utility's penalty equals 100% of the replacement fuel costs. The determination of fuel cost savings or replacement fuel costs is based on a proxy-weighted, average fuel cost.

At an annual capacity factor below 35%, a prudency investigation may be initiated. However, for El Paso Electric, an annual capacity factor below 35% results in an automatic reconsideration of the utility's last general rate in order to determine whether or not continued rate base treatment of the units is appropriate. Unless the PSC orders otherwise, the imposition of performance penalties continues pending the outcome of such reconsideration.

Implementation Results: The reported annual capacity factor and the corresponding revenue adjustments since the program became effective are shown in Table 2.17.

Table 2.17 El Paso Electric's revenue adjustments as determined by composite capacity factor

Period	Composite capacity factor	Incentive values
1987	60.50%	0
1988	70.40%	0
1989	23.40%	-$1,480,000
1990	61.71%	0
1991	75.19%	+$5,457
1992	76.52%	+$61,524
1993	66.02%	0

2.13 State: New Mexico

Program Effective: April 1990

Regulatory Authority: New Mexico Public Service Commission

Utility Affected: Public Service Company of New Mexico: Palo Verde 1 and 2, 10.2%

Program Status: Discontinued effective January 1995

Performance Criterion: No criterion

Type of Incentive Program: Nuclear Performance Incentive

1995 Update/Changes: As of January 1995, no nuclear performance incentive programs will be applicable the Public Service Company of New Mexico.

Implementation Results: Public Service Company of New Mexico will compete in the market with gas, oil, and coal-fired power plants without benefit of an incentive program.

2.14 State: New York

Program Effective: 1985 for Rochester Gas and Electric
1985, with revisions in 1991, for Niagara Mohawk
1985 for New York State Electric and Gas
November 1991 for Long Island Lighting Company
April 1992 for Consolidated Edison

Regulatory Authority: New York Public Service Commission

Utilities Affected:

Rochester Gas and Electric:	Ginna, 100% Nine Mile Point 2, 14%
Niagara Mohawk Power:	Nine Mile Point 1, 100% Nine Mile Point 2, 41%
New York State Electric and Gas:	Nine Mile Point 2, 18%
Long Island Lighting Company:	Nine Mile Point 2, 18% Shoreham 1, 100% (No longer operating)
Consolidated Edison:	Indian Point 2, 100% Indian Point 1, 100% (No longer operating)

Program Status: Program in Operation

Performance Criteria: Fuel Costs (and others unique to each utility)

Type of Incentive Program: Utility Performance Standard, Nuclear Performance Incentive

1994 Update/Changes: Long Island Lighting Company (LILCO) and Consolidated Edison are now both subject to a partial pass-through fuel adjustment clause (FAC). As of 1993, Niagara Mohawk no longer has a Merit Plan. An operating efficiency program for Nine Mile Point 1 was implemented in 1991. Niagara Mohawk's and Rochester Gas and Electric's fuel costs are now indexed in their FACs. New York State and Electric Gas' (NYSEG's) program remains unchanged.

Description: A utility-wide (not just nuclear) partial pass-through fuel adjustment clause (FAC) applies to each of the New York utilities affected. As a result, the utilities are not necessarily allowed to pass through 100% of the actual fuel costs. However, each utility's program is unique. Thus, below is a generic description of a typical New York FAC, with utility-specific descriptions following.

Each month, the Public Service Commission (PSC) compares target unit fuel costs and the actual recoverable fuel cost per unit of sendout for the utility's retail customers. The partial pass-through mechanism uses a sliding scale percentage to reconcile fuel cost departures from the monthly target. For example, an 80/20% share of costs between ratepayers and the utility may apply to departures up to a specified absolute dollar limit for each utility; departures in excess of the specified dollar limit might then be shared 90/10% up to a specified cap, with the utility recovering from ratepayers 100% of departures in excess of the specified cap.

In practice, for a utility that exceeds the targeted costs, an 80/20% share of departures from the target results in passing 80% of the excess cost to the ratepayers and the utility absorbing the remaining 20% of the actual costs. Conversely, if the utility's actual costs are below the target, 80% of the savings are passed on to the ratepayers, and the utility is allowed to retain 20% of the savings as a positive incentive. Therefore, if the utility's fuel costs fall below the target, the utility recovers revenues in excess of actual fuel costs for the month.

Rochester Gas and Electric: RG&E is subject to an 80/20 (ratepayer/shareholder) partial pass-through clause. The maximum exposure for the utility is .05% of outstanding equity (5 basis points). Fuel costs are now indexed to account for volatility of oil and gas prices.

New York State Electric and Gas: NYSEG's FAC provides an 80/20 (ratepayer/shareholder) split for the first $40 million variance from the targeted costs. The split is 90/10 for the next $40 million variance. Beyond that, 100% of fuel costs are passed on to the ratepayer. The maximum exposure to the utility is $12 million.

Long Island Lighting Company: LILCO's FAC split is 60/40 (ratepayer/shareholder) up to a maximum exposure of .2% of outstanding equity (20 basis points). Fuel costs are indexed to account for volatility of oil and gas prices.

Consolidated Edison: The split is 70/30 (ratepayer/shareholder) up to a maximum nuclear and non-nuclear exposure of $30 million. The maximum nuclear exposure is $10 million. The maximum exposure due to generation at Indian Point 2 is $10 million. Costs are indexed to account for volatility.

Niagara Mohawk: Niagara Mohawk is subject to an 60/40 (ratepayer/shareholder) split for the first $37.5 million variance. Beyond this point, 100% of fuel costs are passed on to ratepayers, giving the utility a maximum exposure of $15 million. Fuel costs are indexed to take price volatility of oil and gas into account. In addition to this FAC, other new incentive programs have been implemented by the PSC for Niagara Mohawk. A 5-year plan affecting the whole company, the Merit Plan, began in 1991. It is a performance-based program that allows the company to earn back some or all of its $190 million settlement. Performance rewards are based on a number of company-wide indicators, as well as nuclear performance. There is also a nuclear operating efficiency program for Nine Mile Point 1, taking the place of the normal FAC for the plant. Over the next two fuel cycles, targets for Nine Mile 1 will be based on equivalent net capacity factor. The benefits (costs) in terms of saved (additional) replacement power costs will be shared 70/30 (ratepayer/shareholder) for the first 7% variance from the target of 61.26%, which is the average lifetime capacity factor of plants similar to Nine Mile Point 1. For the second and third 7% variance, the split is 60/40 and 50/50, respectively (ratepayer/shareholder). Unlike the other FAC, the utility bears all of the fuel costs beyond this point.

Implementation Results: As of now, Nine Mile Point 1 is still included in Niagara Mohawk's standard FAC calculations. Credits or debits will be given for Nine Mile 1's contribution when its Nuclear Operating Efficiency incentive is calculated at the end of two fuel cycles (1993 or 1994). As for Niagara Mohawk's Merit Program, the utility was rewarded $52.8 million out of a possible $60 million in 1991. There is a set amount available in each period. If it is not awarded, it is lost. Thus, $120 of the $180 million remains.

The most recent financial impacts on affected utilties are summarized below:

Rochester Gas and Electric: $2.6M reward in 1991

Niagara Mohawk: $1.2M reward for January-December 1993 period under the FAC.
$18.4M reward (out of a possible 30M) under the Merit Program in 1993
Possible rewards for 1994 and 1995 have been set at $34M and $41M, respectively.

New York State Electric and Gas: $990,000 reward for the February 1991-January 1992 period

Consolidated Edison: $10M reward for April 1993-March 1994

Long Island Lighting Company: No impacts yet

Table 2.18 shows the history of financial impacts of each utility's fuel adjustment clause. NYSEG commented that the overall impact of its incentives has been minimal. The sum of the incentives reported below for NYSEG is just $98,000. LILCO's program has not been in place long enough to have any measurable financial impacts.

Table 2.18 Incentives under New York's fuel adjustment clause

Utility	Period	Reward/penalty
Rochester Gas and Electric	1989	-$3,700,000
	1990	+$2,400,000
	1991	+$2,600,000
	July 1991-June 1992	+$3,727,906
	July 1992-June 1993	+$3,980,000
	July 1993-June 1994	+$6,687,510
Niagara Mohawk	July 1988-June 1989	-$14,996,045
	July 1989-June 1990	-$15,019,408
	July 1990-June 1991	-$10,455,122
	July 1991-June 1992	-$1,384,615
	July 1992-Dec. 1993	+$5,701,511
	Jan. 1993-Dec. 1993	+$1,223,502
New York State Electric and Gas	Feb. 1988-Jan. 1989	+$1,875,000
	Feb. 1989-Jan. 1990	-$1,003,000
	Feb. 1990-Jan. 1991	-$1,804,000
	Feb. 1991-Jan. 1992	+$990,000
	Feb. 1992-July 1992	+$40,000
Consolidated Edison	April 1992-March 1993	+$10,000,000
	April 1993-March 1994	+$10,000,000

2.15 State: North Carolina

Program Effective: 1987

Regulatory Authority: North Carolina Utilities Commission

Utilities Affected:	Carolina Power and Light:	Brunswick 1 and 2, 81.5% Robinson, 100% Harris, 83.83%
	Duke Power:	McGuire 1 and 2, 100% Oconee 1, 2, and 3, 100% Catawba 1, 25%
	Virginia Electric and Power:	Surry 1 and 2, 100% North Anna 1 and 2, 88.4%

Program Status: Program in Operation

Performance Criterion: Capacity Factor

Type of Incentive Program: Utility Performance Standard

1994 Update/Changes: Program remained unchanged.

Description: The North Carolina Utilities Commission (NCUC) estimates fuel costs for each 12-month performance period. A utility is permitted to include a fuel charge adjustment as a rider to the rates. The amount of a fuel charge can be reset only once during the 12-month period. It can also be reset at general rate hearings. The NCUC holds a full evidentiary hearing to determine whether an increment or decrement rider is in order. The only allowed portions of a requested fuel charge are those based on reasonable adjustments for fuel expenses that have been prudently incurred under efficient management and operations. Moreover, state statutes limit fuel cost recovery to actual costs; thus, in the event the utility over-collects fuel costs, the utility must reimburse ratepayer the over-collected fuel costs with interest.

The NCUC uses the target capacity factor, in part, to reconcile under-recovery allowances. The target capacity factor is based on an industry-wide average (based on the most recent 5-year NERC average) and considers a particular unit's characteristics and performance history. For a utility which under-collects costs and meets the target capacity factor, the NCUC must establish utility imprudence to deny recovery of costs. However, should the utility fail to achieve the target capacity factor, the utility must establish prudency in order to recover costs that were under-collected. Interest on under-collected costs is not permitted.

Implementation Results: According to Docket No. E-2, Sub 644 , dated September 14, 1993, Carolina Power and Light (CP&L) Brunswick Plant failed to meet the standards set dealing with fuel cost adjustment proceedings and standards of prudence. Public Staff initiated an audit of the Brunswick Plant. The report indicated that part of the outage for the Brunswick Plant was incurred due to management imprudence. After lengthy negotiations, both CP&L and Public Staff entered into a Joint Stipulation. In this stipulation, CP&L agreed to the following: to forgo recovery of $25.5 million of its test year under-recovery, and to certain additional performance standards for the Brunswick Plant over the 3-year period beginning April, 1993 and ending March 31, 1996. CP&L will have to refund up to $15.7 million plus interest to North Carolina customers if the Brunswick Plant does not meet the additional performance standards set forth in the Joint Stipulation.

A refund would take place if the Brunswick Plant capacity factor for the 3-year period is below 63.88% but greater than 57.39%, CP&L shall refund to the North Carolina retail customers a pro-rata portion of the $5,665,232 experience modification factor (emf) with interest at 10%. The refund will be pro-rated based on the level of performance below 63.88% and above 57.39%. If the Brunswick Plant capacity factor for the 3-year period is below 57.39%, the CP&L will also refund to its North Carolina retail customers $20,000 for each one-hundredth of a percentage point below 57.39% with a maximum refund of $10 million; this amount is over and above the $5,665,232 refund plus interest for not exceeding the 57.39% performance level. However, if the plant's average capacity factor for the 3-year period is equal to, or in excess of, 63.88%, CP&L will not be required to refund any additional funds to its North Carolina customers.

2.16 State: Ohio

Program Effective: January 1988

Regulatory Authority: Public Utilities Commission of Ohio

Utilities Affected:	Toledo Edison:	Davis-Besse, 48.6% Perry 1, 19.9% Beaver Valley 2, 19.9%
	Cleveland Electric Illuminating:	Davis-Besse, 51.4% Perry 1, 31.1% Beaver Valley 2, 24.5%
	Ohio Edison:	Perry 1, 28.96% Beaver Valley 1, 35% Beaver Valley 2, 35.6%

Program Status: Program In Operation

Performance Criterion: Composite Measure of System Performance and Utility Efficiency; Operating Availability Factor

Type of Incentive Program: Utility Performance Standard and Nuclear Performance Incentive (Subjective Denial of Under-Collected System Loss Adjustment and Banked Reward and Penalty)

1994 Update/Changes: The program remains unchanged. The 1993 financial results: Toledo Edison $3,173,828 (Banked Reward); Cleveland Electric Illuminating $3,790,976 (Banked Reward); Ohio Edison $1,258,000 (Banked Reward).

Description: The Public Utilities Commission of Ohio (PUCO) conducts a hearing every year to determine allowable fuel cost recovery. Ohio allows for recovery of under-collected system losses through the System Loss Adjustment (SLA) based on a complex composite measure of system performance and utility efficiency, which indicates whether a utility's generating assets have been operated in a prudent manner. Over-collections of system losses are entirely refunded. The PUCO believes that requiring efficiency provides the utility with an incentive to minimize its costs. The procedure for the collection of SLA applies to each Ohio utility and is determined as a function of all generating assets.

In addition, the 1988 rate cases involving Toledo Edison and Cleveland Electric Illuminating and the 1989 rate case for Ohio Edison resulted in the adoption of a performance standard based on the operating availability of each nuclear unit. The nuclear performance standard is based upon the operating availability factor of each unit. The operating availability factor is a comparison of each unit's 3-year, rolling average and the 3-year, rolling, industry average for pressurized water reactors (PWRs) or BWRs (excluding any unit operating at less than 30% availability for the period). The target operating availability and unit performance were determined for the first time in 1991, using the 3-year averages of 1988 through 1990. In the event that performance of a utility's nuclear unit is below the industry average, a fuel disallowance is computed by multiplying the net incremental cost of replacement power by the kilowatts required to raise the availability factor to the industry average. A penalty is applied through the reconciliation adjustment of the electric fuel component rate. Ohio only permits recovery of the actual costs of fuel used in electrical generation; thus, a provision for rewards is not included in the program. However, a mechanism was established such that if a utility's nuclear performance is above the industry average, rewards that might have accrued are "banked." Banked rewards can only be used to offset penalties incurred in the recent past or those that may be incurred in the future.

An operating availability factor was selected rather than a capacity factor because of a unique characteristic of these utility systems. The capacity represented by the nuclear units serving the area exceeded the off-peak demands of the utilities. As a result, all the nuclear units could not be fully loaded during off-peak periods. Under these circumstances, using the capacity factor, which measures actual unit utilization relative to the unit's potential capacity, would not have been appropriate. A stipulation was included in the order stating that, if data on industry-wide equivalent availability becomes readily available, the performance standard will be re-evaluated.

Implementation Results: The nuclear performance standard was first applied to the Ohio utilities in 1991. In 1993 Toledo Edison and Cleveland Electric both saw significant increases in their banked rewards (Toledo Edison $3,173,828; Cleveland Electric Illuminating $3,790,976; Ohio Edison $1,258,000). This reward is based upon the combined penalties/rewards as the program applied to each operating unit. Table 2.19 shows in greater detail the impact of the performance program in its first year.

Table 2.19 Public Utilities Commission of Ohio 1993 nuclear performance incentive program results

Utility	Operating unit	Banked reward or penalty	Combined reward or penalty
Toledo Edison	Davis-Besse	$1,807,590	$3,173,828
	Perry 1	$331,301	
	Beaver Valley 2	$1,034,937	
Cleveland Electric	Davis-Besse	$12,243,668	$3,790,976
	Perry 1	$535,026	
	Beaver Valley 2	$1,012,282	
Ohio Edison	Perry 1	$318,000	$1,258,000
	Beaver Valley 1	$164,000	
	Beaver Valley 2	$776,000	

2.17 State: Pennsylvania

Program Effective: April 1990

Regulatory Authority: Pennsylvania Public Utility Commission

Utility Affected: PECO (formally Philadelphia Electric): Limerick 1 and 2, 100%
Salem 1 and 2, 42.6%
Peach Bottom 2 and 3, 42.5%

Program Status: Program In Operation

Performance Criterion: Composite Capacity Factor

Type of Incentive Program: Nuclear Performance Incentive

1994 Update/Changes: Program remained unchanged. The most recent application of the energy cost adjustment (ECA) the overall capacity factor in 1992 and 1993 resulted in a $529,858 (71% capacity factor) reward in 1992, and a $9,745,236 (78.2% capacity factor) reward in 1993.

Description: The nuclear performance incentive program for Limerick 2, which began commercial operation in January 1990, was revised in a rate case that added the unit to base rates. The revision to the ECA, effective April 1990, incorporates a nuclear performance standard and replaces the existing Energy Cost Rate Factor for all of Philadelphia Electric's nuclear units. The objectives of the nuclear performance standard and corresponding revenue adjustments are to equitably balance the interests of the utility and its ratepayer, and to produce just and reasonable rates.

The ECA measures Philadelphia Electric's composite nuclear capacity factor for the calendar year. A component of the ECA, referred to as the performance adjustment, defines rewards and penalties as a function of the nuclear composite capacity factor. In addition to any over-collection of actual energy costs, the performance adjustment requires Philadelphia Electric to refund a portion of the replacement power costs. These are the costs incurred during the 1-year performance period due to nuclear performance at less than a designated range of acceptable capacity. The performance adjustment also permits the utility to retain a portion of the replacement power costs avoided due to nuclear performance above the designated range of acceptable capacity. The performance adjustment is described in Table 2.20.

The revisions to the ECA also specify that if a nuclear unit is out of service for more than 120 consecutive days, or does not achieve a capacity factor of 50% or more during a performance year, the PUC will retain the authority to conduct an investigation of that unit's performance. The PUC may disallow recovery of up to 100% of replacement power costs found to have been imprudently incurred. Disallowances of 100% of replacement power costs imprudently incurred are consistent with the PUC decisions in the past. A unit that has failed to perform would not be subject to the performance adjustment and would be excluded from the composite capacity factor calculation. However, the normal operation of the ECA will replace routine annual reviews of nuclear performance, and disallowance of replacement fuel costs will not occur if the unit meets the required capacity factor. The ECA will not be subject to modification for a minimum of 3 years in order to provide a fair test of its ability to achieve the desired objectives.

Table 2.20 Philadelphia Electric's performance and revenue adjustment program

Composite capacity factor	Revenue adjustment
Above 85%	40% replacement power savings
Above 75% but not above 85%	30% replacement power savings
Above 70% but not above 75%	20% replacement power savings
Between 60% and 70%	No adjustment
Below 60% but not below 55%	20% replacement power costs
Below 55% but not below 45%	30% replacement power costs
Below 45%	40% replacement power costs

Implementation Results: For calendar year 1992, the capacity factor for which the ECA was based was reported to be 71% and resulted in a $529,858 reward. The overall capacity factor for 1993 was 78.2% and resulted in a reward of $9,745,236. Table 2.21 shows the most recent results.

Table 2.21 Capacity factors and rewards for PECO

Performance year	Overall nuclear capacity factor	Reward
1991	75.8%	$5,645,899
1992	71.0%	$529,858
1993	78.2%	$9,745,236

2.18 State: Texas

Program Effective: Effective April 1990, (new proposal presently under consideration).

Regulatory Authority: Texas Public Utility Commission

Utilities Affected: El Paso Electric: Palo Verde 1, 2, and 3, 15.8%

Program Status: Program in Operation

Performance Criterion: Capacity Factor

Type of Incentive Program: Nuclear Performance Incentive

1994 Update/Changes: The program remains unchanged. Performance from the previous two determinations fell in the "deadband" and did not result in either a reward or a penalty.

Description: The nuclear performance incentive program was a result of the 1987 El Paso Electric rate case. The Texas Public Utility Commission Texas (PUC) staff cites a number of reasons for incentive regulation: the high capital costs of new base-load capacity, a perceived need to encourage greater efficiency in utility operations, and a desire to establish a means of more equitably allocating risks and rewards between shareholders and ratepayer.

The program employs capacity factor as the primary performance indicator for each unit. A composite capacity factor of the three units is used as the basis to determine performance-based rewards or penalties. Penalties or rewards are determined on an annual basis. The actual capacity factor is based on a 3-year rolling average capacity factor of the three units. The deadband range would be equal to the target of 70% $\pm$7.5%. Rewards or penalties for performance outside of the deadband vary depending upon the range excess or shortage of capacity. Table 2.22 describes in detail the breakdown of the incentive program reward and penalty distribution. Fuel replacement or sharing costs are based upon a weighted average. Any reward or penalty is multiplied by the percentage of Texas kilowatt-hour sales divided by total kilowatt-hour sales. Table 2.23 shows the history of El Paso Electric Company's incentive program. Table 2.24 illustrates Palo Verde 1 and 2 performance standards calculation results.

The PUC was in the process of studying a revised nuclear incentive program which may expand coverage to other nuclear utilities. The Commission, however, failed to act on the proposed rule making within the statutory time frame and as such, the proposed rule was withdrawn without further Commission action.

Implementation Results: The first application of the PUCT program resulted in a penalty. The 3-year rolling average determined through April 1991 for Palo Verde plants was 50.8%. This capacity factor fell outside of the deadband range causing El Paso Electric to absorb a $2.48M penalty. For the year, El Paso Electric had $58.7 million in fuel costs. For the period ending in April 1992, the 3-year rolling average capacity factor was 52.4%. This led to a penalty of $1.9M. In 1993 and 1994, however, the average capacity factor fell within the deadband resulting in neither a penalty or reward.

Table 2.22 Public Utility Commission of Texas operating incentive program (El Paso Electric Company)

Composite capacity factor	Revenue adjustment
Above 87.5%	Company will be rewarded based upon the difference between variable fuel costs and Palo Verde fuel costs multiplied by the kilowatt-hours in this band.
Above 77.5% to 87.5%	Company retains 50% of any incremental fuel savings
62.5% to 77.5%	Deadband, no penalty or reward
Below 62.5% to 52.5%	Company absorbs 50% of any incremental fuel cost
Below 52.5% to 35%	100% penalty, the company is penalized based upon the difference between variable fuel costs and Palo Verde fuel costs multiplied by the kilowatt-hours in this range.
Below 35%	No additional penalty; however, an investigation by the TPUC will be initiated.

Table 2.23 History of El Paso Electric Company's incentive program

Reporting year	Unit 1	Unit 2
1990	No Standards	No Standards
1991	Penalty - $2,183,000	$300,000
1992	Penalty - $1,744,000	Penalty - $155,000
1993	Deadband	Deadband
1994	Deadband	Deadband

Table 2.24 Palo Verde 1 and 2 performance standards calculation results

Evaluation reporting period	Palo Verde	Capacity factor	Penalty	Interest	Total	Cumulative total
April 22, 1988	1	43.04%	$2,182,646	$482,297	$2,664,943	
to						
April 21, 1991	2	58.51%	$299,973	$66,287	$366,260	
	Total		$2,482,619	$548,584	$3,031,203	$3,031,203
April 22, 1989	1	44.57%	$1,744,133	$194,347	$1,938,480	
to						
April 21, 1992	2	60.20%	$154,849	$17254	$172,103	
	Total		$1,898,982	$211,601	$2,110,583	$5,141,786
April 22, 1990	1	72.91%	$0	$0	$0	
to						
April 21, 1993	2	75.22%	$0	$0	$0	
	Total		$0	$0	$0	$5,141,786

2.19 State: Virginia

Program Effective: January 1979

Regulatory Authority: Virginia State Corporation Commission

Utility Affected: Virginia Electric and Power: Surry 1 and 2, 100%
North Anna 1 and 2, 88.4%

Program Status: Program in Operation

Performance Criterion: Capacity Factor (primary measure)

Type of Incentive Program: Utility Performance Standard (Subjective denial of replacement fuel costs; Subjective determination of rate of return on equity)

1994 Update/Changes: The program remains unchanged since last reporting period.

Description: The Virginia State Corporation Commission (VSCC) conducts two types of annual utility proceedings: an annual fuel proceeding, to determine the reasonableness of fuel expenses; and a base rate proceeding.

The fuel recovery clause defines a procedure for evaluating the reasonableness of fuel expenses. The procedure is based on factors such as generating unit performance, delivered fuel prices, system load, and interchange levels. Of these factors, generating unit performance is one area over which utilities can exercise a significant degree of control. For nuclear units, evaluations of performance are based on five indices: capacity factor, availability factor, equivalent availability factor, heat rate, and forced outage rate. Capacity is the primary factor; if the capacity factor is high, the rest of the indicators usually are also. The utility provides projected fuel expenses for a 12-month period for the system. Projected expenses assume a performance level for each unit on the system. Over the 12-month period, monthly fuel costs for each unit on the system are submitted to the VSCC and compared to projections. Investigations are conducted when significant discrepancies occur between the projections and the actual costs, or when performance is below expected levels. A utility may be subject to a prudency review and disallowance of fuel costs because of poor performance.

The VSCC, in determining the rate of return on equity, provides for a positive incentive to the utility. The selected rate of return is a function of the performance of the utility's system as a whole, nuclear units being only one component of the utility's system. The recommended rate of return is based on performance over the entire period of commercial operation as well as the current year.

Implementation Results: As determined in the fuel proceeding, a utility neither accrues a reward nor incurs a penalty based on exceeding or failing to meet performance targets. Recovery of fuel costs is based on the reasonableness of a utility's fuel expenses, which is determined, in part, by an examination of performance levels. Utility performance, however, does influence the selected rate of return on equity. The range established in 1985 for the rate of return on equity was 14% to 15%; Virginia Electric and Power's return for this year was 14.5%. The 1986 range was reduced to 12.5% to 13.5%; the return for this year was 13.25%, in recognition of sustained improvement. However, in 1989 it was lowered to 13% as a result of 1988's 48% nuclear capacity factor. In addition, $6 million of fuel costs were disallowed that year. Effective November, 1992, the range was lowered to 10.5% to 11.5%, with the rate of return on equity set at 11.4% due to exceptional generation performance.

3 Findings

3.1 Overview of the Section

Changes within an individual incentive program report (not necessarily to an incentive program) since the 1993 publication of NUREG/CR-5975 are summarized in Table 3.1, Incentive Programs Grouped by State Regulatory Authority and Nuclear Unit. The number of states that apply incentive programs and the number of affected units have not significantly changed.

Table 3.1 is organized alphabetically by state and follows the organization of Chapter 2 of this report. It includes states that have proposed or currently have incentive programs, and those who recently discontinued programs. The nuclear units within a given state are grouped together by state regulatory program, irrespective of utility ownership. For each nuclear unit subject to a state incentive program, the table lists incentive program classification, performance criteria, NRC region, report status, and the page number of the individual program report.

Incentive programs may be classified as a nuclear performance incentive program or a utility performance standard program. The incentive program classification also indicates those programs that specifically address one aspect of a nuclear unit, such as construction costs or safety. Report status indicates whether or not a program as reported in NUREG/CR-5975 remains the same, has been substantially modified, or has been discontinued. Programs previously not reported are indicated to be new. Discontinued programs are cited as required in individual program reports, but are not included as individual program reports.

Table 3.2, Summary of State Incentive Programs Discontinued As of 1992, provides a brief description for incentive programs that ceased to apply prior to 1992. The table's organization identifies the state regulatory authority and incentive program classification, utility, nuclear unit, and effective date of each program. Programs are also described in terms of performance criterion and type of program, including comments. Although the programs listed in Table 3.2 do not appear as individual program reports, they may be referred to in the description of existing incentive programs. For detailed information concerning discontinued programs, see NUREG/CR-4911 (1991), NUREG/CR-5509 (1989), or NUREG-1256 Vol. 1 (1987).

3.2 General Trends

Incentive programs established by state regulators are applicable to 57 nuclear units in 16 states (see Table 3.1). Twelve programs fall into the nuclear performance incentive category and five are utility performance standards. Two state programs, New York and Ohio, have characteristics of each type of plan. Fifteen programs have been discontinued to date. Nuclear performance reached a record high in 1992. The average nuclear capacity factor was 70.9 percent while nuclear generation was 619 billion net kilowatt-hours. In 1989, the average capacity factor stood at 62.2 percent and nuclear generation was 529 net billion kilowatt-hours. The Energy Information Administration (EIA) projects that the average capacity factor will increase to 74 percent in 2010 while nuclear generation will decline to 612 billion kilowatt-hours, or 17 percent of total electricity generation. The projected decline is based upon EIA's assumption that no new nuclear units will be manufactured during that period of time. In fact, the number of generating units declined for the first time from 111 in 1991 to 109 in 1992 (AEO, 1993).

Some in the electric industry believe that there will be a future trend toward the implementation of broad management programs such as a revenue-sharing and price cap plans. These plans are already gaining popularity in some regions. Utilities facing deregulation in the near future view these programs as particularly effective because they allow the plant increased investment flexibility. Under these broad programs, the utility has more freedom to choose between alternative investments. In addition, these programs make incentive regulation redundant because the broad plan promotes efficiency throughout the organization, including the plant.

3.3 Rewards/Penalties vs. Utility Net Income

Table 3.3 shows the average rewards and penalties and average net income from 1990-1993 by investor-owned utility. The average reward and penalty during the 4-year period accounted for less than 2 percent of average annual net income during the same period for 23 of the 28 utilities involved in nuclear incentive programs (rewards/penalties do not apply to the Pacific Gas and Electric program). The exceptions to this, Arkansas Power and Light and Boston Edison, earned rewards over the period that averaged 8.87% and 2.22% of net income, respectively. Conversely, Connecticut Light and Power and Niagara Mohawk Power averaged a penalty of 5.67% and 2.33% of net income, respectively. The impacts of rewards and penalties in a single year can be substantial, and could be sufficiently large to provide incentives or disincentives to safe operations. Nevertheless, the long-term bottom line effect appears to be relatively minor for the majority of utilities and, on average, tends to add to a utilities bottom line.

The average of the rewards and penalties across all utilities over the 1990-1993 period was approximately +$724,000 per year.

3.4 Other Factors

As the nuclear stock ages, plant expenditures on equipment maintenance could become an important safety issue. For example, Portland General Electric announced the closure of the Trojan nuclear plant rather than invest $150 million in new steam generators. Incentive regulation can play an important role in plant decisions involving maintenance shutdowns and equipment replacements. Rewards and penalties stemming from the programs are transferred to shareholders through dividends typically in the year in which they are incurred. However, the pecuniary effects of the programs are small as are the effects on shareholder return in most cases. Despite this, however, utility officials maintain that the programs serve as an effective internal barometer of performance and help to define plant goals.

Table 3.1 Incentive programs grouped by state regulatory authority and nuclear unit

State regulatory authority	Nuclear unit	Incentive classification	Performance criteria	NRC region	Report status	Page
Arizona	Palo Verde 1, 2, & 3	Construction Cost Cap	Total Costs	5	Discontinued	N/A
Arkansas	Arkansas Nuclear 1 & 2	Nuclear Performance	Capacity Factor	4	Same	2.2
California	Diablo Canyon 1 & 2	Nuclear Performance	Generation & Expenses	5	Revised	2.4
	San Onofre 1, 2, & 3 Palo Verde 1, 2, & 3	Nuclear Performance	Capacity Factor	5	Revised	2.6
Connecticut	Millstone 1, 2, & 3 Connecticut Yankee	Performance Standard	Capacity Factor	1	Same	2.10
Florida	Crystal River 3, St. Lucie 1 & 2, Turkey Point 3 & 4	Nuclear Performance	Equivalent Availability Heat Rate	2	Same	2.12
Georgia	Hatch 1 & 2 and Vogtle 1 & 2	Nuclear Performance	Capacity Factor	2	Same	2.15
Illinois	Dresden 2 & 3, La Salle County 1 & 2, Zion 1 & 2, Bryon 1 & 2, Braidwood 1 & 2, Quad Cities 1 & 2, and Carroll County	Performance Standard	Total Fuel Cost	3	Discontinued	N/A

Table 3.1 (Continued)

State regulatory authority	Nuclear unit	Incentive classification	Performance criteria	NRC region	Report status	Page
Maryland	Calvert Cliffs 1 & 2	Performance Standard	Capacity Factor	1	Same	2.17
Massachusetts	Pilgrim	Nuclear Performance	Capacity Factor, Performance Indicators, SALP Ratings	1	Revised	2.19
	Pilgrim and Millstone 1, 2 & 3	Performance Standard	Equivalent Availability Factor (primary measure)	1	Same	2.22
Michigan	Fermi 2	Nuclear Performance	Capacity Factor	3	Same	2.26
New Jersey	Salem 1 & 2, Hope Creek, Peach Bottom 2 & 3, Oyster Creek, Three Mile Island 1	Nuclear Performance	Capacity Factor	1	Same	2.27
New Mexico	Palo Verde 1 & 2	Nuclear Performance	Capacity Factor	5	Same	2.31
	Palo Verde 1 & 2	Nuclear Performance	Capacity Factor	5	Discontinued	2.33
New York	Ginna, Nine Mile Point 1 & 2, Indian Point 2	Nuclear Performance, Performance Standard	Fuel Costs	1	Revised	2.35
North Carolina	Brunswick 1 & 2, Robinson, McGuire 1 & 2, Oconee 1, 2 & 3, Catawba 1, Surry 1 & 2, North Anna 1 & 2	Performance Standard	Capacity Factor	2	Same	2.38
Ohio	Davis-Beese, Perry 1, Beaver Valley 1 & 2	Nuclear Performance, Performance Standard	System Performance & Utility Efficiency, Operating Availability Factor	3	Same	2.40
Pennsylvania	Limerick 2	Construction Cost Cap	Total Costs	1	Discontinued	N/A
	Limerick 1 & 2, Salem 1 & 2, Peach Bottom 2 & 3	Nuclear Performance	Composite Capacity Factor	1	Same	2.43
Texas	Palo Verde 1, 2 & 3	Nuclear Performance	Capacity Factor	4	Same	2.45
Virginia	Surry 1 & 2, North Anna 1 & 2	Performance Standard	Capacity Factor (primary measure)	2	Same	2.47

Table 3.2 Summary of incentive programs discontinued as of 1992

Regulatory authority: program classification	Utility	Nuclear unit	Effective dates	Performance criterion	Comments/type of program
ARIZONA: Nuclear Performance Incentive	Arizona Public Service	Palo Verde 1	Effective 1986; Discontinued 1989	Annual Capacity Factor	Reward and penalty; '87 Penalty $1.7M; '88 Penalty $19K
ARIZONA: Construction Cost Cap	Arizona Public Service	Palo Verde 1, 2, and 3	Effective Nov. 1984; Concluded upon completion of plants	Total Costs	No penalties resulted from this program
CALIFORNIA: Nuclear Performance Incentive	Pacific Gas & Electric	Diablo Canyon 1 & 2	Discontinued 1987	Capacity Factor	Reward and penalty; '86 reward $14.0M; settlement of disputed construction costs established Performance-Based Pricing
COLORADO: Nuclear Performance Incentive	Public Service of Colorado	Fort St. Vrain	Discontinued 1986	Annual Capacity Factor	Penalty; settlement agreement paid accumulated penalties and discontinued incentive plan
FLORIDA: Nuclear Performance Incentive	Florida Power & Light	St. Lucie 2	Effective 1983; discontinued 1984	Annual Capacity Factor	Reward and penalty; reward $3.5M
ILLINOIS: Utility Performance Standard	Commonwealth Edison	Dresden 2 & 3, LaSalle County 1 & 2, Zion 1 & 2, Bryon 1 & 2, Braidwood 1 & 2, Quad Cities 1 & 2, Carroll County	1988 agreement rescinded Dec. 1989	Total Fuel Cost	No financial impacts resulted under this program
MICHIGAN: Utility Performance Standard	Consumers Power	Palisades and Big Rock Point	Not Available	Availability	Rate of return on equity
MISSISSIPPI: Utility Performance Standard	System Energy Resources	Grand Gulf	Concluded 1989	Multiple Performance Parameters	Allowed revenues; fossil generation trial program
NEW JERSEY: Construction	Public Service Electric & Gas	Hope Creek	Concluded 1987	Total Construction Costs	Reward and penalty; $4.0 billion rate base allowance; $516 million disallowance
NEW MEXICO: Utility Performance Standard	Public Service of New Mexico	Palo Verde 1	Discontinued 1989	Excess Capacity	Disallowed due to the accounting treatment of the inventory capacity
NEW MEXICO: Nuclear Performance Incentive	Public Service of New Mexico	Palo Verde 1 & 2	Discontinued 1995	Capacity Factor	
NEW YORK: Nuclear Performance Incentive	Rochester Gas & Electric, Niagara Mohawk, and Consolidated Edison	Ginna, Nine Mile 1 & 2, and Indian Point 2	Withdrawn 1989	NRC SALP Ratings & Fines	Proposed to give bonuses to nuclear plant workers

Table 3.2 (Continued)

Regulatory authority: program classification	Utility	Nuclear unit	Effective dates	Performance criterion	Comments/type of program
OREGON: Utility Performance Standard	Portland General Electric	Trojan	Discontinued 1987	Fuel Costs	Reward and penalty
PENNSYLVANIA: Construction	Philadelphia Electric	Limerick 2	Concluded upon completion of plant	Total Costs	$2.8 billion construction cost; $210 million disallowance
VIRGINIA: Utility Performance Standard	Virginia Electric and Power	Surry 1 & 2, North Anna 1 & 2	Concluded 1985	Fuel Costs	Rate of return on equity; Three year trial basis

Table 3.3 Comparison of rewards/penalties to financial statistics

Utility	Net Income ('000)					Rewards/(Penalties) ('000)					% of Net Income
	1993	1992	1991	1990	Average	1993	1992	1991	1990	Average	
Arkansas Power & Light	205,297	130,529	143,451	129,764	152,261	20,600	11,300	13,300	8,800	13,500	8.87%
Pacific Gas and Electric	106,495	1,170,581	1,026,392	987,170	822,660	N/A	N/A	N/A	N/A	N/A	N/A
Southern California Edison	678,045	672,909	629,533	736,753	679,310	0	5,970	0	5,030	2,750	0.40%
San Diego Gas & Electric	218,715	210,657	208,060	207,841	211,318	2,670	570	0	2,584	1,456	0.69%
Connecticut Light & Power	191,449	206,714	240,818	224,783	215,941	(49,000)	0	0	0	(12,250)	-5.67%
Florida Power	194,900	186,900	108,900	182,300	168,250	1,876	2,024	1,666	1,874	1,860	1.11%
Florida Power & Light	467,960	514,800	417,517	424,804	456,270	3,406	5,586	6,937	2,093	4,506	0.99%
Georgia Power	620,527	578,480	536,556	274,189	502,438	0	8,496	0	0	2,124	0.42%
Baltimore Gas & Electric	309,866	264,347	233,681	213,200	255,274	0	0	0	0	0	0.00%
Boston Edison (2)	118,218	107,298	94,670	79,616	99,951	8,792	0	(375)	471	2,222	2.22%
Western Massachusetts Electric	40,594	31,218	34,637	35,191	35,410	0	0	0	0	0	0.00%
Detroit Edison	521,903	588,047	568,037	514,459	548,112	(147)	0	0	0	(37)	-0.01%
Public Service Electric & Gas	614,868	475,936	545,479	537,619	543,476	(3,900)	0	0	0	(975)	-0.18%
New Jersey Central Power & Light	158,344	117,361	126,460	128,532	132,674	700	(500)	2,700	(3,900)	(250)	-0.19%
El Paso Electric (2)	137,899	28,180	556,014	21,864	185,989	0	(1,838)	(1,878)	0	(929)	-0.50%
Public Service Company of New Mexico	61,486	104,255	22,960	442	47,286	0	131	0	0	33	0.07%
Rochester Gas & Electric	78,563	70,439	57,997	59,881	66,720	0	0	2,600	2,400	1,250	1.87%
Niagara Mohawk Power	271,831	256,432	243,369	82,878	213,628	6,926	(1,384)	(10,455)	(15,019)	(4,983)	-2.33%
New York State Electric & Gas	166,028	183,968	168,643	158,013	169,163	0	1,030	(1,084)	(1,003)	(264)	-0.16%
Long Island Lighting Company	296,563	301,974	305,538	319,637	305,928	0	0	0	0	0	0.00%
Consolidated Edison	668,522	604,088	566,910	571,493	602,753	10,000	0	0	0	2,500	0.41%
Carolina Power & Light	346,496	379,635	376,974	280,429	345,884	0	0	0	0	0	0.00%
Duke Power	626,415	508,083	583,623	538,188	564,077	0	0	0	0	0	0.00%
Virginia Electric & Power	509,000	469,500	487,400	450,354	479,064	0	0	0	0	0	0.00%
Toledo Edison	N/A	71,000	49,613	81,424	67,346	3,174	0	1,278	0	1,113	1.65%
Cleveland Electric Illuminating	N/A	205,000	246,000	242,328	231,109	3,791	0	1,492	0	1,321	0.57%
Ohio Edison	82,724	276,986	264,823	281,676	226,552	1,258	0	1,220	0	620	0.27%
PECO	509,648	478,941	534,860	214,190	434,410	9,745	530	5,646	0	3,980	0.92%
									Average	**$724**	

Note: Rewards/(Penalties) frequently do not correspond to fiscal year. In these cases, revenues from the period in which the reward (penalty) was assessed were used Rewards/(Penalties) do not necessarily correspond to directly to net income year.

Sources: Pocket Guide to U.S. Electric Utilities (2nd edition); UDI, Financial Statistics of Selected Investor-Owned Electric Utilities, 1993, Directory of Electric Utilities, 1994 (102nd edition); Electric World Moody's Public Utility Manual, 1993 & 1994.

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11. ABSTRACT *(200 words or less)*

The U.S. Nuclear Regulatory Commission (NRC) periodically surveys utiltites that operate nuclear plants and state regulatory commissions that regulate utility owners of nuclear power plants. The NRC is interested in identifying states that have established economic or performance incentive programs applicable to nuclear power plants, including states with new programs, how the programs are being implemented, and in determining the financial impact of the programs on the utilities. The NRC interest stems from the fact that such programs have the potential to adversely affect the safety of nuclear power plants.

The information in this report was obtained from interviews conducted with each state regulatory agency that administers an incentive program and each utility that owns at least 10% of an affected nuclear power plant. The agreements, orders, and settlements, that form the basis for each incentive program were reviewed as required. The interviews and supporting documentation form the basis for the individual state reports describing the structure and financial impact of each incentive program.

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