JAN 27 1984

MEMORANDUM FOR: Frank H. Rowsome, Assistant Director for Technology, Division of Safety Technology, NRR

FROM: Jerome Saltzman, Assistant Director for State and Licensee Relations, OSP

SUBJECT: INCENTIVE REGULATION OF NUCLEAR GENERATION FACILITIES BY STATE PUCs

Enclosed is our report on the subject of incentive regulation of generation facilities by State public utility commissions. The incentive programs reported herein are those specifically applicable to nuclear facilities. Other programs apply to fossil plants. In drawing from the three current studies on the subject, an attempt was made to sort out from a large amount of information that material that may be of interest to reactor safety regulators. If there are questions related to this material please contact Jim Petersen of this office on 492-9883.

Jerome Saltzman, Assistant Director
State and Licensee Relations
Office of State Programs

Enclosure:
As stated

Distribution:
Subject: Incentive Regulation by State PUCs
OSP Dir r/f
SLR r/f
w/encl: GWKerr
JSaltzman
DNash
RWood
JPetersen

8501180405 840621
PDR FOIA
BELL84-433 PDR

OFFICE	LR:OSP	LR:OSP	SLR:OSP
SURNAME	JPetersen/cb dr	DNash	JSaltzman
DATE	1/24/84	1/27/84	1/27/84

15

January 27, 1984

INCENTIVE REGULATION OF GENERATION FACILITIES BY STATE PUCs

Incentive plans aimed at increasing the efficiency of operation of nuclear power plants are in effect in eleven States. Two States have plans providing cost incentives related to construction of nuclear plants. This paper summarizes the provisions of such incentive plans. It also summarizes the findings pertinent to nuclear power of the three recent national studies on this subject. An attempt has been made to sort out and highlight the studies' findings that may be most interesting to reactor safety regulators. The recent studies have been done by the National Association of Regulatory Utility Commissioners (NARUC) 1/, the S. M. Stoller Corporation (for the California PUC) 2/, and the Quadrex Corporation (for EEI). 3/

1/ "Incentive Regulation in the Electric Utility Industry," prepared by the NARUC Subcommittee on Electricity, September 1983.

2/ "Standards of Performance Study, SONGS 1," S. M. Stoller Corporation, for California PUC, under contract to Southern California Edison Co., August 1983.

3/ "Incentive Regulation Programs in the Electric Utility Industry," (final draft), Quadrex Corp., for EEI, July 1983.

Summary of Findings - NARUC

Although the NARUC study is primarily a survey and description of individual State incentive plans, it does provide some overall findings and conclusions. NARUC, the national organization of State public utility commissioners and other utility regulators and their staffs (note: NRC is a member of NARUC), says that a very significant level of regulatory effort is being exerted to develop incentive regulation in the electric utility industry.

> "It appears to be widely recognized that incentives may provide a means of assuring reliable electric service at a more reasonable cost than a continuous, rigorous, and detailed review of each utility's operations (as has been the traditional PUC mode of operation). Limitations on the budgets of regulatory agencies, which have always existed, but have become more acute, also indicate the necessity for more effective and efficient regulatory tools. Currently, the greatest regulatory effort appears to be directed at the efficiency of operation and utilization of generation facilities. This is particularly understandable in those States where energy costs (fuel and purchased power) represent 50 percent and more of the electric utilities' total cost of operation." [4/]

[4/] NARUC Study, p. 1-1.

The NARUC study recommended further regulatory initiatives in the area of performance incentives and said that regulatory agencies should establish a high priority for such projects. NARUC recommended the following approaches in carrying this out:

- o The appropriate allocation of replacement energy cost between ratepayers and stockholders.

- o A combination of continuing regulatory review of detailed performance indicators with an indexing system to be applied between major operation reviews (general rate cases).

- o The application of decision analytic techniques to the measurement of relative performance.

- o Aggregate performance as measured by such indicators as average unit revenue and the growth rate of operating and maintenance expenses.

Summary of Findings - Stoller

In October 1981, the California Public Utility Commission (CPUC) directed Southern California Edison Company (Edison) to engage a consultant to carry out a standards of performance study for the SONGS-1 nuclear unit. In November 1982, the CPUC selected the S. M. Stoller Corporation (Stoller) to perform the study. In the course of its study Stoller reviewed and reported on performance standards programs promulgated in other states which could impact the formulation of a program for SONGS-1. Stoller makes the following observation in the background of its report:

"In the past several years, there has been increasing regulatory interest in the performance of large central station generating units, both fossil and nuclear. This interest primarily reflects the well-publicized increasing cost of construction, but as well the increased cost of operation, of such units. Improvements in availability and capacity factor performance of existing units can thus represent very material savings to the ratepayers and to the owner utility, both in deferral of future system additions, and also for low incremental cost units, such as nuclear units, in reduced overall system generating costs.

The SONGS-1 study ordered by CPUC is consistent with the increasing efforts by utility regulators across the country in encouraging efforts to improve availability by the establishment of explicit standards of performance for large generating units. These programs incorporate some formulistic mechanism intended to be capable of simple interpretation and implementation, by which "good" performance of a unit on a utility system can be rewarded, or "poor" performance penalized. Such standard programs are seen as producing two potentially desirable effects:

1. They can act as a further incentive to the utility owner to seek means to improve performance.

2. Such approaches may be preferable from an implementation standpoint to "reasonableness tests," or other retrospective judgments often required for ratemaking purposes.

However, in considering such a program applied specifically to the SONGS-1 nuclear unit, Stoller determined that several important issues needed to be addressed are:

1. The potential exists that a program applied to a nuclear unit could encourage trade-offs which have adverse implications for the public health and safety.

2. The potential similarly exists that such a program could encourage trade-offs between actions designed to maximize the measured performance against which the financial rewards or penalties of the program are applied, at the expense of operating policies and actions which would be more cost-effective in the longer-term interest of the ratepayer.

3. The SONGS-1 plant is one of the very oldest units in current operation and much of that total nuclear power operating experience data base is thus not properly applicable due to design differences between SONGS-1 and the later units. In addition, due to its comparatively advanced age, one must take into account the potential impact of aging or "wear-out" in future SONGS-1 performance.

4. Most important, and as already alluded to, the very extensive plant modifications expected to result from the NRC-required SEP program can be expected to result, as a minimum, in a series of extended planned outages over the next several years. Any standards program, to be effective and practical, must account for such planned outages." 5/

As part of its study, Stoller specifically assessed the emphasis by Edison management on safety versus kilowatt-hour production, especially in gray areas where NRC regulations do not specifically mandate operator action. Stoller points out that it deemed the matter of potential conflict between safety and production to be important enough to be worth exploring with the NRC directly.

5/ Stoller, pp. I-3 through I-5.

Stoller's meeting with NRR management in May 1983 is reviewed in its report. Although the Stoller study was specifically addressed to SONGS-1, the CPUC has not placed any performance incentive requirements on that unit since it has been inactive for the past two years. Reactivation of the unit is dependent on NRC-required upgrades including those related to seismic capability. The Stoller findings were used as background for the performance incentives imposed by the CPUC on SONGS-2 (see individual State summary below) in September 1983. The CPUC staff says that it is reasonable to assume that similar performance incentives will be considered for SONGS-3 which may begin operation in Spring 1984.

Included in Stoller's findings and conclusions are certain points particularly relevant to NRC requirements for nuclear plants:

- "There are no indications that the other state incentive programs studied have distorted the priority relative to nuclear safety, nor any evidence of special concern by NRC for those units included in such programs."

- "It is desirable to avoid sharp thresholds in financial impacts; that is, to smooth the financial impact of a particular decision at a particular point in time. One step in that direction may be to average the performance over longer periods; programs where the measurement is made on very short intervals; e.g., six months, are prone to put undue pressure on an operating decision."

- "Broadening the base of the formula, e.g., to include the performance of more than one unit on the system, either other nuclear units, or some combination of nuclear and fossil, may also serve to diminish the financial importance; and thus, the pressure on the operator of a singular operating division. This would also help to avoid undue management attention to a specific unit."

- "It is probably useful to establish a "null zone" to accommodate variations in performance, for any number of random causes, which inevitably occur in the operation of a unit from year-to-year. This concept may be particularly applicable to nuclear units, for which the statistical experience base is still relatively modest, and quite nonuniform; and therefore, performance predictions are not founded on an especially valid statistical base. However, if such a tolerance band is incorporated in the formulas, it would still be preferable to smooth the financial impact as one departs the zone, rather than have major step changes."

- "The principal administrative burden is associated with accommodating events which are outside the control of the utility, notably NRC backfit requirements. Prior to 1976, for example, the average impact on capacity factor of NRC backfit requirements was less than 1%. In the latter half of the 1970's, this increased dramatically so that by 1979 the annual losses in capacity factor due to NRC backfit requirements on pressurized water reactor units had reached over 16%. In the last two years it has been decreasing, again getting down to about 7% in 1981 and 1982." 6/

Summary of Findings - EEI (Quadrex)

Although the EEI report is a draft, its contents are considered accurate and close to completion. The final report is expected out in early 1984. EEI says its draft is suitable for review and quotation in limited distribution reports such as this but requests that it should not receive wide distribution or quotation. The EEI study, like the NARUC study, is largely survey material but the individual State summaries are more in-depth than those reported by NARUC.

EEI reports that the most popular incentive program objectives are to reduce fuel and/or purchased power costs, and to improve power plant productivity or efficiency. Most of the programs are linked to fuel and purchased power costs. Capacity factors, availability levels, and heat rates are the most frequently used criteria to measure performance. Most of the programs rely on combinations of multiple criteria to measure performance rather than one single

---

6/ Stoller, pp. I-22 through I-24.

measure in order to avoid distortions or unintended outcomes. In some cases, narrowly defined operating measures have led to increases in the cost of service rather than greater efficiency. Just as most of the programs rely on multiple measures of performance, most also provide both rewards and penalties rather than a singular reward or penalty avoidance. Rewards and penalties for almost all of the programs are made through adjustments in allowable fuel and purchased power costs or to the company's return on equity.

Individual State Incentive Programs (Operating Performance)

The NARUC and EEI surveys identify eleven States that have operating performance incentives specifically aimed at nuclear plants. Each of these is individually summarized below using information drawn from Stoller, EEI and NARUC. Conclusions reported herein regarding the effectiveness of the incentives and their relationship to efficient operation and to safety are those of the three referenced studies. In addition to the programs designed for nuclear plants, twelve States have performance incentives applicable to all or most generating units. The following table identifies key elements of the operating performance incentives applicable specifically to nuclear plants. Construction incentives are reviewed separately later.

Summary of State Operating Performance Standards Programs (Nuclear) (Notes on following page.)

Nuclear Plant	Utility	State/ Start of Program	Focus of Program	Type of Target	Reward Range	Penalty Range	Rewards/ Penalties To Date
Arkansas Nuclear One Units 1 & 2	Arkansas Power & Light	Arkansas 1980	Fuel Adjustment Clause	CF Between Scheduled Refueling	CF > 72.9% (#1) CF > 71.5% (#2)	CF < 72.9% (#1) CF < 71.5% (#2)	-$44 M (3 years)
San Onofre NGS Unit 2	Sou. Cal. Ed/ SDG&E	Calif. 1983	Fuel Adjustment Clause	CF	CF > 80%	CF < 55%	N. Avail.
Fort St. Vrain	Pub. Serv. Colorado	Colo. 1981	Rate Base/ Rate of Return	CF Between Scheduled Outages	None	CF < 50%	None
Millstone Conn. Yankee	Conn. L&P/ Hartford Elec.	Conn. 1979	Fuel Adjustment Clause	CF	CF > 70% (1).	CF < 55% (1).	None
Crystal River St. Lucie 1&2 Turkey Point 1&2	Fla. Power Corp. Fla. P&L	Fla. 1981	Return on Equity	EA & HR	(2).	(2).	FPC:-$40K FP&L:+$1.7M
Calvert Cliffs 1&2	BG&E	Md. 1978	Replacement Fuel Cost	EA	None	Judgment	(3).
Pilgrim Yankee-Rowe	Boston Edison Yankee Atomic	Mass. 1981	Fuel Charge	AF, EA, CF, HR & FOR	None	(4).	None
Big Rock Point Palisades	Consumers Pwr.	Mich. 1978	Return on Equity	ECAR Availability	(5)	(5)	+$14M
Brunswick 1&2 McGuire Surry, N. Anna	Carolina P&L Duke Power Co. VEPCO	N. Carolina 1978	Return on Equity	(6).	(6).	(6).	(7).
Davis Besse	Toledo Edison	Ohio 1981	Fuel Cost	Cost Effectiveness	Mce > 1 (8)	Mce ≤ 1 (8)	Not Determinable
Surry 1&2 North Anna 1&2	VEPCO	Va. 1982	Return on Equity	CF	Judgment	Judgment	(9).

Abbreviations in Table:

AF = Availability Factor
EA = Equivalent Availability
CF - Capacity Factor
HR = Heat Rate
FOR = Forced Outage Rate

M = Million
K = Thousand
ECAR = East Central Area Reliability Coordination Agreement

Footnotes:

(1) The Connecticut Program has implicit reward and penalty features in addition to explicit penalty for performance below 55% weighted average nuclear CF. There is an interest penalty for performance between 55% and 70% and an interest reward for performance greater than 70%. Since weighted average nuclear CF has not been below 55%, no penalties have been levied. Amount of interest penalties or rewards are not tracked by Connecticut Division of Public Utilities Control and affected utilities.

(2) Reward/penalty is proportional to the ratio of actual deviation from performance targets to predicted maximum deviation.

(3) BG&E has had 25% of replacement fuel cost and 75% of replacement fuel cost disallowed for two different Calvert Cliffs outages. Associated dollar values of the penalties are not known.

(4) Target values of AF, EA, CF, HR, and FOR are set for each plant covered in Massachusett's program (Specified by Mass. DPU).

(5) The reward and penalty range are ECAR availability plus periodic factor greater than 89% and less than 83.01% respectively.

(6) No. Carolina has not set targets by which performance is judged.

(7) In a 1981 rate case, the No. Carolina Utilities Commission reduced VEPCO's return on equity from 15% to 10%. In a 1982 rate case, the Commission reduced CP&L's return on equity by 1%.

(8) Mce is a complex formula used to measure cost-effectiveness. It involves a number of efficiency measurements including fuel utilization, fuel procurement, sales pricing policy, and purchased power policy.

(9) In a 1981 rate case, VEPCO's return on equity was reduced to low end of authorized range. A ½% reduction in return on equity costs VEPCO approximately $14 million annually. In a 1979 fuel proceeding, VEPCO was ordered to refund to its customers the net replacement energy costs ($3.3 million) associated with a Surry Unit 2 outage.

Arkansas

Affected Nuclear Plant and Utility: Arkansas Nuclear One Units 1 & 2, Arkansas Power and Light

In June 1980 the Arkansas PSC established an incentive to protect ratepayers from the replacement power costs which could result from excessive outages of Arkansas Nuclear One Units 1 and 2. The practical results of the program are as follows:

1. When a nuclear unit is down for refueling, all replacement power costs are passed to the consumer.

2. When a nuclear unit is not refueling and has not been shut down for more than 30 consecutive days, AP&L is penalized all replacement power cost attributable to the nuclear unit's operating below its target capacity factor and keeps any fuel savings attributable to operating above target. Target capacity factors are 72.923% for Unit 1 and 71.55% for Unit 2.

3. For the thirty-first and any subsequent days of any continuous outage, AP&L is penalized 10% of any replacement power costs associated with that outage.

4. Although not explicitly stated in any documentation, the Arkansas PSC treats any refueling outage beyond a specified duration as being an outage subject to (2) and (3) above. The specified refueling outage durations are 10 weeks for Unit 1 and 8 weeks for Unit 2.

Experience with the Arkansas program is reported to be as follows:

1. Capacity factor targets between refueling outages and the outage duration targets were set on the basis of experience prior to the TMI accident. Average capacity factors for similar units to ANO Unit 1 and 2 in recent years have been worse than the Arkansas targets.

2. Each month's rewards and penalties are based on average fossil fuel costs during that month. According to Stoller, since the average fossil fuel costs are lower when nuclear units are not running, AP&L could end up with a net penalty even if both nuclear units ran on the average, exactly at the target capacity factors while experiencing the normally expected month-to-month variations.

3. If either unit refuels less frequently than implied (once every 18 months for Unit 1, and once every 12 months for Unit 2) that unit would have to exceed its target capacity factor between refuelings by some amount in order for AP&L to break even. Stoller provides calculations for such a situation (pp. IIC-7, 8).

4. The Fuel Adjustment Clause Rider does not incorporate provisions for modifying unit performance to account for (a) NRC-mandated outages or outage extensions, and (b) events occurring at other nuclear plants which require additional outage time for ANO units to perform inspections, tests and any necessary changes.

5. The Rider does not allow for reduced power output due to other factors beyond AP&L's control (e.g., reduced demand). In fact, there are times when it will not permit performance credit to ANO units when they are fully operational (i.e., when they provide part of their power output to the Middle South Utilities Power Pool because of reduced demand or availability of cheaper power for the Arkansas ratepayers).

6. The Rider has the potential to guide AP&L in a direction which is not necessarily in the best interests of the ratepayer. Possible concerns include the following:

   o Refueling outage could be scheduled during peak summer months so that if any extension occurs, it takes place during the fall months. Thus, penalties would be reduced and AP&L would absorb a reduced loss under the fuel adjustment calculation.

- o Extending outages rather than return to service and risk a later outage which restarts the Formula I clock. (See Stoller, P. IIc-5 for details of formulas.)

- o Shutdown of the units rather than coastdown to conserve fuel.

7. There are no maximum limits established to protect the utility from financial jeopardy in the case of extended outages.

As a result of this Fuel Adjustment Clause Rider, AP&L has received rewards and penalties in a net penalty of about $44 million in the three years of its implementation (Note: AP&L's net income in 1982 was about $107 million). AP&L has pointed out the impact of a number of factors such as the seven noted above to substantiate its case that the Rider is unfair, and is in fact a penalty-only provision. It was also stated that the Commission person responsible for developing the Rider did not anticipate its working this way other than that provided by reducing the penalty to 10% of the replacement power costs for nonrefueling outages which extend beyond 30 days. AP&L feels that a reasonable incentive program applied to nuclear units requires some mechanism to account for the changing NRC impact upon nuclear unit performance. The magnitude of the NRC's impact can generally be assessed prior to the outage.

Stoller reports that the Arkansas PSC is considering certain revisions to the Rider to moderate its impact on AP&L. One would be the establishment of a null zone in the capacity factor target of $\pm$ 2.5%

about the target. No rewards or penalties would be assessed for ANO performance within this zone. In addition, the target capacity factor would "float" to either end of the band so that the target would be equal to the upper end of the band if performance was better than CF plus 2.5%, and it would take on the lower end of the band (i.e,, CF minus 2.5%) if performance was worse than that value. Another revision being considered would allow AP&L to keep all replacement power cost savings if a nuclear unit operated above its overall capacity factor goal. If a nuclear unit operated below its goal, penalties would normally be limited to 10% of the replacement power costs for all days by which the total of unplanned outage days and extra (beyond the 8 or 10 week target) refueling outage days exceed 30. AP&L's reward-penalty results for the past three years recalculated using the above two revisions would be a net penalty of about $4 million instead of $44 million. The maximum monthly loss of $15 million would be reduced to about $5 million.

With reference to the Arkansas procedures, Stoller concluded that "it is extremely difficult to write a provision that automatically covers all eventualities in a fair manner, thereby precluding the need for competent PSC assessment of extenuating circumstances faced by the utility."

California

Affected Nuclear Plant and Utilities: SONGS 2 - Southern California Edison, San Diego Gas & Electric

In its September 7, 1983 decision, the California PUC softened the reward/penalty provisions that its staff had suggested in the proceeding. The PUC provided that additional fuel costs resulting from SONGS-2 capacity factor below 55% and fuel cost savings for capacity factor above 80% would be shared equally (50/50) between the company (stockholders) and ratepayers. The PUC staff had recommended that additional costs and savings above and below a 65% capacity factor should accrue entirely to the company. The California PUC thought that standard was too harsh, particularly in the relatively untested area of incentives. The Commission emphasized the utility's obligation to adhere to all NRC rules and regulations and stated that the record of its proceedings included examples of other jurisdictions that have instituted nuclear performance standards without apparent detriment to nuclear safety. The PUC agreed with its staff that a performance standard such as a target capacity factor would not compromise safe plant operation. The PUC also recognized that nuclear plant outages may be due solely to factors outside the utility's control and that it would be flexible toward considering the causes and effects of such events on a case-by-case basis.

Colorado

Affected Nuclear Plant and Utility: Ft. St. Vrain, Public Service Company of Colorado

In December 1980, the Colorado Public Utilities Commission ordered that Public Service Company of Colorado would have to refund the rate base return on common equity on Fort St. Vrain to the ratepayers if this plant does not achieve a 50% capacity factor performance in the test year. The 50% capacity factor is based upon 200 MW net capacity, exclusive of scheduled downtime for maintenance and refueling. This order was modified in January 1981 wherein the Commission defined the test year as the first full year after the 1981 refueling or no later than the end of the calendar year 1982. The Commission also determined the annual rate of return on Fort St. Vrain to be 10.19% of the net jurisdictional investment which is equivalent to $807,000 per month. Public Service Company of Colorado was ordered to escrow this amount on a monthly basis separately from the general funds of the Company for ultimate disposition.

Connecticut

Affected Nuclear Plants and Utilities: Millstone and Connecticut Yankee - Connecticut Light & Power Co., Hartford Electric Light Co.

The Connecticut Division of Public Utility Control established the Generation Utilization Adjustment Clause (GUAC) for Millstone and

Connecticut Yankee. The program provides a mechanism to equitably share the risk of nuclear outages. Fuel expenses are set in base rates by applying the annual anticipated nuclear plant capacity factor (NCF). This capacity factor is used in the computation of the GUAC formula which considers the fuel cost differential between fossil and nuclear generation. If the actual weighted average nuclear capacity exceeds the NCF target, customers are credited with a part of the avoided replacement fossil fuel costs. If the capacity factor falls below 55 percent, replacement fuel costs will be borne by the utility. If the nuclear capacity is between the target and 55 percent, customers share in the cost of replacement fuel according to the formula. The DPUC staff has established the NCF target at 70 percent by comparing the historical performance of nuclear units under its control with the historical performance of all nuclear units, practices of other regulatory agencies and utilities, abstract productivity models, and statistical analyses.

The major incentive for the utility is to avoid absorbing replacement fuel costs when capacity is below 55 percent. Since performance between 55 percent and the NCF target results in sharing costs between the utility and customers and superior performance results in customers being credited with avoided replacement fuel costs, the underlying incentive may be to achieve average performance.

Florida

Affected Nuclear Plants and Utilities: Crystal River Unit 3 - Florida Power Corp.; Turkey Point Units 1 & 2, St. Lucie Units 1 & 2 - Florida Power and Light Co.

In September 1980, the Florida Public Service Commission incorporated an explicit incentive factor, the Generating Performance Incentive Factor (GPIF), within the Fuel and Purchased Power Recovery Clause. The purpose of the GPIF is to provide an incentive to utilities to achieve efficient operation of base load generating units. The GPIF targets, actual performance, and incentive are determined on a semi-annual basis. The GPIF program is applied to a utility's largest generating plants that contribute 80% or more of the energy generated.

The incentive program goal is to minimize fuel and purchased power costs. The GPIF uses complex formulas to link the rate of return allowed on common equity to average heat rates and equivalent availability of power generating units. Targets are set for average heat rates and equivalent availability, and fuel expenses are estimated by running several computer simulations of the utility system economic dispatch. Additional computer runs provide estimates of fuel cost savings associated with operations at maximum, minimum, and target levels. Rewards or penalties are determined by comparing actual operating values with targets set for equivalent availability and average heat rate. The commission staff worked with the utility companies to design the program criteria and measures. Targets are set by formula for equivalent availability and average heat rates. Equivalent availability targets are set using the historical performance record for each unit adjusted to reflect maintenance improvements. Average heat rate targets are set by using monthly data weighted according to economic dispatch with adjustments made for unit modifications, fuel changes, and environmental regulations.

Above average performance for both equivalent availability and average heat rate results in a reward, and below average performance results in a penalty. Rewards and penalties may be as much as 0.25 percent of return on common equity. The singular objective of lowering fuel costs as a function of performance targets may result in the company neglecting other areas of utility operations. At issue is whether the program minimizes the overall cost of operation. Finally, the reporting, administrative and technical analysis activities for the annual hearings involve substantial costs and commitment of manpower.

Florida PSC personnel report that the GPIF was meeting its objectives: increased efficient operation of base load plants. The following decreases in system overall heat rates since implementation of the GPIF were noted: approximately 130 BTU/Kwh at both Florida Power & Light and Gulf Power, and 160 BTU/Kwh at Tampa Electric. A decline in planned outage durations also was noted but no figures were given.

The two utilities with nuclear units, FP&L and FPC, have received both rewards and penalties during the first 4 performance periods under GPIF. FP&L has received 3 rewards totaling $1.9 million and 1 penalty of $180 thousand for a net reward of $1.72 million. FPC has received 2 rewards totaling $650 thousand and 2 penalties totaling $690 thousand for a net penalty of $40 thousand. The PSC staff noted that Crystal River 3 (an 800 MW PWR) accounted for approximately 50% of FPC's rewards and penalties. The PSC staff reported one problem with the GPIF; there is some disagreement between the PSC staff and utilities regarding targets, reasonably attainable performance ranges, and adjustments when judgment has been applied in determining these parameters. The PSC staff has required changes in approximately 50% of the performance values it has reviewed.

The response from FP&L and FPC to the GPIF were nearly identical. Both utilities reported that they always strive for high performance and implementation of the GPIF did not always result in any increased emphasis on their efforts. FP&L mentioned that they had a performance improvement program in place when the GPIF went into effect. FP&L and FPC both reported that possible safety impacts were not an issue during hearings on development of the GPIF. Further, they said there has been no NRC interest in the GPIF either during its development phase or the implementation phase. Both utilities reported that the GPIF has not impacted (i.e., neither facilitated nor complicated) the rate hearing and fuel charge hearing processes. FPC reports that the GPIF has increased the workload of the Plant Performance Group due to data tracking, collection and reporting requirements.

Maryland

Affected Nuclear Plant and Utility: Calvert Cliffs Units 1 and 2, Baltimore Gas and Electric

Under a 1978 Maryland law, fuel cost adjustment and determinations were removed from base rate hearings and a separate fuel rate adjustment mechanism was established. The intent of the law was to eliminate electric bills which fluctuated wildly from month to month due to the automatic fuel cost pass through. When a utility's monthly cost of fuel exceeds or falls below the cost fixed in the last fuel rate adjustment hearing by more than 5%, the utility notifies the Maryland Public Service Commission which must hold a new fuel rate adjustment hearing. By law, the PSC must determine if the generating units performed at reasonable levels when evaluating the fuel rate adjustment (Note: Other factors such as fuel purchases and generation mix are also evaluated). In addition, if any party brings evidence that power plant outages were caused by "improper actions: or "imprudent management," the PSC must evaluate the outage. If the PSC determines that one or more generating units did not perform at reasonable levels and/or an outage was caused by improper actions or imprudent management, then the PSC can reduce the utility's proposed fuel rate adjustment. Originally, there were no guidelines or standards for defining terms such as reasonable level of performance, improper actions and imprudent management.

The PSC has set guidelines for evaluating the performance of generating plants. A generating unit is considered to have performed at a reasonable level if its equivalent availability factor (EAF) for the most recent 12-month period exceeds the higher of: 1) its average EAF over the last 3 years, or 2) the 10-year NERC average EAF for plants of the same class. No guidelines or standard have been set to assist in defining improper actions or imprudent management related to outages.

The Public Service Commission and the affected utilities are dissatisfied with the Maryland program. Both parties realize that the program is penalty oriented; there are no rewards for above average or superior performance. In particular, investigations of plant outages and resultant penalties show the major weakness of the program. Some examples are discussed below.

In a 1982 fuel rate adjustment case, Baltimore Gas & Electric applied for an increase in fuel costs. With regard to the Calvert Cliffs nuclear plant, the PSC determined that this plant operated at a reasonable level. In fact, the EAF for the plant in the preceding 12 months was higher than for the previous 3 years and it was higher than the NERC 10-year average for the same class of plant. However, the Office of the People's Council (a state government organization) intervened in the hearings. The Council maintained that a 17-day outage starting in late 1980 was the result of improper utility action. Evidently, a nut from the turbine hoisting equipment had gotten loose, fell into the turbine during maintenance and had caused damage during turbine operation. The hearing examiner recommended that BG&E be disallowed 50% of the replacement fuel cost for the outage. The PSC in its Order disallowed 25% of the replacement fuel cost.

In another fuel rate adjustment case, the PSC again determined that BG&E had operated the Calvert Cliffs station at reasonable performance levels. Once more the Office of the People's Council intervened and claimed that a July 1981 outage was due to improper utility actions. In this case, Unit 1 experienced salt water intrusion into the coolant during startup. The PSC disallowed 75% of the replacement fuel cost for this outage.

The PSC reports that at practically every fuel rate adjustment hearing, even those where actual fuel costs are more than 5% below the current level, the Office of the People's Council intervenes and claims that one or more outages are the result of improper utility actions or imprudent management. As a result of the two Orders for the BG&E fuel adjustment rate cases, BG&E has gone to court in an attempt to have the outage evaluation nullified. Independent of the BG&E legal action, the PSC is considering modifications to the standard that would have the following features: (1) definite standards by which plant performance could be judged, 2) a reward system as well as penalties, and 3) a decreased emphasis on plant outages in determining fuel rate adjustments.

<u>Massachusetts</u>

<u>Affected Nuclear Plants and Utilities</u>: Pilgrim, Boston Edison; Yankee-Rowe, Yankee Atomic

In August 1981 the Massachusetts legislature decided to include evaluation of power plant performance in the fuel charge procedure. The amendment provided for establishment and operation of a fuel charge monitoring bureau to administer and enforce the fuel charge procedure.

At least once a year, affected utilities file a proposed performance program with the Department of Public Utilities (i.e., the Fuel Charge Bureau, Massachusetts DPU). The utility performance program requires evaluation of the following parameters as a minimum, on a unit-by-unit basis: availability; equivalent availability; capacity factor; forced outage rate; and heat rate.

The affected utilities have to file performance statistics on a monthly basis. Any monthly variance has to be explained at the next fuel charge hearing and may become the basis for a determination of "unreasonable or imprudent performance." In fuel charge hearings, if the Department determines that a utility has been unreasonable or imprudent with regard to fuel use, the Department can deduct from the fuel charge proposed for the next period an amount that the Department deems proper as reflective of the fuel costs directly attributable to the "unreasonable or imprudent performance." The statute does not contain any provision for rewards if performance exceeds the targets.

The utilities affected by the performance program are not enthusiastic about it. First, the program has provisions for penalties and none for rewards. The program requires a large data collection, assessment, and reporting effort. In addition, the required heat rate audits are supposed to involve ASME Power Code Testing, which is time consuming and costly, and their value in meeting the acts of 1981 is being challenged by the utilities.

Michigan

Affected Nuclear Plants and Utility: Big Rock Point, Palisades - Consumers Power

In 1978, the Michigan Public Service Commission instituted the Availability Incentive Provision for the Detroit Edison Company and Consumers Power Company. The Availability Incentive Provision was ordered to encourage the two utilities to improve the availability of their generating plants. Both utilities had experienced declining system availability, and reached an all time low of approximately 72% in the mid-1970's.

The performance standard incorporated in the original orders was system average availability using the East Central Area Reliability Coordination Agreement (ECAR) definition. ECAR availability for a single generating unit is defined as unit operating hours plus unit hours available but not operated divided by total hours in the period. The system average is determined by summing individual unit ECAR availabilities weighted by the units' capacity ratings. The performance standard was modified by the PSC in August 1980. The new standard incorporates the following changes: 1) a periodic factor was identified to account for periodic, scheduled maintenance, 2) the neutral or null zone was reduced from 10% to 6%, and 3) the system availability scales were "fine-tuned" and 11 ranges were created instead of the original 3 ranges: variation over the period of the periodic factor, 9 percentage points (or .09) for Consumers Power accounts for scheduled outages and was established based on an analysis of a 10-year history and a 10-year forward projection of scheduled outages for the utility.

Utility performance, as measured by system average availability plus periodic factor is tied to incentives by a scale which equates performance to an adjustment of return on equity. The target of availability plus periodic factor is equivalent to a target on unplanned outage factor (i.e., random outage factor) since the sum of availability plus planned outage factor plus unplanned outage factor equals one. The current scale for Consumers Power is shown in the following table. Note that there is a null zone in which no penalty or reward is levied. The maximum reward is a 1/2% increase in return on equity and the maximum penalty is a 1/4% decrease.

CONSUMERS POWER COMPANY AVAILABILITY INCENTIVE PROVISION

System Availability (ECAR) Plus Periodic Factor	Equity Return Incentive
100% - 94.01%	+.50%
94.00% - 92.76%	+.40%
92.75% - 91.51%	+.30%
91.50% - 90.26%	+.20%
90.25% - 89.01%	+.10%
89.00% - 83.01%	-
83.00% - 82.01%	-.05%
82.00% - 81.01%	-.10%
81.00% - 80.01%	-.15%
80.00% - 79.01%	-.20%
79.00% -	-.25%

The PSC staff and Consumers Power have expressed their satisfaction with the Availability Incentive Provision. Consumers Power had impressive rewards under the Provision. It has received two rewards in four years for a gain of approximately $14 million. This performance improvement also meant considerable savings to their ratepayers.

Cognizant utility personnel stated that Consumers Power was aware of the performance problems (e.g., high random outage factor, low availability) occurring in the 1974-1976 time frame, and that steps were being taken to correct problems and improve performance before the Availability Incentive Provison was implemented. However, the utility felt that the provision provided additional focus on availability within the company, provided the funding necessary to obtain improvements (e.g., production maintenance expenses, base rate), and may have accelerated implementation of some improvement actions.

Consumers Power reported that there was no overt interest by the NRC in the Availability Incentive Provision and no additional NRC interaction as a result of the Provision. The issue of possible safety impacts did not arise. Consumers Power emphasized: 1) the need for pre-established ground rules for allocating NRC-mandated outages to the periodic factor category rather than the random factor category, and 2) the need for a competent PSC staff, such as in Michigan, to make informed judgments about NRC-required actions and other factors impacting upon those items which should be included as planned outages. This mechanism can accommodate factors beyond the utility's control.

North Carolina

Affected Nuclear Plants and Utilities: Brunswick 1 & 2 - Carolina Power and Light; McGuire 1 and 2 - Duke Power Co.; Surry 1 and 2, North Anna 1 & 2 - VEPCO

North Carolina currently does not have a formal performance standard program based upon a North Carolina Utilities Commission Order or a legislative act. However, the Commission does periodically review the performance of utility power plants in both fuel adjustment hearings and general rate case proceedings and, in the past, has levied penalties based on its assessment of poor performance.

Since 1978, the North Carolina Utilities Commission has required electric utilities to file detailed performance data on nuclear and baseload fossil-fired plants on a monthly basis. The performance reports include the following information: outage data, including cause, duration and corrective actions taken; actual generation by each unit; and lost generation by type of outage (i.e., full, partial, scheduled, or forced).

The Commission considers power plant performance in general rate case hearings and has levied penalties for poor plant performance. When a utility files an application for a general rate increase, the Public Staff, acting as a consumer advocate, reviews the performance of the utility's power plants. This review can include a detailed investigation of engineering, operations, maintenance, and management performance. If the Public Staff finds that fuel costs were excessive due to poor plant performance, the Staff can recommend to the Commission that the utility's return on equity be reduced. The utility has the opportunity to defend its plant performance in the rate case hearings. The Commission then makes a judgment as to the utility rate of return. There are no defined standards by which power plant performance is judged.

The Commission adopted a new general rate case procedure in June 1982. The utility fuel cost chargeable to ratepayers is included in the utility base rate. The fuel cost is based, in part, on various classes of power plants achieving specified performance levels. The capacity factor used to determine allowable fuel costs for Duke Power's nuclear plants is 60%, and the capacity factor for Carolina Power and Light's nuclear plants is 52%. Within a year of a general rate case, the utility must have a fuel cost hearing. The Commission can disallow fuel costs, if in its judgment, plant performance has been substandard or poor due to utility imprudence. Again, no formal standards of performance related to fuel cost hearings are in effect, and performance standards and incentive formulas are being considered.

The affected utilities, which are all investor owned, are not satisfied with the current North Carolina system. The main reasons for their dissatisfaction are: 1) there are penalties only and 2) judgment plays a central role in a determination of "poor performance" and in allocating penalties.

For example, in a 1981 decision on a VEPCO general rate case, the Commission reduced VEPCO's authorized return on equity from the 15.5% to 10%. In December 1980, VEPCO filed for a general rate increase. The Public Staff hired consultants to evaluate the following areas: 1) management practices in plant O&M, 2) outages, reductions in power, and O&M practices and procedures, and 3) predicted fuel costs at higher power plant performance levels. The Public Staff's consultants presented testimony that showed poor plant performance due to various VEPCO deficiencies. VEPCO presented extensive testimony to rebut the consultants' testimony. However, the Commission sided with the Public

Staff and held that VEPCO's fuel expenses were excessive due to poor plant performance. The return on equity was reduced as noted above.

In a 1982 CP&L rate case, the Commission reduced the return on equity by 1%. The commission ruled that an outage at the Brunswick nuclear plant, caused by a turbine bearing failure, was the fault of CP&L.

Ohio

Affected Nuclear Plant and Utility: Davis Besse - Toledo Edison

The Ohio program is embodied in the 1981 Tariff M_{ce} and 1982 Tariff M_{ce}. Automatic fuel cost adjustments were eliminated in Ohio with Amended Substitute House Bill 21 which became effective July 2, 1980. This statute contains the Ohio PUC's purchased power cost policies which were originally promulgated in the now defunct 1976 fuel cost adjustment rules. The objective of these policies is to minimize the cost of electric service to customers by providing incentives to investor-owned utilities for minimizing fuel costs.

The specific provisions of the statute were implemented in February 1981 and placed in the Ohio Administrative Code on September 1981. The original cost-effectiveness measure, known as 1981 Tariff M_{ce}, measures the efficiency of fuel procurement and utilization practices of an electric utility and then converts the cost-effectiveness measure, M_{ce}, into a fuel recovery factor. M_{ce} is a complex formula used to measure cost-effectiveness. It involves a number of efficiency measurements including fuel utilization, fuel procurement, sales pricing policy, and purchased power policy.

Toledo Edison reports that it has recovered somewhat less than $1 million in fuel costs under the cost-effectiveness measure system that otherwise would not have been collected under the old fuel cost adjustment clause. The cost-effectiveness measure and incentive program has not had any impact on power plant operations or engineering. The Rate Department of Toledo Edison is almost solely involved with the program. There is practically no involvement by the Engineering and Operations Departments.

However, Toledo Edison stated that its 4 large coal units are in the top 20 units with respect to heat rate, capacity factor, and availability. Davis-Besse performance has been hurt by TMI and generic problems (e.g., pump seals). Any external pressure to improve Davis-Besse performance has come from the Ohio PUC during base rate hearings. For example, the Ohio PUC has suggested that Davis-Besse might be removed from the rate base if performance did not improve. Toledo Edison reports that there has been no discernible concern on the part of the NRC with regard to the Ohio performance standards program.

Virginia

Affected Nuclear Plants and Utility: Surry 1 & 2, North Anna 1 & 2 - VEPCO

A VEPCO rate application settlement establishes a performance incentive program by which rate of return (and therefore, rates) would be tied to generating unit performance based on indices such as equivalent availability and heat rates. Targets for Surry and North Anna units are derived frcm the two-year average capacity factors of all nuclear units built by the same manufacturer. Adjustments to the two-year averages are made to compensate for improvements in reliability resulting from major overhauls of the nuclear units.

The fuel recovery clause is based on a fuel price index and generating performance criteria measured by equivalent availability and unit heat rates. First, the 13-month average procured fuel price is checked against a fuel price index. The index compares the cost per BTU for various fuel types with costs for the mid-Atlantic and south-Atlantic regions of the country. Second, target ranges are set for equivalent availability and unit heat rates using a computer simulation of the economic dispatch of the utility's system. This enables the staff to derive an estimate of the fuel expense for a given value of equivalent availability. The resulting estimate is used to test the reasonableness of the utility's projected and actual fuel expenses.

While there is no specific set of rewards or penalties, the performance criteria affect regulatory decisions on fuel costs. At the annual fuel recovery clause hearing, the utility's fuel account for the previous 12 months is settled. If cost underrecovery is determined to be the result of poor performance because of factors within management's control, complete recovery may not be allowed. If actual performance is on target, the time lag for recovery is reduced.

Construction Performance Incentives

EEI and NARUC identify two States that have construction performance incentives specifically applicable to nuclear plants. (Stoller concentrated on operating performance incentives.) They aim at controlling construction costs and/or expediting construction completion.

New Jersey

Affected Nuclear Plant and Utility: Hope Creek 1 - Public Service Electric & Gas Co.

The Hope Creek program (which provides both penalties and rewards) objective is to control construction costs. Through negotiation between the New Jersey Board of Public Utilities and Public Service Electric & Gas Co. (PSE&G) the target construction cost was set at $3.7 billion. The incentive program provides that PSE&G may recover from customers only 80 percent of costs that exceed the $3.7 billion target by up to 10 percent. Should costs exceed this target by more than 10 percent, the company may recover only 70 percent of costs above the 10 percent threshold. If the plant cost is between $3.5 billion and $3.7 billion, all actual costs wil be recoverd. If the cost is below $3.5 billion, the reward provision becomes operative and the company will recover actual costs plus 20 percent of the difference between $3.5 billion and the actual costs. Thus, the program's incentive is to complete construction at a cost below $3.5 billion to recoup the 20 percent reward, and to avoid penalties resulting from cost overruns.

New York

Affected Nuclear Plant and Utility: Nine Mile Point 2 - Niagara Mohawk Power Corp.

The Nine Mile Point 2 program is designed to control the power plant construction costs. It was instituted because of escalating construction costs and uncertainty of completion dates. The program keys on sharing revenue requirements growing out of cost overruns and underruns. A target cost of $4.6 billion was negotiated and set for the project by Niagara Mohawk and the New York Public Service Commission; the utility will be rewarded for reducing that cost and penalized for exceeding it. The company will receive 20 percent of the savings if the final cost is under target and must absorb 20 percent of cost overruns. Thus, the program's incentive is to share in the benefits by bringing the project in under the targeted amount, and to avoid absorbing 20 percent of cost overruns.

EEI reports that the Nine Mile Point 2 program was instituted well after construction began at a time when it was difficult to obtain accurate and unbiased construction cost estimates. The investment community has not been enthusiastic about the program because it is felt that the PSC may have given up authority to assure a reasonable return on invested capital.