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January 30, 2004

Honorable Christopher Hall, Senate Chair
Honorable Lawrence Bliss, House Chair
Joint Standing Committee on Utilities and Energy
Augusta, ME 04333

Re: Efficiency – Reliability Report

Dear Senator Hall and Representative Bliss:

During the First Regular Session of the 121st Legislature, the Legislature enacted An Act to Encourage Energy Efficiency and Security, P.L. 2003, ch. 219. The Act directs the Public Utilities Commission to investigate regulatory mechanisms and rate designs that provide incentives for transmission and distribution utilities to promote energy efficiency and the security and robustness of the electric grid. The Act requires that the Commission report the results of its investigation to the Utilities and Energy Committee by February 1, 2004.

Attached is the final report. We look forward to working with the Committee on this subject. If you have any questions regarding the report, please contact us.

Sincerely,

Maine Public Utilities Commission
Thomas L. Welch, Chairman
Stephen L. Diamond, Commissioner
Sharon M. Reishus, Commissioner

cc: Utilities and Energy Committee Members
Jon Clark, Legislative Analyst

MAINE PUBLIC UTILITIES COMMISSION

REPORT on UTILITY INCENTIVES MECHANISMS

for the

PROMOTION OF ENERGY EFFICIENCY

and SYSTEM RELIABILITY

Presented to the
Utilities and Energy Committee
February 1, 2004

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EXECUTIVE SUMMARY

I. INTRODUCTION

During its 2003 session, the Legislature passed An Act To Encourage Energy Efficiency and Security. The Act directs the Public Utilities Commission to investigate regulatory mechanisms and rate designs that provide incentives for transmission and distribution utilities to promote energy efficiency and the security and robustness of the electric grid. The Act requires that the Commission submit a report to the Joint Standing Committee on Utilities and Energy by February 1, 2004.

In broad outline, the Commission has concluded that the incentives utilities currently have under rate cap regulation to increase sales, although magnified to some degree, are similar in kind to the incentives they had under more traditional regulation. Moreover, it does not appear that utilities currently acting on these incentives have a significant opportunity to blunt the effectiveness of current efficiency and conservation programs in Maine, especially now that those programs have been removed from utility control. Finally, while there are a number of tools available to the Legislature and the Commission that could to some degree lessen the remaining utility incentives to frustrate conservation efforts, these tools are likely to have ancillary consequences that could, in the Commission's view, create substantial adverse effects. For these reasons, the Commission does not recommend that any major revisions to Maine's current regulatory policies concerning utility incentives and conservation be undertaken.

In addition, the Commission believes that the current system of ensuring adequate service reliability through objective service quality metrics, backed by meaningful penalties, incorporated as part of a utility's alternative rate plan, along with the Commission's ability to use its traditional tools to ensure adequate service, is working well. Accordingly, the Commission recommends that no legislative changes be made in this area. The Commission will continue to monitor Maine's transmission and distribution utilities' service quality performance and refine the standards and penalty mechanisms in ways that improve their operation.

The report is structured into sections that contain discussions and analyses in the following areas:

- **Maine's Current Regulatory Framework**
- **Analysis of Current Regulatory Mechanisms**
- **Alternative Regulatory Mechanisms to Promote Efficiency and Reliability**
- **Other State Mechanisms**
- **Recommendations and Alternatives**

II. MAINE'S CURRENT REGULATORY FRAMEWORK

The report provides background on the utility regulatory framework in Maine. The report describes the attributes of the rate-setting methodology referred to as traditional regulation and the impact of traditional regulation on rates and rate design, operational efficiency, reliability incentives, and efficiency incentives. The report then discusses the development of alternative regulation in Maine beginning in the early 1990s referred to as Alternative Rate Plans or ARPs.

The report describes how regulatory structures changed after the restructuring of Maine's electric industry in 2000. Prior to industry restructuring, the Maine Commission regulated all aspects of retail transactions between Maine utilities and its ratepayers. After industry restructuring, the generation portion of electricity service was no longer subject to rate regulation and the regulated portion of electricity service was broken up into four pieces: (1) the generation component; (2) the transmission component; (3) the stranded cost component; and (4) the distribution delivery component. The report discusses the regulatory structures that now govern these four distinct components. In addition, the impacts of industry restructuring on utility rate design and the obligation of utilities to conduct conservation programs are reviewed.

III. ANALYSIS OF CURRENT REGULATORY MECHANISMS

Electricity rates currently paid by consumers in Maine are a composite of competitive and regulated services, and reflect a variety of ratemaking methodologies that include both traditional and alternative regulation. The report provides an analysis and discussion of the impact of this regulatory mix on rate levels and operational efficiencies, system reliability (both on a regional and distribution system level), energy efficiency, utility rate structures, and economic development incentives.

IV. ALTERNATIVE REGULATORY MECHANISMS TO PROMOTE EFFICIENCY AND RELIABILITY

The report presents and discusses regulatory mechanisms that can be used to alter utility financial incentives with respect to energy efficiency and system reliability. These are revenue decoupling, lost revenue adjustments, return on equity adjustments, shared savings mechanisms, service quality standards, direct pass-through of costs, and a fixed charge rate design. The report includes tables that illustrate the bill impacts for residential and small commercial customers of moving to a completely fixed charge rate design. A table at the end of the section summarizes the incentive impacts of various regulatory mechanisms.

V. OTHER STATE MECHANISMS

The Commission conducted a survey of other states and a literature search to determine the existence of possible mechanisms that can be used to affect or alter utility financial incentives with respect to energy efficiency and conservation and system reliability. The results of the research are presented in the report and summarized in tables.

VI. RECOMMENDATIONS AND ALTERNATIVES

The report presents Commission recommendations regarding utility incentive mechanisms with respect to system reliability and energy efficiency, and viable alternatives that can address legislatively specified policies and goals.

The issues involving system reliability are relatively straightforward. The Commission's view is that, as a general matter, the current regulatory framework has produced a reasonable balance between system reliability and ratepayer cost. Accordingly, no major changes to the regulatory scheme are recommended to address reliability incentives.

The issues involving energy efficiency and the promotion of electricity consumption are relatively more complex. The Legislature must consider in the first instance whether the current incentives that utilities have to promote the use of electricity raise substantial public interest concerns. The threshold question in this context is whether it is the policy of this State to discourage the consumption of electricity. If this is the policy of the State, the next consideration is whether utilities are particularly effective in promoting the use of electricity and thereby frustrating the State's ability to attain its policy goal. Finally, if both questions are answered in the affirmative, in the Commission's view the Legislature should consider whether potential changes to the regulatory structure to alter utility incentives might nevertheless create greater problems than they solve.

The Commission expresses no opinion on whether the State should adopt a policy that the consumption of electricity is against the public interest. However, the Commission has serious concerns regarding the potential consequences of efforts to remove the financial incentives of utilities to promote their product through fundamental changes in regulatory structure or rate design.

A primary question is whether the current regulatory framework is subverting efforts to promote conservation and the efficient use of electricity. The Commission's view is that the current framework does not have this effect. The Commission has some limited evidence that utility efforts to promote consumption are not particularly effective. More importantly, however, the Commission's view is that conservation and energy efficiency are driven more by customer decisions than by utility action. Accordingly, it is more important that consumers have proper price signals to conserve and that the State retain a vibrant state-wide conservation program (i.e., the Commission's Efficiency Maine program) than it is to change utilities' actions.

It is for these reasons that the Commission recommends no fundamental change in the current regulatory structure to address utility financial incentives regarding the consumption of electricity. Nevertheless, the report outlines and evaluates several alternative approaches if the Legislature decides that public policy requires that current financial incentives should be altered.

Recommended Regulatory Approach

The Commission recommends that no fundamental changes be made to the current regulatory structure to alter utility financial incentives.

Rate Cap Regulation

The Commission recommends that multi-year rate cap plans remain the basic regulatory approach for Maine's T&D utilities' distribution delivery rates.

System Reliability Mechanisms

The Commission recommends that service quality standards continue as the primary means to ensure adequate system reliability and that efforts continue to be made to improve the operation of the standards.

Energy Efficiency Mechanisms

The Commission does not recommend that regulatory mechanisms be adopted to alter utilities' current incentives with respect to electricity consumption and energy efficiency.

Rate Design

The Commission recommends against the adoption of a fixed charge rate design for the primary purpose of removing utility incentives to promote electricity consumption.

Alternative Approaches

If the Legislature determines that mechanisms should be employed to change utility incentives with respect to energy efficiency or system reliability, the report discusses approaches that should be considered.

Fixed Charge Rate Design

In the event the Legislature decides that some regulatory change should occur to eliminate utility financial incentives to promote electricity consumption, the Commission recommends that a legislative mandate be adopted that directs the Commission to move towards a fixed charge rate design. Because movement to a fixed charge rate design would involve substantial bill impacts for many customers (e.g., an increase from $7.18 to $35.13 for CMP's smallest residential customers), the

Legislature should consider mandating that rate design changes occur gradually over time.

Revenue Reconciliation Stranded Cost Rate-Setting

In the event that the Legislature desires to take steps to address incentives regarding the promotion of electricity consumption, it should consider amending 35-A M.R.S.A. § 3208 to clearly authorize the Commission to adopt revenue and cost reconciliation mechanisms in setting stranded cost rates. If such a mechanism were adopted, a utility's incentive to increase sales would be reduced, although not eliminated, because a substantial amount of utility costs would continue to be recovered through usage sensitive charges.

Return on Equity Adjustment Mechanism

A mechanism whereby a utility's return on equity is adjusted, either up or down, based on its performance in specified areas can be an effective means to impact incentives. The mechanism is subjective by its nature and the Commission would make determinations based primarily on its expert judgment. The approach is inconsistent with current rate plans and implementation is likely to be extremely contentious. However, a return on equity adjustment mechanism could be made part of a multi-year rate plan with rate adjustments occurring as part of the annual ARP reviews.

Multi-Year Revenue Cap

If the Legislature determines that the State's basic regulatory structure should be changed from the current rate cap regulation to alter incentives so utilities are financially neutral to electricity sale levels, a multi-year revenue cap program for establishing distribution rates can be considered. This type of revenue cap mechanism, if it can be designed correctly, would continue to provide utilities with the incentive to seek operational efficiencies and to reduce their cost of service. However, the Commission has substantial concern over unintended consequences that may accompany the adoption of a regulatory structure that is so dependent on unpredictable events.

Prohibition or Regulation of Promotional Activities

If the Legislature determines that utility promotion of electricity consumption is a serious public interest problem, the most direct solution would be a legislative ban or regulation of promotional activities. Such an approach would raise First Amendment issues that the Commission has not analyzed. The most direct approach would be a ban on promotional advertising. A less intrusive approach would be for all such advertising to include some type of required statement, such as information on the environmental impacts of electricity consumption.

I. INTRODUCTION

During its 2003 session, the Legislature passed An Act To Encourage Energy Efficiency and Security.[1] The Act directs the Public Utilities Commission ("Commission") to investigate regulatory mechanisms and rate designs that provide incentives for transmission and distribution ("T&D") utilities to promote energy efficiency and the security and robustness[2] of the electric grid. The Act requires that the Commission submit a report to the Joint Standing Committee on Utilities and Energy by February 1, 2004.

As a vehicle for conducting its investigation, the Commission initiated an Inquiry on June 18, 2003.[3] As part of the Inquiry, the Commission solicited written comment from interested persons on all issues relevant to the investigation, met or had discussions with entities having expertise in the area of utility incentives, and conducted a survey and other research into mechanisms used in other states to promote energy efficiency and grid reliability. Subsequently, the Commission released a draft report, sought written comment on the draft report from all interested entities, and held a public meeting on all issues relevant to the investigation.[4]

In broad outline, the Commission has concluded that the incentives utilities currently have under rate cap regulation to increase sales, although magnified to some degree, are similar in kind to the incentives they had under more traditional regulation. Moreover, it does not appear that utilities currently acting on these incentives have a significant opportunity to blunt the effectiveness of current efficiency and conservation programs in Maine, especially now that those programs have been removed from utility control. Finally, while there are a number of tools available to the Legislature and the Commission that could to some degree lessen the remaining utility incentives to frustrate conservation efforts, these tools are likely to have ancillary consequences that could, in the Commission's view, create substantial adverse effects. For these reasons, the Commission does not recommend that any major revisions to Maine's current regulatory policies concerning utility incentives and conservation be undertaken.

In addition, the Commission believes that the current system of ensuring adequate service reliability through objective service quality metrics, backed by meaningful penalties, incorporated as part of a utility's alternative rate plan, along with the Commission's ability to use its traditional tools to ensure adequate service, is

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[1] P.L. 2003, ch. 219.

[2] The Commission views the terminology "security and robustness" to essentially mean "reliability" of the system, rather than protection against terrorist attacks. The Commission uses the term "reliability" throughout this report.

[3] *Inquiry into Incentives to Promote Energy Efficiency and Security of the Electric Grid,* Docket No. 2003-423 (June 18, 2003).

[4] The following entities provided input and comment during the Commission's investigation: Public Advocate, Central Maine Power Company, Bangor Hydro-Electric Company and Maine Public Service Company.

working well. Accordingly, the Commission recommends that no legislative changes be made in this area. The Commission will continue to monitor Maine's transmission and distribution utilities' service quality performance and refine the standards and penalty mechanisms in ways that improve their operation.

This report is structured as follows:

- **Section II—Maine's Current Regulatory Framework:** Description of Maine's regulatory framework and corresponding utility incentives.

- **Section III—Analysis of Current Regulatory Mechanisms:** Analysis and discussion of the impact of the current regulatory framework on rate levels and operational efficiencies, energy efficiency and reliability incentives, utility rate structures, and economic development incentives.

- **Section IV—Alternative Regulatory Mechanisms to Promote Efficiency and Reliability:** Discussion of alternative regulatory mechanisms that can affect or alter utility efficiency and reliability incentives.

- **Section V—Other State Mechanisms:** Review of regulatory approaches used in other states to address energy efficiency and system reliability incentives.

- **Section VI—Recommendations and Alternatives:** Presentation of Commission recommendations regarding utility incentive mechanisms and viable alternatives that can address legislatively specified policies and goals.

II. MAINE'S CURRENT REGULATORY FRAMEWORK

A. Background

1. Traditional Regulation

Rates and Rate Design

Pursuant to the provisions of section 301 of Title 35-A, the rates set by the Public Utilities Commission must be just and reasonable. This means that the rates must be fair to the consumer and at the same time must provide the utility with the opportunity to recover its operating expenses and to earn a fair return on its investment. For nearly a century, the Commission attempted to accomplish these objectives through establishing rates based on a rate-of-return or cost-plus rate-setting methodology that is typically referred to as traditional regulation.

Under traditional regulation, utility rates are set through periodic litigated rate cases. In these cases, the Commission examines a utility's underlying costs, current and expected revenues, and reasonable rate of return on capital investment. The Commission prospectively establishes rates to allow utilities a reasonable opportunity to recover their prudent costs[5] of providing safe and adequate service, as well as a reasonable return on shareholder investment. Rate cases are adjudicatory in nature, and can be initiated by the utility, by the Commission, or through petition of a utility's ratepayers. A contested rate case is an extremely complex and imprecise undertaking in the context of multi-million dollar utility companies. Such cases generally take a year to process and resolve, and require a substantial devotion of the resources of the Commission, the utility, the Public Advocate, and interested intervenors.

As part of the rate-setting process, the Commission must also design rates which allow the utility an opportunity to recover its revenue requirement (operating expenses plus a return of and on investment). Revenue requirements can be recovered through three different types of charges or rates: customer or fixed charges;[6] usage or energy (kWh) charges; and demand (kW) charges.

Pursuant to the enactment of the Electric Rate Reform Act in the mid-1980s,[7] the Commission endeavored to design electric rates in a manner that more closely reflected the underlying costs of service. This involved establishing rates

[5] Under traditional regulation, utilities are not permitted to recover costs from ratepayers that the Commission finds to have been imprudently incurred.

[6] For purposes of this report, "fixed charge" or "fixed rate design" means a pre-set monthly charge that does not vary with customer energy (kWh) usage or total customer demand (kW).

[7] 35-A M.R.S.A. §§ 3151-3155.

based on the marginal cost of service, designing rates to reflect cost differences between seasons and time-of-day, and adopting inverted block rates (in which rates increase with higher usage amounts) for residential customers. This approach to ratemaking was intended to promote economic efficiency and the proper allocation of societal resources.

Operational Efficiency

Because utility rates are reset periodically based on an examination of the utility's ongoing costs, traditional regulation does not provide strong incentives for utilities to conduct their business in the most efficient manner or to provide their service at the lowest possible cost. As a practical matter, the Commission's traditional review cannot uncover all potential inefficiencies, and the regulatory approach does not provide incentives for efficient business operations to nearly the same degree as a competitive market. Unlike a competitive business that must price its product based on what the market will bear, a utility whose costs are rising, or whose shareholder returns are considered insufficient, can file for a rate increase. Conversely, a utility that is able to reduce its costs through efficiency measures faces the possibility that ratepayers or the Commission will initiate a rate case to lower rates on the grounds that the utility's returns are too high. Thus, the traditional regulatory system does not instill the type of business discipline that occurs in competitive markets.

Reliability Incentives

Under traditional regulation, utilities were guaranteed the opportunity to obtain a fair return on their total capital investment (referred to as ratebase). In addition, under certain circumstances, a utility might be able to enhance its earnings per share by making additional investments in its plant.[8] Given the utilities' near guarantee of recovery of investment in their systems, the incentive for utilities was to "gold-plate" their systems to some degree to reduce any potential reliability problems that might lead to negative public reactions and greater Commission scrutiny. Traditional regulation has limited effectiveness in protecting against "overbuilding" and its resulting unnecessary increases in rates.

To the extent that reliability problems existed despite the general incentive in favor of capital expenditures,[9] the primary remedy under traditional regulation was for the Commission to react to individual customer complaints. In addition, as part of a rate case proceeding, the Commission would ordinarily hold public witness hearings where customers of the utility could testify about any service problems. This testimony was often anecdotal and did not provide an objective basis to determine whether the utility was in fact providing adequate and reliable service on a

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[8] This would occur when the rate-of-return allowed by the regulatory commission exceeds the capital market rates and is referred to as the Averech-Johnson effect.

[9] If a utility is in financial trouble, it may defer maintenance or be unable to raise capital for investment.

system-wide basis. If the Commission found that the utility was violating its general obligation to provide reasonably reliable and adequate service, the primary tool for addressing the matter was to penalize the utility through a reduction in the utility's return on equity. While any attempt to reduce a utility's return on equity due to service quality issues would likely be contested and subject to court review, the potential for the Commission to act in this manner provided some incentive for utilities to maintain adequate service.

Efficiency Incentives

Under traditional regulation, utilities have the financial incentive to promote the consumption of electricity, and little incentive to pursue energy efficiency or conservation.[10] This is because total company revenues (and thus profits) are a function of sales volumes. Thus, every kilowatt-hour sold increases profits, while every kilowatt-hour saved lowers profits.[11] The disincentive with respect to energy efficiency and conservation is diminished to some degree by the ability of utilities to make up for lost revenues through periodic rate cases. However, rate cases are costly and take a substantial amount of time during which the impact of lost revenues continues, and the ultimate result is higher utility rates that could lead to reduced business and public bad will. The financial incentive between rate cases is for a utility to act to increase electricity sales.

Prior to the restructuring of the electric industry, utilities were obligated to pursue energy efficiency and conservation measures, if such measures were less costly than the generation supply alternative. Because of the inherent disincentive against reduced consumption, the Commission was required to carefully monitor utility operations to ensure that utilities acted in a manner consistent with their legal obligations.

2. Development of Alternative Regulation

In late 1993, following a series of rate increases resulting from a number of causes, including declining sales brought on by a downturn in the economy, introduction of a new rate design, and increases in utility costs above the rate of inflation, the Commission concluded that it should consider setting Central Maine Power Company's ("CMP") rates by means of a rate cap approach. Under a rate cap approach, CMP's rates would be reset based on an external index over a multi-year period. The Commission concluded that a multi-year price-cap, also referred to as an incentive rate plan or Alternative Rate Plan ("ARP"), could provide the following benefits to Maine ratepayers: (1) electricity prices would continue to be regulated in a

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[10] This was the case as long as the utilities' rates were greater than their marginal cost of production, a cost relationship that has existed since the late 1980s.

[11] This is a consequence of the recovery of a substantial portion of utility costs through usage sensitive rates (i.e. per kilowatt-hour charges). The issue of moving towards greater use of fixed rates is discussed in sections IV and VI of this report.

comprehensible and predictable way; (2) rate predictability and stability were more likely; (3) regulatory "administration" costs could be reduced, thereby allowing for the conduct of other important regulatory activities and for CMP to expend more time and resources in managing its operations; (4) risks could be shifted to shareholders and away from ratepayers (in a way that is manageable from the utility's financial perspective); and (5) because exceptional cost management could lead to enhanced profitability for shareholders, stronger incentives for cost minimization would be created.[12] Because the ability of a utility to file for a rate increase is greatly restricted under an ARP, the Commission noted that there is an enhanced incentive, relative to traditional regulation, for a utility to cut costs in ways that could damage system reliability and to increase consumption by cutting back efficiency programs.

The Commission approved an alternative rate plan for CMP in 1995 that was among the first price-cap plans for any electric utility in the country.[13] CMP's first five-year price-cap plan, also now referred to as ARP I, reset CMP's rates annually based on an external index calculated by inflation minus a productivity offset, plus or minus earnings outside a deadband and/or certain costs which qualified as mandated costs. To address incentives that might have been created for the utility to cut costs at the expense of system reliability, the plan also included substantial financial penalties for failure to attain the standards set forth in the ARP's Service Quality Index ("SQI"). ARP I's SQI measured CMP's performance in five areas of which two addressed reliability and three concerned customer service.

The reliability indices included the System Average Interruption Frequency Index ("SAIFI"), which measures the average frequency of sustained interruptions per customer over the year, and the Customer Average Interruption Duration Index ("CAIDI"), which is a calculation of the average time required to restore service to the average customer per sustained interruption. ARP I's SQI provided for penalties of up to $3 million if CMP failed to meet the SQI standards in any one year. In approving ARP I, the Commission concluded that the specific service quality standards of the SQI, with automatic penalties assessed if service deteriorated beyond baseline levels, was superior to the traditional tools of penalizing the Company for poor service through litigated proceedings.

In addition, to address the enhanced disincentive regarding energy efficiency and conservation, ARP I required CMP to submit annual energy resource plans, which included kilowatt-hour and kilowatt savings associated with demand side management ("DSM") activities. In the event CMP failed to achieve 90% of targeted DSM savings in any one year, it would be subject to a penalty of between $1.5 million to $5 million. This mechanism was effective in ensuring that CMP's conservation activities

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[12] *Central Maine Power Company, Proposed Increase in Rates*, Docket No. 92-345 at 130 (Dec. 14, 1993).

[13] *Central Maine Power Company, Proposed Increase in Rates*, Docket No. 92-345(II) (Jan. 10, 1995).

produced energy savings at the targeted levels. However, the motivational impacts of the targets ceased as soon as the targets were met.

B. Regulatory Structures After Industry Restructuring

For the entire 20th century, Maine's utilities were vertically integrated and were monopolies with respect to all aspects of providing and delivering the electricity "product." Because of their monopoly status, the Maine Commission regulated all aspects of retail transactions between Maine utilities and its ratepayers.

On March 1, 2000, Maine's electric industry was restructured to provide Maine consumers with the opportunity to purchase generation services from a competitive market and as of that date, the generation portion of electricity service was no longer subject to rate regulation in Maine. As a result of restructuring, the bundled electricity "product" has been broken up into four pieces: (1) the generation component; (2) the transmission component; (3) the stranded cost component; and (4) the distribution delivery component.

In this portion of the report, the Commission discusses the regulatory structures that now govern these four distinct components. In addition, the impacts of industry restructuring on utility rate design and the obligation to conduct conservation programs are reviewed.

1. Generation Component

As part of industry restructuring, investor-owned electric utilities[14] in Maine were required to divest their generation assets on or before March 1, 2000, and to the extent that a utility desires to enter the competitive retail generation supply market, such activity has to occur through a separate corporate affiliate. Upon restructuring, utilities no longer have the obligation to ensure an adequate supply of generation, and construction of new generation as well as the continued operation of existing generation is now subject to market forces. Like other competitive businesses, generators and competitive electricity suppliers have a direct financial interest in promoting the sale of their products.

2. FERC Regulation of Transmission Rates

The unbundling of generation costs from utility rates has resulted in the Federal Energy Regulatory Commission ("FERC") asserting jurisdiction over retail transmission rates. Under FERC regulation, transmission rates are set through a formula in which rates are established annually based on the utility's prior year's costs and revenues. This type of regulation provides little incentive for operational efficiency because rates are based directly on utility costs. Because rates are reset annually, the

[14] These are: CMP, Bangor Hydro-Electric Company ("BHE") and Maine Public Service Company ("MPS").

FERC ratemaking methodology provides even less incentive for operational efficiency than traditional regulation in that a utility's actual costs are, in essence, automatically recovered. The primary means to ensure some reasonable level of efficiency and to prevent the recovery of imprudent or otherwise impermissible costs from ratepayers is through Commission intervention as a party in the FERC's annual implementation of the transmission rate formulas. The Commission routinely intervenes in Maine utilities' annual formula filings in an effort to ensure that transmission rates are just and reasonable.

FERC's ratemaking approach should generally have the effect of reducing utility reluctance to invest in reliability improvements in that timely cost recovery is essentially ensured. However, utilities have recently argued before FERC (in the context of a proposal to form a Regional Transmission Organization) that the existing regulatory system, given the risks associated with the construction of transmission facilities, does not provide sufficient incentives for the utilities to invest in their transmission systems. The utilities are asking FERC for significantly enhanced allowed returns as an inducement to construct transmission facilities.[15]

Because FERC's ratemaking methodology annually updates rates based on the previous year's revenues, the utility's incentive to increase sales and disincentive to promote energy efficiency and conservation is reduced to some degree relative to traditional or rate cap regulation. The overall impact of FERC regulation on utilities' motivation regarding sales is not substantial because for most customers transmission is not a substantial part of the total utility rate.[16]

3. Stranded Cost Rate Setting

Under the provisions of the Restructuring Act, the Commission was directed to determine and permit recovery of each utility's stranded costs which are defined as the legitimate, verifiable and unmitigatible costs made unrecoverable as a result of the restructuring of the electric industry.[17] Prior to the onset of retail access, and periodically since that time, the Commission has set stranded cost rates for each of the State's investor-owned utilities. The difference between the ongoing costs of qualifying facility ("QF") contracts and the value of the output of those contracts in the wholesale competitive market, generation-related regulatory assets, and costs related to Maine Yankee are the primary components of stranded costs in Maine.

[15] The Commission, as part of the New England Conference of Public Utility Commissioners ("NECPUC"), is opposing increases in returns (which translate into increased rates) as a means to induce utilities to invest in transmission on the grounds that utilities already have the lawful obligation to maintain a reliable system and there has been no showing that higher returns are necessary to raise capital.

[16] For example, transmission is about 15% of CMP's total T&D rate.

[17] 35-A M.R.S.A. § 3208.

Because a major component of each of the utility's stranded costs is dependent on the results of the sales of the output from the utility's QF contracts, the Commission has concluded that it is not feasible to employ an alternative rate setting mechanism for stranded costs. Therefore, the Commission has continued to rely on traditional cost of service rate setting for this category of costs. The Commission has set stranded costs for multi-year periods which run concurrently with the utility's sale of its QF entitlements.

4. Distribution Delivery Rates

During 2000, the Commission approved a second alternative rate plan for CMP (referred to as ARP 2000) applicable in the newly restructured environment.[18] Because generation service is now subject to market competition , and because FERC has asserted jurisdiction over transmission service following a state's unbundling of generation from delivery service, ARP 2000 only applies to distribution delivery rates and service. Similar to ARP I, ARP 2000 adjusts rates annually by a formula of inflation minus a productivity offset adjusted for mandated costs, earnings sharing, and service quality penalties. ARP 2000's SQI mechanism contains the same two indices, CAIDI and SAIFI, to measure reliability. Although CMP's revenues have decreased by about one-third as a result of restructuring, the ARP 2000 plan increased the maximum penalty level for failing to meet the SQI standards from $3.0 million to $3.6 million.

During 2002, the Commission approved an ARP for BHE.[19] Similar to CMP's ARP 2000, the BHE ARP applies only to distribution rates, contains CAIDI and SAIFI performance metrics, and requires BHE to file an Annual Reliability Improvement Report.

At the present time, the only investor-owned utility whose distribution rates remain subject to traditional regulation is MPS. During 2003, MPS submitted a proposal to the Commission requesting a $1.267 million increase in distribution revenues as a "starting point" adjustment for its proposed seven-year ARP. The Commission approved a stipulation which resolved the Company's "starting point" revenue requirement request but did not address MPS's proposed ARP.[20] Under the terms of the stipulation, MPS was given until the end of 2003 to determine whether it wanted to pursue its ARP proposal. MPS has informed the Commission that it does not wish to pursue its proposal at this time.

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[18] *Central Maine Power Company, Request for Approval of Alternative Rate Plan (Post-Merger), "ARP 2000,"* Docket No. 99-666 (Nov. 16, 2000).

[19] *Bangor Hydro-Electric Company, Request for Approval of Alternative Rate Plan,* Docket No. 2001-410 (June 11, 2002).

[20] *Maine Public Service Company, Request for Approval of Alternative Rate Plan,* Docket No. 2003-085 (Sept. 3, 2003).

5. T&D Rate Design

Upon the restructuring of the industry, the Commission removed generation-related costs from utility rates in a manner that avoided negative overall rate impacts for customers and customer classes. The result is that current T&D rates continue to have a basic design that existed when utilities provided generation service. Under that design, T&D utility revenues are primarily recovered through usage sensitive energy charges for the utilities' residential and small commercial customers, and through usage sensitive energy and demand charges for the utilities' large commercial and industrial customers. Currently, a very small percentage of utilities' revenues are recovered through fixed or customer charges that do not vary with usage.

6. Conservation Obligations

Prior to industry restructuring, utilities had the obligation to provide generation supply through a least cost mix of resources that included conservation or DSM programs. In particular, utilities were required to pursue DSM if less costly than an equivalent amount of supply. Thus, utilities were required to conduct DSM even though it was against their financial interest to reduce electricity consumption.[21]

The obligation of Maine utilities to provide generation services through a least cost mix of resources ended with the restructuring of the industry. Utilities are now solely "wires" companies. As such, the pursuit of conservation and DSM are no longer an integral part of the service provided by Maine utilities. In recognition of this change and the continued financial incentive that utilities have not to reduce electricity consumption, the Legislature, pursuant to the recently enacted Conservation Act, transferred responsibilities to implement and administer energy efficiency programs to the Commission.[22]

[21] As a consequence, the Commission considered and adopted many of the mechanisms discussed in section IV of this report to combat the utilities' inherent financial disincentive regarding efficiency and conservation. These include ROE adjustments, direct pass-throughs, revenue decoupling, shared savings, and DSM targets.

[22] P.L. 2001, ch. 624 (codified at 35-A M.R.S.A. § 3211-A).

III. ANALYSIS OF CURRENT REGULATORY MECHANISMS

Electricity rates currently paid by consumers in Maine are a composite of competitive and regulated services, and reflect a variety of ratemaking methodologies. This section of the report provides an analysis and discussion of the impact of this regulatory mix on rate levels and operational efficiencies, energy efficiency and reliability incentives, T&D rate structures, and economic development incentives.

A. Rate Levels and Operational Efficiencies

In 1992, the Commission was faced with what amounted to a ratepayer revolt.[23] Numerous ratepayers expressed concern with both the high level and unpredictability of CMP's rates. On an overall basis, the Commission views the alternative rate plans adopted in Maine to date to have effectively addressed these concerns. Rate stability and predictability have been enhanced by the ARP's use of a pre-established formula to set rates over a period of years. The ARP mechanism has reduced electric rate volatility by limiting rate changes to once a year and has allowed customers to anticipate and take into account future levels of electricity rates.[24]

Not only have the ARPs provided utility ratepayers with a greater rate stability and rate predictability, but they have also had a positive impact on overall rate levels. The annual productivity offsets in CMP's ARP 2000 range from a low of 2.0% in 2002 up to 2.9% in 2007. During the course of ARP 2000, these productivity offsets will serve to decrease distribution rates in real dollar terms by 18.0%. Under the BHE ARP, BHE's distribution rates decreased by 2.5% last year, and are projected to decrease by approximately 2.75% next year, and given current inflation forecasts, by 2.75% in 2005 and by 2.8% in both 2006 and 2007.

By severing the ratemaking link between a utility's rates and its costs over a multi-year period and restricting the ability of utilities to file for rate increases whenever their costs increase or revenues diminish, the rate cap plans have provided a powerful incentive for the utilities to reduce costs and increase operational efficiency. Moreover, the operational efficiency incentive is enhanced under rate cap plans in that utilities are able to maintain the benefits of their successful cost saving measures (in the form of enhanced shareholder returns) for the duration of the plan. This is in contrast to traditional regulation in which the benefits of increased operational efficiency to utility shareholders are essentially removed as soon as rates are reset in periodic rate proceedings.

Thus, the rate cap plans have been effective in mirroring competitive markets by setting prices independent of the utility's costs, and by allowing utilities to

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[23] *See, Public Utilities Commission, Investigation Into Central Maine Power Company, Ratepayer Complaints,* Docket No. 92-078 (Aug. 6, 1992).

[24] Additionally, CMP's first ARP prevented a large amount of Maine Yankee shutdown costs from being recovered from ratepayers.

benefit from their efficiency innovations or suffer losses as a result of either inefficiencies, poor business decisions, or changes in the business climate. At the same time, the productivity offsets contained in the ARPs have worked to ensure that ratepayers receive a fair share of potential operational savings regardless of whether the utility's actual performance produced such savings.

B. System Reliability

There are two areas of reliability issues: those involving the distribution network and those involving the regional system. Most reliability problems result from problems on the local distribution network, such as wind damage, ice damage, lightening strikes, and motor vehicle accidents. Regional problems, such as the blackout that affected much of the Northeast on August 14, 2003, are rare but can have a substantial impact.

1. Regional Reliability

The regional grid is designed to be able to recover from failures of generators or transmission lines without widespread blackouts. However, on occasion (the August 14, 2003 blackout is an example) these recovery operations are not invoked or prove to be inadequate. Since the major blackout in 1965, there have been regional and national efforts to standardize planning criteria and operating protocols under the auspices of the North American Electric Reliability Council or NERC. Those efforts are aimed at eliminating regional blackouts.

State and federal efforts to restructure the electricity industry have resulted in the decentralization of decision-making related to electric system reliability. Prior to restructuring, integrated utilities controlled virtually all aspects of power supply and reliability within their respective service territories. Currently, responsibility in the New England region is divided among a wider range of entities: generators, transmission owners, electricity suppliers and ISO-NE. This decentralization, coupled with still emerging roles of the various market players has, at least arguably, resulted in a slowdown in investment, particularly in transmission facilities that could help to maintain or improve regional reliability.

At present, regional reliability concerns appear more applicable to regions other than New England. Maine currently has a substantial surplus of generation. This means that, in the event of a system problem, electric service in Maine should be maintained so long as the system reacts quickly enough to avoid an external disruption to cascade into the State.[25] Moreover, except for specific load pockets, there is generally excess generation capacity in New England.

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[25] Interestingly, Maine was one of the few Northeastern states which was not part of the seminal 1965 blackout. Oral history has it that the Maine operator was able to isolate Maine from the rest of region quickly enough to avoid a major blackout.

Going forward, ISO-NE can be expected to play an increasing role in ensuring adequate regional reliability. This will occur through market rules intended to maintain adequate generation resources in the region, as well as through longer-term planning and oversight intended to ensure that adequate transmission infrastructure is in place.

2. Distribution Reliability

Multi-year rate cap plans provide powerful incentives to minimize costs that could result in the reduction of distribution system reliability. To counteract those incentives, the plans include service quality standards that utilities must satisfy to avoid financial penalty. The adoption of the CAIDI and SAIFI metrics with automatic penalty mechanisms results in enhanced financial incentives for utilities to provide appropriate reliability and a more effective and objective way to measure service quality than the tools previously relied on by the Commission under traditional regulation. As the Commission has gathered experience with these metrics, it has refined the service reliability evaluation methods and techniques.

Specifically, the Commission has recognized that insufficient investment and deterioration in the utility's plant might not be reflected in degradation of service until some time in the future. Accordingly, the Commission has substantially refined the service reliability information that each utility must submit to the Commission each year. Currently, CMP must submit, as part of its annual ARP filing, a distribution plant report which provides information on the age of the utility's distribution equipment and facilities, its construction budget for the past two years, and actual construction spending for the prior year.[26]

The Commission has also recognized that it is possible for a utility to maintain acceptable service levels on a system-wide average basis, but allow service to customers in certain areas (particularly less densely populated rural areas) to deteriorate. As a result, BHE and CMP are required, as part of their annual filings, to prepare and submit an Annual Reliability Improvement Report which includes a service area specific analysis of service reliability, an identification of the company's worst circuits, an analysis of each circuit's problems and the planned and/or undertaken improvements to address each problem. These reports have enabled the Commission and the Public Advocate to review service area specific problems and to engage in a constructive dialogue with the utilities to ensure that such problems are addressed.

As part of the Commission's monitoring of service reliability issues, it has also recognized that, with customers' increased use of electronic equipment (such as VCRs, digital clocks and computers), the quality of power provided to customers has become more important in recent years. Momentary power interruptions are, therefore, becoming more of a focus of consumers' perception of reliable electric service. While

[26] In the context of reviewing BHE's SQI, the Commission has also requested such data from BHE.

the impact of momentary interruptions may at times be more of a nuisance than a serious problem, frequent occurrences can damage equipment, erode public confidence, and increase the likelihood of complaints to the utilities and to the Commission. In addition, power quality problems can have an adverse effect on the State's efforts to attract high-tech industries that are very sensitive to such interruptions, as well as on the increasingly computer-dependent operations of other commercial enterprises in Maine.

The Commission, therefore, convened a statewide task force of interested stakeholders,[27] referred to as the Power Quality Task Force ("PQTF"), to investigate alternative service quality indicators and, where appropriate, to recommend new indicators for measuring power quality service performance. The PQTF investigated whether a Momentary Average Interruption Frequency Index (MAIFI)[28] should be included as an SQI indicator, and recommended that a MAIFI standard not be established at this time. Instead, the PQTF recommended that each utility collect specific service data for a two-year period which can then be used to determine if MAIFI or some other metric should be adopted to assess the quality of power provided by CMP, BHE and MPS. The data will also be used to determine if a correlation exists between customer satisfaction and momentary interruptions. If the decision is made to adopt a momentary outage metric, the metric would be incorporated into the CMP and BHE ARPs. MPS does not currently have an alternative rate plan, however, the metric could be considered for adoption independent of a rate plan or as part of a future rate plan.

Finally, recognizing that the evaluation of service quality and reliability is an evolving and ongoing process, both the CMP ARP 2000 and the BHE ARP provide for mid-period reviews of the operation of the SQI mechanism. CMP's mid-period review was concluded in December 2003, and included a change in the exemption criteria for the CAIDI and SAIFI metrics. The exemption criteria as originally approved excluded outages that affected 10% of customers within portions of CMP's territory from the metric calculations. The outage exemption mechanism in operation had worked in an unintended manner to exclude minor outages and thus was not properly tracking CMP's service reliability. The exemption criteria were therefore changed so that only outages which affect 10% of CMP's customers on an entire

[27] The task force includes Commission staff members, the Public Advocate, and representatives of CMP, BHE and MPS.

[28] MAIFI is a measure of the number of momentary interruptions on an electric utility system. These events may occur as a precursor to a sustained interruption (which is captured in the other indices) or may be isolated events that are resolved by the automatic operation of resoling devices or other protection devices on the system. MAIFI is calculated by dividing the total number of customer momentary interruptions by the total number of customers served.

service territory basis would be excluded.[29] BHE's mid-period review will occur during 2004.[30]

The Commission will continue to examine ways to improve the operation of the service quality indices.

C. Energy Efficiency

Under the Commission's stranded cost rate setting process, stranded cost rates are set for a several-year period based on a forecast of sales. Because a utility's stranded costs do not vary with volume, after stranded costs are set , the utility has a strong incentive to promote sales because all increases in sales flow directly to the utility's bottom line. While the Commission retains the authority to reset stranded cost rates during the stranded cost rate-setting period to correct substantial inaccuracies, any such change can only be made on a prospective basis. Thus, during the time a case is being litigated to correct for sales volume changes, the utility would retain the amounts collected from ratepayers above those projected to be needed to recover stranded costs. During 2003, the Commission concluded an investigation of CMP's stranded costs to address the issue of higher than projected sales.[31] Typical of traditional cost of service rate setting, the proceeding was controversial and required a significant amount of Commission staff and utility resources.

With respect to ARP rate setting in effect for distribution delivery rates, the incentive for utilities to promote electricity sales and to discourage energy efficiency and conservation are magnified to some degree relative to traditional regulation. As with traditional regulation, a utility's profits are a direct function of sales levels. However, the inability of a utility under a rate cap plan to file for a rate increase in response to increasing costs or decreasing revenues provides a greater motivation for utilities to act to increase sales over the term of the plan, as well as an enhanced financial conflict with conservation activities that serve to reduce the consumption of electricity.

The Legislature, recognizing both that utilities were no longer in the generation business and that there continued to be strong disincentives regarding the conservation of electricity, transferred the responsibility to administer energy efficiency and conservation programs from the utilities to the Commission. This dramatically

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[29] *Mid-Period Review Investigation of CMP's ARP 2000 Service Quality Indices,* Docket No. 2002-445 (Dec. 12, 2003).

[30] It should also be noted that, in addition to service quality standards, the Commission continues to monitor the performance of utilities with respect to system reliability. For example, after an ice storm in 2002, the Commission initiated an investigation of the resulting power outages and adopted numerous measures to improve utility response to storm and other emergency situations. *Investigation into the Adequacy of Utility Services in Maine During Power Outages,* Docket No. 2002-151.

[31] *Investigation of Central Maine Power Company's Stranded Cost Rates and Request for an Accounting Order,* Docket No. 2002-770 (June 20, 2003).

changes the issue of regulatory responses to utility financial incentives regarding energy efficiency and conservation. Utilities, either under traditional regulation (stranded cost) or alternative regulation (distribution delivery) still have the incentive to discourage conservation and promote consumption. However, utilities no longer carry out ratepayer funded conservation measures and, thus, cannot act to hinder the effectiveness of such programs through ineffective or non-performance. The result is that the importance of addressing the inherent disincentive that derives from the ratemaking process through the adoption of alternative regulatory devices or changes to rate design has been greatly diminished.

D. Rate Structures

When utilities were vertically integrated and provided generation supply, it was reasonable to rely on usage sensitive charges because a substantial amount of utility costs varied with actual ratepayer consumption. After restructuring, utilities provide only delivery service and each utility's rates must recover only the costs associated with delivery service and stranded costs. The costs to provide the delivery component of utility service are generally fixed, at least in the shorter term. In the long run, T&D utility costs vary to some degree because the sizing of facilities over the longer term depends on maximum consumption (i.e., "peak load") of customers.

Stranded costs are historic costs and, thus, do not vary with current consumption. Stranded costs, however, were incurred to provide generation service and, therefore, even though such costs do not vary with current usage, as a matter of equity, it may be argued that such costs should continue to be recovered through demand and energy charges because this tends to allocate costs to customer classes and to customers (in general, if not individually) according to their cost causation responsibilities.

The current usage-based delivery and stranded cost rates have the effect of providing the incentive for utilities to promote sales because additional sales translate into additional earnings. This is especially the case with respect to stranded costs which do not vary at all with sales volume. The current T&D utility rate design does, however, provide strong price signals for customer conservation because a substantial portion of costs remain in usage sensitive charges. Thus, lower usage results in reduced bills. It should also be noted that the existence of stranded costs in T&D rates means that rates are actually higher than the ongoing cost of service, resulting in greater incentives for customers to conserve electricity or seek grid alternatives than would actually be efficient if rates more accurately reflected the underlying costs.

During 2001, the Commission initiated an investigation to examine moving more T&D utility costs into fixed charges.[32] The investigation focused on stranded costs because there is little debate that, from an economic efficiency perspective, such costs

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[32] *Investigation of Rate Design of Transmission and Distribution,* Docket No. 2001-245.

(which are sunk) should be recovered through fixed charges. However, the proceeding was controversial. Although utilities were generally supportive of moving stranded costs into fixed charges, the intervenors generally opposed the move. The basis for the opposition was twofold: first, moving rates from usage sensitive to fixed charges would reduce the incentive of consumers to conserve their electricity usage; and second, the change would increase utility bills for low-use customers.[33] Ultimately, the case was resolved by a stipulation that made only a very modest move to fixed charges, by targeting expected rate decreases over several years only to energy charges.[34]

E. Economic Development

Under both traditional and rate cap rate setting methodologies, utilities have a strong incentive to promote economic development of any type within their respective service territories. Economic growth leads to increased sales, which results in increased utility profits. Additionally, the management of utilities, like that of any business, has an interest in increasing the size of their business. Utilities have no particular incentive to attract energy-efficient business, as opposed to any other new enterprise (unless the utility views an energy-efficient business to be more likely to be viable over the long-term).

The financial incentive for utilities to promote economic development under ARPs is magnified relative to traditional regulation due to the inability of a utility to file for a rate increase under a rate cap plan. Generally, this magnified incentive would make it more attractive for utilities to promote energy-intensive businesses.

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[33] The opposition came primarily from the Public Advocate and the Natural Resources Counsel of Maine. In recent comments provided to the Commission during its incentives investigation, the Public Advocate indicated that he is not opposed to a fixed charge rate design in concept, but believes that the resulting bill impacts for low use customers would be “entirely unacceptable.”

[34] Rate decreases were also targeted to winter charges in an effort to reduce the seasonal differentiation.

IV. ALTERNATIVE REGULATORY MECHANISMS TO PROMOTE EFFICIENCY AND RELIABILITY

This section of the report presents and discusses regulatory mechanisms that can be used to alter financial incentives of utilities.

A. Revenue Decoupling

1. General Description

Revenue decoupling is a form of ratemaking intended to remove the financial disincentive that utilities have to engage in or support energy efficiency and conservation activities.[35] The mechanism also acts to remove the financial incentive to promote increases in sales. Revenue decoupling works by severing the link between a utility's sales and its profits. This is accomplished by pre-establishing a utility's "allowed" revenues, which would typically occur in a traditional rate case proceeding. These allowed revenues are periodically compared to the utility's actual revenues and the difference is tracked for ratemaking purposes in a deferred account. In the event actual revenues are greater than allowed revenues, the difference is returned to ratepayers through a rate reduction. Conversely, if actual revenues are below allowed revenues, the difference is collected by the utility through a surcharge on rates.

2. Energy Efficiency Incentives

By establishing a ratemaking process in which the revenue a utility ultimately obtains is independent of sales levels, the financial disincentive that exists under traditional and rate cap regulation to promote energy efficiency and conservation, as well as the incentive to promote increased consumption, is removed because profits are no longer a function of sales volume. Revenue decoupling does not, however, provide any positive incentive for utilities to promote or support energy efficiency or conservation programs; it only makes them financially neutral to such activities.[36]

The implementation of revenue decoupling would reduce a utility's incentive to promote economic development to some degree in that increased electricity consumption would not increase profits. However, depending on the form of revenue decoupling, the incentive in favor of increasing the number of customers would either be enhanced or not affected.

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[35] The implementation of revenue decoupling would have no significant impact on utility financial incentives to provide adequate system reliability relative to traditional or rate cap regulation.

[36] Mechanisms to provide utilities with positive incentives to promote energy efficiency and conservation are discussed below.

3. Operational Efficiency, Rates and Risks

Although revenue decoupling acts to ensure pre-specified levels of revenue, it does not guarantee any level of profits. Thus, under revenue decoupling, a utility maintains its incentive to cut costs or increase efficiency in operations. This incentive to minimize costs can be enhanced through a multi-year revenue decoupling plan. Such a plan would be similar to a multi-year rate cap plan in that increased incentives for operational efficiencies occur as the result of an inability of a utility to file a rate case through the period of the plan. Like a rate cap plan, a revenue decoupling plan would include a formula (such as inflation minus productivity) by which the allowed revenue would change on an annual basis, and could also include any of the other typical attributes of a rate cap plan, such as service quality standards and earning sharing mechanisms.

Revenue decoupling mechanisms are not specific to revenue losses from efficiency or conservation activities. Revenue decoupling results in utilities being financially neutral to the impact on sales levels (either sales decreases or increases) from any cause, most notably economic conditions and the weather. Thus, revenue decoupling has the effect of shifting the risks of economic cycles and weather fluctuations from utilities to ratepayers. This impact combined with the revenue accounting deferrals inherent in revenue decoupling results in increased rate volatility and uncertainty relative to traditional or rate cap regulation.

There are, however, adjustments that can be made to a revenue decoupling mechanism to reduce the shift of risks to ratepayers. For example, the allowed revenue under a revenue cap could be normalized for weather or economic conditions, or allowed revenue could be adjusted based on the number of customers (which would leave utilities subject to economic conditions to some degree). The implementation of these types of adjustments is complicated and would not act to completely avoid the shift of risks onto ratepayers. Another mechanism that would reduce the shift of risks to ratepayers, as well as lower rate volatility impacts, is a limit on the amount of revenue that could be deferred for later recovery. Such an approach, however, would eliminate the incentive impact of the revenue decoupling once the deferral limit was reached.

The shifting of sales level risk to ratepayers that occurs with revenue decoupling might be offset to some degree by a lower cost of capital for utilities that could translate into some level of lower rates.

4. Maine's Experience with Revenue Decoupling

Maine has experience with revenue decoupling. In 1991, the Commission adopted, on a three-year trial basis, a revenue decoupling mechanism for

CMP (referred to as "Electric Revenue Adjustment Mechanism" or "ERAM").[37] The "allowed" revenue was determined in a rate case proceeding and adjusted annually based on changes in the utility's number of customers. Analyses before the Commission at the time indicated that changes in the number of customers were at least as good an indicator of CMP's costs as changes in sales levels. CMP's ERAM was not, however, a multi-year plan, so CMP was free to file a rate case at any time to adjust its "allowed" revenues.

CMP's ERAM quickly became controversial. Around the time of its adoption, Maine, as well as the rest of New England, was at the start of a serious recession that resulted in lower sales levels. The lower sales levels caused substantial revenue deferrals that CMP was ultimately entitled to recover. CMP filed a rate case in October of 1991 that would have increased rates at the time, but likely would have caused lower amounts of revenue deferrals. However, the rate case was withdrawn by agreement of the parties to avoid immediate rate increases during bad economic times.[38]

By the end of 1992, CMP's ERAM deferral had reached $52 million. The consensus was that only a very small portion of this amount was due to CMP's conservation efforts and that the vast majority of the deferral resulted from the economic recession. Thus, ERAM was increasingly viewed as a mechanism that was shielding CMP against the economic impact of the recession, rather than providing the intended energy efficiency and conservation incentive impact. The situation was exacerbated by a change in the financial accounting rules that limited the amount of time that utilities could carry deferrals on their books.

Maine's experiment with revenue cap regulation came to an end on November 30, 1993 when ERAM was terminated by stipulation of the parties.[39]

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[37] *Investigation of Chapter 382 Filing of Central Maine Power Company, Order,* Docket No. 90-085 (May 7, 1991). As discussed, because a revenue cap alone does not provide a positive incentive for a utility to pursue conservation, the Commission also adopted a shared savings program in which CMP would be reimbursed for a portion of the savings from its conservation programs. Such shared savings programs are discussed below.

[38] P*roposed Increase in Rates, Order Granting Motion to Withdraw Proceeding,* Docket No. 91-174 (Jan. 10, 1992).

[39] *Consideration of Issues Concerning ERAM-Per-Customer for Central Maine Power Company, Order Approving Stipulation,* Docket No. 90-085-A (February 5, 1993). After the termination of ERAM, the Commission's efforts regarding incentive regulation moved to the development of rate cap regulation.

B. Lost Revenue Adjustments

1. General Description

Lost revenue adjustments are a common mechanism employed to reduce utility disincentives to pursue energy efficiency and conservation. The mechanism works by estimating the amount of sales that a utility has lost as a result of energy efficiency programs and reimbursing the utility for its lost revenues. The reimbursement occurs through an adjustment in utility rates. The mechanism is considered an alternative to revenue decoupling and could be implemented in conjunction with traditional or rate cap regulation. Lost revenue adjustments are not designed to, and do not, impact utility incentives to provide adequate system reliability.

2. Incentive Impacts

The mechanism, if implemented accurately,[40] makes utilities financially neutral to lost sales resulting from energy efficiency programs. However, it does nothing to impact a utility's incentive to promote increased sales, or to align a utility's interests with a state's efficiency objectives or efficiency activities by other entities for which they are not reimbursed under the mechanism. Moreover, the mechanism is relatively complex to administer, and measurement and evaluation issues are often controversial.

C. Incentive Payments/Penalties

1. ROE Adjustments

Return on equity (ROE) adjustments are a means to reward or penalize a utility for its activities. The Commission has substantial discretion to set a utility's ROE within a reasonable range or bandwidth. Thus, if a utility is found to have acted in an exemplary fashion in the promotion of State policies, the Commission could establish an ROE at the upper end of the reasonable range. Conversely, if the Commission finds that a utility has acted contrary to State policies, a lower ROE can be established.

The mechanism can be used to provide utilities with the incentive to promote energy efficiency and conservation, or to provide appropriate system reliability. As discussed above, the use of ROE adjustments is the primary tool under traditional regulation to ensure that utilities act in a manner consistent with their obligations,[41] but

[40] Lost revenue adjustments are often criticized in that they create an incentive for utilities to make it appear that their programs are saving energy, when they are actually ineffective. This results in a windfall through the reimbursement of lost revenues that were never in fact lost.

[41] The Commission has used ROE adjustments in the past to both reward and penalize utilities.

they can also be employed as part of rate cap or revenue decoupling regulation. The application of ROE adjustments occurs in the context of litigated proceedings, is subjective in nature, and is usually controversial.

2. Shared Savings

Shared savings mechanisms are used to provide utilities with the incentive to aggressively pursue energy efficiency and conservation programs. The mechanism works by allowing utilities to "share" a pre-specified portion of the savings achieved from their energy efficiency and conservation programs, thus linking a utility's profits to its conservation performance. The mechanism is not applicable to system reliability incentives.

Energy efficiency and conservation programs, assuming that they are cost-effective, will cost less than a comparable amount of supply. The difference between the cost of the avoided supply and cost of the efficiency program represents overall ratepayer savings. Under a shared savings program, a utility is able to recover a portion of these savings through an upward adjustment in its rates. The mechanism is relatively complex to administer, and requires rigorous measurement and long-term verification of achieved savings.

Shared savings programs do not remove the basic utility incentive to promote consumption or to discourage conservation. For this reason, a shared savings program is often adopted in conjunction with a lost revenue adjustment or a revenue decoupling mechanism.

D. Service Quality Standards

As discussed above, the Commission has incorporated service quality standards with automatic penalty provisions as part of the alternative rate plans. In addition to penalizing a utility for service that degrades below baseline standards, a service quality standard mechanism could be designed to reward a utility for exceptional service quality. Another possible variation would be to adopt area specific standards within a utility's service territory and penalize (or reward) the utility based on its performance within portions of its service territory. While this approach has been suggested in prior Commission proceedings, the Commission has not adopted it.

It is possible to use service quality standards in the context of different rate-setting mechanisms, such as traditional rate-of-return regulation.

E. Direct Pass-Through

1. General Description

Direct pass-through of utility costs is a ratemaking mechanism that allows utilities to receive dollar-for-dollar recovery of certain categories of costs. The mechanism can be used to remove the incentive utilities may have against making expenditures in certain areas. Under the general approach to ratemaking, utilities do not receive dollar-for-dollar recovery of their expenditures. Instead, rates are set on a prospective basis using historical costs. Direct pass-through of costs is an exception to standard ratemaking that is appropriate in some circumstances. For example, particular costs that are extremely volatile and outside the control of the utility have been candidates for direct pass-through.[42] Additionally, utilities often recover the costs of publicly mandated programs through direct ratepayer pass-throughs. This is done to help ensure that utilities do not under-fund such programs to enhance their bottom line profits.

Utility expenditures on energy efficiency and conservation programs in Maine have historically been subject to direct pass-through rate recovery. This was part of a longstanding regulatory attempt to counter utilities' natural inclination against spending money to reduce the use of its product. Utility expenditures on system reliability, however, have generally not been subject to direct pass-throughs in that they are considered a basic part of utility operations and not subject to special ratemaking treatment. However, there have been exceptions for costs resulting from unusually destructive storms, such as the 1998 ice storm.

2. Incentive Impacts

Direct pass-through of costs removes the incentive utilities have to under-fund certain programs or projects so as to enhance profits. However, any time a category of costs is recovered on a dollar-for-dollar basis, there is no financial incentive for the utility to be efficient or to minimize costs in conducting the program or project.

F. Fixed Charge Rate Design

1. General Description

Maine ratepayers' bills now consist of both unregulated and regulated prices and, within the regulated component, FERC jurisdictional and Maine jurisdictional rates. At the present time, all rates have usage sensitive components. While it would be possible to recover the entire PUC jurisdictional revenue requirement through fixed charges, a significant portion of electricity bills would remain usage sensitive.

2. Incentive Impacts

The more a utility's costs are recovered through fixed charges, the less financial incentive it has to promote sales or to discourage energy efficiency and

[42] For many years, utilities were allowed a direct pass-through of their fuel costs (primarily oil) pursuant to this rationale. This practice came to end for CMP with the adoption of the 1995 ARP.

conservation. [43] However, unless all of a utility's costs are recovered through fixed charges, some incentive to promote consumption on the part of utilities will remain. A movement towards a more fixed charge rate design would also reduce a utility's incentive to promote economic development to some degree since increased electricity consumption would not increase profits. However, increasing the number of utility customers would have a positive impact on profits.

If T&D utility rate design were changed so that it consisted entirely of fixed charges, it would provide no financial incentive for customers to conserve their usage of electricity. However, because the supply portion of the electricity bill would continue to consist of usage-sensitive charges, there would still be some incentive for consumers to conserve. However, the motivation of consumers to conserve would be significantly reduced in that approximately two thirds of electricity bills are comprised of T&D charges.

3. Rate Impacts

Any time rate design is altered some customers benefit through lower bills, while other customers are subjected to higher bills. Therefore, a primary consideration in any attempt to move to a more fixed rate design is customer bill impacts. The movement to a fixed rate design in particular would result in increases for customers with relatively lower usage within a class, and decreases for customers with relatively higher usage.

[43] The recovery of a greater portion of costs through fixed charges would also reduce a utility's risk exposure which should lower its cost of capital.

To illustrate the bill impact effect, the following tables show the impact on CMP's residential and small business customers if all T&D costs (including stranded costs) were recovered through a fixed customer charge.

Comparison of Customer T&D Bills at Current and Fixed Rates
CMP Residential Rate A

Monthly kWh	Monthly Bill (current rate)	Monthly Bill (fixed rate)	Change in Monthly Delivery Bill $/month	%
100	7.18	35.13	$27.95	389%
200	13.87	35.13	21.25	153%
300	20.57	35.13	14.56	71%
400	27.26	35.13	7.87	29%
500	33.95	35.13	1.17	3%
800	54.03	35.13	-18.91	-35%
1,000	67.42	35.13	-32.29	-48%
1,200	80.81	35.13	-45.68	-57%
1,500	100.89	35.13	-65.76	-65%
2,000	134.35	35.13	-99.23	-74%

Comparison of Customer T&D Bills at Current and Fixed Rates (single phase)
CMP Small Commercial Rate SGS

Demand (kW)	Load Factor	Monthly kWh	Monthly Bill at current rate	Monthly Bill at fixed rate	Change in Monthly Delivery Bill $/month	%
0.5	0.3	110	16.03	63.39	$47.36	295%
0.5	0.6	219	22.30	63.39	41.09	184%
1.5	0.3	329	28.57	63.39	34.82	122%
1.5	0.6	657	47.39	63.39	16.00	34%
3	0.3	657	47.39	63.39	16.00	34%
3	0.6	1,314	85.02	63.39	-21.63	-25%
5	0.3	1,095	72.48	63.39	-9.08	-13%
5	0.6	2,190	135.19	63.39	-71.80	-53%
10	0.3	2,190	135.19	63.39	-71.80	-53%
10	0.6	4,380	260.62	63.39	-197.23	-76%
15	0.3	3,285	197.91	63.39	-134.51	-68%
15	0.6	6,570	386.05	63.39	-322.66	-84%
20	0.3	4,380	260.62	63.39	-197.23	-76%
20	0.6	8,760	511.48	63.39	-448.09	-88%

As the tables above illustrate, if T&D charges were fixed, CMP residential customers would pay a flat rate of $35.13 per month and small commercial customers would pay a flat rate of $63.39 per month for T&D delivery service, and lower usage customers in both classes would see significant bill increases.

The following tables show the number of customers in CMP's territory whose average monthly bill falls within various kWh ranges. A customer's bill will vary by month, so the level of bill increase or decrease will vary by month. However, these tables give an idea of the number of customers that will experience bill increases or decreases of the sizes shown above. In general, it is reasonable to estimate that, if the fixed rates described above were implemented, about half of Maine's residential customers would experience bill increases.

Distribution of Small Commercial Customer Usage in CMP Territory

Ave Monthly kWhs in Range	% of Customers in each Range	Number of Customers
0-100	20.0%	8,688
100-200	10.5%	4,530
200-300	9.2%	3,984
300-400	7.7%	3,326
400-500	6.4%	2,782
500-600	4.9%	2,103
600-700	4.0%	1,747
700-800	3.5%	1,524
800-900	3.2%	1,367
900-1000	2.7%	1,155
1000-1200	4.8%	2,098
1200-1500	5.4%	2,335
1500-1700	2.8%	1,224
1700-2000	3.5%	1,532
2000-2500	4.3%	1,851
2500-3000	2.7%	1,152
>3000	4.5%	1,937
Total:	100.0%	43,335

Includes customers on Rate SGS who were on the utility grid for 12 months.
Source: CMP

Distribution of Residential Customer Usage in CMP Territory

Ave Monthly kWh Range	% of Customers in Each Range	Estimated Number of Customers
0-100	8.2%	34,110
100-200	9.3%	38,580
200-300	10.8%	44,950
300-400	12.5%	51,950
400-500	13.4%	55,590
500-600	12.5%	51,850
600-700	9.9%	41,370
700-800	7.6%	31,590
800-900	5.3%	21,840
900-1000	3.5%	14,690
1000-1200	4.1%	16,920
1200-1500	2.1%	8,580
1500-1700	0.5%	1,960
1700-2000	0.2%	990
2000-2500	0.2%	640
2500-3000	0.0%	160
>3000	0.0%	90
Total:	100%	415,860

Includes customers on Rate A who were on the utility grid for 12 months. Based on 10% sample.
Source: CMP

G. Summary of Alternatives

The following table summarizes the incentive impacts of the various alternative regulatory tools discussed in this section, as well as traditional regulation and the rate cap mechanism currently in place in Maine.

Regulatory Incentives and Incentive Mechanisms Incentive Impacts

	Electricity Consumption	Energy Efficiency	System Reliability	Operational Efficiency	Economic Development
Traditional Regulation	Incentive to Promote	Incentive to Discourage	Possible Incentive to Over Invest	Little Incentive to Maximize	Incentive to Promote
Rate Cap Regulation	Enhanced Incentive to Promote	Enhanced Incentive to Discourage	Incentive to Minimize Investment	Enhanced Incentive to Maximize	Enhanced Incentive to Promote
Revenue Decoupling with Rate of Return	No Incentive to Promote	No Incentive to Encourage	Possible Incentive to Over Invest	Little Incentive to Maximize	Reduced Incentive to Promote
Revenue Cap Regulation	No Incentive to Promote	No Incentive to Encourage	Incentive to Minimize Investment	Enhanced Incentive to Maximize	Reduced Incentive to Promote
Fixed Rate Design	No Incentive to Promote	No Incentive to Encourage	No Impact	No Impact	No Impact
Lost Revenue Adjustments	Incentive to Promote	No Incentive to Discourage (Utility Programs)	No Impact	No Impact	No Impact
Shared Savings	Incentive to Promote	Reduced Incentive to Discourage (Utility Programs)	No Impact	No Impact	No Impact
ROE Adjustments	Reduced Incentive to Act Contrary to State Policy	Enhanced Incentive to Promote State Policy	Enhanced Incentive to Provide Appropriate Reliability	No Impact	Enhanced Incentive to Promote State Policy (e.g.., Energy Efficient Business)
Service Quality Standards	No Impact	No Impact	Enhanced Incentive to Provide Adequate Reliability	No Impact	No Impact
Direct Pass-Through	No Impact	Reduced Incentive to Discourage (Utility Programs)	Enhanced Incentive to Provide Adequate Reliability	Little Incentive to Maximize	No Impact

V. OTHER STATE MECHANISMS

The Commission has conducted a survey of other states and a literature search to determine the existence of possible mechanisms that can be used to affect or alter utility financial incentives with respect to energy efficiency and conservation and system reliability. The results of this research are presented in this section of the report and summarized in the following tables. The Commission was not able to obtain information from every state and, accordingly, the presentation in this section is based on those states for which information could be obtained.

A. Energy Efficiency and Conservation

Many states employ a variety of mechanisms to address the financial disincentive of utilities to reduce consumption through energy efficiency and/or conservation. The mechanisms most commonly used are performance incentives, shared savings, and lost revenue adjustments. Some states also employ a direct pass-through of costs and ROE adjustments. A number of states eliminated their conservation incentive mechanisms after their state restructured the electric industry or removed the obligation of utilities to pursue conservation and efficiency programs. The Commission's research revealed no state in which conservation incentive mechanisms are applied to utilities under circumstances in which utilities are not obligated to pursue efficiency and conservation programs.

A number of states adopted a revenue decoupling mechanism in the past. However, no state currently employs this type of mechanism. Decoupling mechanisms have been eliminated either due to dissatisfaction with their operation or as a result of changes in the industry structure. However, two states (California and Montana) are currently considering the re-adoption of a decoupling mechanism. A renewed effort regarding conservation incentives in these states is a result of the failure of restructuring efforts to produce effective retail competition.

Finally, the Commission is unaware of any state that has moved to a fixed charge rate design as means of addressing utility incentives regarding energy efficiency and conservation. However, New York has a pending investigation of electricity delivery rate disincentives against the promotion of energy efficiency, renewable technologies, and distributed generation.

The following table presents a summary of other state energy efficiency and conservation incentive mechanisms.

State	Revenue Decoupling	Lost Revenue Adjustment	Shared Savings	Performance Targets Incentives/ Targets	ROE Adjustments	Direct Pass-through	Mechanisms Eliminated *	Non-utility Efficiency Agency	Revenue Decoupling in Past	None
Arkansas										X
Calif.			X	X					X	
Colo.										X
Conn.				X						
Delaware										X
Florida						X			X	
Illinois										X
Indiana		X	X	X						
Iowa										X
Kansas					X					
Kentucky		X	X						X	
Mass.				X						
Minn.				X						
Missouri										X
Montana					X				X	
Nebraska										X
Nevada				X						
New Jersey		X		X						
New York							X	X	X	
Ohio							X			
Oregon							X	X	X	
Penn.										X
Rhode Island				X						
Tenn.										X
Texas										X
Utah						X			X	
Vermont							X	X		
Virginia										X
Wash.				X					X	
Wisc.			X					X		
Wyoming										X

* State had one or more efficiency mechanisms in the past. These mechanisms were eliminated after industry restructuring or when utility obligations to implement efficiency programs were removed.

B. System Reliability

The majority of states for which the Commission was able to obtain information have no specific mechanism to address the financial incentives for utilities to provide adequate system reliability. However, service quality standards that involve financial penalties for the failure to meet pre-specified standards are common. Some states do adjust ROEs or impose monetary penalties to address service quality issues.

The following table presents a summary of other state's system reliability incentive mechanisms.

State	Service Quality Standards Penalties	Service Quality Standards Rewards	ROE Adjustments	Monetary Penalties	Direct Pass-through	None
Arkansas			X	X		
California	X					
Delaware				X		
Florida	X	X				
Indiana						X
Iowa			X			X
Kansas						X
Kentucky						X
Missouri						X
Montana						X
Nebraska						X
Nevada						X
New York	X					
Ohio						X
Pennsylvania				X		
Tennessee						X
Texas			X			
Utah						X
Vermont	X					
Virginia						X
Washington	X					
Wisconsin						X
Wyoming						X

VI. RECOMMENDATIONS AND ALTERNATIVES

As required by the Legislature, this report covers utility incentives with respect to two distinct areas: system reliability and energy efficiency. The issues involving system reliability are relatively straightforward. The Commission's view is that, as a general matter, the current regulatory framework has produced a reasonable balance of system reliability and ratepayer cost. Accordingly, no major changes to the regulatory scheme should occur to address reliability incentives.

The issues involving energy efficiency and the promotion of electricity consumption are relatively more complex. The Legislature must consider in the first instance whether the current incentives that utilities have to promote the use of electricity raise substantial public interest concerns. The threshold question in this context is whether it is the policy of this State to discourage the consumption of electricity. If this is the policy of the State, the next consideration is whether utilities are particularly effective in promoting the use of electricity and thereby frustrating the State's ability to attain its policy goal. Finally, if both questions are answered in the affirmative, in the Commission's view the Legislature should consider whether potential changes to the regulatory structure to alter utility incentives might nevertheless create greater problems than they solve.

The Commission expresses no opinion on whether the State should adopt a policy that the consumption of electricity is against the public interest. However, as discussed in this section of the report, the Commission has serious concerns regarding the potential consequences of efforts to remove the financial incentives of utilities to promote their product through fundamental changes in regulatory structure or rate design.

A primary question is whether the current regulatory framework is subverting efforts to promote conservation and the efficient use of electricity. The Commission's view is that the current framework does not have this effect. The Commission has some limited evidence that utility efforts to promote consumption are not particularly effective. More importantly, however, the Commission's view is that conservation and energy efficiency are driven more by customer decisions than by utility action. Accordingly, it is more important that consumers have proper price signals to conserve and that the State retain a vibrant state-wide conservation program (i.e., the Commission's Efficiency Maine program) than it is to change utilities' actions.

It is for these reasons that the Commission recommends no fundamental change in the current regulatory structure to address utility financial incentives regarding the consumption of electricity. Nevertheless, in the following section, we have outlined and evaluated several alternative approaches if the Legislature decides that public policy requires that current financial incentives should be altered.

A. Recommended Regulatory Approach

The Commission recommends that no fundamental changes be made to the current regulatory structure to alter utility financial incentives.

1. Rate Cap Regulation

Multi-year rate cap plans (which have been in place for CMP since 1995) have proven to be extremely successful in satisfying their objectives. In effect, rate cap plans mirror the competitive market by providing strong incentives for utilities to increase efficiencies in their operations and lower their costs of providing service, which have the effect of keeping rates as low as possible.

Rate caps were initially adopted in Maine in response to a series of frequent, unpredictable rate increases. The overarching goal of rate cap regulation was, and continues to be, the minimization of rates and rate volatility. Maine has high electric rates relative to other states. High electricity rates and rate level unpredictability have a significant negative impact on the State's residents and businesses and on economic development. Thus, the minimization of rates and the maintenance of rate predictability and stability, in the Commission's view, are high priorities for the State's regulatory system. As discussed in Section III of this report, Maine's implementation of rate cap regulation has satisfied its primary goals.[44] Moreover, rate cap plans have improved the regulation of service reliability through the creation of systematic and objective SQIs. While such plans do act to enhance a utility's incentive to promote consumption relative to traditional regulation, the enhanced incentive is a matter of degree, in that utilities under traditional regulation always had a powerful incentive to promote sales.

The Commission recommends that multi-year rate cap plans remain the basic regulatory approach for Maine's T&D utilities' distribution delivery rates.

2. System Reliability Mechanisms

System reliability is essentially a function of the amount of money spent on facilities and maintenance. Greater reliability can always be achieved, but it would be at a cost to ratepayers. Thus, the question of the proper level of system reliability is one of balancing the reliable supply of power with cost. The Commission's view is that, as a general matter, Maine has achieved a reasonable balance of reliability and cost.[45] This does not mean that there are no problems or concerns. The

[44] The Commission notes that some of the success of rate plans in minimizing rates and maintaining stability is attributable to several years of relatively low inflation.

[45] The Public Advocate has expressed a similar opinion in comments provided in this investigation.

Commission must remain diligent to ensure that Maine consumers have adequate and reliable electric service at a reasonable cost.

The use of service quality standards should remain the primary regulatory means to ensure adequate reliability. As discussed above, service quality standards represent a vast improvement over the traditional regulatory approach to ensuring a proper level of system reliability and providing utilities with appropriate financial incentives. The use of service quality standards allows the Commission to monitor system reliability in a more systematic and comprehensive manner, and results in direct financial consequences if utilities fail to provide adequate service. The Commission will continue it efforts to refine the service quality standards in ways that improve their operation. Refined service quality mechanisms that the Commission may consider in future proceedings would include service area specific CAIDI and SAIFI targets, a metric which measures momentary interruptions (such as MAIFI), and a mechanism to reward superior service by expanding the earnings “dead-band” which would allow the utility to retain additional profits realized through efficiencies without penalizing ratepayers by increasing rates. In addition to service quality standards, the Commission maintains its ability, as well as its obligation, to respond to any indication (such as through customer complaints) of a reliability problem anywhere in the State by initiating investigations and ordering utilities to remedy the situation in a timely fashion.

The Commission recommends that service quality standards continue as the primary means to ensure adequate system reliability and that efforts continue to be made to improve the operation of the standards.

3. Energy Efficiency Mechanisms

As discussed above, rate cap regulation does give utilities financial incentives to promote the consumption of electricity and to discourage energy efficiency and conservation. However, Maine’s T&D utilities no longer have the obligation to undertake energy efficiency and demand side management programs. The elimination of this obligation makes the incentive issue much less critical because utilities are no longer required to design and conduct programs that, if they succeed, reduce their profits. The concern under the current environment is the motivation of utilities to act contrary to the State’s efficiency and conservation policies primarily through the promotion of consumption.

When Maine’s utilities were under the legal obligation to pursue cost-effective conservation measures, the conflicting incentives were of paramount concern. Any system in which an entity’s financial interests are contrary to its legally mandated activities is problematic. Although utilities in Maine accepted their obligations to varying degrees, the Commission was required to continually monitor utility operations to ensure that they were pursuing appropriate efficiency and conservation measures.

This situation no longer exists in Maine. Pursuant to the recently enacted Conservation Act,[46] state-wide ratepayer funded efficiency and conservation programs are now developed and implemented by the Commission and utilities properly have no role.

The current situation is that utilities, like any other business, have the incentive to promote their product. Therefore, it is not surprising that CMP actively advertises the use of electricity (e.g. air conditioning and lighting promotional advertising).[47] However, in a similar manner, oil and propane dealers promote the use of their product, and retail outlets promote the sale and use of appliances, such as air conditioners. The Commission does not view this situation as necessarily improper. As a general matter, it is appropriate for private businesses to pursue the growth of their business and profits, while government acts to promote the public interest through activities such as the sponsorship of energy efficiency and conservation programs.[48]

As mentioned, the Commission has information suggesting that utility activity to promote the consumption of electricity has had limited effect. Through information provided by CMP in a recent Commission proceeding, it appears that CMP's air conditioning ads have had only a very modest impact on its revenues. This modest impact of utility promotional efforts must be weighed against the potential adverse impacts and unintended consequences that may result from efforts to fundamentally alter the State's current regulatory framework. The Commission believes that a better approach to supporting the State's policy in favor of energy efficiency and conservation is to maintain an effective and adequately funded state-wide program in which efforts are made to directly affect the actions and motivations of electricity consumers.

The Commission does not recommend that regulatory mechanisms be adopted to alter utilities' current incentives with respect to electricity consumption and energy efficiency.

4. Rate Design

T&D utilities' current underlying costs vary less with usage than is reflected in the current rate design. Thus, T&D utility rate design should provide for

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[46] As mentioned above, the Conservation Act transferred to the Commission the responsibilities to develop and implement state-wide efficiency and conservation programs. That Act provides the Commission with ample authority to support energy efficiency initiatives in the State (within statutory funding constraints).

[47] Pursuant to Commission rule (Chapter 83), utilities are prohibited from recovering the costs of promotional activities from ratepayers.

[48] Electricity production is generally viewed as having significant environmental impacts. (For example, NEPOOL has calculated the 2001 regional average emission rates as: SO_2 – 4.9 lbs/mWh, NO_x – 1.7 lbs/mWh, and CO_2 – 1394 lbs/mWh). Potential environmental impacts and their effect on the State and its residents are appropriate grounds for government intervention to increase energy efficiency.

more cost recovery through fixed and demand (kW) charges relative to energy (kWh) charges. However, as illustrated in section IV of this report, a movement to a completely fixed rate design would have substantial rate impacts on a large number of the State's consumers. Customers that currently consume relatively low amounts of electricity would have substantial bill increases, while those that use a lot of electricity would experience substantial bill decreases. In addition, the adoption of a fixed rate design would significantly reduce price signals for customers to conserve and could thus promote additional consumption (although the generation portion of the bill is likely to remain usage sensitive and continue to provide some price signals for conservation). In deciding whether to go to a completely fixed rate design, the significant reduction in consumer price signals for conservation and the possible stimulus of increased consumption should be balanced against an assessment of the effectiveness of utility promotional activities.

In addition, it is not clear that a completely fixed rate design is consistent with general ratemaking principles.[49] First, T&D costs are likely to be affected by consumer usage (e.g., total demand) in that those customers that consume more electricity tend to require larger and more costly T&D facilities to serve. Moreover, an equitable design of stranded cost rates would have larger customers paying a higher amount because stranded costs (which are generation-related costs) were incurred based on customers' capacity and energy needs.

Based on principles of economic efficiency and cost causation, it is likely that the Commission will continue to move in the direction of reduced energy (kWh) charges and increased fixed and demand (kW) charges. This may occur through targeting rate decreases to energy charges as has occurred in the recent past. This approach has the benefit of moving away from T&D energy charges without increasing the bills of the State's electricity consumers. However, without specific legislative direction, a completely (or even predominantly) fixed rate design is not likely to occur over the near term.

The Commission recommends against the adoption of a fixed charge rate design for the primary purpose of removing utility incentives to promote electricity consumption.

B. Alternative Approaches

As discussed above, the Commission does not recommend that any fundamental changes to the State's regulatory framework be made to alter T&D utility incentives. However, if the Legislature determines that mechanisms should be

[49] Substantial analyses of the cost structures of Maine's T&D utilities would be required before any determination of a "correct" rate design could be made.

employed to change utility incentives with respect to energy efficiency or system reliability, this section discusses approaches that should be considered.[50]

Overall the Commission has ample statutory authority to implement the ratemaking or rate design incentive mechanisms discussed in this section. In particular, sections 3195 and 3155-A of Title 35-A provide specific authority for the Commission to adopt rate-adjustment or rate design mechanisms to promote utility operational and energy efficiency. However, as explained, the Commission is not inclined to adopt the alternative approaches discussed below without specific legislative direction.

1. Fixed Charge Rate Design

In the event the Legislature decides that some regulatory change should occur to eliminate utility financial incentives to promote electricity consumption, the Commission recommends that a legislative mandate be adopted that directs the Commission to move towards a fixed charge rate design.[51] The Commission strongly prefers this approach over fundamental changes to the regulatory framework (e.g., adoption of revenue decoupling in place of rate caps) because a "correct" rate design for T&D utilities would likely include a substantial amount of cost recovery through fixed charges and there are less likely to be unforeseen consequences.[52]

Movement to a fixed charge rate design would involve substantial bill impacts for many customers. Accordingly, the Legislature should consider mandating that the rate design change occur gradually over time (perhaps by setting annual percentage or dollar caps on bill increases).

2. Revenue Reconciliation Stranded Cost Rate-Setting

As discussed in sections II and III of this report, stranded costs have not been made the subject of incentive or rate cap regulation and are generally governed by traditional ratemaking principles. In addition, the level of stranded costs do

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[50] Some mechanisms used in other states would be questionable at best in Maine where T&D utilities have no obligation to implement conservation programs. These include lost revenue adjustments and shared savings programs. It appears improper to reimburse utilities for lost sales or to reward them with a percentage of savings with respect to efficiency programs that have nothing to do with utility activities.

[51] As a general matter, the Commission's view is that specific rate design determinations should be made by the Commission pursuant to general ratemaking principles. The suggestion that the Legislature mandate a particular rate design is made only in the context of a legislative decision that utility financial incentives to promote the consumption of electricity be removed. In that a case, a legislative mandate regarding a specific rate design would be appropriate.

[52] A completely fixed rate design would result in a significant reduction of financial risk for utilities. Accordingly, a movement towards fixed rates should be accompanied by a review of utilities' cost of capital used for ratemaking purposes.

not vary with volume and increases in sales go directly to the utility's bottom line. Therefore, current stranded cost ratemaking provides utilities with a strong incentive to promote sales.

While stranded costs do not vary with volume, many stranded cost elements are unknown at the time that stranded cost rates are set. As a result, the Commission has in past stranded cost cases issued a number of accounting orders which have allowed the utilities to defer for future recovery any differences between the amounts allowed in rates for specific items and the actual costs of such items when incurred. While the Commission has authorized a true-up approach for specific cost items, it appears that the language of 35-A M.R.S.A. § 3208 might not permit a reconciliation of stranded cost sales.[53] This issue was discussed during CMP's last stranded cost rate setting proceeding, but was not pursued due to uncertainty concerning the Commission's authority.

Given the circumstances surrounding stranded cost ratemaking (stranded costs are not generally subject to reduction through operating efficiencies, they do not vary with volume, and a number of cost items in the past have been reconciled), it might be appropriate to reconcile stranded cost rates for variations in sales and costs projections. In the event that the Legislature desires to take steps to address incentives regarding the promotion of electricity consumption, it should consider amending 35-A M.R.S.A. § 3208 to clearly authorize the Commission to adopt a revenue reconciliation mechanism in setting stranded cost rates. If such a mechanism were adopted, a utility's incentive to increase sales would be reduced, although not eliminated, because a substantial amount of T&D costs would continue to be recovered through usage sensitive charges.

3. ROE Adjustment Mechanism

A mechanism whereby a utility's ROE is adjusted, either up or down, based on its performance in specified areas can be an effective means to impact incentives. Under such a mechanism, the Commission would predetermine a reasonable range for a utility's ROE. For example, such a range might be between 9% and 11%.[54] The Commission would then periodically review a utility's performance in certain areas to determine whether its prior activities warrant either a movement to the upper or lower end of the ROE range. The periodic review might occur on a pre-set schedule (e.g. every 2 years) or upon petition of a party. The areas of review would

[53] 35-A M.R.S.A. § 3208(6) provides: "When correcting stranded cost estimates and adjusting stranded cost charges, the Commission shall make any change effective only prospectively and may not reconcile past estimates to reflect actual values.

[54] An ROE range of 200 basis points should be large enough to get a utility's attention. For example, a reduction of 100 basis points for CMP would amount to a revenue loss in the range of $7 million.

presumably be actions with respect to the promotion of energy efficiency and the provision of reliable service, but could include other activities.[55]

Illustrations of actions that might trigger an ROE adjustment under this mechanism follow:

-A utility violates State energy policy by using deceptive or misleading advertising to promote the inefficient use of electricity.
ROE is reduced.

-A utility acts consistent with State energy policy by acting to induce new energy efficient businesses to locate in the State.
ROE is increased.

-A utility acts to take advantage of a little-used new technology that enhances system reliability at a relatively low cost.
ROE is increased.

-A utility does not take reasonable steps to maintain sufficient reliability in a remote area of the State.
ROE is decreased.

The mechanism is subjective by its nature. The Commission would make a determination based primarily on its expert judgment. Thus, the periodic reviews, which would occur in litigated proceedings, are likely to be controversial and consume significant resources. Adjustments would likely occur rarely, only upon especially egregious or exemplary behavior.

The Commission does not favor this approach because it is inconsistent with current rate plans and implementation is likely to be extremely difficult. However, if the Legislature so mandates, an ROE adjustment mechanism could be made part of a multi-year rate plan with rate adjustments occurring as part of the annual ARP reviews.

4. Multi-Year Revenue Cap

If the Legislature determines that the State's basic regulatory structure should be changed from the current rate cap regulation to alter incentives so utilities are financially neutral to electricity sale levels, a multi-year revenue cap program for establishing distribution rates can be considered. Under a multi-year revenue cap, the utility's "allowed" revenues would be subject to an index constructed to provide the

[55] Direct pass through of costs can also be used in conjunction with ROE adjustments. For example, if a utility makes an investment in cost-effective new technologies that results in enhanced system reliability, it can be allowed to defer the expense for dollar-for-dollar recovery.

utility with the opportunity to earn reasonable returns. This means that, similar to the current rate cap plans, the index would account for inflation and a reasonable level of productivity.

This type of revenue cap mechanism, if it can be designed correctly, would continue to provide utilities with the incentive to seek operational efficiencies and to reduce their cost of service. Moreover, a revenue cap plan can be designed to minimize the shift of revenue fluctuation risks from causes other than energy efficiency measures. In particular, attempts can be made to minimize the shift of risks from changes in economic activity and weather from the utility to ratepayers. This can occur through use of economic activity and weather normalization techniques.[56] Although often controversial, weather normalization techniques are quite common in the forecasts of utility sales. However, techniques to normalize for the economy are not common and it would be extremely difficult to distinguish between sales changes related to the economy and sales changes related to efficiency measures. Although normalization techniques can help lower risk transfers, they are imprecise and would not completely prevent the transfer of risks. However, they would reduce the shift of risks to some degree and, consequently, the rate volatility that would result from revenue cap plan.

The Commission has great reluctance regarding the adoption of any type of revenue decoupling mechanism. Although the mechanism has theoretical appeal, the Commission has substantial concern over unintended consequences that may accompany the adoption of a regulatory structure which is so dependent on unpredictable events. Such unintended consequences rapidly developed with the Commission's experiment with ERAM in the early 1990s and, as discussed in section V of this report, no state currently has a revenue decoupling mechanism (although several states had adopted such mechanisms in the past). The Commission urges great caution in abandoning the current regulatory framework, which is generally working as intended, in favor of an unproven mechanism so as to address an incentive issue that may not be of great consequence.

5. Prohibition or Regulation of Promotional Activities

If the Legislature determines that utility promotion of electricity consumption is a serious public interest problem, the most direct solution would be a legislative ban or regulation of promotional activities. Such an approach would obviously raise First Amendment issues. The Commission has not analyzed those issues, but it is conceivable that if the Legislature finds electricity consumption to be a substantial public concern (e.g., threat to public health), some restrictions on its promotion may be legally permissible.

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[56] For example, normalization techniques might seek to estimate that each additional degree day results in X amount of additional electricity sales or that a percentage increase in the gross state product results in Y amount of additional sales.

The most direct approach would be a ban on promotional advertising. A less intrusive approach would be for all such advertising to include some type of required statement. For example, a requirement can be adopted that all electricity promotional advertising includes information on the environmental impacts of electricity consumption. Such a requirement, of course, would raise a difficult question: why should the Legislature single out electricity from other products (such as gasoline or heating oil) that also provide significant benefits while arguably damaging the environment? Without a satisfactory answer, those promoting electric consumption could reasonably claim unwarranted discrimination.

The Commission emphasizes that it does not recommend such an approach, but offers the concept if utility promotional advertising is the major concern underlying this examination of utility incentives.