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PUBLIC UTILITIES COMMISSION

February 23, 1994

ERAM report

Senator Harry L. Vose, Chair
Representative Herbert E. Clark, Chair
Joint Standing Committee on Utilities
State House Station No. 115
Augusta, ME 04333-0115

Re: P.L. 1991, c. 413, AN ACT to Encourage Electric Utility Efficiency and Economical Electric Rates

Dear Sen. Vose and Rep. Clark:

In 1991, the Legislature enacted P.L. 1991, c. 413, AN ACT to Encourage Electric Utility Efficiency and Economical Electric Rates (attached). The Act creates subchapter VII of Title 35-A entitled "Incentive Ratemaking." Section 3195(1) of the Act clarifies the Commission's authority to order the implementation of rate adjustment mechanisms like the ERAM-per-customer mechanism approved for CMP in Docket No. 90-085. Section 3 of the new law contains unallocated language that directs the Commission to

> consider and adopt a mechanism that limits the rate impact of the per customer electric rate-adjustment mechanism approved for Central Maine Power Company in Commission Docket No. 90-085.

Finally, section 3195(5) of the Act requires the Commission to submit an annual report to the Utilities Committee

> detailing any actions taken or proposed to be taken by the Commission under this section, including actions or proposed actions on mechanisms for protecting

ratepayers from the transfer of risks associated with rate-adjustment mechanisms.[1]

The purpose of this letter is to provide the Commission's report to the Utilities Committee pursuant to Section 3195(5) for the year 1993.[2]

I. CENTRAL MAINE POWER COMPANY

A. <u>ERAM-Per-Customer</u>

On February 5, 1993, the Commission approved a stipulation that, among other things, ended the ERAM-per-customer plan for Central Maine Power Company. As a result of the Commission's Order Approving Stipulation, the ERAM-per-customer ended on November 30, 1993.[3]

The Commission had originally approved the ERAM-per-customer plan, in May 1991, in order to remove the utility's disincentive to engage in demand side management (DSM) activities by decoupling revenue from sales. Under the ERAM-per-customer plan, CMP ultimately recovered the revenue requirement established per customer regardless of actual sales, thereby eliminating the DSM disincentive.

In large part because of Maine's recession, the ERAM-per-customer plan operated so as to increase rates. In fact, the net unrecovered balance relating to ERAM-per-customer accruals totaled $52.4 million at year-end 1992. The Commission's February 5, 1993, Order Approving Stipulation found that the "vast majority" of the accruals resulted from the fact that "the recession has reduced sales" and that a "relatively small portion of these accruals was due to DSM efforts." (Docket Nos. 90-085-A, 90-085-B, 92-174, 92-346, Order, p. 2).

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[1]Under section 3195(5), the Commission is required to consider the transfer of risks associated with the effect of the economy and the weather on the utility's sales.

[2]This report was due on January 3, 1994. The Commission's desire to provide the Committee with the most up-to-date information regarding Docket No. 92-345 (see Part I(B) below), Docket No. 92-102 (see Part I(C) below) and Docket No. 93-062 (see Part II(A) below) as well as the extraordinary press of other critical matters have combined to delay the completion of this report. I apologize for any inconvenience the delayed filing of this report may have caused.

[3]At the same time, increased rates for CMP went into effect in Docket No. 92-345.

The Stipulation, which was signed by all parties to this proceeding except the Industrial Energy Consumer Group (IECG) and Maine Association of Interdependent Neighborhoods (MAIN), resolved all of the ERAM-per-customer issues. Among other things, the Stipulation required that the ERAM-per-customer plan terminate on November 30, 1993 thereby reducing accruals by $15.9 million.[4] Further, the Stipulation resolved certain issues relating to CMP's 1993 Fuel Clause Adjustment, the recovery of certain costs associated with two buyouts of purchased power contracts and the recovery of certain demand-side management (DSM) incentive payments.

The Commission found that:

> We have reviewed the terms of the Stipulation and find that they present a reasonable resolution of the issues under Docket No. 90-085 and of several other related matters. The ability of the parties to address these issues as a package serves the interest of CMP's ratepayers. According to witnesses presented by CMP, the suspension of ERAM-per-customer and the consequent reduction in CMP's earnings would have created a substantial risk that CMP's bond rating might be impaired because of higher risks perceived by investors, thereby raising CMP's cost of capital, which generally must be paid for through higher rates. The substantial reduction in the amount of future ERAM-per-customer accruals (which must ultimately be paid for through rates) proposed by the Stipulation strikes a reasonable compromise between the risks of suspension and the higher level of accruals that would occur if nothing were changed. (Docket Nos. 90-085-A, 90-085-B, 92-174, 92-346, Order, p. 2).

B. <u>Alternative Rate Plans</u>

In the most recently completed CMP rate case, the Commission determined that the "time was ripe" to thoroughly explore issues relating to alternative rate plans (ARPs). Docket No. 92-345, December 14, 1993, p. 125. The Commission is seeking a plan that will meet the needs of utility ratepayers by

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[4]The ERAM-per-customer plan had originally been scheduled to end on February 28, 1994.

providing rate predictability and stability. The Commission outlined the framework of that plan in the rate case Order but acknowledged that a number of details needed to be worked out before the plan can go into effect. Thus, an implementation proceeding will take place in mid-1994 following a period in which the parties to the proceeding are attempting to reach consensus on the plan.

The Commission's decision to investigate and, if appropriate, implement, an ARP is fully consistent with Section 3195. Such a plan would, by its nature, provide positive or negative financial incentives for efficient operations (Section 3195(1)(D)). A particular potential advantage of an ARP is that, unlike the ERAM-per-customer plan, an ARP would tend to protect ratepayers by shifting certain risks, such as the effects of the economy and the weather on the utility's sales, from ratepayers to shareholders in the short-run. (Section 3195(4)).

In its Order in Docket No. 92-345, the Commission found that:

> The record in this proceeding supports prompt consideration of an alternative ratemaking plan for CMP . . . . The Rate Stability Plan we envision would contain three components: a price-cap component, a profit-sharing component, and a pricing flexibility component. The Rate Stability Plan would have a duration of five years, with a brief annual proceeding to implement any applicable rate changes, and a detailed review at the end of the fourth year, to investigate the performance of the Rate Stability Plan and to identify possible changes to the Plan. (Order, page 133).

The Commission believes that the ARP could help to promote efficiency in electric utility operations and least-cost planning. Further, the Plan could provide rate predictability and stability to ratepayers. The Commission's Order notes that:

> Based on the evidence presented in this proceeding, the Commission finds that multi-year price plans is (sic) likely to provide a number of potential benefits: (1) electricity prices continue to be regulated in a comprehensible and predictable way; (2) rate predictability and stability are more likely; (3) regulatory "administration" costs can 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 can 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 can lead to enhanced profitability for shareholders, stronger incentives for cost minimization are created. (Order, Docket No. 92-345, December 14, 1993, p. 130.)

The Commission found, however, that additional review of 11 specific issues was required before the ARP could be put into effect. These issues include:

1) A number of issues related to the specific design of the program including the selection of an appropriate price index, productivity offset, and profit-sharing arrangement.

2) Review of the Plan to assure that important regulatory objectives, such as providing customer satisfaction, reliable service, appropriate incentives to invest in cost-effective energy efficiency and demand-side management, and furtherance of legislative requirements (such as low-income programs) are met. The Plan will be carefully analyzed to assure that the goals set for the Plan are met without creating any inappropriate or perverse incentives to the utility.

3) Regarding pricing flexibility, the ARP implementation proceeding will explore whether a different approach to rate structure changes would better enable CMP to compete to provide end-use energy services. The current "command-and-control" method of regulating the design of rates and tariffs may be overly rigid and inflexible and thus may not be well-suited to the increasingly competitive energy markets of the future.

4) The treatment of fuel and purchased-power costs is the most substantial obstacle to implementation of an ARP. Since the Fuel Adjustment Clause, codified at 35-A M.R.S.A. § 3101, does not provide for Commission discretion regarding the design of the Fuel Adjustment Clause, it is currently unclear whether the Commission will be able to design a plan that can provide potential benefits, as set forth by the Commission above.

C. Fuel Clause Adjustment

The current Fuel Adjustment Clause statute appears to contradict the purpose of Section 3195 since the Commission loses the ability, under Section 3195, to fully design incentive plans that "promote efficiency in electric utility operations and least-cost planning" and thereby provide ratepayer protection. Section 3195(1). Specifically, Section 3195 states that:

> This Title may not be construed to prohibit the commission from or to restrict the commission in establishing or authorizing any reasonable rate-adjustment mechanisms to promote efficiency in electric utility operations and least-cost planning. Section 3195(1).

In a recently completed investigation of certain QF contracts (Docket No. 92-102), the Commission found that:

> the dollar-for-dollar recovery of QF costs through the FCA provides little, if any, financial incentive for CMP to aggressively manage its QF contracts. This shifting of risk to ratepayers has sent a poor signal to CMP's management. Since the FCA allows dollar-for-dollar reconciliation based on actual fuel costs, risk is shifted to ratepayers and away from CMP's shareholders and managers. As discussed above, since this feature reduces the utility's risk, it also has the potential to create "perverse incentives." (Order, page 89).

This concern is particularly noteworthy since it directly relates to an ongoing Supreme Court case regarding the Commission's authority to impose a financial incentive/disincentive in regard to CMP's mismanagement of its efforts to contract for QF capacity. CMP is currently arguing that the Commission does not have the authority to impose the remedy that it chose in its decision in Docket No. 92-102.

The Commission intends to investigate the passthrough of QF capacity costs through the FCA as part of the ARP proceeding (as set forth in the Commission's Order in Docket No. 92-345, dated December 14, 1993). Capacity costs relate to the non-fuel costs associated with QF power purchase contracts. The Commission has discretion under the Fuel Adjustment Clause Statute (Section 3101(4)) to determine how these capacity costs are recovered from ratepayers.

The Commission expects to reach a final decision regarding the ARP by mid-year 1994.

II. BANGOR HYDRO-ELECTRIC COMPANY (BHE)

A. Alternative Rate Plans

In the most recent BHE rate case (Docket No. 93-062), various parties proposed ARPs or pricing flexibility plans. BHE had expressed some interest in a price cap plan but had stated that its primary interest is in gaining additional pricing flexibility. Regarding pricing flexibility, in one ARP model, for example, the rates that the Company is allowed to charge under its tariff would become maximum prices or "caps" with the Company allowed considerable discretion to selectively lower rates; revenue deficits, however, would be borne by shareholders. While the Commission voiced general support for the ARP concept, the Commission was not prepared to adopt a specific ARP without additional review.

In its deliberations in this case, the Commission fully supported the future development of an ARP, and strongly encouraged BHE, Staff and the parties to this proceeding to begin discussions aimed at arriving at a consensus regarding the appropriate design of an ARP.

B. Fuel Clause Adjustment

The Commission has also relied on section 3195 to permit a previously unavailable reconciliation mechanism in BHE's three most recent fuel clause cases.[5] In Docket No. 91-205, BHE, the Commission's Advocate Staff and the Public Advocate all argued that section 3195 allows the Commission to reconcile short-term power purchases. By Order issued on December 5, 1991, in Docket Nos. 91-205 and 91-179, the Commission found that the reconciliation of short-term power purchases would allow BHE to obtain the same amount of power for less money thereby saving money for ratepayers. The Commission therefore approved the proposed reconciliation pursuant to section 3195. By Order issued

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[5] Until the enactment of section 3195, the reconciliation of past expenses that have not been recognized in current rates, or the reconciliation of excess revenues received under existing rates that are not justified by current costs, was generally prohibited. New England Telephone Company v. Public Utilities Commission, 362 A.2d 752-58 (1976).

on October 28, 1993, in Docket No. 93-190, BHE's most recent fuel clause proceeding, the Commission allowed a similar economic purchases/off-system sales adjustment pursuant to section 3195.

Sincerely,

Wayne P. Olson

Wayne P. Olson
Director of Finance

WPO/nlp

APPROVED JUN 20 '91 BY GOVERNOR

CHAPTER 413 PUBLIC LAW

STATE OF MAINE

IN THE YEAR OF OUR LORD NINETEEN HUNDRED AND NINETY-ONE

S.P. 196 - L.D. 505

An Act to Encourage Electric Utility Efficiency and Economical Electric Rates

Be it enacted by the People of the State of Maine as follows:

Sec. 1. 35-A MRSA c. 31, sub-c. VII is enacted to read:

SUBCHAPTER VII

INCENTIVE RATEMAKING

§3195. Commission authority to promote electric utility efficiency

1. Rate-adjustment mechanisms. This Title may not be construed to prohibit the commission from or to restrict the commission in establishing or authorizing any reasonable rate-adjustment mechanisms to promote efficiency in electric utility operations and least-cost planning. Rate-adjustment mechanisms may include, but are not limited to:

A. Decoupling of utility profits from utility sales through revenue reconciliation;

B. Reconciliation of actual revenues or costs with projected revenues or costs, either on a total or per customer basis;

C. Adjustment of revenues based on reconciled, indexed or forecasted costs; and

D. Positive or negative financial incentives for efficient operations.

2. Just and reasonable rates. In determining the reasonableness of any rate-adjustment mechanism established under this subchapter, the commission shall apply the standards of section 301 to assure that the rates resulting from the implementation of the mechanism are just and reasonable.

3. **Value of utility property.** Notwithstanding section 303, rate-adjustment mechanisms established under this section may be used to establish the value of the electric utility's property.

4. **Ratepayer protection.** In determining the reasonableness of any rate-adjustment mechanisms, the commission shall consider the transfer of risks associated with the effect of the economy and the weather on the utility's sales. To the extent these risks are transferred from the utility to its customers, the commission shall consider in a rate proceeding the effect of the transfer of risk in determining a utility's allowed rate of return.

5. **Annual report.** The commission shall submit to the joint standing committee of the Legislature having jurisdiction over utilities matters an annual report detailing any actions taken or proposed to be taken by the commission under this section, including actions or proposed actions on mechanisms for protecting ratepayers from the transfer of risks associated with rate-adjustment mechanisms. The report must be submitted by December 31st of each year.

Sec. 2. Retroactivity. This Act applies retroactively to March 1, 1991.

Sec. 3. Public Utilities Commission Docket 90-085. The Public Utilities Commission shall consider and adopt a mechanism that limits the rate impact of the per customer electric rate-adjustment mechanism approved for Central Maine Power Company in Commission Docket No. 90-085.