Annual Report on Electric Utility Efficiency

Report to the Utilities and Energy Committee On Actions Taken by the Commission Pursuant to 35-A M.R.S.A. § 3195

I. INTRODUCTION

35-A M.R.S.A. § 3195 authorizes the Public Utilities Commission (Commission) to adopt rate mechanisms that promote electric utility efficiency. Subsection 5 states:

> **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.

Since 1995, one or more of the utilities in Maine have operated under an alternative rate plan. These plans replace traditional rate of return regulation with a multi-year price cap approach that places an upper limit on the utility's rate increases, while allowing the utility to retain savings it accomplishes through improved efficiencies. In addition, the plans typically contain pricing flexibility provisions that allow the utility to offer reduced or re-designed rates to customers who would otherwise replace electricity with another fuel or leave the service territory. Pricing flexibility allows the utility to obtain a contribution to its fixed costs that it would otherwise lose, thereby avoiding a shift of those fixed costs to remaining customers. We have found that the alternative rate plans create rate predictability and stability, reduce regulatory costs, shift risks from ratepayers to shareholders, and provide stronger incentives for utilities to minimize their costs. The plans maintain a comprehensible and predictable regulatory approach.

This report describes Commission actions taken during 2000 regarding rate mechanisms that promote electric utility efficiency.[1]

II. PLANS APPROVED DURING 2000

A. Background to the CMP Plan

Prior to the onset of retail access to generation services in Maine (March 1, 2000), each investor-owned utility was regulated pursuant to some type of Commission-approved alternative rate plan. These plans expired shortly before, or coincidently with, the onset of restructuring. Pursuant to the Legislature's directive, we

[1]Copies of documents referred to in this Report may be obtained from the Commission or from its web site (janus.state.me.us/mpuc).

completed T&D revenue requirement and stranded cost cases for each of Maine's transmission and distribution (T&D) utilities prior to the start of retail access.

During the restructuring process, Central Maine Power Company (CMP) requested Commission approval of a proposed merger with Energy East, the parent company of New York State Electric and Gas Company (NYSEG). As part of our approval of the CMP/Energy East merger, we recognized that the rate conditions imposed in connection with the merger approval (assuring that ratepayers receive a reasonable portion of the efficiency savings while allowing Energy East an opportunity to recover its acquisition premium) could best be accomplished through an incentive rate plan. Therefore, on March 10, 2000, we initiated a proceeding to consider an alternative rate plan for CMP as a T&D-only company. As part of this proceeding, we received alternative rate plan proposals from CMP, from the Office of the Public Advocate and from our Advisory Staff.

After extensive discovery and numerous technical conferences on the competing proposals, we received a Stipulation entered into between CMP and the OPA, which resolved all issues in this case and which proposed a new alternative rate plan (ARP 2000 or Plan) for CMP. After carefully reviewing the Stipulation, we concluded that it was consistent with legislative mandates and, on an overall basis, was reasonable and in the public interest. Therefore, on November 16, 2000, we approved the Stipulation and its proposed ARP 2000 Plan.

One party to the ARP 2000 proceeding has appealed the Commission's decision to the Law Court, on the grounds that its approval was beyond the Commission's authority.

B. Scope of ARP 2000

ARP 2000 will be in effect for seven years, from January 1, 2001 through December 31, 2007. Because generation service is now subject to market competition and is no longer regulated by this Commission, and the Federal Energy Regulatory Commission (FERC) takes jurisdiction over transmission service once a state unbundles generation from delivery service, ARP 2000 only applies to distribution delivery rates and service.[2] The Plan does not apply to Maine jurisdictional stranded costs, which we will periodically adjust in accordance with 35-A M.R.S.A. § 3208.

C. Rate Setting Mechanisms of ARP 2000

The Plan provides for annual rate changes to occur on July 1st of each year. Rate changes are based on the now-familiar formula of inflation minus a productivity offset, adjusted for mandated costs, earnings sharing and service penalties. Inflation will be measured in Gross Domestic Product Price Index (GDP-PI) and the productivity offsets are set as follows:

[2]Transmission costs range from 9% to 14% of total utility revenue requirement.

Year of Price Change	Productivity Offset
2001	Equal to Inflation
2002	2.00%
2003	2.25%
2004	2.75%
2005	2.75%
2006	2.75%
2007	2.90%

These productivity offsets are equivalent to an average annual productivity offset of 2.53%. This is significantly higher than the productivity offsets contained in CMP's first ARP (1.0%) and in the rate plan we adopted for Bangor Hydro-Electric Company (BHE) in 1999 (1.2%). During the course of the ARP these offsets will serve to decrease rates in constant dollar terms by 18.0%.

Mandated costs are defined by the Plan as costs beyond CMP's control, which are a result of either 1) *force majeure* events such as storms, floods or riots; or 2) changes in federal or state legislation, regulations, taxes or accounting requirements. To be eligible for recovery, each mandated cost item must exceed $150,000. Eligible mandated costs will be aggregated, and only the amount above $3 million will be included in rates.

The Plan provides for "low-end" earnings sharing. A revenue deficiency below a 5.2% Return on Equity (ROE) in any calendar year will be shared equally between shareholders and ratepayers through the price change in the following year. The Plan does not contain a provision for "top-end" earnings sharing. For the reasons set forth below, we do not believe ratepayers will be significantly harmed by the absence of top-end earnings sharing.

While incentive regulation plans with earnings sharing provisions have been in effect for a number of years, ratepayers have rarely received rate reductions as a result of such provisions. By contrast, the higher productivity offsets in the CMP Plan provide benefits to ratepayers that are both certain and substantial, leading us to conclude that the trade-off was in the public interest. In this instance, the likelihood of extremely high earnings is further reduced by the fact that the FERC will reset transmission rates annually, and we will reset stranded costs several times during the course of ARP 2000.

The price index in 2002 and 2003 will be further reduced by 2.90% and 7.5%, respectively, to reflect the reduction and termination of amortization expenses in March 2003 for ice storm costs, reconcilable and deferred demand-side management costs, and employee transition plans. The 2003 rate reduction also reflects the revenue requirement effect of the elimination of these items from rate base.

D. Service Reliability and Customer Service Provisions

In our decision approving the CMP/Energy East merger, we noted:

> We expect to closely examine service quality standards in the ARP 2000 proceeding. Given the risks involved in this merger, we will likely strengthen the standards relative to those in the existing ARP. We note that the standards in NYSEG's current rate plan are considerably more stringent than CMP's, and we expect to consider whether moving to, or beyond, the NYSEG level would be appropriate. In this context, we would also examine appropriate penalties and sanctions for violating the service quality standards.

ARP 2000 contains an automatic incentive mechanism related to CMP's service quality. The Plan establishes baseline performance levels for several measures of service, and provides for a reduction in CMP's earnings of up to $3.6 million if CMP's performance fails to meet those baselines. Service quality will begin to be measured on January 1, 2001 under the Plan, with any reduction in earnings resulting from service quality performance reflected in price changes on July 1 in the years 2002 through 2007. The Plan does not subject CMP to any penalties related to its performance in 2007.

The Plan initially establishes eight customer service and reliability measures, two of which address service reliability: Customer Average Interruption Duration Index (CAIDI) and System Average Interruption Frequency Index (SAIFI). Five measures address the services delivered to CMP's customers: the number of complaints received by the Commission's Consumer Assistance Division, the speed of answering business calls and outage calls, CMP's installation of new services by the date promised, and a customer survey of customers who called CMP's business line. The remaining measure addresses the speed of CMP's response to requests to enroll customers with Competitive Electricity Providers. The Plan provides an opportunity for any party to request the Commission to modify the initially stipulated service quality indices during 2003, with resulting modifications effective January 1, 2004.

The Plan requires bi-monthly reporting to the Commission by CMP on all service reliability and customer service measures, and requires CMP to file annual reports on specified elements related to service quality, including an Annual Reliability Improvement Report. The Plan further provides that CMP will distribute an annual "report card" on its service quality performance directly to all its customers on an annual basis beginning in August 2002.

The service quality standards agreed to in the ARP 2000 Plan are significantly stronger than those contained in CMP's first ARP and will measure additional areas related to customer service and to the proper enrollment for competitive electricity providers. The Plan also increases the maximum penalty from $3.0 million in the first ARP to $3.6 million despite the fact that CMP's revenues have decreased by about one-third as a result of restructuring. These stronger standards and increased penalty levels will help ensure that earnings during ARP 2000 are not enhanced by the utility's providing inadequate or unreliable service. In addition, we will have an opportunity to review the effectiveness of ARP 2000's service quality standards as part of a mid-period review in 2003.

III. ANTICIPATED ACTIVITY FOR 2001

During December 18th deliberations, we approved a Stipulation granting the proposed merger between Emera, Inc. (the parent company of Nova Scotia Power Company) and BHE. Under the terms of the Stipulation, BHE will file a proposed alternative rate plan within two months of the merger's closing or June 30, 2001, whichever is sooner.

At the present time, the Commission does not anticipate taking any action on an alternative rate plan for Maine Public Service Company (MPS) during 2001. Therefore, MPS MPS continues to operate under traditional rate of return regulation.

IV. PRICING FLEXIBILITY PROGRAMS DURING 2000 AND BEYOND

Each of the alternative rate plans for CMP, BHE and MPS in effect up to the date of electric restructuring, March 1, 2000, allowed the utility significant flexibility to offer reduced or special rates to individual customers or to groups of customers. The plans established criteria and an expedited process for Commission review of these contracts and special rates, allowing the contracts or special rates to take effect in 30 days if the criteria were met. After March 1, 2000, it was necessary to "unbundle" each contract into two parts – a T&D portion and a generation portion. The T&D utility would serve the T&D portion and the competitive market would serve the generation portion. The post-restructuring treatment of pricing flexibility has varied among the three utilities, so we will discuss each separately.

A. Central Maine Power Company

Under the terms of the Stipulation that resolved CMP's unbundled rates starting March 1, 2000, contracts and special rate programs were divided into three categories:

(1) contracts that were entered into under the ARP in place before March 1, 2000 (APR 95) but that extended beyond March 1, 2000, which were unbundled using the customer's generation price from the competitive market if diligently obtained and using a reasonable generation price if the customer was not diligent;

(2) ARP 95-comparable renewals, or contracts that were entered into during ARP 95 and were renewed on essentially the same terms as the earlier contract, except now on an unbundled basis; and

(3) new contracts and contracts with customers who had special contracts during ARP 95 but whose post-restructuring contracts could not be said to be ARP 95-comparable renewals.

Because standard offer rates were not set until shortly before electric restructuring and because the wholesale generation market generally was not settled, we could not estimate the T&D revenue that would result from unbundling the category (1) and (2) contracts. Therefore, the parties to the proceeding agreed to, and we accepted, a plan to reconcile T&D rates at a later time to reflect the value of the contracts after unbundling or renewal.

Because of the reconciliation, ratepayers are at risk for revenue loss associated with category (1) and (2) contracts. Accordingly, these contracts received Commission approval, not the expedited approval allowed under the pricing flexibility plans.[3] Generally, we granted temporary approval to those contacts and then investigated for reasonableness before granting permanent approval.

During 2000, we approved 43 category (1) contracts, 28 category (2) contracts and 19 category (3) contracts. In addition, two contracts went into effect before these categories were established. Because the wholesale generation market over the first months of restructuring has been volatile, we granted temporary approval to some customers' contracts more than once while we monitored market generation prices. We approved one contract under CMP's ARP 2000 Plan.

Finally, during 2000, 18 special targeted rates to groups of customers also were revised or unbundled. Stakeholders challenged the validity of one of those rates, Rate Snow. This rate became effective on October 1, 2000, but a proceeding to address certain issues surrounding CMP's structure and timing of the rate is underway.

B. Bangor Hydro-Electric Company

BHE's pricing flexibility plan in effect before March 1, 2000 was called its Alternative Marketing Plan, or AMP. While the AMP was originally made effective without a formal alternative rate plan, a plan was implemented in 1998. The AMP expired with the rate plan on March 1, 2000.

As with CMP's contract unbundling, because standard offer prices were not determined until shortly before March 1, 2000, parties to BHE's initial T&D rate case could not reasonably estimate the correct contribution that BHE should receive from category (1) and category (2) contracts. Thus, the BHE T&D rate case stipulation approved by the Commission provided that the estimates used to set rates for category (1) and (2) contracts would be revised to reflect the generation prices that customers paid after March 1, 2000.

[3]As part of the 1999 annual review of ARP 95, the parties agreed to continue the rate flexibility plan in the post-restructuring period.

Most category (1) and (2) customers for BHE remain on standard offer service, which has increased twice during the year. Most category (1) and (2) contracts were initially approved on a temporary basis, so that the parties could wait to see if customers could obtain competitive generation service at a lower price than standard offer service. During 2000, we approved six category (1) contracts, two category (2) contracts and one category (3) contract.

Although technically the AMP is not in effect, we review new and changed special contracts (category (3) contracts) using the AMP criteria. During 2001, BHE will likely propose revised pricing flexibility criteria appropriate for restructuring.

Finally, we reviewed BHE's space-heat retention rate for residential and small commercial customers. We allowed BHE to recover some of the revenues that would have been disallowed under the previous program terms, modified the rate structures, and set 5.4 cents/kWh as the maximum rate BHE could charge for service under this rate.

C. Maine Public Service Company

The pricing flexibility plan for MPS also expired with its alternative rate plan. Presently, there is no plan in place for MPS. During 2000, MPS submitted five contracts for unbundling.

The two largest special contracts for MPS were in effect on March 1, 2000 and therefore were candidates for unbundling. MPS negotiated new contracts that extend for up to 11 years and contribute less to MPS's fixed costs in recognition of new generation alternatives available to the customers. However, the contracts guarantee certain levels of stranded cost recovery.

V. SUMMARY

In summary, during 2000 the Commission approved a new 7-year Alternative Rate Plan for Central Maine Power Company's distribution delivery activities and unbundled all utilities' special rate contracts that had been implemented under the flexible rate provisions in effect before restructuring took place. In comparison with CMP's previous ARP, ARP 2000 contains significantly stronger productivity incentives, allows only low-end earnings sharing, and increases the number of service and reliability indices that CMP must maintain. These changes respond to CMP's merger with Energy East. Development of a new alternative rate plan for Bangor Hydro-Electric Company will begin during 2001. Finally, special rate contracts were unbundled in a way that reflected existing market prices for generation and provided incentives for customers to acquire generation at the lowest possible price.