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. Background

35-A M.R.S.A. § 3195 authorizes the Public Utilities Commission (Commission) to adopt rate mechanisms that promote electric utility efficiency.
Subsection 5 of Section 3195 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 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, several Maine utilities have operated under Alternative Rate Plans (ARP). These plans replace traditional rate of return regulation[1] 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 ARPs create rate predictability and stability, reduce regulatory costs, and provide stronger incentives for utilities to minimize their costs. The plans maintain a comprehensive and predictable regulatory approach.

This report describes Commission actions taken during 2002 to promote electric efficiency through incentive rate plans or special rate contracts.

II. Central Maine Power Company's Alternative Rate Plan

During 2000, the Commission approved a new 7-year Alternative Rate Plan (ARP 2000) for Central Maine Power Company (CMP). With generation open to market competition, transmission service subject to Federal Energy Regulatory Commission (FERC) jurisdiction, and stranded costs being periodically adjusted in accordance with

[1] Rate of return regulation is a regulatory approach in which the Commission examines all reasonable expenses a utility is likely to incur and establishes fixed rates that will allow the utility, if operated efficiently, to recover those expenses and earn a reasonable return on its investments.

Maine law, ARP 2000 only applies to distribution delivery activities. CMP's ARP 2000 provides for annual rate changes on July 1st of each year. Rate changes are based on a well-established formula of inflation minus a productivity offset, adjusted for mandated costs, earnings sharing and service quality index (SQI) penalties. In comparison with CMP's previous ARP, the ARP 2000 contained significantly stronger productivity incentives, allowed only low-end earnings sharing, and increased the number of service and reliability indices that CMP must maintain. These changes responded to CMP's merger with Energy East, Inc. In our order approving the CMP/Energy East merger, we recognized that the rate conditions imposed in connection with our merger approval (ensuring 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.[2]

On March 15, 2002, CMP made its annual rate change filing for rates to go into effect on July 1, 2002. The most significant component of this year's price change was a 2.9% reduction in rates to reflect the effect of certain regulatory assets expiring during the course of the coming rate year ('02-'03). Pursuant to the terms of the Commission's order approving the ARP 2000 plan, the productivity offset for the 2002 price change was 2.00%, which resulted in a reduction of .13% when netted against the prior year's inflation rate of 1.87%. In addition, certain collections were flowed back to ratepayers on a one-time basis. Specifically, insurance proceeds received by CMP for clean-up of the O'Connor site resulted in a one-time reduction of .43% and over-collection, or under-spending, in the Electric Lifeline Program resulted in a reduction of 1.03%. Finally, as part of the second-year price change, CMP removed a one-time increase in rates approved in the prior year's price change to recover previously deferred revenues. The overall impact of the second-year price change, including the removal of the prior year's increase, was a 4.84% average reduction to core distribution rates.

CMP's ARP 2000 calls for a mid-period review of the SQI component of the plan. Under the mid-period review provision, on or before June 1, 2003, any party may request that the Commission modify or add to CMP's service quality indices to be effective January 1, 2004. The MPUC Complaint Ratio and the Call Center Service Quality Indicators were specifically targeted by the parties to the ARP 2000 Stipulation for replacement during Mid-Period Review. The parties to the Stipulation agreed to work collaboratively with the Commission Staff to develop a new indicator or indicators that would replace these targeted indicators. We initiated the Mid-Period Review in August 2002 to ensure that all parties have an opportunity to pursue the collaborative effort contemplated in the ARP 2000 Stipulation and to present any unresolved issues to the Commission in sufficient time for implementation on January 1, 2004. At the present time, CMP, our Staff and the parties are engaged in the contemplated collaborative effort.

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[2] *CMP Group, Inc. Et. Al., Request For Approval Of Reorganization And Of Affiliated Interest Transactions,* Docket No. 99-411, Order (Jan. 4, 2000).

III. Bangor Hydro-Electric Company's Alternative Rate Plan

In our order approving the proposed merger between Bangor Hydro-Electric Company (BHE or the Company) and Emera, Inc. (Emera), BHE was directed to file an Alternative Rate Plan proposal within two months of the closing of the merger with Emera or by June 30, 2001, whichever was earlier.[3] In July 2001, BHE filed a proposal to implement an "All-In ARP" that would allow BHE to sell both transmission and distribution (T&D) delivery and standard offer service and to earn a return on the sale of these combined services. The Commission rejected the proposal to allow BHE to sell standard offer service, stating that it was inconsistent with the Legislature's decision to open Maine's retail generation market to competition and prohibiting T&D utilities from selling generation to retail customers.[4]

In response to the Commission's denial of the Company's request to be designated as the standard offer provider as part of its "All-In ARP," on October 15, 2001, BHE filed a revised ARP proposal. In this ARP proposal, BHE proposed to establish "starting point" distribution rates based upon adjusted test year revenue requirements that were 6.11% higher than current distribution rates. BHE further proposed to adjust these rates annually by an inflation minus productivity offset formula and that the productivity offset be set at 1.0% during the pendency of the ARP.

On October 18, 2001, BHE filed a 2-month Notice of Intent to File a Rate Case under the provisions of 35-A M.R.S.A. § 307. In its Notice, BHE stated that it anticipated seeking an increase of approximately 11.6% in its distribution rates. On January 10, 2002, the Commission issued a draft order proposing to initiate a management audit of BHE. In this proposed order, the Commission noted that, given the Company's current high rate structure, recent rate activity and potential for savings from the merger with Emera, it appeared appropriate to conduct a management audit to examine the Company's current cost structure, its operating efficiency, and the potential for savings from the merger. Comments on the draft order were filed by BHE, the Office of the Public Advocate (OPA) and the Industrial Energy Consumers Group (IECG).

In its comments, BHE offered to defer the filing of its rate case for a 90-day period as an alternative to the initiation of the management audit. At the same time, the Commission would defer initiating its management audit. During this period, the Commission Staff and parties to the ARP case could attempt to negotiate a mutually acceptable ARP for BHE. The Company argued that if these discussions were successful, there would be no need for either a management audit or a rate case. BHE further stated that, to demonstrate its good faith, it was willing to use current rates as

[3] *Bangor Hydro-Electric Company Et. Al., Request For Approval of Reorganization (Joint Petition),* Docket No. 2000-663, Order Rejecting Revised Stipulation and Approving Stipulation (Jan. 5, 2001).

[4] *Bangor Hydro-Electric Company, Request For Approval Of Alternative Rate Plan,* Docket No. 2001-410, Order Rejecting Standard Offer Proposal (Sept. 5, 2001).

the starting point for the ARP, assuming the other provisions of the ARP were reasonable.

In an order dated February 28, 2002, we accepted BHE's proposal to defer for 90 days the initiation of the management audit described in our draft order of January 10, 2002, to allow stakeholders to discuss the development of a mutually acceptable ARP. We found that the mutual deferral, or "cooling off" proposal offered by BHE, provided a no-lose situation for ratepayers in that BHE would not begin the formal process to increase its rates during the "cooling off" period and the Commission retained all of its options to initiate an audit if a mutually acceptable ARP was not developed.

Following a series of collaborative sessions involving BHE, our Advisory Staff, the OPA and other stakeholders, on April 21, 2002, BHE and the OPA filed a Stipulation with the Commission which proposed a comprehensive Alternative Rate Plan (BHE ARP). The BHE ARP would apply to BHE's distribution rates, would take effect upon approval and would run through December 31, 2007. Under the terms of the BHE ARP, beginning July 1, 2003 and on each July 1 during the remainder of the Plan, distribution rates would change only in accordance with an Annual Percentage Price Change formula. The Annual Price Change formula would be composed of the following elements: Basic Rate Reductions, Mandated Costs, Net Capital Gains and Losses, Earnings Sharing and Service Quality Penalties. The Basic Rate Reductions (BRR) agreed to are set at –2.5% and –2.75% in 2003 and 2004, respectively. In 2005, 2006 and 2007, if the Inflation Index is less than or equal to 3%, the BRR will be –2.75% in 2005, and 2.00% in 2006 and 2007. If the Inflation Index is greater than 3% in those years, the BRR will be calculated by subtracting 5.75 percentage points from the Inflation Index in 2005 and by subtracting 5.00 percentage points from the Inflation Index in years 2006 and 2007.[5]

Service quality would be measured during the ARP through a Service Quality Index (SQI). The SQI is made up of the following seven indicators: Customer Average Interruption Duration Index (CAIDI); System Average Interruption Frequency Index (SAIFI); Percent of Business Calls Answered Promptly; Service Order Timeliness; MPUC Complaint Ratio; Bill Error Rate; and Market Responsiveness. Baseline performance levels were established for each of the seven indicators. If the Company fails to meet the baseline performance levels, points will be deducted for each indicator for which the Company fails to meet the baseline. Each point deduction is worth $93,000 and will be calculated based on the percentage by which the indicator deviates from the baseline. The maximum penalty for any one year is $840,000.

The Stipulation also proposed that BHE's rate case, and the Commission's pending management audit, be dismissed.

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[5] For purposes of calculating the Basis Rate Reductions, the Inflation Index will be based upon the average annual inflation rates for the preceding two years using the Gross Domestic Product – Price Index (GDP-PI) chain type, as reported by the U.S. Department of Commerce, Bureau of Economic Analysis.

After reviewing the Stipulation, the information collected during the case, our Advisory Staff's Examiner's Report which recommended approval of the Stipulation, and the comments and exceptions filed in response to the Examiner's Report, we concluded that the Stipulation, when viewed a whole, was fair, reasonable and in the public interest and that the benefits of the Stipulation clearly outweighed any possible detriments we could identify.

Specifically, we found that the Stipulation conferred three major benefits upon BHE's ratepayers. The first of such benefits was the withdrawal of the Company's rate increase request. In its rate case notice, the Company estimated its increase request would be $6.4 million. As part of the collaborative process, the Commission's Advisory Staff and the OPA requested the Company to provide the necessary financial data which supported the increase request. While we found that it was not possible to predict with any certainty what the result of a fully litigated rate case would have been, based upon our review of the information collected during the collaborative process, it appeared that a significant portion of the Company's request seemed to have been justified, at least on a strict historic test year basis. Thus, we found the benefit conferred upon ratepayers by the Company's withdrawal of its request to increase distribution rates by $6.4 million or 11.6%, to be real and substantial.

The second major benefit conferred on BHE's ratepayers by the Stipulation was the substantial rate reductions that are likely to occur during the course of the ARP as a result of the Basic Rate Reductions agreed to in the plan. While the actual rate changes may vary due to actual inflation rates, mandated costs, earnings sharing and service quality penalties, under current inflation forecasts[6] the Basic Rate Reductions during the course of the ARP would reduce distribution delivery rates during the course of the ARP by 11.4% in nominal dollar terms.[7] In real dollar terms, the decreases are in the neighborhood of 25%.[8]

We also found that BHE's ratepayers would benefit from the service quality and reliability criteria in the ARP. The service quality indicators will measure the Company's service reliability performance, customer service and market responsiveness. Under the ARP's SQI mechanism, BHE will face automatic penalties of up to $840,000 should its service not meet the established standards.

We found that these major benefits substantially outweighed any possible benefits of pursuing the audit at that time. In making this finding, we noted:

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[6] As used here, the term "current inflation forecast" refers to the Blue Chip Index Consensus Forecast.

[7] The 11.4% total delivery rate reduction reflects the effect of compounding and therefore, is slightly less than the sum of the annual Basic Rate Reductions as set forth in the Stipulation.

[8] This calculation incorporates the impact of the rate freeze during the first year of the BHE ARP.

> "The impetus for the audit was the fact that BHE's distribution rates were high relative to the other Maine transmission and distribution utilities with no obvious reason why such a differential should exist. As noted in the draft order, our consideration of a management audit was not intended to be a punitive response to the Company's notice of a rate case filing. It was indicative of our concern about BHE's already high rates, which BHE was proposing to increase further, and our view that the combined Emera/BHE entity should be able to realize cost savings that would ultimately result in rate reductions to BHE's customers. The management audit then was an expression to the Company of our belief that business as usual was no longer acceptable and that every cost increase experienced by the Company could not be passed on to the Company's ratepayers. It appears to us, given the substantial rate decreases agreed to in the Stipulation, that Emera/BHE's new management team now understand our concerns and have responded appropriately."[9]

In addition, as noted in our decision to accept the Stipulation, the financial modeling done by our Advisory Staff during the collaborative process demonstrated that in order to achieve the level of earnings authorized by the Commission in the Company's last rate case[10] with the agreed-to rate reductions, BHE would have to achieve O&M savings of 20% during the first two years of the plan, would need to keep O&M constant during the remainder of the plan, and would need average sales growth of approximately 2.5%. In order to achieve these savings, the Company would essentially have to reshape itself, a process that appears to have already begun.

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[9] *Bangor Hydro-Electric Company, Request For Approval Of Alternative Rate Plan,* Docket No. 2001-410, *Bangor Hydro-Electric Company, Proposed Rate Change To Increase Annual Revenues Approximately $6.4 Million,* Docket No. 2001-728, Order Approving Stipulation (June 11, 2002).

[10] *Public Utilities Commission Investigation Of Stranded Cost Recovery, Transmission and Distribution Utility Revenue Requirements, And rate Design Of Bangor Hydro-Electric Company,* Docket No. 97-596, Order (Feb. 29, 2000).