**2004 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 (ARPs). 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. 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. At the present time, two of the state's investor-owned utilities (IOUs) operate under ARPs.

This report describes Commission actions taken during 2004 to promote electric efficiency through incentive rate plans or special rate contracts.

## II. Central Maine Power Company's Alternative Rate Plan

In 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 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, ARP 2000 contains significantly stronger productivity incentives, allows only low-end earnings sharing, and increases the number of service and

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[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 rates that will allow the utility, if operated efficiently, to recover those expenses and earn a reasonable return on its investments.

reliability indices that CMP must maintain. These changes responded in part 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, 2004, CMP submitted its annual ARP filing, which contained its proposed price change to take effect on July 1, 2004. In its filing, CMP proposed an overall downward adjustment to rates of 0.53%. This adjustment comprised an inflation index of 1.55%; a productivity offset of -2.75%; no recoverable mandated costs; an inflation index adjustment of 0.61%; other items (including transformer replacement costs) of -0.91%; and the removal of one-time items from the 2003 ARP price change of 0.97%. CMP noted that its 2003 fourth quarter GDP-PI number was preliminary and that it would update its filing to reflect the final GDP-PI number which it expected to be released in March 2004. The Company subsequently provided its updated GDP-PI calculations, which resulted in an increase in the inflation index to 1.62%. Unlike most annual filing proceedings, the parties in CMP's 2004 annual filing case were unable to informally resolve the issues in the case. In our Order, dated June 23, 2004, we approved a 1.06% decrease in the distribution component of CMP's rates.[3]

As part of our Order, we rejected CMP's proposal to revise its rates as part of this year's annual ARP price change to reflect prior revisions to inflation indices. We also referred back to the Hearing Examiner, for further consideration, CMP's proposal to defer as incremental costs certain internal costs associated with the removal of its transformers containing PCBs under 38 M.R.S.A. § 419-B, as well as CMP's calculation of the return component on the replacement transformers. We expect that this issue will be brought back to the Commission during the first part of 2005.

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

In our order approving the proposed merger between Bangor Hydro-Electric Company (BHE) 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.[4] 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

[2] *CMP Group, Inc. Et. Al., Request For Approval Of Reorganization And Of Affiliated Interest Transactions,* Docket No. 99-411, Order (Jan. 4, 2000).
[3] *Central Maine Power Company, Annual Price Change Pursuant to the Alternative Rate Plan* (Post-Merger), Docket No. 2004-167, Order on Contested Issues (June 23, 2004)
[4] *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).

market to competition and to prohibit T&D utilities from selling generation to retail customers.[5]

Subsequent to our rejection of BHE's "All-In ARP," our Staff and the intervenors to the ARP case began a collaborative effort to develop an ARP for BHE. On June 11, 2002, we issued an order which approved a Stipulation entered into by BHE, the OPA, and Georgia-Pacific Company, and thus approved an Alternative Rate Plan for BHE. The BHE ARP, as it was referred to in the Stipulation, took effect on the date of the Order and will run through December 31, 2007. The Stipulation provides for annual rate changes commencing on July 1, 2003. The rate changes will occur in accordance with an Annual Percentage Price Change formula which is composed of Basic Rate Reductions, Mandated Costs, Net Capital Gains and Losses, Earnings Sharing and Service Quality Penalties. The first two Basic Rate Reductions (BRR) in 2003 and 2004 were set at –2.50% and –2.75%. The rate changes in years four (2005) through six (2007) of the ARP depend on inflation. If inflation in the two years prior to the time of those rates changes averages less than 3%, as is currently projected, the Basic Rate Reductions for those years will be –2.75%, -2.00% and –2.00%.[6] Under the terms of the ARP, BHE is required to submit specific information each year on March 15 to be used to compute the annual allowable price change to go into effect on July 1 of that year. The ARP Stipulation also establishes service reliability and customer service performance levels and subjects BHE to penalties of up to $840,000 if BHE's performance drops below the established levels. The BHE ARP calls for a mid-period review of the BHE ARP SQI, which was recently completed.

As noted in last year's report to the Legislature on this subject, on September 24, 2003, BHE filed a petition with the Commission pursuant to the provisions of 35-A M.R.S.A. §§ 1303 and 1321, requesting that the Commission initiate a proceeding to investigate the SQI of its Alternative Rate Plan. Specifically, BHE sought to modify the System Average Interruption Frequency Input (SAIFI)[7] and the Customer Average Interruption Duration Index (CAIDI)[8] components of the SQI. According to BHE, the data used by BHE, and ultimately relied on by the Commission, to develop the CAIDI and SAIFI baselines, were faulty and were thus not an accurate yardstick of BHE's service performance. BHE therefore requested that the Commission initiate an investigation to determine whether the use of the current CAIDI and SAIFI baselines were reasonable and whether such baselines should be modified. The Commission issued a Notice of Investigation on October 7, 2003.

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

[6] *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).

[7] SAIFI measures the average number of non-excluded outages per customer for the utility during the year.

[8] CAIDI measures the average duration of each non-excluded outage.

On April 8, 2004, we received a Stipulation entered into between the Office of the Public Advocate (OPA) and BHE and supported by our Staff. The parties to the Stipulation stated that during 2001 and 2002 BHE implemented a new automated outage management and data collection system and instituted a series of audit measures in an effort to further improve the accuracy of its recorded outage data. These actions led to the capture of numerous outages previously "missed" by BHE's prior outage measurement system. The parties concurred that the apparent increases in measured outages reflect BHE's improved data collection methods, not reductions in its overall efforts to maintain system reliability. The parties further agreed that it was appropriate to modify the CAIDI and SAIFI exemption criteria in a manner similar to that allowed CMP so that only major events would be excluded from the reliability performance metric calculations.[9]

Based on the above finding, the parties agreed and recommended that the CAIDI and SAIFI exemption criteria be modified to exclude outages when in the aggregate 10% or more of the customers in BHE's service territory experience an outage during a calendar day because of an event. If this criterion is met, all outages occurring within BHE's service territory associated with that event shall be excluded for the duration of that event from the calculation of both the CAIDI and SAIFI metrics. In addition, the parties agreed and recommended that the SAIFI metric be modified from its current level of 1.43 interruptions per year to 2.35 interruptions per year. The parties did not recommend any change to the CAIDI baseline metric. The Commission approved the Stipulation on April 15, 2004.[10]

On March 15, 2004, BHE submitted its annual filing pursuant to the Alternative Rate Plan. As part of its filing, BHE proposed to decrease core distribution rates by 1.66%. This overall decrease comprised the ARP Basic Rate Reduction of 2.75% offset by an increase of 1.07% for costs that BHE alleged qualified as mandated costs under the ARP. The company's mandated cost calculation comprised $212,173 for additional Commission and OPA regulatory assessments and $1,152,423 for costs which BHE claimed were associated with six major storms. The totals from these two categories were often offset by the $750,000 mandated cost threshold. In addition, the company proposed an increase of 0.02% related to last year's price change applied to DSM costs pursuant to the ARP's Basic Rate Reduction provisions. According to BHE, Service Quality Index penalties do not apply this year.

On June 16, 2004, we approved a Stipulation[11] entered into by BHE, OPA and the Industrial Energy Consumers Group (IECG) and thus approved, effective July 1,

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[9] See *Order Approving Stipulation in Central Maine Power Company's SQI Mid-Period Review,* Docket No. 2002-445.
[10] *Bangor Hydro-Electric Company, Request for Commission Investigation into BHE's ARP Service Quality Indices,* Docket No. 2003-706, Order Approving Stipulation (April 15, 2004).
[11] *Bangor Hydro-Electric Co., Review of Annual Price Change Pursuant to BHE's Alternative Rate Plan,* Docket No. 2004-192, Order Approving Stipulation (June 16, 2004).

2004, a reduction of 2.44% in BHE's core distribution rates excluding conservation rates unbundled in Docket No. 2003-516 and the discounted portion of BHE's Residential Low Income Rates, as part of the second price change under the BHE ARP. Under the terms of the Stipulation, there would be no mandated cost changes for this price change.

For purposes of calculating mandated costs in the future, the parties agreed that only the following weather events would constitute "extraordinary weather events" and thus qualify as a mandated cost:

1. The event must be classified on the website of the National Climatic Data Center (a division of NOAA) or its successor entity (on a succeeding website) to be an "extreme weather event;"

2. The event must directly result in BHE incurring more than $400,000 of storm restoration costs defined as those costs prudently incurred and necessary to restore service to customers affected by the extreme weather event; and

3. Over three successive calendar days the event must result in disruption of service to more than:

    a. 20% of BHE customers; or

    b. 50% of BHE customers within one of the four BHE operating divisions (Bangor, Northern, Hancock, and Washington).

Finally, on February 18, 2004, the Commission issued a Notice of Investigation to initiate the SQI mid-period review contemplated in our June 11, 2002 Order Approving BHE’s ARP. On December 23, 2004, we received a Stipulation entered into between BHE and the OPA which proposed that only minor modifications to the Service Order Timeliness Metric of BHE’s SQI be made as part of the mid-period review. The parties also proposed that BHE be required to provide quarterly reports to the Commission regarding BHE’s response to events where it was notified by emergency management, fire or police authorities, that there were fire or police personnel on site awaiting the arrival of Bangor Hydro responders. The Commission approved the Stipulation on December 29, 2004.