I. POLICY

A. Overview

On July 1, 2008, the Commission approved a third Alternative Rate Plan (ARP) for CMP. This ARP, referred to as ARP 2008, will expire on December 31, 2013.\(^1\) Pursuant to the provisions of paragraph 39 of the ARP 2008 Stipulation approved by the Commission, the Company submitted Chapter 120 Revenue Requirement information for calendar year 2012 on May 1, 2013. As part of this filing, the Company requested that it be allowed to increase its distribution rates by 8.0% effective July 1, 2014. The 8.0% rate increase proposed by CMP incorporated the Company's proposal to mitigate the increase by $23,165,000 by accelerating the amortization of the Cost of Removal (COR) regulatory reliability. Absent this accelerated amortization, the proposed distribution rate increase would be 18.2%.

CMP also proposed as part of its May 1\(^{st}\) filing, a new ARP (ARP 2014) that would run through December 31, 2018. Under CMP's ARP 2014 proposal as originally filed, rate changes for the capital portion of CMP's revenue requirement would

\(^1\) Central Maine Power Company, Chapter 120 Information (Post ARP 2000) Transmission and Distribution Utility Revenue Requirements and Rate Design and Request for Alternative Rate Plan, Docket No. 2007-215, Order Approving Stipulation (July 1, 2008).
not be based on the traditional inflation minus a productivity offset (X factor) used in prior ARPs. Instead, the majority of CMP's capital revenue requirement would be based on a projected capital revenue requirement, which would then be subject to a Net Plant Reconciliation Mechanism (NPRM). The NPRM would not apply to CMP's proposed Customer Relationship Management and Billing (CRM&B) system, whose costs would be fully reconciled.

On August 2, 2013, the Commission granted a Motion for Partial Dismissal made by the Office of the Public Advocate (OPA) and dismissed CMP's proposed Capital Recovery Mechanism (CRM), finding that the mechanism was inconsistent with the ARP principles enunciated by the Commission in *Central Maine Power Company, Proposed Increase in Rates*. Docket No. 1992-345, Order at 130. In dismissing the CRM, the Commission recognized that its decision would likely require CMP to amend certain parts of its case. The Commission held that CMP was free to propose another mechanism which allowed for increased capital investments without shifting the risk of over-estimation of costs and uncertainty to ratepayers. The Commission noted that CMP's CRM proposal highlighted an interesting problem; namely, how to deal with under-investment during an ARP when moving to the next ARP. Specifically, an ARP without specific capital commitments could provide the utility with an opportunity to allow its system to degrade in order to keep profits high if the next ARP contains specific commitments (and recovery). Thus, the utility might have the opportunity to recover the cost of capital investments that arguably should have been spent in prior years.

On September 20, 2013, CMP submitted a revised proposal in response to the Commission's August 2nd Order of Partial Dismissal. Through this supplemental
filing, the Company reiterated that its proposed capital spending during the ARP 2014 period was necessary and reasonable, argued that its prior level of capital spending was also reasonable; and submitted an amended rate plan proposal that included a revised inflation minus productivity offset rate change mechanism to address its capital spending. Specifically, the Company proposed to incorporate a productivity offset of negative 1.46% in the rate change formula\(^2\). The Company also proposed that it be authorized to amortize an additional $8.2 million of the COR regulatory liability without a corresponding rate or revenue requirement decrease. This additional amortization would essentially flow to the Company's bottom line and was necessary, according to the Company, for it to earn a reasonable return on investment based on its financial projections and avoid a separate rate adjustment mechanism to cover specific capital investments such as the CRM&B.

As part of its September 20\(^{th}\) filing the Company also updated its revenue requirement calculations to incorporate certain updated information and to correct errors which were detected following the May 1\(^{st}\) filing. On November 25, 2013, CMP filed a second Revenue Requirement update. In this filing, based on updated information, the most significant piece being an increase in the discount rate applicable to its Pension and OPEB liabilities, the Company revised its increase request to $16,826,000 or 7.5% which was mitigated by a $15,260,000 amortization of the COR liability. In addition, CMP proposed that the additional COR amortization to enhance earnings be increased from the $8,221,000 as proposed in the September 20\(^{th}\) filing to $18,286,000.

\(^{2}\) A negative productivity offset results in an adder to inflation rather than as an offset to inflation.
Table 1 below presents the Company’s proposed increase for the rate year effective July 1, 2014 (Rate Year 1 also known as the rate effective year) along with its projected increases for Rate Years 2 through 5 during the course of the ARP.

<table>
<thead>
<tr>
<th></th>
<th>Rate Year 1</th>
<th>Rate Year 2</th>
<th>Rate Year 3</th>
<th>Rate Year 4</th>
<th>Rate Year 5</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Amount</td>
<td>Percent</td>
<td>Amount</td>
<td>Percent</td>
<td>Amount</td>
</tr>
<tr>
<td>Base</td>
<td>$37,865</td>
<td>16.87%</td>
<td>$8,275</td>
<td>3.16%</td>
<td>$8,133</td>
</tr>
<tr>
<td>Mitigation</td>
<td>(21,039)</td>
<td>(9.38)%</td>
<td>8,609</td>
<td>3.84%</td>
<td>8,650</td>
</tr>
<tr>
<td>Net Rate Change</td>
<td>$16,826</td>
<td>7.50%</td>
<td>$16,884</td>
<td>7.00%</td>
<td>$16,783</td>
</tr>
</tbody>
</table>

It is important to note that the level of the proposed Rate Year 1 increase shown above is from a base of CMP’s current distribution rates that include $16,657,944 of one-time ARP 2008 costs which will be fully recovered and expire on June 30, 2014 and would otherwise be removed from rates. At the same time, the amortization of the Pension Reevaluation Liability of approximately $5.0 million, which was included as part of the ARP 2008, will expire, as will the $1.9 million funding of the Environmental Reserve. The net impact of these expirations would have been a reduction in rates of approximately $13,558,000 on July 1, 2014. Thus, the Company's proposed increase of $37,865,000, when viewed from a base of current rates after removal of these expiring costs and removing the effect of the proposed mitigation, is actually an increase of approximately $51.5 million or 24.4%. Table 2 below summarizes the rate impacts of CMP's proposal.
It is also important to note that the increases as presented by CMP, for Rate Years 1 and beyond, do not include any amounts for extraordinary storms or the impact of any of the other flow-throughs proposed by the Company. Given the rather extraordinary levels of increases proposed by the Company, the Staff believes it is appropriate to ask whether the ARP has worked as intended and whether an ARP, given the Company’s projection of needed capital expenditures, is the correct ratemaking methodology, at least at this point in time.

B. **Financial Performance Under ARP 2008**

One possible reason why such a large increase could be needed following ARP 2008 is that the rates produced by the current ARP were not sufficient to produce
a reasonable level of earnings. The Company’s earnings presented in Table 2 below suggest, however, that such is not the case.

**TABLE 3**

<table>
<thead>
<tr>
<th>YEAR</th>
<th>ROE EARNINGS</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>9.62%</td>
</tr>
<tr>
<td>2010</td>
<td>10.30%</td>
</tr>
<tr>
<td>2011</td>
<td>12.59%</td>
</tr>
<tr>
<td>2012</td>
<td>10.15%</td>
</tr>
</tbody>
</table>

Assuming a target Return on Equity (ROE) of 9.8%\(^3\), other than 2009, the height of the great recession, CMP has earned its target ROE for all years of the ARP. In this case, however, the increase appears to be required as a result of steep increases in expenses between the end of 2012 and rate effective year (7/1/14-6/30/15). We compare CMP’s spending levels during the ARP 2008 with its projections for ARP 2014 in Figure 1 below.

C. **Comparative Spending Levels**

As Figure 1 shows, CMP’s O&M expense levels are projected to increase sharply in ARP 2014.

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\(^3\) The ARP 2008 was resolved by Stipulation which did not contain a specific ROE that was used to calculate the starting point rates. The Staff’s Bench Analysis filed in Docket No. 2007-215 recommended a 9.8% Return on Equity and an overall Weighted Average Cost of Capital (WACC) of 10.9%. For purposes of calculating carrying costs on deferential and other regulatory assets, the Stipulation agreed to a 10.9% WACC which implicitly would incorporate a 9.8% ROE.
Even more significant, however, is the recent and projected growth in CMP's rate base. As discussed above, in its Order of Partial Dismissal in this proceeding, the Commission expressed a concern about whether the large increase in capital spending was a result of underspending during prior ARPs. Figure 2 below graphically represents CMP's spending during the 2005-2012 time period as well as CMP's projected spending for 2013-2019.
Figure 2 confirms, as CMP asserts in its supplemental testimony, that the Company's overall capital spending during ARP 2008 exceeded the assumed spending levels in the ARP 2008. It is important to note, however, that the spending on the Base Programs and Projects during ARP 2008 was actually less than the assumed level in rates. As shown above, although overall levels of spending are projected to increase dramatically, the Base Program spending will remain relatively level and most of the growth in spending is attributed to CMP's new IT and Billing System, CMP's Automation and Modernization Program, the Distribution Piece of Transmission Projects and CMP's New Asset Condition Replacement Program to be initiated in 2017.
In the Capital Expenditure (CAPEX) section of the Bench Analysis, we look at each of these categories of spending both on a retrospective and prospective basis in greater detail. Several preliminary observations should be made here, however. First, CMP seems to be arguing in its Supplemental Testimony that the reasonableness of its past spending should be based on its relationship to the level of spending approved or assumed in past ARPs. Staff does not believe that the amount included in rates should be a litmus test as to whether the Company was appropriately investing in its system. First, such spending levels could have been influenced by prior historic spending, which may not have been adequate. More importantly, pursuant to the utility’s statutory obligation, the test should be whether the spending level was consistent with the Company’s obligation to provide safe, adequate and reliable service.

Having said that, Staff acknowledges that at this point in time, it is almost impossible to determine whether a particular level of capital spending was adequate looking back over a five to ten year period without knowing the condition of the Company’s system at such points in time. Nonetheless, given the pattern of spending as well as some other problem areas which are discussed in the CAPEX Section, a question certainly exists as to whether the ARP has provided the correct incentives for capital spending or, alternatively, whether sequential ARPs have promoted a pattern of spending driven by the cycle of ARP terminations and rate resettings.
D. **Overall Performance of the ARP**

As part of its Order of Partial Dismissal in this case, the Commission reiterated the following objectives and benefits of an ARP first set forth in Docket No. 1992-345:

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.

The Commission has also recognized that continued service quality and reliability were essential elements to an ARP.\(^4\) Staff looks at these factors in addressing the issue of whether it is appropriate at this time to approve a fourth ARP for CMP.

1. **Rate Stability and Predictability**

Table 3 below sets forth the actual rate changes implemented under ARP 2008:

---
TABLE 4

**Annual ARP 2008 Rate Changes**

<table>
<thead>
<tr>
<th>YEAR</th>
<th>RATE CHANGE</th>
<th>Rate of Inflation</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>5.96%</td>
<td>2.05%</td>
</tr>
<tr>
<td>2010</td>
<td>2.91%</td>
<td>0.68%</td>
</tr>
<tr>
<td>2011</td>
<td>4.48%</td>
<td>1.34%</td>
</tr>
<tr>
<td>2012</td>
<td>2.15%</td>
<td>2.11%</td>
</tr>
<tr>
<td>2013</td>
<td>6.50%</td>
<td>1.79%</td>
</tr>
</tbody>
</table>

As the Table indicates, rates during ARP 2008 have been neither predictable nor stable, and have consistently been above the rate of inflation. To a great extent this is as a result of the “extraordinary storm cost” mechanism. In addition, in 2013, a good deal of the increase is related to the Advanced Meter Infrastructure (AMI) revenue requirement. We discuss the issues surrounding the storm cost mechanism and other flow-throughs in greater detail below.

2. **Regulatory Administration**

It was generally expected that ARP regulation would reduce the amount and burden of regulatory process and oversight. It does not appear that this has been the case.

During ARP 2000, based on concerns expressed by the Legislature, the Commission conducted a Grid Study which explored the impact of the ARP on system reliability. Based on the findings in the Grid Study, the Commission concluded that an in-depth review, conducted by an independent auditor, of CMP's operation and maintenance of its distribution system was warranted. This in-depth audit referred to as the "Williams Study" was completed
in February 2007. The findings of the Williams Study were incorporated and litigated as part of the ARP 2008 proceeding.

In addition, during the course of ARP 2008, there have been six major proceedings, each of which has required significant Commission resources. Those proceedings are listed below with a brief description of the issues involved:

- **Docket No. 2009-18:** This case involved whether and to what extent CMP should be granted an accounting order for storm related costs incurred in December, 2008 prior to the start of ARP 2008's price change formula. The Commission concluded that CMP's improper vegetation management practices during the prior ARP, as documented in the Williams Study, caused the Company's storm restoration costs to be higher than they otherwise would have been. The Commission therefore, reduced the amount of recovery by 30%, or $3.3 million.

- **Docket No. 2008-351:** Prompted by increasing standard offer charge-offs and requests by CMP to increase the uncollectible adder, the Commission instituted an investigation into the allocation of partial payments between standard offer service and utility service. The Commission concluded that CMP's use of a limited set of accounts receivable vintage buckets was contrary to the plain language of the rule because partial payments were not being allocated based on age which resulted in increasing write-offs recovered through the standard offer.
retainage account and decreasing bad debt expenses covered under CMP’s ARP.

- Docket No. 2009-217: On July 10, 2009, CMP filed with the Commission a Petition Requesting that the Commission Issue an Order to Modify CMP’s Service Quality Indicators by Eliminating or Changing the Current MPUC Compliant Ratio and to Waive Penalties. In its Petition, CMP alleged that the unexpected global economic collapse in 2008 and the concurrent recession in the United States, coupled with the Commission's credit and collection rules, resulted in an unprecedented number of credit and collection issues and resulting complaints. As a result, CMP requested that the Commission adjust the Company's SQI indicators effective January 1, 2009 and waive any penalties related to violations of the PUC complaint ratio for 2009. The case was resolved by Stipulation, which provided that the SQI penalty for 2009 would be reduced from $5.0 million to $4.0 million, of which $3.0 million would flow through the ARP 2008 SQI penalty mechanism and $1.0 million would be provided to CMP’s low-income customers as part of an arrears forgiveness program.

- Docket No. 2010-327: In this proceeding, the Commission investigated whether CMP had acted prudently in its collection of its accounts receivables including standard offer receivables and whether the standard offer retainage account had been negatively impacted by CMP’s management and/or accounting practices. After over two years of
litigation, the Commission found CMP’s management of its credit and collections factor was imprudent. Most notably, during the 2006 through 2009 time period, standard offer charge-offs were at least $1.5 million higher than they otherwise would have been. In addition, during the 2008-2010 time period, CMP misapplied $2.6 million in standard offer deposits to T & D receivables to the standard offer retainage account rather than apply such receivables during the 2008-2010 time period.

- Docket No. 2011-77: In this case, the Company sought recovery of $12,697,301 for a February 2010 storm and $3,454,401 for a November 2010 storm. The Staff challenged the inclusion of the November storm on the grounds that the storm did not satisfy the outage criteria for inclusion. As part of this challenge Staff argued that the Company wrongfully interpreted the term "day" as a 24 hour period rather than a calendar day, wrongfully interpreted the term "customer experiencing an outage" to mean total interruptions and also wrongfully included customers interrupted as a result of CMP’s manual intervention to address the deenergization of a downed power line. The Staff also argued that between $1.34 million and $1.58 million in costs paid to one of its storm cost contributors for the February Storm were excessive and should be disallowed.

The Commission found and agreed with Staff on the calendar day issue but disagreed with Staff on the customer interruption issue and thus found the November storm qualified for flow-through treatment. In
addition, the Commission found that CMP had not acted imprudently with respect to the February storm and granted CMP's request for inclusion the full $12,697,301 in rates.

- Docket No. 2010-51: In CMP's most recently completed rate case proceeding, the Company proposed to implement AMI on a company-wide basis. Given the complexity of the project and the rapid changes occurring in AMI standards, the parties to the Stipulation that resolved the rate case, Docket No. 2007-215, agreed that a decision on the Company's AMI proposal, as well as a further examination of AMI cost/benefit issues, should be deferred. On February 25, 2010, based in large part on the estimates of net benefits provided by CMP and the expectation of additional benefits from electricity supply programs, the Commission issued an Order, which approved CMP's AMI Project. *Order Approving Installation of AMI Technology, Docket No. 2007-215(II) (Feb. 25, 2010).*

On June 24, 2013, after trying to resolve the matter for nearly three years, the Commission approved a Stipulation, which put $11.5 million into rates intended to allow CMP to begin collection of its AMI revenue requirements and eliminate the deferred costs pending the outcome of the AMI management audit which the Commission initiated June 17, 2013. The results of that audit will be incorporated into this proceeding and will address the following issues:

1. Whether CMP employed reasonable and prudent management practices in developing the savings estimates provided to the commission in January 2010;
(2) Whether CMP has employed reasonable and prudent practices in its management of the project and has acted in accordance with reasonable and prudent practices to ensure that actual operational costs and savings associated with the AMI project remained reasonably in line with estimates upon which approval of the project was authorized;

(3) Whether CMP has appropriately and accurately identified the savings realized to date from the AMI project and provided reasonable estimates of these savings on a going forward basis; and

(4) Whether CMP has employed prudent and reasonable management to ensure that the AMI and related systems have the capabilities envisioned by the commission at the time that the AMI system was approved.

In addition, a number of the ARP 2008 annual reviews which have been resolved by Stipulation without litigation have involved disputes as to what storm costs which were proposed for recovery by CMP under the extraordinary storm cost provision were actually incremental to the event. Finally, many other annual review proceedings have also required substantial time and resources to examine other issues including issues related to mandated costs such as CMP’s Medicare Part D Subsidy request in 2011.

3. Reliability Issues

As noted above, the Commission has recognized that ARPs create the opportunity for the utility to enhance earnings at the expense of reliability. While the Commission has attempted to address this issue through the use of reliability metrics, these metrics cannot be seen as a panacea. First, there is often a delayed impact between the time when an action should have been taken and the time that inaction results in a reliability issue. This was evidenced during ARP 2000, in which CMP continued to meet its reliability metrics despite its
poor vegetation management practices and the Company's suspension of its line
inspection program as reflected in the Williams Study. In addition, as noted in the
Williams' Report and discussed below in Section VII (E), it is possible to meet the
overall metrics while still providing poor service to less densely populated circuits.
Although CMP appears to have addressed the cycle trim and inspection issues
raised in the Williams’ Report, CMP’s ARP 2014 filing raises questions as to
whether it has inappropriately deferred capital spending resulting in the need for a
large catch-up program. In addition, the question still remains as to whether
CMP's spending appropriately addresses issues on its less densely populated
circuits.

The ARP 2014 filing appears to indicate that prior ARPs may not
have provided a sufficient incentive for appropriate levels of investment for
reliability, and/or that the reliability metrics themselves were inadequate and
created an incentive to manage the metrics only, while deferring other
investments that may have been required. In addition, a review of CMP’s capital
productivity (addressed in Section VII (B)), CMP's historic level of capital spending
(discussed in Section II), and CMP’s capital spending prioritization criteria
reinforce this indication.

E. Risk-Shifting and Incentives for Cost Controls

One key objective of an ARP is to shift risks away from ratepayers to
shareholders, which should also provide financial incentives for efficient company
management and operation. In CMP’s case, however, over time certain
mechanisms have been incorporated that blunt or distort these incentives. Most
notable is the extraordinary storm cost mechanism incorporated into ARP 2008 which has had the exact opposite effect. In addition, by establishing a flow-through mechanism for just one category of costs, a flow-through mechanism may inappropriately incent management to shift spending towards flow-through centers and away from cost centers which are subject to the price cap, since costs cut from the price index centers go directly to the Company's bottom-line, while costs which are shifted to the flow-through centers are subject to full recovery from ratepayers.

As Table 28 in Section VII (D) demonstrates, there was a dramatic increase in storm restoration costs after the flow-through mechanism was adopted as part of ARP 2008, thus providing evidence that the concerns expressed above are valid. Further support for these concerns comes from a statement made by a representative from the Company who at the time was responsible for storm crew deployment, who stated that he is in constant contact with the operations folks so he knows whether the 20% threshold will kick-in, at which point he has the green light for retaining outside crews.

F. Ability Of An ARP To Handle The Projected Changes In Costs

As shown in Figures 1 and 2, CMP is projecting substantial increases in both capital and operations and maintenance costs during the proposed ARP 2014 period. As noted above, CMP initially proposed its CRM, which was rejected by the Commission. In response, the Company submitted a revised proposal which incorporated all costs into the proposed revenue index mechanism, but increased the negative productivity offset contained in the
formula from (0.22) to (1.46) and introduced a flow-through to shareholders of $18.3 million of the COR liability. The revised proposal continues to contain the caveat that CMP's capital spending may vary from projections based on "available resources and system needs," thus, even with the substantial rate increases that would occur, there is no assurance that the projected capital investment would be made.

In many ways, the Company's revised proposal represents a step backwards from the initial proposal rejected by the Commission. First, the Company's revised proposal continues to base ratepayer funding, now in the way of the COR amortization, on the same soft projections contained in its initial proposal and rejected by the Commission. Second, the revised proposal continues to contain the caveat that even if the budget forecast were accurate, the Company may not make the proposed investments depending on resource availability and system needs. Third, the Company's revised proposal continues to ignore O&M savings enabled by the Company's increased capital investments. Finally, whereas the initial proposal had some provision for the flowback of possible underspending and also contained some metrics which were loosely related to the capital investment, the revised proposal contains neither provision.

Given the Company's inability to develop a plan which addresses the reasons why the Commission rejected the Company's initial ARP 2014 proposal, it is Staff's view at this time, that it simply may not be possible to accommodate an ARP within the context of CMP's current capital expansion plans. At a technical conference, Mr. Stinneford seemed to recognize this
difficulty and the option to address future capital expansion through traditional
cost of service ratemaking.\(^5\)

G. Staff Recommendation On The Regulatory Paradigm

Given the issues/concerns with CMP's performance under prior ARPs, as well as the concern that a new ARP cannot adequately address CMP's projected capital plans in a way that meaningfully protects ratepayers, the Staff's recommendation at this time would be that the Commission take an ARP "hiatus" for CMP and allow CMP to operate under cost of service ratemaking for a period of time. This would allow CMP to address its system and spending needs consistent with the interests of both shareholders and ratepayers. In the future, an ARP form of regulation can be revisited and, as appropriate, adopted in a way that meets the Commission's objectives and concerns.

In making this recommendation, the Staff is mindful of the Commission's prior support of the ARP regulatory paradigm. A return to cost of service regulation, however, does not necessarily mean increased regulatory burdens, continuous rate filings and a lack of incentive to control cost. Staff would point to recent experience with Bangor Hydro-Electric Company (BHE) and Maine Public Service Company (MPS). BHE's last ARP expired on December 31, 2007 and MPS has never been under an ARP. The last cost of service rate case filing for both BHE and MPS, before jointly submitting a rate increase request on December 6, 2013, was over seven years ago, in 2006. During that time period, neither BHE nor MPS has filed a request for an accounting order or flow-through

of costs, nor has the Commission received any reliability related complaints from customers. The Staff also notes that during this time period, BHE successfully invested and installed automated meters on its system and also began the process of installing a new customer service billing system which will be completely installed by 2014. Thus, at least for BHE and MPS, the normal "regulatory lag" between rates was sufficient to promote the Commission's objectives of management efficiency, cost containment and rate stability.

II. CAPITAL SPENDING

A. Overview

As shown in Figure 2, CMP's capital spending has increased dramatically over the past three (3) years and is expected to continue to grow at an even faster pace in 2013 and during the rate effective period. For the ARP 2014 period, CMP's projected overall spending, broken down by CMP's broad categories is set forth below:
TABLE 5

ARP 2014 Projected Capital Spending

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Distribution Line Work</td>
<td>25,352</td>
<td>25,554</td>
<td>25,757</td>
<td>25,963</td>
<td>26,188</td>
<td>26,417</td>
</tr>
<tr>
<td>Distribution Equipment</td>
<td>8,202</td>
<td>8,326</td>
<td>8,481</td>
<td>8,611</td>
<td>8,750</td>
<td>8,892</td>
</tr>
<tr>
<td>Service Installations</td>
<td>2,354</td>
<td>2,385</td>
<td>2,416</td>
<td>2,447</td>
<td>2,480</td>
<td>2,516</td>
</tr>
<tr>
<td>Relocations Due to Highway Construction</td>
<td>1,996</td>
<td>2,022</td>
<td>2,049</td>
<td>2,076</td>
<td>2,104</td>
<td>2,133</td>
</tr>
<tr>
<td>Distribution Piece of Transmission Projects</td>
<td>10,378</td>
<td>8,000</td>
<td>4,400</td>
<td>7,000</td>
<td>2,800</td>
<td>2,100</td>
</tr>
<tr>
<td>Distribution Substations</td>
<td>6,039</td>
<td>3,927</td>
<td>5,928</td>
<td>7,432</td>
<td>8,858</td>
<td>7,783</td>
</tr>
<tr>
<td>Distribution System Modernization</td>
<td>5,654</td>
<td>7,914</td>
<td>10,849</td>
<td>7,053</td>
<td>11,554</td>
<td>13,474</td>
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<tr>
<td>Distribution Asset Condition Improvement</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>3,850</td>
<td>7,809</td>
<td>11,712</td>
</tr>
<tr>
<td>Total BEFORE Allocation of Common</td>
<td>59,975</td>
<td>58,128</td>
<td>59,880</td>
<td>64,432</td>
<td>70,543</td>
<td>75,027</td>
</tr>
<tr>
<td>Allocated Customer Relationship Management &amp; Billing</td>
<td>-</td>
<td>19,985</td>
<td>24,359</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Other Allocated Common</td>
<td>23,124</td>
<td>17,108</td>
<td>16,468</td>
<td>13,915</td>
<td>12,969</td>
<td>13,165</td>
</tr>
<tr>
<td>Total AFTER allocation of common</td>
<td>83,099</td>
<td>95,221</td>
<td>100,707</td>
<td>78,347</td>
<td>83,512</td>
<td>88,192</td>
</tr>
</tbody>
</table>

In its Order of Partial Dismissal, the Commission expressed a concern that CMP’s capital spending projections raised the possibility, at least, that these higher capital spending levels may have been caused by CMP’s prior under-investments. In response to this concern the Staff asked CMP to provide historic levels of spending on a subcategory bases and has compared those spending levels to the forecasted levels of spending. See Appendices A and B to this Bench Analysis. We review below the
historic spending levels as well as CMP’s rationale for its projections by the significant spending centers.

B. Core Distribution Program

Staff includes in this category distribution line work (which includes major betterments, minor service center line jobs, and distribution line inspection) distribution equipment, service installations and relocations due to highway construction. The spending levels, both historical and projected, in the Distribution Equipment (other than Meters),\(^6\) Service Installation, and Relocation categories do not raise concerns. In the sections below we discuss those areas where Staff does have concerns either based on historic or projected spending levels.

1. Major Betterments

Major Betterments represent Company spending intended to maintain and enhance distribution system reliability. As such, Major Betterment spending can be seen as the "bread and butter" of the Company's Distribution Reliability Program. In this case CMP's projecting spending for Major Betterments is $9.9 million per year during ARP 2014. This is generally consistent with CMP's projected and actual spending on Major Betterments during ARP 2008.

\(^6\) Staff expressed concern about the level of spending for replacements in the first years of the ARP 2014 budget given the recent change out to AMI meter. On behalf of the Company, Mr. Stinneford suggested that this be reviewed as part of the overall review of the Company's AMI spending which will occur following the filing of the AMI Management Audit Report. We will, therefore, defer our analysis of this issue until such time.
TABLE 6

Comparison of ARP Target Levels of Spending Versus Actual

<table>
<thead>
<tr>
<th>Year</th>
<th>ARP Target for Spending Levels</th>
<th>Actual Spending in Millions</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>$7.2</td>
<td>$7.0</td>
</tr>
<tr>
<td>2010</td>
<td>7.8</td>
<td>7.1</td>
</tr>
<tr>
<td>2011</td>
<td>8.4</td>
<td>11.4</td>
</tr>
<tr>
<td>2012</td>
<td>9.2</td>
<td>10.9</td>
</tr>
<tr>
<td>2013</td>
<td>9.9</td>
<td>9.9*</td>
</tr>
</tbody>
</table>

*Budgeted Amount

Table 7 below shows CMP's spending for Major Betterments during ARP 2000.

TABLE 7

Major Betterment Spending During 2000-2008

<table>
<thead>
<tr>
<th>YEAR</th>
<th>SPENDING IN MILLIONS</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000</td>
<td>$2.92</td>
</tr>
<tr>
<td>2001</td>
<td>$3.74</td>
</tr>
<tr>
<td>2002</td>
<td>$3.76</td>
</tr>
<tr>
<td>2003</td>
<td>$3.97</td>
</tr>
<tr>
<td>2004</td>
<td>$4.56</td>
</tr>
<tr>
<td>2005</td>
<td>$4.85</td>
</tr>
<tr>
<td>2006</td>
<td>$5.37</td>
</tr>
<tr>
<td>2007</td>
<td>$7.10</td>
</tr>
<tr>
<td>2008</td>
<td>$5.27</td>
</tr>
<tr>
<td>TOTAL</td>
<td>$41.57</td>
</tr>
<tr>
<td>Annual Average Spending:</td>
<td>$4.61</td>
</tr>
</tbody>
</table>

As the above tables indicate, CMP’s more recent and projected spending in the category is substantially higher than for earlier years. This disparity may be even greater than the above information indicates because the amounts for Major
Betterments for the earlier years may include projects that are now reported separately and not included in the Major Betterments category.

Based on the above cost trends, it is difficult to assess whether more recent spending reflects a catch-up for projects that should have been done in earlier years. However, Staff noted that as part of its filing in Docket No. 2007-215, the Company submitted testimony from Michael Watson proposing an enhanced betterments program. The Company's Response to EX-018-018 reveals that a significant number of projects identified by Mr. Watson as being necessary because of plant condition, deterioration issues, loading and other violations have been deferred or have not been addressed at all. See Appendix C. In addition, a number of betterments identified in recent years that might be considered high priority have been deferred or not approved.7 The Staff is also concerned that the amounts projected for Major Betterment spending by the Company may be inaccurate as it appears that certain betterment projects are reported to have been completed in several different years. See Appendix D.

Given the discrepancy between past spending levels and current/projected levels, the number of high priority projects which have been deferred in the past, and apparent discrepancy in CMP’s reported actual spending, the Staff cannot at this time, say with certainty that the projected Distribution Betterments are reasonable.

2. Distribution Line Inspections (DLI)

In response to concerns raised during the Williams Initial Grid

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7 EX-018-065
Study, in 2006 CMP reinstituted its line inspection program. CMP initially adopted a 10-year inspection cycle but modified its program to a five year cycle as part of the ARP 2008 Stipulation. The Company's capital spending during the 2000-2007 time period reflects the lack of any real inspection program.

Under its inspection programs, CMP identifies problems as DL1 (Repair within the calendar year), DL2 (Repair within the following calendar year) or DL3 (Repair within the following two calendar years). Table 8 below sets forth the DL1 problems detected and completed by year.

**TABLE 8**

**ARP 2008 – Distribution Line Inspection as of 6/19/13**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>126,587</td>
<td>6,993</td>
<td>2,825</td>
<td>1,596</td>
<td>1,417</td>
<td>888</td>
<td>188</td>
<td>6,914</td>
</tr>
<tr>
<td>2010</td>
<td>133,464</td>
<td>7,685</td>
<td>-</td>
<td>2,723</td>
<td>1,659</td>
<td>1,786</td>
<td>715</td>
<td>6,883</td>
</tr>
<tr>
<td>2011</td>
<td>135,744</td>
<td>6,039</td>
<td>-</td>
<td>-</td>
<td>1,730</td>
<td>1,903</td>
<td>1,099</td>
<td>4,732</td>
</tr>
<tr>
<td>2012</td>
<td>134,744</td>
<td>6,062</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>1,449</td>
<td>719</td>
<td>2,168</td>
</tr>
<tr>
<td>Totals:</td>
<td>530,777</td>
<td>26,779</td>
<td>2,825</td>
<td>4,319</td>
<td>4,806</td>
<td>6,026</td>
<td>2,721</td>
<td>20,697</td>
</tr>
</tbody>
</table>

During ARP 2008, CMP's DLI related capital spending in 2009 was $2,980 and has increased steadily through 2012. CMP's projected spending in the rate effective year and during the remainder of the ARP 2014 period is based on the 2013 level adjusted for inflation. The Staff agrees with CMP with respect to the rate year level. After that, however, spending levels should decline since, as of the end of 2013, CMP will have completed the first five year cycle. Thus, there should be a drop-off in problems identified relative to the initial cycle, during which problems that had gone

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9 For example in 2006, CMP DLI expenditure was $2,000.
3. Distribution Substation – Upgrades to Support Distribution Line
Betterments and Substation/Transformer Replacement

This category of spending includes substation upgrades which are needed to support Major Betterment projects as well as upgrades to address substations that are overloaded, undersized to support other adjacent circuits, or have insufficient circuit positions on the bus work to support new circuits needed to relieve circuit loading or customer counts limit.

During the 2008 – 2012 time period, spending in this category averaged $812,000 per year. In 2013, CMP projects spending to be $2.3 million and during the 2014-2019 time period it projects spending to average $3.5 million annually.

In its testimony, CMP identified 13 substations slated for work during ARP 2014. CMP’s projected spending levels for this work is based on high level engineering estimates that include a 30% contingency factor and a +/- 50\textsuperscript{10} accuracy range.

With regards to the substation transformer/breaker replacement category, the Company projects to spend an average of $2,041,000 per year over the ARP 2014 period. This compares to average spending over the period 2008-2013 (including 2013 budget) of $74,000 per year. The Company has stated that its projected spending levels are based on its Asset Condition Assessment which identifies 11 transformers to be replaced during ARP 2014.

\textsuperscript{10} See Response to EX-018-027
The Staff does not question the need for transformer replacements identified by the Company. However, as with other project categories, the difference between projected needed and past actual spending levels indicates the potential that projects have been deferred.

4. Substation Modernization Program

As stated by CMP, the objective of this program is to upgrade substation equipment as needed to maintain a safe and reliable system. CMP uses the following criteria to identify substations for this program:

- Insufficient space
- Foundation condition
- Roadside substation recloser
- Fuse elements
- 4kV stations
- Insulators
- Major equipment condition
- NESC issues.

CMP’s spending in this category has varied widely during the course of the past ARP. Spending went from $4,424,000 in 2008 down to $215,000 and $425,000 in 2009 and 2010, respectively, then back up to $2,341,000 in 2011 and $6,052,000 in 2012. In 2013, CMP projected spending of $2,292,000. CMP has identified 11 substations slated for rebuilding during ARP 2014 with annual spending levels ranging from $900,000 in 2014 up to $10 million by 2019. These spending projections again are based on estimates with a 30% contingency and a +/- 50 accuracy
factor.

Given the uncertainty surrounding these spending levels and 
CMP’s caveat that these investments are subject to revision based on future events and 
circumstances, the Staff does not believe that the projection, especially long-term can 
be relied on for rate-setting purposes.

C. Asset Condition Improvement Plan

In 2010, Iberdrola USA (IUSA) implemented a Comprehensive Asset 
Management assessment across all companies in the IUSA family. As part of this 
program, asset groups are assessed based on a variety of factors, including failure 
modes, maintenance and inspection records and operational history. Based on these 
factors the assets are scored using a 1-5 health index, with 1 being very good and 5 
being very poor. Based on this assessment, CMP has concluded that for the most part 
its system is in good condition. However, three areas of concern that were identified 
were overhead conductor, underground conductor, and, to a limited degree, substation 
transformers.

With regard to the overhead conductors, CMP currently rated 2,044 miles 
out of it total of 46,448 miles (4.5%) to be in very poor condition. Of this, CMP identified 
890 miles of conductor that were 85 years or older, including 218 miles which were 90 
years or older. To address this situation, CMP plans to adopt a copper conductor 
replacement program beginning in 2017. Under this program, CMP would replace 38 
miles of the old copper conductor in 2017, 75 miles in 2018, and 110 miles in 2019 for a 
total of 223 miles during ARP 2014. In support of this program, CMP relies primarily on 
a recent testing program conducted by National Grid which indicated that, its older
copper conductor typically lost 13% of its tensile strength with continued loss of strength occurring at a rate of 1.4% per year. Reduced conductor tensile strength and ductility leads to increased risk of conductor failure and conductor elongation increases conductor sag causing safety concerns. CMP has stated that it is currently doing testing on its own conductor to determine whether the copper conductor on its system has similar characteristics in terms of tensile strength, ductility and elongation, to National Grid's conductor.

To the extent that CMP’s copper conductor has similar issues with regards to tensility and elongation such that there are existing safety and reliability issues, the planned time-frame for CMP’s replacement program may be inappropriately late. Given CMP’s stated plans, the condition of its system will actually regress since the amount of 90 year old copper would grow from 218 miles to 667 miles, the amount of 85 year old copper would grow from 890 to 1,877 and the amount of overhead conductor in the "very poor" condition category would grow from 2,094 miles to 3,492 miles.

The Staff has similar concerns with regards to CMP's proposed underground conductor replacement. At the current time, 286 miles out of the total of 2,476 miles of underground distribution cables or 11.5% of the underground system, is considered to be in very poor condition. The underground cable which is particularly problematic is pre-1998 "XLP" cable which does not have the same tree retardant characteristics as later XLP cable and, as result, has a high failure rate. CMP has 513 miles of this type of cable on its system.

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XLP is defined as cross-linked polyethylene cable.
CMP is currently replacing seven miles of this type of cable per year and proposes, as part of its ARP 2014 Asset Condition Program, to evaluate 81 miles of cable through 2014. Where possible, CMP will treat this cable rather than replace it given the cost differential ($37,000 per cable mile vs. $208,000 per cable mile). Given this planned rate of treatment/replacement, the Company projects that the amount of underground conductor in "very poor" condition in 2014 will increase from 286 conductor miles to 447 conductor miles, or 18% of CMP's underground distribution system.

CMP projects the following costs for the Asset Replacement Program:

**TABLE 9**

<table>
<thead>
<tr>
<th>Capital Project or Category</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>DISTRIBUTION ASSET CONDITION IMPROVEMENT</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Overhead conductor replacement</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>1,914</td>
<td>3,885</td>
<td>5,742</td>
</tr>
<tr>
<td>Underground conductor replacement</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>1,936</td>
<td>3,924</td>
<td>5,970</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>3,950</td>
<td>7,809</td>
<td>11,712</td>
</tr>
</tbody>
</table>

As noted above, the cost for underground conductor treatment is about 1/5 the cost of replacement. CMP bases its underground conductor cost projections on its estimate that 42% of the miles evaluated can be treated and 58% will be replaced. CMP bases this estimate on the experience of Rochester Gas & Electric Company (RG&E), its sister IUSA Company. CMP acknowledges that there may be some differences between CMP's system and RG&E's system. With regards to the overhead conductor costs, CMP bases its projection on a 2013 estimate of conductor replacement of $48,200 per conductor miles going forward.
Here again, given the uncertainty of both the level of the work which will ultimately be performed and of the cost estimates for the underground conductor, which could subject to large swings depending on whether assets can be treated as opposed to replaced, the Staff does not believe that CMP's projections multiple years into the future can reasonably be relied on for rate setting purposes.

Finally, the age and condition of these assets, which tend to be located in less densely populated areas, and CMP's planned time-frame for the condition improvement program, may be because of the incentives provided by the system-wide metrics that have been in place over the past several years. The Staff discusses this issue further in Section VII (E).

D. Information Tech and Operations Tech

CMP proposes to add approximately $100 million to the rate base for this cost category during ARP 2014. A majority of this, $55 million, is related to CMP's new CRM&B system to be installed in 2015 and 2016.

The deficiencies with CMP's current CIS billing system are, at this point, well documented and the Staff does not contest the need for a replacement system. The issues that Staff has with CMP's proposal to include the spending in rates set in this case relates to the substantial uncertainties surrounding the amount and the timing of the investment. The projections included in CMP's forecast are based on CMP's high level plan.\textsuperscript{12} According to CMP, the biggest component of the cost will be related to costs for the system integrator which would be the firm that would have the expertise to

\textsuperscript{12} Capital Test. Exhibit CAP-2 at 29.
implement the proposed system and return the needed resources. It would seem then, that until that firm is retained and has had the opportunity to work with CMP on the needs and objectives for the project, that the cost projections, at this time, must be viewed as CMP has high level estimates. In addition, at this point, the timing of the investment and when the plant will actually be "used and useful" and be providing service to ratepayers can also be seen as an uncertainty. Given the size of the investment, a delay in full implementation of one year could result in an amount of approximately $5.5 million being wrongfully included in revenue requirements. This concern is highlighted by recent experience with OPTECH (AMI), MDM and other IT costs in 2013. In 2013, CMP budgeted approximately $4.5 million for these cost categories while CMP's actual capital spending was approximately $1.1 million.\textsuperscript{13}

In the IT “other” category which consists of cyclical replacement of IT hardware and other mid-sized projects, CMP has projected capital spending of $5.62 million in 2014 and $6.76 million in 2015. This compares with historical spending during ARP 2008 of $581,000 in 2009, $580,000 in 2010, $976,000 in 2011, and $1,915,000 in 2012. CMP attributes the large increase in this category to projects which were backlogged during the installation of AMI.\textsuperscript{14} Staff notes that future delays and deferrals in this category of projects seems like a possibility given the size and magnitude of the CMP's CRM&B system

\begin{itemize}
\item[E.] \textbf{Automation Program}
\end{itemize}

Under its Distribution Automation Program, the Company proposes to automate the reclosers in those substations that do not have the capability. CMP has

\begin{footnotes}
\item[13] ODR 142-01.
\item[14] ODR 141-01.
\end{footnotes}
stated that it has approximately 263 substations and as of December 31, 2013 only 31 will remain without SCADA capability. In 2012, CMP spent $2.28 million in this category and projects spending $2.3 million in both 2013 and 2014 at which point the program will be completed.

The other major component of the Automation Program is the replacement of the hydraulic reclosers on CMP's distribution system with electronic reclosers. Of CMP's total of 472 three-phase reclosers, 69 were automated in 2013. CMP proposes to complete the automation of its three phase reclosers at a rate of approximately 54 per year during the course of ARP 2014. CMP's budget for the 89 reclosers installed in 2013 was $975,000 and the Company has budgeted the same amount for 55 reclosers to be installed in 2014.

As part of its automation program, CMP also proposes to significantly increase its investment in its Energy Control Center (ECC). Specifically, CMP proposes to invest $9.0 million in 2014 and $5.0 million in 2015 of which 75% gets assigned to transmission costs and 25% is assigned to distribution. These investments compare with $1.27 million invested in 2012, $1.43 million in 2011 and $1.81 million in 2010. CMP states its projections are based on costs for the same type of upgrades incurred by its sister companies in New York.

CMP describes rather extensively, in several parts of its direct case, the benefits of the Automation Program. Staff does not dispute the benefits of the Automation Program. The Staff, however, does question the accuracy of the

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15 Staff does question, however, the accuracy of the ICE Model and its quantification of ratepayer value assigned to outages. For example, the model
projections as well as the timing of these investments. Thus, for rate-setting purposes, spending for this category can best be accommodated through Staff's overall rate base attrition adjustments.

F. **Distribution Piece of Transmission Projects**

The Company breaks down this category into two components, MPRP related projects and Other Transmission-Related projects. The Company projects $900,000 in MPRP related spending in 2013, $3,830,000 for 2014 and $3,200,000 for 2015. For Other Transmission Related projects the Company projects $13,789,000 to be spent in 2013 and $6,549,000 during the 2015-2019, for a total of $41.3 million. The Company states that its cost projections for these projects were influenced by "year of need, timeline for engineering design and procurement, regulatory approval process and required construction sequence and duration."\(^{16}\)

The $1.4 billion dollar MPRP project, which is truly an extraordinary project, has been the subject of extensive Commission scrutiny as part of the CPCN process. The costs of this project have also regularly been reported to the Commission and, at this time appear to be on budget. The Staff therefore believes it appropriate to create a carve-out for these costs based on actual costs incurred and the budgeted costs for the rate year.

The Staff, however, does not have the same level of certainty related to Other Transmission-Related Project costs. First, of the individual projects identified by the Company in the forecast, several have not yet received the required Commission or

\(^{16}\) Cap. Test., Exhibit CAP-3 at 17.
ISO-NE approvals. In addition, we assume that projected costs for the out-year projects are based on high level estimates and, as such include a 30% contingency and +/- 50% uncertainty allowance. Therefore, the Staff believes that the costs of these Other Transmission projects, especially in the out years, are not reliable for rate-setting purposes. Staff believes that it may be possible to create a carve-out for these costs, similar to MPRP components based on further specific information provided on these projects during the case.

G. Conclusion

The Staff's review of CMP's projected capital spending indicates substantial increases compared to capital spending levels in prior years. As noted elsewhere, this raises questions about whether projects that should have been undertaken under prior ARPs have been deferred to the benefit of CMP's shareholder. As discussed in Section VII (B), this would seem to be supported by Dr. Lowry's findings of very high capital productivity during the past 10 year period. However, at this time, sufficient evidence does not exist to warrant cost disallowances. However, as noted above, the data raises serious questions about to extent to which the prior ARPs were failing to provide the correct incentives for CMP to make plant investments and, thus, serve to support the ARP "hiatus" recommended by Staff.

The Company's proposed investment levels, especially going out past the rate effective year, raise two very major concerns. First, the last projections are in many cases, high level estimates and become more speculative as one goes out in time. Second, and of equal importance, is that by way of its ARP 2014 proposal, CMP does

17 ODR 106-01.
not commit to, and reserves to reprioritize or defer, any of the capital projects in its spending plans. For rate-setting purposes then, recognizing the Company's recent increases in investment levels while at the same time recognizing the uncertainties described above regarding CMP’s specific category-by-category projections, the Staff proposes that for the rate effective year, plant additions be incorporated into the attrition analysis by using a standard attrition trending approach. We believe that this approach appropriately balances the needs of the Company and its shareholders to earn a reasonable return during the rate effective period and of ratepayers for safe, adequate and reliable service at just and reasonable rates.

Beyond the rate effective year, we believe that the Company's capital projections are far too uncertain to serve as a basis to set rates. We therefore, recommend that such projections not serve as a basis for the Company proposed "bonus” COR liability amortization or its proposed K factor term in the productivity offset.

III. RETURN ON EQUITY AND COST OF CAPITAL

The Company has proposed an overall rate of return (ROR) of 11.09% which reflects a capital structure as shown in Table 10 below, a cost of preferred stock of 6.00%, a cost of long-term debt of 5.00% and a proposed return on equity (ROE) of 10.15%. Staff has no objection to the costs associated with long-term debt and the preferred equity level and cost; but disagrees with the proposed equity ratio of 50%; the return on common equity; and the cost of short-term debt as more fully explained herein.
### TABLE 10

**CMP Proposed Capital Structure**

<table>
<thead>
<tr>
<th></th>
<th>Balance</th>
<th>Ratio</th>
<th>Cost</th>
<th>Weighted Cost</th>
<th>Tax Gross Up at Pre-Tax Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Common Equity</strong></td>
<td>$1,297,376</td>
<td>50.00%</td>
<td>10.15%</td>
<td>5.075%</td>
<td>8.57%</td>
</tr>
<tr>
<td><strong>Preferred Stock</strong></td>
<td>$571</td>
<td>0.02%</td>
<td>6.00%</td>
<td>0.001%</td>
<td>0.00%</td>
</tr>
<tr>
<td><strong>Long Term Debt</strong></td>
<td>$1,188,306</td>
<td>45.80%</td>
<td>5.00%</td>
<td>2.290%</td>
<td>2.29%</td>
</tr>
<tr>
<td><strong>Short Term Debt</strong></td>
<td>$108,500</td>
<td>4.18%</td>
<td>1.20%</td>
<td>0.050%</td>
<td>0.05%</td>
</tr>
<tr>
<td><strong>Subtotal</strong></td>
<td>$2,594,753</td>
<td></td>
<td>7.416%</td>
<td>10.91%</td>
<td></td>
</tr>
<tr>
<td><strong>Other Interest</strong></td>
<td></td>
<td></td>
<td>0.17%</td>
<td>0.17%</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td>7.59%</td>
<td>11.09%</td>
<td></td>
</tr>
</tbody>
</table>

### A. Cost of Capital

#### 1. Current Capital Environment

As a preliminary matter, it is worth noting the economic and market conditions that currently prevail. Since the significant market upheaval that occurred in late 2008, the U.S. economy has seen modest recovery and relatively slow growth in many sectors. Interest rates currently remain at historically low levels and market forecasts reflect the expectation that interest rates will increase over the next several years. Since the beginning of 2013, the equity market, as reflected by the Dow Jones Industrial Average, has risen by almost 20%, recently closing above 16,000 for the first time in history. Over the past five years, from November 2008 to November 2013, the Dow has risen in value by 82%. From November 2007 to November 2013, the Dow is up approximately 20%.
2. **Peer Group**

In conducting an analysis of the appropriate return on equity for CMP, we begin with the selection of a proxy group and the Company’s proposed screening criteria that it used to choose a proxy group. CMP’s witness began with a group of 49 domestic utilities that Value Line classifies as electric utilities and excluded companies based on a set of criteria. On the whole, Staff does not take issue with the majority of screening criteria used by CMP’s witness. For instance, selection of proxy members based on publicly-traded companies that pay dividends is essential to a discounted cash flow (DCF) analysis. In addition, companies that are covered by more than one analyst and have an investment grade credit rating provide reasonable assurance that the market-based analysis that underlies a return on equity determination reflects market information. Eliminating companies that have been a party to a recent merger transaction is also consistent with the selection of a risk-comparable sample and with the Commission’s prior approaches to selecting a proxy group. We also recognize that the Company’s removal of proxy members whose regulated operating revenues are less than 90% of total revenues tends to choose companies whose risks may be more aligned with those of CMP. However, we do not agree with CMP’s exclusion of companies whose total regulated electric net operating income is less than 90% of total regulated net operating income. This particular screen has the effect of excluding companies that derive a portion of net operating income from other regulated operations, primarily local gas distribution. This threshold seems to be arbitrary and acts to eliminate companies that may better serve as members of the proxy group than other members that have been chosen by CMP. In response to EX-
010-005, Mr. Stewart provided the screening criteria used to arrive at his final proxy group. Several companies that were initially selected as “electric utilities” and met the other screening criteria were eliminated because their regulated operations were not 90% or more electric in nature. In fact, in a few instances, these companies’ electric operations, which screened them from the proxy group, were not significantly below 90%: PG&E (87.41%); Alliant Energy Corporation (89.77%); Xcel Energy, Inc. (88.42%); Northwestern Corporation (82.82%); and MGE Energy Inc. (81%).

We find that the use of this 90% threshold, in the absence of a more qualitative assessment of the utilities’ operations, eliminated certain companies that may bear a closer risk profile to CMP than other members chosen by CMP for its proxy group. For this reason, in selecting an appropriate risk comparable sample, Staff included all those companies that had been excluded based on the requirement that 90% of more of their regulated revenues must be from electric operations. This had the effect of expanding the sample size from thirteen to twenty-two. It is worth noting that all the companies included had at least 65% of regulated revenue from electric operations.

3. Selected Exclusions

We next review the members of the expanded proxy group to determine whether any should be excluded on the basis of specific characteristics or recent activity. Virtually all members of the preliminary proxy group own some amount

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18 Also excluded on the basis of the 90% electric operating revenue alone were: CMS Energy Corporation (73.07%), Dominion Resources (76.69%), UIL Holdings Corporation (68.75%) and Wisconsin Energy Corporation (66.91%).
of regulated or unregulated electric generation. Utilities that own or control generation are generally perceived as presenting a higher risk profile since they retain the construction and operational risk associated with generating assets unlike electric utilities that are primarily transmission and distribution in nature. To further complicate things, many of the members of CMP’s proxy group (even when amended to include other utilities with non-electric operations more than 10%) own coal or nuclear generating assets that may be subject to increased environmental and safety related costs as compared to other forms of generation such as natural gas. A review of the 10-Ks for the companies included in the larger proxy group reveals that coal and nuclear generation present significant political, environmental and economic risks to shareholders and investors that are unique to any risk factors borne by CMP.

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19 Of CMP’s final proxy group, eight of the members (or their subsidiaries) own only regulated generation. Five proxy members own greater amounts of regulated generation than competitive generation. See CMP Response to ODR-033-001.


21 Some of these coal and nuclear generation assets are summarized as follows: Northeast Utilities (under its subsidiary, Public Service Company of New Hampshire (PSNH)) owning two coal boilers with 150 MW of capacity); American Electric Power (owning and operating through various subsidiaries about 80 generation stations in the United States with a combined capacity of nearly 38,000 MW, 66% of which is based on coal fired plants, including, a recently constructed 600 MW Turk Plant placed into service in 2012 at a cost of $1.7 billion, $1.3 billion of which will be recovered by AEP’s subsidiary, SWEPCO); ALLETE (owning generation that is primarily coal fired); IDACORP (parent of Idaho Power Company which owns partial interests in three coal generation stations); CLECO Corporation (owning power plants that use lignite coal, petroleum coke (petcoke) and western coal); Great Plains Energy (parent company of Kansas City Power & Light, which is owner of Iatan 2, a new 850 MW coal power plant near Weston, Missouri); IDACORP (holding company of Idaho Power Company, which owns two natural gas power plants and holds partial interest in three coal fired generators); NV Energy (owning three older coal fired units with combined capacity of 800 MW); Pinnacle West (parent company of Arizona Public Service which holds nuclear and coal generation).
companies’ generation operations present a profile that is likely to be more risky than CMP’s wires only operations, and could lead one to conclude that all such companies should be excluded from a proxy group for CMP. However, Staff hesitates to recommend such an approach at this time, because doing so would eliminate virtually all companies from the “electric utilities” peer group and result in a meaningless sample size. Staff also does not establish an arbitrary threshold of generation resources (such as the relative percentage of a company’s generation resources when compared to overall net plant) at which point a company’s generation enterprises are found to be too generation intensive. First, doing so would be very difficult based on the existence of publicly available data since utilities’ 10-K reports do not necessarily provide comparable data to enable such an analysis. Furthermore, we note that eliminating companies on this basis alone could result in removal of a company from a proxy group whose other operations (e.g., gas LDC operations) make it more comparable to a company such as CMP.

In reviewing the 2012 10-K reports from the preliminary proxy group, we do, however, find a basis for excluding certain companies. For the reasons more fully explained below, we determine that Hawaiian Electric Industries, Empire District Electric Company and NV Energy should be excluded.

a. **Empire District Electric Company**

   Staff first removes Empire District Electric Company. As shown by the Company’s 10-K and other publicly available data, the Board of Directors of Empire District Electric Company, in response to expected lost revenues associated with rebuilding and recovery of the Joplin, Missouri area as a result of the May 22, 2011
severe tornado, suspended its quarterly dividend for the third and fourth quarters of 2011. In February 2012, the Company’s Board determined that it would reinstate dividend payments at a lower level than prior to May 22, 2011. Staff finds that Empire Electric District’s decision to suspend dividend payments for a period of time, when coupled with the financial circumstances that the company continues to experience as a result of the massive reconstruction efforts of the Joplin, Missouri area presents a risk that is unlike that of CMP or other peer members and which may have a disparate market effect on the Company’s dividend yields and growth expectations. We, therefore, exclude Empire from the peer group.

b. **Hawaiian Electric Industries**

A review of the Hawaiian Electric Industries 2012 10-K indicates that Hawaiian Electric includes both a regulated electric utility and a banking operation (American Savings Bank) that represented 8% of total revenues and 31% of operating income. Staff does not view a company that derives almost one-third of its operating income from banking activities as presenting a comparable risk profile to CMP and has excluded Hawaiian Electric from the proxy group.

c. **NV Energy**

In late September 2013, the shareholders of NV Energy, Inc. approved selling the utility to Berkshire Hathaway. Consistent with the screening methodology employed by CMP, NV Energy should be excluded as a result of recent merger activity.
The final electric company proxy group used by the Company’s witness and as revised by the Staff based on the factors discussed above is as follows:

**TABLE 11**

**Revised Final Proxy Group**

<table>
<thead>
<tr>
<th>Electric Proxy Group</th>
<th>Stewart</th>
<th>Staff</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regulated Revenue &gt; 90%</td>
<td>Screen for Electric Revenue &gt; 90%</td>
<td>Includes Gas Revenue &gt; 65% &amp; Selected exclusion</td>
</tr>
<tr>
<td>ALLETE, Inc</td>
<td>ALLETE, Inc</td>
<td>ALLETE, Inc</td>
</tr>
<tr>
<td>Alliant Energy Corporation</td>
<td></td>
<td>Alliant Energy Corporation</td>
</tr>
<tr>
<td>Cleco Corporation</td>
<td>Cleco Corporation</td>
<td>Cleco Corporation</td>
</tr>
<tr>
<td>CMS Energy Corporation</td>
<td></td>
<td>CMS Energy Corporation</td>
</tr>
<tr>
<td>Dominion Resources, Inc</td>
<td></td>
<td>Dominion Resources, Inc</td>
</tr>
<tr>
<td>Empire District Electric Company</td>
<td>Empire District Electric Company</td>
<td></td>
</tr>
<tr>
<td>Hawaiian Electric Industries, Inc</td>
<td>Hawaiian Electric Industries, Inc</td>
<td></td>
</tr>
<tr>
<td>IDACORP, Inc</td>
<td>IDACORP, Inc</td>
<td>IDACORP, Inc</td>
</tr>
<tr>
<td>MGE Energy, Inc</td>
<td></td>
<td>MGE Energy, Inc</td>
</tr>
<tr>
<td>Northeast Utilities</td>
<td>Northeast Utilities</td>
<td>Northeast Utilities</td>
</tr>
<tr>
<td>NorthWestern Corporation</td>
<td></td>
<td>NorthWestern Corporation</td>
</tr>
<tr>
<td>NV Energy, Inc</td>
<td>NV Energy, Inc</td>
<td></td>
</tr>
<tr>
<td>PG&amp;E Corporation</td>
<td></td>
<td>PG&amp;E Corporation</td>
</tr>
<tr>
<td>Pinnacle West Capital Corporation</td>
<td>Pinnacle West Capital Corporation</td>
<td>Pinnacle West Capital Corporation</td>
</tr>
<tr>
<td>Southern Company</td>
<td>Southern Company</td>
<td>Southern Company</td>
</tr>
<tr>
<td>UIL Holdings Corporation</td>
<td></td>
<td>UIL Holdings Corporation</td>
</tr>
<tr>
<td>Westar Energy, Inc</td>
<td>Westar Energy, Inc</td>
<td>Westar Energy, Inc</td>
</tr>
<tr>
<td>Wisconsin Energy Corporation</td>
<td></td>
<td>Wisconsin Energy Corporation</td>
</tr>
<tr>
<td>Xcel Energy, Inc</td>
<td></td>
<td>Xcel Energy, Inc</td>
</tr>
</tbody>
</table>

22 13 19

B. Estimation Models & Results

1. **DCF Model**

In its very simplest form, a DCF estimate of the cost of equity capital uses the formula $K = \frac{D}{P} + g$, where $K$ equals the cost of equity capital, $\frac{D}{P}$ represents the dividend yield and $g$ is the long-term expected growth rate. Generally,
the data required to conduct a DCF analysis are readily available, but the complexity lies in the calculation of a dividend yield and the selection of an appropriate long-term growth rate. Many different models for the calculation of the dividend yield have been developed to account for the fact that companies declare, pay and may increase dividends at different times throughout the year. In past analyses, this Commission has preferred a quarterly compounding model to the annual compounding model. The annual compounding model is unrealistic in that it does not reflect the fact that most companies pay dividends on a quarterly basis. Thus, we provide calculation using only the quarterly model.

A key component of any DCF analysis and perhaps one of the most controversial inputs is the estimated growth rate for dividends. Company witness Mr. Stewart employs both a constant growth DCF model and a multi-stage DCF model. For the growth rate in the constant growth model, he uses the average of three projections of long-term earnings growth rates from Zacks, Thomson First Call and Value Line. For the three stage DCF model, he uses an average of earnings projections for near term (first stage) growth; a measure calculated by him for the long-term projected growth in Gross Domestic Product (GDP) for long-term (third stage) growth rate; and provides a second state growth rate that reflects a transition from the first stage to the third stage on a geometric average basis. As might be expected, there are numerous methods for determining a long-term growth rate from using analyst’s projections of growth in earnings per share, which have been perceived as being overly optimistic, to using projected growth in gross domestic product (GDP) as a surrogate for long-term growth in earnings and dividends. In recent cost of equity analyses, Staff has used projections
of GDP growth provided by the Congressional Budget Office (CBO) for the growth rate in a DCF analysis. *Northern Utilities Inc. d/b/a Unitil, Proposed Increase in Base Rates, Docket No. 2013-00133, Bench Analysis dated September 12, 2013.*

The Congressional Budget Office (CBO) provides projections of GDP growth. In its recent forecast, the CBO provided a growth forecast of 5.7% for 2015-2018 and 4.3% for 2019-2023. Our analysis employs both the average of the two CBO projections of 5% and the CBO GDP growth forecast of 5.7% for 2015-2018 as a method of bracketing an appropriate range of ROEs for CMP. In addition, Staff also examined analyst's projections of EPS growth for the expanded electric group and the gas LDC group to determine whether the use of the CBO GDP forecasts as a growth rate would unfairly slant the results of the analysis. The average of analyst growth projections as reported by First Call Earnings Growth (Yahoo! Finance) for the expanded electric group was 5.33% and for the gas LDC group was 5.37%. Therefore, the use of growth rates of 5.0% and 5.7% should provide an appropriate means of bracketing an indicated range of ROE.

2. **DCF Analysis**

Staff has employed the quarterly compounding DCF model and provided the calculations in Appendix E. The calculations are largely self-explanatory. To summarize, the current quarterly dividend for each utility as of November 20, 2013 was converted to a “forward” dividend. The model assumes that the companies pay dividends quarterly but those dividends are changed only annually by the company in the middle of the year. Thus, the forward dividend reflects two quarters at the current

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dividend rate and two quarters at a higher dividend rate, increased by the assumed growth rate. To calculate the dividend yield, the resulting forward dividend is divided by the share price for each utility. In recognition of the day-to-day variability in closing share prices, we employed both a 50-day moving average of closing share price and a 200-day moving average of closing share price for each utility as reported by Yahoo! Finance on November 20, 2013. To achieve a range of estimates of ROE, the 5.0% and 5.7% growth rates were added to the calculated forward dividend yields. As noted, Staff employed both a 5.0% and a 5.7% growth rate to bracket the results of the analysis. The resulting ROE estimates for the electric group are summarized in Table 12 below.

### TABLE 12

<table>
<thead>
<tr>
<th>Stock Price As Of</th>
<th>5% Growth Rate</th>
<th>5.7% Growth Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Projected Dividend Yield</td>
<td>Indicated ROE</td>
</tr>
<tr>
<td>11/20/2013</td>
<td>3.88%</td>
<td>3.89%</td>
</tr>
<tr>
<td>50 Day Average</td>
<td>3.94%</td>
<td>3.95%</td>
</tr>
<tr>
<td>200 Day Average</td>
<td>3.94%</td>
<td>3.94%</td>
</tr>
</tbody>
</table>

Consistent with the Commission’s Order and the cost of capital analysis in *Public Utilities Commission, Investigation of Central Maine Power Company’s Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design*, Docket No. 97-580, Order (March 19, 1999), Staff also developed a natural gas distribution utility or “LDC” proxy for use in its DCF analysis. As noted in Docket 97-580, a peer group of gas LDCs provides useful information as a
comparable peer group for CMP. LDCs that do not have significant unregulated operations are, like CMP, primarily “pipes and wires” utilities. That is, they have the responsibility for safely delivering natural gas over their system, but generally do not have responsibility for producing natural gas. LDCs instead procure natural gas and sell it to their customers at cost. The gas LDC group used by Staff consists of the same eight member proxy group recently used by Staff in its DCF analysis for Northern Utilities, a gas LDC doing business in Maine, and includes: AGL Resources, Atmos Energy Corporation, LaClede Group, NiSource, Inc, Northwest Natural Gas, Piedmont Natural Gas Company, South Jersey Industries and Southwest Gas Corporation.

*Northern Utilities Inc. d/b/a Unitil, Proposed Increase in Base Rates, Docket No. 2013-00133, Bench Analysis dated September 12, 2013.* We believe that an analysis that includes both an electric proxy group and a gas LDC group is appropriate for evaluating CMPs ROE and would likely bracket the total risk profile of CMP with the electric peer group being a little more risky than CMP and the gas LDC peer group being a little less risky than CMP. Other than Northeast Utilities and UIL, the companies populating the Electric peer group all own generation assets and thus are less “pipes & wires” utilities than CMP is currently. On the other hand, the companies populating the LDC peer group are very much “pipes and wires” utilities, even those owning interstate transmission pipelines.

The actual DCF analysis for the Gas LDC group was conducted in the same way as for the electric group based on market information on November 20, 2013 and using both a 5% and a 5.7% long-term growth rate. The resulting ROE range for the Gas LDC group is as shown in Table 13 below.
Thus, the DCF analysis for the electric proxy group produces an indicated ROE range of 8.88% to 9.65% and the gas LDC group produces an indicated ROE range of 8.55% to 9.35%. The range of “overlap” between the electric group and the gas LDC group is 8.88% to 9.35%; the mid-point of that range is 9.12%. Because of the factors noted, including that CMP has divested all generating assets while the majority of the electric proxy group retains investment in generation, Staff does not believe that the risk profile presented by CMP lies at the high end of the electric group. Correspondingly, CMP is not a gas LDC, so determining a recommended ROE based on a peer group analysis that consists solely of gas LDCs is inappropriate. While the determination of an allowed ROE in the context of a rate making proceeding always involves a measure of judgment, Staff believes that the indicated ROE for CMP lies in the upper half of the range that represents the overlap between the electric proxy group and the gas LDC proxy group and, based on the DCF analysis, would recommend an allowed ROE of 9.25%.

<table>
<thead>
<tr>
<th>Stock Price As Of</th>
<th>5% Growth Projected Dividend Yield</th>
<th>5% Growth Indicated ROE</th>
<th>5.7% Growth Projected Dividend Yield</th>
<th>5.7% Growth Indicated ROE</th>
</tr>
</thead>
<tbody>
<tr>
<td>11/20/2013</td>
<td>3.55%</td>
<td>8.55%</td>
<td>3.56%</td>
<td>9.26%</td>
</tr>
<tr>
<td>50 Day Average</td>
<td>3.57%</td>
<td>8.57%</td>
<td>3.58%</td>
<td>9.28%</td>
</tr>
<tr>
<td>200 Day Average</td>
<td>3.65%</td>
<td>8.65%</td>
<td>3.65%</td>
<td>9.35%</td>
</tr>
</tbody>
</table>

**TABLE 13**

**Gas LDC Proxy Group Average**
2. **Capital Asset Pricing Model (CAPM)**

As the Commission has previously recognized, results from an analysis using the Capital Asset Pricing Model (CAPM) provide a useful check on the DCF analysis. As described in the practitioner’s guide to the cost of capital prepared for the Society of Utility and Regulatory Financial Analysts (SURFA):

The capital asset pricing model (CAPM) describes the relationship between a security’s investment risk and its market rate of return. This relationship identifies the rate of return which investors expect a security to earn so that its market return is comparable with the market returns earned by other securities that have similar risk...Beta is an indicator of investment risk. It is a measure of the expected amount of change in a security’s price that results from a change in the overall market’s security prices. As such, beta indicates the security’s variability of return relative to the return variability of the overall capital market...Although not developed for use in estimating or determining the allowed return on equity capital to be permitted to a utility by a regulatory commission, the CAPM has been used by numerous commissions (Malko and Enholm, 1985; Cooley, 1981; Harrington, 1981).


The general form of the CAPM is:

\[ K = R_f + \beta (R_m - R_f) \]

where:
- \( R_f \) = risk free rate
- \( R_m \) = return on market
- \( \beta \) = beta
- \( R_m - R_f \) = market risk premium

As a check to the results of the DCF analysis, Staff conducted a CAPM analysis using average beta for both the expanded electric proxy group and the gas LDC group. Staff obtained beta estimates from publically available information as provided by Yahoo! Finance and, consistent with the Commission’s preference as
indicated in Docket No. 97-580, used the actual, current 30-year Treasury rate of 3.88% as the risk-free rate. Staff accepted Mr. Stewart’s calculation of the estimated required market return for the S&P 500 of approximately 12.75%. Staff’s betas for the gas LDC group ranged from 0.27 to 0.69 and averaged 0.46. Staff’s betas for the expanded electric group ranged from 0.02 to 0.85 and averaged 0.37. The wide range of betas and the difference between Staff betas and those used by Mr. Stewart (0.700 to 0.731) may call into question the usefulness of a CAPM analysis. Nevertheless, the results of Staff’s CAPM analysis indicate a range of equity returns of 7.12% to 7.96%.

C. Capital Structure

1. Common Equity Ratio

The Company has proposed a capital structure as shown in Table 10 with a 50% equity ratio. In proposing this 50% equity layer, the Company has cited its significant capital expenditure program and its need to access external financing. As discussed elsewhere in this Bench Analysis, Staff does not believe that the Company’s proposed capital expenditure program reflects capital needs in the rate effective year and beyond and, therefore, is too speculative to be reliable for rate-setting purposes. A recommended equity layer that relies on the level of projected capital expenditure raises questions as more fully explained below. Based on an examination of the annual 10-K reports for the electric companies in the proxy group, it is not clear that the calculations done by Mr. Stewart in Exhibit JDS-13, which purport to show that CMP’s capital expenditure plans are significantly higher than its peer group, are entirely reliable. As

23 Although it should be noted that Mr. Stewart estimated the market return by conducting a DCF analysis of the S&P 500 index and using a long-term growth rate of 10.46%, a rate that Staff believes may be overstated.
noted, most of the members of the electric peer group own generating assets and note in their capital expenditure projections that future costs related to the imposition of more stringent environmental regulations are not included in their expectations.24

In addition, a 50% common equity ratio is higher than the common equity ratio of either the electric proxy group or gas LDC proxy group. Based on AUS Monthly Utility Report for December 2013, the average common equity ratio for the electric proxy group is 47.3% and the average common equity ratio for the gas LDC group is 48.8%. Staff does not believe that the Company has demonstrated that a 50% equity ratio is necessary to attract investment or secure external capital resources during the period of the ARP. In the recent proceedings conducted before the Commission related to raising the minimum equity requirement for CMP from 45% to 47%, the Company stated that its petition to require a minimum common equity ratio of 47% should be granted in order to create greater ratings separation between themselves and their ultimate parent, Iberdrola, SA, particularly in light of the ratings criteria employed by S&P. Specifically, CMP stated that the proposed 47% minimum equity requirement would reduce potential adverse impact on the Company’s credit ratings. In fact, subsequent to the filing the petition with the Commission, S&P removed CMP from its Credit Watch, noting that the Company had requested an increase in the minimum equity ratio and, if successful, CMP’s rating would be affirmed. Central Maine Power Company and Maine Natural Gas Corporation, Petition to Amend Minimum Common Equity Provisions of Merger Order, Docket No. 2012-00511, Order Approving

24 Staff recognizes that Mr. Stewart based his capital expenditure calculations on Value Line projections (Exhibit JDS-13). Staff examined the 10-K reports for the relevant electric group companies and determined that the Value Line projections and the company projections contained in the 10-K were almost the same.
Stipulation (April 4, 2013). The Company has not demonstrated that a higher common equity ratio would be required to maintain its credit ratings and ensure continued access to capital markets. Thus, Staff recommends a common equity ratio of 47% of the total capital structure and has reflected that adjustment in Table 14. The amount of capital by which the common equity was reduced to achieve the 47% equity ratio was allocated proportionately between short-term debt and long-term debt.

2. Short Term Debt

In its proposed cost of capital calculation as shown in the Company’s schedule RRP-6, page 2, CMP includes a cost of capital for a category labeled “Other interest” as an addition to the cost calculations for its proposed capital structure. The “Other interest” cost as reported in RRP-6, page 12 represents the costs associated with items such as customer deposits, revolver fees, loss on reacquired debt and interest and dividend income. CMP expresses the cost as a percent of distribution rate base and adds the percentage cost to the overall cost of capital. This treatment has the curious effect of including a cost component in cost of capital that is not associated with any portion of the capital structure. Rather than show this “Other interest” as a stand-alone cost, Staff has included the $1.4 million cost in the calculation in the overall cost of short-term debt, which CMP had calculated using a commercial paper rate, and increased to percentage cost of short-term debt from 1.2% to 2.47%.

D. Revenue Decoupling Mechanism

We next address the Company’s proposed use of an RDM mechanism and its impact on CMP’s rate of return in this case. Under Maine law, when considering the reasonableness of any rate-adjustment mechanisms proposed by utilities, including
their impact on the “justness and reasonableness” of rates under 35-A M.R.S. § 301, the Commission must consider the impact of any such mechanism on mitigating risks or transferring risks upon a utility’s customers. Title 35-A provides:

**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.

35-A M.R.S. § 3195(6) (emphasis added).

The Company is proposing an RDM to fully decouple sales and profits for residential and commercial customers. In his testimony, Mr. Stewart provides an analysis of the effect of whether a particular jurisdiction had approved a revenue decoupling mechanism on the RRA assessment of regulatory risk and the S&P assessment of the credit supportiveness profiles of the jurisdiction in which members of the proxy group operated and determined that the presence or absence of full or partial RDMs had no effect on the perceived regulatory risk. See Stewart Testimony at 42. On the other hand, Stewart later testifies that he believes that CMP is subject to the risk that its estimate of the impact of conservation programs and the potential for more clean energy resources and conservation measures over the five year period (in response to what appears to be more severe weather conditions) could be understated and too low, which would present a “specific risk for CMP that is only eliminated if an RDM is adopted.” See *id.* at 43. From this testimony, Mr. Stewart at least recognizes that RDM mechanisms tend to insulate utilities from declining revenues associated with conservation or measures, increased energy efficiency and decreases in load growth and have the effect of mitigating the risks experienced by CMP. Despite this
recognition, his analysis does not address the mitigating effect of the Company’s proposed RDM mechanism and its impact on the “justness and reasonableness” of CMP’s proposed rates or requested rate of return. Stewart’s analysis is, therefore, inconsistent with Maine law as well as sound principles of utility ratemaking. In addition, Staff finds Mr. Stewart’s analysis, including his RRA and S&P regulatory and credit quality rankings for those members of the proxy group with full decoupling, partial decoupling, or no decoupling set forth in Table JDS-8, not helpful as a way to meaningfully evaluate whether or not individual members of the peer group are perceived as more or less risky when compared to other proxy members based on the presence or absence of a RDM mechanism.

As more fully described in other portions of this Bench Analysis, Staff does not recommend that the Commission approve an RDM mechanism for CMP. Staff’s recommended rate of return, therefore, does not include any qualitative or quantitative assessment of the impact of such a mechanism on mitigating the risks that may be experienced if additional conservation, efficiency or other measures result in declining sales and revenues for CMP. However, in the event that the Commission is inclined to authorize an RDM mechanism, in keeping with its statutory mandate under 35-A M.R.S. § 3195, Staff believes that the Commission is required to adjust CMP’s authorized rate of return based on the effect of any RDM mechanism on mitigating or the risks borne by CMP or transferring such risks upon CMP’s ratepayers. In such an event, the Commission could authorize a rate of return for CMP that is closer to the lower end of the range of CMP’s peers. Although Staff does not believe that there is empirical support for a specific adjustment to ROE based on the presence or absence of an RDM,
other regulatory commissions have imposed a specific ROE adjustment to an allowed rate of return to address the mitigating effect of an RDM on a utility’s risk profile. For example, the Vermont Public Service Board approved 10.25% ROE for Green Mountain Power that included a 50 basis point reduction due to the risk shifting effect of the utility’s alternative regulation plan and its annual adjustment to base rates to account for increases or decreases in power costs. In Oregon, the PUC adjusted Portland General Electric Company’s authorized ROE by 10 basis points to reflect the reduction in the Company’s risks based on its Sales Normalization Adjustment (SNA) balancing account applied to residential and small non-residential customers as well as a Lost Revenue Recovery (LRR) mechanism applied to large non-residential customers with loads less than 1 average megawatt. And the District of Columbia Public Service Commission reduced Potomac Electric Power Company’s authorized ROE by 50 basis points based on the impact of the Company’s Bill Stabilization Adjustment (BSA) mechanism in adjust its base delivery rates to reflect actual changes in the revenue it collects and to account for changes in usage resulting from energy efficiency programs, variations in weather, or customer response to price increases.25

E. ROE Adjustment Mechanism

Mr. Stewart also recommends a mechanism to annually adjust the allowed ROE for years 2-5 of the proposed ARP based on changes in prevailing interest rates.

Specifically, he proposes a 38 basis point adjustment in allowed ROE for every 100 basis point change in the 20 year Treasury Bond yield. In support of this proposal, Mr. Stewart cites the proposed five year duration of the ARP and the fact that Treasury yields and allowed ROEs are at or near an all-time low. Stewart Testimony at 44. Additionally, Mr. Stewart states that the “ROE which I recommend in this proceeding is developed for application for a one year period.” Stewart Testimony at 48.

The fundamental structure of a market based cost of capital analysis is to determine the return that investors will require in the future from their investments. By its very nature, a cost of equity analysis is forward-looking and incorporates a projection of future dividends and a long-term growth rate in determining an appropriate ROE. As reflected in the comments regarding current capital market conditions, interest rates are currently at historically low levels and are expected to rise in the next several years. The recommended ROE developed by Staff already incorporates the market expectation that interest rates will rise in the future. The Company has not demonstrated that a specific mechanism to adjust for an expectation that is already reflected in the capital markets, and incorporated in the analysis, is appropriate or necessary.

F. Summary of Staff Recommendations

Staff recommends an equity ratio of 47%, an ROE of 9.25% and an adjustment to the cost of short term debt as explained. The overall cost of capital recommended by Staff is 9.88% as shown in Table 14 below.
TABLE 14

Staff’s Proposed Capital Structure for CMP

<table>
<thead>
<tr>
<th></th>
<th>Balance</th>
<th>Ratio</th>
<th>Cost</th>
<th>Weighted Cost</th>
<th>Tax Gross Up at</th>
<th>Pre-Tax Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Common Equity</td>
<td>$1,219,534</td>
<td>47.00%</td>
<td>9.25%</td>
<td>4.348%</td>
<td>7.34%</td>
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<tr>
<td>Preferred Stock</td>
<td>$571</td>
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<td>6.00%</td>
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<td>Long Term Debt</td>
<td>$1,259,633</td>
<td>48.55%</td>
<td>5.00%</td>
<td>2.427%</td>
<td>2.43%</td>
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<tr>
<td>Short Term Debt</td>
<td>$115,015</td>
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<td>2.47%</td>
<td>0.109%</td>
<td>0.11%</td>
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<tr>
<td>Subtotal</td>
<td>$2,594,753</td>
<td></td>
<td></td>
<td>6.886%</td>
<td>9.88%</td>
<td></td>
</tr>
<tr>
<td>Other Interest</td>
<td></td>
<td></td>
<td></td>
<td>0.00%</td>
<td>0.00%</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td></td>
<td>6.89%</td>
<td>9.88%</td>
<td></td>
</tr>
</tbody>
</table>

As detailed elsewhere in this Bench Analysis, Staff also recommends adjustments to the Company’s rate base that would result in a reduction to distribution rate base of over $50 million. As shown below in Table 15, Staff has calculated the revenue requirement effect of a lower rate base and a lower allowed return separately and combined.
### TABLE 15

**REVENUE REQUIREMENT EFFECT**

<table>
<thead>
<tr>
<th>CMP Rate Base</th>
<th>CMP</th>
<th>Staff</th>
<th>Difference</th>
</tr>
</thead>
<tbody>
<tr>
<td>$798,333,000</td>
<td>11.09%</td>
<td>9.88%</td>
<td></td>
</tr>
<tr>
<td>Return</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Revenue Requirement</td>
<td>$88,535,130</td>
<td>$78,875,300</td>
<td>$9,659,829</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Staff Rate Base</th>
<th>CMP</th>
<th>Staff</th>
<th>Difference</th>
</tr>
</thead>
<tbody>
<tr>
<td>$745,887,000</td>
<td>11.09%</td>
<td>9.88%</td>
<td></td>
</tr>
<tr>
<td>Return</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Revenue Requirement</td>
<td>$82,718,868</td>
<td>$73,693,636</td>
<td>$9,025,233</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Combined Effect of lower return and lower rate base</th>
<th>CMP</th>
<th>Staff</th>
<th>Difference</th>
</tr>
</thead>
<tbody>
<tr>
<td>$88,535,130</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$73,693,636</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>$14,841,494</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### IV. IBERDROLA COST ALLOCATIONS

As part of this proceeding, the Commission retained The Liberty Consulting Group (Liberty) to review the categories of IUMC costs allocated to CMP as well as the benchmarking study conducted by PA consulting and determine whether the costs allocated to CMP for services provided by IUMC were reasonable. Based on its review of the PA study and discovery conducted in this case, Liberty concluded that the PA study was not reliable for several reasons, including, that the study was not a true market rate analysis and did not provide the information required to support the competitiveness of the IUSA shared service rates and the reasonableness of costs allocated to CMP. Notwithstanding this observation, Liberty analyzed the trends in
IUMC costs and the allocation of these costs to CMP and did not believe that there were any significant anomalies. Liberty’s findings are included in its December 6, 2013 report entitled “Analysis of the PA Consulting Benchmarking Study and IUMC Cost Trends” that is set forth in Appendix F of this Bench Analysis.

It is worth noting that the Company’s benchmarking study does not comply with prior Commission orders as it is not a market rate analysis and does not “demonstrate that the costs billed under these agreements are just and reasonable.” See Central Maine Power Company, Request for Approval of Reorganization and of Affiliated Interest Transactions to Create Energy East Shared Services Corporation, Docket No. 2003-321, Order Approving Stipulation at 5 (July 24, 2003); citing Central Maine Power Company, et al., Request for Approval of Affiliated Interest Transaction for Two Service Agreements With Energy East Management Corporation, Docket No. 2001-178 Order Approving Stipulation (July 10, 2001) (directing that, “[f]or ratemaking purposes, each of the applicants will provide appropriate market information (which shall mean market rates for such services or, of the applicants conclude that no market rates are available, the explanation supporting the unavailability of market rates) to demonstrate that the costs billed under these agreements are just and reasonable.”). However, based on Liberty’s observations and findings, and given the impracticability of having CMP conduct a market rate analysis as part of this proceeding where the effective date of the proposed rate change is July 1, 2014, Staff does not recommend that any alternative analysis be conducted as part of this proceeding. However, Staff recommends that, in keeping with prior Commission Orders, CMP be directed to perform a true market rate analysis that demonstrates the reasonableness of the Company’s charges from IUMC
one year from the date of the Commission Order in this case or as part of a subsequent rate filing. Failure to include such information in a future proceeding should result in a summary dismissal of any the Company’s rate change.

V. \textbf{SALES FORECAST}

Staff does not take any issue at this time with the sales and revenue projections that are included in CMP’s Sales and Revenue Forecast pre-filed testimony. Staff understands that the Company plans to update these forecasts based on any amendments that may be made to the Efficiency Maine Trust’s Triennial Plan as a result of recent legislation. See \textit{An Act to Reduce Energy Costs, Increase Energy Efficiency, Promote Electric System Reliability and Protect the Environment”} LD 1559, P.L. 2013, Ch. 369. However, Staff reserves the right to comment on any updated filing by CMP that may amend the sales and revenue forecasts over the period of the proposed ARP.

VI. \textbf{REVENUE REQUIREMENT}

A. \textbf{Overview}

Under traditional ratemaking, the determination of a utility’s revenue requirement is typically comprised of two components: the test year analysis and the attrition analysis. In the test year analysis a 12-month historic period is used to establish the company's rate year rate base, expenses and revenues. Historic period levels may be adjusted for known and measurable changes to ensure that the revenue requirement will reflect the rate year. To qualify as a known and measurable change there must be a high degree of certainty that the change has occurred or will occur, and it must be reasonably measurable.

An attrition analysis goes beyond that and makes adjustments to the revenue requirement based on projections, if necessary, to ensure that rate base,
expense and revenue levels will remain in balance, or “matched”, during the rate year. The Commission has previously explained the attrition analysis as follows:

It examines the balance between growth in revenues, expenses and rate base. It is done in the realm of uncertainty, because while the events portrayed in an attrition analysis must have some likelihood of occurrence, they are based on projections or forecasts. We recall the old axiom that the best that can be said about forecasts is that they are sure to be wrong in some respect. We have always examined attrition results with a high degree of skepticism, and we will do so in this case. We will examine each adjustment proposed by CMP, as well as the overall result of attrition study, with great care.26

The Staff examines CMP’s proposed rate year revenue requirement with the above principles in mind.

B. Allocation Factors

1. Transmission/Distribution

The Company has allocated common expense and rate base items between transmission and distribution for the Rate Effective Year and for Rate Years 2 through 5 of its proposed ARP 2104 using FERC formula allocation factors from the 2012 Test Year. Table 16 below sets forth the applicable FERC allocators for the past five years.

<table>
<thead>
<tr>
<th>YEAR</th>
<th>WAGE</th>
<th>PLANT</th>
<th>CUSTOMER</th>
<th>RATE BASE</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>T</td>
<td>D</td>
<td>T</td>
<td>D</td>
</tr>
<tr>
<td>2008</td>
<td>18.82%</td>
<td>81.18%</td>
<td>29.02%</td>
<td>70.14%</td>
</tr>
<tr>
<td>2009</td>
<td>22.17%</td>
<td>77.83%</td>
<td>32.03%</td>
<td>67.97%</td>
</tr>
<tr>
<td>2010</td>
<td>20.18%</td>
<td>79.82%</td>
<td>31.88%</td>
<td>68.12%</td>
</tr>
<tr>
<td>2011</td>
<td>19.06%</td>
<td>80.44%</td>
<td>33.98%</td>
<td>66.02%</td>
</tr>
<tr>
<td>2012</td>
<td>20.06%</td>
<td>80.02%</td>
<td>43.97%</td>
<td>56.03%</td>
</tr>
</tbody>
</table>

As the historic information set forth above clearly demonstrates, for all factors other than the wage allocator there is a clear trend of increasing transmission and decreasing distribution allocation factors. This reflects CMP’s increased focus, investment and expenses for transmission relative to distribution. To the extent this trend continues into the rate effective year, yet rates are set based on the historic allocation factors, then costs which are included in distribution rates will also be recovered again in CMP's FERC formula transmission rates which will be based on the updated factors.

Given this trend, and the fact that the 2013 factor will not be known until May of 2014, the Staff proposes that the allocation factors used to calculate the Rate Effective Year Revenue Requirement be adjusted based on the five year combined Compound Average Growth Rate (CAGR) for the historic period shown above. Applying this CAGR yields the following allocation factors for 2013, 2014 and 2015.

**TABLE 17**

**Projected Allocation Factors**

<table>
<thead>
<tr>
<th>Compound Annual Growth, 2008-2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>CAGR</td>
</tr>
<tr>
<td>10.16%</td>
</tr>
<tr>
<td>Plant Allocator</td>
</tr>
<tr>
<td>Trans</td>
</tr>
<tr>
<td>2013</td>
</tr>
<tr>
<td>2014</td>
</tr>
<tr>
<td>2015</td>
</tr>
</tbody>
</table>

*Note: Distribution Allocators are trended using the 2008-2012 CAGR, Transmission is set as the residual.*
2. **O&M Allocation Factor**

For costs that are allocated between O&M and capital, the test year allocation factor was 65% for O&M and 35% for capital. CMP increased the O&M factor to 70% for years 2013 and beyond based on the fact that the $1.4 billion MPRP transmission project will soon be completed. However, a review of CMP's projected capital spending indicates that the MPRP will extend into the rate year and that there will be other significant capital investments ongoing. Therefore, the Staff sees no basis to increase the test year O&M allocation factor, and recommends that it be carried forward and used to calculate the Rate Year revenue requirement. This decreases the Rate Year O&M expense by approximately $4M.

C. **Regulatory Assets And Liabilities**

1. **COR Liability**

   CMP proposed to mitigate the impact of the Rate Year increase and ensure it earns its ROE during ARP 2014 by accelerating the Cost of Removal (COR) liability. The COR liability was established as part of ARP 2008 and was based on removal costs included in depreciation expense in excess of expected actual removal costs. As of July 1, 2008, the balance of this regulatory liability was $75.6 million and it was scheduled to be amortized over 33.6 years at $2,251,000 per year. As of December 31, 2012, the balance of the COR liability was $65.5 million. The Company proposes to use an incremental amount of $46.7 million of this COR balance during ARP 2014, over and above what would be amortized at the scheduled rate. In

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27 EX 09-38.

28 The Staff recognizes that an offsetting increase should, but has not been made, to Rate Base.
addition to the scheduled amortization of $2,251,000, CMP would amortize an additional $14.4 million in Rate Year 1 to mitigate the rate increase and would then taper the mitigation during the ARP such that by the final year the level would be closer to the baseline amortization. CMP would also flow through to shareholders $18.3 million of the COR liability during the ARP as an enhancement to earnings. Based on CMP’s proposal, at the end of ARP 2014 the COR liability would have a balance of $4.1 million.

The Staff does not necessarily oppose using some of the COR liability for rate mitigation. Staff would view using the COR as something of a last resort, though, since it would deplete money that would otherwise be used to offset the costs of future removals and thus mitigate future rate levels. Therefore, the extent of the COR mitigation would be dependent on the level of the increase that would otherwise result from the revenue requirement established by the Commission in this case. For the reasons discussed in Section VII, the Staff opposes using the COR amortization as an earnings enhancement tool during the ARP.

2. **Environmental Reserve**

As part of ARP 2008, an environmental reserve account was established for costs incurred for the clean-up of manufactured gas plant sites and PCB contaminated facilities. The reserve account was funded by ratepayers through the inclusion of $1.9 million in CMP’s ARP 2008 revenue requirements. As of October 31, 2013, the balance in the Environmental Reserve Account was $5.9 million which reflected $3.5 million flowed back to ratepayers as part of the 2013 annual price change to mitigate the rate impact of costs being recovered for extraordinary storms.
The Company has estimated that it will require approximately $893,500 in funds for environmental clean-up costs projected to occur in 2013 and 2014, and $1,339,500 in funds for the period 2014 through 2019. Recognizing that additional ratepayer funds are not needed to fund this account at this point, the Company has removed the $1.9 million annual funding from revenue requirements. The Staff agrees with this proposal. Staff further recommends that, given the rate increase being requested by the Company, the difference between the amounts projected to be spent during the next five years and the projected balance as of July 31, 2014, approximately $5.1 million, $1.0 million per year be refunded to ratepayers over a 3-year period in the form of rate mitigation amortization.

3. **Power Tax Asset**

As part of its May 1st filing, the Company stated that it has established a regulatory asset associated with the deferred income tax expense incurred during 2011 and in subsequent years associated with its implementation of the Power Tax software. As Staff understands it, the Power Tax software enhanced the calculation of federal and state tax depreciation as well as the proposed level of deferred taxes. In 2011, the application of the Power Tax Program resulted in an increase in $781,000 in tax expense and accumulated tax liability. CMP’s distribution portion of the variance was $537,000. CMP projected that through June 2014 the asset would grow to $1,888,000 which when grossed up for taxes would be $3,174,000. In its November 25th filing, the Company updated its regulatory asset calculation to $7,100,000 (again, distribution share, grossed up for taxes). As part of this filing, the
Company also updated the ongoing revenue requirement effect of this issue to be $1,201,000.

The Staff proposes that the costs associated with the Power Tax regulatory asset be excluded from rate base in this case. First, the Staff would note that the Commission has never approved the creation of this regulatory asset. Second, the tax expenses that were incurred during 2011, 2012 and 2013 that give rise to CMP’s proposed regulatory asset occurred during ARP 2008. These expenses like all other ARP 2008 expenses, are assumed to be recovered in the ARP indexed rates, and the Company should not be allowed to retroactively create a regulatory asset to recover such expenses.

The Staff does not object to the incorporation of the impacts of Power Tax Program in rate year expense as an update to the test year.

D. Rate Base

1. Operating Plant

The Staff is recommending that the Company's Operating Plant Rate Base, with the exception of projects related to the MPRP, be set based on the test year as adjusted using a standard attrition technique of trending based on historic growth rates. Based on Staff's calculations, presented below, this would result in a 3.6% increase to test year levels for all non-MPRP-related operating plant rate base. Staff would use the Company’s estimates for the MPRP-related distribution plant additions. This translates into an overall growth in the distribution plant rate base from the test year to the Rate Year of approximately 9% as compared to the Company’s
growth of approximately 12% and would reduce CMP’s proposed Rate Year rate base by approximately $39M.

TABLE 18

<table>
<thead>
<tr>
<th>Year</th>
<th>Plant in Service</th>
<th>MPRP Annual Additions</th>
<th>MPRP Cum Additions w/o MPRP</th>
<th>MPRP Cum Additions with MPRP</th>
<th>Avg growth</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>$955,488</td>
<td></td>
<td>$955,488</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2009</td>
<td>$999,835</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2010</td>
<td>$1,021,995</td>
<td>$755</td>
<td>$755</td>
<td>$1,021,240</td>
<td></td>
</tr>
<tr>
<td>2011</td>
<td>$1,067,220</td>
<td>$3,293</td>
<td>$4,048</td>
<td>$1,063,172</td>
<td></td>
</tr>
<tr>
<td>2012</td>
<td>$1,110,016</td>
<td>$5,140</td>
<td>$9,188</td>
<td>$1,100,828</td>
<td>3.60%</td>
</tr>
</tbody>
</table>

2. Standard Offer Retainage Account

The Company proposes to include in its rate base the balance of the standard retainage account at the test year level of $182,000. The Company states that this treatment of the standard offer retainage account is consistent with how the account was treated in its last rate case. Since the standard offer retainage account is funded through the standard offer rates and not through T&D rates, it may be appropriate to exclude the retainage account from T&D rate base, in which case the Commission would need to establish the appropriate carrying cost to apply to the retainage account balance.

If however, the Commission determines that the account should be included in T&D rate base, the balance should be updated for known and measurable charges. As of September 30, 2013, the balance in the retainage account was $1,980,495. This amount includes a $1.5 million credit to the account as a result of the

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29 EX-09-08
Commission's prudence disallowance in the credit and collections case. In addition, the amount of the credit ordered in the credit and collections case to reflect the misapplication of standard offer deposits in the amount of $2,593,000 should be incorporated into this balance pending a ruling from the Law Court on CMP's appeal of the Commission's Order. These adjustments increase the standard offer retainage balance to $4,573,445.

3. Working Capital

CMP's revenue requirement includes an amount for working capital, which is intended to capture the effect of timing differences between when CMP pays for expenses and when it receives revenue. CMP uses a lead-lag study to determine it working capital requirements, which is intended to measure the net lag days for various categories of expenses. CMP's expense categories include O&M, standard offer payments, purchased power contracts, taxes, and interest on debt. CMP's has proposed a working capital amount of $18.7 million for the rate-effective period. CMP's estimated test year amount is $12.6 million. (Sup RRP-2, Schedule L)

We have the following concerns about the working capital amounts related to standard offer payments and purchased power.

a. Standard Offer Payments

CMP's proposed rate year working capital requirement for standard offer payments is $5 million. This is based on a net lag of 4 days and an annual expense amount of $456 million. (RRP-8-24) With respect to the lag, we note that the rate year reflects a somewhat longer net lag than the test year. Because we are not aware of any changes in the timing of CMP’s payment obligations to standard
offer suppliers, we assume the increase reflects a general increased lag in customer bill payments. We ask CMP to address the reason for this increase in its responsive filing.

With respect to the expense, CMP has reflected annual payments of $456 million in the test year and the rate year. This appears substantially higher than current levels, which we estimate for 2013 to be in the range of $270 million. As for other items discussed above, Staff recommends that the working capital requirement for standard offer payments be set based on actual 2013 levels. Using CMP’s net lag and our estimated expense for 2013, the working capital requirement would be reduced by $2 million, from $5 million to $3 million.

b. Purchased Power Contracts

CMP’s proposed rate year working capital requirement for purchased power contracts is $2.8 million. Its estimate for the test year is negative $0.2 million. (Sup-RRP-2, Schedule L) CMP’s estimated net lag for the rate year is 15.78 days, which reflects an increase of 17 days compared to the test year. The reason for the increase, according to CMP, is the expiration of several contracts with relatively long payment lags. ODR-044. CMP has reflected a test year and rate year purchased power contract expense of $65 million, which does not appear to be net of the revenue CMP receives from the resale of its purchased power entitlements in accordance with Chapter 307. In addition, it is not clear how (or if) CMP has included its recent contracts with Rollins Wind and Verso Bucksport in either the expense amount or the lag calculation.

As an initial matter, Staff recommends that the working capital requirements for purchased power contracts be recovered in stranded
cost rates rather than distribution rates. Recovery in distribution rates has the effect of over-allocating costs that are clearly stranded cost-related to lower voltage customers, particularly customers at secondary voltage. In the event included in the distribution rates set in this case, however, we recommend that purchased power working capital be set based on actuals for 2013, including the lag associated with contracts in effect during the year and actual contract payments net of Chapter 307 revenue. We estimate the 2013 expense to be $25 million rather than $65 million, which assuming no change to the net lag, would reduce the working capital requirement from $2.8 million to $1.1 million.

E. Expense Adjustments

In projecting its expenses for ARP 2014, the Company developed specific forecasts for some items and proposed escalating the others at the GDP-PI rate, as adjusted to remove medical costs from inflation. This approach is similar to what was used for ARP 2008, and except for the six items noted below. Staff supports CMP’s basic approach to establish the revenue requirement for the Rate Year. However, for the following items CMP’s specific forecasts are insufficiently supported and, as such, do not provide the basis for a known and measurable change. Therefore, rather than using CMP’s specific forecasts, Staff would adjust these expense items by the adjusted GDP-PI rate. The effect of Staff’s changes relative to CMP’s proposed levels is shown below:

Payroll Benefits (401k) - rate year effect ($483,000)
IUMC Charges – rate year effect ($1,640,000)
Insurances, except general liability – rate year effect ($95,000)
Rents/Leases – rate year effect ($162,000)

Utilities – rate year effect ($81,000)

Other O&M – Software and Fees – rate year effect ($489,000)

1. **Payroll**

   In addition to the change described earlier related to the O&M/capital allocation factor, the Staff recommends an adjustment to the payroll expense related to assumed number of employees as well as a reduction relative to the Company’s assumed increases in variable compensation. In RRP 8-4 of its filing, the Company provided historic number of employees.

   **TABLE 19**

<table>
<thead>
<tr>
<th>Actual at Year End</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>March 1, 2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Employees</td>
<td>1,128</td>
<td>1,147</td>
<td>1,189</td>
<td>1,162</td>
<td>989</td>
<td>886</td>
<td>906</td>
<td>920</td>
</tr>
</tbody>
</table>

   The Company has assumed that it would add 24 employees in 2013 and another 24 employees in 2014, bringing the total number of employees by year end 2014 to 954. However, during the August 13, 2013 Technical Conference, the Company indicated that upon review, it appeared that as of July, 2013, the Company only had 900 employees. As the proposed rate year staffing levels do not meet the standard for a known and measurable change, the Staff recommends using as of the end of year 2012. Given that as of half way through 2013, the Company had actually decreased its staff by 6, this is perhaps somewhat conservative. Staff’s adjustment would decrease the Rate Year payroll O&M expense by approximately $2 million.30

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30 The Staff’s recommendation is based upon the most recently filed version of RRP 8-4 (filed November 25, 2013). However, it appears that this version of RRP 8-4
In addition to the number of employees, the Company also assumed that the payroll would increase both due to regular merit increases as well as its variable bonus incentives. It appears that at least the regular merit increases are supported by the current bargaining agreements. Therefore, the Staff would propose to include those increases.

With regards to the Company’s variable compensation costs, it is Staff’s position that any incentive compensation program the Company has established should be allocated between ratepayers and shareholders based on which party is the beneficiary of the metric. For example, it seems appropriate that ratepayers fund the variable compensation programs which relate to receiving safe, adequate and reliable service at just and reasonable rates, while compensation metrics – which inure solely to the benefit of shareholders – should be borne by the shareholders. In response to ODR-153-001, it appears that CMP has made some adjustments to the Revenue Requirement filing associated with the CMP Executive Compensation Plan. Staff believes the Company has not adequately demonstrated how the adjustments were determined and how the methodology for determining exclusions from the revenue requirement is derived.

Additionally, it is Staff’s expectation that the Company will clarify how it allocates the expenses associated with these programs in a subsequent filing.

31 In response to EXM 02-29, Attachment 4, the tables listing the objectives and performance scales include citations to “see detail sheet” however, Staff notes these were not provided as part of the response.
2. Advertising

Of the total of $1,609,000 in test year advertising expense, the Company removed $633,000 as not allowable under Chapter 82 as "Promotional" or "Institutional Advertising". Of the remaining $974,000, the Company included $370,000 for other Informational/Instructional Advertising which includes such items as bill inserts, budget plan, tree trimming, and general advertising which primarily includes labor, not charged to other categories. The Staff proposes to allocate these general advertising expenses between allowable and disallowable costs based on the ratio of other disallowable costs to total other advertising costs.\(^{32}\) This results in proposed adjustment of $267,000 to the test year which, escalated at the Company's assumed GDP-PI less medical costs, is approximately $291,000 in the rate effective year.

3. Bad Debt Expense

In its initial case, CMP proposed a Distribution Bad Debt Expense Factor of 1.4711\%. This factor was calculated using a three-year average of actual bad debt and a Reserve Account adjustment, which attempts to predict future write-offs based on the age of existing accounts. The reserve account was further adjusted in this case to attempt to account for the Commission's decision in the credit and collections case, Docket No. 2010-327. In its supplemental filing, the Company revised its Bad Debt Expense Factor to 1.4215\% since the Company had not removed $500,000 from the 2011 reserve adjustment previously added to account for the Credit and Collections Case as a one-time non-recovery cost.

\(^{32}\) This ratio of disallowable costs = 633/1130 or 56\%.
While the Staff recognizes that a reserve adjustment may be required by GAAP for financial reporting purposes, such an approach appears to be unnecessarily complex and without the needed transparency for ratemaking purposes. This complexity seems to have been exacerbated here given the Commission's credit and collections case. The Staff, therefore, recommends using a straight test year approach, which was utilized in CMP's last rate case. Using this approach should adequately account for the Commission's decision regarding allocation of security deposits since by 2012 CMP had fully implemented its unlimited credit and collection buckets and thus eliminated the huge gap between standard offer uncollectibles and T&D uncollectibles. Utilizing the test year approach reduces the Bad Debt Expense Factor to 1.24%.

4. **Energy Manager Services**

CMP launched Energy Manager in June 2012 and anticipates that the program will grow in popularity, reaching 26,750 enrollees by 2014 and reaching a total of 80,000 enrolled customers by 2018. We believe the costs for this program are sufficiently known and measurable to warrant an adjustment to the test year. In approving CMP’s Energy Manager costs, the Staff expects that CMP will meet its goals for customer enrollment. Staff recommends that CMP submit a report to the Commission twice annually updating customer enrollment numbers and including information on any enhanced functionality of the Energy Manager website.

5. **Asset Management Costs**

The Company proposed increasing the test year level of Asset Management costs from $714,000 to $2,157,000 in the rate year. The Company
attributes this growth to (1) an error in the test year by which Distribution Equipment Replacement Costs were incorrectly booked as transmission and (2) to two new projects to be initiated in 2014. The Staff accepts the inclusion of the Distribution Equipment Replacement Costs. CMP has stated that the test year level for these costs was $397,000. The estimated costs for the proposed new projects do not qualify as known and measurable changes and therefore, Staff proposes that they not be included in rate year revenue requirements.

Adding the Distribution Equipment costs to the unadjusted test year amount, increases the test year level to $1,111,000. Adding an inflation adjustment, yields a rate year level of $1,154,000.

6. **Bill Alert and Outage Alert**

CMP proposes to include the costs associated with two new and yet to be rolled out services: Bill Alert and Outage Manager. Under the Bill Alert Program, customers would receive a weekly alert about their energy usage and costs via any or all of the following channels: e-mail, text message, or recorded message.

Similarly, under Outage Manager, customers receive information that an outage is likely to occur, an announcement that an outage has occurred and the estimated time of restoration and after power has been restored, it alerts the customer that their power is back on.

The estimated costs for these programs are based on discussions with vendors and assumptions on take rates. CMP estimates the costs of the Bill Alert Program to be $444,286 in 2014 and $91,155 in 2015. For Outage Manager, CMP estimates the costs to be $526,924 in 2014 and $163,311 in 2015.
The Staff recommends that these costs not be included in revenue requirements at this time. First, the costs for these yet to be offered programs do not qualify for inclusion as known and measurable changes. In addition, the programs seem to be more in the way of premium services and, as such, to the extent that CMP wishes to offer them, Staff proposes that these services be offered as individually tariffed items. The Staff, therefore, proposes that the costs that CMP has included in the rate year revenue requirement associated with the Bill Alert and the Outage Manager Programs be removed.

7. Banking Transaction Fees

CMP proposes to increase the amount included in revenue requirements for credit card and debit card fees based on an assumed growth rate of 24% in the use of such cards, as well an increase in the cost per transaction from $1.03 in the test year to $1.14 by 2014 due to inflation and "shifting costs reactive to the Durbin ruling".33 Thus, CMP proposed increasing the total costs of such fees from the test year level of $337,000 to $602,000 in the rate effective year (the distribution portion of these fees would be 63.95%).

CMP’s 24% growth rate is based on the growth in credit card use in 2009 and 2010, the height of the great recession. Since that time, credit card use has actually come down. Specifically, in 2011 there were 336,905 card transactions and in 2012 that number dropped to 326,564. During the first half of 2013 there were 158,906 transactions, which would be 317,812 transactions on an annualized basis. In addition,

33 Customer Service Test. at 28.
the costs per transaction actually went down in 2013, apparently as a result of the Durbin ruling.\textsuperscript{34}

The Company's proposed adjustment does not satisfy the known and measurable standard and should be rejected. The Staff proposes using the test year level of transactions and adjusting the fees by the rate of inflation. The adjustment reduces CMP’s proposed distribution revenue requirement by ($163,000).

8. Line Clearance/Vegetation Management

In its initial testimony the Company included the test year level of $25.2 million for this item, which reflects the final year costs for the Company's first five-year cycle trim program. This amount was put in as a placeholder pending responses to the Company's RFP for the second five-year cycle program.

As anticipated, the costs for the second cycle will be significantly lower than for the initial cycle. Specifically, the basic circuit maintenance costs will decrease from $23.0 million in 2013 to $16.0 million in 2014 and $16.9 million in 2015.\textsuperscript{35}

The Company proposed to use part of this second–cycle savings to fund three new or expanded programs: an expanded foliar program; an expanded hazard tree program; and a new "ground to sky" clearance program.

Given the large rate increase proposed by the Company in this case, the Staff recommends that the additional second cycle savings proposed to fund these two aspects of the enhanced tree trimming program be flowed back to ratepayers. Since the costs for hazard tree program exists in a number of buckets and since the scope of the "ground to sky" program has not been defined, the Staff estimates these

\textsuperscript{34} ODR-014-001.  
\textsuperscript{35} ODR-125-001.
additional savings to $1.2 million; consisting of $200,000 for the expanded foliar
program and $1.0 million for the "ground to sky" program.

9. **Liability Insurance**

The Company made an adjustment in the distribution share of
general liability insurance that would increase the test year level by 30%, from $508,000
to $658,000. However, according to the Company that actual increase from 2012 to
2013 was 5.5%.

The Company maintains that the initial adjustment of 30% should be
retained as future increases are likely. The Staff disagrees and proposes that the test
year be adjusted for the 5.5% increase as a known and measurable change, and that
this amount then be subject to the attrition inflation adjustment. This results in an
adjustment to test year revenues of ($78,000).

10. **Legal Expense**

The Company has adjusted its test year Legal Expenses by
$150,000 for "other unknown proceedings". In a response to data request, the
Company stated that it "is not able to predict the exact nature or title of future regulatory
proceedings (both adjudicatory and administrative) however, based on actual
experience and reasonable expectations, CMP has planned for this level of legal
representation in these future other unknown proceedings."

By definition, these expenses do not qualify as known and
measurable changes. Therefore, Staff proposes that this adjustment be excluded from
the Rate Effective year revenue requirements.

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36 EX-009-023.
11. Worker’s Compensation

The Company projected that its worker's compensation costs would grow from the test year level of $714,000 to approximately $950,000 in the rate year. After applying the T&D wage allocator and the O&M allocator the Distribution expense portion of the worker's compensation expense would be adjusted from $371,000 test year level to $531,000. The Company based its projected increase on general trends in the worker's compensation area. The Company's projections are contrary to the Company's own worker's compensation historical performance, which is set forth below in Table 20 below.

<table>
<thead>
<tr>
<th>Year</th>
<th>Spending</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>1,054,000</td>
</tr>
<tr>
<td>2009</td>
<td>1,392,000</td>
</tr>
<tr>
<td>2010</td>
<td>790,000</td>
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<tr>
<td>2011</td>
<td>774,000</td>
</tr>
<tr>
<td>2012</td>
<td>714,000</td>
</tr>
<tr>
<td>2013 (thru 8/22)</td>
<td>527,000</td>
</tr>
</tbody>
</table>

Given the historical levels of spending and the fact that worker's compensation costs are reflected in the overall attrition inflation adjustment, Staff proposes that the adjustment for worker's compensation be based on historic test year levels adjusted for inflation. This results in an adjustment to CMP’s proposed revenue requirement of ($139,000).

12. Postage

37 EX-009-024
38 See Responses to ODR 53-01 and ODR 128-01.
In its May 1st filing, the Company proposed to increase level of postage expense from $1,602,000 in the test year to $1,969,000 in the Rate Year. As part of its updated filing, the Company recognized that $186,000 of the additional expense was included erroneously. Of the remaining proposed adjustment, $139,000 was based on an assumed increase in postage rates and $42,000 was based on application of the inflation adjustment. The Staff proposes to remove $139,000 of the adjustment, as it is neither known nor measurable and represents a double count of the inflation adjustment.

13. **Utilities Expense**

CMP adjusted the test year level of utility expense from $1,288,000 to $1,473,000. CMP’s rationale for the adjustment was that 2012 was abnormally low due to weather. Adopting CMP’s weather rationale, the Staff proposes normalizing the test year by using a 3-year normalization. This results in an adjusted test year amount of $1,394,000.

14. **Meals Expense**

The Company has adjusted the tax impact of the IRS treatment of meals expense from a test year level of $34,000 to a rate year level of $132,000. The Staff has asked for, but has not received, the reason for this increase. Therefore, Staff proposes to use the test year level adjusted for inflation.

15. **Other Revenues – Late Payment Revenue**

CMP proposed late payment revenues of $3.25 million in the rate effective year. The Company based this on forecasts of interest rates as well as an

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39 ODR 061-001.
assumption that late payment revenue from the Residential & Small SOP customers would be lowered by 10% per year for 2013 and 2014 and the Late Payment revenue from Medium and Large SOP customer would stay at the 2012 levels. In its Exhibit, RRP 8-17, CMP provided the following historic amounts of late payment revenue:

**TABLE 21**

*(Amounts in Millions)*

<table>
<thead>
<tr>
<th></th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>G/L Acct 450000</td>
<td>$4.659</td>
<td>$3.92</td>
<td>$3.33</td>
<td>$3.60</td>
<td>$3.22</td>
</tr>
</tbody>
</table>

In response to OPA-002-007, CMP indicated that these revenues are decreasing as more customers move away from standard offer service to competitive providers. However, as shown above, these revenues have varied year-to-year, with no obvious trend. Moreover, CMP’s assumption results in a rate effective year amount that is approximately the same level as the lowest level in the five prior years. The Staff recommends using the most recent three-year average, increased for inflation less medical costs. This results in rate year revenues of $3.3M, an increase of approximately $50,000 compared to CMP’s proposal.

F. **AMI**

A review of AMI costs and savings will be made by Staff following the filing of the AMI audit.

G. **Depreciation**
The Staff is not filing a depreciation study. The Staff's recommendations on this issue will be included in the Examiner's Report based on the submittals of the parties and the testimony at the hearings.

H. **Summary of Findings**

See Appendix G.

**VII. ARP**

A. **CMP's Proposed ARP**

On September 20, 2013, in response to the Commission Order of Partial Dismissal, CMP submitted a revised ARP 2014 proposal. CMP's revised proposal contains an index formula which, similar to prior ARPs, would, apply to all aspects of CMP's distribution operations. Unlike prior ARPs, however, CMP's index formula would be applied to revenues and not to rates, as had been done in prior ARPs, to determine an allowed revenue level in each year. Actual revenues would be reconciled to the resulting allowed revenue through CMP's proposed Revenue Decoupling Mechanism (RDM). In addition, the ROE established to set initial rates in this case would be indexed and could result in additional rate changes. The ARP would also include a new flow-through mechanism for any cost changes resulting from audits of CMP's tax positions which result in cost treatments which differ from those assumed in setting rates initially.

In addition to these new reconciliation and flow-through mechanism, CMP proposes to continue flow-throughs for storm costs, mandated costs, DSM assessments and low-income program costs. With regards to storm costs, CMP proposes to expand the storms eligible for recovery to include storms which result
in interruptions of 10% or more of CMP’s customers, up from the current level of 20%. CMP proposed a sliding scale mechanism starting at a 50% cost flow-through for storms which result in customer interruptions of 10% up to 100% at the 20% of customer interruption level.

As for previous CMP ARPs, CMP’s ARP 2014 index formula includes a productivity offset. Unlike previous ARPs, however, the productivity offset in CMP's ARP 2014 is negative, i.e., it would increase the index. Thus, rather than acting as an offset to inflation, CMP’s productivity factor would increase the price change by adding 1.46% to the annual change in the rate of inflation. Thus, under current inflation projections even without any changes resulting from CMP's flow-throughs, rate increases during the ARP (without mitigation), would be approximately 3% per year.

In addition, as part of its revised ARP 2014 proposal, CMP proposes that the Commission authorize it to amortize an additional $18.3 million of the COR liability without any corresponding decrease in revenue requirements or rates, in other words, apply it directly to its bottom line. This "bonus" amortization would be utilized by CMP as it sees fit in order to enhance the Company's earnings during the ARP. The Staff has not been able to fully analyze the basis for CMP's revised proposed "bonus" COR amortization, however, we assume that it is based on the Company's ARP 2014 projected revenues and expenses which

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40 CMP’s proposed negative productivity factor is based on a base productivity factor between negative .29% and negative .90%; a capital (K) factor, designed to allow CMP to pursue additional capital spending, of between negative .36% and negative .63%; a customer growth factor of negative .37%; and a stretch factor of 0%.
would include the Company’s assumptions of both O&M expenses and capital expenditures, and its target ROE of 10.15% and equity ratio of 50%.

In Section I above, the Staff discussed the ways that ARP 2008 has failed to meet key objectives for ARPs established by the Commission. CMP’s ARP 2014 proposal exacerbates these problems, and highlights additional concerns both about the results of CMP’s prior ARPs as well as the potential deficiencies and consequences of ARP 2014. First, rather than shifting risks away from ratepayers and onto shareholders, CMP’s proposed ARP 2014, through its revenue decoupling, ROE index, tax audit and storm cost flow-through mechanisms, significantly shifts risks onto ratepayers and away from shareholders not only when compared to traditional ARPs, but also when compared to traditional cost of service regulation. Second, these same mechanisms also substantially reduce the likelihood that the ARP will produce predictable and stable rates since rates will change annually based on a number of factors other than inflation.

In addition, by the K factor proposed as part of its productivity offset and by its proposed use of the $18.3 million bonus COR amortization, the Company has, in essence, reverse engineered the results of its CRM. This again places the Commission in the position of having to judge the reasonableness of CMP’s five-year projections of O&M and capital spending in order to assess the reasonableness of CMP’s ARP proposal. This approach, which amounts to a five-year attrition case, is far beyond the usual bounds of rate case attrition projections, and would take the Commission into the realm of pure speculation.
In the Order of Partial Dismissal, the Commission found that the Company's capital budgets lacked sufficient specificity to make a determination as to their reasonableness. This difficulty was made worse by the fact that CMP could "reprioritize" and "rearrange" projects as future events warrant. The Company's revised proposal, which continues to rely on the initial capital spending budgets and continues to contain the caveat that these projects are subject to revision and reprioritization, fails to address these concerns.

In addition, in that Order the Commission also found that the Company's initial proposal failed to adequately account for O&M savings which may result from capital programs. Again, the Company's revised proposal fails to adequately address this issue. Moreover, by basing the $18.3 million bonus COR amortization on both CMP's capital and O&M projections, the Commission must now not only judge the reasonableness of the Company's five-year capital expenditures, but also must judge the reasonableness of CMP's five-year O&M projections.

Thus, the Company's ARP 2014 proposal is both inconsistent with the Commission's objectives for ARPs in general, and also fails to remedy the problems that led to the Commission's partial dismissal of CMP’s original proposal. We describe in further detail below our specific concerns with particular components of CMP’s ARP 2014 proposal. For the reasons noted in Section I, we recommend that no ARP be approved for CMP at this point in time. However, to the extent that the Commission determines that an ARP is the appropriate form
of regulation for CMP on a going forward basis, the Staff sets forth an alternative ARP proposal for the Commission’s consideration.

B. CMP’s Revenue Decoupling Proposal

CMP seeks approval of a revenue decoupling mechanism (RDM) covering base distribution revenues. CMP proposes to track monthly, for each of two RDM classes (Residential and Commercial/Industrial), the difference between target and actual billed distribution revenues on a calendar year basis. If monthly billed revenue is less than the revenue target for the RDM class, the shortfall will be deferred for recovery from customers in that class. If billed revenues exceed the target, the excess will be deferred for refund to customers. To avoid potentially large rate impacts, CMP would examine the cumulative deferral for the six month period ending December 2014 and determine at that time if an interim reconciliation is necessary. CMP proposes to implement an interim adjustment as on July 1, 2015 if the cumulative deferral diverges from the target by 5% or more. After that, an interim surcharge/credit may be triggered when billed distribution service revenues diverge from the target by plus or minus 2.5%.

Revenue decoupling has traditionally been used to break the link between sales and profits in the context of utilities’ conducting energy efficiency and conservation programs. Because incremental sales mean incremental profits, utilities have a substantial disincentive regarding the success of these programs. Staff agrees that some mechanism to address this disincentive (either through decoupling or a lost revenue adjustment) may be appropriate when utilities are actually conducting energy efficiency programs and, thus, have a large degree of control over their effectiveness. However, since utility restructuring in 2000, Maine T&D utilities do not conduct efficiency
programs and have little or no control over their effectiveness. In these circumstances, a revenue decoupling mechanism serves primarily to transfer business risk from the utility’s shareholders to ratepayers. For the reasons discussed below, Staff opposes the adoption of a RDM for CMP.

CMP notes Maine’s prior experience with revenue decoupling in the early 1990’s. As a result of a severe economic recession that occurred shortly after decoupling was implemented, substantial deferrals were booked because of declining sales and controversy arose over proposed rate increases to recover the deferred amounts. Ultimately, CMP’s wrote-off a substantial amount of the decoupling deferrals. CMP also references a legislative report on revenue decoupling submitted by the Commission, the Public Advocate and the Office of Energy Independence on January 31, 2008 (the “Report”). This Report did not make any recommendations regarding whether revenue decoupling should be adopted in Maine, but did make recommendations on what should be considered when implementing an RDM.

The primary rationale offered by CMP for its RDM is that its sales and, thus revenues, may be lower than projected as a result of customer energy efficiency activities. JAL (I) at 1-3. Specifically, CMP refers to the Efficiency Maine Trust (EMT) programs intended to achieve the maximum amount of cost-effective efficiency, and to the opportunities for customer load reductions resulting from the implementation of advance metering infrastructure (AMI). JAL (I) at 3. However, CMP’s RDM proposal would not be limited to lost sales from efficiency, but would include lost sales for any reason—including weather and economic conditions. JAL(II) at 3. This is the case even though CMP acknowledged the problems caused by an unrestricted decoupling
mechanism in the early 1990’s and the recommendation in the 2008 Report that weather and economic normalization mechanisms should be considered in adopting a decoupling mechanism. The Staff does acknowledge the difficulty in designing a specific energy efficiency lost revenue adjustment or an economic normalization adjustment to a RDM. However, in the Staff’s view, these adjustments can be developed, and the fact that doing so would be difficult is not a reason for adopting an unrestricted RDM as proposed by CMP.

Although not the primary rationale for its proposed RDM, CMP states that the mechanism will remove its general financial disincentive regarding EMT and AMI programs. JAL (I) at 3,7. Staff does not agree that this would be the result. Although the RDM would remove the link between CMP’s sales and profits, CMP would still have an incentive to minimize rate increases associated with efficiency and conservation so as to reduce customer complaints and concerns regarding its overall level of its rates and to maximize the portion of allowed rate increases that cover actual cost increases and serve to increase returns. Moreover, the RDM would not apply to transmission rates, which are becoming an increasingly large proportion of CMP’s overall revenue. Additionally, while CMP notes that a RDM will eliminate any disincentive to leverage its AMI system for the benefit of customers, it does not give any details of what it will do differently regarding AMI that it would not do if a RDM is not approved. Indeed, the Commission’s approval of CMP’s AMI project was predicated on it leveraging its AMI system for the benefit of customers. Order Approving Installation of AMI Technology, Docket No. 2007-00215(II) (Feb. 25, 2010). CMP’s RDM does not seem to be intended
to incentivize it to do more with its AMI, but simply to insulate it from revenue losses that may occur through energy efficiency opportunities available to customers through AMI.

CMP does not make a case that predicting sales and revenues over the next several years is any more difficult than such predictions in the past—in which CMP operated without a RDM. Moreover, while CMP does not have control over EMT programs that might lower sales below forecasts, it does have control over certain aspects of increasing sales, such as for efficient electric heat, electric vehicles and economic development, and it may be desirable from a policy perspective for CMP’s incentive to be aligned with such growth.

In addition, Staff notes that in this case the proposed RDM may be masking the magnitude of CMP’s rate increase proposal. This is because, as noted above, CMP’s sales forecast reflects EMT program funding at the “Base SBC” level and not at the higher funding levels recently authorized by the Legislature. All else equal, this means that its projected sales are overstated and its required rate increases understated. Finally, Staff notes that a difficulty in predicting future sales is of much less significance when a utility is not operating under a multi-year rate plan, as Staff proposes for CMP. This is because the utility can file for a rate increase if sales turn out to be significantly lower than projected.

1. Alternatives to CMP’s RDM Proposal

While Staff does not recommend approving CMP’s RDM, if the Commission does allow for revenue decoupling, there are alternatives that it may wish to consider. As an initial matter, the Commission should first consider for what purpose an RDM is intended. The potential purposes include addressing (1) disincentives for
conservation and (2) sales/revenue forecast risk. Within the latter category, there are RDMs that can shift the entire risk (as proposed by CMP), or share the risk between shareholders and ratepayers.

As noted above, CMP is proposing full decoupling and would recover its target revenue regardless of the reason for the actual differences between projected and actual sales. CMP does not propose to normalize for weather fluctuations or economic cycles, or to target what differences are actually due to efficiency measures. CMP has indicated that a mechanism to normalize for economic cycles would be too difficult to implement. 11/1/13 Transcript, p 112, lines 12-14. CMP does not propose a weather normalization adjustment either, though it states that it could be done but does not believe such an adjustment is necessary. Id. lines 14-18.

If the Commission determines that an RDM is necessary or desirable to address disincentives for conservation, it should consider an approach referred to as limited decoupling. In this approach, a true-up occurs only when revenue deviates from allowed revenue for specific reasons, such as efficiency measures. In this instance, a weather normalization mechanism and economic adjustment mechanism would be necessary to exclude the losses in sales that are not attributable to efficiency. Another type of decoupling referred to as partial decoupling may also be considered if the Commission determines it is necessary or desirable to shift some but not all of the sales forecast risk. In such mechanisms, a utility recovers only some of the difference between the allowed revenue and the actual revenue. For example, if the utility’s revenue is lower than expected at the time of the true-up, the utility receives a percentage of the difference between actual revenue earned and the allowed revenue.
As noted above, the 2008 Report to the Legislature recommended that the adoption of any decoupling mechanism in Maine should be accompanied by periodic reviews to determine, to the extent possible, if the mechanism is actually working to change the behavior of the applicable utilities. Report at 16. Thus, if an RDM was adopted in this case, such a review should be required and continuation of the mechanism conditioned on a Commission finding that the mechanism is having the desired effect.

2. Revenue Decoupling in Other States

Other states that have utilities that do not administer energy efficiency programs have allowed RDMs or other mechanisms that reduce the link between sales and profits. In Oregon, for instance, Portland General Electric (PGE) was allowed to have a Sales Normalization Adjustment (SNA). The SNA compares actual weather-adjusted revenues that are collected on a per-kWh basis with those that would be collected with a fixed per-customer charge. The difference is accumulated in a balancing account and refunded or collected over a future period. While PGE does not administer energy efficiency programs, the Oregon Commission found that it did have influence over customers’ energy decisions and because of this, it conditioned any future extensions of the SNA on PGE submitting an assessment of the effectiveness of the mechanism in mitigating the utility’s disincentives to promote energy efficiency.


In Vermont, where the utilities also do not administer energy efficiency programs, the Vermont Public Service Board has adopted rate adjustment
mechanisms for Green Mountain Power (GMP) that act to partially decouple sales and profits. Under this ratemaking approach, GMP rates are adjusted quarterly based upon the difference between actual power costs and projected costs trued up based on actual sales volumes, and adjusted annually pursuant to an earnings sharing rate mechanism. The Vermont Public Service Board noted that while these ratemaking mechanisms do not represent full decoupling of sales and earnings, they do reduce the linkage between earnings and sales. The Board noted that because energy efficiency programs are administered by Efficiency Vermont, “GMP has limited ability to undermine efficiency efforts and in light of this role, it is unclear what additional benefits would be provided by broader decoupling.”

Both the Oregon Public Utilities Commission and the Vermont Public Service Board allowed for a reduction in the utility’s ROE in recognition of the shifting of risk toward ratepayers due to decoupling. Vermont Public Service Board, Green Mountain Power Application for Alternative Rate Plan, Docket Nos. 7175 and 7176, Order at 3 (Dec. 22, 2006 (2006 WL 3930867); Oregon Public Utilities Commission in the Matter of Portland General Electric Company, Order No. 09-020 at 22(Jan. 22, 2009) (2009 WL 214804). Such an adjustment was also noted in the 2008 Report which indicated the elimination of a utility’s sales risk that occurs due to RDM should be offset to some degree by a lower cost of capital for the utility. Report at 11. Additionally, 35-A M.R.S. § 3195(4) requires that in determining the reasonableness of
any rate-adjustment mechanisms, the Commission shall consider any transfer of risk from utility to customers in determining the utility’s allowed rate of return.

C. Productivity Offset

1. Overview

In this section, we review the productivity analysis presented by CMP and present additional analysis to aid the Commission in determining a fair, just, and reasonable productivity offset factor ($X^{\text{Consolidated}}$ as referred to in Sup-Lowry-3 Testimony at 3) to the basic inflation adjustment contained in the ARP formula. At this point, Staff does not have a specific recommendation for this offset factor, as reasonable differences in underlying assumptions result in different values. Based on the analysis to-date, it appears that the $X^{\text{Consolidated}}$ factor (X factor) revolves around 0%, indicating that CMP’s costs and revenue should grow simply at inflation, as represented by GDP-PI. However, we have also requested that CMP provide certain additional analysis which will inform our final recommendation.

In contrast to prior ARPs in which the X factor was positive and was an offset, i.e., a reduction, to inflation, in this case CMP has proposed a negative X factor of 1.46%. This implies that CMP’s costs will increase at rates substantially greater than inflation over the next several years. Staff notes that, based on information provided by CMP, there are no distribution utilities in the U.S. with similar style ARPs that feature a negative productivity offset.41 In fact, as also shown in that same data response, of all utilities that have had similar style ARPs, only one, a government-owned utility in Australia, has ever had a negative X factor.

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41 See Response to EXM-019-009 (North American-Style Indexation).
CMP’s proposed X factor is supported by the analysis and testimony of Dr. Lowry, who estimated the X factor to be in a range from -1.02% to -1.90%. (CMP proposes to use the midpoint of the range.) Dr. Lowry’s X factor is made up of five discrete components: (1) a productivity differential, ranging from -0.05% to -0.55%; (2) an input price differential, ranging from -0.24% to -0.35%; (3) a stretch factor of 0.00%; (4) a K factor, ranging from -0.36% to -0.63%; and (5) a customer growth offset factor of -0.37%. The range for the productivity and input price differentials is driven by differences in the sample set. Analysis using the Upper Northeast region for the sample set results in the -1.90% X factor. The Upper Northeast is defined as upstate New York plus New England, and the set includes 14 utilities, two of which are Iberdrola companies (CMP and New York State Electric & Gas). Analysis using the Broad Northeast region results in the -1.02% X factor. The Broad Northeast is defined as New York, New England and the mid-Atlantic states south to Washington D.C., and the set includes 24 utilities.

The productivity and input price differentials, together, comprise the base productivity offset. Dr. Lowry’s ten year analysis period (2002-2011) suggests that these differentials have been negative for these groups of utilities relative to the entire U.S. private business sector. However, the negative magnitude of the X factor for CMP is increased by Dr. Lowry’s proposed K factor and customer growth factor, and not decreased by any positive stretch factor. These X factors presume that distribution utility costs in the Northeast in general, and CMP in particular, will increase substantially more than the rate of inflation over the next several years.
Before addressing each of the components of the formula, we note a basic weakness in the analytical approach proposed to be used by both Dr. Lowry and the Staff. The approach establishes an index for each year *in the future* (2014-2019) based upon a formula for which key component parts are based upon *the past*, thus assuming that observations of the recent past reliably predict outcomes over the next five years. Although the inflation component, GDP-PI, will be based on the actual observed inflation rate in each prior year, the productivity and input price differentials remain constant, derived from trends observed in the recent past (the historic ten year average). While such an approach is warranted to avoid having to recalculate these differentials from year-to-year, it raises issues as to whether the historic time period used is representative of the future time period, and whether any adjustments are appropriate to recognize that the future will not look exactly like the past. To some extent, a stretch factor can account for such adjustments. For instance, operational efficiencies gained through new smart grid technologies might increase utility industry productivity faster than has occurred in the recent past, warranting a more positive stretch factor. Also note that customer growth, while presented as a fixed value based upon a forecast, could be calculated based upon actual customer growth and adjusted from year to year. See November 1, 2013 Technical Conference (November 1 Tr.) at 51.

We also note that if the Commission decides against revenue decoupling and adopts an ARP with a price cap index similar to CMP’s previous ARPs, further analysis on the X factor will be required. This further analysis is required because, as noted by Dr. Lowry in his testimony, the output component of a productivity
analysis assuming a revenue cap (as in this case) is based on number of customers, whereas for a price cap it would be based on kWh sales. See Sup-Lowry Testimony at 10-13. Staff notes that the Alberta Utilities Commission (AUC) recently agreed with this perspective in their distribution performance-based regulation rate regulation initiative.  

2. **ARP Formula Components**
   a. **Inflation**
      GDP-PI has been utilized as the inflation measure in previous CMP ARPs. While GDP-PI may not be the most robust representation of industry input inflation (GDP-PI is a measure of macroeconomic output inflation), we agree that it is an appropriate measure of inflation to utilize in this case. GDP-PI is a readily available and familiar measure for inflation.

   b. **Base Productivity Offset (Productivity and Input Price Differentials)**
      i. **Sample Set**
         As noted above, CMP provided two sensitivities of the potential productivity and input price differentials based upon two sample sets of electric utilities: the Upper Northeast and the Broad Northeast. The results of these two sensitivities alone illustrate the inherent variability in calculating productivity and input price differentials. Applying the same methodology to data provided by CMP, Staff calculated productivity and input price differentials based upon a national sample set. A summary of the results is presented in Table 22.

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42 *Alberta Utilities Commission, Rate Regulation Initiative, Distribution Performance-Based Regulation*, Proceeding No. 566, Decision 2012-237 at 82 (September 12, 2012).

43 See Response to EXM-021-002
TABLE 22

<table>
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<th>Broad Northeast</th>
<th>National</th>
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<tbody>
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</tr>
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<td>-0.24%</td>
<td>-0.05%</td>
</tr>
<tr>
<td>Total</td>
<td>-0.90%</td>
<td>-0.29%</td>
<td>-0.39%</td>
</tr>
</tbody>
</table>

CMP noted that the Upper Northeast is preferred by Bench Staff. To clarify, it was Bench Staff in Docket No. 99-666 that favored the Upper Northeast sample in CMP’s productivity analysis. See *Maine Public Utilities Commission, Central Maine Power Company Alternative Rate Plan (ARP2000)*, Docket No. 1999-666, Bench Analysis at 37-40 (June 22, 2000) (Docket No. 1999-666, Bench Analysis) for rationale. However, in that case Bench Staff conducted other sensitivities for consideration, including one using a sample set of 113 electric utilities over the 17-year period 1982-1998. Id. at 26. CMP, in the ARP 2008 case, in hopes of alleviating conflict, utilized an Upper Northeast sample. See *Maine Public Utilities Commission, Central Maine Power Company Alternative Rate Plan (ARP2008)*, Docket No. 2007-215, May 1, 2007 Testimony of Mark N. Lowry at 26.

In this case, CMP prefers the Broad Northeast sample set. CMP notes that “Dr. Lowry believes that there is no solid empirical evidence supporting New England and upstate New York over the broader Northeast as an O&M productivity peer group for CMP. There are some arguments against the use of … (the Upper Northeast)… peer group. First, only 16 companies are available for inclusion. One of these is CMP, and two others are owned by Iberdrola.”44 Revision of the

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44 See Response to EXM-011-002.
productivity offset analysis to include capital has further reduced the Upper Northeast sample set to 14 companies, two of which are owned by Iberdrola.

The limited sample size and geographic scope of the Upper Northeast sample (and to a lesser degree, the Broad Northeast) should also be considered in the context in which the data are being used. Specifically, the productivity and input differentials would be used as an offset to inflation as represented by GDP-PI, a national level statistic. Because the inflation factor to be utilized in the ARP formula does not account for regional differences in input price inflation, a national sample set could be preferable.

Another issue to consider in selecting the peer group is the extent to which one desires, via the ARP, to simulate the outcome of competitive markets versus reduce potential windfall gains or losses.45 Dr. Lowry states “using the productivity trend of the entire industry to calibrate X is tantamount to simulating the outcome of competitive markets. A competitive market paradigm has broad appeal.”46 Conversely, a more regional analysis tailored to a specific utility’s local conditions may better reduce potential windfall gains or losses.

ii. **Time Period**

Another parameter that can strongly influence the results is the length of time included in the analysis. Consensus amongst experts suggests that at least ten years is necessary.47 However, experts have different

45 See Sup-Lowry Testimony at 13-14.

46 See Sup-Lowry Testimony at 13.

47 *Alberta Utilities Commission, Rate Regulation Initiative, Distribution Performance-Based Regulation*, Proceeding No. 566, Decision 2012-237 at 64 (September 12, 2012) (AUC Decision).
preferences as to a preferred sample time period. Dr. Lowry has generally conducted
his analyses over a 10-15 year time frame. NERA Economic Consulting (NERA), on the
other hand, prefers to use the longest time period possible as the longer time period,
absent any strong evidence for “structural breaks” in the macro-economy, tends to
better reflect long-term trends.\(^{48}\) While in this case Dr. Lowry notes that such a long-
term time period can be controversial,\(^{49}\) he has also noted that “recent empirical results
and NERA’s testimony persuaded him that a minimum of 15 years is typically more
desirable.”\(^{50}\)

In addition, in this case, using a longer time period
would help mitigate any skewing effect that the severe recession of 2008-2009 would
otherwise have on the results. While recessions are common, the severity of the 2008-
2009 recession is not.\(^{51}\)

To approximate the variability that would result from
using different time periods, Staff blended the results of Dr. Lowry’s analysis from the
ARP2008 case with his results in the present case. See Maine Public Utilities
Commission, Central Maine Power Company Alternative Rate Plan (ARP2008), Docket
No. 2007-215, May 1, 2007 Testimony of Mark N. Lowry at 28 and 32 (Tables MNL 2
and 4). The results are presented in Table 23.

\(^{48}\) See, for instance, CMP ARP 2000, AUC Decision 2012-237.

\(^{49}\) See November 1 Tr. at 13.

\(^{50}\) AUC Decision at 63.

\(^{51}\) We note that Dr. Lowry recommended to the Alberta Commission that the
recession years 2008 and 2009 be excluded from the analysis. Although in that case
he specifically noted the effect on volumetric output indexes, his recommendation
highlights the severity of the recession and its impact on potentially skewing results.
See AUC Decision at 66.
### TABLE 23

<table>
<thead>
<tr>
<th></th>
<th>Upper Northeast</th>
<th>Broad Northeast</th>
<th>National</th>
</tr>
</thead>
<tbody>
<tr>
<td>10 years</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Productivity Differential</td>
<td>-0.55%</td>
<td>-0.05%</td>
<td>-0.34%</td>
</tr>
<tr>
<td>Input Price Differential</td>
<td>-0.35%</td>
<td>-0.24%</td>
<td>-0.05%</td>
</tr>
<tr>
<td>Total</td>
<td>-0.90%</td>
<td>-0.29%</td>
<td>-0.39%</td>
</tr>
<tr>
<td>15 years</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Productivity Differential</td>
<td>-0.55%</td>
<td>-0.22%</td>
<td>-0.43%</td>
</tr>
<tr>
<td>Input Price Differential</td>
<td>0.88%</td>
<td>0.95%</td>
<td>1.00%</td>
</tr>
<tr>
<td>Total</td>
<td>0.33%</td>
<td>0.73%</td>
<td>0.57%</td>
</tr>
<tr>
<td>18 years</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Productivity Differential</td>
<td>-0.11%</td>
<td>0.17%</td>
<td>0.00%</td>
</tr>
<tr>
<td>Input Price Differential</td>
<td>0.31%</td>
<td>0.37%</td>
<td>0.41%</td>
</tr>
<tr>
<td>Total</td>
<td>0.22%</td>
<td>0.54%</td>
<td>0.41%</td>
</tr>
</tbody>
</table>

As shown, extending the time period of the analysis appears to substantially increase the base productivity offset across all sample sets. However, we note that the Table 2 results are illustrative only because of the blending of Dr. Lowry’s prior and current analyses, which are not completely comparable. Therefore, in its responsive filing CMP should provide results for the productivity and input price differentials based upon data back to 1993, as was done when developing the O&M productivity analysis in Dr. Lowry’s initial testimony in this case.

c. **K Factor**

Dr. Lowry proposes a K factor of -0.36% to -0.63% for CMP. The K factor would provide additional revenues for CMP’s projected capital spending. The K factor serves as an alternative to other mechanisms, such as a capital cost tracker that recovers expenditures that are typically related to discrete large projects.
often undertaken for safety or other reasons (for instance, see some of the Ontario Incremental Capital Module approvals\textsuperscript{52} or the NSTAR PBR plan\textsuperscript{53}). The K factor developed in this particular case is an original and unique proposal.\textsuperscript{54}

K factors have not been widely utilized. NERA states that “K factors are generally not included in PBR plans because they can dampen efficiency incentives.”\textsuperscript{55} The Ontario Energy Board has also rejected the use of a K factor.\textsuperscript{56}

As noted above, the purpose of the K factor is to generate additional revenue for CMP’s projected capital spending by hard-wiring in a series of pre-determined rate increases over the ARP period. In this sense, it is not unlike CMP’s originally proposed approach, which was rejected by the Commission. Thus, Staff does not support CMP’s proposed use of the K factor. Furthermore, as noted above, (in Section II) the need for such substantial increases in CMPs capital spending may at least in part be a function of underspending under the prior ARPs. Table 24 below shows CMP’s capital productivity over the course of CMP’s previous two ARPs, which, although positive, appears may not to have been sustainable.\textsuperscript{57}

\textsuperscript{52} See Response to EXM-021-11.
\textsuperscript{53} See Sup-Lowry Testimony at 21.
\textsuperscript{54} See Response to EXM-021-15.
\textsuperscript{55} Alberta Utilities Commission, Rate Regulation Initiative, Distribution Performance-Based Regulation, Proceeding No. 566, NERA Economic Consulting, Update, Reply and PBR Plan Review for AUC Proceeding 566 – Rate Regulation Initiative at 36 (February 22, 2012).
\textsuperscript{56} “The Board concludes that there is no need for a capital investment factor in this 2nd Generation IRM plan. Those distributors with an inordinate capital spending program can be accommodated through rebasing.” Ontario Energy Board, Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario’s Electricity Distributors at 37 (December 20, 2006).
\textsuperscript{57} See Sup-Lowry Testimony at 27-32.
TABLE 24

<table>
<thead>
<tr>
<th>Year</th>
<th>O&amp;M Productivity growth rate</th>
<th>Capital Productivity growth rate</th>
<th>Total Productivity growth rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>2002</td>
<td>0.44%</td>
<td>4.38%</td>
<td>2.29%</td>
</tr>
<tr>
<td>2003</td>
<td>2.19%</td>
<td>3.58%</td>
<td>2.85%</td>
</tr>
<tr>
<td>2004</td>
<td>6.86%</td>
<td>3.74%</td>
<td>5.40%</td>
</tr>
<tr>
<td>2005</td>
<td>3.68%</td>
<td>3.72%</td>
<td>3.70%</td>
</tr>
<tr>
<td>2006</td>
<td>-5.21%</td>
<td>3.17%</td>
<td>-1.17%</td>
</tr>
<tr>
<td>2007</td>
<td>1.68%</td>
<td>2.40%</td>
<td>2.02%</td>
</tr>
<tr>
<td>2008</td>
<td>-1.35%</td>
<td>1.61%</td>
<td>-0.08%</td>
</tr>
<tr>
<td>2009</td>
<td>-10.36%</td>
<td>1.53%</td>
<td>-5.85%</td>
</tr>
<tr>
<td>2010</td>
<td>14.80%</td>
<td>2.41%</td>
<td>9.77%</td>
</tr>
<tr>
<td>2011</td>
<td>-0.66%</td>
<td>-4.35%</td>
<td>-2.15%</td>
</tr>
<tr>
<td>Annual Average 2002-2011</td>
<td>1.21%</td>
<td>2.22%</td>
<td>1.68%</td>
</tr>
</tbody>
</table>

As the benchmarking results presented below indicate, CMP appears to have a level of capital productivity that is one of the highest in the nation. However, these results do not provide any insight into the question of whether CMP’s high ranking reflects improvements in efficiency as opposed to deferrals of capital spending that should have occurring over the period. To the extent the former, this result would demonstrate that the ARP mechanism may be considered to have functioned as intended. On the other hand, if it was the latter, the results could also indicate flaws in the basic ARP mechanism, or inadequate design features, such as poorly designed service quality metrics or lack of capital stock maintenance metrics. To the extent CMP must now “catch up” to compensate for prior capital spending levels
that were unsustainable, it raises questions about the extent to which ratepayers should bear these costs, as they would if CMP’s K factor were to be adopted.

In addition to this policy question, the econometric model upon which the K factor was derived suffers from certain statistical weaknesses that render the results suspect. In developing a multivariate statistical model, the selection of explanatory variables is an important part of constructing a robust and accurate representation of data patterns. Statisticians employ factor analysis or principal component analysis techniques to parse a set of possible explanatory variables down to those variables that are significant. Dr. Lowry did not conduct these analyses, and does not appear to have examined many additional variables not included in the final model. Not conducting such an analysis can result in a statistical model that appears to have a high $R^2$, suggesting high explanatory power, but may not be due to the potential for highly correlated underlying variables. While an adjusted $R^2$ helps to

58 Dr. Lowry states that capital productivity growth will be difficult to sustain (See Response to EXM-021-017).

59 Note that, earlier in this proceeding, the Commission observed:

that CMP’s CRM [Capital Expenditure Recovery Mechanism] proposal has highlighted an interesting problem, namely how to deal with under-investment during one ARP when moving to the next. For example, an ARP without specific capital commitments could provide the utility with an opportunity to allow its system to degrade in order to keep profits high. If the next ARP does contain such commitments (and recovery) the utility might have the opportunity to recover the cost of capital that arguably should have been spent in prior years. Put another way, moving from an RPI-X regulatory system as a discipline on management behavior to a capital program of the kind proposed by CMP is especially problematic because it could reward underinvestment by a utility.


60 See November 1 Tr. at 61-64.

61 Sup-Lowry Testimony at 53 states an adjusted $R^2$ of 0.956.
prevent the use of an overspecified model that is more likely to reduce the precision of coefficient estimates and predicted values, as it adjusts for model improvement relative to chance, it does not account for whether the predictor variables were the most appropriate variables to choose in the first place. For instance, Staff is skeptical about the relevance and applicability of the number of gas customers served as an explanatory variable for electric distribution capital costs. Further, Dr. Lowry did not test for the potential multicollinearity of the explanatory variables (e.g., such as between HDD and CDD). The presence of multicollinearity results in a less statistically robust model that can be more influenced by noise (small changes in the data can produce wide swings in the parameter estimates). A potential result of multicollinearity, an overfit model tends to have poorer predictive performance, due to this exaggeration in small fluctuations in the data. CMP states in the 2000 ARP case with regard to econometric models developed in productivity offset analyses that “multicollinearity also can result in increasing R^2, erroneously suggesting that the model has more predictive power than it really does. This problem can also result in an increase in the sensitivity of the model to minor changes in the value of the data. Thus, the existence of multicollinearity comprises the integrity of a regression model.”

In addition, an econometric capital cost model was applied to total (O&M and capital) MFP growth, and thus in the view of Dr. Lowry alleviated the problem that the K factor may be a capital productivity offset that is inappropriately

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62 See November 1 Tr. at 64.
applied as a total productivity offset in the X factor.\textsuperscript{64} However, applying the econometric capital cost model to a sub-selected low capital cost peer group essentially converts his K factor analysis into a total factor productivity analysis but for a much smaller sample size. Specifically, the upper Northeast is based upon six utilities and the broad Northeast is based upon ten utilities.\textsuperscript{65,66} Such small sample sizes, combined with the potential sensitivities in the econometric model to data fluctuations due to reasons outlined above, suggests that the K Factor is a statistically unreliable value.

d. Stretch Factor-Staff Benchmarking Analysis

In this case, CMP has proposed a stretch factor of 0\%. In CMP’s past two ARPs, the stretch factors have not been explicitly set because the cases ended in a settlement. CMP proposed a stretch factor of 0\% (ARP 2000) and 0.2\% (ARP 2008), while Staff proposed a stretch factor of 1\% (ARP 2000) and 0.5\% to 1\% (ARP 2008). For the reasons discussed below, and based on the results of our benchmarking analysis, Staff recommends a stretch factor in the range of 0.3\% to 0.75\%.

It is generally recognized that a “stretch factor” should be added to the base productivity factor when implementing a multi-year ARP. The theory is that by breaking the link between costs and rates for a multi-year period, regulated

\textsuperscript{64} See November 1 Tr. at 20-21.

\textsuperscript{65} See Response to EXM-001-001, Supplemental Attachment 6 and November 1 Tr. at 73-74.

\textsuperscript{66} Benchmarking conducted for the Ontario Energy Board by PEG to derive stretch factors makes sure to include at least 10 distributors to avoid criticism of too small a sample size. Pacific Economics Group Research LLC. Empirical Research in Support of Incentive Rate Setting in Ontario: Report to the Ontario Energy Board at 84 (May 2013).
companies will operate more efficiently. If the base productivity factor is determined using companies that do not have ARPs, the productivity for the company with an ARP will be understated. In general, the utilities in the sample groups used by CMP and Staff have not operated under ARPs, so, in this case, a stretch factor should be added to the base productivity offset for CMP.

In addition, a stretch factor can also be viewed as a consumer dividend, as it effectively provides consumers a share of the benefits realized by efficiency gains. The Commission has long recognized that a stretch factor should be considered. In Docket No. 1992-345, the Commission stated: “A ‘stretch factor’ to the productivity offset should be given serious consideration . . . in order to minimize risk to consumers, as well as to place more pressure on CMP to improve its cost efficiency.”

In this section we present a benchmarking analysis as the basis for a stretch factor. We recommend a stretch factor for CMP that would place it in the upper quintile for productivity. This holds CMP to a standard of performance above that of an average utility, consistent with the theory that a PBR should result in a utility that is operated more efficiently than traditionally regulated companies.

We benchmark using capital and O&M cost per customer and capital and O&M cost per MWh over the 2009-2011 time period.

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69 For O&M, we utilize FERC Form 1 Distribution O&M expense, p. 322, line 156, column (b) to define O&M cost. Number of customers and MWh sales are taken from FERC Form 1, p. 301. For Capital, we utilize NERA’s methodology, with updated data to 2011 and inclusion of Maine utilities, to estimate capital costs as utilized by the Alberta
sample sets: (1) utilities in Upper Northeast and (2) all U.S. utilities for which data were readily available. In both sets, the companies included generally operate under traditional rate regulation rather than PBRs.

The results of Staff’s benchmarking analysis are shown below in Table 25. The analysis indicates that CMP appears to rank favorably with respect to capital spending, which, as noted above, may be due to productivity, or simply to deferred capital spending. CMP ranks quite poorly in terms of O&M productivity and, overall, ranks somewhat below average.

**TABLE 25**

<table>
<thead>
<tr>
<th>Productivity Benchmarking</th>
<th>Central Maine Power Company</th>
<th>National</th>
<th>Upper Northeast</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td><strong>Cost Per Customer Served</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Group Ranking</td>
<td>Percentile</td>
<td>Group Quintile</td>
</tr>
<tr>
<td>Capital</td>
<td>(1 = most efficient)</td>
<td>(100% = most efficient)</td>
<td>(1 = most efficient)</td>
</tr>
<tr>
<td></td>
<td>1</td>
<td>100%</td>
<td>1</td>
</tr>
<tr>
<td>O&amp;M</td>
<td>64</td>
<td>13%</td>
<td>5</td>
</tr>
<tr>
<td>Total</td>
<td>52</td>
<td>29%</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td><strong>Cost Per MWh Delivered</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Group Ranking</td>
<td>Percentile</td>
<td>Group Quintile</td>
</tr>
<tr>
<td>Capital</td>
<td>(1 = most efficient)</td>
<td>(100% = most efficient)</td>
<td>(1 = most efficient)</td>
</tr>
<tr>
<td></td>
<td>1</td>
<td>100%</td>
<td>1</td>
</tr>
<tr>
<td>O&amp;M</td>
<td>10</td>
<td>36%</td>
<td>4</td>
</tr>
<tr>
<td>Total</td>
<td>8</td>
<td>48%</td>
<td>3</td>
</tr>
</tbody>
</table>

Commission in their productivity analysis (details of the method are described in *Alberta Utilities Commission, Rate Regulation Initiative, Distribution Performance-Based Regulation*, Proceeding No. 566, Total Factor Productivity Study for use in AUC Proceeding 566 – Rate Regulation Initiative, NERA Economic Consulting (December 30, 2010)).
In a similar type of benchmarking done for ARP 2000, Staff found at that time that, for O&M, CMP also ranked in the bottom quintile.\(^70\) Thus, it appears that in terms of O&M, CMP’s productivity has not improved relative to the industry despite operating under a PBR for the entire time since the ARP 2000 analysis was conducted.

As noted by Dr. Lowry, the stretch factor used for a PBR depends on the company’s efficiency at the start of the plan.\(^71\) Other recent PBR cases in Vermont and Ontario have developed a sliding scale of stretch factors based upon the quintile ranking of a utility’s cost efficiency. Specifically, in a recent rate case in Ontario, the Ontario Commission, advised by Dr. Lowry’s Pacific Economics Group (PEG), assigned the following stretch factors in Table 26 based on quintile rankings.\(^72\) In the Vermont Green Mountain Power 2010 ARP case (Docket No. 7585), stretch factor quintiles were also assigned.\(^73\)

<table>
<thead>
<tr>
<th>Percentile</th>
<th>Quintile</th>
<th>Stretch Factor (Ontario)</th>
<th>Stretch Factor (Vermont)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0-20(^{th})</td>
<td>5</td>
<td>0.6%</td>
<td>1.00%</td>
</tr>
<tr>
<td>20-40(^{th})</td>
<td>4</td>
<td>0.45%</td>
<td>0.75%</td>
</tr>
<tr>
<td>40-60(^{th})</td>
<td>3</td>
<td>0.3%</td>
<td>0.50%</td>
</tr>
<tr>
<td>60-80(^{th})</td>
<td>2</td>
<td>0.15%</td>
<td>0.25%</td>
</tr>
</tbody>
</table>


\(^71\) See Sup-Lowry Testimony at 35.

\(^72\) Pacific Economics Group Research LLC. Empirical Research in Support of Incentive Rate Setting in Ontario: Report to the Ontario Energy Board at 90.

\(^73\) See *Vermont Public Service Board, Petition of Green Mountain Power Corporation for approval of an alternative regulation plan (Plan II)*, Docket No. 7585, Order at 10 (April 16, 2010).
Given that CMP ranks in the 3rd to 4th quintiles (capital and O&M combined), we believe an appropriate stretch factor for CMP would be in the range of 0.3% to 0.75%. This lower stretch factor range than that recommended by Staff in ARP 2008 (0.5% to 1%) recognizes that CMP may have less opportunities going forward for efficiency improvements than the prior ARP.

e. Customer Growth Factor

Dr. Lowry proposes a -0.37% offset for “customer growth”. His premise as to why a customer growth term could be included in a revenue cap plan is that the index should include a term that captures growth in scale, which he proposes to represent by growth in the number of customers. Unlike a price cap index, which caps prices but allows revenue to increase with growth in sales, a revenue cap index caps both such that sales growth will not account for growth in scale. According to Dr. Lowry, without the customer growth factor as scale increases, CMP’s revenue requirement would grow faster than inflation because of real cost additions that are driven by growth. The proposed -0.37% offset for customer growth is based on the Company’s forecast of average annual customer growth over the 2014-2017 period.74

Thus, this factor would have the effect of increasing CMP’s entire distribution revenue requirement by the expected growth in number of customers.

Staff is skeptical about the inclusion of a customer growth term, particularly one of the magnitude proposed by CMP, for the following reasons: (1) neither Dr. Lowry nor CMP is aware that such a term has been used in any other

74 See Response to EX-21-018.
electric utility PBR;\textsuperscript{75} (2) index logic inconsistencies; (3) CMP’s line extension charges would recover some incremental costs associated with new customers; and (4) potential economies of scale would be ignored.

Extension of the index logic behind the existence of the customer growth term in a revenue cap index appears to become problematic when extending the index logic back to a price cap index, as removal of billing determinants does not appear to return the results of the equation logic back to zero. Specifically, Dr. Lowry states that “if a price escalator rather than a budget escalator is desired, one can subtract the forecasted growth in billing determinants.” Lowry Testimony at 21. As such, the $X$ factor for a price cap escalator, which has been the form of CMP’s previous ARPs, would be defined as:

$$X = \text{(Productivity Diff.)} + \text{(Input Price Diff.)} + \text{Stretch} + \text{(Trend in Billing Dets. - Customer Growth)}$$

Under previous CMP price cap ARPs, the $X$ factor was defined as:

$$X = \text{(Productivity Diff.)} + \text{(Input Price Diff.)} + \text{Stretch}$$

Suggesting that:

$$(\text{Trend in Billing Dets. - Customer Growth}) = 0$$

However, the forecasted billing determinant growth (0.10\%) does not equal the forecasted customer growth trend (0.37\%).\textsuperscript{76} This index logic suggests that the index logic here is not properly formulated (or, alternatively, that CMP’s previous ARPs were incorrectly formulated). The problem may arise from the assumption that growth in scale

\textsuperscript{75} See Response to OPA-029-008.

\textsuperscript{76} Lowry Testimony at 34.
can be reasonably approximated by the growth in the number of customers served.

Sup-Lowry Testimony at 12.  

In reality, cost growth is driven not only by the number of customers served, but at least also by the number of kWhs sold. To the extent that volumetric sales drive cost, growth in number of customers served does not represent the actual trend in costs associated with the growth in output costs. As the forecasted growth in billing determinants is less than the forecasted growth in customers, this suggests, at a minimum, that customer growth over-represents the actual growth in the trend in cost.

As noted above, even if a customer growth term should be included as part of the index, CMP’s approach is not a good proxy for estimating real cost additions. Clearly, the entire distribution cost of service does not track changes in number of customers on a linear basis. Using a customer growth forecast to represent growth in cost, and thus revenue requirement, does not account for economies of scale. CMP’s costs are unlikely to grow linearly with customer growth - for instance, the costs of the hardware and software for CMP’s billing systems would not grow linearly with customer growth. Thus, the magnitude of the term proposed by CMP is likely to be significantly overstated. In addition, the approach ignores the fact that significant costs associated with customer growth are recovered separately through CMP’s line

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77 The premise for the existence of a scale term for a revenue cap escalator is that “the cost growth difference between input price and cost efficiency growth plus growth in operating scale, where growth in scale is measured by the same cost-based output index that is used to calculate productivity growth.” Sup-Lowry Testimony at 12.

78 Lowry Testimony at 34.
extension charges. Thus, using the full rate of forecast customer growth in the index would over-account for customer growth-related costs.

In summary, CMP’s proposed customer growth term, if appropriate to include at all, appears to be significantly overstated. Moreover, the lack of precedent and index logic inconsistencies question the need for the term at all. Note that if the Commission decides against decoupling, and thus a revenue cap mechanism, and for a price cap mechanism like CMP’s previous ARPs, then the customer growth term is dropped from the formula.79

f. Summary of Productivity Offset Factor

Based on the analysis to date, Staff assesses the X factor component parts to be in the following ranges: (1) base productivity (combined productivity and input price differentials) of from -0.90% to -0.29% (although, as noted above, the results of CMP’s analysis using a longer study time period may change these significantly); (2) K factor of 0.00%; (3) stretch factor of from 0.30% to 0.75%; and (4) customer growth offset factor of from 0% to -0.37%. (Staff notes that, at -0.37%, a customer growth factor would be overstated; however, we do not have sufficient data to adjust for such overstatement.) These components result in X factors that range from as low as -0.97% (-0.90% + 0.30% + -0.37%) to as high as 0.46% (-0.29% + 0.75% + 0%). When the results of CMP’s study using a longer time period are included, the X factor may be even greater than 0.46%. (Based on Staff’s “blending” analysis discussed above, the X factor would be as large as 1.48% (0.73% + 0.75% + 0%).) Based on the analysis to-date, Staff’s assessment is that a reasonable X factor appears to be in the

79 Sup-Lowry Testimony at 10-13.
range of -0.60% to 1.48%. This reflects: (1) a base productivity offset (productivity plus input price differentials) of -0.90% to 0.73% depending upon the time frame and geographic scope of the sample set; (2) a K factor of 0.0%; (3) a stretch factor of 0.30% to 0.75%; and (4) a customer growth factor of 0.0% based upon the lack of support for the need for and magnitude of this term. The additional analysis by CMP using a longer time period for the productivity and input price differential calculations will inform our final recommendation.

D. Storm Costs

1. CMP's Proposal

As part of the Company's ARP 2014 proposal, CMP proposes to continue the "extraordinary storm" cost flow-through mechanism initially adopted in ARP 2008. CMP would apply essentially the same criteria for recovery of these costs. Thus, to be eligible for full recovery, a storm must satisfy the following criteria:

- The subject storm must be published by the National Oceanic and Atmospheric Administration (NOAA) as a "severe" weather event on its website;
- That CMP must incur incremental costs of restoring service for the event equal to or greater than $1.5 million; and
- 20 percent or more of CMP's customers must experience an outage during a single day.

In addition, the Company proposes to expand the extraordinary storm mechanism to include events that result in outages to less than 20% but more than 10% of its customers. For storms that resulted in outages to 10% of its customers, the Company would recover 50% of its costs, with the % amount increasing on a sliding scale basis until the 20% threshold is reached, at which point, the Company would be
entitled to full recovery. The Company also proposes to modify the definition of "day" for the measurement period of outages to include any 24-hour period and to define customer outages to include multiple interruptions impacting a single customer. Finally, rather than identify incremental materials associated with each storm event, a fixed 1.35% of restoration costs would be applied as a proxy of material costs.

As discussed previously, the extraordinary storm cost flow-through mechanism is at odds with three important objectives of an ARP. First, the mechanism involves substantial regulatory involvement by requiring annual proceedings to determine whether a storm meets the criteria and whether the related costs are reasonable. Second, the mechanism eliminates, or at least weakens, rate stability and predictability. As shown in Table 4 on page 11, rates during ARP 2008 were not particularly stable, nor predictable, and were consistently above the rate of inflation in large part due to the extraordinary storm cost mechanism. Third, and most importantly, the mechanism is contrary to the objective that the risk of management decisions and levels of efficiency/inefficiency should be shifted to shareholders. CMP's proposed revisions would not change the storm cost flow-through mechanism in these respects, and in certain instances, could exacerbate the problems identified above.

Staff also notes that the NOAA criteria used during ARP 2008 and proposed for continued to not provide a particularly rigorous screen. According to NOAA, between 2008 and 2013 there have been 817 "severe" weather related events in Maine broken down annually as follows:

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80 Note that the data for 2013 included all severe storm events for 2013 as of the Company's response provided on July 2, 2013.
Staff similarly believes that CMP's second proposed criterion would not be particularly limiting. During the first four years of the ARP 2008 there were six "extraordinary storms" that satisfied the $1.5 million threshold. (December 2008 storm - $11,577,336; February 2009 storm - $5,675,714; February 2010 storm - $12,690,546; November 2010 storm - $3,708,491; August 2011 storm - $10,683,474; October 2011 storm - $3,788,408; October 2012 storm - $5,745,696). Storms that occur more frequently than once a year, in our view, should not be considered "extraordinary". It is worth noting here that the $1.5 million threshold, which was used in ARP 2008, was developed based on the level of storm costs incurred during ARP 2000 (which did not contain a flow-through mechanism). As can be seen from a review of the data in Table 28, in subsection (2) below, other than the costs of the April 1, 2007 "Noreaster" for which CMP sought and received partial cost recovery, the Company’s storm costs were fairly flat. The cost recovery pattern seems to support the proposition that the flow-through mechanism has, in fact, blunted the incentive for efficiencies. In addition, given

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81 EX 03-29.

82 These figures are based on the amounts sought by the Company in its annual filings, some of which were adjusted based on agreement with the Company or litigated outcomes.
the increased level of spending since the flow-through mechanism was adopted, the data also suggests that the $1.5 million threshold no longer provides a meaningful screen for "extraordinary storms". Additionally, CMP's increasing practice of engaging contractors in advance of storm situations even for "minor" storms has significantly added to the costs of restoration. CMP's own proposal would seek approval for $1 million dollars annually for pre-staging associated with minor storms. These additional expenditures would further water down any usefulness of the $1.5 million criterion in determining whether an event is major or minor.

In Docket No. 2011-77, which involved the Commission's review of the Company's proposed recovery of certain storm related expenses for the 2010 calendar year, the Commission stated:

[...]In developing future ARP proposals, the parties and the Staff should consider provisions, which remove the incentive for the utility to act in ways that have the effect of increasing the number of interruptions and thus the likelihood that a storm would be included as an Extraordinary Storm. Specifically, the parties and our Staff should consider alternatives to the current binary nature of the Extraordinary Storm cost provision that either includes or excludes all costs related to a storm event based on whether it satisfies the eligibility criteria.


Staff does not believe that the Company's sliding scale methodology would fully address the Commission's concerns noted in Docket No. 2011-77. CMP would still have an incentive to maximize the number of interruptions. Moreover, the mechanism would apply to more events. In summary, CMP's proposed storm cost mechanism would not represent an improvement to ARP 2008 and would be at odds with key objectives of an ARP, including price stability, reduction of regulatory oversight and costs, providing
incentives for efficiency. For the reasons discussed above, this mechanism was not successful in ARP 2008 and would not be remedied by CMP’s proposed changes. Therefore, Staff recommends elimination of the mechanism.

2. **Staff’s Proposal**

   For the reasons discussed above, whether the Commission determines that the Company should operate under a traditional cost of service rate making or under an ARP structure, Staff believes that CMP’s revenue requirement for storm related costs should be a set amount established in base rates without any flow-through mechanism. The amount should be based on a normalized level of incremental expenditures for all storms, including those that met the “extraordinary” storm criteria under ARP 2008.\(^{83}\) The following table sets out what these costs have been historically.

\(^{83}\) The Staff has excluded from this calculation costs which have been excluded by the Commission as imprudent or which have been determined to be non-incremental.
### TABLE 28

*Incremental Storm Costs by the Year Incurred*

(Dollar Amounts in Millions)

<table>
<thead>
<tr>
<th>Year</th>
<th>Incremental Cost (Millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2001</td>
<td>$0.8</td>
</tr>
<tr>
<td>2002</td>
<td>$0.7</td>
</tr>
<tr>
<td>2003</td>
<td>$1.8</td>
</tr>
<tr>
<td>2004</td>
<td>$0.0</td>
</tr>
<tr>
<td>2005</td>
<td>$1.7</td>
</tr>
<tr>
<td>2006</td>
<td>$5.4</td>
</tr>
<tr>
<td>2007</td>
<td>$11.1</td>
</tr>
<tr>
<td>2008</td>
<td>$11.8</td>
</tr>
<tr>
<td>2009</td>
<td>$6.5</td>
</tr>
<tr>
<td>2010</td>
<td>$18.7</td>
</tr>
<tr>
<td>2011</td>
<td>$17.0</td>
</tr>
<tr>
<td>2012</td>
<td>$7.4</td>
</tr>
</tbody>
</table>

**Avg 2001 – 2012**: $6.9

*Excludes $3.3 million disallowed by Commission Order dated July 13, 2010 in Docket No. 2009-18*

Staff proposes that the Commission establish a set amount in base rates based on an average of the authorized storm expenses, $6.9 million, over the last ten years.\(^{84}\) Although the amount included would be intended to cover all storm related costs, the Company would not be precluded from requesting an accounting order for a truly rare, catastrophic storm such as the 1998 ice storm.

This approach would avoid the problems with the flow-through mechanism discussed above and would provide the appropriate incentives for CMP to

\(^{84}\) Staff has agreed to include additional funding for “hot spot” and “hazard tree” programs above the amount that is currently included in CMP’s existing vegetation management cycle trim program. This enhanced vegetation management effort should reduce the number of tree caused outages, improve restoration time during storms and also help reduce restoration costs.
manage storm costs in the most efficient manner possible. With the service quality metrics discussed in subsection E below, CMP would continue to have appropriate incentives to minimize the number and duration of outages. Finally, in the event that the Company fails to take prudent and reasonable steps to restore customers the Commission could initiate an investigation.

E. Reliability and Customer Service

In the prior ARPs, CMP’s service quality has been tracked through a Service Quality Index (SQI). The ARP 2008 SQI was made up of the following seven indicators: Customer Average Interruption Duration Index (CAIDI); System Average Interruption Frequency Index (SAIFI); Percent of Business Calls Answered; Meters Read; New Service Installations (on-time delivery); MPUC Complaint Ratio; and Call Center Service Quality. For each of these indicators there was a benchmark upon which CMP’s annual performance was compared. If the Company’s performance failed to meet any of the established benchmarks, points were deducted based upon the percentage by which the Company’s performance deviated from the benchmark. Each of the seven metrics was worth 14.3 points with each point being worth $500,000. The SQI had a total potential annual penalty of $5,000,000.

In its filing, CMP proposes to continue using six of the seven ARP 2008 metrics, and proposes to replace the MPUC Complaint Ratio with a metric intended to measure the Company’s responsiveness to customers. CMP also recommends new benchmarks for each metric. In the following sections, Staff describes its evaluation of the Company’s proposal and has set forth its own recommended SQIs.
1. **Reliability Programs and Metrics**

CMP recommends retaining the CAIDI and SAIFI reliability metrics used in ARP 2008 with revised benchmarks. Staff agrees that these metrics should be retained, but disagrees with CMP’s benchmark recommendations. Staff also recommends that two additional reliability metrics be added to the SQI.

In determining reliability metrics for ARP2014, the Company’s historic performance should be considered, as should the effects of current or newly proposed programs that will further improve CMP’s system reliability performance. In response to EX-03-08, the Company provided a benchmarking study that depicts CMP’s reliability performance when compared to 37 other utilities operating across 28 states and the District of Columbia, which include CMP’s Iberdrola affiliates operating in New York. This benchmarking study indicated that during the period of 2009 through 2011, CMP’s SAIFI performance consistently fell in the fourth quartile among its peers. However, with regard to CMP’s CAIDI performance, the benchmarking study revealed that CMP’s position improved from 2009 to 2011. CMP was in the third quartile when compared to 37 other utilities for 2009 and 2010. In 2011, CMP had moved to the second quartile. A review of the Company’s reliability performance shown in Table 29

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85 See Attachment 1 provided in response to EX-03-08.

86 Although Staff recognizes that there are many factors that may affect a given utility’s performance when compared to its peers, the benchmarking study does provide some insight on the general trend in CMP’s performance and may help identify which utilities may be outliers or better performers historically. Attached as Confidential Appendix H to this Bench Analysis are copies of the relevant pages from the benchmarking study that illustrate CMP’s recent SAIFI and CAIDI performance when compared to its peer utilities.
below similarly shows that the Company's CAIDI performance has improved steadily since 2005 and that the Company's SAIFI performance has improved since 2008.\textsuperscript{87}

\begin{table}[h]
\centering
\begin{tabular}{|l|cccccccc|}
\hline
Performance\textsuperscript{88} & & & & & & & & & \\
\hline
CAIDI & 2.18 & 2.14 & 2.13 & 1.88 & 1.87 & 1.97 & 1.73 & 1.75 & 1.96* \\
\hline
CAIDI Targets & 2.32 & 2.32 & 2.32 & 2.32 & 2.18 & 2.18 & 2.18 & 2.18 & 2.18 \\
\hline
SAIFI & 1.94 & 2.18 & 2.06 & 2.26 & 2.04 & 2.00 & 1.99 & 1.75 & 1.64* \\
\hline
SAIFI Targets & 2.10 & 2.10 & 2.10 & 2.10 & 2.10 & 2.08 & 2.00 & 1.92 & 1.89 \\
\hline
\end{tabular}
\caption{TABLE 29}
\end{table}

The most significant factors that have led to CMP’s improved reliability performance are the implementation of (1) a Distribution Line Inspection (DLI) program and (2) a Vegetation Management Cycle Trim program. The Company acknowledges that, with regard to SAIFI in particular, much of its improved system performance during ARP2008 has been as a result of the vegetation management cycle trim and hot spot programs. These downward trends for CAIDI and SAIFI should continue going forward based on

\textsuperscript{87} As noted by the asterisks in Table 29, CMP’s year-end SAIFI and CAIDI performance for 2013 is not known at this time. However, CMP’s most recent October 2013 SQI update shows that CAIDI performance through the end of the third quarter is 1.96. Further, a comparison of the Company’s SAIFI performance for third quarters in 2012 and 2013 (1.37 and 1.26 respectively) shows that the Company’s SAIFI continues to trend downward. In fact, if one assumed weather conditions and other factors affecting CMP’s system performance to be the same for the remainder of 2013 as were experienced in 2012, CMP’s SAIFI for year-end 2013 would be approximately 1.64 (Delta of SAIFI data for fourth quarter 2012 [0.38] + SAIFI performance for third quarter 2013 [1.26] = 1.64.

\textsuperscript{88} It is worth noting that the targets set forth in ARP2008 were based on exclusion factors that were different than the prior ARP. Therefore, the data shown in the table does not represent system performance based on identical exclusion factors.

\textsuperscript{89} No CAIDI, SAIFI or other targets or penalties were established for 2008. However, the parties in a subsequent proceeding that dealt with the merger and Acquisition of Energy East by Iberdrola in Docket No. 2007-00355 agreed to the levels set forth under the Table for the purpose of annual reporting requirements by the Company.
continuation of these programs and as well as new programs that CMP plans to implement.

a. Distribution Line Inspection Program

In its ARP 2014 proposal, the Company proposes to continue with the DLI program, which would commence in 2014 and expire as the conclusion of 2019. Staff agrees with the Company’s proposal, which it believes has contributed significantly to the Company's improved reliability performance during ARP 2008.

b. Vegetation Management

Tree caused outages and associated customer interruptions declined significantly over the ARP 2008 term, in large part due to CMP’s cycle trim program. The Company proposes to continue aspects of the ARP2008 vegetation management program, including removal of vegetation from the previously approved clearance zones and "hot spot" trimming. The Company also proposes to implement new vegetation management practices during ARP2014 including: (1) ground to sky trimming along portions of certain circuits; (2) a hazard tree program that would target trees located within the right-of-way and up to fourteen (14) feet outside of the right-of-way; and (3) foliar spraying treatment that would reduce undergrowth along the

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90 In response to a question at the October 29 Technical Conference, CMP’s witness stated:

MR. STINNEFORD: I think if you look at the gains, reductions that have been made in SAIFI during the last rate plan, ARP 2008, the period from -- 2008 to 2012 in this table, I would say that the bulk of those improvements are not necessarily related to capital investment as much as distribution cycle trimming.

See October 29, 2013 Technical Conference Transcript at 134.
distribution circuits. CMP proposes to continue the cycle trim program using contractors and "lump sum" contract structures and amounts similar to ARP2008. CMP would also continue "hot spot" trimming that would target any encroachment of vegetation upon distribution lines over the period of the ARP and to address “hazard trees,” which are trees that are within or close to the public right-of-way and which pose an obvious or imminent threat to distribution lines due to their size, health, and proximity,

Staff is supportive of most of the proposed programs by the Company and believes that continued vegetation management efforts during ARP 2008 should continue to reduce tree caused outages. In response to EX-03-04, the Company provided a table that depicts outages caused by trees in the right-of-way and customer power quality complaints dating back to 2005. This table (reproduced below) shows that the total tree caused outages and customer complaints associated with such outages generally decreased over ARP2008:

TABLE 30

<table>
<thead>
<tr>
<th>Year</th>
<th>Cust Compl (E98)</th>
<th>Qty Customers Impacted</th>
<th>Outage Count</th>
<th>Qty Cust Imp</th>
<th>Outage Count</th>
<th>Qty Cust Imp</th>
<th>Outage Count</th>
<th>Qty Cust Imp</th>
<th>Outage Count</th>
<th>Qty Cust Imp</th>
<th>Outage Count</th>
</tr>
</thead>
<tbody>
<tr>
<td>2005</td>
<td>936</td>
<td>477,055</td>
<td>3,428</td>
<td>477,055</td>
<td>3,428</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2006</td>
<td>931</td>
<td>537,713</td>
<td>3,614</td>
<td>537,713</td>
<td>3,614</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2007</td>
<td>812</td>
<td>618,746</td>
<td>4,169</td>
<td>618,746</td>
<td>4,169</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2008</td>
<td>823</td>
<td>649,245</td>
<td>4,552</td>
<td>649,245</td>
<td>4,552</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2009</td>
<td>1131</td>
<td>450,568</td>
<td>3,353</td>
<td>450,568</td>
<td>3,353</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2010</td>
<td>770</td>
<td>633,900</td>
<td>3,981</td>
<td>633,900</td>
<td>3,981</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2011</td>
<td>649</td>
<td>526,231</td>
<td>3,578</td>
<td>526,231</td>
<td>3,578</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2012</td>
<td>538</td>
<td>358,034</td>
<td>2,578</td>
<td>28,300</td>
<td>223</td>
<td>69,874</td>
<td>429</td>
<td>259,860</td>
<td>1,926</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

91 CMP’s attachment noted that reportable outages included on the table were based on figures in the Distribution Outage Database as of 06/17/2013 and that 2009 – 2012 information was based on information reported in the Annual Reliability Improvement Reports.
Based on the Company’s reliability improvement since ARP2008 and the completion of a five year cycle trim, Staff believes that the cycle trim, hot spot, and hazard tree programs will not only allow the Company to continue to deliver the degree of reliability performance that it achieved over ARP 2008, but will likely further enhance the Company’s SAIFI performance over ARP 2014. Further, these programs can be administered more efficiently on an annual basis now that the Company has completed a complete cycle trim of its system as indicated by the fact that the combined annual cost for these three programs during ARP2014 is projected to be less than the amounts expended during ARP2008 for the cycle trim program alone.

With regards to the Company's proposed ground-to-sky component of the enhanced trimming as well as the Company’s proposed foliar treatment, Staff has been unable to determine whether such programs would provide a meaningful benefit to customers. When questioned about these programs at the technical conferences and responding to data requests, the Company was unable to provide any cost benefit studies or other analyses that would support implementation of these programs.92 The Company also did not identify any projected reductions to the Company’s CAIDI or SAIFI performance or any particular metrics that would be used to determine which circuits would be prioritized for these programs.93

92 See November 5, 2013 Technical Conference at 13 (discussing purported cost reductions associated with foliar program); Response to EX-03-019 (discussing that the savings associated with the enhanced line clearance program would be difficult to predict); Response to OPA-005-004 (stating that the Company has not performed an analysis of the CAIDI and SAIFI improvements that may be attributable to each of CMP’s reliability programs including vegetation management and the DLI program.

93 See July 24, 2013 Technical Conference Transcript at 144, 163-66.
c. CAIDI and SAIFI Metrics for ARP2014

The Company proposes the following targets for these metrics during ARP2014:

TABLE 31

CMP Proposed CAIDI and SAIFI Metrics

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>SAIFI</td>
<td>1.89</td>
<td>1.89</td>
<td>1.89</td>
<td>1.89</td>
<td>1.89</td>
</tr>
<tr>
<td>CAIDI</td>
<td>2.00</td>
<td>1.99</td>
<td>1.98</td>
<td>1.97</td>
<td>1.96</td>
</tr>
</tbody>
</table>

Based on CMP’s CAIDI performance during ARP2008 that is shown in Table 29, which consistently met the ARP targets, Staff believes that achieving CAIDI levels of 2.00 over the next five years should not pose any problem for the Company. Such a level recognizes the CAIDI benefits that have and will continue to result from the Company’s vegetation management and DLI programs as well as additional benefits in responding to outages stemming from the Company’s use of AMI.  

Although not specifically addressed in the Company’s discussion of proposed reliability metrics, at the October 28, 2013 Technical Conference, the Company indicated that it has integrated the meter information into its outage management system and that it is using the ping capabilities to identify power status for customers. In addition, the Company expects to, by year-end 2013, integrate the AMI meter event data into its predictive engine our predictive engine, which should help the Company assess storms faster. See October 28, 2013 Technical Conference Transcript at 5-6. As a result of these benefits, the Company believes that it has realized efficiencies from AMI during its storm restoration efforts, which should continue to improve. Id. at 3-4.
Staff does not agree with the Company’s proposed SAIFI levels, however. Rather, Staff believes that CMP’s past and continued vegetation management programs, coupled with continuation of the DLI program (a complete cycle of which is expected to be completed next year), will continue to reduce SAIFI over the coming years.\(^{95}\) A review of the historic figures shows that the Company’s SAIFI performance has been trending downward with 2012 at 1.76 and 2013 currently on target to finish the year around 1.64.\(^{96}\) Based on this performance coupled with the ongoing benefits of the DLI and vegetation management programs (now enhanced to include additional money for hazard tree removal), Staff believes that a SAIFI index of 1.75 would be more appropriate and would begin to capture the reliability benefits of these programs to date as well as the future benefit of these programs (including an additional vegetation management for hazard trees) over the coming years.\(^{97}\) Staff also believes that such a level will begin providing the appropriate incentive for the Company (“We have achieved and believe we'll continue to improve on the efficiencies around storm restoration and use of the system for outage assessment and restoration.”).

\(^{95}\) Importantly the Company provided no specific analysis to support its assertion that the benefits associated with the various programs that it proposes have been factored into its metrics. See May 1, 2013 Reliability Panel Testimony at 12-13. See also Company Response to OPA-05-04 (stating that the Company has performed no analysis of the CAIDI and SAIFI improvements attributable to each of the reliability programs, including, but not limited to, the five year tree timing cycle and DLI program.

\(^{96}\) See Table 29, \textit{supra} at 122, and n. 87.

\(^{97}\) Although recent SAIFI performance has been trending downward (and Staff believes that it may be reasonable to assume that SAIFI performance may be even lower than 1.75 over the next few years), Staff hesitates to recommend a lower target at this time. Staff feels that doing so could potentially undermine some of its other concerns including those expressed in the Capital Investment and Reliability sections of this Bench Analysis. Specifically, Staff is reluctant to reduce SAIFI figures so drastically that it could cause the Company to target those betterments, capital investments and other programs that would affect the most customers, thereby reducing the overall system-wide metrics, while other customers located in less dense areas have been left behind.
to move out of the fourth quartile among its peer utilities in SAIFI performance and
begin moving towards the top quartile. 98 Staff’s proposed SAIFI and CAIDI targets (with
exclusions) for ARP2014 are therefore as follows:99

TABLE 32

Staff Proposed CAIDI and SAIFI Metrics

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>SAIFI</td>
<td>1.75</td>
<td>1.75</td>
<td>1.75</td>
<td>1.75</td>
<td>1.75</td>
</tr>
<tr>
<td>CAIDI</td>
<td>2.00</td>
<td>2.00</td>
<td>2.00</td>
<td>2.00</td>
<td>2.00</td>
</tr>
</tbody>
</table>

For the reasons discussed below, Staff further proposes that additional customer-specific reliability metrics also be adopted.

d. Additional Reliability Metrics

Under the Company’s prioritization criteria, a key factor in determining which betterment or capital projects are funded is the number of customers affected.100 In 2011, as CMP evaluated the focus of the investment programs in place at the time, CMP states that it became apparent that the SAIFI targets for 2012 and 2013 would require expanded reliability initiatives beyond addressing the 10 worst performing circuits reported annually in the ARP. Capital Investment Testimony at 9. As

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98 See November 8 Technical Conference Transcript at 158- 59 (discussing Attachment 1 provided by Company in response to EX-003-008 and Company’s goal to move into the top quartile of companies in the group of 37 other peer companies with respect to SAIFI performance).

99 In the event that the Commission accepts Staff’s recommendation for no ARP, these metrics should still serve as benchmarks for the Company in achieving satisfactory reliability performance and should be reported by the Company in the same manner as its current annual and quarterly SQI filings.

100 “Criticality” is determined by CMP based on a number of factors, including location, number of customers and restoration time. See Company’s Response to OPA-023-051; See November 8, 2013 Technical Conference Transcript at 57.
a result, the Company decided to implement a method for prioritizing betterments and capital investments that would assess the reliability improvements that may be gained by decreasing the number of customers affected by single outage events, providing alternative sources, implementing automation schemes, and ensuring that circuits operate within established limits. Circuits selected under this prioritization method are based on current reliability data and the following formulas, which are weighted by the number of customers affected:

- % Weighted SAIFI = \( \frac{(\text{number of customers interrupted on the circuit/total 23 number CMP customers connected})/\text{CMP YTD SAIFI}}{100}; \) and

- % Weighted CAIDI = \( \frac{(\text{number of customers interruption hours on the circuit/total CMP customer interruption hours})/\text{CMP YTD CAIDI}}{100} \)

While it is clearly appropriate to consider the number of customers affected as one factor in determining the order and priority for system upgrades, this should not be the sole factor. Staff is concerned that the Company’s prioritization criteria may be too strongly driven by the system-wide CAIDI and SAIFI targets, which are customer-weighted, and that some portions of its system may be allowed to age and degrade as a result. As indicated in the testimony of the Company’s Capital Investment panel, portions of CMP’s system with copper conductor that is 85 years and older are at “increased risk of conductor mechanical failure and conductor related outages.”  

101 This copper conductor is often situated in “short segments on the tail end of circuits” that are often less densely populated and would rank low in the Company’s prioritization given the focus on number of customers. Without additional metrics, the customer-

101 See Capital Investment Testimony at 46.
102 See id. at 45.
weighted approach to prioritizing capital investments and betterments will likely result in continued neglect of these assets which will present even greater reliability issues in the future.\textsuperscript{103} If not addressed, the Company’s copper conductors will age and degrade at a rate that is faster than the Company’s proposed capital programs are intended to address.\textsuperscript{104}

It seems clear that the CAIDI and SAIFI metrics used in recent ARPs have provided incentives for the Company to manage to these metrics. That is not unexpected. However, portions of the system that have less of an impact on these system-wide metrics (e.g., circuits and areas of CMP’s service territory with fewer customers) appear to have been of low priority or even completely overlooked. Staff is concerned that, without additional metrics, the Company’s approach will not change and that safe and reliable service will not be provided to all customers. For example, although the Company’s performance as measured by SAIFI might meet or be well within targets of 1 or 2 sustained outages per year (less exclusions), some customers

\textsuperscript{103} As an example, the Company deferred for several years replacement of older, copper conductors. One such conductor, initially proposed as a betterment in 2008, concerned the Bishop Hill three phase feeder in Leeds Maine along Route 106 (Betterment Number: 5138-2008). This betterment, which would have involved replacement of 3.7 miles of three phase conductor (number 6 copper conductor installed in 1926) for a cost of approximately $440,000 was deferred each year since 2008 until it was finally scheduled to be completed in 2013 and even though the Engineer identified and documented that numerous spans along this segment had NESC clearance violations between the neutral and telephone lines and the conductor was in “extremely deteriorated condition.” See Attachment 1 in response to ODR-001-007 in Docket No. 2011-00420; see also Attachment 1 in response to EX-018-018 (containing list and status of betterments proposed in ARP 2008).

\textsuperscript{104} According to CMP, without replacement, the 85 year old conductor population will increase from 218 miles currently to approximately 2,100 miles by 2019.
(e.g., customers located at the end of circuits or on low-density circuits) often experience five or more sustained outages per year.\textsuperscript{105}

Staff is therefore proposing that additional performance incentive metrics be adopted to provide incentives to help ensure that all customers, no matter where located, have adequate and reasonable service. Specifically, Staff proposes the following two additional performance incentive metrics: Customers Experiencing Multiple Interruptions (CEMI) and Customers Experiencing Long Interruption Duration (CELID).\textsuperscript{106} These two metrics will augment the Commission’s ability to evaluate reliability performance on all areas of CMP’s system, not only those areas that have the greatest impact on CMP’s system-wide SAIFI and CAIDI. CAIDI and SAIFI provides a good indication of a utility’s performance at the aggregate system level but these metrics do not measure the level of reliability experienced by individual customers. As noted above, the service quality provided to customers in less densely populated areas may be masked by system-wide metrics such as CAIDI and SAIFI. CEMI and CELID would evaluate the frequency and duration of outages on a much more granular level. Consistent with other regulatory jurisdictions in recent years, Staff therefore proposes that these additional metrics be adopted and that the Commission


\textsuperscript{106} These metrics are defined by the Institute of Electrical and Electronic Engineers (IEEE).
set a CEMI target of 5 outages per customer (or CEMI$_5$) and a CELID target of 8 hours (or CELID$_8$). In order to establish the customer percentile targets for CEMI$_5$ and CELID$_8$, Staff recommends that historical data (last five years) be provided by the Company and that the parties would vet the appropriate percentages that would form the basis for any penalty assessment as part of a separate compliance proceeding that would follow this rate case.$^{107}$

Metrics similar to these have been used or considered by other regulators in North America. As summarized in a September 2013 Report produced by Pacific Economics Group Research, LLC, several North American jurisdictions have moved towards the adoption of customer-specific reliability metrics, including:

- Florida, where all investor-owned utilities (with one exception) are required to report customers experiencing more than five interruptions in a year, or CEMI-5.
- Idaho, where Scottish Power/Pacificorp reports customers experiencing multiple sustained and momentary interruptions.
- The District of Columbia, where Potomac Electric Power Company (Pepco) reports CEMI-8 and CELDI-8. California, where San Diego Gas and Electric (SDG&E) reported the percentage of customers who experienced interruptions in their power supply of more than 150 minutes in the preceding year. The “SAIDET” indicator that SDG&E developed represents the total minutes within system-wide SAIDI that were attributable to customers experiencing total, annual

$^{107}$ This means that a penalty assessment would be triggered when a certain – to be determined – percentage of customers experienced either five or more outages per year or had outages that lasted for eight hours or more in duration. CMP already maintains a complete outage database that includes the interrupting device ID, the number of customers interrupted, and the duration (the start time/end time) for outages as well as cause codes and other details. Staff therefore believes that more than adequate historical data is available to enable the development of CEMI$_5$ and CELID$_8$ metrics and that a separate compliance proceeding would allow these additional metrics to be used for the purpose of penalty assessment in early 2015.
interruption time that exceeded the established threshold of 150 minutes.

- British Columbia, where BCHydro reports CEMI-4.
- In 2012, Maryland’s administrative rules were changed to require reporting of CEMI-2 (3 or more outages), CEMI-4 (5 or more outages), CEMI-6 (7 or more outages) and CEMI-8 (9 or more outages).
- In North Dakota, Northern States Power has been reporting CEMI-4, CEMI-5 and CEMI-6 since 2012. This was the result of a rate case settlement in which reliability performance was an issue.
- In New Jersey, Atlantic City Electric has been reporting CEMI since 2011 on a company and district basis. The company began reporting this metric as a result of a settlement agreement focused on reliability issues.\(^{108}\)

In addition, the PEG report indicated that in December 2012 the Massachusetts Department of Telecommunications and Energy (DTE) opened an investigation into the service quality regulatory framework for energy utilities in the State of Massachusetts that reviewed the potential implementation of customer specific reliability indicators including CELID and CEMI.\(^{109}\)


\(^{109}\) The Massachusetts Attorney General commissioned work as part of the DTE proceeding from two consultants which, among other things, recommended that electric utilities report customer-specific reliability metrics. According to PEG, the outcome of the Massachusetts service quality review was pending at the time of its report. September 2013 PEG Report at 7. It is worth noting that one consultant report, performed by O’Neill Management Consulting, LLC, recommended that Massachusetts adopt new customer-specific reliability metrics, including, CEMI and CELID. O’Neill suggested that these new metrics be used as additional “penalty-eligible measures of reliability,” which would be adjusted for storm exclusions. O’Neill further recommended revised benchmarks for SAIDI and SAIFI to reflect the need for continuous improvement for these targets. See *Recommendations for Strengthening the Massachusetts Department of Public Utilities’ Service Quality Standards*, O’Neill Management Consulting, LLC (Dec. 13, 2012), available online at [http://www.mass.gov/ago/docs/energy-utilities/ago-sq-review.pdf](http://www.mass.gov/ago/docs/energy-utilities/ago-sq-review.pdf).
Staff believes that the adoption of CELID and CEMI metrics will best ensure that customers in all areas of CMP’s system, including the less densely populated areas, will be assured reasonable utility service and restoration efforts. As discussed below, CMP’s performance with respect to these metrics would be incorporated into the overall SQI penalty mechanism.

Staff further recommends that the Company have an additional CAIDI metric with no exclusions, i.e., that includes all storms and other events that are normally excluded under the IEEE 2.5 Beta method. Staff proposes that this additional metric be reported by CMP on a quarterly and annual basis. Staff does not recommend that this metric be used for the purpose of assessing any penalties, whether or not under an ARP or traditional cost of service ratemaking. Staff believes that this additional metric would provide an additional tool to assist the Commission in evaluating and measuring CMP’s overall system performance and its effectiveness in responding to storm events and other outage conditions.

2. Exclusions

CMP proposes to retain the IEEE Beta 2.5 exclusion criteria adopted in ARP 2008 as a means of eliminating extraordinary events from the reliability and customer service metrics, with the exception of the call center service quality metric. The Company also recommends modifying the criteria to perform exclusion criteria over any 24 hour period as opposed to a calendar day.\footnote{See May 1 Reliability Panel Testimony at 13.}

The IEEE Beta method is used to identify major event days using daily SAIDI data. A “major event day” is a day in which daily SAIDI results exceeds a
threshold $T_{\text{med}}$. In calculating daily SAIDI, interruption durations that extend into subsequent days accrue to the day on which the interruption begins. The major event day identification threshold value $T_{\text{med}}$ is calculated based on a five year reporting period. The threshold value is then applied during subsequent the sixth year. Any day during the reporting period with a daily SAIDI that exceeds the threshold value $T_{\text{med}}$ is designated a “major event day” and removed from the metric’s performance calculation. See *Classification of Major Event Days*, IEEE Working Group on System Design, White Paper, 2003.

Under the Company's proposal, the Company would conduct a review to determine whether any consecutive 24 hour period surrounding that calendar day would exceed $T_{\text{med}}$. If the $T_{\text{med}}$ is exceeded for any consecutive 24-hour period, CMP proposes that the outages that start within that period would be excluded from the reliability calculations.\(^{111}\) Staff does not agree with this proposed methodology.

CMP’s proposed use of a 24 hour rolling period to calculate a major event day (MED) is inconsistent with standard utility practice and the plain language of Standard 1366, and could result in increasing the number of MEDs that are subject to exclusion. Standard 1366 of IEEE defines a “major event” as “an event that exceeds reasonable design and or operational limits of the electric power system. A Major Event includes at least one Major Event Day (MED).” IEEE, Standard 1366, Section 3.12.

This Standard defines a “major event day” as:

\begin{quote}
A day in which the daily system SAIDI exceeds a threshold value, $T_{\text{med}}$.
\end{quote}

For the purposes of calculating daily system SAIDI any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater

\(^{111}\) Company Response to EX-003-027.
than $T_{med}$ are days on which the energy delivery system experienced stresses beyond that normally expected (such as severe weather). Activities that occur on major event days should be separately analyzed and reported.

Standard 1366, Section 3.13.

From the above language, and other provisions in Standard 1366,\textsuperscript{112} it is clear to Staff that a MED is a calendar day in which the daily SAIDI exceeds the threshold value, $T_{med}$. This interpretation is also consistent with the meaning given to the term “major event day” by the authors of the draft IEEE 2.5 Beta Methodology that was ultimately adopted in 2003. In discussing the draft, the authors recognized that a “major event day” means “[a] calendar day on which a major event begins.” See \textit{P1366 Major Event Day Language Draft 2.5 Beta Method}, Rich Christie, Jim Bouford, John McDaniel, Dave Schepers, and Cheri Warren at page 1 (2002 Draft 2.5 Beta Method).\textsuperscript{113} In this document, the authors further stated:

When a major event occurs which lasts through midnight (for example, a six hour hurricane which starts at 9:00 p.m), the reliability impact of the event may be split between two days, neither of which would exceed the $T_{MED}$ and therefore be classified as a major event day. \textit{This is a known inaccuracy in the method that is accepted in exchange for the simplicity and ease of calculation of the method.}

See \textit{id.} at 6 (emphasis added).

More importantly, the baseline values for $T_{med}$ are based on a calendar day (which CMP does not propose to change). Thus, CMP’s use of a 24 hour rolling period in calculating a MED would lead to inconsistent and distorted results and

\textsuperscript{112} Section 4.5 also defines a MED as “a day,” not a 24 hour period, in which the daily system SAIDI exceeds a threshold value $T_{med}$  

\textsuperscript{113} This draft language, portions of which were stated verbatim in the Company’s response to EX-003-027, can be found online at: \url{http://grouper.ieee.org/groups/td/dist/sd/doc/2002-08-P1366MajorEventDayLanguageDraft4.pdf}
an “apples to oranges” approach when comparing the Company’s performance to baseline data. Allowing the Company to determine which rolling 24 hour period constituted a “day” would undermine the objective and standard approach for determining a MED that is intended by the IEEE 2.5 Beta methodology. Rather, CMP would be permitted to decide which 24 hour period best served the Company and could combine SAIDI data occurring over multiple calendar days, which, individually, would not qualify as a MED, but which, when combined, would result in an exclusion.\footnote{If the Commission was inclined allow CMP to utilize a rolling 24 hour method for determining a MED, Staff believes it would be appropriate to lower the reliability targets because more event days would be subject to exclusions.} To allow for an apples-to-apples comparison of the 24 hour period chosen by CMP to the Tmed threshold value, the Tmed would have to be re-calculated using the same 24 hour period for the previous five-year baseline period as the 24 hour period selected by CMP used to calculate the SAIDI for the observed 24 hour period. This is impractical and would be inconsistent with CMP’s original intent of using the 24 hour period it selected.

For all of the above reasons, Staff recommends that the Commission reject the Company’s proposal to use a 24 hour rolling period in calculating a major event day. Rather, consistent with prior ARPs and generally accepted utility practice, Staff recommends that the Commission use the IEEE Beta method in calculating “major event days,” which should be defined as calendar day in which the daily SAIDI results exceeds a threshold value, Tmed.

Finally, CMP proposes that a “discretionary exclusion” provision apply to the customer service metrics, with the exception of the call center service quality metric. Specifically, CMP requests that it be allowed to seek permission from the
Commission to exclude data from the performance calculations related to specific events that are otherwise non-excludable and that are beyond the Company’s control including, but not limited to, software viruses and catastrophic equipment failures, work stoppages or strikes.\(^{115}\) Staff does not oppose CMP’s proposal to request permission on a case-by-case basis for a discretionary exclusion for the customer service metrics based on appropriate justifications.

3. Customer Service Metrics

a. Meter Reads

This metric measures the percentage of the Company’s meters that are read and not estimated on an annual basis. This metric was added to CMP’s SQI in ARP 2008 when the Company was manually reading its meters and had a benchmark of 94% of meters read on-time. CMP recommends that this metric be continued in ARP 2014, with a revised metric of 97% of meters read on-time.\(^{116}\) Under ARP 2008, CMP excluded from this calculation the estimated reads on days that were excluded from the CAIDI and SAIFI calculations using the IEEE 2.5 Beta approach. CMP recommends that the same exclusion process apply for ARP 2014.

CMP states in its testimony that it is important to recognize that the mere presence of the AMI system does not mean that there will not be any estimated reads. Unplanned and unforeseen events may occur which prevent an AMI read such as a device failure, tampering or a communication outage. \textit{Id.} Also, there are approximately 8,247 opt-out customers for whom the Company must manually read

\(^{115}\) See Customer Service Testimony at 5 – 18.

\(^{116}\) See May 1 Customer Service Panel Testimony at 3 (Customer Service Testimony).
meters every other month. Accordingly, CMP proposes the following exclusions in determining compliance with this SQI: (1) Opt-out customers will be read on a bi-monthly basis; and (2) that a “discretionary exclusion” provision for this meter reading service quality indicator be adopted, similar to the discretionary exclusion provisions of ARP2008 for the calls answered and CAIDI and SAIFI service quality indicators. Specifically, the Company proposes that it be permitted to request permission from the Commission to exclude data from the calculation of the meter read rate related to specific events, otherwise non-excludable, that are beyond the Company’s control including but not limited to software viruses and catastrophic equipment malfunctions, work stoppages or strikes that affect CMP’s ability to maintain meter reading levels. CMP would request such a discretionary exclusion within 45 days of the associated event.

Staff questions the value of the meter read metric, as well as the 97% Company recommended benchmark, in light of the full implementation of AMI. In 2012, CMP read 99.6% of meters “on-time,” even though AMI had not yet been fully implemented. CMP states in its testimony that the low number of estimated reads in 2012 is a result of keeping high staffing levels in place to support the transition to the new AMI system and that unplanned and unforeseen events may occur which may prevent an AMI read. CMP also stated that if power is lost during the three day time period that the smart meter has to relay a reading, the customer’s bill would have to be

\[\text{\textsuperscript{117}} \text{The Commission’s June 22, 2011 Order (Part II) issued in Docket No. 2010-345 specifies that the no-read month will not be considered an estimate.}\]

\[\text{\textsuperscript{118} Customer Service Testimony at 4.}\]

\[\text{\textsuperscript{119} Customer Service Testimony at 3.}\]

\[\text{\textsuperscript{120} Id. at 3 - 4.}\]
estimated for that month.\textsuperscript{121} CMP also acknowledged, however, that a power outage would have to last the entire three day period to prevent an AMI reading from taking place.

Staff recommends that the meter read metric be eliminated from the SQI. With the full implementation of AMI, the need for this metric is obviated. Besides a faulty meter or tampering by a customer, which Staff believes would be rare events, the most likely reason a meter read could not be obtained with AMI is the loss of power. Consequently, absent an outage lasting three days or longer, CMP is virtually assured of meeting this benchmark. Staff finds it unlikely that power would be lost for the entire three day period that the smart meter has to relay a reading. In any case, under such an event CMP would be likely to receive an exemption for the weather event. Further, CMP did not provide a basis for its recommended benchmark. The previous benchmark of 94\% was based on historical performance during a time that CMP was manually reading its meters. As discussed above, the only situation in which CMP will have to manually read its meters under ARP 2014 is for the few customers that have opted-out of the smart Meter program. In light of this, Staff recommends that this metric be eliminated from the SQI.

b. Percent of Business Calls Answered

CMP’s “percent of business calls answered” metric and the “80 percent of calls answered within 30 seconds” benchmark, were established in 1995 as part of CMP’s ARP95 in Docket No. 92-45(Phase II) and were continued through ARP 2000 and ARP 2008. CMP recommends retaining this metric, but modifying the

\textsuperscript{121} July 24, 2013 Technical Conference Transcript at 4-5.
benchmark from 80% of calls answered in 30 seconds to 80% of calls answered in 45 seconds.

In April 2013, the Commission issued an Order in Docket 2007-215(Phase II) that extended the 30 second answer period to 45 seconds for the duration of the ARP year due to the potential for CMP staff to spend additional time answering questions from customers regarding the Commission’s “green power offering.” Specifically, customers calling CMP because they are moving from one location to another or potential customers calling about new construction are notified by the CMP person handling the call of the Green Power Program and offered the opportunity to speak with someone else if they are interested to learn more. CMP states in its testimony in this case that it agreed with the Commission’s finding that CMP should not have any additional risks with respect to achieving its SQI target performance as a result of its agreement to assist in the implementation of the green power offer and that revising the business calls answered service quality metric as described in the Order would reduce the risk that CMP would be exposed to missing this SQI.

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122 In that Order, the Commission modified CMP’s business calls answered service quality metric contained in its current ARP so that the metric will be 80% of calls answered within 45 seconds for the remainder of the current ARP. The Commission also stated that this modification was in recognition of CMP’s agreement to have its customer service department provide support in the implementation of the statewide green power offer.

123 During the 2009 session, the Legislature enacted An Act To Establish the Community-based Renewable Energy Pilot Program (Act), P.L. 2009, ch. 329. Part B of the Act requires the Commission to arrange for a green power offer that is composed of green power supply and to ensure that the green power offer is available to residential and small commercial electricity customers. 35-A M.R.S.A. § 3212-A(1-A).

124 Customer Service Testimony at 7 – 8.
Staff agrees that this metric should be retained, but disagrees with CMP’s request for extension of the time period for answering from 30 seconds to 45 seconds. Rather, Staff recommends that the Commission retain the 30 second standard for this metric. CMP cites the Commission Order issued in Docket No. 2007-215 as justification for continuing the 45 second answer time. However, the Commission also noted in that Order that “…the business calls answered metric, as well as all of the service quality standards, will be subject to review in the next ARP proceeding and that our decision here should not be viewed as binding or precedent as to what metric or service quality standard should be set in that proceeding.” Order at 2. We do not believe that the Company has demonstrated that a 45 second time period is either necessary or appropriate.

A review of CMP’s move in/move out call answer times shows that CMP’s call times have not increased since it agreed to notify these customers of the Green Power Program.\footnote{125} Further, between April 10, 2013, the date when CMP agreed to begin providing the green power statement to customers, and July 5, 2013, no customer requested additional information regarding the Green Power Program.\footnote{126} Consequently, any additional time to the move-in/move-out and construction calls in relation to the Green Power Program has been \textit{de minimis}. In addition, a review of CMP’s calls answer statistics between April 10, 2013 and June 21, 2013, shows that calls relating to move-in/move-outs represented only 17\% of the total number of business calls received. See \textit{id}. Thus, in addition to any additional time being negligible, the number of move-in/move-out calls represents only a fraction of the

\begin{footnotesize} 
\footnotetext[125]{See Company Response to EX-004-002.} 
\footnotetext[126]{See Company Response to EX-004-003.} 
\end{footnotesize}
overall calls. Therefore, any additional time allowance is not warranted, and Staff proposes returning to the 30 second metric utilized in the prior three ARPs.

c. Call Abandonment Rate

In addition to the “Percent of Business Calls Answered” metric, Staff recommends that the Commission adopt a new metric to measure the number of calls to CMP’s business line that are abandoned by callers. Call centers often use a speed of answer metric combined with a call abandonment rate to measure call center performance. The “call abandonment rate” measures the number of calls terminated by the caller prior to being answered. A high call abandonment rate is an indicator of inadequate service. This metric helps ensure that utilities do not “abandon” callers that wait beyond the designated call answer period of the speed of answer metric because these calls have already exceeded the metric’s wait time.127

Staff recommends a 5% benchmark for this metric. This represents CMP’s poorest performance for this metric over the past three years (2012).128 See Attachment 1 of Company’s Response to EX-004-002. As with the “percent of business calls answered” metric, Staff also recommends excluding days from this calculation that are excluded from the CAIDI and SAIFI calculations using the IEEE 2.5 Beta approach.

d. Call Center Service Quality

CMP’s SQI has contained a Call Center service quality metric since its first ARP in 1995. The current metric is based on customer responses

127 CMP’s “percent of business calls answered” metric is a “speed of answer” metric.

128 This methodology is consistent with the methodology used to establish benchmarks for the ARP 2008 service quality metrics.
to two questions contained on a postcard survey that is mailed weekly to a random sample of 200 customers who call CMP’s business line and speak with a Customer Relations Center Specialist. The first question is "Was the employee you spoke with on the telephone knowledgeable"? The second question is "Overall, how satisfied are you with the customer service representative who answered your call"? The percent responding "yes" to the first question or "very satisfied" to the second are averaged to calculate the benchmark. The baseline is 85% and when one of the two survey questions is not answered, that single question is not included in the calculation.

CMP proposes to retain this metric, as well as the 85% benchmark, but proposes that both "very satisfied" and "somewhat satisfied" responses should be counted as positive. CMP claims this proposal is necessary for two reasons. First, it states that most transactions administered by the call center, and measured by the survey, are collections-related and that attainment of a “highly satisfied” rating from a customer who cannot afford to pay their bill is more difficult. CMP also states that in follow-up conversations with customers regarding an unsatisfactory response to a postcard survey, CMP staff has been told that the call center representative was “fine” and that the customer indicated they gave a score of “somewhat satisfied” because “no one is perfect” and that the customer did not indicate a problem with the service provided. CMP further states that as it moves more customer transactions to “self-service” through its interactive voice recognition (IVR) system, as opposed to being handled by a customer service representative (CSR), that achieving the 85% response rate will more challenging because the transactions that it expects to handle through

129 See Customer Service Testimony at 11 – 12.
self-service will not be credit and collections related. Thus, the proportion of credit and collection calls handled by the CSRs will increase.\textsuperscript{130}

Staff agrees with CMP that the “call center service quality” metric should be retained and agrees that a “somewhat satisfied” customer response to the survey should be counted towards the 85% benchmark. However, Staff disagrees with the methodology CMP has been using to calculate its performance. As discussed above, CMP averaged the “yes” answer with the “highly satisfied” answer to the second question when calculating performance towards the 85% benchmark under ARP 2008. Consequently, CMP has been achieving partial credit when only one of the required responses was provided. This methodology is not consistent with the methodology the Staff believes was originally intended for this metric, nor is it consistent with the methodology Staff believes is appropriate for this metric. Staff believes that CMP should not be able to receive partial credit when only one of the required answers is provided and that CMP should only receive credit when a customer provides both required answers.

Staff requested in EX-04-05 that CMP provide its performance under ARP 2008 for this metric in situations in which customers responded “yes” to the first question and also responded “highly satisfied” or “somewhat satisfied” to the second question. CMP’s performance is depicted in Table 33 below. A review of this Table shows that the poorest performance for this metric, using this methodology to measure performance, was 84.8% in 2012. Because this result would be rounded up to

\textsuperscript{130} See July 24, 2013 Transcript at 72-73 (emphasis added).
85% for this particular benchmark, Staff believes the 85% benchmark used for this metric in ARP 2008 should be continued.\textsuperscript{131}

TABLE 33

<table>
<thead>
<tr>
<th>Year</th>
<th>% of customers responding to “yes” on question 3 \textbf{and} either “very” satisfied or “somewhat” satisfied on question 5.</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>84.8%</td>
</tr>
<tr>
<td>2011</td>
<td>87.0%</td>
</tr>
<tr>
<td>2010</td>
<td>85.3%</td>
</tr>
<tr>
<td>2009</td>
<td>85.4%</td>
</tr>
<tr>
<td>2008</td>
<td>86.0%</td>
</tr>
</tbody>
</table>

e. CMP’s Responsiveness to Customer Complaints

The “PUC Complaint Ratio” has been included as a metric in each of CMP’s ARPs since 1995. In 2010, the Commission initiated an investigation of CMP’s credit and collection practices and how such practices and related accounting methods may have influenced CMP’s standard offer-related uncollectible balances and write-offs.\textsuperscript{132} In that investigation, CMP argued that the “PUC Complaint Ratio” creates a tension between the need for it to aggressively pursue its collections to control its

\textsuperscript{131} Because the benchmark is expressed as a whole number, the performance results would also be expressed as whole numbers. Further, the 85% result represents ‘the poorest performance’ for that metric over the past three years and this is the methodology used to establish the other benchmarks when such historical data is available.

uncollectible balances and the need to minimize customer complaints to the CAD to avoid incurring a penalty under its SQI. In the Order closing that case, the Commission stated “[W]e believe that CMP has presented a strong argument for closely examining the issue of whether it’s appropriate to continue to include the PUC Complaint ratio, as it is currently measured, as part of the SQI metric in any future ARP.”

In its current case filing, CMP proposes to eliminate the “PUC Complaint Ratio” and replace it with a new metric that measures its responsiveness to customer disputes or complaints that are not related to collections issues (non-collections complaints). Further, CMP also recommends excluding complaints that relate to customer dissatisfaction with pricing tariffs, public policy or regulatory rule interpretation/understanding, and AMI issues because customers should not be allowed to file a complaint regarding Commission-approved systems and processes. Finally, CMP recommends that complaints involving multiple topics be coded as a “collections complaint,” and be excluded from the metric if one part of the complaint involves collections. Customer Service Testimony at 15 - 16.

The justification that CMP cites for eliminating the “PUC Complaint Ratio” metric is that, according to the Company, it provides conflicting incentives for the Company to minimize the number of complaints from a small percentage of customers with poor payment histories while also striving to minimize bad debt costs for all customers. See May 1 Policy Panel Testimony at 31. To remedy this conflict, CMP instead proposes to restructure this metric to measure the timeliness of CMP’s response to customers’ non-collections related complaints. See id. Under

\(^{133}\) Customer Service Testimony at 14.
CMP’s recommendation, all non-collections complaints received by the CAD would be referred back to CMP for resolution prior to any further action by the CAD. CMP would then have to “respond to” at least 85% of referred complaints within 25 calendar days of the complaint’s receipt. CMP would assume responsibility for reporting the results of its investigation by issuing a “document of resolution” to the CAD which the CAD could then use to close the case.134 See Customer Service Testimony at 18.

Staff acknowledges some of the problems and tensions associated with the “PUC Complaint Ratio” metric, but disagrees with the Company’s recommendation that this metric be replaced with a new metric designed to measure CMP’s responsiveness to customer complaints. Staff instead recommends that the PUC Complaint Ratio be eliminated due to reasons cited by CMP and that the Commission should also reject CMP’s proposed metric. This recommendation is based on the following.

The process proposed by CMP of referring non-credit and collections complaints back to CMP is not consistent with PUC rules and is not good customer service. Chapter 815, Section 13(H)(1) allows a customer to file a complaint with the CAD once the customer has attempted to resolve the complaint with the utility and was unsuccessful. Referring a customer that contacts the CAD for assistance who has already attempted to resolve their complaint with CMP is not consistent with this requirement. Further, Staff believes that requiring a customer to attempt to resolve a dispute with the Company, after they have already been unsuccessful in doing so,

134 Staff is not sure what “case” would be closed in this situation because it referred the matter to CMP prior to opening a case.
would likely be futile, would not meaningfully increase the likelihood that a dispute would be resolved, an may only lead to customer confusion and/or frustration.

Second, Staff finds CMP’s proposed metric too vague to be a good measure of CMP’s “responsiveness to customers.” For example, CMP will consider a matter “responded to” when the Company provides an answer or a proposed resolution to the customer’s complaint.\textsuperscript{135} Thus, as long as the Company responds in some way to the customer’s complaint within the 25 day period – even if that response is unsatisfactory to the customer and is not a comprehensive response to the customer’s complaint – the benchmark that is proposed by CMP would be “met.”

Finally, non-collection complaints represent a small portion of the overall complaints received by CMP. Measuring CMP’s responsiveness to only this small subset of customer complaints may not be an accurate reflection of CMP’s overall responsiveness to customer complaints and disputes. Therefore, Staff recommends that the “PUC Complaint Ratio” be eliminated from the SQI and that CMP’s proposed replacement metric also be rejected.

f. New Service Installations

The current “New Service Installation” metric was added to CMP’s SQI in ARP 2008 and measures the time it takes CMP to complete the various stages of a new service line installation. The Stipulation entered for ARP 2008 did not establish a specific metric or benchmark for new service installations. Rather, the Stipulation called upon the Commission to conduct a proceeding beginning in July 2008.

\textsuperscript{135} See Company’s Response to EX-04-010.
to determine a New Service Installation Metric for implementation beginning in 2009.\textsuperscript{136} In \textit{Maine Public Utilities Commission, Investigation Into Establishing a New Service Installation Service Quality Metric for CMP’s ARP 2008}, Docket No. 2008-00294, Order Approving Stipulation (Mar. 31, 2009), the New Service Installation Metric was established in order to measure CMP’s performance in responding to six types of new service installation requests. Each new service type is comprised of several stages that are measured and summed together to calculate the number of days to complete the new service type. For example, CMP’s service drop installation component of the metric will be comprised of the time CMP takes to provide service information from the initial call; to do a meter inspection from the time of the customer request; and to energize the line from the time forms are completed, applicable fees paid, dig safe requirements met, and successful meter inspection completed. The sum of CMP’s response times to these items will then be measured against the overall metric (12 days) for this service type. In that same proceeding, a benchmark of at least 85% of new service installations completed within the specified timeframes was also established. The 85% benchmark represented an agreed-upon time period among the parties to the case and was not based on historical performance.

CMP proposes to retain the “new service installation” metric from ARP 2008, but increase the benchmark from 85% of deadlines met to 90% of deadlines met.\textsuperscript{137} CMP recommends increasing the benchmark from 85% to 90% due to its strong performance regarding this metric over the past four years. CMP further states that service installation programs historically follow housing start projections and

\textsuperscript{136} See ARP 2008 \textit{Stipulation at ¶ 31.}

\textsuperscript{137} Capital Investment Testimony at 15 – 16.
that a modest increase in housing starts is forecasted by IHS Global insights for 2014 and 2015 with minor fluctuations thereafter.\textsuperscript{138} Based on this modest projected increase, CMP recommends the 90% benchmark.

Staff agrees with CMP’s recommendation to retain the “new service installation metric” but disagrees with the 90% benchmark that the Company proposes. As stated above, the 85% benchmark from ARP 2008 was not based on historical performance because this was a newly created metric. Staff believes that, at this point in time, we have four years of historical data upon which to base the benchmark and recommends that the appropriate benchmark be based on historical performance. This historical performance is depicted in Table 34 below.

\textbf{TABLE 34}

<table>
<thead>
<tr>
<th></th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>New Service Installation</td>
<td>99%</td>
<td>99%</td>
<td>97%</td>
<td>98%</td>
</tr>
</tbody>
</table>

Staff agrees with CMP that the number of new service installations related to new housing construction will likely increase in 2014 and 2015. With the improving economy, housing starts are likely to increase. However, CMP’s own testimony indicates that only a “modest” increase in housing starts is expected. Thus, this modest increase should be considered when reviewing the Company’s past performance regarding this metric. Considering the fact that the worst performance for this metric under ARP 2008 was 97% in 2011, it is Staff’s view that the difference between that result and CMP’s proposed benchmark of 90% represents more than an

\textsuperscript{138} \textit{Id.} at 14.
expected “modest” increase in housing starts. Further, Staff believes that CMP should be able to handle a modest increase in housing starts, which may translate into an equally modest increase in new service requests, without any deterioration in performance. Thus, Staff recommends a benchmark of 95%. This recommendation takes into consideration both CMP’s strong performance over the past four years regarding this metric, as well as the expected “modest” increase in housing starts in 2014 and 2015.

4. **SQI Penalty Structure**

CMP proposes to separate the penalty structure for the reliability metrics from the other aspects of customer service quality, and assign to the reliability metrics a greater maximum penalty exposure. Specifically, the Company proposes that SAIFI and CAIDI be each subject to penalties of up to $2 million per year. For the remaining metrics, CMP proposes that a penalty amount of $2 million be equally allocated among the five metrics. CMP states that this recommendation is based on its experience and research that shows customers place a far greater value on the reliability of electric delivery service than on any other aspect of customer service. See Policy Testimony at 33.

CMP proposes to retain the ARP 2008 methodology of penalty calculation for all service quality measures other than SAIFI and CAIDI.\(^{139}\) For these metrics, the $2 million penalty pool would be assessed on a point-based system in which 100 points are equally allocated among the five indicators. Points for each

\(^{139}\) These five metrics are: meter read rate; percent of business calls answered; customer service quality (phone center staff); company response to customer complaints; and new service installations.
indicator would be assessed based upon the percentage variance of actual performance relative to the indicator baseline. Total points assessed for these five indicators are then summed and multiplied by the average point value of $200,000 per point.  

For SAIFI and CAIDI, the $2 million maximum penalty would be assessed at SAIFI and CAIDI performance levels of 2.10 and 2.18 or above, respectively. For performance levels between the applicable current year target and these maximum penalty levels, the penalty amount would be interpolated linearly. Id.  

Staff recommends that the Commission accept CMP’s proposal to increase the maximum penalty to $6 million and agrees with CMP that the reliability metrics should have a higher potential penalty value than the customer service metrics, but disagrees with, and recommends that the Commission reject, CMP’s recommended penalty calculation methodology. Instead, Staff recommends that the penalty calculation methodology used in the SQI under ARP 2008 be continued in ARP 2014, with the exception that the points associated with the reliability metrics have a higher value than the points related to the customer service metrics.  

Under CMP’s recommended penalty calculation formula, the value of the customer service metrics are significantly reduced due to the total cumulative penalty for all metrics being reduced from $6 million to $2 million. Under Staff’s recommended methodology, the full penalty amount of $6 million can be realized with a 10 point miss, either collectively or individually, for the reliability metrics and a 15 point miss, either collectively or individually, for the customer service metrics. In addition, as  

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140 See Response to EX-002-023.
discussed in the Reliability section of this analysis, staff recommends the addition of two new reliability metrics, CEMI and CELID. Because these are new metrics without a previous benchmark, CMP’s proposed methodology for establishing benchmarks for the reliability metrics would not be possible. For these reasons, Staff recommends that the Commission reject CMP’s proposed methodology for calculating penalties under the SQI and instead use the same methodology as that used under ARP 2008.

Staff’s recommended SQI has a total of eight metrics, with each metric having a value of 12.5 points. The point value for each of the reliability metrics will be $600,000 and the point value for each of the customer service metrics will be $400,000.\(^{141}\) As with the methodology under ARP 2008, if the Company’s performance fails to meet any of the baselines, points will be deducted for each metric for which the company fails to meet the baseline. The deduction will be based on the percentage by which actual performance deviates from the baseline. For example, if actual performance deviates from the baseline by 2.5%, the deduction would be 0.3 points (12.5 X .025). No penalty will be imposed for point deductions less than 0.3 points. Point deductions less than 0.3 for a given year shall be carried over to any subsequent year where penalties are imposed. See Table 35 below for a summary of the ARP 2008 metrics and benchmarks, CMP’s recommended ARP 2014 metrics and benchmarks, as well as Staff’s recommended ARP 2014 metric and benchmarks.

\(^{141}\) This point value means the full penalty of $6 million will be incurred with a 10 point deduction for the reliability metrics and a 15 point reduction for the customer service metrics. This is the same methodology employed under ARP 2008, but with the points associated with the reliability metrics having a higher value than the points associated with the customer service metrics.
### TABLE 35

**Proposed Metrics and Penalty Provisions**

<table>
<thead>
<tr>
<th>Metric</th>
<th>ARP 2008 Benchmark</th>
<th>CMP Proposed Benchmark</th>
<th>Staff Proposed Benchmark</th>
</tr>
</thead>
<tbody>
<tr>
<td>Meter Read</td>
<td>94%</td>
<td>97%</td>
<td>Eliminate metric</td>
</tr>
<tr>
<td>Calls Answered</td>
<td>80% in 30 seconds</td>
<td>80% in 45 seconds</td>
<td>80% in 30 seconds</td>
</tr>
<tr>
<td>Customer Rep Survey</td>
<td>85%</td>
<td>85%</td>
<td>85%</td>
</tr>
<tr>
<td>Customer Response/formerly complaint ratio</td>
<td>1.2 complaints per 1,000 customers</td>
<td>85 % responded to within 25 days</td>
<td>Eliminate metric</td>
</tr>
<tr>
<td>News Service Installation</td>
<td>85%</td>
<td>90%</td>
<td>95%</td>
</tr>
<tr>
<td>CAIDI</td>
<td>2.18</td>
<td>2.00; 1.99; 1.98; 1.97; 1.96</td>
<td>2.00</td>
</tr>
<tr>
<td>SAIFI</td>
<td>2.10; 2.08; 2.00; 1.92; 1.89</td>
<td>1.89</td>
<td>1.75</td>
</tr>
<tr>
<td>CEMI</td>
<td>N/A</td>
<td>N/A</td>
<td>5 outages for X% of total CMP customers</td>
</tr>
<tr>
<td>CELID</td>
<td>N/A</td>
<td>N/A</td>
<td>8 hours for X% of total CMP customers</td>
</tr>
<tr>
<td>Call Abandonment Rate</td>
<td>N/A</td>
<td>N/A</td>
<td>5%</td>
</tr>
<tr>
<td>CAIDI (no exclusions)</td>
<td>N/A</td>
<td>N/A</td>
<td>Reporting only</td>
</tr>
</tbody>
</table>

### F. Mandated Costs

The Staff recommends using the same criteria for mandated costs used in the current ARP with certain clarifications. First, the *force majeure* event would not apply to storms which would be recovered either through the storm cost allowance included in rates or via a request for an accounting order. Second, recovery for mandated costs should be limited to the event’s impact revenues and expenses during the current ARP period. In other words, there would be no prior period adjustments. Further, Staff would not incorporate CMP’s proposed expansion of this category to include changes resulting from tax audits.
Carrying costs on mandated costs deferred from January 1 of the year following the cost incurred until when reflected in rates in the next annual rate change would be at CMP's short-term borrowing cost.

G. Flow-Through Items

The Staff would propose that the following costs continue to be subject to flow-through/reconciliation; system benefit charges; Electric-Lifeline Program (ELP) costs; and costs related to CMP's Line Clearance Contractor Costs (not storm related). Such costs would be subject to carrying costs at CMP's short term borrowing rate.

H. Transmission Cost Allocation Adjustment

The current ARP contains a provision to account for changes in the FERC Customer Cost Allocation Factor so as to avoid the double-counting of such costs. Given the large recent changes in the other transmission allocation factors, Staff recommends that this provision be expanded to include those costs subject to the FERC Plant and Rate Base factors.

I. Capital Gains or Losses

The Staff recommends retaining the current ARP provision governing capital gains or losses.

J. Earnings Sharing

The Staff finds CMP's proposed earnings sharing mechanism acceptable with the following modification/clarifications. First, that the target ROE be set at 150 basis points above the allowed ROE in this case. The ROE would be calculated based on equity ratio approved by the Commission in this case. Finally, earnings sharing would be used to offset storm costs which would already be incorporated into rates.
K. **Overall Formula**

Based on the above discussion, Staff recommends the following rate change formula if the Commission adopts an ARP in this proceeding:

\[ PI = GPP - PI - \text{Productivity Offset(s)} +/- \text{Flow-through Items} +/- \text{Mandated Costs} +/- \text{Transmission Costs Allocations} - \text{Earnings Sharing} – SQI \text{Penalties} +/- \text{Capital Gains or Losses} \]

**VIII. REVENUE ALLOCATION AND RATE DESIGN**

A. **Marginal and Embedded Cost Studies**

Staff has not performed a detailed analysis of CMP’s marginal cost or embedded cost study and has no position at this time regarding the reasonableness of the studies. We note that CMP appears to have relied upon both of these studies for general guidance on the direction its class revenue allocations and rate designs should move, but has not applied the results of either study precisely. We agree with this use of the studies, given that they are neither precise nor necessarily “correct.” Given the nature of CMP’s use of the studies, and the more fundamental and policy issues raised by CMP’s rate design proposals, at this point Staff’s focus has been to address the Company’s proposals at a higher level rather than analyze the cost-of-service studies from a technical perspective.

B. **Revenue Allocation Among Customer Classes**

At this time, Staff has no issues or comments on CMP’s proposed approach to revenue allocation among customer classes as described in its testimony. RARD at 4-6.
C. Residential and Small Commercial Customer Rate Design

The overriding theme of CMP’s proposed rate design is that the costs of its distribution system are essentially “fixed” and therefore its rate design should transition to higher “service” charges and lower “variable” charges. RARD at 5. However, CMP’s continued use of the term “fixed costs” in its filings is confusing in that CMP’s use of the term includes “demand-related” costs (EXM 015-006, Oct 7, 2013 Tr. at 69), and therefore obscures the distinction between customer-related and demand-related costs.

The commonly accepted approach to electric or T&D rate design is to classify costs as: 1) customer-related (recovered through a fixed monthly customer charge); 2) demand-related (recovered through a demand charge); and 3) energy-related (recovered through a usage charge). CMP does not disagree with this basic approach. Oct 7, 2013 Tr. at 26-27. However, the residential and small commercial classes do not have a demand charge. This raises the issue of which type of charge should be used to recover demand-related costs—customer charges or energy charges.

CMP argues that fixed customer charges should be used to recover demand-related costs, because these costs do not vary with energy usage. Oct 7, 2013 Tr. at 10, 73-77, 10. Staff disagrees. In Staff’s view, demand-related costs should be recovered through energy charges which are a better proxy for demand charges than fixed monthly customer charges. Demand-related costs are essentially driven by usage, albeit maximum usage in a given hour (i.e., kWh per hour). Accordingly, energy charges provide both a superior price signal and a more equitable cost recovery mechanism with respect to demand-related costs than fixed monthly charges. By way
of comparison, in the rate classes for medium-to-large C&I customers, MGS, IGS and LGS, the higher use customers will generally pay for more of these costs than lower use customers. The same should be true for residential and small commercial customers. Therefore, the Staff’s position is that for classes that do not have demand charges, the fixed monthly charges should reflect only customer-related costs and demand-related costs should be recovered through energy charges.

The next issue is determining what costs should be classified as customer-related. CMP states that meters and services (referred to as customer costs) and transformers and secondary lines (referred to as local facilities costs) are customer-related, leaving substations and primary lines (referred to as distribution grid costs) as demand-related. Although there is no dispute that that meters and services are customer-related costs, there is an issue of whether local facilities costs should be properly classified as customer-related and recovered through monthly customer charges. This issue is illustrated by CMP witnesses’ characterization at the October 7, 2013 technical conference that meter and services are “purely fixed customer costs,” and substations and primary lines are “pure demand,” and their acknowledgement that each customer does not require its own transformer. Oct 7, 2013 Tr. at 69-70.

Moreover, CMP’s marginal cost study classifies transformers and secondary charges as “demand charges, see e.g., Schedule PMN-3, page 1a of 2.

Staff’s view is that CMP’s “local facilities costs” should not be classified as customer-related and, instead are more properly classified as demand-related.

Although we agree with CMP that, once in place, secondary lines and transformers do not vary with demand in the short-term, over the long-term these facilities must be
designed and sized to meet the demands of the customers they serve. Accordingly, the costs of should be recovered in demand charges or, for residential and small commercial customers, in energy charges, and the fixed monthly charges should reflect only the costs of meters, services and customer-related O&M.

Based on its position regarding “fixed cost” recovery, CMP proposes to change the monthly service charge as follows (RARD at 20-23):

<table>
<thead>
<tr>
<th>Rate Class</th>
<th>Current</th>
<th>Proposed 7/2014</th>
<th>End of Rate Plan</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rate A</td>
<td>$5.71</td>
<td>$12.00</td>
<td>$20.00</td>
</tr>
<tr>
<td>SGS (1 Ph)</td>
<td>$11.48</td>
<td>$13.00</td>
<td>$25.00</td>
</tr>
<tr>
<td>SGS (3 Ph)</td>
<td>$19.10</td>
<td>$22.00</td>
<td>$42.00</td>
</tr>
</tbody>
</table>

CMP’s marginal cost study indicates that its marginal customer and local facilities costs for Rate A customers are $15.52, PWN-2, Oct 7, 2013 Tr. at 72, of which the marginal customer costs alone are approximately $10.00, PWN-2. Accordingly, Staff can support an increase in the residential Rate A charge to $10.00.\textsuperscript{143} Similarly, Staff’s view is that the fixed monthly charges for CMP’s other customer classes should reflect only the marginal costs of meters and services. Based on our review of CMP’s marginal cost study, it appears that, for many classes, the existing fixed monthly charges are well in excess of the marginal customer costs. Schedule PWN-2. Consideration should be given to decreasing the fixed monthly charges and increasing the demand charges for those classes.

\textsuperscript{142} Rate A currently include 100 kWh as part of the monthly charge. CMP proposes to remove this minimum charge. See discussion below.

\textsuperscript{143} As discussed below, the $10.00 monthly charge would include 100 kWh of usage.
D. Optional Demand Charge for Residential and Small Commercial Customers

CMP has indicated that, with the implementation of AMI, it has the capability to charge residential and small commercial customers a demand charge. EXM-015-015, 016, 017. Although a demand-base rate would provide an improved price signal, Staff agrees with CMP that making such a rate design mandatory for these customer classes at this time would be disruptive and confusing. However, Staff suggests that CMP consider an optional rate for these classes that include demand charges in place of energy charges. Demand charges may actually help reduce customer confusion in the long run because by replacing energy charges, the fixed and demand charges would solely represent costs to pay CMP for delivery, while energy charges would solely represent costs paid to the standard offer or competitive electricity provider for supply.

The optional rate would be implemented through the current residential and small class meters that measure demands over one hour periods. Staff is aware that several utilities in the country have such an optional rate. These include Virginia Electric Power Company, Alabama Power Company, Otter Tail Power Company, Alaska Electric Light and Power Company, and Swanton Village and Stowe Electric Departments in Vermont.

E. Seasonality/ Time-of-Use

CMP proposes to eliminate seasonality rate differences, RARD at 11, upon the rationale that the cost differential between summer and winter is not enough to warrant seasonal pricing, Oct 7, 2013 Tr. at 28-29. However, CMP’s marginal cost study did not examine seasonal costs, Oct 7, 2013 Tr. at 92, because of CMP’s
assumption that there are no seasonal cost differences. However, CMP acknowledges that it is summer demands that drive costs. Oct 7, 2013 Tr. at 92. CMP’s position in this regard appears inconsistent. It may be that CMP’s consideration of the question is in terms of broad “seasons” for which, on average, it believes that costs do not vary. If so, such consideration masks the issue of whether costs are higher at certain times of the year than at others. For example, although costs on average over the “summer period” may be the same as costs on average over the “winter period”, this does not address the question of whether costs are higher in July and January than they are in April or September.

CMP also has the view that it costs do not vary by time-of-day (Oct 7, 2013 Tr. at 109), but again appears to agree that times of peak loads do drive system costs, Oct 7, 2013 Tr. at 111. Again, CMP positions appear to be inconsistent. Moreover, despite its position that costs do not vary by time of day, CMP would maintain diurnal variations in its pricing. CMP would remove shoulder period pricing from its time of use rate, and roll those hours into the on-peak period, RARD at 10-11, and would maintain the current rate structure in which there are generally no demand charges in the off-peak time periods. In addition, CMP would maintain its diurnally differentiated A-TOU and SGS-TOU structures in which prices are much higher during the on-peak periods, and would also maintain its A-LM rate which provides a significantly reduced price for usage during off-peak periods.

Staff disagrees with CMP’s position that its marginal cost of service does not vary by time of year or time of day. The system is built and maintained to be able to provide T&D service at the time the system peaks. Therefore, as a matter of logic, the
marginal cost of service must be higher at the time of peaks, either seasonally or time of day. We note that CMP’s marginal cost study did not include an analysis of cost differentials by time of year or time of day. EX-015-014. Recent marginal cost studies in other jurisdictions, however, have taken into account variations in time of year and time of day for demand-related costs (e.g., see Direct Testimony of Dr. Hethie S. Parmesano, NERA Economic Consulting, Marginal Cost Study, on behalf of Otter Tail Power Company, South Dakota Public Utilities Commission, October 31, 2008).

Staff does not necessarily disagree with CMP that, within its existing “winter/summer” period structure, the costs on average may not be that different. However, without an analysis of marginal costs at different times of the year, e.g., when load is very high and very low, it is not possible to determine whether alternative period structures with rates designed to reflect cost differentials should be considered. Staff asks CMP to comment on this issue in its responsive filing, including addressing how such an analysis could be provided. However, because Staff’s view is that costs do vary by time of day, we generally agree that that demand charges should not be assessed in off-peak periods, and that diurnally differentiated rates for residential and small commercial customers are appropriate.

F. **Rate O**

Staff agrees that with CMP’s proposal to eliminate Rate O.

G. **Redesign of IGS-P-TOU**

CMP states that IGS-P-TOU is the only remaining demand-based rate class that has demand and energy charges. RARD at 12. CMP proposes to eliminate
the energy charge and collect this revenue through demand charges. Staff concurs with this approach.

H. **B-SVA**

The Staff disagrees with CMP’s proposal to eliminate its best rate option-rate option B-SVA. RARD at 12-13. This rate was implemented pursuant to Commission directive in Docket No. 2009-397. In that proceeding, the Commission considered the issue of businesses that implement energy efficiency measures and, as a result, are moved from the medium general service to the small general service class. In some cases, businesses would receive higher electricity bills as a consequence of employing energy efficiency. To address this issue, the Commission, through its Order in Docket No. 2009-397, directed that the T&D utilities implement a “best rate” option.

In Staff’s view, the basic policy underlying the best rate option has not changed, and accordingly, the rate should be maintained. However, Staff would agree to changing the approach from considering the best rate on a bundled (including supply costs) to evaluating the best rate on a T&D-only basis.

In addition, Staff requests that CMP provide an analysis, including revenue impacts, of a best rate option to address customer movement in the other direction, from small to medium general service. This best rate option would avoid substantial bill impacts when customers, through business expansion or otherwise, would be moved from the small general service rate to the medium general service rate.

I. **Standby Rates**

CMP currently has only optional standby rates and, because of their structure, only three customers are taking standby rate service (all of whom are either
subtransmission or transmission level customers). Oct 7, 2013 Tr. at 57. CMP proposes that, for all classes, recovery of what it refers to as “customer” and “local facilities” costs from standby customers occur through fixed monthly charges. For demand-based classes, CMP proposes to recover what it refers to as “distribution grid” costs through a “contract demand” monthly kW charge, as opposed to an actual kW demand charge as is currently charged to standby customers. For residential and small commercial customers, CMP proposes to recover “distribution grid” costs through a fixed monthly charge apparently based on customers' kW demand.

At this point, Staff does not support CMP’s proposal to recover demand-related costs from demand-based customer classes through a “contract demand” charge. CMP’s proposal is a substantial departure from the current rate structure for standby customers and requires further analysis of bill impacts before such a change should be considered. Staff requests CMP to provide in its responsive filing a “bill frequency” analysis for all existing standby customers that would show the impacts of its proposed change.

Staff opposes CMP’s proposed standby rate structure for residential and small commercial customers. The proposal applies to customers with any generating facility of any size (such as solar panels and small wind turbines), but would not apply to customers with emergency generators. CMP’s proposal to require these customers to take service under a standby rate that contains fixed monthly charges would substantially lower or eliminate the economic benefit of installing renewable units and would frustrate state promotional mechanisms such as net energy billing. Over a thousand CMP customers have installed small renewable units in reliance of the
availability of net energy billing. CMP’s proposal would be contrary to the reasonable reliance of these customers on State promotional mechanisms and would be inconsistent with State energy policy. CMP recognizes this concern. Oct 7, 2013 Tr. at 58, 108. Moreover, CMP’s proposal in this regard would be inconsistent with rate design principles of customer understanding and rate stability. Finally, Staff notes that a customer that installs a demand response technology that reduces the apparent load on the system to the same degree and manner as a generation facility (and thus incurring the same marginal cost on the system) would not be subject to the proposed standby rate, Oct 7, 2013 Tr. at 60-62, and would be inconsistent with the principle of equity in rate design.

J. Residential Class Minimum Charge

For the residential class Rate A, CMP currently has a minimum monthly charge that includes the first 100 kWh of usage. CMP proposes to eliminate the 100 kWh minimum usage from its monthly customer charge. RARD at 20. Historically, this minimum usage charge is a result of a statutory provision that states:

1. **Utilities required to provide minimum charge.** Any transmission and distribution utility serving more than 5,000 customers that has a residential rate combining energy and demand costs in a single rate that neither declines nor increases, but is flat as consumption increases shall recover its customer costs through the same rate. As part of that rate, each such transmission and distribution utility shall provide for a minimum charge to include such an amount of kilowatt hours as the commission determines.

35-A M.R.S. § 3103 (1).

CMP asserts that this statutory language no longer applies after industry restructuring and generation asset divestiture, because it no longer has any “energy costs.” EX-015-020. Staff disagrees with CMP’s position in this regard. Industry
restructuring does not change or negate the basic policy underlying section 3103(1), which is that residential customer’s minimum monthly charge should include some amount of kWh usage. There is nothing in the restructuring laws that suggest that the Legislature intended to change this basic policy.

K. **Rate A-LM: Residential Load Management**

CMP proposes to remove the existing requirement that electric thermal storage units operate only during off-peak hours. RARD at 23. CMP states that the significant price differential in the on-peak and shoulder hours would provide a substantial deterrent for customers operating thermal storage units at times other than the off-peak. Staff does not oppose the elimination of the off-peak usage requirement.

Staff notes that the existence of the Rate A-LM is generally inconsistent with CMP’s view that its underlying system costs do not vary by time of day. However, as noted above, Staff disagrees with this premise and generally supports time-of-use pricing. We do, however, question the need for a separate residential load management rate and a separate meter given that CMP has a generally applicable TOU rate. If this rate is properly designed, there would appear to be no cost basis for a separate storage heat rate. Nevertheless, Staff concurs with CMP’s view, EXM-015-028, that eliminating Rate A-LM could be disruptive to customers who installed heating units in reliance on the existence of the heating rate.

L. **Transmission Rate Design**

CMP currently recovers its transmission revenue requirements through a per kWh charge for residential and small commercial customers (the residential minimum bill includes 100 kWh at the per kWh charge). CMP proposes to change
transmission rates to recover the same percentage of transmission revenue through a fixed charge as is proposed for distribution. RARD at 21. CMP states that its FERC open-access tariff requires that it allocate transmission-related costs to rate classes based on coincident peak contribution. 15 EXM 40. The tariff also states that, for those customers not billed on demand, transmission costs will be recovered through kWh charges. Accordingly, CMP proposal to move transmission costs into fixed charges would require a change in its FERC tariff. Oct 7, 2013 Tr. at 64

During a technical conference, CMP acknowledged that its transmission costs tend to be demand driven. Oct 7, 2013 Tr. at 63. For reasons discussed above, Staff opposes CMP’s proposal to recover a portion of transmission costs through fixed monthly charges.

Staff also notes that, with the AMI meters, customer usage can be measured and transmission rates could be designed in a way that would much more closely and narrowly reflect the underlying costs drivers for transmission. An improved rate design could provide customers with the tools to significantly lower their bills, as transmission rates are becoming an increasingly large portion of the total. In addition, unlike for most rate design changes that would be “revenue neutral” such that the amounts saved by some customers would be recovered from other customers, transmission rate design could potentially result in a lower overall revenue requirement right away by reducing CMP’s allocated share of regional network service (RNS) transmission costs. Because RNS costs are allocated among the regional transmission companies based on each company’s load in the hours of the twelve monthly system
peaks, CMP’s allocated share would be lowered if its customers reduced demand in these hours. We ask CMP to comment on this in its responsive filing.

M. Fees for Service/Modification of Terms and Conditions

Staff does not currently have any issues with CMP’s proposals, RARD at 26-28, regarding:

- Establishment of Service
- Off-Cycle Termination Costs
- Special Facilities
- Energy Efficient New Home Inspection
- Home Energy Profile Service
- Residential Load Cycling Program

N. Street and Area Lighting

Staff does not currently have any issues with CMP’s proposal, RARD at 28-29.

O. Pricing Flexibility Guidelines

Staff does not currently have any issues with CMP’s proposal, RARD at 29-31, assuming that all rate components are above their applicable marginal costs.

P. Standard Form Contract Reporting

Staff does not currently have any issues with CMP’s proposal, RARD at 28-29.
IX. CONCLUSION

The Staff, through this Bench Analysis has put forth its preliminary view on the issues in this case. Since the Staff has not provided an analysis on certain issues, and could not fully model the results of all its recommendations, the Staff did not attempt to provide rate recommendations as part of this analysis. The final recommendations of the Staff along with its rate recommendations will be provided in the Examiner's Report scheduled to be issued on May 30, 2014.

Dated: December 12, 2013 Respectfully Submitted by the Hearing Examiners,

[Signatures]

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