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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2014-0370

DIRECT TESTIMONY OF
TIM WOOLF

ON THE TOPIC OF
KANSAS CITY POWER AND LIGHT'S
RATE DESIGN PROPOSAL

ON BEHALF OF
SIERRA CLUB

APRIL 16, 2015

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title and employer.

A. My name is Tim Woolf. I am a Vice President at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics (Synapse) is a research and consulting firm specializing in electricity and gas industry regulation, planning and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources; energy efficiency policies and programs; integrated resource planning; electricity market modeling and assessment; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission and the National Association of Regulatory Utility Commissioners. Synapse has over twenty-five professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. Before rejoining Synapse Energy Economics, I was a commissioner at the Massachusetts Department of Public Utilities (DPU). In that capacity, I was responsible for overseeing a substantial expansion of clean energy policies, including significantly increased ratepayer-funded energy efficiency programs; an update of the DPU energy efficiency guidelines; the implementation of decoupled rates for electric and gas companies; the promulgation of net metering regulations; review and approval of smart grid pilot programs; and review and approval of long-term contracts for renewable power. I was also responsible for overseeing a variety of other dockets before the commission, including several electric and gas utility rate cases.

Prior to being a commissioner at the Massachusetts DPU, I was employed as the Vice President at Synapse Energy Economics; a Manager at Tellus Institute; the Research Director at the Association for the Conservation of Energy; a Staff Economist at the Massachusetts Department of Public Utilities; and a Policy Analyst at the Massachusetts Executive Office of Energy Resources.

I hold a Masters in Business Administration from Boston University, a Diploma in Economics from the London School of Economics, a BS in Mechanical Engineering and a BA in English from Tufts University. My resume, attached as Schedule TW-1, presents additional details of my professional and educational experience.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of Sierra Club.

Q. Have you previously testified before the Missouri Public Service Commission?

A. Yes. I provided rebuttal testimony on behalf of the Missouri Office of the Public Counsel regarding Ameren Missouri's 2011 IRP in Case No. EO-2011-0271, and I provided rebuttal on behalf of Sierra Club regarding Ameren's MEEIA filing in Case No. EO-2015-0055.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address Kansas City Power and Light's (KCP&L or the Company) proposed rate design, especially for residential customers. The Company's overall proposal in this docket, particularly the increased customer charge, fuel adjustment clause, and various new cost trackers, represents a significant departure from previous rate setting practices, primarily to address concerns about revenue sufficiency and volatility. My testimony explains why such a departure is not warranted and why the Company's proposal does not adhere to fundamental rate design principles. I provide recommendations that will be more equitable, efficient and effective at addressing concerns about revenue sufficiency and volatility.

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your primary conclusions.

A. My conclusions can be summarized as follows:

1. The Company uses the results of its class cost of service (CCOS) study to inform its proposed customer charges, but the estimates of unit customer costs in the CCOS study appear to be significantly overstated. The customer costs for all customer classes are dramatically higher than in recent years, apparently because the Company reclassified some demand-related costs as customer-related costs. This reclassification is not sufficiently described or justified by the Company.

2. These higher, unjustified unit customer costs in the CCOS study call into question the Company's rationale and justification for increasing residential customer charges.

3. The Company's proposal does not adhere to the widely accepted rate design principle of providing customers with an incentive to use electricity efficiently.

4. The Company's proposal does not adhere to the widely accepted rate design principle of promoting customer equity. The proposed rate design is inequitable both across customer classes and within each residential customer class.

5. The Company's proposal does not meet the widely accepted rate design criterion of rate stability. A portion of residential customers are likely to experience increases in their total bills of as much as 25 percent to 45 percent.

6. Revenue decoupling offers a far better option for managing revenue sufficiency and volatility, while adhering to the fundamental principles of efficiency, equity and gradualism.

7. Revenue decoupling can and should be designed in ways that are in customers' interest.

Q. Please summarize your recommendations.

A. I offer the following recommendations:

1. The Commission should reject the Company's proposal to significantly increase the customer charge for residential customers.

2. The Commission should require the Company to increase the residential customer charge and energy rate by the same amount, which should equal the amount that rates are increased for other classes. This approach eliminates the problem of inter-class

equity, mitigates the problem of intra-class equity, and strikes an appropriate balance between equity, efficiency and gradualism.

3. The Commission should investigate revenue decoupling as a means of addressing several issues in this rate case. Decoupling is a much better option for addressing revenue volatility and sufficiency than increased customer charges. Revenue decoupling can also help align the Company's financial incentives with the goals of promoting energy efficiency under the MEEIA statute and regulations. Any such investigation should consider revenue decoupling options that adhere to fundamental ratemaking principles and are generally in customers' best interest.

3. OVERVIEW OF KCP&L'S RATE DESIGN PROPOSAL

Q. Please summarize KCP&L's proposal.

A. KCP&L has requested an overall rate increase of $120.9 million, or 15.75 percent, and proposes to collect this additional revenue from each rate class on an equal percentage basis.[1] That is, revenues from each class will increase by approximately 15.75 percent.

Q. Does the Company propose to increase all rate elements by 15.75 percent?

A. No. The Company is proposing to generally maintain the existing rate structure for commercial and industrial (C&I) customer classes, but to significantly alter the relationship between the customer charge and energy rate for the residential classes.

[1] Direct Testimony of Tim Rush, ER-2014-0370, October 2014, page 58.

Q. Please explain how rates will change under the Company's proposal.

A. KCP&L proposes to increase the residential customer charge from $9 per month to $25 per month, an increase of 177 percent, while the volumetric charge would remain virtually unchanged.[2] Conversely, C&I customers will generally experience an increase of 15.75 percent in all rate elements and no change in the relationship between customer charges and other rates.[3]

Q. Is KCP&L's proposed residential customer charge similar to that in use at other utilities?

A. No. The proposed customer charge would be much higher than the customer charge levied by any other Midwestern utility, and would be more than 20 percent higher than the next highest customer charge in the Midwest. KCP&L's proposed customer charge is shown relative to other customer charges in the figure below.

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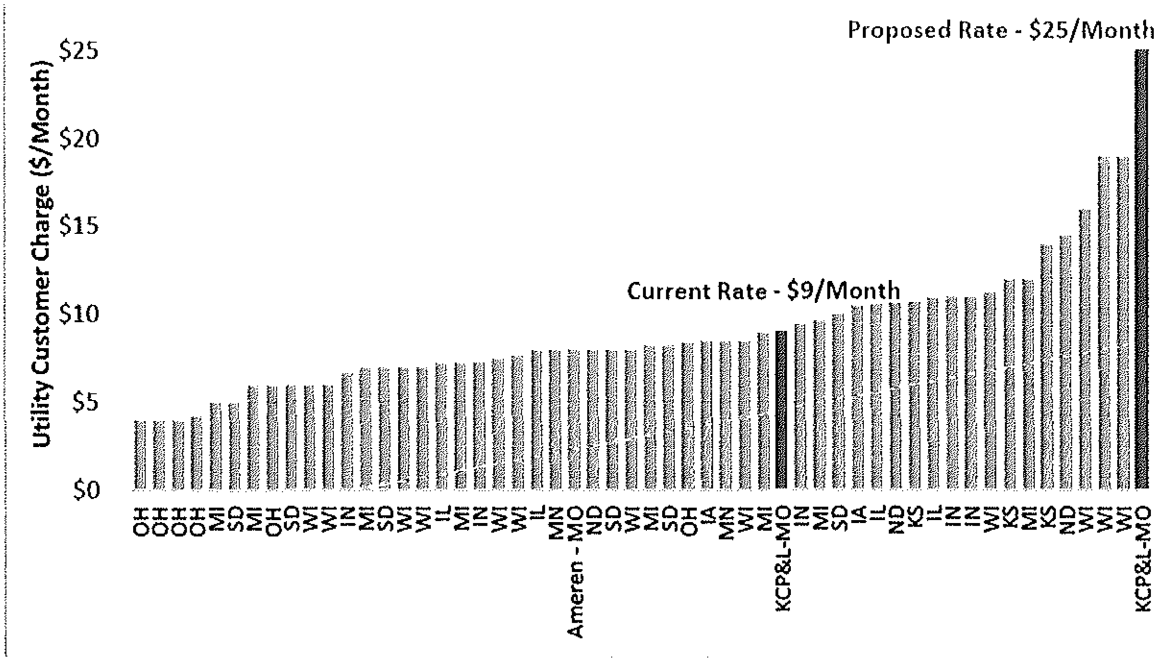
[2] Direct Testimony of Tim Rush, ER-2014-0370, October 2014, pages 58-59.

[3] The Company notes a few exceptions in the All-Electric rates, within which the Company proposes to realign certain elements with the General Use rates. Direct Testimony of Tim Rush, ER-2014-0370, October 2014, page 59.

Figure 1. Current Customer Charges at Midwestern Utilities



Source: Direct Testimony of David Dismukes, ER-2014-0351, February 11, 2015

4. IMPLICATIONS OF KCP&L'S CLASS COST OF SERVICE STUDY

Q. What is the purpose of the class cost of service (CCOS) study?

A. There are two basic purposes of a class cost of service (CCOS) study. The first is to help establish class revenue requirements by determining the costs of providing service to each class of customers. The second purpose is to provide unit costs,[4] which can be used as one of the inputs to designing rates.

[4] The term "unit costs" refers to costs that are defined on the basis of specific units; in other words, per customer per month (for customer-related costs), per kWh (for energy-related costs), and per KW for (demand-related costs).

Q. How is a CCOS study performed?

A. A CCOS study is performed in three steps: First, costs are functionalized, meaning that they are defined based upon their function (e.g., production, distribution, transmission). Second, each cost is classified as energy-related (which vary by the amount of energy a customer consumes), demand-related (which vary according to customers' maximum demands), and customer-related (which vary by the number of customers). Finally, these costs are allocated to the appropriate customer classes.

Q. Please explain how unit costs from the CCOS study are used in rate design.

A. Unit costs from the CCOS study are used as a point of reference for rate design. However, cost-causation is not the only criterion used when setting rates. Other considerations such as rate stability, equity, and efficiency also play into the design of rates, as I will discuss later in this testimony.

Q. Did the Company perform a CCOS study to determine customer-related unit costs?

A. Yes, the Company performed a cost of service study, as presented by Company Witness Tim Rush.

Q. Do you have any comments regarding the customer-related unit costs from the Company's CCOS study?

A. Yes. The results of the Company's most recent CCOS study differ markedly from the results of the CCOS studies produced by the Company's consultant in prior years. In 2008 and 2012, the Company hired an outside expert, Paul Normand, to perform the CCOS study, presumably because of Mr. Normand's expertise in this area. Mr.

Normand's estimates for unit customer costs are significantly lower than the estimates produced internally by the Company for this proceeding.

Q. Please describe how the unit customer costs produced by the Company's consultant in 2008 and 2012 differ from the Company's results in this proceeding.

A. The results of Mr. Normand's CCOS analysis for unit customer costs in 2008 and 2012 are less than half the magnitude of the estimates produced by Mr. Rush in this proceeding. For example, in 2012, Mr. Normand estimated residential customer-related costs to be $11.08,[5] much less than the $25.94 estimate produced by Mr. Rush. These unit customer cost results from Mr. Normand and Mr. Rush are reproduced for comparison purposes in Schedule TW-2.

Figure 2 illustrates how unit customer costs differ between the two previous CCOS studies produced by the Company's consultant and the current estimates produced by the Company in this proceeding.[6] Note that the scale of Figure 2 does not allow for a full appreciation of the increase in residential customer cost estimates. The percentage increases between the Company's 2012 and 2014 estimates for the residential, small business, medium business and large business customer costs are: 134 percent, 115 percent, 223 percent and 165 percent, respectively.

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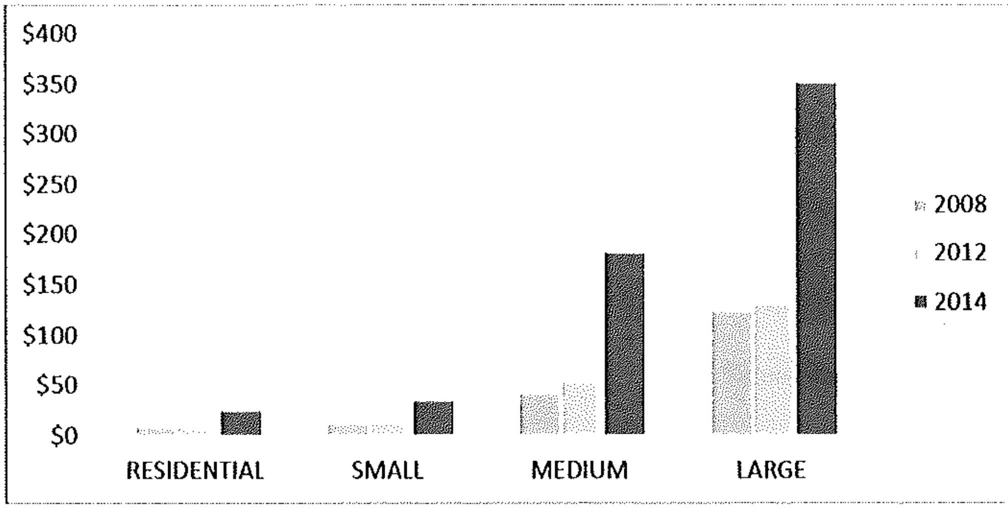
5 Direct Testimony of Paul Normand, Docket ER-2012-0174, February 2012, page 24-25. In Table 4 of Mr. Normand's testimony, these costs are labeled as a "customer charge." However, Mr. Normand's testimony refers to them as customer-related costs on page 24, lines 9-11.

6 Large Power Service is excluded from the graph due to the magnitude of the estimates, but the actual estimates are provided in Schedule TW-2.

Figure 2. Results of the CCOS for Unit Customer Costs



Source: Direct Testimony of Rush, Docket ER-2014-0370, Schedule TMR-8; Direct Testimony of Normand, Docket ER-2012-0174, Table 4, page 25; Direct Testimony of Normand, Docket ER-2009-0089, Table 4, page 20.

Q. Why have the customer cost estimates from the Company's CCOS study increased by so much since the previous CCOS studies?

A. Mr. Rush does not compare the estimates of customer-related costs from the current CCOS study with those of previous CCOS studies, nor does he explain why the customer-related costs are so much higher in the current study. Thus, it is not clear why the estimates of customer costs have increased so much.

It appears that the increase in estimated customer costs is a result of KCP&L reclassifying certain demand-related costs as customer-related. In Schedule TMR-8, Mr. Rush presents the estimates of customer costs from the current CCOS study. This table is identical in format to the table presented by Company Witness Paul Normand in his testimony in 2012.[7] Mr. Rush's table includes only one footnote, which states that the

[7] Direct Testimony of Paul Normand, Docket ER-2012-0174, February 2012, Table 4, page 25.

monthly customer charge "includes local facilities." No such footnote appears in the table presented by Mr. Normand. This new footnote suggests that the Company has modified its methodology for classifying costs by reclassifying certain local distribution facilities as a part of the customer costs.

Q. Has the Company described or explained a new methodology for classifying customer-related costs?

A. Mr. Rush explains the methodology and the results of his CCOS study in Section XII of his testimony, on pages 48 through 58. Nowhere in that text does he mention a new methodology for classifying customer-related costs.

However, it is very unlikely that customer-related costs themselves have changed over the past three years by the extent indicated in Table 1. The most likely explanation for such a significant change in customer-related costs is that the Company applied a new methodology for classifying customer-related costs. The footnote in Schedule TMR-8 that the analysis there "includes local facilities" supports this explanation.

Q. If it is true that the Company has applied a new methodology for classifying customer-related costs, does this raise any concerns?

A. If the Company has applied a new methodology for classifying customer-related costs, then it should have fully described and justified such a change in its initial filing in this case. This new methodology for classifying costs represents a substantial departure from past cost allocation practices, as indicated by the increase in costs presented in Table 1. Any such departure from past ratemaking practice should be fully explained and justified in order for the Commission and other parties to examine it.

Q. How might the Company's new methodology for classifying costs affect customer charges?

A. As noted above, CCOS study results are typically used as a point of reference in setting customer charges. If KCP&L continued to use its previous method of classifying costs, then the estimated customer costs would likely be close to the values found in previous CCOS studies, namely $10-$11. If the Company's own CCOS study found that customer-related costs were in this range, then it could not justify customer charges significantly higher than this range.

Q. Are the CCOS study estimates of customer-related costs the only consideration used when setting customer charges?

A. No. CCOS study estimates of customer-related costs are not the only or the defining consideration when setting customer charges. The Commission acknowledged this point in its recent order on Union Electric's rate case:

> The Commission is not bound to set the customer charges based solely on the results of the cost of service studies. The Commission must also consider the public policy implications of changing the existing customer charges. There are strong public policy considerations in favor of not increasing the customer charges.[8]

[8] Missouri Public Service Commission, Report and Order, In the Matter of Union Electric Company Tariff to Increase Its Annual Revenues for Electric Service, File No. ER-2012-0166, December 12, 2012, page 110.

Q. Please summarize the conclusions of your assessment of the KCP&L CCOS study as it pertains to the Company's proposed residential customer charge.

A. The Company uses the results of its CCOS study to inform its rate design, specifically the higher customer charges it proposes for the residential class. The estimates of unit customer costs in the CCOS represent a dramatic change from the Company's own studies in recent years, yet the Company has not sufficiently described the cause of this change or justified it. The lack of justification for these higher unit customer cost estimates raises serious questions regarding the Company's reasons for proposing an increase in residential customer charges.

5. KCP&L'S PROPOSAL TO INCREASE RESIDENTIAL CUSTOMER CHARGES

Q. What reason does the Company provide for its large increase in the residential customer charge?

A. Company Witness Rush states that the proposed rates move "certain costs currently recovered from the energy rates to the customer charges," due to concerns regarding the alignment of rates with costs.[9]

Q. Do you agree?

A. No. As noted above, the CCOS study is used to determine the cost to serve each class of customers, and these costs are classified according to whether they are energy-, demand-, or customer-related. The Company has not explained why it is appropriate to move certain costs into the customer charge, nor has it explained why its rationale for

[9] Direct Testimony of Tim Rush, ER-2014-0370, October 2014, page 58.

significantly increasing the residential customer charge should be applied to only the residential classes but not the other classes.

Q. Please explain how the Company has "singled out" the residential class.

The Company is proposing to significantly increase the residential customer charge relative to the energy charge for residential customer classes, but not for any of the other customer classes. This is inconsistent with the Company's own CCOS study that indicates that all customer classes' unit customer costs increase significantly, and in most cases even more significantly than the residential customers. The Company provides no justification for why it is proposing to treat the residential customer classes so differently, given the increase in unit customer costs across all classes.

6. PRINCIPLES OF RATE DESIGN

Q. What ratemaking principles should be considered when designing rates?

A. In his seminal work, *Principles of Public Utility Rates*, Professor James Bonbright discusses eight key criteria for a sound rate structure. These criteria are:

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers.

6. Fairness of the specific rates in the appointment of total costs of service among the different customers.

7. Avoidance of "undue discrimination" in rate relationships.

8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:

   (a) in the control of the total amounts of service supplied by the company;

   (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).[10]

Q. Are these principles widely recognized and used by commissions?

A. Yes. The principles listed above have been recognized for many years, and Bonbright's principles are referenced by Company Witness Rush.[11]

Q. Is the Company's rate design proposal consistent with Bonbright's principles?

A. No. The Company's proposal does not meet the principles of rate stability (often referred to as "gradualism"), fairness among customers, or efficiency. I will describe these failings below.

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[10] James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, page 291, provided in Schedule TW-3.

[11] Direct Testimony of Tim Rush, ER-2014-0370, October 2014, page 60.

7. INCONSISTENCY WITH THE PRINCIPLE OF RATE STABILITY

Q. Please describe Bonbright's principle regarding rate stability.

A. This principle means that customer rates should not change suddenly, particularly if this will cause harm to customers.

Q. In what way should customer rates exhibit stability?

A. Customer rates generally have two or three primary components (the energy charge, customer charge, and possibly a demand charge). Bonbright's principle refers to how much these charges change from one period to the next, and specifies that unexpected, adverse changes be minimized.

Q. Is the Company's proposal consistent with this principle?

A. No. The Company proposes to increase the customer charge for residential customers from $9 to $25, an increase of 177 percent. This change is large and adverse to customers as, under the Company's proposal, more than one quarter of residential customers will experience an increase in their monthly bill of 24 percent or more.[12]

8. INCONSISTENCY WITH THE PRINCIPLES OF FAIRNESS AND AVOIDANCE OF UNDUE DISCRIMINATION

Q. Please describe Bonbright's principles regarding fairness and avoiding undue discrimination.

A. These principles refer to treating similarly-situated customers in a similar manner.

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[12] Analysis based on residential customer usage provided by KCP&L in discovery response SC-23 (QSC23_LIHEAP-General Usage Data Analysis_HC.xlsx).

Q. Is the Company's rate design proposal consistent with the principle of fairness and avoidance of undue discrimination?

A. No, it does not even come close. KCP&L's proposal raises significant inequity problems between residential customers and all other classes. The Company proposes to increase the residential customer charge by 177 percent, but to increase the customer charges for other rate classes by 15.75 percent. This proposal to single out the residential class for a substantially different rate design creates much greater risks and harm for residential customers than for all other customers.

The Company's own CCOS study does not support such a different rate design across classes. As indicated in Table 1, if the Company were to apply the new estimates of customer costs from its CCOS study in determining the rate design for all classes, then other customer classes would see very different rate designs than those proposed by the Company; the Small GS customer charge would have to be doubled and the Medium GS customer charge would have to be tripled.

Q. Are there other ways in which the Company's proposal creates fairness concerns?

A. Yes. In addition to the inter-class inequities described above, KCP&L's proposal creates intra-class inequities in the residential classes.

Q. In what way would KCP&L's rate design unfairly impact different types of residential customers?

A. The impact on residential customers will vary considerably across customers, as the Company's proposed rate design has a much larger impact on customers who use less energy. The Company designed the residential rate structure such that half of residential customers would experience bill increases of more than 15.75 percent, while half of customers would shoulder less of the overall rate increase. This effectively shifts the majority of the rate increase onto low-usage customers, as shown in Figure 2.[13]

Figure 2. Increase in Average Bill from KCP&L's Proposed Residential Rate Design

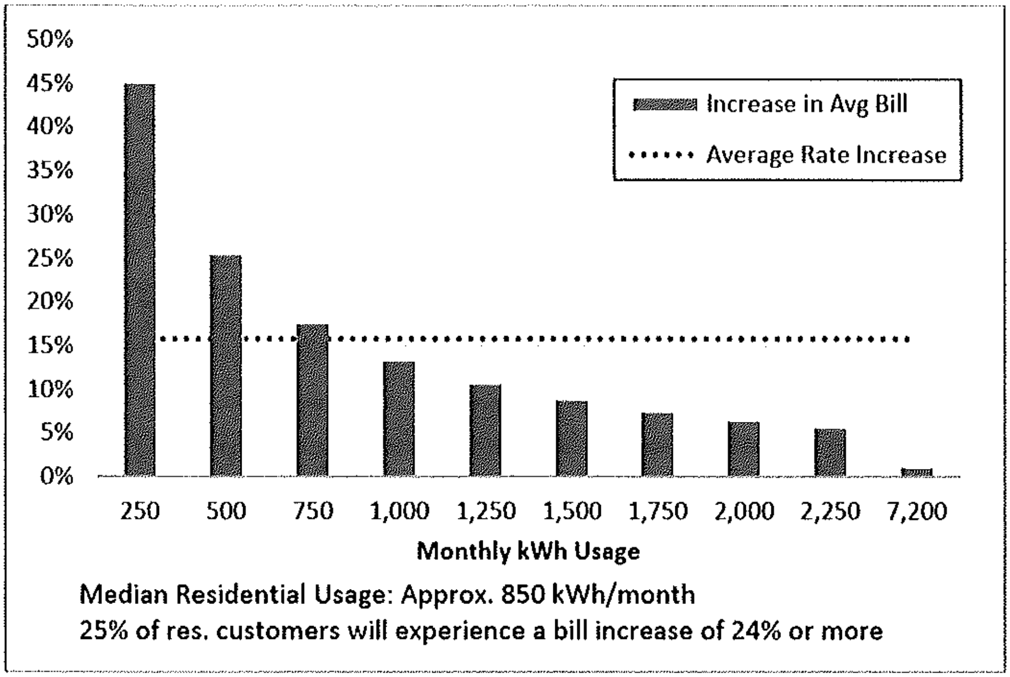

Figure 2 clearly indicates the inequities that the Company's rate design proposal would create across customers in the residential classes. As indicated, some low-use customers will experience a bill increase of approximately 25 to 45 percent, while some high-use customers will experience a bill increase of 5 to 10 percent or less.

[13] Analysis based on residential customer usage provided by KCP&L in discovery response SC-23 (QSC23_LIHEAP-General Usage Data Analysis_HC.xlsx).

9. INCONSISTENCY WITH THE PRINCIPLE OF EFFICIENCY

Q. How does Bonbright define the principle related to efficiency?

A. Bonbright defines the principle of efficiency as "discouraging wasteful use of service while promoting all justified types and amounts of use."[14]

Q. Please explain what this means.

A. The concept of efficiency means that rates should be designed to send price signals that encourage customers to pursue cost-effective energy efficiency.

Q. Does Missouri have relevant energy efficiency policies?

A. Yes. In 2009, the Missouri Energy Efficiency Investment Act (MEEIA) was signed into law and was implemented through a Commission rulemaking in 2011. The purpose of MEEIA is "to create new energy efficiency options that can help consumers cut down on the amount of energy consumed and ultimately reduce costs."[15]

Q. Please explain the price signal that fixed customer charges send to customers.

A. In general, a fixed customer charge sends the signal to customers that they have no control over that portion of their bill, as they will have to pay the fixed portion of the bill regardless of how much electricity they consume. An increase in the fixed customer charge sends the signal that customers have less control over their bill than they used to,

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[14] James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, page 291, provided in Schedule TW-3.

[15] Missouri Public Service Commission, "PSC Approves Agreement to Implement Energy Efficiency Programs Under the Missouri Energy Efficiency Investment Act (MEEIA) for KCP&L." June 6, 2014.

and that any actions to reduce their bills through reduced consumption will be less effective.

Q. What impact would KCP&L's rate design proposal have on customer incentives to use electricity more efficiently or install distributed generation?

A. A higher fixed charge relative to the volumetric charge reduces customers' incentive to use electricity more efficiently because more of the costs are recovered through the fixed component of the rate. Since only the variable component is avoidable, increasing the customer charge makes customer efforts to reduce their electricity bill by lowering their energy consumption less effective. As a consequence, the price signal sent by higher fixed charges is likely to discourage many customers from implementing efficiency measures or installing distributed generation—resulting in greater future energy consumption than would have occurred under the current rate design.

Q. Has the Commission recognized the negative effect of increased customer charges on energy efficiency?

A. Yes. In 2012, File No. ER-2012-0166, the Commission rejected Ameren Missouri's proposed increase in the customer charge for residential and small general service classes, writing:

> Shifting customer costs from variable volumetric rates, which a customer can reduce through energy efficiency efforts, to fixed customer charges, that cannot be reduced through energy efficiency efforts, will tend to reduce a customer's incentive to save electricity. Admittedly, the effect on payback periods associated with energy efficiency efforts would be small, but increasing customer charges at this time would send exactly [the]

> wrong message to customers that both the company and the Commission are encouraging to increase efforts to conserve electricity.[16]

Q. Have other Commissions recognized the detrimental impact of higher customer charges?

A. Yes, the negative effects of increasing customer charges are well-recognized. For example, in 2013 the Maryland Public Service Commission rejected a small increase in the customer charge, noting that doing so would reduce customer control of their bills and would be inconsistent with the state's policy goals.

> Even though this issue was virtually uncontested by the parties, we find we must reject Staff's proposal to increase the fixed customer charge from $7.50 to $8.36. Based on the reasoning that ratepayers should be offered the opportunity to control their monthly bills to some degree by controlling their energy usage, we instead adopt the Company's proposal to achieve the entire revenue requirement increase through volumetric and demand charges. This approach also is consistent with and supports our EmPOWER Maryland goals.[17]

Q. How will increased electricity consumption affect overall costs borne by customers?

A. By reducing customers' incentives to conserve, energy consumption is likely to increase more than it otherwise would have, which could increase customer costs in three ways:

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[16] Missouri Public Service Commission, Report and Order, In the Matter of Union Electric Company Tariff to Increase Its Annual Revenues for Electric Service, File No. ER-2012-0166, December 12, 2012, pages 110-111.

[17] In The Matter of the Application of Baltimore Gas and Electric Company for Adjustment in its Electric and Gas Base Rates. Maryland Public Service Commission. Case No. 9299. Order No. 85374, Issued February 22, 2013, p. 99, provided in Schedule TW-4.

- First, as energy consumption grows, so too will the need for more generation, transmission and distribution capacity, the costs of which will be passed on to consumers.
- Second, the price signal sent by higher fixed charges will reduce the effectiveness of energy efficiency programs because customers will be less able to lower their bills by reducing their energy consumption. Consequently, KCP&L's MEEIA energy efficiency programs might result in less savings for a given budget, or might require increased budgets to achieve the same level of savings.
- Third, energy efficiency represents an abundant, low-cost option for complying with the Clean Power Plan. Price signals that reduce customers' incentives to conserve will require the utilities to rely upon more expensive options to comply with the Clean Power Plan.

10. DECOUPLING IS A BETTER WAY TO REGULATE REVENUES

Q. What challenges does the Company face regarding revenue recovery?

A. The Company states that it is facing rapidly increasing costs, while sales are flat or declining. This contributes to a misalignment of revenues and costs during the period between rate cases, making it difficult for the Company to recover its costs and earn a fair return.[18]

Company witness Rush summarizes the link between sales and utility earnings as follows:

[18] Direct Testimony of Tim Rush, ER-2014-0370, October 2014, page 5.

> From the Company perspective, reductions in usage, driven by reduced customer growth, energy efficiency, or even customer self-generation, result in under recovery of revenues. Growth would have compensated or completely covered this shortfall in the past. With the accelerating deployment of initiatives that directly impact customer growth, it is becoming increasingly difficult for the Company to accept this risk of immediate under recovery.[19]

Q. What mechanisms has the Company proposed to address revenue sufficiency and volatility concerns?

A. The Company has proposed a fuel adjustment clause (FAC), a property tax tracker, a vegetation management tracker, and considerably higher customer charges for residential customers.

Q. How do these mechanisms enable the Company to address revenue sufficiency and volatility concerns?

A. The FAC and cost trackers address "regulatory lag"—the time between rate cases when costs may fluctuate, but rates do not adjust. Instead, these mechanisms would permit the utility to adjust rates based on changes in costs for fuel, taxes, and vegetation management.

Higher customer charges are an effort to slow the decline of revenues between rate cases, since revenue collected through the customer charge is not affected by reduced sales.

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[19] Direct Testimony of Tim Rush, ER-2014-0370, October 2014, page 63.

Thus, all else equal, higher customer charges result in greater revenue stability and certainty for the Company.

Q. Are these mechanisms consistent with traditional cost-of-service ratemaking principles?

A. Generally not. Traditional cost-of-service ratemaking sets rates based on known and measurable costs identified in a test year. These rates remain fixed until the following rate case. Customer charges under traditional cost-of-service ratemaking are frequently a relatively small portion of customer bills.

Q. What incentives does traditional cost-of-service ratemaking provide?

A. Regulatory lag may provide utilities with incentives for efficient management and cost control because utilities are able to benefit from any cost savings that they create between rate cases. However, as the Company has pointed out, regulatory lag can also pose financial challenges for a utility, causing it to apply for rate cases more frequently.

Cost trackers and fuel adjustment charges reduce risks to utilities by shifting all of the risks associated with such costs to customers. These mechanisms can reduce utility incentives to operate efficiently, and FACs may dampen management incentives related to fuel diversity in order to reduce exposure to fuel price volatility.

Q. Do alternative mechanisms exist for managing revenue sufficiency and volatility?

A. Yes. A revenue decoupling mechanism offers a far superior way to address revenue sufficiency and volatility compared to increasing fixed customer charges. As described above, increasing customer charges can result in significant negative impacts on some customers, and will reduce customers' financial incentives to reduce their bills through energy efficiency or other means. A revenue decoupling mechanism in combination with the existing rate design would significantly reduce the rate impacts on lower-use customers while providing revenue certainty to the Company.

Q. Please describe what you mean by "revenue decoupling."

A. Under traditional ratemaking, the utility's revenue requirement is determined through a rate case. Prices are then determined by dividing the utility's revenue requirement by sales. These prices are then held constant until the following rate case, and any change in sales would cause the utility's revenues to increase or decrease proportionally, depending on the direction of the sales.

Decoupling removes this fluctuation in revenues, and instead adjusts prices so that the revenues recovered by a utility are more closely aligned with the costs incurred. If sales increase for any reason (for example, due to weather or economic growth), the utility returns the excess revenues to ratepayers in the next decoupling adjustment. Similarly, if sales decline for any reason (for example, due to weather, economic decline, energy efficiency or distributed generation), the utility is permitted to collect the unrecovered revenues in the next decoupling adjustment. In this way, full decoupling actually allows for a utility's revenues to be more closely aligned with costs than under traditional ratemaking.

Q. Why do you see revenue decoupling as an alternative to the Company's ratemaking proposals in this docket?

A. The Company notes that one of the key reasons why it is requesting a rate increase at this time is because it has experienced flat or declining sales in recent years.[20] However, KCP&L's proposals in this docket do not adequately or properly address this key issue.

- The Company's proposal to increase residential customer charges will partly help reduce revenue losses from reduced sales by requiring that a greater portion of residential revenues will be recovered regardless of sales levels. However, this only affects a small portion of residential revenues, as many other components of the rate design are still variable and can still change with fluctuations in sales. In addition, the Company is still subject to revenue losses from all of the other customer classes.
- The FAC and the trackers proposed by the Company will partly and indirectly help with reduced revenues from declining sales by reconciling a portion of the Company's revenue requirements. However, these mechanisms only address a certain portion of KCP&L's revenue requirements; the other portions will continue to be at risk from declining sales.

Revenue decoupling, on the other hand, will address the issue of declining sales (and sales volatility in general) directly and completely. Revenue decoupling will ensure that the Company recovers its allowed revenues each year, thereby completely eliminating KCP&L's concerns about revenue sufficiency and volatility. In fact, revenue decoupling

[20] Direct Testimony of Darren Ives, ER-2014-0370, October 2014, page 6; and Direct Testimony of Scott Heidtbrink, ER-2014-0370, October 2014, page 16.

is more consistent with Bonbright's principle of providing the utility with the ability to recover revenues. If the Commission were to implement a revenue decoupling mechanism for KCP&L, then the purported need for increased customer charges would be immediately eliminated, and the purported need for the FAC and new trackers would be significantly reduced.

Q. Does revenue decoupling affect utility incentives regarding demand-side resources?

A. Yes. This is an additional advantage of revenue decoupling. A revenue decoupling mechanism will remove the financial disincentive that the Company experiences regarding demand-side resources. Currently, as customers implement demand-side resources (including energy efficiency, demand response, and distributed generation), the Company's sales are reduced, leading to reduced revenues and reduced profits. A revenue decoupling mechanism would eliminate this significant financial disincentive by enabling the Company to earn its allowed revenues regardless of sales levels.

As such, the adoption of a revenue decoupling mechanism can lead to a significant shift in the mindset of utility management, where it becomes much more likely to support (and less likely to oppose) demand-side resources. This shift can help enable a much broader implementation of demand-side resources, potentially leading to significantly reduced electric costs for many customers and empowering customers with the tools to better manage and control their bills. Furthermore, the US Environmental Protection Agency's proposed Clean Power Plan and other increasingly stringent environmental regulations make it even more important for utilities to support demand-side resources as low-cost options for reducing the costs of complying with environmental regulations—costs that are eventually borne by customers.

Q. Are there ways that ratepayers can be protected when implementing a decoupling mechanism?

A. Yes. Revenue decoupling mechanisms can be designed in many ways, and it is important to design a mechanism that protects customers, and even makes customers better off than under traditional ratemaking. For example, the following customer protection measures can be included in a decoupling mechanism:

1. Allowed revenue targets under a decoupling mechanism can be established through a fully-litigated rate case with active participation from stakeholders. Relatively frequent rate cases can be used to ensure that the utility's allowed revenues remain in line with its actual costs.

2. Decoupling adjustments can be made on a fixed, pre-determined schedule to provide some stability and predictability.

3. Decoupling adjustments can be subject to a cap in order to protect customers from significant rate increases from one period to the next.

4. The utility's allowed return on equity can be reduced to reflect any lower risk that the utility faces as a result of reduced volatility in revenues, as appropriate.

5. The utility can be required to make reasonable commitments toward supporting cost-effective demand-side resources, or other measures to support customers, in return for reducing revenue volatility.

Q. Is it true that revenue decoupling shifts risk from utilities to ratepayers?

A. Not really. One of the criticisms of revenue decoupling is that it shifts risk from the utility to its customers. However, this is not an accurate depiction of how the utility is affected relative to how its customers are affected. Revenue decoupling does shift *volatility* from the utility to its customers: customers' rates will be slightly more volatile, while the utility's revenues (and therefore profits) will be less volatile. However, it is critical to recognize that volatility means something very different to the utility than to the customers.

- From the utility's perspective, revenue volatility generally translates into profit volatility. For utility shareholders, profit volatility is essentially the same thing as risk. Volatility, frequently measured as the standard deviation of returns on equity investments, is the most common measure of financial risk, as it exposes investors to uncertain change. Consequently, a reduction in revenue volatility is equivalent to a reduction in risk for utility shareholders.

- From the customers' perspective, increased volatility in electricity rates will result in increased volatility in electricity bills. However, it is critical to note two things in order to understand the extent to which this increased volatility represents increased risks to customers. First, the volatility works in both directions, where rates can be adjusted either up or down. Second, the magnitude of the decoupling adjustments (up or down) will be small relative to other factors that cause customers' bills to increase or decrease. As noted above, the decoupling mechanism should include a cap on the amount of the periodic decoupling adjustment. This cap is typically on the order of one to three percent of total revenues, and the decoupling adjustments are typically implemented once a year. Thus, an annual adjustment (up or down) to customer bills of roughly one to three percent is quite small relative to the monthly swings in a customer bills as a result of weather and consumption patterns. Consequently, the volatility in customer bills is not significantly increased, and as such customers' risk is not significantly increased.

Q. Is it true that revenue decoupling removes a utility's incentive to control costs?

A. No. Generally speaking, under traditional ratemaking a utility can influence its profits between rate cases in two ways: (1) it can increase sales to gain additional revenues, or (2) it can reduce its costs. Under decoupling, a utility's revenues are fixed, so it is limited to reducing costs in order to maximize profits. In this way, decoupling actually serves to strengthen the utility's cost control incentives.

Q. Is it true that decoupling reduces a customer's incentive to consume electricity more efficiently?

A. No. This is a common misconception about revenue decoupling. It is sometimes argued that customers will be less inclined to reduce their electricity consumption through efficiency measures because doing so will lead to an increase in their rates as a result of the decoupling mechanism.

However, this argument is without merit. Revenue decoupling will have essentially no impact on any one customer as a result of his or her efficiency investments because the magnitude of the decoupling adjustment from any one customer's efficiency efforts would be so small as to be unnoticeable by the customer, and would be completely dwarfed by the ten percent reduction in the customer's electric bill.[21]

Q. Do you have experience with decoupling in other states that would be relevant to this docket?

A. Yes. I have addressed decoupling in recent testimony before the Maine Public Utilities Commission. Some elements of that docket are of interest here.

Q. Please provide some background on Maine's history with decoupling.

A. Maine was one of the first states to establish a revenue decoupling mechanism, although that initial mechanism was terminated after a few years. In 1991, the Maine Public Utility Commission approved a decoupling mechanism for Central Maine Power Company (CMP), as part of a newly-established performance-based regulation mechanism. Shortly after the decoupling mechanism was established, the US was subject to a serious recession, some large paper mills in Maine shut down, and the electricity sales in Maine declined dramatically. The reduction in sales resulted in significant rate increases, so the Commission chose to terminate the decoupling mechanism.[22] This experience is sometimes cited as one of the reasons why decoupling poses risks to customers.

Q. Have there been any recent developments in Maine on decoupling?

A. Yes. In 2013, CMP filed a rate case requesting, among other things, to implement a revenue decoupling mechanism. CMP was experiencing flat or declining sales, and was

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[21] The one exception may be for large industrial customers, where there are relatively few customers that have large loads and large potential for efficiency savings.

[22] Regulatory Assistance Project, *Revenue Regulation and Decoupling: A Guide to Theory and Application*, June 2011, page 47, provided in Schedule TW-5.

forecasting that its current ratemaking approach would not provide it with sufficient revenues to cover its anticipated costs.

Synapse worked as a consultant for the Maine Office of the Public Advocate (OPA) on this CMP rate case, with a focus on the decoupling mechanism. I provided direct and surrebuttal testimony supporting a decoupling mechanism that included several customer protection measures. One of the most important measures was a cap on the annual decoupling adjustment equal to one percent of total utility revenues.[23] This cap was intended to ensure that the annual decoupling adjustments will not cause customers' bills to increase by any more than one percent, thereby preventing the problems experienced with the previous decoupling mechanism in Maine.

The Maine OPA was initially concerned about the impacts of decoupling on customers, but eventually decided that a decoupling mechanism with sufficient customer protection measures would be in the best interest of Maine electricity customers, and would be more appropriate for the current regulatory and industry conditions in Maine. The Public Utility Commission Staff was initially opposed to decoupling, due to concerns about customers bearing increased risks.[24]

After the parties submitted testimony and attended hearings, the rate case was settled. The settlement included, among many other provisions, a decoupling mechanism with a

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[23] Direct testimony of Tim Woolf, on behalf of the Maine Office of the Public Advocate, Docket No. 2013-168, December 12, 2013, provided in Schedule TW-6.

[24] Surrebuttal testimony of Tim Woolf, on behalf of the Maine Office of the Public Advocate, Docket No. 2013-168, March 21, 2014, provided in Schedule TW-7.

cap on the annual decoupling adjustment of two percent of distribution revenues.[25] (The electricity rates in Maine are unbundled by generation, transmission and distribution rates. A two percent cap on distribution revenues is equivalent to a cap on total revenues of less than one percent.)

Q. What conclusions do you draw from this experience in Maine?

A. The recent experience in Maine indicates that decoupling can be designed in a way that addresses the utility's revenue recovery needs, is suited for current industry conditions, and is in the best interest of customers.

11. RECOMMENDATIONS

Q. What do you recommend with regard to the Company's proposed rate design for residential customers?

A. I recommend that the Commission reject the Company's proposal to significantly increase the customer charge for residential customers. It represents a dramatic departure from past rate design practices, and it does not adhere to the fundamental principles of equity, efficiency, or rate stability.

In addition, I recommend that the Commission require the Company to increase the residential customer charge and energy rate by the same amount, which should equal the amount that rates are increased for other classes. This approach eliminates the problem of

[25] Maine Public Utility Commission, Order Approving Stipulation, Central Maine Power Company, Request for New Alternative Rate Plan, Docket No. 2013-00168, August 25, 2014, provided in Schedule TW-8.

inter-class equity, mitigates the problem of intra-class equity, and strikes an appropriate balance between equity, efficiency and gradualism.

Q. What do you recommend with regard to revenue decoupling?

I recommend that the Commission investigate revenue decoupling as a means of addressing several issues in this rate case. Decoupling is a much better option for achieving revenue stability and sufficiency than increased customer charges. Revenue decoupling can also help align the Company's financial incentives with the goals of promoting energy efficiency under the MEEIA statute and regulations. Any such investigation should consider revenue decoupling options that adhere to fundamental ratemaking principles and are generally in customers' best interest.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	)))	Case No. ER-2014-0370

AFFIDAVIT OF TIM WOOLF

County of Middlesex)
) ss
State of Massachusetts)

I, Tim Woolf, of lawful age and being duly sworn, state and affirm the following: that the foregoing prepared testimony in question and answer format constitutes my Direct Testimony in the above-captioned proceeding; that the answers set forth therein were given by me and that I have knowledge of the matters set forth in such answers; and that the answers contained therein are true and correct to the best of my information, knowledge, and belief.

Tim Woolf
Tim Woolf

SUBSCRIBED AND SWORN before me this 15th day of April, 2015.

Notary Public

My commission expires:
11/2/2018

INDIRA ZVEKIC
Notary Public
Commonwealth of Massachusetts
My Commission Expires Nov. 2, 2018

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Vice President*, 2011 – present.

Provides expert consulting on the economic, regulatory, consumer, environmental, and public policy implications of the electricity and gas industries. The primary focus of work includes technical and economic analyses, electric power system planning, climate change strategies, energy efficiency programs and policies, renewable resources and related policies, power plant performance and economics, air quality, and many related aspects of consumer and environmental protection.

Massachusetts Department of Public Utilities, Boston, MA. *Commissioner*, 2007 – 2011.

Oversaw a significant expansion of clean energy policies as a consequence of the Massachusetts Green Communities Act, including an aggressive expansion of ratepayer-funded energy efficiency programs; the implementation of decoupled rates for electric and gas companies; an update of the DPU energy efficiency guidelines; the promulgation of net metering regulations; review of smart grid pilot programs; and review of long-term contracts for renewable power. Oversaw six rate case proceedings for Massachusetts electric and gas companies. Played an influential role in the development of price responsive demand proposals for the New England wholesale energy market. Served as President of the New England Conference of Public Utility Commissioners from 2009-2010. Served as board member on the Energy Facilities Siting Board from 2007-2010. Served as co-chair of the Steering Committee for the Northeast Energy Efficiency Partnership's Regional Evaluation, Measurement and Verification Forum.

Synapse Energy Economics Inc., Cambridge, MA. *Vice President*, 1997 – 2007.

Tellus Institute, Boston, MA. *Senior Scientist, Manager of Electricity Program*, 1992 – 1997.

Association for the Conservation of Energy, London, England. *Research Director*, 1991 – 1992.

Massachusetts Department of Public Utilities, Boston, MA. *Staff Economist*, 1989 – 1990.

Massachusetts Office of Energy Resources, Boston, MA. *Policy Analyst*, 1987 – 1989.

Energy Systems Research Group, Boston, MA. *Research Associate*, 1983 – 1987.

Union of Concerned Scientists, Cambridge, MA. *Energy Analyst*, 1982-1983.

EDUCATION

Boston University, Boston, MA
Master of Business Administration, 1993

London School of Economics, London, England
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Tufts University, Medford, MA
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Florida Public Service Commission (Dockets No. 130199-EI et al.): Direct testimony on the topic of setting goals for increasing the efficiency of energy consumption and increasing the development of demand-side renewable energy systems. On behalf of the Sierra Club. May 19, 2014.

Massachusetts Department of Public Utilities (Docket No. DPU 14-__): Testimony regarding the cost of compliance with the Global Warming Solution Act. On behalf of the Massachusetts Department of Energy Resources and the Department of Environmental Protection. May 16, 2014.

Kentucky Public Service Commission (Case No. 2014-00003): Direct testimony regarding Louisville Gas and Electric Company and Kentucky Utilities Company's proposed 2015-2018 demand-side management and energy efficiency program plan. On behalf of Wallace McMullen and the Sierra Club. April 14, 2014.

Maine Public Utilities Commission (Docket No. 2013-168): Direct and surrebuttal testimony regarding policy issues raised by Central Maine Power's 2014 Alternative Rate Plan, including recovery of capital costs, a Revenue Index Mechanism proposal, and decoupling. On behalf of the Maine Public Advocate Office. December 12, 2013 and March 21, 2014.

Colorado Public Utilities Commission (Docket No. 13A-0686EG): Answer and surrebuttal testimony regarding Public Service Company of Colorado's proposed energy savings goals. On behalf of the Sierra Club. October 16, 2013 and January 21, 2014.

Kentucky Public Service Commission (Case No. 2012-00578): Direct testimony regarding Kentucky Power Company's economic analysis of the Mitchell Generating Station purchase. On behalf of the Sierra Club. April 1, 2013.

Nova Scotia Utility and Review Board (Matter No. M04819): Direct testimony regarding Efficiency Nova Scotia Corporation's Electricity Demand Side Management Plan for 2013 – 2015. On behalf of the Counsel to Nova Scotia Utility and Review Board. May 22, 2012.

Missouri Office of Public Counsel (Docket No. EO-2011-0271): Rebuttal testimony regarding IRP rule compliance. On behalf of the Missouri Office of the Public Counsel. October 28, 2011.

Nova Scotia Utility and Review Board (Matter No. M03669): Direct testimony regarding Efficiency Nova Scotia Corporation's Electricity Demand Side Management Plan for 2012. On behalf of the Counsel to Nova Scotia Utility and Review Board. April 8, 2011.

Rhode Island Public Utilities Commission (Docket No. 3790): Direct testimony regarding National Grid's Gas Energy Efficiency Programs. On behalf of the Division of Public Utilities and Carriers. April 2, 2007.

North Carolina Utilities Commission (Docket E-100, Sub 110): Filed comments with Anna Sommer regarding the Potential for Energy Efficiency Resources to Meet the Demand for Electricity in North Carolina. Synapse Energy Economics on behalf of the Southern Alliance for Clean Energy. February 2007.

Rhode Island Public Utilities Commission (Docket No. 3765): Direct and Surrebuttal testimony regarding National Grid's Renewable Energy Standard Procurement Plan. On behalf of the Division of Public Utilities and Carriers. January 17, 2007 and February 20, 2007.

Minnesota Public Utilities Commission (Docket Nos. CN-05-619 and TR-05-1275): Direct testimony regarding the potential for energy efficiency as an alternative to the proposed Big Stone II coal project. On behalf of the Minnesota Center for Environmental Advocacy, Fresh Energy, Izaak Walton League of America, Wind on the Wires and the Union of Concerned Scientists. November 29, 2006.

Rhode Island Public Utilities Commission (Docket No. 3779): Oral testimony regarding the settlement of Narragansett Electric Company's 2007 Demand-Side Management Programs. On behalf of the Division of Public Utilities and Carriers. November 24, 2006.

Nevada Public Utilities Commission (Docket Nos. 06-04002 & 06-04005): Direct testimony regarding Nevada Power Company's and Sierra Pacific Power Company's Renewable Portfolio Standard Annual Report. On behalf of the Nevada Bureau of Consumer Protection. October 26, 2006

Nevada Public Utilities Commission (Docket No. 06-06051): Direct testimony regarding Nevada Power Company's Demand-Side Management Plan in the 2006 Integrated Resource Plan. On behalf of the Nevada Bureau of Consumer Protection. September 13, 2006.

Nevada Public Utilities Commission (Docket Nos. 06-03038 & 06-04018): Direct testimony regarding the Nevada Power Company's and Sierra Pacific Power Company's Demand-Side Management Plans. On behalf of the Nevada Bureau of Consumer Protection. June 20, 2006.

Nevada Public Utilities Commission (Docket No. 05-10021): Direct testimony regarding the Sierra Pacific Power Company's Gas Demand-Side Management Plan. On behalf of the Nevada Bureau of Consumer Protection. February 22, 2006.

South Dakota Public Utilities Commission (Docket No. EL04-016): Direct testimony regarding the avoided costs of the Java Wind Project. On behalf of the South Dakota Public Utilities Commission Staff. February 18, 2005.

Rhode Island Public Utilities Commission (Docket No. 3635): Oral testimony regarding the settlement of Narragansett Electric Company's 2005 Demand-Side Management Programs. On behalf of the Division of Public Utilities and Carriers. November 29, 2004.

British Columbia Utilities Commission. Direct testimony regarding the Power Smart programs contained in BC Hydro's Revenue Requirement Application 2004/05 and 2005/06. On behalf of the Sierra Club of Canada, BC Chapter. April 20, 2004.

Maryland Public Utilities Commission (Case No. 8973): Oral testimony regarding proposals for the PJM Generation Attributes Tracking System. On behalf of the Maryland Office of People's Counsel. December 3, 2003.

Rhode Island Public Utilities Commission (Docket No. 3463): Oral testimony regarding the settlement of Narragansett Electric Company's 2004 Demand-Side Management Programs. On behalf of the Division of Public Utilities and Carriers. November 21, 2003.

California Public Utilities Commission (Rulemaking 01-10-024): Direct testimony regarding the market price benchmark for the California renewable portfolio standard. On behalf of the Union of Concerned Scientists. April 1, 2003.

Québec Régie de l'énergie (Docket R-3473-01): Direct testimony with Philp Raphals regarding Hydro-Québec's Energy Efficiency Plan: 2003-2006. On behalf of Regroupment national des Conseils régionaux de l'environnement du Québec. February 5, 2003.

Connecticut Department of Public Utility Control (Docket No. 01-10-10): Direct testimony regarding the United Illuminating Company's service quality performance standards in their performance-based ratemaking mechanism. On behalf of the Connecticut Office of Consumer Counsel. April 2, 2002.

Nevada Public Utilities Commission (Docket No. 01-7016): Direct testimony regarding the Nevada Power Company's Demand-Side Management Plan. On behalf of the Bureau of Consumer Protection, Office of the Attorney General. September 26, 2001.

United States Department of Energy (Docket Number-EE-RM-500): Comments with Bruce Biewald, Daniel Allen, David White, and Lucy Johnston of Synapse Energy Economics regarding the Department of

Energy's proposed rules for efficiency standards for central air conditioners and heat pumps. On behalf of the Appliance Standards Awareness Project. December 2000.

US Department of Energy (Docket EE-RM-500): Oral testimony at a public hearing on marginal price assumptions for assessing new appliance efficiency standards. On behalf of the Appliance Standards Awareness Project. November 2000.

Connecticut Department of Public Utility Control (Docket No. 99-09-03 Phase II): Direct testimony regarding Connecticut Natural Gas Company's proposed performance-based ratemaking mechanism. On behalf of the Connecticut Office of Consumer Counsel. September 25, 2000.

Mississippi Public Service Commission (Docket No. 96-UA-389): Oral testimony regarding generation pricing and performance-based ratemaking. On behalf of the Mississippi Attorney General. February 16, 2000.

Delaware Public Service Commission (Docket No. 99-328): Direct testimony regarding maintaining electric system reliability. On behalf of Delaware Public Service Commission Staff. February 2, 2000.

Delaware Public Service Commission (Docket No. 99-328): Filed expert report ("Investigation into the July 1999 Outages and General Service Reliability of Delmarva Power & Light Company," jointly authored with J. Duncan Glover and Alexander Kusko). Synapse Energy Economics and Exponent Failure Analysis Associates on behalf the Delaware Public Service Commission Staff. February 1, 2000.

New Hampshire Public Service Commission (Docket No. 99-099 Phase II): Oral testimony regarding standard offer services. On behalf of the Campaign for Ratepayers Rights. January 14, 2000.

West Virginia Public Service Commission (Case No. 98-0452-E-GI): Rebuttal testimony regarding codes of conduct. On behalf of the West Virginia Consumer Advocate Division. July 15, 1999.

West Virginia Public Service Commission (Case No. 98-0452-E-GI): Direct testimony regarding codes of conduct and other measures to protect consumers in a restructured electricity industry. On behalf of the West Virginia Consumer Advocate Division. June 15, 1999.

Public Service Commission of West Virginia (Case No. 98-0452-E-GI): Filed expert report ("Measures to Ensure Fair Competition and Protect Consumers in a Restructured Electricity Industry in West Virginia," jointly authored with Jean Ann Ramey and Theo MacGregor) in the matter of the General Investigation to determine whether West Virginia should adopt a plan for open access to the electric power supply market and for the development of a deregulation plan. Synapse Energy Economics and MacGregor Energy Consultancy on behalf of the West Virginia Consumer Advocate Division. June 1999.

Massachusetts Department of Telecommunications and Energy (DPU/DTE 97-111): Direct testimony regarding Commonwealth Electric Company's energy efficiency plan, and the role of municipal aggregators in delivering demand-side management programs. On behalf of Cape and Islands Self-Reliance Corporation. January 1998.

Delaware Public Service Commission (DPSC 97-58): Direct testimony regarding Delmarva Power and Light's request to merge with Atlantic City Electric. On behalf of Delaware Public Service Commission Staff. May 1997.

Delaware Public Service Commission (DPSC 95-172): Oral testimony regarding Delmarva's integrated resource plan and DSM programs. On behalf of the Delaware Public Service Commission Staff. May 1996.

Colorado Public Utilities Commission (5A-531EG): Direct testimony regarding the impact of proposed merger on DSM, renewable resources and low-income DSM. On behalf of the Colorado Office of Energy Conservation. April 1996.

Colorado Public Utilities Commission (3I-199EG): Direct testimony regarding the impacts of increased competition on DSM, and recommendations for how to provide utilities with incentives to implement DSM. On behalf of the Colorado Office of Energy Conservation. June 1995.

Colorado Public Utilities Commission (5R-071E): Oral testimony on the Commission's integrated resource planning rules. On behalf of the Colorado Office of Energy Conservation. July 1995.

Colorado Public Utilities Commission (3I-098E): Direct testimony on the Public Service Company of Colorado's DSM programs and integrated resource plans. On behalf of the Colorado Office of Energy Conservation. April 1994.

Delaware Public Service Commission (Docket No. 96-83): Filed comments regarding the Investigation of Restructuring the Electricity Industry in Delaware (Tellus Institute Study No. 96-99). On behalf of the Staff of the Delaware Public Service Commission. November 1996.

Colorado Public Utilities Commission (Docket No. 96Q-313E): Filed comments in response to the Questionnaire on Electricity Industry Restructuring (Tellus Institute Study No. 96-130-A3). On behalf of the Colorado Governor's Office of Energy Conservation. October 1996.

State of Vermont Public Service Board (Docket No. 5854): Filed expert report (Tellus Institute Study No. 95-308) regarding the Investigation into the Restructuring of the Electric Utility Industry in Vermont. On behalf of the Vermont Department of Public Service. March 1996.

Pennsylvania Public Utility Commission (Docket No. I-00940032): Filed comments (Tellus Institute Study No. 95-260) regarding an Investigation into Electric Power Competition. On behalf of The Pennsylvania Office of Consumer Advocate. November 1995.

New Jersey Board of Public Utilities (Docket No. EX94120585Y): Initial and reply comments ("Achieving Efficiency and Equity in the Electricity Industry Through Unbundling and Customer Choice," Tellus Institute Study No. 95-029-A3) regarding an investigation into the future structure of the electric power industry. On behalf of the New Jersey Division of Ratepayer Advocate. September 1995.

Resume dated August 2014

Table 1. Summary of Results of Recent Company CCOS Studies

Customer Class	Cost of Service Results: Customer Costs (1) 2008	2012	2014
RESIDENTIAL	$10.43	$11.08	$25.94
Regular	$10.24	$10.80	$24.90
Time of Day	$15.03	$17.66	$34.87
All Electric	$10.67	$11.34	$28.37
Separately Metered	$13.25	$14.85	$35.00
SMALL	$14.02	$16.61	$35.67
Primary & Secondary	$14.20	$16.87	$36.29
Other	$7.86	$8.61	$14.27
All Electric	$15.40	$18.70	$51.45
Separately Metered	$21.17	$25.56	$58.04
MEDIUM	$43.64	$56.62	$182.75
Primary	$138.14	$163.71	$37.69
Secondary	$43.89	$56.36	$177.68
All Electric	$36.74	$50.04	$252.45
Separately Metered	$43.65	$55.59	$234.31
LARGE	$125.43	$132.90	$351.85
Primary	$204.90	$272.28	$140.65
Secondary	$111.36	$123.18	$331.58
All Electric	$144.84	$119.17	$492.80
Separately Metered	$138.40	$117.44	$360.85
LARGE POWER SERVICE	$755.22	$139.70	$2,808.15
Primary	$581.71	$165.62	$2,419.56
Secondary	$736.19	$56.95	$3,434.25
Substation	$1,523.14	$352.24	$2,268.68
Transmission	$8,010.74	$352.23	$2,268.46

(1) The Company labels the columns reproduced above as "Monthly Customer Charge," but these values represent customer-related costs. This can be seen by dividing the total customer component (customer costs) for the residential class by the annual number of residential customers in Normand's CCOS results.

Source: Direct Testimony of Rush, Docket ER-2014-0370, Schedule TMR-8; Direct Testimony of Normand, Docket ER-2012-0174, Table 4, page 25; Direct Testimony of Normand, Docket ER-2009-0089, Table 4, page 20.

of principles, these chapters are mere essays on the nature of the more controversial, largely unresolved, problems rather than attempts at systematic development. All of them have one theme in common: the thesis that the most formidable obstacles to further progress in the theory of public utility rates are those raised by conflicting goals of rate-making policy.

CRITERIA OF A DESIRABLE RATE STRUCTURE

Throughout this study we have stressed the point that, while the ultimate purpose of rate theory is that of suggesting feasible *measures* of reasonable rates and rate relationships, an intelligent choice of these measures depends primarily on the accepted *objectives* of rate-making policy and secondarily on the need to minimize undesirable side effects of rates otherwise best designed to attain these objectives. No rational discussion, for example, of the relative merits of "cost of service" and "value of service" as measures of proper rates or rate relationships is possible without reference to the question what desirable results the rate maker hopes to secure, and what undesirable results he hopes to minimize, by a choice between or mixture of the two standards of measurement. Not only this: the very *meaning* to be attached to ambiguous, proposed measures such as those of "cost" or "value"—an ambiguity not completely removed by the addition of familiar adjuncts, such as "out-of-pocket" costs, or "marginal costs," or "average costs"—must be determined in the light of the purposes to be served by the public utility rates as instruments of economic policy. This is a commonplace; but it is a commonplace which, so far from being taken for granted, needs repeated emphasis.

What then, are the good attributes to be sought and the bad attributes to be avoided or minimized in the development of a sound rate structure? Many different answers have been suggested in the technical literature and in the reported opinions by courts and commissions; and a number of writers have summarized their answers in the form of a list of desirable attributes of a rate structure, comparable to the "canons of taxation" found in the treatises on public finance. The list that follows is fairly typical, although I have derived it from a variety of sources instead of relying on any

one presentation. The sequence of the eight items is not meant to suggest any order of relative importance.

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")
6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
   (a) in the control of the total amounts of service supplied by the company:
   (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).

Lists of this nature are useful in reminding the rate maker of considerations that might otherwise escape his attention, and also useful in suggesting one important reason why problems of practical rate design do not readily yield to "scientific" principles of optimum pricing. But they are unqualified to serve as a base on which to build these principles because of their ambiguities (how, for example, does one define "undue discrimination"?), their overlapping character, and their failure to offer any rules of priority in the event of a conflict. For such a base, we must start with a simpler and more fundamental classification of rate-making objectives.

THREE PRIMARY CRITERIA

General principles of public utility rates and rate differentials are necessarily based on simplified assumptions both as to the objectives of rate-making policy and as to the factual circumstances un-

Schedule TW-3

ORDER NO. 85374

IN THE MATTER OF THE APPLICATION OF BALTIMORE GAS AND ELECTRIC COMPANY FOR ADJUSTMENT IN ITS ELECTRIC AND GAS BASE RATES.	* * * *	BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND CASE NO. 9299

Before: W. Kevin Hughes, Chairman
Harold D. Williams, Commissioner
Lawrence Brenner, Commissioner
Kelly Speakes-Backman, Commissioner

Issued: February 22, 2013

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I. INTRODUCTION AND EXECUTIVE SUMMARY

In this Order, we consider Baltimore Gas and Electric Company's ("BGE" or "Company") Application for adjustments in its electric and gas base rates, which it filed on July 27, 2012. Ultimately, based upon our obligation to ensure safe, reliable and economic utility services to the ratepayers of Maryland, we will grant the Company's request in part.

The record in this case included thousands of pages of written testimony from 21 witnesses, and included 6 days of evidentiary hearings, 5 separate public evening hearings in Annapolis, Baltimore City, Towson, Bel Air, and Ellicott City, and post-hearing briefs. Despite the voluminous evidence and testimony presented in this case, the Company's request was fairly narrow in scope, and we appreciate the fact that the adjustments and issues which have most recently been considered and ruled upon were not re-introduced in this case. Consequently, the time, energy and resources required to be expended by all parties as well as the Commission in this matter were greatly reduced.

Although narrow in scope of request, the amount of increase BGE requested is quite large (approximately $130 million for electric distribution and approximately $45 million for gas distribution). In this respect, as we do in all rate requests, we examined each item closely, for its direct impact upon, and relevance to the costs and functions central to BGE's mission to provide safe and reliable service.

We have not given BGE everything it asked for in its request. We have been consistent in this proceeding in our use of historic, average test year ratemaking principle, except in the treatment of certain safety and reliability plant investment incurred during the test year and for two months post test-year. For those safety and reliability projects that were undertaken during the test year and for the two months post test-year, such as gas plant major infrastructure replacements and 4 kV distribution infrastructure replacements, we have granted the terminal test-year and two months post test-year adjustments proposed by the Company. We again have declined to include projected rate base additions or projected operating and maintenance expenses for certain safety and reliability compliance projects. However, consistent with our prioritization and obligation to ensure safe and reliable service to ratepayers, we have allowed ample recovery for reliability and safety spending, both for the Company's electric and gas systems, and accounted fairly for the overall trend of increased infrastructure spending at a time of decreasing demand.

For the reasons explained in the body of the Order, we authorize an increase in base rate revenues for electric distribution service of $80,554,000 and an increase in base rate revenues for gas distribution service of $32,416,000. The authorized additional revenue equates to a typical standard residential customer monthly electricity bill[1] increase of $3.33, which represents a 2.6 percent increase in the overall electric bill. For average residential gas customers,[2] this increase equates to a monthly bill impact of $2.70, which represents a 4.26 percent increase in the overall gas bill.

We reject BGE's request for a single, combined return on equity for its electric and gas operations. Nor do we adopt BGE's recommended return on equity for either the electric or gas operations enhancing the return to the shareholders. We find that a return

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[1] We use 1000 kilowatt hours ("kWh") per month as the monthly usage for a typical standard residential electric customer (R Class).
[2] We use 52 therms as the monthly usage for an average residential gas customer.

on equity of 9.75 percent for electric distribution resulting in overall rate of return of 7.60 percent (compared with the return on equity of 9.86 percent resulting in an overall rate of return of 8.06 percent set in BGE's last rate case, Case No. 9230[3]) is sufficient and balances the risk profile of the Company with the expectations of its ratepayers. For the gas distribution operations, we set a return on equity of 9.60 percent resulting in an overall rate of return of 7.53 percent (compared with the return on equity of 9.56 percent resulting in an overall rate of return of 7.90 percent set in Case No. 9230[4]). We also have made adjustments to certain expenses to reflect the relative benefits received from the expenditures between the ratepayers and the Company's shareholders.

We have accepted BGE's Cost of Service Studies as proposed. As we have in prior rate cases, we have allocated the rate increases to move all rate classes closer to the system average rate of return, but in a manner to avoid rate shocks to any one class. Based on the traditional methodology employed in our other rate case decisions, we have utilized a two-step process for both electric and gas service.

For electric rates, in the first step we have allocated 15 percent of the rate increase to under-returning R, RL and P classes. In the second step, we allocate the remaining amount to all customer classes, except the T and SPE class, which are returning significantly above the system average. We have declined to decrease the rates for the T class, as the Maryland Energy Group suggested, when the other classes' (except the SPE class) rates are increasing. For the gas rates, in the first step, we move the relative rate of return for Schedules IS and ISS to 0.68, which is less than the allocation proposed by BGE. We also authorize a relative rate of return for Schedules D and C to 1.025 and

[3] Order No. 83714, *Re Baltimore Gas and Electric Company,* Case No. 9230 (Dec. 6, 2010).
[4] *Id.*

0.96, respectively. In the second step, we allocate the remainder of the gas revenue increase to customer classes in proportion to the adjusted test-year revenues, except to the over-earning classes, Schedule PLG and SP.

BGE also sought acceptance of its riders, Sparrows Point Riders, which are designed to enable the Company to collect the revenues previously recovered from Schedules SP (gas tariff) and SPE (electric tariff), both of which are a single customer class for RG Steel, LLC. After carefully considering the arguments by the Office of People's Counsel asking us to reject these riders, we find that the riders are reasonable under the circumstance, and are a short-term solution for the recovery of revenues previously allocated to the Schedules SP and SPE. In BGE's next distribution rate case, new cost of service studies will more completely address this issue.

Consistent with our decision in Case No. 9230, we have authorized BGE to include the full $2.3 million in matching BGE credits expended in the test year for low-income customers who received grants from the Fuel Fund of Maryland. We find that BGE provided sufficient evidence to demonstrate that its Fuel Fund program is cost-effective, and benefits all customers by reducing the level of the Company's bad debt expenses and thereby reducing bills for all customers. In addition, the program assists the low-income customers in keeping utility service in their homes.

Finally, we have considered Staff's requests to: (1) require BGE to submit: (a) a formal written gas infrastructure replacement plan; and (b) a formal work plan detailing how BGE will implement the replacement or upgrading of its electric infrastructure, including poles in service over 40 years; and (2) to direct BGE to use the average test-year usage per customer when calculating its monthly Rider 25 (decoupling mechanism rider). We decline to direct BGE to submit the formal plans as recommended by Staff at this time, but direct the parties to meet, develop and submit a reporting requirement for gas and electric infrastructure replacement plans for the Commission's consideration. We also find that there is not sufficient information for us to decide the Rider 25 issue, and direct BGE to submit a revised Rider 25 addressing Staff's concerns, which we will then consider at a future Administrative Meeting.

II. BACKGROUND

On July 27, 2012, BGE filed an Application for Revisions in Electric and Gas Base Rates ("Application"), pursuant to §§ 4-203 and 4-204 of the Public Utilities Article, *Annotated Code of Maryland* ("PUA"), for authority to increase its rates for the retail distribution of electricity and natural gas in Maryland. BGE's last electric rate and gas rate case occurred in 2010.[5] In its Application, BGE used a 12-month test year ending September 30, 2012, with 8 months of actual data and 4 months of projected data, and stated that its evidence supported a $150.8 million increase in its electric distribution revenue requirement and a $53.4 million increase in its gas distribution revenue requirement. Based upon updated actual data for the full test year, BGE revised its claimed electric revenue requirement increase to $130.5 million and revised its claimed gas revenue requirement increase to $45.2 million.[6]

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[5] *Re Baltimore Gas and Electric Company*, Case No. 9230, Order Nos. 83714 (Dec. 6, 2010) and 83907 (March 9, 2011).
[6] BGE Exhibit ("Ex.") 15, Supplemental Direct Testimony of David M. Vahos ("Vahos Supp. Direct") at 5.

A number of parties filed written testimony in this proceeding.[7] BGE sponsored the testimony of Kenneth W. DeFontes, Jr., President and Chief Executive Officer, who testified on the general basis for the rate increase;[8] Stephen J. Woerner, Senior Vice President and Chief Operating Officer, who testified on the significant historical and rate-effective year investments the Company is making in its electric and gas distribution infrastructure in support of certain safety and reliability rate-making adjustments proposed by the Company;[9] Carim V. Khouzami, Vice President, Chief Financial Officer and Treasurer, who testified regarding financial matters, including the rate of return, cost of capital, capital structure, and revenue decoupling;[10] David M. Vahos, Vice President and Controller, who testified about rate base and development of the revenue requirement;[11] Michael J. Cloyd, Director of Pricing and Tariffs, who testified about gas and electric rate designs;[12] and George R. Pleat, Manager of Pricing and Tariffs, who testified about the Actual Calendar Year ("CY") 2011 Company Recommended Gas Embedded Cost of Service Study and the Actual CY 2011 Company Recommended Electric Embedded Cost of Service Study.[13] Additionally, two other witnesses testified

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[7] The Mayor and City Council of Baltimore City's petition to intervene as a party in the proceeding was granted, but the City did not file any written testimony.

[8] BGE Ex. 26, Prepared Direct Testimony of Kenneth W. DeFontes, Jr. ("DeFontes Direct"); BGE Ex. 27, Prepared Rebuttal Testimony of Kenneth W. DeFontes, Jr. ("DeFontes Rebuttal").

[9] BGE Ex. 2, Prepared Direct Testimony of Stephen J. Woerner ("Woerner Direct"); BGE Ex. 3, Prepared Rebuttal Testimony of Stephen J. Woerner ("Woerner Rebuttal").

[10] BGE Ex. 4, Prepared Direct Testimony of Carim V. Khouzami ("Khouzami Direct"); BGE Ex. 5, Prepared Supplemental Direct Testimony of Carim V. Khouzami ("Khouzami Supp. Direct"); BGE Ex. 6, Prepared Rebuttal Testimony of Carim V. Khouzami ("Khouzami Rebuttal").

[11] BGE Ex. 14, Prepared Direct Testimony of David M. Vahos ("Vahos Direct"); BGE Ex. 15, Vahos Supp. Direct; BGE Ex. 16, Prepared Rebuttal Testimony of David M. Vahos ("Vahos Rebuttal"); BGE Ex. 17, Prepared Surrebuttal Testimony of David M. Vahos ("Vahos Surrebuttal").

[12] BGE Ex. 10, Prepared Direct Testimony of Michael J. Cloyd ("Cloyd Direct"); BGE Ex. 11, Prepared Supplemental Direct Testimony of Michael J. Cloyd ("Cloyd Supp. Direct"); BGE Ex. 12, Prepared Rebuttal Testimony of Michael J. Cloyd ("Cloyd Rebuttal").

[13] BGE Ex. 8, Prepared Direct Testimony of George R. Pleat ("Pleat Direct"); BGE Ex. 9, Prepared Rebuttal Testimony of George R. Pleat ("Pleat Rebuttal").

on behalf of BGE: Dr. Samuel C. Hadaway, a principal in the consulting firm of FinanCo, Inc., Financial Analysis Consultants, testified regarding the fair rate of return on equity;[14] and Jonathan Weinstein, Managing Partner of Pay Governance, testified on BGE's compensation levels compared to market practices and the results of research conducted on the prevalence of indirect employee reward practices among large utilities.[15]

The Office of People's Counsel ("OPC") presented the testimony of Bion C. Ostrander, President of Ostrander Consulting and an independent regulatory consultant and Certified Public Accountant (Kansas), who testified regarding the revenue requirements of BGE;[16] Charles W. King, Emeritus President of the economic consulting firm Snavely King Majoros & Associates, Inc., who testified regarding gas and electric rates of return, cost of capital issues, and the correct test year depreciation accruals proposed by BGE;[17] and Dr. Karl R. Pavlovic, a Senior Consultant with Snavely King Majoros & Associates, Inc., who testified regarding BGE's proposals regarding regulatory lag, post-test year reliability investment, reliability expenses, electric and gas class distribution cost, revenue requirements and distribution rate design.[18]

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[14] BGE Ex. 21, Prepared Direct Testimony of Samuel C. Hadaway ("Hadaway Direct"); BGE Ex. 22, Prepared Rebuttal Testimony of Samuel C. Hadaway ("Hadaway Rebuttal"); BGE Ex. 23, Prepared Surrebuttal Testimony of Samuel C. Hadaway ("Hadaway Surrebuttal").
[15] BGE Ex. 20, Prepared Direct Testimony of Jonathan Weinstein ("Weinstein Direct").
[16] OPC Ex. 23, Pre-filed Confidential Direct Testimony of Bion C. Ostrander and OPC Ex. 23A, Public Version of Direct Testimony of Bion C. Ostrander (collectively, "Ostrander Direct"); OPC Ex 24 , Pre-filed Confidential Supplemental Direct Testimony of Bion C. Ostrander and OPC Ex. 24A, Public Version of Supplemental Direct Testimony of Bion C. Ostrander (collectively, "Ostrander Supp. Direct"); OPC Ex. 25, Pre-filed Confidential Surrebuttal Testimony of Bion C. Ostrander and OPC Ex. 25A, Public Version of Surrebuttal Testimony of Bion C. Ostrander (collectively, "Ostrander Surrebuttal").
[17] OPC Ex. 19, Direct Testimony of Charles W. King ("King Direct"); OPC Ex. 20, Supplemental Direct Testimony of Charles W. King ("King Supp. Direct"); OPC Ex. 21, Rebuttal Testimony of Charles W. King ("King Rebuttal"); OPC Ex. 22, Surrebuttal Testimony of Charles W. King ("King Surrebuttal").
[18] OPC Ex. 26, Direct Testimony of Karl R. Pavlovic (Confidential) and OPC Ex. 26A, Direct Testimony of Karl R. Pavlovic (Public) (collectively, "Pavlovic Direct"); OPC Ex. 27, Supplemental Direct Testimony

The Maryland Energy Group ("MEG") presented the testimony of Richard A. Baudino, a consultant with J. Kennedy and Associates, who testified regarding class cost of service, revenue allocation, rate design and tariff issues, and rate of return.[19]

The Public Service Commission Technical Staff ("Staff") presented the testimony of Patricia M. Stinnette, Director of the Accounting Investigations Division, who testified regarding revenue requirements;[20] Yulia Poberesky, Public Utility Auditor in the Accounting Investigations Division, who also testified regarding revenue requirements;[21] Julie McKenna, a Regulatory Economist in the Electricity Division, who testified about the cost of capital, capital structure and rate of return for the electric operations of BGE;[22] Kevin D. Mosier, a Wholesale Markets Liaison in the Energy Analysis and Planning Division, who testified about the cost of capital, capital structure and rate of return for the gas operations of BGE;[23] James Currier, a Regulatory Economist in the Electricity Division, who testified regarding the electric rate design and proposed tariff changes;[24]

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of Karl R. Pavlovic (Confidential) and OPC Ex. 27A, Supplemental Direct Testimony of Karl R. Pavlovic (Public) (collectively, "Pavlovic Suppl. Direct"); OPC Ex. 28, Surrebuttal Testimony of Karl R. Pavlovic (Confidential) and Surrebuttal Testimony of Karl R. Pavlovic (Public) (collectively, "Pavlovic Surrebuttal").

[19] MEG Ex. 1, Direct Testimony and Exhibits of Richard A. Baudino ("Baudino Direct"); MEG Ex. 2, Rebuttal Testimony of Richard A. Baudino ("Baudino Rebuttal"); MEG Ex. 3, Surrebuttal Testimony of Richard A. Baudino ("Baudino Surrebuttal").

[20] Staff Ex. 12, Direct Testimony and Exhibits of Patricia M. Stinnette ("Stinnette Direct"); Staff Ex. 13, Rebuttal Testimony and Exhibits of Patricia M. Stinnette ("Stinnette Rebuttal"); Staff Ex. 14, Surrebuttal Testimony and Exhibits of Patricia M. Stinnette ("Stinnette Surrebuttal").

[21] Staff Ex. 5, Direct Testimony and Exhibits of Yulia Poberesky ("Poberesky Direct"); Staff Ex. 6, Confidential Rebuttal Testimony and Exhibits of Yulia Poberesky and Staff Ex. 6A, Public Version of Rebuttal Testimony and Exhibits of Yulia Poberesky (collectively, "Poberesky Rebuttal"); Staff Ex. 7, Surrebuttal Testimony and Exhibits of Yulia Poberesky ("Poberesky Surrebuttal").

[22] Staff Ex. 15, Direct Testimony and Exhibits of Julie McKenna ("McKenna Direct"); Staff Ex. 16, Rebuttal Testimony and Exhibits of Julie McKenna ("McKenna Rebuttal"); Staff. Ex. 17, Surrebuttal Testimony and Exhibits of Julie McKenna ("McKenna Surrebuttal").

[23] Staff Ex. 18, Testimony of Kevin D. Mosier ("Mosier Direct"); Staff Ex. 19, Rebuttal Testimony of Kevin D. Mosier ("Mosier Rebuttal"); Staff Ex. 20, Surrebuttal Testimony of Kevin D. Mosier ("Mosier Surrebuttal").

[24] Staff Ex. 24, Direct Testimony and Exhibits of James R. Currier, III and Staff Ex. 25, Errata to Direct Testimony and Exhibits of James R. Currier, III (collectively, "Currier Direct"); Staff Ex. 26, Rebuttal

Gunter Elert, Assistant Director, Telecommunications, Gas and Water Division, who testified regarding the gas cost of service study, rate design, and proposed tariff changes;[25] Dr. Ozlen D. Luznar, a Regulatory Economist in the Electricity Division, who testified regarding the electric cost of service study;[26] John J. Clementson, II, an Assistant Chief Engineer in the Engineering Division, who testified on BGE's plans for replacing portions of its aging gas distribution infrastructure over the next twenty years;[27] and De Andre T. Wilson, an Electric Distribution Engineer in the Engineering Division, who testified regarding BGE's Rulemaking 43[28] reliability spending and the reliability performance of the electric distribution system.[29]

Staff, OPC and MEG filed direct testimony on October 20, 2012. The Company filed supplemental direct testimony on October 22, 2012, updating the Company's direct testimony for actual data for the full test year. On November 2, 2012, OPC filed leave to file supplemental direct testimony. On November 7, 2012, the Commission accepted OPC's supplemental direct testimony, and modified the procedural schedule to have any accounting or policy witnesses rebuttal testimony filed on November 13, 2012. Rebuttal testimony was filed by the parties on November 9, 2012, except for BGE's accounting and policy witnesses' rebuttal testimony which was filed on November 13, 2012. Surrebuttal testimony was filed by the parties on November 20, 2012. Evidentiary

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Testimony and Exhibits of James R. Currier, III ("Currier Rebuttal"); Staff Ex. 27, Surrebuttal Testimony and Exhibits of James R. Currier, III ("Currier Surrebuttal").

[25] Staff Ex. 21, Direct Testimony and Exhibits of Gunter J. Elert ("Elert Direct"); Staff Ex. 22, Rebuttal Testimony and Exhibits of Gunter J. Elert ("Elert Rebuttal"); Staff Ex. 23, Surrebuttal Testimony and Exhibits of Gunter J. Elert ("Elert Surrebuttal").

[26] Staff Ex. 10, Direct Testimony and Exhibits of Ozlen D. Luznar ("Luznar Direct"); Staff Ex. 11, Rebuttal Testimony and Exhibits of Ozlen D. Luznar ("Luznar Rebuttal").

[27] Staff Ex. 8, Direct Testimony and Exhibits of John J. Clementson, II ("Clementson Direct").

[28] In this Order, we use "RM43" to refer to the service quality and reliability standards that we adopted pursuant to the administrative docket proceeding RM43. The actual regulations are codified as COMAR 20.50.10, and became effective on May 28, 2012.

[29] Staff Ex. 9, Direct Testimony and Exhibits of De Andre T. Wilson ("Wilson Direct").

hearings were conducted at the Commission's offices on December 3 – 7 and December 12, 2012. Evening public comment hearings were held throughout the Company's service territory in Anne Arundel County, Baltimore City, Baltimore County, Harford County and Howard County on January 7, January 9, January 10, January 15, and January 16, 2013, respectively. Initial Briefs were filed on January 9, 2013, and Reply Briefs were filed on January 23, 2013.

On December 14, 2012, the Staff filed, on behalf of the parties, a Final Summary of Positions on Revenue Requirements (hereinafter, the "Chart").[30] The Chart reflects BGE's final purported revenue deficiencies of $130,065,000 for electric distribution operations and $45,583,000 for gas distribution operations. Staff's final position reflects an electric revenue requirement deficiency of $80,990,000 and a gas revenue deficiency of $22,679,000, while OPC's final position reflects an electric revenue deficiency of $36,320,000 and a gas revenue deficiency of $19,598,000.

All of the evidence presented, including the comments received at the five public hearings, has been thoroughly and carefully reviewed by the Commission in reaching the decisions in this Order.

[30] *See* Mail log No. 144198, Docket Item No. 55. A copy of the Chart is attached to this Order as Appendix III.

III. DISCUSSION AND FINDINGS

A. Operating Income and Rate Base[31]

In this section, we discuss and resolve the contested adjustments to operating income[32] and rate base[33] proposed by the Company or other parties. Those uncontested adjustments are not discussed herein. The undisputed portion of the electric operating income is $157,741,000, and the undisputed gas net operating income is $54,467,000. The undisputed electric rate base is $2,576,323,000, and the undisputed gas rate base is $933,546,000.

1. Rate Case Expenses

<u>**Positions of the Parties**</u>

BGE has requested recovery of $181,000 (net)[34] in rate case expenses for this case. BGE argued that recovery of such expenses is both appropriate and precedented, and that the Commission has normally approved recovery of rate case expense in past base rate cases.

Staff witness Poberesky favored excluding from rates all of the rate case expenses BGE seeks to recover for this proceeding. Staff objected to BGE's payments to three consulting firms on the grounds that they variously presented an open-ended contract, failed to adequately describe their services in invoices, and provided services that BGE's employees could have provided.

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[31] In prior rate case orders, we have separated discussion resolving contested adjustments to the undisputed portion of the operating income and the undisputed portion of the rate base. In this case, we conclude combining the two is more efficient.
[32] Operating income is based on the revenues that BGE receives for its utility service minus the costs it incurs in providing that service.
[33] Rate base reflects the investments made by BGE in plant and equipment to provide its service.
[34] Vahos Rebuttal at 39.

In rebuttal, BGE's witness Vahos stated that "the Company is simply requesting recovery of its actual rate case expenses incurred in the test period," which he claims were "modest."[35] Staff witness Poberesky, he noted, agreed with BGE that rate case expenses generally were an appropriate item to be reflected in rates. Mr. Vahos also claimed that BGE had provided updated contracts, invoices, and other "proper documentation" in response to Staff's assertion that documentation was lacking. Mr. Vahos concluded that BGE should therefore recover its actual rate case expenses, as documented.[36]

In her surrebuttal testimony Ms. Poberesky again reiterated that the invoices BGE provided were inadequate, as they either lacked detail, were based on open-ended contracts, or were for services Staff considered unnecessary. Therefore, Ms. Poberesky maintained her original position that BGE's rate case expenses should be disallowed in this instance.[37]

Commission Decision

The amount of rate case expenses to be recovered were not disputed in BGE's previous rate case, Case No. 9230, although BGE used outside consultants to testify in that proceeding.[38] In this case, the services provided BGE by the three contractors whose payments are at issue did not include outside legal representation,[39] which BGE provided

[35] *Id.*
[36] *Id.* at 40-41.
[37] Poberesky Surrebuttal at 2.
[38] In Case No. 9230, William E. Avera testified regarding the fair rate of return on equity and the reasonableness of BGE's equity ratio; Susan D. Abbot testified regarding utility risks, investment ratings, decoupling mechanisms and certain expenses; and Ralph Cavanagh testified about electric decoupling issues. Order No. 83907 at 4-5.
[39] In several recent rate cases filed by Potomac Electric Power Company ("Pepco") and Delmarva Power & Light Company ("Delmarva"), we have addressed the amount of rate case expenses incurred by these companies for outside legal representation, when, in our opinion, the companies have or should have the necessary in-house counsel expertise to litigate a rate case. *See Re Potomac Electric Power Company*,

through its own employees. We find it reasonable to obtain a modest amount of external support for rate case preparation, and in this situation, we find BGE kept the expenditures to what we consider a modest amount, considering the size of BGE's base rate request. However, we caution BGE that significant rate case preparation expenses for outside contractors will not necessarily be recoverable, given BGE's level of in-house expertise. Based on the foregoing, we accept recovery of BGE's rate case expenses in operating income in this case.

2. Merger Costs

__Positions of the Parties__

BGE witness Vahos testified that BGE expects to realize cost saving synergies as a result of Constellation Energy Group's merger with Exelon.[40] Mr. Vahos explained, however, that the savings were achieved with "up front" costs, or "costs to achieve" ("CTA"). The Company has made an operating income adjustment to "reverse" or remove $3,858,338 ($2,777,038 (electric) and $1,081,300 (gas)) in CTA from its operating income.[41] BGE then established a regulatory asset for $1,146,909 ($825,487 (electric), $321,421 (gas))[42] of CTA that it proposes to include in rate base on a 13-month average basis as of September 30, 2012.[43]

OPC witness Ostrander agreed with BGE's decision to remove $3,858,338 in CTA from its operating income requirement. He did not agree, however, with BGE's decision to create a regulatory asset of $1,146,909 to amortize and recover CTA.

Case No. 9217, Order 83516, 101 MD PSC 290 (Aug. 6, 2010); *See also Delmarva Power & Light Company*, Case No. 9285, Order 85029 (July 20, 2012); Potomac *Electric Power Company*, Case No. 85028, Order No. 85028 (July 20, 2012).

[40] BGE is a subsidiary of Constellation Energy Group ("CEG").

[41] Vahos Supp. Direct – Adj. 17.

[42] The electric and gas components do not add up to $1,146,909, probably due to rounding.

[43] Vahos Supp. Direct – Adj. 18.

Mr. Ostrander concluded BGE had not shown that its CTA were known and measurable, and therefore he contended that they should not be recovered through rate base. OPC argued to remove all CTA amounts from this case.[44]

In his rebuttal testimony, Mr. Vahos objected to Mr. Ostrander's proposed elimination of CTA from rate base at the same time that Mr. Ostrander proposed to retain all merger synergies, including estimated synergies, as a revenue requirement component. According to Mr. Vahos, the result is objectionable because inclusion of all merger synergies in revenue would reduce BGE's revenue requirement at the same time removal of CTA from rate base would prevent any recovery of costs necessary to achieve those synergies. To Mr. Ostrander's statement that he eliminated recovery of CTA because they were not known and measurable, Mr. Vahos responded that the CTA were actual costs for the test period ending September 2012 and contained no estimated amounts.[45]

In his surrebuttal testimony, Mr. Ostrander again claimed that "BGE has not provided the actual due diligence documents and analysis regarding the Constellation merger."[46] Mr. Ostrander explained that the documents he found lacking were the "actual" due diligence documents upon which BGE's synergy savings analysis was based.[47] Mr. Ostrander contended that BGE had underestimated the amount of merger savings that should be included in this rate case. Specifically, Mr. Ostrander proposed including $13.60 million[48] of merger savings in BGE's revenue requirement calculations, while BGE has only proposed to include $9.65 million[49] of savings in the revenue

[44] Ostrander Supp. Direct at 23-24.
[45] Vahos Rebuttal at 30.
[46] Ostrander Surrebuttal at 24-25.
[47] *Id.* at 25.
[48] Case No. 9271, Confid. Table No. 4, cited in Ostrander Confidential Supp. Direct at 29.
[49] Ostrander Supp. Direct, Ex. BCO-2, Sch. A-19.

requirement[50] in this case. Mr. Ostrander asserted that, based on his own calculations, the $9.65 million amount was his lowest level of estimated merger savings for a five-year period. Mr. Ostrander also claimed that his proposed merger savings of $13.60 million was "actually less than BGE's estimate of merger savings for all remaining years 2 through 5."[51]

Mr. Ostrander rejected BGE's assertion that it was "grossly unfair" to exclude CTAs from rate base and include all synergies in operating income. He pointed out that the Commission recently rejected recovery of amortization of costs to achieve a contract in Case No. 9267,[52] and that the CTA at issue here are similar to the costs in Case No. 9267.

Commission Decision

Historically, we have favored a symmetrical treatment of merger synergies and costs-to-achieve. There is no clear reason to use merger synergies to adjust BGE's operating income while removing costs to achieve those synergies from the Company's rate base, as long as those CTAs are prudent, known and measurable. The Commission accepts BGE's proposal to include a regulatory asset on a 13-month average basis of $1,146,909 ($825,487 for electric and $321,421 for gas)[53] in rate base over a five-year recovery period.[54] BGE's recovery of this regulatory asset will not approach the total

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[50] The $9.65 million result from Mr. Ostrander's grossing up BGE Adjustments 17, 18, and 19 based on his revenue conversion factor. *See* Ostrander Supp. Direct, Ex. BCO-2, Sch. A-19.

[51] Ostrander Surrebuttal at 19. (Mr. Ostrander appears to conclude that, based on the predicted merger savings in Case No. 9271, BGE is realizing too little merger savings in this case. *See* Ostrander Supp. Dir. at 25.)

[52] *In the matter of the Application of the Washington Gas Light Company for Authority to Increase Its Existing Rates and Charges and to Revise its Terms and Conditions for Gas Service*, Order No. 84475 at 57 (Nov. 14, 2011) (*Re Washington Gas Light Company*, Order No. 84475").

[53] *See* fn 33.

[54] See fn 39.

CTA it is removing from its operating income request and is therefore less burdensome for ratepayers than operating income treatment of the full CTA would be. This results in a net rate base increase of $492,000 for electric and $192,000 for gas.[55]

We reject OPC's argument that BGE's merger savings are wrongly calculated because they do not match the Company's merger savings estimate in BGE's prior rate case. The failure to match an estimate is not an indication of error; it is an indication of reality.

Further, we reject OPC's suggestion that, as we did not include CTA in rate base in Case No. 9267,[56] we should similarly reject such treatment here. CTA were heavily estimated in Case No. 9267, and here they are actual costs. Therefore, the two cases are not on the same footing. Further, the Commission found in Case No. 9267 that Washington Gas Light had in fact not realized any customer benefits at that time from the out-sourcing program that had given rise to costs-to-achieve.[57] In the present case, customer benefits have actually been achieved. This decision, related to annualization of merger synergies, increases BGE's net operating income by $2,714,000 ($1,953,000 for electric and $761,000 for gas).[58]

3. Employee Activity Costs

<u>Positions of the Parties</u>

BGE requested recovery of $968,710 in employee activity costs,[59] on the basis that such costs benefit ratepayers by improving employee morale and therefore improving productivity. For OPC, Mr. Ostrander requested full denial of these costs,

[55] Vahos Direct. – Adj. 8.
[56] *Re Washington Gas Light Company*, Order No. 84475.
[57] *Id.* at 54-57.
[58] Vahos Dir. – Adj. 18.
[59] Ostrander Public Supp. Direct at 30.

based on the Commission's decision in BGE's last rate case, Case No. 9230, to deny 100 percent of the Company's employee activity costs. Mr. Ostrander found nothing in either Mr. DeFontes' testimony, which he claimed was too broad, nor Mr. Weinstein's testimony, which he claimed was too narrow, to justify inclusion of employee activity costs in BGE's revenue requirement.[60]

Staff witness Poberesky recommended the Commission allow recovery of only 50 percent of the costs.[61] Ms. Poberesky reasoned that the programs provided by the Company's employee activity costs, such as Company picnics and other social functions, benefited both ratepayers and shareholders and so should be shared between them.[62]

Commission Decision

Employee activity costs generally finance events designed to improve employee morale, and indeed Mr. DeFontes testified to such regarding annual employee picnics. We conclude that improved employee morale (and possible resulting improvements in productivity) benefits both shareholders and ratepayers, but employee activity costs must be within careful limits if recovery from ratepayers is sought.[63] As to BGE's skybox, however, we find it is primarily of benefit to Company executives and their guests and is not an expense that ratepayers should pick up, even partially. Therefore, we have removed the skybox expense ($110,473) from BGE's request as OPC witness Ostrander suggested,[64] and assign ratepayers a 50 percent recovery of the remainder, which is then allocated to electricity and gas. The net operating income effect of this adjustment is $232,000 on the electric side and $90,000 on the gas side.

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[60] Ostrander Direct at 51.
[61] Poberesky Direct at 4.
[62] Poberesky Direct at 4.
[63] Ostrander Public. Supp. Direct at 30.
[64] *Id.*

4. 2012 Wage Adjustment

Positions of the Parties

BGE proposed an adjustment to implement a 2.5 percent wage increase in March 2012 for electric and gas operations in the amount of $1,584,197 and $616,841, respectively.[65] OPC witness Ostrander rejected the entire proposed wage increase because BGE "failed to provide any specific signed contract or other legally enforceable agreement to support those costs, and thus this amount does not represent a known and measurable post-test year expense increase."[66] Mr. Ostrander noted that his reasoning was based on the Commission's decision in Case No. 9230[67] in which the Commission rejected BGE's proposed 2011 wage adjustment because it was not supported by a signed contract or other legally enforceable agreement.[68] Mr. Ostrander found other problems with the proposed increase: uncertainty about whether it applied to employees leaving BGE due to workforce reduction, and whether the 2.5 percent is a cost of living adjustment or incentive pay.[69]

Staff also disagreed with this adjustment, as Staff witness Stinnette claimed that the 2.5 percent increase was only an estimate and not known and measurable.[70] Staff also objected that the proposed wage increase extended beyond the test year and thus violated the matching principle.[71] Ms. Stinnette therefore eliminated wage increases that extended

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[65] Vahos Direct, Operating Income Adjustment 7.
[66] Ostrander Direct at 53.
[67] Case No. 9230, Commission Order No. 83907 at 36 (2011).
[68] Ostrander Direct at 53.
[69] *Id.* at 55.
[70] Stinnette Direct at 10.
[71] *Id.*

beyond the test period, thus removing $945,000 from the electric wage increase and $368,000 from the gas wage increase.[72]

In rebuttal, Mr. Vahos stated that the 2.5 percent wage increase reflected the actual wage and salary increase that occurred beginning March 2012, and the adjustment's purpose was to annualize the impact of the wage and salary change.[73] Mr. Vahos pointed out that the Commission approved "this specific adjustment" in Case Nos. 9230 and 9036.[74] He further contended that the adjustment would not duplicate or overstate test period costs or apply to those who voluntarily left BGE's employ.[75] The adjustment, he maintained, simply "annualized the portion of the actual 2.5 percent wage and salary increase that was made in March 2012, which was not fully reflected in the test period."[76] Mr. Vahos likewise dismissed concerns that the 2.5 percent across-the-board increase was inconsistent with merit pay protocols. Merit or incentive pay, he pointed out, is influenced by other considerations than an across-the-board increase and varies by individual.[77]

In surrebuttal, Ms. Stinnette and Mr. Ostrander still rejected the proposed increase for lack of documentation.[78] Mr. Ostrander also could not understand why BGE's October 22, 2012 updated filing did not change the amount of increased wages over the

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[72] *Id.*
[73] Vahos Rebuttal at 31.
[74] *Re the Application of Baltimore Gas and Electric Company for Revisions in Its Electric and Gas Base Rates* and *Re the Application of the Baltimore Gas and Electric Company for Revision in Its Gas Base Rates*, respectively.
[75] Vahos Rebuttal at 32.
[76] *Id.*
[77] *Id.* at 32-33.
[78] Stinnette Surrebuttal at 2; Ostrander Rebuttal at 28-29.

earlier projected amounts. He therefore continued to oppose BGE's 2.5 percent wage adjustment.[79]

Commission Decision

We find the 2.5 percent salary increase instituted in March 2012 to be a routine expense not requiring proof in the form of new contracts or other special documents. While the Company was able to show only six months of actual data on this expense, it annualized the expense for the full test year, to reflect that this expense is an ongoing expense for the rate effective period. We therefore approve and annualize this salary increase.[80] This adjustment reduces BGE's net electric operating income by $945,000 and BGE's net gas operating income by $368,000.

5. Safety & Reliability and RM43 and RM44 Adjustments

Safety and reliability are a foremost concern when we consider costs and revenue requests by utilities. In the most recent rate proceedings, the Commission has recognized that under appropriate circumstances, and when properly supported, adjustments to the historically accepted average test year may be warranted for safety and reliability investments and expenses, provided the safety and reliability investments or expenses do not generate additional utility revenues. "Non-revenue producing" safety and reliability investments generally serve existing customers, rather than attain new customers, which result in incremental utility revenues.

In this case, BGE has proposed general safety and reliability rate base adjustments and specific RM43 reliability rate base adjustments to recognize: (1) the terminal test-

[79] Ostrander Surrebuttal at 29.
[80] No party contested allowing recovery of $2.2 million ($1.6 million for electric and $0.6 million for gas) in BGE executive compensation. We therefor approve it for recovery in BGE's revenue requirement.

year value of safety and reliability and RM43 investments; (2) actual post test-year safety and reliability and RM 43 investments for October and November 2012; and (3) planned post test-year safety and reliability and RM43 investments for the period December 2012 through December 2013. The Company also proposed concomitant operating income adjustments to reflect the impact on depreciation expense of the rate base adjustments.[81] Staff and OPC support the proposed adjustments for the October - November 2012 period, but oppose terminal test-year safety and reliability and RM43 adjustments and post test-year safety and reliability and RM43 adjustments for the 13 month period, December 2012 - December 2013, as they argue they are not known and measurable.

Additionally, the Company proposed operating and maintenance ("O&M") adjustments to annualize anticipated RM43 and Rulemaking 44 ("RM44")[82] expenses during the rate effective year, December 2012 - December 2013. Staff supports the Company's proposed RM43 and RM44 O&M adjustments, but OPC does not. Below we explain the parties' positions and the basis for our decisions.

Positions of the Parties

BGE

According to BGE witness DeFontes, the "significant driver" behind the Company's request for a rate increase "is to enable BGE to make needed investments in upgrades to maintain and enhance the safety and reliability of our systems and to comply with new laws and regulations."[83] He stated that while the Company continuously

[81] Vahos Direct at 9-10. Mr. Vahos states that the adjustments also include the appropriate accumulated depreciation and deferred income tax impact. *Id.*
[82] In this Order, we use "RM44" to refer to the Deanna Camille Green Rule, our contact voltage survey requirements and reporting regulations adopted in the administrative docket proceeding RM44. The actual regulations are codified as COMAR 20.51.09, and became effective November 28, 2011.
[83] DeFontes Direct at 12.

maintains its system, significant portions of BGE's infrastructure have been in service for decades and coupled with rising customer expectations it will require BGE to do much more to replace and upgrade certain aspects of its system.[84]

BGE witness Vahos stated that the "inclusion of safety and reliability and Rulemaking 43 and 44 costs will provide for a better matching of costs and rates, and are needed to provide BGE with a reasonable opportunity to earn its authorized return."[85] He asserted that the combination of using a historical test period to set rates along with rising operating costs and significant safety and reliability investments has prevented the Company from earning its Commission-authorized return.[86] Mr. Vahos argued that since one of the foundations of the rate setting process is the matching principle, "achieving just and reasonable rates necessitates a better alignment of customers' cost of service with distribution rates in the rate effective period."[87] Mr. Vahos noted that, as a condition of the merger of Constellation Energy Group (BGE's parent) with Exelon Corporation, BGE is obligated to spend at or above 95 percent of its planned 2012 and 2013 O&M and capital expenditures. Under these circumstances he argued that these are appropriate adjustments.[88] Moreover, he noted that the Commission has approved many of these same adjustments for other utilities operating in Maryland.[89]

According to BGE witness Khouzami, the Company expects to invest more than $700 million in capital spending in 2013, which represents an increase of more than 8 percent over the test year unadjusted average rate base. BGE also expects an 8 percent

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[84] DeFontes Direct at 19.
[85] Vahos Direct at List of Issues and Major Conclusions.
[86] Vahos Direct at 4-5.
[87] Vahos Direct at 6.
[88] Vahos Direct at 10-11.
[89] Vahos Direct at 7.

increase in O&M spending, normalized for storms.[90] He asserted that, in such a rising cost environment, it is not reasonable to argue that BGE will have an opportunity to earn its authorized return if rates are based solely on a historic test year.[91] Mr. Khouzami also stated that the credit rating agencies would view favorably any regulatory outcome that minimizes regulatory lag while ensuring BGE recovery of its prudently incurred costs and an opportunity to earn a fair and reasonable rate of return, noting that the agencies are "fully aware" of the scope of the Company's investment program in its infrastructure and operations.[92]

BGE witness Woerner testified that BGE's construction investments totaled $594 million in 2011 and should exceed $600 million in 2012 and $700 million in 2013.[93] Mr. Woerner stated that BGE anticipates spending more than $3 billion in total capital over the next five years noting that more than 50 percent of the overhead wire and underground cable on BGE's system is more than 20 years old. He also noted that due to the nationwide need for utility investment that there will also be an increase in the competition for capital.[94]

Addressing the non-revenue producing safety and reliability investments specifically, Mr. Woerner stated that in 2011 they totaled $171 million and are expected to be $231 million in 2012 and $241 million in 2013.[95] He noted that one cause of this increase is the need to replace aging infrastructure, much of which has been in use for more than 40 years. Additionally, Mr. Woerner noted the need to comply with new

[90] Khouzami at 6.
[91] Khouzami at 6-7.
[92] Khouzami Direct at 25.
[93] Woerner Direct at 3.
[94] Woerner Direct at 7-8.
[95] Woerner Direct at 4.

federal and state laws and regulations, including those adopted in the Commission's recent rulemakings, RM43 and RM44.[96] According to Mr. Woerner, BGE expects to spend over $20 million more in O&M expenses in the rate effective year to comply with RM43 and RM44 compared to current levels of test-year expense.[97] For these reasons, BGE requests that the Commission "match" recovery of these investments with service provided in the rate effective year.[98]

OPC

OPC witness Ostrander disagreed with BGE's proposal to reflect safety and reliability plant on a terminal test-year basis. Mr. Ostrander reduced this adjustment to reflect plant on a 13-month average basis, which he contends is consistent with prior Commission decisions. Mr. Ostrander also rejected BGE's proposal to reflect safety and reliability plant in rate base for the period December 2012 through December 2013 because the amount is projected by BGE, is not known and measurable, and because the Commission has previously rejected such adjustments. Likewise, Mr. Ostrander made similar modifications or rejected BGE's proposed RM43 reliability adjustments for the various periods for the same reasons.[99]

Mr. Ostrander contended that BGE's use of terminal plant investment "results in improper and significant increases in plant investment and related depreciation expense in this rate case," noting that the Commission rejected such adjustments in BGE's last base rate proceeding, Case No. 9230.[100] Mr. Ostrander did acknowledge that in several

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[96] Woerner Direct at 5.
[97] Woerner Direct at 20. *See* p. 21-22 for details.
[98] Woerner Direct at 6.
[99] Ostrander Direct at 12-14. OPC, in its final position, accepted the Company's proposed adjustments to reflect general S&R plant additions and RM43 additions for October and November 2012. *See* Chart.
[100] Ostrander Direct at 15. *See* Order No. 83907.

recent utility cases the Commission has allowed use of terminal plant investment but he emphasized that this was restricted to actual amounts through the approximate date of hearings only.[101] He noted that no post test period projected or forecasted amounts have been allowed. Further, Mr. Ostrander stated that the Commission has pointed to a need to demonstrate at least a two-year trend of increased spending and that the burden is on the utility to show that a change from traditional average rate base treatment to terminal treatment is appropriate.[102] Mr. Ostrander concluded that BGE's terminal test-year safety and reliability and RM43 adjustments should be rejected because: they violate the matching principle since a 13-month average is used for other plant and expenses; BGE has failed to document a significant and sustained increase in safety and reliability spending (with related reliability improvement); and regulatory lag is not an adequate reason for using a terminal rate base. For these reasons, OPC concluded that BGE has failed in its burden of proof to show that terminal rate base treatment for general safety and reliability and RM43 investment is appropriate in this case.[103]

Mr. Ostrander stated that BGE's safety and reliability and RM43 terminal plant adjustments also should be rejected because BGE still only spends about 28 percent of its total capital budget on reliability plant, a figure similar to that in BGE's last rate case. He stated that BGE's five-year budget for 2012-2016 shows projected reliability spending of only 28.87 percent of its total budget. Thus, Mr. Ostrander concluded that there has not

[101] Ostrander Direct at 15.
[102] Ostrander Direct at 16-17.
[103] Ostrander Direct at 21-22. Mr. Ostrander also stated that he reduced BGE's operating income adjustments for S&R and RM43 terminal plant related depreciation expense for the same reasons that he modified or rejected the plant balance adjustments. *Id.* at 29-30.

been any real improvement in BGE's commitment to reliability spending.[104] Further, Mr. Ostrander stated that BGE only spent $171 million on reliability plant in 2011, a figure he says is "substantially less" than what BGE told the Commission it would spend in 2011 during its last rate case. Mr. Ostrander stated that this raises a concern about the accuracy and reliability of BGE's budgeting process.[105]

Mr. Ostrander noted that BGE proposed forecasted O&M adjustments for RM43 and RM44 operating expenses for the period December 2012-December 2013. He rejected both adjustments because these costs are not known and measurable and due to BGE's inaccurate budget forecasting.[106] Furthermore, Mr. Ostrander stated that denying RM44 forecasted costs is consistent with the Commission's approach to post-test year adjustments in BGE's last rate case; however, he acknowledged that the Commission allowed a similar RM44 post test - year adjustment in Pepco's and Delmarva's recent rate cases.[107] Mr. Ostrander also noted that some of the RM43 and RM44 costs may be one-time non-recurring costs. He asserted that the vast majority of these compliance costs are not verifiable nor are the material and miscellaneous costs. Further, he stated that related BGE employee costs may duplicate existing costs. He also asserted that RM43 expenses do not reconcile.[108]

OPC witness Pavlovic asserted that BGE has not demonstrated a need for its proposed post test-year safety and reliability adjustments and that such adjustments would "disturb the balance of interests and incentives between BGE and its

[104] Ostrander Direct at 23-24. However, according to Mr. Ostrander's Table 1, BGE's total budget increases from $3.29 billion for 2010-2014 to $3.89 billion for 2012-2016. *Id.*
[105] Ostrander Direct at 25-26.
[106] Ostrander Direct at 31-32.
[107] Ostrander Direct at 32-33.
[108] Ostrander Direct at 42-44.

ratepayers."[109] Dr. Pavlovic stated that in the traditional regulatory model regulatory lag is an "important incentive" for BGE to improve the productivity and efficiency of its operation.[110] He further stated that even if BGE demonstrated it was under-earning, it is not necessarily due to increased safety and reliability capital and operating expenses combined with the use of a historical test year. In Dr. Pavlovic's view, BGE has not conducted an empirical analysis to support its assertion.[111]

Dr. Pavlovic argued that post test-year adjustments are "a species of forward or forecasted test year," and combined with a decoupling mechanism (which BGE has), are essentially the same as a capital expense tracker, which the Commission has rejected several times.[112] Further, he stated that such mechanisms violate the fundamental regulatory principle that costs are recovered from ratepayers during the period in which facilities are "used and useful." He stated that this principle provides utilities with an incentive to be prudent and efficient. Adoption of any such mechanism, he concluded, would reduce the utility's risk and should be reflected in the resulting rate of return. Moreover, Dr. Pavlovic stated that BGE's post test-year adjustments are neither known nor measurable.[113]

Dr. Pavlovic also asserted that "more than half the value of the electric projects and almost half of the value of gas projects represent normal replacement of facilities and not incremental reliability and safety improvements to the electric and gas infrastructure."[114] Therefore, he concluded that BGE's proposed post test-year safety and

[109] Pavlovic Direct at 5.
[110] Pavlovic Direct at 7.
[111] Pavlovic Direct at 14-15.
[112] Pavlovic Direct at 15-16.
[113] Pavlovic Direct at 17-18.
[114] Pavlovic Direct at 19.

reliability adjustments greatly overstate the amount of incremental safety and reliability investment, that the adjustments would result in rates that over recover depreciation, and that BGE's proposed adjustments are a solution to a problem that has not been demonstrated to exist.[115] Based upon his analysis, Dr. Pavlovic recommended removing from plant in service balances, those BGE adjustments that represented "normal replacement" of facilities. He emphasized that he is not proposing to disallow those amounts, but that the capital costs for normal replacements are already accounted for in the revenue requirement and do not need to be additionally recovered in BGE's adjustments.[116] For these reasons, he recommended a full rejection of BGE's proposed safety and reliability and RM43 adjustments.

Mr. Ostrander stated that if the Commission adopts terminal test-year safety and reliability and RM43 plant treatment then Dr. Pavlovic's rationale and related calculations should be relied upon as an alternative adjustment. In other words, for the test year ended September 30, 2012, the $55 million of safety and reliability plant identified by Dr. Pavlovic that represents "normal replacement" plant should be reflected on a 13-month average basis and only the remaining reliability and safety "improvement" plant should be reflected on a terminal basis.[117]

As for BGE's proposed post hearing/post test-year safety and reliability adjustments, although BGE would reflect this plant on a 13-month average basis, Mr. Ostrander stated that the adjustments should still be rejected as inconsistent with the Commission's decision in Case No. 9230 as well as the Commission's decisions in

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[115] Pavlovic Direct at 20.
[116] Pavlovic Surrebuttal at 16-17.
[117] Ostrander Surrebuttal at 2-4. He cited Dr. Pavlovic's Table 3 for the appropriate breakdown in Mr. Pavlovic's Supp. Direct testimony at pages 5-6.

Pepco's (Case No. 9286) and Delmarva's (Case No. 9285) recent rates cases. He stated that the Commission has consistently rejected the use of forecasted safety and reliability plant costs that occur subsequent to the hearings for the rate effective period.[118]

Mr. Ostrander argued that BGE has not shown that its RM43 expenses are known and measurable. He stated that BGE's updated filing shows that it has incurred only $3.7 million of test year expenses, less than half of the $8.5 million in expenses BGE originally indicated it would incur in the test period. He noted that the RM43 expenses expected to be incurred in the rate-effective period have risen approximately $4.7 million in BGE's updated filing due to costs being deferred. Mr. Ostrander concluded that RM43 expenses are becoming less certain.[119] He also emphasized that while some RM43 and RM44 costs will be recurring, some costs may be one-time costs related to the start-up of compliance.[120]

Staff

Staff witness Stinnette stated that the Commission generally uses a historical test year to develop rates, which are based on known and measurable, reasonable and necessary costs and used and useful capital investments in order to provide reasonable and least cost service to customers. Additionally, she noted that rates are to provide investors with a reasonable *opportunity* (not a guarantee) to earn a reasonable return on invested capital. This return traditionally recognizes normal business risks, including regulatory lag, which is inherent in a historic test year. Moreover, these principles match

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[118] Ostrander Surrebuttal at 8-9.
[119] Ostrander Surrebuttal at 15-16.
[120] Ostrander Surrebuttal at 16-17.

revenues, expenses and invested capital with the service provided to customers – the "matching principle."[121]

Ms. Stinnette stated that to be known and measurable, costs must have happened or will happen based on contracted, legal, or other enforceable obligations. Further, the quantitative effects must be measurable with reasonable accuracy. She stated that promises, plans or expectations, including estimates or budgets are not sufficient.[122] Ms. Stinnette acknowledged that the Commission has allowed the inclusion of terminal test-year end plant in service and post test-year items when their exclusion could damage a utility's financial integrity.[123] She concluded that in the final analysis customer rates should be set at the lowest reasonable levels while providing adequate protection for shareholders.[124]

Ms. Stinnette rejected BGE's rate base adjustments to reflect terminal rate base treatment for safety and reliability and RM43 plant for the test year because these adjustments are both single issue and piecemeal ratemaking, violate the matching principle, and would reflect an "excessive level" in rate base because the investments exceed the 13-month average.[125] Additionally, Ms. Stinnette stated that these adjustments are not required to address regulatory lag as it is a normal result of using a historical test year. She stated that regulatory lag is accounted for in the rate of return granted the Company and therefore terminal rate base adjustments would result in "double counting," unless the Commission adjusted the return on equity downward to recognize the

[121] Stinnette Direct at 3.
[122] Stinnette Direct at 4.
[123] Stinnette Direct at 5.
[124] Stinnette Direct at 4.
[125] Stinnette Direct at 6 and 8.

reduction in risk effect of the adjustment.[126] As a consequence of rejecting terminal rate base treatment for safety and reliability and RM43 plant, Ms. Stinnette also adjusted operating income to remove BGE's increased depreciation expense adjustments.[127] However, for the October – November 2012 period, Staff accepted BGE's rate base and operating income adjustments for safety and reliability and RM 43 plant.[128]

Staff rejected BGE's proposed rate base and operating income adjustments to reflect forecasted post test-year safety and reliability and RM43 investments during the period December 2012 – December 2013. According to Ms. Stinnette, these Company proposals do not meet the known and measurable standard, do not comply with the matching principle, and the Commission has historically excluded this type of post test-year adjustment.[129] Consequential adjustments to operating income to remove BGE's proposed increases in depreciation expense were also made by Ms. Stinnette.[130]

BGE Responses to Other Parties' Positions

Mr. DeFontes stated that OPC's assertion that BGE's safety and reliability investments are neither significant nor sustained is inaccurate as BGE has increased its overall capital program dramatically in recent years.[131] Mr. Khouzami stated that the Company's average rate base has grown by approximately 11 percent ($350 million) from December 2010 through the end of the test year, September 2012, which he asserted has led to a "mismatch" of customer's cost of service with the currently authorized distribution rates. Furthermore, he stated that BGE has demonstrated a clear pattern of

[126] Stinnette Direct at 5-6.
[127] Stinnette Direct at 6 and 8.
[128] *See* Ms. Stinnette's Rebuttal Exhibits for the calculations of her adjustments.
[129] Stinnette Direct at 7 and 8-9.
[130] Stinnette Direct at 7 and 9.
[131] DeFontes Rebuttal at 4.

increasing "core" distribution investments, which have risen from $224 million in 2009 to $325 million in 2011, an increase of more than 45 percent. Additionally, Mr. Khouzami stated that RM43 and RM44 compliance expenses will be $29 million in the rate effective period.[132] Mr. Khouzami emphasized that the adjustments for the test period and through November 2012 represent actual spending, not forecasts, and therefore concluded that these adjustments meet the known and measurable standard.[133] Moreover, Mr. Khouzami stated that BGE's actual safety and reliability spending was approximately 1 percent above its budget for the period from 2009 through September 2012. Consequently, Mr. Khouzami concluded that BGE's budget forecasting is accurate.[134]

Mr. Vahos also responded to Staff and OPC's rejection of terminal test-year safety and reliability balances.[135] He asserted that the terminal test-year balances "clearly meets the known and measurable standard" because these adjustments "will fully reflect the *actual* rate base and operating income effects of assets that have been placed in service."[136] He also asserted that these adjustments adhere to the matching principle as they are calculated on a consistent basis using actual information. He noted that it is undisputed that these safety and reliability investments are non-revenue producing. Mr. Vahos asserted that these expenditures represent "a *far superior* matching of customer's true cost of service and revenue requirements in the rate effective period."[137]

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[132] Khouzami Rebuttal at 5-6.
[133] Khouzami Rebuttal at 8.
[134] Khouzami Rebuttal at 8-10.
[135] Vahos Rebuttal at 13-15.
[136] Vahos Rebuttal at 14.
[137] *Id.*

Mr. Vahos also claimed that BGE's post test-year (December 2012 – December 2013) safety and reliability adjustments meet the known and measurable standard for several reasons. First, BGE has a clear pattern of significant and sustained necessary investments and the amount is not zero. Second, BGE's distribution system requires significant investments to maintain safety and reliability and based upon experience BGE can reasonably *estimate* the costs associated with these projects. Lastly, as a condition to the Exelon/Constellation merger, BGE is obligated to spend at or above 95 percent of its planned 2012 and 2013 O&M and Capital expenditures, "which represents a floor to BGE's spending plans."[138] He stated that the adjustments, which are calculated on an average basis and not a terminal basis, will ensure that all pieces of rate base that are impacted are consistent and aligned. He concluded that without these adjustments, there will be a mismatch of the true cost of service and the service being received by customers during the period.[139]

Mr. Vahos noted that RM43 became effective during the test year, May 28, 2012, and that BGE has begun its compliance plan, has incurred actual test year costs and has a track record for estimating the incremental costs. He again claimed that the costs are known and measurable as this is not a new type of work for BGE and that the Company knows how to get the work done and the associated costs. He concluded that ignoring the full annual cost is inappropriate and will result in a poor matching of the cost of service and the revenue requirement in the rate-effective period. He emphasized that annualizing the $3.8 million cost incurred in the last four months of the test year results in an

[138] Vahos Rebuttal at 17.
[139] Vahos Rebuttal at 16-17.

estimated annual cost of approximately $12 million.[140] As for RM43 capital investments, Mr. Vahos essentially made the same arguments he made regarding general safety and reliability investments. He did note one difference, namely that this BGE rate case is the first that could possibly include actual incremental RM43 capital investments by a Maryland electric utility, as the standards only became effective on May 28, 2012.[141]

Mr. Vahos stated that RM44 is a new mandate for safety-related contact voltage inspections that will result in new costs for BGE, and that BGE plans to spend $4.7 million to comply. Mr. Vahos noted that BGE has already filed its compliance plan (on August 2, 2012) and that once approved it will be implemented. Since these incremental costs will be incurred in the rate-effective period he asserted that the adjustment is appropriate. He also noted that the Commission has approved similar forecasted adjustments for Pepco and Delmarva previously. Additionally, he stated that there will be yearly costs for related surveys and inspections. He noted that BGE's annual inspection cost estimate is based on the detailed survey plan filed with the Commission, which included a quote from a contractor for some of the work. Further, he stated that the estimate is based on actual BGE repair cost experience. Lastly, he stated that there is no duplication of material costs as materials inventory will need to be replenished. For these reasons, he argued that the RM44 adjustment is also appropriate.[142]

<u>Commission Decision</u>

We cannot emphasize enough the need for gas and electric utilities to improve safety and reliability. Not only have we encouraged them to increase the level of safety

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[140] Vahos Rebuttal at 18-21.
[141] Vahos Rebuttal at 33-35.
[142] Vahos Rebuttal at 22-24.

and reliability investment, we have mandated specific and objective safety and reliability improvements as reflected in the adoption of our RM43 and RM44 regulations. In fairness, we have stated that when a utility demonstrates a commitment to improve safety and reliability, we will consider adjustments to the test year to reflect actual non-revenue producing safety and reliability investment.

At our direction during the evidentiary hearings, the Company introduced BGE Exhibit 13, which details the level of safety and reliability investment in recent years and other "core" distribution capital investment. In BGE Exhibit 13, the Company provided evidence of increasing, non-revenue producing safety and reliability capital investments rising from $124 million in 2007 to $205 million for 2012, with a substantial increase in safety and reliability investment during the period 2010-2012 compared to earlier years. BGE's budget forecast for safety and reliability investment in 2013 is $241 million.

We rejected the Company's last request in Case No. 9230 to reflect test-year safety and reliability plant on a terminal basis because the Company failed to demonstrate an increasing trend in safety and reliability investment.[143] However, in this case, BGE has satisfied its burden of proof and demonstrated to our satisfaction an increased commitment to safety and reliability, which is reflected in its actual test-year level of safety and reliability investment. In this regard, we emphasize that these costs have already been incurred and the safety and reliability plant is currently providing utility service to customers. Since the Company's proposed terminal test-year rate base and associated operating income adjustments are for non-revenue producing investments, we find it appropriate to grant the Company terminal test-year treatment. Therefore, electric

[143] Case No. 9230, Commission Order No. 83907 at 8-15.

rate base will be increased by $39,294,000 to reflect general safety and reliability projects and by $2,405,000 to reflect specific RM43 investment, and the Company's operating income will reflect decreases for the associated depreciation expense impact of $717,000 and $34,000, respectively. Gas rate base will be increased by $29,313,000 and gas operating income reduced by $404,000 for depreciation expense for general safety and reliability projects.

The Company also proposed adjustments to reflect post test-year safety and reliability plant investments made in October and November 2012, which also are non-revenue producing. Both Staff and OPC accepted BGE's proposed adjustments. We find these adjustments to be reasonable as they reflect actual safety and reliability investments already made by BGE. Therefore, electric rate base will be increased by $14,492,000 for general safety and reliability projects and by $1,922,000 for specific RM43 projects while operating income is decreased for depreciation expense by $167,000 and $22,000, respectively. Gas rate base is increased by $12,809,000 and gas operating income is decreased by $117,000 for depreciation expense for general safety and reliability projects.

Unlike the Company's proposed test-year and October/November 2012 adjustments, its proposal to reflect safety and reliability and RM43 investments for the period December 2012 through December 2013 is based upon estimates of future spending. The Company proposed to increase electric and gas rate base by $113,744,000 and to reduce operating income by $2,060,000. This translates to approximately

$19,270,000 in requested revenue requirements based upon the Company's proposed rate of return.[144]

We find that the Company has failed to support its proposal to reflect projected, estimated safety and reliability investments. Not only are these investments not currently used and useful, they are not even known and measurable. While we do not question the Company's good faith to arrive at such an estimate, we note that by the Company's own admission estimates, forecasts and budgets can prove unreliable. In footnote 7 to BGE's Exhibit 13, the Company acknowledged that due to the Derecho storm in 2012 that "work on planned investments was shifted from non-revenue producing safety and reliability investments to storm restoration." Thus, even with the best of intentions, budgets and forecasts can prove unreliable. We conclude that it would not be just and reasonable[145] to saddle customers with almost $20 million in additional utility costs based upon estimates that are not fully reliable.

This Commission has long been committed to the principle that Maryland's utilities must be held to objective, verifiable and high standards for providing safe and reliable service to Marylanders.[146] Our commitment to this standard is demonstrated in our adoption of the service quality and reliability standards in RM43 and the contact voltage survey requirements and reporting standards in RM44. The Company proposed an (electric) operating income adjustment of $12,284,000 in this case to reflect anticipated O&M expenses in the rate effective year to meet the reliability standards in

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[144] *See* Chart.
[145] PUA, § 4-102.
[146] *See* PUA § 7-213(b) ("It is the goal of the State that each electric company provide its customers with high levels of service quality and reliability in a cost-effective manner, as measured by objective and verifiable standards, and that each electric company be held accountable if it fails to deliver reliable service according to those standards.").

RM43. This proposed adjustment would increase the Company's revenue requirement by more than $21 million.[147] Although Staff did not oppose the Company's proposal, OPC did oppose the adjustment.

Although RM43 only became effective on May 28, 2012, it embodies the reliability and system maintenance practices that Maryland's electric utilities should have been following all along. Moreover, even though there may be some incremental costs associated with the RM43 requirements, we find that the Company's proposed adjustment is not sufficiently supported by the record. Specifically, we find that the adjustment fails to meet the "known and measurable" standard because it is simply an estimate. Furthermore, the estimate is based upon limited experience. And as we noted above, even meaningful forecasts can change due to unforeseen events. For these reasons, we disallow the Company's proposed RM43 O&M adjustment.

The contact voltage survey requirements adopted in RM44 are safety-related regulations that became effective November 28, 2011. BGE proposes to reflect $2,791,000 in additional electric O&M expenses during the rate effective year for compliance, and Staff supports the adjustment. We approve this proposed adjustment for several reasons. First, the Company has approximately one full year of experience upon which to base its adjustment. Second, recognition of the RM44 adjustment is consistent with safety-related adjustments that we have approved for other utilities in recent years.[148] Third, we find that recognition of this adjustment appropriately balances our

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[147] Chart, Electric – Co. Adj. 20

[148] *See Re Washington Gas Light Company*, Case No. 9267, Order No. 84475 at 36-40; *In the Matter of the Application of Delmarva Power & Light Company for Authority to Increase it Rates and Charges for Electric Distribution Service,* Case No. 9285, Order No. 85029 at 21-25; and *In the Matter of the Application of Potomac Electric Power Company for Authority to Increase its Rates and Charges for Electric Distribution Service,* Case No. 9286, Order No. 85028 at 30-35.

safety and reliability priorities with the rate-making principle that expenses included in rates must be known and measurable. Therefore, operating income is reduced by $2,791,000.

6. Depreciation

Positions of the Parties

OPC witness King noted that the source of the depreciation rates used by BGE in this case are those that were adopted by the Commission in BGE's depreciation proceeding, Case No. 9096.[149] Mr. King asserted that he has subsequently determined that those depreciation rates reflect the use of the Equal Life Group ("ELG") procedure, a depreciation procedure previously rejected by the Commission.[150] Therefore, Mr. King recommended that "the Commission reject the ELG rates that it inadvertently adopted in Case No. 9096."[151] Mr. King recommends that the Commission approve depreciation rates based upon the Vintage Group ("VG") approach to calculating removal cost accruals, which was also presented in Case No. 9096.[152] Mr. King concluded that BGE's depreciation expense should be reduced by $13,434,696 for electric distribution service and by $1,021,281 for gas distribution service.[153]

BGE opposed OPC's depreciation recommendations. Mr. Vahos stated that the rates adopted in Case No. 9096 were presented by a Staff witness, not BGE's witness, and the Company can neither confirm nor deny Mr. King's representations regarding the analysis or methodologies that led to the adopted depreciation rates. Additionally, Mr.

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[149] King Direct at 29.
[150] King Direct at 28-31.
[151] King Direct at 31.
[152] King Direct at 31.
[153] King Supp. Direct at 3. *See* revised Exhibit CWK-4 for OPC's recommended depreciation expense and rates.

Vahos argued that changing the depreciation accrual for this single item while ignoring all other changes in depreciation rates that may be required is inappropriate. Mr. Vahos concluded that without the benefit of a full depreciation study the proper information is not available to determine whether or not Mr. King's revision would properly re-set depreciation rates. Mr. Vahos noted that BGE has made significant infrastructure investments since its last depreciation study, which would undoubtedly impact depreciation rates. Consequently, BGE proposed that the Commission direct it to perform and file a new depreciation study, which will permit all parties to examine depreciation in the context of a full study.[154]

Mr. King countered that there is "no question" that BGE's depreciation rates are based on the ELG methodology. He noted that in Case Nos. 9285 and 9286 Staff witness Dunkel presented depreciation rates that followed the same methodology that Mr. Dunkel ultimately used in Case No. 9096, which the Commission adopted in that case. However, Mr. King stated that he demonstrated in Case Nos. 9285 and 9286 that those depreciation rates were based upon the ELG methodology. Mr. King noted that, in Case Nos. 9285 and 9286, the Commission adopted his recommended depreciation rates, which use the alternative Vintage Group method for net salvage calculations. He recommended that the Commission do so as well in this case.[155]

Additionally, Mr. King stated that this (ELG rate) is not just "one item" that requires correction. He stated that the ELG methodology underlies every single depreciation rate for which there is a net salvage allowance. His "correction" addresses a "fundamental flaw" in BGE's proposed depreciation rates. If Mr. King's "correction" is

[154] Vahos Rebuttal at 37-39.
[155] King Surrebuttal at 10-11.

not adopted he stated that customers will be overcharged more than $14 million annually for one year or possibly longer. While he does not oppose BGE's submission of a new depreciation study next year, Mr. King concluded that this is not an acceptable solution in this case.[156]

<u>Commission Decision</u>

OPC's proposed depreciation expense adjustments were not proposed in the context of a full depreciation study, and for that reason we reject its proposal on its face. BGE's depreciation rates were last adjusted in Case No. 9096 pursuant to Order No. 83310, which was issued May 4, 2010. In that case, the Commission had the benefit of a full depreciation study, which provided an appropriate context in which to examine the positions and recommendations of the parties.

In this proceeding, no party offered a depreciation study, and so we find Mr. King's analysis deficient for several reasons. Although Mr. King may be correct that the depreciation rates approved in Case No. 9096 may reflect the use of the ELG procedure, Mr. King fails to address the numerous other issues that might require examination in order to establish new, appropriate depreciation rates for BGE.[157] Specifically, we note the Company's acknowledgment that it has made significant investments in its infrastructure since the last depreciation study was conducted, which will likely impact depreciation rates significantly.

We also find that there is a lack of information to determine whether making one change, as OPC recommends, would properly re-set depreciation rates for all plant

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[156] King Surrebuttal at 11-12.

[157] In its Brief, OPC acknowledges that "the purpose of a new depreciation study is to revise the three parameters – life, survivor curve, and net salvage – that underlie each depreciation rate, and those revisions are not known and can only be identified through a detailed analysis of BGE's plant records." OPC Brief at 38, citing King Surrebuttal at 12.

accounts, which we doubt. For example, there was no examination of the salvage rate component of BGE's depreciation rates, which has been a vigorously contested issue in recent years. Furthermore, the Commission specifically pointed out in Case No. 9285 (Delmarva) and Case No. 9286 (Pepco) that it "would leave to another day" to resolve whether the ELG method is an appropriate depreciation procedure, which Mr. King acknowledges was addressed by the Commission in the 1980s.[158] Finally, our decision in this case is consistent with our decision in Case No. 9217, where we rejected Pepco's proposal to make a piecemeal change to its depreciation rates, which OPC opposed.[159] For these reasons, OPC's depreciation adjustments are denied.

Adjusted Rate Base and Operating Income

Based on the uncontested adjustments and our decisions regarding the contested adjustments for electric operations, we find that the total rate base on which the revenue requirement shall be calculated is $2,634,928,000 and the adjusted operating income is $153,597,000. For gas operations, the adjusted rate base is $975,860,000, and adjusted operating income is $54,950,000.

B. Cost of Capital

The cost of capital is a utility's overall rate of return ("ROR"), which is the sum of the weighted returns the utility must earn on its stock (equity) and bonds (debt) to attract investors in those securities. Unlike return on debt, return on equity ("ROE") is not directly observable and must be estimated based on market data.

[158] Case No. 9285, Order No. 85029 at 53, fn 208 and King Direct at 28. Case No. 9286, Order No. 85028 at 79, fn 325 and King Direct at 28.
[159] *Re Potomac Electric Power Company,* Case No. 9217, Order No. 83516, 101MDPSC 290 at 310-312.

In 1923, in *Bluefield Waterwork & Improvement Co. v. West Virginia Public Service Commission,*[160] the Supreme Court held that "[t]he return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties."

The Supreme Court later expanded upon *Bluefield*, stating, "[f]rom the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock." The return to the equity owner should be "commensurate with the returns on investments in other enterprises having corresponding risks."[161]

Different methods and models can be used to estimate the cost of equity such as discounted cash flow methods, risk premium methods, and capital asset pricing models.

The discounted cash flow ("DCF") method is a valuation method used to estimate the attractiveness of an investment opportunity. A DCF analysis uses future free cash flow projections and discounts them to arrive at a present value, which is then used to evaluate the potential for investment. The purpose of the DCF analysis is to estimate the money one would receive from an investment and to adjust for the time value of money.[162] Risk premium methods start with current observable market returns, and add an increment to account for the additional equity risk. The capital asset pricing model

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[160] 262 U.S. 679, 693 (1923).
[161] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).
[162] McKenna Direct at 5-6.

("CAPM") estimates the cost of equity by combining the "risk-free" government bond rate with risk measures to determine the risk premium required by the market.[163]

1. Electric Cost of Capital

Positions of the Parties

BGE

BGE's witness Dr. Hadaway applied four versions of the DCF model to a 29-company proxy group of gas and electric utilities, upon which criteria he selected companies with similarities in: (1) bond ratings; (2) at least 70 percent of revenues generated from regulated utility sales; (3) financial records unaffected by recent mergers or restructuring; and (4) dividend records with no dividend cuts or resumptions during the past 2 years.[164]

In the first version of the DCF model, Dr. Hadaway used the constant growth format with long-term expected growth based on analysts' estimates of five-year utility earnings growth.[165] This method indicates a ROE range of 9.6 percent to 10.0 percent.[166] In the second version of the DCF model, for estimated growth rate, Dr. Hadaway used only the long-term estimated gross domestic product ("GDP") growth rate and arrived at a ROE of 10.1 percent.[167] In the third version, Dr. Hadaway used a two-stage growth approach, with stage one based on Value Line's three-to-five year dividend projections and stage two based on long-term projected growth in GDP.[168] The multistage model

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[163] Hadaway Direct at 35-36.
[164] *Id.* at 5.
[165] *Id.* at 44.
[166] *Id.* at 49.
[167] *Id.*
[168] *Id.* at 45.

indicates a ROE of 9.9 percent.[169] In the fourth version, Dr. Hadaway applied a terminal value approach in which investors receive the dividend projected by Value Line for the first four years and are assumed to sell their stock at the prevailing market price at the end of the fourth year.[170] The result from the terminal value model was a ROE range of 10.6 percent to 10.9 percent.[171] The ROE range of all 4 versions of Dr. Hadaway's DCF models is 9.6 percent to 10.9 percent. Dr. Hadaway discounted the lower end of the range which came from the traditional constant growth format because he believes the results of this method are skewed by the government's ongoing efforts to maintain low interest rates.[172]

Dr. Hadaway next applied equity risk premium models and reviewed projected economic conditions and projected capital costs for the coming year.[173] The equity risk premium studies indicate an ROE range of 9.9 percent to 10.1 percent.[174] Again, Dr. Hadaway discounted the lower end of the risk premium range because these results are dictated by the sharp drop in interest rates that has occurred.[175] Dr. Hadaway believes that the current, historically low interest rates cannot capture the current equity volatility or the increased level of risk aversion for equity investors, and that the cost of equity has not declined to the extent interest rates on utility debt have dropped.[176]

Taking the high end of the risk premium analysis range (10.1%) and the high end of the DCF analysis (10.9%), Dr. Hadaway arrived at a cost of equity range 10.1 percent

[169] *Id.* at 49.
[170] *Id.* at 45.
[171] *Id.* at 50.
[172] *Id.*
[173] *Id.* at 44.
[174] *Id.* at 50.
[175] *Id.*
[176] *Id.*

to 10.9 percent.[177] His recommended ROE of 10.5 percent is the mid-point of that range.[178]

Dr. Hadaway reasoned that a downward adjustment to account for decoupling is necessary because the average bond ratings for the companies in his comparable group are slightly higher than BGE's, and he stated that all of the 29 companies have some form of decoupling or other revenue recovery mechanisms, making their operating risks similar to BGE's.[179]

Using BGE's capital structure of 47.3 percent long-term debt, 4.3 percent preferred stock, and 48.4 percent common equity, and the utility's proposed ROE of 10.5%, cost of preferred stock of 7.02 percent and cost of debt of 5.46 percent, BGE's weighted average cost of capital ("WACC") would be 7.96 percent.[180]

OPC

Mr. King accepted BGE's calculation of 5.58 percent as its cost of long-term debt,[181] and 7.02 percent as its cost of preference stock.[182]

Mr. King limited his comparison group to 17 heavily regulated electric utilities with risks comparable to BGE.[183] His screening criteria were: (1) each comparison company must derive at least 50 percent of its revenue from electric utility service; (2) each company must derive no more than 25 percent of its revenue from non-regulated activities; (3) each company must have an S&P bond rating within one grade, plus or

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[177] *Id.* at 53-54.
[178] *Id.* at 54.
[179] *Id.*
[180] Khouzami Supp. Direct at 2.
[181] Now 5.46% per Khouzami Supp. Direct at 2.
[182] King Direct at 4.
[183] *Id.* at 7.

minus, of the BBB+ rating assigned to BGE; and (4) each company must not have subsidiaries with revenue decoupling mechanisms similar to BGE's.[184]

Mr. King used the DCF procedure as the principal methodology for obtaining indications of appropriate ROE, and developed three applications of this approach to offer guidance as to whether the classic DCF results provide appropriate estimates of ROE: the classic DCF procedure; the FERC 2-step growth model; and the "sustainable growth" model.[185] He placed the most reliance upon the classic DCF approach, somewhat less reliance on the FERC 2-step DCF and even less reliance on the sustainable book value growth model.[186] From the classic DCF analysis, Mr. King obtained mean and median indications of 9.65 percent.[187] The FERC 2-step growth DCF model resulted in an indication of 9.18 percent.[188] The sustainable growth DCF resulted in a mean indication of 8.44 percent and a median indication of 8.41 percent.[189]

Mr. King gave the classic DCF result of 9.65 percent a weight of 5; the 2-step DCF of 9.18 percent, a weight of 4; and the average of sustainable growth DCF mean and median values of 8.42 percent, a weight of 3.[190] He also gave the risk premium test, which resulted in an indication of 10.40 percent, a weight of 3.[191] Mr. King gave less weight, a weighting of 2, to the CAPM calculation, 10.08 percent, because he considers it unreliable due to the underlying assumptions and considerable judgment required in the

[184] *Id.*
[185] *Id.* at 8.
[186] *Id.* at 22.
[187] *Id.* at 11.
[188] *Id.* at 14.
[189] *Id.* at 16.
[190] *Id.*, Ex. CWK-2 Schedule 7.
[191] *Id.*

selection of critical inputs.[192] Mr. King testified that during the last two quarters of 2011 and the first two quarters of 2012, there were 60 electric utility rate cases, and the average equity return award was 10.31 percent.[193] However, Mr. King also gave these recent equity return awards a weight of 2 because of likely circularity in decision-making.[194] After applying the weighting to each of the above calculations, Mr. King arrived at a total composite indication of 9.59 percent, which he then adjusted by 50 basis points to 9.1 percent.[195] Mr. King believes that the ROE of the comparison group is not appropriate for BGE because BGE's business risk is considerably lower than that of the comparison group.[196] Mr. King testified that a minimum adjustment would be the 50 basis point adjustment the Commission made in its decisions in the last Delmarva and Pepco rate cases, Case Nos. 9285 and 9286, respectively.[197]

MEG

Mr. Baudino employed a DCF analysis for a group of comparable electric companies. He also employed two CAPM analyses using both historical and forward-looking data, but he did not incorporate the CAPM results into his recommended ROE.[198]

Mr. Baudino's first step was to construct a comparison group of companies with risk profiles he felt were reasonably similar to BGE's regulated electric distribution operations.[199] His first swath included electric companies that were rated BBB/Baa by

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[192] *Id.*, Ex. CWK-2 Schedule 7; *Id.* at 21.
[193] *Id.* at 22.
[194] *Id.*
[195] *Id.*, Ex. CWK-2 Schedule 7.
[196] *Id.* at 23.
[197] *Id.* at 26.
[198] Baudino Direct at 29.
[199] *Id.* at 34.

either S&P or Moody's.[200] From that group, he selected companies that had at least 50 percent of their revenues from electric operations and had long-term earnings growth forecasts from Value Line, Zacks Investment Research ("Zacks"), and Thomson Financial ("Thomson").[201] He then eliminated companies that had recently cut or eliminated dividends, were recently or currently involved in merger activities, or had recent experience with significant earnings fluctuations.[202] He also eliminated any companies that had recently been or were currently being restructured in a significant way. He then eliminated Ameren Corporation and Edison International from the group because Value Line noted that these companies are being affected by low power prices and/or more stringent environmental rules for their merchant and unregulated generation assets.[203] Mr. Baudino's resulting comparison group consisted of 19 companies.[204]

Mr. Baudino used two different methods to obtain DCF results for the electric company comparison group. The first method utilized the average growth rates for the comparison group using Value Line earnings and dividend growth forecasts and the consensus analysts' forecasts.[205] The average DCF result under the first method was 9.36 percent and the midpoint of the range was 9.41 percent.[206] The second method employed the median growth rates from Value Line, Zacks, and Thomson.[207] From this second

[200] *Id.*
[201] *Id.*
[202] *Id.* at 34-35.
[203] *Id.* at 35.
[204] *Id.* at 36.
[205] *Id.* at 43.
[206] *Id.*
[207] *Id.*

method, the average DCF result was 9.26 percent and the midpoint of the results was 8.82 percent.[208]

Mr. Baudino recommended that the Commission adopt his DCF and cost of equity estimates for the comparison group of utility companies that he compiled.[209] Based on the DCF results for the electric company comparison group, his recommended ROE range is 8.82 percent to 9.41 percent.[210] He recommended that the Commission adopt a 9.40 percent return on equity for BGE's regulated electric distribution operations in this proceeding.[211] This recommendation reflects the average of results from the first method used in his DCF analysis.[212]

Staff

Ms. McKenna used a standard constant growth DCF analysis as well as an internal rate of return ("IRR") model, which is a variation of the DCF that incorporates projected stock prices into the model over a finite period of time.[213] Ms. McKenna conducted the standard DCF analysis using a proxy group.[214] All of the companies she selected for her proxy group also appear in Witness Hadaway's proxy group.[215] Ms. McKenna eliminated companies with ROEs exceeding 2 standard deviations from the unadjusted proxy group mean of 11.01 percent ROE,[216] which resulted in eliminating outliers with returns less than 4.9 percent or greater than 17.2 percent.[217] After

[208] *Id.*
[209] *Id.* at 50.
[210] *Id.*
[211] *Id.*
[212] *Id.*
[213] McKenna Direct at 4.
[214] *Id.* at 4-5.
[215] *Id.* at 5.
[216] *Id.*
[217] *Id.*

eliminating outliers, the result of Ms. McKenna's DCF analysis was an estimate of BGE's cost of equity at 10.45 percent.[218]

Ms. McKenna then produced a five-year IRR model using the data from Value Line, and the same 90-day average of the moving averages stock price for initial investment value as was used in her standard DCF model.[219] She used forecasted dividends through 2015 and the forecasted stock price in 2015 from Value Line.[220] This analysis resulted in an average ROE of 5.91 percent for the proxy group.[221] Ms. McKenna rejected the result of the IRR analysis as too low since it was not close to the results from the other methods she utilized and only slightly higher than the 12-month average yield on a triple-B public utility bond (debt).[222]

Next, Ms. McKenna performed both a standard CAPM analysis and a variation of the CAPM, an empirical capital asset pricing ("ECAPM") method. The CAPM and ECAPM look at the historical return of the stock market compared to a risk-free investment and adjust returns based on the relative risk of the company's stock compared in the market.[223] Ms. McKenna used the same proxy group for the CAPM analysis as she used in the DCF and IRR analyses, and again used data (Betas) from Value Line.[224] The result of Ms. McKenna's standard CAPM analysis was a ROE of 9.88 percent.[225] Ms. McKenna believes using an empirical CAPM model may result in a better estimate for ROE in the current economic environment because the ECAPM model adjusts for the

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[218] *Id.* at 7.
[219] *Id.*
[220] *Id.*
[221] *Id.*
[222] *Id.* at 8.
[223] *Id.* at 4.
[224] *Id.* at 8-9.
[225] *Id.* at 9.

tendency of the CAPM model to underestimate returns for low Beta stocks.[226] The result of the ECAPM analysis is a ROE of 10.35 percent.[227]

Finally, Ms. McKenna used the Build-up method of risk premium analysis which uses the risk free rate of return, equity risk premium, a size adjustment, and an industry adjustment to estimate BGE's ROE.[228] Ms. McKenna used the same data from her CAPM analyses for the risk free rate and equity risk premium resulting in a ROE estimate of 8.41 percent.[229]

Ms. McKenna took the weighted average of the ROEs she obtained from the various methods she used. In order to maintain a balance between DCF and risk premium methods, she gave her DCF result (10.45%) a weight of 50 percent, and the risk premium results from the ECAPM and Build-up method of 10.35 percent and 8.41 percent, respectively, each a weight of 25 percent.[230] Ms. McKenna chose to use the ECAPM result instead of the CAPM result. She indicated that while her CAPM results were not sufficiently low to require that they be excluded from her final analysis, she believed that the ECAPM model produced a better estimate in the current economic situation.[231] Pursuant to her prior testimony in connection with the IRR results, she gave no weight to the IRR result.[232] The weighted average of the ROE is 9.91 percent.

[226] *Id.*
[227] *Id.*
[228] *Id.* at 10.
[229] *Id.* at 10-11.
[230] *Id.* at 13.
[231] *Id.* at 13-14.
[232] *Id.* at 14.

Consistent with Commission precedent, Ms. McKenna made a 50 basis point reduction to the ROE to account for the risk mitigating effects of BGE's electric decoupling mechanism, or BSA.[233] Her final recommended ROE is 9.40 percent.[234]

Responses of Parties to other Parties' Positions

BGE and OPC

BGE's Witness Hadaway disagreed with OPC Witness King primarily with regard to Mr. King's DCF analysis.[235] Dr. Hadaway believed there are significant flaws in Mr. King's comparable company selection process.[236] Second, Dr. Hadaway found Mr. King's long term GDP growth rate used in his FERC 2-Step approach to be significantly understated.[237] Dr. Hadaway believed the sustainable growth DCF approach used by Mr. King is unreliable and should not be considered in the final growth rate estimate.[238]

Dr. Hadaway believed that Mr. King's rejection of eight companies because they have subsidiaries with revenue decoupling plans similar to BGE's renders his ROE analysis faulty.[239] Mr. King rejected these eight companies because he was of the opinion that it is inappropriate to adjust BGE's ROE by 50 basis points for the risk reducing effect of Rider 25 if the comparison group contains similar decoupling adjustments in place.[240] However, in so doing, Dr. Hadaway noted that Mr. King has rejected companies

[233] *Id.* at 11.
[234] *Id.*
[235] Hadaway Rebuttal at 17.
[236] *Id.*
[237] *Id.*
[238] *Id.*
[239] *Id.* at 18.
[240] King Direct at 7.

that are comparable to BGE, which is the basis for selection into a comparable group in the first place.[241]

Dr. Hadaway argued that three of the companies in Mr. King's comparable group should have been excluded because they were involved in recent merger activities, derive more than 25 percent of their revenue from non-regulated activities, or are undergoing a period of erratic earnings caused by extraordinary events resulting in an interruption of normal dividend growth.[242] If those three companies were eliminated, the result of Mr. King's classic DCF analysis would have been a range of 9.65 percent to 10.04 percent.[243]

Dr. Hadaway believed that Mr. King understated the dividend yield in his FERC 2-Step analysis, and grossly underestimated the long-term GDP growth rate.[244] Dr. Hadaway argued that the current GDP forecasts from the various government agencies, as used by Mr. King, use estimates of permanently low inflation and lower real growth rates that do not reflect the long-term U.S. economy.[245] The FERC 2-Step result increases from 9.18 percent to 9.33 percent if only the dividend yield is corrected.[246] The recalculated result after changing the long-term growth rate to what Dr. Hadaway argued is a more reasonable level (as well as eliminating the three non-comparable companies) is 9.99 percent.[247]

Dr. Hadaway further stated that the sustainable growth DCF approach has generally been rejected because it fails to include growth rate sources beyond earnings retention and new common stock sales above book value, and because the method is

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[241] Hadaway Rebuttal at 18.
[242] *Id.* at 19-20.
[243] *Id.* at 21.
[244] *Id.*
[245] *Id.* at 22.
[246] *Id.* at 22-23.
[247] *Id.* at 23.

circular.[248] Mr. King acknowledged the unreliability of the sustainable growth model but still gives some weight to that model in his final analysis.[249] Dr. Hadaway argued that it should be given no weight.[250]

In total, Dr. Hadaway made the following adjustments to Mr. King's computations: (1) eliminated companies with ongoing circumstances that make them inappropriate choices for BGE's comparable sample; (2) recalculated the proxy group's dividend yield excluding these companies; (3) substituted a higher estimate of long term GDP growth into Mr. King's FERC 2-Step analysis; (4) rejected the sustainable growth DCF model; and (5) rejected Mr. King's adjustment for lower risk.[251] After these adjustments, Dr. Hadaway arrived at a ROE of approximately 10.1 percent.[252]

Mr. King responded to Dr. Hadaway's criticisms of his analysis. Mr. King maintained that the 50 basis point adjustment is proper based on Commission precedent and his selection of comparable companies. Mr. King asserted that most of the revenue stabilization mechanisms provided to the companies identified as "non-revenue decoupling" are limited to revenue lost due to energy efficiency measures which he argues does not cover the entire spectrum of potential revenue losses as Rider 25 does for BGE.[253]

Mr. King stood by his selection of comparable companies. He asserted that there will always be reasons why individual companies are not truly comparable to BGE and

[248] *Id.*
[249] King Direct at 16-17.
[250] Hadaway Rebuttal at 24.
[251] *Id.* at 25.
[252] *Id.*
[253] King Surrebuttal at 4.

that there is little likelihood of finding companies that are exactly comparable to BGE.[254] He noted that the companies with highest results also are arguably not truly comparable to BGE.[255] Mr. King argued that the comparable group should be comprised of companies that provide the same electric distribution services as BGE with the evident overstatements and understatements of prospective earnings growth among a large enough group balancing out to provide a reasonably reliable indication of the return expectations of a company like BGE.[256] Mr. King also pointed out that Dr. Hadaway selectively challenged only the companies with the lowest ROE indications which biased this balance in favor of an unreasonably high result.[257]

In critiquing the Company's analysis, Mr. King found Dr. Hadaway's 5.7 percent growth forecast not credible because the value is based on retrospective data that includes periods when inflation was rampant in the 1970s and explosive economic growth following the Second World War.[258]

Mr. King argued that the sustainable growth model should not be dismissed entirely because it is a conceptually sound model.[259] Mr. King recognized the computational weakness, and thus, gave less weight to the indications provided by the sustainable growth model but believed the approach still has some value.[260]

Lastly, Mr. King responded to Dr. Hadaway's criticism that Mr. King failed to recognize the distortive nature of the "current, artificially low interest rate environment." Mr. King asserted that there is nothing "artificial" about the current interest rate

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[254] *Id.* at 5-6.
[255] *Id.*
[256] *Id.* at 6.
[257] *Id.*
[258] *Id.* at 7-8.
[259] *Id.* at 8.
[260] *Id.*

environment.[261] Low interest rates are a present fact and are likely to remain so for at least the next two to three years.[262] Mr. King argued that because low interest rates drag down the opportunity cost of alternative investments such as corporate bonds and stocks, the ROE indications are below the returns historically allowed for electric utilities.[263]

BGE and MEG

Dr. Hadaway disagreed with MEG witness Baudino's 9.4 percent electric ROE recommendation, contending that Mr. Baudino's recommended ROE is understated because it includes growth rate estimates (Value Line's 3-to-5 year dividend growth rates) inconsistent with the long-term expectations required by the standard, constant growth DCF model.[264] Dr. Hadaway argued that in the current government-induced low interest rate environment, Mr. Baudino should have adjusted his DCF results upward (rather than averaging them downward) with an inappropriately low dividend growth rate.[265] In order to balance current market anomalies, Dr. Hadaway suggested a broader range of DCF growth rate sources, such as long-term GDP growth.[266]

Mr. Baudino argued that the Commission should not give any weight to Dr. Hadaway's P/E Ratio Terminal Value Model because the Commission is trying to estimate the long-term required rate of return for investors.

Dr. Hadaway asserted that although the standard DCF model requires a long-term estimate of expected growth, the Commission is determining the current cost of equity capital.

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[261] *Id.* at 3.
[262] *Id.*
[263] *Id.*
[264] Hadaway Rebuttal at 30.
[265] *Id.*
[266] *Id.* at 31.

Dr. Hadaway argued that a variety of factors should be considered in estimating ROE, and that Mr. Baudino's claim that only the standard DCF model should be considered is an extremely narrow view that should not be accepted.[267]

BGE and Staff

Regarding Ms. McKenna's comparable company selections, Dr. Hadaway argued that Ms. McKenna should have eliminated IDA CORP which had the lowest estimate, in order to balance her elimination of PNM Resources which had an exceptionally high estimate.[268]

Dr. Hadaway disagreed with Ms. McKenna's P/E Ratio IRR analysis because she replaced current, historically high, market-based P/E ratios with Value Line's future price estimates or its estimates of future P/E ratios.[269] Dr. Hadaway argued that this effectively eliminates the tendency of the IRR model to balance the low dividend yield aspects of the traditional models.[270] If current P/E ratios were used, Ms. McKenna's IRR model would produce a ROE range of 10.4 percent to 11.3 percent.[271]

Dr. Hadaway also disagreed with Ms. McKenna's inclusion of the result of 8.41 percent from her Build-up risk premium analysis, a model that is not widely used in regulatory settings.[272] Dr. Hadaway argued that the Build-up model requires more inputs and even more subjective inputs than CAPM, and that the result of 8.41 percent is not reasonable; as such it should be excluded as an outlier.[273] Dr. Hadaway noted that if the Build-up method had not been included in Ms. McKenna's weighted average, her base

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[267] *Id.* at 36.
[268] *Id.* at 8-9.
[269] *Id.* at 9.
[270] *Id.*
[271] *Id.*
[272] *Id.* at 10.
[273] *Id.*

ROE before BSA reduction would have been 10.4 percent.[274] If Ms. McKenna also had balanced her standard DCF analysis by eliminating both the highest and the lowest ROE estimates, and excluded the Build-up results, Ms. McKenna's base ROE would have been 10.6 percent.[275]

Lastly, Dr. Hadaway disagreed with the 50 basis point BSA adjustment. BGE believes there should be no reduction to the ROE for the Rider 25 mechanism. The major argument the Company makes is that the proxy group formulated by Dr. Hadaway contains existing or proposed revenue stabilization mechanisms in 20 of the 29 listed companies. In addition, Dr. Hadaway argued that because the bond ratings for the comparable companies are slightly above BGE's ratings, BGE does not have lower financial and operating risks than the comparable companies.[276] As such, Dr. Hadaway contended that a further 50 basis point reduction to BGE's allowed ROE is not necessary.[277]

Ms. McKenna identified 4 out of 15 companies in her proxy group which have revenue decoupling mechanisms, or approximately 27 percent of the total proxy group.[278] Ms. McKenna does not consider mechanisms designed only to recover energy efficiency costs to be equivalents to revenue decoupling mechanisms as Dr. Hadaway does; Ms. McKenna also does not consider a *proposed* revenue decoupling mechanism the same as already having a revenue decoupling mechanism in place as Dr. Hadaway did.[279]

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[274] *Id.*
[275] *Id.*
[276] Hadaway Direct at 8.
[277] *Id.*
[278] McKenna Direct at 15.
[279] *Id.*

Ms. McKenna responded to Dr. Hadaway's criticism of her inclusion the ROE result for IDA CORP. Ms. McKenna developed the framework of 2 standard deviations from the expected value for determining an outlier, and IDA CORP's ROE result falls within that range.[280]

Ms. McKenna indicated that the purpose of the P/E Ratio IRR Implementation was illustrative.[281] Ms. McKenna discussed the comparison, but claimed to have not been advocating for a particular method or performing her own analysis.[282]

Ms. McKenna defended her use of the 8.41 percent result from her Build-up Risk Premium Method stating that this result is not an outlier but rather a result reflective of possible reduced risks for the size and industry type of BGE, to which she gave half the weight of the DCF method.[283]

Lastly, Ms. McKenna disagreed with Dr. Hadaway's view regarding bond ratings as they relate to the incorporation of revenue decoupling mechanisms. Ms. McKenna, citing Standard and Poor's explanation of bond ratings, argued that since bond ratings reflect the risk of default, they do not purport to measure equity risk.[284] Additionally, bond ratings reflect other factors such as a company's management, capital expenditures, legal and regulatory risks, as well as the potential impact of future events on credit risk.[285]

OPC and MEG

OPC Witness King disputed MEG witness Baudino's recommendation because it is based on only one source; Mr. King does not feel it is appropriate to disregard

[280] McKenna Surrebuttal at 4.
[281] *Id.*
[282] *Id.* at 4-5.
[283] *Id.* at 5.
[284] *Id.* at 6.
[285] *Id.*

indications from CAPM.[286] Mr. King also took issue with Mr. Baudino's failure to apply the 50 basis point adjustment for the Rider 25 bill stabilization adjustment.[287] Mr. King removed five companies from Mr. Baudino's comparison group because they have similar bill stabilization mechanisms, before making the 50 basis point reduction, to arrive at a ROE of 8.7 percent, 13 basis points below his recommended ROE.[288]

Staff and OPC

Mr. King's principal objections to Staff Witness McKenna's analyses are (1) use of Value Line only as the basis for DCF earnings forecasts; (2) inclusion of companies with decoupling mechanisms; and (3) use of historical Treasury bond yields as the risk-free rate in CAPM and risk premium methods.[289]

Though Ms. McKenna does not disagree with Mr. King's use of multiple analyses to estimate earnings growth rates when utilizing the DCF method, Ms. McKenna defended her singular use of Value Line stating that it is an independent, reputable and widely used source of financial data, and one that Staff has relied on in the past for its DCF analyses.[290] Also, the Commission has endorsed and accepted Staff's use of a DCF analysis using Value Line as a source.[291] Although she used only Value Line as the basis for DCF earnings forecasts, Ms. McKenna believed the combination of the DCF model with other analyses minimizes any possible errors and biases from affecting the final result and recommendation.[292]

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[286] King Rebuttal at 7.
[287] *Id.*
[288] *Id.* at 7-8.
[289] King Rebuttal at 4.
[290] McKenna Surrebuttal at 1-2.
[291] *Id.* at 2.
[292] *Id.*

Ms. McKenna argued that use of historical Treasury bond yields is appropriate in the current economic climate, and she believes the use of historical data provides a better estimate of long term credit market costs and conditions than do currently observable interest rates that are the direct outcome of the Federal Reserve's unsustainably low interest rate policy.[293]

Ms. McKenna disagreed with Mr. King's reasoning that it is inappropriate to reduce the ROE for BGE by 50 basis points to account for the effects of revenue decoupling when the proxy group includes companies with such mechanisms. Ms. McKenna noted that many of the companies in both of their proxy groups receive the majority of their revenue from generation, thus a distribution decoupling mechanism would have a smaller impact on the holding companies' overall ROE than it would on the ROE of a subsidiary providing electric distribution only.[294] Ms. McKenna does not believe there have been any findings since BGE's last rate case that would support a finding that her recommended reductionism inappropriate.[295]

Staff and MEG

Staff Witness McKenna disagreed with MEG witness Baudino's use of only one method in making his ROE recommendation. Ms. McKenna argued that the various DCF, CAPM and risk premium methods typically used when developing an ROE recommendation each have their own strengths and weaknesses, and a combination of the methods should be used in accordance with Commission objectives.[296]

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293 *Id.*
294 *Id.* at 3
295 *Id.*
296 McKenna Rebuttal at 3.

Commission Decision

In seemingly every case – and not just rate cases[297] – the company before us argues that its access to capital or the terms on which it will be able to borrow will be impaired unless we approve a series of "constructive" adjustments. BGE is no exception, and this case is no exception. The requests may vary, but the same argument is made every time. It's true that we have identified this dynamic before, and recognized the importance of credit ratings to utility companies.[298] But it's also true that over the last four years, after denying requests for enhanced returns on equity, cost recovery trackers and other deviations from historic ratemaking, the threatened restrictions and impairments have not materialized – and, more to the point, no company (including BGE) has introduced any actual *evidence* of restricted or impaired access to capital based on our decisions.[299]

In fact, the record in this case demonstrates the opposite. In the time since the worldwide capital markets froze in 2008, BGE has had ample access to capital on good terms, and could not cite a single instance in which it has been unable to borrow whatever it needed on favorable terms.[300] Notably, the only knowable impact on a Maryland utility's credit rating or access to capital from any decision of this Commission since 2008 came when Standard & Poor's ("S&P") *upgraded* BGE by two notches based on

[297] *See, e.g.*, Case No. 9208.
[298] *See* CEG/EDF.
[299] *See* Transcript ("TR") at 162-167.
[300] The Tampa Electric example cited by Mr. Khouzami on the stand, *see* Tr.at 165, doesn't change this analysis. The entire record on the point (which was elicited entirely through questions from the bench) consists of Mr. Khouzami's general memory of the deal and a one-page term sheet. BGE Ex. 18. We have no basis on which to analyze the relative similarity of BGE and Tampa Electric, the relative risks of the two debt issuances, the relative ROEs, or other characteristics of the two companies or the two deals that may have borne on the outcome. But even if we assume the truth of Mr. Khouzami's premise, *i.e.*, that Tampa Electric was able to borrow more or on better terms because its ROE and/or regulatory environment are more constructive than BGE's, the example shows at most a one-instance correlation with no record to support the causal leap BGE assumes.

the ring-fencing provisions of our order approving Constellation's transaction with EDF in 2009.[301]

The record before us here reveals fears regarding anticipated limitations of access to credit and terms, which are articulated as more generic and speculative than tangible. In our view, the remedies of enhanced returns on equity would overcompensate for those fears. We must maintain the appropriate balance among all of the interests at stake here, and to do so objectively rather than in response to the perceived or predicted reactions of others – especially when past speculation has not borne out in reality.[302]

We find BGE is a lower-risk investment than the companies in Dr. Hadaway's proxy group or the average utility; our restructured environment and other characteristics of BGE diminish its business and financial risks overall compared to the proxy group, and even compared to BGE at the time of its last rate case. BGE's witness DeFontes conceded that that there aren't any other companies that are exactly like BGE.[303] Unlike most of the companies in Dr. Hadaway's proxy group, BGE is a distribution only

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[301] *See Re Current and Future Financial Conditions of BGE*, Case No. 9173, Phase II, Transcript of Status Conference of February 24, 2010, at 7, lines 1 - 4 (According to Daniel P. Gahagan, Vice President and General Counsel of BGE,, ". . .a few days after the Commission issued its order [in Case No. 9173], S&P raised BGE's credit rating on the unsecured, senior unsecured debt to triple B plus. I believe we are the only Maryland electric utility with a triple B plus rating. They directly cited the Commission's action in Case Number 9173 in terms of the ring-fencing in support of that position.")

[302] BGE reminds us again, as others have before, that this Commission is ranked "Below Average 2" by Regulatory Research Associates ("RRA"), and suggests that this is a bad grade that we should consider trying to raise with our decisions here. The problem is that these rankings represent a single and highly interested point of view – the interests of investors – not an objective measure of this Commission's skill, performance, or the overall quality of the regulatory environment in Maryland. RRA is a division of SNL Financial, an industry publication company, and by its own reckoning ranks commissions based on the "relative investor risk level for each jurisdiction," *see* http://www.snl.com/Sectors/Energy/RRA.aspx, not on a balance of different viewpoints. It is interesting to think about whether this Commission might (or might not) be judged differently by surveys or rankings grounded in the myriad other points of view that are represented by parties to this case and others. Ultimately, though, we cannot play to the critics: we must, and we do, make the best decisions we can based on the law and the record we have before us, and we let the analytical and critical chips fall where they may.

[303] Witness DeFontes said, "There's no perfection that I've got 29 companies that look exactly like BGE. There aren't any." Tr. at 594.

company. Having no generation, BGE does not face the environmental risk that some of the vertically integrated companies in Dr. Hadaway's proxy group face. We wholly reject the notion that companies with similar bond ratings deserve similar ROEs. Bond ratings measure risk of default, not equity values.[304]

Additionally, BGE is now part of a larger corporate enterprise, which provides advantages that did not exist at the time of BGE's prior rate case (Case No. 9230). Also since Case No. 9230, the ring-fencing around BGE has been greatly enhanced, further limiting its risk profile. In addition to a limitation on dividends, there is enormous protection against Exelon's non-regulated operations including ring-fencing provisions that protect BGE from bankruptcy filings by Exelon's non-regulated businesses. BGE enjoys full surcharge cost recovery outside of rates for EmPower programs, both energy efficiency and demand response. BGE also is allowed full cost recovery outside of rates for Standard Offer Service contracts, for complying with State-mandated renewable energy portfolio standards, and for its rate stabilization bonds.

A major source of dispute among the parties involves whether a basis point reduction should be made for the risk-stabilizing effect of the Bill Stabilization Adjustment ("BSA"), which decouples sales of electricity from BGE's revenues. Staff is correct that the Commission has in the past, most recently in Case No. 9286 involving Pepco, applied a 50 basis point reduction for the BSA. However, since the entry of the order in that rate case, the Commission, in Case Nos. 9257 – 9260, issued Order Nos. 85177 and 85178 on October 26, 2012, in which the Commission held that the

[304] Moreover, Dr. Hadaway's comparable companies include companies with S&P bond ratings between triple B minus to A plus, a wide range around BGE's triple B plus, rendering his conclusion without the precision he suggests.

Companies are disallowed from collecting any lost revenues due to major outage events. Going forward then, the effectiveness of the weather-related decoupling of the BSA is somewhat less certain. At this point, without experience with the effect of the modified BSA, a strict basis point reduction of 50 points may no longer be warranted. However, the BSA remains a "very good" decoupling mechanism,[305] better than almost all others in any of the experts' proxy groups, which serves to limit the risk, and therefore the appropriate ROE for BGE

Other characteristics influencing the risk associated with BGE are that we use historic test years and employ no infrastructure trackers, though these two characteristics remain unchanged since we decided Case No. 9230. Although BGE is a combined gas and electric utility, we are, as in the past, not setting a combined ROE.

Given that, as Mr. DeFontes testified, there are no companies exactly like BGE, we are left to set an electric ROE based on what is reasonable under the real-world circumstances of the broader economic environment we find ourselves in today and as anticipated for the rate-effective period. Interest rates are at historic lows and will stay that way until unemployment falls below 6.5 percent and inflation is less than 2.5 percent.[306] And although we have taken investor expectations into account, it is not realistic or reasonable in this environment to expect returns over 10 percent for low-risk investments. Dr. Hadaway confirmed, both in his written and oral testimony, that low yields on conventional low-risk investments are sending low-risk investors to utility stocks.[307] But the conclusion he draws from that phenomenon – that we need to increase

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[305] TR at 394.
[306] *See, e.g.*, http://www.businessinsider.com/fomc-december-meeting-2012-12
[307] Hadaway Direct at 25; TR at 417.

the return to BGE's shareholders – has the analysis backwards, in our view. We think the flight of investors to utility stocks implies more competition for the same investment. As such, there is certainly no need to increase returns in order to attract investment, and current conditions would allow us to reduce returns without repelling investment.

Next we consider the political and regulatory environment. We disagree that BGE should be downgraded, or deemed riskier, for being in an environment that's perceived to be less "constructive." Yes, there were some struggles back in 2005-06, when we were transitioning to restructuring. But that was years ago, and since 2007 we have brought calm and consistency to ratemaking. We have decided cases according to consistent principles and applied them, in our view, fairly. Earnings may be lower for some companies in some years than they or Wall Street would like, but they have all earned and maintained strong, investment grade bond ratings, and we have devoted the resources to addressing rate increase requests fully and fairly. We are committed to ensuring safe and reliable service at just and reasonable rates, and we recognize that in some instances this means that distribution rates may need to go up.

Dr. Hadaway's comparable companies include companies with S&P bond ratings between triple B minus to A plus, a wide range around BGE's triple B plus. He then used the *upper* end of his risk premium analysis (10.1%) and the *upper* end of his DCF analysis (10.9%) to arrive at a cost of equity range 10.1 percent to 10.9 percent.[308] He justified the use of the upper end of his analyses on the current economic climate and government-induced low interest rates. However, Dr. Hadaway testified that the current environment of low interest rates is likely to continue at least until 2015, possibly longer.

[308] *Id.* at 3.

Thus, given BGE's pattern of frequently seeking rate adjustments, we do not believe it is appropriate to set a rate beyond the likely rate effective period. Dr. Hadaway's full range of ROEs was 9.6 percent to 10.9 percent, the midpoint of which is 10.25 percent.

Staff's recommended electric ROE, which includes the full historic adjustment for the BSA, is 9.40 percent; OPC's recommended ROE, which also includes an adjustment for the BSA, is 9.1 percent; and MEG's recommended ROE, which does not adjust for the BSA, is 9.40 percent. Our final chosen ROE of 9.75 percent recognizes the less risky nature of BGE's operation, is based on a wide and varied range of sound methodologies, and balances the interests of BGE's ratepayers and shareholders. The return BGE's investors will be allowed to earn in this case is appropriate, particularly under the present economic climate. We are convinced by the evidence and by past market performance that a monopoly company in a stable service territory with a BSA mechanism and the potential of earning 9.75 percent on its equity will be able to attract the necessary capital in the current low interest rate environment to meet its statutory requirements to provide safe and reliable service to its customers.

There being no dispute as to BGE's capital structure, BGE's weighted average cost of capital for electricity is as follows:

Type of Capital	Percent of Total Capital		Embedded Cost Rate	Weighted Cost Rate
Long-Term Debt	47.3%	*	5.46%	2.58%
Preferred Equity	4.3%	*	7.02%	0.30%
Common Equity	48.4%	*	9.75%	4.72%
Total	100%			7.60%

2. Gas Cost of Capital

Positions of the Parties

In his direct testimony, BGE witness Dr. Hadaway did not distinguish between the Company's electric and gas operations for purposes of recommending a return on equity. Instead, he argued that the return on equity for each operation should be the same. Similarly, BGE witness Khouzami testified that because the Company does not raise capital separately for its electric and gas businesses, or maintain separate pools of funds for their investments, a combined ROE for gas and electric operations is appropriate.[309]

In contrast, OPC witness King testified that gas distribution service presents less risk to investors than electric utility service and that the Commission should accordingly prescribe a lower return on equity for gas service.[310] In support, Mr. King observed that in every year since 2007, the average return on equity award for gas utilities has been lower than the return for electric utilities.[311] Mr. King also argued it would be unfair to require natural gas ratepayers to incur higher rates to compensate BGE for the greater risk of its electric operations. Like Mr. King, MEG witness Baudino recommended a separate return for BGE's natural gas operations.[312] Likewise, Staff witness Mosier presented testimony directed specifically to BGE's gas operations and recommended that the Commission approve a separate return on equity for BGE's gas operations.

[309] Khouzami Direct at 15.
[310] King Direct at 2, 23.
[311] King Surrebuttal at 9.
[312] Baudino Direct at 4, 55.

i. Proxy Groups

In recommending a return on equity for BGE's natural gas operations (or in the case of Dr. Hadaway, combined gas and electric operations), several parties put together proxy groups for purposes of conducting their DCF analysis. Dr. Hadaway applied four versions of the DCF model to a proxy group comprised of 29 electric and gas utilities.[313] He did not attempt to select gas-only utilities to recommend a return on equity specific to BGE's gas operations, recommending instead a combined ROE.

In determining his recommended proxy group, Mr. King included all 11 companies classified by Value Line Investment Survey[314] as natural gas distribution utilities and added Sempra Energy and UIL Holdings, which are combined gas and electric companies.[315] He then applied the same criteria he utilized for electric utilities to reduce the list of comparables to three companies. In order to obtain a more sizeable proxy group, he relaxed the S&P grade criterion to include two companies with S&P ratings two grades different than BGE's BBB+ rating to obtain a final natural gas proxy group of five gas utilities.[316]

Mr. Baudino also selected gas distribution companies from Value Line, limiting his selection to companies that demonstrated five-year earnings and dividend growth forecasts. He excluded AGL Resource because of its 2011 merger, and he rejected UGI Corp. because only a minority of its earnings comes from gas distribution operations.[317] He did not utilize a bond rating as a screening criterion because the resulting three-

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[313] Hadaway Direct at 44.
[314] Value Line Investment Survey, September 7, 2012.
[315] King Direct at 7.
[316] *Id.* at 8.
[317] Baudino Direct at 36.

member proxy group would have been too small, in his opinion.[318] His final proxy group is comprised of nine companies.[319]

Mr. Mosier selected a proxy group of all publically traded natural gas companies with a financial strength of B++ and above listed in Value Line, thereby forming a comparison group of eight companies.[320]

ii. Methodologies Utilized and Recommended Return on Equity

Dr. Hadaway recommended a single return on equity for the combined electric and gas operations, and the method by which he determined his recommendation to the Commission is described in the Electric Cost of Capital section.[321]

Mr. King calculated a separate return on equity for his gas comparison group utilizing the classic formulation of the DCF method in addition to two variations of the DCF, namely the FERC 2-step growth model and the sustainable growth model.[322] Mr. King calculated an 8.56 percent mean and 8.59 percent median equity return indication through application of the classic DCF model, an 8.56 percent return indication utilizing the FERC two-step growth formulation, and an 8.94 percent mean and 9.06 percent median for the sustainable growth model.[323] Employing the CAPM analysis, Mr. King reached an ROE indication of 10.73 percent for the gas comparison group, however, he gave little weight to this indication given the "considerable judgment" he stated that the method required regarding selection of critical inputs.[324] Considering all of this analysis,

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[318] *Id.* at 37.
[319] *Id.* at 37.
[320] Mosier Direct at 8.
[321] Hadaway Direct at 3.
[322] King Direct at 12.
[323] *Id.* at 11-16.
[324] *Id.* at 21.

Mr. King recommended that the Commission approve a 9.0 percent equity return for BGE's gas service, which is ten basis points below his recommendation for BGE's electric service.

Mr. Baudino evaluated BGE's return on equity through the DCF methodology in addition to the CAPM. Regarding the DCF, Mr. Baudino utilized the sustainable growth method in estimating the expected growth rate for the comparison group and calculated an expected growth rate for the gas distribution company comparison group of 2.50 to 5.72 percent.[325] He then calculated DCF results using two separate methods, including (1) utilizing the average growth rates for the comparison group, and (2) employing the median growth rates from Value Line, Zacks, and Thomson. He reached a DCF calculation of 8.68 percent for the first method and 8.13 percent for the second method for the gas distribution company comparison group.[326] Regarding the CAPM analysis, Mr. Baudino calculated a return of 9.47 percent to 9.98 percent using the 20-year and 5-year Treasury bond yields and Value Line market return data. Using the historical Ibbotson data, his CAPM results ranged from 5.65 percent to 7.06 percent.[327] He testified that the DCF is a better technique for determining an appropriate return because the CAPM requires "a considerable amount of judgment," through he concluded that the CAPM provides useful supplemental evidence and should not be entirely disregarded.[328] Considering both of these methodologies, Mr. Baudino recommended that the Commission approve an ROE of 9.0 percent for BGE's gas distribution operations, which

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[325] Baudino Direct at 42.
[326] *Id.* at 43.
[327] *Id.* at 49.
[328] *Id.* at 45-46.

is 40 basis points below his electric recommendation.[329] To arrive at that figure, Mr. Baudino started with an 8.7 percent ROE, which he adjusted upward by 30 basis points to account for the higher bond ratings of the natural gas companies in his proxy group.[330]

Mr. Mosier applied the DCF, the risk premium, and the CAPM methods to determine a recommended return on equity for BGE.[331] His DCF analysis produced an ROE estimate of 9.18 percent, his risk premium calculations yielded a return of 8.99 percent, and his CAPM analysis produced a result of 10.06 percent.[332] Utilizing these three methodologies, he calculated a range of reasonableness for BGE's ROE between 8.99 percent and 10.6 percent. Based on his opinion of the reliability of the methodologies, he awarded the DCF method a weight of 50 percent and the CAPM and risk premium methods a weight of 25 percent each. He thereby arrived at a final ROE recommendation of 9.35 percent, which is five basis points below Ms. McKenna's recommended ROE for electric operations.[333]

iii. Adjustment for Decoupling

Dr. Hadaway urged the Commission not to reduce BGE's return on equity as a result of the inclusion of a decoupling mechanism in BGE's tariff, either for its electric or its gas operations.[334] To support this view, Dr. Hathaway observed that all of the natural gas companies in his proxy group have decoupling mechanisms similar to BGE's.[335] He therefore concluded that whatever reduction in risk BGE receives from its decoupling mechanism is also enjoyed by the companies in his proxy group.

[329] *Id.* at 50.
[330] *Id.*
[331] Mosier Direct at 7.
[332] *Id.* at 11-14.
[333] *Id.* at 15.
[334] Hadaway Direct at 8.
[335] *Id.* at 9, 16.

Although Mr. King recommended that the Commission reduce BGE's return on equity for its electric operations as a result of its revenue decoupling mechanism, he did not advise the same with regard to the Company's gas return.[336] He testified that there is not a significant difference between the business risks of BGE's gas operations and the operations of the companies in his gas comparison group. Additionally, he stated that rate decoupling is much more common in the gas distribution industry than in the electric distribution industry, making it likely that some form of decoupling mechanism will be found in the tariffs of the gas comparison companies.

Mr. Baudino also saw no reason to adjust BGE's return on equity as a result of its decoupling mechanism.[337]

iv. Parties' Responses

Dr. Hadaway criticized the use by several witnesses of proxy groups taken from Value Line because the number of natural gas distribution companies (11) is insufficient in his opinion to form an adequate comparison group, especially if it is further reduced to remove companies dominated by non-regulated activities.[338] He also disagreed with Mr. King's decision to eliminate NiSource from his proxy group, arguing that a significant portion of the company's revenue comes from regulated activities.[339] In response, Mr. King asserted that the small proxy group is unavoidable given the limited number of gas distribution companies and it would be unfair to BGE's gas ratepayers to include companies that are not heavily engaged in gas distribution operations simply to obtain a

[336] King Direct at 26.
[337] Baudino Direct at 54.
[338] Hadaway Rebuttal at 14.
[339] *Id.* at 26-27.

larger sample size.[340] Regarding NiSource, he responded that the company was clearly an outlier because its DCF result was 450 basis points higher than the next highest company in the comparison group.[341] Mr. Mosier criticized Dr. Hadaway's proxy group for containing only four natural gas companies out of a comparison group containing 29 entities.[342] He testified that BGE should have separately evaluated BGE's natural gas operations, including through a separate proxy group.

Dr. Hadaway testified that Mr. King understated the dividend yield in his FERC 2-step DCF analysis.[343] He argued that current low interest rates, inflation, and growth rates are not reflective of the long-term trends of the U.S. economy and that Mr. King's reliance on government agency forecasts for nominal GDP growth (including the Congressional Budget Office ("CBO") and Social Security Administration ("SSA")) was erroneous because those agencies underestimate future inflation and growth rates.[344] Dr. Hadaway also claimed that Mr. King should not have put any weight on the sustainable growth model, which is not reliable in his estimation. Dr. Hadaway criticized Mr. Baudino's analysis for including Value Line's growth rates, which in Dr. Hadaway's opinion underestimates long-run growth rate expectations.[345]

Mr. King criticized Dr. Hadaway's use of the risk premium analysis to estimate return, arguing that any analysis that bases returns on those awarded by other regulatory commissions is inherently circular.[346] Mr. King also faulted Mr. Mosier for relying exclusively on Value Line as a basis for his DCF earnings forecasts and for using

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[340] King Surrebuttal at 9.
[341] *Id.* at 10.
[342] Mosier Direct at 15.
[343] Hadaway Rebuttal at 21.
[344] *Id.* at 22.
[345] *Id.* at 30-31.
[346] King Direct at 18.

historical Treasury bond yields as the risk-free rate in the CAPM and risk premium tests.[347] Mr. King argued that Treasury bond yields are currently at historic lows and that using an 82-year average Treasury bond yield disconnects the CAPM and risk premium tests from "current reality."[348] He also claimed that Staff's analysis would have produced a significantly lower ROE if current rates had been used. In response to Dr. Hadaway's argument that current interest rates are artificially low, Mr. King stated that "[l]ow interest rates are a present fact and likely to remain so for at least the next two to three years."[349] He defended the analyses of the SSA and CBO, arguing that they are based on sophisticated econometric models of the U.S. economy, and criticized Dr. Hadaway's reliance on retrospective data, including periods when inflation was rampant in the 1970s.[350] Mr. King concluded that the current low-interest rate environment has forced investors to accept low returns on variable-return equity investments, including utility bond yields.

Mr. Baudino also disagreed with several aspects of Dr. Hadaway's analysis. Specifically, he criticized Dr. Hadaway for inflating dividend growth forecasts in the formulation of his comparable group DCF analyses and using forecasted growth in Gross Domestic Product as a proxy for investor growth expectations. He also found fault with Dr. Hadaway's use of the terminal value model and failure to use current interest rates in his risk premium analysis.[351]

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[347] King Rebuttal at 4.
[348] *Id.* at 6.
[349] King Surrebuttal at 3.
[350] *Id.* at 8.
[351] Baudino Direct at 55.

Commission Decision

We agree with the majority of parties in this case and find it appropriate to retain separate returns on equity for BGE's electric and gas operations. The Commission made the same finding in BGE's last rate case, where it determined that "gas and electric services are separable on the Company's books, and have different financing needs."[352] Although we recognize, as Mr. Khouzami has testified, that BGE does not raise capital separately for its electric and gas businesses, we find that the proper focus for this issue is on the ratepayer rather than the investor. As such a utility's electric operations present a slightly elevated risk to investors compared to natural gas operations, and investors in the electric utility will therefore require a slightly higher return to compensate for that risk.[353] In a combined utility like BGE, investors might average the risks of the company's combined operations to calculate an appropriate return. However, when we consider a ratepayer's obligations to pay for service, combining BGE's separate operations to produce a single return for the Company would lead to cross subsidization of services. BGE's natural gas ratepayers should not be required to subsidize BGE's electric operations by paying a higher combined return to BGE. Instead, for purposes of clarity and fairness from an end user's perspective, we will require that BGE receive separate returns on its electric and gas operations.

Consistent with our decision regarding Electric Cost of Capital, we observe that BGE has ample access to capital, and on good terms. Interest rates are currently at

[352] Case No. 9230, *In the Matter of the Application of Baltimore Gas and Electric Company for Revisions in its Electric and Gas Base Rates,* Order No. 83907, March 9, 2011 at 61.
[353] As Mr. Mosier noted, Staff, OPC, and MEG all recommended returns on equity that are lower for natural gas than for electricity, despite having used different methodologies. Mosier Surrebuttal at 5.

historic lows and will likely continue that way for the foreseeable future.[354] Whether the historic low interest rates are the result of a sluggish economy gradually recovering from a devastating recession, or are the consequence of artificial government interference in financial markets as testified by Dr. Hadaway, or both, they are as Mr. King stated, "current reality."[355] Additionally, the evidence presented in this case is that the federal government will continue to act to keep interest rates low for the next several years.[356] Especially given BGE's recent predilection for filing rate cases frequently with the Commission, we see no value in awarding an anomalously high ROE during a time of historic low interest rates because of the risk that interest rates could increase several years in the future.

The expert witnesses on cost of capital have provided substantial testimony using several different methodologies and proxy groups with varying members. We do not find that any one methodology is definitive to the exclusion of other analyses. As admitted by the witnesses, each methodology requires some level of judgment and assumptions. Taking all of the evidence into consideration, however, including current interest rates and BGE's ongoing and increasing need to access capital at reasonable rates, we find that a reasonable return on equity for BGE's gas operations is 9.60 percent. We will not further reduce that return as a result of BGE's decoupling mechanism. No party argued that the Company should have a reduced ROE for its natural gas operations because of decoupling. Instead, as the parties testified, decoupling provisions are common among natural gas distribution companies.

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[354] King Surrebuttal at 3.
[355] King Rebuttal at 6.
[356] *See,* King Direct at 27, stating "the Federal Reserve Open Market Committee has committed to maintain interest rates at very low levels for at least three more years," through at least mid-2015.

Accordingly, BGE's weighted average cost of capital for gas is as follows:

Type of Capital	Percent of Total Capital		Embedded Cost Rate	Weighted Cost Rate
Long-Term Debt	47.3%	*	5.46%	2.58%
Preferred Equity	4.3%	*	7.02%	0.30%
Common Equity	48.4%	*	9.60%	4.65%
Total	100%			7.53%

Authorized Revenue Requirement for Electric and Gas

The authorized revenue requirement for electric operations is $80,554,000, and the authorized revenue requirement for gas operations is $32,416,000.

C. BGE Cost of Service Studies

The Company, through witness George Pleat, presented the results of an Actual Calendar Year ("CY") 2011 Company Recommended Electric Embedded Cost of Service Study ("ECOSS") and the Actual CY 2011 Company Recommended Gas Embedded Cost of Service Study ("GCOSS"),[357] each providing a framework for how BGE should collect, by customer class, any authorized increase in gas or electric base revenues. Company witness Michael J. Cloyd used the ECOSS and GCOSS to develop the proposed rate design and resulting tariffs.[358]

[357] Pleat Direct at 2.

[358] BGE also proposed a Sparrows Point Rider for both its Electric and Gas Service Tariffs. The rider is designed to provide the Company a method by which to collect revenues previously recovered from Schedule SP from a new owner in the event a successful sale and resumption of operations of Sparrow Point occurs or recover the shortfall through a rate surcharge to the other classes. The Rider will be discussed as a separate sub-section in this Order.

1. Electric Cost of Service Study

Positions of the Parties

BGE

In developing its ECOSS, Mr. Pleat utilized the FERC Uniform System of Accounts and identified electric distribution system embedded costs for the 2011 calendar year.[359] BGE's ECOSS "is developed to allocate costs to individual classes and then match distribution based revenues derived from each rate class with base rate and expenses allocated to a given class."[360] BGE's ECOSS excluded all transmission investment and related O&M expenses, as well as Rider 1 electric supply costs.[361]

Mr. Pleat used the non-coincident peak ("NCP") allocator in the ECOSS to reflect how substations and distribution feeders are actually planned and sized. Mr. Pleat explained that use of the NCP in the allocation of demand-related distribution investment is a generally accepted methodology in electric cost of service development. He further stated that distribution substations and distribution feeder connections are planned such that sufficient capacity is available to meet customer loads at localized voltage service levels. Comparatively, network transmission facilities are constructed to meet system-wide capacity requirements and are assigned using the system coincident peak allocator.[362] According to Mr. Pleat, "local area peak loads are the major factors in sizing electric distribution equipment, and customer class NCPs are the normally accepted approach in allocating the demand-related component of distribution plant – with the

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[359] Pleat Direct at 14.
[360] Pleat Direct at 14.
[361] Pleat Direct at 14.
[362] Pleat Direct at 15.

exception of direct assignment of dedicated facilities for customers."[363] The NCP concept does not consider when total *system* peak is recorded, but instead reflects more closely the diversity in customer group load patterns.[364]

In the ECOSS, the Company measured all residential customer peak kilowatt ("kW") demand (Schedule R, Schedule RL) in aggregate form on an hourly basis and then measured its maximum hourly kW demand.[365] Similarly, the Company measured all small commercial customer peak demand (Schedule G and Schedule GS) in aggregate form on an hourly basis and then tracked the maximum hourly kW demand.[366]

Under the Company's recommended ECOSS, the following are the relative rates of return for the various electric customer classes:

[Chart follows on next page]

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[363] Pleat Direct at 15.
[364] Pleat Direct at 15.
[365] Pleat Direct at 16.
[366] Pleat Direct at 17.

Schedule	Relative Return
R (Residential)	0.69
RL (Residential Time of Use)	0.51
G* (General Service)	1.79
GS (General Service Small)	2.54
GL (General Service Large)	1.33
P (Primary Voltage Service)	0.79
SL (Street Lighting)	1.43
PL (Private Area Lighting)	2.89
SPE (Sparrows Point)	2.03
T (Transmission Voltage Service)	20.16
System Total	1.00

*includes Schedule GU (General Unmetered Service)

Mr. Pleat testified that the Schedule T relative rate of return has declined since Case No. 9230 but remains at a high level. He further stated that the major factor behind Schedule T's high relative rate of return is the delivery service charge that it continues to recover as investment costs associated with 34 kV and 13 kV substation and distribution lines from when Schedule T customers were served under Schedule P.

OPC

OPC witness Dr. Pavlovic took exception to the Company's use of different twelve months periods for its cost studies and revenue requirement (addressing both the ECOSS and the GCOSS). BGE's cost studies use accounting data for the twelve-month period ending December 31, 2011, whereas the revenue requirement uses data for the twelve month period ending September 30, 2012.[367] According to Dr. Pavlovic, this difference represents a significant flaw because it creates a mismatch between the underlying cost structure and the revenue requirement. Dr. Pavlovic explained that the "because the cost study measures the cost structure of BGE's operations and that the cost structure is then used to distribute the revenue requirement and set charges for rate elements, the costs studies should be based on the costs assumed in the revenue requirement."[368] Consequently, Dr. Pavlovic argued that "if the rates are designed assuming a cost structure different from the one assumed in the revenue requirements, the rates will either under or over recover from customers the actual cost of service."[369]

Dr. Pavlovic further testified that a fundamental principle underlying class costs studies is that the direct assignment and allocation of costs to the customer classes should reflect the cost causative impact of each class on the distribution system. Dr. Pavlovic identified two issues that prevented the ECOSS from following this cost causation principal: (1) the development of ECOSS's NCP allocators; and (2) the manner in which BGE allocates underground versus overhead facilities to customer classes. It is on these bases that Dr. Pavlovic recommended that the Commission reject the Company's ECOSS.

Currently, BGE uses as a proxy each classes' peak demand on the system overall, which may or may not be a good proxy measure of each class' aggregate demand on the

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[367] Pavlovic Direct at 23.
[368] Pavlovic Direct at 23.
[369] Pavlovic Direct at 23.

system, depending on how uniform class demands are at each substation.[370] After examining data provided by BGE, including a list of substations and the corresponding usage data such as number of R, RL, G and GS customers and the peak demand and time of peak demand at each substation, Dr. Pavlovic found that there is little uniformity in either the magnitude and time of substation peak demand or the class customer mix at each substation.[371] With regard to the development of ECOSS's NCP allocators, Dr. Pavlovic recommended that the Commission direct BGE to determine the degree of error there is in using class peak demand on the system as a proxy for class demand on individual substations.[372]

Concerning underground and overhead facilities, Dr. Pavlovic argued that the Company's use of the same demand allocator for both underground and overhead facilities yields an over allocation of costs to the residential classes and an under allocation to commercial classes.[373] He pointed out that it would not be difficult for BGE to develop separate underground and overhead allocators and integrate them into the ECOSS. He noted that the District of Columbia PSC ("DCPSC") recently directed Pepco to develop separate underground and overhead allocators.[374] Accordingly, Dr. Pavlovic recommended that the Commission follow the DCPSC approach and direct BGE to develop separate underground and overhead allocators for use in the ECOSS.[375]

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[370] Pavlovic Direct at 25.
[371] *Id.*
[372] Pavlovic Direct at 25.
[373] Pavlovic Direct at 25.
[374] Pavlovic Direct at 26.
[375] Pavlovic Direct at 26.

MEG

Mr. Baudino testified for MEG concerning the Company's ECOSS. Overall, Mr. Baudino concluded that the Company's ECOSS appeared to be consistent with its approach in BGE's last rate cases and Commission Orders.[376] Mr. Baudino noted, as he had in previous cases, that the Company's ECOSS allocates too much responsibility to larger customers because it does not utilize a minimum size or zero intercept study to classify the distribution account.[377] Having put forth his minimum size or zero intercept study analysis previously, Mr. Baudino acknowledged that since the Commission has declined to accept the classification of distribution costs using that approach, he accepts the Company's ECOSS as a "rough guide to costs and revenue allocation" in this proceeding.[378]

Staff

Dr. Luznar presented Staff's position on the ECOSS in this proceeding. Dr. Luznar concluded that BGE's ECOSS is consistent with the ECOSS the Company presented and the Commission approved in Case No. 9230. Therefore, Dr. Luznar recommends that the Commission use BGE's recommended ECOSS as a guideline for ratemaking purposes in this proceeding.

Staff witness Luznar addressed Dr. Pavlovic's concerns about the mismatch between the cost of service study period and the test year period. Although she agreed that it would be "ideal" if the Company based its cost of service study on the test year,

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[376] Baudino Direct at 14.
[377] Baudino Direct at 14.
[378] Baudino Direct at 14.

she noted that there was some actual overlap between the periods.[379] She was not aware of any rate cases within the past six years in which a cost of service study was concurrently developed with the test year.[380] Nor could she estimate what improvement in the cost allocation could be achieved if the cost of service study results matched the test year period. Finally, she noted that cost of service studies have been generally used as a guide rather than an "absolute measurement to develop cost-based rates."[381] She opined that the added expense of conducting a separate study as suggested by Dr. Pavlovic may not prove cost effective since he was unable to state with any certainty the benefits the study would provide.[382]

To Dr. Pavlovic's concern that the NCP is not conducted at the substation level, Dr. Luznar responded that it may be a valid point, but questioned whether the added expense of conducting that separate study would be worth the potential benefit.[383] Dr. Luznar, therefore, did not support Dr. Pavlovic's recommendation that BGE determine the degree of error there is in using class peak demand on the system as a proxy for class demand on individual substations.[384]

Dr. Luznar also concluded that Dr. Pavlovic did not provide sufficient evidence to demonstrate a substantial variation in the use of underground and overhead facilities among customer classes. Consequently, she did not support his recommendation.[385]

Finally, in her rebuttal testimony, Dr. Luznar addressed MEG witness Baudino's critique of BGE's ECOSS and his prior request that a minimum system cost of service

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[379] Luznar Rebuttal at 2 – 3.
[380] *Id.* at 3.
[381] *Id.* at 5.
[382] *Id.*
[383] Luznar Rebuttal at 6.
[384] Luznar Rebuttal at 9.
[385] Luznar Rebuttal at 11.

study be conducted. Dr. Luznar noted that Staff has supported and recommended the use of the minimum system studies in the past, but she noted that the primary barrier to its use has been the work and data needed to provide a meaningful result for the Commission in a timely manner.[386]

Commission Decision

We concur with the Company's and Staff's reasons and will accept BGE's recommended ECOSS. We discuss its application in the rate design subsection.

2. Gas Cost of Service Study

Positions of the Parties

BGE

In compliance with the "Alternative" GCOSS filed by the Company in Case 9230 and adopted by the Commission in Order No. 83097, Mr. Pleat stated that BGE "is filing in this case its Recommended GCOSS that does not allocate to Schedule SP any main pipe investment less than 12 inches in diameter."[387] Mr. Pleat explained that the Company functionalizes its delivery service gas assets and related expenses as Production, Storage, or Distribution operations.[388] Mr. Pleat stated that the Company's GCOSS "is developed to allocate costs to individual classes and then 'match' base revenues derived from each rate class with rate base and expenses allocated to the given class."[389] The Company's GCOSS excludes gas commodity costs recovered through BGE's Rider 2 – Gas Commodity Price.[390]

[386] Luznar Rebuttal at 14.
[387] Pleat Direct at 6.
[388] Pleat Direct at 4.
[389] Pleat Direct at 7.
[390] Pleat Direct at 8.

Under BGE's GCOSS, production and storage plant and associated O&M expenses generally are classified as demand-related and allocated only to the firm customer classes based on their coincident peak ("CP")[391] send-out demand.[392] Distribution mains and associated O&M expenses are also classified as demand-related and thus allocated to customer classes based on each class' contribution to the winter period total NCP demand.[393] On the other hand, services and meters and their associated O&M expenses are classified as customer-related, and are allocated to the customer classes according to corresponding number of customers and investment related to size/type of service line and meters.[394] Mr. Pleat noted that costs associated with billing functions are also classified as customer-related and are generally driven by the number of customers in each class.[395]

Under the Company's recommended GCOSS, the following are the relative rates of return for the various classes:

[Chart follows on next page]

[391] The CP allocator is the firm classes' contribution to the total firm service send-out on the day of the year with the highest send-out (January 22, 2011). Interruptible service customer consumption is not considered when determining the CP allocator as production and storage capacity is planned only to meet firm service design day conditions with the exception of critical use gas, which is a minimal amount of gas required for pilot use or to protect life, health, or public safety, or where gas outage of up to 24 hours would cause irreparable damage to the environment and/or to the customer property. Pleat Direct at 8 - 9.

[392] Pleat Direct at 7-8. Mr. Pleat also identified the firm customer classes as Schedules D, C, PLG, SPG – firm load only, and ISS/IS contracted Critical Use Gas.

[393] Pleat Direct at 8. The NCP allocator is based on each class's highest hourly demand and is the maximum hourly demand observed during the winter months (November through March) of every class regardless of the hour or day. *Id.* at 9.

[394] Pleat Direct at 8.

[395] Pleat Direct at 8.

Schedule	Relative Rate of Return
D (Residential/Grantors[396])	1.05
C General Services	0.93
IS (Interruptible Large Volume Service)	0.57
ISS (Interruptible Small Volume Service)	0.58
PLG (Private Area Lighting-Gas)	10.82
SP (Sparrows Point[397])	2.01

Mr. Pleat acknowledged that the Company's recommended GCOSS was adjusted for the Schedule IS 2011 Sales of Gas Revenue to properly include $2.1 million of distribution revenues that were inadvertently excluded within the gas distribution revenue.[398] Mr. Pleat asserted that only Schedule IS was impacted by the adjustment.[399]

OPC

OPC witness Pavlovic found that the Company's GCOSS "reasonably reflects class costs causation,"[400] and recommended that the Commission accept it as a reasonable basis for gas class revenue requirement distribution.[401] OPC witness Pavlovic also addressed the same concern with the mismatch in the GCOSS study period and the test year period as he had with the ECOSS.

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[396] "Grantors" are a small number of residential customers who have an interstate pipeline located on their property. Cloyd Direct at 8.

[397] Schedule SP is a single customer class for RG Steel, Inc. The Schedule SP rate of return remains well above the system average because historically SP rates have been set on the assumption that this customer recovers main plant cost below 12 inches in diameter. Pleat Direct at 12 – 13.

[398] Pleat Direct at 7.

[399] Pleat Direct at 7.

[400] Pavlovic Direct at 5.

[401] Pavlovic Direct at 6.

MEG

Mr. Baudino, on behalf of MEG, opposed the Company's recommended GCOSS, and provided two primary objections to the Company's approach. First, Mr. Baudino reiterated in this proceeding, as he previously testified in Case No. 9230, that "BGE's gas CCOSS does not recognize a customer-related component of distribution mains in the classification process."[402] Second, Mr. Baudino claimed that interruptible service customers in the IS and ISS classes do not receive any credit or reduction in cost responsibility due to the fact that they are interruptible."[403] Mr. Baudino noted that the Company's NCP allocator allocates the costs of distribution mains to interruptible customers on the same basis as firm service customers, e.g. residential class, which he argued has the effect of allocating too much cost responsibility in the Company's gas COSS to larger customer classes such as IS and ISS.[404]

He recommended that "BGE's study be used as a very rough guide to allocating any revenue increase in this case" and not be strictly adhered to by the Commission or other parties.[405]

Staff

Staff witness Elert, supported BGE's GCOSS and concluded that it "has been correctly developed and has resulted in an appropriate allocation of costs across the Company's rate classes and should be adopted by the Commission."[406]

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[402] Baudino Direct at 5.
[403] *Id.*
[404] Baudino Direct at 5-6.
[405] Baudino Direct at 5.
[406] Elert Direct at 2.

Commission Decision

We concur with the Company's and Staff's reasoning, and will accept BGE's recommended GCOSS. We discuss its application in the rate design subsection.

D. Rate Design

1. Electric Rate Design

Positions of the Parties

BGE

Mr. Cloyd proposed to apportion the electric revenue increase by using a two-step process so that each customer's class's rate of return moves toward a reasonable band around the system average rate of return.[407] Mr. Cloyd used the rates of return for each electric class of service from the 2011 ECOSS for this process.[408] Revenue for each rate class was adjusted to the extent reasonable to fall within +/- 10 percent of the system average return, with several exceptions. Customer class Schedules R, RL, and P were below the -10 percent band, and required a Step One adjustment. Schedules R, RL, and P were moved to relative rates of return of 0.90 from 0.69, 0.51, and 0.79, respectively.[409] In Step Two, all remaining revenue was allocated to existing rate classes in proportion to the adjusted test year base distribution revenues, except Schedule T and Schedule SPE. Schedule T has a significantly higher relative rate of return of 20.16 and did not receive a Step Two increase.[410] Schedule SPE did not receive any Step Two increase due RG Steel, LLC, the owner of the Sparrows Point facility, filing for bankruptcy protection on

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[407] Cloyd Direct at 11.
[408] *Id.*
[409] *Id.*
[410] *Id.*

Schedule TW-4

May 31, 2012, so that revenue was not recognized beginning in May 2012, and Schedule SPE's relative rate of return of 2.03 in the CY 2011 ECOSS.[411]

BGE's electric rate proposal allocated over half the proposed revenue increase to residential customers, Schedules R and RL. Mr. Cloyd testified that such allocation was appropriate because Schedules R and RL "were the only classes significantly under-earning compared to the system average rate of return."[412] In addition to the residential classes under-earning, Mr. Cloyd further testified that BGE's revenue increase allocation could be rationalized because "the total residential customer base comprises over half of both the total Distribution rate base and the total electric base Distribution revenues according to the ECOSS."[413] Mr. Cloyd contended that the proposed rate increase for residential customers is consistent with the cost of service study approach for ratemaking purposes and represents the most equitable methodology for all customer classes for the Company to allocate the proposed revenue increase.[414] With the Company's proposed revenue increase, residential customers would receive an increase of approximately 5.0 percent in their overall electric bills.[415] Mr. Cloyd further noted that the Company proposes that the entire electric rate increase be allocated to the volumetric Distribution charge, leaving customers charges unchanged which is consistent with BGE's last rate case.[416]

For residential customers, Schedules R and RL, the additional revenue requirement was assigned to the Delivery Service Charge such that the volumetric charge

[411] *Id.* at 11 – 12.
[412] Cloyd Direct at 12.
[413] *Id at 13.*
[414] *Id.*.
[415] Cloyd Supp. Direct at 5.
[416] Cloyd Direct at 15.

for both Schedules is equivalent.[417] The primary distinction between these two customer classes is the type of meter,[418] and the distinction is recognized in the higher Customer Charge for Schedule RL customers, so a levelized Delivery Service Charge is appropriate.[419] The additional revenue requirement was reflected as an increase in the secondary and primary Schedule G Delivery Service Charge,[420] and maintain the current differential between the secondary and primary rates (four percent difference).[421] The Schedule GU Delivery Service Charge is increased as was the Schedule GS Delivery Service Charge. The proposed rates for Schedule GL were designed to continue to recover the current percentage of revenues from the Delivery Service Charge and Demand Charge rate components.

Mr. Cloyd further described his proposal to increase the volumetric rates to recover the entire additional revenue requirement attributable to the Schedule P class, which is currently earning a return below the system average.[422] Mr. Cloyd did not increase Schedule T customers' class revenue requirement.[423] Nor did he propose an increase for Schedule SPE, but addressed the impact of Sparrows Point in his testimony addressing the Sparrows Point Rider proposal. For Schedule SL, Mr. Cloyd proposed to increase the Delivery Service Charge for a portion of the additional revenue, and recover the remaining additional revenue from a proportionate increase in facilities (for cable, lamp fixtures and poles) and maintenance charges.[424] The increase in revenue

[417] *Id. at 16.*
[418] *Id.*
[419] *Id.*
[420] *Id. at 16-17.*
[421] *Id.* at 17.
[422] *Id. at 18.*
[423] *Id.*
[424] *Id. at 19.*

requirement for Schedule PL was recovered from a proportionate increase in charges for the installation and maintenance of overhead-supplied lamp fixtures (after subtracting the embedded (bundled) charge for the supply of electricity), under-ground supplied lamp poles and cables, and miscellaneous equipment.[425]

In his supplemental direct testimony, Mr. Cloyd updated his revenue allocations to reflect the revenue requirements after the four months of actual data (from $150.8 million to $130.5 million) were submitted by the Company. In addition, Mr. Cloyd also testified that the $1.3 million one-time credit associated with the Derecho storm was adjusted out of the test-year target return to avoid the effect of developing rates that would double-count and include the credit on an ongoing basis.

In his rebuttal testimony, Mr. Cloyd addressed the positions and recommendations of MEG witness Baudino, Staff witness Currier, and OPC witness Pavlovic. In defense of the Company's cost allocation method, Mr. Cloyd noted that the Company's approach follows the principle of cost causation. Additionally, he stated that the Company's proposal follows the past Commission precedent of using a two-step process in which the first step assigns revenue to under-earning classes, and the second step assigns the remaining revenue to certain of the remaining classes.[426] He notes Staff witness Currier's proposal to allocate one-fourth of the revenue increase to the under-earning classes ends in a result similar to Mr. Cloyd's. He disagreed with OPC witness Pavlovic's proposal to eliminate the Step One allocation to under-earning classes because it fails to recognize the cost causation principle of rate making and results in an unfair distribution of

[425] *Id.* at 19-20.
[426] Cloyd Rebuttal at 1.

revenues to classes already over-earning.[427] Mr. Cloyd testified that the Company did not oppose MEG witness Baudino's proposal for a ten percent reduction in base revenue for Schedule T customers.[428] Although the Commission precedent is not to *reduce* any customer class's rates when *increasing* the overall revenue requirement, Mr. Cloyd indicated the reduction in the base revenues proposed for Schedule T is very small compared to total electric base revenues, so the amount of revenue each class would absorb to offset a Schedule T reduction would be a smaller portion of that amount. Further, Schedule T has a relative rate of return of 20.16, which is an order of magnitude higher than any other class.

Mr. Cloyd also indicated that BGE does not oppose Staff witness Currier's proposal to increase fixed charges to customers so less fixed charges are recovered through variable rates.

Mr. Cloyd addressed Staff witness Currier's opposition to BGE's proposal to levelize the Delivery Service Charge between Schedule R and RL. Staff witness Currier opposed the change because it would reduce the incentive for residential customers to take service under Schedule RL. Mr. Cloyd responded that offering low rates for off-peak usage and higher rates for on-peak usage is a way to incent customers to reduce their peak load. BGE currently has only one volumetric rate for Schedule RL – which is different from its volumetric rate for Schedule R – that applies at all times of the day. Mr. Cloyd also indicated that implementing a rate design to incent certain behaviors runs contrary to long-standing cost-causation principles. Finally, he reiterated that the primary distinction between the two classes is the type of meter, and that difference is largely

[427] Cloyd Rebuttal at 3

[428] Cloyd Rebuttal at 3.

recovered through the Customer Charge. The cost to serve R and RL customers before the meter are the same. Thus, he recommended that the same volumetric rate be assessed for both Schedule R and RL.

Mr. Cloyd did not object to an alternative rate design for Schedule P, as proposed by MEG witness Baudino, which would increase the Schedule P Demand Charge and Delivery Service Charge by applying the same percentage of revenue increase to each rate element.

OPC

OPC witness Pavlovic recommended that the Commission accept for the purposes of this proceeding BGE's proposed gas and electric class rate structures. In Direct testimony, Dr. Pavlovic noted that placing the revenue increase on the volumetric charge of distribution rates is not a particularly efficient means of encouraging conservation, but he accepted this as the Commission's policy.[429] Further, Dr. Pavlovic recommended that the Commission accept BGE's proposed distribution of the class revenue increase to the volumetric and demand charges.

MEG

For MEG, Mr. Baudino recommended that the Commission adopt BGE's general approach to revenue allocation. However, Mr. Baudino disagreed with the Company's proposal for Schedule T customers. He argued that the rate of return for Schedule T customers is so far above true cost of service that the Commission should consider a reasonable decrease to Schedule T that would not burden other customers. Mr. Baudino proposed that the Commission order a 10 percent decrease in base revenue for Schedule

[429] Pavlovic Direct at 30.

T. He also recommended that the Commission adopt a rate design for Schedule P that increases the demand charge and the volumetric charge by equal percentages. Lastly, Mr. Baudino recommended that the Commission reject BGE's proposed rate design for Schedule P.

Staff

Mr. Currier, testifying on behalf of Staff, argued in his direct testimony that Staff does not support the Company's proposed rate design primarily because the amount of the revenue increase induces a rate shock to both Schedule R and RL customers.[430] Mr. Currier elaborated that the distribution portion of the monthly bill would increase by 22 percent for a 1,000 kWh a month Schedule R user and by 24 percent for a 1,500 kWh a month Schedule RL user.[431] Furthermore, Currier noted that BGE did not show whether and to what extent cross subsidization is still occurring.[432]

Mr. Currier recommended "distributing the proposed revenue increase across customer classes in two steps, consistent with the methodology used by the Commission in BGE's,[433] Pepco's[434] and Delmarva's[435] previous rate cases." Rather than utilizing the Company's 50 percent allocation in Step One, Mr. Currier recommended distributing 25 percent in the first step to under-earning classes, based on the proportion of their sales revenue, and then to the remaining revenue among the rest of the classes, with the exception of Schedules T and SPE.[436] Mr. Currier contends that Staff's recommendation

[430] Currier Direct at 16.
[431] *Id.*
[432] *Id.*
[433] Case No. 9230, Order 83907, at pages 102-103.
[434] Case No. 9286, Order 85028, at pages 124-125.
[435] Case No. 9285, Order 85029, at pages 88-89.
[436] Currier Direct at 17.

"brings all classes closer to unity and does not impose rate shock on any class."[437] Company witness Cloyd did not explicitly adopt Staff's recommendation; nonetheless, he testified that it produces results very similar to the company's methodology.[438]

<u>Commission Decision</u>

Based on the record and consistent with our decision in the last BGE rate case, we find that apportioning the electric revenue increase to the classes in accordance with a two-step allocation method is the best balance among all applicable rate-making principles. We agree with Staff that the Company's proposal to utilize a 50 percent allocation in Step One could induce rate shock for the under-earning classes, but even Staff's recommended allocation of 25 percent is more than we find appropriate at this time. We therefore adopt a more gradual Step One increase by allocating 15 percent of the increase to the under-earning classes, Schedules R, RL, and P. In Step Two, we allocate the remainder of the electric increase amongst all customer classes, with the exception of Schedule T and SPE.

This two step allocation method is consistent with the Commission's precedent to bring under-earning classes closer to the system average, while also allocating a portion of the increase to all other classes except for the highest over-earning classes. With regard to the recommendation by MEG to decrease the Schedule T rate of return by 10 percent, we are not convinced on this record to depart from our general principle to not reduce any customer class when the overall revenue requirement is increasing. On its face, it just does not seem fair.

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[437] *Id.* at 18.
[438] Cloyd Rebuttal at 2.

Even though this issue was virtually uncontested by the parties, we find we must reject Staff's proposal to increase the fixed customer charge from $7.50 to $8.36. Based on the reasoning that ratepayers should be offered the opportunity to control their monthly bills to some degree by controlling their energy usage, we instead adopt the Company's proposal to achieve the entire revenue requirement increase through volumetric and demand charges. This approach also is consistent with and supports our EmPOWER Maryland goals.

The effect of the rate design we adopt results in a typical BGE residential electricity customer experiencing an approximately $3.33 per month increase, which is 53 percent of the Company's request. For this typical residential electricity customer using 1000 kWh, this will represent a 2.6 percent increase in the overall monthly bill.

2. Gas Rate Design

<u>Positions of the Parties</u>

BGE

Based upon the Company's recommended GCOSS, Company witness Cloyd proposed a rate design for each customer class that would produce the requested increase in gas revenues proposed by the Company. Mr. Cloyd proposed to apportion the gas revenue increase among the customer classes using a two-step approach.[439] Step One is designed to bring under-earning classes closer to the system average and Step Two is designed to allocate the remainder to customer classes in proportion to adjusted test year revenues.

[439] Cloyd Direct at 3.

Mr. Cloyd proposed in Step One to move Schedule ISS and Schedule closer to the system average rate of return set in the CY 2011 GCOSS.[440] "This first step resulted in Schedule ISS increasing from a relative rate of return of 0.58 to 0.75, and Schedule IS also increasing from 0.57 to 0.75."[441] Mr. Cloyd testified that these schedules were increased consistent with the principle of gradualism.[442] Mr. Cloyd did not propose a Step One increase to the other customer classes because they "were either within a +/- 10% band from the system average, or over-earning (as shown in the GCOSS)."[443]

In Step Two, Mr. Cloyd proposed that the remaining revenue increase be allocated to the customer classes in proportion to the adjusted test year base Distribution revenues with two exceptions – Schedule PLG and Schedule SP. First, Mr. Cloyd did not allocate a Step Two increase to Schedule PLG because its relative rate of return from CY 2011 GCOSS was 10.82, which was significantly above all other Schedules. Second, Schedule SP did not receive a Step Two increase due to RG Steel LLC, the owner of Sparrows Point facility, filing for bankruptcy protection on May 31, 2012. As a result of the bankruptcy filing, Mr. Cloyd noted that revenue was not recognized beginning in May 2012 (and is excluded from the test year), and Schedule SP has a relative rate of return of 2.01 in the CY 2011 GCOSS.[444] These two facts led Mr. Cloyd to determine that Schedule SP should not receive a Step Two revenue allocation.

Mr. Cloyd proposed that for Schedule D - Residential/Grantors, the entire $37.0 million of additional revenue requirement be assigned to the volumetric charge with an increase in the effective rate from $0.3542 per therm to $0.3855 per therm. Schedule

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[440] Cloyd Direct at 3.
[441] Cloyd Direct at 3.
[442] Cloyd Direct at 3.
[443] Cloyd Direct at 3.
[444] Cloyd Direct at 4.

D/Grantors are a small number of Residential Service customers who have an interstate pipeline located on their property.[445] For Schedule C- General Services, Mr. Cloyd recommended an increase to the volumetric rates in order to recover the entire $12.8 million of additional revenue requirement.[446] He recommended: (1) increasing the first block distribution charge for the first 10,000 therms per month from an effective rate of $0.2674 per therm to $0.2866 per therm; and (2) decreasing the second block distribution charge, for all therms over 10,000 per month, from an effective rate of $0.1489 to $0.1432 per therm.[447] For Schedules ISS and IS, the Company's proposed rates were designed to recover approximately 50 percent of the revenues from the Customer Charge and Demand Price rate components.[448] Consistent with the Company's last rate case filing, Mr. Cloyd did not propose any changes to the existing Customer Charges. Hence, the Demand and Delivery Service prices will be adjusted such that the Customer Charge and Demand Revenue remain approximately 50 percent of the total revenue requirement for Schedules ISS and IS.[449] For Schedule PLG – Private Area Lighting, Mr. Cloyd proposed that the rates remain unchanged because currently this class is significantly over-earning.

OPC

OPC witness Pavlovic testified that "the proper rate design is a matter of policy and seeks fair balance of interests and incentives of the utility and its ratepayers."[450] Dr. Pavlovic further stated that the principal question is whether rates for the individual class

[445] Cloyd Direct at 8.
[446] Cloyd Direct at 8.
[447] Cloyd Direct at 8.
[448] Cloyd Direct at 7.
[449] Cloyd Direct at 9.
[450] Pavlovic Direct at 29.

ratepayer accurately reflect the value of the service consumed by the ratepayer as determined by the Commission's rate design policies. Dr. Pavlovic argued that rate structure must reflect cost causation, and he asserted that the Company "has not undertaken the studies and analyses necessary to design such rates."[451] Dr. Pavlovic recommended that the Commission accept BGE's current class rate structure but direct the Company to perform analyses of short term and long term impacts on customer rates.[452] While Dr. Pavlovic found that volumetric charge distribution rates is not efficient, OPC recommended that the Commission accept BGE's proposed distribution of the class revenue increase to the volumetric and demand charges.

MEG

Mr. Baudino, testifying for MEG, opposed the Company's revenue allocation. Mr. Baudino argued that given the Company's proposed 17.1 percent base revenue increase, the 26 – 27 percent increase to Schedules IS and ISS are excessive.[453] He further explained that such increases represented 1.55 times the overall system average increase.[454] Mr. Baudino recommended that given the current economic climate, the Commission limit any class rate schedule increases to 1.25 times the overall retail percentage increase in gas base revenues. He indicated that such a cap serves to mitigate the base revenue impact on IS and ISS with minimal impact on Schedule D and C. However, MEG agreed with the Company's proposal to collect 50 percent of the increase from the Demand Price and 50 percent from the Delivery Charge.[455]

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[451] Pavlovic Direct at 30.
[452] Pavlovic Direct at 30.
[453] Baudino Direct at 7.
[454] Baudino Direct at 7.
[455] Baudino Direct at 11.

Staff

Staff witness Elert testified that Staff supports the Company's rate design methodology and found that it was consistent with the Commission's previous decisions.[456] In his direct testimony, Mr. Elert made clear that the Staff "only supports the Company's initial re-allocation of $1,115,830 to Schedules IS and ISS if the Commission grants the Company's overall revenue increase." Otherwise, Staff advised that should the Commission grant an increase less than requested by BGE, the Company should still allocate the proportionate amounts of the increase to each customer class. Mr. Elert noted that Staff's recommended Step One increase to Schedules IS and ISS is $943,880 (combined).[457] Staff supported the Company's proposed methodology for Step Two of the proposed allocations but modified the step by allocating a smaller increase to residential customers and a slightly larger increase to non-residential classes. Staff noted that at the average usage level the Company's proposed rates would increase residential customers' bills by $4.62.[458]

Commission Decision

In considering rate design, we counter-balance the principles of cost causation, gradualism and overall fairness to each class. Consistent with our decision in BGE's last rate case in Order No. 83907, the Commission adopts a two-step process to allocate increased gas revenues. The first step moves under-earning classes closer to the system average. However, adhering to the principles of gradualism, the Commission modifies the Company's Step One recommendation to move both Schedules IS and ISS from 0.57 and

[456] Elert Direct at 16.
[457] Elert Direct at 16.
[458] Elert Direct at 20.

0.58, respectively, to 0.75. Instead, we believe a more gradual movement toward unity for these two classes is best, and therefore in Step One authorize a relative rate of return for Schedules IS and ISS of 0.68. By taking a more gradual approach with Schedules IS and ISS, we better align the relative rate of return in Step One for Schedules D and C with the system average return, and authorize a 1.025 relative rate of return for Schedule D and a 0.96 relative rate of return for Schedule C.

The second step allocates the remainder of the gas revenue increase to customer classes in proportion to the adjusted test year revenues. The Commission adopts the Step Two allocation recommended by the Company, including the exemption of over-earning classes Schedules PLG and SP, which was uncontested by the other parties.

This rate design results in an average monthly residential customer gas bill increase of approximately $2.70, which is 63 percent of the Company's request. For the average household natural gas customer using 52 therms per month, this will represent a 4.26 percent increase in the overall monthly bill. For IS and ISS classes, this will also result in a lower increase than requested by the Company with the average per-customer impact on the distribution side of 14.25 percent for the IS class and 13.85 percent for the ISS class.

E. Sparrows Point Rider Proposal

<u>Position of the Parties</u>

Mr. Cloyd testified that, on May 31, 2012, RG Steel, LLC, the current owner of the Sparrows Point facility, filed for bankruptcy protection after previously announcing the shut-down of operations at the Sparrows Point facility. Revenues for Schedule SP and Schedule SPE were not recognized beginning in May 2012 and are excluded from the test year.[459] In his rebuttal testimony, Mr. Cloyd provided an update on the potential for future operations at the Sparrows Point facility. He testified that the only certainty gained since the Company's initial filing is that RG Steel will not be a going concern at this facility. The entity that owns the buildings and inventory on the property announced a three-month period, which ended on December 21, 2012, during which it would accept bids to sell the steel making capabilities and assets on the grounds, either in whole or in part.[460]

According to Mr. Cloyd, the purpose of the Sparrows Point Rider proposal (one for gas and one for electric), is to allow BGE's customers to have an opportunity to benefit from any positive outcomes such as a successful sale, a resumption of operations, and a ramp-up in production over test year levels at Sparrows Point.[461] In addition, the Company should have an opportunity to collect revenues irrespective of the outcome based on the premise that both the electric and gas distribution system are integrated systems benefitting all customer classes.[462] Mr. Cloyd described the manner in which the refund/surcharge would be calculated and billed to the customer classes.

The Riders are designed to true-up the difference between the test year revenues under Schedules SP and SPE and the actual revenues recognized by BGE.[463] To the extent that actual revenues under Schedules SP and SPE exceeded the test-year revenues, customers would receive the benefit through a rate credit. If there is no resumption of operations, BGE would be allowed to recover the shortfall through a rate surcharge. The

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[459] *Id.* at 4.
[460] Cloyd Rebuttal at
[461] Cloyd Direct at 20.
[462] *Id.*
[463] *Id.*

Riders are a temporary solution until the next distribution base rate proceeding when new cost of service studies would more completely address the issue.[464]

The base distribution revenues are currently estimated to be $1.3 million for electric and $4.1 million for gas.[465] A volumetric adjustment for both electric and gas would be calculated to either refund base revenues should actual Sparrows Point revenues exceed test year levels, or recover base revenues should actual Sparrows Point revenues lag test year levels. The adjustment would be filed every four months by comparing the revenues collected under Schedules SP and SPE, with the pro-rata portion of levelized test year revenues for Schedules SP and SPE for the same period. The resulting difference will be allocated to each customer class based on the total estimated delivery sales during the subsequent four month period for each customer class, as a percentage of the total delivery sales for all customer classes over the same period. The allocated revenue difference by customer class will then be divided by the estimated delivery sales over the four month rate effective period, resulting in an effective rate for that four month period.[466]

The rates for each Rider will be set to zero upon an Order in this rate case proceeding. The initial rates will be filed within 135 days of an Order covering the period from the date of the Order through the first three full calendar months. Subsequent rate adjustments will also account for any imbalances by customer class for the pervious four month period.[467]

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[464] *Id.*
[465] *Id.* at 21.
[466] *Id.*
[467] *Id.* at 22.

In his rebuttal testimony, Mr. Cloyd stated that the Riders do follow cost causation principles, contrary to OPC witness Pavlovic's contention, because even though Sparrows Point is no long operational, the costs associated with BGE's distribution systems are not reduced.[468] The proposed Riders address the cost recovery of the rate base and operating expenses assigned to the Sparrows Point rate schedule under the cost of service study. The Riders are not a permanent solution and were proposed to address the uncertainty caused by the Sparrows Point situation. Mr. Cloyd also disagreed with Dr. Pavlovic's assertion that the proposed Rider removes any potential incentive for resumption and increase of production at Sparrows Point as the Riders have no impact upon the rates paid by a new customer taking service at the Sparrows Point facility.[469]

OPC witness Pavlovic recommended the Commission reject the Riders because they are "premature and inconsistent with sound rate design principles."[470] He submitted that it would more consistent with cost causation principles and more appropriate to reduce the test year revenue requirement for Sparrows Point and bring the SP and SPE rate classes into the gas and electric decoupling mechanisms.[471] He also testified that the manner in which BGE proposed to collect the revenue shortfall removed a potential incentive for resumption and increase of production at Sparrows Point.[472]

MEG witness Baudino proposed that, if the Commission approves the Riders, the lost revenues from Sparrows Point should be allocated to BGE's gas and electric customers based on each class's share of base revenues.[473] He indicated that "in a similar

[468] Cloyd Rebuttal at 8.
[469] *Id.* at 9.
[470] Pavlovic Direct at 31.
[471] *Id.*
[472] *Id.*
[473] Baudino Direct at 4.

fashion to the Company's gas tariff proposal, the allocation for recovery from electric ratepayers should be based on each class's share of base electric revenues rather than the Company's proposed sales volumes (kWh).[474] The Company did not oppose the rate design proposed by Mr. Baudino.[475] In his rebuttal testimony, Mr. Elert disagreed with Mr. Baudino's recommendation to collect the Sparrows Point revenue shortfall by an allocation of base revenues rather than sales volume.[476] Mr. Elert found the Company's proposal fairer because it would "more clearly allocate" the revenue impact on larger commercial and industrial customers that have demand characteristics most similar to the facilities served at Sparrows Point.[477]

Staff witness Elert disagreed with Dr. Pavlovic's testimony because Mr. Elert found no reason to re-determine a cost-of-service basis because it already had been determined under schedule SP.[478] He also found Dr. Pavlovic's recommendation to collect the revenues under the existing decoupling mechanisms to be misplaced as the mechanism is only for certain rate classes, and would not collect from the larger commercial and industrial rate classes.[479]

Staff witness Currier testified that, in response to a Staff data request, Dr. Pavlovic explained more fully that the only way to distribute the revenue shortfall is to remove the Sparrows Point class from the electric cost study and re-distribute the costs to the remaining classes based on the study's cost specific allocators.[480] Mr. Currier did not disagree with Dr. Pavlovic's proposal if the Sparrows Point class were to be eliminated.

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[474] *Id.* at 20.
[475] Cloyd Rebuttal at 10.
[476] Elert Rebuttal at 8.
[477] *Id.* at 9.
[478] Elert Rebuttal at 6.
[479] *Id.* at 6 – 7.
[480] Currier Rebuttal at 12.

Because the proposed Rider is temporary, however, Mr. Currier found the proposed Rider a sound approach to collect the revenue shortfall and then have a new cost of service study more completely address the issue in the next distribution base rate case.[481] Mr. Currier indicated that, because the revenue is to be recovered based upon sales volumes and the proposal is to distribute the revenue shortfall to other classes on a volumetric basis, it does not violate cost causation principles.[482]

In his surrebuttal testimony, Dr. Pavlovic explained that he disagreed with Mr. Cloyd's testimony because Mr. Cloyd cannot remove the fact that the proposed rider will recover Sparrows Point costs from rate classes that are not the cause for those costs.[483] He claimed that Mr. Elert, in his rebuttal testimony, did not understand Dr. Pavlovic's Sparrows Point recommendations because it misstated Dr. Pavlovic's testimony.[484] Dr. Pavlovic claimed that he did not indicate that the Sparrows Point cost of service needed to be re-determined or that the shortfall should be recovered from schedules that currently have decoupling mechanisms.[485] As to Mr. Currier's rebuttal testimony, again Dr. Pavlovic indicated that distribution of the Sparrows Point shortfall to other customers on any basis is inconsistent with the principles of cost causation.

Staff witness Elert described the unique circumstances surrounding Sparrows Point's bankruptcy and potential termination as a customer. He indicated that, typically, if a commercial/industrial customer goes bankrupt and leaves the service territory of a gas or electric utility, the existing facilities of the utility that serve the customer can be re-directed to serve another similarly-sized customer. Further, he stated that when larger

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[481] *Id.* at 13.
[482] *Id.*
[483] Pavlovic Surrebuttal at 14.
[484] *Id.*
[485] *Id.*

commercial or industrial customers exit a service territory, the other customer in that rate class would pick up the "slack," and this would be addressed in a subsequent rate base.[486] Because Sparrows Point is in a customer class of its own, Mr. Elert submitted there is no similarly-sized customer to pick up the costs of the facilities that served Sparrows Point. Consequently, Mr. Elert found the proposed riders to be a reasonable short-term solution to an uncertain event. Finally, Mr. Elert testified that, if no new large customer replaced Sparrows Point, an electric residential customer that uses 1000 kWh per month would be charged approximately $0.04 per month, or $0.48 per year; a residential gas customer that uses 52 therms per month, the charge will on average be approximately $0.22 per month, or about $2.70 per year in additional charges.[487]

Mr. Currier, in his direct testimony, described BGE's Sparrows Point Rider in the proposed electric tariff. Similar to Mr. Elert, Mr. Currier found the proposal to be a reasonable temporary recovery mechanism in light of the unique circumstances of the Sparrow Point rate class.[488] Mr. Currier suggested that the rider only collect the difference between the billed revenue and the test year revenue, rather than the "collected" revenue and the test year revenue.[489] Mr. Cloyd indicated that the Company did not oppose Staff witness Currier's recommendation to change the electric rider wording from "collected" to "billed."[490]

Commission decision

The Sparrows Point Riders address a unique circumstance in which the single customer within a rate class filed for bankruptcy during the test-year period and may

[486] Elert Direct at 24.
[487] *Id.* at 26.
[488] Currier Direct at 28-29.
[489] *Id.* at 30.
[490] Cloyd Rebuttal at 10.

potentially terminate all operations within the rate-effective period of this proceeding. We will accept the Sparrows Point Riders because each provides a short-term solution to the issue of the recovery of costs that have previously been allocated to Schedules SPE and SP. We adopt BGE's proposed allocation methodology rather than MEG's. After review, we find that BGE's methodology fairly allocates the recovery of the Sparrows Point lost revenue among all the classes unlike MEG's, which results in the residential customers being allocated significantly more of the allocation than other classes. We expect the riders to be in effect only until the next distribution base rate proceeding, when a new COSS will more completely address this issue.

We also accept Staff's recommendation to change the electric rider wording from "collected" to "billed," and direct the Company to make this modification to its electric Sparrows Point Rider.

F. Miscellaneous

1. Rider 25 Monthly Rate Adjustment

Staff witness Currier raised in his direct testimony a concern about BGE's use of the weighted test year average use per customer for Schedules R and RL in calculating BGE's Rider 25 rate to be recovered from ratepayers. According to Mr. Currier, for Schedules R and RL, the weighted test year average use per customer is developed by dividing each class into heating and non-heating sub-classes and adjusting the changes in the proportion of each subclass.[491] Mr. Currier, however, asserts that the language in Rider 25 reads, "the change in revenues associated with kilowatt (kWh) sales is the test year average per customer" and does not include language referring to "weighted test

[491] Currier Direct at 33.

year average use."[492] Further, Mr. Currier states that the calculation of weighted average energy use per customer is not consistent with the three other Maryland utilities with an electric decoupling mechanism.[493]

Mr. Currier proposes that the Company use the average test year usage per customer, which means the arithmetic mean for the test year.[494] He indicated that the numbers used to determine the base year revenue should be calculated by dividing the test year electric sales for each class by the respective class' number of customers for each month and adjusting for weather.[495] Based on data provided by BGE to a Staff data request, Mr. Currier used the Company's weather-adjusted test year energy sales and customers to develop the average test year energy usage per customer.[496]

In Mr. Cloyd's rebuttal testimony, he explains how the Company's use of the average usage for heating and non-heating subclasses in developing the total target revenue results in a more accurate calculation as the load profiles of these two customer types differ significantly.[497] The aggregation of heating and non-heating subclass calculations results in the presentation of a weighted average use per customer as shown in the monthly filings.[498] Mr. Cloyd stated that BGE was the first utility to implement the electric decoupling mechanism in Maryland, it has not changed its design since its implementation, and it mirrors the methodology in place for the Company's approved gas decoupling mechanism (Rider 8) used since 1998.[499]

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[492] *Id.*
[493] *Id.*
[494] *Id.*
[495] *Id.*
[496] *Id.* at Exhibit JRC-9.
[497] Cloyd Rebuttal at 6.
[498] *Id.*
[499] *Id.*

Mr. Cloyd also noted that in the prior rate case, Case No. 9230, the Company recommended a revision to its methodology to calculate the cap of the monthly rate adjustment to make it consistent with Pepco and Delmarva.[500] In the Case No. 9230 Order, the Commission found that the proposed tariff revision was better considered outside the context of a lengthy and complex gas and electric base rate proceeding. Mr. Cloyd, therefore, suggested that if Staff's intent is to review all utility decoupling mechanisms for uniformity, such review should be in a separate forum.[501] In its brief, the Company continued to object to Staff's proposed changes to Rider 25, but offered to file revised tariff pages further clarifying the use of sub-classes in rider 25 (and Rider 8) calculations.[502]

In his rebuttal testimony, Staff witness Currier disagreed with Mr. Cloyd's testimony that the Company's calculation methodology is appropriate. Mr. Currier reviewed the Commission's letter order, dated December 19, 2007, which approved Supplement 404 to P.S.C. Md. E-6 – Rider 25 – Monthly Rate Adjustment, and did not find any reference to the term "weighted average," within the text of the letter order. Although Mr. Currier did not suggest that the Company is violating its tariff by utilizing the current calculation, he believed that his proposed calculation is more accurate. Further, Mr. Currier asserted that BGE's tariff should specifically state how the calculation is actually done.

Mr. Currier prepared a chart to demonstrate the difference in the results of the calculations using the Company's methods and Staff's method; the weighted average use

[500] *Id.* at 7.
[501] *Id.*
[502] Reply Brief of BGE field January 23, 2013, at 56.

per customer is 1,370 kWh and the average use is 1,143 kWh.[503] Mr. Currier explained the discrepancy between the two occurred because the utility gained more heating customers, who typically use more electricity, than non-heating customers.[504] Mr. Currier disagreed with Mr. Cloyd that the matter should be resolved outside the rate case because Rider 25 rates are calculated using data from this case.[505] Mr. Currier clarified that Staff is more concerned with BGE's lack of transparency in explaining its weighted average methodology than with its calculation method being inconsistent with other Maryland electric companies with decoupling mechanisms.[506]

During the evidentiary hearing, Mr. Cloyd explained that if the Company were to add one more customer, it could not add that customer at the weighted average usage per customer.[507] Instead it would add the customer in the appropriate heating or non-heating subclass so that the target base revenue is set at the correct amount. He indicated that if the Company used an average and added a non-heating customer, the Company would be setting the target revenue higher than that non-heating customer has shown through its non-heating customer profile.[508] Mr. Cloyd did not recall whether the subclasses of heating or non-heating are identified in the Company's tariff, but stated the subclasses are recognized in the Company's billing system and that the Company has been collecting data on these two subclasses for approximately 50 years.[509]

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[503] Currier Surrebuttal at 4 – 5.
[504] *Id.* at 4.
[505] *Id.* at 5
[506] *Id.* at 6
[507] TR. at 230.
[508] *Id.*
[509] *Id.*

Commission decision

Staff clarified that its purpose in raising this issue was to ensure transparency of the manner in which BGE is calculating its monthly decoupling rates. BGE has offered to revise the applicable decoupling mechanism rider in each of its gas and electric tariffs to reflect the sub-classes of heating and non-heating residential customers. Based on the record, it is unclear whether such proposed tariff revisions will satisfy Staff's concerns or not, and it would not address the inconsistencies between BGE's methodology and the other three "decoupled" Maryland electric companies' calculations. Accordingly, we decline to address this tariff issue in this Order. Instead, we believe that this matter should be considered as we do other tariff revisions, at an Administrative Meeting based upon the submission of a proposed tariff revision. We therefore direct BGE to file its proposed tariff revisions separately from its revised tariffs filed for purposes of increasing the rates as authorized in this Order, which would reflect the existence of the two sub-classes of residential customers. Further, we direct the Company to file verbiage that specifies its methodology to determine the test year average per customer. Along with the tariff revisions related to Rider 25, BGE is directed to file the following supporting data covering the period since Rider 25 has been in effect through the most recent available data:

1) The calculation and source data used to calculate the weighted average use per customer for the volumetric charge impact of the Rider 25 calculation; and

2) The difference in Rider 25 revenue by month based on using the Company's weighted average method compared with the arithmetic mean proposed by Staff.

Staff, OPC or other interested persons may submit comments on these revisions once filed, and we will consider the matter at a future Commission Administrative Meeting.

3. Staff's Engineering Proposals

Positions of the Parties

Staff witness Clementson testified regarding BGE's plans to replace portions of its aging gas infrastructure over the next 20 years.[510] He stated that the main threats to BGE's gas distribution system are breaks in cast iron pipe, corrosion leaks on bare steel pipe and third-party excavator damage.[511] He noted that BGE is proposing an accelerated 20 year systematic replacement program (Operation Pipeline Program) for the cast iron and bare steel pipe in its distribution system, which is designed to maximize capital investment benefits. The program will eliminate all bare steel main, all bare steel services, and replace or upgrade 50 percent of the cast iron gas mains.[512] According to Mr. Clementson, BGE estimates replacing about 107 miles of the 1,333 miles of cast iron pipe on its system over the next five years, and approximately 25 of the 67 miles of bare steel pipe. Mr. Clementson noted that BGE will meet its 20 year goals for bare steel replacement but not for cast iron replacement unless it increases the rate of replacement in years 6 through 20.[513] Mr. Clementson also noted that BGE's program includes replacement of leaking residential "ski-bar" risers because they could "create a dangerous situation.[514]

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[510] Clementson Direct at 20.
[511] Clementson Direct at 6.
[512] Clementson Direct at 7.
[513] Clementson Direct at 3 and 8.
[514] Clementson Direct at 9. BGE has approximately 14,000 remaining ski-bar risers.

Mr. Clementson concluded that BGE's current replacement program is "insufficient" because "it only addresses the replacement of half of its existing cast iron pipe and only a portion of the remaining 'ski-bar' risers."[515] He concluded that the Commission should require BGE to file a formal written gas infrastructure replacement plan, including the year that BGE will fully eliminate the remaining cast iron and bare steel pipe and "ski-bar" risers. This plan should detail, in five-year intervals, BGE's proposed replacement plan. Mr. Clementson recommended that all cast iron pipe be replaced over 40 years (33.3 miles/yr.), all bare steel pipe over a 15 year period (4.5 miles/yr.), and all ski-bar risers over 7 years (2,000 services/yr.).[516]

Mr. Woerner responded that from 2007-2011 BGE eliminated 53 miles of cast iron and bare steel main but plans to eliminate 133 miles from 2012-2016, an increase of approximately 2.5 times. However, he noted that BGE's Operation Pipeline Program is not intended to cover the entire lifecycle of gas asset replacements. Mr. Woerner asserted that "under BGE's current regulatory construct it is not feasible to expand further the rate of main replacement on the gas distribution system … To increase main replacements further, a more constructive means of cost recovery is necessary to ensure BGE's financial health."[517] Mr. Woerner noted that BGE plans to eliminate "ski-bar" risers by approximately 2019. Mr. Woerner concluded that all internal BGE stakeholders are "aligned" on the need to replace cast iron and bare steel pipe to ensure safety and reliability.[518]

[515] Clementson Direct at 9.
[516] Clementson Direct at 9-10.
[517] Woerner Rebuttal at 11.
[518] Woerner Rebuttal at 10-12.

Staff witness Wilson addressed BGE's plans to comply with the requirements of RM43 and offered recommendations on how BGE can best improve electric service quality and reliability.[519] He noted that the intent of RM43 is to improve service quality and reliability by establishing certain minimum standards for vegetation management, including minimum trim cycles and minimum horizontal and vertical clearances when trimming vegetation from conductors.[520] He stated that there is a correlation between the trim cycles, the amount of work involved and the spending trends expected of the utilities as a result of complying with RM43 over the next 4-5 years.[521] According to BGE's 2012 vegetation management plan the Company is implementing a 4-year trim cycle with activities planned evenly (25 percent per year), which Mr. Wilson noted is "more aggressive" than the required 5-year trim cycle.[522] Mr. Wilson stated that BGE's system-wide System Average Interruption Frequency Index ("SAIFI"), and Customer Average Interruption Duration Index ("CAIDI") are indices for all interruption data, minus major outage events, and have complied with Code of Maryland Regulations ("COMAR") Commission-required reliability standards over the past several years. Mr. Wilson also stated that from 2002-2006 BGE spent, on average, $12.2 million per year on vegetation management but that average has increased to $20.5 million per year since 2007.[523]

Mr. Wilson also discussed the importance of an effective pole maintenance and inspection program, which RM43 addresses. He noted Mr. Woerner's testimony that over 50 percent of BGE's poles have been in service for more than 40 years and need replacement. Mr. Wilson stated that BGE did not address how many of the 200,000 poles

[519] Wilson Direct at 3.
[520] Wilson Direct at 4.
[521] Wilson Direct at 5.
[522] Wilson Direct at 6.
[523] Wilson Direct at 7.

need to be replaced or why. Mr. Wilson asserted that age alone is not a reason to replace a pole. He noted that BGE has an existing O&M program that includes pole inspections and maintenance, whereby if poles fail the inspections they are reported for reinforcement or replacement. Mr. Wilson stated that further information is required to assess the effectiveness of BGE's pole program.[524]

Mr. Wilson concluded that the Commission should require BGE to file a formal work plan that details how BGE will implement the replacement or upgrading of its electric infrastructure, including poles in service over 40 or more years. He stated that the plan should include details for pole inspection records, pole reinforcements and the reasons for repairs, relocations and replacements because this will allow BGE to better assess its pole program. Mr. Wilson also concluded that BGE is in compliance with RM43 and is planning to exceed yearly trimming requirements. He stated that the full effect of RM43 will not be able to be assessed until after completion of the trim cycles. Finally, he asserted that increased spending should be expected and regulated on a case by case basis in order to maintain service quality and reliability.[525]

Mr. Woerner responded that BGE has had a program to inspect and treat wood poles for three decades. He stated that BGE does not, and is not proposing to, replace wood poles simply because they reach a certain age. BGE evaluates the strength and integrity of each pole on a ten-year cycle and initiates work to reinforce or replace poles that fail inspection. Consequently, Mr. Woerner asserted that there is no need for BGE to file a formal work plan as recommended by Staff witness Wilson.[526]

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[524] Wilson Direct at 9-10.
[525] Wilson Direct at 10-11.
[526] Woerner Rebuttal at 12-15.

Commission Decision

We have reviewed the record and will not, at this time, direct BGE to make alterations to its gas and electric safety and reliability programs. However, we remind BGE here that it is responsible for maintaining safe and reliable gas and electric systems, including compliance with the RM43 and RM44 regulations, and its programs must be designed to meet such goals. As to Staff's reporting recommendations, we find merit and usefulness in Staff having the ability to review the work plans. As such, we direct the parties to meet to resolve how best to accomplish Staff's recommendations. The parties are to be guided by the principles that Staff has a duty to monitor safety and reliability, but that the Company should not be burdened with unnecessary requests. If the parties are unable to resolve the reporting requirements, this matter will be scheduled for resolution at a Commission Administrative Meeting.

4. Maryland Fuel Fund

In BGE's last base rate case, Case No. 9230, BGE sought designation of $2.6 million in Fuel Fund matching credits. The Company matches by $1.00 every $2.00 that the Fuel Fund and limited income customer combined pay. The Commission first authorized recovery of this expense in 1999.[527] In Case No. 9230, the Commission authorized a $2.6 million BGE's Fuel Fund matching program test-year level expense in determining BGE's revenue requirement, but directed the Company to present a cost – effectiveness analysis of the program for the Commission's consideration in the next rate

[527] Case No. 8829.

case.[528] The Commission asked the Company to focus its analysis on the benefits of uncollectible reductions as compared to the expense incurred.

As directed, BGE prepared a cost-effectiveness analysis of the Fuel Fund credit program, presented by BGE witness Vahos.[529] According to Mr. Vahos, the analysis demonstrated that for every $1.00 of customer investment in the Fuel Fund program, customers realize over $1.60 in benefits.[530] Mr. Vahos stated that the benefit is based on a reduction on all customer bills due to the lower bad debt expense realized as a result of the Fuel Fund program. Consequently, BGE included the test period level of Fuel Fund matching credits, $2.3 million, in its revenue requirements.[531]

OPC asked Mr. Vahos to explain what happens to the $2.6 million annual Fuel Fund allocation if the full amount is not distributed in a year. According to Mr. Vahos, similar to other costs recovered through rates, typically there is a change from the test year level of expense to the actual level of expenses incurred in a year, and that "any delta, be that higher or lower, will flow through results."[532] OPC also asked a similar question of Mr. DeFontes. Mr. DeFontes' response echoed Mr. Vahos' explanation. Mr. DeFontes indicated that like other parts of the Company's rates, the costs which the rates were designed to recover may go up or down.[533] According to Mr. DeFontes, in past years, the Company has paid out significantly more in credits that it has collected, but BGE trued that up in the last case when it requested 2.6 million.[534]

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[528] Order 83714 at 113.
[529] Vahos Direct, Company Exhibit DMV-7; Vahos Direct at 14 – 18..
[530] *Id.* at 14.
[531] TR.at 278.
[532] *Id.* at 280.
[533] *Id.* at 25.
[534] *Id.*

No party opposed the inclusion of the $2.3 million test level Fuel Fund expense in BGE's revenue requirements.

Commission Decision

We find that the Company's analysis demonstrates that the Fuel Fund matching credit program is cost effective, in that it lowers the level of the Company's bad debt expense and therefore reduces bills for all customers. We also conclude that, in addition to providing a benefit to all customers, the continued existence of the Fuel Fund program provides a direct benefit to low-income customers by keeping utility services in their homes. Accordingly, based on the record in the proceeding, the Commission authorizes the test year level of $2.3 million in Fuel Fund matching credits. As testified by Mr. Vahos and Mr. DeFontes, the Commission expects that the Company will continue to voluntarily provide additional credits in excess of the test year level authorized, if necessary, at no cost to ratepayers.

IT IS, THEREFORE, this 22nd day of February, in the year Two Thousand Thirteen, by the Public Service Commission of Maryland;

ORDERED: (1) That the Application of Baltimore Gas and Electric Company, filed July 27, 2012 (as supplemented on October 22, 2012), seeking to increase distribution rates for electric service by $130 million and gas service by $45 million, is hereby granted in part and denied in part as set forth in this Order;

(2) That Baltimore Gas and Electric Company is hereby authorized, pursuant to § 4-204 of the Public Utilities Article, *Annotated Code of Maryland*, to file tariffs that shall increase electric distribution rates by no more than $80,554,000 and that shall increase gas distribution rates by no more than $32,416,000,

for service rendered on or after February 23, 2013, and that otherwise shall be consistent with the findings in this Order;

(3) That Baltimore Gas and Electric Company and the Commission's Staff are directed to meet and develop reporting requirements for gas and electric infrastructure replacement plans as discussed in this Order for the Commission's consideration no later than April 23, 2013, or by this date notify the Commission that the parties are unable to reach an agreement.;

(4) That Baltimore Gas and Electric Company is hereby directed its proposed tariff revisions related to Rider 25 separately from its revised tariffs filed for purposes of increasing the rates as authorized in this Order, which would reflect the existence of the two sub-classes of residential customers consistent with the discussion on the Rider 25 issue in this Order;

(5) That all motions not granted herein are denied.

/s/ W. Kevin Hughes

/s/ Harold D. Williams

/s/ Lawrence Brenner

/s/ Kelly Speakes-Backman
Commissioners

APPENDICES

Appendix I

Baltimore Gas and Electric Company
Case No. 9299
Electric Operations

Revenue Requirement
($000's)

Adjusted Rate Base	$2,634,928
Rate of Return	7.60%
Required Operating Income	$200,255
Adjusted Operating Income	$153,597
Operating Income Deficiency	$46,658
Conversion Factor	1.7265
Revenue Requirement	$80,554

Rate Base
($000's)

Per Books Balance	$2,579,929
Uncontested Adjustments	($3,606)
Total Uncontested	$2,576,323
Contested Adjustments	
Terminal Reliability Projects as of Sept 2012	$39,294
Terminal Reliability Projects as of Oct-Nov 2012	$14,492
Average Reliability Projects as of Dec 2013	$0
Terminal RM 43 Capital as of Sept 2012	$2,405
Terminal RM 43 Capital as of Oct-Nov 2012	$1,922
Average RM 43 Capital as of Dec 2013	$0
Regulatory Asset of Merger Costs to Achieve	$492
Adjusted Rate Base	$2,634,928

Appendix I
Baltimore Gas and Electric Company
Case No. 9299
Electric Operations

Operating Income
($000's)

Per Books Balance	$93,426
Uncontested Adjustments	$64,315
Uncontested Balance	$157,741
Contested Adjustments	
2012 Wage Increases	($945)
Reliability Projects Depreciation as of Sept 2012	($717)
Reliability Projects Depreciation as of Oct-Nov 2012	($167)
Reliability Projects Depreciation as of Dec 2013	$0
Annualization of Merger Synergies	$1,953
Annualize RM 43 Reliability Operating Expenses	$0
Annualize RM 43 Depreciation as of Sept 2012	($34)
Annualize RM 43 Depreciation as of Oct-Nov 2012	($22)
Annualize RM 43 Depreciation as of Dec 2013	$0
Annualize RM 44 Costs	($2,791)
Employee Activity Costs	$232
Operating Income Adjustments	($2,491)
Interest Synchronization	($1,653)
Adjusted Operating Income	$153,597

Appendix II
Baltimore Gas and Electric Company
Case No. 9299
Gas Operations

Revenue Requirement
($000's)

Adjusted Rate Base	$975,860
Rate of Return	7.53%
Required Operating Income	$73,482
Adjusted Operating Income	$54,950
Operating Income Deficiency	$18,532
Conversion Factor	1.7492
Revenue Requirement	$32,416

Rate Base
($000's)

Per Books Balance	$935,075
Uncontested Adjustments	($1,529)
Total Uncontested	$933,546
Contested Adjustments	
Terminal Reliability Projects as of Sept 2012	$29,313
Terminal Reliability Projects as of Oct-Nov 2012	$12,809
Average Reliability Projects as of Dec 2013	$0
Regulatory Asset of Merger Costs to Achieve	$192
Adjusted Rate Base	$975,860

Appendix II
Baltimore Gas and Electric Company
Case No. 9299
Gas Operations

Operating Income
($000's)

Per Books Balance	$33,990
Uncontested Adjustments	$20,477
Uncontested Balance	$54,467
Contested Adjustments	
2012 Wage Increases	($368)
Reliability Projects Depreciation as of Sept 2012	($404)
Reliability Projects Depreciation as of Oct-Nov 2012	($117)
Reliability Projects Depreciation as of Dec 2013	$0
Annualization of Merger Synergies	$761
Employee Activity Costs	$90
Operating Income Adjustments	($38)
Interest Synchronization	$521
Adjusted Operating Income	$54,950

Appendix III
Baltimore Gas and Electric Company
Case No. 9299
Final Summary of Positions on Revenue Requirement – Electric Operations

Case No. 9299
Baltimore Gas and Electric Company
For the Twelve Months Ended September 30, 2012
Comparison Operations Revenue Requirement Positions
Electric Operations

Final Summary of Positions on Revenue Requirements
Updated December 14, 2012

(Thousands of Dollars)

			BGE				STAFF				OPC		
Conversion		1.7265				1.7265				1.7265			
ROR		7.96%	Rate	Operating	Revenue	7.43%	Rate	Operating	Revenue	7.29%	Rate	Operating	Revenue
			Base	Income	Requirement		Base	Income	Requirement		Base	Income	Requirement
			$ 2,579,929	$ 93,426	$ 193,256		$ 2,579,929	$ 93,426	$ 169,651		$ 2,579,929	$ 93,426	$ 163,415
Company	OPC	**Uncontested Adjustments**											
OPI/RBA	Adj #	Adjustment											
1		Eliminate Advertising, Nonoperating and Lobbying		948	(1,637)			948	(1,637)			948	(1,637)
2		Amortize Real Estate		55	(95)			55	(95)			55	(95)
3		Normalize Major Storm Costs		10,256	(17,707)			10,256	(17,707)			10,256	(17,707)
4		Eliminate Exelon Rate Credit		47,761	(82,459)			47,761	(82,459)			47,761	(62,459)
5		Eliminate CAMP Credits		423	(730)			423	(730)			423	(730)
6		Amortize Conservation Voltage Reduction Costs		(112)	193			(112)	193			(112)	193
8		2012 taxes other than income taxes		(352)	608			(352)	608			(352)	608
9		Incentive Compensation		261	(451)			261	(451)			261	(451)
10		Elimination of Executive Compensation		913	(1,576)			913	(1,576)			913	(1,576)
11		Interest in Customer Deposits		7	(12)			7	(12)			7	(12)
12		Annualization of 7.96% ROR		(124)	214			(124)	214			(124)	214
13		Elimination of Postretirement		1,307	(2,257)			1,307	(2,257)			1,307	(2,257)
17		Merger Costs to Achieve		1,656	(2,859)			1,656	(2,859)			1,656	(2,859)
19		Annualization of Voluntary Severance		575	(993)			575	(993)			575	(993)
25		Eliminate Decoupling		741	(1,279)			741	(1,279)			741	(1,279)
1		Real Estate Unamortized Gains	(28)		(4)		(28)		(4)		(28)		(4)
9		Regulatory Asset for Postretirement & Other Benefits	(978)		(134)		(978)		(125)		(978)		(123)
		Contested Adjustments											
7	6	2012 Wage Increases		(945)	1,632			-	-				-
14	2.1	Reliability Projects Depreciation as of Sept 2012		(717)	1,238			-	-				-
15	2.2	Reliability Projects Depreciation as of Oct-Nov 2012[1]		(167)	288			(167)	288			(167)	288
16	2.3	Reliability Projects Depreciation as of Dec 2013		(1,253)	2,163			-	-				-
18	4.1	Annualization of Merger Synergies		1,953	(3,372)			1,953	(3,372)			3,344	(5,774)
20	3.1	Annualize RM 43 Reliability Operating Expenses		(12,284)	21,208			(12,284)	21,208				-
21	2.4	Annualize RM 43 Depreciation as of Sept 2012		(34)	59			-	-				-
22	2.5	Annualize RM 43 Depreciation as of Oct-Nov 2012[1]		(22)	38			(22)	38			(22)	38
23	2.6	Annualize RM 43 Depreciation as of Dec 2013		(218)	376			-	-				-
24	3.2	Annualize RM 44 Costs		(2,791)	4,819			(2,791)	4,819				-
26		Tax Impact on Interest Synchronization		(861)	1,487			994	(1,716)			(861)	1,487
2	1.1	Terminal Reliability Projects as of Sept 2012	39,294		5,400				-				-
3	1.2	Terminal Reliability Projects as of Oct-Nov 2012[1]	14,492		1,992		14,492		1,859		14,492		1,824
4	1.3	Average Reliability Projects as of Dec 2013	63,686		8,752				-				-
5	1.4	Terminal RM 43 Capital as of Sept 2012	2,405		331				-				-
6	1.5	Terminal RM 43 Capital as of Oct-Nov 2012[1]	1,922		264		1,922		247		1,922		242
7	1.6	Average RM 43 Capital as of Dec 2013	11,540		1,600				-				-
8	4.2	Regulatory Asset of Merger Costs to Achieve	492		68		492		63				-
10		Cash Working Capital	(2,600)		(357)		(2,600)		(334)		(2,600)		(327)
NA		Rate Case Expenses						132	(228)				
NA	5	Employee Activity Costs						211	(364)			416	(718)
	2.8	OPC Witness King's Depreciation Adjustment - Rate Base									6,717		645
	2.8	OPC Witness King's Depreciation Adjustment - Expense										8,012	(13,833)
									-				-
		Total	$ 2,710,254	$ 140,402	$ 130,065		$ 2,593,229	$ 145,767	$ 80,990		$ 2,599,454	$ 168,463	$ 36,320

[1] The amounts included in these adjustments represent actual amounts updated by BGE during the course of the hearings.

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Appendix III
Baltimore Gas and Electric Company
Case No. 9299
Final Summary of Positions on Revenue Requirement – Gas Operations

Case No. 9299
Baltimore Gas and Electric Company
For the Twelve Months Ended September 30, 2012
Comparison of Gas Operations Revenue Requirement Positions
Gas Operations

Final Summary of Positions on Revenue Requirements
Updated December 14, 2012

(Thousands of Dollars)

			BGE			STAFF			OPC		
Conversion		1.7492				1.7492			1.7492		
ROR		7.96%	Rate Base	Operating Income	Revenue Requirement	7.41% Rate Base	Operating Income	Revenue Requirement	7.24% Rate Base	Operating Income	Revenue Requirement
			$ 935,075	$ 33,990	$ 70,741	$ 935,075	$ 33,990	$ 61,745	$ 935,075	$ 33,990	$ 58,965
Company	OPC	**Uncontested Adjustments**									
OPI/RBA	Adj #	Adjustment									
1		Eliminate Advertising, Nonoperating and Lobbying		354	(619)		354	(619)		354	(619)
2		Amortize Real Estate		24	(42)		24	(42)		24	(42)
3		Normalize Major Storm Costs									
4		Eliminate Exelon Rate Credit		18,239	(31,904)		18,239	(31,904)		18,239	(31,904)
5		Eliminate CAMP Credits		223	(390)		223	(390)		223	(390)
6		Amortize Conservation Voltage Reduction Costs[2]									
8		2012 taxes other than income taxes		(167)	292		(167)	292		(167)	292
9		Incentive Compensation		101	(177)		101	(177)		101	(177)
10		Elimination of Executive Compensation		354	(619)		354	(619)		354	(619)
11		Interest in Customer Deposits		3	(5)		3	(5)		3	(5)
12		Annualization of 7.96% ROR		20	(35)		20	(35)		20	(35)
13		Elimination of Postretirement		457	(799)		457	(799)		457	(799)
17		Merger Costs to Achieve		645	(1,128)		645	(1,128)		645	(1,128)
19		Annualization of Voluntary Severance		224	(392)		224	(392)		224	(392)
1		Real Estate Unamortized Gains	(12)		(2)	(12)		(2)	(12)		(2)
9		Regulatory Asset for Postretirement & Other Benefits	(343)		(48)	(343)		(44)	(343)		(43)
		Contested Adjustments									
7	6	2012 Wage Increases		(368)	644		-	-			-
14	2.1	Reliability Projects Depreciation as of Sept 2012		(404)	707			-	-		-
15	2.2	Reliability Projects Depreciation as of Oct-Nov 2012[1]		(117)	205		(117)	205	-	(117)	205
16	2.3	Reliability Projects Depreciation as of Dec 2013		(589)	1,030			-	-		-
18	4.1	Annualization of Merger Synergies		761	(1,331)		761	(1,331)		1,302	(2,277)
20	3.1	Annualize RM 43 Reliability Operating Expenses[2]									
21	2.4	Annualize RM 43 Depreciation as of Sept 2012[2]									
22	2.5	Annualize RM 43 Depreciation as of Oct-Nov 2012[1,2]									
23	2.6	Annualize RM 43 Depreciation as of Dec 2013[2]									
24	3.2	Annualize RM 44 Costs[2]									
26		Tax Impact on Interest Synchronization		927	(1,622)		1,936	(3,386)		927	(1,622)
2	1.1	Terminal Reliability Projects as of Sept 2012	29,313		4,081						-
3	1.2	Terminal Reliability Projects as of Oct-Nov 2012[1]	12,809		1,783	12,809		1,660	12,809		1,622
4	1.3	Average Reliability Projects as of Dec 2013	38,418		5,349						-
5	1.4	Terminal RM 43 Capital as of Sept 2012[2]									
6	1.5	Terminal RM 43 Capital as of Oct-Nov 2012[1,2]									
7	1.6	Average RM 43 Capital as of Dec 2013[2]									
8	4.2	Regulatory Asset of Merger Costs to Achieve	192		27	192		25			-
10		Cash Working Capital	(1,174)		(163)	(1,174)		(152)	(1,174)		(149)
NA		Rate Case Expenses					49	(86)			
NA	5	Employee Activity Costs					78	(136)		162	(283)
	2.8	OPC Witness King's Depreciation Adjustment - Rate Base							511		65
	2.8	OPC Witness King's Depreciation Adjustment - Expense								609	(1,065)
											-
		Total	$ 1,014,278	$ 54,677	$ 45,583	$ 946,547	$ 57,174	$ 22,679	$ 946,866	$ 57,349	$ 19,598

[1] The amounts included in these adjustments represent actual amounts updated by BGE during the course of the hearings.
[2] These adjustments related to the Electric Operations only, therefore no adjustment is necessary.

RAP Energy solutions for a changing world

Revenue Regulation and Decoupling:

A Guide to Theory and Application

June 2011

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Contents

Preface

This guide was prepared to assist anyone who needs to understand both the mechanics of a regulatory tool known as *decoupling* and the policy issues associated with its use. This includes public utility commissioners and staff, utility management, advocates, and others with a stake in the regulated energy system.

Many utility-sector stakeholders have recognized the conflicts implicit in traditional regulation that compel a utility to encourage energy consumption by its customers, and they have long sought ways to reconcile the utility business model with contradictory public policy objectives. Simply put, under traditional regulation, utilities make more money when they sell more energy. This concept is at odds with explicit public policy objectives that utility and environmental regulators are charged with achieving, including economic efficiency and environmental protection. This *throughput incentive* problem, as it is called, can be solved with decoupling.

Currently, some form of decoupling has been adopted for at least one electric or natural gas utility in 30 states and is under consideration in another 12 states. As a result, a great number of stakeholders are in need, or are going to be in need, of a basic reference guide on how to design and administer a decoupling mechanism. This guide is for them.

More and more, policymakers and regulators are seeing that the conventional utility business model, based on profits that are tied to increasing sales, may not be in the long-run interest of society. Economic and environmental imperatives demand that we reshape our energy portfolios to make greater use of end-use efficiency, demand response, and distributed, clean resources, and to rely less on polluting central utility supplies. Decoupling is a key component of a broader strategy to better align the utility's incentives with societal interests.

While this guide is somewhat technical at points, we have tried to make it accessible to a broad audience, to make comprehensible the underlying concepts and the implications of different design choices. This guide is accompanied by a spreadsheet that can be used to demonstrate the impacts of decoupling using different pricing structures or, as the jargon has it, *rate designs*.

This guide was written by Jim Lazar, Frederick Weston, and Wayne Shirley. The RAP review team included Rich Sedano, Riley Allen, Camille Kadoch, and Elizabeth Watson. Editorial and publication assistance was provided by Diane Derby and Camille Kadoch.

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1 Natural Resources Defense Council, *Gas and Electric Decoupling in the U.S.*, April 2010.

1. Introduction

This document explains the fundamentals of *revenue regulation*[2], which is a means for setting a level of revenues that a regulated gas or electric utility will be allowed to collect, and its necessary adjunct *decoupling*, which is an adjustable price mechanism that breaks the link between the amount of energy sold and the actual (allowed) revenue collected by the utility. Put another way, *decoupling* is the means by which *revenue regulation* is effected. For this reason, the two terms are typically treated as synonyms in regulatory discourse; and, for simplicity's sake, we treat them likewise here.

Revenue regulation does not change the way in which a utility's allowed revenues (i.e., the "revenue requirement") are calculated. A revenue requirement is based on a company's underlying costs of service, and the means for calculating it relies on long-standing methods that need not be recapitulated in detail here. What is innovative about it, however, is how a defined revenue requirement is combined with decoupling to eliminate sales-related variability in revenues, thereby not only eliminating weather and general economic risks facing the company and its customers, but also removing potentially adverse financial consequences flowing from successful investment in end-use energy efficiency.

We begin by laying out the operational theory that underpins decoupling. We then explain the calculations used to apply a decoupling price adjustment. We close the document with several short sections describing some refinements to basic revenue regulation and decoupling.

To assist the reader, a companion MS-Excel spreadsheet is also available. It contains both the examples shown in this guide, as well as a functioning "decoupling model." It can be downloaded at http://www.raponline.org/docs/RAP_DecouplingModelSpreadsheet_2011_05_17.xlsb

2 Revenue regulation is often called revenue *cap* regulation. However, when combined with decoupling, the effect is to simply regulate revenue – i.e., there is a corresponding *floor* on revenues in addition to a *cap*.

2. Context for Decoupling

Decoupling is a tool intended to break the link between how much energy a utility delivers and the revenues it collects. Decoupling is used primarily to eliminate incentives that utilities have to increase profits by increasing sales, and the corresponding disincentives that they have to avoid reductions in sales. It is most often considered by regulators, utilities, and energy-sector stakeholders in the context of introducing or expanding energy efficiency efforts; but it should also be noted that, on economic efficiency grounds, it has appeal even in the absence of programmatic energy efficiency.

There are a limited number of things over which utility management has control. Among these are operating costs (including labor) and service quality. Utility management can also influence usage per customer (through promotional programs or conservation programs). Managers have very limited ability to affect customer growth, fuel costs, and weather. Decoupling typically removes the influence on revenues (and profits) of such factors and, by eliminating sales volumes as a factor in profitability, removes any incentive to encourage consumers to increase consumption. This focuses management efforts on cost-control to enhance profits.

In the longer run, this effort constrains future rates and benefits consumers. It also means that energy conservation programs (which reduce customer usage) do not adversely affect profits. A performance incentive system and a customer-service quality mechanism can overlay decoupling to further promote public interest outcomes.

Although it is often viewed as a significant deviation from traditional regulatory practice, decoupling is, in fact, only a slight modification. The two approaches affect behavior in critically different ways, yet the mathematical differences between them are fairly straightforward. Still, it goes without saying that care must be taken in designing and implementing a decoupling regime, and the regulatory process should strive to yield for both utilities and consumers a transparent and fair result.

While traditional regulation gives the utility an incentive to preserve and, better yet, increase sales volumes, it also makes consumer advocates focus on price – after all, that is the ultimate result of traditional regulation. Because decoupling allows prices to change between rate cases, consumer advocates can move the focus of their effort from prices to all cost drivers, including sales volumes – focusing on bills rather than prices.

3. How Traditional Regulation Works

In virtually all contexts, public utilities (including both investor-owned and consumer-owned utilities) have a common fundamental financial structure and a common framework for setting prices.[3] This common framework is what we call the utility's overall *revenue requirement.* Conceptually, the revenue requirement for a utility is the aggregate of all of the operating and other costs incurred to provide service to the public. This includes operating expenses like fuel, labor, and maintenance. It also includes the cost of capital invested to provide service, including both interest on debt and a "fair" return to equity investors. In addition, it includes a depreciation allowance, which represents repayment to banks and investors of their original loans and investments.

In order to determine what price a utility will be allowed to charge, regulators must first compute the total cost of service, that is, the revenue requirement. Regulators then compute the price (or rate) necessary to collect that amount, based on assumed sales levels. In most cases, the regulator relies on data for a specific period, referred to here as the *test period,* and performs some basic calculations.

Here are the two basic formulae used in traditional regulation:

Formula 1: **Revenue Requirement = (Expenses + Return + Taxes)** TEST PERIOD
Formula 2: **Rate = Revenue Requirement ÷ Units Sold** TEST PERIOD

The rate is normally calculated on a different basis for each customer class, but the principle is the same – the regulator divides the revenue requirement among the customer classes, then designs rates for each class to recover each class's revenue requirement. Table 1 is an example of this calculation, under the simplifying assumption that the entire revenue requirement is collected through a kWh charge.

3 Conditions vary widely from country to country or region to region, and utilities face a number of local and unique challenges. However, for our purposes, we will assume that there is a fundamental financial need for revenues to equal costs – including any externally imposed requirements to fund or secure other expense items (such as required returns to investors, debt coverage ratios in debt covenants, or subsidies to other operations, as is often the case with municipal- or state-run utilities). In this sense, virtually all utilities can be viewed as being quite similar.

3.1 Revenue Requirement

Table 1

Traditional Regulation Example: Revenue Requirement Calculation	
Expenses	100,000,000
Net Equity Investment	100,000,000
Allowed Rate of Return	10.00%
Allowed Return	$10,000,000
Taxes (35% tax rate)	$5,384,615
Total Return & Taxes	$15,384,615
Total Revenue Requirement	$115,384,615
Price Calculation	
Revenue Requirement	$115,384,615
Test Year Sales (kWh)	1,000,000,000
Rate Case Price ($/kWh)	$0.1154

A utility's revenue requirement is the amount of revenue a utility will actually collect, only if it experiences the sales volumes assumed for purposes of price-setting. Furthermore, only if the utility incurs exactly the expenses and operates under precisely the financial conditions that were assumed in the rate case will it earn the rate of return on its rate base (i.e., the allowed investment in facilities providing utility service) that the regulators determined was appropriate. While much of the rate-setting process is meticulous and often arcane, the fundamentals do not change: in theory a utility's revenue requirement should be sufficient to cover its cost of service — no more and no less.

3.1.1 Expenses

For purposes of decoupling, expenses come in two varieties: production costs and non-production costs.[4]

3.1.1.1 Production Costs

Production costs are a subset of total power supply costs, and are composed principally of fuel and purchased power expenses with a bit of variable operation and maintenance (O&M) and transmission expenses paid to others included. Production costs as we use the term here are those that vary more or less directly with energy consumption in the short run. The mechanisms approved by regulators generally refer to very specific accounts defined in the utility accounting manuals, including "fuel," "purchased power," and "transmission by others."

4 A utility's expenses are often characterized as "fixed" or "variable". However, for purposes of resource planning and other long-run views, all costs are variable and there is no such thing as a fixed cost. Even on the time scale between rate cases, some non-production costs that are often viewed as fixed (e.g., metering and billing) will, in fact, vary directly with the number of customers served. When designing a decoupling mechanism, it is more appropriate to differentiate between "production" and "non-production," since one purpose of the mechanism is to isolate the costs over which the utility actually has control in the short run (i.e., the period between rate cases).

Production costs for most electric utilities are typically recovered through a flow-through account, with a reconciliation process that fully recovers production costs, or an approximation thereof.[5] This is usually accomplished through a separate fuel and purchased-power rate (fuel adjustment clause, or FAC) on the customer's bill. This may be an "adder" that recovers total production costs, or it may be an up-or-down adjustment that recovers deviations in production costs from the level incorporated in base rates.

In the absence of decoupling, a fully reconciled FAC creates a situation in which any increase in sales results in an increase in profits, and any decrease in sales results in a decrease in profits. This is because even if very high-cost power is used to serve incremental sales, and if 100% of this cost flows through the FAC, the utility receives a "net" addition to income equal to the base rate (retail rate less production costs) for every incremental kilowatt-hour sold.[6] An FAC is therefore a negative influence on the utility's willingness to embrace energy efficiency programs and other actions that reduce utility sales. Decoupling is an important adjunct to an FAC to remove the disincentive that the FAC creates for the utility to pursue societal cost-effectiveness.[7]

Because they vary with production and because they are separately treated already, production costs are not usually included in a decoupling mechanism. If a utility is allowed to include the investment-related portion of costs for purchased power contracts (i.e., it buys power to serve load growth from an independent power producer, and pays a per-kWh rate for the power received), it may be necessary to address this in the structure of the FAC to ensure that double recovery does not occur. This can also be addressed by using a comprehensive power cost adjustment that includes all power supply costs, not just fuel and purchased power. Unless otherwise noted, we assume that production costs are not included in the decoupling mechanism.

5 Many commissions use incentive mechanisms in their fuel and purchased-power mechanisms, to provide utilities with a profit motive to minimize fuel and purchased-power costs and to maximize net off-system sales revenues. For our purposes, these are deemed to fully recover production costs. Some regulators include both fixed and variable power supply costs in their power supply cost recovery mechanism, in which case all of those would be classified as "production" costs and deemed to be fully recovered through the power supply mechanism.

6 See *Profits and Progress Through Least Cost Planning*, NARUC, page 4, at: http://www.raponline.org/Pubs/General/Pandplcp.pdf

7 If a utility does not have an FAC at all, or acquires power from independent power producers on an ongoing basis to meet load growth, the framework for decoupling may need to be slightly different. In those circumstances, revenues from the sale of surplus power or avoided purchased power expense resulting from sales reductions flows to the utility, not to the consumers, through the FAC. In this situation, the definition of "production costs" may need to include both power supply investment-related costs and production-related operating expenses for decoupling to produce equitable results for consumers and investors.

3.1.1.2 Non-Production Costs

Non-production costs include all those that are not production costs — in essence, everything that is related to the delivery of electricity (transmission, distribution, and retail services) to end users. This normally includes all non-production related O&M expenses, including depreciation and interest on debt. In many cases, the base rates also include the debt and equity service (i.e., the interest, return, and depreciation) on power supply investments, in which case the form of the FAC becomes important.

Statistically, a utility's non-production costs do not vary much with consumption in the short run, but are more affected by changes in the numbers of customers served, inflation, productivity, and other factors.[8] Of course, a utility with a large capital expenditure program, such as the deployment of smart grid technologies or significant rebuilds of aging systems, will experience a surge in costs that is unrelated to customer growth. Decoupling does not address this issue, which is better handled in the context of a rate case or infrastructure tracking mechanism.

Non-production costs are usually recovered through a combination of a customer charge,[9] plus one or more volumetric (per kWh, per kW) rates. A utility may face the risk of not recovering some non-production costs if sales decline. Put another way, many of the costs do not vary with sales, so each dollar decline in sales flows straight to — and adversely affects — the bottom line.

3.1.2 Return

For our purposes, the utility's "return" is the same as its net, after-tax profit, or net income for common stock.[10] When computing a revenue requirement for a rate case, this line item is derived by multiplying the utility's net equity investment by its "allowed" rate of return on common equity. We have simplified this return in the illustration, but will address it in more detail in Section 10, *Earnings Volatility Risks and Impacts on the Cost of Capital.*

In a rate case, the return is a static expected value. In between rate cases,

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8 Eto, Joseph, Steven Stoft, and Timothy Belden, *The Theory and Practice of Decoupling*, Lawrence Berkeley National Laboratory, January 1994. URL: http://eetd.lbl.gov/ea/EMS/reports/34555.pdf

9 In place of a customer charge, one may also find other monthly fixed charges, such as minimum purchase amounts, access fees, connection fees, or meter fees. For our purposes, these are all the same because they are not based on energy consumption, but, instead, are a function of the number of customers.

10 Regulatory commissions often calculate an "operating income" figure in the process of setting rates; this does not take account of the tax effects on the debt and equity components of the utility capital structure. Net income includes these effects.

11 Shirley, W., J. Lazar, and F. Weston, *Revenue Decoupling: Standards and Criteria, A Report to the Minnesota Public Utilities Commission*, Regulatory Assistance Project, 30 June 2008, Appendix B, p. 36.

realized returns are a function of actual revenues, actual investments, and actual expenses, all of which change between rate cases in response to many factors, including sales volumes, inflation, productivity, and many others.

As a share of revenues in a rate case revenue requirement calculation, the return on equity to shareholders may be as small as 5%-10%. As a result, small percentage changes in total non-production revenues (all of which largely affect return and taxes) can generate large percentage changes in net profits.[11]

3.1.3 Taxes

In a rate case, the amount of taxes a utility would pay on its allowed return is added to the revenue requirement.

In between rate cases, taxes buffer the impact on the utility's shareholders of any deviations of realized returns from expected returns. When realized returns rise, some portion is lost to taxes, so shareholders do not garner gains one-for-one with changes in net revenues. Conversely, if revenues fall, so do taxes. As a result, investors do not suffer the entire loss. If the tax rate is 33%, then one third of every increase or decrease in pre-tax profits will be absorbed by taxes.

From a customer perspective, there is no buffering effect from taxes. To the contrary, customers pay all additional revenues and enjoy all savings, dollar for dollar.

3.1.4 Between Rate Cases

With traditional regulation, while the determination of the revenue requirement *at the time of the rate case decision* is meticulous, the utility will almost certainly *never* collect precisely the allowed amount of revenue, experience the associated assumed levels of expenses or unit sales, or achieve the expected profits. The revenue requirement is only used as input to the price determination. Once prices are set, *realized* revenues and profits will be a function of *actual sales and expenses* and will have only a rough relationship with the rate case allowed revenues or returns.

Traditional regulation fixes the price between rate cases and lets revenues float up or down with actual sales.

Put another way, traditional regulation fixes the price between rate cases and lets revenues float up or down with actual sales. At this point, the rate case formulae no longer hold sway. Instead, two different mathematical realities operate:

Formula 3: **Revenues $_{\text{ACTUAL}}$ = Units Sold Actual X Price**

Formula 4: **Profit $_{\text{ACTUAL}}$ = (Revenues – Expenses – Taxes) $_{\text{ACTUAL}}$]**

These two formulae reveal the methods by which the utility can increase its profits. One approach is to reduce expenses. Providing a heightened incentive to operate efficiently is sound. However, there is a floor below which expenses simply cannot be reduced without adversely affecting the level of service, and to ensure that utilities cut fat, but not bone, some regulators have established service quality indices that penalize utilities that achieve lower-than-expected customer service quality. The easier approach is to increase the Units Sold, as this will increase revenues and therefore profits.[12] This is the heart of the throughput incentive that utilities traditionally face – and this is where decoupling comes in.

3.2 How Decoupling Works

There are a variety of different approaches to decoupling, all of which share a common goal of ensuring the recovery of a defined amount of revenue, independent of changes in sales volumes during that period. Some are computed on a revenue-per-customer basis, while others use an attrition adjustment (typically annual) to set the allowed revenue. Some operate on an annual accrual basis, while others operate on a current basis in each billing cycle. Table 2 categorizes these and provides an example of each approach; a greater discussion of these approaches is contained in the appendix.

Table 2

Decoupling Methodology	Key Elements	Example of Application
Accrual Revenue Per Customer	Allowed revenue computed on an RPC basis; one rate adjustment per year	Utah, Questar
Current Revenue Per Customer	Allowed revenue computed on an RPC basis; rates adjusted each billing cycle to avoid deferrals	Oregon, Northwest Natural Gas Company; DC: Pepco
Accrual Attrition	Allowed revenue determined in periodic general rate cases; changes to this based on specified factors determined in annual attrition reviews; rates adjusted once a year	California, PG&E and SCE Hawaii, Hawaiian Electric
Distribution-Only	Only distribution costs included in the mechanism; all power costs (fixed and variable) recovered outside the decoupling mechanism	Massachusetts, NGrid Maryland, BG&E Washington (PSE, 1990-95)

12 This is because, as noted earlier, the utility faces virtually no changes in its non-production costs as its sales change. This means that marginal increases in sales will have a large and positive impact on the bottom line, just as marginal reductions in sales will have the opposite effect.

3.2.1 In the Rate Case (It's the same)

With decoupling there is no change in the rate case methodology, except perhaps for the migration of some cost items into or out of the production cost recovery mechanism.[13] Initial prices are still set by the regulator, based on a computed revenue requirement.

Formula 1: **Revenue Requirement = (Expenses + Return + Taxes)** $_{\text{TEST PERIOD}}$
Formula 5: **Price** $_{\text{END OF RATE CASE}}$ **= Revenue Requirement ÷ Units Sold** $_{\text{TEST PERIOD}}$

3.2.2 Between Rate Cases (It's different)

There are two distinct components of decoupling which are embedded in the decoupling formulae: determination of the utility's allowed revenues and determination of the prices necessary to collect those allowed revenues.

With decoupling, the price computed in the rate case is only relevant as a reference or beginning point. In fact, the rate case prices may never actually be charged to customers. Instead, under "current" decoupling (described below), prices can be adjusted immediately, based on actual sales levels, to keep revenues at their allowed level. Rather than holding prices constant between rate cases as traditional regulation would do, decoupling adjusts prices periodically, even as frequently as each billing cycle, to reflect differences between units sold $_{\text{TEST PERIOD}}$ and units sold $_{\text{ACTUAL}}$, as necessary to collect revenues $_{\text{ALLOWED}}$. This is accomplished by applying the following formulae:

Formula 6: **Price** $_{\text{POST RATE CASE}}$ **= Revenues** $_{\text{ALLOWED}}$ **÷ Units Sold** $_{\text{ACTUAL}}$
Formula 7: **Revenues** $_{\text{ACTUAL}}$ **= Revenues** $_{\text{ALLOWED}}$
Formula 4: **Profits** $_{\text{ACTUAL}}$ **= (Revenues – Expenses – Taxes)** $_{\text{ACTUAL}}$

Table 3 gives an example of the calculations.

13 Examples of costs that are sometimes recovered on an actual cost basis include nuclear decommissioning (which rises according to a sinking fund schedule), energy conservation program expenses, and infrastructure trackers for non-revenue-generating refurbishments. Where a utility does not have an FAC or purchases power from independent power producers to meet load growth, it may be necessary to include all power supply costs, fixed and variable, in the definition of "production costs."

There are two distinct actions embedded in the decoupling formulae: determination of the utility's *allowed* revenues and determination of the *prices* necessary to collect those allowed revenues. The former can involve a variety of methods, ranging from simply setting allowed revenues at the amount found in the last rate case to varying revenues over time to reflect non-sales-related influences on costs and revenues, as discussed in Section 5, *Revenue Functions.* The latter is merely the calculation which sets the prices that, given sales levels (i.e., billing determinants), will generate the allowed revenue.

Table 3

Decoupling Example:
Revenue Requirement Calculation

Expenses	$100,000,000
Net Equity Investment	$100,000,000
Allowed Rate of Return	10.00%
Allowed Return	$10,000,000
Taxes (35% tax rate)	$15,384,615
Total Revenue Requirement	$115,384,615
Price Calculation	
Revenue Requirement	$115,384,615
Actual Sales (kWh)	990,000,000
Decoupling Price ($/kWh)	$0.1166
Decoupling Adjustment ($/kWh)	$0.0012

Put another way, while traditional regulation sets prices, then lets revenues float up or down with consumption, decoupling sets revenues, then lets prices float down or up with consumption. This price recalculation is done repeatedly – either with each billing cycle or on some other periodic basis (e.g., annual), through the use of a deferral balancing and reconciliation account.[14]

While traditional regulation sets prices, then lets revenues float up or down with consumption, decoupling sets revenues, then lets prices float down or up with consumption.

There are two separate elements in play in the price-setting component of decoupling. The first is that prices are allowed to change between rates, based on deviations in sales from the test period assumptions. The second is the frequency of those changes. We discuss the frequency idea in greater detail in Section 8, *Application of Decoupling: Current vs. Accrual Methods.*

14 There are, however, good reasons to seek to limit the magnitude of deviations from the reference price. For example, many decoupling mechanisms allow a maximum 3% change in prices in any year, deferring larger variations for future treatment by the regulator. Significant variability in price may threaten public acceptance of decoupling and the broader policy objectives it serves. Policymakers should be careful to design decoupling regimes with this consideration in mind.

14 Conclusion

Revenue regulation and decoupling provide simple and effective means to eliminate the utility throughput incentive, remove a critical barrier to investment in effective energy efficiency programs, stabilize consumer energy bills, and reduce the overall level of business and financial risk that utilities and their customers face.

This guide has identified and explained key issues in decoupling for the benefit of regulators and participants in the regulatory process alike. Each utility and each state will be a little bit different, so there may not be a cookie-cutter approach that is right for all. However, the principles remain fairly constant: minor periodic adjustments in rates stabilize revenues, so that the utility is indifferent to sales volumes. This eliminates a variety of revenue and earnings risks, in particular those associated with effective investment in end-use energy efficiency, and can bring provision of least-cost energy service closer to reality for the benefit of utilities and consumers alike.

A secondary issue is whether the changes in price occasioned by decoupling should, themselves, be detailed in a line item on the bill or subsumed in a total price. We are all familiar with changing prices at the gas pump, but do not expect a "line item" description of the latest adjustment up or down in that price. We expect to pay the price on the sign, and expect it to include all taxes, fees, profit, transportation charges, and other elements of cost. In fact, if gas stations were required to track price changes in such a way, consumers would see a confusing array of information that is largely unrelated to changes in the total price being paid. Again, simplicity argues for rolling the decoupling adjustments directly into the total price, rather than having a separate decoupling adjustment line item. The full detailed tariff must be available for the customer to review, generally on the utility website, but it may not need to be on the bill; only the effective prices – what a customer pays if he or she uses more or less service – is relevant to the consumption decision.

When decoupling is implemented, a communication strategy should be in place to help consumers understand why prices are being allowed to vary from bill to bill. They may see decoupling as a "profit guarantee" rather than a "revenue assurance." Information making clear the ultimate impacts of decoupling will likely be more understandable than a brochure that attempts to, say, summarize the contents of this guide.

Aside from the total size of their bills, customers tend to be most concerned about whether they are being fairly charged by their utility. Decoupling strikes to the heart of this issue because, unlike traditional regulation, it has a high probability, if not certainty, that consumers will actually pay the revenue requirement determined by the Commission. In addition, where weather risk is eliminated, decoupling has the effect of countering the impacts of high bills during extreme weather (with the symmetric effect of slightly increasing bills during mild weather).

Most consumers would likely welcome a little "help" when the bills are higher than usual, at the "cost" of a slightly higher bill when bills are lower. This is merely the softening of the peaks and valleys. It is these aggregate effects that consumers should understand, and which a communication strategy should address.

Table 13a

Example of an electric bill that lists all adjustments to a customer's bill.

Your Usage: 1,266 kWh

Base Rate	**Rate**	**Usage**	**Amount**
Customer Charge	$5.00	1	$5.00
First 500 kWh	$0.05000	500	$25.00
Next 500 kWh	$0.10000	500	$50.00
Over 1,000 kWh	$0.15000	266	$39.90
Fuel Adjustment Charge	$0.01230	1,266	$15.57
Infrastructure Tracker	$0.00234	1,266	$2.96
Decoupling Adjustment	$(0.00057)	1,266	$(0.72)
Conservation Program Charge	$0.00123	1,266	$1.56
Nuclear Decommissioning	$0.00037	1,266	$0.47
Subtotal:	$139.74		
State Tax	5%		$6.99
City Tax	6%		$8.80
Total Due			**$155.53**

Table 13b

The rate above, with all of the surcharges, credits, and taxes applied to each of the usage-related components of the rate design.

Base Rate	**Rate**	**Usage**	**Amount**
Customer Charge	$5.56500	1	$ 5.56
First 500 kWh	$0.07309	500	$ 36.55
Next 500 kWh	$0.12874	500	$ 64.37
Over 1,000 kWh	$0.18439	266	$ 49.05
Total Due			**$155.53**

13 Communicating with Customers about Decoupling

Preparing a utility's customers for the effects of decoupling on their bills can be a challenge, both because the components of a utility's bill are not always straightforward, indeed are often confusing, and because variable prices are a new phenomenon to most. Regulators, utilities, and consumer advocates should all want to make the transition to decoupling as smooth as possible for customers. This requires some thought about bill design and consumer education. The guiding principle here should be simplicity. In fact, the implementation of decoupling offers an opportunity to overhaul the utility's bill with an eye toward simplification.

In many states, the utility bill has become a rather dense tangle of line items that represent, in many cases, a long history of policy initiatives and regulatory decisions. In many cases, they are a kind of tally of the rate-case battles won and lost by advocates and utilities, a catalogue of special charges and "trackers" dealing with particularly knotty investment and expenditure requirements. The accumulated result is often a bill that consumers find difficult to navigate. A customer's electric bill typically consists of a monthly customer charge, one or more usage blocks (or time-of-use periods), and as many as ten surcharges, credits, and taxes added to these usage-related prices. Some utilities present all of the detail on the bill, and it can be confusing and overwhelming to the consumer. Table 13a shows an example of how the customer's bill may look with all of the detail. To the extent that line items can be eliminated or combined, consumer confusion is likely to be reduced.

Alternatively, all of the detail can be provided, but the bill should "roll up" all of the rate components, adjustments, taxes, surcharges, and credits into an "effective" rate that the consumer pays. Table 13b shows what the customer actually pays if they use more electricity, or saves if they use less electricity. Utilities should be encouraged to display the "effective" rate to customers, including all surcharges, credits, and taxes, so consumers can measure the value of investing in energy efficiency or other measures that reduce (or increase) their electricity consumption.

Tables 13a and 13b show a conversion of a rate with multiple surcharges into an effective rate.

12.12 "The problem is that utility profits don't reward utility performance."

At least two states have tried to overcome utility resistance to energy efficiency investment by allowing a higher rate of return for investment in energy efficiency than utilities receive on supply-side investments. While this can work in theory, it is difficult to make it work in practice, because the incentive return must be quite high to overcome the lost margin effect that decoupling addresses. In addition, a premium return may tend to reinforce the Averch-Johnson effect, giving utilities an incentive to spend as much as possible (to attract the incentive return) on measures that save little or no energy (to avoid creating lost margins). An incentive return mechanism can be a very important part of regulation, for example, by tying the utility's return (or the utility's recovery of deferral margins under decoupling) to the utility's achievement of energy efficiency achievement and cost control targets approved by the commission. But, as a general matter, incentive return mechanisms have not been effective alternatives to decoupling; in combination *with* decoupling, however, they can be.

12.10 "The use of frequent rates cases using a future test year eliminates the need for decoupling."

A future test year may have the effect of causing a utility's "revenue requirement" to more closely track a utility's revenue requirement over time. A future test year does not, however, have the effect of constraining *allowed revenues* to a utility's revenue requirement. In addition, a future test year does not address the throughput issue, which is one of the primary reasons for using decoupling. The term "decoupling" itself is rooted in the notion of separating the utility's incentive to increase profits through increased sales, and to avoid decreased profits through decreased sales by breaking the link between — that is, by decoupling revenues from sales.

12.11 "Decoupling diminishes the utility's incentive to restore service after a storm."

This can be a problem if not addressed in the design of the decoupling mechanism. After a storm, utilities normally bring in extra crews, pay overtime, airlift in supplies, and otherwise do everything reasonably possible to restore service. The primary reasons for this are the deeply-held sense of obligation that drives utilities and their employees to provide reliable service and their appreciation of the far-reaching and deleterious impacts of an outage.

But there is also a more prosaic motive: the need to "get the cash register running" again, so revenue flows to the utility. If a decoupling mechanism allows the utility to receive the revenues that it would have collected if the power were on, consumers both suffer an outage and pay for service they did not receive. The utility is made whole, and really does not suffer any penalty from slow service restoration.

This is easily addressed in the design of an RPC decoupling mechanism. One approach would be to adjust the number of customers for whom the allowed revenue is computed to reflect only those who were receiving service during a particular time period, deducting days when power was unavailable. (This same concern applies equally to straight fixed/variable pricing: the charges to consumers must be halted during an outage, or the incentive to restore service is diminished.) Another approach would be to address service quality issues such as outages separately, in a comprehensive Service Quality Index, with penalties tied to outage frequency and duration.

concerns, and the public utility commission (PUC) opened an inquiry into the Puget's resource decisions. The Commission found that, with respect to certain power supply contracts, the utility had acted imprudently. The combined mechanism was terminated. The rate adjustments due to the decoupling portion had been minor, and were not the primary focus of the Commission's inquiry. Shortly thereafter, Puget applied for a merger with Washington Natural Gas Company. A multi-year rate plan was approved as part of the merger, displacing both the power-cost and base-cost decoupling mechanisms.

12.9 "Classes that are not decoupled should not share the cost of capital benefits of decoupling."

Many commissions have excluded large-volume electricity and natural gas consumers from decoupling mechanisms. The reason for this is that classes of customers with few members may really require customer-specific attention in ratemaking, and a decoupling mechanism could result in significant rate increases to remaining customers if another customer or customers in the class discontinued or reduced operations.

Because decoupling results in a lower risk profile for the utility, particularly with respect to weather and economic cycles, it is expected (either immediately or over time) that a reduction in the cost of capital will result. A class that is not exposed to decoupling rate adjustments due to sales variations is not a part of the cause of the lower risk profile. However, because Commissions normally apply the same rate of return to all classes, it may not be pragmatic to calculate a different rate of return for each class.

As a practical matter, large-use customer classes often have other revenue stabilization elements in their rates, such as contract demand levels, demand ratchets, and straight fixed/variable rate designs that have a stabilizing effect on revenues similar to that of decoupling. Consequently, one might argue that, under traditional regulation, the classes with more variable loads were benefiting from the risk-reducing nature of larger-volume customers, and that decoupling merely balances the scales.[35]

35 But it is fairer to say that all loads impose both risks and benefits on the utility. A large-volume user may have a higher-than-average load factor and provide stable revenues to the utility, but the adverse impacts of its leaving the system are significantly greater than those of individual lower-volume customers. Many factors affect the market's valuation of the risks that a utility faces; load diversity is only one of them.

12.7 "Decoupling is not needed because energy efficiency is already encouraged, since it liberates power that can be sold to other utilities."

This condition does exist in some low-cost utilities that have excess capacity available for sale and that do not have FACs. Any utility with a traditional FAC does not benefit from off-system sales, because those revenues are credited to their retail consumers through the adjustment clause.

This concern, however, overlooks the temporary nature of excess capacity, especially if some of it is the result of an aging generation approaching retirement, and the changing nature of power markets. Decoupling encourages utilities to take actions that may increase off-system sales revenues, but only if power costs are covered by a decoupling mechanism will those sales result in increased profits for the companies.

Lastly, off-system sales have less certainty and are subject to the vagaries of market prices, whereas sales to native loads are more certain and subject to less price volatility. Conservative utility managers are likely to prefer the "bird in hand" in such cases.

12.8 "Decoupling has been tried and abandoned in Maine and Washington."

Maine and Washington initiated decoupling mechanisms in the late 1980s and early 1990s, and both terminated the programs after a few years. The reasons for termination were different.

In Maine, the decoupling mechanism was instituted for Central Maine Power shortly before a serious recession hit the country. Sales declined and the decoupling mechanism generated significant rate increases, because of the large annual adjustment resulting from the use of an accrual methodology. The Commission elected to discontinue the mechanism. Of course, for the most part, decoupling only implemented what a new rate case would have yielded in any event, the root cause of the problem not being the mode of regulation, but the recession. The lesson learned is that a cap on annual rate increases may be appropriate, and a complete review of costs, sales, and revenues (i.e., a general rate case or equivalent) should be required every few years under a decoupling mechanism.

In Washington, a decoupling mechanism applied to "base costs" was introduced at the same time that a separate mechanism was introduced to recover "power costs." The utility (Puget Sound Power and Light Company) was acquiring significant new resources to replace expiring power supply contracts. Rates went up sharply due to the operation of the power cost mechanism, not the decoupling mechanism. The increases raised public this sales decline will trigger rate cases. This longer time period provides a stronger incentive for the utility to achieve operational efficiencies and reduce costs, because the utility will be allowed to retain the cost savings for a longer time, until the next general rate case. If costs and revenues become unbalanced for any reason, the utility or the regulator can initiate a general rate case at any time.

12.5 "What utilities really want sales for is to have an excuse to add to rate base —that is, the Averch Johnson Effect."

In a rate case, the net-income line item in the cost of service is a function of the size of the rate base and the return allowed>>. The greater the rate base, the greater the net income that is included in the cost of service (for a given allowed return). Utilities may be motivated to increase sales in order to add to rate base capital assets needed to serve additional load, despite countervailing risks associated with permitting and construction, for instance. This is not a concern decoupling can address, nor is it intended to address. Rather, sound integrated resource planning that identifies the least-cost long-term resource acquisition strategy is the best way to manage incentives associated with the capital program.

12.6 "Decoupling violates the 'matching principle'."

The matching principle in ratemaking is an implicit assumption that revenues, sales, and costs will move in synchronization: as sales change (go either up or down), revenues and costs will change at the same rate. Absent changes in customers, programs, or policies, this has been generally effective in allowing traditional regulation to function effectively. Implied in the matching principle is that inflation is offset by productivity, and that new customers are about the same in terms of usage, revenue, and cost of service as existing customers. However, as discussed in the sections *How Traditional Regulation Works and How Decoupling Works,* it is the very fact that the matching principle does not hold true (that is, that marginal revenue almost always exceeds marginal cost in providing distribution service) that drives the need for decoupling.

Correspondingly, a change to a more comprehensive approach to energy efficiency means that deliberate programs and policies are implemented to achieve sales reductions for which there are no corresponding cost reductions, at least (for the most part) in distribution services. The very circumstances that counsel most regulators to consider decoupling — a desire to step up the rate of achievement of customer energy efficiency — directly undermine the foundation of the matching principle.

12.2 "Decoupling adds cost."

This reflects a misunderstanding of decoupling. Decoupling increases the likelihood that the revenue requirement found appropriate in a rate case will be the amount actually collected from customers. Certain decoupling elements (e.g., adjustments for inflation, productivity, and numbers of customers) project how those approved costs might change, and allow these changes to be reflected in future collections; but these changes represent costs that are likely to be approved in a rate case, because they are essential to providing service. Decoupling itself adds no significant new costs; to the extent that decoupling reduces the frequency of general rate cases, it can significantly reduce regulatory costs.

12.3 "Decoupling shifts risks to consumers."

Full decoupling means that utility profits are no longer adversely affected by weather conditions that reduce sales volumes, and some critics consider this a shift of weather risk to consumers. This is a fundamentally flawed argument. First, decoupling also removes the profit enhancement that occurs under traditional regulation when weather conditions cause sales increases. Second, with current decoupling, although prices go up when sales go down, they do so simultaneously, so that customer bill volatility is reduced, a benefit to consumers attempting to live within a budget. In addition, when sales go up, prices come down, thereby mitigating the bill's impacts. In this sense, decoupling mitigates earnings risk for utilities and expense risk for consumers, making both better off — and in the process, it creates the earnings stability to justify a lower overall cost of capital, which reduces absolute costs to consumers.

12.4 "Decoupling diminishes the utility's incentive to control costs."

In fact, precisely the opposite is true. Decoupling does not guarantee utilities a level of earnings, only an assurance of a level of *revenue*. If the utility reduces costs, it increases earnings, just as it would under traditional regulation. Also, because the utility cannot increase profits by increasing sales, improved operational efficiency is the *only* means by which it can boost profits.

Because decoupling provides recovery of lost margin due to customer conservation efforts, however, it may extend the period between general rate cases. This is particularly true if aggressive utility conservation efforts are producing significant declines in customer usage; absent decoupling,

12 Decoupling Is Not Perfect: Some Concerns Are Valid

There are many critics of decoupling, and many different issues that they criticize. Decoupling is not a perfect form of regulation — but neither is conventional regulation. Both seek to set prices for utility service that approximate the cost of providing that service. Both seek to provide incentives for management to take actions to reduce costs and to maximize profits.

In this section, we discuss some of the common critiques of decoupling mechanisms, recognizing that all forms of regulation involve compromise.

12.1 "It's an annual rate increase."

Some rate case participants view decoupling as an annual rate increase without a rate case. This may be the case if the use per customer is declining over time, but it does not provide any indication of whether customer energy bills are rising or falling. That may be due to utility programs and policies, or it may be due to other factors that can be taken into account in the design of the decoupling mechanism.

If the decline in usage per customer is due to utility programs and policies, an annual upward rate adjustment (which produces annual decreases in annual bills due to declining usage) may be exactly why the decoupling mechanism was created. If energy efficiency is less expensive than energy production, then customer energy bills are declining. Absent decoupling, the utility would likely be filing annual rate cases, creating a significant workload on the Commission and leading to similar rate increases, since the underlying causes are the same.

To the extent that less frequent rate cases produce fewer opportunities for consumers to present policy issues to the Commission, it is probably appropriate for the regulator to create an alternative forum for such policy review. One approach, for example, might be for the regulator to initiate a general rate case at least once every three to five years, to ensure that the allowed revenues under decoupling do not deviate too far from the utility's underlying costs.

FACs and PGAs are therefore of great concern when trying to design a regulatory framework that encourages utility support of energy efficiency.[34] A properly designed decoupling mechanism can overcome this effect by assuring that only the allowed level of non-fuel or non-power revenues are received if utility sales increase.

11.5 Independent Third-Party Efficiency Providers

Several states have implemented third-party energy efficiency utilities, such as Efficiency Vermont and the Energy Trust of Oregon. Some advocates believe that by moving efficiency outside the utility, there is no longer a need for revenue decoupling, because the utility is no longer in a position to resist or obstruct energy efficiency investment. It is instructive that both Vermont and Oregon have found that revenue decoupling is a useful addition to a framework that includes a third-party provider, because utilities affect energy efficiency in many more ways than simply making grants and loans to consumers for energy efficiency measures.

11.6 Real-Time Pricing

Some academics have taken the position that dynamic utility pricing will result in efficient deployment of energy-efficiency measures, without any need for government or utility intervention. While advanced pricing has many advantages, it does not in any way overcome the multiple barriers to energy efficiency — such as access to capital, perfect information, or short time horizons of consumers, particularly renters. These barriers have been well-documented, and no form of energy pricing has been demonstrated to overcome them.

34 See Moskovitz, David, *Profits and Progress Through Least Cost Planning* for a detailed discussion of the problems with FACs and PGAs at: http://www.raponline.org/docs/rap_moskovitz_leastcostplanningprofitandprogress_1989_11.pdf

11.3 Straight Fixed/Variable Rate Design (SFV)

SFV is an approach to rate design in which all utility fixed costs are recovered in a fixed monthly charge, with only variable costs included in the per-therm or per-kWh rate. The definition of "fixed" costs varies from a strict accounting measure (interest and depreciation) to a broad measure that includes the return on equity, taxes, and labor expenses, but the principle is the same: customers do not pay for utility service on a primarily volumetric basis.

SFV is attractive due to simplicity, but has numerous adverse side effects. These include:

- Energy prices are set far below long-run marginal cost, leading to uneconomic usage;
- Small users, particularly seniors and apartment dwellers, pay much higher electric and gas bills;
- Consumer investment in energy efficiency is discouraged, since the bill savings are small;
- A mismatch occurs between the cost-responsibility and cost-collection for seldom-used peaking facilities (for which the costs should be recovered in incremental usage block rates).

Some studies have estimated that SFV pricing can cause usage to go up 10% or more, enough to offset much or all of the benefit of energy efficiency programs.[33]

11.4 Fuel and Purchased Energy Adjustment Mechanisms

Fuel adjustment clauses (FACs) and purchased gas adjustment (PGAs) mechanisms are used by nearly all gas utilities, and by most electric utilities, to recover variable costs of fuel and purchased energy. They evolved during the first and second oil embargoes in 1973 and 1977, and have become nearly ubiquitous. The benefit of these is that utilities are assured of recovery of a very large set of costs over which they have little control. The side effect is that an FAC or PGA ensures that ANY incremental sale is profitable, since ALL of the increased variable cost is covered, and the incremental sales margin results in incremental profit.

33 See *Pricing Do's and Don'ts*, www.raponline.org/docs/RAP_PricingDosAndDonts_2011_04.pdf

11 Other Revenue Stabilization Measures, and How They Relate to Decoupling

There are a number of other revenue stabilization measures used by regulatory commissions, some of which are proposed as possible alternatives to decoupling. Some of these provide nearly the same benefits to utility shareholders as decoupling, but all of them fall short of the full range of benefits that revenue decoupling provides, particularly those for consumers and the environment. We discuss several of these below, comparing the consumer impacts and societal benefits to those of decoupling.

11.1 Lost Margin Recovery Mechanisms

A lost margin mechanism provides recovery to the utility for distribution margin that is lost when customers participate in the utility-sponsored energy efficiency programs. The benefit is that the utility resistance to offering such programs is addressed. One side effect is creation of a bias in favor of utility-funded programs to the exclusion of codes, standards, and other lower-cost means to achieve savings. In one experience, a utility was simultaneously offering incentives for participation in its programs, while conducting a political campaign against other types of energy efficiency marketing, to ensure that any lost margins were recovered.

11.2 Weather-Only Normalization

Typically the largest rate adjustments under decoupling are weather-induced. Many natural gas utilities have weather normalization clauses, in which small surcharges are imposed during periods of mild weather, and small surcredits during severe weather. A weather-only adjustment does not address lost sales due to either programmatic energy efficiency on consumer-funded energy efficiency, and therefore does not address one of the principal objectives of decoupling, which is to eliminate utility disincentives for energy efficiency.

10.4 Consumer-Owned Utilities

Consumer-owned utilities (COUs) do not pay cash dividends, but they do need to maintain a sound bond rating to support future investments. The rating agencies look at the TIER (times interest earned ratio) of COUs.[32] Typical bond covenants for COUs obligate the utility to maintain its TIER above a minimum defined level, so they might be required to raise rates if they suffered severe earnings attrition (from any cause).

A loss of revenue due to conservation, weather, or other factors can impair the TIER, and therefore the borrowing capacity of a COU. A decoupling mechanism will provide the same stability of earnings for a COU as for an investor-owned utility (IOU). However, there is a smaller body of research on whether decoupling will actually have a meaningful effect on the borrowing costs of COUs, assuming that their TIER remains within a range in which they are able to borrow.

Without decoupling, COUs tend to set rates at levels that provide 75%-90% assurance that the TIER will remain at an acceptable level. It is clear that a decoupling mechanism will ensure that the TIER remains in an acceptable range, and that the COU will be able to borrow. A decoupling mechanism may thus allow a COU to set rates at a slightly lower level, without fear that a variation in weather or sales will cause it to fall to a level that would trigger a larger rate adjustment.

10.5 Earnings Caps or Collars

Some commissions have imposed an earnings cap, or an earnings collar, as part of a decoupling mechanism. These ensure that, if earnings are too high above a baseline (or too low below the baseline), the decoupling mechanism is automatically subject to review. Because decoupling reduces earnings volatility, it should be unlikely for earnings to vary outside a range of reasonableness. Therefore such a cap or collar, while unlikely to be triggered, may provide greater comfort with the change represented by decoupling.

Even so, in practical application, it is simpler to impose a cap on the variability in prices than in earnings, because the calculation of earnings for regulatory purposes can be significantly different than earnings reporting under generally accepted accounting principles and may invite disputes over methodology.

attempt to measure the change in probability that a utility would exhaust its ability to pay dividends from cash earnings, which is reduced if the utility is protected from variations in earnings driven by weather and economic cycles. These are factors that lead RAP to believe that adjusting the capital structure is more appropriate than adjusting the allowed return on equity when decoupling is implemented on a permanent basis. See Brattle Group, The Impact of Decoupling on the Cost of Capital, March, 2011.

32 TIER is a measure of the extent of which earnings are available to meet interest payments. Mathematically it is defined by this formula: TIER = (net income + interest) / (interest).

principal reason for preferring the equity capitalization option is that it can be implemented concurrently with the imposition of the risk mitigation measure, so that consumers receive an immediate economic benefit when the measure is implemented. The lag to a bond rating upgrade can be years, or as much as a decade; and the cost savings will phase in very slowly as new bonds are issued.

10.3 Risk Reduction: Reflected in ROE or Capital Structure?

Some ratepayer advocates have proposed an immediate reduction in the allowed return on common equity as a condition of implementing decoupling. This may create controversy in the ratemaking process, with the risk that utilities then become resistant to implementation of decoupling. Utilities have pointed to rate cases in other jurisdictions, where many of the "comparable" utilities used to estimate the required return on equity already have risk mitigation measures in place.

Economic theory supports the notion that risk mitigation is valuable to investors and that that value will (eventually) be revealed in some way in the market — through a lower cost of equity, a lower cost of debt, or a lower required equity capitalization ratio. Any of these will eventually produce lower rates for consumers, in return for the risk mitigation measure. Regardless of the theory, however, utilities may tend to view a reduction in the return on equity as a penalty associated with decoupling. In contrast, a restructuring of the capitalization ratio does not necessarily alter the required return on equity, and it is more directly reflective of the risk mitigation that decoupling actually provides — that is, stabilization of earnings with respect to factors beyond the utility's control. By reducing volatility, the utility needs less equity to provide the same assurance that bond coverage ratios and other financial requirements will be met.

Rating agencies have recognized the linkage between risk mitigation and the required equity ratio to support a given bond rating, rather than to the required return on equity. For this reason, there may be advantages to focusing on the utility's capital structure, rather than on its allowed return on equity or the cost of debt, when regulators consider how to flow through the risk-mitigation benefits of decoupling to consumers when a mechanism is put into place.[31]

31 One recent paper concluded that decoupling did not result in a decrease in the cost of equity capital in the short run. The study focused on only one approach to measure the cost of capital, the discounted cash flow method. It did not consider the reduction in systematic risk (the change in earnings relative to the change in the overall market earnings in the same period) that is measured by the Capital Asset Pricing Model. Decoupling will reduce systematic risk (reducing earnings volatility due to economic cycles) because sales variations in business cycles do not affect earnings under decoupling. The study also did not

Cost savings from implementation of decoupling can fully fund a modest energy conservation program at no incremental cost to consumers.

The overall impact is on the order of a 3% reduction in the equity capitalization rate, which in turn can produce about a 3% decrease in revenue required for the return on rate base, or about a 1% decrease in the total cost of service to consumers (including power supply or natural gas supply). This is not a large impact — but it is on the same order of magnitude as many utility energy conservation budgets, meaning that cost savings from implementation of decoupling can fully fund a modest energy conservation program at no incremental cost to consumers.

It is important to recognize that this type of change involves neither a reduction in the return on equity, nor a reduction in the allowed cost of debt. It simply reflects a realignment of the amount of each type of capital required.

A utility could adapt its actual capital structure to reflect this change, either by issuing debt rather than equity for a period of months or years, or by paying a special dividend (reducing equity) and issuing debt to replace that capital.

The second approach to reflecting the risk reduction afforded by decoupling is simply to reduce the utility's allowed return on equity, discounting by some number of basis points what would otherwise have been approved. This has been done in a number of jurisdictions. There are, however, several points that regulators should consider when weighing this option against the first.

10.2 Some Impacts May Not Be Immediate, Others Can Be

If rating agencies perceive that a risk mitigation measure will be in place for an extended period, they may be willing to recognize the benefit of risk mitigation immediately upon implementation. If the risk mitigation measure is put in place only for a limited period, or the regulatory commission has a record of changing its regulatory principles frequently, the rating agency may not recognize the measure.

If the regulator does not change the allowed equity capitalization ratio when a new risk mitigation measure is implemented, the rating agency will eventually realize that the mitigation is occurring, and that earnings are more stable; and eventually a bond rating upgrade is possible. Once that occurs, the cost of debt will eventually decline, and consumers will realize the benefit of lower costs of debt in the conventional ratemaking process.

In theory, the total cost savings from a bond rating upgrade should be about the same as the savings from an equity capitalization reduction. The

10.1 Rating Agencies Recognize Decoupling

The bond rating agencies have come to recognize that decoupling mechanisms, weather adjustment mechanisms, fuel and purchased-gas adjustment mechanisms, and other outside-the-rate-case adjustment mechanisms all reduce net earnings volatility and risk, and therefore contribute to a lower cost of capital for the utility. It is important when selecting "comparable" utilities for cost of capital studies to use only utilities with similar risk-mitigation tools in place, so that an apples-to-apples comparison is possible.

Standard and Poor's has explicitly recognized risk mitigation measures by rating the "business risk profile" of utility sector companies on a scale of 1 to 10. The distribution utilities without supply responsibility and with risk mitigation measures are mostly rated 1 to 3, whereas the independent power producers without stable customer bases or any risk mitigation measures are 7 to 10. The vertically integrated utilities with some risk mitigation measures are in between.[30]

The risk mitigation of decoupling can be reflected in either of two ways. First, it can be directly applied to reduce the equity capitalization ratio of the utility in a rate case. This has the effect of reducing the overall cost of capital and revenue requirement, without changing either the cost of debt or the allowed return on equity. This approach recognizes that a utility with more stable earnings does not require as much equity in its capital structure, because there is less likelihood of the utility depleting its retained earnings.

Table 12 summarizes how a change in the equity capitalization ratio reduces the revenue requirement.

Table 12

Quantification of Savings from Capital Structure Shift

Element	Allowed Return	Ratio w/o Decoupling	Ratio with Decoupling
Equity	11%	45%	42%
Debt	8%	55%	58%
Overall Return with Taxes		10.48%	10.13%
Revenue Requirement ($ millions)		$104.80	$101.30
Difference			-$3.50

30 See Standard and Poor's *New Business Profile Scores Assigned for US Utility and Power Companies: Financial Guidelines*, revised 2 June 2004. See also Moody's Investor Services, *Local Gas Distribution Companies: Update on Revenue Decoupling And Implications for Credit Ratings*, 2006, and Standard and Poor's, *Industry Report Card: U.S. Electric Utilities Well Positioned For 2011 Challenges*, December 10, 2010.

10 Earnings Volatility Risks and Impacts on the Cost of Capital

Utility earnings can be volatile because of the way weather and other factors influence sales volumes and revenues in the short run, without corresponding short-run impacts on costs. They can also be volatile because of the way weather and other factors influence costs in the short run, without corresponding short-run impacts on revenue (such as a drought has on a hydro-dependent utility). As a result of this volatility, utilities typically retain a relatively higher level of equity in their capital structure, so that a combination of adverse circumstances (adverse weather, economic cycle, cost pressures, and customer attrition) does not render them unable to service their debt. In addition, utilities also try to pay their dividends with current income or from retained earnings. In fact, most bond covenants prohibit paying dividends if retained earnings decline below a certain point. A utility that is forced to suspend its dividend is viewed as a higher-risk venture.

Decoupling can significantly reduce earnings volatility due to weather and other factors, and can eliminate earnings attrition when sales decline, regardless of the cause (e.g., appliance standards, energy codes, customer- or utility-financed conservation, self-curtailment due to price elasticity). This in turn lowers the financial risk for the utility, and that is reflected in the company's cost of capital.

The reduction in the cost of capital resulting from decoupling could, if the utility's bond rating improves, result in lower costs of debt and equity; but this generally requires many years to play out, and the consequent benefits for customers are therefore slow to materialize. New debt issues will carry lower interest rates, but utility bonds carry long maturities, and it can take 30 years or more to roll over all of the debt in a portfolio.

Alternatively, a lower equity ratio may be sufficient to maintain the same bond rating for the decoupled utility as for the non-decoupled utility. This would allow the benefits associated with the lower risk profile of the decoupled company to flow through to customers in the first few years after the mechanism is put in place. However, for this to be justified, the investors must have confidence that the decoupling mechanism will remain in effect for many years; a typical three-year approval period may not provide that confidence.

adjusts prices to maintain the allowed revenue requirement. Any change in consumption associated with weather or other causes will result in an inverse change in prices, according to the following formula:

***Formula 6:* Price = Allowed Revenue ÷ Actual Units of Consumption**

As consumption rises, prices are reduced. As consumption falls, prices are increased. This means that decoupling will mitigate the higher overall bill increases associated with extreme weather and mitigate overall bill decreases associated with mild weather. With full decoupling, all changes in units of consumption, regardless of cause, are translated into price changes to maintain the allowed revenue level. Thus, no matter the amount of consumption, the utility and the consumers as a whole will receive and pay the allowed revenue. Neither the company nor its customers are exposed to weather or economic risks in this case.

Under partial decoupling, only a portion of the indicated price adjustment is collected or refunded. To the extent the adjustment falls short of recovering the indicated price adjustment, both weather and economic risks are placed upon the utility and its customers.

Under limited decoupling, the weather or economic risks may be selectively imposed on the utility and its customers. Some states have preserved the existing burden of weather risk in a decoupled environment by weather-normalizing actual unit sales before computing the new price under limited decoupling. This has the effect of fully exposing the utility and its customers to weather risk.

Conversely, one might limit the changes in unit sales to those directly attributable to efficiency programs. Lost margin mechanisms, discussed later in *Other Revenue Stabilization Measures*, are one example of this type of limited decoupling. This has the effect of preserving all of the risks, including weather and economic risks, customers and the utility bear under traditional regulation.

Any risks placed on the utility and its customers will likely increase the overall revenue requirement of the utility because of its impact on the utility's financial risk profile. This is explored further in the following section, *Earnings Volatility Risks and Impacts on the Cost of Capital.*

utility's Revenue Requirement. Also, if extreme weather occurs as often as mild weather, over time the utility's revenues will, on average, approximate the revenue requirement. In theory, this protects the company from under-recovery, and customers from over-payment of the utility's cost of service — because there should be an equal chance of having weather that is more extreme or milder than normal.

With traditional regulation, in economic terms, weather-driven sales changes cause a wealth transfer between the utility and its customers which is unrelated to what the utility needs to recover and what customers ought to pay.

In reality, this is hard to accomplish, because in any given year, the actual weather is unlikely to be normal. Thus, even if the traditional methodology results in prices that are "right" and the weather normalization method used was accurate, the actual revenues collected by the utility and paid by the customers will be a function of the actual units of consumption, which are driven, in large part, by actual weather conditions, according to the following formula:

***Formula 3:* Actual Revenues = Price * Actual Units of Consumption**

With this formula, extreme weather increases sales above those assumed when prices were set, in which case utility revenues and customer bills will rise. Conversely, mild weather decreases utility revenues and customer bills.

To the extent that the utility's costs to provide service due to the weather-related increases or decreases in sales do not change enough to fully offset the revenue change, then the utility will either over- or under-recover its costs. With traditional regulation, in economic terms, weather-driven sales changes cause a wealth transfer between the utility and its customers that is unrelated to the amount that the utility needs to recover and that customers ought to pay. This transfer is not a function of any explicit policy objective. Rather, it is simply an unintended consequence of traditional regulation. There is a volatility risk premium embedded in the utility's cost of capital that reflects the increased variability in earnings associated with weather risk. This premium may be reflected in the equity capitalization ratio, the rate of return, or both.

9.2 The Impact of Decoupling on Weather and Other Risks

Full decoupling causes a utility's non-production revenues to be immune to both weather and economic risk. Once the revenue requirement is determined (in the rate case or via the RPC adjustment), decoupling

9 Weather, the Economy, and Other Risks

While traditional regulation aims to determine a utility's costs and then provide appropriate prices to recover those costs, there are a number of factors that prevent this from happening. Foremost among these are the effects of weather and economic cycles on utility sales and customer bills. These effects are directly related to how prices are set. Full or limited decoupling, and some forms of partial decoupling, will have a direct impact on the magnitude of these risks.

For the most part, full decoupling will eliminate these risks completely. Limited decoupling partially eliminates these risks. Partial decoupling may or may not affect these risks, depending upon whether the presence of a particular risk is desired.

9.1 Risks Present in Traditional Regulation

The ultimate result of a traditional rate case is the determination of the prices charged consumers. In simple terms, a utility's prices are set at a level sufficient to collect the costs incurred to provide service (including a fair rate of return — the utility's profits). Because most of the revenues are normally collected through volumetric prices, based on the amount of energy consumed or the amount of power demanded, the assumed units of consumption are critical to getting the price "right."[29]

As noted earlier, the basic pricing formula under traditional regulation is:

***Formula 13:* Price = Revenue Requirement ÷ Units of Consumption**

This formula is applied using Units of Consumption associated with normal weather conditions. As long as the units of consumption remain unchanged, the prices set in a rate case will generate revenues equal to the

29 By "right," we mean consistent with the cost of service methodology.

accruing credits for the following year.

Unlike commodity adjustment clauses, however, there are no forecasting components needed in decoupling. This is true even for utilities whose rate cases use a future test year. While future test years necessarily involve forecasting the revenue requirement, the calculation of the actual price to be charged to collect that revenue requirement is a function of actual units of consumption. To calculate the price with Revenue Cap Decoupling, one need only divide the Allowed Revenue by the Actual Unit Sales. To calculate the price with RPC Decoupling, one must first derive the Allowed Revenues (based on the current number of customers), and then divide that number by Actual Unit Sales. In either case, all of the information needed to make the calculation is known at the time that customer bills are prepared. For this reason, the required decoupling price adjustment can be applied on a current rather than an accrual basis. This also means there will be no error in collection associated with forecasts of consumption and, hence, no need for a reconciliation process.

This can be done by using the same temperature adjustment data used to produce the test-year normalized results, except to calculate a daily or monthly (or more likely a billing cycle) RPC with the data, not just an annual RPC. In each billing cycle, the "allowed" RPC can be a time-weighted average of the number of days in each month of the year included in the billing cycle,[27] or it can be built up from daily information.[28]

27 For example, if the allowed RPC is $50 for March and $40 for April, and the billing cycle runs from April 16 to March 15 (i.e., 15 days in April and 15 days in March), the allowed RPC would be $45.

28 For more information on this point, see section 3.1.1.2 Non-Production Costs.

8 Application of Decoupling – Current vs. Accrual Methods

Under traditional regulation, utilities have often had different adjustment factors on customer bills. Perhaps the most common is the fuel and purchased-power adjustment clause (FAC) for electric utilities and the purchased gas adjustment (PGA) clause for gas utilities. In both of these cases, utilities compute the actual costs for these items, and then customer bills are adjusted to reflect changes in those costs. There is often a lag in the determination of these costs, and the adjustment factor itself is often based on the forecast units of sales expected in the period when adjustment will be collected. As a result, actual collections usually deviate from expected collections, and a periodic reconciliation must be made to adjust revenues accordingly.

In the application of decoupling, many states use a similar approach or make the calculations on an annual basis. Any accrued charges or credits are held in a deferral account for subsequent application to customers' bills. When applied in this manner, the same reconciliation routines are used to assure collection of the amounts in the accrual account.

The variations in rates and bills caused by decoupling mechanisms are typically very small compared with those caused by FAC and PGA mechanisms. While decoupling adjustments tend to deal with variations in usage of a few percent, the price of natural gas can change by 50% or more over the year after a general rate case. Further, as described earlier, decoupling tends to moderate billing variations, whereas the FAC and PGA mechanism tend to magnify bill variations, because the cost of gas tends to rise in cold winters when demand is highest, and the cost of power tends to rise in the summer with cooling-related demands.

When a lag is present in the application of these adjustments, it has the effect of disassociating individual customers from their respective responsibility for the adjustment. The result may be a shift in revenue responsibility among those customers, and between years. For example, if a warmer-than-average winter produces a significant deferral of costs to be collected, and it is collected the following year, it is possible that the surcharge will be effective during a colder-than-average winter, exacerbating customer bill volatility, during a period when the customer is otherwise

Establishing theoretically defensible rate designs such as those used by PG&E provides consumers with very clear economic signals about the costs their usage imposes, but evidence in California is that even with these high prices, utility energy efficiency programs are an essential element of a successful energy policy. The inverted rates tend to drive consumers to the programs, but if the programs are not available, they may be unlikely (or unable) to respond to the incremental cost-based prices.

Decoupling is a tool that allows the utility's interest in stable net revenues, the consumer's interest in stable bills, and the society's interest in cost-based pricing all to be met. Under decoupling, the utility can implement an inverted rate, knowing that lost distribution revenues that are incurred when sales decline will be recovered. If implemented on a "current" basis as proposed in Section 8 of this report, decoupling can also stabilize customer bills, by reducing the unit rates in months when extreme weather causes a significant variation in sales from the levels assumed in the rate case where rates are set.

7.3.4 Time-of-Use Rates

Rates that collect much higher amounts during the on-peak hours can convey to consumers that usage during those hours puts the entire system under stress and causes investment in new peaking capacity. However, peak-hour consumption is highly weather-sensitive, so time-of-use (TOU) rates make utility revenues more weather-sensitive, just like inverted block rates. Decoupling removes the revenue stability risk associated with TOU rates, allowing the utility to have efficient prices and still be assured of recovering non-production costs in years when weather is mild.

7.4 Summary: Rate Design Issues

A hypothetically "correct" rate design for an electric and gas utility can consist of a customer charge that recovers metering and billing costs (these are both incremental and decremental with changes in customer count) and an inverted block rate structure based on the load factors of typical end-uses. The rates shown for PG&E in California are designed along these lines.

For electric utilities, lights and appliances have steady year-round usage characteristics, and therefore the lowest cost of service. For gas utilities, water heating, cooking, and clothes drying have steady year-round usage characteristics. For both types of utilities, space conditioning (heating and cooling) loads, which are associated with the upper blocks of usage, have the lowest load factors, and therefore the highest costs of service.

Taking a hypothetical electric utility with typical meter reading and billing costs, capacity costs of $15/kW per month, and energy costs of $.05/kWh produces the following cost-based rate design:

Table 11

Cost-Based Rate Design - Hypothetical Rates

Rate Element	Load Factor	Capacity Cost	Energy Cost	Total Cost
Customer Charge				$5.00
First 400 kWh Lights/Appliances	70%	$0.03	$0.05	$0.08
Next 400 kWh Water Heat	40%	$0.05	$0.05	$0.10
Over 800 kWh Space Conditioning	20%	$0.10	$0.05	$0.15

confused customers. Simple commodity billing was the easiest way to make cost comparisons possible for consumers. As natural gas utilities have taken on more of the characteristics of monopoly providers, they have sought to increase fixed charges.

The California utilities, under decoupling, have retained zero or minimal customer charges. In several cases, such as with the PG&E rates discussed earlier in Section 7, it comes in the form of a "disappearing minimum bill," in which customers with zero consumption pay a minimum amount, but once usage passes 100 kWh or so (and 99% of consumption is by customers exceeding this minimum), they pay only for the energy used. In December 2008, the Public Service Commission of Wisconsin approved a settlement of the parties that, among other things, created a decoupling mechanism for Wisconsin Public Service Corporation and, at the same time, reduced the level of fixed customer charges.[26]

7.3.2 Inverted Rate Blocks

Inverted block rates, of the type shown earlier for PG&E, serve several useful functions. First, they align incremental rates with incremental costs, including incremental capacity, energy and commodity, and environmental costs. Second, they recognize that upper-block usage (mostly for space conditioning) is characterized by high seasonality, usage concentrated during the peak hours, and low load-factor end-uses, all of which are more expensive to serve than other end-uses. Inverted block rates therefore properly collect the appropriate costs from these infrequent but expensive end uses. They also serve to encourage energy efficiency and energy management practices by consumers. However, they reduce net revenue stability for utilities by concentrating recovery of return, taxes, and O&M expenses in the prices for incremental units of supply, which tend to vary greatly with weather and other factors.

7.3.3 Seasonally Differentiated Rates

Seasonal rates are typically imposed in service territories whose utilities experience significant seasonal cost differences. For example, a gas utility with a majority of its capacity costs assigned to the winter months will typically have a higher winter rate than summer rate. With traditional regulation, seasonal rates reduce net revenue stability for utilities, by concentrating revenue into the weather-sensitive season.

26 Docket 6690-UR-119, *Application of the Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates*, Order of December 30, 2008.

production component of the rate design automatically declines, so that they pay the allowed revenue requirement (and no more) for distribution services. Conversely, when weather is unusually mild, and customer usage declines, they would pay slightly more per unit for distribution services, again ensuring the utility receives its allowed revenue. This effect is most pronounced when decoupling is applied on a current, rather than an accrual basis, as discussed later.

7.3 Rate Design Opportunities

In 1961, James Bonbright published what is considered the seminal work on ratemaking and rate design for regulated monopolies. His context was, of course, traditional price-based utility regulation, and he identified eight principles, some of which are in tension with each other, to guide the design of utility prices. That tension is demonstrated in particular by three of those principles — that rates should yield the total revenue requirement, they should provide predictable and stable revenues, and they should be set so as to promote economically efficient consumption.[24] In certain instances, more economically efficient pricing structures could lead to customer behavior that results in less stable and, in the short run, significant over- or under-collections of revenue. Decoupling mitigates or eliminates the deleterious impacts on revenues of pricing structures that might better serve the long-term needs of society. Some innovative rate designs that regulators may want to consider with decoupling include:

7.3.1 Zero, Minimal, or "Disappearing" Customer Charge

A zero or minimal customer charge allows the bulk of the utility revenue requirement to be reflected in the per-unit volumetric rate. This serves the function of better aligning the rate for incremental service with long-run incremental costs, including incremental environmental and supply costs that may already be trending upward.[25] During the early years of the natural gas industry, this type of rate design was almost universal, as the industry was competing to secure heating load from electricity and oil, and imposing fixed customer charges would have disguised the price advantage being offered and

24 Bonbright, James C., *Principles of Public Utility Rates*. Columbia University Press, New York, 1961, p. 291.

25 For electric utilities depending on coal for the majority of their supply, valuing CO2 at the levels estimated by the EPA to result from passage of the Warner-Lieberman bill (in the range of $30 to $100/tonne) would add up to $.03/kWh to $.10/kWh to the variable costs of electricity. For natural gas utilities, the environmental costs of supply are on the order of $0.30/therm, or approximately equal to total distribution costs for most gas utilities. See http://www.epa.gov/climatechange/economics/economicanalyses.html.

7.1 Revenue Stability Is Important to Utilities

Clearly these rate designs produce a great deal of revenue volatility for the utility. Without decoupling, the utility could face extreme variations in net income from year to year. However, with decoupling, this type of rate design produces very stable earnings. The earnings per share for PG&E (the utility) for the past three years (since decoupling was restored after the termination of the California deregulation experiment) have been $1.01 billion, $971 million, and $918 million. This stability was achieved despite a $1.4 billion increase in operating expenses, mostly the cost of electricity, during this period.

The revenue stability needs of the company can conflict with principles of cost-causation as they relate to pricing. Utilities are interested in revenue stability, so that they have net income that can predictably provide a fair rate of return to investors, regardless of weather conditions, business cycles, or the energy conservation efforts of consumers. Cost-of-service considerations, however, can produce a very different result. To the extent that utility fixed costs are associated with peak demand (peaking resources, transmission capacity, natural gas storage, and liquefied natural gas (LNG) facilities) and those capacity costs are allocated exclusively to increased use in winter and summer months, the cost to consumers of incremental usage is dramatically higher than the cost of base usage.

A steeply inverted block rate design, such as those used by PG&E, correctly associates the cost of seldom-used capacity with the (infrequent) usage for which that capacity exists. Although this is arguably fair, doing so can result in serious revenue stability problems for the utility. Decoupling is one way to provide revenue stability for the utility, without introducing rate design elements such as high fixed monthly charges, in the form of a Straight Fixed/Variable rate design, that remove the appropriate price signals to consumers.

7.2 Bill Stability Is Important to Consumers

Customers also have an interest in bill stability, because in extremely cold winters or hot summers, their bills can quickly become unmanageable. Absent decoupling, rates such as those used in California, while accurately conveying the real cost of seldom-used capacity, accentuate bill volatility. In a hot summer or cold winter, consumer bills can soar as their end-block usage increases. With decoupling (and budget billing), however, customers can enjoy bill stability at the same time that utilities enjoy revenue stability, without the adverse impacts on usage that a Straight Fixed/Variable rate design can cause. When their usage (as a group) increases, the nonrevenues at a greater rate than it will produce savings in short-run costs, simply because most distribution, billing, and administrative costs are relatively fixed in the short run.

Conversely, with decoupling, the utility no longer experiences a net revenue decrease when sales decline, and will therefore be more willing to embrace rate designs that encourage customers to use less electricity and gas. This can be achieved through energy efficiency investment (with or without utility assistance), through energy management practices (turning out lights, managing thermostats), or through voluntary curtailment.

Currently, the best examples of this are the natural gas and electric rate designs used by California electricity and natural gas utilities, where decoupling has been in place for many years. The residential rates applicable to most customers of Pacific Gas and Electric (PG&E), typical of those of all gas utilities and at least the investor-owned electric utilities in the state, are shown in Table 9. Both the gas and electric rates are set up with a "baseline" allocation, which is set for each housing type and climate zone. Neither rate has a customer charge, although there is a minimum monthly charge for service. If usage in a month falls below the amount covered by the minimum bill, the minimum still applies.

Table 9

PG&E Natural Gas Rate at May 1, 2008

Rate Element	Baseline Quantities	Excess Quantities
Minimum Monthly Charge	~$3.00	
Base Rate per therm	$1.45131	$1.68248
Multi-Family Discount (per unit per day)	$0.01770	$0.17700
Low-income Discount (per therm)	$0.29026	$0.33650
Mobile Home Park Discount (per unit per day)	$0.35600	$0.35600

Table 10

PG&E Natural Gas Rate at May 1, 2008

Rate Element	Low Income	All Other Customers
Minimum monthly Charge	~$3.50	~$4.45
Baseline Quantities	$0.83160	$0.11559
101%-130% of Baseline	$0.09563	$0.13142
131%-200% of Baseline	$0.09563	$0.22580
201%-300% of Baseline	$0.09563	$0.31304
over 300% of Baseline	$0.09563	$0.35876

7 Rate Design Issues Associated With Decoupling

As it does with respect to increased investment in end-use energy efficiency itself, decoupling should also remove traditional utility objections to electric and natural gas rate designs that encourage conservation, voluntary curtailment, and peak load management. For example, assuming average usage of 500 kWh/month, the two following rate designs produce the same amount of revenue, but the volumetric rate provides a much stronger price signal for consumers to pursue energy efficiency:

Table 8

High vs. Low Customer Charges		
Rate Element	**High Customer**	**Low Customer**
Customer Charge	$25.00	$5.00
Usage Charge	$0.10	$0.14
Total Bill for 500 kWh average usage	$75.00	$75.00

Under volumetric pricing without decoupling, utilities have a significant portion of their revenue requirement for rate base and O&M expenses associated with throughput. In addition, those with fully reconciled fuel and purchased-power adjustment mechanisms completely recover the high cost of augmenting power supply during peak periods when expensive power resources are used, so even increased peak-period sales generate a distribution sales margin.[23] A reduction of throughput will likely reduce

23 See Subsection 3.1.1.1 above, and Moskovitz, *Profits and Progress Through Least Cost Planning*, 1990, at pp. 3-5. Fuel adjustment mechanisms are the antithesis of energy efficiency mechanisms. They guarantee that any additional sale, no matter how expensive to serve, adds to profit, and any foregone sale diminishes profitability. This is because the clauses ensure that the marginal fuel or purchase cost of incremental sales will be fully recovered, so that the non-production cost component of base rates will always contribute to the bottom line (by either increasing profits or reducing losses). www.raponline.org/Pubs/General/Pandplcp.pdf .

Table 6

Single RPC for Existing and New Customers	Existing Customers	New Customers	Total
Number of Customers	200,000	10,000	210,000
Revenue per Customer	$50.00	$50.00	
Allowed Revenues	$10,000,000	$500,000	$10,500,000
Average Unit Sales	500	450	
Decoupled Price	$0.100478	$0.100478	
Collected Revenues	$10,047,847	$452,153	$10,500,000
Average Customer Contribution	$50.24	$45.22	$50.00

To correct for this, a separate RPC value can be calculated for new customers — in our example, the amount for them would be $45.00. As shown in Table 7, the RPC allowed revenues would not be increased from $10,000,000 to $10,025,000. Instead, the increase would be equal to only $22,500.

This results in collection of an average of $50.00 from existing customers and $45.00 from new customers, thus reflecting the overall lower usage of new customers. On a total basis, the average revenues per customer are equal to $49.76. Accounting for these differences affects the *allowed* revenue to assure no over- or under-recovery, while differences in bills for these two types of customers are automatically reflected in their respective units of consumption applied to the decoupled price.

Table 7

Separate RPC for Existing and New Customers	Existing Customers	New Customers	Total
Number of Customers	200,000	10,000	210,000
Revenue per Customer	$50.00	$45.00	
Allowed Revenues	$10,000,000	$450,000	$10,450,000
Average Unit Sales	500	450	
Decoupled Price	$0.100000	$0.100000	
Collected Revenues	$10,000,000	$450,000	$10,450,000
Average Customer Contribution	$50.00	$45.00	$49.76

6 Application of RPC Decoupling: New vs. Existing Customers

As much as half of the change in average usage per customer over time may be explained by differences between existing and new customers. Where new customers, on average, have significantly different usage than existing customers, their addition to the decoupling mechanism can result in small cross-subsidies.

New customers may be significantly different from existing customers. For example, new building codes and appliance standards may mean that new customers are fundamentally more efficient. Typical new homes may be larger or smaller than the average of existing homes (or may reflect a different mix of single-family and multi-family construction). If urban areas are becoming more densely populated, it may mean that new customers are closer together, and thus there is a smaller distribution system investment per customer. If line extension policies require new customers to pay a larger share of distribution system expansion costs than existing customers did, the investment added to the utility rate base per customer may be smaller for new customers. If the regulator is concerned that there may be meaningful differences between new and existing customers, it can require the utility to perform a detailed analysis of usage characteristics (quantity, seasonality, time-of-day) for each cohort of customers connected to the system.

Where new customers, on average, have significantly different usage than existing customers, their addition to the decoupling mechanism can result in small crosssubsidies

As illustrated in Table 6, new customers, on average, use 450 kWh in a billing period, but the rate case-derived RPC for existing customers is 500 kWh, application of the test year RPC values to new customers has the effect of causing old customers to bear the revenue burden associated with the 50 kWh not needed or used by new customers. This is because the allowed revenue is increased by an amount associated with 500 kWh of consumption, whereas the actual contribution to revenues from the new customers is only the amount associated with 450 kWh.

5.5 Need for Periodic Rate Cases

It is useful to have periodic rate cases in which all costs, expenses, investments, programs, policies, and tariff designs can be examined. Many regulators have required general rate cases every three to five years as part of decoupling (or set expiration dates for the decoupling mechanism). Another approach would be a built-in decline in the allowed revenue (or RPC) after three to five years. This would allow the utility to avoid a new general rate case (in which all of the utility's costs would be examined), but only if it reduced customer bills. This leaves the utility with the option to continue to retain a portion of expense containment savings motivated by decoupling (see Formula 4) without a rate case, if it can reduce costs sufficiently to give consumers a measurable benefit.

5.6 Judging the Success of a Revenue Function

One of the shortcomings of traditional utility pricing approaches is that a utility's actual revenue collection can be significantly higher or lower than its actual cost of providing service. The different revenue functions that can be applied with decoupling offer means of keeping the utility's revenue collections much closer to its actual cost of service over time. This should result in smaller rate case revenue deficiencies or excesses, lessening their associated potential for "rate shock."

A "successful" revenue function would be one that keeps the utility's actual revenue collection as close as possible to its actual cost of service throughout the period between rate cases. Indeed, the theoretically ideal result, by this standard, would be to have a zero revenue deficiency or excess in the next rate case and at most points in between, meaning that rates had tracked costs perfectly over time.

Of course, when judging the revenue function on this basis, one should disregard special circumstances that may cause a significant revenue deficiency, such as large additions to the utility's plant-in-service accounts (e.g., the addition of a new transmission line, the installation of an expensive new management information system, or the deployment of smart-grid advanced metering infrastructure).

inflation-minus-productivity method or the RPC method; it could be, for example, a specified percentage per year. Although one could vary the K factor itself over time, in this context the most likely application would simply set an annual between-rate-case growth rate for revenues, resulting in a steady change (probably an increase) in year-to-year allowed revenues for each period between rate cases. Such an approach has a high degree of certainty, but runs the risk of being disassociated from, and therefore out of sync with, measurable drivers of a utility's cost of service. All of the data used in a rate case change over time, and the elements making up the K factor are no different. The K factor therefore may become obsolete within a few years, providing another reason why periodic general rate cases should be required by regulators under decoupling (and, arguably, under traditional regulation as well).

A "successful" revenue function would be one that keeps the utility's actual revenue collection as close as possible to its actual cost of service throughout the period between rate cases.

An alternative approach is to use the K factor as an adjustment to the RPC allowed revenue determination. Here, the K factor growth rate (positive or negative) would be applied to the RPC values, rather than to the allowed revenue value itself. This approach would be useful when an additional revenue requirement is anticipated due to identifiable increases in revenues from capital expenditures or operating expenses, or because of some underlying trend in the RPC values. An example would be a utility with a distribution system upgrade program driven by reliability concerns, where the investment is not generating new revenue. It may also be used as an incentive for the utility to make specific productivity gains, in which case the K factor would be a negative value causing revenues to be slightly lower than they otherwise would have been.

In any case, allowed revenues would still be primarily driven by the number of customers served, but the revenue total would be driven up or down by the K factor adjustment.

Formula 11: **Revenue Per Customer** $_{\text{ALLOWED}}$ **=**
Revenue Per Customer $_{\text{TEST PERIOD}}$ *** K**
Formula 12: **Revenues** $_{\text{ALLOWED}}$ **= Revenue Per Customer** $_{\text{ALLOWED}}$ **X**
No. of Customers $_{\text{ACTUAL}}$
Formula 10: **Price** $_{\text{ACTUAL}}$ **= Revenues** $_{\text{ALLOWED}}$ **÷ Units Sold** $_{\text{ACTUAL}}$

billing period, normal seasonal variations in consumption are automatically captured. This causes revenue collection to match the underlying seasonal consumption patterns of the customers.

Some decoupling schemes exclude very large industrial customers. Because the rates for these customers are often determined by contractual requirements and specified payments designed to cover utility non-production costs, there may be little or no utility throughput incentive opportunity relating to these customers anyway. Also, in many utilities, this class of customers may consist of only a small number of large and unique (in load-shape terms) customers, so that a "class" approach is not apt.

In cases in which new customers (that is, those who joined the system during the term of the decoupling plan) have significantly different consumption patterns (and, therefore, revenue contributions to the utility) than existing customers, regulators may want to modify the decoupling formula to account for the difference. This can be accomplished by using different RPC values for new customers and existing customers. The nature of this issue and methodologies for addressing it are discussed in Section 6, *Application of RPC Decoupling: New vs. Existing Customers.*

5.3 Attrition Adjustment Decoupling

Some jurisdictions take a different approach to decoupling. They set base rates in a periodic major rate case, then conduct annual abbreviated reviews to determine whether there are particular changes in costs that merit a change in rates. In such instances, the regulators adjust rate base and operating expenses only for known and measurable changes to utility costs and revenues since the rate case, and adjust for them through a small increment or decrement to the base rates (called "attrition adjustments"). The regulators normally do not consider more controversial issues such as new power plant additions or the creation of new classes of customers, which are reserved for general rate cases.

In attrition decoupling, the utility's allowed revenue requirement is the amount allowed in the first year after the rate case, plus the addition (or reduction) that results from the attrition review. Every few years, a new general rate case is convened to re-establish a cost-based revenue requirement considering all factors.

5.4 K Factor

The K factor is an adjustment used to increase or decrease overall growth in revenues between rate cases.

In its simplest application, the K factor can be used in lieu of either the post-rate-case period, the allowed revenues for energy and demand charges are calculated by multiplying the actual number of customers served by the RPC value for the corresponding billing period. The decoupling adjustment is then calculated in the manner detailed in the earlier sections.

Formula 9: **Revenues $_{\text{ALLOWED}}$ = Revenue per Customer $_{\text{TEST PERIOD}}$ X No. of Customers $_{\text{ACTUAL}}$**

Formula 10: **Price $_{\text{ACTUAL}}$ = Revenues $_{\text{ALLOWED}}$ ÷ Units Sold $_{\text{ACTUAL}}$**

The table below demonstrates the RPC calculations for three billing periods for a sample small commercial rate class. In this example, the billing periods are assumed to be monthly. Note that the revenues per customer are different in each month, because of the seasonality of consumption in the test period.[22]

By calculating the energy and demand revenues per customer for each

Table 5

Deriving the Revenue per Customer Values

Small Commercial Class Example
Test Period Values

Billing Period	**1**	**2**	**3**
Number of Test Period Customers	142,591	142,769	142,947
Customer Charge	$25.00	$25.00	$25.00
Total Customer Charge Revenues	$3,564,775	$3,569,225	$3,573,675
Energy Revenue per Customer			
Energy Sales (kWh)	181,238,883	189,304,436	170,240,013
Rate Case Price	$0.165	$0.165	$0.165
Total Energy Sales Revenues	$29,904,416	$31,235,232	$28,089,602
Energy Revenue per Customer	$209.72	$218.78	$196.50
Demand Revenue per Customer			
Demand Sales (kW)	1,189,355	1,165,396	1,148,975
Rate Case Price	$4.4600	$4.4600	$4.4600
Total Demand Sales Revenues	$5,304,523	$5,197,667	$5,124,429
Demand Revenue per Customer	$37.20	$36.41	$35.85

22 Most utilities typically have 22 or 23 billing cycles per month. For simplicity, we have assumed here that all customers in a month are billed in the same billing cycle (one per month). In the future, with new "smart" metering and communication platforms, a single billing cycle per month, for all customers, may be possible.

Table 4

Lines & Feeders

Growth in Lines & Feeders Investment vs. Growth in System Peak

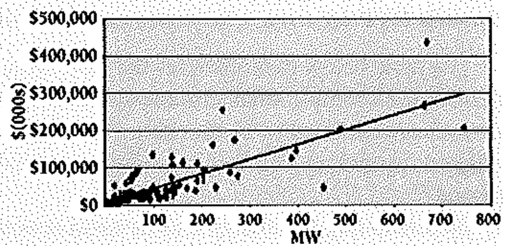
(Five Year Adjusted Average, 1995-1999)

Statistical Summary

Standard Deviation . . $2,129,439

Average $608,215

Correlation 0.80



Growth in Lines & Feeders Plant Investment vs. Growth in System Energy

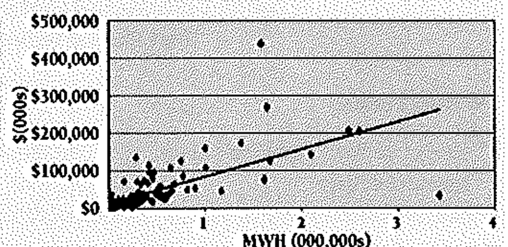
(Five Year Average, 1995-1999/Excludes Negative Growth)

Statistical Summary

Standard Deviation $606

Average $74

Correlation 0.53



Growth in Lines & Feeders Plant Investment vs. Growth in Customers

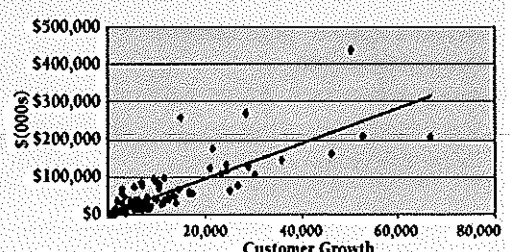
(Five Year Average, 1995-1999/Excludes Negative Growth)

Statistical Summary

Standard Deviation $13,191

Average $4,551

Correlation 0.82



5.2 Revenue-per-Customer (RPC) Decoupling

As noted earlier, analysis has shown that, in the time between rate cases, changes in a utility's underlying costs vary more directly with changes in the number of customers served than they do with other factors such as sales, although the correlation on a total expense basis to any of these is relatively weak. When examining only non-production costs, however, the correlations are much stronger, especially for the number of customers.

In 2001, we previously studied the relationships between drivers such as system peak, total energy, and number of customers to investments in distribution facilities.[21]

The data indicate that customer growth is closely correlated to growth of non-production costs.

RAP prepared studies for correlations between investments in transformers and substations versus lines and feeders as they relate to growth in customers served, system peak, and total energy sales. The data indicate that customer count is somewhat more closely correlated with growth in non-production costs, stronger than either growth in system peak or growth in energy sales. These data support using the number of customers served as the driver for computing allowed revenues between rate cases, particularly in areas where customer growth has been relatively stable and is expected to continue. The revenue-per-customer, or RPC method, may not be appropriate in areas with stagnant economies or volatile spurts of growth, or where new customers are significantly different in usage patterns than existing customers, but in these situations, the attrition method may still work well.

The RPC value is derived through an added "last" step in the rate case determination. It is computed by taking the test period revenues associated with each volumetric price charged, and dividing that value by the end-of-test period number of customers who are charged that volumetric price. This calculation must be made for each rate class, for each volumetric price, and for each applicable billing period (most likely a billing cycle):

Formula 8: **Revenue per Customer** $_{\text{TEST PERIOD}}$ =
Revenue Requirement $_{\text{TEST PERIOD}}$ ÷ **No. of Customers** $_{\text{TEST PERIOD}}$

With this revenue-per-customer number, allowed revenues can be adjusted periodically to reflect changes in numbers of customers. In any

21 See *Distributed Resource Policy Series: Distribution System Cost Methodologies for Distributed Generation* available at http://www.raponline.org/docs/RAP_Shirley_DistributionCostMethodologiesforDistributedGeneration_2001_09.pdf and the accompanying Appendices at: http://www.raponline.org/docs/RAP_Shirley_DistributionCostMethodologiesforDistributedGenerationAppx_2001_09.pdf

value).[18] Prices were allowed to grow at the rate of inflation, less productivity, in an effort to track these expected changes in the utility's cost of service. In some cases, other factors (often called "Z" factors) were added to the formulae to represent other explicit or implicit cost drivers. For example, if a union contract had a known inflationary factor, this might be used in lieu of a general inflation index, but only for union labor expenses.

This adjustment is being used in revenue-decoupling regulation, too, to determine a revenue path between rate cases. Rather than applying this adjustment to prices, it is applied to the allowed revenue between rates cases.[19] This approach is used in California, with annual "attrition" cases that consider other changes since the last general rate case, then add (or subtract) these from the revenue requirement determined in the rate case.

With the inflation and productivity factors in hand, the allowed revenue amount can be adjusted periodically. In practice, this adjustment has usually been done through an annual administrative filing and review. In theory, however, there is no practical reason these adjustments could not be made on a current basis, perhaps with each billing cycle.[20] In application, the net growth in revenue requirement is usually spread evenly across all customers and all customer classes.

The inflation-minus-productivity approach does not remove all uncertainty from price changes, because the actual inflation rate used to derive allowed revenues (and, therefore, reference prices) will vary over time.

community during their upcoming public auction. The initial regulatory timeframe was set at the fiscal year 1990/1995 time period." See http://actrav.itcilo.org/actrav-english/telearn/global/ilo/frame/elect2.htm. (Note that this adjustment is actually referred to as "negative productivity," since it indicates a reduction, rather than an increase, in productivity. Mathematically, it's denoted as the negative of a negative, and so for simplicity's sake we've described it as positive here.)

19 Under this approach, a government-published (or other accepted "third party" source), broad-based inflation index is used. The productivity factor, which serves to offset inflation, is also an administratively determined or, in some cases, a stakeholder agreed-upon value. It should not, however, be calculated as a function of the particular company's own productivity achievements. Doing so would reward a poorly performing company with an overall revenue adjustment (inflation-minus-productivity factor) that is too high (and which does not give it strong enough incentives to control costs) and would punish a highly performing company with a factor that reduces the gains it would otherwise achieve, in effect holding it to a more stringent standard than other companies face.

20 See also *Current vs. Accrual Methods*, below, for more on the implications of using *accrual* methodologies for decoupling versus using a *current* system. It goes without saying, of course, that price changes of this sort can only be effected through a simple, regular ministerial process, if the adjustment factors on which they are based are transparent, unambiguous, and factual in nature (e.g., customer count). If, however, the adjustment is driven by changes that are within management's discretionary — say, capital budget — then a more detailed review may be required to assure that prudent decisions are underlying the revenue adjustments.

5 Revenue Functions

One of the collateral benefits of decoupling is the potential for reducing the frequency of rate cases. In its simplest form, a decoupling mechanism maintains revenues at a constant level between rate cases. However, this would inevitably put increasing downward pressure on earnings due to general net growth in the utility's cost structure as new customers are added and operating expenses are driven by inflation, to the extent these are not offset by depreciation, productivity gains, and, in certain cases, cost decreases.

To avoid this problem, the allowed (or "target") revenue a utility can collect in any post-rate-case period can be adjusted relative to the rate-case revenue requirement. Most decoupling mechanisms currently in effect make use of one or more revenue functions to set allowed revenues between rate cases, and we describe the four standard ones here: (1) adjusting for inflation and productivity; (2) accounting for changes in numbers of customers; (3) dealing with attrition in separate cases; and (4) the application of a "K" factor to modify revenue levels over time. There may be others that are, in particular circumstances, also appropriate.

5.1 Inflation Minus Productivity

Before development of the current array of decoupling options, a number of jurisdictions used what has been called "performance-based regulation" (PBR) — relying on a price-cap methodology, instead of decoupling's revenue-based approach. These plans, first developed for telecommunications providers, often included a price adjuster under which the affected (usually non-production) costs of the utility were assumed to grow through the net effects of inflation (a positive value) and increased productivity (a negative

18 Under normal economic conditions, inflation will be a positive value and productivity a negative value, but there can be circumstances that violate this presumption — an extended period of deflation, for instance. In fact, when Great Britain's state-owned electric transmission and distribution companies were privatized in the late 1980s, their prices were regulated under PBR formulas that included positive productivity adjustments. "[Positive] X (that is, an apparent allowance for annual rates of productivity decreases of X percent) factors were chosen in order to provide the industry with sufficient future cash flow in part to meet projected future investment needs and also to increase the attractiveness of the companies to the investment

revenues from which the utility would not be insulated — that is, all else being equal, energy efficiency would adversely affect the company's bottom line. Weather-only adjustment mechanisms have been implemented for several natural gas distribution companies.

- Lost-margin mechanisms, which recover only the lost distribution margin related to utility-operated energy efficiency programs, have been implemented for several utilities. These generally provide a removal of the disincentive for utilities to operate efficiency programs, but may create perverse incentives for utilities to discourage customer-initiated efficiency measures or improvements in codes and standards that cause sales attrition, because these are not compensated.
- Reduced usage by existing customers may be "decoupled," whereas new customers are not included in the mechanism, on the theory that the utility is more able to influence, through utility programs, the usage of existing customers who were a part of the rate-case determination of a test year revenue requirement.
- Variations due to some or all other factors (e.g., economy, end-use efficiency) except weather are included in the true-up. In this instance, the utility and, necessarily, the customers still bear the revenue risks associated with changes in weather. And, lastly,
- Some combination of the above.

Limited decoupling requires the application of more complex mathematical calculations than either full or partial decoupling, and these calculations depend in part on data whose reliability is sometimes vigorously debated. But more important than this is the fundamental question that the choice of approaches to decoupling asks: how are risks borne by utilities and consumers under decoupling, as opposed to traditional regulation? What value derives from removing sales as a motivator for utility management? What value derives from creating a revenue function that more accurately collects revenue to match actual costs over time? What are the expected benefits of decoupling, and what, if anything, will society be giving up when it replaces traditional price-based regulation with revenue-based regulation?

Limited decoupling does not fully eliminate the throughput incentive. The utility's revenues (and profits, therefore) are still to some degree dependent on sales. So long as it retains a measure of sales risk, the achievement of public policy goals in end-use efficiency and customer-sited resources, environmental protection, and the least-cost provision of service will be inhibited.[17]

17 "Limited decoupling" is synonymous with "net lost revenue adjustments." "Net lost revenue adjustments" is the term of art that describes earlier methods of compensating a utility for the revenue to cover non-production costs that it would have collected had specified sales-reducing events or actions (e.g., cooler-than-expected summer weather, or government-mandated end-use energy investments) not occurred.

cover specific costs (independently of base rates and the underlying cost of service) are not incompatible with full decoupling. They would be reflected in separate tariff surcharges or surcredits.

Full decoupling renders a utility indifferent to changes in sales, regardless of cause. It eliminates the "throughput" incentive. The utility's revenues are no longer a function of sales, and its profits cannot be harmed or enhanced by changes in sales. Only changes in expenses will then affect profits.

Decoupling eliminates a strong disincentive to invest in energy efficiency. By itself, however, decoupling does not provide the utility with a positive incentive to invest in energy efficiency or other customer-sited resources, but it does remove the utility's natural antagonism to such resources due to their adverse impact on short-run profits. Assuming that management has a limited ability to influence costs and behavior, this allows concentration of that effort on cost reductions, rather than sales enhancements.

4.2 Partial Decoupling

Partial decoupling insulates only a portion of the utility's revenue collections from deviations of actual from expected sales. Any variation in sales results in a partial true-up of utility revenues (e.g., 50%, or 90%, of the revenue shortfall is recovered).

One creative application of partial decoupling was the combination conservation incentive/decoupling mechanism for Avista Utilities in Washington. The utility was allowed to recover a percentage of its lost distribution margins from sales declines in proportion to its percentage achievement of a Commission-approved conservation target. If it achieved the full conservation target, it was allowed to recover all of its lost margins, but if it fell short, it was allowed only partial recovery.[16] This proved a powerful incentive to fully achieve the conservation goal.

4.3 Limited Decoupling

Under limited decoupling only specified causes of variations in sales result in decoupling adjustments. For example:

- Only variations due to weather are subject to the true-up (i.e., actual year revenues [sales] are adjusted for their deviation from weather-normalized revenues). This is simply a weather normalization adjustment clause. Other impacts on sales would be allowed to affect revenue collections. Successful implementation of energy efficiency programs would, in this context, result in reductions in sales and

16 Washington Utilities and Transportation Commission, Docket UG-060518, 2007. The recovery was capped at 90%.

4 Full, Partial, and Limited Decoupling

We use a specialized vocabulary to differentiate various approaches to decoupling.

4.1 Full Decoupling

Full decoupling can be likened to the setting of a budget.

Decoupling in its essential, fullest form insulates a utility's revenue collections from any deviation of actual sales from expected sales. The cause of the deviation — e.g., increased investment in energy efficiency, weather variations, changes in economic activity — does not matter. Any and all deviations will result in an adjustment ("true-up") of collected utility revenues with allowed revenues. The focus here is delivering revenue to match the revenue requirement established in the last rate case.

Full decoupling can be likened to the setting of a budget. Through currently used rate-case methods, a utility's revenue requirement — i.e., the total revenues it will need in a period (typically, a year) to provide safe, adequate, and reliable service — is determined. The utility then knows exactly how much money it will be allowed to collect, no more, no less. Its profitability will be determined by how well it operates within that budget. Actual sales levels will not, however, have any impact on the budget.[15]

The most common form of full decoupling is revenue-per-customer decoupling, which is more fully explained with other forms of decoupling in the next section. The California approach, wherein a revenue requirement is fixed in a rate case and incremental (or decremental) adjustments to it are determined in periodic "attrition" cases, is also a form of full decoupling. Tracking mechanisms, designed to generate a set amount of revenue to

15 This is the simplest form of full decoupling. As described in the next section, most decoupling mechanisms actually allow for revenues to vary as factors other than sales vary. The reasoning is that, though in the long run utility costs are a function of demand for the service they provide, in the short run (i.e., the rate-case horizon) costs vary more closely with other causes, primarily changes in the numbers of customers.

Revenue Regulation & Decoupling: A Case Study

Revenue Regulation & Decoupling: Case Study

The Regulatory Assistance Project

Contents

Decoupling: A Case Study

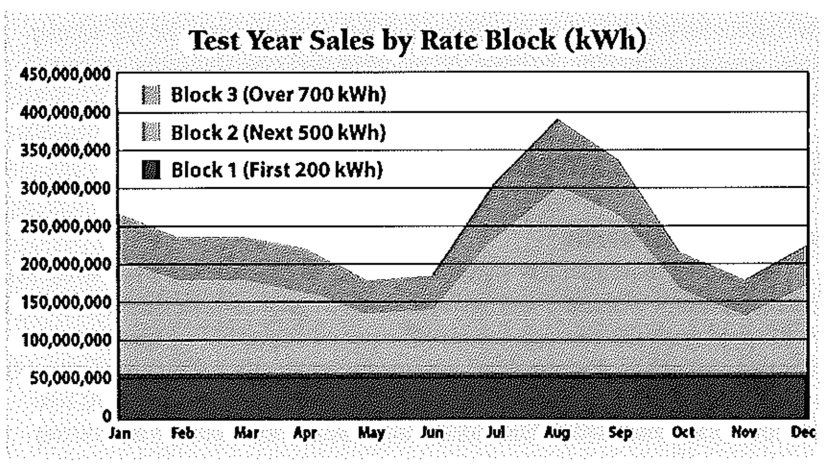
The following is a simple case study that demonstrates many of the properties of decoupling. The study concept is to model the impacts of decoupling on a single class of customers, in an environment where fairly aggressive demand-side reductions are being achieved. The analysis is intended to focus on the decoupling impacts driven by those reductions. Except for the abnormal weather comparison, weather is ignored – i.e., assumed to be "normal" in all years.

The model uses a single "test" period as a beginning point, as a rate case would provide, and then analyzes results for the following three-year period on a monthly basis. An analysis of an accrual method for decoupling is shown at the end of this case study.

Characterization of the Prototypical Utility Residential Rate Class

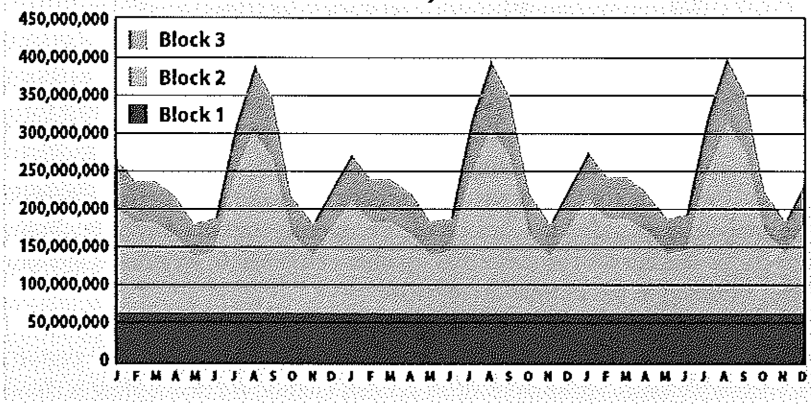
Source Data

The general scale and structure of our prototypical utility is derived from data for the residential class in a recent rate proceeding for Public Service Company of New Mexico (PNM)[1].



1 However, this analysis is not intended to be, nor is it, an attempt to "model" PNM. PNM data was used solely to establish a reference for scale (numbers of customers and their consumption patterns) and for an associated set of prices.

Post Test Year Sales by Rate Block (kWh)



The study begins with annual consumption and pricing information from the rate case. That consumption level was then allocated across the months of the years to reflect normal weather. Resulting *Test Year Sales* are shown on the previous page. Weather data are from the National Weather Service for Albuquerque. Weather data are used solely to seasonalize annual sales amounts.

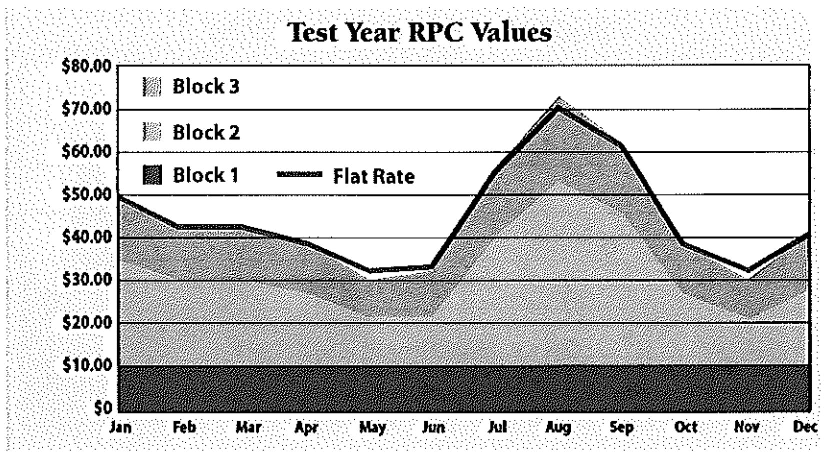
PNM's original block rates for residential customers were also seasonal, with higher rates in the June-August period. For simplicity, the model is based on revenue-equivalent non-seasonal block rates.

For bill analyses, fuel costs are the same fuel costs as in the PNM data — \$0.020243/kWh. For bill analyses, avoided fuel costs are also assumed to be \$0.020243/kWh. This has the effect of *slightly* understating the bill savings from energy reductions, because the marginal fuel cost should be at least somewhat higher (possibly much higher) than the average.

Scenario Parameters

Customer Growth

The model requires a few significant inputs to characterize a scenario. The most important of these is the customer growth grate, which drives increases in allowed revenues through the revenue per customer (RPC) mechanism. For this case study, customers are assumed to grow at a 2.0% annual rate, on a beginning base of approximately 405,000 customers. For simplicity, new customers are assumed to have identical consumption patterns as existing customers. If new customers are using more (or less) power than existing customers, or have different seasonal or time-of-use patterns, the growth in revenues will not be linear with the growth in customers, and an adjustment to RPC decoupling may be needed.



Business as Usual Sales

Monthly energy sales for the *business as usual* case are shown below>>. Block 1 sales are assumed to experience no seasonal variation. Block 3 sales are assumed to reflect the full seasonality of normal weather. Block 2 sales are assumed to experience one quarter of the variability of Block 3 sales.

RPC Values

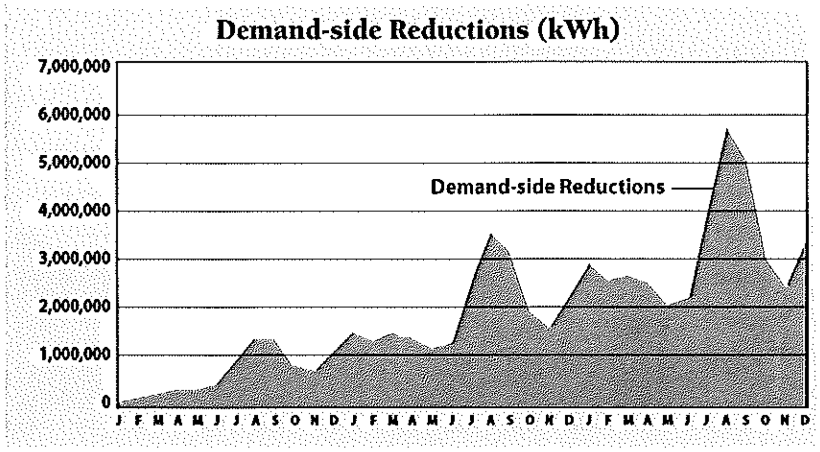
Applying Test Years Sales to the tariff prices, yields total revenues per rate block. These are then divided by the number of customers to derive the allowed RPC values for each rate block. The results are shown at right. These values will be used to compute allowed revenues for Post Test Year periods, based on the number of customers then being served.

Demand-side Reductions

The other significant input assumptions are the percentages of sales growth that are offset by demand-side reductions. Because the primary sales data in the model is constructed around an inclining 3 block rate design, the reductions in sales can be, and are, separately allocated to each block. For this case study, 50% of the growth in Block 3 is assumed to be avoided through demand-side reductions. For Block 2, 25% of the growth is assumed to be avoided, and for Block 1, 5% of the growth is avoided.

Avoided Costs

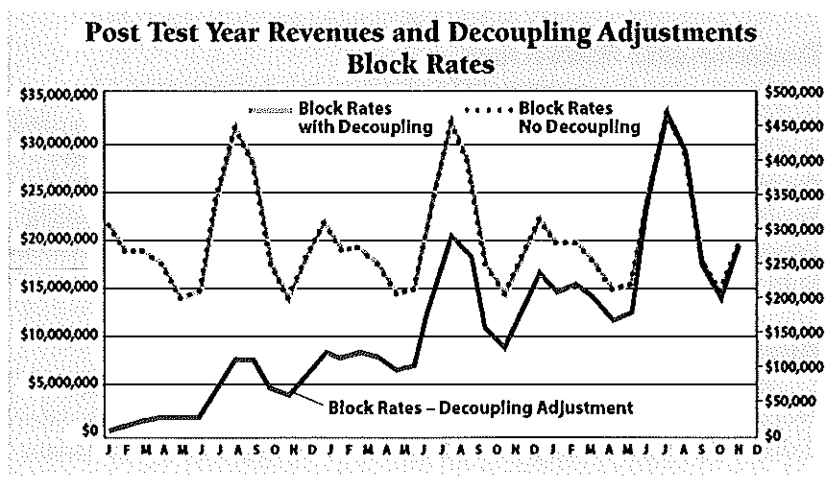
This study assumes that in the short run the only costs that will be avoided by the utility are those that flow through the fuel adjustment clause. If the utility is able to sell power off-system, or avoid purchases, we assume



that those revenues or costs flow through the fuel mechanism. The power plant inventory is assumed to be unchanged, and load variations are met exclusively by either dispatching utility-owned generation or by making spot market purchases and sales of power. If the utility were adding resources, particularly independent power producer (IPP) IPP-owned generation in which all costs (not just variable costs) flow through the fuel adjustment mechanism, a different modeling approach would be required.

Current Period Decoupling

In each example below, we assume that the utility is implementing current period decoupling, meaning that lost distribution margins due to sales variation are recovered in the billing cycle in which the sales reductions



occur. This is easily modeled, and fairly easy to implement, but some commissions have chosen to implement deferred recovery of decoupling surcredits and surcharges, usually on an annual basis. It would mask the impact of decoupling to present the effect on a deferral basis.

Decoupling Adjustment Results

RPC decoupling has the effect of offsetting the reduction in revenues caused by reductions in sales, with the objective of tracking actual non-fuel revenues with the results of the last rate case. As shown at right, total revenues are driven upward to restore reduced sales from demand-side reductions. The bottom line represents the monthly revenue associated with decoupling. This amount grows as the magnitude of demand-side reductions increases.

Comparing Different Rate Designs in a Decoupled Environment

Rate Designs Compared

The case study analyzed three different rate designs in a decoupled environment for this residential customer class: inverted block rates, flat rates, and straight-fixed variables rates. Inverted block rates have increasing prices as overall consumption increases over three tiers of consumption: first 200 kWh, the next 500 kWh, and over 700 kWh. Flat rate designs have a single volumetric price for all consumption. Straight-fixed variable rates collect all non-production costs through a customer charge. Each of the assumed rate designs collects $239.2 million in annual revenues, and is reflected in Table 1 (production costs are recovered separately through a fuel and purchased power adjustment tariff rider):

Table 1

Non-Seasonal Inclining Block Rate Design

Price Type	Total Revenue	Total Determinants	Rate Billing	Rate Units
Customer Charge	$19,484,784	4,871,196	$4.00	$/mo.
Block 1 (First 200 kWh)	$47,640,783	898,696,181	$0.05301	$/kWh
Block 2 (Next 500 kWh)	$109,014,161	1,395,256,018	$0.07813	$/kWh
Block 3 (>than 700 kWh)	$63,067,176	709,610,240	$0.08887	$/kWh
Demand	$ -	-	$ -	$/kW

Non-Seasonal Flat Rate

Price Type	Total Revenue	Total Determinants	Rate Billing	Rate Units
Customer Charge	$19,484,784	4,871,196	$4.00	$/mo.
Energy Charge	$219,722,120	3,003,562,439	$0.07315	$/kWh
Demand	$ -	-	$ -	$/kW

Non-Seasonal Straight-Fixed-Variable Rate (SFV)

Price Type	Total Revenue	Total Determinants	Rate Billing	Rate Units
Customer Charge	$239,206,904	4,871,196	$49.11	$/mo.
Energy Charge	$ -	3,003,562,439	$ -	$/kWh
Demand	$ -	-	$ -	$/kW

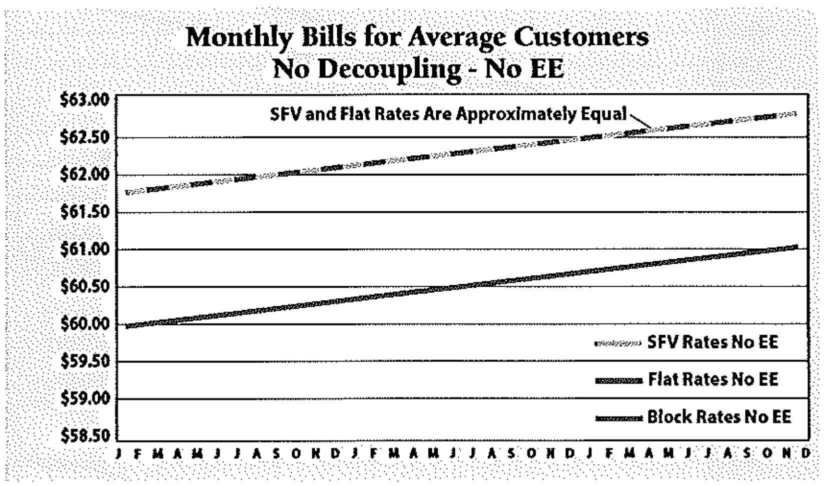
Description of Bills: Low, Average, and High

The case study looks at three different types of customers, a low usage (150 kWh/month), average usage (617 kWh/month), and high usage (1500 kWh) customer. No attempt was made to seasonalize the usage of such customers (but the underlying usage and the savings from efficiency investments are reflected through the rate design described earlier). Although it is likely that the larger customers would have significant seasonality in practice, perhaps beyond the underlying seasonality of the total block usage, this is immaterial to our illustrative example. Instead, the case study looks at the monthly bills and relative impacts of decoupling for a customer who uses the stated amount of energy in that month. Thus, the analysis is not one of a typical customer, but what a customer experiences in a given month at a particular usage level. Average usage was derived by dividing total annual usage by the number of customers and by 12.

Average Use Customers

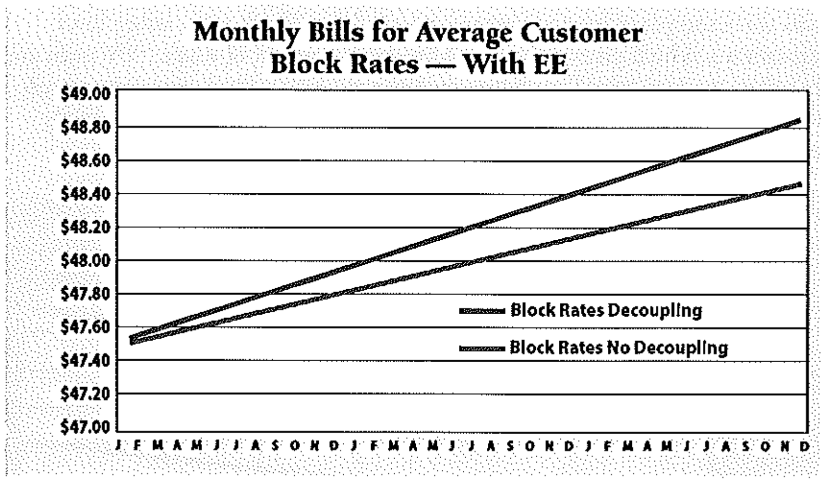
Business as Usual Bills

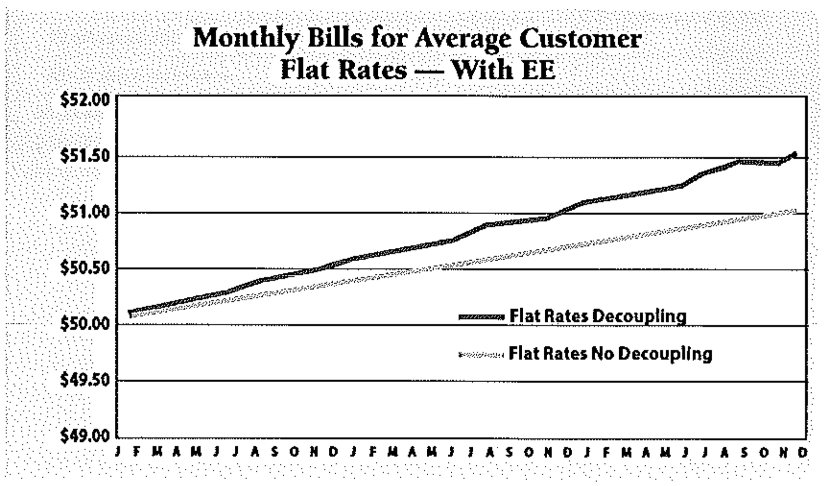
Each of these rate designs has a different impact on different types of users. For example, an "average" customer using 617 kWh in every month would see the bills shown at right before decoupling and without any energy efficiency savings. Note that SFV rates impose a minimum bill significantly higher than that imposed by either block or flat rates. That said, for an average customer, SFV rates produce bills comparable to flat rates. This is because the flat rate case and the SFV are both applied across all usage and this example is for an average customer. For block rates, usage level determines which rates are used for the same amount of usage. SFV rates are, in effect, average rates for average customers, so an average user pays nearly the same with SFV rates as with flat rates. Small users would be adversely impacted by SFV rates, and large users would benefit.



Customers Who Reduce Usage

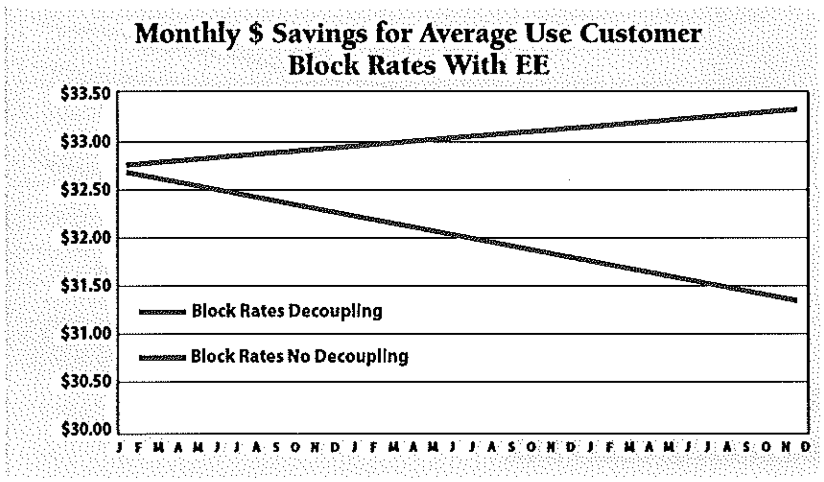
If we assume the same customer deploys sufficient energy efficiency to reduce consumption by 20% per month, bills will be as shown in the two charts below for block rates and flat rates. Monthly average differences associated with decoupling over the three-year period are $1.22 for block rates and $1.37 for flat rates. SFV with decoupling is not shown because decoupling has no effect on SFV bills. Block rates for this level of usage result in a blended effective energy price less than the flat rate. As a result, block rate bills are roughly $2.50 per month lower than for flat rates.

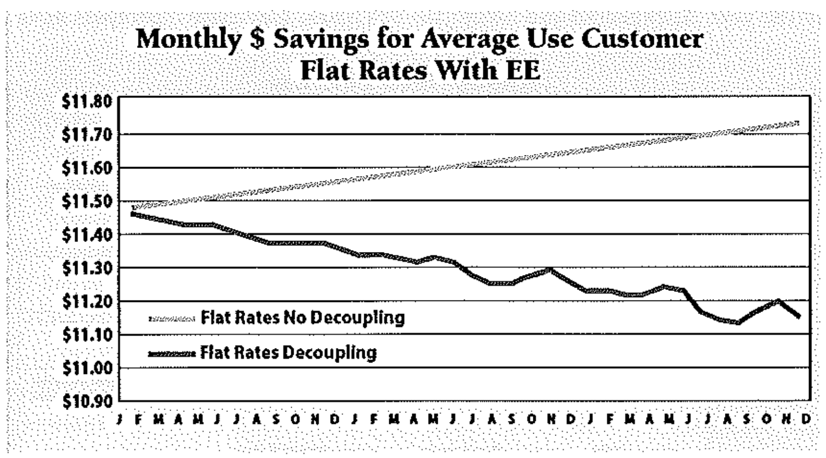




Monthly Savings

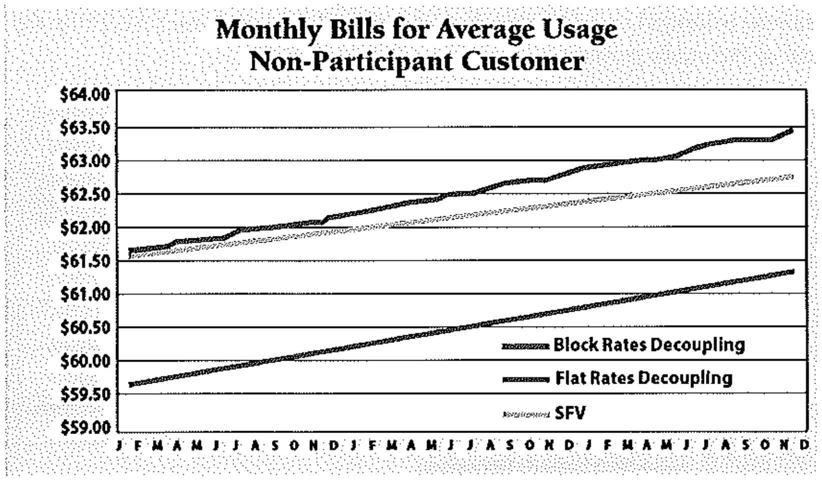
The associated monthly bill savings for the customer with a 20% reduction in consumption is shown in the two charts at right. The declining monthly benefits under both rate designs represent the erosion in savings occasioned by decoupling price adjustments. Block rate customers experience a $9 reduction in savings by the end of the study period, while flat rate customers experience a $3.00 reduction. Monthly savings for SFV customers (not shown) is limited to avoided fuel costs with inflation and reach $2.72 by the end of the study period.





Customers Who Do Not Reduce Usage

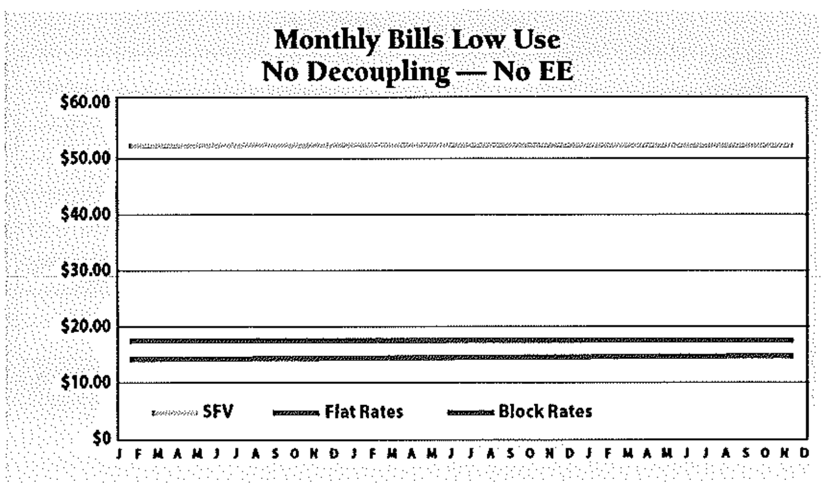
Bills for the average customer who does not reduce usage are shown at right. Because they are both versions of an average rate, flat rate and block rate customers experience an average of $1.60, while flat rate customers experience a $1.71 average increase in bills by the end of the study period. SFV customers only experience fuel inflation of $1.14 over the study period.



Low Usage Customers

Business as Usual Bills

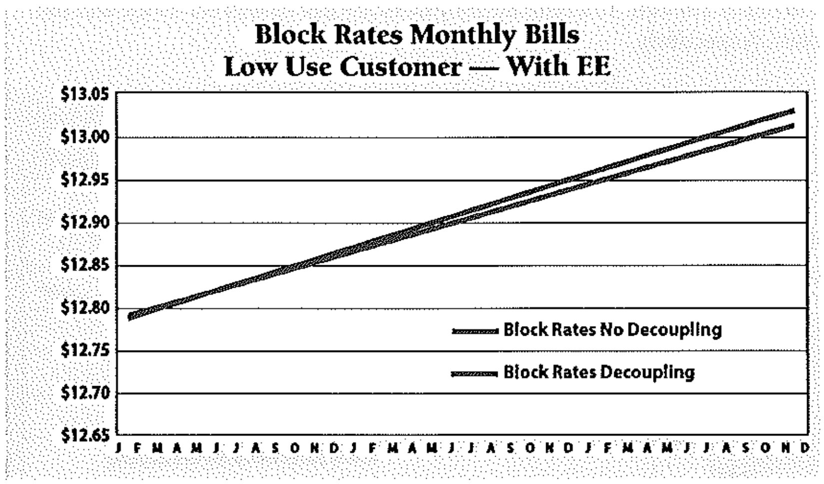
The low usage customer is assumed to consume 150 kWh each month of the year. As expected and except for SFV rates, low usage customers have

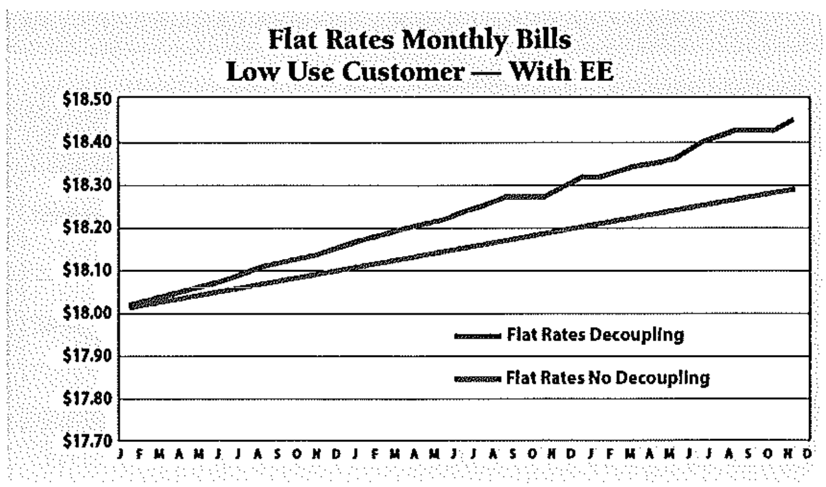


bills that are much lower than average customers. Without decoupling, all customers only experience an increase in bills from inflation in fuel costs of $0.28 each over the study period.

Customers Who Reduce Usage

Bills for a customer who reduces usage by 20% (30 kWh) are shown in the charts at right. For block rate bills, because most of the assumed energy savings occur in Block 3 and Block 2, virtually no decoupling adjustments show up in low use bills. As a result, bills for low usage customers with block rates are very stable.

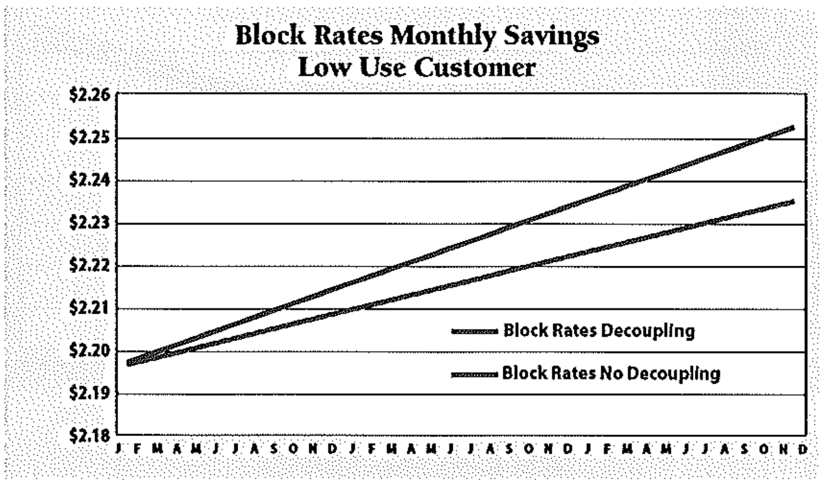


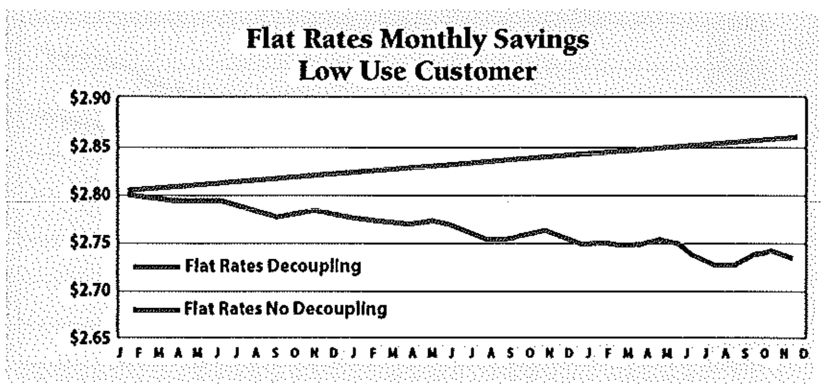


In the case of flat rate, because a uniform decoupling adjustment is applied to all consumption, low use customers experience an increase of approximately $1.20 per month by the end of the study period.

Monthly Savings

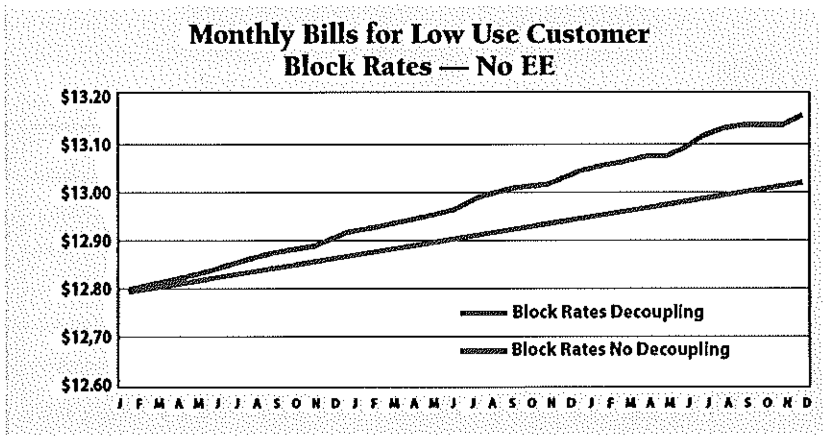
For customers who reduce usage by 20%, the monthly savings before and after decoupling are shown at right. SFV is ignored, because the only savings for an SFV customer is through the fuel clause. In this case, SFV fuel savings average $0.61 per month. With the assumed demand-side reductions in sales, pre-decoupling revenues are declining every month, so the decoupling adjustment has the effect of slightly eroding savings over time, though not by a material amount, reaching $0.39 and $0.64 per month for block and flat rates, respectively.

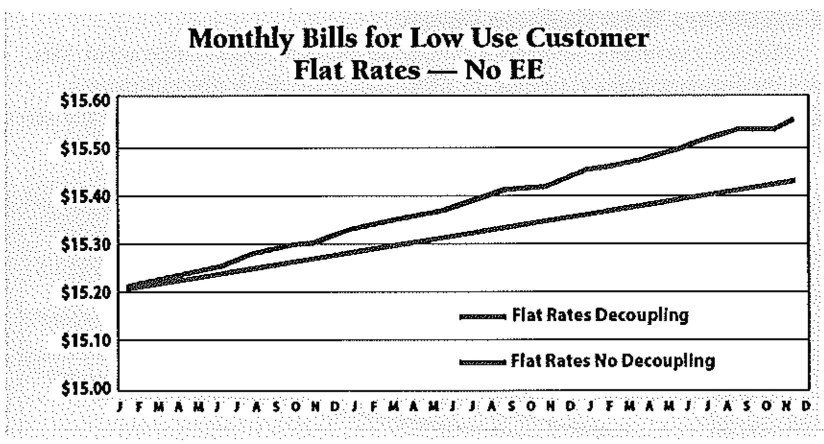




Low Use Customers Who Do Not Reduce Usage

The impact of decoupling on bills for customers who do not reduce usage is shown at right. Because very little of the revenue shortfall occurs in the first block, block rate customers do not see much impact from decoupling, with the maximum monthly impact occurring at the end of the study period at $0.03. Flat rate customers see a slightly greater impact, reaching $0.74 by the end of the study period.

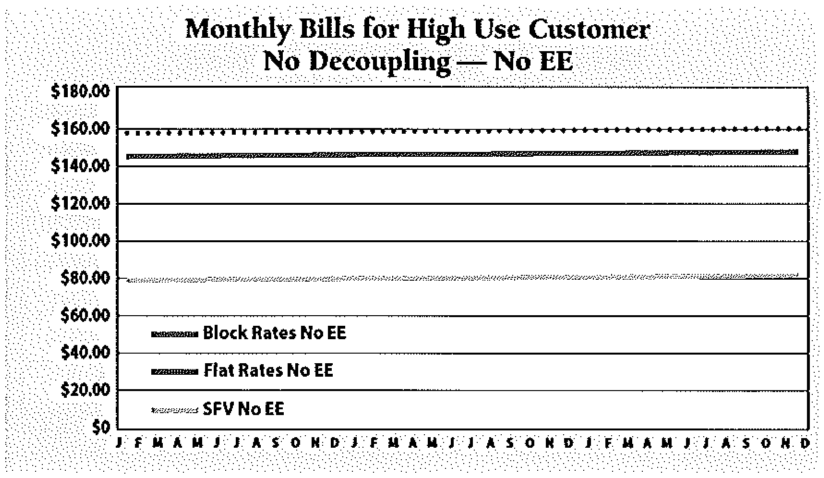




Impact of Decoupling on High Usage Customers

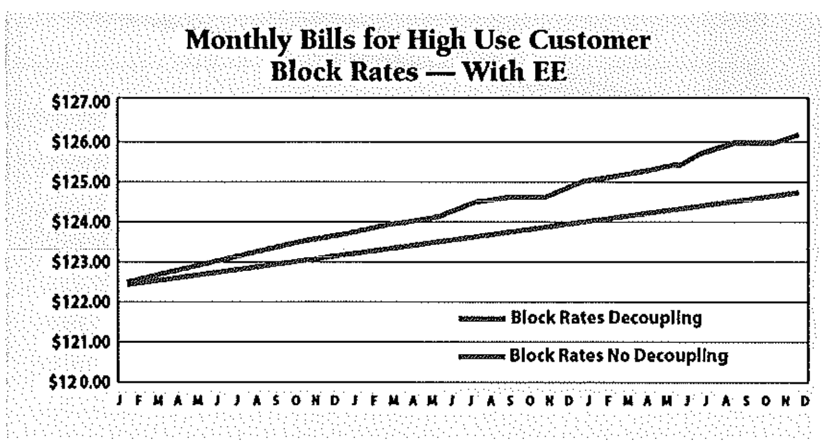
Business as Usual Bills

Business as usual bills for high usage customers are shown below. Because of the fixed nature of SFV rates, bills are much lower for high usage customers than with either block or flat rates.



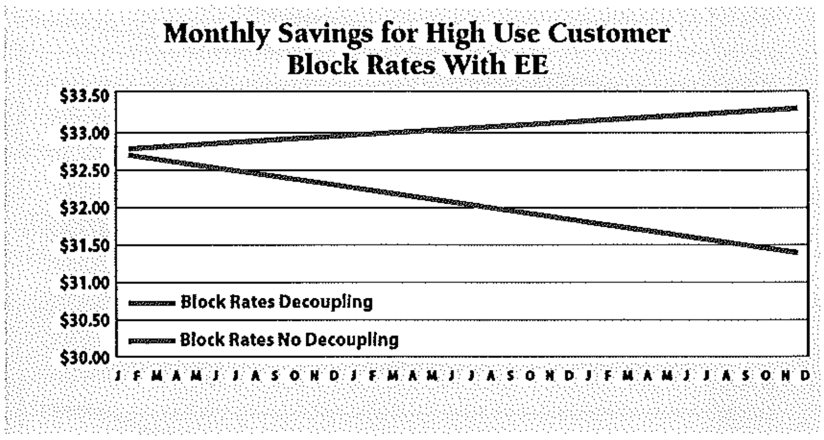
Customers Who Reduce Usage

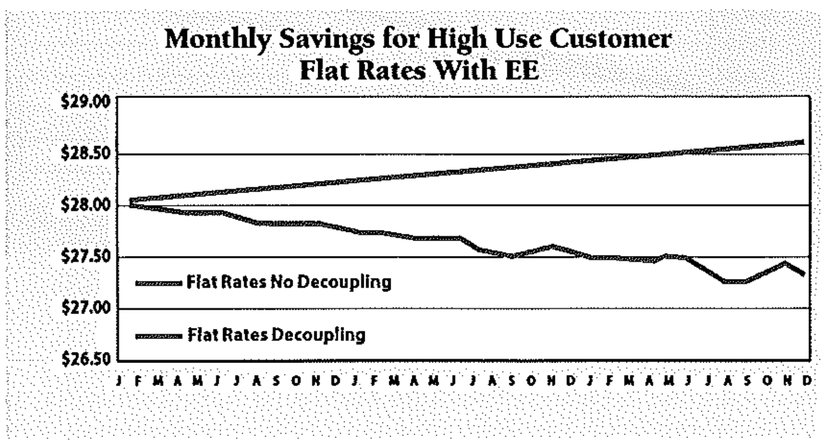
Bills for customers who reduce usage are shown below. Once again, rate design does not make a significant difference. For block rate customers, decoupling has an average monthly impact on savings of $3.95, and flat rates customers see $3.33 average monthly impact.



Monthly Savings

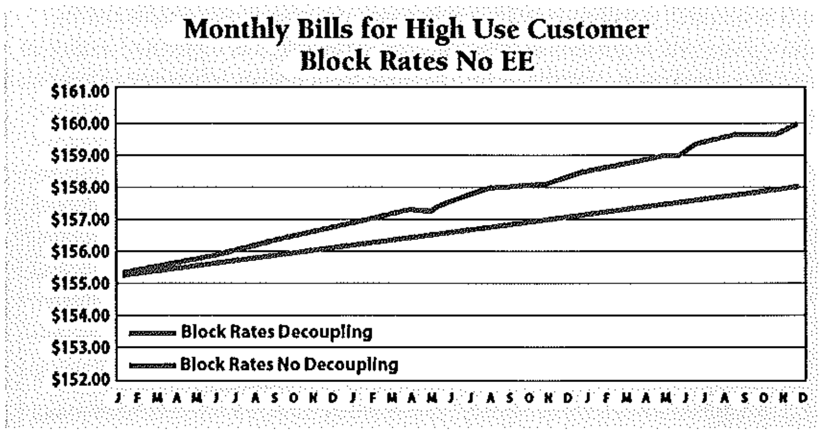
Monthly savings for customers who reduce usage are shown below. For block rate customers, because most of the demand-side reductions come from the tail block, most of the decoupling adjustments are recovered through that block. This concentrates the decoupling effect on large users. In this manner, smallusers with stable usage are essentially unaffected by decoupling rate adjustments. This has the same effect as expressed earlier in the bill comparison, translated into savings from energy efficiency as opposed to total bills.

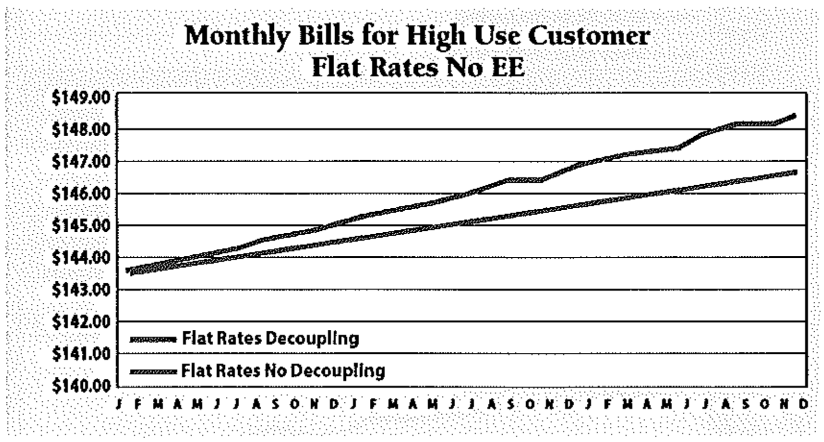




High Use Customers Who Do Not Reduce Usage

Bills for customers who do not reduce usage are shown below. Monthly average bill increases attributable to decoupling are $4.26 for block rate customers and $4.16 for flat rate customers.

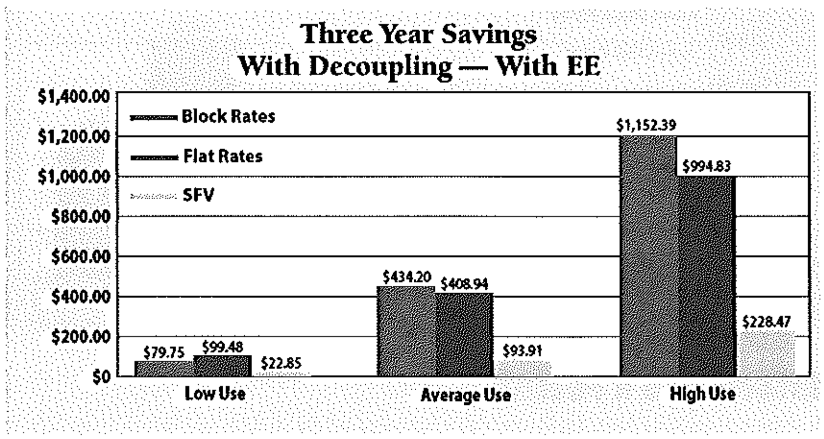




Three-Year Summary of Different Rate Designs

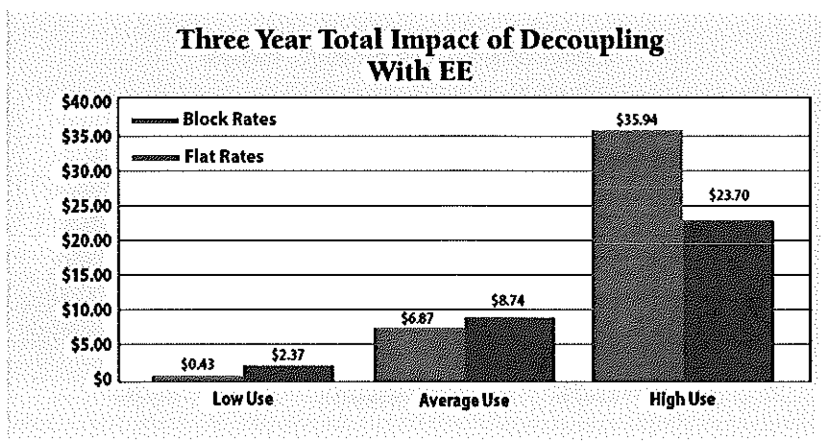
Three-Year Savings

This chart reflects the three-year savings for each type of customer for the three different rate designs. As usage grows, the savings increase accordingly. SFV rates limit savings to fuel costs only, however, resulting in significantly lower customer savings.



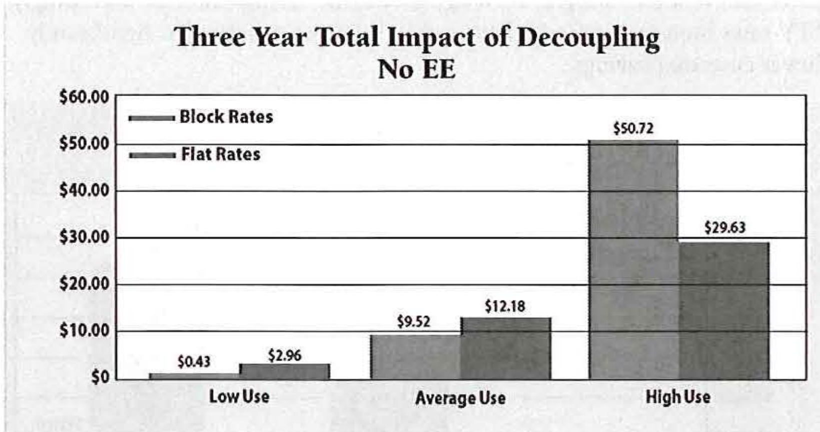
Impact of Decoupling for Customers With Energy Efficiency

The next chart reflects the impact of decoupling on the three types of customers with block and flat rates. SFV has no decoupling effect and is excluded.



Impact of Decoupling for Customers Who Do Not Implement Energy Efficiency

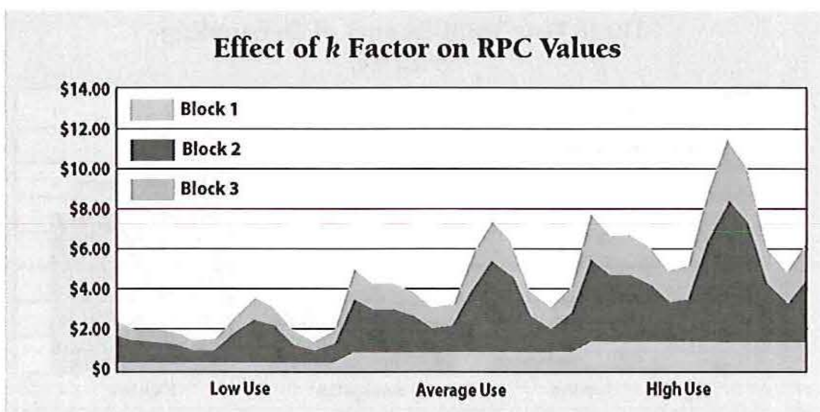
Finally, the chart below reflects the impact of decoupling on customers with no energy efficiency, often referred to as non-participants.



Effects of a k Factor

Applying a *k* Factor To RPC Values

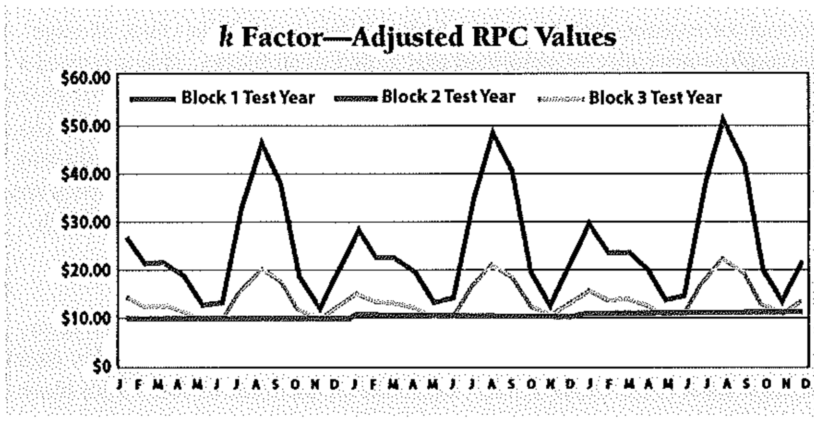
A *k* factor can be applied to the RPC values in decoupling to induce a "slope" (up or down) over time. A *k* factor would most likely be used as a proxy for inflation or other trends in underlying costs that are not captured by the core RPC values. For example, the impact of a 5% annual upward *k* factor on RPC values is shown at right. A slight upward slope can be seen for



each month over the prior year's month (and 5% is clearly higher than recent inflation rates and was chosen to illustrate the effect of an allowed upward attrition adjustment over time). Because the first block is assumed to have zero weather sensitivity, it "steps" up over time, rather than following seasonal patterns.

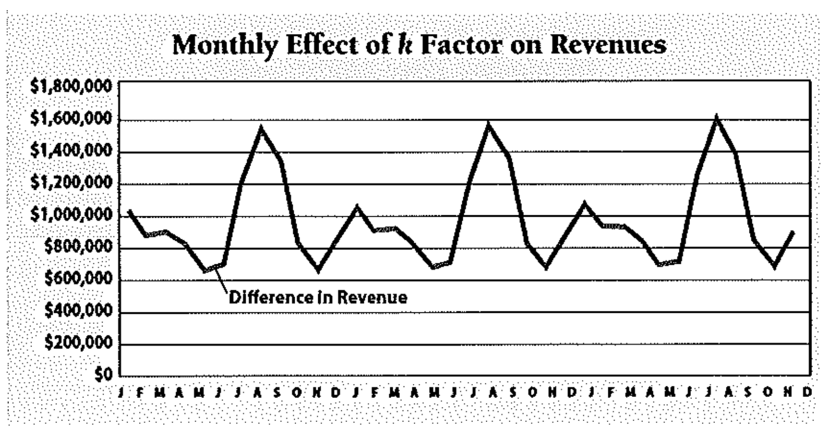
Impact of a *k* Factor on RPC Values

The *k* factor is applied to each RPC value. The resulting increase in the RPC for each block rate is shown below. Most of the revenues come from Block 2, which experiences the greatest growth over time.



Monthly Effect of a *k* Factor

The revenue impact of the *k* factor is shown below. In this case, it has the effect of adding approximately $650,000 to $1.3 million per month to



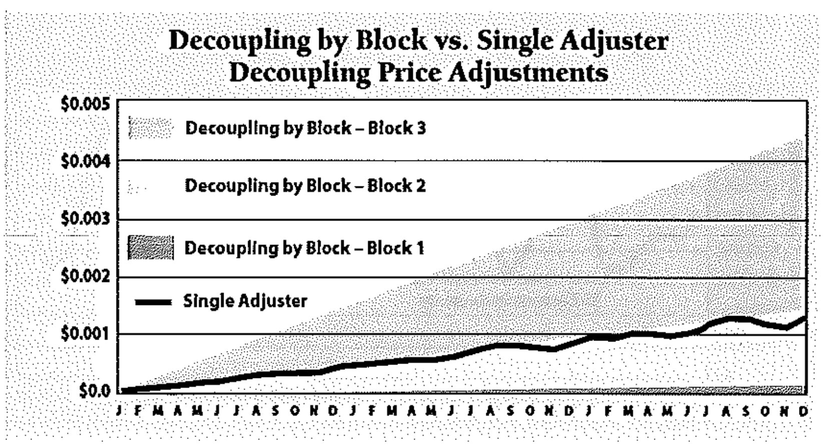
total revenues, or slightly more than 4.5% of total non-fuel revenues. This hypothetical k factor represents, for example, the effect of an assumption of increased costs over time due to inflation, replacement of non-revenue-producing infrastructure, and increasing costs associated with environmental compliance.

Decoupling by Block Method vs. Single Adjuster Method

In a block rate environment, revenue differences are inherently driven by the individual revenue increases or decreases in each block. In a Decoupling by Block Method, modeled below, each individual block price is adjusted to correct for revenue deviations. As an alternative, a single (in effect, average) decoupling price can be computed and added to all blocks. This is termed a Single Adjuster Method. Another method, proposed by Tucson Electric Power (TEP) in Arizona, is to apply any decoupling surcharges to the upper blocks of usage, and any decoupling surcredits to the initial block of usage, thereby ensuring that low-users are never harmed by decoupling, and high-users are never advantaged by increased usage. We have not modeled this approach.

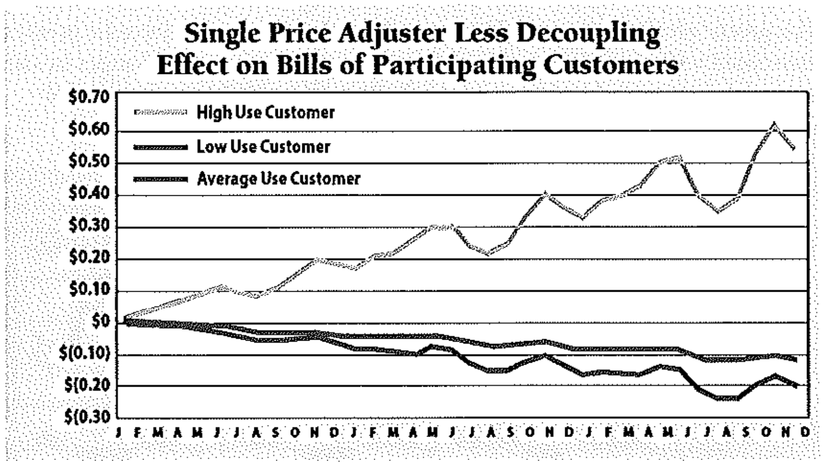
Decoupling Price Adjustments

The chart at right displays the price increases for each block in the Decoupling by Block Method (shaded areas) and the equivalent Single Adjuster (line). Because most of the demand-side reductions are assumed to come from Block 3, that block receives the lion's share of the decoupling price adjustments. Low usage customers have their consumption concentrated in the first block, which sees hardly any adjustment at all with the Block Method, but with the Single Adjuster Method they see the same increase in prices as all other customers.



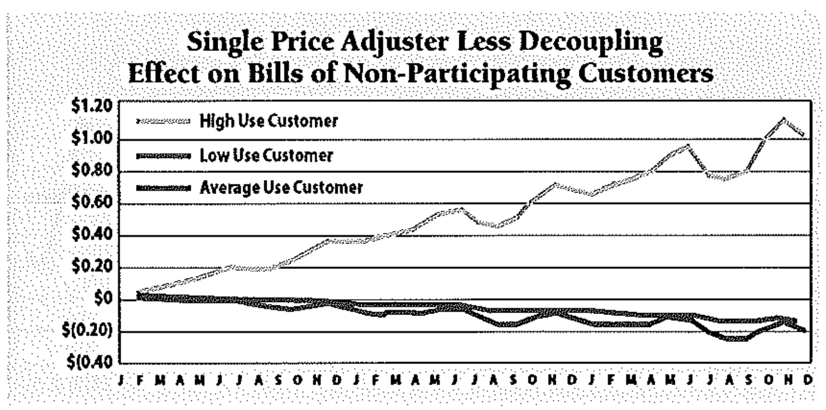
Impact on Bills of Customers Who Reduce Usage

The impact of the Single Adjuster Method versus the Decoupling by Block Method is shown below. Low energy users and average energy users experience an increase in bills of up to $0.13 (low) and $0.23 (average) per month, whereas high usage customers experience decreases in bills of up to $0.59 per month. In effect, the Single Adjuster Method mitigates the rate design impact of inclining block rates and reduces bills for large users at the expense of other users.



Impact on Bills of Customers Who Do Not Reduce Usage

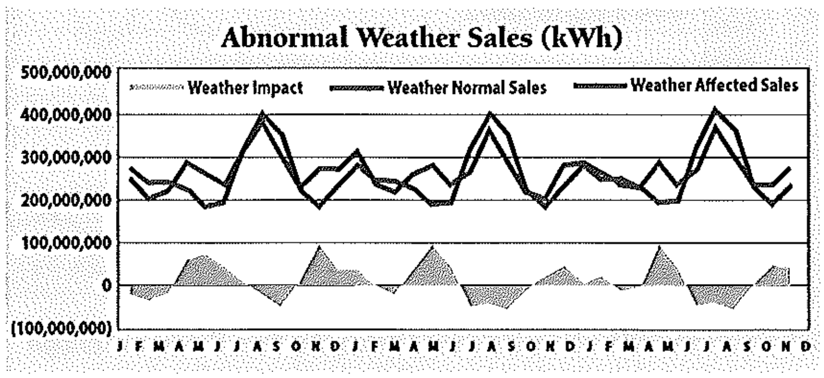
The impact of the Single Adjuster Method is shown below. For customers with greater usage, the impact is greater. Here the savings to high usage customers reaches $1.23 per month, again at the expense of low usage and average customers, who experience $0.16 (low) and $0.25 (average) per month increases.



Impact of Weather on Decoupling Adjustments

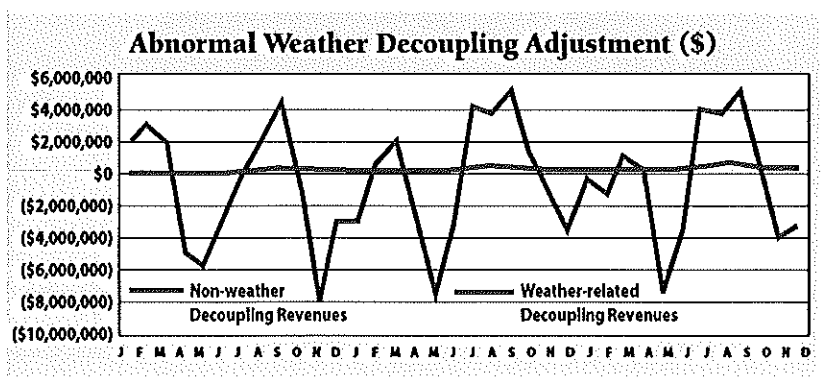
Sales Deviations Caused by Weather

Full decoupling eliminates the effects of weather on revenues. For our case study, we took a three-year period (2000-2002) that had the highest combined heating degree days (HDD) and cooling degree days (CDD) and modeled prototypical sales under these conditions. The chart below compares normal weather sales and our resulting "extreme" weather sales. The green "area" graph at the bottom reflects the increase or decrease in sales associated with the HDD and CDD for the three-year period. Changes in sales range from an increase of approximately 55 million kWh to a decrease of approximately 60 million kWh.



Weather-related Decoupling Revenue Adjustments

The case study assumes that the changes in revenues from non-normal weather affect Blocks 1 and 2 in the same proportion as that associated with normal weather. The chart below shows the revenue impacts from abnormal weather and, separately, the revenue impacts from demand-side reductions

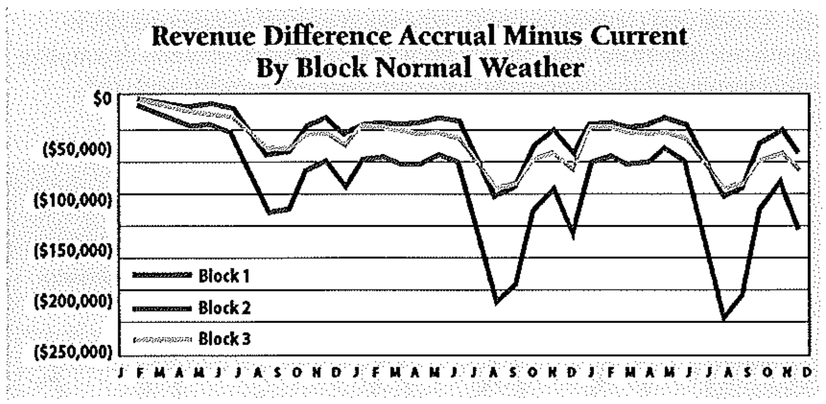


(non-weather related changes). Weather is, by far, the greatest volatility risk for consumers, whereas the balance of the decoupling adjustment is miniscule. At the same time, changes in bills and revenues from weather risk are eliminated by full decoupling. During the three-year period, the maximum shortfall in revenues is approximately $4.7 million and the maximum is approximately $5 million.

Impact of Accrual versus Annual Method

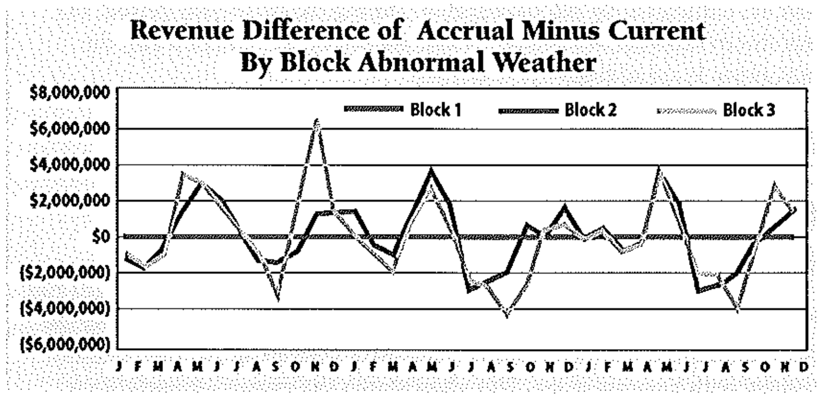
Revenue Difference of Current and Accrual Methods With Normal Weather

In all of the previous analyses, the indicated decoupling adjustment has been applied in the month during which it occurs, a method we term the Accrual Method. However, many states have applied an Accrual Method, usually with a one-year lag. This chart shows the impact on each block rate of using the Annual Method instead of the Accrual Method in normal weather conditions. Because of the lag imposed by the Accrual Method, the relationship between the decoupling adjustment and the underlying consumption that caused the adjustment is shifted by one year, resulting in a steadily increasing downward impact on revenues in all three blocks.



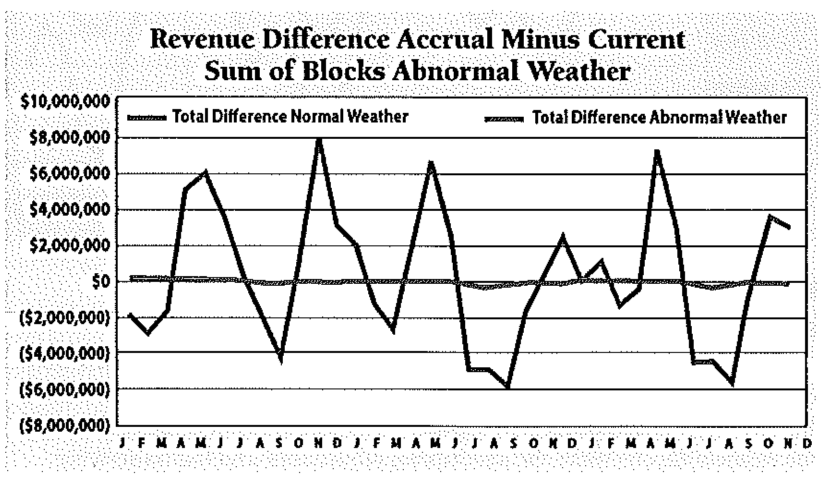
Revenue Difference of Current and Accrual Methods With Abnormal Weather

The next chart reflects the same impact on revenues for each block in the abnormal weather case. As can be seen, the occurrence of abnormal weather has the effect of imposing much greater volatility on total revenues. In effect, the relationship between the decoupling adjustment and the underlying consumption patterns that cause the decoupling adjustment is completely lost, and the underlying lag caused by the annual method is overwhelmed by the effects of weather.



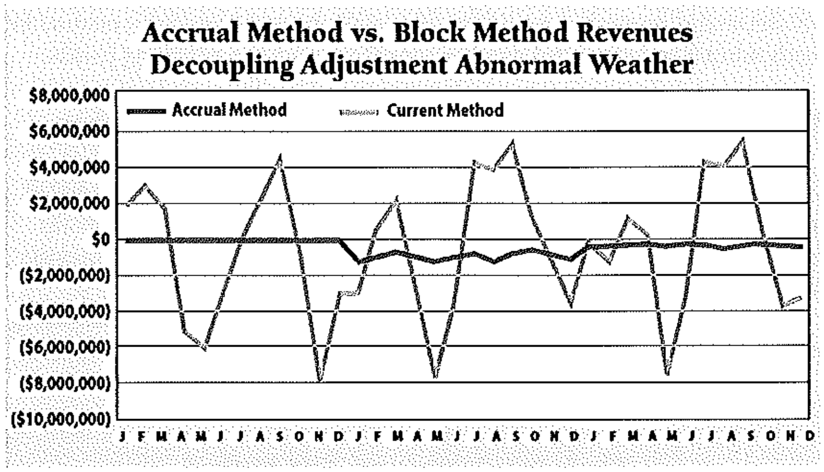
Accrual vs. Current Difference Revenues – Impact of Abnormal Weather

The chart below reflects the differences in abnormal weather conditions occasioned by the use of the Annual Method versus the Accrual Method. As can be seen, the normal weather results in small differences between the Accrual and Current methods, whereas abnormal weather results in significant departure. This chart reflects the disconnect between decoupling adjustments and the underlying cause for those adjustments with the Accrual Method.



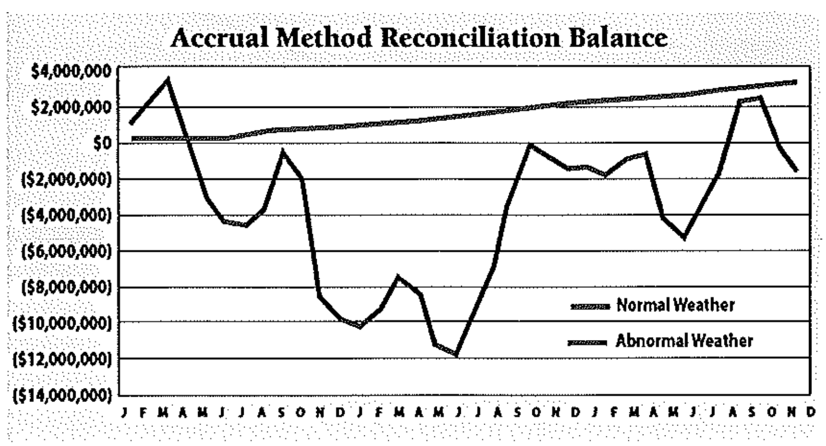
Accrual vs. Current Decoupling Adjustment Revenues With Abnormal Weather

The next chart reflects the differences in the Current and Accrual methods in periods of abnormal weather. The Current Method reflects the adjustment associated with abnormal weather for the associated period. The Accrual Method has no direct relationship to the current period weather. The difference between the two reflects the amount by which the Accrual Method fails to match up to the adjustment caused in the associated period.



Accrual Reconciliation Balance – Normal vs. Abnormal Weather

The final chart reflects the Reconciliation Balance Account during normal weather and abnormal weather. In normal weather conditions, there is a



steady increase in the balancing account caused by the lag in collection and the underlying growth in customers and consumption. This effect essentially disappears in abnormal weather conditions, when consumption varies significantly, both up and down, relative to normal weather consumption.

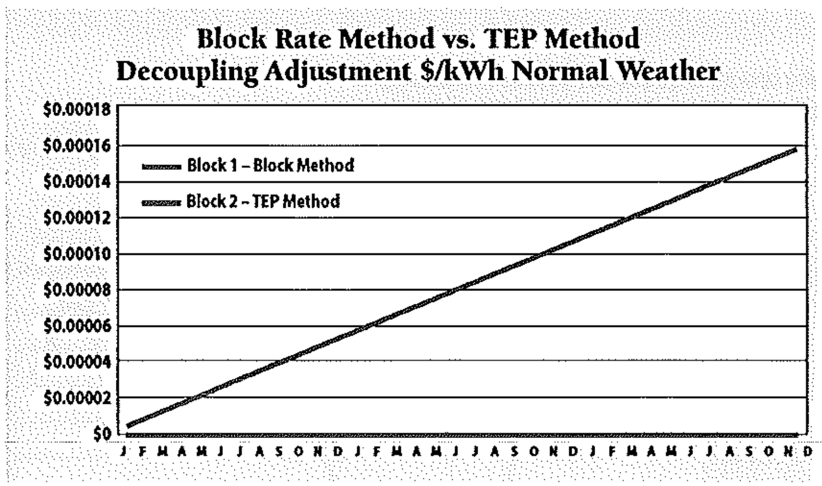
The Tucson Electric Power Decoupling Method

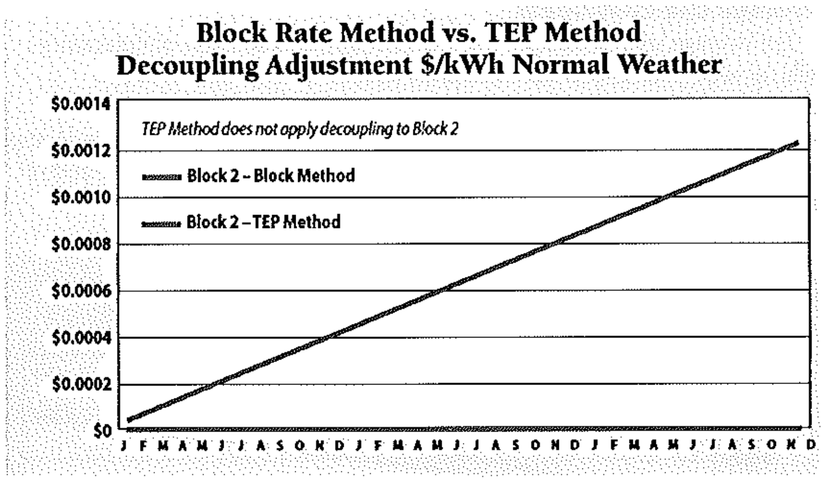
In decoupling workshops held by the Arizona Corporation Commission, Tucson Electric Power (TEP) proposed a method of decoupling in which all surcharges would be applied to the tail block in a block rate design and credits would be applied to the first block. We have modeled this method for both normal and abnormal weather conditions with the following results.

Decoupling Adjustments By Block — Normal Weather

The chart at right reflects the decoupling adjustment for Block 1 for both the block rates method and the TEP method. Because normal weather resulted in a positive decoupling adjustment in every period, there are no adjustments to this block using the TEP method. We omit Block 2, because the TEP method never makes adjustments to this block.

The next chart reflects the decoupling adjustment for Block 3, comparing the normal block method with the TEP method. For the TEP method, Block 3 receives all of the adjustments in normal weather conditions.

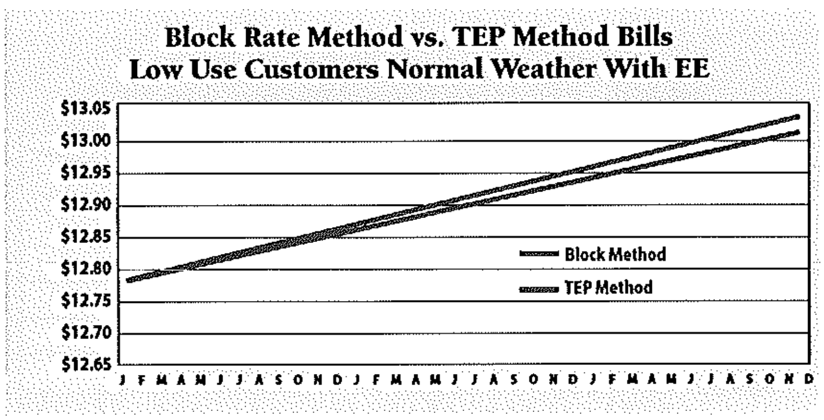




Impact of the Tucson Electric Power Method on Bills of Customers — Reduced Usage — Normal Weather

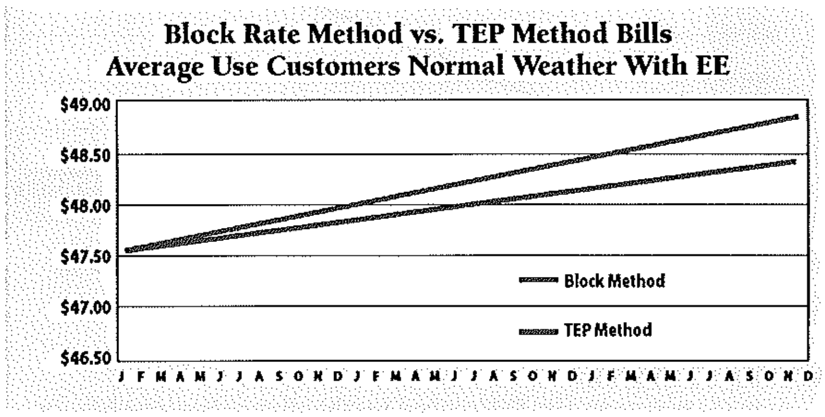
Low Use Customers

As in the next chart, the TEP method has the effect of lowering bills for low use customers, all of whose usage is in the first block. This is because when the adjustment is positive, it is not applied to the first block, while the normal block rate method adjusts each block according to its contribution to the overall surcharge or credit. Low use customers receive an average $0.19 reduction in monthly bills, reaching a maximum of $0.39 savings by the end of the study period.



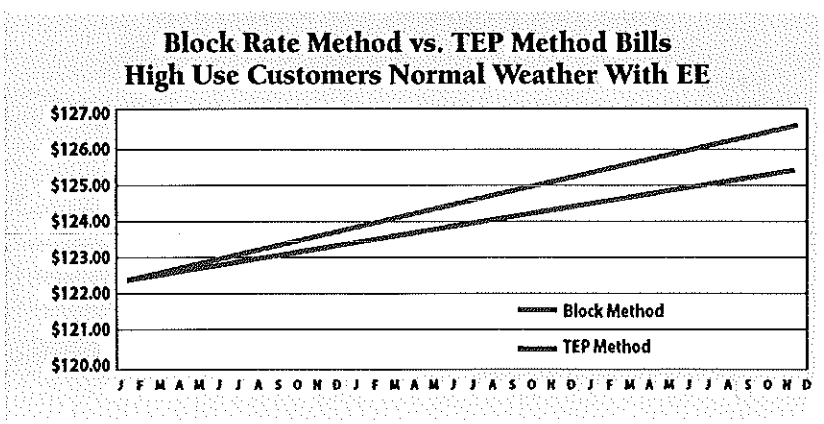
Average Use Customers

For average use customers, the TEP method has the effect of decreasing bills, as well. This is because in normal weather conditions, all of the decoupling adjustments are positive and the TEP method makes no adjustments to Block 2. Average use customers enjoy average monthly savings of $1.22 per month, reaching a maximum of $2.63 in savings by the end of the study period.



High Use Customers

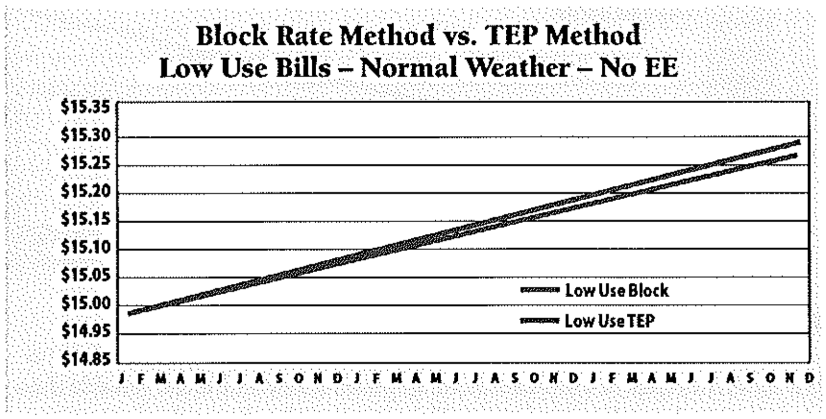
For high use customers, the results are quite different. For these customers, whose usage reaches the tail block, the positive decoupling adjustments during normal weather are exclusively applied to these customers. For high use customers, the average monthly increase in bills is $2.10, reaching a maximum of $4.60 by the end of the study period.



Impact of the Tucson Electric Power Method on Bills of Customers – No Reduced Usage – Normal Weather

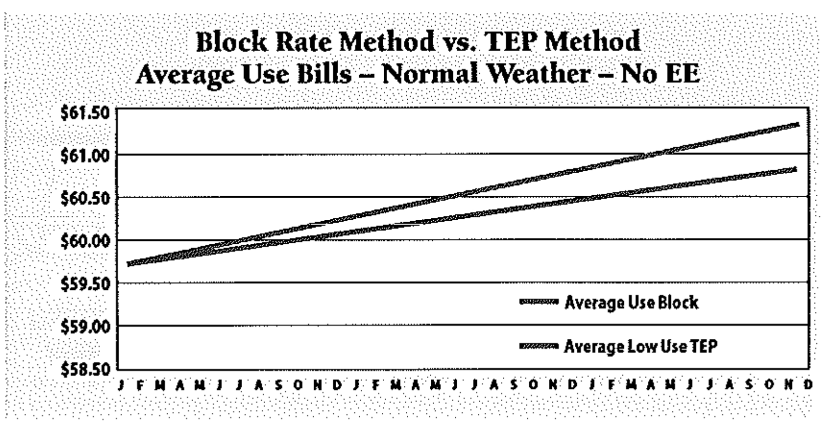
Low Use Customers

Low use customers who do not employ energy efficiency or otherwise reduce usage enjoy a slightly higher level of savings with the TEP method than with the normal block rate method. For these customers, the average monthly decrease in bills in normal weather conditions is $0.24, reaching a maximum of $0.49 by the end of the study period.



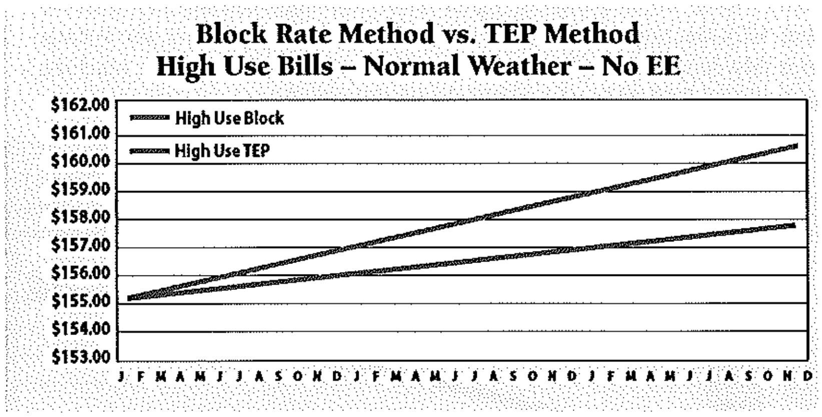
Average Use Customers

Non-participant average use customers also enjoy a reduction in bills with the TEP method. For these customers, the monthly average savings over the study period is $1.60, reaching a maximum of $3.47 by the end of the study period.



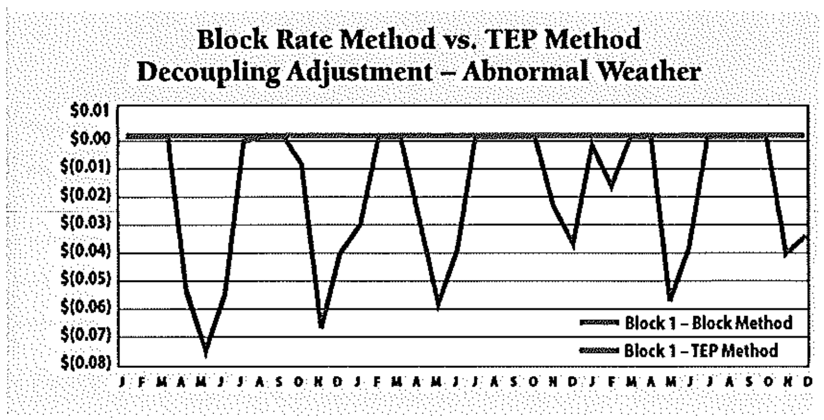
High Use Customers

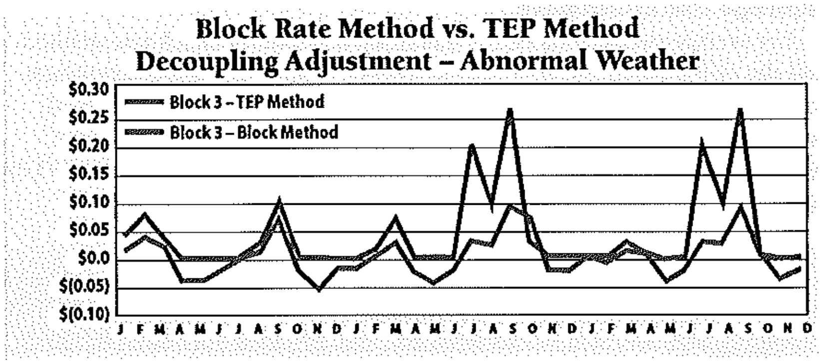
Non-participant high use customers receive an increase in bills with the TEP method. For these customers, the average monthly increase in bills is $4.47 per month, reaching a maximum of $9.78 by the end of the study period.



Decoupling Adjustments By Block – Abnormal Weather

Under abnormal weather conditions, the impacts of the TEP method on the different types of users can be more pronounced and more variable than under normal weather conditions. The chart at right shows the decoupling adjustments applied to low use customers, all of whose usage is in the first block. Because the TEP method only allows negative decoupling adjustments to be applied to the first block, the TEP adjustments are either negative or zero. The average monthly difference versus the regular block rate method is approximately $0.02, with a maximum difference of approximately $0.075.





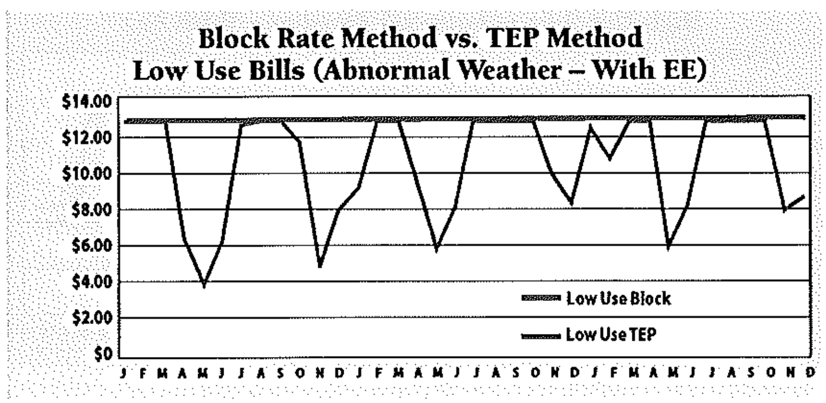
Once again, we omit the Block 2 analysis, because the TEP method is never applied to Block 2.

The Block 3 decoupling adjustments also exhibit greater magnitude and variability under abnormal weather conditions. The average decoupling adjustment for Block 3 is $0.05, whereas the maximum adjustment is approximately $0.28.

Impact of the Tucson Electric Power Method on Bills of Customers – Reduced Usage – Abnormal Weather

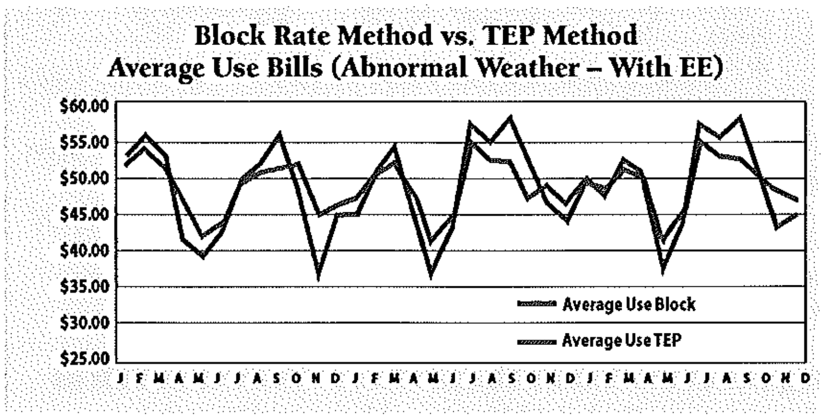
Low Use Customers

The chart below reflects the monthly bills for low use customers for the normal block rate method and the TEP methods under abnormal weather conditions. While the block rate method results in a fairly steady increase over time, the bills for the TEP method vary from as low as $12.34 and as high as $13.00, with an average of $12.79.



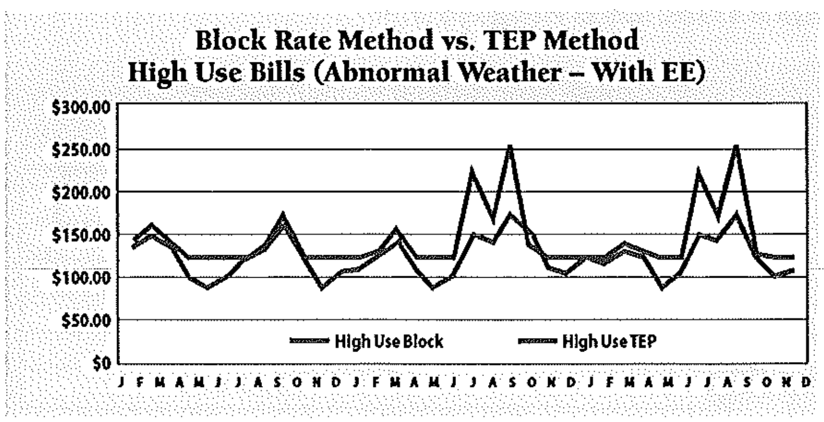
Average Use Customers

For average use customers, the difference between the block rate method and the TEP method is caused by the absence of any decoupling adjustment in the TEP method. The average bill with the block rate method is $48.01, with a minimum of $38.67 and a maximum of $56.31. TEP bills average $47.83, just $0.18 different than with block rates, with a minimum of $33.89 and a maximum of $60.67.



High Use Customers

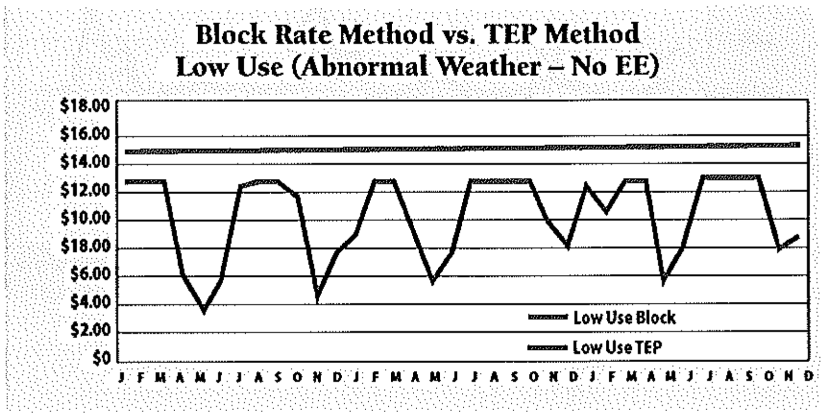
For high use customers, the TEP method results in bills that are mostly higher and occasionally approximately the same as with the block rate method. Block rates result in an average bill of $126.19, with a minimum of $86.28 and a maximum of $320.09.



Impact of the Tucson Electric Power Method on Bills of Customers – No Reduced Usage – Abnormal Weather

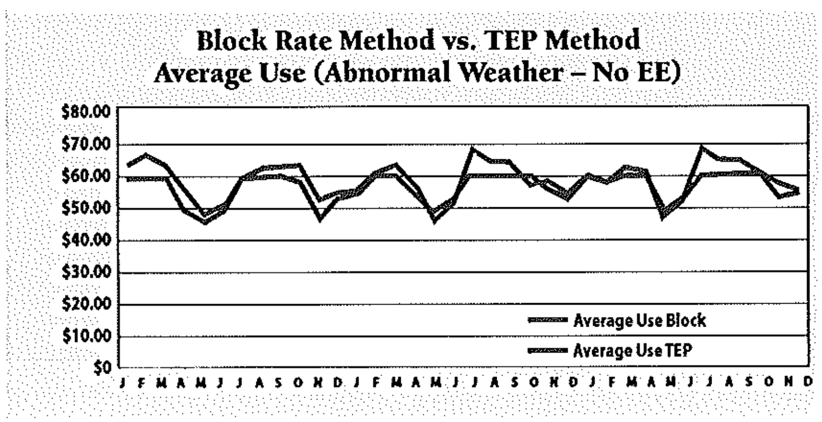
Low Use Customers

This graph shows the effect of using the TEP methodology under abnormal weather for low use customers.



Average Use Customers

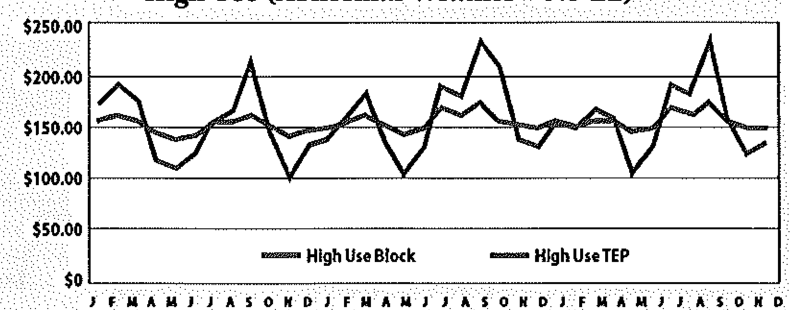
This graph shows the effect of using the TEP methodology under abnormal weather for average use customers.



High Use Customers

This graph shows the effect of using the TEP methodology under abnormal weather for high use customers.

Block Rate Method vs. TEP Method
High Use (Abnormal Weather – No EE)



BEFORE THE

MAINE PUBLIC UTILITIES COMMISSION

CENTRAL MAINE POWER: Re: Request for Approval of an Alternative Rate Plan (Arp 2014) Pertaining to Central Maine Power Company.	Docket No. 2013-168

DIRECT TESTIMONY

OF

TIM WOOLF

ON BEHALF OF THE

MAINE PUBLIC ADVOCATE OFFIC

December 12, 2013

Office of the Public Advocate

112 State House Station

Augusta, Me 04333-0112

Table of Contents

1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title, and employer.

A. My name is Tim Woolf. I am Vice President at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity and gas industry regulation, planning and analysis. Our work covers a range of issues, including integrated resource planning; economic and technical assessments of energy resources; electricity market modeling and assessment; energy efficiency policies and programs; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including attorneys general; consumer advocates; public utility commissions; environmental groups; federal agencies including the Environmental Protection Agency, Department of Energy, Department of Justice, and Federal Trade Commission; and the National Association of Regulatory Utility Commissioners. Synapse has over 20 professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. I have worked on a variety of electricity industry planning and regulatory issues for over 30 years. As Vice President of Synapse, I am responsible for providing expert testimony, preparing reports, conducting technical analyses, managing and participating in stakeholder working groups, and providing technical support to a range of clients.

From 2007 through 2011, I was a commissioner at the Massachusetts Department of Public Utilities (DPU). In that capacity I was responsible for overseeing a significant expansion of clean energy policies, including significantly increased ratepayer-funded energy efficiency programs; an update of the DPU energy efficiency guidelines; the implementation of decoupled rates for electric and gas companies; the promulgation of net metering regulations; review of smart grid pilot programs; and review and approval of long-term contracts for renewable power. I was also responsible for overseeing a variety of other dockets before the commission, including several electric and gas rate cases.

Prior to being a commissioner at the Massachusetts DPU, I was employed as the Vice President at Synapse Energy Economics; a Manager at Tellus Institute; the Research Director of the Association for the Conservation of Energy; a Staff Economist at the Massachusetts Department of Public Utilities; and a Policy Analyst at the Massachusetts Executive Office of Energy Resources.

I hold a Master's degree in Business Administration from Boston University, a Diploma in Economics from the London School of Economics, a BS in Mechanical Engineering and a BA in English from Tufts University.

Q. Please describe your professional experience as it relates to performance-based ratemaking, decoupling, and ratemaking in general.

A. In the 1990s, when the electricity industry was debating whether and how to introduce restructuring, I addressed performance-based ratemaking (PBR) for several of my clients, including the Delaware Public Service Commission Staff, the Mississippi Attorney General, the Kentucky Attorney General, the Colorado Office of Energy Conservation, and the Connecticut Office of Consumer Counsel. In 1997, I was the editor and co-author of a report prepared for the National Association of Regulatory Commissioners entitled "Performance-Based Ratemaking in a Restructured Electricity Industry." I have also published articles on PBR in *Public Utilities Fortnightly* and *The Electricity Journal*.

More recently, I addressed many issues related to PBR while I was a commissioner at the Massachusetts DPU. I oversaw several rate cases for electric utilities where PBR was the underlying structure of the rate-setting process. Furthermore, I was the lead commissioner on the Department's generic docket investigating revenue decoupling, where one of the key issues pertained to the adjustments that should be made between rate cases in the PBR mechanism, in light of the introduction of decoupling.

Even more recently, from August 2012 through June 2013, I was a co-leader of the Massachusetts Grid Modernization stakeholder working group process, as a consultant to the Massachusetts DPU. This working group debated in detail the various regulatory options for encouraging and incentivizing smart grid investments, and PBR emerged as one of the central options evaluated by the group.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Maine Office of the Public Advocate (OPA).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address several of the policy issues raised by Central Maine Power Company's (CMP, or the Company) 2014 Alternative Rate Plan (ARP2014). I focus on the recovery of capital costs; the Revenue Index Mechanism (RIM) proposal; and the decoupling proposal. My testimony responds to the initial and supplemental testimony of the Policy Panel provided by Steven Adams, Eric Stinneford, and Laney Brown, as well as the initial and supplemental decoupling testimony provided by Mr. Lahtinen. My testimony builds off of the testimony of other witness for the OPA, particularly the testimonies of Charlie King, Tom Catlin, and David Dismukes.

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your primary conclusions.

A. My primary conclusions include the following:

- The Company's proposed ARP2014 is not consistent with the underlying principles of performance-based ratemaking, nor does it meet the original goals of the Commission when it established CMP's Alternative Rate Plan in 1994.
- The Company's proposed ARP2014 represents a fundamental shift in ratemaking policy relative to ARP2008, yet CMP has not provided justification for such a dramatic shift.
- The Company's proposed Rate Index Mechanism essentially provides CMP with pre-approval of its current capital expenditure plan and allows CMP to recover projected capital costs each year of the ARP2014 period, regardless of whether the costs are incurred.
- The Company's proposed Rate Index Mechanism significantly reduces the financial incentive for CMP to plan for and operate the company as efficiently as possible.

- The Company's proposal for recovery of the regulatory liability further reduces the financial incentive for CMP to plan for and operate the company as efficiently as possible.
- In total, the Company's proposal significantly reduces risk to the Company and its shareholders, and shifts an unacceptable amount of risk to the utility customers.
- The Company's decoupling proposal will mitigate the Company's desire to increase customer charges; reduce the pressure for recovery of increased costs through the Rate Index Mechanism; and eliminate the negative financial incentives that CMP faces with regard to demand-side resources.

Q. Please summarize your primary recommendations.

A. My primary recommendations include the following:

- The Commission should reject the Company's proposed ARP2014 on the basis of my findings above.
- The Commission should require the Company to ensure that its new Alternate Rate Plan meets the key objectives of performance-based ratemaking, as well as the objectives identified by the Commission.
- The Commission should make a distinction between the treatment of "baseline" capital expenditures (i.e., standard capital expenditures to maintain reliability and quality of service), and "major" capital expenditures (i.e., large, infrequent expenditures for distinct projects).
    - Baseline capital expenditures should be recovered through the ARP mechanism, as they have been to date.
    - Major capital expenditures should be recovered using traditional, cost-of-service ratemaking, i.e., outside of the ARP mechanism.
- The Commission should require that the X-factor used in the ARP2014 mechanism:
    - Reflects the potential productivity improvements from baseline capital expenditures, but not major capital expenditures.

- Be more clearly tied to relevant performance of peer utilities, and should not be designed to recover costs associated with the Company's projected capital plan.
- Be set to the factor proposed by Mr. King in his testimony for the OPA.

- The Commission should reject the Company's proposal to use $29.5 million of the regulatory liability to enable it to recover its allowed return on equity.
- The Commission should approve the Company's proposal to decouple revenue from sales, and require specific measures to protect consumers in light of this significant ratemaking development. These measures include: reducing the Company's allowed return on equity (ROE) to reflect the reduced risk resulting from the RDM; installing a cap of one percent of total revenues on the annual decoupling adjustment; and modifying the ROE threshold for the Company's earnings sharing mechanism so that it is commensurate with the new ROE allowed by the Commission in this docket.

3. OBJECTIVES OF THE ALTERNATE RATE PLAN

Q. Is the Alternate Rate Plan currently in place a form of performance-based ratemaking?

A. Yes. The Company's current Alternate Rate Plan (ARP2008) is a form of performance-based ratemaking. It was first established in Maine at a time when regulators in New England and elsewhere were investigating options for introducing greater competition into the electricity industry. Several states adopted various forms of PBR at that time, with the goal of creating more market-like incentives for an electric utility to increase its operational efficiency and maintain high-quality service to customers.

Q. Please provide a brief description of performance-based ratemaking.

A. Performance-based ratemaking can take a variety of forms. However, it typically includes several key elements.

- The initial (first year) rates are set in a rate case, based upon the revenue requirements in a historical test year, using traditional cost-of-service principles.

- The utility is not allowed to apply for a rate case for a fixed period of time, e.g., five years or more.
- Because of the presumably longer period of time between rate cases, the utility is allowed to increase the first-year rates by a predetermined amount at regular intervals between rate cases.
- The amount by which rates can be increased between rate cases is set in such a way as to provide the utility with the flexibility and the incentive to manage its expenditures so as to reduce costs, increase operational efficiency and increase profits. This is often achieved by allowing the utility to increase rates by inflation minus a productivity factor, where the productivity factor is an indication of how the utility can improve its operational efficiency relative to a group of peer utilities.
- Customer service and reliability standards are established to ensure that a utility's incentive to reduce costs does not lead to reduced quality of service to customers.
- Earnings sharing mechanisms are sometimes established to protect consumers from utilities earning especially high returns on equity (ROE), or to protect utilities from earning especially low ROEs.

Note that the description above pertains to a price-cap form of PBR. It is also possible to apply the same elements using a revenue-cap form of PBR, where the utility is allowed a fixed amount of revenue requirements, and the allowed revenues are adjusted between rate cases instead of the prices. With a revenue-cap PBR, a utility's revenues are decoupled from its sales levels, which eliminates the utility's financial incentive to increase sales or to oppose activities that reduce sales.

Q. What are the key objectives of performance-based ratemaking in general?

A. Performance-based ratemaking has several objectives, including the following:

1. To provide the utility with the flexibility and proper financial incentives to make sound management decisions to reduce costs and improve operational efficiency.

2. To strike the appropriate balance between the risks to the utility versus the risks to customers, by tying the utility's risk more closely to its managerial decisions regarding expenditures and operational efficiency.

3. To establish a target set of rates (or revenues) that gives the regulators some confidence that revenues recovered by a utility between rate cases will be limited, reasonable and appropriate.

4. To reduce the time and resources necessary for a commission and other stakeholders to review a utility's costs in rate cases. Less time should be required to review a utility's costs because there is a presumption that such costs are reasonable as long as they are consistent with inflation and the productivity trends of their peer utilities.

Q. Has the Commission articulated its objectives for the Company's Alternative Rate Plan?

Yes. In the Commission's Order of Partial Dismissal on August 2, 2013, the Commission noted that it had previously approved price-cap rate plans "to encourage efficiencies and cost effectiveness." The Commission quoted its order approving CMP's first ARP to reiterate that the benefits and objectives of an ARP include:

> (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.[1]

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[1] Order of Partial Dismissal, pp. 5-6, citing Central Maine Power Company, Proposed Increase in Rates, Docket No.92-345, Order at 130 (December 14, 1993).

Q. Have the Company's Alternative Rate Plans to date achieved these objectives?

While I have not had the opportunity to review the historical performance of the Company in detail, it appears as though the current Alternate Rate Plan (ARP2008) has been successful. The Company has apparently maintained its distribution system sufficiently to provide safe, reliable service. CMP characterizes its distribution system as being "in good to very good condition based on the findings of the recent comprehensive asset health studies,"[2] and notes that it has met its System Average Interruption Frequency Indicator (SAIFI) and Customer Average Interruption Duration Indicator (CAIDI) service quality indicators in all but one instance over the last 13 years.[3] Furthermore, the Company has earned a reasonable rate of return on equity, ranging from a low of 9.62 percent to a high of 12.59 percent.[4]

Q. Does the Company's proposal for ARP2014 achieve the objectives of performance-based ratemaking or the objectives of ARP outlined by the Commission?

A. No. The Company's ARP2014 proposal includes two provisions that will result in a significant deviation from performance-based ratemaking, and that will make the ARP2014 inconsistent with the key objectives of PBR and the key objectives outlined by the Commission.

First, the Company's ARP2014 proposal essentially provides the Company with pre-approval and automatic recovery for its projected capital expenditures plan. I explain why this is so in Section 4. Pre-approval and automatic recovery of expenditures is not consistent with PBR practices in general, nor is it consistent with the Alternative Rate Plan objectives identified by the Commission.

Second, the Company's proposal includes a provision to use the regulatory liability depreciation schedule to ensure that it will earn its allowed ROE. This is a significant deviation from PBR because it essentially guarantees the Company its allowed ROE, regardless of how well the Company performs. I discuss this issue below in Section 5.

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[2] Reynolds, Kruppenbacher, Montanye, Conroy, Wacker. Supplemental Testimony of the Capital Investment Panel, September 20, 2013. SUP-CAP-1 to SUP-CAP-2

[3] Reynolds, Kruppenbacher, Montanye, Conroy, Wacker. Supplemental Testimony of the Capital Investment Panel, September 20, 2013, SUP-CAP-2

[4] Response to Examiner 019-004.

Q. Why is it so important to acknowledge that the Company's proposal is a significant deviation from performance-based ratemaking?

A. In establishing any rate plan, it is important to identify the rationale and the objectives of the ratemaking framework, so that a proposed rate plan can be evaluated relative to that framework. Performance-based ratemaking is a useful framework for reviewing the Company's ARP2014 proposal.

It is important to note that PBR can be applied in a variety of forms. There is no one single formula that must be used in all applications. When I refer to a "deviation" from PBR, I am referring to a modification that is inconsistent with the fundamental principles and objectives of PBR.

Q. Are there any instances where it may be appropriate to deviate from the performance-based ratemaking framework?

A. Possibly. There may be good reasons why it would be appropriate to deviate from a PBR framework because of lessons learned over time or significant changes to the electric utility or to the electricity industry in general. However, if the Company wishes to deviate from a PBR framework in designing its ARP, it should be allowed to do so only if it meets three important criteria. First, the proposal must be appropriate (i.e., it must meet the overall ratemaking goals of the Commission). Second, the proposal must be justified (i.e., the Company must demonstrate why there is a need to deviate from PBR). Third, the proposal must be transparent (i.e., it must be clear to the Commission and other stakeholders how the proposal works relative to the PBR framework).

Q. Are there other ratemaking frameworks that the Commission should bear in mind while reviewing the Company's ARP2014 proposal?

A. Yes. I am not suggesting that the PBR framework is the only option available or appropriate. Traditional cost-of-service ratemaking is still in use in many states and is still a viable framework for utility ratemaking. My main point is that CMP's ARP was originally established as a PBR framework, and that framework should be used to evaluate the Company's ARP2014 proposal. If the Company wishes to deviate from that framework—whether it is relying upon traditional cost-of-service ratemaking or some other framework—it should only be allowed to do so if the proposal is appropriate, justified and transparent.

Q. Is the Company's ARP2014 proposal appropriate, justified and transparent?

A. No. The Company's proposal for the treatment of capital costs represents a significant deviation from PBR, but it is not appropriate, it has not been justified by CMP, and it is not transparent. I explain why this is so in the following section.

Q. What are the implications of the Company's proposal to deviate from PBR practices?

A. The Company's ARP2014 proposal will not achieve any of the four PBR objectives that I identify above. First, the Company will not have the financial incentive to improve operational efficiency, because its current capital expenditure plan will essentially be pre-approved by the Commission and because CMP will be guaranteed its allowed ROE as a result of its proposal regarding the regulatory liability depreciation schedule.

Second, the ARP2014 proposal does not strike an appropriate balance of risks between the utility and the customers, because pre-approval of the capital expenditure plan shifts a significant amount of risk from the utility to the customers.

Third, the ARP2014 proposal does not provide any confidence, at least for the OPA, that the Company's expenditures during the term of the ARP will be appropriate relative to peer utilities. The productivity factor proposed by CMP is apparently designed to allow the Company to recover the costs of its projected capital plan and is not sufficiently tied to productivity or to the performance of peer utilities.

Fourth, the ARP2014 proposal does not reduce the need for regulatory oversight, because the Commission is essentially asked to pre-approve the Company's proposed capital expenditure plan. In order to make a determination as to whether the proposed plan is reasonable, the Commission and other intervenors would have to spend a considerable amount of effort to review the details of the plan.

Q. What do you recommend with regard to these issues?

A. I recommend that in evaluating the various elements of the Company's proposal for ARP2014, the Commission be mindful of how likely it is that the proposal will achieve the overall goals of PBR and the specific objectives identified by the Commission. Those elements that are not consistent with these goals and objectives should be rejected. I provide more specific recommendations in the following sections.

4. TREATMENT OF CAPITAL COSTS

Q. Please summarize the Company's proposal for the recovery of capital costs in its initial filing in this docket.

A. In its May 1, 2013 initial filing, CMP proposed to deviate significantly from both ARP2008 capital spending levels and the manner in which capital costs are recovered. CMP's proposed capital investment plan was projected to "average nearly $90 million per year, which is approximately one-third greater than the level of distribution capital investment during ARP2008…" (not adjusted for inflation).[5] CMP's capital investment plan included annual investments in base distribution capital programs, as well as significant investments in "distribution system modernization" projects, "distribution asset condition improvement projects," and a new IT system: the Customer Relationship Management & Billing System (CRM&B).

Figure 1 shows CMP's proposed capital investment levels relative to recent historical amounts, adjusted for inflation.[6] As indicated, the Company's average capital investment expenditure levels for 2014 (upper dashed line) exceed average ARP2008 expenditure levels (lower dashed line). However, this increase is due almost entirely to the CRM&B system, described by CMP as representing "a large, once in a generation" replacement of CMP's customer relations and billing system with an estimated cost of approximately $55 million.[7] When this major capital project is removed, the inflation-adjusted average ARP2014 capital expenditures (dotted black line) are essentially identical to the inflation-adjusted average ARP2008 capital expenditures (dashed red line).

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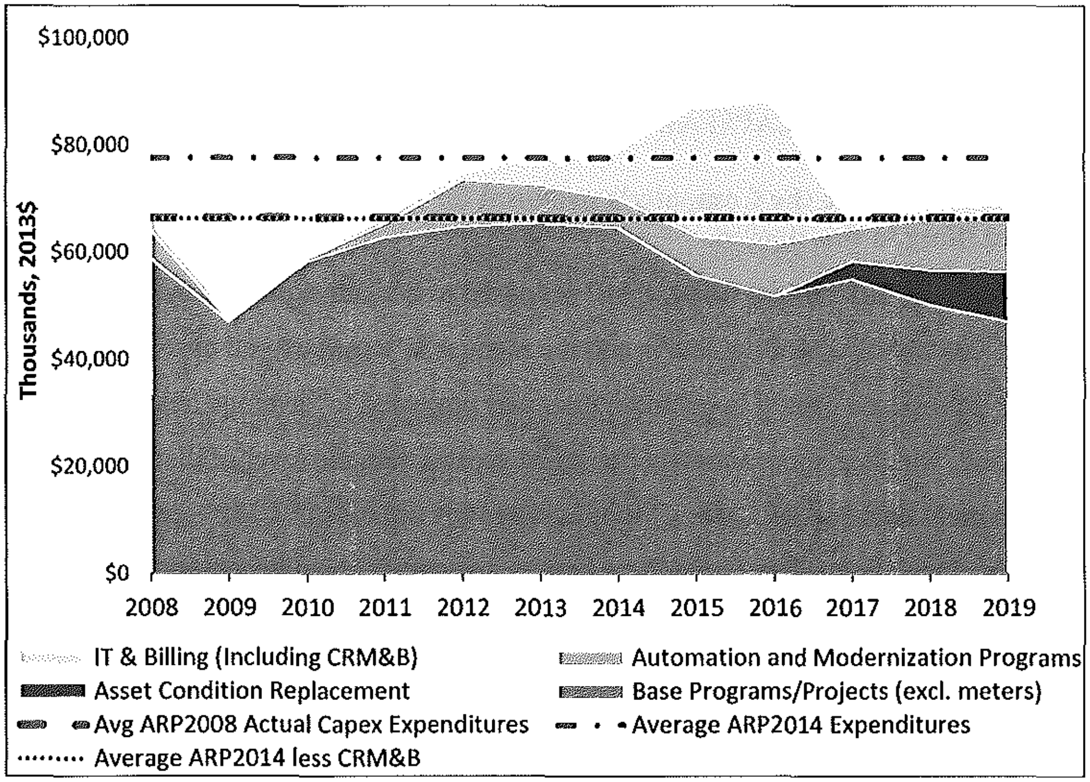
[5] Stinneford. CMP Filing Letter, Docket No. 2013-168, May 1, 2013, Page 2.

[6] Inflation adjustments made using Handy-Whitman Index for prior year through 2011. For 2012 – 2019, the adjustments use a projected Handy-Whitman Index increasing at 3.8 percent based upon the average percent increase from 2008 to 2011.

[7] Reynolds, Kruppenbacher, Montanye, Conroy, Wacker. Supplemental Testimony of the Capital Investment Panel, September 20, 2013, SUP-CAP-2.

Figure 1. CMP's proposed capital investments[8]



Q. How did CMP propose to recover the costs associated with its capital investment plan in its initial filing?

In its initial filing, CMP proposed to alter the previous ARP mechanism to allow separate treatment of capital costs. CMP proposed to maintain the (Inflation – X) formula for O&M expenses, while applying a capital recovery mechanism (CRM) with pre-established annual revenue requirements for capital cost recovery. The capital recovery mechanism would also enable net plant reconciliation and allow the company to retain net plant savings within a 10 percent bandwidth, provided System Average Interruption Frequency Indicator (SAIFI) or Customer Average Interruption Duration Indicator (CAIDI) performance targets were met. This net plant reconciliation mechanism would apply to plant investments other than the CRM&B.

[8] Graph created from CMP's response to OPA-023-007, with metering costs omitted due to separate treatment of AMI costs.

Q. What was the OPA's response to the Company's original proposal?

A. On June 19, 2013, the OPA filed a Motion and Brief seeking dismissal of CMP's cost recovery mechanism, arguing in part that the Company's proposal inappropriately shifts the risks and burdens from the Company to ratepayers.

Q. How did the Commission rule on the OPA's petition?

The Commission granted OPA's motion, citing a number of factors, including that the CRM removes one of the core objectives of an ARP (the elimination of the incentive to over-capitalize), and shifts the risk of overestimation and uncertainty to ratepayers. The Commission declined to pre-approve CMP's capital plan, stating:

> We are also not persuaded by CMP's arguments that its 6-year capital distribution plan should be fully vetted and blessed by the Commission in this proceeding. Detailed long-term capital planning is an activity that, at least in detail, should be left to management subject to prudency review. In addition, as a practical matter, by requiring that the parties and the Commission pre-approved specific capital programs years in advance, whenever CMP acknowledges that there is uncertainty relating to the timing, cost and even the ultimate need for the projects, the CRM introduces a level of predictive uncertainty into the ratemaking process that we find to be unacceptable.[9]

In essence, the Commission refused to allow the Company to collect revenues through its CRM for capital investments that are uncertain in their timing, cost, and need, and declined to engage in pre-approval of capital expenditures, reasoning that such decisions should be left to management subject to prudency review.

Q. Please describe the Company's current proposal.

A. CMP submitted supplemental testimony on September 20, 2013 that responded to the Commission's Order of Partial Dismissal. In this testimony, CMP reiterated its intention to move forward with its capital investment plan as laid out in its May 1, 2013 filing, but with a different cost recovery mechanism. The Company's testimony states that "CMP continues to believe that the investments and programs included within the Plan are appropriate for implementation during ARP2014. As such, CMP continues to offer the

[9] Order of Partial Dismissal, p.7

May 1 testimony of the Capital Investment Panel, with the exception of the capital investment delivery metrics…."[10]

Q. How does the Company propose to recover these capital costs?

A. To support this capital investment plan, the Company proposed to employ a Revenue Index Mechanism (RIM) equal to (Inflation – X).

Q. Do you have any concerns about the Company's Revenue Index Mechanism?

A. Yes, my general concern is that CMP has designed the Revenue Index Mechanism, particularly the X-factor, so that the Company will be able to recover those revenues needed to pay for its projected capital expenditure plan. This approach has several flaws: it is a significant deviation from PBR; it will essentially result in pre-approval of the Company's capital expenditure plan; it will reduce the Company's incentive to optimize its capital expenditures and O&M costs; and it will shift risk from the utility to its customers.

Q. How does the Company's proposed Revenue Index Mechanism differ from previous ARPs, and how does it deviate from PBR?

A. As in ARP2008, the Company's proposed RIM is equal to (Inflation – X). However, the X-factor proposed by the Company for ARP2014 was intentionally designed to allow the Company to recover enough revenue to undertake the same capital expenditures that it proposed in its initial filing. In previous ARPs, rates were allowed to increase between rate cases by inflation minus a productivity factor, where the productivity factor was designed to provide CMP with financial incentives to improve operational efficiency relative to comparable peer utilities.

The RIM proposed for ARP2014 bears superficial resemblance to the mechanism used in previous ARPs, but differs in several key ways. In particular, the X-factor now includes a "K" factor in order to allow CMP to recover revenue to support its capital expenditure plan. Company Witness Mark Lowry states this in several responses to discovery, including the following:

[10] Reynolds, Kruppenbacher, Montanye, Conroy, Wacker. Supplemental Testimony of the Capital Investment Panel, September 20, 2013, SUP-CAP-3.

- "Dr. Lowry's approach to the calculation of the K factor is a sensible means of providing the Company with supplemental revenue to finance its capex program."[11]
- "[The K factor] will help the Company finance a program of higher capital spending that began in the expiring ARP."[12]
- "A K factor has been calculated only for the present proceeding, in which CMP has special capex needs but the Commission prefers not to rely heavily on company forecasts to establish compensation."[13]

Q. In what way does the Company's proposal essentially constitute pre-approval of its capital expenditure plan?

A. The Company has abandoned its originally proposed Capital Recovery Mechanism, but not its request to recover its proposed capital investment costs as set forth in its May filing. Rather, it appears that the Company has simply designed another mechanism—a RIM with a negative X-factor— "for the recovery of the Company's incremental capital investments and related costs."[14]

Table 1. May 1 Revenue Requirement and Supplemental Revenue Forecast

Rate Year	Revenue Requirement in May 1 Filing	Supplemental Revenue Forecast	Percent Difference
RY 1	$246,040	$241,792	-2%
RY 2	$263,770	$258,722	-2%
RY 3	$280,871	$275,542	-2%
RY 4	$297,736	$292,068	-2%
RY 5	$312,818	$305,059	-2%
Total for RY1-RY5	**$1,401,235**	**$1,373,183**	**-2%**

Sources:
May 1 Revenue Request from Exhibit RRP-2 of May 1 Revenue Requirements Testimony.
Supplemental Revenue Forecast from Exhibit SUP-RRP 2, p.3 of 32, of Supplemental Revenue Requirements Testimony.

As designed, this mechanism will allow the Company to recover essentially the same amount of revenue as previously proposed, thereby implicitly requesting pre-approval of

[11] Response to OPA-029-005.
[12] Response to OPA-029-001.
[13] Response to OPA-029-002.
[14] Reynolds, Kruppenbacher, Montanye, Conroy, Wacker. Supplemental Testimony of the Capital Investment Panel, September 20, 2013, SUP-CAP-1.

the CMP capital expenditure plan. In fact, the revenues that would be recovered from the Company's September Supplemental filing differ very little from the Company's revenue requirement set forth in its May 1 testimony.

Table 1 presents the revenue requirement included in the Company's initial filing in this docket, compared to the forecast of supplemental revenues that would be recovered by CMP under its current proposal for the Revenue Index Mechanism. As indicated the difference between these two revenue streams is very small, on the order of two percent.

Q. What is wrong with the Company essentially asking for pre-approval for its capital expenditure plan?

As noted above, in its Order of Partial Dismissal the Commission has rejected the concept of regulatory review of the Company's capital expenditure plan in this docket. The OPA agrees with the Commission's findings in that order. The purpose of the ARP mechanism is not to conduct an *a priori* regulatory review of the Company's projections and estimates of future expenditures—either capital or O&M expenditures. The purpose of the ARP mechanism is to set a reasonable cap on prices (or revenues) between rate cases, so that the Company has the flexibility and the incentive to make efficient and prudent decisions regarding expenditures and operational improvements.

In addition, pre-approval of capital expenditures is not consistent with PBR. It reduces the Company's financial incentive to optimize costs and increase operational efficiency between rate cases.

Pre-approval of capital expenditures is also inconsistent with PBR because it shifts risk from the Company to its customers. With pre-approval of expenditures, a utility has the incentive to overstate the estimated future capital costs. In order to prevent this, the Commission and other intervenors must spend a considerable amount of time and resources to review and assess the proposed capital expenditures. The OPA is not in a position to conduct such a review in this docket, nor does it need to conduct such a review given that it would not be consistent with PBR in general or the Alternative Rate Plan system established in Maine, or indeed with the Commission's Order of Partial

Dismissal in which it said it would not entertain preapproval.[15] In the absence of such a review, the Company's customers are subject to a significant risk that (a) the capital projects are not the optimal projects to undertake between rate cases, and (b) the costs associated with those capital projects are overstated.

Another risk results from the fact that the Company would recover the costs of the capital expenditures plan, regardless of whether it actually makes the capital investments. As stated by the Company, CMP "cannot commit definitively to complete each of the programs as set forth in the Capital Investment Plan."[16] Although this statement is made because CMP is not sure that the mechanism will generate funding sufficient to cover all of its proposed investments, it highlights the fact that the Company's proposed cost recovery mechanism will provide the Company with funds without commensurate incentives to ensure that the Company implements all of the programs that drove the development of its revenue index mechanism. To the contrary, Company could profit from not implementing its proposed capital expenditures plan, as long as it can continue to achieve its service quality index targets.

Q. What do you think is the underlying cause of the problems with the Company's proposed productivity factor?

A. I think that a big challenge facing the Company in this docket is caused by its plan to make the large capital investment in its CRM&B system before the next rate case. A typical "inflation minus productivity" adjustment may not provide the Company with sufficient revenues to recover the costs associated with such a large capital investment. Consequently, the Company has proposed a productivity factor that is essentially designed to make room for such large capital investments. This point was demonstrated by Mark Lowry in one of the Technical Conferences:

> MR. WOOLF: So if the company were to decide to invest in this [CRM&B] system, then it should have the right incentive and the right revenue recovery under the formula you've proposed?

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[15] Order of Partial Dismissal at 7.

[16] Reynolds, Kruppenbacher, Montanye, Conroy, Wacker. Supplemental Testimony of the Capital Investment Panel, September 20, 2013, SUP-CAP-3.

DR. LOWRY: Yes.[17]

The problem with this approach, as discussed above, is that it essentially amounts to pre-approval and it eliminates one of the central elements of PBR.

In fact, this issue points to one of the biggest challenges regarding the Alternate Rate Plan as designed for CMP to date. It may not provide the Company with sufficient revenues to recover the costs required to make reasonable, prudent major capital expenditures. This challenges exists because (a) the first-year revenue requirement for capital expenditures is based on the Company's historical expenditures, which might not be a good reflection of major capital expenditures needed in the future; and (b) the changes in allowed revenue requirements between rate cases are based on a productivity relative to peer utilities, which may not adequately capture the need for or the impact of major capital expenditures.

Q. What do you recommend with regard to the treatment of capital expenditures in ARP2014?

A. I recommend that major capital expenditures be treated separately from the ARP mechanism. This will prevent the problem facing the Company and the Commission in this case, where CMP wants some assurance that it will be able to recover the costs of major capital expenditures such as the CRM&B. Instead, the ARP mechanism should only apply to baseline capital expenditures that generally do not deviate significantly from previous levels of investment.

Q. If major capital expenditures are not recovered through the ARP mechanism, how should they be recovered?

A. I recommend that the Company have the opportunity to recover major capital expenditures using traditional, cost-of-service ratemaking practices. This would include the following elements:

- The Company would have the flexibility to undertake major capital projects based upon its own assessment of the need for the projects, either on the grounds of

[17] Transcript of Productivity Technical Conference, Nov. 1, 2013, p. 96.

maintaining customer service needs, improving operational efficiency, or achieving some other goal.

- The Commission would not review such capital projects in advance, and would not provide any sort of pre-approval for such capital projects.

- When the Company undertakes a major capital project, it would be allowed to place those expenditures into an account for ongoing recovery. The Company would be allowed to recover the depreciation expense, taxes and return associated with the capital investment through an automatic adjustment mechanism. The undepreciated portion of the investment would remain in the account, to be treated at the time of a subsequent rate case.

- In the rate case following the placement into service of the capital project, the Company would file a request to place the remaining undepreciated amounts into rate base.

- At that time, the Commission would conduct a retrospective analysis to determine whether the capital project is reasonable and prudent. Expenditures that are not found to be reasonable and prudent would be disallowed, including any refunds to customers of funds already collected.

Q. How should major capital expenditures be defined?

A. Major capital expenditures should include infrequent, large capital projects that are not included in the historical pattern of capital expenditures, and are designed to achieve specific improvements to the Company's system. The Company's proposal for the CRM&B system is an example of something that should be considered a major capital expenditure and should therefore be treated outside of the ARP mechanism.

Q. Is this treatment of major capital expenditures consistent with the goals of PBR and the objectives of the Commission regarding ARP?

A. Yes. Treating major capital expenditures this way is a significant deviation from the current ARP. However, I believe that this approach to capital expenditures is appropriate at this time, and is consistent with the goals and objectives of PBR and ARP. Allowing the Company to recover prudent investments in major capital projects outside of the ARP ensures that the company faces incentives to make sound management decisions to invest in necessary capital infrastructure without requiring that these costs be pre-approved and immediately recovered, thereby preventing the utility's managerial decision risk from being unduly shifted to ratepayers.

Further, removing large capital investments from the revenue index mechanism enables target revenues to be established in a manner that is more clearly tied to the performance of peer utilities facing similar baseline capital investment costs. This provides regulators with some assurance that the Company's expenditures will be reasonable and appropriate, enhances incentives for the Company to control costs, and reduces the amount of time and resources required to review the Company's proposal.

Finally, review of major capital expenditures after they have been made ensures that the investments will be used and useful and reduces information asymmetry between the Company and interveners inherent in evaluating cost forecasts.

Q. Does this treatment of capital expenditures provide the Company with the proper incentives for balancing capital expenditures with O&M costs?

A. Yes, it does. In its Order of Partial Dismissal, the Commission expressed concern that the Company's original CRM mechanism would create a mismatch of costs and savings by not reflecting productivity improvements from capital investments.[18] I agree that the Company's CRM proposal would create such a mismatch, which would be inconsistent with the ARP objectives.

However, this concern is mitigated in my proposal in two ways. First, the baseline capital costs are kept within the ARP mechanism, therefore the connection between baseline capital costs and O&M costs will be maintained throughout the ARP period. Second, for major capital projects that are treated outside of the ARP mechanism, the costs will be recovered only after the project has been completed and is operational. As long as the major capital project is operational prior to the test year for the next rate case, the operational efficiencies resulting from the project will flow through to consumers.

[18] Order of Partial Dismissal, p. 7.

Q. What do you recommend with regard to setting the productivity factor?

A. The Commission should require that the productivity factor be more clearly tied to relevant performance of peer utilities, and should not be designed to recover costs associated with the Company's projected capital plan. With regard to the productivity factor for ARP2014, I recommend that the Commission adopt the productivity factor proposed by Mr. King in his testimony for the OPA.

5. TREATMENT OF THE REGULATORY LIABILITY

Q. Please describe briefly how the Company proposes to use the accelerated amortization of the cost of removal regulatory liability.

A. The Company is proposing to modify the current cost of removal regulatory liability amortization schedule for two reasons. In its supplemental policy testimony, the company first proposes to mitigate rate increases by modifying the amortization schedule over the ARP2014 period. Second, the Company proposes to modify the amortization schedule by an additional $19.5 million "to allow the Company to earn its requested return."[19] This second amount of $19.5 million was subsequently increased by an additional $10.0 million in the Company's November 25 Revenue Requirement Update testimony, for a total of $29.5 million of "base" shaping "in order for the Company to achieve its requested return."[20]

Q. Do you have concerns regarding the Company's proposal for the regulatory liability?

A. I do not have any concerns with the Company's proposal to mitigate rate increases by amortizing a portion of the regulatory liability over the ARP2014 period. The Company's proposal essentially results in an accelerated schedule for returning the regulatory liability to customers. Over the long term, customers will experience the same cumulative impact from either schedule.

However, I am concerned with the Company's proposal to amortize an additional $29.5 million to allow the Company to earn its allowed return, i.e., the ROE shaping

[19] Adams, Stinneford, Brown. Supplemental Policy Panel Testimony, Sept. 20, 2013, p. SUP-POL-9.
[20] Adams, Stinneford, Cohen, Pelletier, Fitzgerald. Revenue Requirement Update Testimony, Nov. 25, 2013, p. RRP-Update-8.

mechanism. First, the ROE shaping mechanism will reduce the amount of regulatory liability that will eventually flow to customers. Unlike the rate mitigation mechanism, which holds customers harmless over the long term, the ROE shaping mechanism will result in increased rates to customers over the long-term.

Second, the ROE shaping mechanism will reduce the Company's incentive to plan for and operate the Company as efficiently as possible, because it would provide the Company with its allowed ROE, regardless of how well it performs. Such an outcome would be inconsistent with the goals and objectives of PBR and ARP, would likely lead to higher costs incurred by the Company and passed on to customers, and would significantly shift risk from the utility to its customers.

Q. What do you recommend with regard to the Company's proposal to use a portion of its regulatory liability to allow it to earn its requested return on equity?

A. I recommend that the Commission reject the Company's proposed ROE shaping mechanism. Instead, I recommend that the Commission adopt the OPA's proposal, as described in the testimony of Tom Catlin, which applies an inflation adjustment to enable the Company to collect sufficient revenues during the course of ARP2014. This adjustment is more closely tied to the underlying cause of the Company's revenue requirement needs, and therefore helps to retain the logic and the objectives of PBR. It is also more transparent than the Company's proposal to use the amortization of the regulatory liability to make up for revenues that it would not otherwise recover.

Q. Are there other options available to address this issue?

A. Yes. The underlying issue here is that the Company is concerned that if it undertakes its proposed capital expenditure plan, then the Revenue Index Mechanism will not provide it with enough revenues to cover those costs and earn its allowed ROE. The PBR framework offers a mechanism to address concerns that a specific price-cap (or revenue-cap) formula will not result in a company earning its allowed ROE: the earnings sharing mechanism. Instead of adopting the Company's proposed ROE shaping mechanism, the Commission could establish a shared savings mechanism designed to provide the Company with revenues in the event that its ROE falls significantly below it's allowed ROE. These mechanisms are sometimes used in the context of PBR to (a) ensure that a utility's ROE is not subject to extreme fluctuations, and (b) provide the utility with the incentive to optimize its investments and seek cost savings where possible.

Q. Does the Company's proposal include an earnings sharing mechanism?

A. Similar to ARP2008, the Company's proposal for ARP2014 includes a high-end earnings sharing mechanism. Specifically, the Company's proposal provides that returns exceeding 135 basis points of the Company's allowed ROE be apportioned 50 percent to Customers and 50 percent to CMP shareholders.[21]

If the Commission decides that a low-end sharing approach is preferable to the OPA's proposal to apply an inflation adjustment, then it should establish a low-end earnings sharing mechanism to protect the Company from significant losses outside a certain bandwidth. The bandwidth could be, for example, ±350 basis points. An earnings sharing mechanism of this form was incorporated in the Stipulation that established the CMP's first ARP in 1994.[22]

6. THE REVENUE DECOUPLING MECHANISM

Q. Please summarize the Company's Revenue Decoupling Mechanism proposal.

A. The Company's Revenue Decoupling Mechanism (RDM) proposal is a new feature for its Alternate Rate Plan that would fully decouple the amount of distribution revenues recovered from the volume of sales to customers, regardless of whether the sales are caused by energy efficiency investments, weather, changes in the wider economy, or other reasons. The Company claims that the RDM is appropriate at this time, because there is a high level of uncertainty regarding future energy efficiency investments.

Q. Please summarize the key features of the Company's RDM proposal.

A. The Company's proposal includes the following features:

- Establishment of target annual revenues for the classes covered by the RDM;

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[21] Adams, Stinneford, Brown. Supplemental Policy Panel Testimony, Sept. 20, 2013, Exhibit SUP-POL-5. The Company's supplemental testimony contains an earnings sharing mechanism in which an ROE in excess of 11.5 percent (135 basis points above Stewart's recommended ROE of 10.15 percent) is shared 50/50 between customers and shareholders.

[22] *Central Maine Power Company, Proposed Increase in Rates,* Docket No. 92-345 (Phase II), Detailed Opinion and Subsidiary Findings, page 9 (January 10, 1995).

- Reconciliations for differences between the RDM target revenues and actuals, generally on an annual basis unless the difference between targeted revenues and actual revenues exceeds 5 percent;[23]

- Two reconciliation groups:

    - Residential (A/R, A/R-TOU, A-TOU_OPTS, A-LM)

    - Commercial/Industrial (SGS, SGS-TOU, MGS-S, MGS-S-TOU, MGS-P, MGS-P-TOU, IGS-S, IGS-P, LGS-S, LGS-P, and targeted programs that track changes in core rate, e.g., Easy Hours for Business)

- Interest would be computed using CMP's short-term borrowing rate for period between the end of the calendar and the beginning of the next rate year, with additional interest calculated over the term of the recovery period using CMP's proposed average cost of capital.[24]

Q. Do you support the application of a revenue decoupling mechanism for the Company at this time?

A. Yes. I support a revenue decoupling mechanism for CMP at this time for several reasons. First and foremost, a decoupling mechanism will result in the actual revenues collected by the Company being more closely matched to its allowed revenues. In the absence of a revenue decoupling mechanism, the actual revenues can deviate from the allowed revenues as a result of changes in sales volumes. These changes in sales volumes can be a result of the Company's actions, or they can be completely beyond the control of the Company (e.g., as a result of weather conditions or economic swings). With a revenue decoupling mechanism in place, the actual revenues collected by the Company will be more closely tied to the revenues allowed by the Commission, because they are no longer affected by the changes in sales volumes between rate cases. In my view, this is a more

[23] As explained in Lahtinen's Revenue Decoupling Mechanism testimony dated May 1, 2013, p. JAL-14, reconciliations would be based on the difference between actual and target revenues at the end of each calendar year, with the exception of the first reconciliation, which would be done over 18 months, ending December 2015, unless, after 6 months, the difference between target and actual revenues is 5 percent or more.

[24] Lahtinen. Revenue Decoupling Mechanism Testimony, May 1, 2013, p. JAL-14.

accurate way of providing a utility with the revenues that it is allowed in a rate case, relative to a system where the prices are guaranteed but the revenues are not.

Q. What are the other reasons why you support a revenue decoupling mechanism for CMP at this time?

A. A revenue decoupling mechanism will reduce the pressure for the Company to request increased revenues through the ARP mechanism. In the past, when sales were typically increasing each year, the Company could rely upon increased sales to lead to increased revenues. However, the Company is currently expecting sales to decline slightly during the ARP2014 period. In the absence of decoupling, the Company's actual revenues are likely to decline slightly as well, all else being equal. Consequently, the Company may seek a higher amount of revenues in its ARP to offset the declining revenues due to declining sales. A revenue decoupling mechanism should reduce the pressure for the Company to seek higher revenues in anticipation of declining sales.

Q. Will a revenue decoupling mechanism help reduce the Company's interest in increasing its customer charges?

Yes. CMP has proposed significant increases to its customer charges, as a means of recovering more of the distribution costs through fixed charges, and less through variable charges. A revenue decoupling mechanism can help meet one of the key goals of increasing customer charges: to ensure a more predictable and stable collection of revenues.[25]

A revenue decoupling mechanism is a far superior way to address revenue uncertainty than increasing fixed customer charges. Increasing fixed customer charges can result in significant negative impacts on some customers, and will reduce customers' financial incentive to reduce their bills through energy efficiency or other means. In fact, the Company compares its proposed RDM to the alternative of increasing customer charges, and notes that moving to a system with no RDM and a fully fixed charge rate redesign

[25] Lahtinen. Revenue Decoupling Mechanism Testimony, May 1, 2013, p. JAL-6; and Lahtinen. Revenue Decoupling Mechanism (Phase II) Testimony, August 1, 2013, p. JAL-2.

would lead to "significantly higher rate impacts than lower use customers would see under the proposed rate design" in combination with its proposed RDM.[26]

The problems with increasing fixed customer charges are addressed in more detail in the testimony of David Dismukes on behalf of the OPA. My main point is that adopting a revenue decoupling mechanism for CMP at this time will significantly reduce the pressure on the Company to increase customer charges.[27]

Q. Are there any other reasons why you support a revenue decoupling mechanism for CMP at this time?

Yes. A revenue decoupling mechanism will remove the financial disincentive that the Company currently experiences regarding demand-side resources. Currently, as customers implement demand-side resources (including energy efficiency, demand response, and behind-the-meter generation), the Company's sales are reduced, leading to reduced revenues and reduced profits. A revenue decoupling mechanism would eliminate this significant financial disincentive by enabling the Company to earn its allowed revenues regardless of sales levels.

A revenue decoupling mechanism can lead to a significant shift in the mindset of utility management, where it becomes much more likely to support (and less likely to oppose) demand-side resources. This shift can help enable a much broader implementation of demand-side resources, potentially leading to significantly reduced electric costs for many customers. Furthermore, as state, regional, and federal climate change requirements become increasingly stringent over time, it will be even more important for utilities to support demand-side recourse as low-cost options for reducing carbon emissions.

Q. In Maine the ratepayer-funded efficiency programs are implemented by Efficiency Maine, not by CMP. Does this arrangement eliminate the need for decoupling?

A. No. As I describe above, there are several reasons why a revenue decoupling mechanism is appropriate for CMP at this time, regardless of the financial disincentives related to demand-side resources. In addition, it is important to remove CMP's financial

[26] Lahtinen. Revenue Decoupling Mechanism Testimony, May 1, 2013, p. JAL-5.
[27] Adams, Stinneford, Brown. Policy Testimony, May 1, 2013, p. Policy Panel-27.

disincentive to demand-side resources, as well as its financial incentive to increase sales, regardless of which entity implements the ratepayer-funded efficiency programs.

First, there may be ways that the Company can cooperate with and support the efforts of Efficiency Maine. Ideally, a utility should have the financial incentive to make the ratepayer-funded programs as effective and as successful as possible, and should not have the incentive to limit or undermine those programs. Decoupling helps align a utility's goals with the goals of the independent energy efficiency program administrator.

Second, there are a variety of demand-side measures and resources that Efficiency Maine might not influence, but that might be influenced by the Company. Such measures include, for example: the installation of combined heat and power, rooftop photovoltaics, and other behind-the-meter generation resources; the development and enforcement of appliance efficiency standards and building codes; the implementation of evolving demand response or smart grid technologies; and the establishment of new legislation to support any of these measures. A revenue decoupling mechanism should provide the Company with the proper financial incentive to support such measures and thereby be more consistent with Maine's energy goals.

These points have already been recognized by the Commission. The 2008 *Report on Revenue Decoupling for Transmission and Distribution Utilities*, prepared for the Maine legislature by the Office of Energy Independence and Security (OEIS), the OPA and the Commission (the 2008 Maine Decoupling Report) noted that decoupling may be needed despite the role of Efficiency Maine in implementing efficiency programs. In particular, the study found that:

> Maine's utilities continue to have an incentive to promote sales and act in ways that can be viewed as contrary to State policies regarding energy efficiency and conservation. This continuing financial incentive has led to utility efforts to enhance sales (or reduce the erosion of sales) through such activities as use of bill inserts to encourage usage by promoting air conditioners, space heaters or increased lighting, opposing legislation that would increase efficiency spending through increases in electricity rates, and

resisting the installation of on-site generation (generally on the grounds that purchases from the grid are more cost-effective).[28]

Q. Do you recommend any modifications to the Revenue Decoupling Mechanism proposed by the Company?

A. Yes. I recommend three important modifications to the Company's RDM proposal, to ensure that customers are not harmed by decoupling and to maintain the appropriate balance of risk between the Company and its customers. These include: (a) placing a cap (equal to one percent of revenues) on the amount of revenues that can be recovered from customers in any one RDM adjustment; (b) reducing the Company's allowed ROE to reflect the reduced risk associated with the RDM; and (c) the earnings sharing mechanism should include a lower ROE threshold, commensurate with the new allowed ROE set by the Commission in this docket. I elaborate on each of these modifications below.

Q. Please explain why you recommend a cap on the amount of revenues that can be recovered from customers in any one RDM adjustment.

A. In general, one of the disadvantages to customers of a revenue decoupling mechanism is that rates may be more volatile than they would have been otherwise. In the case of CMP's ARP2014 proposal, this volatility risk is mitigated by the fact that decoupling applies only to a portion of customers' rates (i.e., distribution rates). This volatility risk is also mitigated because under the Alternate Rate Plan, CMP historically reset rates each year using the previous year's sales levels, and therefore any decoupling adjustment would be smaller than would be the case for a utility that sets rates using the sales levels from the test year.

Nonetheless, customers may experience some rate volatility from the Company's proposed RDM, and it is difficult to predict how much volatility there may be over the course of the next five years. In order to prevent customers from experiencing significant rate increases as a result of the RDM, I recommend that the Commission require the Company to apply a cap to the annual RDM adjustments. The cap should be set at one percent of the total allowed revenues for CMP for the period covered by the annual

[28] Maine Public Utilities Commission, Maine Office of the Public Advocate, and Office of Energy Independence and Security. *Report on Revenue Decoupling for Transmission & Distribution Utilities.* Jan. 31, 2008, p.10.

adjustment. Applying this cap would guarantee that customers will not see their total bill go up by more than one percent between rate cases as a result of the RDM adjustments.

If the difference between allowed revenue and actual revenue turns out to be greater than one percent of total revenues in any one year (i.e., the difference exceeds the cap), the Company should be allowed to carry any unrecovered revenues into the next period, and these unrecovered revenues would be added to the allowed revenues for that next period. In other words, unrecovered revenues could be rolled over from one period to the next. This way, the Company can recover the unrecovered revenues from the previous year in the next year, as long as the one percent cap is not exceeded that next year. If there remains some unrecovered revenues at the end of the 2014 ARP period, then the Company would not be allowed to recover those remaining unrecovered revenues.

Q. Please explain why it is appropriate to reduce the Company's allowed ROE to reflect the reduced risk associated with the RDM.

A. There is no question that decoupling will reduce the risk to a utility's shareholders. By definition, decoupling will reduce the instability and uncertainty associated with revenue collection. This will, in turn, reduce the instability and uncertainty associated with a utility's profits. Reduced volatility of utility profits is the equivalent of reduced risk to shareholders. When a utility is exposed to reduced risk, its ROE should be reduced accordingly. Stated differently, when shareholders are exposed to reduced risk, they should be willing to earn a lower return on equity (ROE), all else being equal. The 2008 Maine Decoupling Report concluded that decoupling will reduce a utility's risk, and recommended that there should be a return on equity adjustment to account for reduced risk.[29] I recommend that the Commission reduce CMP's allowed ROE to reflect the reduced risk to the Company as a result of introducing the RDM. Charlie King addresses the issues involved in setting the allowed ROE in his testimony on behalf of the OPA.

[29] Maine Public Utilities Commission, Maine Office of the Public Advocate, and Office of Energy Independence and Security. *Report on Revenue Decoupling for Transmission & Distribution Utilities.* Jan. 31, 2008, pp. 11 and 16.

Q. Please explain why you recommend that the earnings sharing mechanism threshold ROE should be different from that proposed by the Company.

A. My colleague Charlie King, in his testimony on behalf of the OPA, is recommending an allowed ROE that is significantly lower than the ROE requested by the Company. If the Commission establishes an allowed ROE that is lower than that proposed by the Company, then the threshold ROE for the earnings sharing mechanism should be lowered commensurately. Specifically, the ARP2014 earnings sharing mechanism should have a threshold of 350 basis points above the allowed ROE.

Q. Please summarize the OPA's position with regard to the Company's RDM proposal.

A. The OPA supports the Company's RDM proposal, under the condition that the OPA's other recommendations in this docket are accepted. This includes the recommendations of all the OPA's witnesses in this case, as well as the recommendations in my testimony.

7. SUMMARY OF RECOMMENDATIONS

Q. Please provide your recommendations regarding the topics you cover above.

A. First, I recommend that the Commission reject the Company's proposed ARP2014, on the basis of my findings above.

Second, I recommend that the Commission require the Company to continue to use the basic structure of the ARP2008, and to ensure that its Alternate Rate Plan meets the key objectives of performance-based ratemaking in general, as well as the objectives identified by the Commission.

Third, I recommend that the Commission modify the Alternate Rate Plan by making a distinction between the treatment of baseline capital expenditures, and major capital expenditures. Baseline capital expenditures should be recovered through the ARP mechanism, as they have been to date. Major capital expenditures should be recovered using traditional, cost-of-service ratemaking, i.e., outside of the ARP mechanism.

Fourth, I recommend that the Commission clarify the purpose of the productivity factor and how it should be used in the ARP mechanism. In particular, the Commission should clarify that the productivity factor should reflect the potential productivity improvements from baseline capital expenditures, but not major capital expenditures. The Commission should require that the productivity factor be more clearly tied to relevant performance of peer utilities, and should not be designed to recover costs associated with the Company's projected capital plan. With regard to the productivity factor for ARP2014, I recommend that the Commission adopt the factor proposed by Mr. King in his testimony for the OPA.

Fifth, I recommend that the Commission reject the Company's proposal to use $29.5 million of the regulatory liability to enable it to recover its allowed return on equity.

Finally, I recommend that the Commission approve the Company's proposal to decouple revenues from sales. The Commission should also require specific measures to protect consumers in light of this significant ratemaking development. These measures include: (a) reducing the Company's allowed return on equity to reflect the reduced risk from decoupling; (b) installing a cap of one percent of total revenues on the annual decoupling adjustment; and (c) the Company's the earnings sharing mechanism should have an ROE threshold that is commensurate with the new ROE allowed by the Commission.

Q. Does this conclude your pre-filed testimony?

A. Yes, it does.

BEFORE THE

MAINE PUBLIC UTILITIES COMMISSION

CENTRAL MAINE POWER: Re: Request for Approval of an Alternative Rate Plan (Arp 2014) Pertaining to Central Maine Power Company.	Docket No. 2013-00168

SURREBUTTAL TESTIMONY

OF

TIM WOOLF

ON BEHALF OF THE

MAINE PUBLIC ADVOCATE OFFICE

March 21, 2014

Office of the Public Advocate

112 State House Station

Augusta, Me 04333-0112

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title, and employer.

A. My name is Tim Woolf. I am Vice President at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Have you previously testified in this docket?

A. Yes. I provided direct testimony on December 12, 2013.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Maine Office of Public Advocate (OPA).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to three issues raised in the rebuttal testimony of Central Maine Power Company (CMP, or the Company) and other interveners. The three issues that I will address are: (1) the role of the Alternative Rate Plan (ARP), (2) the Revenue Decoupling Mechanism (RDM), and (3) the treatment of the Customer Relationship Management & Billing System (CRM&B) surcharge.

Q. Please summarize your testimony.

A. My primary conclusions and recommendations are as follows:

- If the Commission decides to continue with an Alternative Ratemaking Plan for CMP, then the OPA's proposal is the best way to design the ARP. However, if the Commission wishes to consider a return to traditional cost-of-service regulation, the OPA would not be opposed to such a move.
- The OPA's proposed RDM mechanism does not increase risks for customers. In fact, the RDM will make customers better off, as long as the OPA's recommended consumer protection measures are also adopted.
- The OPA opposes the recovery of CRM&B costs prior to the project being placed in service and used and useful. The costs for the project should be recovered through a surcharge only at the time that the project becomes operational in order to avoid

carrying costs and to ensure that customers are receiving the benefit for which they are paying.

2. ROLE OF THE ALTERNATIVE RATE PLAN IN SETTING RATES

Q. Please summarize the Staff's proposal regarding the overall role of the Company's Alternative Ratemaking Plan.

A. Staff has numerous concerns with the Company's ARP proposal and therefore recommends taking a "hiatus" from the ARP mechanism. The Staff proposes a return to traditional cost-of-service ratemaking, at least for sufficient time to assess the best option.[1]

Q. What is your position regarding the Staff's proposal?

A. As I noted in my direct testimony, a return to traditional cost-of-service ratemaking is a viable alternative to the Alternative Rate Plan.[2] However, if the Commission decides to continue with an ARP, the OPA believes that its proposal is the best way to design the ARP mechanism under current conditions.

Q. Why do you believe that the OPA's proposal represents the best means of continuing the ARP?

A. The OPA's ARP proposal, taken as a whole, includes several components that will protect customers, while maintaining the overall construct of an Alternative Ratemaking Plan and providing the Company with sufficient revenues to provide safe, reliable, low-cost electricity services.

First, the OPA's proposal requires the Company to treat the cost recovery of the CRM&B separately from the other capital costs. As noted in my direct testimony "I think that a big challenge facing the Company in this docket is caused by its plan to make the large capital investment in its CRM&B system before the next rate case."[3] Many of the concerns about the Company's productivity factor arise from the fact that the CRM&B is a large, atypical, and infrequent type of investment. The OPA's proposal addresses this

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[1] Bench Analysis, December 12, 2013, p. 20
[2] Woolf Direct Testimony, December 12, 2013, p. 9.
[3] Woolf Direct Testimony, December 12, 2013, p. 17.

challenge directly by removing the CRM&B from the ARP, and therefore from the productivity analysis. The CRM&B cost recovery would be comparable to cost treatment under traditional cost-of-service ratemaking. Thus, the OPA's proposal is essentially taking a step in the direction of traditional cost-of-service ratemaking, as recommended by Staff, but only for the most significant and most challenging of the Company's future capital expenditures.

Second, the OPA proposes a more meaningful and appropriate productivity offset for O&M expenses than the Company's proposal. The OPA is proposing a productivity offset of positive 0.95 percent,[4] which is much greater than the Company's proposed productivity offset of negative 1.85 percent.[5] The OPA's greater productivity offset will reduce the revenue requirements that customers would otherwise have to pay for, and provide a stronger incentive for the Company to be more efficient with regard to O&M expenses.

Third, the OPA proposes an allowed return on equity (ROE) of 8.5 percent.[6] This is significantly lower than the Company's proposed allowed ROE of 10.15 percent.[7] The OPA's lower allowed ROE provides the appropriate ratepayer risk reduction to account for the proposed decoupling mechanism, the Company's rate of return adjustment proposal, as well as the OPA's proposed adjustment to inflation proposal that allows CMP to earn its authorized rate of return.[8]

Fourth, the OPA proposes a revenue decoupling mechanism (RDM) that incorporates appropriate consumer protection measures. The OPA's RDM proposal, taken as a whole, is likely to provide net benefits to customers, without exposing them to increased risks. I elaborate upon this important point in the following two sections.

In sum, if the Commission decides to continue with an Alternative Ratemaking Plan for CMP, then the OPA's proposal is the best way to design the ARP mechanism under

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[4] King Direct Testimony, December 12, 2013, p. 38.
[5] Adams, Stinneford, and Policy Brown, Rebuttal Testimony, February 4, 2014, p. REB-POL-6
[6] King Direct Testimony, December 12, 2013, p. 3.
[7] Adams, Stinneford, and Brown, Policy Rebuttal Testimony, February 4, 2014, p. REB-POL-10.
[8] King Direct Testimony, December 12, 2013, p. 28-29.

current conditions. However, if the Commission wishes to consider a return to traditional cost-of-service regulation, the OPA would not be opposed to such a move.

3. REVENUE DECOUPLING MECHANISM: ADJUSTMENT CAP

Q. Please summarize the RDM adjustment cap that you proposed in your direct testimony.

A. In my direct testimony I recommended that the Commission establish a cap on the amount of revenues that can be recovered from customers in any one RDM adjustment. I recommended that "The cap should be set at one percent of total allowed revenues for CMP for the period covered by the annual adjustment. Applying this cap would guarantee that customers will not see their total bill go up by more than one percent between rate cases as a result of the RDM adjustments."[9] Further, I recommended that unrecovered revenues could be rolled over from one year to the next, but that the Company would not be able to recover any unrecovered revenues that might remain at the end of the ARP2014 period.[10]

Q. Did you provide any clarification of your proposal in response to discovery?

A. Yes. The Company asked several discovery requests regarding the details of my proposed RDM adjustment cap.

Q. Would you like to clarify these details at this time?

A. Yes. First, I recommend that the cap be based on the revenues estimated for the first rate year in ARP2014.[11] This approach would be simpler than estimating a different RDM adjustment cap for each year throughout the ARP. It also provides more certainty regarding the magnitude of the cap throughout the ARP.

Second, I recommend that the cap should be applied separately to each of the two reconciliation groups defined by the Company (residential and commercial/industrial). In this way, each group will have some assurance that their RDM adjustments will be no more than one percent each year.

[9] Woolf Direct Testimony, December 12, 2013, pp. 28-29.
[10] Woolf Direct Testimony, December 12, 2013, p. 29.
[11] OPA Response to CMP-013-001.

Third, I wish to clarify that my proposed cap of one percent would be based on the Company's total distribution and transmission revenues combined with standard offer revenues. In its rebuttal testimony, the Company estimates that a one percent cap based on its total delivery rates (including standard offer revenues) would be approximately $8.4 million.[12]

Q. Why do you recommend that the RDM adjustment cap be based on total revenues, including standard offer revenues, given that the Company does not control standard offer revenues or costs?

A. The purpose of the RDM adjustment cap is to protect customers from significant swings in prices as a result of the RDM. There are several benchmarks that could be used to set such a cap. The two most obvious benchmarks are a percent of distribution revenues, and a percent of total revenues. I prefer that the RDM cap be based on total revenues, because this provides a better overall indication of the extent to which customers' total electric bills might be affected by the adjustment. A one percent RDM cap based on total revenues means that in general customers' total electric bills will not increase by more than one percent as a result of the RDM adjustment. This benchmark in terms of total electric bills helps to place in context concerns about price volatility and risk, as described in the next section of my testimony.

Q. Do you recommend that the RDM adjustment cap be symmetrical? That is, in the event that the Company collects more than its target revenues, should it limit the amount that it returns to customers through the RDM adjustment?

A. No. In this instance there is good reason for an asymmetrical mechanism. In the event that the Company collects significantly more than its target revenues (as a result of increased sales), the Company is not harmed in any way by returning the excess to customers. Even after returning the excess revenues to customers, the Company would have collected its target revenues, and the revenues collected should be sufficient to cover its costs, based upon the construct of the ARP and the RDM. Thus, the Company is not harmed in any way by returning all excess revenues to customers in each RDM adjustment.

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[12] Lahtinen Rebuttal Testimony, February 4, 2014, p. 17.

On the other hand, in the event that the Company collects significantly less than its target revenues (as a result of reduced sales), customers could be harmed as a result of price increases at the time of the RDM adjustment. The reason for the RDM adjustment cap is to limit the extent to which customers will be exposed to such price increases. There is no need to have a comparable cap on rate decreases, to limit any harm to the Company from returning excess revenues to customers, because there is no harm in that instance.

Q. CMP believes that any RDM adjustment balance (either positive or negative) at the end of the ARP should be fully recovered or returned to customers in a subsequent rate period.[13] Do you agree?

A. No. I recommend that if there remains some uncollected revenues at the end of the 2014 ARP period, then the Company would not be allowed to collect those remaining uncollected revenues.[14] Again, this is simply a measure to protect customers in the event that uncollected revenues turn out to be greater than expected at the end of the ARP period.

4. REVENUE DECOUPLING MECHANISM: RISK VERSUS VOLATILITY

Q. Does Staff support the adoption of a Revenue Decoupling Mechanism?

A. No. Staff is concerned that revenue decoupling (together with other mechanisms in CMP's proposal) "reduces 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," and "significantly shifts risks onto customers and away from shareholders."[15]

Q. Do you agree with Staff's point that RDM will lead to unstable rates?

A. No. Any RDM adjustments for CMP will be based on deviations in revenues from one year to the next, and are thus likely to be small. That is, rates will be set on an on-going basis to recover the following year's target revenues, and will utilize recently forecasted customer counts and sales. Actual deviations from such forecasts are likely to be small, and therefore RDM adjustments will also be small. While fluctuations in the economy

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[13] Lahitinen Rebuttal Testimony, February 4, 2014, p.REB-JAL-18.
[14] Woolf Direct Testimony, December 12, 2013, p. 29.
[15] Bench Analysis, p. 85

and weather will cause some deviation from forecasts, it is reasonable to expect that such adjustments will be both up and down, and will generally balance out over time.

Q. Do you agree with Staff's point that the RDM will shift risk from the Company onto customers?

A. No. It is a commonly held misconception that decoupling will result in shifting risk from the utility to its customers. With regard to the OPA's proposal, this is not the case. It is very important to recognize that the RDM shifts *volatility* from the utility to the customers, but while this shift in volatility reduces risk for the utility, it does not materially increase risk for customers.

Q. Please explain what you mean by RDM shifts volatility from the utility to customers.

A. Under the RDM, electricity rates will be adjusted annually to correct for over-recovery or under-recovery relative to the target revenues. This means that electric rates will be slightly more volatile than they would be in the absence of the RDM. At the same time, utility revenues will be less volatile than they would be in the absence of RDM. Consequently, it is volatility that is shifted from the utility to the customers.

Q. Is there a difference between volatility and risk?

A. That depends upon whether you are a customer or a utility shareholder.

Q. What is the impact of revenue volatility on utility shareholders?

A. For the utility, revenue volatility translates into profit volatility. For utility shareholders, profit volatility is essentially the same thing as risk. Volatility, frequently measured as the standard deviation of returns, is the most common measure of financial risk, as it exposes investors to uncertain change.[16] A reduction in volatility is equivalent to a reduction in risk for shareholders. From the utility shareholder perspective, reduced volatility from the RDM is equivalent to reduced risk. This is why it is important to reduce a utility's allowed ROE when rates are decoupled.

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[16] See, for example, the definitions of risk and volatility given in: Gary Gastineau and Kritzman,M., *Dictionary of Financial Risk Management,* American Stock Exchange, New York: 1999; and Jon Danielsson, *Financial Risk Forecasting: The Theory and Practice of Forecasting Market Risk, with Implementation in R and MATLAB,* Wiley & Sons, Chichester, United Kingdom: 2011.

Q. What is the impact of price volatility on customers?

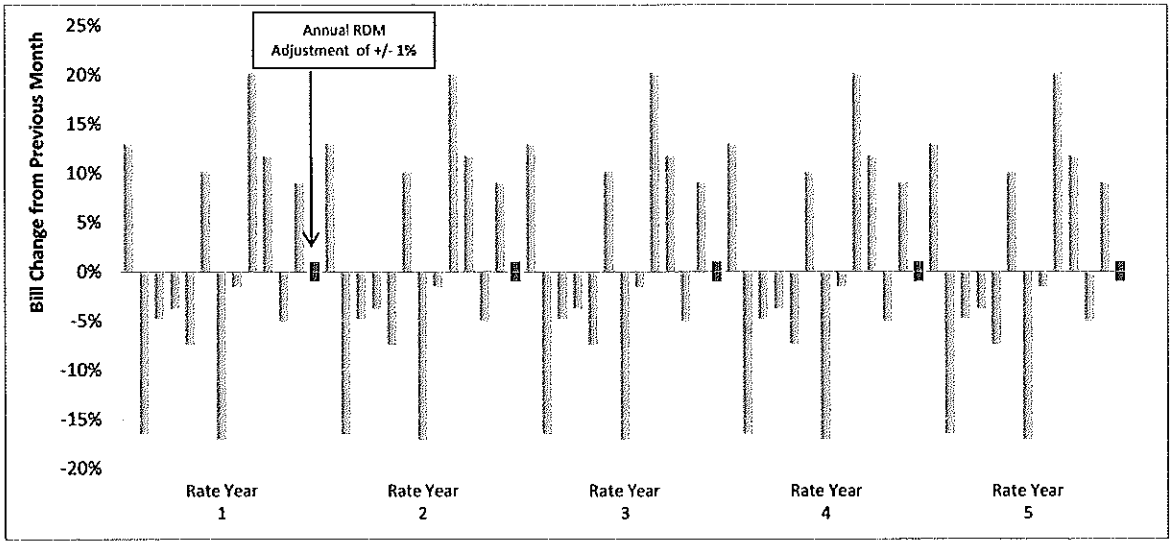
A. The impact of volatility on customers is very different than for utility shareholders. For customers, increased volatility means that their bills will be slightly higher or lower over time. If the cause of the volatility (e.g., weather or economic conditions) is roughly symmetrical, then their long-term costs will be the same. From a long-term cost perspective, customers are no worse off. Thus, from the customers' perspective, increased volatility is not equivalent to increased risk.

Furthermore, the magnitude of the volatility will be quite small, by design. The OPA proposes that the RDM adjustments be capped at one percent of total revenues. This means that RDM will cause customers' bills to change by a maximum of only one percent each year. This is a very small increase in the volatility of electric bills, especially compared with the extent to which customer bills typically fluctuate from month to month, season to season, and year to year based on changing consumption levels and changing costs.

I offer Figure 1 for illustrative purposes. It presents month-to-month electricity bill volatility for a sample electricity customer. Each of the blue bars indicates the month-to-month percent change in the customer's bill resulting from varying consumption levels from one month to the next. Each of the smaller red bars indicates a one percent (positive or negative) change in bills between rate years, as a result of the OPA's proposed RDM.[17] As indicated, increased volatility of one percent of bills once a year is essentially *de minimus,* relative to the month-to-month volatility that ratepayers experience.

[17] For this illustration, an actual residential customer's historic monthly consumption levels were used to indicate the monthly percent change in bills. The historic monthly percent changes were then simply extended out over all of the rate years, without changing distribution, transmission or generation rates over time. In practice, actual bills would experience a different volatility pattern due to the changes in rates over this period.

Figure 1. Month-to-Month Volatility in the Electric Bill of a Sample Residential Customer



Q. What, then, are the ultimate implications of shifting volatility from the utility to customers?

A. In sum, utility shareholders are better off with reduced volatility of revenues, while customers are essentially no worse off with increased volatility of bills (as long as the OPA's proposed cap is applied).

The Commission should accept the OPA's proposal to reduce the Company's allowed ROE due to the reduced volatility of revenues, because this is fair to shareholders and provides important additional benefits to customers in terms of lower rates. With this additional component of the OPA's RDM proposal, customers are likely to be better off with RDM than without it, despite the very small increase in the volatility of bills.

Q. Please explain why you believe that customers will be better off with the RDM than without it.

A. As described immediately above, customers have little, if anything, to lose from the OPA's proposed RDM. While there will theoretically be an increase in the volatility of rates, in practice this will be so small as to be un-noticeable, and will be offset by the reduced ROE.

Furthermore, there will be additional benefits to customers as a result of the RDM. First, as I describe in my direct testimony, an RDM eliminates the pressure to increase fixed customer charges as the Company has requested in this docket. From the customers' perspective, an RDM is a far superior way to address revenue uncertainty and volatility than increasing customer charges.

Second, the RDM should result in greater investment in cost-effective energy efficiency and distributed generation resources. These resources can provide multiple benefits to customers, including lower-cost electricity services.

Third, in the context of the ARP, when sales are flat or declining, the RDM reduces the need for inflation adjustments to the Revenue Index Mechanism. The RDM helps to ensure the Company will recover the revenues needed to cover its costs, regardless of actual sales volumes. In the absence of RDM, the Company's proposed X-factor would need to be greater (under the Company's proposal), or the OPA's proposed inflation adjustment[18] would need to be greater (under the OPA's proposal) to offset flat or declining sales.

Fourth, if the Commission decides to revert to traditional cost-of-service ratemaking (under the Staff's proposal), then the RDM will allow for less frequent rate cases.

5. THE SEPARATE CRM&B SURCHARGE

Q. Please summarize your proposal for a separate CRM&B surcharge.

A. As noted above, one of the biggest challenges in this rate case is how to provide the Company with the flexibility to undertake large, atypical, infrequent capital projects such as the CRM&B project. The ARP mechanism is not well-suited to account for this type of major capital expenditure, because the year-to-year rate increases are based upon inflation minus a productivity factor, which is not capable of adequately accounting for large, atypical, infrequent capital projects.[19] To address this challenge I recommend that major capital expenditures such as the CRM&B be accounted for outside of the ARP, in a separate surcharge. These major capital expenditures would be treated in a way that is comparable to traditional cost-of-service ratemaking, where (a) the utility decides whether and when to undertake major capital projects; (b) the capital costs are not put

[18] Catlin Direct Testimony, December 12, 2013, p. 13.
[19] Woolf Direct Testimony, December 12, 2013, p. 18.

into rates until the capital project is operational, used and useful; and (c) the Commission has the ability to review the capital project for prudence retrospectively when the costs are formally entered into rates during the subsequent rate case.

Q. Would you like to provide more detail on your recommendation regarding the Commission review and approval of major capital expenditures that are placed into the separate surcharge?

A. Yes. I wish to expand upon my recommendation that "The Commission would not review such capital projects in advance, and would not provide any sort of pre-approval for such capital projects."[20] By this I mean that the Commission would not pre-approve the *magnitude* of capital expenditures associated with the proposed project. The Company would have the responsibility to implement the capital project as efficiently as possible, and to ensure that the magnitude of costs is reasonable and prudent. Any concerns about the magnitude of the capital expenditures would be addressed after the project is complete, in the subsequent rate case, consistent with traditional cost-of-service ratemaking.

However, the Commission could make a finding with regard to the *need* for the proposed capital project, or in this case, the need to replace the existing billing system. Such a finding would provide the Company with some comfort that it is not likely to be subject to a challenge at a future date about the decision to proceed with the proposed capital project.

Q. Would you like to provide more detail on your recommendation regarding the timing of when major capital expenditures can be placed into the separate surcharge?

A. Yes. I wish to expand upon my recommendation that "When the Company undertakes a major capital project, it would be allowed to place those expenditures into an account for on-going recovery."[21] It is important to clarify when the capital project expenditures would be placed into the separate surcharge.

[20] Woolf Direct Testimony, p. 19.
[21] Woolf Direct Testimony, p. 19.

In its rebuttal testimony, the Company proposes that the CRM&B surcharge go into effect beginning on July 1, 2016, despite the fact that the Company does not anticipate that the CRM&B will go into service until January 2017. This timing is proposed in order to avoid carrying costs on the project from February 2017 to June 2017, and to help smooth the rate impact.[22]

The OPA does not agree with the Company's proposal of placing the costs of the CRM&B into the surcharge before the project is operational. The costs of major capital expenditures should not be placed into rates until the capital project is in-service, and is used and useful. This is a standard concept that is applied under traditional cost-of-service ratemaking, and is relevant in this context as well. Put simply, customers should not be charged costs for a project that is not in-service and is therefore not providing them benefits. In addition, there may be project delays or deviations from projected costs, making the costs placed in rates that much more inappropriate.

The OPA believes that the best option would be to place the capital project expenditures into the capital cost surcharge at the time the project becomes operational. In the case of the CRM&B, the Company expects this to be January 2017. At that point in time, the appropriate costs would go into the capital cost surcharge. This would mean adjusting rates in January, which would require a separate rate adjustment in addition to the CMP rate adjustments that typically occur in July. The OPA believes that making the adjustment at this time is preferable to making the adjustment in July, because it ensures that rates are not increased until the project is operational, and it eliminates the need for interest costs that would be incurred if the project costs were placed in the surcharge at a later date.

Q. Would you like to provide more detail on your recommendation regarding the types of costs that should be placed in the separate surcharge?

A. Yes. The rationale for the separate surcharge is to provide the Company with the ability to undertake major, infrequent capital projects between rate cases during the ARP period and still be able to recover those costs in a way that is comparable to what they would

[22] Adams, Stinneford, and Brown, Policy Rebuttal Testimony, February 4, 2014, pp. REB-POL-48-49.

recover if there were a rate case. At the time of a rate case, capital costs are typically placed into rate base, and the Company is allowed to collect the depreciation expense, taxes, and the return on equity associated with those costs. The capital expenditure surcharge should work the same way. Once the project enters service, the Company should be able to recover in the surcharge the depreciation, taxes, and return on equity associated with the costs. At the time of the next rate case, the surcharge account is zeroed out, the undepreciated portion of the costs is added into the Company's rate base, and the remainder of the project costs are recovered through rate base going forward.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2013-00168

August 25, 2014

CENTRAL MAINE POWER COMPANY,
Request for New Alternative Rate Plan
("ARP 2014")

ORDER APPROVING
STIPULATION

WELCH, Chairman; Littell and Vannoy, Commissioners

I. SUMMARY

In this Order, we approve a Stipulation filed in the above-referenced matter which resolves all revenue requirement matters in this proceeding other than those revenue requirement matters involving Automated Metering Infrastructure (AMI), which are resolved by our approval of a Supplemental Stipulation issued concurrently with this Order. The Stipulation also resolves some, but not all, of the rate design issues which were raised during this proceeding. Pursuant to the Stipulation, the remaining rate design issues were reserved for Commission determination and are addressed in a companion order.

II. BACKGROUND

A. Procedural History

On July 1, 2008, the Commission approved a five-year Alternative Rate Plan (ARP) for CMP which took effect on January 1, 2009 and expired on December 31, 2013. *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). Pursuant to the provisions of the Commission's Order Approving Stipulation, on May 1, 2013, CMP filed revenue requirement information based on a 2012 calendar year consistent with the requirements of Chapter 120 of the Commission's Rules. In that filing, CMP proposed a distribution rate increase of $41.4 million, or 18.2%. As part of its proposal, CMP proposed to accelerate the amortization of the Company's Cost of Removal (COR) Regulatory Liability to mitigate the impact of the proposed rate increase. After mitigation the proposed increase in rates would be $18.2 million, or 8%.

As part of its filing, the Company also proposed a new ARP (ARP 2014) which would run from January 1, 2014 through December 31, 2018. Under the terms of its ARP 2014 proposal, the Company's operations and maintenance revenue requirements would continue to be subject to the traditional inflation minus X formula. However, CMP's capital revenue requirement, which would include depreciation, property taxes and return on investment, would be based on CMP's proposed Capital Recovery Mechanism (CRM). Under the Company's CRM, CMP's capital revenue requirement would be based on CMP's projections of capital costs subject to reconciliation and a proposed sharing mechanism.

A Notice of Proceeding that provided customers and other interested persons with an opportunity to intervene was issued on May 9, 2013. Petitions to intervene were filed by the following entities and were subsequently granted by the Examiners: the Office of the Public Advocate (OPA); the Conservation Law Foundation (CLF); Environment Northeast (ENE); GridSolar, LLC (GridSolar); the Natural Resources Council of Maine (NECM); the Industrial Energy Consumer Group (IECG); Maine Independent Colleges Association (MICA); Ski Maine (Ski Maine); Midcoast Regional Redevelopment Authority (MRRA); Maine Association of Building Efficiency Professionals (MABEP); Efficiency Maine Trust (EMT); VCharge, Inc. (VCharge); Thermal Energy Storage of Maine (TESM); FISC Solutions, Pregrine Turbine Technologies; Edward Friedman; Mary Fournier and David Fournier (the Fourniers); Gary Goldsmith; Sandra Kelley; and Diane Wilkins.

On June 19, 2013, the OPA filed a Motion of Partial Dismissal seeking dismissal of CMP's CRM. The Commission issued an Order of Partial Dismissal on August 2, 2013 which granted the OPA's Motion pursuant to Section 10(G)(2) of Chapter 110 of the Commission's Rules of Practice and Procedure. In granting the OPA's Motion, the Commission found that CMP's own evidence did not provide a basis for deciding the CRM proposal in its favor, that proceeding to hearing would needlessly prolong the decision-making process causing undue burden and expense to the parties and to the Commission, and that there were no additional policy reasons present here to allow the CRM proposal to remain in the case. As part of the Commission's Order of Partial Dismissal, CMP was provided an opportunity to amend its case and to propose another mechanism which allows for increased capital investments without shifting the risk of over estimation and uncertainty to ratepayers.

On August 1, 2013, CMP filed Phase II of its rate case proposal, which included a proposed Revenue Allocation and Rate Design as well as supporting testimony for CMP's Revenue Decoupling Mechanism (RDM) proposal. CMP filed an amended rate plan in light of the Commission's Order of Partial Dismissal and also filed an updated Revenue Requirement proposal on September 20, 2013. On November 25, 2013, CMP submitted an additional update to its Revenue Requirement proposal.

On December 12, 2013, Staff filed a Bench Analysis and the OPA, GridSolar, EMT, IECT, MICA, MEBEP, and TESM filed direct testimony on the Company's proposed revenue requirement, ARP 2014 and revenue allocation and rate design proposals. In its Bench Analysis, Staff recommended that the Commission reject the Company's ARP proposal and made certain recommended adjustments to CMP's revenue requirement that would result in a lower of the rate increase. Staff's recommendation included an allowed ROE of 9.25% and a common equity ratio of 47%. The Bench Analysis also opposed the implementation of an RDM and rejected CMP's proposal to continue the extraordinary storm cost recovery mechanism. Instead of the Company's extraordinary storm costs mechanism, the Staff presented a storm cost recovery methodology based upon a normalized average level of historic incremental storm expenditures over a 12-year period.

The OPA's direct testimony proposed additional adjustments to the Company's revenue requirements, including alternative depreciation rates and an allowed ROE of 8.5%, and a common equity ratio of 50%. The OPA supported implementing an RDM with certain modifications to the Company's request. The OPA also proposed treating the Company's proposed Customer Relationship Management and Billing (CRM&B) system through a separate rate adjustment mechanism, which would go into effect when the CRM&B system is put into service.

The OPA, GridSolar, IECG, MABEP, MICA, and TESM opposed CMP's proposed rate design, with particular objection to the Company's proposed standby rates for customers with installed behind-the-meter generation. GridSolar proposed an alternative rate design methodology consisting of a fixed customer charge and a demand charged based upon a customer's average hourly peak load during certain specified hours on the day of CMP's annual system peak.

In their direct testimonies, the Intervenors all supported, or did not object to, some form of an RDM. The only exception was the IECG, who advised the Commission to exercise caution in approving an RDM in general, but did not comment on specifics of CMP's RDM proposal.

CMP filed rebuttal testimony on February 4, 2014. On March 21, 2014, Staff filed a Reply Bench Analysis and the OPA, GridSolar, IECG, MICA, and Ski Maine filed Surrebuttal testimony. In the Reply Bench Analysis, Staff recommended additional changes to CMP's revenue requirement, as well as an increase in the amount to be included in rates for an incremental storm recovery mechanism calculated based on a nine year period. In its surrebuttal testimony, the OPA raised an issue regarding CMP's treatment of tax basis repairs during ARP 2008.

Public witness hearings were held at the Commission's Offices in Hallowell, Maine on April 2, 2014 and in Portland, Maine on April 3, 2014. Hearings on the pre-filed testimonies in the case and on the Staff's analyses were held on April 9-10 and April 14-18, 2014.

Following the hearings, settlement conferences was held between the Company, Staff and many of the Intervenors on May 9, 2014; May 20, 2014; May 28, 2014; June 2, 2014; June 3, 2014; June 5, 2014; June 10, 2014; June 11, 2014, June 20, 2014, June 24, 2014, June 26, 2014 and July 1, 2014. Additional settlement conferences were held between the Staff and Parties, without the Company, on May 19, 2014, May 30, 2014, June 6, 2014 and June 25, 2014.[1]

On July 3, 2014, the Commission received a Stipulation and Supplemental Stipulation in this matter which was entered into by CMP, the OPA, GridSolar, CLF,

[1] CMP waived the ex parte rules to allow the non-CMP Parties to hold a settlement conference with Staff without the presence of the Company.

NRCM, IECG, MICA, Ski Maine, MRRA, MABEP, EMT, VCharge and TESM (Collectively referred to as the Settling Parties). The Stipulation proposes to resolve all revenue requirement, storm treatment, ARP and RDM issues in the case. Issues involving the AMI Revenue Requirement are addressed in the Supplemental Stipulation and are the subject of a separate order being issued concurrently with our decision here. The Stipulation also addresses certain, but not all, rate design issues. The rate design issues not resolved by the Stipulation were the subject of additional litigation and are also addressed in a separate order.

By way of a Procedural Order dated July 7, 2014, non-signatory parties in the case were given an opportunity to oppose the stipulations by filing a Statement in Opposition. The Fourniers opposed the stipulations and, on July 11, 2014, a Notice of Hearing was issued by the Examiners which scheduled a hearing on the stipulations for July 21, 2014. At the request of the Fourniers, the hearing on the stipulations was rescheduled to July 28, 2014.

B. Opposition to the Stipulations

In a Pre-Hearing Order issued on July 24, 2014, the Examiner required that CMP make available the following panel of witnesses to address the Fourniers' general objections: Eric Stinneford, Steven Adams (all matters), Peter Cohen (revenue requirement), Mark Marini or Ann Theriault (rate design). In addition, the Staff would be made available to answer questions on all areas covered by the stipulations. The Pre-Hearing Order also provided that, to the extent the Fourniers wished to present any documentary evidence not already in the record, they should identify such evidence in a memorandum to be filed with the Commission by noon on July 25, 2014.

On July 25, 2014, the Fourniers submitted a Memorandum along with twelve pictures the Fourniers took, which according to the Memorandum and subsequent affidavit filed by the Fourniers on July 28, 2014, showed that CMP was taking down trees outside of its right-of-way without the permission of landowners. At the hearing, counsel for CMP objected to the introduction of the Fourniers proposed photographs on the grounds of relevance. The Hearing Examiner concluded that the question of whether CMP had properly obtained the consent of landowners to take down the trees pictured was not an issue in the case and was not relevant to any issue resolved by the Stipulation. The Examiner noted that if the Fourniers believed that CMP was not obtaining land-owner consent for tree-trimming, the proper avenue would be to file either a complaint with the Commission's Consumer Assistance Division (CAD) or to file a ten-person complaint with the Commission. Therefore, the Examiner ruled that the pictures submitted by the Fournier's along with the accompanying affidavit of July 29, 2014 were inadmissible. The Fourniers orally moved that the Commission reconsider the Examiner's ruling. On reconsideration, the Examiner's ruling was sustained by the Commission. The Fourniers were provided with an opportunity to question CMP's witness panel and the Staff panel at the hearing and to also present oral argument in support of their opposition to the stipulations.

III. DESCRIPTION OF THE STIPULATION

A. Distribution Revenue Requirement (Stipulation, Part IV(A)) And Rate Increase Implementation (Stipulation, Part IV(B))

Under the terms of the Stipulation, CMP's distribution revenue requirement will increase by an amount of $24.257 million effective July 1, 2014. The Company's revenue requirement reflects the Settling Parties' agreement on the amount for recovery from customers of the Company's O&M expense items, certain adjustments set forth in the Supplemental Stipulation regarding AMI, depreciation accrual rates and income tax matters, including the tax basis repairs/unit of property deduction and PowerTax regulatory asset, and allowed return on its rate base. The revenue requirement is calculated based on a rate base of $782.001 million a pretax weighted cost of capital of 10.32%, which is based on a 9.45% return on equity (ROE) and a 50% equity ratio.

Under the Stipulation, the agreed upon increase in CMP's distribution revenue requirement will be included in CMP's distribution rate schedules on September 1, 2014, with CMP permitted to recover the value of the two-month delay from July 1 to September 1 through a one-time increase in the amortization of the COR regulatory liability in the amount of $4.227 million. To minimize the customer impact of the agreed upon distribution revenue requirement increase, the Settling Parties have agreed that, to the extent possible and consistent with the requirements of applicable law and the functionality of CMP's existing billing system, CMP's share of the damage awards received by Yankee Atomic Electric Company and Connecticut Yankee Atomic Power Company in connection with Phase II of the litigation against the U.S. Department of Energy (DOE) will be used to reduce customer costs from stranded cost rates effective September 1, 2014.

B. Storm Costs Treatment (Stipulation, Part IV(D))

The Stipulation provides that, effective July 1, 2014, CMP will implement a new recovery mechanism for incremental storm restoration costs. Under this mechanism, CMP's distribution rates will annually include $10 million for storm cost recovery. Storms will be classified into three categories: Tier 1 (Normal); Tier 2 (Large); and Tier 3 (Extraordinary). Tier 1 Storms are defined as storms where the incremental restoration costs are less than $3.5 million. Tier 2 Storms are defined as storms where the incremental restoration costs are between $3.5 million and $15 million. Tier 3 Storms are defined as storms where incremental restoration costs total more than $15 million. Of the $10 million included in rates annually, $4 million will be allocated for Tier 1 storm costs. The annual costs for Tier 1 storms will not be subject to reserve accounting or reconciliation treatment.

The remaining $6 million collected annually in rates will be credited to a reserve account for Tier 2 storm costs. As provided in detail in the Stipulation, Tier 2 storm costs will be charged against the reserve account. On an annual basis, CMP will reconcile its actual incremental, prudently incurred Tier 2 storm costs against the reserve balance. In the event that the reserve balance at the end of the calendar year exceeds $10 million (positive or negative), CMP and customers will share on a 50/50 basis any such overage with CMP's share of any negative balance capped at $3 million per year. Distribution rates will be adjusted effective July 1 (with the first adjustment effective date being July 1, 2015, if necessary) of the following year to include the customers' share of any such overage (positive or negative).

For Tier 3 storms, the first $15 million of incremental storm costs will be subject to Tier 2 treatment and charged against the reserve account. CMP's exposure for sharing under the above Tier 2 storm provisions for any single Tier 3 storm event is capped at $2 million. Tier 3 storm amounts above $15 million will be deferred for future recovery pursuant to an individual accounting order request. Distribution rates will be adjusted on July 1 of the year following the Tier 3 storm for the recovery of deferred amounts over $15 million.

C. Revenue Decoupling Mechanism (Stipulation, Part IV(C))

The Stipulation provides that, effective September 1, 2014, a revenue decoupling mechanism (RDM) will apply to CMP's distribution revenues. The RDM will remain in effect until changed by a subsequent Commission Order. The RDM will have two RDM classes: (1) Residential; and (2) Commercial and Industrial. The LGS-T, LGS-ST and Area and Street Lighting rate classes will be excluded from the RDM.

Under the RDM, the actual revenues for each of the RDM classes will be reconciled against the revenue targets for the RDM classes. The first reconciliation will cover the sixteen month period from September 1, 2014 through December 31, 2015. All subsequent reconciliations will be calculated on a calendar year basis (January 1 through December 31). The initial RDM Revenue Targets for the RDM classes will be based on the applicable rate year revenue requirement. The RDM revenue targets for subsequent years (beginning July 1, 2015) will be adjusted annually by 75% of the average annual year over year customer growth rate (positive or negative) for the rate classes within those RDM classes.

The recovery of any under-collection under the RDM will be subject to an annual cap set at 2% of distribution revenues applicable to each RDM class. For the initial 16 month reconciliation period (September 1, 2014 through December 31, 2015), the cap will be proportionately adjusted for the applicable period. Any under-collection amount over the annual cap will be deferred for recovery in a subsequent year. No cap will apply to the return of any over-collection. For as long as the RDM is in place, CMP will collaborate with the Efficiency Maine Trust on ways to promote efficiency, including, through CMP's web site, bill inserts, Energy Manager platform and the Bill Alert program.

D. Alternative Rate Plan (Stipulation, Part IV(F))

As part of the Stipulation, CMP agrees to withdraw its request for a new alternative rate plan (ARP2014). As such, CMP will not be subject to Service Quality Indicator (SQI) penalties. However, each year by April 1, CMP will file an Annual Reliability Report with the Commission that will provide service quality and reliability performance information for the prior year, including Customer Average Interruption Duration Index (CAIDI), System Average Interruption Frequency Index (SAIFI), Feeder Average Interruption Frequency Index (FAIFI) (for circuits that exceed 6.3), Business Calls Answered within 30 seconds, and New Service Installations.

E. New Customer Billing System (Stipulation, Part IV(E))

The Settling Parties agree that there is a need to replace CMP's current customer service billing system (CSS), which is more than 23 years old and based on obsolete technology. To facilitate CMP's implementation of a new billing system, no later than March 1, 2015, CMP will initiate a separate Commission proceeding addressing the capabilities and functionalities of the new billing system. CMP's filing shall incorporate the Commission's decision in this docket regarding rate design issues and shall include the Company's recommendation regarding appropriate billing system capabilities and functionalities. The Company will also include a good faith proposal for billing all customers on a demand charge basis and a preliminary cost estimate for the Company's recommended billing system with such capabilities and functionalities. Nothing in the Stipulation shall preclude CMP, Staff or Parties from raising additional issues in this future proceeding, including, but not limited to, whether any portion of the new billing system or its capabilities and functionalities should be outsourced. The Parties agree to endeavor to complete the proceeding within six months of the date of CMP's initial filing to allow adequate time to construct and implement the new billing system.

CMP may also initiate a single issue revenue requirement adjustment proceeding, under 35-A M.R.S. § 3195, associated with the new billing system (as part of any capabilities docket or separately) whereby distribution rates will be adjusted to recover the prudently incurred net costs of the new billing system. Any such rate adjustment for the new billing system will take effect no earlier than the in-service date for the system. CMP's option to initiate a specific rate proceeding regarding the new billing system does not in any way limit the Company's right to initiate a general rate case at any time allowed by statute.

F. Revenue Allocation (Stipulation, Part IV(I)) And Rate Design (Stipulation, Part IV(J))

The Settling Parties agree that the agreed upon revenue requirement increase will be allocated so that the MGS-P and the IGS-S rate classes receive revenue increases at 1.5 times the overall system average increase resulting from the

Stipulation. No revenue allocation increase will be applied to rate classes A-LM, SGS, LGS-ST and LGS-T. All other classes will be allocated a proportional share of the remaining revenue requirement.

The Settling Parties also agree to several changes to CMP's rate design and Terms and Conditions. These changes will be effective on September 1, 2014 and will remain in effect until modified by subsequent Commission Order. The agreed upon changes include setting the fixed monthly customer charges for CMP's rate classes as follows:

a. Rate A: $10.00 per month, including 50 kWh of usage.
b. Rate A-TOU: $10.00 per month.
c. Rate A-LM: $13.53 per month.
d. SGS: Single Phase: $15.00 per month; Three Phase: $19.10 per month.
e. All Other Rate Classes: The fixed monthly customer charges for all other classes will remain at July 1, 2013 levels.

The Settling Parties also agree that:[2]

- The per-kWh charges for the distribution component of the IGS-P-TOU rate will be eliminated.

- CMP will apply a uniform increase on all unit charges to recover the revenue requirement assigned the Area Lighting and Street Lighting rate classes, and CMP will remove from its rate schedules Area and Street Lighting options that have not been utilized in the last three years.

- CMP will set the rate charged for the shoulder period (*i.e.*, 12:00 pm to 4:00 pm) equal to the rate charged for the peak period (7:00 am to 12:00 pm and 4:00 pm to 8:00 pm) for all TOU rate classes.

- The Rate O tariff sheets will be modified as provided in Attachment 9 to the Stipulation. In addition, CMP agrees that without prior Commission approval it will not seek to eliminate the Rate O rate schedule, or to amend or eliminate the provisions in Schedule 12(D)(5) of Schedule 21-CMP to the ISO-New England Open Access Transmission Tariff, relating to load used for calculating the transmission rates applicable to transmission level customers eligible to take service under Rate O. CMP will not initiate a proceeding

[2] The full text of the Stipulation sets forth all the changes in detail. The Stipulation's terms, incorporated into this Order by reference, govern CMP's rate design under this Order.

requesting the Commission to approve the elimination of Rate O for a period of at least five years.

In addition, as part of the Stipulation, CMP agrees to withdraw its request for standby rates in this proceeding. CMP's withdrawal is without prejudice to the Company's or any other party's right to advocate, at any time after the Commission's order approving this Stipulation, for or against standby rates in any appropriate forum including, without limitation, in future Commission adjudicatory and/or rulemaking proceedings and before the Maine Legislature. Finally, the Settling Parties also agree that certain rate design issues specified in Paragraph 73 of the Stipulation are not resolved by the Stipulation and will be presented to the Commission for litigation in this proceeding.

IV. OPPOSITION TO THE STIPULATION

The Fourniers are the only parties to oppose the Stipulation. The Fourniers oppose the Stipulation for the following reasons:

1. The process that lead to the Stipulation was unfair because the settlement discussions that lead to the Stipulation were considered confidential.

2. The process that lead to the Stipulation was unfair because Ms. Fournier states that she was treated rudely and that the questions that she raised during the settlement process were not adequately answered.

3. The Stipulation will result in rates that are not affordable to most customers and, therefore, are not just and reasonable in accordance with Maine law.

4. That the Stipulation does not provide the proper incentive to the Company to operate as efficiently as possible.

V. DECISION

A. Standard of Review

To approve a Stipulation, the Commission must consider the following criteria:

1) Whether the parties joining the stipulation represent a sufficiently broad spectrum of interests that the Commission can be sure that there is no appearance or reality of disenfranchisement;

2) Whether the process that led to the stipulation was fair to all parties;

3) Whether the stipulated result is reasonable and is not contrary to legislative mandate; and

4) Whether the overall stipulated result is in the public interest.

Chapter 110 § 8(D)(7). For the reasons set forth below, we find that all of the criteria for approval have been satisfied in this instance.

B. Whether the Parties to the Stipulation Represent A Sufficiently Broad Spectrum of Interests

The Stipulation in this case was entered into by CMP, the OPA, the IECG, GridSolar and other parties including environmental groups, trade associations and competitive energy suppliers. This very broad array of signatories clearly satisfies our first criterion for approval.

C. Whether the Process That Led to Stipulation Was Fair to All Parties

Based on the information that was presented in this case, we find that the process that led to Stipulation was fair to all parties. The Commission's Rules provide that all parties shall be given an opportunity to participate in stipulation discussions. MPUC Rules Ch. 110 § 8(D)(1). In this instance, all parties, including the Fourniers, were provided with notice of all settlement discussions either through a procedural order or through e-mail correspondence. This fact does not appear to be in dispute. The Fourniers, however, argue that the process was not fair because the settlement discussions were considered confidential.

Treating settlement discussions and settlement offers made during such discussions as confidential is certainly not unique or novel to Commission proceedings. In contested court cases, settlement discussions are always kept confidential. The reason for such treatment is to allow parties to engage in such discussions without the concern that the offers that they make during settlement will be used against them in the litigation process if settlement discussions fail. As such, the settlement process and the potential to resolve matters by agreement are enhanced. We find that our rules, which require that all parties be provided with an opportunity to participate in settlement discussions, strike an appropriate balance between openness in the process and the parties needs for confidentiality of such discussions. We also note that in this case, the Stipulation was not filed until after all hearings and discovery had been completed. Thus, it is clear here that there was no short-circuiting of the process and that all parties had an opportunity to explore all relevant issues in the case.

With regards to Ms. Fournier's allegations that she was treated rudely during the settlement process and that the parties did not adequately address her substantive questions during the settlement discussions, we certainly take allegations concerning disrespect and inaccessibility seriously. Our rules require that our process be fair to all parties and this requires that all parties be treated with respect. At the same time, no one party should be allowed to interrupt or interfere with orderly settlement discussions at the expense of other parties. While the Commission will continue to assess how it can make its process more "user-friendly", understandable and accessible to ordinary citizens, it must also be recognized that many of the issues involved in public utility ratemaking are sometimes complex. It is for that very reason that State law created the OPA to participate in Commission proceedings.

In this case, based on the record before us, we find that the process established by the Hearing Examiners in this case was fair to all parties to the proceeding, including the Fourniers.

D. Whether the Stipulation is Reasonable, In The Public Interest, and Consistent With Legislative Mandates

In deciding whether a stipulation is reasonable, fair and consistent with the public interest, the entire stipulation must be considered as a package. Whether we disagree with a particular provision of the stipulation, or would have come up with a different result were we to decide the case after litigation, is not the question. Rather, the question is whether the stipulation when viewed as a whole is fair, reasonable and consistent with the public interest. *Central Maine Power Company, Proposed Increase In Rates*, Docket No. 92-345 (aa), Detailed Opinion and Subsidiary Findings at 3 (Jan. 10, 1995). For the reasons set forth below, we find that the stipulated result, when evaluated as a whole, is fair, reasonable and in the public interest.

In their opposition to the Stipulation, the Fourniers argue that the rates that will result from the Stipulation are not affordable to many Mainers. In this regard, we would first note that by deferring the distribution rate change until September 1, 2014 and coupling that rate change with the decrease in stranded cost rates, the Settling Parties have been able to significantly reduce the impact of the distribution price change which was the subject of this proceeding. As can be seen from Table I below, the overall distribution rate increase is 10.5% reflecting a revenue requirement increase of approximately $24 million. However, when the stranded cost revenue requirement reductions, including offsets from the DOE Yankee litigation settlement proceeds and RGGI costs credits approved in Docket No. 2014-00077 and Docket No. 2013-00433 are also considered, the overall rate change for all customer classes will be approximately -0.4%. For the majority of residential customers who take service under CMP's Rate A, the rate change will be approximately 4.0%.

TABLE I

Percentage Change in CMP Core Rates – July 1, 2013 to September 1, 2014	Distribution	ELP	Conservation	Stranded Cost	Transmission	TOTAL
Residential Service (Rate A)	11 6%	0%	0%	-151%	5.7%	4.0%
Residential Time-of-Use Service (Rate A-TOU)	11 6%	0%	0%	-150%	6.1%	3.2%
Load Management Service (Rate A-LM	-0.5%	0%	0%	-159%	-38.1%	-10.7%
Small General Service (Rate SGS)	-0.5%	0%	0%	-151%	-1.9%	-6.3%
Medium General Service - Secondary Voltage (Rate MGS-S)	11.6%	0%	0%	-149%	4.9%	-6.6%
Medium General Service - Primary Voltage (Rate MGS-P)	17.1%	0%	0%	-150%	-0.2%	-6.9%
Intermediate General Service - Secondary Voltage (Rate IGS-S)	17.1%	0%	0%	-147%	4.0%	-13.3%
Intermediate General Service - Primary Voltage (Rate IGS-P)	11.6%	0%	0%	-149%	6.2%	-7.2%
Large General Service - Secondary Voltage (Rate LGS-S)	11.6%	0%	0%	-148%	2.3%	-14.9%
Large General Service - Primary Voltage (Rate LGS-P)	11.6%	0%	0%	-149%	6.6%	-9.3%
Large General Service - SubTransmission Voltage (Rate LGS-ST)	-0.5%	0%	0%	-100%	-9.1%	-18.0%
Large General Service - Transmission Voltage (Rate LGS-T)	-0.5%	0%	0%	-100%	30.4%	6.2%
Area Lighting (Rate AL)	11.6%	0%	0%	-154%	22.7%	10.9%
Street Lighting (Rate SL)	11.6%	0%	0%	-154%	22.7%	11.0%
TOTAL	10.5%	0%	0%	-145%	5.1%	-0.4%

While we recognize that even a modest increase such as this can be difficult for some customers to afford, our obligation to ensure just and reasonable rates also encompasses our duty to ensure that the utility will be provided sufficient revenues to furnish safe, adequate and reliable service and have the opportunity to meet its operating expenses and earn a fair return on its investment. 35-A M.R.S. § 301, *Camden and Rockland Water Company v. Maine Public Utility Commission*, (1481) Me. 432 A. 2d 1284. The Stipulation in this instance was filed after all testimony was submitted and the Commission conducted more than a week of expert witness hearings and held two public witness hearings. Based on this ample record, we find that the results of the Stipulation are well within the range of reasonableness.

In particular, we find the Return on Equity (ROE) used in the calculation of the Stipulation's revenue requirement to be reasonable and consistent with recent Commission decisions on the issue. We also note that the RDM mechanism agreed to in the Stipulation is reasonably designed and will reduce CMP's financial reliance on throughput. By doing so, the utility's incentive to oppose efficiency measures is reduced and the State's objective of promoting efficiency is enhanced. The state's efficiency objectives are further promoted by CMP's commitments to work with EMT and actively promote energy conservation and efficiency programs.

We also find the Stipulation's Storm Recovery Mechanism to be reasonable. In *Central Maine Power Company, Annual Price Changes Pursuant to Alternative Rate Plan (ARP 2008)*, Docket No. 2011-00077, Order at 17 (July 27, 2012), we noted that in future storm costs proposals CMP and the Staff should consider provisions which remove the incentive for the utility to act in ways which have the effect of increasing the number of interruptions and also consider alternatives to the binary nature of CMP's ARP 2008 provision, which either fully included or fully excluded all costs related to a storm event. We find that the Stipulation's Storm Cost Recovery Mechanism addresses these concerns and through its sharing mechanism provides CMP with new incentives to control storm costs that may operate more effectively than the prior storm recovery mechanism. We also find that the increased amount included in rates for storm costs in the Stipulation, along with the Stipulation's Storm Reserve Account Mechanism, should reduce the rate volatility which has resulted from extraordinary storms in the past.

We also find that the Stipulation's provision for recovery of CMP's proposed new billing system in a separate future proceeding to be reasonable. In that future proceeding, the costs and capabilities of the billing system will be more clearly established and recovery of those costs can be timed to coincide with the system's implementation.

With regards to the rate design issues resolved by the Stipulation, we find the resolution to be modest but directionally well supported by moving rates closer to costs. For example, the Stipulation allows for the fixed monthly customer charge for residential and small commercial customers to increase to more appropriately reflect the fixed costs of service. In their opposition to the Stipulation, the Fourniers cited the number of public comments which were submitted to the Commission in opposition to CMP's Rate Proposal in this case. We note that most, although not all, of these comments referred to, and opposed, CMP's proposed standby rate. Under the terms of the Stipulation, CMP has withdrawn its standby rate proposal.

Finally, we find that the Stipulation is not contrary and is wholly consistent with all relevant legislative mandates and criteria.

Accordingly, we

ORDER

1. That the Stipulation submitted in this matter on July 3, 2014 is approved. A copy of the Stipulation is attached hereto and is incorporated into this Order.

2. That CMP is authorized to change its distribution rates effective September 1, 2014 consistent with the terms of this Order.

3. That the Director of the Commission's Electric and Gas Utility Industries is authorized to approve rates filed by CMP which are in compliance with this Order.

Dated at Hallowell, Maine, this 25th day of August, 2014

BY ORDER OF THE COMMISSION

/s/ Harry Lanphear
Harry Lanphear
Administrative Director

COMMISSIONERS VOTING FOR: Welch
Littell
Vannoy

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S. § 9061 requires the Public Utilities Commission to give each party to an adjudicatory proceeding written notice of the party's rights to review or appeal of its decision made at the conclusion of the adjudicatory proceeding. The methods of review or appeal of PUC decisions at the conclusion of an adjudicatory proceeding are as follows:

1. Reconsideration of the Commission's Order may be requested under Section 11(D) of the Commission's Rules of Practice and Procedure (65-407 C.M.R. 110) within 20 days of the date of the Order by filing a petition with the Commission stating the grounds upon which reconsideration is sought. Any petition not granted within 20 days from the date of filing is denied.

2. Appeal of a final decision of the Commission may be taken to the Law Court by filing, within 21 days of the date of the Order, a Notice of Appeal with the Administrative Director of the Commission, pursuant to 35-A M.R.S. § 1320(1)-(4) and the Maine Rules of Appellate Procedure.

3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S. § 1320(5).

Note: The attachment of this Notice to a document does not indicate the Commission's view that the particular document may be subject to review or appeal. Similarly, the failure of the Commission to attach a copy of this Notice to a document does not indicate the Commission's view that the document is not subject to review.