STATE OF VERMONT
PUBLIC SERVICE BOARD

Petition of Green Mountain Power Corporation for Approval of a Successor Alternative Regulation Plan	)))	Docket No. 8191

PRE-FILED DIRECT TESTIMONY OF DAVID E. DISMUKES, PH.D.

ON BEHALF OF
AARP

MAY 20, 2014

Summary: Dr. Dismukes discusses how elements of GMP's Alternative Regulation Plan are unnecessarily complex and shifts risks away from the Company and onto ratepayers. Dr. Dismukes presents AARP's recommended modifications to the ongoing Alternative Regulation Plan to make the plan more transparent and result in a more equitable balance of risks and rewards between GMP and ratepayers.

TABLE OF CONTENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is David E. Dismukes. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808. I am a Consulting Economist with the Acadian Consulting Group ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered Limited Liability Company, formed in 1995, and located in Baton Rouge, Louisiana.

Q. DO YOU HOLD ANY ACADEMIC POSITIONS?

A. Yes. I am a full Professor, Associate Executive Director, and Director of Policy Analysis at the Center for Energy Studies, Louisiana State University. I am also a full Professor (Department of Environmental Sciences) and Director of the Coastal Marine Institute in the School of the Coast and the Environment at LSU. I serve as an Adjunct Professor in the E. J. Ourso College of Business Administration (Department of Economics), and I am member of the graduate research faculty at LSU. Attachment A provides my academic vita that includes a full listing of my publications, presentations, pre-filed expert witness testimony, expert reports, expert legislative testimony, and affidavits.

Q. HAVE YOU PREPARED ANY EXHIBITS IN SUPPORT OF YOUR RECOMMENDATIONS?

A. Yes. I have prepared 13 exhibits in support of my direct testimony that were prepared by me or under my direct supervision.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been retained by AARP (previously known also as the American Association of Retired Persons) to provide an expert opinion to the Vermont Public Service Board ("the Board") on the proposal by Green Mountain Power ("GMP" or "the Company") to continue its alternative rate plan ("ARP") with modifications for the term October 1, 2014 to September 30, 2018.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into the following sections:

- Section II: Summary of Recommendations
- Section III: Summary of Alternative Rate Plan Proposal
- Section IV: Cost Benchmarking Analysis
- Section V: Recommendations for Improving GMP's ARP Design
- Section VI: Conclusions and Recommendations

II. SUMMARY OF RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S ALTERNATIVE REGULATION PLAN.

A. I recommend the Board make the following modifications to the Company's proposed ARP laid out in the Company's December 20, 2013 application:

1) The Non-Power Supply Cost Incentive Adjustment be removed or modified;
2) The Capital Spending Adjustment be removed or modified;
3) The Earnings Sharing Adjustor be modified; and
4) The Incremental ROE Adjustment be removed.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE NON-POWER SUPPLY COST INCENTIVE ADJUSTMENT?

A. My primary recommendation regarding the non-power supply cost incentive is that the Board eliminate the benchmarking component of this adjustment. The current net inflation (inflation less productivity) adjustment is set in a fashion that is contrary to most performance-based regulation ("PBR") plans, prejudices ratepayers, and incorporates an additional degree of analysis and complication that is not really needed. The Board could greatly simplify the ARP by eliminating the benchmarking component, and deferring to a base productivity offset of 1.0. I also recommend that the Board change the ESA sharing bands to reflect this potential modification to the ARP.

Q. DO YOU HAVE ANY ALTERNATIVE RECOMMENDATIONS REGARDING THE NON-POWER SUPPLY COST INCENTIVE ADJUSTMENT?

A. Yes. If the Board prefers to keep the benchmarking component of the ARP in place, I recommend that the current 1.0 productivity adjustment be divided into two equal parts: one part will consist of a 0.5 base productivity offset and the second part will consist of a 0.5 stretch factor adjustment. Benchmarking will apply to the 0.5 stretch factor component only, not the 0.5 base productivity offset. This adjustment would lower the stretch factor by 0.3 for cost benchmarking results in the top quartile, 0.2 for results in the second quartile, and 0.1 for results in the third quartile. No adjustment would be given for cost performance in the bottom quartile of peer utility. Thus, the stretch factor would vary from 0.2 to 0.5 percent depending on GMP cost performance

relative to its peers, while combined productivity adjustment would vary between a minimum of 0.7 percent and a maximum of 1.0 percent.

Q. WHAT DO YOU RECOMMEND REGARDING THE CAPITAL SPENDING ADJUSTMENT COMPONENT OF THE ARP?

A. I recommend the Board remove the capital spending adjustment component of the ARP. The adjustment is contrary to the principles underlying PBR-based ratemaking, which attempts to maximize utility incentives for both operational and capital investment decision efficiencies. The capital spending adjustment component also shifts the risk of capital cost recovery and performance away from the Company and onto ratepayers. The capital spending adjustment is akin to an investment tracker which reduces capital investment incentives created by regulatory lag and PBRs. Regulatory lag has long been recognized by scholars and practitioners alike as a positive element of the regulatory process that enhances, not diminishes, incentives for innovation and cost-effective investment.

Q. DO YOU HAVE ANY ALTERNATIVE RECOMMENDATIONS SHOULD THE BOARD MAINTAIN THE COMPANY'S CAPITAL SPENDING ADJUSTMENT?

A. Yes. The Board should strengthen the Company’s annual reporting and minimum filing requirements in order to facilitate the prudence evaluation of the proposed capital investments. The Company’s capital investments should also be subjected to a number of ratepayer protection provisions that limit the potential negative rate impacts that could be imposed on customers from excessive capital spending.

Collectively, these new minimum filing requirements and ratepayer protections should include:

1) Clear identification of individual capital investments, and identification of investment purpose for each major capital investment/program and how that purpose is consistent with (a) state energy policy, (b) the Company's IRP, and/or (c) meeting the Company's reliability requirements and/or resiliency goals. All of these investments should be accompanied by cost-benefit analyses, if not individually, then at least collectively, for all investments in excess of $1.0 million on an annual basis.
2) Financial analyses (similar to attrition analyses) that shows the potential financial harm that could be imposed on the Company if immediate capital cost recovery is not allowed.
3) A ratepayer protection provision that limits the annual capital spending adjustment to three percent of total revenue in any given year. Any investments in excess of the cap should be treated in a manner consistent with traditional ratemaking practices.
4) New annual filing requirements that should include: competitive bid comparisons and evaluations on major resource acquisitions/developments; monthly budget-to-actual comparisons of capital projects with explanations for deviations in budget greater than 10 percent; submission of capital authorization reports, work orders, and change orders; and audits performed on capital expenditures included in the capital spending adjustment. Parties

should have the opportunity to review and opine on the Company's capital expenditure proposals and offer recommendations as part of the expanded review process (and period) included in the Company's current ARP proposal.

Q. WOULD EITHER YOUR PRIMARY OR ALTERNATIVE RECOMMENDATIONS REGARDING THE CAPITAL EXPENDITURE COMPONENT OF THE COMPANY'S ARP UNDERMINE THE COMPANY'S ABILITY TO IMPROVE ITS INVESTMENT RESPONSIVENESS TO STATE ENERGY POLICIES?

A No. Both of my recommendations should preserve the Company's ability to make investments that are responsive to state energy policies. The Company, like most regulated utilities, should be required to make investments that result in outcomes where benefits are greater than costs. Excluding capital costs from the PBR will not change that outcome. If the benefits are greater than costs, the investments, in theory, should pay for themselves and the Company will not be disadvantaged. This is how PBRs discipline capital investment decisions: PBRs force utilities to make very hard and calculated decisions about capital investments. PBRs are set up to incent very efficient investments that improve efficiencies, and generate opportunities for increased earnings, that can be shared between the utility and ratepayers.

Q. CAN "ABOVE-MARKET" CAPITAL INVESTMENTS BE ACCOMMODATED UNDER YOUR RECOMMENDATIONS?

A. Yes. Current state energy policies across the country often promote investment in assets or programs that have difficult to measure benefits. Many of these types of investments are thought to be "above-market" given traditional market valuation

approaches: renewables and resiliency investments can often fall into these categories. My direct and alternative recommendations can still accommodate these types of above-market investments. If the Board accepts my primary recommendation, it could allow GMP to submit requests for the inclusion of "above-market" capital investments into the "exogenous" cost component of its current ARP structure. It would be incumbent upon GMP to show that these above market investments are necessary to meet state energy policy and are still the least cost method for meeting those policies, even if the investments themselves may not pass typical cost-benefit tests. If the Board accepts my alternative recommendation, the new filings requirements included in those recommendations explicitly require GMP to show that any capital investment included in the ARP is consistent with state energy policy and/or its IRP. Thus, above-market investments can be accommodated under either set of recommendations. The only difference is that my recommendations "re-inject" a degree of performance and accountability for making these investments that does not exist under the current ARP structure.

Q. WHAT ARE YOUR PRIMARY RECOMMENDATIONS FOR THE EARNINGS SHARING ADJUSTOR ("ESA")?

A. My primary recommendation for the Company's ESA is tied to my earlier-discussed productivity offset recommendation. My productivity offset recommendation is that the benchmarking analysis be removed, and the Board simplify adjustment of its annual revenues by inflation less a 1.0 productivity offset. Since this offset is (a) higher than the currently "effective" productivity offset, and (b) gives ratepayers an up-front

performance-based benefit, the ESA should be adjusted to provide corresponding incentives for the Company's efficiency activities and investments. I recommend the ESA be modified such that it has:

- A dead-band of 25 basis points above and below the Board-approved ROE;
- An initial 50/50 sharing band for returns 25 to 100 basis points above or below the Board-approved ROE;
- A second, 75 percent utility – 25 percent customer, sharing band for returns 100 to 200 basis points above or below the Board-approved ROE; and
- An ultimate cap of 200 basis points above or below the Board-approved ROE.

Q. DO YOU HAVE ANY ALTERNATIVE ESA RECOMMENDATIONS?

A. Yes. My alternative recommendation for the Company's ESA is tied to my earlier-discussed alternative productivity offset recommendation that breaks the offset into two components: a base productivity offset of 0.5 percent and a stretch factor adjustment of 0.5 percent. The stretch factor adjustment will be the only component subject to a benchmarking analysis. If my alternative recommendation is accepted, the new productivity offset will likely be (a) higher than the currently effective rate, but (b) will also give ratepayers less of an up-front performance-based benefit relative to my primary recommendation. Therefore, as an alternative, I recommend that the ESA be modified such that it has:

- A dead-band of 25 basis points above and below the Board-approved ROE;
- An initial, 75 percent customer – 25 percent utility, sharing band for returns 25 to 100 basis points above or below the Board-approved ROE;

- A second, 50 percent utility – 50 percent customer, sharing band for returns 100 to 200 basis points above or below the Board-approved ROE; and
- An ultimate cap of 200 basis points above or below the Board-approved ROE.

Q. SHOULD THE BOARD ALSO MAINTAIN THE COMPANY'S ROE PERFORMANCE ADJUSTMENT?

A. No. The ROE Performance Adjustment gives the Company an additional reward for efficiencies already incented in the ARP structure (i.e., through the ESA). This effectively allows the Company to "double-count" efficiencies (and earnings) it achieves relative to its peers. The ROE performance incentive is also misaligned since it penalizes ratepayers for "good" utility cost performance and rewards ratepayers when that cost performance is poor, thereby undermining one of the primary benefits of the ARP listed by the Company. The incentives and rewards should be consistent for ratepayers and the utility under the ARP; both receive larger benefits when performance is good, and both receive smaller benefits when performance is poor.

III. SUMMARY OF COMPANY'S ALTERNATIVE RATE PLAN

Q. HAS AN ARP BEEN PREVIOUSLY APPROVED FOR THE COMPANY BY THE BOARD?

A. Yes. If approved, the proposed ARP would be the Company's third such plan approved by the Board. The Company first proposed an ARP in 2006, covering the term February 1, 2007 to December 31, 2009, as part of Docket No. 7176.[1] In that

[1]Petition of Green Mountain Power Corporation for Approval of an Alternative-Regulation Plan, Docket No. 7176, Final Order dated December 22, 2006, p. 19.

proceeding, the Board approved a Memorandum of Understanding ("MOU") between the Company and the Vermont Department of Public Service ("the Department") in which the Company agreed to a rate increase less than originally requested in return for support for the ARP.[2] The Board approved the MOU including a minor modification of the term of the plan, which had the effect of extending the expiration of the plan to September 30, 2010.[3]

Q. PLEASE SUMMARIZE THE SECOND ARP APPROVAL.

A. The second approved ARP, referred to at that time as the "Modified Plan," was proposed by the Company as part of Docket No. 7585.[4] This proposal included a series of modifications to the structure of the original ARP, perhaps most notable of which was the inclusion of a Return on Equity ("ROE") Performance Adjustment mechanism that allowed the Company to earn a higher ROE if its performance exceeded that observed through a benchmark analysis of comparable utilities.[5] The Board approved the proposed modification, stating that GMP's prior performance under alternative regulation had "fostered the Company's success in strengthening its financial profile"

[2] Petition of Green Mountain Power Corporation for Approval of an alternative-regulation plan, Docket No. 7176, Final Order dated December 22, 2006, p. 3; This agreement was opposed by both International Business Machines Corporation ("IBM") and the Conservation Law Foundation ("CLF").
[3] See, Petition of Green Mountain Power Corporation for Approval of Revisions to its Alternative Regulation Plan, Docket No. 7438, Final Order dated June 16, 2008, p. 1.
[4] See, Petition of Green Mountain Power Corporation for Approval of an Alternative-Regulation Plan (Plan II), Docket No. 7585, Final Order dated April 16, 2010, p. 3.
[5] Petition of Green Mountain Power Corporation for Approval of an Alternative-Regulation Plan (Plan II), Docket No. 7585, Final Order dated April 16, 2010, p. 4.

that proved to be "beneficial to both GMP's ratepayers and shareholders."[6] The Board stated that, in adopting the Modified Plan, it expected "equally desirable results."[7]

Q. DID THE BOARD ORDER ANY CHANGES TO THE MODIFIED ARP APPROVED IN DOCKET NO. 7585?

A. Yes. The MOU between parties in Docket No. 7585 requested the Board approve the Modified Plan with some specific changes to the proposed filing and notification requirements, as well as aggregating the quarterly power adjustments into a single annual bill adjustment for only the commercial and industrial transmission customer classes.[8] The Board also noted that the Company and the Department had agreed to the proposed ROE performance adjustment in order to save litigation expense, and to allow the Company an opportunity to earn its way to what was claimed by the Company as an average ROE for electric utilities. The Board found the proposed ROE adjustment to be a conservative experiment in general, but was uncomfortable with allowing the Company an immediate increase of 25 basis points since the first achieved returns were driven more by past performance than future performance. As a result, the Board delayed implementation of the ROE Performance Adjustment mechanism until October 1, 2011, effectively removing the first year adjustment.[9]

[6] Petition of Green Mountain Power Corporation for Approval of an Alternative-Regulation Plan (Plan II), Docket No. 7585, Final Order dated April 16, 2010, p. 3.
[7] Petition of Green Mountain Power Corporation for Approval of an Alternative-Regulation Plan (Plan II), Docket No. 7585, Final Order dated April 16, 2010, p. 3.
[8] Petition of Green Mountain Power Corporation for Approval of an Alternative-Regulation Plan (Plan II), Docket No. 7585, Final Order dated April 16, 2010, p. 14.
[9] Petition of Green Mountain Power Corporation for Approval of an Alternative-Regulation Plan (Plan II), Docket No. 7585, Final Order dated April 16, 2010, p. 16.

Q. HAS THE COMPANY PROPOSED ANY MODIFICATIONS TO ITS ARP RELATIVE TO THE ONE APPROVED IN DOCKET NO. 7585?

A. Yes. According to the Company, its currently-proposed ARP is very similar to the ARP approved by the Board in Docket No. 7585; however, the Company proposes several modifications that it groups into four categories: (1) base rate adjustment changes; (2) changes in the ARP term; (3) transparency and reporting improvements; and (4) miscellaneous changes.[10]

Q. PLEASE DESCRIBE THE COMPANY'S BASE RATE ADJUSTMENT CHANGES.

A. The Company proposes to modify the implementation of two components of the ARP (the current power adjustment and ESA mechanism). Currently the power adjustment mechanism is implemented on customers' bills four times per year, and separately from the ESA. These multiple and separate adjustments have been claimed by some stakeholders as creating confusion and leading to large volatility concerns.[11] Therefore, the Company proposes to compress its power adjustment mechanisms charges to just one a year that occurs simultaneously with the currently-scheduled ESA.[12] According to the Company, the quarterly power adjustment will still be calculated on a quarterly basis for informational purposes only. However, the annual adjustment

[10] Direct Testimony of Christopher Cole, 10:20 to 12:6.
[11] Alternative Regulation Workshop dated December 12, 2013, Tr. 101:7-16.
[12] Direct Testimony of Christopher Cole, 11:3-9.

included on customers' bills will simply be the average of the four prior quarterly adjustment calculations.[13]

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED CHANGE IN THE ARP TERM.

A. Prior ARPs were proposed, and approved, for three-year terms. The Company proposes to expand the duration of the term to four years, from October 1, 2014 to September 31, 2018.[14] The Company states that it believes the proposed four-year term strikes the balance between the goals of revisiting the plan at regular intervals while allowing a reasonable period for the plan to work.[15]

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED ARP REPORTING AND TRANSPARENCY IMPROVEMENTS.

A. The Company proposes three changes aimed at improving ARP reporting and transparency. First, the Company proposes that whenever rate changes are proposed, the Company will explain, "in plain English," the reason for the base rate adjustment(s).[16] This includes the operation of the component ARP mechanisms, including the power adjustment mechanism and the ESA. Second, the Company proposes that future draft annual filings, notably all annual adjustments, and not just base rate adjustments, will be submitted to the Board by June 1. The Company states that this change in filing timing will more than double the existing public review timeframe. Lastly, the Company states that new annual reporting requirements will

[13] Alternative Regulation Plan (December 20, 2013), Green Mountain Power Corporation, pp. 7-8.
[14] Direct Testimony of Christopher Cole, 11:10-13.
[15] Direct Testimony of Christopher Cole, 13:5-8.
[16] Direct Testimony of Christopher Cole, 13:22 to 14:3.

address the "action plan" concerning expected future capital expenditures regarding the Company's Integrated Resource Plan ("IRP"). The Company states that the updated requirements will describe any material changes from previous estimates of scope, need, and/or implementation schedule.[17]

Q. PLEASE DESCRIBE THE MISCELLANEOUS CHANGES THE COMPANY HAS INCLUDED IN THE PROPOSED ARP.

A. The Company's category of "miscellaneous changes," includes four separate changes from the Company's existing alternative regulation plan that includes changes to: (1) the non-power supply cost incentive benchmarking process; (2) the ROE performance incentive benchmarking process; (3) the ARP's exogenous adjustment provision; and (4) the plan's goals including a new provision clarifying the Company's support for statewide energy goals and some other minor modifications described as housekeeping in nature by the Company.[18]

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED CHANGE TO ITS NON-POWER SUPPLY COST INCENTIVE ADJUSTMENT BENCHMARKING PROCESS.

A. The Company proposes to change the benchmarking sample from quintiles to quartiles for the non-power supply cost incentive portion of its plan.[19] The Company also proposes to make a corresponding change to the maximum incentive adjustment from one percent to 0.75 percent.[20] The Company notes that this change will remove its

[17] Direct Testimony of Christopher Cole, 14:5-11.
[18] Direct Testimony of Christopher Cole, 14:14 to 17:13.
[19] Direct Testimony of Christopher Cole, 14:21-22.
[20] Alternative Regulation Plan (December 20, 2013), Green Mountain Power, Attachment 5.

ability to eliminate the annual one percent productivity factor included in the non-power cost cap.[21]

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED CHANGE TO ITS ROE PERFORMANCE INCENTIVE ADJUSTMENT BENCHMARKING PROCESS.

A. The Company also proposes to change the benchmarking sample from quintiles to quartiles for the ROE component of its plan as well as reduce the maximum positive or negative adjustment from 50 to 25 basis points.[22] With these changes, the Company will only receive a positive or negative ROE adjustment of 25 basis points if it falls in the first or fourth quartiles, respectively. If the Company falls in the second or third quartiles, it will not see any adjustment through the ROE performance incentive adjustment.[23]

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED CHANGES TO THE EXOGENOUS CHANGES PROVISION OF THE ARP.

A. The Company proposes to incorporate the definition of a "major storm" from the Company's Service Quality & Reliability Performance, Monitoring & Reporting Plan ("SQRP") into the exogenous changes provision of the ARP.[24] Specifically, all costs experienced by the Company related to incremental maintenance expenses in the aftermath of a defined Major Storm are excluded from the ARP, and further not subject to the $1.2 million minimum threshold the Plan places on potential exogenous changes. Lastly, the ARP notes that in the event the Company has not exceeded the storm cost

[21] Direct Testimony of Christopher Cole, 14:22.
[22] Direct Testimony of Christopher Cole, 15:11-14.
[23] Alternative Regulation Plan (December 20, 2013), Green Mountain Power, Attachment 5.
[24] Direct Testimony of Christopher Cole, 15:20-22.

amount included in base O&M costs, then the exogenous storm changes shall be reduced by the difference between that included in base O&M costs and that included in the exogenous storm changes.[25]

Q. PLEASE DESCRIBE THE COMPANY'S CLARIFICATION OF SUPPORT FOR STATE ENERGY GOALS AND OTHER HOUSEKEEPING CHANGES.

A. The Company's last miscellaneous changes include the addition of a new provision of the ARP that clarifies the Company's support for Vermont's statewide energy goals of advancing promising new technologies and services. The Company states that the proposed change is to clarify the purpose of the plan in maximizing GMP's ability to pursue investments, initiatives and operations that help achieve the State's energy policy goals, in particular the State's commitment to reducing carbon emissions, on a cost-effective basis. Finally, the Company has deleted references to separate cost calculations for the C&I Transmission Rate class, which are no longer relevant, updated and clarified Attachments 3 and 4 of the plan, and eliminated much of the language related to merger savings as the Board's Order in Docket No. 7770 fully lays out such provisions. These last changes are classified as housekeeping in nature by the Company.[26]

Q. HAVE YOU EXAMINED THE COMPANY'S CURRENTLY PROPOSED ARP RELATIVE TO GMP'S PRIOR-APPROVED ARP?

[25] Alternative Regulation Plan (December 20, 2013), Green Mountain Power, p. 7.
[26] Direct Testimony of Christopher Cole, 16:15 to 17:13.

A. Yes. Exhibit DED-1 presents a comparison between prior-approved GMP historical ARPs and the currently proposed 2014-2018 plan. The exhibit shows that many elements of the ARP originally approved by the Board in 2006 have been modified through its two subsequent iterations.

IV. COST BENCHMARKING ANALYSIS

Q. HAVE YOU CONDUCTED ANY COST BENCHMARKING ANALYSIS?

A. Yes, I have conducted a cost benchmarking analysis in order to evaluate the Company's operating performance under the ARP since 2007. My analysis compares the Company's cost performance against the same set of "benchmarked utilities" that are included in its ARP. The data utilized in this benchmarking analysis comes from the annual report information each utility submits to the Federal Energy Regulatory Commission ("FERC"), commonly referred to as the FERC Form 1.[27]

Q. WHAT TYPES OF COSTS ARE INCLUDED IN YOUR BENCHMARKING ANALYSIS?

A. I examine six different expense categories that, collectively, include the same set of "benchmarked expenses" that are part of the Company's ARP including: administrative and general ("A&G") costs; customer accounts costs; customer service and information costs; sales costs; distribution operation and maintenance ("O&M") costs; and transmission O&M costs.[28] Hereafter, I will refer to this total set of "benchmarked" expenses as "aggregate expenses" or "aggregate costs" in an attempt

[27] Alternative Regulation Plan (December 20, 2013), Green Mountain Power, Attachment 5, pp. 1-2.
[28] Alternative Regulation Plan (December 20, 2013), Green Mountain Power, Attachment 5, p. 1.

to reduce any possible confusion that could arise in the discussion about "benchmarking" in general. Individual components of these aggregate expenses will be referenced by their common FERC account names (i.e., distribution O&M expenses, customer account expenses, etc.). The data utilized in my benchmarking analysis spans a time period from 2002 to 2012, or the most recent decade of information available from the FERC at the time I prepared my testimony.

Q. DID YOU STANDARDIZE THE COSTS INCLUDED IN YOUR BENCHMARKING ANALYSIS?

A. Yes, these costs are standardized in terms of customers (i.e., costs per customer) as well as on a per volume (costs on a per megawatt hour, or "MWh") basis.

Q. HOW ARE THE RESULTS FROM YOUR BENCHMARKING ANALYSIS PRESENTED?

A. The results from the first part of my benchmarking analysis are provided in two separate exhibits: Exhibit DED-2 (benchmark analysis of aggregate costs on a per customer basis) and Exhibit DED-3 (benchmark analysis of aggregate costs on a per MWh basis). The first page of each exhibit compares the Company's cost performance on an aggregate cost basis while the second page provides a time series chart of that aggregate cost performance relative to the total peer group.

Q. WHAT DO THE RESULTS OF YOUR AGGREGATE COST PER CUSTOMER ANALYSIS SHOW?

A. Exhibit DED-2, page 1, compares the Company's aggregate costs over the past decade relative to its ARP peer utilities. The Company's aggregate costs per customer

in the most recent year, 2012, are estimated to be 28 percent lower than the peer average and 40 percent higher than the "best performing company" in the sample where the "best performing company" is defined as the one with the absolute lowest unit cost in each year over the past decade. Overall, the Company's aggregate costs performance is relatively good, and while not the best in the sample, the Company consistently ranks in the top half of peer utilities in terms of its benchmarked cost performance. The chart on page 2 of Exhibit DED-2 shows that the Company's benchmarked expense performance has been improving relative to the regional peer average.

Q. ARE THE RESULTS COMPARABLE WHEN THE AGGREGATE COSTS ARE STANDARDIZED ON A PER MWH BASIS?

A. Yes. Exhibit DED-3, page 1, provides a similar comparison of the Company's aggregate costs except that the comparison standardizes these cost on volumetric terms. In 2011, the Company's aggregate costs per MWh were 39 percent lower than other peer utilities. Aggregate costs per MWh are estimated to have fallen to a level that is 23 percent better than the peer average in 2012.

Q. WAS THE COMPANY PERFORMING RELATIVELY WELL PRIOR TO THE ADOPTION OF ITS ARP?

A. Yes. Prior to 2007, the Company's aggregate costs per customer were, on average, some 17 percent below the peer utility average. The Company's aggregate cost performance has improved since 2007 to a level that has averaged about 30 percent better than the peer utility average. The results are similar if costs are

examined on a per MWh basis. On a volumetric basis, the Company's aggregate unit costs are estimated to have averaged some 20 percent better than the peer average prior to the adoption of the ARP, and have improved to a level that is now 29 percent better than its peers in the post-ARP adoption time period.

Q. DID THE COMPANY PROVIDE ANY ANALYSES EXAMINING THE EFFECTIVENESS OF THE ARP ON ITS COST PERFORMANCE?

A. Yes. The Company provided historical cost benchmarking for each of its legacy companies conducted per the Non-Power Supply Cost Incentive Adjustment included in each Company's ARP. The Company's information shows that historically, prior to its merger with Central Vermont Public Service Company ("CVPS"), GMP's cost performance ranked in the 2nd quintile for 2008 and 2009, and improved to the first quintile in 2010 and 2011. CVPS' cost performance, however, consistently ranked in the fourth quintile, or below average, throughout the scope of its historical ARP.[29]

Q. HOW DOES THE COMPANY'S ANALYSIS COMPARE WITH YOUR BENCHMARKING RESULTS?

A. The Company's analysis is consistent with my analysis of aggregate cost per customer for GMP, for the years 2008 through 2012.[30] The Company, however, also provided an analysis showing year-to-year non-supply-related expenses for both of the legacy companies under the Non-Power Supply Cost Incentive Adjustment. This analysis shows that while GMP, prior to the merger with CVPS, reduced total expenses

[29] Company's Response to AARP 1-67, Attachment.
[30] Company's Response to AARP 1-67, Attachment.

subject to the Non-Power Supply Cost Incentive Adjustment by more than $2.8 million from 2008 to 2011, CVPS increased its analogous expenses by almost $9.7 million from 2008 to 2011.[31] The Company's analysis also shows that subsequent to the merger, it has reduced total expenses by approximately $6 million when compared to an aggregation of the two companies prior to the merger.[32] The Company's historical cost benchmarking analysis indicates that this would be the equivalent of a cost performance improvement from the 3rd quintile to the 2nd quintile.[33]

Q. DOES YOUR ANALYSIS OF THE COMPANY'S COSTS ON AN "AGGREGATE" BASIS MASK ANY LESS THAN STELLAR COST PERFORMANCE TRENDS?

A. Yes. The aggregation of the Company's costs into one composite cost estimation hides a number of less than stellar cost trends associated with its total distribution O&M. The Company's superior performance appears to be driven in large part by its historic and current A&G cost efficiency. This A&G cost performance is important since A&G expenses have averaged, in 2012, about 43 percent of the Company's total aggregate costs (see the pie chart provided on Exhibit DED-4). Distribution O&M costs, while representing a smaller share of total expenses, are still a significant cost driver, representing 37 percent of total aggregate costs, suggesting that the Company's overall aggregate cost performance could be improved, notwithstanding its recent performance.

[31] Company's Response to AARP 1-29, Attachment 1-29b.
[32] Company's Response to AARP 1-29, Attachment 1-29b.
[33] Company's Response to AARP 1-67, Attachment.

Q. HAVE YOU EXAMINED THE COMPANY'S DISTRIBUTION O&M COSTS?

A. Yes. Exhibits DED-5 and DED-6 provide benchmarking analyses that focus exclusively on the Company's total distribution O&M and not total aggregate costs. Each of these distribution O&M cost comparisons are prepared with the same data and in a fashion similar to the aggregate unit cost analysis I discussed earlier.

Q. CAN YOU PLEASE EXPLAIN THE RESULTS FROM YOUR ANALYSIS OF THE COMPANY'S DISTRIBUTION O&M COST ON A PER CUSTOMER BASIS?

A. Yes. Exhibit DED-5, page 1, shows the Company's pre- and post-ARP distribution O&M cost performance relative to its peers on a per customer basis. During the period 2002-2006 (prior to the adoption of the ARP), the Company ranked between 9th and 16th in its total distribution O&M cost per customer performance. Distribution O&M costs per customer during that time period averaged some 6 percent above the peer average, rising as high as 16 percent above the peer average in 2005 and 2006. The Company's distribution O&M cost per customer performance has not fared much better post-ARP adoption. The Company's distribution O&M costs, while down in 2010 and 2011 relative to the peer group, has generally remained above the peer average since the ARP was adopted. In fact, the Company's distribution O&M costs on a per customer basis have averaged some five percent above the peer average since 2007. A chart of the Company's total distribution O&M costs per customer performance related to the peer average is provided on page 2 of Exhibit DED-5.

Q. CAN YOU PLEASE EXPLAIN THE RESULTS FROM YOUR ANALYSIS OF THE COMPANY'S DISTRIBUTION O&M COST PERFORMANCE ON A PER MWH BASIS?

A. Yes, and these results are summarized in Exhibit DED-6. Page 1 shows the Company's distribution cost per MWh performance was relatively inconsistent prior to the adoption of the ARP. In fact, in the several years prior to 2007, the Company posted distribution O&M costs on a per MWh basis that ranged from 11 percent worse to 15 percent better than its peers. The Company's distribution O&M costs per MWh rose relative to its peers in the two years prior to the ARP adoption (2005, 2006), and distribution O&M costs on a per MWh basis remained worse in the post-ARP period relative to the Company's peers, with the exception of 2010 and 2011. On average, the Company's distribution O&M costs per MWh have averaged to be some three percent higher than its peers since the adoption of the ARP, compared to being, on average, two percent lower than its peers before the adoption of ARP.

Q. WHY IS THE DISTRIBUTION O&M ANALYSIS IMPORTANT?

A. The distribution O&M analysis is important for two reasons. First, the Company's cost performance, while good on an aggregate basis, could be improved given recent distribution O&M cost performance trends. These opportunities for cost improvement should reduce any concerns that there may be diminishing returns from modifying the ARP's mechanics in a fashion that could help streamline the way the mechanism works and increase its performance-improving incentives. Second, distribution O&M costs are increasing as a share of the Company's total aggregate costs. Exhibit DED-7 shows

that in 2002, distribution O&M costs were 31 percent of total aggregate non-production-related costs. Those costs shares increased to 34 percent in the first year of the ARP (2007) and represent 37 percent of the Company's non-production related costs in 2012. Thus, the impact that distribution O&M costs have on future ARP performance will likely increase, and not diminish, as time passes. It is not unreasonable, therefore, for the Board to consider modifications to the ARP that may enhance its performance-related incentives as well as balance the risks and rewards between ratepayers and shareholders. A number of potential ARP modifications of this nature will be discussed in the next section of my testimony.

V. RECOMMENDATIONS FOR IMPROVING GMP'S ARP DESIGN

A. Performance-Based Ratemaking

Q. IS THE COMPANY'S ALTERNATIVE REGULATION PLAN A CONCEPT UNIQUE TO GMP?

A. No. PBR-type mechanisms have been discussed, researched, and implemented across a number of industries and countries over the past several decades. PBR-type mechanisms were extensively used in the regulation of U.S. telecommunications utilities starting in the 1980s after the breakup of AT&T and the Bell Operating System.[34] With regards to the U.S. regulation, however, PBR mechanisms have not seen extensive use in the electric and natural gas distribution business.[35] Such mechanisms are more

[34] Biewald, *Performance-Based Regulation in a Restructured Electric Industry* (November 8, 1997), National Association of Regulatory Utility Commissioners, pp. 12-13.
[35] *Alternative Regulation for Evolving Utility Challenges: An Updated Survey* (January 2013), Edison Electric Institute, pp. 33-35.

commonly found in Canadian and European utility regulation than in U.S. utility regulation.[36]

Q. PLEASE DISCUSS THE PURPOSE OF A PBR-STYLE APPROACH TO REGULATION.

A. PBR-style regulation is premised upon the belief that traditional cost-of-service regulation is likely to be ineffective at incenting efficient utility cost outcomes since the regulatory informational requirements to do so are relatively high. This inefficient outcome is premised upon the belief that there is "asymmetrical information" between regulated companies and their regulators.[37] In other words, regulated companies tend to know more about their true costs than regulators, placing regulators at a disadvantage in the regulatory process.[38] PBR-type mechanisms, therefore, have been offered as a form of alternative regulation that attempts to minimize the negative impacts of information-created regulatory inefficiencies by focusing regulatory goals on "outputs" as opposed to "inputs."

Q. EXPLAIN HOW THE APPROACH FOCUSES ON "OUTPUTS" AS OPPOSED TO "INPUTS."

[36] *See*, Exhibit DED-8.
[37] Bell, Matthew (2002), "Performance-Based Regulation: A View from the Other Side of the Pond," *The Electricity Journal*, Vol. 2002-02, p. 67; *see also*, Mark Armstrong and David Sappington (June 2003), *Recent Developments in the Theory of Regulation*, Discussion Draft, pp. 43-50.
[38] Bell, Matthew (2002), "Performance-Based Regulation: A View from the Other Side of the Pond," *The Electricity Journal*, Vol. 2002-02, p. 67.

A. Typical PBR mechanisms effectively "decouple" rates and costs through the use of a formulaic-based approach.[39] Rates are initially set in a rate case and then allowed to increase annually based upon a pre-defined formula over a pre-specified time period. If a utility contains its costs to levels that are below those allowed by the formula, it can increase its achieved earnings. Likewise, if the utility fails to garner enough efficiencies to keep its costs in line with the formula, its achieved earnings will fall below those typically allowed under traditional regulatory approaches.[40]

Q. HOW DOES THIS APPROACH DIFFER FROM TRADITIONAL REGULATION?

A. Traditional regulation attempts to effectively manage all costs and rates. Regulators scour copious amounts of information, typically provided through the course of an evidentiary hearing, to ascertain what it thinks are a utility's true costs. Rates are then set on what are believed to be an accurate set of costs and frozen at those levels until such time as a utility files its next rate request. If a utility garners enough efficiencies to increase its earnings in the period after the rate case, it can effectively increase its achieved earnings to levels that are above those allowed in the prior rate case. There is likely an upper bound on just how high these earnings can progress under traditional rate of return regulation since excessive earnings can, at least in theory, serve as the basis for a regulator-initiated rate case. Traditional regulation differs from a PBR since between rate cases, utility rates are allowed to vary, and

[39] Knittel, Christopher R. (August 2002), "Alternative Regulatory Methods and Firm Efficiency: Stochastic Frontier Evidence from the U.S. Electricity Industry," *The Review of Economics and Statistics*, Vol. 84(3), p. 531.
[40] Navarro, Peter (1996), "The Simple Analytics of Performance-Based Ratemaking: A Guide for the PBR Regulator," *The Yale Journal on Regulation*, Vol. 13, p.111.

utilities can typically make claim to a certain share of any excess earnings without fear of being brought in for an entirely new rate review. In this sense, a PBR "institutionalizes" and strengthens the incentives created by regulatory lag that are inherent in traditional regulation.

Q. WHAT DO YOU MEAN BY REGULATORY LAG?

A. Regulatory lag can be defined in a variety of ways, but can generally be defined as the time period in which the achieved earnings of a utility consistently and materially differ from those allowed in its prior rate case. This deviation can move positively or negatively: achieved earnings can progress to levels that are materially and consistently above those allowed in current rates, as well as those that are below the allowed returns embedded in existing rates. This is one of the reasons that it is difficult (and not likely very productive) to assign a normative interpretation to the presence of regulatory lag since the outcomes can vary over time, circumstances, and even utilities.

Q. EXPLAIN GENERALLY HOW THE FORMULAIC APPROACH TO PBR INSTITUTIONALIZES REGULATORY LAG.

A. PBRs are comprised of three different components that define (a) how rates will be allowed to change; (b) the time period over which rates will be allowed to change prior to any new "re-calibrations" (i.e., a rate case); and (c) how earnings will be shared among ratepayers and shareholders during the PBR plan period. An appropriately designed PBR should recognize the trade-off or interdependence between all three

components.[41] For instance, a PBR that allows greater rate flexibility (i.e., allowing rates to increase in a more significant fashion) should be accompanied by a longer time program period (the time period in which a utility "stays out" of a rate case), and potentially a reduced share (to the utility) of any excess earnings that arise from a utility's efficiency investment decisions. A PBR constructed in such a fashion recognizes a relatively lower level of upfront risk being borne by the utility (since it is allowed greater pricing flexibility) relative to ratepayers. However, the overall risk-reward relationships are relatively balanced since given the program period duration (or "stay-out" period), and allocating a more-than-proportional initial share of excess earnings to ratepayers first as opposed to the utility and its shareholders.

Q. COULD THIS DESIGN BE SET UP IN A FASHION THAT PLACES GREATER UPFRONT RISK ON A UTILITY?

A. Yes. Another potential program design could include one where the utility is assigned a relatively low degree of pricing flexibility (i.e., it faces limited flexibility in the degree to which rates may increase in any given year), but in return would face a much shorter program period, and would be given a higher than proportional share of the initial earnings associated with the PBR plan. In this example, the utility would be assuming a greater degree of risk in achieving efficiency gains (i.e., the utility would have less pricing flexibility with which to fund additional efficiency efforts), but would be allowed to come in for more frequent rate adjustments (through a shorter program time

[41] Vogelsang, Ingo (2002), "Incentive Regulation and Competition in Public Utility Markets: A 20-Year Perspective," *Journal of Regulatory Economics*; Vol. 22:1, pp. 5-27.

duration) and would have claim to relatively higher excess earnings that may arise from its efforts.

Q. HOW DOES THIS CONCEPTUAL DISCUSSION RELATE TO THE COMPANY'S PROPOSED PBR?

A. The Company's proposed PBR includes a number of components that makes it unnecessarily complex, and also unnecessarily shifts the risk-reward relationships that I discussed earlier more in its favor at ratepayers' expense. There are a few important, but limited, modifications to the plan that I believe would simplify the ARP's administration, make it more transparent, and result in a more equitable balance of risks and rewards between ratepayers and shareholders. My recommendations include:

1) Elimination or modification of the proposed benchmarking approach associated with the Company's non-production costs.
2) Elimination or modification of the Company's proposed capital expenditure ("capex") proposal.
3) Elimination of the Company's ROE bonus proposal and a re-calibration of its ESA.

I will discuss each of these recommendations in greater detail in the following sections of my testimony.

B. Benchmarking Component of the Company's Non-Power Supply Cost

Q. PLEASE EXPLAIN THE FORMULA COMMONLY USED TO ADJUST PRICES UNDER MANY PBR MECHANISMS.

A. Exhibit DED-8 presents a survey of various PBR mechanisms around North America and their various different program design features. The formula commonly used to adjust prices (or revenues) under most PBRs is usually expressed as:

$$RR_t = RR_{t-1} * (1 + (I_t - X_t)) + Z_t$$

Where RR_t is the revenue requirement in the current time period, RR_{t-1} is the revenue requirement in the prior period, I_t is the inflation factor adjustment, X_t is the productivity factor adjustment, and Z_t is an adjustment for exogenous changes. The formula simply allows current period (t) revenues to increase relative to their prior period levels (t-1) by inflation ("I") less an adjustment for productivity ("X" often called an "X factor"). Exogenous costs ("Z" often called a "Z factor") can be added to the formula, however, in this section of my testimony I would like to limit the discussion to just the "inflation less productivity" ("I – X") component of the formula.

Q. EXPLAIN HOW INFLATION AND PRODUCTIVITY INTERACT IN THIS FORMULA.

A. The "net" increase in revenues allowed under a PBR is defined by the annual reported rate of inflation less some commonly-accepted (or measured) industry average productivity measure. This adjustment simply says that revenues can be increased by the average inflation rate in the economy to reflect changes in costs, but those increases will be tempered by the productiveness of the industry over the same time period. So revenues will be allowed to increase as the general rate of inflation increases in the economy, holding productivity constant. However, revenues will increase by a much smaller amount if the industry is highly productive, holding inflation

constant. In fact, revenues could, in theory, decrease if the productivity adjustment is greater in absolute value than inflation.

Q. HOW IS INFLATION MEASURED?

A. Most PBR mechanisms use a measure of inflation that is tied to measures of macroeconomic price inflation rather than industry specific input price inflation. The Gross Domestic Product Price Index ("GDP-PI") published by the Bureau of Economic Analysis ("BEA"), or final goods and services inflation, as measured by the Consumer Price Index ("CPI") published by the Bureau of Labor Statistics ("BLS"), represent two common price inflation indices used in PBRs.[42]

Q. PLEASE DISCUSS HOW PRODUCTIVITY FACTORS ARE USED IN A PBR MECHANISM.

A. The productivity factor, or "X" factor, is perhaps the most important factor in a PBR mechanism.[43] In general, the X factor represents expected productivity growth; however, a great deal of disagreement surrounding the appropriateness of a chosen X factor inevitably arises during many PBR filings.[44] Total factor productivity ("TFP") analyses are used in some jurisdictions to set a specific X factor[45] while others, such as

[42] Comnes, GA, et. al., Performance-Based Ratemaking for Electric Utilities: Review of Plans and Analysis of Economic and Resource-Planning Issues (November 1995), Lawrence Berkeley National Laboratory, p. 22.
[43] Bernstein, Jeffrey I. and David E.M. Sappington, "Settign the X Factor in Price Cap Regulation Plans" (June 1998), National Bureau of Economic Research ("NBER"), Working Paper 6622, p. 1.
[44] Joskow, Paul L., *Incentive Regulation in Theory and Practice: Electricity Distribution and Transmission Networks* (January 21, 2006), National Bureau of Economic Research Conference on Economic Regulation, pp. 19-21.
[45] Performance-Based Regulation for Distribution Utilities (December 2000), The Regulatory Assistance Project, p. 30.

Vermont, utilizes a fixed productivity factor agreed upon through the policy making process.[46]

Q. PLEASE DISCUSS THE INCORPORATION OF A "STRETCH FACTOR" IN A PBR MECHANISM.

A. Exhibit DED-8 shows that many PBR programs utilize a "stretch factor" in their "inflation less productivity" adjustment. A "stretch factor" is nothing more than an additional productivity factor adjustment that can be included in a PBR mechanism to give customers an increased share of the benefits from the plan.[47] Some regulators have adopted these additional "stretch factors" to reflect the additional efficiency enhancing attributes of PBR over traditional regulation. The stretch factor is combined with the productivity factor as a composite factor that reduces the rate at which revenues are allowed to increase in any given year. Stretch factors are currently used in all currently active Canadian PBR plans; however, they are not currently utilized in any currently active U.S. PBR plans.[48]

Q. DOES THE "INFLATION LESS PRODUCTIVITY" COMPONENT OF THE COMPANY'S ARP CONFORM TO THE GENERAL DESIGN OF OTHER PBRs?

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[46] *See,* Petition of Green Mountain Power Corporation for Approval of a Modified Alternative Regulation Plan, Pursuant to 30 V.S.A. § 218d, Docket No. 7585, Direct Testimony of Robert J. Griffin, 5:8-11; *see also,* Petition of Green Mountain Power Corporation for Approval of a Modified Alternative Regulation Plan, Pursuant to 30 V.S.A. § 218d, Docket No. 7585, Memorandum of Understanding Between the Vermont Department of Public Service and Green Mountain Power Corporation, Attachment 1; *and* Petition of Green Mountain Power Corporation for Approval of a Modified Alternative Regulation Plan, Pursuant to 30 V.S.A. § 218d, Docket No. 7585, Order dated April 16, 2010, p. 3. A one percent productivity factor was originally proposed by the Company as part of its revised ARP petition, but was subsequently agreed to by the Department as part of its MOU with the Company, and the Board in the subsequent Order.

[47] Bernstein, Jeffrey I. and David E.M. Sappington, "Settign the X Factor in Price Cap Regulation Plans" (June 1998), National Bureau of Economic Research ("NBER"), Working Paper 6622, p. 19.

[48] *See*, Exhibit DED-8.

A. No. The specific mechanics of the "inflation less productivity" component of the Company's ARP does not conform to the general design of other common PBRs. For instance, the Company's Non-Power Supply Costs are allowed to increase in any given year by inflation less a productivity offset.[49] On its face, this adjustment would seem comparable to other North American PBRs. However, the productivity offset (the "X factor") is scaled in any given year based upon the results of a benchmarking comparison that compares the Company's non-supply related operating cost performance to group of 20 comparably sized electric utilities.[50]

Q. WAS THIS BENCHMARKING COMPONENT PART OF THE ARP APPROVED BY THE COMMISSION IN 2010?

A. Yes, although the Company proposes to change the statistical evaluation criteria from quintiles to quartiles in its current filing. Under the Company's proposed plan, the Company's ranking amongst this peer group will be split into four quartiles, with an increasing incentive adjustment of 0 to 0.75 percent, in 0.25 increments, depending on the Company's ranking.[51] This incentive is applied against the Company's 1.0 percent productivity factor, meaning that with the incentive benchmark the Company's combined productivity factor can range from an absolute high of 1.0 percent (if performance is

[49] Direct Testimony of Christopher Cole, Exhibit CC-3, pp. 3 and 8; Non-Power Supply Costs are defined as all costs other than those included in the Power Adjustor, which includes as Committee Costs (defined as demand charges, transmission costs and ancillary charges) and Open Position Costs specified in Attachment 3 of the Application.
[50] Application, Attachment 5, pp. 1-2.
[51] Application, Attachment 5, p. 1.

poor relative to its peers) to as low as 0.25 percent (if the Company's performance is superior relative to its peers).[52]

Q. PLEASE EXPLAIN THE PROBLEMS YOU SEE WITH THIS BENCHMARKING ADJUSTMENT.

A. There are two primary problems. First, the incentive associated with the mechanism is somewhat backwards since it penalizes ratepayers for "good" utility cost performance and rewards ratepayers when that cost performance is poor. Second, this component of the Company's ARP has tended to reduce the effective "base" productivity offset that ratepayers receive from the PBR mechanism.

Q. EXPLAIN WHAT YOU MEAN BY THE OFFSET BEING SET IN A FASHION THAT PENALIZES RATEPAYERS FOR GOOD UTILITY COST PERFORMANCE.

A. The Company's productivity offset is set in a fashion that reduces near-term ratepayer benefits from the PBR mechanism. While the Company's proposed plan includes a base 1.0 percent productivity offset, this offset can be reduced by 0.75 percent if the Company's cost performance is in the upper quartile of its annual benchmark analysis.[53] Thus, ratepayers, at least during the APR plan period, will likely see a very small, sub-average productivity offset for each year in which the Company reports superior cost performance. As I noted earlier in my testimony, most PBR plans work in an opposite fashion: ratepayers are typically allocated a "base" (industry average) productivity offset of some level, and any achieved productivity gains the utility

[52] *See*, Direct Testimony of Christopher Cole, 14:21-22.
[53] Application, Attachment 5, p. 1.

attains in excess of this base productivity offset goes towards increasing the utility's potential earnings.

Q. HAVE YOU EXAMINED THE POTENTIAL BENEFITS TO UTILITY SHAREHOLDERS AND RATEPAYERS FROM THE COMPANY'S ARP AND A TRADITIONAL PBR?

A. Yes. Exhibit DED-9 presents an example of benefits that accrue to utility shareholders and ratepayers under the ARP and traditional PBR under "best-case" conditions where available productivity gains exceed the set 1 percent productivity offset by 0.5 percent, and under "worst-case" conditions where available productivity gains equal the 1 percent productivity offset. This exhibit assumes that potential productivity gains available to the Company are at least equal to those seen in the industry average, i.e. the base productivity offset. This assumption is made for three reasons: (1) as shown earlier, the Company's cost data shows areas of potential productivity gains; (2) the Company's cost benchmarking results itself does not show GMP's cost performance as the absolute best performer among its peers; and (3) if this condition does not hold, incentive regulation would produce inferior results for both the utility and ratepayers compared to traditional cost-of-service ratemaking since GMP would essentially be penalized for being unable to reach expected industry productivity gains.[54]

[54] With regards to this last element, that the Company is not proposing to eliminate the ARP in this proceeding shows that it is unlikely that all potential productivity gains in excess of industry averages have been exhausted.

Q. PLEASE EXPLAIN THIS ILLUSTRATION OF THE DIFFERING PLAN BENEFITS.

A. Exhibit DED-9 shows that the presence of the Non-Power Supply Cost Incentive Adjustment skews the benefits of the ARP in the Company's favor as compared to a traditional PBR structure. Specifically, the adjustment redistributes benefits typically seen by ratepayers to the Company, while maintaining a cap on downside results. In the example shown in Exhibit DED-9, the ARP permits the Company to see a 1.25 percent earnings increase per year if available productivity gains exceed the industry average by 0.5 percent (assuming a 2.0 percent inflation factor for both plans). At the same time, ratepayers only see a modest 0.25 percent benefit from reduced rate increases relative to inflation. Under a traditional PBR, without the Non-Power Supply Cost Incentive Adjustment, the Company would see earnings increases of 0.5 percent per year, while ratepayers would maintain a 1.0 percent benefit from reduced rate increase relative to inflation under the same conditions.

Q. DOES THE NON-POWER SUPPLY COST INCENTIVE ADJUSTMENT WEAKEN INCENTIVES TO FIND PRODUCTIVITY GAINS?

A. Yes. While Exhibit DED-9 shows that the Company's optimal earnings decision is to reduce costs under both the existing ARP structure and traditional PBR, the exhibit does not include the effects of the Company's ESA. As explained later, the ESA is designed in a manner which caps above average earnings to only 75 basis points above the target return on equity level. As the Non-Power Supply Cost Incentive Adjustment increases the Company's benefits from modest productivity gains, the

adjustment increases the chance that earnings will exceed the de-facto earnings cap included in the ESA, holding other things equal. Therefore, the Non-Power Supply Cost Incentive Adjustment exacerbates the situation where the Company is only incentivized to seek modest gains, while ignoring larger potential efficiency opportunities.

Q. IS THERE ANY LOGIC TO BENCHMARKING PRODUCTIVITY OFFSETS UNDER A PBR?

A. Yes, but primarily when that adjustment is applied to the "stretch factor" component of the productivity offset, not the base productivity adjustment. For instance, all currently operating PBR plans in Canada include a "stretch factor" which purposefully sets a second productivity offset that is in excess of industry averages in anticipation of extra productivity gains on the part of the utility.[55] Under the Canadian mechanisms, ratepayers are always guaranteed some meaningful, known "base" productivity offset under the plan mechanics: additional offsets are a function of how the "stretch factor" is set. Ontario, for instance, establishes appropriate "stretch factors" for electric distribution companies based on a benchmarking of costs in a manner similar to that utilized by the Company.[56] However, the Ontario stretch factor benchmarking approach represents an adjustment over and beyond a relatively significant base level productivity offset which does not change in any given year based upon the benchmark analysis.

Q. PLEASE DESCRIBE THE COST BENCHMARKING APPROACH UTILIZED IN ONTARIO FOR ELECTRIC DISTRIBUTION COMPANIES.

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[55] *See*, Exhibit DED-8.
[56] *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (July 14, 2008), Ontario Energy Board Docket EB-2007-0673, p. 23.

A. In a July 14, 2008 report on 3rd Generation Incentive Regulation for the Province's electric distribution utilities, the Ontario Energy Board ("OEB") determined that stretch factors will continue to be important for several years after switching from cost of service regulation to PBR. Furthermore, the OEB found that determining such factors based on cost benchmarking was "a well-established technique with ample precedent in the academic literature and regulatory proceedings."[57] The OEB thus established a mechanism that categorized the electric distribution utilities into three equal categories, with the top third of performers being assigned a stretch factor of 0.2 percent, average performers being assigned a 0.4 percent stretch factor, and the bottom third of performers being assigned a stretch factor of 0.6 percent.[58]

Q. DOES THE ONTARIO COST BENCHMARKING APPROACH COMPORT TO THAT INCLUDED IN THE COMPANY'S ARP?

A. No. Importantly, the stretch factors determined by cost benchmarking in Ontario are applied as an addition to the overall productivity factor, and not as reduction to the overall productivity factor in which is the case in the Company's ARP. Specifically, in the Ontario structure, the overall combined productivity factor a utility is subjected to can vary from 0.92 to 1.32 percent, depending on the cost benchmark rankings of the

[57] *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (July 14, 2008), Ontario Energy Board Docket EB-2007-0673, p. 20.
[58] *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (July 14, 2008), Ontario Energy Board Docket EB-2007-0673, p. 22.

utility.[59] Alternatively, under the Company's revised ARP, the Company's combined productivity factor can be as low as 0.25 percent.[60]

Q. HAS THE BOARD PREVIOUSLY COMMENTED ON THE REASONABLENESS OF UTILITY PRODUCTIVITY FACTORS?

A. Yes. In Docket No. 7803, an MOU was reached between parties which established a productivity offset for Vermont Gas Systems ("VGS") of 0.39 percent. In its Order approving the MOU, the Board noted that it approved the low productivity offset merely because it was a term of the parties' settlement, but noted that a 1.0 percent productivity offset is the standard for alternative regulation plans in effect in Vermont. The Board furthermore required the Company to show reason in its next filing subsequent to the conclusion of the plan as to why the productivity offset should not be increased to 1.0 percent.[61] It is also important to note that the VGS mechanism, while utilizing a relatively low productivity offset, does not utilize a benchmarking adjustment like the one in place for GMP.

Q. DO YOU FIND A ONE PERCENT PRODUCTIVITY OFFSET TO BE REASONABLE?

A. Yes. Exhibit DED-10 presents the combined productivity offsets applied in active North American incentive regulation plans. Exhibit DED-10 shows that, besides VGS, the lowest productivity factor included in currently active North American plans is 0.50

[59] *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (July 14, 2008), Ontario Energy Board Docket EB-2007-0673, pp. 12 and 22.
[60] *See*, Application, Attachment 5, p. 1; *see also*, Direct Testimony of Christopher Cole, 14:21-22.
[61] Petition of Vermont Gas Systems, Inc., for Approval of a Successor Alternative Regulation Plan, Docket No. 7803, Order dated August 21, 2012, pp. 4 and 16.

percent for PacifiCorp in California. However, the majority of plans feature productivity offsets at or near 1.0 percent, with the average of current non-Vermont plans at 0.96 percent.

Q. IS THE COMPANY'S ONE PERCENT PRODUCTIVITY FACTOR DIRECTLY COMPARABLE TO THE 0.39 PERCENT VGS PRODUCTIVITY FACTOR THE BOARD FOUND OBJECTIONABLE?

A. No since the base or starting productivity offset included in the Company's ARP, while starting at a higher 1.0 percent level, is also subject to a (downward) benchmarking-related adjustment. As noted earlier, the ARP approved for VGS in Docket No. 7803 does not include a benchmarking adjustment.[62] The use of a benchmark-based reduction in the Company's ARP leads to an effective productivity offset close to, or lower than, the 0.39 percent productivity offset the Board found questionable in Docket No. 7803. For instance, the 2012 cost data for GMP shows that the newly combined Company ranked 7th among its peer group, or in the second quartile.[63] This means that if the Company merely maintains its current cost performance, its effective productivity offset will likely be 0.5 percent: a level only slightly higher than the objectionable VGS offset of 0.39. Furthermore, if the Company improves its performance by two ranks such that the Company is ranked in the top quartile, the effective productivity factor is reduced to 0.25 percent, less than the current

[62] See, Petition of Vermont Gas Systems, Inc., for Approval of a Successor Alternative Regulation Plan, Docket No. 7803, Petition, Exhibit 1.
[63] Company Response to AARP 1-67, Attachment.

VGS factor.[64] Indeed, historically the effective productivity factor with benchmarking for GMP prior to its merger has always been 0 percent.[65]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE NON-POWER SUPPLY COST INCENTIVE ADJUSTMENT?

A. My primary recommendation regarding the Company's non-power supply cost incentive is that the Board eliminate the benchmarking component of this adjustment. The current net inflation (inflation less productivity) adjustment is set in a fashion that is contrary to most PBR plans, prejudices ratepayers, and incorporates an additional degree of analysis and complication that is not really needed. The Board could greatly simplify the ARP by eliminating the benchmarking component, and deferring to a base productivity offset of 1.0. I also recommend that the Board change the ESA sharing bands to reflect this potential modification to the ARP since the proposed modification will assign a larger upfront benefit to ratepayers relative to the Company. I will discuss this proposed ESA change in greater detail later in my testimony.

Q. DO YOU HAVE ANY ALTERNATIVE RECOMMENDATIONS REGARDING THE COMPANY'S NON-POWER SUPPLY COST INCENTIVE ADJUSTMENT?

A. Yes. If the Board prefers to keep the benchmarking component of the ARP in place, I recommend that the current 1.0 productivity adjustment be divided into two equal parts: one part will consist of a 0.5 base productivity offset and the second part will consist of a 0.5 stretch factor adjustment. Benchmarking will apply to the 0.5 stretch

[64] See, Alternative Regulation Plan (December 20, 2013), Green Mountain Power, Attachment 5, p. 1.
[65] Company Response to AARP 1-67, Attachment. See also, Petition of Green Mountain Power Corporation for Approval of an Alternative Regulation Plan (Plan II), Docket No. 7585, Petition, Alternative Regulation Plan, Attachment 5, p. 1.

factor component only, not the 0.5 base productivity offset. This adjustment would lower the stretch factor by 0.3 for cost benchmarking results in the top quartile, 0.2 for results in the second quartile, and 0.1 for results in the third quartile. No adjustment would be given for cost performance in the bottom quartile of peer utility. Thus, the stretch factor would vary from 0.2 to 0.5 percent depending on depending on GMP cost performance relative to its peers, while combined productivity adjustment would vary between a minimum of 0.7 percent and a maximum of 1.0 percent. If the Board were to approve this alterative recommendation, I also recommend a change in the ESA to reflect these proposed changes in the potential risk-reward relationships of the ARP. I will discuss these proposed alternative ESA changes later in my testimony.

C. Capital Spending Adjustment

Q. PLEASE DESCRIBE THE COMPANY'S CAPITAL SPENDING ADJUSTMENT.

A. The Capital Spending Adjustment component of the Company's ARP is defined as the return of investment, including taxes and depreciation, of (1) incremental net rate year utility plant in service investment, (2) incremental GMP Efficiency Fund and Community Energy & Efficiency Development ("CEED") Fund spending, and (3) incremental Preliminary Service costs.[66] This capex adjustment is analogous to an exogenous change adjustment. The problem with an adjustment component of this nature is that the Company's capital expenditures are not largely out of its own control, and thus not "exogenous" from a PBR perspective.

[66] Direct Testimony of Christopher Cole, Exhibit CC-3, pp. 3-4.

Q. DO OTHER PBRs ALLOW CAPITAL EXPENDITURE ADJUSTMENTS IN A MANNER SIMILAR TO THE COMPANY'S ARP?

A. No, as shown on Exhibit DED-8, other PBRs may include capital adjustments; however, these are almost usually limited to capital investments considered outside of the Company's control and thus normal course of operations. For instance, Enmax in the Province of Alberta allows some capital investments to by-pass the Company's PBR mechanism; however, this allowance is restricted to electric transmission investments only.[67] In Alberta, the Alberta Electric System Operator ("AESO") functions in a similar manner to ISO New England in terms of long-term transmission planning, and thus decisions involving transmission investments are considered largely outside of the utility's control.[68] The Company's ARP, however, is broad-based, including all net changes to utility plant in service, including preliminary survey and investigation costs.[69]

Q. HAVE ANY OTHER CANADIAN JURISDICTIONS COMMENTED ON THE RELATIONSHIP OF CAPITAL EXPENSES AND PBRs?

A. Yes. The Alberta Utilities Commission ("AUC"), in determining new PBR plans for the Province's electric and gas distribution utilities, decided to allow utilities to petition the commission for the recovery of capital investments through a capital tracker outside of the approved plan if a certain set of pre-defined criteria were met. The recovery of capital expenditures, however, was not guaranteed like the Company's

[67] Enmax Power Corporation: 2007-2016 Formula Based Ratemaking (March25, 2009), Alberta Utilities Commission Decision 2009-035, ¶216.
[68] *See*, http://www.aeso.ca/ourcompany/ourCompany.html; Enmax Power Corporation: 2007-2016 Formula Based Ratemaking (March 25, 2009), Alberta Utilities Commission Decision 2009-035, ¶191.
[69] Direct Testimony of Christopher Cole, Exhibit CC-3, pp. 3-4.

ARP. The AUC adopted the following predefined criteria that need to be met for approval of capital trackers:

1) The project must be outside of the normal course of company's ongoing operations.
2) Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party.
3) The project must have a material effect on the company's finances.[70]

Likewise, the OEB, in its July 14, 2008 report on 3rd Generation Incentive Regulation for the Province's electric distribution utilities, allowed utilities to petition the board for recovery of incremental capital expenditures during the term of a rate plan, but also stated that such proposal would need to show (1) materiality, or significant financial influence on the operation of the distributor; (2) need, or that such investments are clearly non-discretionary and outside of factors rates were initially derived; and (3) prudence.[71]

Q. ARE CAPITAL INVESTMENTS USUALLY ALLOWED AS A SEPARATE COST RECOVERY COMPONENT IN PBRs?

A. No. The claimed superiority of PBRs, relative to traditional regulation, does not rest on operating cost efficiencies alone. PBRs were also developed, in large part, to facilitate the efficient deployment of capital and infrastructure investment.[72] The theory

[70] Rate Regulation Initiative: Distribution Performance-Based Regulation (September 12, 2012), Alberta Utilities Commission Decision 2012-237, ¶592.
[71] *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* (July 14, 2008), Ontario Energy Board Docket EB-2007-0673, p. 33.
[72] Navarro, Peter (1996), "The Simple Analytics of Performance-Based Ratemaking: A Guide for the PBR Regulator," *The Yale Journal on Regulation*, Vol. 13, pp. 119-122.

and practice of utility regulation over the past 60 or more years recognizes the incentives utilities can have for over-capitalization, often referred to as the "Averch-Johnson" or "A-J" effect, in recognition of the two academic economists that first formalized this relationship.[73] PBR mechanisms seek to correct this overcapitalization incentive through the institutionalization of regulatory lag that I discussed earlier.

Q. DOES THE INCLUSION OF A CAPITAL EXPENDITURE COMPONENT REDUCE THE POSITIVE POTENTIAL BENEFITS OF A PBR-TYPE MECHANISM?

A. Yes. The capital spending adjustment allows the utility to begin to recover incremental capital investments as soon as the annual base rate adjustment is approved, regardless of other cost increases. This significantly weakens the effect regulatory lag, and thus the Company's ARP, has on controlling potential over-capitalization.

Q. HAS THE COMPANY CLAIMED IN PRIOR FILINGS THAT THERE WAS A NEED FOR EXTRAORDINARY PLANT INVESTMENTS?

A. No. In its prior filing proposing the inclusion of a capital spending adjustment in its ARP, the Company simply noted that such costs could be "very volatile and periodic," and that, as such, were inappropriate to include within the ARP.[74] The Company

[73] H. Averch and L. Johnson. (1962) "Behavior of the Firm under Regulatory Constraint." *American Economic Review*. 52:1052-1069.
[74] Petition of Green Mountain Power Corporation for Approval of a Modified Alternative Regulation Plan, Pursuant to 30 V.S.A. § 218d, Docket No. 7585, Direct Testimony of Robert J. Griffin, 5:3-6.

specifically referenced generation investment costs as an example of a cost that is volatile.[75]

Q. HAVE YOU EXAMINED THE COMPANY'S CURRENT CAPITAL BUDGETS?

A. Yes. The Company provided capital budgets for fiscal years 2014 and 2015 approved by its Board of Directors.[76] The Company's capital budgets do not show that production-related investments are anticipated to constitute the majority of the Company's capital budget in either fiscal year. Indeed, the largest category of spending in each fiscal year is associated with transmission and distribution infrastructure capex, representing more than 39 percent of total capex in fiscal year 2014, and slightly less than half (50 percent) of total capex in fiscal year 2015. The remaining portions of the Company's capital budgets consists of: information technology; other distribution plant (such as meters and transformers); and production plant associated with Kingdom Community Wind, solar generation, and Vermont Marble Hydro. The production plant portion of the Company's capex budget represents approximately 27 percent of total capex for fiscal years 2014 and 2015.

Q. CAN YOU EXPLAIN HOW THE INCLUSION OF A BROAD CAPITAL SPENDING ADJUSTMENT IS ANTITHETICAL TO PBR?

A. Yes. As explained earlier, PBR in a sense "institutionalizes" and strengthens the incentives created by regulatory lag that are inherent in traditional regulation. This is done because rates are set relative to a formula for multiple years at a time. This

[75] Petition of Green Mountain Power Corporation for Approval of a Modified Alternative Regulation Plan, Pursuant to 30 V.S.A. § 218d, Docket No. 7585, Direct Testimony of Robert J. Griffin, 5:4-5.
[76] Company's Response to DPS 6-5.

prevents over-capitalization as the utility is unable to request rate increases outside of that allowed for in its formula during the term of the plan. Likewise, if a utility is able to discipline its capital expenditures relative to the levels afforded by the rate increases included within the PBR formula (without sacrificing service quality), the utility can make claim to a certain share of any excess earnings without fear of being brought in for an entirely new rate review, as may happen under traditional ratemaking. The capital spending adjustment included in the Company's ARP breaks this important linkage by significantly reducing the regulatory lag associated with these investments. As noted earlier, the claimed superiority of PBRs, relative to traditional regulation, does not rest on operating cost efficiencies alone.

Q. IS REGULATORY LAG UNFAIR OR CONFISCATORY TO UTILITIES?

A. No. The premise that regulatory lag is somehow unfair is simply antithetical to most of the research in utility regulation over the past 40 years. Regulatory lag has long been recognized as a key component of the overall regulatory process given the discipline it can impose on utility operational and investment decisions. Regulatory lag prevents utility regulation from devolving into a "cost-plus" regulatory approach, upon which most tracker proposals are based, that simply passes through costs on a dollar-for-dollar basis to ratepayers, and can lead to cost and investment inefficiencies. If regulators simply change prices on a period-to-period basis, much like what occurs under the capital spending adjustment, "there would be no [regulatory] lag and,

importantly, no incentive for cost efficiency."[77] As mentioned earlier, this cost-plus regulatory approach shifts a considerable amount of performance-related risk away from utilities and onto ratepayers and leads to inefficient outcomes, which was recognized as early as the 1960s (i.e., the "A-J" effect discussed earlier).

Q. CAN THE CAPITAL SPENDING ADJUSTMENT SHIFT REGULATORY RISK AWAY FROM THE UTILITY AND ONTO RATEPAYERS?

A. Yes, since the capital spending adjustment, for all intents and purposes, is functionally equivalent to a capital tracker mechanism with a very limited review process. Capital trackers, and trackers in general, by their very nature, tend to reverse the burden of determining the cost-effectiveness or prudence of utility investments and expenses. Under traditional regulation, utilities typically make investments and seek cost recovery once those investments are operational and placed into service. Trackers shift this cost recovery and regulatory review process, at least from a practical perspective, since utilities begin to recover their costs immediately through rates, leaving regulators and ratepayers in the position of having to demonstrate, on an annual basis, why those costs (or some share of those costs) should be removed from tracker-based rates. This reversed prudence review process is often challenged by the nature of many longer-term investments that can be comprised of differing individual investment components, over multiple years, leading to a "forest versus the trees" evaluation dilemma. In other words, it is difficult to annually evaluate the individual

[77] W. Viscusi, J. Vernon, J. Harrington, Jr. *Economics of Regulation and Antitrust*. Second Edition (1997). Cambridge, MA: MIT Press: 380.

"trees" associated with a capital investment plan in any given year without having some perspective about the impact that those trees will have on the overall "forest" of quality of service, which itself may only materialize at some point well into the future.

Q. ARE THERE ANY APPLIED SURVEYS ON COST AND INVESTMENT TRACKERS THAT ARE CRITICAL OF THEIR USE?

A. Yes. A recent survey report on cost trackers by the National Regulatory Research Institute ("NRRI"), the research arm for the National Association for Regulatory Utility Commissioners ("NARUC") notes:

> Cost trackers can, in various ways, result in higher utility costs. First, they undercut the positive effects of regulatory lag on a utility's costs. "Regulatory lag" refers to the time gap between when a utility undergoes a change in cost or sales levels and when the utility can reflect these changes in new rates. Economic theory predicts that the longer the regulatory lag, the more incentive a utility has to control its costs; when a utility incurs costs, the longer it has to wait to recover those costs, the lower its earnings are in the interim. The utility, consequently, would have an incentive to minimize additional costs. Commissions rely on regulatory lag as an important tool for motivating utilities to act efficiently. As economist and regulator Alfred Kahn once remarked:
>
> > Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards for their opposites; companies can for a time keep the higher profits they reap from a superior performance and have to suffer the losses from a poor one.
>
> Rational utility management, as a general rule, would exert minimal effort in controlling costs if it has no effect on the utility's profits. This condition occurs when a utility is able to pass through (with little or no regulatory scrutiny) higher costs to customers with minimal consequences for sales. Cost containment constitutes a real cost to management. Without any expected benefits, management would exert minimum effort on cost containment. The difficult problem for the regulator is to detect when management is lax. Regulators should concern themselves with this problem; lax management translates into a higher cost of service and, if

> undetected, higher rates to the utility's customers. Regulators should closely monitor and scrutinize costs, such as those subject to cost trackers, that utilities have little incentive to control.[78]

Q. HAVE YOU EXAMINED THE COMPANY'S INVESTMENT PROJECTIONS?

A. Yes, projected data was provided for the years 2014 and 2015, and these are shown on Exhibit DED-11. This Exhibit contains the capital investments included in the capital spending adjustment. In total, the Company plans to spend approximately $202.7 million on investments that appear to be included in the capital spending adjustment. Specifically, the Company has budgeted as $108.0 million for these investments for 2014 and $94.6 million in 2015.

Q. HOW DO THE COMPANY'S PROPOSED INVESTMENT PROJECTIONS COMPARE TO HISTORICAL LEVELS?

A. As shown on Exhibit DED-12, the Company spent a total of $178.5 million on primary components of its capital spending adjustment for the years 2009 through 2013, or approximately $35.7 per year. This compares to its proposed budget for the same components of $77.3 million for the 2014 and $77.9 million for 2015, which constitutes a 117 percent increase over historical expenditures.

Q. WHAT DO YOU RECOMMEND REGARDING THE CAPITAL SPENDING ADJUSTMENT COMPONENT OF THE ARP?

A. I recommend the Board remove the capital spending adjustment component of the ARP. As explained above, the adjustment is contrary to the principles underlying

[78] K. Costello. *How Should Regulators View Cost Trackers?* Washington, DC: National Regulatory Research Institute: pp. 4-5, September 2009 [footnotes excluded].

PBR-based ratemaking, by removing a key cost driver from the incentive effects of the ARP. The adjustment shifts the risk of capital cost recovery and performance away from the Company's and onto ratepayers. The capital spending adjustment is akin to an investment tracker which reduced capital investment incentives created by regulatory lag as well as PBRs. Regulatory lag has long been recognized by scholars and practitioners alike as a positive element of the regulatory process that enhances, not diminishes, incentives for innovation and cost-effective investment.

Q. DO YOU HAVE ANY ALTERNATIVE RECOMMENDATIONS SHOULD THE BOARD DECIDE TO MAINTAIN THE COMPANY'S CAPITAL SPENDING ADJUSTMENT?

A. Yes. The Board should strengthen the Company's annual reporting and minimum filing requirements in order to facilitate the prudence evaluation of the proposed capital investments. The Company's capital investments should also be subjected to a number of ratepayer protection provisions that limit the potential negative rate impacts that could be imposed on customers from excessive capital spending. Collectively, these new minimum filing requirements and ratepayer protections should include:

1) Clear identification of individual capital investments, and identification of investment purpose for each major capital investment/program and how that purpose is consistent with (a) state energy policy, (b) the Company's IRP, and/or (c) meeting the Company's reliability requirements and/or resiliency goals. All of these investments should be accompanied by cost-benefit

analyses, if not individually, then at least collectively, for all investments in excess of $1.0 million on an annual basis.

2) Financial analyses (similar to attrition analyses) that shows the potential financial harm that could be imposed on the Company if immediate capital cost recovery is not allowed.

3) A ratepayer protection provision that limits the annual capital spending adjustment to three percent of total revenue in any given year. Any investments in excess of the cap should be treated in a manner consistent with traditional ratemaking practices.

4) New annual filing requirements that should include: competitive bid comparisons and evaluations on major resource acquisitions/developments; monthly budget-to-actual comparisons of capital projects with explanations for deviations in budget greater than 10 percent; submission of capital authorization reports, work orders, and change orders; and audits performed on capital expenditures included in the capital spending adjustment. Parties should have the opportunity to review and opine on the Company's capital expenditure proposals and offer recommendations as part of the expanded review process (and period) included in the Company's current ARP proposal.

Q WOULD EITHER OF YOUR RECOMMENDATIONS REMOVE UNANTICIPATED, OR TRULY "EXOGENOUS," CAPITAL COST RECOVERY FROM THE ARP?

A No. The Company should continue to be allowed to recover costs that are genuinely "exogenous" within its ARP. It will be incumbent upon the GMP, however, to prove that the capital costs it seeks to recovery through the ARP are truly unanticipated and exogenous. "Normal course of business" capital investments, however, should not be eligible for this type of exogenous capital cost recovery.

Q. WOULD EITHER YOUR PRIMARY OR ALTERNATIVE RECOMMENDATION UNDERMINE THE COMPANY'S ABILITY TO IMPROVE ITS INVESTMENT RESPONSIVENESS TO STATE ENERGY POLICIES?

A No. Both of my recommendations should preserve the Company's ability to make investments that are responsive to state energy policies. The Company, like most regulated utilities, should be required to make investments that result in outcomes where benefits are greater than costs. Excluding capital costs from the PBR will not change that outcome. If the benefits are greater than costs, the investments, in theory, should pay for themselves and the Company will not be disadvantaged. This is how PBRs discipline capital investment decisions: PBRs force utilities to make very hard and calculated decisions about capital investments. PBRs are set up to incent very efficient investments that improve efficiencies, and generate opportunities for increased earnings, that can be shared between the utility and ratepayers.

Q. CAN "ABOVE-MARKET" CAPITAL INVESTMENTS BE ACCOMMODATED UNDER YOUR RECOMMENDATIONS?

A. Yes. Current state energy policies across the country often promote investment in assets or programs that have difficult to measure benefits. Many of these types of

investments are thought to be "above-market" given traditional market valuation approaches: renewables and resiliency investments can often fall into these categories. My direct and alternative recommendations can still accommodate these types of above-market investments. If the Board accepts my primary recommendation, it could allow GMP to submit requests for the inclusion of "above-market" capital investments into the "exogenous" cost component of its current ARP structure. It would be incumbent upon GMP to show that these above market investments are necessary to meet state energy policy and are still the least cost method for meeting those policies, even if the investments themselves may not pass typical cost-benefit tests. If the Board accepts my alternative recommendation, the new filings requirements included in those recommendations explicitly require GMP to show that any capital investment included in the ARP is consistent with state energy policy and/or its IRP. Thus, above-market investments can be accommodated under either set of recommendations. The only difference is that my recommendations "re-inject" a degree of performance and accountability for making these investments that does not exist under the current ARP structure.

D. Earnings Sharing Adjustor

Q. PLEASE DESCRIBE THE COMPANY'S ESA.

A. The Company's ESA provides for the sharing of revenue excesses and shortfalls between the Company and ratepayers. Specifically, the Company's ESA provides for a 50 – 50 equal sharing of earnings between the Company and ratepayers for earnings below a 75 basis point dead-band (referred to as the Earnings Sharing Band by the

Company) but above a 125 basis point lower bound. All earnings below this lower bound are fully recovered from ratepayers. Likewise, all earnings above the 75 basis point dead-band are return to ratepayers.[79]

Q. DO OTHER PBR PLANS INCLUDE AN EARNINGS SHARING MECHANISM ("ESM") SIMILAR TO THE COMPANY'S ESA?

A. While some incentive regulation plans include an ESM, many are designed in a manner different from the Company's ARP. As stated previously, PBR regulation incents utilities to find efficiencies through efficient cost controls, which requires some investment as well as some risk. As a result, utilities should be allowed to share in some excess earnings to promote this productivity (efficiency) growth. While the Company's ESA allows for some above-average earnings, these earnings sharing bands are capped at a relatively low level, potentially stifling additional productivity incentives.

Q. PLEASE EXPLAIN HOW THE COMPANY'S ESA MAY DISINCENT ADDITIONAL EFFICIENCIES.

A. The Company's ESA is designed as a non-symmetrical sharing mechanism, in which only utility under-earnings between 75 and 125 basis points below the Board's target ROE are subject to earnings sharing. This insulates the Company from under-earnings, however, it denies the Company the ability to keep any earnings in excess of 75 basis points above the Board's target ROE. In this manner, the Company is incentivized to seek small efficiency gains to obtain above-average earnings, but only to

[79] Direct Testimony of Christopher Cole, Exhibit CC-3, pp. 4-5.

a level that is 75 basis points above target ROE, since any earnings in excess of this amount would be simply returned to ratepayers. Therefore, the current ARP ESA may hamper the objective of incentive regulation to encourage the utility to find all possible efficiency opportunities.

Q. DOES THE COMPANY'S ACHIEVED ROE SUGGEST ANY POSSIBLE ESA DESIGN FLAWS?

A. Yes. Exhibit DED-13 shows the Company's historic achieved ROE relative to the Board's target ROE. With the exclusion of 2012, the Company has consistently exceeded its target ROE over the course of its ARP experience. However, importantly, the Company has never had earnings which has deviated from target levels such that the achieved ROE value was outside of the upper 75 basis point dead-band provided for in the ESA. In other words, the Company has consistently found productivity gains to achieve moderate above-average earnings, up to the level permitted by the ESA before which earnings would be shared with ratepayers.

Q. WHAT ARE YOUR PRIMARY RECOMMENDATIONS FOR THE ESA?

A. My primary recommendation for the Company's ESA is tied to my earlier-discussed productivity offset recommendation. My productivity offset recommendation is that the benchmarking analysis be removed, and the Board simplify adjustment of its annual revenues by inflations less a 1.0 industry average productivity offset. Since this offset is (a) higher than the currently "effective" "productivity offset, and (b) gives ratepayers an up-front performance based benefit, the ESA should be adjusted to

provide corresponding incentives for the Company's efficiency activities and investments. I recommend the ESA be modified such that it symmetrically has:

- A dead-band of 25 basis points above and below the Board-approved ROE;
- An initial 50/50 sharing band for returns 25 to 100 basis points above or below the Board-approved ROE;
- A second, 75 percent utility – 25 percent customer, sharing band for returns 100 to 200 basis points above or below the Board-approved ROE; and
- An ultimate cap of 200 basis points above or below the Board-approved ROE.

Q. DO YOU HAVE ANY ALTERNATIVE ESA RECOMMENDATIONS?

A. Yes. My alternative recommendation for the Company's ESA is tied to my earlier-discussed alternative productivity offset recommendation that breaks the offset into two components: a base productivity offset of 0.5 percent and a stretch factor adjustment of 0.5 percent. The stretch factor adjustment will be the only component subject to a benchmarking analysis. If my alternative recommendation is accepted, the new productivity offset will likely be (a) higher than the currently effective rate, but (b) will give ratepayers less of an up-front performance based benefit relative to my primary recommendation. Therefore, as an alternative, I recommend that the ESA be modified such that it has:

- A dead-band of 25 basis points above and below the Board-approved ROE;
- An initial, 75 percent customer – 25 percent utility, sharing band for returns 25 to 100 basis points above or below the Board-approved ROE;

- A second, 50 percent utility – 50 percent customer, sharing band for returns 100 to 200 basis points above or below the Board-approved ROE; and
- An ultimate cap of 200 basis points above or below the Board-approved ROE.

Q. SHOULD THE BOARD ALSO MAINTAIN THE COMPANY'S ROE PERFORMANCE ADJUSTMENT?

A. No. The ROE Performance Adjustment provides an additional incentive for the Company to seek productivity gains which it already has, effectively allowing the Company to "double-count" any earnings growth it achieves relative to its peers. The ROE performance incentive is also misaligned since it penalizes ratepayers for "good" utility cost performance and rewards ratepayers when that cost performance is poor, thereby undermining one of the primary benefits of the ARP listed by the Company. The incentives for the PBR should be consistent for ratepayers and the utility under the ARP; both receive larger benefits when performance is good, and both receive lower benefits when performance is poor.

Q. WHAT IS THE STATED PURPOSE OF THE COMPANY'S ROE PERFORMANCE ADJUSTMENT?

A. The Company's ROE performance adjustment allows a 25 basis point addition to its target ROE if the Company's cost performance is in the top quartile of its peer group. Likewise, the mechanism also provides a 25 basis point penalty to the Company's target ROE if the Company's cost performance is in the bottom quartile of its peers.[80] In proposing the adjustment in the prior ARP, the Company stated that the adjustment

[80] Application, Attachment 5, p. 1.

provides "a strong incentive to manage controllable costs and will provide benefits similar to the non-power cost cap efficiency adjustment."[81]

Q. DID THE BOARD MODIFY THE COMPANY'S ORIGINALLY-PROPOSED ROE ADJUSTMENT MECHANISM IN DOCKET NO. 7585?

A. Yes. The Board modified the Company's originally-proposed ROE Adjustment Mechanism by removing the first year of the proposed adjustment. The Board noted that the Department had agreed to the proposed mechanism in the MOU in order to save litigation expense, and to allow the Company an opportunity to earn its way to what was characterized as an average ROE for electric utilities. The Board found the proposed ROE adjustment to be a conservative experiment in general, but was uncomfortable with allowing the Company an immediate increase of 25 basis points since the first achieved returns were driven more by past, rather than future performance. As a result, the Board delayed implementation of the ROE Performance Adjustment mechanism until October 1, 2011, effectively removing the first year adjustment.[82]

Q. HAS THE COMPANY HISTORICALLY INCLUDED AN ADJUSTMENT TO ITS AUTHORIZED RETURN ON EQUITY AS AN ELEMENT OF THE ARP?

A. The Company in its testimony states that the Company's equity costs have historically been lowered by 50 basis points to reflect the risk sharing features of the

[81] Petition of Green Mountain Power Corporation for Approval of a Modified Alternative Regulation Plan, pursuant to 30 V.S.A. § 218d, Docket No. 7585, Direct Testimony of Robert J. Griffin, 7:16-18.
[82] Petition of Green Mountain Power Corporation for Approval of an Alternative Regulation Plan (Plan II), Docket No. 7585, Final Order dated April 16, 2010, pp. 16-17.

plan.[83] The Company even finds this reduced cost of equity as one of the main beneficial feature that customers have received from the ARP.[84] Specifically, the Company calculated that GMP ratepayers saw $4.2 million in benefits from 2008 to 2012 from reduced equity costs. Likewise, the Company calculates that CVPS customers saw $6.1 million in benefits from 2009 to 2012 from reduced equity costs. Finally, the Company estimates customers of the newly merged Company have seen nearly $9 million in savings from 2013 and 2014 alone.[85]

Q. HAS THE BOARD ADOPTED A SIMILAR ADJUSTMENT FOR ANY OTHER UTILITY OPERATING UNDER AN ALTERNATIVE RATE PLAN IN THE STATE?

A. Yes. In approving the 2012 MOU between the Department and VGS in Docket No. 7803, the Board approved a ROE that represented a 50 basis point adjustment from that originally provided by VGS.[86] In approving this reduction, the Board specifically noted that:

> This reduction in the ROE was driven by the fact that the Successor Plan transfers much of VGS' operating risk from the Company to its ratepayers as a result of the ESM mechanism, which reduces fluctuations in VGS' earnings, and by indexing VGS's authorized ROE to changes in the yield of the 10-Year Treasury Note.[87]

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[83] Direct Testimony of Christopher Cole, 8:7-9; *see also,* Petition of Green Mountain Power Corporation for Approval of an Alternative-Regulation Plan, Docket No. 7176, Direct Testimony of Ron Behrns, 12:11-15. Interestingly, the Department in reaching its MOU with the Company in its original ARP filing did not describe the 50 basis point difference between its negotiated ROE under the ARP and traditional regulation as reflecting any risk sharing element of the ARP, but as "attributable to the general overall settlement and not to any specific identifiable issues."
[84] Direct Testimony of Christopher Cole, 8:6-9.
[85] Company's Response to AARP 1-26, Attachment a.
[86] Petition of Vermont Gas Systems, Inc., for Approval of a Successor Alternative Regulation Plan, Docket No. 7803, Order dated August 21, 2012, p. 27.
[87] Petition of Vermont Gas Systems, Inc., for Approval of a Successor Alternative Regulation Plan, Docket No. 7803, Order dated August 21, 2012, p. 27.

Q. IS THE COMPANY PROPOSING A SPECIFIC ADJUSTMENT TO ITS COST OF EQUITY IN THE CURRENT PROCEEDING?

A. No. The Company's ROE recommendation of 10.0 percent is premised on the ARP being approved. If the ARP is not approved, the Company states that it's recommended ROE would "be at the higher end of the range of (ROE Model) results."[88] When asked for further information in discovery, the Company specified that an ROE value of 10.5 percent would be appropriate if the ARP is not approved.[89]

Q. DOES THE ROE PERFORMANCE ADJUSTMENT CORRESPOND TO ANY TRADITIONAL ELEMENT OF PBR MECHANISM?

A. No. The purpose of PBR is to encourage capital investment, as well as operational efficiencies through the use of an ESM. The Company has an ESA in its current ARP and layering an additional earnings incentive is comparable to it being allowed two bites of the same proverbial apple.

Q. ARE THERE ANY CONTRADICTIONS IN THE COMPANY'S FILING REGARDING THE RELATIONSHIP BETWEEN THE ARP AND THE ROE ADJUSTMENT MECHANISM?

A. Yes. Within its filing, the Company lists many of the benefits it believes the ARP has provided to customers, including:

> … the Current Plan [ARP] has provided customer benefits by reducing the cost of equity and debt compared to traditional ratemaking. Equity costs have been lower than what would have likely been experienced under traditional regulation

[88] Direct Testimony of James M. Coyne, 53:9-12.
[89] Company's Response to DPS 5-9.

> because the authorized ROE was set 50 basis points lower when the plan was approved to reflect the risk sharing features of the plan. There can be no doubt that GMP's allowed return on equity since implementation of alternative regulation has been low on any comparable basis with other utilities. This enduring discount relative to the traditional equity return has reduced customer cost significantly in the last seven years.[90]

These ARP benefits, however, are likely undermined by the presence of an ROE incentive mechanism. Under the ROE incentive, good performance will actually increase, not reduce overall equity cost for ratepayers.

VI. CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S ALTERNATIVE REGULATION PLAN.

A. I recommend the Board make the following modifications to the Company's proposed ARP laid out in the Company's December 20, 2013 application:

1) The Non-Power Supply Cost Incentive Adjustment be removed or modified;
2) The Capital Spending Adjustment be removed or modified;
3) The Earnings Sharing Adjustor be modified; and
4) The Incremental ROE Adjustment be removed.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE NON-POWER SUPPLY COST INCENTIVE ADJUSTMENT?

A. My primary recommendation regarding the Company's non-power supply cost incentive is that the Board eliminate the benchmarking component of this adjustment.

[90] Direct Testimony of Christopher Cole, 8:6-13.

The current net inflation (inflation less productivity) adjustment is set in a fashion that is contrary to most PBR plans, prejudices ratepayers, and incorporates an additional degree of analysis and complication that is not really needed. The Board could greatly simplify the ARP by eliminating the benchmarking component, and deferring to a base productivity offset of 1.0. I also recommend that the Board change the ESA sharing bands to reflect this potential modification to the ARP.

Q. DO YOU HAVE ANY ALTERNATIVE RECOMMENDATIONS REGARDING THE NON-POWER SUPPLY COST INCENTIVE ADJUSTMENT?

A. Yes. If the Board prefers to keep the benchmarking component of the ARP in place, I recommend that the current 1.0 productivity adjustment be divided into two equal parts: one part will consist of a 0.5 base productivity offset and the second part will consist of a 0.5 stretch factor adjustment. Benchmarking will apply to the 0.5 stretch factor component only, not the 0.5 base productivity offset. This adjustment would lower the stretch factor by 0.3 for cost benchmarking results in the top quartile, 0.2 for results in the second quartile, and 0.1 for results in the third quartile. No adjustment would be given for cost performance in the bottom quartile of peer utility. Thus, the stretch factor would vary from 0.2 to 0.5 percent depending on GMP cost performance relative to its peers, while combined productivity adjustment would vary between a minimum of 0.7 percent and a maximum of 1.0 percent.

Q. WHAT DO YOU RECOMMEND REGARDING THE CAPITAL SPENDING ADJUSTMENT COMPONENT OF THE ARP?

A. I recommend the Board remove the capital spending adjustment component of the ARP. The adjustment is contrary to the principles underlying PBR-based ratemaking, which attempts to maximize utility incentives for both operational and capital investment decision efficiencies. The capital spending adjustment component also shifts the risk of capital cost recovery and performance away from the Company and onto ratepayers. The capital spending adjustment is akin to an investment tracker which reduces capital investment incentives created by regulatory lag and PBRs. Regulatory lag has long been recognized by scholars and practitioners alike as a positive element of the regulatory process that enhances, not diminishes, incentives for innovation and cost-effective investment.

Q. DO YOU HAVE ANY ALTERNATIVE RECOMMENDATIONS SHOULD THE BOARD MAINTAIN THE COMPANY'S CAPITAL SPENDING ADJUSTMENT?

A. Yes. The Board should strengthen the Company's annual reporting and minimum filing requirements in order to facilitate the prudence evaluation of the proposed capital investments. The Company's capital investments should also be subjected to a number of ratepayer protection provisions that limit the potential negative rate impacts that could be imposed on customers from excessive capital spending. Collectively, these new minimum filing requirements and ratepayer protections should include:

1) Clear identification of individual capital investments, and identification of investment purpose for each major capital investment/program and how that purpose is consistent with (a) state energy policy, (b) the Company's IRP,

and/or (c) meeting the Company's reliability requirements and/or resiliency goals. All of these investments should be accompanied by cost-benefit analyses, if not individually, then at least collectively, for all investments in excess of $1.0 million on an annual basis.

2) Financial analyses (similar to attrition analyses) that shows the potential financial harm that could be imposed on the Company if immediate capital cost recovery is not allowed.

3) A ratepayer protection provision that limits the annual capital spending adjustment to three percent of total revenue in any given year. Any investments in excess of the cap should be treated in a manner consistent with traditional ratemaking practices.

4) New annual filing requirements that should include: competitive bid comparisons and evaluations on major resource acquisitions/developments; monthly budget-to-actual comparisons of capital projects with explanations for deviations in budget greater than 10 percent; submission of capital authorization reports, work orders, and change orders; and audits performed on capital expenditures included in the capital spending adjustment. Parties should have the opportunity to review and opine on the Company's capital expenditure proposals and offer recommendations as part of the expanded review process (and period) included in the Company's current ARP proposal.

Q. WHAT ARE YOUR PRIMARY RECOMMENDATIONS FOR THE EARNINGS SHARING ADJUSTOR ("ESA")?

A. My primary recommendation for the Company's ESA is tied to my earlier-discussed productivity offset recommendation. My productivity offset recommendation is that the benchmarking analysis be removed, and the Board simplify adjustment of its annual revenues by inflation less a 1.0 productivity offset. Since this offset is (a) higher than the currently "effective" productivity offset, and (b) gives ratepayers an up-front performance-based benefit, the ESA should be adjusted to provide corresponding incentives for the Company's efficiency activities and investments. I recommend the ESA be modified such that it has:

- A dead-band of 25 basis points above and below the Board-approved ROE;
- An initial 50/50 sharing band for returns 25 to 100 basis points above or below the Board-approved ROE;
- A second, 75 percent utility – 25 percent customer, sharing band for returns 100 to 200 basis points above or below the Board-approved ROE; and
- An ultimate cap of 200 basis points above or below the Board-approved ROE.

Q. DO YOU HAVE ANY ALTERNATIVE ESA RECOMMENDATIONS?

A. Yes. My alternative recommendation for the Company's ESA is tied to my earlier-discussed alternative productivity offset recommendation that breaks the offset into two components: a base productivity offset of 0.5 percent and a stretch factor adjustment of 0.5 percent. The stretch factor adjustment will be the only component subject to a benchmarking analysis. If my alternative recommendation is accepted, the new productivity offset will likely be (a) higher than the currently effective rate, but (b) will also give ratepayers less of an up-front performance-based benefit relative to my

primary recommendation. Therefore, as an alternative, I recommend that the ESA be modified such that it has:

- A dead-band of 25 basis points above and below the Board-approved ROE;
- An initial, 75 percent customer – 25 percent utility, sharing band for returns 25 to 100 basis points above or below the Board-approved ROE;
- A second, 50 percent utility – 50 percent customer, sharing band for returns 100 to 200 basis points above or below the Board-approved ROE; and
- An ultimate cap of 200 basis points above or below the Board-approved ROE.

Q. SHOULD THE BOARD ALSO MAINTAIN THE COMPANY'S ROE PERFORMANCE ADJUSTMENT?

A. No. The ROE Performance Adjustment gives the Company an additional reward for efficiencies already incented in the ARP structure (i.e., through the ESA). This effectively allows the Company to "double-count" efficiencies (and earnings) it achieves relative to its peers. The ROE performance incentive is also misaligned since it penalizes ratepayers for "good" utility cost performance and rewards ratepayers when that cost performance is poor, thereby undermining one of the primary benefits of the ARP listed by the Company. The incentives and rewards should be consistent for ratepayers and the utility under the ARP; both receive larger benefits when performance is good, and both receive smaller benefits when performance is poor.

Q. DOES THIS COMPLETE YOUR TESTIMONY FILED ON MAY 20, 2014?

A. Yes, it does.

Attachment A

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EDUCATION

Ph.D., Economics, Florida State University, 1995.
M.S., Economics, Florida State University, 1992.
M.S., International Affairs, Florida State University, 1988.
B.A., History, University of West Florida, 1987.
A.A., Liberal Arts, Pensacola State College, 1985.

Master's Thesis: *Nuclear Power Project Disallowances: A Discrete Choice Model of Regulatory Decisions*

Ph.D. Dissertation: *An Empirical Examination of Environmental Externalities and the Least-Cost Selection of Electric Generation Facilities*

ACADEMIC APPOINTMENTS

Louisiana State University, Baton Rouge, Louisiana

Center for Energy Studies

2007-Current	Director, Division of Policy Analysis
2006-Current	Professor
2003-Current	Associate Executive Director
2001-2006	Associate Professor
2000-2001	Research Fellow and Adjunct Assistant Professor
1995-2000	Assistant Professor

School of the Coast and the Environment (Department of Environmental Studies)

2010-Current	Adjunct Professor

E.J. Ourso College of Business Administration (Department of Economics)

2006-Current	Adjunct Professor

2001-2006	Adjunct Associate Professor
1999-2000	Adjunct Assistant Professor

Florida State University, Tallahassee, Florida

College of Social Sciences, Department of Economics

1995	Instructor

PROFESSIONAL EXPERIENCE

Acadian Consulting Group, Baton Rouge, Louisiana

2001-Current	Consulting Economist/Principal
1995-2000	Consulting Economist/Principal

Econ One Research, Inc., Houston, Texas

2000-2001	Senior Economist

Florida Public Service Commission, Tallahassee, Florida
Division of Communications, Policy Analysis Section

1995	Planning & Research Economist

Division of Auditing & Financial Analysis, Forecasting Section

1993	Planning & Research Economist
1992-1993	Economist

Project for an Energy Efficient Florida &
Florida Solar Energy Industries Association, Tallahassee, Florida

1994	Energy Economist

Ben Johnson Associates, Inc., Tallahassee, Florida

1991-1992	Research Associate
1989-1991	Senior Research Analyst
1988-1989	Research Analyst

GOVERNMENT APPOINTMENTS

2007-Current	Louisiana Representative, Interstate Oil and Gas Compact Commission; Energy Resources, Research & Technology Committee.
2007-Current	Louisiana Representative, University Advisory Board Representative; Energy Council (Center for Energy, Environmental and Legislative Research).
2005	Member, Task Force on Energy Sector Workforce and Economic Development (HCR 322).
2003-2005	Member, Energy and Basic Industries Task Force, Louisiana Economic Development Council
2001-2003	Member, Louisiana Comprehensive Energy Policy Commission.

PUBLICATIONS: BOOKS AND MONOGRAPHS

1. *Power System Operations and Planning in a Competitive Market*. (2002). With Fred I. Denny. New York: CRC Press.

2. *Distributed Energy Resources: A Practical Guide for Service.* (2000). With Ritchie Priddy. London: Financial Times Energy.

PUBLICATIONS: PEER REVIEWED ACADEMIC JOURNALS

1. "An Empirical Analysis of Differences in Interstate Oil and Natural Gas Drilling Activity." (2012). With Mark J. Kaiser and Christopher J. Peters. *Exploration & Production: Oil and Gas Review*. 30(1): 18-22.

2. "The Value of Lost Production from the 2004-2005 Hurricane Seasons in the Gulf of Mexico." (2009). With Mark J. Kaiser and Yunke Yu. *Journal of Business Valuation and Economic Loss Analysis*. 4(2).

3. "Estimating the Impact of Royalty Relief on Oil and Gas Production on Marginal State Leases in the US." (2006). With Jeffrey M. Burke and Dmitry V. Mesyanzhinov. *Energy Policy* 34(12): 1389-1398.

4. "Using Competitive Bidding As A Means of Securing the Best of Competitive and Regulated Worlds." (2004). With Tom Ballinger and Elizabeth A. Downer. *NRRI Journal of Applied Regulation.* 2 (November): 69-85. (*Received 2005 Best Paper Award by NRRI*)

5. "Deregulation of Generating Assets and the Disposition of Excess Deferred Federal Income Taxes." (2004). With K.E. Hughes II. *International Energy Law and Taxation Review*. 10 (October): 206-212.

6. "Reflections on the U.S. Electric Power Production Industry: Precedent Decisions Vs. Market Pressures." (2003). With Robert F. Cope III and John W. Yeargain. *Journal of Legal, Ethical, and Regulatory Issues*. Volume 6, Number 1.

7. "A is for Access: A Definitional Tour Through Today's Energy Vocabulary." (2001) *Public Resources Law Digest*. 38: 2.

8. "A Comment on the Integration of Price Cap and Yardstick Competition Schemes in Electrical Distribution Regulation." (2001). With Steven A. Ostrover. *IEEE Transactions on Power Systems.* 16 (4): 940 -942.

9. "Modeling Regional Power Markets and Market Power." (2001). With Robert F. Cope. *Managerial and Decision Economics.* 22:411-429.

10. "A Data Envelopment Analysis of Levels and Sources of Coal Fired Electric Power Generation Inefficiency" (2000). With Williams O. Olatubi. *Utilities Policy.* 9 (2): 47-59.

11. "Cogeneration and Electric Power Industry Restructuring" (1999). With Andrew N. Kleit. *Resource and Energy Economics*. 21:153-166.

12. "Capacity and Economies of Scale in Electric Power Transmission" (1999). With Robert F. Cope and Dmitry Mesyanzhinov. *Utilities Policy* 7: 155-162.

13. "Oil Spills, Workplace Safety, and Firm Size: Evidence from the U.S. Gulf of Mexico OCS." (1997). With O. O. Iledare, A. G. Pulsipher, and Dmitry Mesyanzhinov. *Energy Journal* 4: 73-90.

14. "A Comment on Cost Savings from Nuclear Regulatory Reform" (1997). *Southern Economic Journal*. 63:1108-1112.

15. "The Demand for Long Distance Telephone Communication: A Route-Specific Analysis of Short-Haul Service." (1996). *Studies in Economics and Finance* 17:33-45.

PUBLICATIONS: PEER REVIEWED PROCEEDINGS

1. "Technology Based Ethical Issues Surrounding the California Energy Crisis." (2002). With Robert F. Cope III and John Yeargain. *Proceedings of the Academy of Legal, Ethical, and Regulatory Issues*. September: 17-21.

2. "Electric Utility Restructuring and Strategies for the Future." (2001). With Scott W. Geiger. *Proceedings of the Southwest Academy of Management*. March.

3. "Applications for Distributed Energy Resources in Oil and Gas Production: Methods for Reducing Flare Gas Emissions and Increasing Generation Availability" (2000). With Ritchie D. Priddy. *Proceedings of the International Energy Foundation – ENERGEX 2000*. July.

4. "Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry" (1998). With Fred I. Denny. *IEEE Proceedings: Large Engineering Systems Conference on Power Engineering*. June: 294-298.

5. "New Paradigms for Power Engineering Education." (1997). With Fred I. Denny. *Proceedings of the International Association of Science and Technology for Development*. October: 499-504.

6. "Safety Regulations, Firm Size, and the Risk of Accidents in E&P Operations on the Gulf of Mexico Outer Continental Shelf" (1996). With Allan Pulsipher, Omowumi Iledare, and Bob Baumann. *Proceedings of the American Society of Petroleum Engineers: Third International Conference on Health, Safety, and the Environment in Oil and Gas Exploration and Production*, June.

7. "Comparing the Safety and Environmental Records of Firms Operating Offshore Platforms in the Gulf of Mexico." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. *Proceedings of the American Society of Mechanical Engineers: Offshore and Arctic Operations 1996*, January.

PUBLICATIONS: OTHER SCHOLARLY PROCEEDINGS

1. "A Collaborative Investigation of Baseline and Scenario Information for Environmental Impact Statements" (2005). *Proceedings of the 23rd Annual Information Technology Meetings*. U.S. Department of the Interior, Minerals Management Service, Gulf Coast Region, New Orleans, LA. January 12, 2005.

2. "Trends and Issues in the Natural Gas Industry and the Development of LNG: Implications for Louisiana. (2004) *Proceedings of the 51st Mineral Law Institute*, Louisiana State University, Baton Rouge, LA. April 2, 2004.

3. "Competitive Bidding in the Electric Power Industry." (2003). *Proceedings of the Association of Energy Engineers*. December 2003.

4. "The Role of ANS Gas on Southcentral Alaskan Development." (2002). With William Nebesky and Dmitry Mesyanzhinov. *Proceedings of the International Association for Energy Economics: Energy Markets in Turmoil: Making Sense of It All*. October.

5. "A New Consistent Approach to Modeling Regional Economic Impacts of Offshore Oil and Gas Activities." (2002). With Vicki Zatarain. *Proceedings of the 2002 National IMPLAN Users Conference*: 241-258.

6. "Analysis of the Economic Impact Associated with Oil and Gas Activities on State Leases." (2002). With Dmitry Mesyanzhinov, Robert H. Baumann, and Allan G. Pulsipher. *Proceedings of the 2002 National IMPLAN Users Conference*: 149-155.

7. "Do Deepwater Activities Create Different Impacts to Communities Surrounding the Gulf OCS?" (2001). *Proceedings of the International Association for Energy Economics: 2001: An Energy Odyssey?* April.

8. "Modeling the Economic Impact of Offshore Activities on Onshore Communities." (2000). With Williams O. Olatubi. *Proceedings of the 20th Annual Information Transfer Meeting*. U.S. Department of Interior, Minerals Management Service: New Orleans, Louisiana.

9. "Empirical Challenges in Estimating the Economic Impacts of Offshore Oil and Gas Activities in the Gulf of Mexico" (2000). With Williams O. Olatubi. *Proceedings of the International Association for Energy Economics: Transforming Energy Markets*. August.

10. "Asymmetric Choice and Customer Benefits: Lessons from the Natural Gas Industry." (1999). With Rachelle F. Cope and Dmitry Mesyanzhinov. *Proceedings of the International Association for Energy Economics: The Only Constant is Change* August: 444-452.

11. "Modeling Electric Power Markets in a Restructured Environment" (1998). With Robert F. Cope and Dan Rinks. *Proceedings of the International Association for Energy Economics: Technology's Critical Role in Energy and Environmental Markets*. October: 48-56.

12. "Assessing Environmental and Safety Risks of the Expanding Role of Independents in E&P Operations on the Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Bob Baumann, and Dmitry Mesyanzhinov. *Proceedings of the 16th Annual Information Transfer Meeting*. U.S. Department of Interior, Minerals Management Service: New Orleans, Louisiana: 162-166.

13. "Comparing the Safety and Environmental Performance of Offshore Oil and Gas Operators." (1995). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. *Proceedings of the 15th Annual Information Transfer Meeting*. U.S. Department of Interior, Minerals Management Service: New Orleans, Louisiana.

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1. "The Role of Distributed Energy Resources in a Restructured Power Industry." (2006). In *Electric Choices: Deregulation and the Future of Electric Power*. Edited by Andrew N. Kleit. Oakland, CA: The Independent Institute (Rowman & Littlefield Publishers, Inc.), 181-208.

2. "The Road Ahead: The Outlook for Louisiana Energy." (2006). In *Commemorating Louisiana Energy: 100 Years of Louisiana Natural Gas Development*. Houston, TX: Harts Energy Publications, 68-72.

3. "Competitive Power Procurement An Appropriate Strategy in a Quasi-Regulated World." (2004). In *Electric and Natural Gas Business: Using New Strategies, Understanding the*

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PUBLICATIONS: BOOK REVIEWS

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2. Review of ***Electricity Transmission Pricing and Technology***, edited by Michael Einhorn and Riaz Siddiqi. (Boston: Kluwer Academic Publishers, 1996) pp. 282. ISBN 0-7923-9643-X. *Energy Journal* 18 (1997): 146-148.

3. Review of ***Electric Cooperatives on the Threshold of a New Era*** by Public Utilities Reports. (Vienna, Virginia: Public Utilities Reports, 1996) pp. 232. ISBN 0-910325-63-4. *Energy Journal* 17 (1996): 161-62.

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1. "Unconventional Natural Gas and the U.S. Manufacturing Renaissance" (2013). *BIC Magazine*. Vol. 30: No. 2, p. 76 (March).

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3. "The Impact of Legacy Lawsuits on Louisiana's Conventional Drilling Activity" (2012). *LOGA Industry Report*. Spring 2012: 27-34.

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5. "Value of Production Losses Tallied for 2004-2005 Storms." (2008). With Mark J. Kaiser and Yunke Yu. *Oil and Gas Journal*. Vol. 106.27: 32-26 (July 21) (part 3 of 3).

6. "Model Framework Can Aid Decision on Redevelopment." (2008). With Mark J. Kaiser and Yunke Yu. *Oil and Gas Journal*. Vol. 106.26: 49-53 (July 14) (part 2 of 3).

7. "Field Redevelopment Economics and Storm Impact Assessment." (2008). With Mark J. Kaiser and Yunke Yu. *Oil and Gas Journal*. Vol. 106.25: 42-50 (July 7) (part 1 of 3).

8. "The IRS' Latest Proposal on Tax Normalization: A Pyrrhic Victory for Ratepayers," (2006). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 55(1): 217-236

9. "Executive Compensation in the Electric Power Industry: Is It Excessive?" (2006). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 54(4): 913-940.

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13. "The Nuclear Power Plant Endgame: Decommissioning and Permanent Waste Storage. (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 53 (4): 981-997

14. "Can LNG Preserve the Gas-Power Convergence?" (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 53 (3):783-796.

15. "Competitive Bidding as a Means of Securing Opportunities for Efficiency." (2004). With Elizabeth A. Downer. *Electricity and Natural Gas* 21 (4): 15-21.

16. "The Evolving Markets for Polluting Emissions: From Sulfur Dioxide to Carbon Dioxide." (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 53(2): 479-494.

17. "The Challenges Associated with a Nuclear Power Revival: Its Past." (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 53 (1): 193-211.

18. “Deregulation of Generating Assets and The Disposition of Excess Deferred Federal Income Taxes: A ‘Catch-22’ for Ratepayers.” (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 52: 873-891.

19. “Will Competitive Bidding Make a Comeback?” (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 52: 659-674

20. “An Electric Utility’s Exposure to Future Environmental Costs: Does It Matter? You Bet!” (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 52: 457-469.

21. “White Paper or White Flag: Do FERC’s Concessions Represent A Withdrawal from Wholesale Power Market Reform?” (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 52: 197-207.

22. “Clear Skies” or Storm Clouds Ahead? The Continuing Debate over Air Pollution and Climate Change” (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 51: 823-848.

23. “Economic Displacement Opportunities in Southeastern Power Markets.” (2003). With Dmitry V. Mesyanzhinov. *USAEE Dialogue*. 11: 20-24.

24. "What’s Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook" (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 51: 635-652.

25. "Is There a Role for the TVA in Post-Restructured Electric Markets?" (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 51: 433-454.

26. “The Role of Alaska North Slope Gas in the Southcentral Alaska Regional Energy Balance.” (2002). With William Nebesky and Dmitry Mesyanzhinov. *Natural Gas Journal*. 19: 10-15.

27. “Standardizing Wholesale Markets For Energy.” (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 51: 207-225.

28. “Do Economic Activities Create Different Economic Impacts to Communities Surrounding the Gulf OCS?” (2002). With Williams O. Olatubi. *IAEE Newsletter*. Second Quarter: 16-20.

29. “Will Electric Restructuring Ever Get Back on Track? Texas is not California.” (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 50: 943-960.

30. “An Assessment of the Role and Importance of Power Marketers.” (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly. 50: 713-731.*

31. “The EPA v. The TVA, et. al. Over New Source Review.” (2001) With K.E. Hughes, II. *Oil, Gas and Energy Quarterly*. 50:531-543.

32. “Energy Policy by Crisis: Proposed Federal Changes for the Electric Power Industry.” (2001). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 50:235-249.

33. "A is for Access: A Definitional Tour Through Today's Energy Vocabulary." (2001). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 49:947-973.

34. "California Dreaming: Are Competitive Markets Achievable?" (2001). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 49: 743-759.

35. "Distributed Energy Must Be Watched As Opportunity for Gas Companies." (2001). With Martin Collette, and Ritchie D. Priddy. *Natural Gas Journal*. January: 9-16.

36. "Clean Air, Kyoto, and the Boy Who Cried Wolf." (2000). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. December: 529-540.

37. "Energy Conservation Programs and Electric Restructuring: Is There a Conflict?" (2000). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. September: 211-224.

38. "The Post-Restructuring Consolidation of Nuclear-Power Generation in the Electric Power Industry." (2000) With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 49: 751-765.

39. "Issues and Opportunities for Small Scale Electricity Production in the Oil Patch." (2000). With Ritchie D. Priddy. *American Oil and Gas Reporter*. 49: 78-82.

40. "Distributed Energy Resources: The Next Paradigm Shift in the Electric Power Industry." (2000). With K.E. Hughes II *Oil, Gas and Energy Quarterly*. 48:593-602.

41. "Coming to a Neighborhood Near You: The Merchant Electric Power Plant." (1999). With K.E. Hughes II. *Oil, Gas, and Energy Quarterly.* 48:433-441.

42. "Slow as Molasses: The Political Economy of Electric Restructuring in the South." (1999). With K.E. Hughes II. *Oil, Gas, and Energy Quarterly.* 48: 163-183.

43. "Stranded Investment and Non-Utility Generation." (1999). With Michael T. Maloney. *Electricity Journal* 12: 50-61.

44. "Reliability or Profit? Why Entergy Quit the Southwest Power Pool." (1998). With Fred I. Denny. *Public Utilities Fortnightly*. February 1: 30-33.

45. "Electric Utility Mergers and Acquisitions: A Regulator's Guide." (1996). With Kimberly H. Dismukes. *Public Utilities Fortnightly.* January 1.

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3. *The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana*. (2012). Baton Rouge, LA: LSU Center for Energy Studies, 62 pp.

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17. *Comparison of Methods for Estimating the NO_x Emission Impacts of Energy Efficiency and Renewable Energy Projects Shreveport, Louisiana Case Study*. (2005). With Adam Chambers, David Kline, Laura Vimmerstedt, Art Diem, and Dmitry Mesyanzhinov. Golden, Colorado: National Renewable Energy Laboratory.

18. *Economic Opportunities for a Limited Industrial Retail Choice Plan in Louisiana*. (2004). With Elizabeth A. Downer and Dmitry V. Mesyanzhinov. Baton Rouge, LA: Louisiana State University Center for Energy Studies.

19. *Economic Opportunities for LNG Development in Louisiana*. (2004). With Elizabeth A. Downer and Dmitry V. Mesyanzhinov. Baton Rouge, LA: Louisiana Department of Economic Development and Greater New Orleans, Inc.

20. *Marginal Oil and Gas Production in Louisiana: An Empirical Examination of State Activities and Policy Mechanisms for Stimulating Additional Production*. (2004). With Dmitry V. Mesyanzhinov, Jeffrey M. Burke, Robert H. Baumann. Baton Rouge, LA: Louisiana Department of Natural Resources, Office of Mineral Resources.

21. *Deepwater Program: OCS-Related Infrastructure in the Gulf of Mexico Fact Book.* (2004). With Louis Berger Associates, University of New Orleans National Ports and Waterways Institute, and Research and Planning Associates. MMS Study No. 1435-01-99-CT-30955. U.S. Department of the Interior, Minerals Management Service.

22. *The Power of Generation: The Ongoing Benefits of Independent Power Development in Louisiana.* With Dmitry V. Mesyanzhinov, Jeffrey M. Burke, and Elizabeth A. Downer. Baton Rouge, LA: LSU Center for Energy Studies, 2003.

23. *Modeling the Economic Impact of Offshore Oil and Gas Activities in the Gulf of Mexico: Methods and Application.* (2003). With Williams O. Olatubi, Dmitry V. Mesyanzhinov, and Allan G. Pulsipher. Prepared by the Center for Energy Studies, Louisiana State University, Baton Rouge, LA. OCS Study MMS2000-0XX. U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA.

24. *An Analysis of the Economic Impacts Associated with Oil and Gas Activities on State Leases*. (2002) With Robert H. Baumann, Dmitry V. Mesyanzhinov, and Allan G. Pulsipher. Baton Rouge, LA: Louisiana Department of Natural Resources, Office of Mineral Resources.

25. *Alaska In-State Natural Gas Demand Study*. (2002). With Dmitry Mesyanzhinov, et.al. Anchorage, Alaska: Alaska Department of Natural Resources, Division of Oil and Gas.

26. *Moving to the Front of the Lines: The Economic Impacts of Independent Power Plant Development in Louisiana*. (2001). With Dmitry Mesyanzhinov and Williams O. Olatubi. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

27. *The Economic Impacts of Merchant Power Plant Development in Mississippi.* (2001). Report Prepared on Behalf of the US Oil and Gas Association, Alabama and Mississippi Division. Houston, TX: Econ One Research, Inc.

28. *Energy Conservation and Electric Restructuring In Louisiana*. (2000). With Dmitry Mesyanzhinov, Ritchie D. Priddy, Robert F. Cope III, and Vera Tabakova. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

29. *Assessing the Environmental and Safety Risks of the Expanded Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS.* (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

30. *Restructuring the Electric Utility Industry: Implications for Louisiana.* (1996). With Allan Pulsipher and Kimberly H. Dismukes. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

GRANT RESEARCH

1. *Principal Investigator*. "Analysis of the Potential for Combined Heat and Power (CHP) in Louisiana. (2013). Louisiana Department of Natural Resources. Total Project: $90,000. Status: In Progress.

2. *Co-Principal Investigator*. "CNH: A Tale of Two Louisianas: Coupled Natural-Human Dynamics in a Vulnerable Coastal System" (2013) With Nina Lam, Margaret Reams, Kam-Biu Liu, Victor Rivera, and Kelley Pace. National Science Foundation. Total Project: $1.5 million. Status: In Progress (Sept 2012-Feb 2017).

3. *Principal Investigator*. "Examination of Unconventional Natural Gas and Industrial Economic Development" (2012). America's Natural Gas Alliance. Total Project: $48,210. Status: Completed.

4. *Principal Investigator*. "Investigation of the Potential Economic Impacts Associated with Shell's Proposed Gas-To-Liquids Project" (2012). Shell Oil Company, North America. Total

Project: $76,708. Status: Completed.

5. *Principal Investigator*. "Analysis of the Federal Wind Energy Production Tax Credit." American Energy Alliance. Total Project: $20,000. Status: Completed.

6. *Principal Investigator*. "Energy Sector Impacts Associated with the Deepwater Horizon Oil Spill." Louisiana Department of Economic Development. Total Project: Open. Status: Completed.

7. *Principal Investigator*. "Economic Contributions and Benefits Support by the Port of Venice." Port of Venice Coalition. Total Project: $20,000. Status: Completed.

8. *Principal Investigator.* "Energy Policy Development in Louisiana." Louisiana Department of Natural Resources. Total Project: $150,000. Status: Completed.

9. *Principal Investigator.* "Preparing Louisiana for the Possible Federal Regulation of Greenhouse Gas Regulation." With Michael D. McDaniel. Louisiana Department of Economic Development. Total Project: $98,543. Status: Completed.

10. *Principal Investigator*. "OCS Studies Review: Louisiana and Texas Oil and Gas Activity and Production Forecast; Pipeline Position Paper; and Geographical Units for Observing and Modeling Socioeconomic Impact of Offshore Activity." (2008). With Mark J. Kaiser and Allan G. Pulsipher. U.S. Department of the Interior, Minerals Management Service. Total Project: $377,917 (3 years). Status: Completed.

11. *Principal Investigator*. "State and Local Level Fiscal Effects of the Offshore Petroleum Industry." (2007). With Loren C. Scott. U.S. Department of the Interior, Minerals Management Service. Total Project: $241,216 (2.5 years). Status: Awarded, In Progress.

12. *Principal Investigator*. "Understanding Current and Projected Gulf OCS Labor and Ports Needs." (2007). With Allan. G. Pulsipher, Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $169,906. (one year). Status: Awarded, In Progress.

13. *Principal Investigator*. "Structural Shifts and Concentration of Regional Economic Activity Supporting GOM Offshore Oil and Gas Activities." (2007). With Allan. G. Pulsipher, Michelle Barnett. U.S. Department of the Interior, Minerals Management Service. Total Project: $78,374 (one year). Status: Awarded, In Progress.

14. *Principal Investigator*. "Plaquemine Parish's Role in Supporting Critical Energy Infrastructure and Production." (2006). With Seth Cureington. Plaquemines Parish Government, Office of the Parish President and Plaquemines Association of Business and Industry. Total Project: $18,267. Status: Completed.

15. *Principal Investigator*. "Diversifying Energy Industry Risk in the Gulf of Mexico." (2006). With Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $65,302 (two years). Status: Awarded, In Progress.

16. *Principal Investigator*. "Post-Hurricane Assessment of OCS-Related Infrastructure and Communities in the Gulf of Mexico Region." (2006). U.S. Department of the Interior, Minerals Management Service. Total Project Funding: $244,837. Status: In Progress.

17. *Principal Investigator*. "Ultra Deepwater Road Mapping Process." (2005). With Kristi A. R. Darby, Subcontract with the Texas A&M University, Department of Petroleum Engineering. Funded by the Gas Technology Institute. Total Project Funding: $15,000. Status: Completed.

18. *Principal Investigator*. "An Examination of the Opportunities for Drilling Incentives on State Leases." (2004). With Robert H. Baumann and Kristi A. R. Darby. Louisiana Office of Mineral Resources. Total Project Funding: $75,000. Status: Completed.

19. *Principal Investigator*. " An Examination on the Development of Liquefied Natural Gas Facilities on the Gulf of Mexico." (2004). With Dmitry V. Mesyanzhinov and Mark J. Kaiser. U.S. Department of the Interior, Minerals Management Service. Total Project Funding $101,054. Status: Completed.

20. *Principal Investigator*. "Examination of the Economic Impacts Associated with Large Customer, Industrial Retail Choice." (2004). With Dmitry V. Mesyanzhinov. Louisiana Mid-Continent Oil and Gas Association. Total Project Funding: $37,000. Status: Completed.

21. *Principal Investigator*. "Economic Opportunities from LNG Development in Louisiana." (2003). With Dmitry V. Mesyanzhinov. Metrovision/New Orleans Chamber of Commerce and the Louisiana Department of Economic Development. Total Project Funding: $25,000. Status: Completed.

22. *Principal Investigator*. "Marginal Oil and Gas Properties on State Leases in Louisiana: An Empirical Examination and Policy Mechanisms for Stimulating Additional Production." (2002). With Robert H. Baumann and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $72,000. Status: Completed.

23. *Principal Investigator*. "A Collaborative Investigation of Baseline and Scenario Information for Environmental Impact Statements." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $557,744. Status: Awarded, In Progress.

24. *Co-Principal Investigator*. "An Analysis of the Economic Impacts of Drilling and Production Activities on State Leases." (2002). With Robert H. Baumann, Allan G. Pulsipher, and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $8,000. Status: Completed.

25. *Principal Investigator*. "Cost Profiles and Cost Functions for Gulf of Mexico Oil and Gas Development Phases for Input Output Modeling." (1998). With Dmitry Mesyanzhinov and Allan G. Pulsipher. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $244,956. Status: Completed.

26. *Principal Investigator*. "An Economic Impact Analysis of OCS Activities on Coastal Louisiana." (1998). With Dmitry Mesyanzhinov and David Hughes. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $190,166. Status: Completed.

27. *Principal Investigator*. "Energy Conservation and Electric Restructuring in Louisiana." (1997). Louisiana Department of Natural Resources." Petroleum Violation Escrow Program Funds. Total Project Funding: $43,169. Status: Completed.

28. *Principal Investigator*. "The Industrial Supply of Electricity: Commercial Generation, Self-Generation, and Industry Restructuring." (1996). With Andrew Kleit. Louisiana Energy Enhancement Program, LSU Office of Research and Development. Total Project Funding: $19,948. Status: Completed.

29. *Co-Principal Investigator*. "Assessing the Environmental and Safety Risks of the Expanded Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, Grant Number 95-0056. Total Project Funding: $109,361. Status: Completed.

ACADEMIC CONFERENCE PAPERS/PRESENTATIONS

1. "Economies of Scale, Learning Curves, and Offshore Wind Development Costs" (2012). With Gregory Upton. Southern Economic Association Annual Conference, New Orleans, LA November 17.

2. "Analysis of Risk and Post-Hurricane Reaction." (2009). 25th Annual Information Transfer Meeting. U.S. Department of the Interior, Minerals Management Service. January 7.

3. "Legacy Litigation, Regulation, and Other Determinants of Interstate Drilling Activity Differentials." (2008). With Christopher Peters and Mark Kaiser. 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3, 2008.

4. "Gulf Coast Energy Infrastructure Renaissance: Overview." (2008). 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3, 2008.

5. "Understanding the Impacts of Katrina and Rita on Energy Industry Infrastructure." (2008). American Chemical Society National Meetings, New Orleans, Louisiana. April 7, 2008.

6. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2007). With Kristi A. R. Darby and Michelle Barnett. International Association for Energy Economics, Wellington, New Zealand, February 19, 2007.

7. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007). 34th Annual Public Utilities Research Center Conference, University of Florida. Gainesville, FL. February 16, 2007.

8. "An Examination of LNG Development on the Gulf of Mexico." (2007). With Kristi A.R. Darby. US Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 9.

9. "OCS-Related Infrastructure on the GOM: Update and Summary of Impacts." (2007). US Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 10.

10. "The Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006). With Michelle Barnett. Third National Conference on Coastal and Estuarine Habitat Restoration. Restore America's Estuaries. New Orleans, Louisiana, December 11.

11. "The Impact of Implementing a 20 Percent Renewable Portfolio Standard in New Jersey." (2006). With Seth E. Cureington. Mid-Continent Regional Science Association 37th Annual Conference, Purdue University, Lafayette, Indiana, June 9.

12. "The Impacts of Hurricane Katrina and Rita on Energy infrastructure Along the Gulf Coast." (2006). Environment Canada: 2006 Artic and Marine Oilspill Program. Vancouver, British Columbia, Canada.

13. "Hurricanes, Energy Markets, and Energy Infrastructure in the Gulf of Mexico: Experiences and Lessons Learned." (2006). With Kristi A.R. Darby and Seth E. Cureington. 29th Annual IAEE International Conference, Potsdam, Germany, June 9.

14. "An Examination of the Opportunities for Drilling Incentives on State Leases in Louisiana." (2005). With Kristi A.R. Darby. 28th Annual IAEE International Conference, Taipei, Taiwan (June).

15. "Fiscal Mechanisms for Stimulating Oil and Gas Production on Marginal Leases." (2004). With Jeffrey M. Burke. International Association of Energy Economics Annual Conference, Washington, D.C. (July).

16. "GIS and Applied Economic Analysis: The Case of Alaska Residential Natural Gas Demand." (2003). With Dmitry V. Mesyanzhinov. Presented at the Joint Meeting of the East Lakes and West Lakes Divisions of the Association of American Geographers in Kalamazoo, MI, October 16-18.

17. "Are There Any In-State Uses for Alaska Natural Gas?" (2002). With Dmitry V. Mesyanzhinov and William E. Nebesky. IAEE/USAEE 22nd Annual North American Conference: "Energy Markets in Turmoil: Making Sense of It All." Vancouver, British Columbia, Canada. October 7.

18. “The Economic Impact of State Oil and Gas Leases on Louisiana.” (2002). With Dmitry V. Mesyanzhinov. 2002 National IMPLAN Users’ Conference. New Orleans, Louisiana, September 4-6.

19. “Moving to the Front of the Lines: The Economic Impact of Independent Power Plant Development in Louisiana.” (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. 2002 National IMPLAN Users’ Conference. New Orleans, Louisiana, September 4-6.

20. “New Consistent Approach to Modeling Regional Economic Impacts of Offshore Oil and Gas Activities in the Gulf of Mexico.” (2002). With Vicki Zatarain. 2002 National IMPLAN Users’ Conference. New Orleans, Louisiana, September 4-6.

21. “Distributed Energy Resources, Energy Efficiency, and Electric Power Industry Restructuring.” (1999). American Society of Environmental Science Fourth Annual Conference. Baton Rouge, Louisiana. December.

22. “Estimating Efficiency Opportunities for Coal Fired Electric Power Generation: A DEA Approach.” (1999). With Williams O. Olatubi. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November.

23. "Applied Approaches to Modeling Regional Power Markets." (1999.) With Robert F. Cope. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November 1999.

24. “Parametric and Non-Parametric Approaches to Measuring Efficiency Potentials in Electric Power Generation.” (1999). With Williams O. Olatubi. International Atlantic Economic Society Annual Conference, Montreal, October.

25. “Asymmetric Choice and Customer Benefits: Lessons from the Natural Gas Industry.” (1999). With Rachelle F. Cope and Dmitry Mesyanzhinov. International Association of Energy Economics Annual Conference. Orlando, Florida. August.

26. “Modeling Regional Power Markets and Market Power.” (1999). With Robert F. Cope. Western Economic Association Annual Conference. San Diego, California. July.

27. “Economic Impact of Offshore Oil and Gas Activities on Coastal Louisiana” (1999). With Dmitry Mesyanzhinov. Annual Meeting of the Association of American Geographers. Honolulu, Hawaii. March.

28. “Empirical Issues in Electric Power Transmission and Distribution Cost Modeling.” (1998). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association. Sixty-Eighth Annual Conference. Baltimore, Maryland. November.

29. “Modeling Electric Power Markets in a Restructured Environment.” (1998). With Robert F. Cope and Dan Rinks. International Association for Energy Economics Annual Conference. Albuquerque, New Mexico. October.

30. "Benchmarking Electric Utility Distribution Performance." (1998) With Robert F. Cope and Dmitry Mesyanzhinov. Western Economic Association, Seventy-sixth Annual Conference. Lake Tahoe, Nevada. June.

31. "Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry." (1998). With Fred I. Denny. IEEE Large Engineering Systems Conference on Power Engineering. Nova Scotia, Canada. June.

32. "Benchmarking Electric Utility Transmission Performance." (1997). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-seventh Annual Conference. Atlanta, Georgia. November 21-24.

33. "A Non-Linear Programming Model to Estimate Stranded Generation Investments in a Deregulated Electric Utility Industry." (1997). With Robert F. Cope and Dan Rinks. Institute for Operations Research and Management Science Annual Conference. Dallas Texas. October 26-29.

34. "New Paradigms for Power Engineering Education." (1997). With Fred I. Denny. International Association of Science and Technology for Development, High Technology in the Power Industry Conference. Orlando, Florida. October 27-30

35. "Cogeneration and Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Western Economic Association, Seventy-fifth Annual Conference. Seattle, Washington. July 9-13.

36. "The Unintended Consequences of the Public Utilities Regulatory Policies Act of 1978." (1997). National Policy History Conference on the Unintended Consequences of Policy Decisions. Bowling Green State University. Bowling Green, Ohio. June 5-7.

37. "Assessing Environmental and Safety Risks of the Expanding Role of Independents in E&P Operations on the Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 16th Annual Information Transfer Meeting. New Orleans, Louisiana.

38. "Empirical Modeling of the Risk of a Petroleum Spill During E&P Operations: A Case Study of the Gulf of Mexico OCS." (1996). With Omowumi Iledare, Allan Pulsipher, and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

39. "Input Price Fluctuations, Total Factor Productivity, and Price Cap Regulation in the Telecommunications Industry" (1996). With Farhad Niami. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

40. "Recovery of Stranded Investments: Comparing the Electric Utility Industry to Other Recently Deregulated Industries" (1996). With Farhad Niami and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

41. "Spatial Perspectives on the Forthcoming Deregulation of the U.S. Electric Utility Industry." (1996) With Dmitry Mesyanzhinov. Southwest Association of American Geographers Annual Meeting. Norman, Oklahoma.

42. "Comparing the Safety and Environmental Performance of Offshore Oil and Gas Operators." (1995). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 15th Annual Information Transfer Meeting. New Orleans, Louisiana.

43. "Empirical Determinants of Nuclear Power Plant Disallowances." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

44. "A Cross-Sectional Model of IntraLATA MTS Demand." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

ACADEMIC SEMINARS AND PRESENTATIONS

1. "Air Emissions Regulation and Policy: The Recently Proposed Cross State Air Pollution Rule and the Implications for Louisiana Power Generation." Lecture before School of the Coast & Environment. November 5, 2011.

2. "Energy Regulation: Overview of Power and Gas Regulation." Lecture before School of the Coast & Environment, Course in Energy Policy and Law. October 5, 2009.

3. "Trends and Issues in Renewable Energy." Presentation before the School of the Coast & Environment, Louisiana State University. Spring Guest Lecture Series. May 4, 2007.

4. "CES Research Projects and Status." Presentation before the U.S. Department of the Interior, Minerals Management Service, Outer Continental Shelf Scientific Committee Meeting, New Orleans, LA May 22, 2007.

5. "Hurricane Impacts on Energy Production and Infrastructure." Presentation Before the 53rd Mineral Law Institute, Louisiana State University. April 7, 2006.

6. "Trends and Issues in the Natural Gas Industry and the Development of LNG: Implications for Louisiana. (2004) 51st Mineral Law Institute, Louisiana State University, Baton Rouge, LA. April 2, 2004.

7. "Electric Restructuring and Conservation." (2001). Presentation before the Department of Electrical Engineering, McNesse State University. Lake Charles, Louisiana. May 2, 2001.

8. "Electric Restructuring and the Environment." (1998). Environment 98: Science, Law, and Public Policy. Tulane University. Tulane Environmental Law Clinic. March 7, New Orleans, Louisiana.

9. "Electric Restructuring and Nuclear Power." (1997). Louisiana State University. Department of Nuclear Science. November 7, Baton Rouge, Louisiana.

10. "The Empirical Determinants of Co-generated Electricity: Implications for Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Florida State University. Department of Economics: Applied Microeconomics Workshop Series. October 17, Tallahassee, Florida.

PROFESSIONAL AND CIVIC PRESENTATIONS

1. "Leveraging Energy for Industrial Development." (2013). 2013 Governor's Energy Summit, Jackson, Mississippi. December 5.

2. "Natural Gas Markets: Leveraging the Production Revolution into an Industrial Renaissance." (2013). International Technical Conference, Houston, TX. October 11.

3. "Replacement, Reliability & Resiliency: Infrastructure & Ratemaking Issues in the Power & Natural Gas Distribution Industries." (2013). Louisiana State Bar, Public Utility Section Meetings. November 15.

4. "Natural Gas & Electric Power Coordination Issues and Challenges." (2013). Utilities State Government Organization Conference, Pointe Clear, Alabama. July 9.

5. "Louisiana Unconventional Natural Gas and Industrial Redevelopment." (2013). Risk Management Association Luncheon, March 21.

6. "Unconventional Resources and Louisiana's Manufacturing Development Renaissance." (2013). Baton Rouge Press Club, De La Ronde Hall, Baton Rouge, LA, January 28.

7. "New Industrial Operations Leveraged by Unconventional Natural Gas." (2013) American Petroleum Institute-Louisiana Chapter. Lafayette, LA, Petroleum Club, January 14.

8. "What's Going on with Energy? How Unconventional Oil and Gas Development is Impacting Renewables, Efficiency, Power Markets, and All that Other Stuff." (2012). Atlanta Economics Club Monthly Meeting. Atlanta, GA. December 11.

9. "Trends, Issues, and Market Changes for Crude Oil and Natural Gas." (2012). East Iberville Community Advisory Panel Meeting. St. Gabriel, LA. September 26.

10. "Game Changers in Crude and Natural Gas Markets." (2012). Chevron Community Advisory Panel Meeting. Belle Chase, LA, September 17.

11. "The Outlook for Renewables in a Changing Power and Natural Gas Market." (2012). Louisiana Biofuels and Bioprocessing Summit. Baton Rouge, LA. September 11.

12. "The Changing Dynamics of Crude and Natural Gas Markets." (2012). Chalmette Refining Community Advisory Panel Meeting. Chalmette, LA, September 11.

13. "The Really Big Game Changer: Crude Oil Production from Shale Resources and the Tuscaloosa Marine Shale." (2012). Baton Rouge Chamber of Commerce Board Meeting. Baton Rouge, LA, June 27.

14. "The Impact of Changing Natural Gas Prices on Renewables and Energy Efficiency." (2012). NASUCA Gas Committee Conference Call/Webinar. 12 June 2012.

15. "Issues in Gas-Renewables Coordination: How Changes in Natural Gas Markets Potentially Impact Renewable Development" (2012). Energy Bar Association, Louisiana Chapter, Annual Meeting, New Orleans, LA. April 12, 2012.

16. "Issues in Natural Gas End-Uses: Are We Really Focusing on the Real Opportunities?" (2012). Energy Bar Association, Louisiana Chapter, Annual Meeting, New Orleans, LA. April 12, 2012.

17. "The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana." (2012). Louisiana Oil and Gas Association Annual Meeting, Lake Charles, LA. February 27, 2012.

18. "The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana." (2012) Louisiana Oil and Gas Association Annual Meeting. Lake Charles, Louisiana. February 27, 2012.

19. "Louisiana's Unconventional Plays: Economic Opportunities, Policy Challenges. Louisiana Mid-Continent Oil and Gas Association 2012 Annual Meeting. (2012) New Orleans, Louisiana. January 26, 2012.

20. "EPA's Recently Proposed Cross State Air Pollution Rule ("CSAPR") and Its Impacts on Louisiana." (2011). Bossier Chamber of Commerce. November 18, 2011.

21. "Facilitating the Growth of America's Natural Gas Advantage." (2011). BASF U.S. Shale Gas Workshop Management Meeting. Florham Park, New Jersey. November 1, 2011.

22. "CSAPR and EPA Regulations Impacting Louisiana Power Generation." (2011). Air and Waste Management Association (Louisiana Section) Fall Conference. Environmental Focus 2011: a Multi-Media Forum. Baton Rouge, LA. October 25, 2011.

23. "Natural Gas Trends and Impact on Industrial Development." (2011). Central Gulf Coast Industrial Alliance Conference. Arthur R. Outlaw Convention Center. Mobile, AL. September 22, 2011.

24. "Energy Market Changes and Policy Challenges." (2011). Southeast Manpower Tripartite Alliance ("SEMTA") Summer Conference. Nashville, TN September 2, 2011.

25. "EPA Regulations, Rates & Costs: Implications for U.S. Ratepayers." (2011). Workshop:

"A Smarter Approach to Improving Our Environment." 38th Annual American Legislative Exchange Council ("ALEC") Meetings. New Orleans, LA. August 5, 2011.

26. Panelist/Moderator. Workshop: "Why Wait? Start Energy Independence Today." 38th Annual American Legislative Exchange Council ("ALEC") Meetings. New Orleans, LA. August 4, 2011.

27. "Facilitating the Growth of America's Natural Gas Advantage." Texas Chemical Council, Board of Directors Summer Meeting. San Antonio, TX. July 28, 2011.

28. "Creating Ratepayer Benefits by Reconciling Recent Gas Supply Opportunities with Past Policy Initiatives." National Association of State Utility Consumer Advocates ("NASUCA"), Monthly Gas Committee Meeting. July 12, 2011.

29. "Energy Market Trends and Policies: Implications for Louisiana." (2011). Lakeshore Lion's Club Monthly Meeting. Baton Rouge, Louisiana. June 20, 2011.

30. "America's Natural Gas Advantage: Securing Benefits for Ratepayers Through Paradigm Shifts in Policy." Southeastern Association of Regulatory Commissioners ("SEARUC") Annual Meeting. Nashville, Tennessee. June 14, 2011.

31. "Learning Together: Building Utility and Clean Energy Industry Partnerships in the Southeast." (2011). American Solar Energy Society National Solar Conference. Raleigh Convention Center, Raleigh, North Carolina. May 20, 2011.

32. "Louisiana Energy Outlook and Trends." (2011). Executive Briefing. Counsul General of Canada. LSU Center for Energy Studies, Baton Rouge, Louisiana. May 24, 2011.

33. "Louisiana's Natural Gas Advantage: Can We Hold It? Grow It? Or Do We Need to be Worrying About Other Problems?" (2011). Louisiana Chemical Association Annual Legislative Conference, Baton Rouge, Louisiana, May 5, 2011.

34. "Energy Outlook and Trends: Implications for Louisiana. (2011). Executive Briefing, Legislative Staff, Congressman William Cassidy. LSU Center for Energy Studies, Baton Rouge, Louisiana. March 25, 2011.

35. "Regulatory Issues in Inflation Adjustment Mechanisms and Allowances." (2011). Gas Committee, National Association of State Utility Consumer Advocates ("NASUCA"). February 15, 2011.

36. "Regulatory Issues in Inflation Adjustment Mechanisms and Allowances." (2010). 2010 Annual Meeting, National Association of State Utility Consumer Advocates ("NASUCA"), Omni at CNN Center, Atlanta, Georgia, November 16, 2010.

37. "How Current and Proposed Energy Policy Impacts Consumers and Ratepayers." (2010). 122nd Annual Meeting, National Association of Regulatory Utility Commissioners ("NARUC"), Omni at CNN Center, Atlanta, Georgia, November 15, 2010.

38. "Energy Outlook: Trends and Policies." (2010). 2010 Tri-State Member Service Conference; Arkansas, Louisiana, and Mississippi Electric Cooperatives. L'Auberge du Lac Casino Resort, Lake Charles, Louisiana, October 14, 2010.

39. "Deepwater Moratorium and Louisiana Impacts." (2010). The Energy Council Annual Meeting. Gulf of Mexico Deepwater Horizon Accident, Response, and Policy. Beau Rivage Conference Center. Biloxi, Mississippi. September 25, 2010.

40. "Overview on Offshore Drilling and Production Activities in the Aftermath of Deepwater Horizon." (2010) Jones Walker Banking Symposium. The Oil Spill: What Will it Mean for Banks in the Region? New Orleans, Louisiana. August 31, 2010.

41. "Long-Term Energy Sector Impacts from the Oil Spill." (2010). Second Annual Louisiana Oil & Gas Symposium. The BP Gulf Oil Spill: Long-Term Impacts and Strategies. Baton Rouge Geological Society. August 16, 2010.

42. "Overview and Issues Associated with the Deepwater Horizon Accident." (2010). Global Interdependence Meeting on Energy Issues. Baton Rouge, LA. August 12, 2010.

43. "Overview and Issues Associated with the Deepwater Horizon Accident." (2010). Regional Roundtable Webinar. National Association for Business Economics. August 10, 2010.

44. "Deepwater Moratorium: Overview of Impacts for Louisiana." Louisiana Association of Business and Industry Meeting. Baton Rouge, LA. June 25, 2010.

45. Moderator. Senior Executive Roundtable on Industrial Energy Efficiency. U.S. Department of Energy Conference on Industrial Efficiency. Office of Renewable Energy and Energy Efficiency. Royal Sonesta Hotel, New Orleans, LA. May 21, 2010.

46. "The Energy Outlook: Trends and Policies Impacting Southeastern Natural Gas Supply and Demand Growth." Second Annual Local Economic Analysis and Research Network ("LEARN") Conference. Federal Reserve Bank of Atlanta. March 29, 2010.

47. "Natural Gas Supply Issues: Gulf Coast Supply Trends and Implications for Louisiana." Energy Bar Association, New Orleans Chapter Meeting. Jones Walker Law Firm. January 28, 2010, New Orleans, LA.

48. "Potential Impacts of Federal Greenhouse Gas Legislation on Louisiana Industry." LCA Government Affairs Committee Meeting. November 10, 2009. Baton Rouge, LA

49. "Regulatory and Ratemaking Issues Associated with Cost and Revenue Tracker Mechanisms." National Association of State Utility Consumer Advocates ("NASUCA") Annual Meeting. November 10, 2009.

50. "Louisiana's Stakes in the Greenhouse Gas Debate." Louisiana Chemical Association

and Louisiana Chemical Industry Alliance Annual Meeting: The Billing Dollar Budget Crisis: Catastrophe or Change? New Orleans, LA.

51. "Gulf Coast Energy Outlook: Issues and Trends." Women's Energy Network, Louisiana Chapter. September 17, 2009. Baton Rouge, LA.

52. "Gulf Coast Energy Outlook: Issues and Trends." Natchez Area Association of Energy Service Companies. September 15, 2009, Natchez, MS.

53. "The Small Picture: The Cost of Climate Change to Louisiana." Louisiana Association of Business and Industry, U.S. Chamber of Commerce, Louisiana Oil and Gas Association, and LSU Center for Energy Studies Conference: Can Louisiana Make a Buck After Climate Change Legislation? August 21, 2009. Baton Rouge, LA.

54. "Carbon Legislation and Clean Energy Markets: Policy and Impacts." National Association of Conservation Districts, South Central Region Meeting. August 14, 2009. Baton Rouge, LA.

55. "Evolving Carbon and Clean Energy Markets." The Carbon Emissions Continuum: From Production to Consumption." Jones Walker Law Firm and LSU Center for Energy Studies Workshop. June 23, 2009. Baton Rouge, LA

56. "Potential Impacts of Cap and Trade on Louisiana Ratepayers: Preliminary Results." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

57. "Natural Gas Outlook." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

58. "Gulf Coast Energy Outlook: Issues and Trends." (2009). ISA-Lafayette Technical Conference & Expo. Cajundome Conference Center. Lafayette, Louisiana. March 12, 2009.

59. "The Cost of Energy Independence, Climate Change, and Clean Energy Initiatives on Utility Ratepayers." (2009). National Association of Business Economists (NABE). 25th Annual Washington Economic Policy Conference: Restoring Financial and Economic Stability. Arlington, VA March 2, 2009.

60. Panelist, "Expanding Exploration of the U.S. OCS" (2009). Deep Offshore Technology International Conference and Exhibition. PennWell. New Orleans, Louisiana. February 4, 2009.

61. "Gulf Coast Energy Outlook." (2008.) Atmos Energy Regional Management Meeting. Louisiana and Mississippi Division. New Orleans, Louisiana. October 8, 2008.

62. "Background, Issues, and Trends in Underground Hydrocarbon Storage." (2008). Presentation before the LSU Center for Energy Studies Industry Advisory Board

Meeting. Baton Rouge, Louisiana. August 27, 2008.

63. "Greenhouse Gas Regulations and Policy: Implications for Louisiana." (2008). Presentation before the Praxair Customer Seminar. Houston, Texas, August 14, 2008.

64. "Market and Regulatory Issues in Alternative Energy and Louisiana Initiatives." (2008). Presentation before the 2008 Statewide Clean Cities Coalition Conference: Making Sense of Alternative Fuels and Advanced Technologies. New Orleans, Louisiana, March 27, 2008.

65. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007) Presentation before the New Hampshire Public Utilities Commission. Workshop on Energy Efficiency and Revenue Decoupling. November 7, 2007.

66. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives, and Energy Efficiency." (2007). National Association of State Utility Consumer Advocates, Mid-Year Meeting. June 12, 2007.

67. "Regulatory and Policy Issues in Nuclear Power Plant Development." (2007). LSU Center for Energy Studies Industry Advisory Council Meeting. Baton Rouge, LA. March 23, 2007.

68. "Oil and Gas in the Gulf of Mexico: A North American Perspective." (2007). Canadian Consulate, Heads of Mission EnerNet Workshop, Houston, Texas. March 20, 2007.

69. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives & Energy Efficiency. (2007). National Association of State Utility Consumer Advocates ("NASUCA") Gas Committee Monthly Meeting. February 13, 2006.

70. "Recent Trends in Natural Gas Markets." (2006). National Association of Regulatory Utility Commissioners, 118th Annual Convention. Miami, FL November 14, 2006.

71. "Energy Markets: Recent Trends, Issues & Outlook." (2006). Association of Energy Service Companies (AESC) Meeting. Petroleum Club, Lafayette, LA, November 8, 2006.

72. "Energy Outlook" (2006). National Business Economics Issues Council. Quarterly Meeting, Nashville, TN, November 1-2, 2006.

73. "Global and U.S. Energy Outlook." (2006). Energy Virginia Conference. Virginia Military Institute, Lexington, VA October 17, 2006.

74. "Interdependence of Critical Energy Infrastructure Systems." (2006). Cross Border Forum on Energy Issues: Security and Assurance of North American Energy Systems. Woodrow Wilson Center for International Scholars. Washington, DC, October 13, 2006.

75. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006) The Economic and Market Impacts of Coastal

Restoration: America's Wetland Economic Forum II. Washington, DC September 28, 2006.

76. "Relationships between Power and Other Critical Energy Infrastructure." (2006). Rebuilding the New Orleans Region: Infrastructure Systems and Technology Innovation Forum. United Engineering Foundation. New Orleans, LA, September 24-25, 2006.

77. "Outlook, Issues, and Trends in Energy Supplies and Prices." (2006.) Presentation to the Southern States Energy Board, Associate Members Meeting. New Orleans, Louisiana. July 14, 2006.

78. "Energy Sector Outlook." (2006). Baton Rouge Country Club Meeting. Baton Rouge, Louisiana. July 11, 2006.

79. "Oil and Gas Industry Post 2005 Storm Events." (2006). American Petroleum Institute, Teche Chapter. Production, Operations, and Regulations Annual Meeting. Lafayette, Louisiana. June 29, 2006.

80. "Concentration of Energy Infrastructure in Hurricane Regions." (2006). Presentation before the National Commission on Energy Policy Forum: Ending the Stalemate on LNG Facility Siting. Washington, DC. June 21, 2006.

81. "LNG—A Premier." (2006). Presentation Given to the U.S. Department of Energy's "LNG Forums." Los Angeles, California. June 1, 2006.

82. "Regional Energy Infrastructure, Production and Outlook." (2006). Executive Briefing for Board of Directors, Louisiana Oil and Gas Plc., Enhanced Exploration, Inc. and Energy Self-Service, Inc. Covington, Louisiana, May 12, 2006.

83. "The Impacts of the Recent Hurricane Season on Energy Production and Infrastructure and Future Outlook." Presentation before the Industrial Energy Technology Conference 2006. New Orleans, Louisiana, May 9, 2006.

84. "Update on Regional Energy Infrastructure and Production." (2006). Executive Briefing for Delegation Participating in U.S. Department of Commerce Gulf Coast Business Investment Mission. Baton Rouge, Louisiana May 5, 2006.

85. "Hurricane Impacts on Energy Production and Infrastructure." (2006). Presentation before the Interstate Natural Gas Association of America Mid-Year Meeting. Hyatt Regency Hill Country. April 21, 2006.

86. "LNG—A Premier." Presentation Given to the U.S. Department of Energy's "LNG Forums." Astoria, Washington. April 28, 2006.

87. Natural Gas Market Outlook. Invited Presentation Given to the Georgia Public Service Commission and Staff. Georgia Institute of Technology, Atlanta, Georgia. March 10, 2006.

88. The Impacts of Hurricanes Katrina and Rita on Louisiana's Energy Industry. Presentation to the Louisiana Economic Development Council. Baton Rouge, Louisiana. March 8, 2006.

89. Energy Markets: Hurricane Impacts and Outlook. Presentation to the 2006 Louisiana Independent Oil and Gas Association Annual Conference. L'Auberge du Lac Resort and Casino. Lake Charles, Louisiana. March 6, 2006

90. Energy Market Outlook and Update on Hurricane Damage to Energy Infrastructure. Presentation to the Energy Council 2005 Global Energy and Environmental Issues Conference. Santa Fe, New Mexico, December 10, 2005.

91. "Putting Our Energy Infrastructure Back Together Again." Presentation Before the 117th Annual Convention of the National Association of Regulatory Utility Commissioners (NARUC). November 15, 2005. Palm Springs, CA

92. "Hurricanes and the Outlook for Energy Markets." Presentation before the Baton Rouge Rotary Club. November 9, 2005, Baton Rouge, LA.

93. "Hurricanes, Energy Supplies and Prices." Presentation before the Louisiana Department of Natural Resources and Atchafalaya Basin Committee Meeting. November 8, 2005. Baton Rouge, LA.

94. "The Impact of the Recent Hurricane's on Louisiana's Energy Industry." Presentation before the Louisiana Independent Oil and Gas Association Board of Directors Meeting. November 8, 2005. Baton Rouge, LA.

95. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before the Baton Rouge City Club Distinguished Speaker Series. October 13, 2005. Baton Rouge, LA.

96. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before Powering Up: A Discussion About the Future of Louisiana's Energy Industry. Special Lecture Series Sponsored by the Kean Miller Law Firm. October 13, 2005. Baton Rouge, LA.

97. "The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Special Lecture on Hurricane Impacts, LSU Center for Energy Studies, September 29, 2005.

98. "Louisiana Power Industry Overview." Presentation before the Clean Air Interstate Rule Implementation Stakeholders Meeting. August 11, 2005. Louisiana Department of Environmental Quality.

99. "CES 2005 Legislative Support and Outlook for Energy Markets and Policy." Presentation before the LMOGA/LCA Annual Post-Session Legislative Committee Meeting. August 10-13, 2005. Perdido Key, Florida.

100. "Electric Restructuring: Past, Present, and Future." Presentation to the Southeastern Association of Tax Administrators Annual Conference. Sheraton Hotel and Conference Facility. New Orleans, LA July 12, 2005.

101. "The Outlook for Energy." Lagniappe Studies Continuing Education Course. Baton Rouge, LA. July 11, 2005.

102. "The Outlook for Energy." Sunshine Rotary Club. Baton Rouge, LA. April 27, 2005.

103. "Background and Overview of LNG Development." Energy Council Workshop on LNG/CNG. Biloxi, Ms: Beau Rivage Resort and Hotel, April 9, 2005.

104. "Natural Gas Supply, Prices, and LNG: Implications for Louisiana Industry." Cytec Corporation Community Advisory Panel. Fortier, LA January 14, 2005.

105. "The Economic Opportunities for a Limited Industrial Retail Choice Plan." Louisiana Department of Economic Development. Baton Rouge, Louisiana. November 19, 2004.

106. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Association of Business and Industry, Energy Council Meeting. Baton Rouge, Louisiana. October 11, 2004.

107. "Energy Issues for Industrial Customers of Gas and Power." Annual Meeting of the Louisiana Chemical Association and the Louisiana Chemical Industry Alliance. Point Clear, Alabama. October 8, 2004.

108. "Energy Issues for Industrial Customers of Gas and Power." American Institute of Chemical Engineers – New Orleans Section. New Orleans, LA. September 22, 2004.

109. "Natural Gas Supply, Prices and LNG: Implications for Louisiana Industry." Dow Chemical Company Community Advisory Panel Meeting. Plaquemine, LA. August 9, 2004.

110. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Chemical Association Post-Legislative Meeting. Springfield, LA. August 9, 2004.

111. "LNG In Louisiana." Joint Meeting of the Louisiana Economic Development Council and the Governors Cabinet Advisory Council. Baton Rouge, LA. August 5, 2004.

112. "Louisiana Energy Issues." Louisiana Mid-Continent Oil and Gas Association Post Legislative Meetings. Sandestin, Florida. July 28, 2004.

113. "The Gulf South: Economic Opportunities Related to LNG." Presentation before the Energy Council's 2004 State and Provincial Energy and Environmental Trends Conference. Point Clear, AL, June 26, 2004.

114. "Natural Gas and LNG Issues for Louisiana." Presentation before the Rhodia Community Advisory Panel. May 20, 2004, Baton Rouge, LA.

115. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association Plant Managers Meeting. May 27, 2004. Baton Rouge, LA.

116. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association/Louisiana Chemical Industry Alliance Legislative Conference. May 26, 2004. Baton Rouge, LA.

117. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Petrochemical Industry Cluster, Greater New Orleans, Inc. May 19, 2004, Destrehan, LA.

118. "Industry Development Issues for Louisiana: LNG, Retail Choice, and Energy." Presentation before the LSU Center for Energy Studies Industry Associates. May 14, 2004, Baton Rouge, LA.

119. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Board of Directors, Greater New Orleans, Inc. May 13, 2004, New Orleans, LA.

120. "Natural Gas Outlook: Trends and Issues for Louisiana." Presentation before the Louisiana Joint Agricultural Association Meetings. January 14, 2004, Hotel Acadiana, Lafayette, Louisiana.

121. "Natural Gas Outlook" Presentation before the St. James Parish Community Advisory Panel Meeting. January 7, 2004, IMC Production Facility, Convent, Louisiana.

122. "Competitive Bidding in the Electric Power Industry." Presentation before the Association of Energy Engineers. Business Energy Solutions Expo. December 11-12, 2003, New Orleans, Louisiana.

123. "Regional Transmission Organization in the South: The Demise of SeTrans" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. December 9, 2003. Baton Rouge, Louisiana.

124. "Affordable Energy: The Key Component to a Strong Economy." Presentation before the National Association of Regulatory Utility Commissioners ("NARUC"), November 18, 2003, Atlanta, Georgia.

125. "Natural Gas Outlook." Presentation before the Louisiana Chemical Association, October 17, 2003, Pointe Clear, Alabama.

126. "Issues and Opportunities with Distributed Energy Resources." Presentation before the Louisiana Biomass Council. April 17, 2003, Baton Rouge, Louisiana.

127. "What's Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. November 12, 2002. Baton Rouge, Louisiana.

128. "An Introduction to Distributed Energy Resources." Presentation before the U.S. Department of Energy, Office of Renewable Energy and Energy Efficiency, State Energy Program/Rebuild America Conference, August 1, 2002, New Orleans, Louisiana.

129. "Merchant Energy Development Issues in Louisiana." Presentation before the Program Committee of the Center for Legislative, Energy, and Environmental Research (CLEER), Energy Council. April 19, 2002.

130. "Power Plant Siting Issues in Louisiana." Presentation before 24th Annual Conference on Waste and the Environment. Sponsored by the Louisiana Department of Environmental Quality. Lafayette, Louisiana, Cajundome. March 12, 2002.

131. "Merchant Power and Deregulation: Issues and Impacts." Presentation before the Air and Waste Management Association Annual Meeting. Baton Rouge, LA, November 15, 2001.

132. "Moving to the Front of the Lines: The Economic Impact of Independent Power Production in Louisiana." Presentation before the LSU Center for Energy Studies Merchant Power Generation and Transmission Conference, Baton Rouge, LA. October 11, 2001.

133. "Economic Impacts of Merchant Power Plant Development in Mississippi." Presentation before the U.S. Oil and Gas Association Annual Oil and Gas Forum. Jackson, Mississippi. October 10, 2001.

134. "Economic Opportunities for Merchant Power Development in the South." Presentation before the Southern Governor's Association/Southern State Energy Board Meetings. Lexington, KY. September 9, 2001.

135. "The Changing Nature of the Electric Power Business in Louisiana." Presentation before the Louisiana Department of Environmental Quality. Baton Rouge, LA, August 27, 2001.

136. "Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Interagency Group on Merchant Power Development . Baton Rouge, LA, July 16, 2001.

137. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Office of the Governor. Baton Rouge, LA, July 16, 2001.

138. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Department of Economic Development. Baton Rouge, LA, July 3, 2001.

139. "The Economic Impacts of Merchant Power Plant Development In Mississippi." Presentation before the Mississippi Public Service Commission. Jackson, Mississippi, March 20, 2001.

140. "Energy Conservation and Electric Restructuring." With Ritchie D. Priddy. Presentation before the Louisiana Department of Natural Resources. Baton Rouge, Louisiana, October 23, 2000.

141. "Pricing and Regulatory Issues Associated with Distributed Energy." Joint Conference by Econ One Research, Inc., the Louisiana State University Distributed Energy Resources Initiative, and the University of Houston Energy Institute: "Is the Window Closing for Distributed Energy?" Houston, Texas, October 13, 2000.

142. "Electric Reliability and Merchant Power Development Issues." Technical Meetings of the Louisiana Public Service Commission. Baton Rouge, LA. August 29, 2000.

143. "A Introduction to Distributed Energy Resources." Summer Meetings, Southeastern Association of Regulatory Utility Commissioners (SEARUC). New Orleans, LA. June 27, 2000.

144. Roundtable Moderator/Discussant. Mid-South Electric Reliability Summit. U.S. Department of Energy. New Orleans, Louisiana. April 24, 2000.

145. "Electricity 101: Definitions, Precedents, and Issues." Energy Council's 2000 Federal Energy and Environmental Matters Conference. Loews L'Enfant Plaza Hotel, Washington, D.C. March 11-13, 2000.

146. "LSU/CES Distributed Energy Resources Initiatives." Los Alamos National Laboratories. Office of Energy and Sustainable Systems. Los Alamos, New Mexico. February 16, 2000.

147. "Distributed Energy Resources Initiatives." Louisiana State University, Center for Energy Studies Industry Associates Meeting. Baton Rouge, Louisiana. December 15, 1999.

148. "Merchant Power Opportunities in Louisiana." Louisiana Mid-Continent Oil and Gas Association (LMOGA) Power Generation Committee Meetings. Baton Rouge, Louisiana. November 10, 1999.

149. Roundtable Discussant. "Environmental Regulation in a Restructured Market" The Big E: How to Successfully Manage the Environment in the Era of Competitive Energy. PUR Conference. New Orleans, Louisiana. May 24, 1999.

150. "The Political Economy of Electric Restructuring In the South" Southeastern Electric Exchange, Rate Section Annual Conference. New Orleans, Louisiana. May 7, 1999.

151. "The Dynamics of Electric Restructuring in Louisiana." Joint Meeting of the American Association of Energy Engineers and the International Association of Facilities Managers. Metairie, Louisiana. April 29, 1999.

152. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Lafayette, Louisiana, March 24, 1999.

153. "What's Happened to Electricity Restructuring in Louisiana?" Louisiana State University, Center for Energy Studies Industry Associates Meeting. March 22, 1999.

154. "A Short Course on Electric Restructuring." Central Louisiana Electric Company. Sales and Marketing Division. Mandeville, Louisiana, October 22, 1998.

155. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Shreveport, Louisiana, October 13, 1998.

156. "How Will Utility Deregulation Affect Tourism." Louisiana Travel Promotion Association Annual Meeting, Alexandria, Louisiana. January 15, 1998.

157. "Reflections and Predictions on Electric Utility Restructuring in Louisiana." With Fred I. Denny. Louisiana State University, Center for Energy Studies Industry Associates Meeting. November 20, 1997.

158. "Electric Utility Restructuring in Louisiana." Hammond Chamber of Commerce, Hammond, Louisiana. October 30, 1997.

159. "Electric Utility Restructuring." Louisiana Association of Energy Engineers. Baton Rouge, Louisiana. September 11, 1997.

160. "Electric Utility Restructuring: Issues and Trends for Louisiana." Opelousas Chamber of Commerce, Opelousas, Louisiana. June 24, 1997.

161. "The Electric Utility Restructuring Debate In Louisiana: An Overview of the Issues." Annual Conference of the Public Affairs Research Council of Louisiana. Baton Rouge, Louisiana. March 25, 1997.

162. "Electric Restructuring: Louisiana Issues and Outlook for 1997." Louisiana State University, Center for Energy Studies Industry Associates Meeting, Baton Rouge, Louisiana, January 15, 1997.

163. "Restructuring the Electric Utility Industry." Louisiana Propane Gas Association Annual Meeting, Alexandria, Louisiana, December 12, 1996.

164. "Deregulating the Electric Utility Industry." Eighth Annual Economic Development Summit, Baton Rouge, Louisiana, November 21, 1996.

165. "Electric Utility Restructuring in Louisiana." Jennings Rotary Club, Jennings, Louisiana, November 19, 1996.

166. "Electric Utility Restructuring in Louisiana." Entergy Services, Transmission and Distribution Division, Energy Centre, New Orleans, Louisiana, September 12, 1996

167. "Electric Utility Restructuring" Louisiana Electric Cooperative Association, Baton Rouge, Louisiana, August 27, 1996.

168. "Electric Utility Restructuring -- Background and Overview." Louisiana Public Service Commission, Baton Rouge, Louisiana, August 14, 1996.

169. "Electric Utility Restructuring." Sunshine Rotary Club Meetings, Baton Rouge, Louisiana, August 8, 1996.

170. Roundtable Moderator, "Stakeholder Perspectives on Electric Utility Stranded Costs." Louisiana State University, Center for Energy Studies Seminar on Electric Utility Restructuring in Louisiana, Baton Rouge, May 29, 1996.

171. Panelist, "Deregulation and Competition." American Nuclear Society: Second Annual Joint Louisiana and Mississippi Section Meetings, Baton Rouge, Louisiana, April 20, 1996.

EXPERT WITNESS, LEGISLATIVE, AND PUBLIC TESTIMONY; EXPERT REPORTS, RECOMMENDATIONS, AND AFFIDAVITS

1. Expert Testimony. Docket No. 2013-00168 (2014). Before the Maine Public Utilities Commission. In the Matter of the Request for Approval of an Alternative Rate Plan (ARP 2014) Pertaining to Central Maine Power Company. On behalf of the Office of the Public Advocate. Issues: class cost of service study, marginal cost of service study, revenue distribution and rate design.

2. Expert Testimony. Docket No. 13-115 (2013). Before the Delaware Public Service Commission. In the Matter of the Application of Delmarva Power & Light Company FOR an Increase in Electric Base Rates and Miscellaneous Tariff Changes (Filed March 22, 2013). On the Behalf of Division of the Public Advocate. Issues: pro forma infrastructure proposal, class cost of service study, revenue distribution, and rate design.

3. Expert Testimony. Formal Case No. 1103 (2013). Before the Public Service Commission of the District of Columbia. In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for

Electric Distribution Service. On the Behalf of the Office of the People's Counsel of the District of Columbia. Issues: Pro forma adjustment for reliability investments.

4. Expert Testimony. Case No. 9326 (2013). Before the Public Service Commission of Maryland. In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates. On the Behalf of the Maryland Office of the People's Counsel. Issues: Electric Reliability Investment ("ERI") initiatives, pro forma gas infrastructure proposal, tracker mechanisms, class cost of service study, revenue distribution, and rate design

5. Rulemaking Testimony. (2013). Before the Louisiana Tax Commission. Examination of Louisiana Assessors' Association Well Diameter Analysis, economic development policies regarding midstream assets and industrial development.

6. Expert Testimony. Case No. 9317 (2013). Before the Public Service Commission of Maryland. In the Matter of the Application of Delmarva Power & Light Company for Adjustments to its Retail Rates for the Distribution of Electric Energy. Direct, and Surrebuttal. On the Behalf of the Maryland Office of the People's Counsel. Issues: Grid Resiliency Charge, tracker mechanisms, pipeline replacement, class cost of service study, revenue distribution, and rate design.

7. Expert Testimony. Case No. 9311 (2013). Before the Public Service Commission of Maryland. In the Matter of the Application of Potomac Electric Power Company for an Increase in its Retail Rates for the Distribution of Electric Energy. Direct, and Surrebuttal. On the Behalf of the Maryland Office of the People's Counsel. Issues: Grid Resiliency Charge, tracker mechanisms, pipeline replacement, class cost of service study, revenue distribution, and rate design.

8. Expert Testimony. Docket No. 12AL-1268G (2013). Before the Public Utilities Commission of the State of Colorado. In the Matter of the Tariff Sheets Filed by Public Service Company of Colorado with Advice No. 830 – Gas. Answer. On the Behalf of the Colorado Office of Consumer Counsel. Issues: Pipeline System Integrity Adjustment, tracker mechanisms, pipeline replacement and leak rate comparisons.

9. Expert Testimony. BPU Docket No. EO12080721 (2013). Before the New Jersey Board of Public Utilities. In the Matter of the Public Service Electric & Gas Company for Approval of an Extension of Solar Generation Program. On the Behalf of the New Jersey Division of Rate Counsel. Direct, Rebuttal, Surrebuttal. Issues: solar energy market design, solar energy market conditions, solar energy program design and net economic benefits.

10. Expert Testimony. BPU Docket No. EO12080726 (2013). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Loan III Program. On the Behalf of the New Jersey Division of Rate Counsel. Direct, Rebuttal and Surrebuttal. Issues: solar energy market design, solar energy market conditions, solar energy program design.

11. Expert Testimony. BPU Docket No. EO11050314V. (2012). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Fishermen's Atlantic City Windfarm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates. On the Behalf of the New Jersey Division of Rate Counsel. December 17, 2012. Issues: approval of offshore wind project and ratepayer financial support for the proposed project.

12. Expert Testimony. D.P.U. 12-25. (2012). Before the Massachusetts Department of Public Utilities. In the Matter of Bay State Gas Company d/b/a/ Columbia Gas Company of Massachusetts Request for Increase in Rates. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Target infrastructure replacement program rider, pipeline replacement and leak rate comparisons.

13. Expert Testimony. Docket Nos. UE-120436, et.al. (consolidated). (2012). Before the Washington Utilities and Transportation Commission. Washington Utilities and Transportation Commission v. Avista Corporation D/B/A Avista Utilities. On the Behalf of the Washington Attorney General, Office of the Public Counsel. Issues: Revenue Decoupling, lost revenues, tracker mechanisms, attrition adjustments.

14. Expert Testimony. Case No. 9286. (2012) Before the Public Service Commission of Maryland. In Re: Potomac Electric Power Company ("Pepco") General Rate Case. On the Behalf of the Maryland Office of the People's Counsel. Issues: Capital tracker mechanisms/reliability investment mechanisms, reliability issues, regulatory lag, class cost of service, revenue distribution, rate design.

15. Expert Testimony. Case No 9285. (2012) Before the Public Service Commission of Maryland. In Re: the Delmarva Power and Light Company General Rate Case. On the Behalf of the Maryland Office of the People's Counsel. Issues: Capital tracker mechanisms/reliability investment mechanisms, reliability issues, regulatory lag, class cost of service, revenue distribution, rate design.

16. Expert Testimony. Docket Nos. UE-110876 and UG-110877 (consolidated). (2012). Before the Washington Utilities and Transportation Commission. Washington Utilities and Transportation Commission v. Avista Corporation D/B/A Avista Utilities. On the Behalf of the Washington Attorney General, Office of the Public Counsel. Issues: Revenue Decoupling, lost revenues, tracker mechanisms.

17. Expert Testimony. BPU Docket No. EO11050314V. (2012). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Fishermen's Atlantic City Windfarm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates. On the Behalf of the New Jersey Division of Rate Counsel. February 3, 2012. Issues: approval of offshore wind project and ratepayer financial support for the proposed project.

18. Expert Testimony. Docket No. NG 0067. (2012). Before the Public Service Commission of Nebraska. In the Matter of the Application of SourceGas Distribution, LLC Approval of a General Rate Increase. On the Behalf of the Public Advocate. January 31, 2012.

Issues: Revenue Decoupling, Customer Adjustments, Weather Normalization Adjustments, Class Cost of Service Study, Rate Design.

19. Expert Testimony. Docket No. G-04204A-11-0158. (2011). Before the Arizona Corporation Commission. On the Behalf of the Arizona Corporation Commission Staff. In the Matter of the Application of UNS Gas, Inc. for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of Its Arizona Properties. Issues: Revenue Decoupling; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

20. Expert Testimony. Formal Case Number 1087. (2011). Before the Public Service Commission of the District of Columbia. On the Behalf of the Office of the People's Counsel of the District of Columbia. In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service. Issues: Regulatory lag, ratemaking principles, reliability-related capital expenditure tracker proposals.

21. Expert Affidavit. Case No. 11-1364. (2011). *The State of Louisiana, the Louisiana Department of Environmental Quality, and the Louisiana Public Service Commission v. United States Environmental Protection Agency and Lisa P. Jackson.* Before the United States Court of Appeals for the District of Columbia Circuit. On the behalf of the State of Louisiana, the Louisiana Department of Environmental Quality, and the Louisiana Public Service Commission. Issues: Impacts of environmental costs on electric utilities, compliance requirements, investment cost of mitigation equipment, multi-area dispatch modeling and plant retirements.

22. Expert Affidavit. Docket No. EPA-HQ-OAR-2009-0491. (2011). Before the U.S. Environmental Protection Agency. Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals. On the Behalf of the Louisiana Public Service Commission. Issues: Impacts of environmental costs on electric utilities, compliance requirements, investment cost of mitigation equipment, multi-area dispatch modeling and plant retirements.

23. Expert Testimony. Case No. 9296. (2011). Before the Maryland Public Service Commission. On the Behalf of the Maryland Office of People's Counsel. In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges and Revise its Terms and Conditions for Gas Service. Issues: Infrastructure Cost Recovery Rider; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

24. Expert Testimony. Docket No. G-01551A-10-0458. (2011). Before the Arizona Corporation Commission. On the Behalf of the Arizona Corporation Commission Staff. In the Matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of its Properties throughout Arizona. Issues: Revenue Decoupling; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

25. Expert Testimony. Docket No. 11-0280 and 11-0281. (2011). Before the Illinois Commerce Commission. On the Behalf of the Illinois Attorney General, the Citizens Utility Board, and the City of Chicago, Illinois. In re: Peoples Gas Light and Coke Company and North Shore Natural Gas Company. Issues: Revenue Decoupling and Rate Design. (Direct and Rebuttal)

26. Expert Testimony. D.P.U. 11-01. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Petition of the Fitchburg Electric and Gas Company (Electric Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. Issues: Capital Cost Rider, Revenue Decoupling.

27. Expert Testimony. D.P.U. 11-02. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Petition of the Fitchburg Electric and Gas Company (Gas Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. Issues: Pipeline Replacement Rider, Revenue Decoupling.

28. Expert Affidavit. Docket No. EL-11-13 (2011). Before the Federal Energy Regulatory Commission. Petition for Preliminary Ruling, Atlantic Grid Operations. On the Behalf of the New Jersey Division of Rate Counsel. Issues: Offshore wind generation development, offshore wind transmission development, ratemaking treatment of development costs, transmission development incentives.

29. Expert Opinion. Case No. CI06-195. (2011). Before the District Court of Jefferson County, Nebraska. On the Behalf of the City of Fairbury, Nebraska and Michael Beachler. In re: Endicott Clay Products Co. vs. City of Fairbury, Nebraska and Michael Beachler. Issues: rate design and ratemaking, time of use and time differentiated rate structures, empirical analysis of demand and usage trends for tariff eligibility requirements.

30. Expert Testimony. D.P.U. 10-114. (2010). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Petition of the New England Gas Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. Issues: infrastructure replacement rider.

31. Expert Testimony. D.P.U. 10-70. (2010). Before the Massachusetts Department of Public Utilities. Petition of the Western Massachusetts Electric Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure replacement rider; performance-based regulation; inflation adjustment mechanisms; and rate design.

32. Expert Testimony. G.U.D. Nos. 998 & 9992. (2010). Before the Texas Railroad Commission. In the Matter of the Rate Case Petition of Texas Gas Services, Inc. On the Behalf of the City of El Paso, Texas. Issues: Cost of service, revenue distribution, rate

design, and weather normalization.

33. Expert Testimony. B.P.U Docket No. GR10030225. (2010). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of New Jersey Natural Gas Company for Approval of Regional Greenhouse Gas Initiative Programs and Associated Cost Recovery Mechanisms Pursuant to N.J.S.A. 48:3-98.1. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy proposals, solar securitization issues, solar energy policy issues.

34. Expert Testimony. D.P.U. 10-55. (2010). Before the Massachusetts Department of Public Utilities. Investigation Into the Propriety of Proposed Tariff Changes for Boston Gas Company, Essex Gas Company, and Colonial Gas Company. (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; pipeline-replacement rider; performance-based regulation; partial productivity factor estimates, inflation adjustment mechanisms; and rate design.

35. Expert Testimony. Cause No.43839. (2010). Before the Indiana Utility Regulatory Commission. In the Matter of Southern Indiana Gas and Electric Company d/b/a/ Vectren Energy Delivery of Indiana, Inc. (Vectren South-Electric). On the behalf of the Indiana Office of Utility Consumer Counselor (OUCC). Issues: revenue decoupling, variable production cost riders, gains on off-system sales, transmission cost riders.

36. Congressional Testimony. Before the United States Congress. (2010). U.S. House of Representatives, Committee on Natural Resources. Hearing on the Consolidated Land, Energy, and Aquatic Resources Act. June 30, 2010.

37. Expert Testimony. Before the City Counsel of El Paso, Texas; Public Utility Regulatory Board. (2010). On the Behalf of the City of El Paso. In Re: Rate Application of Texas Gas Services, Inc. Issues: class cost of service study (minimum system and zero intercept analysis), rate design proposals, weather normalization adjustment, and its cost of service adjustment clause, conservation adjustment clause proposals, and other cost tracker policy issues.

38. Expert Testimony. Docket 09-00183. (2010). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Chattanooga Gas Company for a General Rate Increase, Implementation of the EnergySMART Conservation Programs, and Implementation of a Revenue Decoupling Mechanism. On the Behalf of Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling and energy efficiency program review and cost effectiveness analysis.

39. Expert Testimony and Exhibits. Docket No. 10-240. (2010). Before the Louisiana Office of Conservation. In Re: Cadeville Gas Storage, LLC. On the Behalf of Cardinal Gas Storage, LLC. Issues: alternative uses and relative economic benefits of conversion of depleted hydrocarbon reservoir for natural gas storage purposes.

40. Expert Testimony. Docket No. 09505-EI. (2010). Before the Florida Public Service

Commission. In Re: Review of Replacement Fuel Costs Associated with the February 26, 2008 outage on Florida Power & Light's Electrical System. On the Behalf of the Florida Office of Public Counsel for the Citizens of the State of Florida. Issues: Replacement costs for power outage, regulatory policy/generation development incentives, renewable and energy efficiency incentives.

41. Expert Testimony. Docket 09-00104. (2009). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Piedmont Natural Gas Company, Inc. to Implement a Margin Decoupling Tracker Rider and Related Energy Efficiency and Conservation Programs. On the Behalf of the Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling, energy efficiency program review, weather normalization.

42. Expert Testimony. Docket Number NG-0060. (2009). Before the Nebraska Public Service Commission. In the Matter of SourceGas Distribution, LLC Approval for a General Rate Increase. On the Behalf of the Nebraska Public Advocate. October 29, 2009. Issues: revenue decoupling, inflation trackers, infrastructure replacement riders, customer adjustment rider, weather normalization rider, weather normalization adjustments, estimation of normal weather for ratemaking purposes.

43. Expert Report and Deposition. Before the 23rd Judicial District Court, Parish of Assumption, State of Louisiana. On the Behalf of Dow Hydrocarbons and Resources, Inc. September 1, 2009. (Deposition, November 23-24, 2009). Issues: replacement and repair costs for underground salt cavern hydrocarbon storage.

44. Expert Testimony. D.P.U. 09-39. Before the Massachusetts Department of Public Utilities. (2009). Investigation Into the Propriety of Proposed Tariff Changes for Massachusetts Electric Company and Nantucket Electric Company (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure rider; performance-based regulation; inflation adjustment mechanisms; revenue distribution; and rate design.

45. Expert Testimony. D.P.U. 09-30. Before the Massachusetts Department of Public Utilities. (2009). In the Matter of Bay State Gas Company Request for Increase in Rates. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; target infrastructure replacement program rider; revenue distribution; and rate design.

46. Expert Testimony. Docket EO09030249. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of a Solar Loan II Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design, renewable portfolio standards, solar energy, and renewable financing/loan program design.

47. Expert Testimony. Docket EO0920097. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Verified Petition of Rockland Electric Company for Approval

of an SREC-Based Financing Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design; renewable energy portfolio standards; solar energy.

48. Expert Rebuttal Report. Civil Action No.: 2:07-CV-2165. (2009). Before the U.S. District Court, Western Division of Louisiana, Lake Charles Division. Prepared on the Behalf of the Transcontinental Pipeline Corporation. Issues: expropriation and industrial use of property.

49. Expert Testimony. Docket EO06100744. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Atlantic City Electric Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

50. Expert Testimony. Docket EO08090840. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Jersey Central Power & Light Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

51. Expert Testimony. Docket UG-080546. (2008). Before the Washington Utilities and Transportation Commission. On the Behalf of the Washington Attorney General (Public Counsel Section). Issues: Rate Design, Cost of Service, Revenue Decoupling, Weather Normalization.

52. Congressional Testimony. (2008). Senate Republican Conference: Panel on Offshore Drilling in the Restricted Areas of the Outer Continental Shelf. September 18, 2008.

53. Expert Testimony. Appeal Number 2007-125 and 2007-299. (2008). Before the Louisiana Tax Commission. On the Behalf of Jefferson Island Storage and Hub, LLC (AGL Resources). Issues: Valuation Methodologies, Underground Storage Valuation, LTC Guidelines and Policies, Public Purpose of Natural Gas Storage. July 15, 2008 and August 20, 2008.

54. Expert Testimony. Docket Number 07-057-13. (2008). Before the Utah Public Service Commission. In the Matter of the Application of Questar Gas Company to File a General Rate Case. On the Behalf of the Utah Committee of Consumer Services. Issues: Cost of Service, Rate Design. August 18, 2008 (Direct, Rebuttal, Surrebuttal).

55. Rulemaking Testimony. (2008). Before the Louisiana Tax Commission. Examination of

Replacement Cost Tables, Depreciation and Useful Lives for Oil and Gas Properties. Chapter 9 (Oil and Gas Properties) Section. August 5, 2008.

56. Legislative Testimony. (2008). Examination of Proposal to Change Offshore Natural Gas Severance Taxes (HB 326 and Amendments). Joint Finance and Appropriations Committee of the Alabama Legislature. March 13, 2008.

57. Public Testimony. (2007). Issues in Environmental Regulation. Testimony before Gubernatorial Transition Committee on Environmental Regulation (Governor-Elect Bobby Jindal). December 17, 2007.

58. Public Testimony. (2007). Trends and Issues in Alternative Energy: Opportunities for Louisiana. Testimony before Gubernatorial Transition Committee on Natural Resources (Governor-Elect Bobby Jindal). December 13, 2007.

59. Expert Report and Recommendation: Docket Number S-30336 (2007). Before the Louisiana Public Service Commission. In re: Entergy Gulf States, Inc. Application for Approval of Advanced Metering Pilot Program. Issues: pilot program for demand response programs and advanced metering systems.

60. Expert Testimony. Docket EO07040278 (2007). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Energy Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: renewable energy market development, solar energy development, SREC markets, rate impact analysis, cost recovery issues.

61. Expert Testimony: Docket Number 05-057-T01 (2007). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Direct, Rebuttal, and Surrebuttal Testimony)

62. Expert Testimony (Non-sworn rulemaking testimony) Docket Number RR-2008, (2007). Before the Louisiana Tax Commission. In re: Commission Consideration of Amendment and/or Adoption of Tax Commission Real/Personal Property Rules and Regulations. Issues: Louisiana oil and natural gas production trends, appropriate cost measures for wells and subsurface property, economic lives and production decline curve trends.

63. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29213 & 29213-A, ex parte, (2007). Before the Louisiana Public Service Commission. In re: In re: Investigation to determine if it is appropriate for LPSC jurisdictional electric utilities to provide and install time-based meters and communication devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: demand response

programs, advanced meter systems, cost recovery issues, energy efficiency issues, regulatory issues.

64. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29712, ex parte, (2007) Before the Louisiana Public Service Commission. In re: Investigation into the ratemaking and generation planning implications of nuclear construction in Louisiana. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: nuclear cost power plant development, generation planning issues, and cost recovery issues.

65. Expert Testimony, Case Number U-14893, (2006). Before the Michigan Public Service Commission. In the Matter of SEMCO Energy Gas Company for Authority to Redesign and Increase Its Rates for the Sale and Transportation of Natural Gas In its MPSC Division and for Other Relief. On the behalf of the Michigan Attorney General. Issues: Rate Design, revenue decoupling, financial analysis, demand-side management program and energy efficiency policy. (Direct and Rebuttal Testimony).

66. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29380, ex parte, (2006). Before the Louisiana Public Service Commission. In re: An Investigation Into the Ratemaking and Generation Planning Implications of the U.S. EPA Clean Air Interstate Rule. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: environmental regulation and cost recovery; allowance allocations and air credit markets; ratepayer impacts of new environmental regulations.

67. Expert Affidavit Before the Louisiana Tax Commission (2006). On behalf of ANR Pipeline, Tennessee Gas Transmission and Southern Natural Gas Company. Issues: Competitive nature of interstate and intrastate transportation services.

68. Expert Affidavit Before the 19th Judicial District Court (2006). Suit Number 491, 453 Section 26. On behalf of Transcontinental Pipeline Corporation, et.al. Issues: Competitive nature of interstate and intrastate transportation services.

69. Expert Testimony: Docket Number 05-057-T01 (2006). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Rebuttal and Supplemental Rebuttal Testimony)

70. Legislative Testimony (2006). Senate Committee on Natural Resources. Senate Bill 655 Regarding Remediation of Oil and Gas Sites, Legacy Lawsuits, and the Deterioration of State Drilling.

71. Expert Report: Rulemaking Docket (2005). Before the New Jersey Bureau of Public Utilities. In re: Proposed Rulemaking Changes Associated with New Jersey's Renewable Portfolio Standard. Expert Report. The Economic Impacts of New Jersey's Proposed Renewable Portfolio Standard. On behalf of the New Jersey Office of

Ratepayer Advocate. Issues: Renewable Portfolio Standards, rate impacts, economic impacts, technology cost forecasts.

72. Expert Testimony: Docket Number 2005-191-E. (2005). Before the South Carolina Public Service Commission. On behalf of NewSouth Energy LLC. In re: General Investigation Examining the Development of RFP Rules for Electric Utilities. Issues: Competitive bidding; merchant development. (Direct and Rebuttal Testimony).

73. Expert Testimony: Docket No. 05-UA-323. (2005). Before the Mississippi Public Service Commission. On the behalf of Calpine Corporation. In re: Entergy Mississippi's Proposed Acquisition of the Attala Generation Facility. Issues: Asset acquisition; merchant power development; competitive bidding.

74. Expert Testimony: Docket Number 050045-EI and 050188-EI. (2005). Before the Florida Public Service Commission. On the behalf of the Citizens of the State of Florida. In re: Petition for Rate Increase by Florida Power & Light Company. Issues: Load forecasting; O&M forecasting and benchmarking; incentive returns/regulation.

75. Expert Testimony (non-sworn, rulemaking): Comments on Decreased Drilling Activities in Louisiana and the Role of Incentives. (2005). Louisiana Mineral Board Monthly Docket and Lease Sale. July 13, 2005

76. Legislative Testimony (2005). Background and Impact of LNG Facilities on Louisiana. Joint Meeting of Senate and House Natural Resources Committee. Louisiana Legislature. May 19, 2005.

77. Public Testimony. Docket No. U-21453. (2005). Technical Conference before the Louisiana Public Service Commission on an Investigation for a Limited Industrial Retail Choice Plan.

78. Expert Testimony: Docket No. 2003-K-1876. (2005). On Behalf of Columbia Gas Transmission. Expert Testimony on the Competitive Market Structure for Gas Transportation Service in Ohio. Before the Ohio Board of Tax Appeals.

79. Expert Report and Testimony: Docket No. 99-4490-J, *Lafayette City-Parish Consolidated Government, et. al. v. Entergy Gulf States Utilities, Inc. et. al*. (2005, 2006). On behalf of the City of Lafayette, Louisiana and the Lafayette Utilities Services. Expert Rebuttal Report of the Harborfront Consulting Group Valuation Analysis of the LUS Expropriation. Filed before 15th Judicial District Court, Lafayette, Louisiana.

80. Expert Testimony: ANR Pipeline Company v. Louisiana Tax Commission (2005), Number 468,417 Section 22, 19th Judicial District Court, Parish of East Baton Rouge, State of Louisiana Consolidated with Docket Numbers: 480,159; 489,776;480,160; 480,161; 480,162; 480,163; 480,373; 489,776; 489,777; 489,778;489,779; 489,780; 489,803; 491,530; 491,744; 491,745; 491,746; 491,912;503,466; 503,468; 503,469; 503,470; 515,414; 515,415; and 515,416. In re: Market structure issues and competitive implications of tax differentials and valuation methods in natural gas transportation

markets for interstate and intrastate pipelines.

81. Expert Report and Recommendation: Docket No. U-27159. (2004). On Behalf of the Louisiana Public Service Commission Staff. Expert Report on Overcharges Assessed by Network Operator Services, Inc. Before the Louisiana Public Service Commission.

82. Expert Testimony: Docket Number 2004-178-E. (2004). Before the South Carolina Public Service Commission. On behalf of Columbia Energy LLC. In re: Rate Increase Request of South Carolina Electric and Gas. (Direct and Surrebuttal Testimony)

83. Expert Testimony: Docket Number 040001-EI. (2004). Before the Florida Public Service Commission. On behalf of Power Manufacturing Systems LLC, Thomas K. Churbuck, and the Florida Industrial Power Users Group. In re: Fuel Adjustment Proceedings; Request for Approval of New Purchase Power Agreements. Company examined: Florida Power & Light Company.

84. Expert Affidavit: Docket Number 27363. (2004). Before the Public Utilities Commission of Texas. Joint Affidavit on Behalf of the Cities of Texas and the Staff of the Public Utilities Commission of Texas Regarding Certified Issues. In Re: Application of Valor Telecommunications, L.P. For Authority to Establish Extended Local Calling Service (ELCS) Surcharges For Recovery of ELCS Surcharge.

85. Expert Report and Testimony. Docket 1997-4665-PV, 1998-4206-PV, 1999-7380-PV, 2000-5958-PV, 2001-6039-PV, 2002-64680-PV, 2003-6231-PV. (2003) Before the Kansas Board of Tax Appeals. (2003). In the Matter of the Appeals of CIG Field Services Company from orders of the Division of Property Valuation. On the Behalf of CIG Field Services. Issues: the competitive nature of natural gas gathering in Kansas.

86. Expert Report and Testimony: Docket Number U-22407. Before the Louisiana Public Service Commission (2002). On the Behalf of the Louisiana Public Service Commission Staff. Company examined: Louisiana Gas Services, Inc. Issues: Purchased Gas Acquisition audit, fuel procurement and planning practices.

87. Expert Testimony: Docket Number 000824-EI. Before the Florida Public Service Commission. (2002). On the Behalf of the Citizens of the State of Florida. Company examined: Florida Power Corporation. Issues: Load Forecasts and Billing Determinants for the Projected Test Year.

88. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic Impacts of Merchant Power Generation.

89. Expert Testimony: Docket Number 24468. (2001). On the Behalf of the Texas Office of Public Utility Counsel. Public Utility Commission of Texas Staff's Petition to Determine Readiness for Retail Competition in the Portion of Texas Within the Southwest Power Pool. Company examined: AEP-SWEPCO.

90. Expert Report. (2001) On Behalf of David Liou and Pacific Richland Products, Inc. to

Review Cogeneration Issues Associated with Dupont Dow Elastomers, L.L.C. (DDE) and the Dow Chemical Company (Dow).

91. Expert Testimony: Docket Number 01-1049, Docket Number 01-3001. (2001) On behalf the Nevada Office of Attorney General, Bureau of Consumer Protection. Petition of Central Telephone Company-Nevada D/b/a Sprint of Nevada and Sprint Communications L.P. for Review and Approval of Proposed Revised Performance Measures and Review and Approval of Performance Measurement Incentive Plans. Before the Public Utilities Commission of Nevada.

92. Expert Affidavit: Multiple Dockets (2001). Before the Louisiana Tax Commission. On the Behalf of Louisiana Interstate Pipeline Companies. Testimony on the Competitive Nature of Natural Gas Transportation Services in Louisiana.

93. Expert Affidavit before the Federal District Court, Middle District of Louisiana (2001). Issues: Competitive Nature of the Natural Gas Transportation Market in Louisiana. On behalf of a Consortium of Interstate Natural Gas Transportation Companies.

94. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic and Ratepayer Benefits of Merchant Power Generation and Issues Associated with Tax Incentives on Merchant Power Generation and Transmission.

95. Expert Testimony: Docket Number 01-1048 (2001). Before the Public Utilities Commission of Nevada. On the Behalf of the Nevada Office of the Attorney General, Bureau of Consumer Protection. Company analyzed: Nevada Bell Telephone Company. Issues: Statistical Issues Associated with Performance Incentive Plans.

96. Expert Testimony: Docket 22351 (2001). Before the Public Utility Commission of Texas. On the Behalf of the City of Amarillo. Company analyzed: Southwestern Public Service Company. Issues: Unbundled cost of service, affiliate transactions, load forecasting.

97. Expert Testimony: Docket 991779-EI (2000). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Competitive Nature of Wholesale Markets, Regional Power Markets, and Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

98. Expert Testimony: Docket 990001-EI (1999). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

99. Expert Testimony: Docket 950495-WS (1996). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Company analyzed:

Southern States Utilities, Inc. Issues: Revenue Repression Adjustment, Residential and Commercial Demand for Water Service.

100. Legislative Testimony. Louisiana House of Representatives, Special Subcommittee on Utility Deregulation. (1997). On Behalf of the Louisiana Public Service Commission Staff. Issue: Electric Restructuring.

101. Expert Testimony: Docket 940448-EG -- 940551-EG (1994). Before the Florida Public Service Commission. On the Behalf of the Legal Environmental Assistance Foundation. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Comparison of Forecasted Cost-Effective Conservation Potentials for Florida.

102. Expert Testimony: Docket 920260-TL, (1993). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: BellSouth Communications, Inc. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

103. Expert Testimony: Docket 920188-TL, (1992). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: GTE-Florida. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

REFEREE AND EDITORIAL APPOINTMENTS

Referee, 2010-Current, *Economics of Energy & Environmental Policy*
Referee, 1995-Current, *Energy Journal*
Contributing Editor, 2000-2005, *Oil, Gas and Energy Quarterly*
Referee, 2005, *Energy Policy*
Referee, 2004, *Southern Economic Journal*
Referee, 2002, *Resource & Energy Economics*
Committee Member, IAEE/USAEE Student Paper Scholarship Award Committee, 2003

PROPOSAL TECHNICAL REVIEWER

California Energy Commission, Public Interest Energy Research (PIER) Program (1999).

PROFESSIONAL ASSOCIATIONS

American Economic Association, American Statistical Association, Southern Economic Association, Western Economic Association, International Association of Energy Economists (IAEE), Unites States Association of Energy Economics and the National Association for Business Economics (NABE).

HONORS AND AWARDS

National Association of Regulatory Utility Commissioners (NARUC). Best Paper Award for papers published in the *Journal of Applied Regulation* (2004).

Baton Rouge Business Report, Selected as "Top 40 Under 40" (2003).

Omicron Delta Epsilon (1992-Current)

Interstate Oil and Gas Compact Commission (IOGCC) "Best Practice" Award for Research on the Economic Impact of Oil and Gas Activities on State Leases for the Louisiana Department of Natural Resources (2003).

Distinguished Research Award, Academy of Legal, Ethical and Regulatory Issues, Allied Academics (2002).

Florida Public Service Commission, Staff Excellence Award for Assistance in the Analysis of Local Exchange Competition Legislation (1995).

TEACHING EXPERIENCE

Energy and the Environment (Survey Course)
Principles of Microeconomic Theory
Principles of Macroeconomic Theory

Lecturer, Environmental Management and Permitting. Lecture in Natural Gas Industry, LNG and Markets.

Lecturer, Electric Power Industry Environmental Issues, Field Course on Energy and the Environment. (Dept of Environmental Studies).

Lecturer, Electric Power Industry Trends, Principles Course in Power Engineering (Dept. of Electric Engineering).

Lecturer, LSU Honors College, Senior Course on "Society and the Coast."

Continuing Education. Electric Power Industry Restructuring for Energy Professionals.

"The Gulf Coast Energy Situation: Outlook for Production and Consumption." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, New Orleans, LA, December 2, 2004

"The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Educational Course and Lecture Prepared for the Foundation for American

Communications and the Society for Professional Journalists, Houston, TX, September 13, 2005.

"Forecasting for Regulators: Current Issues and Trends in the Use of Forecasts, Statistical, and Empirical Analyses in Energy Regulation." Instructional Course for State Regulatory Commission Staff. Institute of Public Utilities, Kellogg Center, Michigan State University. July 8-9, 2010.

"Regulatory and Ratemaking Issues with Cost and Revenue Trackers." Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 29, 2010.

"Demand Modeling and Forecasting for Regulators." Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 30, 2010.

"Demand Modeling and Forecasting for Regulators." Michigan State University, Institute of Public Utilities, Forecasting Workshop, Charleston, SC. March 7-9, 2011.

"Regulatory and Cost Recovery Approaches for Smart Grid Applications." Michigan State University, Institute of Public Utilities, Smart Grid Workshop for Regulators. Charleston, SC. March 7-11, 2011.

"Regulatory and Ratemaking Issues Associated with Cost and Expense Adjustment Mechanisms." Michigan State University, Institute of Public Utilities, Advanced Regulatory Studies Program. Lansing, Michigan. September 28, 2011.

"Utility Incentives, Decoupling, and Renewable Energy Programs." Michigan State University, Institute of Public Utilities, Advanced Regulatory Studies Program. Lansing, Michigan. September 29, 2011.

"Regulatory and Cost Recovery Approaches for Smart Grid Applications." Michigan State University, Institute of Public Utilities, Smart Grid Workshop for Regulators. Charleston, SC. March 6-8, 2012.

"Traditional and Incentive Ratemaking Workshop." New Mexico Public Utilities Commission Staff. Santa Fe, NM October 18, 2012.

"Traditional and Incentive Ratemaking Workshop." New Jersey Board of Public Utilities Staff. Newark, NJ. March 1, 2013.

THESIS/DISSERTATIONS COMMITTEES

Active:
2 Thesis Committee Memberships (Environmental Studies)
1 Ph.D. Dissertation Committee (Economics)

Completed:
6 Thesis Committee Memberships (Environmental Studies, Geography)
4 Doctoral Committee Memberships (Information Systems & Decision Sciences, Agricultural and Resource Economics, Economics, Education and Workforce Development).
2 Doctoral Examination Committee Membership (Information Systems & Decision Sciences, Education and Workforce Development)
1 Senior Honors Thesis (Journalism, Loyola University)

LSU SERVICE AND COMMITTEE MEMBERSHIPS

Co-Director/Steering Committee Member, LSU Coastal Marine Institute (2009-Current).

CES Promotion Committee, Division of Radiation Safety (2006).

Search Committee Chair (2006), Research Associate 4 Position.

Search Committee Member (2005), Research Associate 4 Position.

Search Committee Member (2005), CES Communications Manager.

LSU Graduate Research Faculty, Associate Member (1997-2004); Full Member (2004-2010); Affiliate Member with Full Directional Rights (2011-current).

LSU Faculty Senate (2003-2006).

Conference Coordinator. (2005-Current) Center for Energy Studies Conference on Alternative Energy.

LSU CES/SCE Public Art Selection Committee (2003-2005).

Conference Coordinator. Center for Energy Studies Annual Energy Conference/Summit. (2003-Current).

Conference Coordinator. Center for Energy Studies Seminar Series on Electric Utility Restructuring and Wholesale Competition. (1996-2003).

Co-Chairman, Review Committee, Louisiana Port Construction and Development Priority Program Rules and Regulations, On Behalf of the LSU Ports and Waterways Institute. (1997).

LSU Main Campus Cogeneration/Turbine Project, (1999-2000).

LSU InterCollege Environmental Cooperative. (1999-2001).

LSU Faculty Senate Committee on Public Relations (1997-1999).

LSU Faculty Senate Committee on Student Retention and Recruitment (1999-2003).

PROFESSIONAL SERVICE

Advisor (2008). National Association of Regulatory Utility Commissioners ("NARUC"). Study Committee on the Impact of Executive Drilling Moratoria on Federal Lands.

Steering Committee Member, Louisiana Representative (2008-Current). Southeast Agriculture & Forestry Energy Resources Alliance. Southern Policies Growth Board.

Advisor (2007-Current). National Association of State Utility Consumer Advocates ("NASUCA"), Natural Gas Committee.

Program Committee Chairman (2007-2008). U.S. Association of Energy Economics ("USAEE") Annual Conference, New Orleans, LA

Finance Committee Chairman (2007-2008). USAEE Annual Conference, New Orleans, LA

Committee Member (2006), International Association for Energy Economics ("IAEE") Nominating Committee.

Founding President (2005-2007) Louisiana Chapter, USAEE.

Secretary (2001) Houston Chapter, USAEE.

Advisor, Louisiana LNG Buyers/Developers Summit, Office of the Governor/Louisiana Department of Economic Development/Louisiana Department of Natural Resources, and Greater New Orleans, Inc. (2004).

Table of Exhibits

Comparison of Green Mountain Power's Alternative Regulation Plans

	2007-2009 Plan	2010-2013 Plan	Proposed 2014-2018 Plan
Rate Adjustment Frequency	(1) annual base rate filings; (2) quarterly power cost adjustments; (3) annual earnings reconciliation adjustments	(1) annual base rate filings; (2) quarterly power cost adjustments; (3) annual earnings reconciliation adjustments	(1) annual base rate filings; (2) annual power cost adjustments; (3) annual earnings reconciliation adjustments
Adjustment to Authorized ROE to Reflect Lower Risk	50 bps	50 bps	None
Rate Design	Base rate and earnings sharing adjustments are reflected as a uniform percentage change to customers' bills, and the Power Adjustor is reflected as a kWh charge. All three adjustments are implemented on a bills-rendered basis.	Base rate and earnings sharing adjustments are reflected as a uniform percentage change to customers' bills, and the Power Adjustor is reflected as a kWh charge. All three adjustments are implemented on a bills-rendered basis.	Base rate and earnings sharing adjustments are reflected as a uniform percentage change to customers' bills, and the Power Adjustor is reflected as a kWh charge. All three adjustments are implemented on a service-rendered basis.
Incorporates Service Quality/Reliability Performance	Yes	No. The SQRP is treated as a stand-alone document that may be amended on its own without requiring an amendment to the ARP.	No. The SQRP is treated as a stand-alone document that may be amended on its own without requiring an amendment to the ARP.
Annual Base Rate Filings			
Loads and Revenues	Based on forecast for the year rates would be in effect.	Based on forecast for the year rates would be in effect.	Based on forecast for the year rates would be in effect.
Adjustments for Operating Costs	Increases capped at $1.25 million (2008) and $1.5 million (2009)	Increases capped by a percentage tied to the rate of inflation ("CPI-NE") and further adjusted by a benchmarked productivity factor.	Increases capped by a percentage tied to the rate of inflation ("CPI-U Northeast") and further adjusted by a benchmarked productivity factor.
Adjustment to ROE	Reflects 50% of the difference between the average 10-year Treasury note yield to maturity (a) as of the last 20 trading days prior to October 15 before the filing, and (b) the later of the last 20 trading days prior to October 15 of the previous year or the last 20 trading days prior to the last day of evidentiary hearings.	Reflects 50% difference between the average 10-year Treasury note yield to maturity (a) as of the last 20 trading days ending 2 weeks before the annual filing and (b) as of the 20 trading day period used for the last adjustment to the ROE component. Thereafter the ROE would receive an additional "ROE Performance Adjustment" of up to 50 basis points (upward/downward) depending on benchmarked efficiency.	Reflects 50% difference between the average 10-year Treasury note yield to maturity (a) as of the last 20 trading days ending 2 weeks before the annual filing and (b) as of the 20 trading day period used for the last adjustment to the ROE component. Thereafter the ROE would receive an additional "ROE Performance Adjustment" of up to 50 basis points (upward/downward) depending on benchmarked efficiency.

Comparison of Green Mountain Power's Alternative Regulation Plans

	2007-2009 Plan	2010-2013 Plan	Proposed 2014-2018 Plan
Incentive Adjustment	None	The size of the incentive adjustment would vary depending on the Company's rank within the benchmark peer group and the quintile corresponding to that rank: 1st Quintile (top 4 utilities), 1.00%; 2nd Quintile, 0.75%; 3rd Quintile, 0.50%; 4th Quintile, 0.25%, and 5th Quintile, 0%.	The size of the incentive adjustment would vary depending on the Company's rank within the benchmark peer group and the quartile corresponding to that rank: 1st Quartile (top five utilities), 0.75%; 2nd Quartile, 0.50%; 3rd Quartile, 0.25%; 4th Quartile, 0%.
ROE Performance Adjustment	None	The ROE Performance Adjustment is determined using the same benchmark peer group ranking system employed in adjusting the Company's operating cost cap, but with a different corresponding adjustment scale: 1st Quintile (top four utilities), 0.50%; 2nd Quintile, 0.25%; 3rd Quintile, 0%; 4th Quintile, -0.25%; 5th Quintile, -0.50%.	The ROE Performance Adjustment is determined using the same benchmark peer group ranking system employed in adjusting the Company's operating cost cap, but with a different corresponding adjustment scale: 1st Quartile (top five utilities), 0.25%; 2nd Quartile, 0%; 3rd Quartile, 0%; 4th Quartile, -0.25%.
Increases in Base Rates Cap	2% annually	Limited to an amount equal to the operating costs included in the previous base rate adjustment plus (1) inflation ("CPI-NE") less a 1% productivity factor, subject to an "incentive adjustment" reflecting the Company's operating efficiency relative to an efficiency "benchmark" set by reference to a peer group of utilities, and (2) return, taxes and depreciation on incremental plant investment, efficiency spending and preliminary survey costs.	Limited to an amount equal to the operating costs included in the previous base rate adjustment plus (1) inflation ("CPI-NE") less a 1% productivity factor, subject to an "incentive adjustment" reflecting the Company's operating efficiency relative to an efficiency "benchmark" set by reference to a peer group of utilities, and (2) return, taxes and depreciation on incremental plant investment, efficiency spending and preliminary survey costs.
Allowance for Exogenous Changes	Base Rate Adjustment can be exceeded to reflect Exogenous Changes, cost or revenue changes in excess of $600K relating to certain specified events that are outside the Company's control.	Base Rate Adjustment can be exceeded to reflect Exogenous Changes, cost or revenue changes in excess of $600K relating to certain specified events that are outside the Company's control.	Base Rate Adjustment can be exceeded to reflect Exogenous Non-Storm Changes, cost or revenue changes in excess of $1.2 million relating to certain specified events that are outside the Company's control. Exogenous Storm Changes include increased costs relating to incremental maintenance expenses incurred for Major Storms and are subject to the annual minimum applied to Exogenous Non-Storm Changes. In the event that the Company has not exceeded the amount of storm costs included in base rates, Exogenous Storm Changes will be reduced by the difference. Over/under collections shall be deferred and included in the next base rate adjustment.

Comparison of Green Mountain Power's Alternative Regulation Plans

	2007-2009 Plan	2010-2013 Plan	Proposed 2014-2018 Plan
Quarterly Power Adjustments			
Passed Through Power Costs	"Committed Costs" related to capacity, transmission, and ancillary service charges. 90% of "Non-Committed Cost" changes greater than $300,000 ("Power Efficiency Band").	"Committed Costs" related to capacity, transmission, and ancillary service charges. 90% of "Non-Committed Cost" changes greater than $300,000 ("Power Efficiency Band").	"Committed Costs" related to capacity, transmission, and ancillary service charges. Quarterly Power Adjustment changed to annually. 90% of "Non-Committed Cost" changes greater than $615,000 ("Power Efficiency Band").
Cap	Subject to a quarterly cap of $10/MWh with any differences deferred to the next quarter.	Subject to a quarterly cap of $10/MWh with any differences deferred to the next quarter.	None
Earnings Sharing			
Deadband	75 bps above and below authorized return.	75 bps above and below authorized return.	75 bps above and below authorized return.
Earnings Sharing Band	There is a 50/50 sharing of earnings shortfalls between 75 and 125 basis points below the target return.	There is a 50/50 sharing of earnings shortfalls between 75 and 125 basis points below the target return.	There is a 50/50 sharing of earnings shortfalls between 75 and 125 basis points below the target return.

Sources: In the Matter of Petition of Green Mountain Power Corporation for Approval of an Alternative-Regulation Plan, Before the State of Vermont Public Service Board, Docket No. 7176, Order dated December 22, 2006; In the Matter of Petition of Green Mountain Power Corporation for Approval of an Alternative Regulation Plan (Plan II), Before the State of Vermont Public Service Board, Docket No. 7585, Order Dated April 16, 2010; Direct Testimony of Christopher Cole.

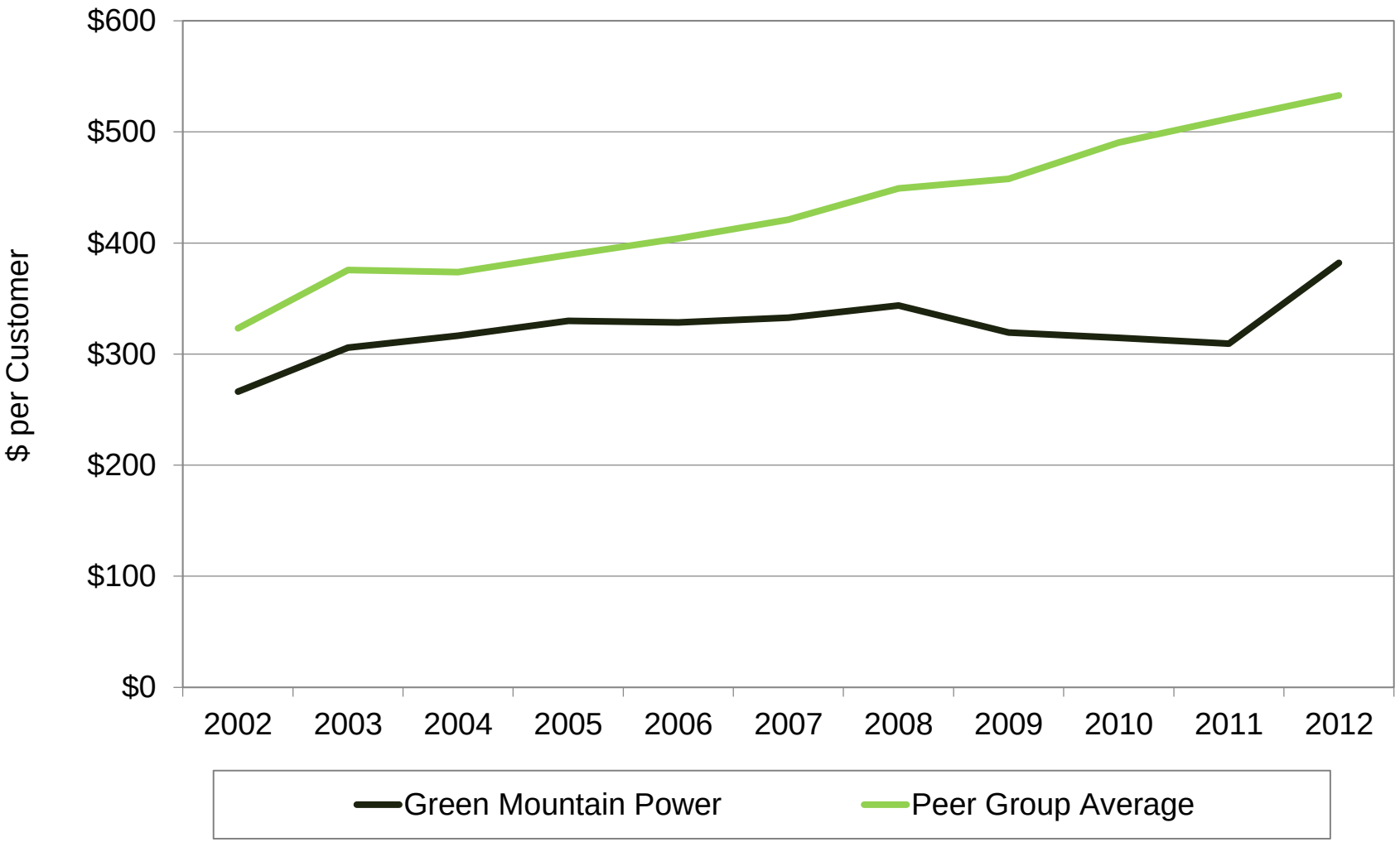
Peer Group Cost per Customer - Aggregate Operating Cost

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	($/Customer)										
Green Mountain Power Corporation	**$266.18**	**$305.75**	**$316.45**	**$329.99**	**$328.42**	**$332.80**	**$343.71**	**$319.42**	**$314.63**	**$309.33**	**$382.17**
Bangor Hydro Electric Company	272.63	245.21	230.00	218.24	177.45	185.16	207.41	218.51	248.16	215.25	272.78
Black Hills Power, Inc.	346.59	382.41	422.19	496.83	457.96	445.91	497.88	541.84	563.78	605.43	641.34
ALLETE, Inc.	525.74	630.42	647.37	659.69	723.13	671.12	881.98	712.65	818.21	890.03	880.81
Central Hudson Gas & Electric Corporation	264.52	313.01	276.56	272.34	358.57	424.79	464.18	553.65	652.08	697.41	716.57
Fitchburg Gas and Electric Light Company	298.68	344.12	341.92	342.81	351.63	343.25	392.93	447.20	427.83	502.42	545.16
Granite State Electric Company	262.92	293.83	243.85	193.43	272.81	311.44	324.03	360.44	317.75	374.92	470.68
Madison Gas and Electric Company	307.12	358.07	357.12	345.59	377.00	387.53	432.52	415.68	470.26	471.26	509.08
MDU Resources Group, Inc.	275.81	308.12	352.63	342.51	334.83	335.20	344.03	310.85	324.10	340.52	331.44
Northern States Power Company (Wisconsin)	322.33	340.99	364.66	360.46	395.52	404.23	407.78	437.20	494.73	525.82	534.75
Otter Tail Power Company	442.68	471.24	483.53	544.93	557.93	568.82	597.26	570.77	614.30	604.05	607.42
Public Service Company of New Hampshire	260.84	291.00	304.84	329.89	334.02	372.86	393.34	433.00	449.26	446.40	457.03
Rochester Gas and Electric Corporation	502.06	594.83	392.42	412.79	394.68	434.29	427.57	473.91	519.55	506.65	516.33
Rockland Electric Company	425.82	473.08	480.01	561.57	581.82	557.29	646.28	653.82	652.63	709.46	722.38
The Empire District Electric Company	265.63	300.79	321.40	325.35	325.20	406.39	377.84	399.72	448.18	485.63	504.87
The United Illuminating Company	471.46	497.19	506.78	525.28	577.52	606.87	625.46	667.40	708.24	745.51	668.93
Unitil Energy Systems, Inc.	-	236.34	230.66	231.59	225.14	226.25	229.55	215.11	255.29	274.30	298.57
Upper Peninsula Power Company	339.67	428.55	487.05	518.22	528.40	558.59	529.94	570.24	545.50	543.58	488.85
Western Massachusetts Electric Company	291.41	323.27	343.73	385.57	374.58	425.20	411.79	398.24	492.87	477.96	574.13
Peer Group Average	**323.27**	**$375.70**	**$373.85**	**$389.32**	**$404.03**	**$420.95**	**$449.23**	**$457.88**	**$490.39**	**$511.89**	**$532.80**
% Difference from Mean	**-18%**	**-19%**	**-15%**	**-15%**	**-19%**	**-21%**	**-23%**	**-30%**	**-36%**	**-40%**	**-28%**

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	(Rank)										
Green Mountain Power Corporation	**6**	**6**	**6**	**7**	**5**	**4**	**4**	**4**	**3**	**3**	**4**
Bangor Hydro Electric Company	7	2	1	2	1	1	1	2	1	1	1
Black Hills Power, Inc.	14	13	14	14	14	14	14	13	14	15	15
ALLETE, Inc.	19	19	19	19	19	19	19	19	19	19	19
Central Hudson Gas & Electric Corporation	4	8	4	4	9	11	13	14	16	16	17
Fitchburg Gas and Electric Light Company	10	11	8	9	8	6	7	11	6	10	12
Granite State Electric Company	3	4	3	1	3	3	3	5	4	5	6
Madison Gas and Electric Company	11	12	11	10	11	8	12	8	9	7	9
MDU Resources Group, Inc.	8	7	10	8	7	5	5	3	5	4	3
Northern States Power Company (Wisconsin)	12	10	12	11	13	9	9	10	11	12	11
Otter Tail Power Company	16	15	16	17	16	17	16	16	15	14	14
Public Service Company of New Hampshire	2	3	5	6	6	7	8	9	8	6	5
Rochester Gas and Electric Corporation	18	18	13	13	12	13	11	12	12	11	10
Rockland Electric Company	15	16	15	18	18	15	18	17	17	17	18
The Empire District Electric Company	5	5	7	5	4	10	6	7	7	9	8
The United Illuminating Company	17	17	18	16	17	18	17	18	18	18	16
Unitil Energy Systems, Inc.	1	1	2	3	2	2	2	1	2	2	2
Upper Peninsula Power Company	13	14	17	15	15	16	15	15	13	13	7
Western Massachusetts Electric Company	9	9	9	12	10	12	10	6	10	8	13

Note: For purposes of this analysis, “best performing observation” is defined as the average of the lowest observed unit cost for each year. This comparison has been provided to identify the most significant possible unit cost improvement possible based upon the observed sample data during the 2002-2012 time period.

Peer Group Cost per Customer - Aggregate Operating Cost



Peer Group Cost per MWh - Aggregate Operating Cost

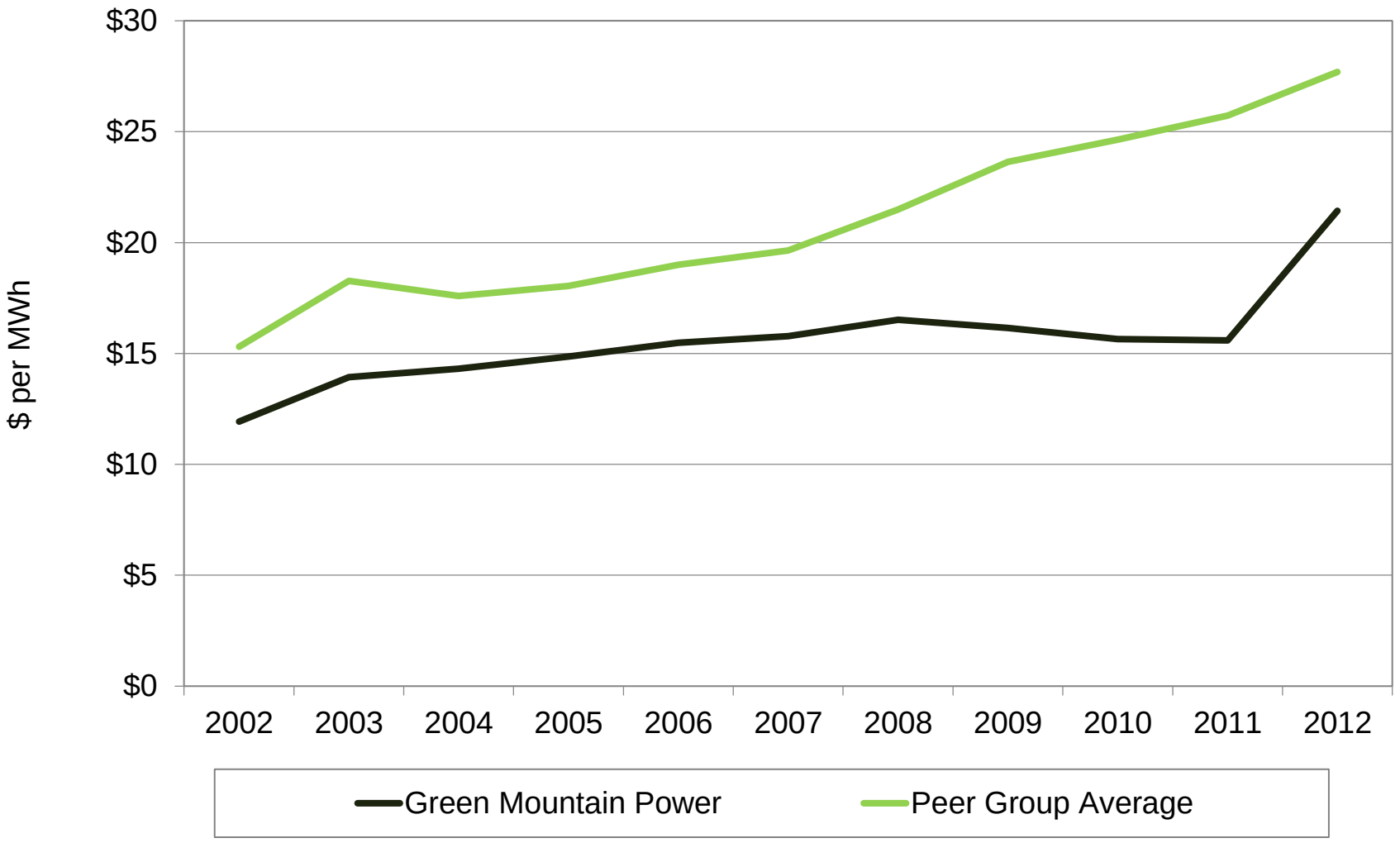
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	($/MWh)										
Green Mountain Power Corporation	**$ 11.93**	**$ 13.93**	**$ 14.31**	**$ 14.86**	**$ 15.48**	**$ 15.78**	**$ 16.53**	**$ 16.15**	**$ 15.65**	**$ 15.60**	**$ 21.44**
Bangor Hydro Electric Company	21.58	20.59	19.04	17.58	14.99	15.56	17.92	19.16	21.60	19.27	24.56
Black Hills Power, Inc.	13.68	15.12	17.32	19.83	18.02	17.31	19.62	22.01	23.07	24.07	25.71
ALLETE, Inc.	7.93	10.01	9.86	10.01	11.09	10.49	13.66	15.97	13.66	13.77	13.43
Central Hudson Gas & Electric Corporation	15.51	20.04	18.22	18.47	25.83	26.22	35.90	47.05	55.99	61.87	67.61
Fitchburg Gas and Electric Light Company	16.04	18.32	17.25	18.66	19.44	20.09	24.07	28.78	26.26	30.63	36.38
Granite State Electric Company	12.58	13.77	11.39	9.72	14.86	19.20	20.86	24.77	21.71	25.95	34.40
Madison Gas and Electric Company	12.81	15.37	15.26	14.22	15.81	15.91	18.10	18.19	19.86	19.85	21.65
MDU Resources Group, Inc.	14.11	15.28	17.99	16.77	16.03	15.45	15.65	14.25	14.38	14.88	14.33
Northern States Power Company (Wisconsin)[1]	12.96	13.61	14.68	14.66	16.35	16.24	16.63	18.10	20.39	20.50	20.77
Otter Tail Power Company	15.21	16.14	16.38	17.95	18.00	17.82	18.20	17.38	18.62	18.19	18.55
Public Service Company of New Hampshire	15.77	17.07	18.05	19.47	20.24	22.52	24.46	27.56	28.44	28.45	29.22
Rochester Gas and Electric Corporation	28.21	38.10	20.03	19.57	19.74	20.67	21.48	24.23	26.07	25.54	26.35
Rockland Electric Company	19.44	21.50	21.62	23.11	25.07	23.64	27.88	29.80	28.16	30.87	31.96
The Empire District Electric Company	9.57	10.90	11.74	11.39	11.34	14.19	13.27	14.72	15.62	17.14	18.50
The United Illuminating Company	26.12	27.69	27.40	27.59	31.37	33.14	35.43	39.47	40.11	43.28	39.64
Unitil Energy Systems, Inc.	-	14.09	13.76	13.64	13.56	13.58	14.23	13.90	15.89	17.17	19.14
Upper Peninsula Power Company	22.40	29.45	33.03	36.45	34.27	33.60	32.39	35.37	35.44	34.97	30.29
Western Massachusetts Electric Company	14.91	16.23	16.99	18.98	19.43	21.96	22.10	22.32	27.18	26.69	32.23
Peer Group Average	**$ 15.30**	**$ 18.27**	**$ 17.60**	**$ 18.05**	**$ 19.00**	**$ 19.65**	**$ 21.49**	**$ 23.64**	**$ 24.64**	**$ 25.72**	**$ 27.69**
% Difference from Mean	**-22%**	**-24%**	**-19%**	**-18%**	**-18%**	**-20%**	**-23%**	**-32%**	**-36%**	**-39%**	**-23%**

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	(Rank)										
Green Mountain Power Corporation	**4**	**5**	**5**	**7**	**6**	**6**	**5**	**5**	**4**	**3**	**7**
Bangor Hydro Electric Company	16	15	15	9	5	5	7	9	9	7	9
Black Hills Power, Inc.	8	7	11	16	11	9	10	10	11	10	10
ALLETE, Inc.	2	1	1	2	1	1	2	4	1	1	1
Central Hudson Gas & Electric Corporation	12	14	14	11	17	17	19	19	19	19	19
Fitchburg Gas and Electric Light Company	14	13	10	12	13	12	14	15	13	15	17
Granite State Electric Company	5	4	2	1	4	11	11	13	10	12	16
Madison Gas and Electric Company	6	9	7	5	7	7	8	8	7	8	8
MDU Resources Group, Inc.	9	8	12	8	8	4	4	2	2	2	2
Northern States Power Company (Wisconsin)	7	3	6	6	9	8	6	7	8	9	6
Otter Tail Power Company	11	10	8	10	10	10	9	6	6	6	4
Public Service Company of New Hampshire	13	12	13	14	15	15	15	14	16	14	12
Rochester Gas and Electric Corporation	19	19	16	15	14	13	12	12	12	11	11
Rockland Electric Company	15	16	17	17	16	16	16	16	15	16	14
The Empire District Electric Company	3	2	3	3	2	3	1	3	3	4	3
The United Illuminating Company	18	17	18	18	18	18	18	18	18	18	18
Unitil Energy Systems, Inc.	1	6	4	4	3	2	3	1	5	5	5
Upper Peninsula Power Company	17	18	19	19	19	19	17	17	17	17	13
Western Massachusetts Electric Company	10	11	9	13	12	14	13	11	14	13	15

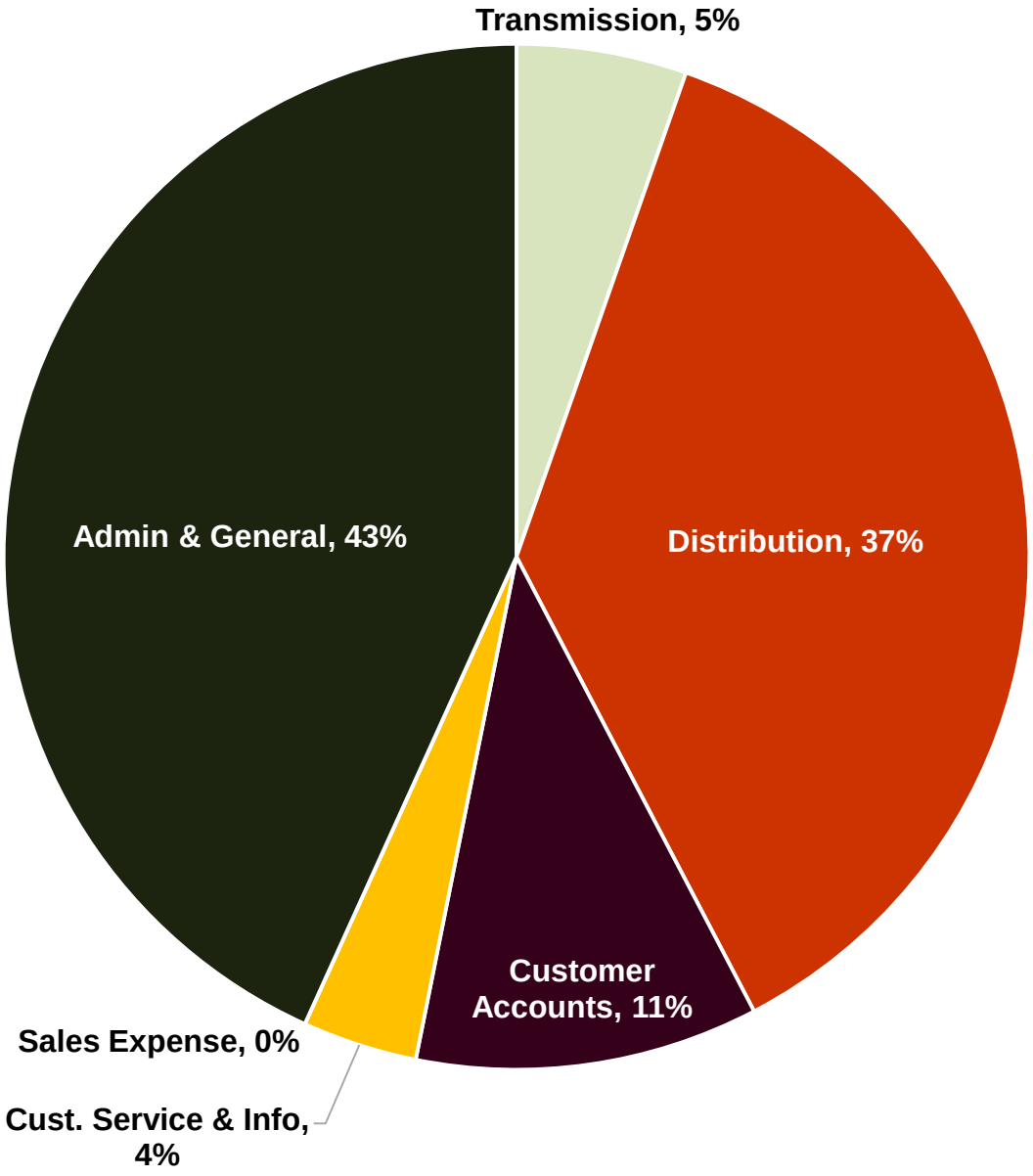
[1]Northern States Power Company (Wisconsin) FERC Form 1 contains no data for account (565).

Note: For purposes of this analysis, “best performing observation” is defined as the average of the lowest observed unit cost for each year. This comparison has been provided to identify the most significant possible unit cost improvement possible based upon the observed sample data during the 2002-2012 time period.

Peer Group Cost per MWh - Aggregate Operating Cost



Peer Group Cost per Customer - 2012 Aggregate Operating Cost Components



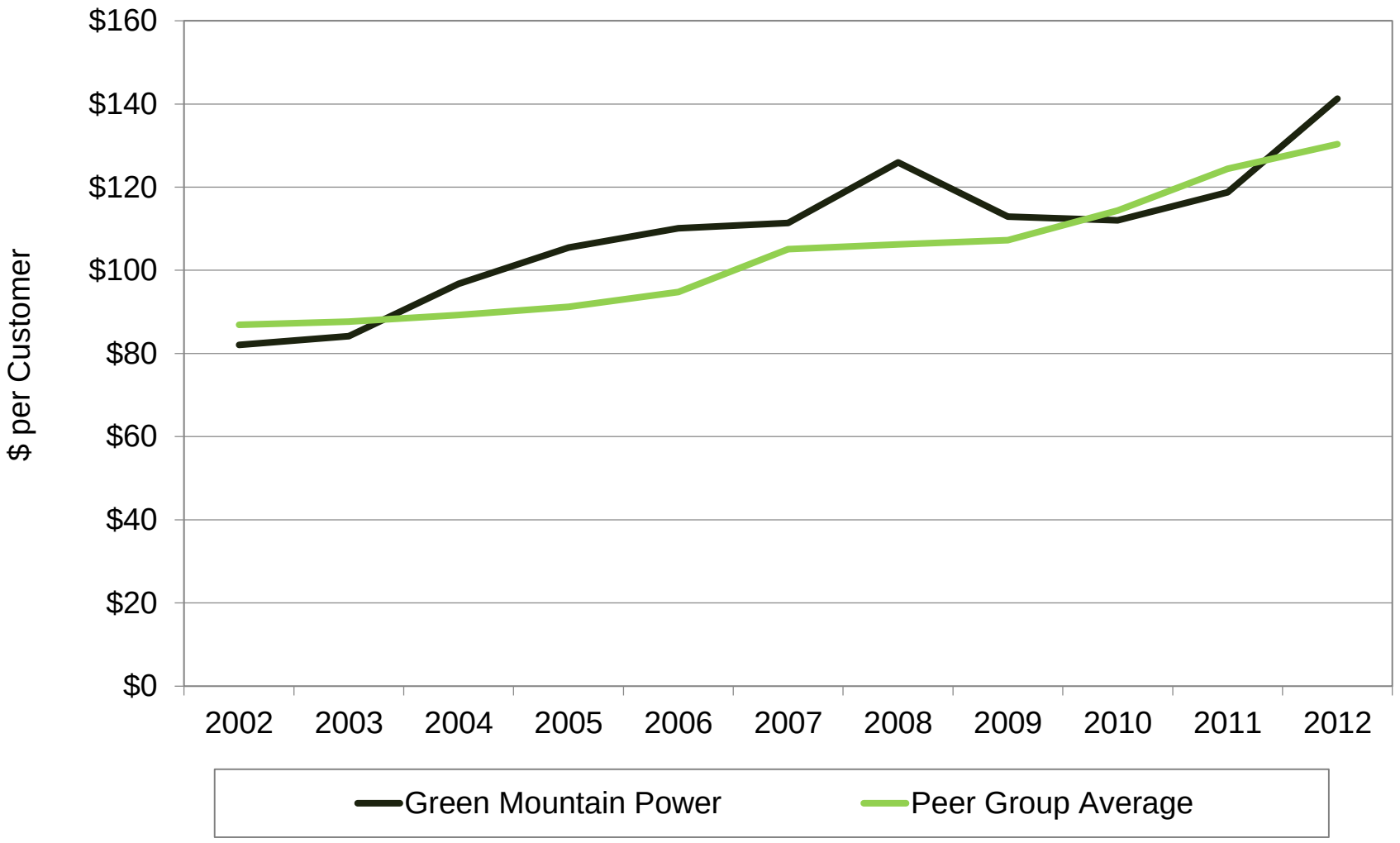
Peer Group Cost per Customer - Operations and Maintenance Expense

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	($/Customer)										
Green Mountain Power Corporation	**$ 82.09**	**$ 84.18**	**$ 96.79**	**$ 105.44**	**$ 110.14**	**$ 111.40**	**$ 125.94**	**$ 112.92**	**$ 112.02**	**$ 118.74**	**$ 141.28**
Bangor Hydro Electric Company	86.12	71.87	67.64	58.57	60.74	64.82	67.08	72.11	71.76	72.02	77.95
Black Hills Power, Inc.	59.49	67.10	61.26	69.01	73.37	71.08	85.82	87.78	93.95	101.40	110.35
ALLETE, Inc.	107.04	108.19	121.37	134.62	137.85	155.01	148.51	145.29	154.69	165.20	173.18
Central Hudson Gas & Electric Corporation	92.02	119.39	81.46	88.62	110.40	104.17	123.97	125.87	149.99	179.28	163.74
Fitchburg Gas and Electric Light Company	66.22	63.48	57.44	62.11	61.08	63.70	68.38	65.23	72.71	89.34	110.51
Granite State Electric Company	87.13	91.43	99.84	73.02	105.88	148.42	135.94	144.07	87.01	139.86	128.89
Madison Gas and Electric Company	62.01	82.65	81.13	72.26	82.49	89.51	93.32	81.58	90.97	95.75	96.48
MDU Resources Group, Inc.	69.70	74.72	82.95	89.38	90.88	94.39	93.23	86.35	86.09	93.07	101.56
Northern States Power Company (Wisconsin)	86.19	72.11	80.10	74.94	76.18	81.10	76.30	74.35	81.64	96.04	88.46
Otter Tail Power Company	65.95	78.63	84.13	92.85	100.89	113.69	114.33	110.89	121.39	116.72	122.51
Public Service Company of New Hampshire	71.30	74.67	73.95	75.44	75.27	86.14	96.85	91.25	101.20	103.68	102.03
Rochester Gas and Electric Corporation	137.16	93.65	88.32	115.04	110.05	94.71	99.13	105.30	152.38	124.34	106.50
Rockland Electric Company	76.53	85.36	113.92	104.02	84.45	101.07	100.85	120.20	136.93	130.38	143.77
The Empire District Electric Company	73.65	76.41	80.18	78.45	86.81	136.10	116.05	137.60	147.08	162.16	155.78
The United Illuminating Company	106.77	99.89	90.25	101.41	108.47	116.49	116.89	112.25	132.24	185.27	219.37
Unitil Energy Systems, Inc.	-	43.54	42.64	45.39	47.21	47.92	50.35	49.72	57.26	77.89	104.13
Upper Peninsula Power Company	137.26	183.75	193.60	191.73	179.92	210.41	199.49	211.49	215.78	215.68	217.40
Western Massachusetts Electric Company	97.50	94.71	98.60	100.97	98.42	106.06	105.56	103.15	108.34	97.41	113.12
Peer Group Average	**$86.90**	**$87.67**	**$89.24**	**$91.23**	**$94.76**	**$105.06**	**$106.21**	**$107.23**	**$114.39**	**$124.43**	**$130.37**
% Difference from Mean	**-6%**	**-4%**	**8%**	**16%**	**16%**	**6%**	**19%**	**5%**	**-2%**	**-5%**	**8%**

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	(Rank)										
Green Mountain Power Corporation	**9**	**11**	**14**	**16**	**16**	**13**	**16**	**13**	**11**	**11**	**13**
Bangor Hydro Electric Company	10	4	4	2	2	3	2	3	2	1	1
Black Hills Power, Inc.	1	3	3	4	4	4	5	7	8	8	8
ALLETE, Inc.	16	17	18	18	18	18	18	18	18	16	17
Central Hudson Gas & Electric Corporation	13	18	9	10	17	11	15	15	16	17	16
Fitchburg Gas and Electric Light Company	4	2	2	3	3	2	3	2	3	3	9
Granite State Electric Company	12	13	16	6	13	17	17	17	6	14	12
Madison Gas and Electric Company	2	10	8	5	7	7	7	5	7	5	3
MDU Resources Group, Inc.	5	7	10	11	10	8	6	6	5	4	4
Northern States Power Company (Wisconsin)	11	5	6	7	6	5	4	4	4	6	2
Otter Tail Power Company	3	9	11	12	12	14	12	11	12	10	11
Public Service Company of New Hampshire	6	6	5	8	5	6	8	8	9	9	5
Rochester Gas and Electric Corporation	17	14	12	17	15	9	9	10	17	12	7
Rockland Electric Company	8	12	17	15	8	10	10	14	14	13	14
The Empire District Electric Company	7	8	7	9	9	16	13	16	15	15	15
The United Illuminating Company	15	16	13	14	14	15	14	12	13	18	19
Unitil Energy Systems, Inc.		1	1	1	1	1	1	1	1	2	6
Upper Peninsula Power Company	18	19	19	19	19	19	19	19	19	19	18
Western Massachusetts Electric Company	14	15	15	13	11	12	11	9	10	7	10

Note: For purposes of this analysis, “best performing observation” is defined as the average of the lowest observed unit cost for each year. This comparison has been provided to identify the most significant possible unit cost improvement possible based upon the observed sample data during the 2002-2012 time period.

Peer Group Cost per Customer - Aggregate Operating Cost



Peer Group Cost per MWh - Operations and Maintenance Expense

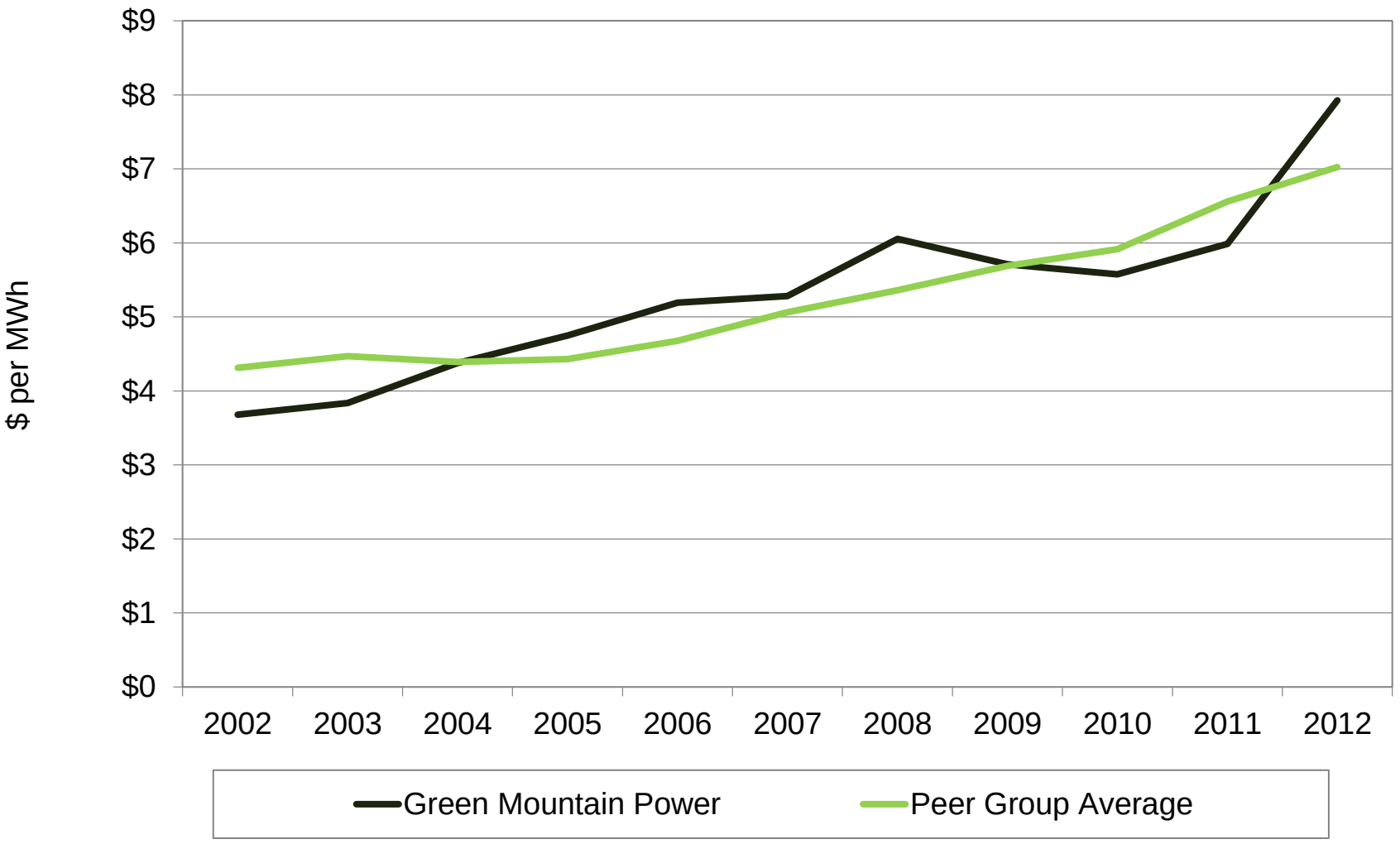
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	($/MWh)										
Green Mountain Power Corporation	**$ 3.68**	**$ 3.84**	**$ 4.38**	**$ 4.75**	**$ 5.19**	**$ 5.28**	**$ 6.06**	**$ 5.71**	**$ 5.57**	**$ 5.99**	**$ 7.92**
Bangor Hydro Electric Company	6.82	6.03	5.60	4.72	5.13	5.45	5.80	6.32	6.25	6.45	7.02
Black Hills Power, Inc.	2.35	2.65	2.51	2.76	2.89	2.76	3.38	3.57	3.84	4.03	4.42
ALLETE, Inc.	1.62	1.72	1.85	2.04	2.11	2.42	2.30	3.26	2.58	2.56	2.64
Central Hudson Gas & Electric Corporation	5.40	7.64	5.37	6.01	7.95	6.43	9.59	10.70	12.88	15.90	15.45
Fitchburg Gas and Electric Light Company	3.56	3.38	2.90	3.38	3.38	3.73	4.19	4.20	4.46	5.45	7.37
Granite State Electric Company	4.17	4.29	4.67	3.67	5.77	9.15	8.75	9.90	5.94	9.68	9.42
Madison Gas and Electric Company	2.59	3.55	3.47	2.97	3.46	3.68	3.90	3.57	3.84	4.03	4.10
MDU Resources Group, Inc.	3.57	3.71	4.23	4.38	4.35	4.35	4.24	3.96	3.82	4.07	4.39
Northern States Power Company (Wisconsin)	3.47	2.88	3.22	3.05	3.15	3.26	3.11	3.08	3.37	3.74	3.44
Otter Tail Power Company	2.27	2.69	2.85	3.06	3.25	3.56	3.48	3.38	3.68	3.52	3.74
Public Service Company of New Hampshire	4.31	4.38	4.38	4.45	4.56	5.20	6.02	5.81	6.41	6.61	6.52
Rochester Gas and Electric Corporation	7.71	6.00	4.51	5.45	5.50	4.51	4.98	5.38	7.65	6.27	5.44
Rockland Electric Company	3.49	3.88	5.13	4.28	3.64	4.29	4.35	5.48	5.91	5.67	6.36
The Empire District Electric Company	2.65	2.77	2.93	2.75	3.03	4.75	4.08	5.07	5.12	5.72	5.71
The United Illuminating Company	5.92	5.56	4.88	5.33	5.89	6.36	6.62	6.64	7.49	10.76	13.00
Unitil Energy Systems, Inc.	-	2.60	2.54	2.67	2.84	2.88	3.12	3.21	3.56	4.88	6.68
Upper Peninsula Power Company	9.05	12.63	13.13	13.49	11.67	12.65	12.19	13.12	14.02	13.88	13.47
Western Massachusetts Electric Company	4.99	4.76	4.87	4.97	5.11	5.48	5.66	5.78	5.98	5.44	6.35
Peer Group Average	**$4.31**	**$4.47**	**$4.39**	**$4.43**	**$4.68**	**$5.06**	**$5.36**	**$5.69**	**$5.91**	**$6.56**	**$7.02**
% Difference from Mean	**-15%**	**-14%**	**0%**	**7%**	**11%**	**4%**	**13%**	**0%**	**-6%**	**-9%**	**13%**

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
	(Rank)										
Green Mountain Power Corporation	10	10	11	14	14	13	15	12	10	12	15
Bangor Hydro Electric Company	16	17	18	13	13	14	13	15	14	14	13
Black Hills Power, Inc.	3	3	2	4	3	2	4	5	7	4	6
ALLETE, Inc.	1	1	1	1	1	1	1	3	1	1	1
Central Hudson Gas & Electric Corporation	14	18	17	18	18	17	18	18	18	19	19
Fitchburg Gas and Electric Light Company	8	7	5	8	7	7	8	8	8	9	14
Granite State Electric Company	11	12	13	9	16	18	17	17	12	16	16
Madison Gas and Electric Company	4	8	8	5	8	6	6	6	6	5	4
MDU Resources Group, Inc.	9	9	9	11	10	9	9	7	5	6	5
Northern States Power Company (Wisconsin)	6	6	7	6	5	4	2	1	2	3	2
Otter Tail Power Company	2	4	4	7	6	5	5	4	4	2	3
Public Service Company of New Hampshire	12	13	10	12	11	12	14	14	15	15	11
Rochester Gas and Electric Corporation	17	16	12	17	15	10	11	10	17	13	7
Rockland Electric Company	7	11	16	10	9	8	10	11	11	10	10
The Empire District Electric Company	5	5	6	3	4	11	7	9	9	11	8
The United Illuminating Company	15	15	15	16	17	16	16	16	16	17	17
Unitil Energy Systems, Inc.		2	3	2	2	3	3	2	3	7	12
Upper Peninsula Power Company	18	19	19	19	19	19	19	19	19	18	18
Western Massachusetts Electric Company	13	14	14	15	12	15	12	13	13	8	9

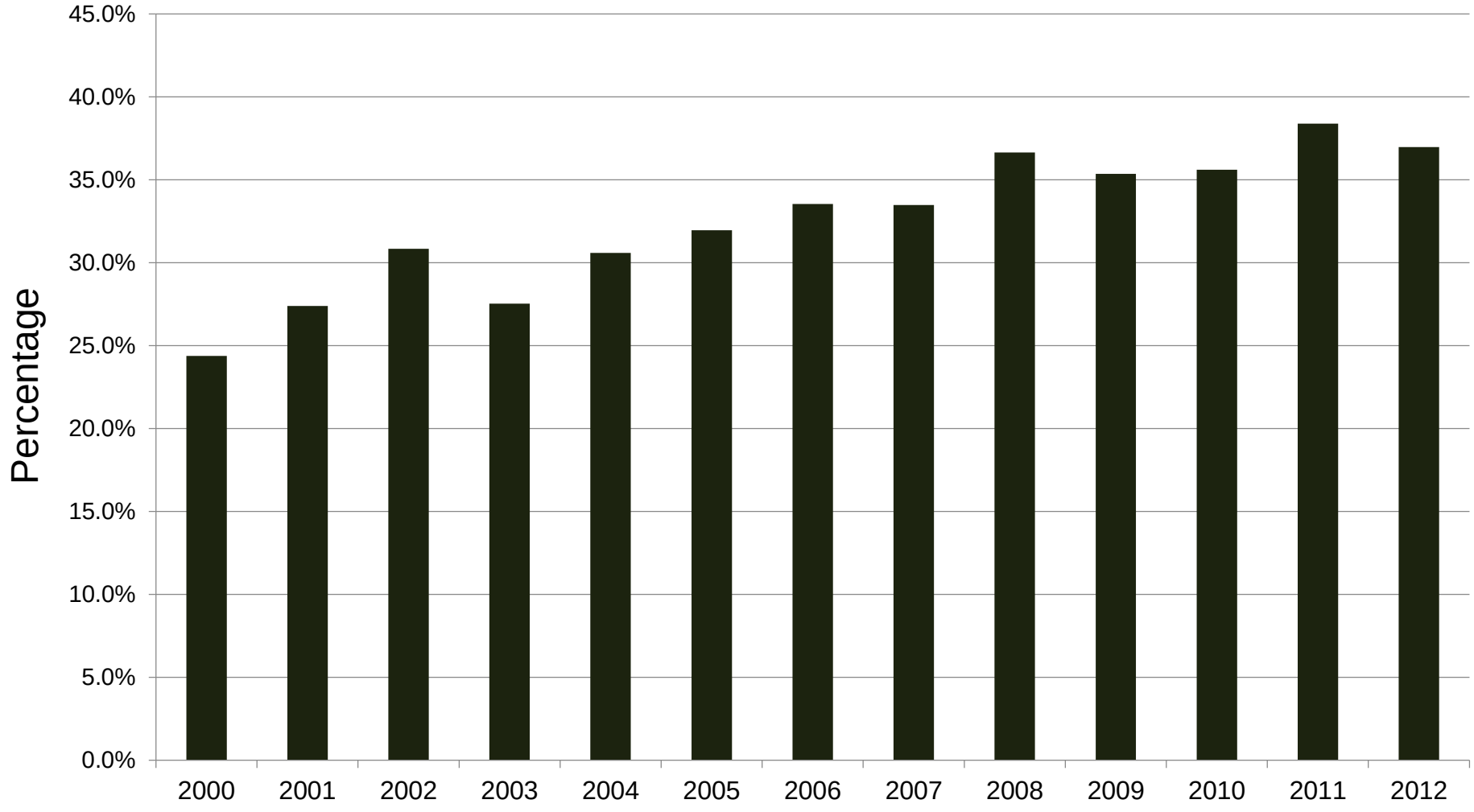
[1]Northern States Power Company (Wisconsin) FERC Form 1 contains no data for account (565).

Note: For purposes of this analysis, “best performing observation” is defined as the average of the lowest observed unit cost for each year. This comparison has been provided to identify the most significant possible unit cost improvement possible based upon the observed sample data during the 2002-2012 time period.

Peer Group Cost per MWh - Operations and Maintenance Expense



GMP Operations & Maintenance Expenses vs. Total Aggregate Operating Costs



Source: Company's FERC Form 1s.

Comparison of Active Performance-Based Ratemaking Mechanisms

Utility	State / Provence	Term	Inflation Factor	Productivity Offset	Stretch Factor	Formula Benchmark	Exogenous Adjustment	Capital Adjustment	ROE Benchmark Adjustment	Earnings Sharing Mechanism		
										Yes / No	Bands	Sharing Ratio
Electric Utilities												
Green Mountain Power / Central Vermont Public Service	VT	2010/2011 - 2013	CPI - Northeast	1.00%	None	Yes - Applied against Productivity Offset	Yes; Committed Power Costs, 90% of Non-Committed Power Costs greater than $615,000, Major Storm Costs; and government and regulation changes.	Yes	Yes	Yes	ROE Indexed to Long-Term Treasury. Dead-Band 75 bps above and below target ROE. Earnings sharing between 75 and 125 bps below target ROE.	50% ratepayer - 50% Company
PacifiCorp	CA	2011 - 2013/2014	Global Insights Forecast of CPI	0.50%	None	No	No	Yes; Utility may file request for major resource additions not already included in base rates.	No	No		
Central Maine Power ("CMP")	ME	2009 - 2013	GDP - Price Index	1.00%	None	No	Yes; Extraordinary Storm Costs, *force majeure* events or government and regulation changes, capital gains and losses on sale of property, and service quality penalties.	No	No	Yes	Earnings Sharing for earnings in excess of 11.0% ROE	50% ratepayer - 50% Company
Enmax	Alberta	2007 - 2013	Composite Index of Canadian Price Indexes	0.80%	0.40%	No	Yes; criteria adopted for exogenous adjustments: outside management's control, material impact, insignificant influence on inflation factor, and prudent; flow-through adjustment criteria: not unforeseen one-time events, arise through the normal course of business but outside control of the utility.	For transmission investments only.	No	Yes	Dead-Band to 100 bps above target ROE.	50% ratepayer - 50% Company
All Other Alberta Electric Utilities	Alberta	2013 - 2017	Composite Index of Alberta-Specific Price Indexes	0.96%	0.20%	No	Yes; material costs for which the utility has no other recovery or refund mechanism; flow-through costs must be material, outside utility control, and variable in nature. Utility is also allowed to Petition in cases of material events, with restrictions.	Separate Capital Tracker for costs: (1) outside normal course of operations, (2) projects required by an external party, (3) material effect on company finances.	No	No	Plan is re-opened if earnings is greater than +/- 500 bps for a year, or greater than +/- 300 bps for two consecutive years. Earnings can also be carried over after the end of the PBR limited to 0.5%.	
All Ontario Electric Distribution Utilities	Ontario	2010 - 2013	Canadian GDP - Price Index	0.72%	Variable: 0.20% - 0.60%	Yes - Applied to Stretch Factor	Yes; events that are outside management control, amount must be clearly outside what is included in base rates, exceeds materiality threshold, and prudent.	Yes; if exceeds materiality threshold, shows needs, and prudent.	No	No	Plan is re-opened if earnings is greater than +/- 300 bps for a year.	
Gas Utilities												
Vermont Gas System ("VGS")	VT	2012 - 2015	CPI - Northeast	0.39%	None	No	Yes; Government and regulation changes. The mechanism also includes a Purchased Gas Adjustment.	No	No	Yes	ROE Indexed to 10-Year Treasury Note. Deadband 25 bps above and 50 bps below authorized ROE. Over- / Under-earnings capped at 200 bps.	
All Alberta Gas Utilities	Alberta	2013 - 2017	Composite Index of Alberta-Specific Price Indexes	0.96%	0.002	No	Yes; material costs for which the utility has no other recovery or refund mechanism; flow-through costs must be material, outside utility control, and variable in nature. Utility is also allowed to Petition in cases of material events, with restrictions.	Separate Capital Tracker for costs: (1) outside normal course of operations, (2) projects required by an external party, (3) material effect on company finances.	No	No	Plan is re-opened if earnings is greater than +/- 500 bps for a year, or greater than +/- 300 bps for two consecutive years. Earnings can also be carried over after the end of the PBR limited to 0.5%.	

Note: PacifiCorp's mechanism applies to capital investments only.
Source: Direct Testimony of Christopher Cole; Commission Orders.

Matrix of ARP and Traditional PBR Results

GMP ARP

Rate Increases = I - (X - Cost Benchmark)

Growth in Utility Costs = I - Productivity Gains

	Best-case Potential Productivity Gains			Worst-case Potential Productivity Gains	
Utility Benefits	Revenue Growth = 2 - (1 - 0.75)	Revenue Growth = 1.75%		Revenue Growth = 2 - (1 - 0)	Revenue Growth = 1.00%
	Growth in Costs = 2 - 1.5	Growth in Costs = 0.50%		Growth in Costs = 2 - 1.0	Growth in Costs = 1.00%
	Growth in Earnings = Revenue Growth - Growth in Costs	**Growth in Earnings = 1.25%**	**<-- Utility Incentive to Reduce Costs of Production**	**Growth in Earnings = Revenue Growth - Growth in Costs**	**Growth in Earnings = 0.00%**
Ratepayers Benefits	Rate Increase = 2 - (1 - 0.75)	Rate Increase = 1.75%		Rate Increase = 2 - (1 - 0)	Rate Increase = 1.00%
	Overall Cost Inflation	Inflation = 2.00%		Overall Cost Inflation	Inflation = 2.00%
	Rate Increase relative to Inflation = Inflation - Rate Increase	**Rate Increase relative to Inflation = -0.25%**	**Ratepayers Incentive -->**	**Rate Increase relative to Inflation = Inflation - Rate Increase**	**Rate Increase relative to Inflation = -1.00%**

Traditional PBR

Rate Increases = I - X

Growth in Utility Costs = I - Productivity Gains

	Best-case Potential Productivity Gains			Worst-case Potential Productivity Gains	
Utility Benefits	Revenue Growth = 2 - 1	Revenue Growth = 1.00%		Revenue Growth = 2 - 1	Revenue Growth = 1.00%
	Growth in Costs = 2 - 1.5	Growth in Costs = 0.50%		Growth in Costs = 2 - 1.0	Growth in Costs = 1.00%
	Growth in Earnings = Revenue Growth - Growth in Costs	**Growth in Earnings = 0.50%**	**<-- Utility Incentive to Reduce Costs of Production**	**Growth in Earnings = Revenue Growth - Growth in Costs**	**Growth in Earnings = 0.00%**
Ratepayers Benefits	Rate Increase = 2 - 1	Rate Increase = 1.00%		Rate Increase = 2 - 1	Rate Increase = 1.00%
	Overall Cost Inflation	Inflation = 2.00%		Overall Cost Inflation	Inflation = 2.00%
	Rate Increase relative to Inflation = Inflation - Rate Increase	**Rate Increase relative to Inflation = -1.00%**	**<-- Ratepayers Indifferent -->**	**Rate Increase relative to Inflation = Inflation - Rate Increase**	**Rate Increase relative to Inflation = -1.00%**

Assume:

1) Inflation (I) equals 2.0 percent per year.
2) Board expected productivity gains (productivity offset: X) equal 1.0 percent per year.
3) Best-case productivity gains available to GMP equal 1.5 percent per year.
4) Worst-case productivity gains available to GMP equal industry average productivity gains of 1.0 percent per year.

Combined Productivity Offsets in Active North American Performance-Based Regulation Plans

Utility	State / Provence	Productivity Offset	Stretch Factor	Combined Productivity Offset
Green Mountain Power / Central Vermont Public Service	VT	1.00%	None	1.00%
Vermont Gas System ("VGS")	VT	0.39%	None	0.39%
PacifiCorp	CA	0.50%	None	0.50%
Central Maine Power ("CMP")	ME	1.00%	None	1.00%
Enmax	Alberta	0.80%	0.40%	1.20%
All Other Alberta Electric and Gas Utilities	Alberta	0.96%	0.20%	1.16%
All Ontario Electric Distribution Utilities	Ontario	0.72%	Variable: 0.20% - 0.60%	0.92%
			Average Non-Vermont Productivity Offsets:	0.96%

Source: Direct Testimony of Christopher Cole; Application of California Pacific Electric Company, LLC (U933E) for an Order Modifying Decision 09-10-041, Granting Waiver of the Three Year Filing Requirement Contained in Decision 07-07-004 and Increasing General Rates Pursuant to the Post Test Year Adjustment Mechanism Attrition Factor for 2012, Decision 12-04-026; In the Matter of the Application of PACIFICORP (U 901 E), an Oregon Company, for an Order Authorizing a Rate Increase Effective January 1, 2011, Settlement Agreement dated June 23, 2010; Central Maine Power Company, Request for Approval of Post-Merger Alternative Rate Plan (ARP 2008) and Annual Price Change for Remaining Items from ARP 2000, Docket Nos. 2007-215 and 2008-111, ARP 2008 Stipulation dated June 6, 2008; Petition of Vermont Gas Systems, Inc., for Approval of a Successor Alternative Regulation Plan, Docket No. 7803, Order entered August 21, 2012; ENMAX Power Corporation: 2007-2016 Formula Based Ratemaking (March 25, 2009), Alberta Utilities Commission Decision 2009-035; Rate Regulation Initiative: Distribution Performance-Based Regulation (September 12, 2012), Alberta Utilities Commission Decision 2012-237; Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (July 14, 2008), Ontario Energy Board Docket EB-2007-0673.

Company's Projected Capital Investment

	Budget FY 2014	Budget FY 2015
Computer Hardware	$ 4,930	$ 4,834
Computer Software	11,758	3,840
Total Information Technology	$ 16,688	$ 8,674
Distribution Lines Large Cap	$ 11,195	$ 12,586
Distribution Lines Line Extensions	5,150	2,533
Distribution Lines Line Extensions Reimb's	(2,562)	
Distribution Lines Small Cap	15,495	14,788
Distribution Substation	5,697	9,079
Transmission Lines	4,274	5,957
Transmission Substations	3,231	2,045
Total T&D	$ 42,480	$ 46,988
Communications	$ 1,256	$ 109
General Plant	289	312
Jt Ownership	3,329	2,405
Synchronous Condenser	4,701	
Vermont Marble - Hydro		10,436
Production	5,714	8,872
Meters	660	928
Property & Structures	11,088	4,877
Regulators and Capacitors	825	882
Solar	10,054	2,453
Transformers	3,685	4,010
Transportation	1,384	2,731
Vermont Marble	5,156	856
Wind Generation	740	77
Total Capex	**$ 108,049**	**$ 94,610**

Source: Docket No. 8190, Company's Response to DPS 6-5.

Company's Historical Capital Spending

	2009	2010	2011	2012	2013	2014	2015
Production							
Budget[1]	$ 6,784	$ 14,186	$ 6,885	$ 8,792		$ 29,694	$ 25,099
Actual	10,645	15,167	7,006	6,151			
Variance	$ 3,861	$ 981	$ 121	$ (2,641)			
% Variance	57%	7%	2%	-30%			
Blanket Spending							
Meters							
Budget Combined[2]	$ 953	$ 355	$ 337	$ 140	$ 678	$ 660	$ 928
GMP	564	60	156	60			
CPVS	389	295	181	80			
Actual	$ 529	$ 366	$ 697	$ 418	$ 393		
Variance	$ (424)	$ 12	$ 360	$ 278	$ (285)		
% Variance	-45%	3%	107%	198%	-42%		
Distribution Lines							
Budget Combined[2]	$ 26,931	$ 22,760	$ 20,237	$ 19,629	$ 26,884	$ 42,480	$ 46,988
GMP	14,004	10,572	7,724	7,625			
CPVS	12,927	12,188	12,513	12,004			
Actual	$ 18,539	$ 20,015	$ 20,716	$ 22,994	$ 27,158		
Variance	$ (8,392)	$ (2,745)	$ 479	$ 3,366	$ 274		
% Variance	-31%	-12%	2%	17%	1%		
Transformers[2]							
Budget Combined[3]	$ 5,537	$ 5,197	$ 3,981	$ 3,955	$ 4,306	$ 4,510	$ 4,892
GMP	2,590	2,200	1,500	1,250			
CPVS	2,947	2,997	2,481	2,705			
Actual	3,459	3,901	3,758	4,527	3,890		
Variance	$ (2,078)	$ (1,296)	$ (222)	$ 572	$ (416)		
% Variance	-38%	-25%	-6%	14%	-10%		

Company's Historical Capital Spending

	2009	2010	2011	2012	2013	2014	2015
Distribution and Transmission Minor Additions and Substations							
Budget Combined[4]	$ 3,808	$ 3,612	$ 3,563	$ 3,873	$ 1,853	$ -	$ -
GMP	3,128	2,900	2,675	2,943	-		
CPVS	$ 680	$ 712	$ 888	$ 930	$ -		
Actual	1,345	1,620	1,626	1,732	1,824		
Variance	$ (2,463)	$ (1,992)	$ (1,937)	$ (2,141)	$ (29)		
% Variance	-65%	-55%	-54%	-55%	-2%		
Total Production and Blankets							
Budget	$ 44,013	$ 46,109	$ 35,003	$ 36,389	$ 33,721	$ 77,344	$ 77,907
Actual	34,517	41,070	33,804	35,822	33,265		
Variance	$ (9,496)	$ (5,039)	$ (1,199)	$ (567)	$ (456)		
% Variance	-22%	-11%	-3%	-2%	-1%		
Other							
Information Technology						$ 16,688	$ 8,674
Communications						1,256	109
General Plant						289	312
Property & Structures						11,088	4,877
Transportation						1,384	2,731
Total						$108,049	$ 94,610

[1]Years 2014 and 2015 include Vermont Marble - Hydro facility, Solar and Wind Generation. It is not clear if these costs are included in earlier years. The 2013 budgeted and actual capital expenditures were not provided by the Company. [2]The combined value is the sum of GMP and CVPS. [3]GMP combined the budgets for Regulators, Capacitors and Transformers. CVPS budgeted these amounts separately. These values have been combined for comparison purposes. [4]GMP does not separately budget transmission costs; these costs are included in the distribution budget. These values have been combined for comparison purposes.
Source: Docket No. 8190, Company's Response to DPS 1-12 and DPS 2-18.

Historical Target and Achieved ROE Levels

Year	Target ROE	Achieved ROE	Over/Under Earning	Inside 75 bps Deadband
2007	10.25%	10.26%	0.01%	YES
2008	10.21%	10.33%	0.12%	YES
2009	9.81%	10.23%	0.42%	YES
2010	9.69%	10.30%	0.61%	YES
2011	9.45%	9.98%	0.53%	YES
2012	9.93%	9.67%	-0.26%	YES
2013	8.84%	9.44%	0.60%	YES

Source: Direct Testimony of Christopher Cole, Exhibit CC-1.