VERMONT

PUBLIC SERVICE DEPARTMENT

Annual Report on the Public Advocacy of the Vermont Department of Public Service Pursuant to Act 130, Section 5f –

A Report to the Vermont House Committee on Commerce and Economic Development, the House Committee on Natural Resources and Energy, the Senate Committee on Finance, and the Senate Committee on Natural Resources

January 2017

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Introduction

Pursuant to Act 130 Section 5f, the Department of Public Service is pleased to present the first annual report of major activities at the Department. As this is the first of its kind, we cover more than just proceedings concluded this year, and generically summarize the major utility activities of the last several years, back to 2012, to put this year's report in context.

From this perspective, the Department Advocacy work has saved Vermont ratepayers approximately $44 million over the last several years, and if our recommendations are upheld in the pending Vermont Gas Systems rate case, the savings in this period will be over $56 million.

This year, the Department participated in the review of all actions taken before the Board, which number approximately 1000 applications. Most of these are interconnections under net metering or other energy developments that may have associated aesthetic and siting issues. Several, however, are rate-related and are major proceedings before the Board. It is on the later that this report focuses, although two examples of the former are discussed as well.

In this report, we explain several of the major specific cases we undertook during the past year, and we describe what we accomplished, what we decided and why, and the benefits we derived for ratepayers and the public of Vermont.

Pursuant to the Act, the Attorney General's office (AGO) followed one case (the GMP Base Rate Case) and its assessment is attached as an appendix to this report. In short, the AGO found we represented the public competently and independently, achieving meaningful results for ratepayers. They also found that the current Alternative Regulation process is imposing specific pressures on the Department that should be addressed. We agree there are improvements to be made, which the Department has both identified and is undertaking, but we also believe it is important for all to realize the Alternative Regulation process is the mechanism by which we achieve many important results – including "revenue decoupling." Decoupling results in the elimination of the perverse incentive of utilities to sell more power or fuel, rather than help us achieve our energy and efficiency goals. As such, it is an important tool which must be maintained. Most states have some form of "alternative regulation" as they believe the modified process more efficiently addresses appropriate regulation of utilities in this day and age. We agree, and the benefits and challenges of the alternative regulation process are discussed later in this report.

<u>DPS Mission</u>:

The mission of the DPS is to serve all citizens of Vermont through public advocacy, planning, programs, and other actions that meet the public's need for least cost, environmentally sound, efficient, reliable, secure, sustainable, and safe energy, telecommunications, and regulated utility systems in the state for the short and long term.

This necessarily means we are supporting ratepayers, first and foremost, to ensure efficient and cost effective services, but do so in the context of a regulatory structure that considers sustainability, reliability, safety and environmental impacts. We must also insure our utilities are compensated for their work fairly and consistently, so that they are healthy and able to serve the consumers, providing efficient, reliable and secure services.

Over the past four years, we have successfully managed this relationship to ensure value for ratepayers and low and stable rates for consumers. The following chart shows, for two major utilities in the state, their applications for rate changes and our response:

Green Mountain Power Rate Case Filing						
		Original Request		After PSD Review		
FY	Case	Amount ($)	%	%	Variance %	Savings
2013	Alt Reg Base Rate Filing	$9,864,000	1.67%	0.40%	-1.27%	$ 7,501,365
2014	Alt Reg Base Rate Filing	$20,922,000	3.81%	2.46%	-1.35%	$ 7,413,307
2015	Traditional Rate Filing	($155,000.00)	-0.03%	-1.46%	-1.43%	$ 7,388,333
2016	Alt Reg Base Rate Filing	$7,021,000	1.26%	0.73%	-0.53%	$ 2,953,278
2017	Alt Reg Base Rate Filing	$19,559,000	3.35%	0.93%	-2.42%	$ 14,129,188
	Total GMP reduction from PSD review					$39,385,472

Vermont Gas Rate Case Filing						
		Original Request		After PSD Review		
FY	Case	Amount ($)	%	%	Variance %	Savings
2014	Alt Reg Base Rate Filing	($4,900,000)	-5.86%	-5.86%	0.00%	$ -
2015	Alt Reg Base Rate Filing	$2,007,875	2.34%	-1.31%	-3.65%	$3,131,942
2016	Alt Reg Base Rate Filing	($755,518)	-0.90%	-3.00%	-2.10%	$1,762,875
2017	*Traditional Rate Filing**	*$11,204,397*	*10.13%*	*-1.03%*	*-11.16%*	*$12,343,640*
	Total VGS reduction from PSD review					$ 17,238,457
	Total reduction from PSD review					***$56,623,928***

***** *This 2017 case is currently pending before the Public Service Board. The savings noted here are DPS's recommendation as of this writing.*

From this, it can be seen that the Department's work has saved ratepayers approximately $44 million to date, and is currently advocating for a total savings of $56.6 million through this year, and we've done so while maintaining reliable and secure service.

Specific Requirements of Act 130

Pursuant to Act 130 of 2016, the Department of Public Service is required to submit annually to the Vermont General Assembly a report addressing the positions taken and the concessions obtained through the advocacy work of the Department. As characterized in the law: "The primary purpose of the reporting requirement … is to help address concerns regarding any potential compromise of the effectiveness or independence of the Department's representation of ratepayers in rate proceedings, including base rate filings under an alternative regulation plan."[1]

Further, the law requires that the Attorney General's Office "monitor and detail at least one rate proceeding annually and make findings and recommendations related to the effectiveness and independence of the Department's ratepayer advocacy." The Attorney General's findings and recommendations are included as an appendix to this report.

Specific requirements of the law include the following:[2]

- A summary of significant cases concluded within the past year;
- The positions taken by the Department of Public Service in those cases;
- A summary of the Department's role and positions with respect to other significant topics addressed by the Department's Public Advocacy Division pursuant to alternative regulation or to litigation before the Public Service Board or other tribunal;
- Specific reference to the Department's duties and responsibilities under Title 30, and explanation of how the Department's positions and activities align with those statutory provisions;
- The terms of any settlement or memorandum of understanding (MOU) negotiated by the Department in such cases, the parties that participated in any settlement or MOU negotiations, and documentation of what the Department was able to negotiate on behalf of residential ratepayers and what the Department conceded that was beneficial to the applicable public service company.

<u>Significant Cases During the Past Year</u>

The following cases were identified by the Department of Public Service as significant cases to report on for the past year. These were:

Three cases reviewed under § 248:

Docket No. 7970 - Vermont Gas Systems (VGS) Addison Expansion Project
Docket No. 8400 – TDI buried transmission line (merchant transmission)
Docket No. 8188 – Cold River Solar

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[1] Act 130 of 2016, Section 5f.

[2] In crafting the law, the General Assembly notes that "[t]he Department shall not be required to disclose privileged information in connection with a report submitted under this section…."

One rate design case[3]:

Docket No. 8525 – Green Mountain Power rate design

One base rate filing under an alternative regulation plan

Tariff Filing No. 8618 -- Green Mountain Power base rate filing

One case involving rates for PURPA projects:

Docket No. 8684 – PSB Rule 4.100 rates

And one telephony case:

Docket No. 8390 – FairPoint service quality.

Department's Duties under Title 30

General Provisions

The statutes directing the Department's work are found in Title 30. Section 2(a) directs the DPS to "supervise and direct the execution of all laws" relating to public service entities. Section 2(a)(6) directs the DPS to represent "the **interests of the consuming public** in proceedings to change rate[s] . . . ." Section 2(b) broadens that focus, stating that "In cases requiring hearings by the Board, the Department, through the Director for Public Advocacy, shall represent the **interests of the people of the State,** unless otherwise specified by law."

The duties of the Department of Public Service under Title 30 fall into two broad categories – planning and regulating. Regarding the planning functions, the Department prepares and issues long range plans that guide the evolution of the energy and telecommunications industries in Vermont. The regulatory functions of the Department include representing the public interest (as developed in the various plans) as a party in virtually all cases before the Public Service Board. This report focuses on the participation of the Department in cases undertaken under its regulatory functions.

In its regulatory functions, the Department participates in cases where a party petitions the Board to construct an energy or telecommunications facility, and in cases involving rates charged and services rendered by regulated service providers. The cases involving construction of energy facilities are reviewed under Title 30, Section 248, with the applicant seeking a Certificate of Public Good ("CPG") to build a facility. Rate cases, service quality cases, and other cases are generally brought by a utility wishing to increase its rates, change its services, or undertake another action for which Board approval is required. Additionally, the Department may initiate

[3] The difference between a rate case and a rate design case is that in a rate case, the DPS reviews the costs to be incurred by the company and adjusts all rates by the same amount to allow recovery of those costs. In a rate design case, rates are being adjusted differentially to reflect the contribution of each class of customers to the total costs of the utility. A rate case is supported by a filing detailing the various costs likely to be incurred by the utility and comparing it to historical costs. A rate design case is supported by an "allocated cost of service" study which looks at the characteristics of each customer group to determine the costs that group imposes on the system.

proceedings on its own motion before the Public Service Board, with respect to any matter within the jurisdiction of the Board, and may initiate rule-making proceedings before the Board.

Section 248

A petition for a Certificate of Public Good proceeds under Title 30, Section 248. Pursuant to its broad statutory responsibilities under Title 30, the Department is responsible for representing the interests of ratepayers and, more broadly, the state in reviewing the petition for its consistency with this section.

Pursuant to Section 248(a)(2), before a company can exercise the right of eminent domain or begin site preparation for generation or transmission facilities in the state, the Public Service Board must issue a CPG and must find that the following criteria are met pursuant to subsection 248(b):

That the facility . . .

(1) will not unduly interfere with the orderly development of the region;
(2) meets the need for present and future demand for service which could not otherwise be provided in a more cost-effective manner through energy conservation programs and measures and energy-efficiency and load management measures;
(3) will not adversely affect system stability and reliability;
(4) will result in an economic benefit to the State and its residents;
(5) with respect to an in-state facility, will not have an undue adverse effect on aesthetics, historic sites, air and water purity, the natural environment, the use of natural resources, and the public health and safety;
(6) is consistent with the principles for resource selection expressed in that company's approved least cost integrated plan;
(7) is in compliance with the electric energy plan approved by the Department under section 202 of this title, or that there exists good cause to permit the proposed action;
(8) does not involve a facility affecting or located on any segment of the waters of the State that has been designated as outstanding resource waters by the Secretary of Natural Resources, except that with respect to a natural gas or electric transmission facility, the facility does not have an undue adverse effect on those outstanding resource waters;
(9) meets planning requirements for with respect to a waste to energy facility;
(10) load can be served economically by existing or planned transmission facilities without undue adverse effect on Vermont utilities or customers;
(11) with respect to an in-state generation facility that produces electric energy using woody biomass, meets air, performance and wood harvesting standards.

Not all of the listed provisions apply to each petition. For example, (b)(9) applies only to waste-to-energy facilities, and (b)(6) does not apply to merchant generators, who are not required to have integrated resource plans. Other state agencies and town and regional planning bodies also participate in the process to represent their respective concerns. Regional and town planning and governing entities may focus on aesthetics or orderly-development concerns related to subsections (1) and (5). The Department of Historic Preservation would be most concerned with provisions of subsection (5) related to historic sites. The Agency of Natural Resources addresses the other provisions of the same section along with subsection (8). Coordinating with other parties, the Department of Public Service may take positions that are related to the concerns of other state agencies, towns, regional planning commissions and other intervenors, and will typically have concerns of its own as well.

Other provisions of Section 248 pertain to process, notice to other agencies, public hearings, and provisions related to the eventual decommissioning of the facilities constructed. In proceedings and forums affecting the regional grid, the DPS is directed to "advance positions that are consistent with the statutory policies and goals set forth in 10 V.S.A. §§ 578, 580, and 581 and sections 202a, 8001, 8004, and 8005 of this title. 30 V .S.A. § 2(g). The policies and goals of the statutes cited in § 2(g) apply to more than just the regional context, and are not confined to an interest in the lowest possible rates. For example, section 202a articulates "State Energy Policy" and provides that:

> It is the general policy of the state of Vermont:
>
> (1) To assure, to the greatest extent practicable, that Vermont can meet its energy service needs in a manner that is adequate, reliable, secure and sustainable; that assures affordability and encourages the state's economic vitality, the efficient use of energy resources and cost effective demand side management; and that is environmentally sound.
>
> (2) To identify and evaluate on an ongoing basis, resources that will meet Vermont's energy service needs in accordance with the principles of least cost integrated planning; including efficiency, conservation and load management alternatives, wise use of renewable resources and environmentally sound energy supply

Similarly, §§ 8001 *et seq.* speak to efficient use of resources, protecting air and water quality, reducing global climate change, and securing a diverse energy supply - as well as benefitting ratepayers. Sections 8004 and 8005 relate to the Renewable Energy Standard, which requires investments to accomplish a number of stated purposes with the explicit overall goal of securing the economic *and* environmental benefits of renewable energy generation. The cited sections of Title 10 relate to the State's goals with respect to greenhouse-gas reduction, renewable energy, and the efficiency of Vermont's housing stock.

<u>Section 218d – Alternative Regulation</u>

Regulation of utility rates in Vermont was historically accomplished with "traditional regulation," using long-standing procedures and statutory directives (e.g. 30 V.S.A. §§ 218, 225, 226, and 227). Under this model, utilities typically filed rate cases on their own initiative, at irregular intervals that could span a number of years.[4] These cases are "contested cases" subject

[4] The DPS has authority to seek, and the Board can open on its own, a rate review without a utility petition. This does happen but is much less common than rate cases initiated by the utilities.

to the Administrative Procedures Act. While many of these cases were litigated to a final PSB order, it was not uncommon for them to be settled, either before or after hearings.

In 2003 the General Assembly enacted what is now 30 V.S.A. § 218d, authorizing "alternative forms of regulation" provided that a number of criteria were met by a proposed plan. It is important to note that the rubric of "alternative regulation" (or "Alt Reg") is very broad and can include a wide variety of regulatory structures and procedures. One concern about the Alt Reg structure is that it is structured to be an expedient process with only the Utility and the Department participating. As passed by the Legislature, Vermont's alternative regulation process allowed for an Alt Reg plan to go for four years, with another four year renewal. Thus, it could be eight years before a traditional rate case was heard and other parties could participate meaningfully. As a matter of policy, we have changed the practice to allow Alt Reg plans only for three years, with a one year extension possible, thereby ensuring a traditional rate case at least once every four years.

It is very important to keep in mind the goals of alternative regulation, and its advantages and disadvantages compared to traditional regulation as one assesses its effectiveness. Three areas of difference between these regulatory structures are described below: revenue decoupling, power adjustment pass-through, and performance regulation.

Revenue Decoupling

Under traditional regulation, utilities earn more profit when they sell more energy, creating a strong financial incentive to increase sales.[5] This incentive is directly at odds with Vermont's long-standing policy goals of promoting energy efficiency and non-utility-owned small-scale renewable generation (such as rooftop solar systems). Both energy efficiency and customer-owned renewable generation drive down utility electric sales. Under traditional regulation, utilities have a strong financial incentive to actively work against efficiency and renewable goals. (If electric sales are increasing utilities are unlikely to file rate cases, and are allowed to keep any profits attributable to the increased sales.)

Revenue decoupling refers to removing the association between sales and profit. In Vermont, as elsewhere, revenue decoupling is effectuated through alternative regulation. The alternative regulation statute specifically references this disassociation as a goal. 30 V.S.A. § 218d(a)(4). This serves an important policy objective of reducing the need for electricity, and deriving it from small, local, renewable sources. If structured thoughtfully, decoupling can enlist the utility as an ally in efforts to move Vermont toward its efficiency and renewable-energy goals.

However, there are many ways to structure alternative regulation, and other jurisdictions have

[5] Lazar, J., Weston, F., Shirley, W., (2016), *Revenue Regulation and Decoupling: A Guide to Theory and Application (incl. Case Studies).* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/wp-content/uploads/2016/11/rap-revenue-regulation-decoupling-guide-second-printing-2016-november.pdf.

successfully decoupled in a variety of ways.[6] Vermont's current approach to alternative regulation, and its attendant issues, could be addressed by changing the present structure of alternative regulation rather than by dispensing with it altogether. Decoupling remains an important tool for aligning utility interests with state policy goals, which is difficult at best under traditional regulation.

Power Cost Pass-through

Another feature of alternative regulation that has significant benefit is the direct flow-through to customers of changes in energy costs. This is the Power Supply Adjuster in GMP's current plan and the Purchased Gas Adjustment in VGS's plan.[7] These features allow the utility to pass wholesale costs for electricity or gas directly through to customers on a quarterly basis without the need for a rate case. Any decrease in power costs goes back to customers through a rate decrease, as we have seen in natural gas for several years. This mechanism benefits the utility by reducing the risk of rapidly escalating wholesale power costs, over which they have little control, eating into operating revenue before they can be reflected in rates.

These features also reduce the cost of capital, which benefits ratepayers. For example, if wholesale electricity suddenly tripled in price for a sustained period because of shortages, under traditional regulation utilities would have a very difficult time maintaining financial solvency. Under a direct energy-cost pass through, utilities can collect those costs sooner, reducing financial risk. Credit rating agencies consider this risk when rating utilities. If utilities have better credit ratings, they can borrow capital at a lower interest rate, saving customers money in borrowing costs. This feature is enabled by the alternative regulations statute and is not allowed under traditional regulation.

Performance Regulation

In many jurisdictions, alternative regulation is used to tie utility profitability to performance (rather than sales). For example, a utility may earn part of its revenue for providing reliable service, reducing outages, managing peak demand to control costs, or providing excellent customer service. Previous alternative regulation plans in Vermont have not used this type of financial performance incentive, but may well include them in the future. Performance incentives provide a way for the utility to earn profit other than investing in rate base. In other words, performance incentives can potentially reduce the incentive to invest heavily in infrastructure that may not be strictly needed to deliver energy. Performance incentives are generally not permitted under traditional regulation.

[6] Migden-Ostrander, J., Watson, B., Lamont, D., and Sedano, R. (2014), *Decoupling Case Studies: Revenue Regulation Implementation in Six States*. Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/7209.

[7] Vermont Gas and the Department have recently agreed to terminate VGS's current alt-reg plan, except for the Purchased Gas Adjustment. As noted in the text, this adjustment mechanism has benefitted customers in recent years.

Conclusion: Department's Statutory Responsibilities

The legislative directions to the Department balance the pecuniary interests of ratepayers with other goals. Other statutory goals include promotion of environmental quality, efficient use of energy, reliability of energy systems, etc. Pursuit of these other goals may put upward pressure on rates in the interest of other values that are not always readily monetized.

The Department's over-arching goal can be summarized as the pursuit of *reliable, least cost* utility service. The term "least-cost" may suggest a focus on the lowest possible rates right now. The statutes provide a more comprehensive and nuanced definition that guides the Department, Board, and utilities. Electric and gas utilities are required to prepare and implement a "least cost integrated plan," defined in 30 V.S.A. § 218c as:

> (a)(l) A "least cost integrated plan" for a regulated electric or gas utility is a plan for meeting the public's need for energy services, after safety concerns are addressed, at the lowest present value life cycle cost, including environmental and economic costs, through a strategy combining investments and expenditures on energy supply, transmission, and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs. Economic costs shall be assessed with due regard to:
> (A) The greenhouse gas inventory developed under the provisions of 10 V.S.A. §582;
> (B) The State's progress in meeting its greenhouse gas reduction goals;
> (C) The value of the financial risks associated with greenhouse gas emissions from various power sources; and
> (D) Consistency with section 8001 (renewable energy goals) of this title.

This statute explicitly requires the Department, as well as the Board, to consider not only monetary but also economic and environmental costs and safety, and to do so on a life-cycle basis. This will not result in the lowest rates today, a fact of which the General Assembly was undoubtedly aware. For example, energy efficiency (a/k/a demand-side management) by its nature tends to require up-front investment that may incur costs, but can lower bills both in the short term and in the longer term as transmission upgrades, new power plants, and other costs associated with growing loads are avoided. The Department of Public Service is affirmatively instructed to "supervise and direct" the execution of the statutes cited above as well as many others in Title 30.

In its other regulatory functions, the Department is guided by the policies and direction set out in Title 30 and those goals established in its plans. For example, Section 202(c) provides guidance on telecommunications policy.

Case Summaries

1. Docket No. 8400 – TDI New England High Voltage Transmission Line (merchant transmission)

This case involves a petition filed in December of 2014 by Champlain VT, LLC, d/b/a TDI New England ("TDI-NE" or "Petitioner") for a certificate of public good ("CPG") under 30 V.S.A. §

248, seeking authority to install and operate a high voltage direct current ("HVDC") underwater and underground electric transmission line with a capacity of 1,000 MW. The project also includes the construction of a converter station and other associated facilities, collectively known as the New England Clean Power Link (the "Project"). The Project is to be located within the Vermont portion of Lake Champlain and in the counties of Grand Isle, Chittenden, Addison, Rutland, and Windsor, Vermont. On January 5, 2016, the Vermont Public Service Board issued a Final Order in the proceeding in which it approved the proposed Project subject to numerous conditions negotiated by the Department and other parties as set forth in several memoranda of understanding.

Besides the Petitioner and the Vermont DPS, 18 other parties petitioned for and received intervenor status in the proceeding. These included several state agencies and regional planning commissions. Intervenors also included towns that were traversed by the project.

In addition to the technical hearings and review by the Board, the Board also held a public hearing on February 24, 2015 at Fair Haven Union High School.

Some of the listed provisions in 30 V.S.A. § 248 do not apply to this petition (e.g., subsection (b)(6), (9), (10) and (11)), either because the applicant is not a traditional regulated distribution utility, or the provisions pertain to a gas utility.

<u>Position taken by the Department of Public Service</u>

Need for Present and Future Demand

30 V.S.A. § 248(b)(2) relates to the question of whether the project is needed and whether that need could be met more cost effectively through other means. The DPS's testimony noted that the project is more analogous to a merchant generation facility than to a traditional transmission line, since traditional drivers of transmission like reliability are not the driver for this project. Rather the project is driven by market opportunities that are perceived by a third-party merchant developer. Traditional notions of "need" and consideration of alternatives that may obviate the need at a lower cost or through less environmental damage do not apply as they would to a traditional utility project. The Department reasoned that the need criteria may best be applied by considering the impacts on regional markets for energy, capacity, and renewables.

With respect to energy, the result is likely a reduction in state (and regional) energy prices, although, in the opinion of the DPS, the state impacts here are not of the magnitude estimated by the Petitioners. With respect to capacity, the project would likely increase the cost of capacity to the state as it would render the state an import-constrained zone for capacity. The DPS concluded that the project is consistent with 30 V.S.A. § 248(b)(2), provided that it serves to transfer renewable energy. This was a result that seemed likely but was not assured through the original petition. Additional assurances would be required. The Department also concluded that project would contribute to regional resource diversity.

Adverse System Impact

30 V.S.A. § 248(b)(3) relates to the impacts of the project on system stability and reliability.

The DPS initially indicated that it was too early to conclude that the project met the standard and followed that statement with recommendations for additional information needed to form a conclusion on this point. Additionally, the DPS recommended other conditions necessary to protect ratepayers from the additional costs of interconnecting the Project to VELCO's system. Among the recommendations were that additional determinations are needed in the technical review of the project (a System Impact Study, or SIS) to address concerns associated with system impacts, and that "the Board should include in a CPG issued for this project a condition that TDI will pay the capital and operating costs of all transmission and subtransmission upgrades identified by the SIS."

Economic Benefit

30 V.S.A. § 248(b)(4) relates to the Project's economic benefits to the state. The DPS's testimony indicated that while there are indeed economic benefits to the state, these benefits are likely a fraction of those reported by the petitioner's witness. The DPS also indicated that the project is not paid for by ratepayers and that provides a significant reason supporting an economic benefit to the state. The developer bears the cost and risk of the Project. The DPS highlighted four public benefit funds associated with the Project that contribute to its economic benefits, including:

- Vermont Electric Ratepayer Benefit
- Vermont Renewables Program
- Lake Champlain Phosphorus Cleanup
- Lake Champlain Trust Fund

These are described further below.

Consistency with Integrated Resource Plan

30 V.S.A. § 248(b)(6) asks whether the Project is consistent with a utility's approved least cost integrated plan. The DPS testimony explains that the project does not require such a determination, since there is no such planning requirement for a merchant transmission provider.

Consistency with Electric Energy Plan

30 V.S.A. § 248(b)(7) relates to compliance with the state's electric energy plan. The DPS testimony indicates that the plan does not make express provision for such merchant transmission projects. The relationship with non-transmission alternatives is obscured by the fact that this project is not intended to address a traditional reliability need, but is rather an electric transmission upgrade intended to increase market access to more energy resource options. There is no definitive framework for inclusion or consideration of potential non-transmission alternatives that could otherwise serve the need. For a variety of reasons cited in testimony, the transmission project appears to be broadly consistent with provisions of the plan, especially as it relates to increasing availability of renewable energy in Vermont and New England. The DPS agreed with significant portions of the petitioner's position with respect to the project and its consistency with the plan, although it disagreed with certain of the Petitioner's characterizations about the project's consistency with the plan.

The DPS also addressed the question of whether the project meets the less-specific "general good" requirements of Section 248(a). Here, the DPS testimony noted that this criterion would require balancing considerations that included the benefit funds listed above.

Terms of the Stipulation and Concessions Garnered or Given by the Department

As noted above, the Department's position was largely supportive of the project but also advocated for additional public benefits relative to the Project's impacts on the grid. The Department further noted that any additional costs incurred by the transmission system would need to be borne by the Petitioner to ensure that the project met requirements for impacts on reliability without economic burden to the state's ratepayers.

In the end, the Department of Public Service joined with the Agency of Natural Resources and the Division of Historic Preservation in signing a memorandum of understanding (MOU) resolving the major outstanding issues in the case that pertained to these agencies. Under the stipulation the parties did not waive their right to take positions in the "collateral" investigations examining the subsequent facilities that are deemed necessary for the ultimate success of the Project (Stipulation, Paragraph #4.c.)

The major benefit that was garnered through negotiations with the Petitioner concerned the increases in the Public Benefit Funds. The MOU reflects the following public benefit funds:

- Vermont Electric Ratepayer Benefit – Averaging $3.4 million a year for 40 years. (no change from the Petition)
- Vermont Renewable Programs (through the CEDF) – $109 million over a forty year period with payments of $5 million per year for the first 20 years (beginning with the first year of the project)
- Lake Champlain Pollution Abatement and Restoration Fund – Includes $201 million over the 40 years of the project
- Lake Champlain Enhancement and Restoration Trust Fund – Includes almost $60 million deposited in a fund over the 40 years of the project.

In addition to the above, the Project brings the economic benefits initially identified by the Petitioner. These included an estimated $301.2 million in property taxes, $328.3 million in state corporate income taxes, VTrans Lease Payments of $21.9 million, Vermont Sales Tax of $31.4 million during construction, Vermont Employment and Non-Employment Expenditures of $184 million during construction, and the roughly $310 million in spending during operations. Vermont ratepayer savings in the first 10 years are substantial, ranging from $89 million to $134 million, depending on the level of assumed hedging (between 50 and 25 percent). The Board found that other savings to Vermont ratepayers would flow from reductions in capacity costs and ancillary services. In total, the Board found that the economic benefit of the Project to Vermont would be approximately $1.935 billion.[8]

[8] Board Order, 1/5/16 at 41.

While the Vermont Electric Ratepayer Benefit remained the same in both the original Petition and the Stipulation, the other three public benefit programs reflected substantial increases over the original petition. ***The Department, acting on behalf of residential and all other ratepayers and citizens of Vermont negotiated substantial increases in public benefits. The monies flowing to the Vermont Renewable Program reflected an increase of $69 million over the course of the project. The Lake Champlain Phosphorous Cleanup reflected an increase of $119 million over the course of the project. The Lake Champlain Trust Fund reflected an increase of $20 million over the course of the project. These add to a total of $208 million in achieved benefits for Vermonters.***

The Stipulation also includes a long list of requirements that are imposed upon the Petitioner in later stages of the review and ultimate construction of the project. These include (i) the submission of final plans for review, (ii) compliance with representations, (iii) provision for Board review and opportunity for comment of substantive changes pursuant to permitting, (iv) Board review of the system impact statement, (v) permissible timeframes for construction, (vi) noise limits on the converter, (vii) Board review of the blasting plan, (viii) a decommissioning plan and cost estimates, (ix) that all host town agreements shall be enforceable under the CPG, (x) compliance and membership of the Petitioner in dig safe, (xi) submission of a underground damage prevention plan, (xii) provisions related to the environment and historic preservation, (xiii) good faith negotiations with Vermont distribution utilities for up to 200 MW of transmission service for 20 years, (xiv) contracts and verifications of the renewable character of the energy supplied over the lines consistent with representations of the Petitioner, (xv) aesthetic conditions, and (xvi) a commitment to renegotiate in good faith the public benefit provisions of the project by its owners, in the event that the project's life exceeds expectations.

As a concession to the Petitioner, the Department agreed that from its perspective and subject to the conditions of the MOU, the Project and the Petitioner have satisfied the requirements of Section 248, including the requirement of Section 248(a) regarding promoting the general good of the state (Stipulation, Paragraph # 1, and Subparagraph #3.b.) This concession provided for the timely review and project approval, which was important to the project developers. The Department and other parties to the stipulation also allowed that the Petitioner <u>may</u> operate beyond the 40 year period that is covered by the manufacturer's warranty, understanding that the Certificate of Public Good does not have an expiration date. Another concession related to the need for a decommissioning fund. Current practice before the Board would require the establishment of a project decommissioning fund. However, the nature of the project was such that it made little sense to do more than leave the line in the ground at the end of the Project's life. Even while the decommissioning fund issue was an important concession, it was one that could be offered without regret.

The Agency of Natural Resources conceded that the agreement allows use of the Korean Veterans Access Area in Alburgh to construct a portion of the project. In exchange, the Petitioner will provide $350,000 for a new boat ramp in the area.

2. Docket No. 8188 – Cold River Project – 2.3MW Solar Installation

This case involves a petition from Rutland Renewable Energy, LLC for a certificate of public good, pursuant to 30 V.S.A. § 248, authorizing the construction of the "Cold River Project" consisting of a photovoltaic electric generating facility of up to 2.3 MW located at the intersection of Cold River Road and Stratton Road in Rutland, Vermont. The Petition was filed in December of 2013. The Board issued a CPG on March 11, 2015. The decision was appealed to the Vermont Supreme Court and a decision affirming the original Board decision was issued on April 29, 2016.

There were five parties to the case, including the Department and the Agency of Natural Resources. In addition, the town of Rutland as well as a group of nearby landowners (the Neighbors), and Green Mountain Power were also granted party status. 21 individuals also participated in a public hearing held on March 26, 2014.

A site visit by the Board was held on April 18, 2014 and a second site visit was held on August 18, 2014. Technical hearings were held on the project over three days in August of 2014.

<u>Position taken by the Department of Public Service</u>

The position taken by the Department of Public Service were presented through testimony of one expert witness, and in post-hearing briefing. The Department's expert focused on the aesthetic impact of the proposed project on the surrounding area. Department counsel also successfully argued in briefs for permit conditions that helped to protect public health and safety and increase the project's decommissioning fund to an appropriate level.

The Department's expert concluded that the project would have an adverse aesthetic impact on the surrounding area, but that the impact would not be undue. The Department then briefed this issue consistent with the expert's conclusions. The Department also briefed a public health and safety issue related to the specifications for the proposed perimeter fence surrounding the project. The Department recommended that the Public Service Board require the project developer to submit an affidavit from a Vermont-licensed master electrician or electrical engineer prior to project operation, certifying that the fence satisfied all applicable electrical safety codes aimed at discouraging unauthorized entry into the project site. Finally, the Department recommended in briefing that the Board require the project developer to revise its decommissioning cost estimate upward, to include costs not included in the initial cost estimate submitted with the project petition.

Once the Department was able to conclude that the project would not have an undue adverse impact on the aesthetic resources of the area or on public health and safety, and an appropriate project decommissioning fund was in place, it was able to support the project. This support for a renewable energy project is consistent with the Department's responsibilities under Title 30 "to assure, to the greatest extent practicable, that Vermont can meet its energy service needs in a manner that is adequate, reliable, secure and sustainable; that assures affordability and encourages the state's economic vitality, the efficient use of energy resources and cost effective demand side management; and that is environmentally sound.[9]" Further, support of this project also furthers the renewable energy goals of the state as expressed in 30 V.S.A. § 8001.

Aesthetics, Historic Sites, and Rare and Irreplaceable Natural Areas

With respect to the criteria of 30 V.S.A. § 248(b)(5) (incorporating 10 V.S.A. § 6086 (a)(8)), related to the question of whether the project creates an undue aesthetic impact, the Department's witness used the Quechee test to evaluate the aesthetic impact of the proposal. There are three critical questions to be answered under the Quechee test. The first prong of the test is: Does the project violate a clear, written community standard intended to preserve the aesthetics or scenic, natural beauty of the area? The witness determined that there was no such standard that applied to the project. The second prong of the test is: Does the project offend the sensibilities of the average person? The witness position was that while the project would have an impact on the aesthetics of the area, that impact would not be undue. The third part of the test is: Has the Applicant failed to take generally available mitigating steps which a reasonable person would take to improve the harmony of the proposed project with its surroundings? The Department concluded that the applicant had, in fact, taken reasonable measures to mitigate the impact. The Board agreed with the Department's position. The town disagreed and appealed, stating that the Board (and by inference, the Department) had not given sufficient weight to the Town's position that the aesthetic impact will, in fact, be undue. Additionally, the town contended that the project will interfere with the orderly development of the region.

The town and the adjoining landowners appeal relied, in part, on a document entitled Town of Rutland Solar Facility Siting Standards, adopted by the select board on October 23, 2013. The document was drafted as an amendment to the town plan, but never formally adopted into that plan. It contained numerous setback requirements for solar projects, as well as a prohibition against locating solar projects on prime agricultural soils and a prohibition against siting within 500 feet of a historic building.

Regarding the impact on development of the region, the Supreme Court found that nearly all of the evidence submitted in the case was related to impact on the town, rather than the region. As a result, there was no basis in the record for a finding regional impact, and denied the town on that point. Because of that, it was not necessary to examine whether "due consideration" was given to the town's position on that point.

Regarding the notion that the aesthetic impact was undue, the Court found that the project met the three tests of the Quechee test as described by the Department witness. Regarding the first prong of the test, the Board found that the various setback and other requirements pertaining to a solar development were de facto zoning requirements and they were precluded, since 24 V.S.A. § 4413 (b) provides that zoning bylaws "shall not regulate public utility power generating plants and transmission facilities regulated under 30 V.S.A. § 248."

[9] 30 V.S.A. § 202(a)(1)

The court also agreed with the Board’s holding that the town had not designated a specific area for aesthetic protection, and therefore their objection did not rest on a community standard.

The Court upheld the Board’s decision on the second element of the Quechee test as well; the project does not offend the sensibilities of the average person. The town and the neighbors considered the impact from their point of view, rather than from the viewpoint of the average person as the Board is required to do. The Court found that while the Board is not required to consider the vantage points of individual landowners, it did so when recommending additional and improved visual mitigation measures, as recommended by the Department in the testimony of its expert witness.

The court also found that the applicant met the third prong of the Quechee test in that the developer had taken generally available mitigation steps to minimize the aesthetic impact. The court went on to discuss the neighbor’s contention that the project should have been relocated to a more appropriate site.

In this case, the position of the Department was adopted by both the Board and the Supreme Court. The Department had to walk a delicate line of promoting the renewable objectives contained in statutes while balancing this with the rights of both the project developer as well as the towns and adjoining property owners. In this case, the Department’s position was affirmed as consistent with the applicable statutes and precedent.

Public Health and Safety

The Board is also required to find that a proposed project will not have an undue adverse impact on the public health and safety under the 30 V.S.A. §248(b)(5) criteria. The developer of the proposed project had represented in its petition that the perimeter fence surrounding the project would meet all applicable electrical safety codes specifically aimed at limiting unauthorized access to potentially dangerous components of the facility. The required specifications of a perimeter fence are generally outlined in the relevant electric safety codes, but specific code requirements are open to interpretation in some areas.

In this case, the Department recommended a new approach to evaluating the veracity of the developer’s claims regarding the effectiveness of the proposed perimeter fence. Rather than attempt to evaluate the site-specific fencing proposed for the project against the applicable safety codes as it had done in past cases, the Department established through cross examination at hearing that the proposed fence met all applicable safety codes. The Department then recommended in briefing that prior to project construction, the Board require the developer obtain certification from a Vermont-certified master electrician or electrical engineer that the proposed fence did, in fact, meet the applicable safety codes.

The Department’s recommendation was adopted by the Board in its final order, and the condition was not challenged by the developer on appeal. This new approach appropriately placed the burden on the developer to show beyond mere representation that the proposed fence would be effective at limiting unauthorized site access, as opposed to forcing the Department to evaluate and potentially challenge the fence safety claims on a case-by-case basis. This new condition language has been adopted by the Board in cases since this one.

Project Decommissioning Fund

Under Board Rule 5.402(c)(2) a petition for the construction of a non-utility generation facility with a capacity of more than one megawatt must include a decommissioning plan for the project at the end of its useful life. The Cold River Solar project is subject to this requirement. The project petition proposed to establish a fund of approximately $72,000 to cover the projected costs of decommissioning the project. The Department established through discovery and cross examination at hearing that the developer had reduced the decommissioning cost estimate by approximately $96,000 by subtracting out anticipated salvage value for certain project components, contrary to Board precedent. The Department argued in briefing that petitioners are required to account for any and all decommissioning related costs regardless of any anticipated salvage value for project components, and recommended that the project decommissioning fund be initially established at $170,000. The Board adopted the Department's recommendation and required that the developer more than double the proposed funding amount, and set the fund consistent with the Department's recommendation. The developer did not contest this condition on appeal.

3. Docket No. 8684 – Establishing Rate Schedules for Power Sold to the Purchasing Agent

This case involves a petition from the Department of Public Service to open an Investigation into Establishing Rate Schedules for power sold to the Purchasing Agent pursuant to Public Service Board Rule 4.100, l6 U.S.C. § 824a-3 and 30 V.S.A. § 209(a)(8). The Petition was filed in October 30, 2015.

History and Background

In Vermont, the Public Service Board (Board) is the state regulatory authority that has the responsibility for implementing the Public Utilities Regulatory Policy Act ("PURPA"). 30 V.S.A. § 209(a)(8). This Act requires that electric utilities offer to purchase electric energy and capacity from "Qualifying Facilities" at rates that are just and reasonable, non-discriminatory, and which do not exceed "the incremental cost to the electric utility of alternative electric energy", or "avoided costs".

The Board issued Rule 4.100 to provide guidance and structure for meeting Vermont's responsibilities under PURPA and FERC regulations. Rule 4.104(E) sets forth the process for establishing the avoided cost rates to which QFs may become entitled, provided other provisions of the rule are met. That section provides that the Department should annually determine the avoided capacity and energy costs of the Vermont composite electric utility system and file proposed rate schedules with the Board. After hearing, the Board shall approve or modify those rate schedules.

After a long hiatus, this process again took place over the course of 2014. The Department proposed generic avoided cost rate schedules in August 2014, and the Board adopted them, with minor adjustments, on February 9, 2015.

However, in the time between when those rates that were developed, market conditions had changed significantly, making the rates developed in 2014 and adopted in 2015 significantly higher than more current projections. This change in market conditions necessitated the petition from the Department.

<u>Position taken by the Department of Public Service</u>

The Department realized that expectations of market prices had declined and took action to file a petition with the Board to adjust the rates. This was significant because current projects in the queue were eligible for the higher rates. The Department's action stood to benefit both consumers and power producers. Consumers benefit from the lower costs for power; while producers benefit because they might otherwise run the risk of a challenge to their proposal by selling power under outdated rates. *See, e.g., East Georgia Cogeneration LP*, 158 Vt. 525 (1992). In fact, such challenges did materialize during the pendency of this case.

In taking this action, the Department also sought to have the new rates adopted on an interim basis, subject to a final determination from the Board regarding their adequacy. For the reasons stated above, this also protected consumers and benefitted producers. To expedite the proceedings and provide transparency, the Department filed complete work papers and testimony describing the rates along with the petition to the Board.

<u>Current Status of the Case</u>

This matter was heard and briefed during the summer of 2016; the Board has not yet issued an order. However, shortly after the hearing in this case, a revised Rule 4.100 went into effect. The revised rule no longer requires annual rate-setting proceedings

4. Docket No. 8390 – FairPoint Communications, Provision of Service Quality

This case involves an investigation into the quality of service provided by the Telephone Operating Company of Vermont LLC. The Telephone Operating Company of Vermont is doing business as FairPoint Communications ("FairPoint").

The investigation was opened following a petition filed by the Department on December 1 of 2014. The Department's petition was triggered by an event in late November of 2014 that presented an immediate concern for public health and safety. FairPoint experienced a network outage after weather conditions contributed to two fiber cuts on its network. This event resulted in all customers unable to reach emergency services and 911 for a period of some number of hours. This event was coupled with and reflected overall poor service quality and performance by FairPoint. Between September 4, 2014 and November 30, 2014, the Department received 388 complaints regarding the quality of service provided by FairPoint, at least 3 times the normal levels. In addition, FairPoint had failed to meet the baseline service quality standards for Residential Troubles Cleared within 24 hours for straight 5 quarters.

The Department's petition noted that FairPoint was failing to meet service quality standards established in Docket 5903 and that the Department was receiving a high number of customer complaints concerning service interruptions and delays in the repair of service. (In 1999, Docket 5903 established eleven performance metrics for Vermont telecommunications providers.[10] FairPoint began reporting results from the Docket 5903 Metrics on April 1, 2013. Prior to then, FairPoint successfully adhered to standards from its Docket 7724 Retail Service Quality Plan.) Concern was expressed that other related factors were likely to further contribute to the poor performance of the company and its ability to deliver promised levels of service. This included the labor strike called by FairPoint's union workers in mid-October of 2014.

Shortly following the petition, the Board opened an investigation and asked that the parties address common concerns associated with FairPoint, including, billing practices, failure to show up for scheduled appointments, untimely provision of new service, failure to fix outages or address poor service issues quickly, and unauthorized disconnection of service. Complaints from customers had been high and increased during the labor strike that occurred from October 2014 to late February 2015.[11]

The authority to investigate and pursue this investigation into the service quality and reliability performance of FairPoint by the Board and Department rests with their broad authority under 30 VSA Section 203 and Section 209(a)-(c), which extends authority to address service quality and to protect the health and safety of utility customers. Section 209(b) provides authority to create rules that are relevant to the oversight of telecommunications (and other) utilities.

Terms of the Stipulation and Concessions Garnered or Given by the Department

The Department and FairPoint agreed on a settlement that was memorialized in the MOU entered on August 10, 2016. The MOU addresses four main issue areas: (1) service quality, (2) the SS7 network, (3) Board Rule7.609(C), and (4) the Connect America Fund II with accompanying commitments to broadband delivery.

Service Quality

FairPoint suffered very poor service quality performance prior to the investigation. Service levels were as poor as they had ever been. By the time that the Department reached a settlement with FairPoint, remediation steps had resulted in the Company once again achieving the performance targets under the metrics, save the one metric related to Troubled Cleared within 24 hours.

[10] http://publicservice.vermont.gov/sites/dps/files/documents/Info_Utilities/RETAIL_SERVICE_QUALITY_REPORTING_INSTRUCTIONS.doc
[11] Final Order Docket 5390, 12/18/15.

Under the MOU, FairPoint will continue to report its performance under the Docket 5903 metrics on a quarterly basis, except for the "Troubles Cleared" metric. The "Troubled Cleared" metric was to be reported on an annual basis.

The MOU changes the way that FairPoint's performance will be regulated under the Docket 5903 metrics. It requires FairPoint to file only one Action Plan annually for the Troubles Cleared metric. The Department conceded that multiple Action Plans are not needed as this metric represented a special category with vulnerability to even some common weather events like a heavy rain.

The Department and FairPoint agreed to defer certain issues in the proceeding to allow for timely treatment of the CAF II issue. As such, the Department also agreed to support FairPoint's request for a separate proceeding that considers alternatives to the current performance standards, as well as continued service quality reporting requirements concerning FairPoint customers who do not have access to an alternative telecommunications provider.

The SS7 Network

Under the MOU, the Department and FairPoint agreed to requirements to ensure the reliability of the SS7 network. FairPoint had agreed to implement all changes and protocols recommended by the Department's experts, and instituted several SS7 network upgrades to improve the network and operational changes to improve its ability to prevent and respond to SS7 outages going forward. Within three months of the issuance of the final Order, FairPoint committed to completing the needed upgrades and improvements to its SS7 network and procedures regarding its SS7 network.

The Department agreed, and so did the Board, that these measures would address issues related to the SS7 system.[12]

(Alternative landline services are available in the majority of the state.) In exchange for the Department's agreement on the above issues, FairPoint committed to accepting CAF II funding that is needed to build out its broadband services to underserved areas within its service territory. The CAF II commitment is a multi-year commitment to upgrade the broadband capabilities of the network for the affected population.

Bill Credits

FairPoint agreed to provide retroactive bill credits calculated under Board Rule 7.609(C) to existing customers who were out of service for more than 24 hours at any time between April 1, 2013, and February 28, 2015. Further, FairPoint agreed to train and require center representatives to inform any customer calling to report a service interruption or outage that a bill credit will be available if the repair is not completed in 24 hours and the customer calls back to request the credit. Not all issues related to the issue of bill credits were resolved in this proceeded and were left to be addressed in the subsequent service quality investigation.

[12] PSB Order 8390 at 16.

Connect America Fund (CAF II)

FairPoint agreed to accept CAF II program funding for Vermont. Under the CAF II fund, FairPoint is eligible for approximately $52.7 million in federal funding to Vermont over six years to be used toward increasing broadband. Federal funds require a commitment of considerable additional funds from FairPoint that will be necessary to provide the upgrades. The commitment will require significant broadband buildout to underserved areas as identified and required by the FCC, at significant additional FairPoint capital investment. This investment will result in additional fiber facilities that will likely provide improved system reliability and capability for the for FairPoint's system.

The FCC funds and capital commitments of FairPoint will be used to increase speeds for approximately 28,400 customers within the state. The commitment has a clear value to the 28,400 customers, but also to other customers that will realize additional improvements to service capabilities and speed. It is acknowledged that the broadband capabilities are not considered "cutting edge" but represent a material step forward in service delivery for the customers affected. But without the commitment to CAF II, there is no assurance that these needs will be substantially improved in the near future.

This commitment is regarded by the Department as an important achievement in agreeing to the terms of the MOU.

The Department and FairPoint segmented portions of this dispute for review under a separate service quality proceeding. The MOU, however, addressed the immediate shortcomings of the company, established forward-looking remedies, and extracted an important commitment to broadband service capabilities for rural segments of the customer base looking forward into the more distant future. The investigation was launched by the Department of Public Service. All issues were either substantially remedied going forward or were deferred for separate investigation. All recommendations related to the SS7 network were agreed to by the Company. No material concessions were made to the company over the course of negotiations beyond deferring a subset of issues for a later investigation that was necessary to secure the commitment to the CAF II fund.[13] Time was of the essence for the Department and FairPoint, as the CAF II fund offer was time limited. The Department managed to achieve the commitment.

5. Docket No. 7970 – Vermont Gas Systems Addison Natural Gas Project

In 2012, Vermont Gas applied under § 248 for an expansion of its system, proposing a transmission system from Chittenden and Franklin Counties down through Addison County to Middlebury. Originally proposed at $86 million, our analysis yielded approximately $180

[13] Interim concessions included in the MOU included that the "% Troubles Cleared Within 24 Hours" metric will be measured on a calendar year basis, that FairPoint will not be required to prepare more than one Action Plan during any calendar year, and that the Department will not seek any remedial measures relating to FairPoint's results under the Docket 5903 metrics.

million in benefits from this project, and thus, we supported it. After the issuance of a CPG in December of 2013, Vermont Gas noted project estimate changes that meant the project would cost $121 million. We reviewed that, and still found the benefits to outweigh the costs. Subsequently, the costs were re-estimated again at $154 million. Again, benefits still outweighed costs, but obviously ratepayer and Vermont public benefits compared to costs were becoming reduced. It is during this time we negotiated a cost cap of $134 million for the Addison project, recognizing our concern about ultimate potential costs to ratepayers that would be properly decided in a rate case, and that there were, in our opinion, mis-steps in the initial execution of this project. The CPG remained intact, but we acknowledged and represented we would perform an evaluation during the now-pending rate case to determine how much of this project should be passed through to ratepayers. As of this writing, we are recommending that only $112 million be allowed in rates, and that the company should absorb the difference between these costs and the current cost estimate of $165 million to complete the project. This issue is presently being litigated before the Public Service Board in Docket No. 8710.

The 2015 Memorandum of Understanding

As discussed above, we entered into a Memorandum of Understanding with the company to cap potential recovery for the Addison project at $134 million. This MOU was subsequently accepted by the Board. At the time, this meant a potential $20 million benefit for ratepayers, and now after rate-case review it may be closer to $31 million. We reserved all our rights to review the prudency of costs incurred as well as to challenge when any costs incurred should be allowed to be put into rates. Said another way, we reserved all our rights to challenge costs and to recommend disallowances. What we conceded in this negotiation was the conclusion that IF the project was completed as designed and approved by the Board, we would not challenge a conclusion that the project would be "used and useful" at the time it goes into service. We also acknowledged that there may be certain costs incurred that are beyond the company's control that should be accommodated above the cap – notably costs incurred due to excessive rights of way processes or due to protests. In the current rate case, the company has asked for $250,000 be allowed for these expenses. We have not evaluated the merits of the claims, but regardless said this addition should not be allowed in this rate year.

While protecting ratepayers with the cap, we still believe the project is worthwhile and gives Vermonters in the project footprint a choice to switch to a cleaner, cheaper and more stably-priced fuel, and one that is more environmentally sound than the oil or propane alternatives they have been used to.

As we proceed though the rate case, we will ensure that consumers are protected from both imprudent expenses and expenses not yet sufficiently documented. We will also work to ensure the rate impact of this project is modest in each year it is put into rates, and that it is stabilized by an appropriate use of the System Expansion and Reliability Fund (SERF) over the next several years.

From our review, although the case is still pending, we are proposing to the Board a rate reduction and we see no reason that the rates should not be flat or not increase at above the rate of inflation over the next several years if the SERF is properly used. We also believe that within 3-5 years, the SERF will be collecting as much as is being returned to ratepayers, and therefore should be suspended or eliminated.

6. Docket No. 8525 – GMP Rate Design – Proposed rate design reflecting the integration of legacy-GMP and legacy-Central Vermont Public Service Corporation rates

This case involves a petition from the Green Mountain Power Corporation to integrate its legacy tariffs from both GMP and CVPS for the commercial and industrial classes of customers. The Petition was filed in May 4, 2015.

<u>History and Background</u>

On June 15, 2012, the Board issued a Final Order in Docket 7770 approving, subject to conditions, the proposed acquisition of Central Vermont Public Service Corporation by a subsidiary of Gaz Métro Limited Partnership, the subsequent merger of Central Vermont Public Service Corporation and Green Mountain Power Corporation, and certain related transactions and proposals. One of the conditions included in that approval required GMP to file a proposed rate design and plan for integration of legacy-GMP and legacy-CVPS rates by May 4, 2015. This docket dealt with that filing and the method and timing for integrating the legacy rates.

For a regulated utility, rates for each customer class are supposed to reflect the costs that particular customer segment places on the utility. The rates are designed to collect those costs from that customer segment with rates for various services placed at a level to do so. While in theory, this is the appropriate thing to do, in practice it is difficult because many of the cost items are shared by the different classes. Allocation of those cost burdens can be difficult. Rate design is part art and part science.[14]

Prior to this proceeding, GMP had already integrated the general residential rates for the legacy companies into a combined Rate 1.

This case addressed the remaining legacy rates for GMP and CVPS. Rates covered include residential time-of-use (TOU) rate classes and other, non-residential rate classes. Since customers make purchasing and operating decisions based in part on power costs, any unanticipated changes can affect the viability of those decisions. Therefore, it is often necessary to phase in any such changes to mitigate the impacts of sudden change.

Two large customers intervened in this case: OMYA Inc. and GlobalFoundries.

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[14] Rate design is distinct from a rate case where all costs in each tariff are changed (usually increased) by the same percentage. In a rate design case, the costs in each tariff are adjusted individually (up or down) and by differing amounts to reflect changes in the allocation of company-wide costs. In simple terms, a rate case determines the size of the pie, and a rate design case determines how much of the pie is served to each customer class.

Position taken by the Department of Public Service

In this case, there were two rate design objectives to be addressed and recognized by the Department. The first was to ensure that changes to customer's rates, where justified, are made over a sufficient time period so as not to unfairly burden any customer segment with rapid changes in their costs for electric service. The second was to ensure that each customer class is charged the appropriate amount for the services that it requires. The cost that each customer class pays for utility service is intended to recover an appropriate portion of the total costs incurred by the utility to provide the service. Rates should cover incremental costs that can be directly assigned to the class and a fair allocation of joint and common costs. If one class is paying too little, another class is presumably paying too much. Such rates would potentially be unfair and could result in cross-subsidies. The objective here is to improve the fair allocation and assignment of costs for ratemaking purposes, the fundamental principle being "cost causer pays."

In its initial petition, GMP recognized both issues. Under GMP's proposal, adverse bill impacts would be managed by phasing in the rate changes over a period of one to five years (for different rate classes), generally limiting bill impacts to 2% annually, and by creating a new optional rate for one subgroup of customers that would experience more significant rate impacts as a result of the rate integration.

It is important to recognize that GMP's initial proposal in this case was both methodologically sound and customer-friendly. GMP also did significant outreach in advance of the filing to alert customers to the proposed changes. For these reasons, the Department generally agreed with GMP's approach, but sought further changes. The Department sought to lay the ground work for further improvement to GMP's rate structure in the near future, and to expand the effort to include recruitment and retention of manufacturers to the state in accordance with 30 V.S.A. § 218e. (§ 218e requires consideration of the effect of energy policy on businesses and manufacturers in the State.)

An MOU was agreed to by GMP, the Department, GlobalFoundries and OMYA (i.e. all parties to the case). Terms of the MOU covered the following:

(1) it prescribes the timing and certain requirements for GMP's next rate design;
(2) it required certain changes to the residential TOU rate classes, with an interim step aimed at integrating some of those rate classes;
(3) it makes certain changes to GMP's proposed Rate 14 and requires a marketing and evaluation plan; and
(4) it confirms the availability of GMP's Curtailable Load and Critical Peak riders to a broader range of customers.

The interests of residential ratepayers were not at issue in this proceeding. Since rate design is revenue-neutral to the utility, the MOU did not confer any particular benefit to GMP, apart from regulatory guidance for future rate designs.

Regarding timely improvements to GMP's rate structure, the MOU developed by the parties moved up the timeline for GMP's next rate design effort, and included some basic principles to guide the future effort. One focus envisioned for the next rate design is better incorporation of the features of smart meter technology to enable customers to receive and respond to price signals to manage their load and lower their bills. This goal is consistent with the concurrent draft of the Comprehensive Energy Plan which has certain goals pertaining to "smart rates" and targets 2018 for their deployment.

The MOU also included some changes related to residential TOU rates. These changes further the Department's goal of integrating the legacy company rates through the elimination of idiosyncratic and/or grandfathered residential TOU rate schedules, thereby simplifying the rate structure.

Regarding the Department's responsibilities under 30 V.S.A. § 218e, it is anticipated that some economic efficiency will be gained through the proposed rate design as it is expected to be in closer alignment to the rate class cost of service. The Department sought to empower customers to lower their electric bills by changing their load shapes in ways that benefit the operation of the grid and lower costs for all. The MOU confirms the expanded availability of GMP's Curtailable Load and Critical Peak riders to a wider range of participants, which could result in both improved grid operation (at lower cost) and savings to participating customers. The MOU also commits GMP and the Department to establish a new pilot program for schools to assist them in evaluating participation in these programs.

Additionally, the MOU requires certain changes to the residential Time of Use ("TOU") rate classes, with an interim step aimed at integrating some of those rate classes. It also makes certain changes to GMP's proposed Rate 14 and requires a marketing and evaluation plan to measure the success of the new rate offerings. These evaluations will help inform future rate design reforms planned for in the future.

Current Status of Case

The parties to the case, including Global Foundries and Omya Corporation, filed a MOU containing the agreements discussed above on November 5, 2015. On March 24, 2016, the Board approved the conditions in the MOU and issued an order approving the proposed revised tariffs, reflecting the integration of legacy-GMP and legacy-Central Vermont Public Service Corporation rates as well as a revised rate design. The Board also approved the Memorandum of Understanding dated November 5, 2015, among GMP, the Vermont Department of Public Service, GlobalFoundries, and Omya, Inc. supporting the proposed tariffs.

7. Tariff Filing No. 8618 – Green Mountain Power Base Rate Filing

On August 1, 2016, Green Mountain Power Corporation (GMP) made a filing (Tariff Filing #8618) pursuant to its Alternative Regulation Plan (Plan) to increase the rates it charges customers 0.93 percent. The proposed increase was made up of two primary components: (1) a 0.03 percent (approx. $142,000) decrease in GMP's base rates; and (2) a 0.96 percent (approx. $5.342 million) increase in its power costs. The Department supported the August 1 filing, as it reflected a negotiated resolution to all issues in the case, and resulted in rates that both the

Department, and its longtime rate consultant, Larkin and Associates, PLLC (Larkin) found to be just and reasonable. The Board accepted the Department's recommendation and allowed the proposed rates to go into effect on October 1, 2016.

The August 1 filing reflected a rate adjustment that was much less than the proposed 3.53 percent increase proposed in GMP's initial filing, which GMP filed on June 1. The June 1 filing sought the same 0.96 percent (approx. $5.342 million) increase in its power costs. However, in contrast to the August 1 filing, the June 1 filing sought a base rate increase of 2.57 percent (approx. $14.217).

<u>Positions taken by the Department of Public Service</u>

The $14.3 million difference between the initial June 1 filing and the final August 1 filing was primarily the product of two things: (1) GMP's Plan, and (2) the months of work by Department staff, in close coordination with Larkin.

First, GMP's Plan includes certain features meant to streamline aspects of the rate review. The most important feature in this case is the formula that established GMP's return on equity (ROE) for the year. That formula, which basically requires GMP's ROE to change at half the year over year change in 10-year Treasuries, resulted in a 42 basis point reduction in GMP's ROE. Whereas GMP's 2016 ROE was 9.44 percent, the formula resulted in a 2017 ROE of 9.02 percent. The impact on rates is significant. About a third of the $14.3 million reduction can be attributed to this change in ROE. Importantly, because of the clarity of the Plan on this point, this was achieved without the expensive and time-consuming financial analyses that are required to litigate a utility's ROE, allowing the Department to focus its attention on other aspects of the filing.[15]

Second, the remaining two thirds of the reduction from the June 1 to August 1 filing can be attributed to the review conducted by the Department and Larkin. This work included a review of GMP's actual FY 2015 earnings, its actual power costs for the year ending March 2016, and its proposed base rates for FY 2017. In order to complete the review, the Department conducted multiple rounds of discovery on GMP, performed site visits in conjunction with Larkin staff, and held numerous meetings and calls with relevant GMP staff to work through issues. The work culminated in the final weeks of July with negotiations between the Department and GMP.

The work began in November 2015, with GMP's ESAM filing for FY 2015 costs. The ESAM, or Earnings Sharing Adjustment Mechanism, is a feature of GMP's Plan that requires a "look back" at a previously completed rate year to compare GMP's actual earnings with the authorized

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[15] In the currently-pending Vermont Gas Systems rate case the Department and VGS each hired experts to calculate an appropriate return on equity. The Department's expert conducted several standard analyses and ultimately testified to an ROE of 9%, i.e. within a rounding error of the result under GMP's Plan. The return allowed to GMP is on the low end of allowed ROEs across the nation. In Q2 of 2016 the average allowed ROE nationally was 9.57%.

earnings previously set for that year. The actual under- or over-earnings are then shared between ratepayers and shareholders pursuant to formulas based on certain deadbands.[16]

This year's ESAM was novel in two key ways. First, it was the first ESAM under the most recent version of GMP's Plan (approved in Docket No. 8191). This is important because under the new Plan GMP files the ESAM in November, but it does not take effect until October of the following year (rather than in January of that year as had previously been the case). This gave the Department additional time to review the filing. Second, it was the first time that GMP sought to collect alleged under-earnings from ratepayers. GMP claimed under-earnings of $1.524 million, and pursuant to the Plan sought to recover 50% of those under-earnings (or $762,000) from ratepayers.

With the assistance of Larkin, the Department conducted multiple rounds of discovery on the ESAM and developed and performed a comparison of projected to actual plant additions for FY 2015. This data-intensive analysis enabled the Department to forcefully argue against GMP's request to collect $762,000 from ratepayers pursuant to the ESAM by demonstrating that GMP's "under-earnings" were largely attributed to spending decisions made by GMP that were untethered to the basis upon which its rates were initially set.

Also, during the winter and spring, Department staff performed a review of GMP's vegetation management practices. The issue came up in the prior year's base rates proceeding in which GMP sought cost recovery for the millions of dollars of damage caused by the historic December 2014 storm. Larkin had raised concerns at that time as to whether GMP was performing adequate vegetation management and it was agreed that the Department and GMP would continue to address the issue during the "off-season." These discussions, including additional discovery and a site visit to visually assess GMP rights of way at various stages of the vegetation management cycle, did in fact take place. The result of the Department's analysis on this point was to require GMP to devote additional resources to vegetation management pursuant to an agreed-upon framework for cost allocation.

As June 1 approached, the work pertaining to the base rate filing began to pick up. In May of this year, GMP provided the Department and Larkin with their list of proposed capital additions and Larkin performed its annual site visit to review and assess the cost support GMP had for its proposals. During that time, the Company and the Department (with Larkin) engaged in initial discussions regarding the proposed capital additions as well as other issues anticipated to arise over the course of the two month review period.

On June 1, GMP filed its proposed base rates adjustment. Throughout the next month and a half, the Department conducted five rounds of discovery. While Larkin focused on capital additions and other non-power costs, internal Department staff focused on power supply issues. The

[16] The ESAM mechanism provides GMP with greater assurance that its actual earnings will come close to its allowed return, effectively "decoupling" earnings from sales. This is valuable to the Company, and also to the public. Absent decoupling a utility has a strong incentive to increase its sales of electricity, and consequently to resist energy efficiency programs even if they are highly cost-effective for ratepayers. This "through-put incentive" is one of the weaknesses of traditional regulation, which rewards increased consumption of electricity.

review revealed a number of concerns, which the Department articulated to the Company in a July document setting forth an Issues List. This document served as the basis for subsequent negotiations and was later supplemented to describe the outcome of each issue and was filed by GMP with its August 1 filing. This was a new practice put in place to allow stakeholders and the public to have greater insight into an admittedly opaque process.

Importantly, as the *DPS Recommendations and Associated Outcomes* sheet and associated documents demonstrate, the Department achieved a significant beneficial outcome for ratepayers. The Department successfully excluded more than $37 million of proposed rate base additions from the base rates filing. The Department achieved a first-of-its-kind $300,000 "slippage" adjustment to account for a history of overly optimistic projected in-service dates – an adjustment only achievable by virtue of the data-heavy ESAM analysis demonstrating the historical slip in in-service dates. The Department achieved numerous additional adjustments that are small by themselves, but significant in the aggregate.

The end result is a rate adjustment for GMP customers of below 1 percent, keeping GMP rates more or less on par, if not slightly below, the rate of inflation. This is an important outcome. Perhaps even more importantly, the Department achieved nearly all, if not all, of the objectives it sought to achieve, including the recommendations of Larkin. This is significant given that the result was a negotiated one, in which the Department must credibly advance and articulate its position to GMP and rebut arguments advanced by GMP.

Perhaps more important, the achievement was made in the context of GMP's Plan. An evaluation of GMP's alternative regulation plan, its benefits and its challenges, is well beyond the scope of this report and of Act 130. At the end of the day, alternative regulation, much like traditional regulation, is a tool that is capable of being used to strong effect. However, they are different tools and must therefore be used in different ways in order to achieve a successful outcome. Two observations are relevant to this year's base rates proceeding on this point. First, the timeline for review of the base rates filing is very challenging, even where most of GMP's O&M costs are effectively unreviewed due to the 10-year Shared Savings Plan approved in the Merger Order in Docket 7770. The outcomes described above were achieved without the benefit of the more lengthy timeframe afforded by a traditional case.

Second, while this base rates review is shortened in comparison to a traditional case, the overall structure of GMP's Plan affords the Department a degree of access and visibility into GMP's finances and operations that is much greater than it would be in traditional regulation. The multiple reviews of capital additions before and after they are made are a far cry from the ad hoc and limited reviews that take place under traditional regulation. In light of the heightened visibility afforded by alternative regulation, the Department need not resort to "winner take all" litigation on every issue, but can instead advance certain issues incrementally. This year's proceeding saw incremental gains in the areas of vegetation management, calculation of working capital allowance, and the interpretation of certain provisions relating to the Exogenous Event Adjustment. This ongoing engagement and review is an important feature of alternative regulation and key to its successful use.

Section 2(a)(6) of Title 30 directs the Department to represent "the interests of the consuming public in proceedings to change rate schedules . . . ." The Department did so in this case, as it has historically done, on behalf of all customer classes served by GMP.[17] The Department's advocacy in this rate proceeding saved GMP's customers $14.359 million, and secured virtually all of the adjustments recommended by our long-time rate consultant Larkin & Associates. Moreover, the value of the more regular periodic reviews of the company's costs and practices under alternative regulation is demonstrated by the Department's continuing engagement with the company on the issue of vegetation management. This activity is critical to the reliability of electric service and therefore important to the public. *See* 30 V.S.A. § 2(a)(3) (DPS to supervise the quality of service of public utilities). The formulaic adjustment of the company's allowed return also represents a savings for ratepayers of thousands of dollars that would otherwise be expended to retain and cross-examine experts. This savings is a direct result of the alternative regulation plan.

[17] Section 2(f) directs the Department to favor certain specified classes over others. This provision is not implicated by general rate proceedings since the interests of different customer classes are not adverse.

Appendix A

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December 8, 2016

Christopher Recchia
Commissioner of the Department of Public Service
112 State Street, Third Floor,
Montpelier, VT 05620-2601

Dear Chris,

Enclosed please find the Attorney General's findings and recommendations on the advocacy of the Department of Public Service in the recently concluded Green Mountain Power (GMP) rate case.

As you know, the Legislature directed the Department to prepare and submit a performance report on its work in utility rate cases. *See* 2016 Acts and Resolves No. 130, Sec. 5f(a). The "primary purpose" of the Department's report is "to help address concerns regarding any potential compromise of the effectiveness or independence of the Department's representation of ratepayers in rate proceedings, including base rate filings under an alternative regulation plan." Act No. 130, Sec. 5f(b).

Also, "to assist with meeting the purpose stated in subsection (b)," the Legislature directed the Attorney General to "monitor and detail" a rate proceeding and to "make findings and recommendations related to the effectiveness and independence of the Departments' ratepayer advocacy." Act No. 130, Sec. 5f(c). The Attorney General's findings and recommendations will be included in the Department's annual report.

In summary, the Attorney General's findings and recommendations are that:

1. The Department of Public Service served as an effective advocate on behalf of ratepayers in the GMP rate case.

2. The Department's attorneys and experts demonstrated their "independence" in this case.

3. The Department should require GMP to file a rate case not later than January 2018, with the expectation that that case will be litigated and will not be reviewed under an "alternative regulation plan."

The Attorney General's findings and recommendations were developed by Robert Simpson, a Burlington attorney. Mr. Simpson's legal experience includes years of public service as an Assistant Attorney General, as Chittenden County State's Attorney and as an advocate for ratepayers at the Department of Public Service. The AGO retained him to help us assess the Department's work in the GMP case.

The AGO also retained the George E. Sansoucy firm. Mr. Sansoucy and his firm have engineering, appraisal and regulatory expertise with a focus on electric utilities. They helped Mr. Simpson and the AGO develop the recommendations required by Act No. 130.

Mr. Simpson's work is reflected in the enclosed documents. They include his report, the attached recommendations of Mr. Sansoucy and Exhibits 1 through 20. As you can see, Mr. Simpson did a thorough job. He reviewed GMP and Department filings and reports, met several times with Department representatives, spoke with the attorney who represented the AARP in the proceeding, attended a GMP presentation, attended a PSB workshop, spoke with the Department's expert, consulted with Mr. Sansoucy and kept the AGO informed about his progress. His findings and recommendations are footnoted and documented.

As noted at several places in Mr. Simpson's report, the Department has been an effective advocate. For example:

- "The Department's lawyers and experts were able, through negotiation, to convince GMP to reduced its proposed base rate increase to a slight rate decrease for the Base Rate Adjustment." Simpson report at p. 10.

- "The Department's lawyers and experts were successful in getting GMP to agree to exclude $37.325 million from GMP's proposed additions to rate base in the 2016 filing for failure to meet the 'known and measurable' standard." Simpson report at p. 15.

Mr. Simpson also reported, and AGO staff observed, that the Department advocated for ratepayers in a very professional and independent manner. "There is no evidence that the 'independence' of the Department lawyers and experts" who worked on the GMP rate case was compromised in any way by a too close relationship with GMP. Simpson report at p. 3.

Both Mr. Simpson and Mr. Sansoucy conceded that "alternative regulation" has some advantages, but expressed concern that GMP's rates have been set through an alternative process and without a fully litigated rate case for more than ten years. Mr. Simpson found that the time constraints imposed by the alternative process meant that some financial matters are not reviewed "in the same level of detail" as they would be reviewed in a fully litigated case. Simpson report at pp. 17 and 18 (citing the Department's expert). Mr. Sansoucy advised that the alternative process "does not allow for the robust review essential" in these cases. Sansoucy recommendations at p. 1. They recommended – and the AGO concurs – that the next GMP filing should be litigated and should not be reviewed under an "alternative regulation plan."

This will come as no surprise to you, but your deputy and your lawyers have been very professional, helpful and cordial throughout this process. The Legislature directed the Department to give the AGO full access to its work and work product, but your staff went well beyond this requirement. They responded fully to all of our requests for information, provided information that went beyond our requests and were more than generous with their time from start to finish. Hopefully the AGO findings and recommendations will be useful to the Department and to the Legislature.

Please let me know if you have any related questions.

Thank you.

Very truly yours,

Bill

William Griffin
Chief Assistant Attorney General

VERMONT DEPARTMENT OF PUBLIC SERVICE'S "RATEPAYER ADVOCACY" IN GREEN MOUNTAIN POWER'S 2016 RATE ADJUSTMENT FILING UNDER ALTERNATIVE REGULATION

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2016 REPORT ON THE "INDEPENDENCE" AND "EFFECTIVENESS" OF THE VERMONT DEPARTMENT OF PUBLIC SERVICE'S "RATEPAYER' ADVOCACY"

Summary of Findings and Recommendations

The 2016 Vermont Legislature directed the Vermont Attorney General (AGO) to review the independence and effectiveness of the Vermont Department of Public Service's (Department) advocacy on behalf of ratepayers in at least one proceeding conducted under Alternative Regulation (Alt. Reg.). The AGO chose to review the Department's efforts on behalf of ratepayers in reviewing and challenging Green Mountain Power's (GMP)'s 2016 request for a rate adjustment under the Company's Alt. Reg. Plan.

The review's most significant findings are:

1. There is no evidence that the "independence" of the Department lawyers and experts who reviewed Green Mountain Power's (GMP) 2016 Rate Adjustment[1] Filing was compromised due to an overly "cozy" relationship with GMP employees;
2. The current Alt. Reg. plan does not give Department experts enough time to review GMP's proposed rate base investments[2] which were authorized to grow by $188 million over the past two years (16%);
3. The current Alt. Reg plan discourages litigation. Instead, it encourages annual negotiated settlement of all disputes between the Department and GMP. Ratepayers would be better-served if the Department litigated and obtained a final judgment from the Vermont Public Service Board on such important issues as:
    - GMP's repeated failure to meet its obligation to prove why the rate base investments it proposes are in the best interests of ratepayers;
    - The appropriate rate of return on equity (ROE) for GMP in light of the fact that there is little risk under Alt. Reg that GMP will not earn its authorized ROE;
    - The appropriate capital structure for GMP in light of the fact that the Company is a wholly owned subsidiary;
    - The proper interpretation of important provisions of the current Alt. Reg plan such as the "Exogenous Change Adjustment."
4. There should be a three-year "pause" in alternative regulation when GMP's current Alt. Reg Plan expires on September 30, 2017. During that pause, the Department should advocate for the process proposed by George Sansoucy, P.E. LLC ("Sansoucy")[3] which would require GMP to file a "traditional rate case" with the Vermont Public Service Board (Board) no later than January 1, 2018. (Sansoucy's complete proposal is attached to this report.)

[1] The 2016 proceedings set GMP's rates to serve its customers in the 2017 "rate year" (10/1/2016-9/30/2017). This process has been referred to by the parties as the "2017 Base Rate Filing", the "2017 Cost of Service Filing" or the "Plan Rate Adjustment Filing." Since the "filing" and the "process" took place in 2016, it is referred to in this report as the "2016 Rate Adjustment Filing" to avoid confusion.
[2] GMP's "rate base" is the total amount of the Company's investment in "plant" (generation facilities, distribution lines, trucks etc.) that serves ratepayers. Ratepayers pay for additions to rate base investment through electric rates. They pay a "return of" that investment (depreciation expense component in rates) and a "return on" that rate base investment (cost of capital component, including a return on equity component).
[3] George Sansoucy, is an expert in a variety of areas related to utilities and utility regulation. He has worked and testified as an expert before the New Hampshire Public Utilities Commission, the Michigan Public Service Commission and the San Francisco Public Service Commission.

Background

In its 2016 session, the Vermont Legislature amended 30 VSA § 3075 to require the Commissioner of the Department of Public Service (Department) to submit an annual report to the Legislature which:

> ". . . summarize (s) the Department's role and positions with respect to other significant topics addressed by the Department's Public Advocacy Division pursuant to alternative regulation or to litigation before the Public Service Board or other tribunal. The report specifically shall refer to the Department's duties and responsibilities under Title 30 and explain how the Department's positions and activities align with those statutory provisions." Sec. 5f (a)

The Legislature explained the "primary purpose" of the Commissioner's report:

> "(b) The primary purpose of the reporting requirement of this section is to help address concerns regarding any potential compromise of the effectiveness or independence of the Department's representation of ratepayers in rate proceedings, including base rate filings under an alternative regulation plan.

The Legislature directed the Vermont Attorney General (AGO) to assist the Commissioner by providing "findings and recommendations" which are to be included in the Commissioner's annual report:

> "(c) To assist with meeting the purpose stated in subsection (b) of this section, the Attorney General shall monitor and detail at least one rate proceeding annually and make findings and recommendations related to the effectiveness and independence of the Department's ratepayer advocacy. In performing his or her duties under this section, the Attorney General shall have full access to the work and work product of the Department as it relates to each proceeding he or she monitors. The Attorney General's findings and recommendations shall be included in the Department's annual report."

I. PROCESS ADOPTED TO COMPLY WITH THE LEGISLATURE'S DIRECTIVE

Green Mountain Power (GMP) is Vermont's largest electric utility. The AGO selected GMP's 2016 Rate Adjustment" Filing under the Company's Alt. Reg. Plan as the proceeding to follow in assessing the "effectiveness" and "independence" of the Department's advocacy on behalf of GMP ratepayers.

On June 29, 2016, the AGO retained the undersigned[4] to follow the process and draft the "findings and recommendations" mandated by the Legislature. At roughly the same time., the AGO

[4] Bob Simpson - I worked as a lawyer in the Public Advocacy Division of the Department of Public Service from 1990-94. During that time, I was involved in litigating two GMP rate cases before the Vermont Public Service Board (Board) under what is now called "traditional rate-making." Following my work for the Department of Public Service, I went to work in the Chittenden County State's Attorney's Office where I served as Chief Deputy from 1997-2001 and as State's Attorney from 2001-2006. During my time at the State's Attorney Office, I also served on

retained Sansoucy to provide technical advice, and later, to draft a proposal to replace the process for reviewing and approving proposed additions in GMP's annual Rate Adjustment Filing.

Under Alt. Reg, GMP files annually for adjustment of its rates. This annual rate adjustment process sets the rates ratepayers will pay to generate the revenue needed to cover GMP's costs to provide electric service to its customers ("Cost of Service") in the upcoming "rate year" – the twelve -month period running from October 1 through September 30.

By the time Sansoucy and I were in place in late June and early July, the work of the Department and its consultant, Larkin Associates (Larkin) of Livonia, Michigan[5] in reviewing GMP's 2016 filing had been underway for several months[6]. It was expected the Department's work would wind up within a month (on August 1) after which the Department and GMP would announce an agreement on the Company's rates.

At that point, it was not possible to "monitor and detail" the Department's performance in this "rate proceeding" in the way a news reporter, or legal or regulatory expert, might have reviewed the Department's performance under "traditional ratemaking." This was true, not only because the process was nearly over; but also, because of the nature of the proceeding, itself.

GMP's 2016 Rate Adjustment "proceeding" was unlike a "rate case" under traditional regulation. The Alt. Reg. process did not involve pre-filed testimony, cross examination of experts or the filing of legal memos which explained each party's position. Instead, the Alt. Reg. process was a two-month period of intense review of scores of issues which necessitated informal give-and-take between the Department's technical experts and lawyers and their counterparts at GMP. This negotiating process was expected to culminate in a "global agreement" on August 1.

I decided it would be very difficult to "monitor" and "detail" this process in the one month left to me before the projected August 1 agreement without seriously disrupting the work of Department's lawyers and experts who were involved in intense negotiations.

There was another problem. Since the Board first approved GMP's Alt. Reg. Plan in 2006, each of GMP's annual "rate adjustment" filings has been resolved through a negotiated "global agreement" between GMP and the Department. As far as I could tell from the Board's records[7], the Department had not asked the Board to make a formal decision on the merits of any disputed issue in these annual rate

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the Burlington Electric Commission (1999-2001). I have served as a part-time hearing officer for seven different Vermont administrative agencies since 2007.

[5] The Larkin firm is an expert in utility regulation and accounting. Larkin has served as an expert to ratepayer advocates in numerous states in all parts of the country. Larkin accounting expert, Helmuth W. (Bill) Schultz, has served as an expert for the Department and the Vermont Public Service Board for approximately 25 years.

[6] A chronological summary of events affecting GMP's Rate Adjustment Filing is attached as exhibit 1.

[7] The Board's website has the formal decisions it has made since it approved GMP's first Alt. Reg. Plan in 2006. In each decision, the Board approved an agreement between GMP and the Department. I found no record of a Board ruling on the merits deciding any disputed issue raised by the Department involving Alt. Reg. https://www.google.com/webhp?sourceid=chrome-instant&ion=1&espv=2&ie=UTF-8#q=Vermont+public+service+Board+alternative+regulation

adjustment filings or, for that matter, on any one of the three Alt. Reg. Plans GMP has had since 2006. This meant that there was no "Alt. Reg. precedent" for me to use to assess the Department's performance in GMP's 2016 filing.

American Association of Retired Persons (AARP)

The American Association of Retired Persons (AARP) has been the Department's harshest and most persistent critic since the Board approved GMP's current Alt. Reg. Plan in August, 2014.

In January, 2015, AARP provided financial support for An Analysis of Vermont Alternative Regulation, by Dr. David Dismukes, Ph. D. of the Center for Energy Studies, Louisiana State University (2015 AARP Report)[8]. The study begins by explaining how alternative regulation plans are meant to benefit both regulated utilities and their ratepayers through "modifications" to traditional regulation which enable shareholders and ratepayers to share "efficiency savings." The study goes on to allege that the 2010 predecessor to GMP's current Alt. Reg. Plan provided significant benefits to GMP and its shareholders and meager benefits to the Company's ratepayers.

In February, 2016, roughly thirteen months after the first study, AARP commissioned a second study by Dr. Dismukes (2016 AARP Report).[9] This second study was published while the Department was reviewing components of GMP's 2016 Rate Adjustment Filing - the filing which is the subject of this report. The AARP study was sharply critical of the role played by the Department's Public Advocacy Division in approving GMP's current Alt Reg. Plan (2014-2017) and its predecessor (2010-2013). It was also critical of the Department's performance in negotiating the "global agreement" on GMP's 2015 Rate Adjustment Filing - an agreement that set rates that GMP ratepayers would pay from October 1, 2015 through September 30, 2016.

Since there were no hearings to monitor, no expert testimony to consider and no legal briefs and memos to review in order to make the assessment, I decided that under the circumstances, the best way to assess the Department's performance in the 2016 GMP filing was to determine: (1) whether AARP's criticism of the Department's past performance was valid, and, if so, (2) whether the specific elements of this criticism continued to have validity when "tested" against the Department's performance in reviewing and negotiating the settlement of GMP's 2016 Rate Adjustment Filing.

For example, the AARP's February, 2016 report said that the process the Department had agreed to in GMP's current Alt. Reg. Plan for reviewing and approving proposed additions to GMPs "rate base" failed to set any standard to ensure these projects were: (1) "needed" to provide service to GMP's ratepayer's; (2) "cost-effective" in that they had been compared to less expensive alternatives and (3) "in service" to ratepayers on the date GMP said they would be.[10]

[8] 2015 AARP Report, Exhibit 2

[9] David E. Dismukes, Ph D, A Critique of the Vermont Department of Public Service's Ratepayer Advocacy Activities, Organization and Act 56, Section 21 (b) Report, Acadian Consulting Group, February 24, 2016, -(2016 AARP Report - Exhibit 3

[10] 2016 AARP report, p.7 -Exhibit 3

I was confident the detailed 2016 "Larkin Reports" (discussed below) would serve as an effective means of determining whether the process for reviewing capital additions continued to fail ratepayers in 2016.

Larkin Reports

The GMP Alt. Reg. Plan calls for Larkin[11] to complete a review of the agreement which GMP and the Department have negotiated to ensure that, among other things, the agreement complies with "traditional rate-making and Board orders regarding cost-of-service filings."

On August 15, 2016, Larkin filed two reports to meet this requirement. One was a detailed, issue-by-issue analysis of the August 1 agreement which not only identified the issues which were addressed during the negotiations; but also, noted how these issues were resolved in the Department agreement with GMP on August 1, 2016. The other report dealt specifically with the Earnings Sharing Adjustment (ESAM) in GMP's Alt. Reg Plan and GMP's effort to have ratepayers pay for 50% of GMP's alleged "under earnings" in the 2015 rate year.

The clarity and detail of the analysis in these reports made it possible to test the validity of the criticism of the Department's advocacy on behalf of GMP's ratepayers in AARP's February 2016 Report[12].

II. FINDINGS

The Department's statutory obligation to protect the interest of GMP's ratepayers is set out in 30 VSA§ 2(a) (6):

> "(6) Review of proposed changes in rate schedules and petition to the public service board, and representation of the interests of the consuming public in proceedings to change rate schedules of public service companies . . ."

As a "licensed monopoly" GMP does not have to fight for "market share." Scott Hempling, an expert in regulatory law, who has testified as an expert witness for the Department in the past, describes the distinction between competitive markets and regulatory monopoly markets:

> "Competitive Markets - Since the market sets the price, you make money by beating competitors. Regulatory Monopoly Markets - *Since the regulators set the price, you make money by persuading the regulators."*[13] (emphasis added)

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[11] Board Order, Dockets 8190, 8191, August 25, 2014 ¶ 72, p. 19 calls for an independent party with expertise in ratemaking and accounting to file a review of each base rates filing within two weeks of the August 1 agreement between GMP and the Department. The review is to assess the agreement's "(1) accuracy, (2) completeness, (3) compliance with traditional ratemaking and Board orders regarding cost-of-service filings, including calculation of regulated earnings, and (4) consistency with GMP's actual cost and with" the Alt. Reg. Plan in effect at the time. Larkin has been retained to do the report for the past several years.

[12] Dr. David Dismukes, A Critique of Vermont Department of Public Service's Ratepayer Advocacy, Organization and Act 56, Section 21 (b) Report, February 24, 2016 (AARP 2016 Report) - Exhibit 3

[13] Scott Hempling, Are Regulators Allowing Returns on Equity Above the Real Cost of Equity? Presentation to the NARUC Consumer Affairs Committee July 13, 2014, Section I, D p.3 – Exhibit 4

The Department was obligated to “carry the fight” for ratepayers to ensure rates generated through GMP’s2016 Rate Adjustment Filing were “just and reasonable.”

Traditional Regulation in Vermont

The Board set GMP’s rates for decades through what is now called “traditional regulation” or “traditional rate-making.” Put very simply, this process involved taking GMP’s costs in one twelve-month period and then “adjusting” them upward or downward to set rates that would cover the costs GMP would incur to serve its ratepayers in a future twelve- month period.

Traditional rate-making in Vermont often involved “fully-litigated rate cases.” These cases were time-consuming and expensive; but, they did subject GMP’s rate requests to intense scrutiny.

For instance, on April 20, 1990, GMP filed for a 15.69% rate increase. (Docket 5428). Department experts and lawyers, joined by outside experts, including Larkin, conducted intensive discovery involving many rounds of interrogatories, requests to produce and depositions and then cross-examined GMP witnesses over the course of five days of hearings in late August and early September. Department witnesses submitted pre-filed testimony on September 21, 1990. The Department’s testimony challenged more than forty components of GMP’s case. Department witnesses were cross-examined over the course of six days of hearings in mid-October and early November. Witnesses from the Department and GMP were cross-examined over the course of three days of rebuttal testimony from November 26-28, 1990.[14]

GMP filed a second petition for a rate increase of 9.9% on July 20, 1991 – just 15 months after it had filed for a 15.69% rate increase in Docket 5428. Department lawyers engaged in the same process in this case (Docket 5532) as they had a little over a year earlier. They eventually submitted pre-filed testimony that challenged approximately twenty-five components of GMP’s case. Hearings in the case were conducted over the course of six months from November,1991 into April, 1992.
The Board issued a decision which granted GMP a 5.6% rate increase on May 21, 1992 1992 – approximately ten months after GMP had filed for the rate increase.[15] The decision specifically addressed, and ruled on, each of the issues raised by the Department.

The Department appealed (p. 15 below) components of the Board’s decision to the Vermont Supreme Court.

Alternative Regulation (Alt. Reg.)

In 2003, the Vermont Legislature authorized the Department and the Board to approve “alternative forms of regulation.” It was evidently an effort to make the rate-setting process more efficient and effective by providing rate stability for ratepayers and limiting risk for utilities such as GMP – utilities which were being asked to make major investments in “Vermont-based renewable energy” and “demand side management.”

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[14] Department’s Brief in Docket 5428, submitted to the Board on December 7, 1990, - Exhibit 5
[15] Department’s Brief, Vermont Supreme Court, Docket NO. 92-353, filed October 1, 1992 p. 2 -Exhibit 6

The statute authorizes the Board and the Department to approve "Alt. Reg." Plans which offer utilities like GMP:

> (1) clear incentives to provide least cost energy service to their customers; (2) provide just and reasonable rates to all classes of customers; (3) deliver safe and reliable service; (4) offer incentives for improved performance that advance state energy policy such as increasing reliance on Vermont-based renewable energy and decreasing the extent to which the financial success of distribution utilities between rate cases is linked to increased sales to end use customers and may be threatened by decreases in those sales; (5) promote improved quality of service, reliability and service choices; (6) encourage innovation in the provision of service; (7) establish a reasonably balanced system of risks and rewards that encourages the company to operate as reasonably as possible using sound management practices; and (8) provide a reasonable opportunity, under sound and economical management, to earn a fair rate of return, provided such opportunity must be consistent with flexible design of alternative regulation and with the inclusion of effective financial incentives in such alternatives." 33 VSA§ 218 d (a)

Dr. Dismukes, AARP's utility expert, explained the justification for alternative regulation in his 2015 report:

1. Under traditional cost of service ratemaking, regulators typically have less information about the true cost of service and the nature of that service than the utilities they regulate.
    - This can lead to circumstances in which ratepayers pay a return on capital additions that are "inefficient" (e.g. "gold plated")[16]

2. Under traditional cost of service ratemaking, it is not uncommon for there to be significant "lag" time between the time rates go into effect and the time regulated utility comes in for a traditional rate case.
    - If the utility saves on costs during this "lag time" by operating more efficiently, ratepayers may not get the benefit of these savings.[17]

3. The goal of "alternative regulation" is to take "a little of the "old" (cost of service ratemaking) and combine it with a little of the "new" (formulaic increases in rates and fixed regulatory review periods) to increase the effectiveness of the utility regulatory process, thereby enabling both parties (utility and ratepayers) to share "efficiency savings" while at the same time reducing administrative costs for both parties. [18]

GMP's Alternative Regulation (Alt. Reg. Plan)

The Board approved GMP's first Alt. Reg. Plan[19] in 2006. It approved updated Alt. Reg. Plans for the Company in 2010 and 2014.[20]

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[16] 2015 AARP Report, Slide 2-3-Exhibit 2
[17] Ibid.
[18] 2015 AARP Report, slides 4, 19 – Exhibit 2
[19] Board order in Docket Nos. 7175, 7176 (December 22, 2006)
[20] Board Order in Docket Nos. 8190 and 8191 (August 25, 2014)

The 2016 Larkin Report explains the fundamental benefit that the switch from "traditional ratemaking" to "Alt. Reg." has brought to GMP:

> "Under traditional ratemaking, the Company is afforded an opportunity to earn a reasonable rate of return. Under Alt. Reg. . . . the Company is essentially guaranteed a return with minimal risk."[21] (emphasis added)

Base Rate Adjustment

The Base Rate Adjustment was the focal point of the negotiated agreement between the Department and the Company in 2016. When GMP filed its annual proposal for a rate adjustment on June 1, 2016, its filing reflected a base rate revenue deficiency of $14.217 million which would have required a 2.57 % rate increase. The Department's lawyers and experts were able, through negotiation, to convince GMP to reduce its proposed base rate increase to a slight rate decrease for the Base Rate Adjustment.[22]

The Base Rate Adjustment is central to the GMP's Alt. Reg. Plan. It is meant to "forecast" the "adjustments" to the Company's "test year"[23] costs that will be needed to produce "just and reasonable" rates in the upcoming "rate year" which in 2016 is the period from 10/1/2016 through 9/30/2017.

The Base Rate Adjustment is, in fact, the sum of five "adjustments" to the Company's "test year" costs. The "capital spending adjustment" is the only one of the five that must be developed in compliance with traditional ratemaking principles. The other four components of the Base Rate Adjustment are either adjustment by formula or adjustment by "true up" - a practice that the Vermont Supreme Court and other high courts in the U.S., had determined was illegal under traditional ratemaking as "retroactive ratemaking."[24]

(1) "Capital Spending Adjustment" - GMP's Alt. Reg. Plan, provides for "adjustments" to historic rate year costs for GMP's proposed additions to its rate base investment through the end of the "rate year." These proposed additions can only be included in the Company's rate

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[21] Larkin Associates, PLLC, Report on Analysis of Rate Year Ending September 30, 2016 Green Mountain Power Cost of Service Request and Cost of Capital Request Under Alternative Regulation (August 14, 2015) (2015 Larkin) pp. 1-2 - Exhibit 8

[22] Larkin Associates, PLLC, Report on Analysis of Rate Year Ending September 30, 2017 Green Mountain Power Cost of Service Request and Cost of Capital Request Under Alternative Regulation (Augus15, 2016) (2016 Larkin) pp. 1-2 – Exhibit 8

[23] GMP's "historic test year" for the 2016 Base Rate Adjustment was the twelve-month period between April 1, 2015 and March 31, 2016.

[24] "Retroactive ratemaking" is defined as "the setting of rates which permit a utility to recover past losses or which require it to refund past excess profits collected under a rate that did not perfectly match expenses plus rate-of-return with the rate actually established." *In Re Central Vermont Public Service Corporation,* 144 Vt. 46, 52 (1984)

base if GMP proves that each proposed addition meets the "known and measurable" standard/ "test" as it has developed under Vermont law.

(2) Base O&M Costs/ "Current Non-Power Costs" Adjustment - Under GMP's Alt. Reg. Plan, rate year costs that are neither projected power costs or estimated rate base additions ("current non-power costs" or "platform costs"), are calculated by multiplying the sum of these "Current Non-Power Costs" x CPI -U-Northeast. [25] (The CPI-U Northeast for GMP's 2016 Base Rate Adjustment was 0.6%[26])

(3) "Earnings Sharing Adjustor" (ESAM) The ESAM is the difference between GMP's authorized return on rate base for the last full rate year's Base Rate Adjustment and GMP's actual return on rate base for the previous rate year. The amount of the ESAM is added to the Base Rate Adjustment and included in rates for the upcoming rate year. [27]

(4) Exogenous Change Adjustment – This adjustment consists of two potential adjustments for cost or revenue changes occurring in the test year (4/1 – 3/31):

- Exogenous Non-Storm Changes - are material cost or revenue changes that in aggregate exceed in any year $1.2 million adjusted annually for inflation.
  - "Changes" that are covered include: all "judicial, regulatory, or legislative changes affecting" GMP, net loss of major customer(s) load (not related to storms), major unplanned maintenance costs or investments and major repairs to company-owned power plants. [28]
- Exogenous Storm Changes - are increased costs relating to incremental maintenance expenses incurred by GMP due to major storms that exceed $1.2 million, adjusted annually for inflation.
- GMP's proposed exogenous change adjustment must be filed with the Department by May 1for inclusion in the Base Rate Adjustment for that year.[29]

(5) Return on Equity (ROE) Adjustment – GMP's authorized return on equity is calculated in July. It is tied to the 10-year treasury bond.

"... allowed return on equity component shall be adjusted by a percentage amount equal to 50% of the difference of the average of the ten-year Treasury note yield to maturity(a) as of the last twenty trading days ending two weeks prior to filing and (b) as of the twenty-day period used for the last return on equity component." [30]

Power Adjustor

Although Sansoucy says the "basis for the procedure (Power Adjustor) is sound," Sansoucy proposes changes to add a "robust adjudication process":

[25] Consumer Price Index for All Urban Consumers in the Northeast Region. (June 4 MOU), §III A. 5 – Exhibit 9
[26] 2016 Larkin, p. 4 -Exhibit 8
[27] June 4, 2014 MOU -GMP-AARP (June 4 MOU), pp.6-8 - Exhibit 9
[28] Board Order, Docket No. 8090, 8191, F. 20-22

[29] Board Order 8190, 81891, F-21-23
[30] June 4, 2014 MOU, p.4 - Exhibit 9

> "Costs relative to power supply are not to be included in the base rates. As such, a separate power supply cost recovery procedure shall be established. The current procedure requires quarterly filings reporting the actual power costs vs. the forecast power costs. These quarterly variances are then aggregated to establish as Power Adjustor to base rates for the following year. The basis of this procedure is sound but, similar to the Alt. Reg. Plan, it lacks a robust adjudication process. As such, we recommend that the Company file a Power Supply Cost Recovery Plan and a Power Supply Cost Recovery Reconciliation annually." (This process is described in the "Sansoucy Proposal" which is attached to this report.")

AARP's Criticism of the Department's "Ratepayer Advocacy"

AARP's February, 2016 report, was sharply criticized the Department in four important areas. However, it is important to note at the outset that AARP and the Department had taken steps to address each of these problems well before the AGO began its review in late June, 2016. In fact, three of the four problems had been addressed (with varying degrees of success) in 2014 when the Board approved GMP's current Alt. Reg. Plan.

1. <u>"Performance Adjustment" to GMP's Return on Equity (ROE)</u>

Dr. Dismukes, charged that this mechanism for annual adjustment of the Company's ROE gave GMP "bonus rates of return" if GMP's overall earnings were higher than those of utilities that were comparable to GMP – i.e. GMP was entitled to an even greater return if it could show it "was already earning more than most of its peer utilities."

1. Dr. Dismukes said: "This ROE performance adjustment mechanism effectively allowed GMP to "double dip" on excess earnings since the adjustment gave the utility a "bonus" rate of return if its overall earnings were higher than a peer group of comparable utilities.

2. In other words, according to Dr. Dismukes, "the mechanism allowed the utility to earn more in excess earnings, if it could show that it was already earning more than most of its peer utilities." Again, the "deal negotiated by the Department provided significant benefits to GMP, inexplicably at ratepayers' expense." 2016 AARP Report. P.7[31]

3. <u>Problem Addressed in 2014</u> **-** AARP negotiated the elimination of the ROE "performance adjustment."[32]

<u>2016 – "Effectiveness" of the Department's "Ratepayer Advocacy" on the ROE Issue</u>

The 2014 amendment eliminating the "earnings performance" adjustment to ROE had relatively little impact on ROE in GMP's 2016 "rate adjustment." But, Britain's vote to leave the European Union did. Britain's Brexit vote in June, 2016 served to move ROE in the right direction for GMP ratepayers. They will be paying a 9.02% ROE in rates for the period from October 1, 2016 – September 30, 2017.

[31] 2016 AARP Report. P.7 – Exhibit 3

[32] Board Order Docket 8190, 8191¶ 10

Under the terms of GMP's Alt. Reg. plan, ROE is adjusted annually based on the yield of the ten-year treasury bond[33]. Yield on the bond had dropped sharply[34] by the time of annual ROE adjustment in July, 2016, which happened not long after Britain's vote to leave the European Union. The result was the ROE dropped from 9.44% to 9.02.

- 10.25% - ROE when GMP's first Alt. Reg. Plan was adopted in 2006[35]
- 9.6% - ROE when GMP's current Alt. Reg. Plan was adopted in 2014[36]
- 9.02% - ROE in rates for the 2017 "rate year" (10/1/2016-9/30/2017)[37]

The trend is obviously going in the right direction for GMP ratepayers. But, the question remains whether the current ROE is still unreasonably high. The Board's Deputy General Counsel, George Young, raised the issue at the Board's annual workshop on GMP's proposed rate adjustment. He noted that Mr. Schultz, primary author of the annual Larkin reports, had said that under Alt. Reg., GMP is "essentially guaranteed a return with minimal risk." Mr. Young questioned whether it is reasonable to allow GMP such a "risk premium above the long bond" (30-year U.S. Treasury Bond) under circumstances where GMP's risk of not earning its authorized return is "drastically reduced."[38]

2. <u>"Capital Expenditure Mechanism" – Reviewing Rate Base Projects</u>

This is a particularly significant issue. The Department's agreements with GMP have authorized GMP to add $188 million to the company's rate base over the two-year period from September 30, 2015 through September 30, 2017.[39] This is an increase of 16%[40] over two years. If rate base growth continues at this pace, GMP's rate base will double in 9 years.

Ratepayers pay GMP a "return of" its rate base investment (rate component for depreciation expense) and a "return on" this investment (rate component for ROE)[41]. The Department is responsible for ensuring these investments are: (1) "needed", (2) cost-effective and (3) in service to ratepayers at the time GMP says they will be in service to ratepayers.

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33 "The allowed return on equity component shall be adjusted by a percentage amount equal to 50% of the difference of the average of the ten-year Treasury note yield to maturity(a) as of the last twenty trading days ending two weeks prior to filing and (b) as of the twenty-day period used for the last return on equity component." June 4, 2014 MOU, p.4 - Exhibit 9

34 Sam Goldfarb, Jon Sindrieu, Min Zeng, *Treasury Yields Hit Historic Lows Amid Brexit Fallout*, Wall Street Journal, July 4, 2016 http://www.wsj.com/articles/treasury-yields-hit-historic-lows-amid-brexit-fallout-1467414740

35 Order Docket 7175, 7176, December 22, 2006, pp. 13-14

36 Order Docket 8190, 8191, August 25,2014, p. 6

37 GMP, schedule 3, August 1, 2016 – Exhibit 11

38 Transcript of Board Workshop Re: Docket/Tariff 8618 (9/13/2016) pp. 79-80 - Exhibit 12

39 $1,164,743,000 on 9/30/2015 (Larkin ESAM Report, p.5) and $1,352,771,000 authorized through 9/30/2017 - (GMP Schedule 4, August 1, 2016) – 1,352,771,000 -1,164,743,000 = 188,028,000. Exhibit 10, Exhibit 13

40 188,028,000/ 1,164,743,000 = .1614

41 In the 2015 rate year, the Department agreed to have ratepayers pay GMP a $86.89 million "return on" its rate base investment. (GMP Schedule 4, May 31, 2014) It agreed to have ratepayers pay a $95.235 million return in the 2017 rate year (GMP Schedule 4, August 1, 2016) Exhibits 13, 14

AARP Criticism

Dr. Dismukes was critical of the Department's approval of a "capital expenditure mechanism" which, he alleged, permitted GMP to "pass through in rates" the estimated cost and in-service dates of these capital additions without requiring GMP to provide documentation such as: "the purpose" of the project and a cost-benefit analysis or the "anticipated and final costs" of a project.[42] Dr. Dismukes charged that "mechanisms of this sort are entirely inconsistent with alternative regulation principles."[43]

(1) Dr. Dismukes explained further:

- "Typically, utilities under ARP (Alt. Reg. Plan) -type mechanisms are given pricing flexibility to cover rising costs, including any capital-related costs. (footnote omitted) The Department, however, agreed to a mechanism which effectively allowed GMP to have its proverbial cake and eat it too. GMP would increase rates based on the ARP's formulaic method and would also be allowed under the Department's settlement to pass along additional capital expenses on a dollar-for-dollar basis without going through a standard rate case. The Department did not *impose or require the utility provide any documentation on these capital expenditures, including identify individual capital projects, the purpose of the capital project, and how it met the utility's longer run capital plan, the anticipated and final cost for each capital project, or any other standard information*. . ." [44] (emphasis added)

(2) Problem Addressed in 2014

In 2014, the Department negotiated an amendment which did address what Dr. Dismukes described as the Department's failure to require GMP to provide any of the "standard" documentation that is required before a capital addition can added to rate base.

(3) "Attachment 7" to GMP's current Alt. Reg. Plan requires GMP to prepare and file the following for each new capital project:

- "A capital project summary sheet with amounts tying out to the amounts requested";
- A work order describing: the proposed project; GMP's reason(s) for doing the project and "projected start and end dates of the project";
  A detailed cost benefit analysis for projects over $3 million; a cost-benefit analysis or a financial analysis for projects in over $300,000 but less than $3 million and a quantitative analysis for projects under $300,000
- "Actual Cost and Cost Estimates" [45]
- If GMP fails to provide the detailed analyses referred to above when it makes its base rate filing on June 1, a specific provision of Attachment 7 gives the Department, and ultimately the Board, the authority to "exclude from rates" any, and all, capital projects which were not properly documented. [46]

[42] 2016 AARP Report, pp. 6-7- Exhibit 3
[43] 2016 AARP Report p. 6 – Exhibit 3
[44] 2016 AARP Report, p.7 – Exhibit 3
[45] Attachment 7 to GMP's current Alt. Reg. Plan (Attachment 7) pp. 1-2 -Exhibit 9
[46] Attachment 7 p. 1 - Exhibit 9

2016 –Effectiveness of Department's Efforts to Review GMP's Proposed Additions to Rate Base

The Department's lawyers and experts were successful in getting GMP to agree to exclude $37.325 million[47] from GMP's proposed additions to rate base in the 2016 filing for failure to meet the "known and measurable" standard. That is, GMP was unable to prove why a proposed project would benefit ratepayers, or why there was not a less expensive alternative to a proposed project or why the Company's estimates "in service" dates for a proposed project were reasonable. However, the 2016 proceedings exposed a serious problem with the Alt. Reg. process for pre-approving proposed additions to rate base. The Company went back on its agreement to "exclude" millions of dollars from its rate base in 2015 and suffered little consequence for it.

"Known and Measurable" Standard

The "known and measurable test" has served as an important protection for GMP's ratepayers for decades. In 1994, the Vermont Supreme Court upheld the Department's claim that the Board had abused its discretion by failing to properly apply the "known and measurable standard" in a "fully-litigated[48]" GMP rate case in 1992. *In Re Green Mountain Power Corp*. 162 Vt. 378, 381 (1994)

The Department's Director of Public Advocacy at the time was James Volz, current Board Chair. The basis for the Department's appeal was testimony from Larkin Associates-at that time a new comer to Vermont.

The court explained that "known and measurable" changes to plant investment/ rate base were changes that are "measurable with a reasonable degree of accuracy and have a high probability of being in effect" in the year when the new rates were to go into effect.[49]

The Supreme Court found that the Board had exceeded its authority when it declined to give GMP ratepayers credit for $3.076 in "accumulated depreciation" which ratepayers had already paid for in rates. The effect of the rate approved by the Board was to require ratepayers to pay a return on an investment they had already paid off[50].

The Court also made it clear that GMP "had the burden" of proof when the Company sought recovery for projected costs in rates[51]. The Court found that GMP had "failed to meet its burden" of proof on its

[47] 2016 Larkin, p. 11 - Exhibit 8

[48] The Board considered testimony from GMP and Department witnesses on multiple issues raised by the Department in its challenge of GMP's proposed rate increase. The Board then issued an opinion which decided each issue and set out the factors supporting its decision on each issue.

[49] 162 Vt. 338

[50] 162 Vt. 382-84

[51] 162 Vt. 385

claim that ratepayers should pay in rates for a $785,000 project that was "known" to have been "cancelled."[52].

GMP's Repeated Failure to Meet Its Burden of Proof

In the years after GMP's Alt. Reg. Plan was approved in 2006, GMP consistently failed to provide "documentation" for proposed capital projects that was sufficient to meets it burden under the known and measurable standard.[53] As noted earlier, in 2014, GMP agreed to provide the Department with specific documentation with each proposed addition to rate base.[54] However, in 2015 and again in 2016, Larkin found that GMP continued to fail to provide the documentation it had committed to provide in 2014.

2016- Proposed Additions to Rate Base

1. In its 2016 Base Rate filing, GMP proposal a total for 228 projects, estimated to cost $132.85 million for additions to rate base during the 2017 rate year. This compared to 206 projects for a total of $86.499 million for 2016 rate year.[55]
2. Larkin found that the "financial analysis" that GMP had agreed to provide in 2014 was generally "insufficient" and that under "strict application" of the 2014 agreement, "a large number" of projects could have been excluded from the request.[56]
3. Larkin noted that GMP had failed to provide the agreed upon documentation for specific projects in 2015 as well.
4. For example, Larkin said "there was *no financial analysis*" provided for any of the 52 computer software projects estimated to cost $13.82 million (increase of 68% from 2015 request) that GMP proposed to add to rate base by the end of the 2017 rate year.[57]
5. There were numerous, documented instances where projects estimated to be "in service" on a particular date could not reasonably be completed on the estimated date or even within the 2017 rate year.[58] Larkin refers to this as "slippage;" but, it means if the estimate is not changed, ratepayers will be paying a "return of" and a "return on" plant investment before it is serving them.

Board Concern

On September 13, 2016, during the workshop mentioned earlier, Deputy General Counsel Young noted that "a number of" GMP's proposed additions to rate base "that are put in cost of service" either "aren't being built or aren't being built within the estimated time period." He said that this is a problem that had come up "at multiple" such workshops over the years since GMP's first Alt. Reg. Plan was approved in 2006.[59]

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[52] 162 Vt. 385
[53] 2016 Larkin, p. 4 – Exhibit 8
[54] June 4, 2014 MOU, Attachment 7 – Exhibit 9
[55] 2016 Larkin, p. 9 -Exhibit 8
[56] 2016 Larkin, p.10 – Exhibit 8
[57] 2016 Larkin, pp. 18-19 – Exhibit 8
[58] 2016 Larkin, pp. 13, 16-23 – Exhibit 8
[59] Transcript, Board Workshop re: Docket/ Tariff 8618 - GMP's 2016 rate filing (Board Workshop) p.72

Mr. Young questioned whether "there is something that we need to start to build into future alternative regulation plans, assuming there are future alternative regulation plans, because we talk about it every year at this time."[60]

Alt. Reg. Process Does Not Give the Department Enough Time for Adequate Review

The size of the rate base investments the Department must review has risen dramatically since the days of traditional ratemaking.

- There has been a $188 million authorized increase in GMP's rate base over the past two years.
- In 2016, GMP proposed adding $132.853 million worth of projects to an authorized rate base of $1.260 billion. [61]
- In 1991, GMP asked the Board to authorize an increase that would make its entire rate $164.55 million. [62]

Any future Alt. Reg. Plan must "build in" enough time for the Department to complete a thorough review of each project that GMP proposes to ensure that GMP has met its burden to prove each project meets the "known and measurable standard.

1. GMP's Alt. Reg. Plan gives the Department's lawyers and experts, including Larkin, a little less than three months (May 3 -July31) to review and approve capital additions.[63]
2. As noted earlier, in Docket 5532, a "traditional rate" case involving GMP in 1992, the Department's lawyers and Larkin had approximately six months (July 19, 1991- February 15, 1992) to review and conduct discovery on proposed additions to rate base, write pre-filed testimony that challenged proposed additions to rate base and then cross-examine GMP experts in hearings before the Board.[64]
3. The "allowance for plant additions" under GMP's Alt. Reg. plan "goes beyond what would be allowed under traditional ratemaking which would limit additions to non-growth and reliability/safety projects."[65]
4. In 2015, Larkin selected 134 of proposed capital projects for review.[66] Larkin reported in 2015 that "due to time constraints" some costs were not reviewed "in the same level of detail." In other words, "Larkin not taking issue with certain rate base items should not be construed as there is no issue."[67]
5. In 2015, Larkin found an error in GMP's calculations which would have justified a rate base reduction of "approximately $2 million" but the reduction was not made because by the time Larkin noticed the error, "the Department and GMP had already reached agreement . . ."[68]
6. In 2016, GMP proposed that 228 capital projects be added to its rate base. Larkin selected 155 of them for review.[69] Larkin reported, as it had in 2015, that "due to time constraints not all costs

[60] Board Workshop, Transcript., p.73 -Exhibit 12
[61] 2016 Larkin, p. 9, GMP Schedule 4, August 1, 2015 -Exhibit 8, Exhibit 17
[62] Department Brief in Docket 5532, p. 1 – Exhibit1 5
[63] 2016 Larkin, p. 8 – Exhibit 8
[64] Department's Brief in *In Re: Green Mountain Power Corporation*, Vermont Supreme Court Docket No. 92-353, p. 2 and Department' Brief filed with the Board (2/24/1992) -Table of Contents – Exhibit 6, Exhibit 15
[65] 2016 Larkin- ESAM Report pp.7-8 – Exhibit 10
[66] 2015 Larkin, p.8 – Exhibit 7
[67] 2015 Larkin, pp. 32-33 – Exhibit 7
[68] 2015 Larkin, p.29 - Exhibit 7
[69] 2016 Larkin, p. 9 – Exhibit 8

> are looked at in the same level of detail." Again, "Larkin not taking issue with certain rate base items should not be construed as there is no issue".[70]

In short, under Alt. Reg. in 2016, those who are charged with protecting ratepayers' interests have more projects to review, a wider variety of projects to review and less time to review them in than they had under traditional regulation. The Department and Larkin simply cannot submit GMP's proposals to the level of scrutiny ratepayers are entitled to.

Mr. Schultz, primary author of the 2016 Larkin reports, submitted pre-filed testimony on behalf of the Department in Vermont Gas proceedings on August 22, 2016. Mr. Schultz said he was speaking specifically of "his experience with alternative regulation in Vermont" with "electric companies."[71]

> One of the "cons," of alternative regulation is that "abuse and complacency can occur, resulting in higher rates. The abuse that can occur is that the company can develop what I think of as a 'blank check' approach to planning. The attitude that 'if money is spent, it can be recovered in rates' can develop because the level of scrutiny is limited under Alternative Regulation."[72]
>
> * *
>
> "My experience in Vermont is <u>schedule has been a factor</u> on the review process, limiting what can be analyzed as opposed to a traditional rate filing. A limited review means that some costs that would not typically be allowed in rates can fall through the cracks and get passed on and into rates. <u>With an ARP (Alternative Regulation Plan) review, the review of costs is even more important because of the ability to pass on costs so readily.</u> [73] (emphasis added)

Larkin does not have enough time under the current process to do a thorough review. The lack of time is exacerbated by the fact that under the current process, GMP lacks any incentive to meet its burden of proof under the "known and measurable standard."

This is demonstrated by the company's repeated failure to provide the documentation it has agreed to provide. Since Larkin and the Department only has three months, at most, to complete its "known and measurable" review, it is crucial that GMP provide the documentation it has agreed to provide on June 1. Since in many cases that is not done, Larkin is forced to request the documentation. And, since the process is a "negotiation" and in many cases, the Company has already invested its money, the burden of proof effectively shifts to Larkin to justify why the project should be excluded from rate base.

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[70] 2016 Larkin, pp. 29-30- Exhibit 8

[71] Pre-filed testimony of Helmuth W. Schultz in Docket 8698, August 22, 2016, p. 3- Exhibit 16

[72] Pre-filed testimony of Helmuth W. Schultz in Docket 8698, August 22, 2016, p.5 – Exhibit 16

[73] Pre-filed testimony of Helmuth W. Schultz in Docket 8698, August 22, 2016, pp. 5-6 -Exhibit 16

The result is the "known and measurable standard" is lost in the shuffle despite the best efforts of Larkin and the Department. This, in turn, has created an unreasonable risk that ratepayers are paying for millions of dollars in rate base investments that the Company has failed to prove: (1) "needed" to serve ratepayers -e.g. consistent with Company's long term plan or budget; (2) cost-effective – e.g. compared against less expensive alternative or (3) reasonably likely to be in service at the time GMP says it will be in service.

3. <u>"Earnings Sharing Adjustor" (ESAM)</u>

<u>AARP Criticism</u>

In his February 2016 critique, Dr. Dismukes charged that the Department had agreed to a lopsided "mechanism" (ESAM) for sharing any "over earnings" - revenue that exceeded GMP's authorized rate of return in the <u>previous rate year</u>[74]. Dr. Dismukes claimed the ESAM negotiated by the Department gave GMP and its shareholders an overly "generous percentage of any excess earnings" leaving little for ratepayers. [75]

1. Dr. Dismukes presented a chart which showed that over the period from 2007-2013, this "earnings sharing mechanism" (ESAM) enabled GMP and its shareholders to retain nearly $8 for every $1 it "shared" with ratepayers under the ESAM agreed to by the Department. That is, GMP took $6,647,631 for GMP over that period under the ESM while $852,447 went to ratepayers over the same period.[76]

2. <u>Problem Addressed</u>

   In 2014, AARP negotiated an amendment to GMP's Alt. Reg. Plan which required GMP to share more of its "over earnings" with its ratepayers.
3. Under the ESAM that expired in 2013, GMP was entitled to retain "over earnings" that were up to 75 basis points above its authorized return on equity. GMP was also required to absorb some "under earnings" – earnings that fell short of its authorized return.[77] However, if the earnings shortfall was between -75 to -125 basis points below GMP's authorized return, ratepayers would be required to "share the pain" on a 50/50 basis. [78] For instance, if "under earnings" that exceeded 75 basis points were $1 million, ratepayers would pay an additional $500,000 in rates to make up the "loss."
4. The amendments to the Earnings Sharing Adjustment Mechanism (ESAM) negotiated by AARP in 2014[79] meant that GMP was required to share more "over earnings" – earnings above the authorized ROE- with ratepayers. But, the amendment also called for ratepayers to share more of

[74] Dr. Dismukes refers to earnings that exceeded GMP's authorized return as "excess earnings." GMP's Alt. Reg. plan refers to these earnings as "efficiency savings."
[75] 2016 AARP Report, p. 6 – Exhibit 3
[76] 2016 AARP Report, p. 10 – Exhibit 3
[77] This "band" of 75 basis points either way is known as the "dead band."
[78] Board Order in Docket No. <u>7176</u> (December 22, 2006) --p.21 -paragraph 40
[79] Board Order, Docket Nos. 8190, 8191, (8/25/2014) pp. 11-12, ¶¶ 30-34

the "pain" if there were "under earnings." [80] (i.e. GMP's earnings fell short of the authorized ROE)

5. The 2014 amendment reduced the size of the so-called "dead band" for "over earnings"– the range in earnings above GMP's authorized return on equity (ROE) in which the Company is permitted to retain all its "over earnings."

- The "dead band" under GMP's predecessor Alt. Reg. Plan was set at within <u>75 basis points above, and below</u>, GMP's authorized ROE.[81]
- The 2014 amendment to the ESAM reduced the dead band to within 35 basis points above the authorized ROE- once above 35 basis points GMP would have to begin sharing "over earnings."

6. But the 2014 Amendment also reduced the size of the dead band for "under earnings" from 75 basis points below GMP's authorized ROE to 50 basis points below the Company's authorized ROE. That meant greater exposure for ratepayers if GMP "under earned."

- Under the former Alt. Reg. Plan, ratepayers were not required to pay for 50% of GMP's "under earnings" until the Company's earnings fell more than <u>75 basis points</u> below the Company's authorized ROE.
- Under the 2014 Amendment, ratepayers were responsible for 50% of the Company's "under earnings" as soon as GMP's earnings fell to more than <u>50 basis points</u> below its authorized ROE.[82]

<u>2016- GMP Says ESAM Requires Ratepayers to Pay 50% of the Company's Under Earnings</u>

GMP said it had "under – earned" by $1.524 million[83]in the 2015 rate year (10/1/2014-9/30/2015). The Company claimed that under the terms of the Alt. Re. Earnings Sharing Adjustment (ESAM), the GMP was entitled to have the ratepayers pay 50% of the $1,524,000 million under-earnings as part of the 2016 Rate Adjustment.

Larkin found that this "earnings shortfall" was "driven in large part" by the fact that GMP's rate base on September 30, 2015 – the end of the 2015 rate year- was more than <u>$41.071 million larger</u>[84] than the amount in the projection approved by the Department and the Board in 2014 Rate Adjustment filing. The increase in rate base was, in turn, due in large part to the fact that by the end of the 2015 "rate year" (9/30/2015) GMP had $24.186 million more in additions to rate base than had been authorized.[85].

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[80] <u>Id.</u> ¶ 34
[81] <u>Id.</u> ¶ 33
[82] <u>Id.</u> ¶ 31
[83] Larkin ESAM Report p. 1- Exhibit 10
[84] Larkin ESAM Report, p. 8- Exhibit 10
[85] <u>Ibid.</u> The $41.071 million over projected rate base figure had two components – (1) $24.186 million above projected plant additions and (2) accumulated depreciation was $16.885 million below projected accumulated depreciation. -Exhibit 10

GMP's authorized return on the projected rate base approved by the Department and the Board was $86.890 million. That amount was built into the rates that GMP ratepayers paid in the 2015 rate year[86]. However, the "authorized return" on the "actual" rate base – the one with the additional $24.186 million in unauthorized additions to rate base- was $88.809 million[87]. That resulted[88] in the $1.524 million in "under earnings" claim from GMP in its proposed ESAM adjustment and the claim that under the terms of the ESAM ratepayers were required to pay half of that amount ($762,000) as part of the 2016 Rate Adjustment.

The Department objected:

> "… it would be inappropriate for the Company to recover under earnings from ratepayers (or avoid paying over earnings) by including costs in the ESAM for plant that had not previously been reviewed and approved. To allow recovery of costs for such unapproved plant as part of ESAM would be to expand beyond established ratemaking standards and result in a process that loses the validation principle for setting reasonable rates."[89]

Larkin did a detailed review of the projects which were included in GMP's rate base on September 30, 2015 – the end of the 2015 rate year. It found, as it had in prior filings, that there had been "slippage." That is, projects that had been approved for inclusion in rate base on a certain date were not actually "in service to ratepayers" until much later. This meant that ratepayers had been paying for months, sometimes years for projects that were not "in service."

Larkin also found, as it had in prior filings, that projects that <u>had not been subject to "known and measurable" review</u> were "substituted" for projects that <u>had been</u> found to have met the "known and measurable standard."

Computer software projects provide a good example.

1. Thirty-five projects were approved for inclusion in rate base for 2015 rate year at an approved cost of $<u>12.295 million</u>.
2. Of the 35 projects approved, only 8 were completed on time, 10 projects were completed late and 17 projects (total cost <u>$1.053 million</u>) were not done it all.
3. The total spent on the 18 approved projects which were completed was <u>$11.654 million</u>.
4. GMP <u>substituted 46 projects (total cost $10.649 million)</u> for the 17 approved projects that had not been done.
5. GMP admitted that 29 of the substituted projects <u>had not been reviewed</u> by the Department at all and acknowledged that most of the remaining 17 projects had been approved <u>and included in</u> rates for the 2013 and 2014 rate years. [90]

[86] GMP Schedule 4, 2014 Rate Adjustment Filing of the 2015 rate year (10/1/2014-9/30/2015). – Exhibit 14
[87] Larkin ESAM Report p. 5. Exhibit 10
[88] Under the ESAM ratepayers were not required to pay under earnings within the 50-basis point "dead band." June 4 MOU p. 5 - Exhibit 9
[89] Larkin ESAM Report p.8 -Exhibit 10
[90] Larkin ESAM Report, pp. 16-17 -Exhibit 10

GMP's decision to add $24.186 million in unauthorized projects to rate base worked a "triple whammy" on its customers.

First, ratepayers will be paying rates for millions of dollars in projects that have not been subject to "known and measurable review" by the Department. Second, the Department had negotiated exclusion of $21 million[91] in projects from rate base in the 2015 rate year because they did not meet the "known and measurable standard.[92] By including $24 million in additional unauthorized projects in the 2015 rate year rate base, GMP effectively nullified the $21.1 million in exclusions, the Company had already agreed to. Third, under the terms of the ESAM, GMP's ratepayers owed the Company $762,000 for under earnings caused in part by the fact that the Company had added projects to rate base without regard for its obligation to prove they would benefit ratepayers.

The ESAM is a "true up" designed, in part, to make GMP "whole" for "under earnings." As noted earlier, the Vermont Supreme Court outlawed this form of protection under traditional ratemaking as "retroactive ratemaking" – i.e. "the setting of rates which permit a utility to recover past losses or which require it to refund past excess profits collected under a rate that did not perfectly match expenses plus rate-of-return with the rate actually established." *In Re Central Vermont Public Service Corporation,* 144 Vt. 46, 52 (1984)

The Maine Supreme Court explained the basis for its rejection of retroactive ratemaking in a 1998 decision:

> The rule against retroactive ratemaking serves two basic functions: (1) "it protects the public by ensuring that present consumers will not be required to pay for past deficits of the company in their future payments," and (2) "it prevents the company from employing future rates as a means of ensuring the investments of its stockholders," thereby removing the utility's incentive to operate in an efficient, cost-effective manner." *Public Advocate v. Public Utilities Commission*, 718 A2d 201, 207 (Me., 1998) (emphasis added)

The rule against "retroactive ratemaking" clearly did not survive Alt. Reg. But the principle behind the ban on "true ups" still makes sense. Requiring ratepayers to pay for "past deficits" relieves the Company of the incentive to operate in an "efficient cost -effective manner."

The Department did negotiate removal of the demand that ratepayers pay for 50% of GMP's under earnings from the 2016 Rate Adjustment Filing.[93]But, given GMP's demonstrated unwillingness to meet its legal obligation to prove that the capital projects it proposes to add to rate base are cost-effective and will benefit to ratepayers, there is no reasonable basis for a provision in the ESAM which requires ratepayers to make up 50% of the Company's under earnings.

[91] Larkin ESAM Report, p. 18 – Exhibit 10
[92] Id.
[93] Larkin ESAM Report p.28 -Exhibit 10

4. Department's Alleged Failure to Accept the Recommendations of Its Consultant

AARP Criticism

In his February, 2016 Report, Dr. Dismukes, AARP's consultant, was also sharply critical of the Department's performance in negotiating the "global agreement" in GMP's annual rate adjustment filing in 2015. He specifically faulted the Department's failure to follow Larkin's advice[94] on two important issues lodged in GMP's proposed "exogenous change adjustment" for extraordinary costs incurred in a December 9, 2014 snowstorm. GMP claimed the right to recover $15.283 million[95] for these "major storm" costs.

"Storm Bonuses"

1. GMP asked ratepayers to pay $770,410 for "storm bonuses" for salaried/exempt employees who worked more than 5 hours of overtime during the December 9, 2014 storm.[96]
2. Larkin argued that the $770,410 plus $69,337 in associated payroll taxes should be excluded from rates because: (1) salaried employees are expected to work extra hours without additional compensation; (2) bonuses are discretionary, if management believes exempt employees should be paid bonuses, shareholders should at least pay some of the cost and (3) some of the extra storm costs came as a result of management's failure to do "preventive maintenance" – in light of this, Larkin argued, there is no justification for ratepayers to pay bonuses to salaried employees for working extra hours in the storm.[97]
3. Despite Larkin's advice the $770, 410 was not excluded, "as it was ultimately resolved pursuant to a global agreement" negotiated by the Department. [98]

"Vegetation Management" to Limit Storm Costs –

1. An estimated 95 % of the storm damage was caused by trees falling on wires and poles after being brought down by heavy snow.[99]
2. Larkin had argued in past annual rate adjustment filings that GMPs "vegetation management"/ "tree trimming" cycle was not aggressive enough and that company's continuing failure to address this issue "will only increase storm damage and costs in the future."[100]
3. Larkin advised that the $15.283 million "exogenous costs" should have been "adjusted" to account for the fact that GMP had failed to act "proactively" to limit damage from falling trees, but in the end, no such adjustment was made.[101]

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[94] 2016 AARP Report, pp. 10-11-Exhibit 3
[95] 2015 Larkin, p. 48 – Exhibit -Exhibit 7
[96] 2015 Larkin p.52 – Exhibit 7
[97] 2015 Larkin pp. 52-53-Exhibit 7
[98] 2015 Larkin p.53
[99] 2015 Larkin, p.54- Exhibit 7
[100] 2015 Larkin p.56 - Exhibit 7
[101] 2015 Larkin p. 56-57- Exhibit 7

2016 – "Recurring Issues" Left Unresolved After "Global Agreement"

The "vegetation management" issue came up again in 2016. But, the issue was not resolved in the 2016 "global agreement" and the Department did not choose to litigate the issue before the Board. Larkin mentioned three other important recurring issues that ought to be resolved by the Board. The issues identified by Larkin are set out below.

Underspending on "Vegetation Management" – Dispute Over Proper Accounting

1. Larkin noted that GMP failed, in 2015, to spend $1,190,248 it had agreed to spend on "vegetation management/ "tree-trimming."
2. Larkin "reflected a deferred regulatory credit" for the 2017 rate year and recommended that the it be continued until the money for vegetation management is "expended as intended."[102]
3. GMP disagreed arguing that accounting on this issue had changed after the merger with CVPS (2012).[103]
4. Larkin recommended "the Board review the issue and provide guidance to whether the accounting on this issue should continue as was previously ordered.[104]

Working Capital

1. In 2016, GMP requested a working capital allowance of $46.769 million.[105]
2. Larkin has been involved in an ongoing dispute "for years" with GMP over how to calculate the working capital allowance.[106]
3. Larkin and GMP made progress in resolving some of the issues involved but "agreed to disagree" on at least one more issue.[107]
4. Larkin recommended that if these issues "are not resolved in the next filing, Larkin will recommend that the issue be litigated."[108]

Capital Structure

1. The "global agreement" calls for a capital structure of 49.70% debt-50.30% equity[109]
2. Larkin had called for a 50%-50% capital structure in this filing and recommends the same 50%-50% split "in future filings[110] because:
    - GMP is a wholly owned subsidiary of Gaz Metro of Montreal, Canada.
    - It is "not uncommon for the capital structure to reflect a 50/50 split between debt and equity when a subsidiary is the utility requesting a change in rates." [111]
3. Larkin explained:

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[102] 2016 Larkin, p. 33 -Exhibit 8
[103] Id.
[104] 2016 Larkin, p. 34 – Exhibit 8
[105] 2016 Larkin, p. 30 – Exhibit 8
[106] Id.
[107] 2016 Larkin, p. 32 – Exhibit 8
[108] Id.
[109] GMP, Schedule 3, 8/1/2016 – Exhibit 11
[110] 2016 Larkin pp. 36-37 – Exhibit 8
[111] Id.

- The level of equity of a wholly owned subsidiary "is based on its earnings and parent company investment;"
- "If the funds invested are from borrowed funds, this creates a profit mechanism for the parent because the return on equity is significantly higher than any debt rate the parent incurs to make the investment."[112]

Interpretation of Provisions in the "Exogenous Cost Adjustment"

1. This issue arose in the context of the dispute between Larkin and GMP over the additional $15.283 million GMP asked ratepayers to pay in 2016 rates as an "Exogenous Change Adjustment" for extraordinary damage caused by the December 9, 2014 snow storm.
2. The Board has said that if GMP meets its burden of proof, these extraordinary storm costs can be "fully recovered in rates in the next year's rates." [113]
3. The Department and GMP disagreed on the interpretation of two provisions of the "Exogenous Cost Adjustor" in the Alt. Reg. Plan
   - Threshold - GMP interpreted the language in the plan to mean that ratepayers should begin paying costs of extraordinary storm once GMP's costs reach $600,000. Larkin read the same provision to mean that ratepayers do not have to begin paying until GMP's extraordinary storm costs reach $1,200,000.
     *Larkin asked the parties to "consider drafting clarifying language to the exogenous provision to avoid further issues."[114]
   - Subparts 2 & 4 of the "Exogenous Change Adjustment - The Department and GMP had differing interpretations of these provisions and how they interrelate. The difference in interpretations in the case of the December 9, 2014 snowstorm amounted to $2.259 million.
     *Larkin recommended "the Board make a determination of how the provision should be applied or instruct the Department and GMP to clarify the language in the Alt. Reg. Plan…"[115]

III. Conclusions

1. Additions to Rate Base – "Capital Spending Adjustment"

The 2016 Rate Adjustment Filing exposed the reality that the current process for pre-approving the projects GMP proposes to add to rate base in the upcoming rate year creates an unreasonable risk that ratepayers spend millions of dollars on projects that are not cost-effective, not needed to serve them or are not "in service" when ratepayers start paying for them.

Scott Hempling is an expert on regulatory law who, as noted earlier, has testified for the Department in past rate cases. Mr. Hempling has written, or co-authored, several articles on alternative regulation in the 10 years since the Board approved GMP's first Alt. Reg. Plan.

[112] 2016 Larkin p. 36- Exhibit 8
[113] 2015 Larkin, p.50 – Exhibit 7
[114] 2016 Larkin, pp.40-42 – Exhibit 8
[115] 2016 Larkin p. 44 – Exhibit 8

In 2008, Mr. Hempling co-authored an article on "pre-approvals" for the National Institute of Regulatory Research. He listed six conditions regulators should ensure are met when considering "pre-approvals."

1. "Any pre-approvals are granted only on a supported showing that regulatory action will benefit customers."
2. "Regulatory actions are based on a full review of relevant facts, and supported by evidentiary showings."
3. Whatever regulatory action is taken is appropriately limited or conditioned. Approval of an action as a "prudent" choice is not the same thing as approving for inclusion in rates whatever dollars are expended to pursue it. For example, if the utility seeks the commission's blessing that a particular project is "prudent," require the applicant to explain why other options were rejected (not simply why the applicant's option is appropriate)" Approving "preliminary" or "planning" costs should not be construed as approving the recovery of later incurred dollars. The key is to be certain that regulator flexibility and discretion are retained to the greatest extent possible.
4. "The regulator has adequate resources to conduct appropriate reviews of whatever is requested. . . "
5. "Roles remain properly defined. For example, while it may be appropriate to require that a utility provide periodic reports on the progress of a utility project, the regulator's oversight should not leave it as the party with responsibility for managing the project."
6. "Consideration is given for offsetting adjustments. If pre-approval will reduce the utility's going-forward risk profile, consider whether an adjustment to the utility's return on equity should be ordered in connection with whatever pre-approval is granted."[116] (emphasis added)

The process for pre-approving proposed additions to rate base in the 2016 Rate Adjustment Filing did not satisfy at least three of Mr. Hempling's pre-conditions.

The "Capital Spending Adjustment" process failed to satisfy Conditions 1 and 2. That is, the Department and Larkin repeatedly lacked the time and the documentation to conduct a "full review of relevant facts, supported by an evidentiary showing" that Department pre-approval of a project proposed for inclusion in rate base would "benefit customers."

The process failed to meet Condition 3 as well. The Capital Spending Adjustment process provided no incentive for GMP to prove a project met the "known and measurable standard." The 2016 proceedings have shown that the Department must retain discretionary authority to deny GMP the ability to add projects to rate base before the Company has proven that these projects are cost-effective and in service and providing a benefit to ratepayers.

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[116] Scott Hempling, Esq., Scott Strauss, Esq., Pre-Approval Commitments: When and Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Capital Projects? National Regulatory Research Institute, (November, 2008) pp. 31-32 – Exhibit 18

The “pause” in alternative regulation proposed by Sansoucy makes sense. However, when alternative regulation returns, the new Alt. Reg. process should give the Department enforceable authority to ensure no project is added to rate base without first meeting the known and measurable standard. One way to do this is:

This could be accomplished as follows:

Year 1 – On May 1, GMP provides Larkin and Department experts with a list of projects proposed for the upcoming “rate year” together with the documentation that GMP promised to provide in 2014. If Larkin and Department experts are satisfied with GMP’s proposal for a project, the financing costs for the project will be approved (by August 1) for inclusion in rates for the upcoming “rate year”

Year 2 - On May 1, GMP provides Larkin and Department experts with a list of completed projects and the evidence necessary to satisfy the Department that each project is “in service”, cost-effective and benefiting ratepayers. Sansoucy advises that “at a minimum this filing should include a comparison of:

- the planned scope of work vs. the actual scope of work with an explanation of any changes;
- the planned placed in service date vs. the actual placed in service date with an explanation of any changes;
- the planned expense vs. the actual expense to include an explanation of any cost variance exceeding 10% (more or less than planned) for planned total cost of capital that is less than $1 million and 5% (more or less than planned) for planned total cost of capital of more than $1 million.”

If Larkin and Department experts agree that GMP has met its burden of proof, each approved project will be added to rate base.

2. Earnings Sharing Adjustment (ESAM)

The 2016 Rate Adjustment filing showed how easily GMP can manipulate the ESAM to the detriment of its customers. The Department exposed the Company’s effort to require ratepayers to pay the Company $752,000 for what was, in effect, the Company’s abuse of the process. But, there is no good reason why the Department should have been put in a position where it had to expend the resources to expose this practice.

GMP has control over when it will add projects to its rate base. The Company has also repeatedly demonstrated its unwillingness to meet its legal obligation to prove that the capital projects it proposes to add to rate base are cost-effective and will benefit ratepayers. Under these circumstances, there is nothing “just and reasonable” in a provision in the ESAM which requires ratepayers to make up 50% of the Company’s “under earnings.”

3. Return on Equity (ROE)

Mr. Schultz of Larkin has said that “a key feature” of GMP’s Alt. Reg. Plan “which distinguishes it from other jurisdictions is that essentially all” of GMP’s “costs are covered” by the Plan’s “sharing mechanisms.”[117] Mr. Young, the Board’s Deputy General Counsel questioned at the Board’s Workshop on GMP’s 2016 Rate Adjustment whether ratepayers should continue to pay such a relatively high “risk premium above the long bond” (30-year U. S. Treasury Bond) when Mr. Schultz has said the Company is “essentially guaranteed a return with minimal risk.”

The Department should conduct a “return on equity study and determination of equity rate” in preparation for the 2018 rate case as recommended in the Sansoucy proposal.

4. <u>Department Should Litigate to Get Board Guidance on “Recurring Issues”</u>

Under normal circumstances, it is best to resolve disputes through a negotiated settlement rather than litigation.[118] Litigation should be the last resort- not the first impulse. This is particularly true in cases as complex as cost-of-service ratemaking. However, experience also shows that a willingness and ability to litigate has tended to strengthen the State’s position in negotiations.

As noted earlier, fully-litigated rate cases under traditional ratemaking in Vermont were time-consuming and expensive. There may well be a good argument that GMP’s ratepayers would not be well-served if the Department spent the time and money necessary to litigate contested issues in <u>every annual</u> rate adjustment filing. But, there is no such argument in the context here. When it approved GMP’s first Alt. Reg. Plan in 2006, the Board expressed concern that ratepayers might not have been fairly compensated for the fact that the Plan shifted risk from GMP shareholders to GMP ratepayers:

> “*In particular, we are concerned that the Plan shifts risks from GMP's shareholders to Vermont ratepayers. No party presented evidence that permits us to accurately quantify the magnitude of this reallocation of risks.* . . Due to this uncertainty, it is not clear that the reduction of GMP's ROE by 50 basis points fully compensates ratepayers for the changes in risk. The Department and GMP have persuaded us that GMP's improved financial status will provide long-term financial benefits to ratepayers that are not directly quantifiable and are likely to outweigh any change to the risk allocation.[119] (emphasis added)

It appears from the record, though, that in the ten years since the Board’s approval of GMP’s first Alt. Reg. Plan, the Department has not sought a formal Board ruling to resolve any dispute between the Department and GMP over a rate adjustments proposed by GMP. Nor has the Department sought a Board ruling to resolve any dispute over any provision of either of the two GMP Alt. Reg. Plans that have been approved since the first plan was approved. This, in turn, has meant that there have been no final Board decisions on several recurring issues raised by Larkin -decisions which are likely to have benefitted ratepayers.

[117] Larkin 2016 ESAM Report, p3 – Exhibit 10
[118] Vermont prosecutors tend to try fewer criminal cases today than they did 15-20years ago. But, even back in 2001, prosecutors in Chittenden County only tried 2% of the felony cases they charged (23 out of 1139). Vermont Judiciary 2001 Annual Statistics (7/1/2000 -6/30/2001). Pp. 22, 28 -Exhibit 19
[119] Board Order, Docket 7175, 7176, p. 34

There are several good reasons to “fully litigate” (i. e. obtain a Board decision) the recurring issues identified by Larkin.

First, Larkin has a good track in testifying before the Board. It is reasonable to believe the Board will agree to many of the positions Larkin has taken on these issues. This could save ratepayers millions of dollars.

Second, the goal of “just and reasonable rates” is best achieved if those involved in negotiating further Rate Adjustment Filings have Board rulings telling them what the rules are - on how provisions of the “Exogenous Change Adjustment should be interpreted for instance. Without these rulings, negotiations are more inefficient because they involve unnecessary wrangling over issues that should have been resolved years ago.

Third, litigating issues is likely to improve public confidence in the Department. It is an understatement to say that GMP’s annual Rate Adjustment Filing is “not readily accessible to the public.” The annual rate adjustment process begins with GMP filing a series of complex schedules with the Department. This filing is followed by two months of hard work and intense negotiations between Department experts and GMP experts which culminate in a “global agreement” on August 1- an agreement which is memorialized through the filing of another series of complex schedules [120]- this time with the Board.

Fully-litigated rate cases are much more accessible to the public. This process involves submission of pre-filed testimony which explains important issues raised in schedules, open hearings with live cross-examination of experts and questioning by the Board which clarifies positions taken by each expert witness and filing of briefs and memos which set out the positions the Department has taken and the reasoning behind these positons. The hearings are almost always open to the public and the pre-filed testimony and briefs and memos are, with a few exceptions, public records. Finally, the Board rules on each issue raised by the parties and explains the basis for the ruling.

This process is bound to improve public confidence in the Department because it provides the press and public with the opportunity to see and understand the important work the Department’s Public Advocates do on behalf of ratepayers.

Finally, the Department, itself, recently sponsored testimony by Mr. Schultz of Larkin which makes a good case for litigation instead of serial negotiated agreements:

> “Complacency occurs when traditional ratemaking requirements are compromised by attempting to resolve issues in alternative regulation proceedings. Once the issues get resolved through compromise, subsequent negotiations will test the leniency of the requirements more and more and costs that would not be allowed under traditional ratemaking get allowed. Compromise can be good but when it erodes the standards of traditional ratemaking someone is harmed. That

[120] In 2016, the Department tried to make the Alt. Reg. Process more accessible to the public by attaching a detailed summary of the issues raised during the negotiation process and brief statement of how they were resolved. This summary was included in the schedules filed in the August 1, 2016 “global agreement” (Schedules 2.6.1 - 2.6.3, pp. 114-119) -Exhibit 20

someone most often will be ratepayers. Additionally, there is the problem that settlements do not provide binding and instructive Board precedent. Under traditional regulating when the Department and a utility litigate an issue, the Board resolves the issue and everyone has to follow it afterward. That does not happen with settlements under alternative regulation. And while litigation is possible under alternative regulation, the plans are not set up for litigation; they are set up for cases to be resolved through settlement. I think the erosion of a body of developing Board ratemaking precedent is one of the unanticipated results of alternative regulation that can result in complacency I refer to above."[121]

The Department should adopt Sansoucy's recommendation and require GMP to file a "traditional rate case no later January 1, 2018. The Department should litigate the issues raised by Larkin and its other experts to obtain a final judgment by the Board rather than resolving them through a negotiated settlement.

__________/s/__________
Robert V. Simpson, Jr.

[121] Pre-filed testimony of Helmuth W. Schultz in Docket 8698, August 22, 2016, p. 7. – Exhibit 16

ATTACHMENT

PROPOSED RECOMMENDATIONS OF CHANGES TO GREEN MOUNTAIN POWER'S RATE MAKING PROCEDURES

Prepared by: George E. Sansoucy, P.E., LLC.

Introduction:

Since the Vermont Public Service Board ("Board") approved its first Alternative Regulatory Plan ("Alt. Reg. Plan") in 2006, Green Mountain Power ("GMP") has not filed a fully litigated rate case. Instead, GMP has been subject to alternative regulation as defined by its 2006 Alt. Reg. Plan and subsequent plans, approved in 2010 and 2014. A primary goal of alternative regulation is to establish an efficient rate-making process that properly incentivizes the utility to deliver safe and reliable energy at fair and stable rates to all rate classes, while limiting a utility's risks. GMP's Alt. Reg. Plan is effective in reducing the time and expense that would be required in traditional ratemaking, however, is does not allow for the robust review essential in regulating a monopolistic entity such as GMP.

It is clear, based on a review of the GMP's Alt. Reg. Plan filings, the results of oversight performed by the Vermont Public Service Department's ("Department") consultant, Larkin Associates, and the analyses provided by Dr. David Dismukes, commissioned by the American Association for Retired Persons ("AARP"), that there is significant cause for concern that ratepayers are not being treated fairly under GMP's current ratemaking procedures.

Recommendations:

1. Fully-Litigated Rate Case

The inadequate regulatory provisions, lack of sufficient time necessary to conduct a robust and complete review of GMP's annual alternative regulation filing, and the fact that there has not been a fully litigated rate case in ten years, has created a regulatory environment that fails to hold GMP accountable to its regulators and ratepayers. As years go on without a comprehensive review of GMP's ratemaking, the potential for inequities mounts and established baseline information becomes less reliable. As such, we recommend that the current Alt. Reg. Plan be allowed to expire, the baselines be established based on current factors, and a fully litigated rate case be initiated. The recommended rate case should include and/or address the following issues:

1. Term: The current Alt. Reg. Plan, filed June 4, 2014 shall be allowed to expire at the end of its term, September 30, 2017. Base rates, established as part of the last Alt. Reg. Plan filing,

effective 10/01/2016, and valid through 09/30/2017, shall remain in effect through December 31, 2018 during the adjudication of a traditional rate case.

2. Base Rate Adjustments:
   a. GMP shall file a traditional rate case no later than January 1, 2018 for rates to be effective January 1, 2019. This process shall include an extensive litigation process whereby the Department and stakeholder intervenors shall conduct intensive discovery involving interrogatories, requests for production of documents, depositions and/or technical sessions, written direct testimony, submission of relevant studies (e.g. depreciation studies), cross-examination of witnesses to take place during public hearings, and legal briefings.
   b. GMP may seek temporary rate increases pursuant to 30 V.S.A. § 226(a) and the Company may file modified or new tariffs for new services or adjustments on a revenue-neutral basis subject to Board approval pursuant to 30 V.S.A § § 225, 226, 227.
   c. Under the rate plan, GMP shall propose to revise its base rates on a service rendered basis commencing January 1, 2019 and will support its proposal with cost of service information filed with the Board on January 1, 2018.
      i. The cost of service filing shall be calculated in a manner consistent with the traditional Vermont rate making principles.
      ii. The test year shall be based on the 12-month period ending December 31, 2017 in conjunction with pro-forma adjustments to revenues, expenses, assets, liabilities and capital issuances forecast for the following 12-month period ending December 31, 2018, thereby creating a hybrid test year considering both historical and anticipated future needs of the State of Vermont and the Company.
      iii. The percentage rate base change will be determined by comparison of forecasted rate year total cost of service to the revenues that would be raised by existing base rates and projected rate year sales.
      iv. Amounts recoverable in base rates include all prudent and measurable costs other than those recoverable as a Power Supply Cost.
      v. A complete depreciation study shall be prepared by a Board approved contracted depreciation specialist. The depreciation study shall include, but not be limited to, an analysis to determine the original cost of plant, the estimated service life of assets, the accumulated depreciation reserve, gains and losses on the disposition of assets, the effects of asset retirement obligations, a determination of negative salvage, and a recommended course of action to stop negative salvage and reverse existing negative salvage in a way

that minimizes the effect on ratepayers and complies with the Federal Accounting Standards.

vi. A return on equity study and determination of equity rate.

vii. A debt to equity study and determination of the Company's debt to equity ratio.

3. Base rates established as the result of the traditional rate case shall be effective for a 3-year term ending December 31, 2021. A subsequent traditional rate case shall be filed one year prior to the expiration of the existing term (January 1, 2021) and shall include the Company's proposal for an Alt. Reg. Plan. Any authorized Alt. Reg. Plan(s) shall not exceed a term of five years, at which time a traditional litigated rate case must be filed.

2. Power Supply Cost Recovery

Costs relative to power supply are not to be included in the base rates. As such, a separate power supply cost recovery procedure shall be established. The current procedure requires quarterly filings reporting the actual power costs vs. the forecasted power costs. These quarterly variances are then aggregated to establish a Power Adjustor to base rates for the following year. The basis of this procedure is sound but, similar to the Alt. Reg. Plan, it lacks a robust adjudication process. As such, we recommend that the Company file a Power Supply Cost Recovery Plan and a Power Supply Cost Recovery Reconciliation annually.

1. <u>Power Supply Cost Recovery Plan</u>:
    a. The Company shall file annually a complete power supply cost recovery plan describing the expected sources of electric power supply and the anticipated changes in the cost of power supply anticipated over the future 12-month period ending December 31st.
    b. The plan shall be filed no later than 3 months prior to the effective date, January 1 of the following year, of the proposed power supply cost recovery factor, e.g. filing for the effective date of 01/01/2018 shall be filed not later than 10/01/2017.
    c. The plan shall describe all major contracts and power supply arrangements, including transmission of power, entered into by the utility for providing power supply during the specified 12-month period.
    d. The description of the major contracts and arrangements shall include the price of fuel, where applicable, the duration of the contract or arrangement, and an explanation or description of any other term or provision as required by the Department.
    e. The plan shall include the Company's evaluation of the reasonableness and prudence of its decisions to provide power supply in the manner described in the plan and an explanation of the actions taken by the Company to minimize the cost of such supply to the utility.

f. The Company shall also file, contemporaneously with the power supply cost recovery plan, a 5-year forecast of the power supply costs, based on its existing sources of electrical generation and anticipated sources of electrical generation supply. The forecast shall include a description of all relevant major contracts and power supply arrangements entered into or contemplated by the Company, and such other information as the Department may require.

g. Upon the filing of the power supply cost recovery plan, the Department shall conduct a proceeding to review the power supply and costs submitted for the purpose of evaluating the reasonableness and prudence of the plan and establishing the power supply cost recovery factor to be incorporated in the electric rates or rate schedules of the Company.

h. The power supply and cost plan proceeding shall permit reasonable discovery in order to assist the Department and intervening stakeholders to obtain information relevant in determining the reasonableness and prudence of the plan.

i. The final disposition of the proceeding shall approve, disapprove or amend the power supply cost recovery plan and provide an evaluation of the decisions underlying the 5-year forecast.

j. The power supply cost recovery proceeding shall be scheduled in such a way as to allow for comprehensive, yet expedient review, as to allow the power supply cost recovery factor to be included in rates as of January 1st of the following year.

2. Power Supply Cost Recovery:

a. Not later than three months following the end of the 12-month period covered by the utility's power supply cost recovery plan, the Department shall commence a contested cost reconciliation proceeding, to be known as a power supply cost reconciliation.

b. The Company shall file with the Department an Application, Testimony and Exhibits pertaining to plan period ending December 31st of the previous year. The filing shall include, but not be limited to, a comparison of the power supply cost recovery factors and the allowance for the cost of power supply established as part of the corresponding plan and the amounts actually expensed and included in the cost of power supply by the utility.

c. The proceeding shall permit reasonable discovery in order to assist the Department and intervening stakeholders to obtain information relevant in determining the reasonableness and prudence of the expenditures and amounts collected pursuant to the plan.

d. In its Order pertaining to a power supply cost reconciliation proceeding, the Department shall disallow costs that are deemed unreasonable or imprudent. Upon conclusion of the reconciliation proceeding the Department may authorize an adjustment to the current power supply cost recovery factor to account for the reconciliation of planned expenses vs. actual expenses of the prior plan year.

3. **Hearing to Examine the Alternative Regulation of GMP in Vermont**

Green Mountain Power has operated under alternative regulation for ten years. This ten-year history has been studied and documented through Department, as well as intervenor, oversight. While our recommendation calls for GMP to step back into traditional ratemaking, it leaves the door open for alternative regulation in the future. Institutional knowledge will likely be lost and forgotten during the time until a new alternative regulation plan is submitted for Board consideration. This offers an opportunity for the Board and Department to stop and consider the positive and negatives of GMP's Alt. Reg. Plans and document the discussions and conclusions. That way, in three or four years when/if a new plan is submitted for approval, the Board will have an institutional memory to rely on in its decision making process.

1. The Department should petition the Board for hearings to consider the terms of GMP's Alt. Reg. Plans that have been in place over the past ten years in order to evaluate the process and effectiveness of alternative regulation compared to a traditional rate making model.
2. At these hearings, evidence should be introduced through expert testimony and supporting exhibits which considers the effectiveness of GMP's Alt. Reg. Plan in adequately protecting ratepayers' statutory right to "just and reasonable rates." This testimony should:
    a. identify the strengths and weaknesses inherent in the current process for reviewing and approving proposed additions to rate base ("Capital Spending Adjustment");
    b. consider the fairness of the "Earnings Sharing Adjustment" (ESAM);
    c. consider GMP's ROE, given the fact that the Company's risk of not earning its authorized ROE is virtually non-existent;
    d. evaluate the "Exogenous Change Adjustment" language to ascertain if it provides clear and concise direction; and
    e. consider any and all other matters that the Department and/or Board deem necessary.
3. A Board decision should document the proceeding's purpose, history, arguments and conclusions, thus creating a written institutional memory of GMP's alternative regulation for future decision-makers.

Exhibits

Exhibit 1 - Chronology of Green Mountain Power's (GMP) 2016 Rate Adjustment "proceeding." (Tariff 8618)

Exhibit 2 - 2015 AARP Report

Exhibit 3 - 2016 AARP Report

Exhibit 4 - Hempling 2014 Article re: Alternative Regulation and Return on Equity (ROE)

Exhibit 5 - Relevant portion of the Brief filed by the Vermont Department of Public Service (Department) with the Vermont Public Service Board (Board)in Docket 5428 (1990-91).

Exhibit 6 - Relevant portion of the Brief filed with the Vermont Supreme Court (Docket No. 92-353) by the Department in its appeal of the Board decision in - *In Re Green Mountain Power Corporation* – on October 1, 1992. The decision in the matter is reported as *In Re Green Mountain Power Corp*. 162 Vt. 378 (1994)

Exhibit 7 - 2015 Larkin Report

Exhibit 8 - 2016 Larkin Report

Exhibit 9 - June 4, 2014 Memorandum of Understanding (MOU) which is GMP's current (2014-2017) Alternative Regulation Plan

Exhibit 10 –Larkin Report on GMP's proposed Earnings Sharing Adjustment (ESAM) for in the 2016 Rate Adjustment Filing.

Exhibit 11 - GMP Schedule 3 dated 8/1/2016

Exhibit 12 - Transcript of the Board's September 13, 2016 Work Shop in GMP's 2016 Rate Adjustment Filing.

Exhibit 13 –GMP Schedule 4 dated 8/1/2016

Exhibit 14 - GMP Schedule 4 dated 5/31/2014

Exhibit 15 - Relevant Portion of the Brief filed by the Department with the Board in Docket 5532 (February 25, 1992)

Exhibit 16 - Pre-filed testimony (dated 8/22/2016) of Helmuth W. Schultz III of Larkin Associates on behalf of the Department in Vermont Gas proceedings.

Exhibit 17 –GMP Schedule 4, 8/1/2015

Exhibit 18 - Hempling 2008 Article re: "pre-approvals"

Exhibit 19 - 2001 Vermont Judiciary Statistics re: felony jury trials in Chittenden County

Exhibit 20 - GMP Schedules August 1, 2016 – includes summary of resolution of issues raised in negotiations – pp. 114-119, 2016 "global agreement."

<u>Exhibit 1</u> - Chronology of Green Mountain Power's (GMP) 2016 Rate Adjustment "proceeding." (Tariff 8618)

Chronology of GMP's 2016 Rate Adjustment Filing (Exhibit 1)

2015

11/20– Department and Larkin & Associates (Larkin) began review of GMP's proposal under the Alt. Reg. Plans' "Earnings Sharing Adjustment"

2016

1/28 - First Quarter Power Costs were filed for "Power Adjustor"

4/29 – Second quarter Costs were filed for Power Adjustor

5/3 – Larkin began review of selected capital projects for "Capital Spending Adjustment"

6/1 – GMP proposed Base Rate Adjustment filed

- Includes proposed (1) "Non- Power Cost Adjustment"; (2) "Capital Spending Adjustment"; (3) "Power Adjustor"; (4) "Earnings Sharing Adjustment"; (5) "Exogenous Change Adjustment" (discussion of "vegetation management" continued from November 2015- May 30, 2016)
- Proposal was for a 3.53 % rate increase in

6/1 -7/29 – "Discovery" of the basis for GMP's proposed rate increase was conducted b DPS experts and lawyers aided by Larkin.

6/27 – 7/15 –"ROE Adjustment" was calculated (9.02%)

7/15 -7/29 - DPS negotiations leading to agreement between DPS and GMP on rates GMP ratepayers will pay during the 2017 "rate year" (10/1/2016 -9/30/2017)

8/1 – GMP filed the negotiated "global agreement" it had reached with the Department

- The agreement calls for a 0.93% rate increase.

8/15 - "Larkin Report" was filed with the DPS and the Board. Larkin was required to reviews GMP's 2016 Rate Adjustment Filing for: (1) accuracy, (2) completeness, (3) compliance with traditional ratemaking and existing Board orders regarding "cost of service" filings including the calculation of regulated earnings and (4) consistency with the Company's actual cost and the GMP Alt. Reg. Plan.[1]

9/13 – The Vermont Public Service Board held a work shop and asked questions of GMP and Department regarding the 2016 Rate Adjustment Filing.

9/15– Department formally recommended Board approval of the agreement it had reached with the GMP on August 1.

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[1] Board Order, Docket 8190, 8191 (August 25, 2014) Finding 72, p. 19

9/23 - Board accepted the joint recommendation of GMP and the Department.

10/1– Rates for the 2017 “rate year” (10/2016 -9/30/2017) went into effect

Exhibit 2 - 2015 AARP Report

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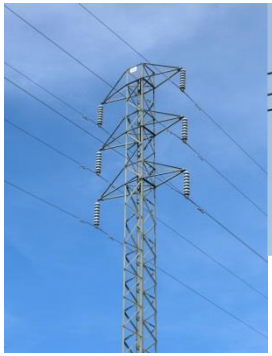




Analysis of Vermont Alternative Regulation

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January 22, 2015

Disclosure: Financial support for this report provided by AARP.

LSU CENTER FOR ENERGY STUDIES

Executive Summary – Traditional Regulation

Utilities are regulated because they are **natural monopolies** and provide services **imbued with the public interest**.

In competitive markets, prices are set at costs. **Regulators also seek to emulate some aspects of competitive markets** by setting rates equal to costs. In competitive markets, **efficient firms are profitable, inefficient firms go out of business.**

Traditional regulation is data-intensive and relies heavily on information **transparency and incentives**. Rate cases are the primary means by which regulators attain information about their regulated firms' costs.

Regulatory lag is the primary incentive mechanism associated with traditional regulation. Regulatory lag represents the time period between when a utility's rates are set and their next rate change request.

Rates are set on costs and are fixed in the time period between rate cases: if a utility can **increase efficiencies** between rate cases it can **increase its earnings and profitability** and vice versa, **just like competitive markets**.

Executive Summary – Challenges to Traditional Regulation

Alternative regulation arose to (1) address the informational asymmetries between regulators and regulated firms that can often lead to capital investment inefficiencies (i.e., “gold plating”) and (2) to **institutionalize “regulatory lag”** by making it an active (rather than passive) means of promoting efficient utility performance.

A commonly-recognized aspect of most types of regulation is that **regulators typically have less information than regulated companies** about the true cost and nature of providing service (i.e., “asymmetric information”). The over-capitalization experience of the nuclear power plant development period for electric utilities is a good example of this problem.

In addition, under traditional regulation, **a utility’s ability to maximize its efficiency opportunities within regulatory lag can be potentially constrained** if a regulator pulls the utility in for a rate case and effectively “expropriates” the excess earnings generated by efficiency investments.

Alternative regulation is a process that seeks, in part, to **minimize** these two traditional regulation **deficiencies**.

Executive Summary – Alternative Regulation

Alternative regulation is a modification of, not a substitute for, traditional regulation. This modification seeks to de-emphasize (but not eliminate) the role of rate cases in determining actual utility costs and rates. Alternative regulation typically defines a fixed time period (or program "term") in which rate cases are avoided in preference of an **alternative method of adjusting utility rates**.

Alternative regulation uses a **formula-based approach** for changing rates during the program's term. The rates utilized at the beginning of the program term, however, are still set by a traditional regulatory process. It is the process by which rates are allowed to change between rate cases that differs from the traditional approach.

Alternative regulation uses an earnings sharing mechanism ("ESM") to define the manner in which **efficiency-created excess earnings** will be shared between shareholders and ratepayers (i.e., institutionalizes or codifies regulatory lag).

Thus, **alternative regulation** takes a little of the **"old"** (cost of service ratemaking and regulatory lag) to combine with a little of the **"new"** (formulaic increases in rates and fixed regulatory review periods) to increase the effectiveness of the utility regulatory process for both parties (utilities and ratepayers).

Executive Summary – Vermont Experience

Vermont's two alternative regulation plans (Vermont Gas Systems, Green Mountain Power) have common components that include a fixed term, a formula-based plan for adjusting rates, and an earnings sharing mechanism. There are, however, **two important problems with the current Vermont alternative regulation plans**.

First, the **sharing of risks and rewards** within both plans' various components is not balanced and is **skewed in favor of the utilities**. For instance, the rate adjustment formula for both plans give generous rate adjustments and utilize **very small consumer dividend offsets** (as represented by what is called the "productivity offset adjustment") that might condition the degree to which rates can increase in any given year.

Second, and more importantly, **both plans allow utilities to include large capital investments** to be entered into rates on a dollar-for-dollar basis with little regulatory accountability (as reflected in the lack of annual reporting requirements). The **GMP alternative regulation plan**, however, was recently **modified to address this deficiency**.

Summary of Recommendations

1. Require the Board to open a proceeding to **reconcile alternative regulation plans** between VGS and GMP with the goal of **creating program consistency that balances the risks** between utilities and ratepayers.

2. Limit the **use of capital expenditure cost recovery mechanisms** within the plans:

    a) No capex mechanisms allowed until **project-specific and financial need** is proven.

    b) If major capital program costs are allowed, utilities must be required to provide a **detailed set of minimum filing requirements for annual reconciliations** (similar to the recent GMP settlement agreement).

    c) If major capital program costs are allowed, utilities must **include performance-based measures with penalties for non-performance.**

    d) If capital program costs are allowed, they must be **subjected to ratepayer protection mechanisms** that include, but are not limited to, total annual investment caps, rate impact caps, minimum filing requirements, and performance benchmarks with penalties for non-compliance.

3. Consider additional modifications to make the Department more **consumer advocacy-oriented.**

Traditional Regulation

Why Are Utilities Regulated?

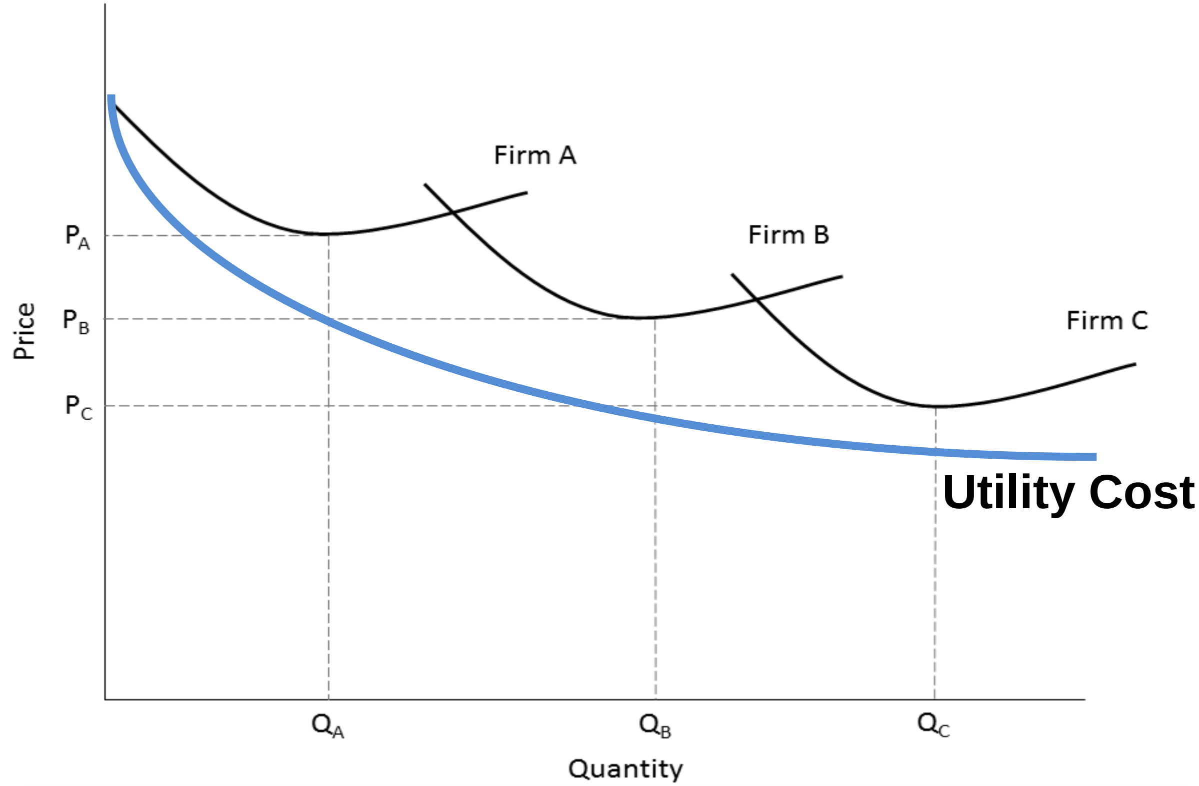
Utilities are regulated for two reasons:

1. Utilities are **imbued with the public interest**: utilities provide critical services (electricity, natural gas) that are essential for a modern economy; and
2. Utilities are "**natural monopolies**." Utilities have (natural) cost characteristics that allow them to drive competitors out of the market and then price their services at rates higher than competitive markets.

These two conditions serve as the basis for utility regulation.

Utility Natural Monopoly Conditions

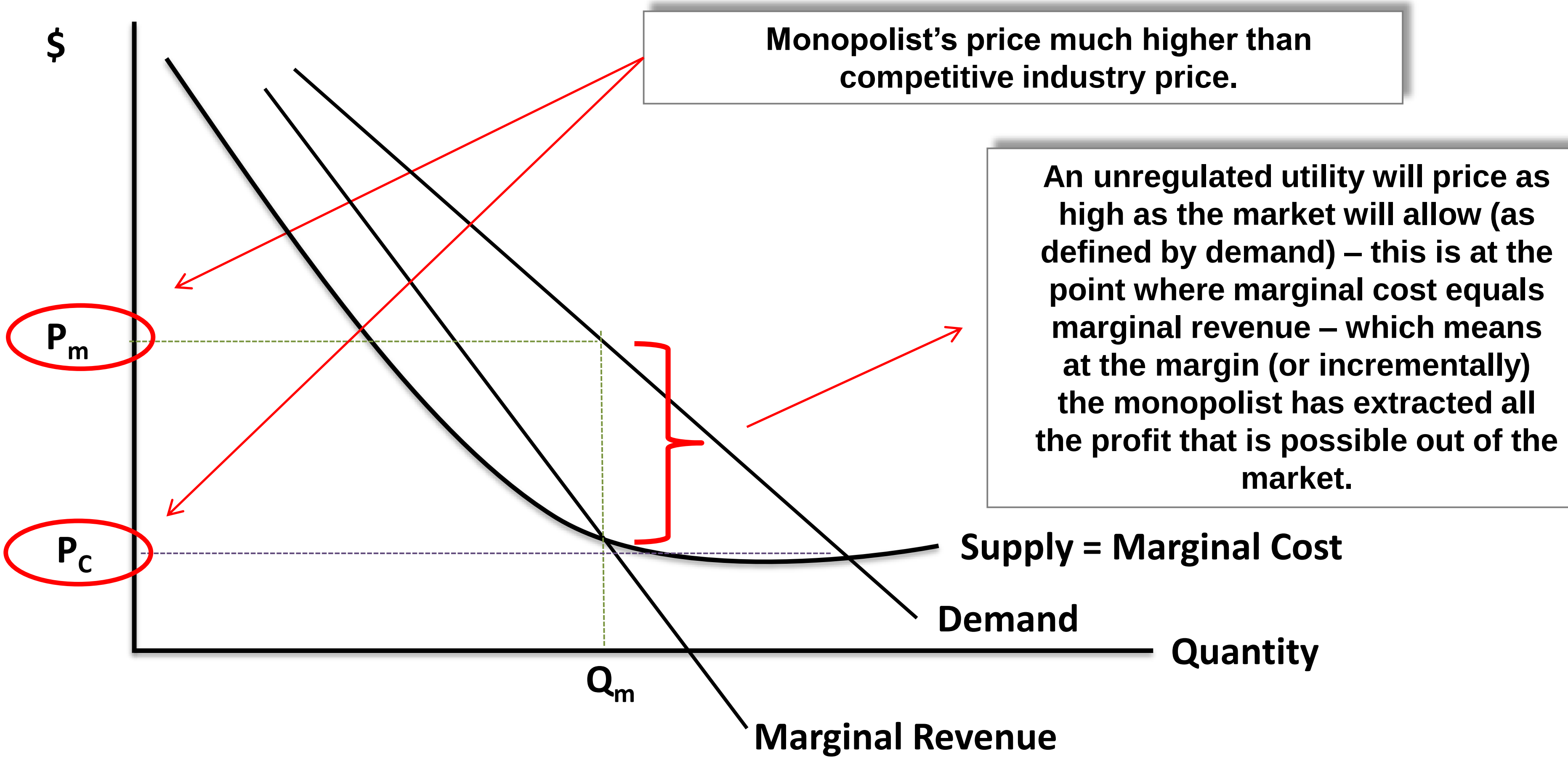
- Natural monopolies have large "economies of scale" which means that a utility's average costs tend to decrease as output expands.
- This cost advantage allows utilities to squeeze out potential higher-cost competitors.
- This cost advantage also means that the most efficient outcome for society is to let one, low-cost firm serve the entire market.



The problem with only allowing one firm to serve the market is that the single firm becomes a monopolist that has the ability to charge unnecessarily high prices and limit how much it produces.

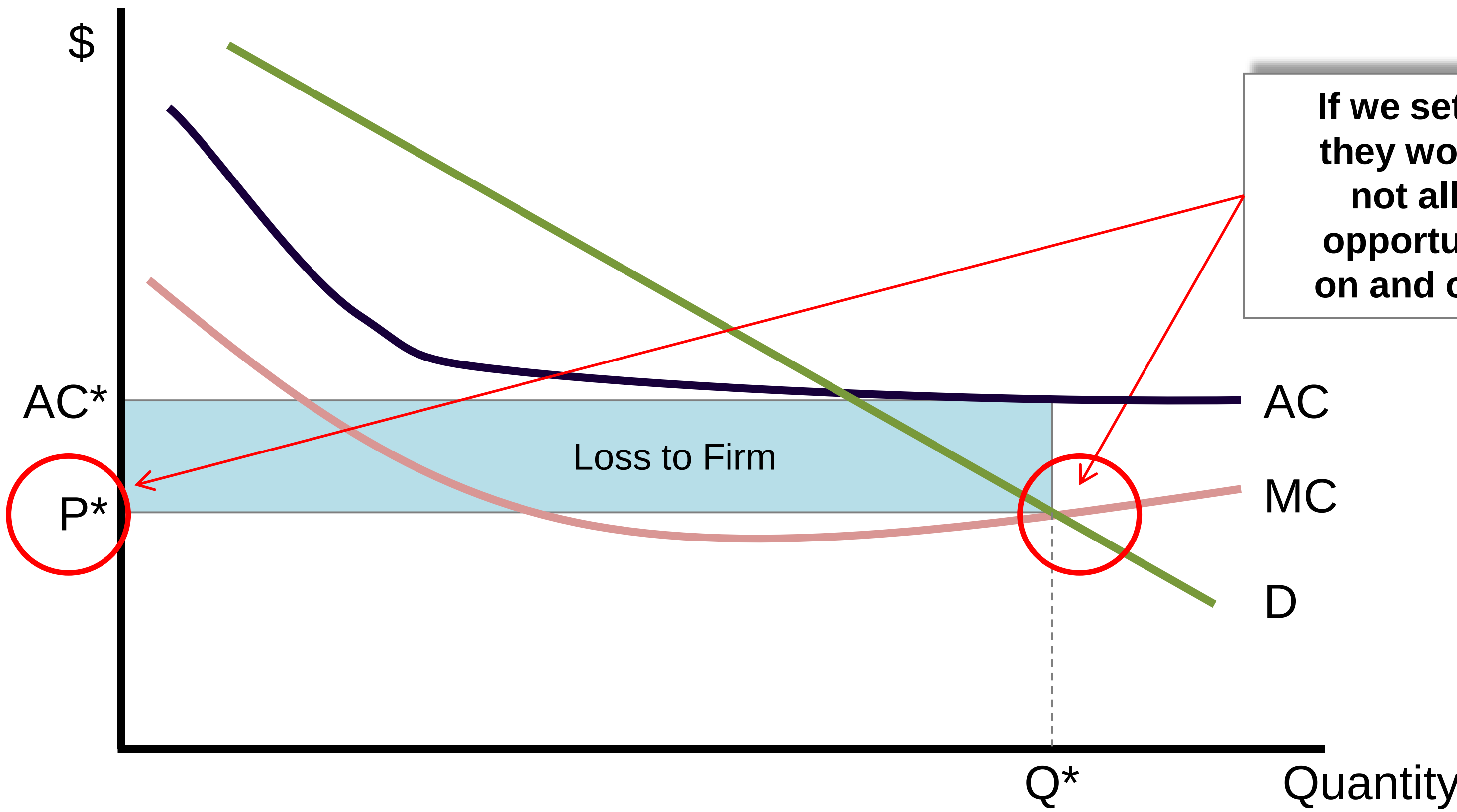
What Would Happen if We Didn't Regulate?

If we did not regulate utilities, they could price far higher than what would normally occur in a competitive market.



The Natural Monopoly Problem: Setting Prices at Optimal Levels

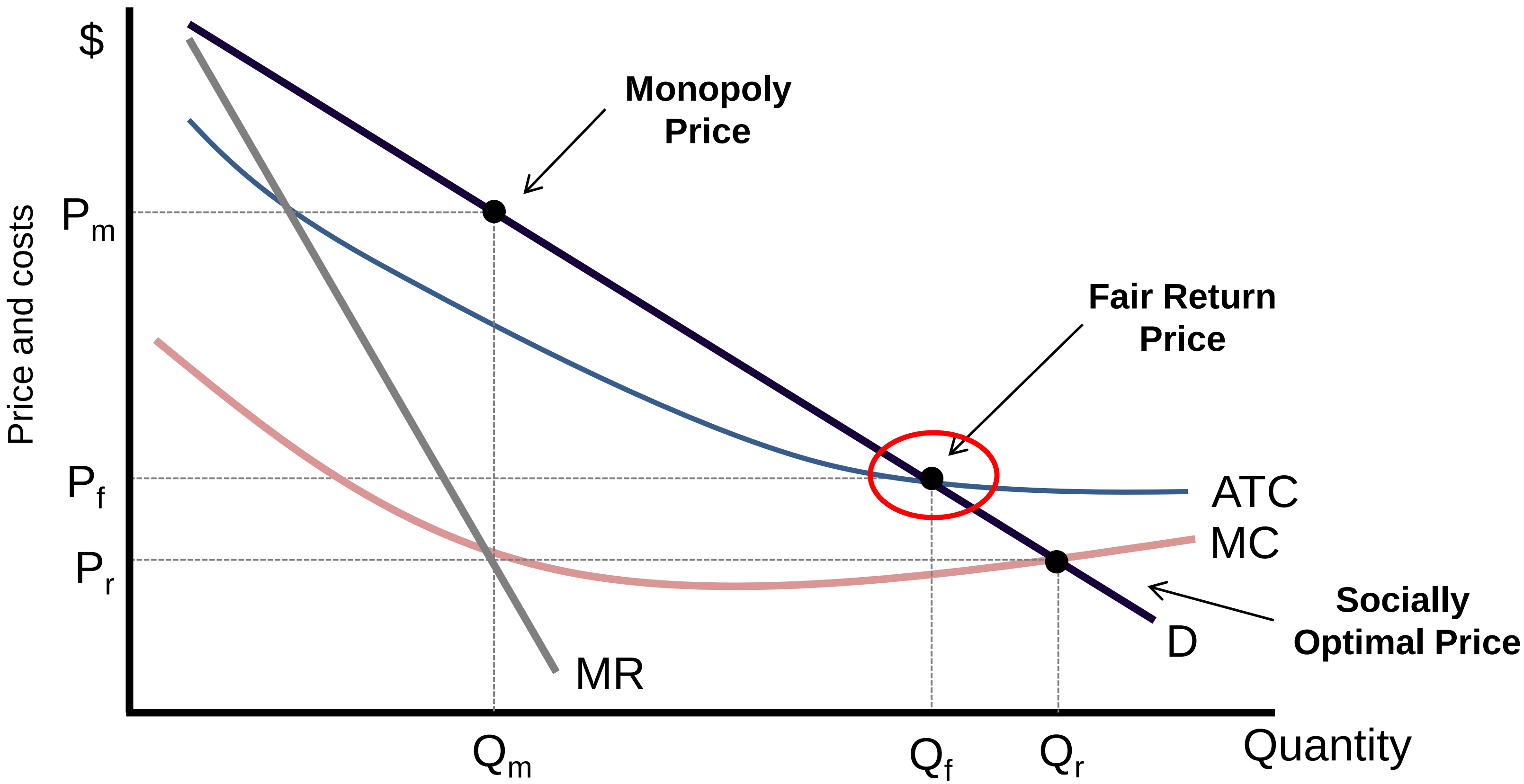
If competitive industries set prices at marginal costs, why don't we force utilities to simply price their services at marginal costs? Primarily, because they have a large amount of shorter run fixed costs that have to get recovered. If we priced at marginal costs, utilities would go bankrupt.



If we set prices to MC then they would be too low and not allow the utility the opportunity to earn return on and of their investment.

Comparison of Various Monopoly/Regulated Pricing Outcomes

Regulators, therefore, have to choose prices that reflect some middle ground that give utilities a "fair-return" for their investments. This results in prices lower than what would occur under an unregulated monopoly, but higher than those arising in competitive markets.



Why Regulation?

At the turn 20th century, **many industrialized nations did not adopt a system of utility regulation**, but instead "nationalized" their utility industries. The **state owned these industries** and operated them in the public interest. (i.e., British Gas, Gaz de France, National Grid, Scottish Power, Deutsche Telecom)

Utility regulation in the U.S. started out as a **unique means of maximizing utility industry development and efficiencies**, and reconciling the utility industry's natural monopoly structure to the American system of **private capital ownership**.

However, U.S. utility regulation is **not just a process of governing rates and services**. The process is often said to be one that attempts to emulate competitive market forces, or serve as a "**proxy for competition**," in order to maximize potential investment and operating efficiencies.

The Relationship Between Regulation and Competition

Traditional regulation limits the degree, nature, and **timing** of price changes **much like competitive markets**.

For instance, **competitive firms** cannot increase market prices, and if they increase their own prices unilaterally, without any industry-wide cost justification (like input cost inflation), they will likely **lose market share and profits**.

In addition, **competitive firms** that **invest in innovative technologies** that reduce costs and/or efficiently expand their abilities to increase the scope of their services, **can increase market share and profitability**.

Traditional regulation can facilitate similar competitive market outcomes through the **timing** of rate changes (rate cases) and what is known as "**regulatory lag**."

Regulatory Lag and a Form of Market Discipline

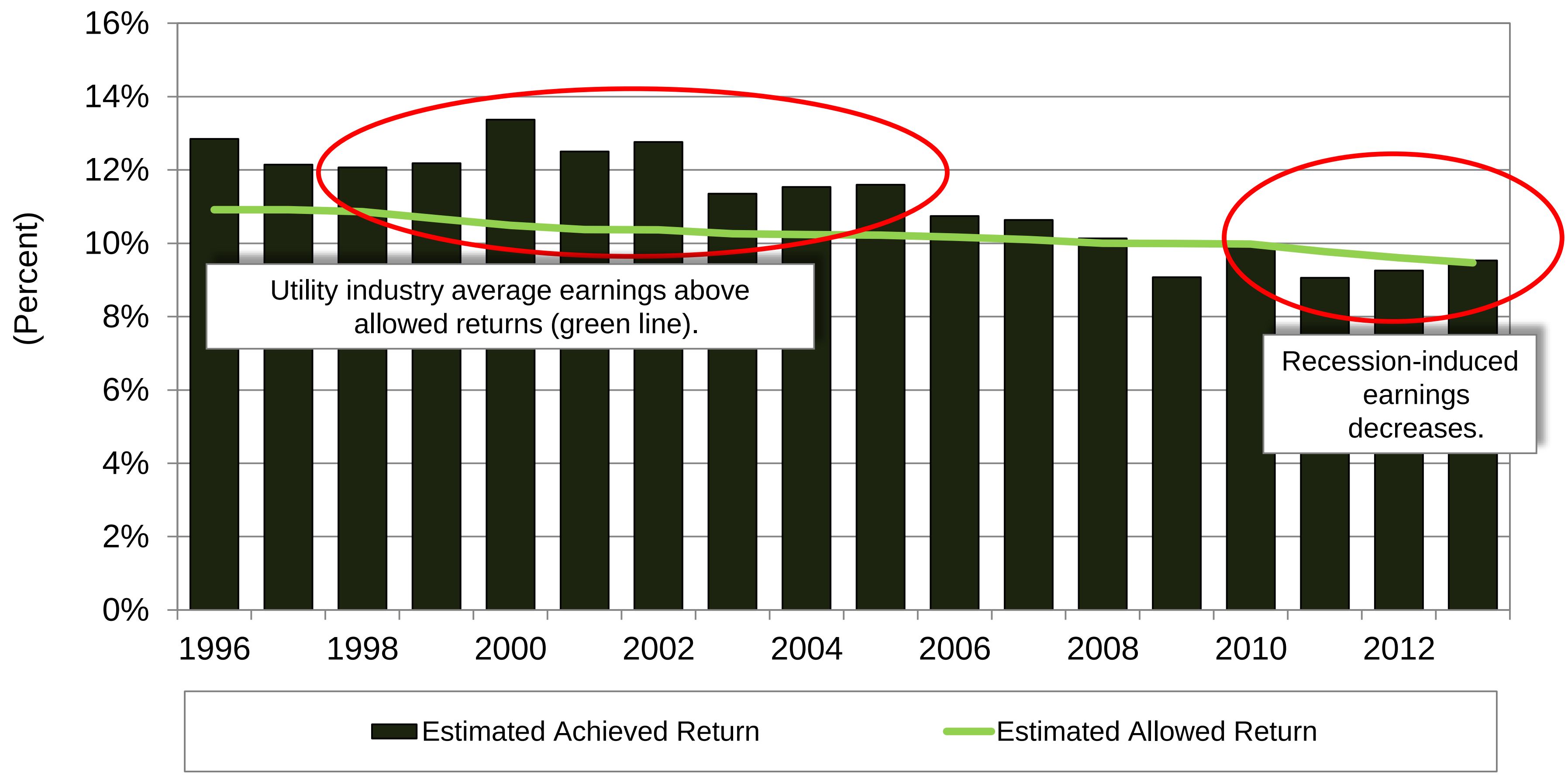
Regulatory lag is the period of time between when a utility's rates go into effect and its next rate case and is an important means by which **traditional regulation** is thought to **inject discipline upon utilities similar to that arising in competitive markets**.

Under traditional regulation, **rates are set on a utility's prudently-incurred costs**:

- If a **utility improves its operating/investment efficiencies** after a rate case, then **the increased profits** associated with these actions accrue to the utility much like they would in a **competitive market.**
- The **inverse occurs if a utility becomes less efficient** or is unable to contain its costs after a rate case: profits will fall much like they would in a competitive market.

Historic Utility Earnings Compared to Estimated Allowed ROE for Industry Overall

Historically, electric utilities (on an industry average), have seen periods where they have clearly benefited from regulatory lag. The 2009-2010 recession, however, challenged achieved utility earnings relative to those allowed by regulators.



Note: Estimated achieved return is calculated as Net Income divided by Proprietary Stock (less preferred stock).
Source: Federal Energy Regulatory Commission; and Public Utilities Fortnightly.

Regulatory Lag and Risk

Thus, regulatory lag is only “bad” for inefficient utilities. Some utilities have found **regulatory lag beneficial** and have not filed a traditional rate case for time periods that span anywhere from 7 to 15 years.

Regulatory lag, however, can **increase utility earnings risk** since future market conditions, weather, and the opportunities for innovation are not known with 100 percent certainty: but this is also true for many other energy industries, particularly those **operating in competitive markets**.

Further, **utilities get a fair (i.e., market-based) rate of return** to compensate for operating in markets with these types of rates.

Thus, utilities are compensated in two ways for this risk: (1) they are given an allowed rate of return that **factors in these market risks** and conditions and (2) have the opportunity to achieve **some degree of additional earnings through regulatory lag** (assuming they manage that lag successfully).

Alternative Regulation

What is Alternative Regulation?

Alternative regulation is a means of regulating utilities that relies **less on a traditional rate case** structure and more on an **annual formulaic-based approach** of setting rates.

Alternative regulation **modifies traditional regulation**: it does not replace traditional regulation. Alternative regulation focuses more on **output and performance** rather than inputs (measuring the cost of service in any given year).

Rationales for the use of alternative regulation:

- “Institutionalize” regulatory lag.
- Reduce asymmetric information problems.
- Reduce administrative costs.

How Does Alternative Regulation "Institutionalize" Regulatory Lag?

Regulatory lag gives **efficient utilities** the opportunity to increase their achieved earnings after a rate case.

These efficiency-induced excess earnings, however, are limited. In theory, under traditional regulation, a regulator can force a utility to **decrease its rates if it finds earnings to be "excessive**." The ambiguity in what constitutes excessive earnings can discourage utilities from pursuing additional efficiency measures.

Alternative regulation attempts to release this excess earnings boundary (and ambiguity) through the use of **pre-defined sharing bands** and percentages with ratepayers. Future changes in rates, under an alternative regulation plan, are **defined by utility performance and its ability to maximize the efficiency opportunities created by regulatory lag**.

In this way, alternative regulation "institutionalizes" or formally "codifies" regulatory lag. This is another reason why **alternative regulation** is often called **"performance-based regulation**."

Definition: Asymmetric Information

What do we mean by **"asymmetric information?"**

Definition: when one contracting party has a **different set of relevant information** relative to another contracting party it can lead to an inefficient outcome.

Pervasive problem in all forms of regulation (utility, environmental, financial, etc.) that **regulators typically have less information about a regulated company's operations** and costs than the regulated company itself.

Informational asymmetries can result in **"gold-plating"** of capital investments and expenses (i.e. cost-inefficiencies). Since cost-of-service regulation is based upon costs, this can lead to inefficient rates.

Alternative regulation is thought to reduce the regulatory problems of asymmetrical information since (1) the regulatory emphasis shifts from **inputs to outputs** and (2) utilities have active rather than passive **profit-maximization incentives**.

How Does Alternative Regulation Reduce Administrative Costs?

Most alternative regulation methods use a formula or pre-defined approach to setting rates on a periodic basis.

This formula is typically set for a **fixed number of years** which can be anywhere from between 3-5 years.

No rate cases are usually allowed during the alternative regulation program time period. Rate cases are not, however, prohibited.

Rates only change by the formula or guidelines.

Avoiding rate cases is thought to **reduce administrative costs** of repeated rate cases although there are annual reviews of costs by regulatory staff during the alternative regulation program period.

Specific alternative regulation plan structure really determines whether or not administrative costs are actually reduced.

Alternative Regulation: Theory v. Practice

Alternative regulation has several theoretical appeals. However, the biggest challenge in program design is in **appropriately assigning risks and rewards** of the alternative regulation plan.

Conceptually, risks can be borne by either party (ratepayer, utility) provided they are **corresponding opportunities for rewards.**

All to often, **program performance risks are shifted entirely on ratepayers**, with few to little rewards.

Few states have an alternative regulation plan like Vermont. California is the only other state with an active alternative regulation plan comparable to Vermont.

Alternative Regulation:
Program Design, Risks, and Rewards

Primary Components of an Alternative Regulation Plan

Alternative regulation plan should be based upon a structure that balances risk and rewards between ratepayers and utilities. These plans are typically based upon three primary components

Formula for allowed annual rate change → Formulas that defines how annual rate changes will be allowed to occur. This also includes a definition of the costs eligible for annual increases.

Earnings sharing mechanism → This mechanism defines how excess earnings, or under-earnings, will be shared between ratepayers and utilities. This can be thought of as the "profit-sharing" aspect of the plan that occurs after the fact.

Program duration → The program duration defines the time period under which utilities will be subjected to the plan and the time period in which formal rate cases are not allowed.

Alternative Regulation: Framework for Allowed Rate Changes

Alternative regulation plans allow revenues/prices to grow by a pre-defined formula during the program duration.

<u>Traditional formula:</u>

Allowed Revenue (or Price) Increase =

(Change in Inflation) less (Productivity Offset) plus ("Exogenous" Factor)

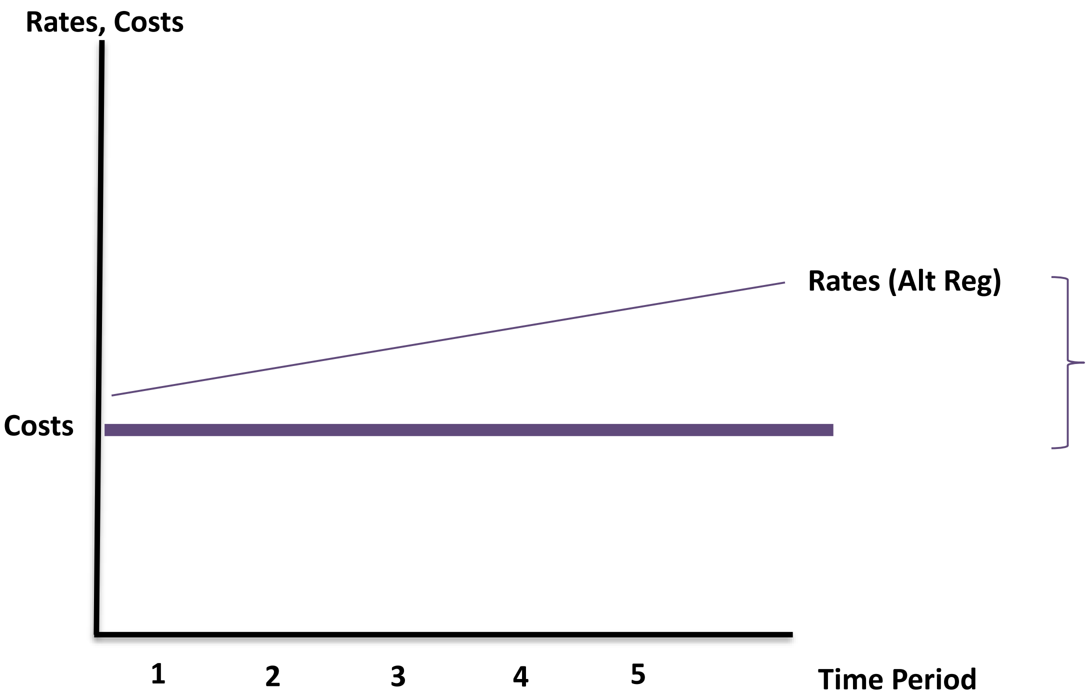
Revenues/prices allowed to increase by the rate of inflation as measured by standard government indices like the CPI.

Revenues/prices are reduced by a fixed measure of industry productivity. This adjustment forces some cost discipline on utility since it reduces the magnitude of the overall inflation adjustment.

Utilities are often allowed to increase revenues/prices for unexpected ("exogenous") changes in costs like unexpected tax changes or costs associated with severe weather events.

<u>Trade-offs:</u> A low productivity offset, and a generous exogenous factor adjustment, will reduce utility risk by providing for a relatively stable, undiscounted increase in rates. High productivity offsets and narrow exogenous adjustment allowances will tend to reduce risks for ratepayers.

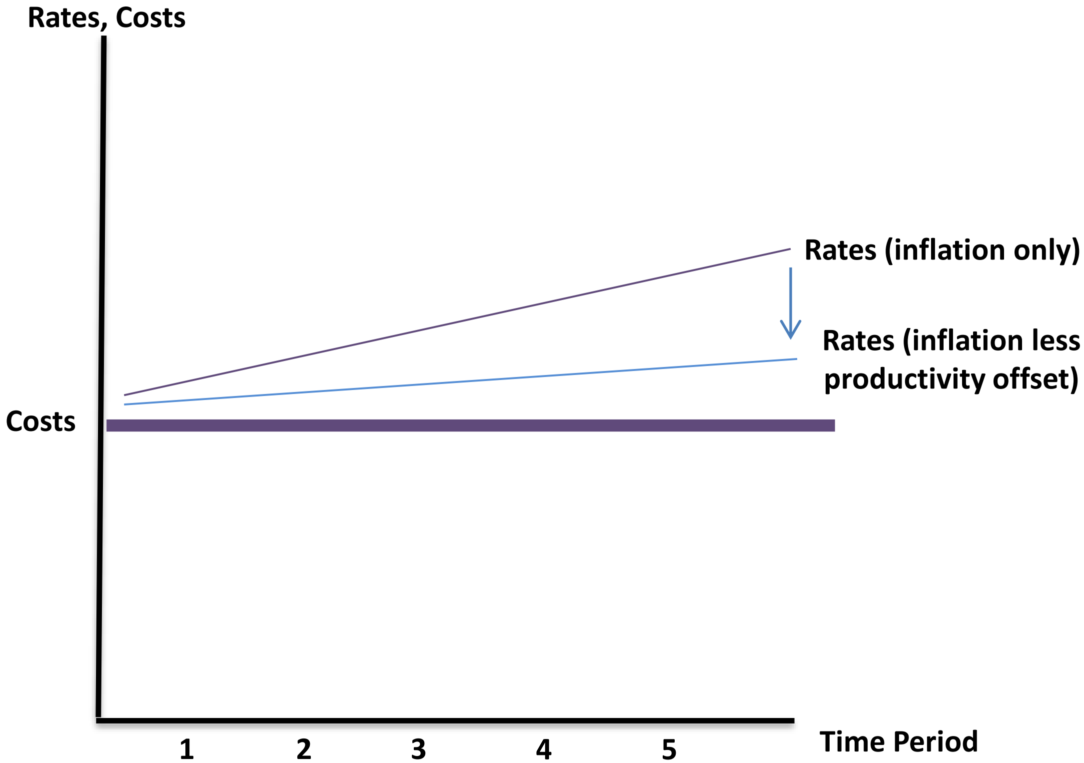
Alternative Regulation: Why Allow Rate Changes Without a Rate Case?



Annual rate changes allowed under alternative regulation is thought to facilitate a utility's ability to continue to invest in its system and to explore cost efficiency opportunities including cost efficiency investments such as automation and equipment upgrades.

The regulatory emphasis on determining the potential cost of service is reduced in favor or monitoring performance outcomes. Utilities are allowed to increase rates and must live within the means allowed by the price change formula. **Alternative regulation was originally developed to facilitate capital investment by allowing rates to change without rate cases**. This approach differs from "trackers" which allow explicit costs to be flowed-through rates on a dollar-for-dollar basis.

Alternative Regulation: Productivity Offsets (Illustration)



Time Period	Inflation Increase (%)	Productivity Offset (%)	Net Allowed Rate Change (%)
1	3.0%	1.0%	2.0%
2	2.8%	1.0%	1.8%
3	4.2%	1.0%	3.2%
4	2.5%	1.0%	1.5%
5	3.0%	1.0%	2.0%

The productivity offset works to adjust allowed inflation increase. The offset is fixed (does not vary like inflation) to account for industry-wide productivity that would normally be passed along to customers if the industry were competitive. **The larger the productivity offset, the smaller the allowed annual rate change** (holding inflation constant).

Alternative Regulation: Exogenous Shocks

Most alternative regulation plans recognize the possibility that **"outside" (exogenous) factors** can influence utility costs like an unexpected change in taxes or the costs of unexpected weather events.

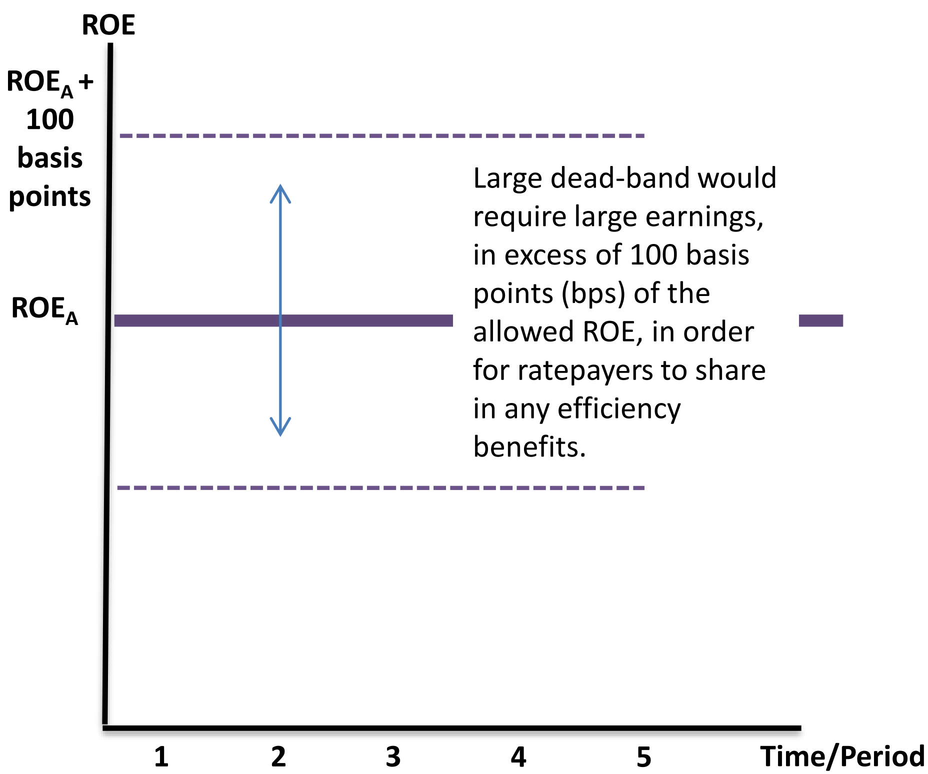
Exogenous adjustments in most alternative regulation plans are designed to address changes in costs that are infrequent in nature and associated with events **outside utility control**.

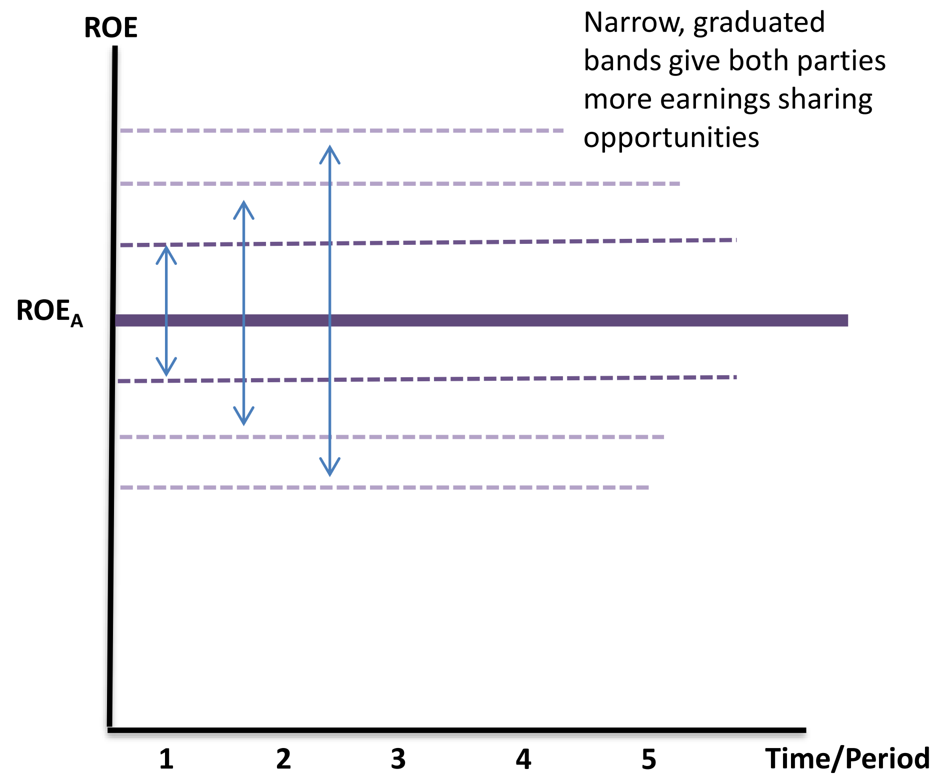
Exogenous adjustments **should not be used** to facilitate cost recovery **for known and measureable costs (like new asset development)** that are entirely within a utility's control or large enough to justify a traditional rate case. **Unfortunately, both Vermont alternative regulation plans allow rates to be increased for exactly these kind of known and controllable costs**.

Passing through large, known costs within a utility's control, and with little active regulatory oversight, **incorporates one of the worst aspects of cost-plus regulation** into alternative regulation.

Alternative Regulation: Risks & Earnings Sharing Mechanisms -- Bands

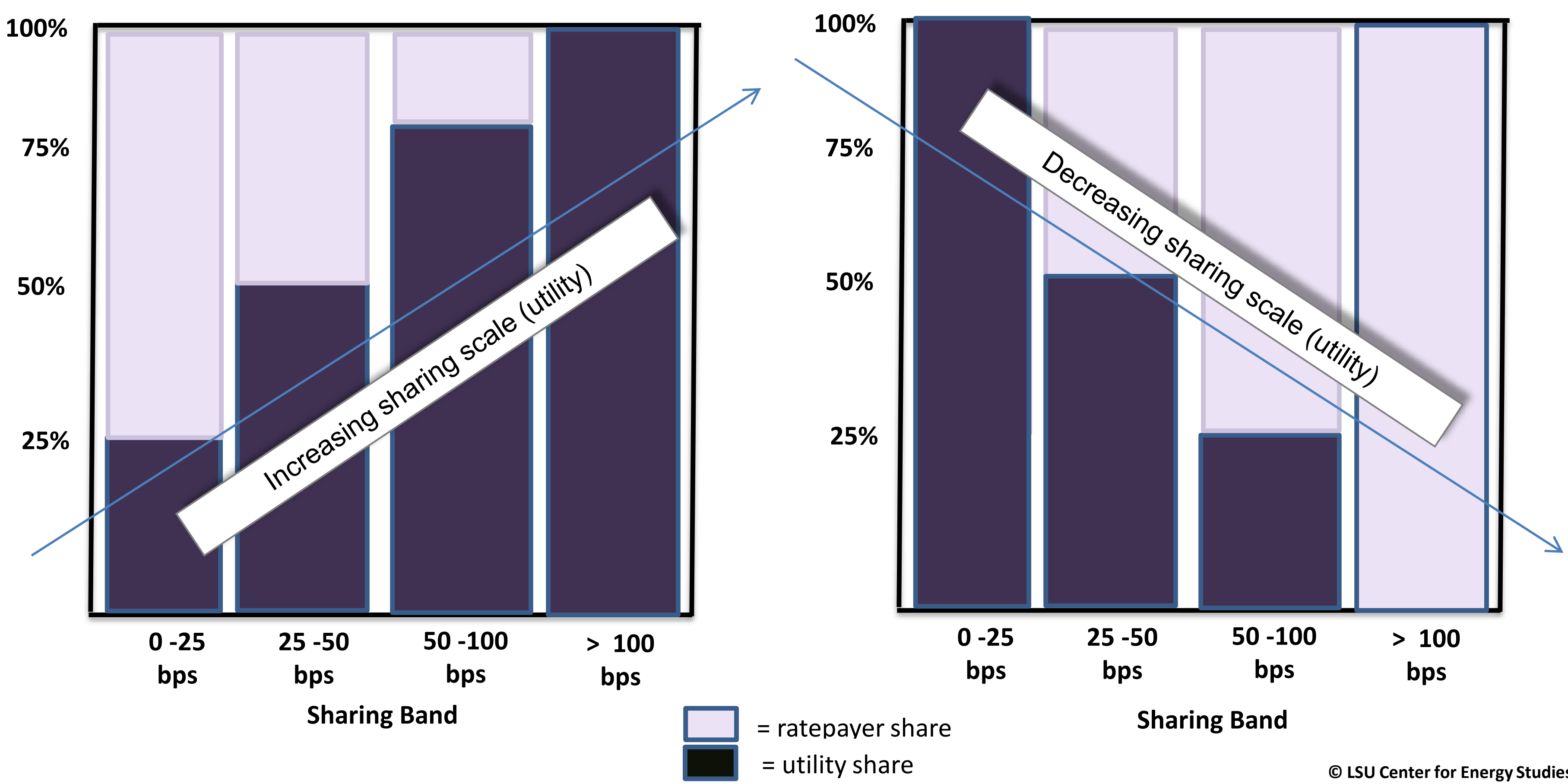
A large number of narrow sharing bands creates more graduated opportunities for sharing. Broad bands reduce those opportunities – increased sharing opportunities will require exceptionally large excess earnings.





Alternative Regulation: Risks & Earnings Sharing Mechanisms – Sharing Percentages

Increasing sharing percentages require utilities to work harder in order to share in excess earnings whereas a declining sharing percentage scale gives utilities first claim to excess earnings.



Alternative Regulation: Risks & Program Durations

Alternative regulation plans are commonly set in **three to five year range**, although some are set for much longer periods that can include up to one decade.

Length is often part of the regulatory bargain between utilities and regulators and likely determinant on other program components (like earnings sharing bands).

Longer stay-out periods are thought to give utilities the opportunity for making **longer-run investments** that will yield **efficiency gains** (and returns) over a period of time. Longer stay out periods help to create opportunity to attain the **full return from the investments**.

Shorter stay-out periods, however, can help to reduce any long periods of time unanticipated **disconnects that can arise between rates and costs** without rate recalibration.

Summary of Alternative Regulation Design Characteristics - Risks

Alternative Regulation Plan Component	Risk Characteristics
Formula for Allowed Rate Change	Less risky provision of an alt regulation plan since price changes will occur in any given year and only vary by the degree to which inflation in the economy varies. These rate increases could be used to facilitate efficiency investments that pay dividends (through excess earnings) over time.
Earnings Sharing Mechanism	More risky component of alt regulation plan since earnings outcomes (excess earnings) are entirely dependent upon utility performance. Programs that allow relatively larger initial rate increases should provide some later concessions for those funding the investments (i.e., ratepayers) through inclining sharing blocks.
Program Duration	Moderately risky component of alt regulation plan since it is defined early in the process. Utility does bear risk that the gains of its efficiency efforts could be expropriated by a future rate case if duration is set too short.

Critique of Vermont Alternative Regulation: Opportunities for Design Improvement

Current Vermont Approach

Vermont alternative regulation programs for Vermont Gas Systems (“VGS”) and Green Mountain Power (“GMP”) have a number of **major features that are similar to other alternative regulation methods** including:

- Fixed program duration periods with sunsets.
- Formula-based base rate increases.
- Earnings sharing mechanisms.

Program experience to date, however, has led to few ratepayer benefits. **Program design issues have tipped the scales** of the current mechanism more in favor of shareholders rather than ratepayers.

Vermont Alternative Regulation: Major Program Deficiencies

Vermont experience, to date, underscores the proverbial "devil in the details" problems with regulatory policy design. The issue with Vermont's alternative regulation programs rests with **how alternative regulation has been constructed, and modified, since 2006**.

The three primary Vermont alternative regulation design deficiencies include:

(1) The trade-offs between annual base rate increases and the ESM is **skewed**, and **primarily benefits shareholders**, not ratepayers.

(2) Recent modifications to both alternative regulation plans (VGS, GMP) have **shifted a considerable degree of uncompensated risk** away from the utilities and to ratepayers. This is particularly true for VGS.

(3) The **provisions for "exclusions" included in both alternative regulation plans** are based upon a **questionable premise** (that capital expenditures cannot be accommodated). This combines the worst of "cost-based regulation" and alternative regulation.

Earnings Sharing Experience To Date (Green Mountain Power)

To date, ratepayers have received a total of over $800,000 from the sharing portion of the GMP alternative regulation plan. GMP's shareholders, however, have received close to $7.0 million.

	Earnings Sharing Experience Green Mountain Power					
Year	Ratepayer ESM Shares	Contribution to Customer Energy Efficiency Programs (Power Partners)	Ratepayer - Total Share	Deadband Share	Utility ESM Shares	Utility - Total Share
2007	$0	$2,849	$2,849	$25,637	$0	$25,637
2008	$0	$31,718	$31,718	$285,458	$0	$285,458
2009	$0	$120,125	$120,125	$1,081,129	$0	$1,081,129
2010	$0	$178,792	$178,792	$1,609,124	$0	$1,609,124
2011	$0	$182,388	$182,388	$1,641,489	$0	$1,641,489
2012	$0	$0	$0	-$1,024,350	$0	-$1,024,350
2013	$0	$336,572	$336,572	$3,029,144	$0	$3,029,144
	$0	$852,442	**$852,442**	$6,647,631		**$6,647,631**

Recently-Adopted Provisions Shifting Risk to Ratepayers

Recent modifications to both the VGS and GMP plans shift risks away from utility shareholders and onto ratepayers. Examples of these risk shifting provisions include:

Provision	Effect
Return on equity (ROE) is now indexed to market rates.	**Historically, and under traditional regulation, the allowed ROE is fixed. Now allowed ROEs are variable and move with market conditions which can be both favorable and unfavorable. This makes base rate adjustments more variable.**
ESM calculated on weather normalization basis (VGS only).	**Traditionally, utility earnings vary based upon general economic conditions. Utilities bear the risk of changes in weather and the economy. This modification eliminates one component of earnings variation.**
Gas cost sharing mechanisms eliminated (VGS only). **Reduction of power adjustor efficiency band (GMP only).**	**Both provisions were originally adopted to require some "buy-in" from each utility in terms of their off-system gas and power purchases. This "buy-in" has been substantially reduced.**
Creation of SERF that permanently "expropriates" prior ratepayer alternative regulation benefits.	**The SERF diverted approximately $4.4 million in what should have been commodity gas-related savings (PGA) to a new fund designed to cover the investment costs of new infrastructure investments. This action effectively expropriated ratepayer savings and creates regulatory risk regarding whether future ratepayer savings will also be skimmed.**

Provisions for “Exclusion” Costs

Both plans (GMP, VGS) have provisions that **allow for the recovery of certain annual capital investments**. These types of costs are referred to as “exclusionary” in the VGS plan and include items that impact utility costs and are **under utility control.**

These costs are allowed because it is believed that in doing so the Board will be **removing an incentive to avoid costs that would otherwise be desirable**. In other words, under the belief that **alternative regulation will incent utilities to not make investments needed to provide safe, economic and reliable service**. This should not be the case and the premise is inconsistent with the origins of alternative regulation.

Price increases allowed under alternative regulation are made to facilitate utility investments, much like those which would arise in competitive markets. Competitive firms, for instance, must facilitate their own capital investments through annual price increases, efficiencies, and the cost-effectiveness of the investment. **Competitive firms don’t get “pass-through” trackers for capital investments**.

Relationship Between ARP "Exclusions" and Trackers

The use of exclusions in the Vermont ARP creates a **cost-plus based mechanism** (or "pass-through" mechanism or "tracker") that directly incorporates costs into annual rate adjustments on a dollar-for-dollar basis.

Trackers **run counter** to the two primary **goals of alternative regulation**: (1) creating greater operating efficiencies and (2) reducing regulatory/administrative costs.

Cost plus mechanisms **reduce the beneficial aspects of regulatory lag** that disciplines utility decision making and efficiency incentives.

Regulatory/administrative costs are increased since the costs associated with these mechanisms need to be reviewed annually (and more quickly). Makes the process more difficult for stakeholder group participation.

Exclusions and Ratepayer Protections

These exclusions are even more problematic since they **do not include ratepayer protection mechanisms** that are often utilized with cost trackers in other states such as:

- Term/cap/sunset provision.
- Rate Impact cap.
- Deferrals/Carrying charge limitations.
- Risk-Adjusted ROEs.
- Performance Benchmarks.
- Detailed Annual Minimum Filing requirements.

The **recent GMP successor plan did, however, include a number of new annual minimum filing requirements** that should assist in the annual regulatory review of these types of investments.

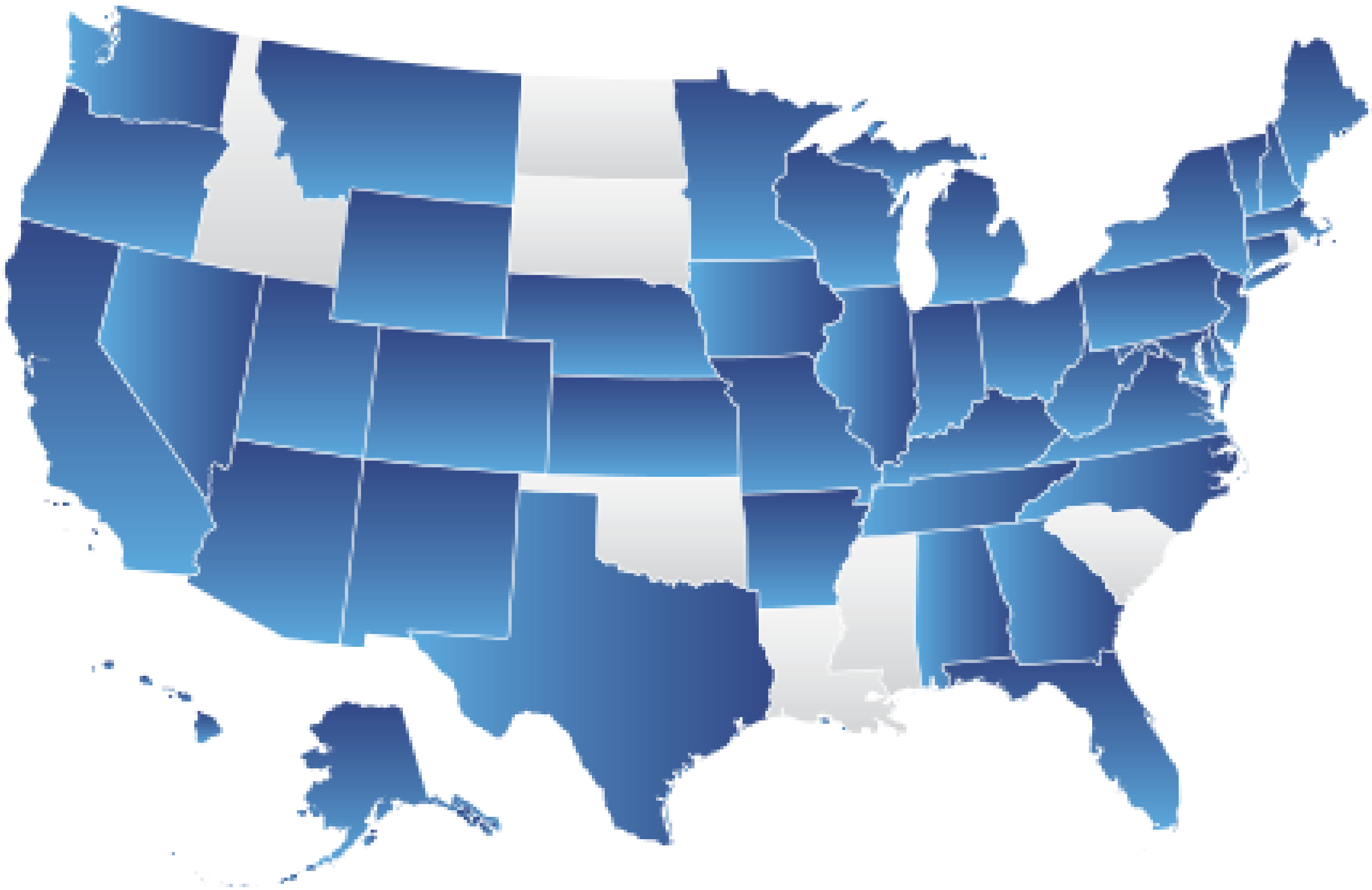
Ratepayer Advocacy

Why is Ratepayer Advocacy Important?

- Ratepayer advocacy is important because **it provides official sanction and resources** for the express purpose of representing the **collective interests of ratepayers** that typically do not have the collective organization, resources, or information to advocate individually before regulatory commissions.
- **Utilities** often have considerable resources to adequately **advocate for their interests** on both an individual and collective basis.
- Industrial and large commercial groups typically have **trade associations** to represent their interests.
- Residential and small commercial customers typically fall into this **under-represented** category.

U.S. Offices of Ratepayer Advocacy

There are currently 40 different legislatively-created ratepayer advocacy offices in the U.S.



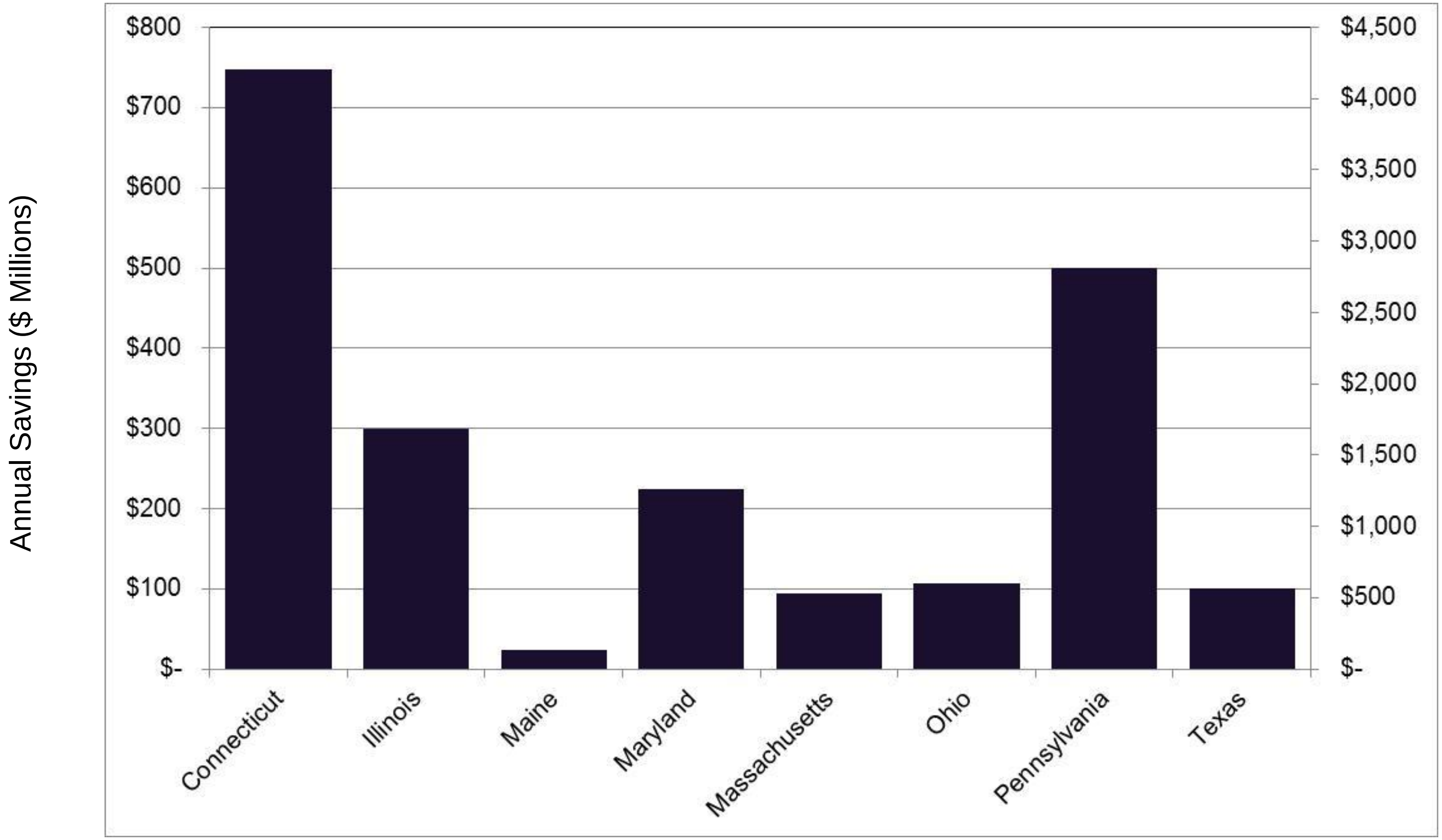
Source: National Association of State Utility Consumer Advocates ("NASUCA").

What is a Ratepayer Advocate?

- Ratepayer advocates are usually statutorily-created offices designed to represent and **advocate for ratepayer interests**.
- In some states, this advocacy is defined broadly across all customer classes. In some instances the legislatively-set advocacy mission is limited to just **residential and small commercial customers**.
- A **ratepayer advocate's mission should be as an active and independent advocate and representative for ratepayers** taking positions that directly support economic, safe and reliable service.
- Ratepayer advocacy does not translate into unbridled litigation nor does it suggest consistent opposition to utility and stakeholder positions. **It does mean strong, independent, and transparent representation**.

Selected Performance of Ratepayer Advocacy Offices

Most major Ratepayer Advocate offices are estimated to provide ratepayer benefits that are multiples of their respective annual budgets. California (not pictured) reports saving over $4.2 billion in 2012 alone.



How is the Independence of Ratepayer Advocacy Ensured?

1. **Organization:** optimally, ratepayer advocates should be an **independent office or agency** that is removed from the regulatory commission's structure and oversight. Many state ratepayer advocates are either independent offices that answer to the Governor or Legislature, or part of the Office of the Attorney General.

2. **Funding:** ratepayer advocates should have **independent financial resources to litigate effectively in a regulatory proceeding**. These funds can come a direct draw on regulatory assessments (as approved by other state administrative agency or legislative office) or covered directly from utilities (for fixed amount) on a proceeding-by-proceeding basis.

3. **Selected Individual:** a large part of a successful ratepayer advocate rests with the individual selected for the job. **Ratepayer advocates** should have technical and/or legal expertise and **should have strong track record for independent action and advocacy**. Individual should (optimally) have limited direct ties with commission and utilities.

Differences between a Ratepayer Advocate and Commission Staff

- A ratepayer advocate's mission is (and should be) **entirely different than a regulatory commission or regulatory commission's staff**.
- The goal of regulatory commissioner should be to **serve as a neutral arbiter of fact**, balancing the interest of regulatory stakeholders.
- The mission of a commission staff should be to **ensure that the regulatory commission has adequate information** to make decisions: the commission staff should not be an active advocate for any party.
- Commission staffs should only actively provide testimony in a regulatory proceeding in those instances where **the evidentiary record is known to be incomplete.**
- Commissions staffs should be **professional advisors and experts, not advocates.**

Conclusions & Recommendations

Conclusions

Regulatory lag is not "bad" and is the primary incentive mechanism included in regulation that should **increase utility efficiency incentives** in a manner **similar to competitive markets** (efficiency leads to increased profitability).

Alternative regulation is a **modification** of, not a **substitute** for, traditional regulation by taking a little of the "old" (cost of service ratemaking and regulatory lag) and combining this with a little of the "new" (formulaic increases in rates and fixed regulatory review periods) to **increase the effectiveness** of the regulatory process for both parties (utilities and ratepayers).

Alternative regulation **changes the regulatory emphasis** from focusing on **"inputs"** (i.e., the cost of service) to one that emphasizes **"outputs"** (i.e., efficiency and profitability): this is why **alternative regulation is often referred to as performance-based regulation**, because its underlying goal is encourage efficient **performance**.

A good alternative regulation program ensures that the **risks and rewards** between ratepayers and utilities are **balanced**. The current Vermont alternative regulation plans **do not do a good job at balancing risks and rewards** but could be easily changed to ameliorate each of the programs' shortcomings.

Summary of Recommendations

1. Require the Board to open a proceeding to **reconcile alternative regulation plans** between VGS and GMP with the goal of **creating program consistency that balances the risks** between utilities and ratepayers.

2. Limit the **use of capital expenditure cost recovery mechanisms** within the plans:

   a) No capex mechanisms allowed until **project-specific and financial need** is proven.

   b) If major capital program costs are allowed, utilities must be required to provide a **detailed set of minimum filing requirements for annual reconciliations** (similar to the recent GMP settlement agreement).

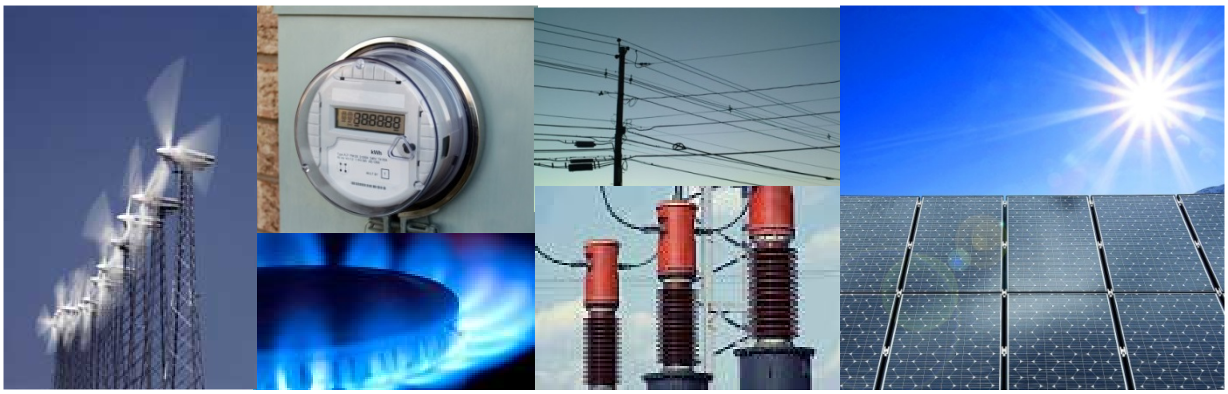
   c) If major capital program costs are allowed, utilities must **include performance-based measures with penalties for non-performance.**

   d) If capital program costs are allowed, they must be **subjected to ratepayer protection mechanisms** that include, but are not limited to, total annual investment caps, rate impact caps, minimum filing requirements, and performance benchmarks with penalties for non-compliance.

3. Consider additional modifications to make the Department more **consumer advocacy-oriented.**

<u>Exhibit 3</u> - 2016 AARP Report

A Critique of the Vermont Department of Public Service's Ratepayer Advocacy Activities, Organization And Act 56, Section 21(b) Report



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Report
February 24, 2016

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Executive Summary

Last year, the Vermont Legislature passed Act 56, Section 21(b), directing the Department of Public Service to conduct a thorough review of its ratepayer advocacy structure and how that compares to other statutorily-created ratepayer advocates around the country. This Act was passed to provide the Legislature with information that could be useful in addressing what has become a significant concern by many consumer-oriented stakeholder groups, individuals, and policymakers regarding the Department's actions, positions, and policies over the past several years.

The Department released its final report on February 22, 2016 ("DPS Report"). It consists of a very general survey of state ratepayer advocacy structures and is devoid of any serious or critical analysis. The report concludes that the Department's current structure is the most beneficial to the public, with any misgivings about the Department's current and prior actions can be attributed to nothing more than problems of public perception. The DPS Report concludes with three recommendations that will do little to nothing to address the fundamental problems associated with its past ratepayer advocacy positions and policies.

The DPS Report fails to recognize that the Department's problems lie deeper than a mere failure to effectively communicate its actions to the public. One of the primary problems with the Department's actions rests with the confusing and sometimes conflicting statutory language that defines the Department's ratepayer advocacy responsibilities. Currently, ratepayer advocacy is pursued in one of four divisions within the DPS: the Division of Public Advocacy, which is directed by a Public Advocate. The Public Advocate and its division, however, are comprised of attorneys who, by statute and ethical codes, are required to act on the behalf of their client, the Commissioner of the Department of Public Service, not ratepayers. Thus, the office of the Public Advocate is, unfortunately, a misnomer since he or she does not represent ratepayers by statutory definition, but instead, represents the Commissioner – who, in turn, reports to the Governor.

The Department's mission confusion extends further to the agency's Commissioner. Recently, the Vermont Legislature modified the statutory language (30 V.S.A. § 2(f)) defining the Department (and its Commissioner's) mission to emphasize advocacy for ratepayer classes not independently represented in proceedings before the Board (i.e. residential, low-income, and small businesses). The Commissioner of the Department, to this date, appears to be either confused or unaware of this legislatively-directed mission change since the DPS Report, as well as Department's actions and policies over the past several years, still center on protecting what they believe are the state's broader "public interest" considerations, not those specific to residential and small commercial ratepayers. The Department cannot on one hand promote the interests of the state as a whole and, on the other hand, defend the interests of a specific group within the public, such as residential and small commercial ratepayers.

It is also clear from the DPS Report that the Department's current structure is not only mission-confused, but mission-conflicted. The Department currently conducts both energy planning and policy functions alongside its ratepayer advocacy functions. No other state in the U.S. combines these functions given their inherently conflicted purposes. State energy planning and policy offices typically pursue activities that facilitate energy technology and deployment projects, as well as a number of energy efficiency programs, across a wide range of stakeholders and interests groups; they are not organized to litigate extensive and complex cases before regulatory tribunals to ensure that utilities provide least cost reliable utility service. In addition, state energy offices tend to represent the broad public interest, not those specific and isolated to residential and small commercial ratepayers.

The DPS Report underscores that the Department is not a cost-effective ratepayer advocate: ratepayers are simply not getting any advocacy "bang for their buck" since the Department fails repeatedly to take positions that are consistent with ratepayer interests. Therefore, the Legislature should undertake a considerable and meaningful reform of ratepayer advocacy in Vermont in the following general fashion:

Major Recommendations

- The Legislature should eliminate the Division of Public Advocacy and the position of the Public Advocate in the Department of Public Service. In its place, the Legislature should create an independent Ratepayer Advocate ("RA") that supervises an Office of Ratepayer Advocacy ("ORA").[1] The mission of the ORA and RA should be made explicit and unequivocally clear: to focus exclusively on residential and small commercial ratepayers.
- For administrative purposes, the RA and ORA can be housed in any relevant state agency, including the Department or the Office of the Attorney General, provided that a high degree of independence included in the recommendations below, or some version of the recommendations listed below, are adopted. This recommendation is consistent with the 42 other states that possess a clearly defined ratepayer advocate. Further, the majority of states (over three-quarters) have ratepayer advocacy agencies as independent agencies or part of AG's offices.
- If the RA/ORA functions are removed from the Department, it should continue to conduct its statewide energy planning and policy activities like any other state

[1] This new office can remain in the Department if certain organizational, independence, and accountability reforms are undertaken. If the Legislature were to choose to keep this new ratepayer advocate in the Department, the "elimination" of the current PA would effectively consist of a name, mission, and organizational change, rather than a true "elimination." Likewise, a movement to another agency could also be seen as effectively "transferring" rather than eliminating.

energy office. Further, the dollars associated with the former PA's activities (and its division) should be eliminated from the Department's future budget.

Mission Recommendations

One of the most important policy recommendations that can be made to the Legislature in this matter is to clearly and unambiguously identify the RA's mission as being one dedicated to:

- Representing and forcefully advocating for residential and small commercial ratepayer interests.
- Supporting low-income and disadvantaged utility customers.
- Being fuel and technology neutral, focusing on securing the lowest cost, most reliable utility service possible.
- Defending residential and small commercial ratepayers from assuming utility business, financial, and regulatory risk without appropriate and reasonable compensation.

Organizational Recommendations

The RA and the ORA need an independent organizational and oversight structure. This can be accomplished through the following recommendations:

- A volunteer stakeholder committee (Committee for Ratepayer Advocacy or "Committee") should be established that provides guidance on ratepayer advocacy and governance issues.
  - The committee should be comprised of six members: two appointed by the Governor; one appointed by the Senate President Pro Tempore; one appointed by the Speaker of the House; and two appointed by the Committee itself.
  - Members will serve staggered four-year terms and should represent a balanced, cross-section of stakeholder groups, including small business groups, consumer groups, low-income groups, and environmental groups.
  - Committee members can be removed by a majority vote of other committee members.
- The Committee shall solicit qualified RA candidates that have prior consumer advocacy experience. The RA does not have to be an attorney.
- The Committee will submit three RA candidates to the Governor for selection. The Governor will appoint the RA who will also be confirmed by the Senate Finance Committee.

- The RA will serve a four year term and can be re-nominated and re-confirmed for additional terms.
- The RA can be removed for cause by a recommendation of the Governor provided that recommendation is approved by both the majority of the Committee and the Senate Finance Committee.
- The RA and ORA may operate within any state agency. However, the RA and ORA shall be completely independent of any agency Secretary, Commissioner, or other type of administrative director. The RA and ORA will have a separate line item budget from the agency in which it is housed that will be funded through regulatory assessment fees.
- The ORA shall be comprised of a moderate-sized staff that is composed primary of attorneys with one attorney serving as a Director of Litigation.
    - The RA can serve as the Director of Litigation if she/he is a Vermont Bar-certified attorney in good standing.
    - The ORA should be comprised of a small number of professional staff members such as economists, engineers, accountants, and other policy/utility analysts to assist in case management and non-docketed regulatory matters.
    - The RA/ORA will primarily rely on outside consultants for litigated matters. The RA will be limited to a total consulting budget not to exceed $125,000 per docket. The RA can increase this expenditure to $175,000 per docket upon a showing of special circumstances provided this amount is approved by the Committee. Consulting fees will be recovered through the regulatory assessment fee, or a direct utility reimbursement, and will not be part of the ORA's normal operating budget.

Other Recommendations

- All settlement agreements, memoranda of understanding, or other agreements entered into by the RA with other parties (including utilities) in litigated proceedings before the Board must be approved by the Committee.
- The RA will brief the Committee on a quarterly basis. At least two of these briefings will be on an in-person basis.
- The RA shall prepare an annual report that will be submitted to the Committee that will also be submitted to the Governor and the Senate Finance Committee. The report will explicitly discuss: the RA's actions during the prior year; the specific positions taken by the RA on each major proceeding during the prior year and how those positions compare to the Board's final decision in each matter; an explicit discussion regarding the rationale and basis for any settlements or memoranda of understanding entered into by the RA during the prior year (prepared in a fashion that does not compromise the statutorily-required confidentiality of such agreements); the RA's position and status associated with any pending proceedings; and a

discussion and analysis of the value delivered to ratepayers during the course of the prior year. Assumptions, caveats, and other conditions associated with the analysis of ratepayer value and any quantification of this value shall be clearly provided in the report.

1 Introduction

The Acadian Consulting Group ("ACG") was asked by AARP-VT to examine the current structure of the Department of Public Service ("DPS" or the "Department") and to offer a critical assessment of the final report issued by the DPS on February 22, 2016 (hereafter, "DPS Report").[2] ACG is a research and consulting firm specializing in the analysis of economic, statistical, financial, and accounting issues that arise through public policy and in the regulation energy and related industries.[3] ACG provides expert witness testimony, research, and reports primarily for state consumer counsels, ratepayer advocates, Attorneys Generals, and regulatory commission staff.[4] Founded in July 1995, ACG consists of a professional staff with more than 95 years and 500 regulatory proceedings worth of combined experience in the electric, natural gas, water, and telecommunications fields, in over 20 states. AARP is a non-profit, nonpartisan organization, which advocates on behalf of more than 37 million citizens 50 and older nationwide.[5] AARP advances a variety of issues its members find important to them, including the high costs of electric and natural gas utility rates. AARP Vermont represents AARP interests in Vermont, on behalf of the 128,000 members in the State.[6]

The DPS Report was prepared in direct response to Act 56, Section 21(b) of the Vermont Legislature directing the Department to:

> …evaluate the pros and cons of various forms of ratepayer advocate offices and report on or before December 15, 2015, to the House Committee on Commerce and Economic Development and the Senate Committee on Finance with

[2] An Evaluation of Ratepayer Advocate Structures Pursuant to Act 56, Section 21(b): A Report to the Vermont Hose Committee on Commerce and Economic Development and the Senate Committee on Finance (February 22, 2016), Vermont Public Service Department.
[3] http://www.acadianconsulting.com
[4] http://www.acadianconsulting.com/pages/clients.html
[5] http://www.aarp.org/about-aarp/
[6] http://web.vermont.org/Family-Household-Resources/AARP-Vermont-1407

> any recommendations on how to improve the structure and effectiveness of the Division for Public Advocacy within the Department of Public Service.[7]

A close examination of the DPS Report, as well as the actions of the Department over the past eight years, suggests that there are a number of opportunities to improve ratepayer advocacy in Vermont. The current structure is not only mission-confused, but mission conflicted. The Department currently conducts both energy planning and policy functions, alongside its ratepayer advocacy functions. As will be discussed later in this Report, no other state in the U.S. combines these functions given their inherently conflicted purposes. State energy planning and policy offices typically pursue activities that facilitate energy technology and deployment projects, as well as a number of energy efficiency programs, across a wide range of stakeholders and interests groups; these state energy offices are not developed to litigate extensive and complex cases before regulatory tribunals to ensure that utilities provide least cost reliable utility service. While the goals of these state energy policy and planning agencies may appear to be consistent with certain ratepayer goals, that is not often the case and there are numerous examples (provided later) where state energy planning offices and ratepayer advocates have taken opposing positions in utility regulatory proceedings.

The remainder of this Report is organized into four remaining sections. Section 2 discusses the DPS Report's failure to conduct any critical self-examination of the Department's past activities and positions before the Vermont Public Service Board, and offers a series of examples of past DPS actions that may be leading to the current crisis of confidence regarding the Department's ratepayer advocacy activities. Section 3 discusses the conflict of interest problem alluded to earlier, and explains how the DPS

[7] Act 56 of the 2015-2016 Legislative Session, §21(b)(a).

Report fails to address the fundamental problem with the Department's mission and structure. Section 4 examines the DPS Report's recommendations and explains why they are deficient and unlikely to result in any positive improvement in Vermont ratepayer advocacy. Section 5 presents a series of recommendations that could lead to an improvement in ratepayer advocacy in Vermont.

2 Critical Assessment of the Department's Prior Regulatory Activities

2.1 Overview

The DPS Report recognizes that several interested stakeholders have expressed concerns about the Department's past actions before the Vermont Public Service Board (the "Board") and whether those actions have been in ratepayer's best interests.[8] Act 56, Section 21(b), while not explicitly referencing frustration with the Department's actions, was certainly not passed to satisfy the academic curiosity of the Vermont Legislature. Despite ratepayer concerns, the DPS Report dances around addressing how its current structure has impacted its recent actions and policies, either in practice or appearance. Instead, the DPS Report provides a rather cursory tally of the organization of other state ratepayer advocates,[9] and concludes that the Department's current structure, and presumably the Department's recent activities before the Board, are "the most beneficial to the public."[10] Any misgivings about the Department's current and prior actions, according to the DPS Report, can be attributed to nothing more than public perception problems.[11]

The DPS Report provides no context or response to what has been a series of actions taken in a variety of proceedings before the Board that have been unexplainably contrary to ratepayer interests. Examples of these types of actions can be found in

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[8] An Evaluation of Ratepayer Advocate Structures Pursuant to Act 56, Section 21(b): A Report to the Vermont Hose Committee on Commerce and Economic Development and the Senate Committee on Finance (February 22, 2016), Vermont Public Service Department, p. 9.

[9] *Ibid.*, Appendix A.

[10] *Ibid.*, p. 6.

[11] An Evaluation of Ratepayer Advocate Structures Pursuant to Act 56, Section 21(b): A Report to the Vermont Hose Committee on Commerce and Economic Development and the Senate Committee on Finance (Draft dated January 15, 2016), Vermont Public Service Department, p. 19; see also, An Evaluation of Ratepayer Advocate Structures Pursuant to Act 56, Section 21(b): A Report to the Vermont Hose Committee on Commerce and Economic Development and the Senate Committee on Finance (February 22, 2016), Vermont Public Service Department, p. 35.

proceedings associated with various utility alternative regulation plans ("ARPs"), special utility ratemaking proposals, as well as recent certificate of public good ("CPG") proceedings before the Board.

2.2 Examples of Deficiencies in the Department's Prior ARP Actions

In 2009, the Department entered into a Memorandum of Understanding ("MOU") with Green Mountain Power Corporation ("GMP") recommending the establishment of a second ARP for GMP.[12] ARPs are a form of alternative regulation that allow utilities to change their rates, usually based upon a pre-defined set of formulas, rather than filing a full rate case before regulators. The purported advantages of utilizing ARPs, instead of full rate cases, is that this pricing flexibility should (a) give the utility adequate pricing flexibility to cover its costs and (b) send signals to become more efficient since any excess earnings that are generated from an incentive-based approach (instead of a cost-based approach) will be shared between the utility and its ratepayers.

Unfortunately, the Department settled with GMP even before the company filed its 2009 ARP with the Board.[13] In other words, the Department did not use the 2009 ARP proceeding to closely examine whether or not this new form of regulation was working well for GMP's ratepayers: no reports nor expert witness testimony was filed by the Department on the mechanics of the plan and whether it represented an appropriate sharing of risks and rewards between the utility and ratepayers. The 2009 ARP settlement between the Department and GMP was not the result of a hard-fought proceeding, but instead represented one of several proceedings over the course of the

[12] Petition of Green Mountain Power Corporation for approval of an alternative regulation plan (Plan II), Vermont Public Service Board Docket No. 7585, Memorandum of Understanding between the Vermont Department of Public Service and Green Mountain Power Corporation.

[13] Petition of Green Mountain Power Corporation for approval of an alternative regulation plan (Plan II), Vermont Public Service Board Docket No. 7585, Order dated April 16, 2010, p. 4.

past eight years where the Department summarily settled with a regulated utility without attempting to litigate or go through the standard evidentiary process. Part of the Department's settlement included agreeing to three components of GMP's ARP that were particularly rewarding to the utility and not ratepayers.

One of these components was a relatively generous "earnings sharing mechanism" ("ESM") that was meaningfully modified from that included in GMP's original ARP.[14] This ESM was designed to give the utility incentives to achieve higher and higher levels of efficiency savings. ESMs have been common parts of ARPs used in other states in the past, particularly in telecommunications regulation. The fact that the Department agreed to an ESM was not the problem: it was the structure of the excess earnings sharing between ratepayers and utility shareholders that is so troubling. The Department did not agree to a sharing approach that equitably balanced risks and rewards between ratepayers and the utility, but instead agreed to one that gave the utility and its shareholders a very generous percentage of any excess earnings.

Second, and most importantly, the Department agreed in this settlement to continue to include what was known as a capital expenditure mechanism that would allow GMP to pass-through, in rates, capital expenditures on a dollar-for-dollar basis.[15] Mechanisms of this sort are entirely inconsistent with alternative regulation principles.

[14] *Ibid.*, p. 12.

[15] Petition of Green Mountain Power Corporation for approval of an alternative regulation plan (Plan II), Vermont Public Service Board Docket No. 7585, Green Mountain Power Corporation Alternative Regulation Plan II.

Typically, utilities under ARP-type mechanisms are given pricing flexibility in order to cover rising costs, including any capital-related costs.[16] The Department, however, agreed to a mechanism that effectively allowed GMP to have its proverbial cake and eat it too: GMP could increase rates based upon the ARP's formulaic method, and would also be allowed under the Department's settlement to pass along additional capital expenses on a dollar-for-dollar basis without having to go through a standard rate case. The Department did not impose or require the utility provide any documentation on these capital expenditures, including; identify individual capital projects, the purpose of the capital project and how it met the utility's longer run capital plan, the anticipated and final costs for each capital project, or any other standard information. Quite a good deal for GMP, but not such a good deal for ratepayers.

Third, the Department's 2009 GMP settlement agreement included the continuation of what was called a "ROE Performance Adjustment" mechanism in GMP's pricing/earnings formula.[17] This ROE adjustment mechanism allowed GMP to effectively "double-dip" on excess earnings since the adjustment gave the utility "bonus" rates of return if its overall earnings were higher than a peer group of comparable utilities. In other words, the mechanism allowed the utility to earn more in excess earnings, if it could show that it was already earning more than most of its peer utilities. Again, the deal negotiated by the Department provided significant benefits to GMP, inexplicably at ratepayers' expense.

[16] Here, capital-related costs are those associated with longer-lived utility investments such as transformers, poles, substations, and power generation facilities. These investments are usually growth-related so the revenues from new sales requiring these investments are also a source of funding, in addition to the price increases allowed by the ARP.

[17] Petition of Green Mountain Power Corporation for approval of an alternative regulation plan (Plan II), Vermont Public Service Board Docket No. 7585, Order dated April 16, 2010, p. 15.

Interestingly, while the Department had no issues with allowing the utility to maintain this generous level of excess returns, the Board did raise questions with this component of the settlement. In the final order for the proceeding, the Board actually eliminated the first year of its implementation since it would have been too generous and would have financially rewarded the utility for effectively doing nothing.[18] Again, the Department had no issue entering into an agreement that financially rewarded the utility for doing nothing, it was the Board that imposed these limited constraints, contrary to the original terms of the settlement agreement.

The Department's 2009 settlement agreement with GMP expired in 2013 when the ARP was scheduled for an additional periodic regulatory review. Like the 2009 review, this 2013 periodic review was the time in which the Department could have sought additional ratepayer protections and modifications to the ARP. It also represented the first opportunity that the Department would have to potentially unwind some of its poor decisions arising from the 2009 settlement agreement discussed earlier: provided, of course, that the Department recognized that these prior agreements were not in ratepayers' best interest. The Department, unfortunately, did not make such recommendations.

The Department failed to file any expert testimony or present any independent opinion to the Board regarding the merits of the proposed ARP in the 2013 periodic review, despite the obvious shortcomings of the 2009 settlement agreement.[19] Fortunately for ratepayers, AARP-VT did intervene and actively participated in the proceeding. Unlike the Department, AARP-VT did sponsor the testimony of an expert

[18] *Ibid.*, p. 17.
[19] Petition of Green Mountain Power Corporation for approval of an Alternative Regulation Plan, pursuant to 30 V.S.A. § 218d, Vermont Public Service Board Docket No. 8191.

witness in this proceeding that highlighted many of the design deficiencies associated with GMP's ARP.[20] Interestingly, even GMP recognized that its ROE Performance Adjustment mechanisms was probably a little too rich, and agreed to remove this provision in the 2013 ARP review with little argument.[21]

AARP-VT conducted an analysis that examined the ratepayer benefits of GMP's ARP, something the Department did not conduct at that time. The Department was apparently satisfied with the structure of the ARP and preserving the terms and conditions of its 2009 settlement with the utility. Part of AARP-VT's analysis, replicated in

Table 1 below, showed that over the course of the ARP's existence, GMP ratepayers had received $852,442 in benefits. GMP shareholders, however, had received over $6.5 million in excess earnings under the earnings sharing mechanisms repeatedly agreed to by the Department. When questioned by the Senate Finance Committee about these issues in a 2014 committee hearing, the Department maintained that it was still "learning" the intricacies of the ARPs nearly a decade after the first alternative regulation plan was implemented in Vermont.

[20] See, Petition of Green Mountain Power Corporation for approval of an Alternative Regulation Plan, pursuant to 30 V.S.A. § 218d, Vermont Public Service Board Docket No. 8191, Direct Testimony of David E. Dismukes.

[21] Petition of Green Mountain Power Corporation for approval of an Alternative Regulation Plan, pursuant to 30 V.S.A. § 218d, Vermont Public Service Board Docket No. 8191, Order dated August 25, 2014, p. 7.

Table 1 Green Mountain Power's Earnings Sharing Trends

	Earnings Sharing Experience Green Mountain Power					
Year	Ratepayer ESM Shares	Contribution to Customer Energy Efficiency Programs (Power Partners)	Ratepayer - Total Share	Deadband Share	Utility ESM Shares	Utility - Total Share
2007	$0	$2,849	$2,849	$25,637	$0	$25,637
2008	$0	$31,718	$31,718	$285,458	$0	$285,458
2009	$0	$120,125	$120,125	$1,081,129	$0	$1,081,129
2010	$0	$178,792	$178,792	$1,609,124	$0	$1,609,124
2011	$0	$182,388	$182,388	$1,641,489	$0	$1,641,489
2012	$0	$0	$0	-$1,024,350	$0	-$1,024,350
2013	$0	$336,572	$336,572	$3,029,144	$0	$3,029,144
	$0	$852,442	**$852,442**	$6,647,631		**$6,647,631**

The Department appears to have been just as careless in its other reviews of GMP's ARP. In a later compliance filing examining the prudence of GMP's base rates, the Department's own consultant noted multiple imprudent expenditures and practices of GMP. First, the consultant noted that GMP had paid $770,410 to exempt employees for overtime during storm events.[22] Exempt employees are salaried employees typically not eligible for overtime benefits, but GMP apparently has a policy compensating such employees for additional time worked if the employee works more than five hours during a storm event. As the consultant concluded, restoration activities during outage events are already a significant burden on ratepayers without the inclusion of additional overtime benefits for employees who are expected as part of a salaried position to work extra hours as appropriate.[23] Furthermore, since the overtime benefits being provided

[22] Larkin & Associates, PLLC: Report on Analysis of Rate Year Ending September 30, 2016 Green Mountain Power Corporation Cost of Service Request and Cost of Capital Request Under Alternative Regulation (August 14, 2015), Tariff No. 8580, p. 51.

[23] *Ibid.*, p. 52.

represented a discretionary management bonus, the consultant recommended that GMP shareholders should at least share some responsibility for these costs.[24]

Furthermore, the Department's consultant also found in an earlier proceeding that GMP's vegetative management activities to control tree growth near power lines were deficient. This deficiency led to higher than necessary restoration costs during a major storm event as 95 percent of outages and damages to the utility's system were due to tree-related damage. The consultant thus recommended that GMP adopt a shorter trim cycle and an aggressive enhanced maintenance program that focused on dangerous and hazardous trees. The Department's consultant also noted an absence of a proactive program, and recommended that GMP perform a tree growth study to be used in improving vegetative management efforts.[25] While GMP did produce a study in response to this earlier recommendation, the Department's consultant felt it was deficient. The Department's consultant also noted that GMP failed to recognize and acknowledge its own role in the high cost of restoration activities during a 2014-2015 major storm event.[26] In the consultant's opinion, GMP's exogenous cost request associated with storm restoration should have been decreased to reflect a sort of shared pain due to the company's own negligence.

Ultimately, the Department did not heed the recommendations of its own consultant on these issues. The Department negotiated a "global agreement" resolving all issues between itself and GMP regarding the company's costs of operations. This agreement did not address excess storm-restoration costs associated with bad vegetative management policies or employee bonuses policies, leaving the issue to be

[24] *Ibid.*, p. 52.
[25] *Ibid.*, p. 55.
[26] *Ibid.*, p. 56.

resolved in future regulatory proceedings. The Department's consultant had recommended $770,410 in employee compensation be removed from rates due to over-time bonuses.[27] Likewise, the Department's consultant noted GMP and the Department "did discuss a plan to address the (vegetative management) cycle issue and to aggressively address the hazard/danger tree issue that is causing the damage during storms."[28] This concern however was not resolved during the proceeding, with discussions between the Department and GMP remaining only "ongoing" when the Department entered into its settlement with GMP.[29]

The Department's acquiescence to utility ARP plans, and their relatively generous terms, was not limited to proceedings involving GMP alone. On October 4, 2011, VGS filed an ARP pursuant to 30 V.S.A. § 218d, to replace an expiring plan under which the company had been operating.[30] Here again, the Department entered into a settlement, or MOU, with VGS on June 26, 2012, to settle all issues in the Board's proceeding.[31]

One provision in VGS' ARP allows the utility to index its allowed rates of return to changes in market rates.[32] This provision allows the utility to increase its allowed rates of return as market rates begin to increase, without filing a rate case.[33] Under most ARPs, the allowed rate of return under the program is fixed, not variable, until the time of the utility's next rate case. This rate of return provision effectively shifts financial

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[27] *Ibid.*, p. 52.
[28] *Ibid.*, p. 56.
[29] *Ibid.*, p. 56.
[30] Petition of Vermont Gas Systems, Inc., for approval of a Successor Alternative Regulation Plan, Vermont Public Service Board Docket No. 7803, Order dated August 21, 2012, p. 3.
[31] *Ibid.,* p. 4.
[32] *Ibid.*, p. 7.
[33] The inverse is also true, but given recent interest rate trends, it is hard to imagine further large interest rate decreases that would result in substantially lower rates.

market risk away from utility shareholders and onto ratepayers and is a provision that went unchallenged by the Department in its settlement agreement with the utility. Likewise, the terms of VGS's ARP allow for immediate recovery of all capital investment costs associated with transmission and distribution integrity-management programs,[34] without any performance benchmarking requirements, thereby shifting the regulatory risk of reviewing the costs associated with these plans, as well as the performance risk of the integrity management plans themselves, away from the utility and its shareholders and onto ratepayers.

Furthermore, VGS' ARP included an earnings sharing approach designed to share over-earnings in a fashion similar to the ESM discussed earlier for GMP.[35] However, unlike GMP, the VGS ESM included a weather normalization factor, wherein the utility's earnings sharing would be determined on a weather-normalized basis.[36] VGS argued that weather normalization is a ratemaking principle used in other jurisdictions and the Department appears to have unquestionably accepted this assertion in its settlement agreement with the utility.[37] While weather normalization adjustments do exist for natural gas utilities, the adjustments are made with respect to utility throughput levels, which in turn normalizes utility sales-related revenues: these adjustments are not tied to earnings (or profits). Once again, even the Board recognized a provision included in a Department-supported settlement agreement that had risk-shifting implications to ratepayers. While the Board approved the mechanism,

[34] Petition of Vermont Gas Systems, Inc., for approval of a Successor Alternative Regulation Plan, Vermont Public Service Board Docket No. 7803, Order dated August 21, 2012, p. 23.
[35] *Ibid.*, p. 7.
[36] *Ibid.*, pp. 7-8.
[37] *Ibid.*, p. 13.

it noted that it "realize(d) that (weather normalization) **substantially** reduces VGS's earnings risk, and may be viewed as a shift of risk to ratepayers."[38]

Admittedly, the settlement agreement executed by the Department included a provision setting VGS' base allowed rate on equity at 9.75 percent.[39] Notably, this level represents a 50 basis point reduction from the ROE originally-proposed by VGS (i.e., 10.25 percent). This reduction was purportedly a concession for the risk-shifting nature of the weather-normalization of the Company's profits.[40] The problem with this agreement is that this 50 basis point reduction did not discount VGS' rate of return from an industry average level, which would have been appropriate, but instead, reduced its rate of return from an abnormally high level (10.25 percent). Thus, the final rate of return agreed to by the Department simply lowered VGS' rate of return to an average rate, not one representing any fair compensation for risk shifting nature of the various components of its ARP. In fact, the same can be said of GMP's allowed rate of return as well.

Table 2 below compares both GMP's and VGS' allowed rates of return (specifically, ROEs) to industry averages and shows that these returns, are only slightly lower (not 50 basis points lower) than the US average, and are actually **higher** than recent industry averages utilized in other New England states. This means that the Department has entered into a series of differing settlement agreements with both utilities over the past several years that have shifted a tremendous amount of financial and performance risk away from the utility and onto ratepayers, in return for virtually no

[38] *Ibid.*, p. 13. The Board approved the mechanism since, as will be discussed in the later part of this section, the agreement included a rate of return adjustment, in addition to an ESM adjustment. The Board also believed it would be in the public interest to decouple the utility's earnings from its throughput.
[39] *Ibid.*, p. 27.
[40] *Ibid.*

financial compensation for ratepayers. Importantly, VGS' allowed rate of return is not meaningfully lower than industry averages, even after including the 50 basis point reduction included in the Department's MOU.

Table 2 Comparison of Allowed Returns on Equity

	Allowed ROE (Percentage)
US Average, All Retail Electric Utilities (2010 - current)	10.00
New England Average, All Retail Electric Utilities (2010 - current)	9.49
Green Mountain Power (MOU from Docket 8190)	9.6
Differences:	
GMP to US Average	**-0.40**
GMP to NE Average	**0.11**
US Average, All Retail Natural Gas Utilities (2010 - current)	9.88
New England Average, All Retail Natural Gas Utilities (2010 - current)	9.47
Vermont Gas Systems (MOU from Docket 7803)	9.75
Differences:	
VGS to US Average	**-0.13**
VGS to NE Average	**0.28**

2.3 Examples of Deficiencies in the Department's Prior Ratemaking Actions

The Department has also entered into settlement agreements on various other ratemaking adjustments and financial mechanisms, outside the context of an ARP, that have also been equally adverse to residential and small commercial ratepayers. On February 7, 2011, VGS filed a petition with the Board requesting an accounting order that would establish a System Expansion and Reliability Fund ("SERF") to be used to fund future, yet undefined, natural gas system expansions.[41] VGS proposed to fund this

[41] Request of Vermont Gas Systems, Inc. to establish a System Expansion and Reliability Fund with funds provided by reductions in the quarterly Purchase Gas Adjustment rate under the Alternative Regulation Plan, Vermont Public Service Board Docket No. 7712, Re: Request of Vermont Gas Systems, Inc. for an Accounting Order Establishing a Vermont System Expansion and Reliability Fund (February 7, 2011).

new regulatory mechanism out of the excess revenues it had been recovering in its fuel charges to customers arising from the regularly-occurring natural gas commodity price decreases.

For instance, VGS noted that in the 10 quarters prior to its filing, it had implemented nine rate reductions due to considerable reductions in commodity natural gas prices.[42] Rather than file for a tenth rate reduction estimated to be approximately 4.5 percent of a customer's overall rates (or $3.7 million annually), VGS proposed to "escrow" the rate decrease into the SERF to offset future rate increases that "might otherwise be required for an eventual system expansion project."[43] On May 16, 2011, the Department entered into a MOU with VGS supporting the establishment of the proposed SERF.[44] Indeed, the May MOU contained no major revisions to the general proposal made by VGS in its initial petition.

It is difficult to understate the extent to which the Department's actions regarding the SERF deviate from residential and small commercial ratepayer interests. At the time of this settlement agreement, no formally-proposed pipeline project had been submitted to, or approved by the Board. This fund was proposed, and agreed to by the Department, based upon a concept, or idea alone, not a specific investment supported by the necessary and appropriate due diligence. It is virtually impossible to imagine any other ratepayer advocate in the U.S. agreeing to a settlement of this nature for a variety of reasons.

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[42] *Ibid.*, p. 2.

[43] *Ibid.*, p. 3.

[44] Request of Vermont Gas Systems, Inc. to establish a System Expansion and Reliability Fund with funds provided by reductions in the quarterly Purchase Gas Adjustment rate under the Alternative Regulation Plan, Vermont Public Service Board Docket No. 7712, Memorandum of Understanding (May 16, 2011).

First, by supporting the proposed SERF, the Department supported denying ratepayers a deserved decrease in rates and any increase in disposable income that those ratepayers were entitled to as a result of a decrease in wholesale natural gas prices. This agreement effectively allowed rates to be unnecessarily inflated in order to be placed in a fund for a project (or projects) that had not been approved by the Board. Thus, the Department, by agreeing to a proposal to fund expansion projects that did not exist, also agreed to inflate rates to levels that were not truly cost-based since the costs for natural gas had unquestionably decreased. The Department, in effect, volunteered and committed the valuable funds and resources of its client (ratepayers) to an entity that it was (or should be) designed to protect. Thus, it should come as no surprise to the Department that some public stakeholders have expressed the belief that it has a too "cozy" relationship with utilities.[45]

Second, the Department's SERF settlement agreement violates not one, but several seminal ratemaking principles. The Department's settlement agreement committed residential and small commercial customers to fund speculative, unknown, and non-measurable projects and costs. While it is true that ratepayers could be called upon in the future to fund prudently-incurred natural gas expansion investments, that possibility is not justification enough for the establishment of the SERF. Consider that ratepayers are typically not required to fund utility investments until: (1) an investment proposal has been made and approved by a utility's regulators; (2) the utility successful develops the project and brings it to commercial operation; and (3) the utility attains cost-recovery for its investments after a regulatory showing that these investments were

[45] An Evaluation of Ratepayer Advocate Structures Pursuant to Act 56, Section 21(b): A Report to the Vermont Hose Committee on Commerce and Economic Development and the Senate Committee on Finance (February 22, 2016), Vermont Public Service Department, p. 25.

prudently-incurred and used and useful. Yet the Department's settlement agreement did the exact opposite, putting the proverbial cart before the horse, allowing the utility to collect money before any investments are identified, approved, and proven reasonable. This is entirely inconsistent with the regulatory principle of setting overall rates in a fashion that are fair, just, and reasonable since, in this instance, rates were inflated to fund what, at best, were speculative investments, not known and measureable costs.

Third, by entering into a settlement agreement for speculative, unknown, and non-measurable projects and costs, the Department effectively committed its clients (residential and small commercial ratepayers) into financing a natural gas pipeline hedge fund. Indeed, one Board member, John D. Burke, dissented from the Board's ultimate decision to approve the Department's SERF settlement agreement.[46] Mr. Burke stated that the Department's SERF settlement agreement "allowed for existing customers to provide venture capital to study expansion feasibility."[47] Underscoring his concern, Mr. Burke noted provisions in the Department's SERF settlement that would allow the utility to use the fund to recover business development costs. Mr. Burke also criticized the lack of a professional feasibility study investigating the viability of VGS's promulgated expansion of natural gas service into Vergennes and Middlebury,[48] a project that would eventually be referred to as the Addison Natural Gas Pipeline. Mr. Burke stated that the information provided by VGS amounted to little more than a

[46] Request of Vermont Gas Systems, Inc. to establish a System Expansion and Reliability Fund with funds provided by reductions in the quarterly Purchase Gas Adjustment rate under the Alternative Regulation Plan, Vermont Public Service Board Docket No. 7712, Order dated September 28, 2011, pp. 20-23.
[47] *Ibid.*, p. 20.
[48] *Ibid.*, p. 21.

"quasi-educated guess,"[49] that essentially reduced to the company believing, "if we build it, they will come."[50]

Fourth, by agreeing to this proposal, the Department agreed to the adoption of a ratemaking mechanism that represented a "substantial exception to normal ratemaking principles."[51] The funding mechanism shifted a considerable level of financial and ratemaking risk away from VGS and onto residential and small commercial ratepayers. The SERF had no grandfathering provisions, nor any parameters outlining when it would or should be return to ratepayers, or even how it would be returned to ratepayers. To this day, it represents an open-ended, and more importantly, free regulatory "call option" for VGS provided at great expense by residential and small commercial ratepayers.

2.4 Examples of Deficiencies in the Department's Prior CPG Actions

The most recent and perhaps most controversial of the Department's adverse ratepayer positions is reflected by actions in VGS' CPG proceeding for the Addison Natural Gas Pipeline ("ANGP") project.[52] The Department has consistently supported the development of this project stating that the ANGP "constitute(d) an important addition to the service territory of Vermont Gas."[53] The Department's positions during

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[49] *Ibid.*, p. 21.
[50] *Ibid.*, p. 21.
[51] *Ibid.*, p. 14.
[52] AARP-VT, the sponsor of this Report, intervened in this proceeding and recommended that the Board re-open the CPG since the terms and conditions under which the original certificate were based had changed. AARP-VT was unsuccessful in its challenge. Further, the author of this report served as the expert witness for AARP-VT in this proceeding.
[53] Petition of Vermont Gas Systems, Inc., for a certificate of public good, pursuant to 30 V.S.A. Section 248, authorizing the construction of the "Addison Natural Gas Pipeline" consisting of approximately 43 miles of new natural gas transmission pipeline in Chittenden and Addison Counties, approximately 5 new distribution mainlines in Addison County, together with three new gate stations in Williston, New Haven, and Middlebury, Vermont; Vermont Public Service Board Docket No. 7970; Order dated December 23, 2013; p. 18.

the ANGP CPG proceeding, however, appear to have been influenced heavily by the Department's conflicting political functions.

Under 30 V.S.A. § 202b, the Department is required to complete a Comprehensive Energy Plan ("CEP") for the State.[54] The 2011 CEP prepared by the Department, prior to VGS's petition, stated explicitly that "Vermont should encourage the increased use of natural gas by supporting economically viable expansion of the natural gas service territory promoting attachments to the current distribution system … and promoting the use of natural gas vehicles."[55] Because of this requirement, and the Department's finding, a sizeable portion of the Department's filed testimony with the Board in the ANGP CPG proceeding was devoted towards advocating the perceived benefits of increased natural gas availability in the State, consistent with its 2011 CEP findings.[56] This undoubtedly impacted the ability of the Department to provide a critical review of VGS' proposal.

In the months subsequent the Board's initial granting of the certificate, VGS disclosed that the gas pipeline's estimated costs had increased by more than 40 percent, or $35 million.[57] In the months following this problematic disclosure, VGS once again disclosed that the estimated costs of the project had increased by another $33

[54] Petition of Vermont Gas Systems, Inc., for a certificate of public good, pursuant to 30 V.S.A. Section 248, authorizing the construction of the "Addison Natural Gas Pipeline" consisting of approximately 43 miles of new natural gas transmission pipeline in Chittenden and Addison Counties, approximately 5 new distribution mainlines in Addison County, together with three new gate stations in Williston, New Haven, and Middlebury, Vermont; Vermont Public Service Board Docket No. 7970; Direct Testimony of Walter Poor; 2:24-25.

[55] *Ibid.*, 5:6-9; citing 2011 Comprehensive Energy Plan, Volume 2, p. 220.

[56] See, generally, *Ibid.*

[57] Petition of Vermont Gas Systems, Inc., for a certificate of public good, pursuant to 30 V.S.A. Section 248, authorizing the construction of the "Addison Natural Gas Pipeline" consisting of approximately 43 miles of new natural gas transmission pipeline in Chittenden and Addison Counties, approximately 5 new distribution mainlines in Addison County, together with three new gate stations in Williston, New Haven, and Middlebury, Vermont; Vermont Public Service Board Docket No. 7970; Supplemental Prefiled Testimony of Eileen Simollardes, Exhibit Petitioner Supp. EMS-1.

million, such that in the course of a year, estimated project costs increased by nearly 78 percent.[58] Each of these disclosures prompted parties to request that the Board issue Orders announcing a decision to seek remands of its earlier CPG, requests the Board agreed with on both occasions. In the subsequent remand proceedings, however, the Department once again demonstrated its inability to adequately represent the interests of Vermont residential and small commercial ratepayers.

First, the Department inexplicitly joined VGS in objecting to petition for intervention status from two parties, Vermont Public Interest Research Group ("VPIRG"), a consumer and environmental non-profit organization and AARP-VT.[59] While there were arguably some concerns regarding the direct relevance of the practice of hydraulic fracturing in the proceeding (an issue raised by VPIRG), it is unconscionable that the Department would advocate against the representation of two entities that also represent ratepayers, particularly AARP-VT's advocacy for senior and elderly ratepayers.

Second, the Department modified its later economic impact analysis of the ANGP to produce results that supported its position that the development of the ANGP would produce net economic benefits to Vermont and Vermont ratepayers.[60] The nature of

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[58] Petition of Vermont Gas Systems, Inc., for a certificate of public good, pursuant to 30 V.S.A. Section 248, authorizing the construction of the "Addison Natural Gas Pipeline" consisting of approximately 43 miles of new natural gas transmission pipeline in Chittenden and Addison Counties, approximately 5 new distribution mainlines in Addison County, together with three new gate stations in Williston, New Haven, and Middlebury, Vermont; Vermont Public Service Board Docket No. 7970; Prefiled Testimony of Ralph Roam, Exhibit Petitioner RR-2.

[59] See, Petition of Vermont Gas Systems, Inc., for a certificate of public good, pursuant to 30 V.S.A. Section 248, authorizing the construction of the "Addison Natural Gas Pipeline" consisting of approximately 43 miles of new natural gas transmission pipeline in Chittenden and Addison Counties, approximately 5 new distribution mainlines in Addison County, together with three new gate stations in Williston, New Haven, and Middlebury, Vermont; Vermont Public Service Board Docket No. 7970; Order RE: Rule 60(B) Reconsideration, pp. 5-6.

[60] See, Petition of Vermont Gas Systems, Inc., for a certificate of public good, pursuant to 30 V.S.A. Section 248, authorizing the construction of the "Addison Natural Gas Pipeline" consisting of

these estimates were highly questioned by other stakeholders (including AARP-VT), many of who believed that the Department's experts had placed an analytic "thumb on the scale" of evaluating project benefits and costs. However, even if the Department's analysis is taken at face value, its results underscore its significant bias in favor of broad state interests, and against those of residential and small commercial ratepayers.

Overall, the Department's analysis concluded that the ANGP would create net benefits for Vermont of some $80 million on net present value ("NPV") terms, with $29.5 million resulting from direct benefits.[61] The Department's analysis, however, was presented from the perspective of **all Vermont stakeholders**: ratepayers, construction companies, municipal governments, competitive fuel oil dealers, and most importantly, utilities. The Department's analysis **did not focus on its clients** (i.e., residential and small commercial ratepayers), but looked at the net benefits to the state, thereby underscoring its focus on the entire state, not residential ratepayers.

Figure 1 summarizes the information found in the Department's net economic benefit analysis. The information has been re-ordered to show the impacts on residential ratepayers versus other Vermont stakeholder groups. The Department's own analysis estimated total direct residential ratepayer net benefits of a negative $64.4 million over 35 years.[62] What this means is that the direct economic costs of the ANGP are higher than the direct economic benefits that arise to residential ratepayers, even

approximately 43 miles of new natural gas transmission pipeline in Chittenden and Addison Counties, approximately 5 new distribution mainlines in Addison County, together with three new gate stations in Williston, New Haven, and Middlebury, Vermont; Vermont Public Service Board Docket No. 7970; Second Remand Testimony of Asa S. Hopkins.

[61] *Ibid.*, p. 6; and Workpaper "REMI results.xlsx".

[62] *Ibid.*

considering the energy savings that arise to new natural gas residential ratepayers that can take service from the new pipeline.

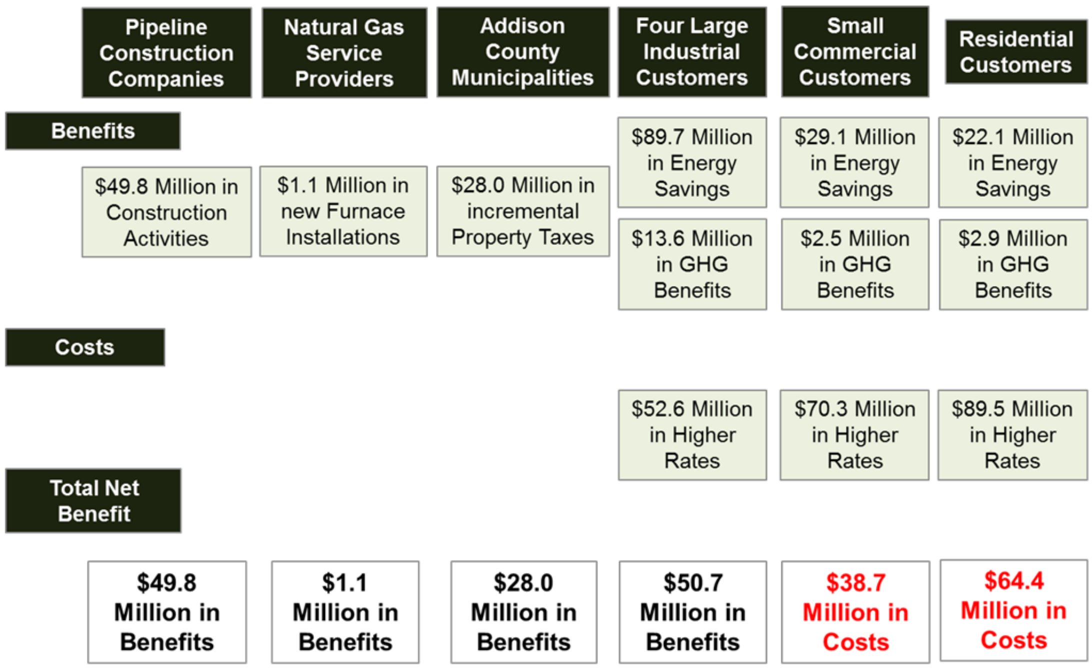

Figure 1. Estimate of Net Economic Benefits, Ratepayers vs. the Public Good[63]

The Department's own analysis regarding the impacts to residential customers begs the question: who benefits from the AGNP, based upon the Department's analysis, if residential customers, overall, are net losers? The answer is a handful of stakeholders benefit including: (1) four large industrial customers; (2) the construction industry; (3) a few municipal governments (due to increased tax revenues); and VGS and its shareholders. Thus, even if one accepts the Department's net economic benefits numbers, the scale of those net benefits are highly tilted in favor of a handful of stakeholders, not the broader interests of residential ratepayers. The revised orientation of the Department's net benefits analysis highlights the bias in its advocacy efforts as those in favor of the state's energy planning goals, not ratepayer interests.

[63] Estimates are provided in present value, or "PV" terms.

This is the fundamental problem that the Department and the DPS Report fails to understand.

Perhaps the best example of the Department's anti-ratepayer bias in the ANGP remand proceedings is associated with the settlement, or MOU, it entered into with VGS after all parties had submitted their evidence regarding whether or not the CPG proceeding for the ANGP should be re-opened.[64] This settlement, between the Department and VGS only, purportedly caps rate recovery associated with the ANGP at $134 million, a level that is $20 million less than VGS's current cost estimate.[65] The Department represented this $20 million reduction as a "meaningful" reduction to the expected costs of the project, thus limiting ratepayer exposure.[66]

The Department's views on its own MOU, however, are deeply problematic. For starters, the Board had already ruled that the ANGP was in the economic best interests of the State at a price tag of $121.6 million in its first remand proceeding.[67] Likewise, the Department fully agreed that VGS's management missteps caused cost overruns in

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[64] Petition of Vermont Gas Systems, Inc., for a certificate of public good, pursuant to 30 V.S.A. Section 248, authorizing the construction of the "Addison Natural Gas Pipeline" consisting of approximately 43 miles of new natural gas transmission pipeline in Chittenden and Addison Counties, approximately 5 new distribution mainlines in Addison County, together with three new gate stations in Williston, New Haven, and Middlebury, Vermont; Vermont Public Service Board Docket No. 7970; Memorandum of Understanding Between the Vermont Department of Public Service and Vermont Gas Systems, Inc.

[65] *Ibid.,* p. 2.

[66] Petition of Vermont Gas Systems, Inc., for a certificate of public good, pursuant to 30 V.S.A. Section 248, authorizing the construction of the "Addison Natural Gas Pipeline" consisting of approximately 43 miles of new natural gas transmission pipeline in Chittenden and Addison Counties, approximately 5 new distribution mainlines in Addison County, together with three new gate stations in Williston, New Haven, and Middlebury, Vermont; Vermont Public Service Board Docket No. 7970; Supplemental Hearing Testimony of Commissioner Christopher Recchia; 3:17-19.

[67] Petition of Vermont Gas Systems, Inc., for a certificate of public good, pursuant to 30 V.S.A. Section 248, authorizing the construction of the "Addison Natural Gas Pipeline" consisting of approximately 43 miles of new natural gas transmission pipeline in Chittenden and Addison Counties, approximately 5 new distribution mainlines in Addison County, together with three new gate stations in Williston, New Haven, and Middlebury, Vermont; Vermont Public Service Board Docket No. 7970; Order RE: Rule 60(B) Reconsideration.

the ANGP that were "both significant and a cause for concern."[68] Arguably, if VGS had pledged to not seek rate recovery of any expenses in excess of this previous Board-approved amount, the entire question of the continued CPG designation before the Board would be moot. In other words, with the Department's MOU, the Department argued that VGS should be allowed rate recovery of an additional $12.4 million over that already approved by the Board to recover cost overruns caused in part because of VGS' likely mismanagement.

Likewise, the Department also argued before the Board that it was increasingly concerned that regulatory uncertainty was exacerbating the project's timeline and increasing cost, noting that VGS decided to send crews home after completing 11 miles of the proposed project due to the possibility of the Board withdrawing its support of the project.[69] This "concern" is telling since it shows that the Department is, once again, more interested in reducing the financial risk and exposure of regulated utilities rather than the longer run rate impacts imposed on ratepayers.

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[68] Petition of Vermont Gas Systems, Inc., for a certificate of public good, pursuant to 30 V.S.A. Section 248, authorizing the construction of the "Addison Natural Gas Pipeline" consisting of approximately 43 miles of new natural gas transmission pipeline in Chittenden and Addison Counties, approximately 5 new distribution mainlines in Addison County, together with three new gate stations in Williston, New Haven, and Middlebury, Vermont; Vermont Public Service Board Docket No. 7970; Supplemental Hearing Testimony of Commissioner Christopher Recchia; 4:10-11.

[69] *Ibid.,* 2:20 to 3:4.

3 The DPS Report Fails to Understand the Problem

3.1 The "Public Interest" and "Ratepayer Interest" are not Synonymous

The DPS Report repeatedly uses the terms "public interest" and "ratepayer interests" as synonymous and interchangeable.[70] This is not an error of semantics, but one that underscores an important misunderstanding the Department appears to have about its role in litigation matters before the Board. The Department cannot, on the one hand, promote the interests of the state as a whole ("the public") and, on the other, defend the interests of a specific group within the public, such as residential and small commercial ratepayers.

Further, in attempting to represent the public interest, broadly, the Department wastes Vermont ratepayer resources by duplicating the activities of the Board. Ratepayers should not have to pay twice for the defense of the public interest. For instance, the Department has a statutory charge to "represent the interests of the consuming public."[71] Yet, the Department represents its mission to the public as:

> The mission of the Department of Public Service (DPS) **is to serve all citizens** of Vermont through public advocacy, planning, programs, and other actions that meet the public's need for least cost, environmentally sound, efficient, reliable, secure, sustainable, and safe energy, telecommunications, and regulated utility systems in the state for the short and long term. The Department does this by:
>
> - **Promoting the interest of the general public** in the provision of the state's regulated public services--electricity, natural gas, telephone, cable television, and to a limited degree water and wastewater. [emphasis added][72]

[70] An Evaluation of Ratepayer Advocate Structures Pursuant to Act 56, Section 21(b): A Report to the Vermont Hose Committee on Commerce and Economic Development and the Senate Committee on Finance (February 22, 2016), Vermont Public Service Department, pp. 19-20.
[71] 30 V.S.A. § 2 (2016)
[72] http://publicservice.vermont.gov/about_us

The Department does not recognize that advocating for ratepayer interests requires it to pursue policies that are partisan in nature and result in the least-cost and most reliable utility service possible. Advocacy does not involve pursuing policies that balance the interests of regulated utilities and their shareholders against those of captive ratepayers. A ratepayer advocate is not a neutral arbiter of fact, nor the defender of the "public good" in litigation matters before the Board. Suggesting that the public interest and ratepayer interests are synonymous is the same as suggesting that anything in a utility's best interest is in ratepayers' best interest. Just because a large, in-state capital project may result in a benefit to a utility and its shareholders, and may increase local employment and taxes to a few municipalities and counties, does not make that project one that is in ratepayers' best interests. Likewise, supporting a utility's proposal to offer highly discounted, or special contract utility service rates to a large industrial customer usually does not mean that it is in residential ratepayers' best interest since, more often than not, captive residential ratepayers are the ones left holding the bag for these types of "public good" initiatives.

The DPS Report, while making a few passing references to the "consuming public,"[73] appears frightened to even mention the term "ratepayer interests" much less "residential ratepayer interests," despite the fact that Act 51, Section 21(b) requires the Department to conduct a survey of other state agencies and their organizational structures and approaches to protecting "residential ratepayer" interests, not the "public interest" or the "public good."[74] The DPS Report surveys these structures, in terms of a

[73] An Evaluation of Ratepayer Advocate Structures Pursuant to Act 56, Section 21(b): A Report to the Vermont Hose Committee on Commerce and Economic Development and the Senate Committee on Finance (February 22, 2016), Vermont Public Service Department, p. 19.

[74] *Ibid.*, p. 13.

simple tally of the agency in which these advocates are located.[75] However, the DPS Report does not include a critical comparison of the advocacy mission of these agencies and how they differ from that of the Department.

For instance, the DPS Report includes the Utah Office of Consumer Services ("UOCS") in its ratepayer advocacy survey.[76] The UOCS was first established by the Utah Legislature in 1977 and is governed by a nine-person committee of laypersons that represent certain segments of the population and have relevant professional and technical expertise.[77] While the Director of the UOCS is appointed by the Governor, that appointment has to be approved by the layperson committee and the Utah Senate.[78]

The express goal of the UOCS is to represent residential, small commercial, and agricultural customers in utility matters, not to represent the public interest or the public good. The goal is not to maximize state employment opportunities resulting from utility capital investments, nor to underwrite speculative utility investments to provide new service in the state. For instance, the UCOS' responsibilities include, among others, advocating:

- positions and actions that will result in public utilities providing reliable service to Utah customers at the lowest reasonable cost, while appropriately considering risk factors. Contrary to the actions taken by the Department over the past several years, the goals of the UOCS are not to promote policies that shift risk away from utilities and their shareholders and onto ratepayers.
- processes for determining new resources that considers all appropriate costs, benefits and risks to consumers that does not preference for a type of fuel or generating resource, but rather a decision that minimizes costs (appropriately considering risks) and maximizes the benefits to consumers in the long run.

[75] *Ibid.*, Appendix A.
[76] *Ibid.*, Appendix A.
[77] Utah Code Ann. § 54-10a-202.
[78] Utah Code Ann. § 54-10a-201.

- policy changes that impact ratepayers in a manner that minimizes ratepayer costs and maximizes ratepayer benefits – not the benefits of the public at large.
- policies that support a reasonable level of funding for low income programs recognizing that they do have benefits despite the difficulty in their quantification.[79]

The DPS Report purportedly surveys the Illinois Citizens Utility Board ("CUB") in its analysis[80] but, once again, fails to analyze how CUB's advocacy emphasis and activities differ considerably from the Department's. For instance, the Illinois CUB was created by the Illinois General Assembly in 1983 as an independent, non-profit, non-partisan organization to explicitly represent the interest of residential utility customers in the state: their goal is not to represent or balance the public interest, but to advocate for residential ratepayers only.[81] Like the UOCS, the Illinois CUB also has an independent, volunteer-based board of directors that provides input into the CUB's policy positions and advocacy efforts.

The DPS Report purportedly included the New Hampshire Office of Consumer Advocacy ("OCA") in its survey of ratepayer advocates,[82] but outside of looking at its organizational structure, the Department appears to have paid little attention to the OCA's mission, its advocacy activities, and how those differ from the Department. The New Hampshire OCA represents another state agency-based ratepayer advocate that has the express mission to represent residential ratepayer interests: not the public good

[79] http://ocs.utah.gov/objectives.html

[80] An Evaluation of Ratepayer Advocate Structures Pursuant to Act 56, Section 21(b): A Report to the Vermont Hose Committee on Commerce and Economic Development and the Senate Committee on Finance (February 22, 2016), Vermont Public Service Department, p. 16.

[81] 220 ILCS 10/4 and 220 ILCS 10/5.

[82] An Evaluation of Ratepayer Advocate Structures Pursuant to Act 56, Section 21(b): A Report to the Vermont Hose Committee on Commerce and Economic Development and the Senate Committee on Finance (February 22, 2016), Vermont Public Service Department, Appendix A.

or public interest.[83] The OCA also has an independent board of directors, selected by a variety of elected officials, which govern its activities.

In Ohio, the Office of the Ohio Consumers' Counsel ("OCC") "advocates for Ohio's residential utility consumers through representation and education in a variety of forums."[84] The OCC Governing Board is made up of nine members, three each representing residential consumers, organized labor and family farmers. In addition, no more than five members of the board may be from the same political party.[85] After the legislature created the OCC in 1976, one of the first items accomplished was the adoption of the "Residential Utility Consumers' Bill of Rights." The bill identifies 10 basic rights that "each residential utility consumer is entitled to" and serves as the "foundation of the OCC's commitment to represent residential utility customers."[86]

In Delaware, the 2013 General Assembly amended its statutes to clarify its intent that the Department of Public Advocate ("DPA") is to "principally advocate on behalf of residential and small commercial consumers."[87] The DPA's fundamental mission is to advocate "the lowest reasonable rates for consumers, consistent with the maintenance of adequate utility service and consistent with an equitable distribution of rates among all classes of consumers." The DPA may also provide guidance to the Governor, the General Assembly or the Secretary of State on matters of energy policy and utility consumers,[88] but it is not the primary agency formulating energy policy on the behalf of the state.

[83] RSA 363:28
[84] http://www.occ.ohio.gov/message.shtml
[85] ORC Ann. 4911.17
[86] http://www.occ.ohio.gov/about/history/historical_1978.shtml
[87] *29 Del. C. § 8716.*
[88] http://publicadvocate.delaware.gov/aboutagency.shtml

The previously-discussed examples show that most ratepayer advocates have explicit missions dedicated to defending residential and small commercial ratepayer interests. These advocates' missions are not dedicated to promoting the resource planning or economic development goals of a particular governor: they do not serve as state energy offices or planning agencies, and they have express missions entirely different than their respective state regulators. Unfortunately, the DPS Report, which purportedly surveys the activities of other state ratepayer advocates, is entirely deficient in recognizing the considerable differences between the Department's mission and those of other state ratepayer advocates. The DPS Report is also deficient in identifying a set of best practices from the mission statements of other state ratepayer advocates to improve ratepayer advocacy in Vermont.

3.2 Fails to Understand its Role as Ratepayer Advocate

The DPS Report also highlights the Department's confusion about who within the agency is primarily responsible for ratepayer advocacy. The DPS Report initially notes that ratepayer advocacy is spearheaded from within the Department in its Division of Public Advocacy, which itself, is headed by the Director of Public Advocacy.[89] The Director of Public Advocacy (the Public Advocate or "PA") is appointed by the Department of Public Service Commissioner and serves at the Commissioner's pleasure. However, the DPS Report also notes that according to state statutes, (1) the Division of Public Advocacy is comprised primarily of attorneys that represent its client: the Commissioner; and (2) these attorneys, including the Public Advocate, are not authorized to formulate policy nor independent advocacy strategy. This means that

[89] An Evaluation of Ratepayer Advocate Structures Pursuant to Act 56, Section 21(b): A Report to the Vermont Hose Committee on Commerce and Economic Development and the Senate Committee on Finance (February 22, 2016), Vermont Public Service Department, p. 10.

ratepayer advocacy does not originate from a division or office exclusively focused on ratepayer issues, but from the Commissioner's office itself. The structure of public advocacy within the Department, therefore, is highly flawed for a number of reasons.

First, the Division of Public Advocacy has no independent authority to pursue activities that are in residential and small commercial ratepayers' best interests.[90] As a division of attorneys, they are compelled by statute and ethical codes to represent the wishes of their client, the Commissioner, not ratepayers. The Commissioner, in his or her mission in promoting the broad public interest, has an inherent and unresolvable conflict of interest between his or her planning mission, on the one hand, and his or her advocacy mission, on the other; a conflict that will be discussed in greater detail in the following sub-section of this report.

Second, the PA itself has no independence of action. The PA is appointed by the Commissioner, serves at the Commissioner's pleasure, and serves for a term coincident with that of the Commissioner.[91] Further, as a lawyer, the PA cannot formulate policy independent from his or her client, the Commissioner. Conflicts or differences of opinion on ratemaking or other utility regulatory issues, will be resolved according to the wishes of the Commissioner, not the PA.

Third, the PA is beholden to the Commissioner for all of the resources needed to undertake his or her advocacy functions.[92] The PA's budget and financial support is approved by the Commissioner. In addition, the PA must seek approval, or at minimum must ensure no disapproval, for the use of technical resources within the Department such as economic, engineering, and other technically-trained experts.

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[90] See, 30 V.S.A. §1(b).
[91] *Ibid.*
[92] 30 V.S.A. §1(c)

The DPS Report, however, appears to acknowledge, or at least understand, many of these conflicts and barriers to true advocacy independence.[93] Despite this ambiguity in function, the inherent conflicts of interests, and lack of independence, the DPS Report suggests that Vermont has a unique system of ratepayer advocacy that is somehow preferable to the structure used in the rest of the country.[94] Particularly troubling is that despite its recognition of potential conflict of interests and barriers to true advocacy independence, the Department has:

- Never attempted to develop any internal rules or protocols to remedy these conflicts.
- Appears to have never sought any legislative remedy to these challenges.
- Continues not to seek any legislative remedy to these challenges in the DPS Report recommendations.

3.3 The Conflict of Interest between Planning and Advocacy functions

The DPS Report notes that the Department's structure, which purportedly blends energy planning and ratepayer advocacy, is "one of the more unusual"[95] in the U.S. However, the DPS Report is deficient in explaining how the coupling of energy planning and advocacy activities lead to ratepayer synergies. This failure likely stems from the fact that it is impossible to show these synergies since both serve mutually-exclusive purposes and are not complimentary, contrary to what is suggested in the DPS Report.[96] These two functions are often in conflict with one another, both in theory and in practice. This is why most states have opted to keep the two functions separate. If there were considerable synergies and benefits between energy planning and ratepayer

[93] An Evaluation of Ratepayer Advocate Structures Pursuant to Act 56, Section 21(b): A Report to the Vermont Hose Committee on Commerce and Economic Development and the Senate Committee on Finance (February 22, 2016), Vermont Public Service Department, pp. 19-20.
[94] *Ibid.*, p. 6.
[95] *Ibid.*, p. 6.
[96] *Ibid.*, pp. 8-9.

advocacy, more states would likely house these entities within one agency, and not keep them separated from one another. Vermont is simply the exception to the rule in this matter, and not in a good way.

Consider that the energy policy and planning functions associated with most states are housed either directly in the executive office of the Governor, within a separate state executive agency, or part of another comparable state executive agency (like a state planning agency or natural resources department). These entities usually serve as the official state energy office ("SEO") and, in fact, the National Association of State Energy Officials ("NASEO") identifies the Department as being the prime SEO for Vermont. NASEO identifies 56 SEOs associated with each state and U.S. protectorate.[97]

The organization and specific emphasis of each SEO can differ, but, according to NASEO, SEOs, like the Department, are committed to becoming "… important agents of change – advancing practical energy policies and supporting energy technology research, demonstration, and deployment" and to accelerating "…energy-related economic development and enhance environmental quality through energy solutions that address their citizens' needs and enhance national energy security."[98] The mission of most SEOs is to promote energy development, with a particular emphasis on energy efficiency and emerging technologies.

SEOs tend to provide subsidies, loan programs, and other support programs to remove market barriers with more risky technologies, or efficiency measures that face a number of market barriers that can lead to cost and development uncertainty. While

[97] National Association of State Energy Officials, About State Energy Offices. http://www.naseo.org/state-energy-offices.
[98] *Ibid.*

these may be important state-level activities, they have nothing to do with ratepayer advocacy and, in fact, can often run afoul of ratepayer interests.

This conflict is likely why most states have opted to keep their planning and energy development activities separate from often conflicting ratepayer advocacy activities. SEOs often tend to exhibit considerable resource and technology preferences, particularly those associated with "advanced" or "emerging" technologies. Ratepayer advocates, on the other hand, tend to be exceptionally fuel and technology neutral since often, emerging energy resources are characterized by a number of challenges that raise ratepayer costs (i.e., limited manufacturing/suppliers, untested functionalities, limited commercial experience and information, questionable operating performance over extended time periods, to name a few). These differences in mission are often the reason why SEOs and ratepayer advocates are kept separate.

As an example, in Massachusetts, the Department of Energy Resources ("DOER") within the Executive Office of Energy and Environmental Affairs, serves as the state's SEO. Ratepayer advocacy however, is handled by the Office of Ratepayer Advocacy within the Office of the Attorney General ("AG").[99] This separation is not restricted to just large states. Several smaller states keep the functions of the SEO and the functions of the ratepayer advocate separate. New Hampshire, for example, maintains the Office of Energy and Planning ("OEP") within the state's executive branch yet, as noted earlier, New Hampshire also maintains an OCA that has a mission

[99] See, Members, National Association of State Utility Consumer Advocates, available online at: http://nasuca.org/members/.

dedicated to advocating for residential customers proceedings before the New Hampshire Public Utilities Commission ("NH PUC").[100]

There are several examples of recent conflicts between SEOs and ratepayer advocates in regulatory proceedings. A recent example arose in Massachusetts' push to upgrade ageing gas distribution systems and replace leak-prone systems comprising of non-catholically protected steel pipe.[101] In recent years this movement has extended to replacing small diameter cast iron assets that can tend to break and create methane leaks.[102] Massachusetts utilities petitioned regulators (the Department of Public Utilities or "DPU") for a set of exceptionally generous cost recovery mechanisms for these replacement activities that shifted a considerable degree of cost and performance risk away from utilities and onto ratepayers. These program proposals would pass along, on a dollar-for-dollar basis, an exceptional level of capital expenditures through rates without a rate case and with no performance standards guaranteeing that leaks and/or safety-related accidents would be reduced as pipeline replacement activities accelerated.

The state energy office in Massachusetts strongly supported these ratemaking provisions. The state ratepayer advocate, however, opposed these cost recovery mechanisms (at least as they were proposed), despite her strong support for pipeline replacement and improved safety performance. The state energy office also opposed

[100] The Office of the Consumer Advocate, New Hampshire Office of Consumer Advocate, available online at: http://www.oca.nh.gov/.

[101] See, Petition of Bay State Gas Company, pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., for Approval of a General Increase in Gas Distribution Rates Proposed in Tariffs M.D.P.U. Nos. 70 through 105, and for Approval of a Revenue Decoupling Mechanism, Massachusetts Department of Public Utilities Docket D.P.U. 09-30, Order dated October 30, 2009, p. 118.

[102] See, Petition of Bay State Gas Company, d/b/a Columbia Gas of Massachusetts, pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., for Approval of a General Increase in Gas Distribution Rates Proposed in Tariffs M.D.P.U. Nos. 105 through 139, Massachusetts Department of Public Utilities Docket D.P.U. 12-25, Order dated November 1, 2012, p. 26.

every proposal offered by the state ratepayer advocate to develop a cost recovery mechanism that facilitated pipeline replacement, yet balanced cost and performance risk more equitably between utilities and ratepayers. The SEO in this proceeding did not collaborate, nor enter into a joint participation agreement in this proceeding but were active litigants taking opposing positions.

A similar example of conflicts between a state SEO and a ratepayer advocate can be highlighted in a 2012 electric utility proceeding in Maryland. On July 25, 2012, in the wake of prolonged power outages brought by hurricanes, blizzards, and a derecho, Governor Martin O'Malley of Maryland signed an executive order directing the state energy advisor, in collaboration with other state agencies to create a "Grid Resiliency Task Force."[103] The Grid Resiliency Task Force was charged with evaluating options for infrastructure investments to improve resiliency of the electric grid, as well as financing and cost recovery options for utility capital investments. After publishing a final report entitled *Weathering the Storm* on September 24, 2012,[104] the Potomac Electric Power Company ("Pepco") filed a proposal with the Maryland Public Service Commission ("MPSC") for a special ratemaking mechanism that would have allowed them to recover the costs associated with accelerating the replacement of its infrastructure, as well as developing new technologies, on a dollar-for-dollar basis.[105]

The Maryland SEO, represented by the Maryland Energy Administration ("MEA"), fully supported the utility proposal in that proceeding. The Maryland Office of People's

[103] Grid Resiliency Task Force: Weathering the Storm, Maryland Energy Administration, available online at: http://energy.maryland.gov/Pages/gridresiliencytf.aspx.

[104] Weathering the Storm: Report of the Grid Resiliency Task Force (September 24, 2012), Office of Governor Martin O'Malley.

[105] In the Matter of the Application of Potomac Electric Power Company for an Increase in its Retail Rates for the Distribution of Electric Energy, Public Service Commission of Maryland Case No. 9311, Direct Testimony of Frederick J. Boyle, pp. 13-14.

Counsel ("OPC"), which is the ratepayer advocate in Maryland, directly opposed the cost-recovery proposals associated with the utility's proposed resiliency and modernization investments.[106] The Maryland OPC argued that Pepco's proposal was premature since regulators had not determined the appropriate level of resiliency needed in Maryland, or the cost effectiveness of establishing more aggressive resiliency standards. Furthermore, the Maryland OPC noted that the cost recovery mechanism associated with Pepco's proposed accelerated infrastructure investment was inconsistent with the Governor's report, choosing only those parts that were favorable to its shareholders, and not those that would have imposed cost and performance discipline on the utility's actions.[107]

The above examples of conflicts between agencies focused on energy planning, and those associated with ratepayer advocacy, are not uncommon. Yet, the DPS Report fails to recognize the inherent conflict of interest in the energy development and planning functions of an SEO versus the least cost, fuel-neutral emphases usually pursued by ratepayer advocates. The examples provided above highlight SEO and ratepayer advocate conflicts. Each example dealt with regulatory proceedings where a significant amount of utility capital investment was on the line. These proceedings also involved instances where relatively risky technologies were also being proposed, in some instances before a definitive state goal had been defined. In other instances, the conflict arose out of promoting the replacement of aged assets versus ensuring that

[106] In the Matter of the Application of Potomac Electric Power Company for an Increase in its Retail Rates for the Distribution of Electric Energy, Public Service Commission of Maryland Case No. 9311, Order No. 85724, p. 144.

[107] *Ibid.*, p. 145.

those replacements were tied to performance benchmarking to ensure that the investments delivered upon their promises.

These examples, however, are not instances in which the ratepayer advocate, in the spirit of minimizing costs, just said “no” and the SEO, in the spirit of advancing technology, said “yes.” The differences of opinion were related to issues on (1) cost recovery matters; and (2) utility performance risk. Ratepayer advocates and SEOs view these issues in an entirely different light.

SEOs, for instance, have incentives to promote technologies and capital investment since it is usually consistent with gubernatorial energy and economic development policies. Ratepayer advocates are not opposed to such investments, per se, but often argue that these large capital investment proposals need to (1) meet the muster of cost-effectiveness and (2) most importantly, ensure that the risk associated with the development and operation of such technologies are not unnecessarily shifted away from utility shareholders and onto ratepayers. SEOs tend to be less sensitive to these issues (cost recovery, risk shifting), and as noted in Section 2 of this Report, it is exactly this degree of insensitivity to risk shifting that has made the Department’s actions entirely inconsistent with effective ratepayer advocacy in Vermont.

Likewise, it should be recognized that in the earlier-provided examples the SEOs were on the same side of the argument as the regulated utility. This result should come as no surprise since both parties (utilities and SEOs) often have very similar interests in seeking additional utility capital investment. SEOs want to see additional capital investment in order to create jobs, promote innovative technologies, and support the energy policy goals of their respective governors. Utilities want to see additional capital investment in order to enhance shareholder value: and if these utilities can reduce the risk of cost recovery or can enhance their ability to earn, or exceed their allowed rates of return, all the better.

Such an alignment of interests (i.e., utility and energy planning) was clearly apparent in VGS CPG proceeding for the ANGP project, where the Department was strongly supportive of VGS' proposal to increase the availability of natural gas to underserved regions, despite the exceptional riskiness and costliness of the proposition.[108] Whether real or imagined, it cannot be denied that this alignment of interests between utilities and the Department creates the appearance of a conflict of interest, if not an outright conflict. Even the DPS Report noted that members of the public expressed concern at public hearings that the Department was "cozy" with utilities in the state or out-and-out "advocates for utilities."[109] It may very well be the case that the Department is not "cozy" with utilities, but it does appear to be the case that the Department has an inherent incentive to promote policies consistently aligned with those of Vermont's electric and natural gas utilities and not those associated with residential and small commercial ratepayers.

[108] See, Petition of Vermont Gas Systems, Inc., requesting a Certificate of Public Good pursuant to 30 V.S.A. § 248, authorizing the construction of the "Addison Natural Gas Project" consisting of approximately 43 miles of new natural gas transmission pipeline in Chittenden and Addison Counties, approximately 5 miles of new distribution mainlines in Addison County, together with three new gate stations in Williston, New Haven, and Middlebury, Vermont, Vermont Public Service Board Docket No. 7970.

[109] An Evaluation of Ratepayer Advocate Structures Pursuant to Act 56, Section 21(b): A Report to the Vermont Hose Committee on Commerce and Economic Development and the Senate Committee on Finance (February 22, 2016), Vermont Public Service Department, pp. 25-26.

4 Deficiencies in the DPS Report Recommendations

4.1 Overview of DPS Report Recommendations

The DPS Report repeatedly challenges whether a move from the current structure of ratepayer advocacy in Vermont would be cost effective, and the degree to which any reform would impact accountability and independence.[110] The DPS Report conducts a cursory review of other state ratepayer advocates, focusing only on whether or not the advocate in any particular state was part of an independent agency, part of an office of the Attorney General, or some other reporting structure.[111] From there, the DPS Report jumps to a series of rather anecdotal summaries of why each structure would be inappropriate or would not work in Vermont, and concludes that Vermont's unique structure is superior.[112] In summary, the DPS Report concludes:

- It would not be cost-effective to reform the current structure in Vermont since the Department, on the behalf of the Governor's office, will continue to intervene and represent the public interest before the Board. Creating a new entity independent of the Department would result in a duplication of effort. Further, any newly-created independent ratepayer advocacy entity would have to secure additional technical staff that would also duplicate the Department's efforts.
- There is no alternative ratepayer advocacy structure that could create better accountability to the citizens of Vermont since the Department is required to answer directly to the Governor, who in turn, must answer to the electorate every two years.
- The greater the degree of independence, the less the degree of accountability. In other words, more independence for a ratepayer advocate is bad since it reduces accountability, and accountability is preferable to independence.

The DPS Report's conclusions, however, are based upon a set of false choices that include:

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110 *Ibid.*, p. 23.
111 *Ibid.*, Appendix A.
112 *Ibid.*, p. 6.

- The recommendations, on their face, suggest that every other state in the U.S. has an inefficient structure for ratepayer advocacy, is structured in a fashion that has little to no accountability, and presumably an unhealthy degree of independence. This is clearly an unreasonable as well as unsupported conclusion.
- Section 2 of this Report underscores how the Department's current activities already have little to no accountability to residential and small commercial ratepayers. The Department has entered into settlement after settlement with utilities on terms that are highly advantageous to the utility, not ratepayers. To date, no accountability has been imposed on the Department for having taken these decisions. This accountability needs to be improved substantially.
- Independence of action and accountability are not mutually exclusive and the structure of most ratepayer advocates around the U.S. provide numerous examples of how accountability can be reconciled with independence. Section 2 of this Report highlights that the Department does not formulate ratepayer advocacy and litigation strategies that are independent and in the best interest of residential and small commercial ratepayers. Further, once these actions have been taken by the Department, there is little to no accountability.

4.2 Cost-Effectiveness of Reformed Ratepayer Advocacy

The DPS Report reaches a number of bold and unsupported conclusions about the efficiency of reforming Vermont ratepayer advocacy suggesting that any change in the current structure would result in waste and duplication of effort.[113] Nowhere does the DPS Report attempt to quantify the financial requirements that would be wasted, nor does the Report attempt to detail the efficiency of the Department's own past regulatory activities, and how those regulatory activities would change if the Department's planning and advocacy activities were separated from those associated with ratepayer advocacy. Instead, the DPS Report conclusions rest upon a herculean assumption (not an analysis) that any new ratepayer advocacy entity would purse the same activities, address the same issues, and utilize the same resources as the Department.

[113] *Ibid.*, p. 23.

However, assume that the DPS Report's assumptions are reasonable and that a successor ratepayer advocacy entity did purse the same activities, address the same issues, and utilize the same resources as the Department. The fact that this new ratepayer advocate utilizes a level of financial resources comparable to the Department is simply immaterial since the Department's report is focusing, once again on the wrong issue. Financial resources are an "input" to the regulatory litigation process; advocacy and the effectiveness of that advocacy is the "output." As Section 2 displayed, Vermont ratepayers are getting very little "output" (advocacy) for their financial "inputs" to support the Department's current activities. Clearly, the Department is not a cost-effective ratepayer advocate: Vermont ratepayers are simply not getting any advocacy "bang for their buck" since the Department fails repeatedly to take positions that are consistent with ratepayer interests and instead, takes positions (by entering into settlements) that reduce utility financial and regulatory risks, and imposes those risks, without adequate compensation, onto residential and small commercial ratepayers. Thus, the creation of a new entity to pursue these activities will actually represent a cost-effective improvement to the status quo.

The DPS Report's cost efficiency conclusions also run counter to the experience in every state in the U.S. that has a statutorily-defined ratepayer advocate. As discussed earlier in this Report, there are 42 states that have both a statutorily-defined ratepayer advocate separate from its state energy office. None of these states would argue that their separation of state energy policy and planning from ratepayer advocacy is inefficient nor have there been any proposals to merge such activities in order to attain efficiencies or economies of scale.

Consider that most SEOs originated during the energy crises of the 1970s. The original (and continued) goal of these SEOs has been to foster the development of energy efficiency, energy resource diversity, and new advanced energy technologies during a period of considerable energy uncertainty.[114] Similarly, ratepayer advocacy positions came about during the same time period. These ratepayer advocates however, were created with an entirely different mission: namely, to represent ratepayers before regulatory commissions during a time period seeing considerable rate increases arising from volatile energy prices and rampant inflation.[115]

There have been no major initiatives to merge SEO-type functions (energy policy and planning) with ratepayer advocacy activities despite the fact that both types of agencies arose during the same time period and under similar circumstances. No studies showing the efficiencies or synergies associated with merging these two activities have been conducted. Since that time, neither NASEO nor the National Association of State Utility Consumer Advocates ("NASUCA") has issued any individual or joint resolutions suggesting mergers or the opportunities for mergers between their individual memberships. In fact the two organizations tend to interact on a relatively infrequent basis, and when there are interactions, particularly in regulatory proceedings, it is not uncommon for the two types of entities to take opposing positions on the same issue (as highlighted in Section 3 of this Report). Thus, the DPS Report's claim there

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[114] See, for example, Alabama Energy Division (http://adeca.alabama.gov/Divisions/energy/Pages/default.aspx); Massachusetts Department of Energy Resources (http://www.mass.gov/eea/grants-and-tech-assistance/guidance-technical-assistance/agencies-and-divisions/doer/doer-overview.html); and Rhode Island Office of Energy Resources (http://www.energy.ri.gov/about/).

[115] See, About Us, National Association of State Utility Consumer Advocates, available online at: (http://nasuca.org/about-us/).

will be inefficiencies or lost synergies by separating Vermont's SEO-type activities from its ratepayer advocacy activities is without merit in both theory and practice.

4.3 Accountability and Independence of Reformed Ratepayer Advocacy

The DPS Report also concludes that the Department has a higher degree of accountability compared to any other state ratepayer advocates in the U.S. since it answers to a governor that is required to face an electorate every two years.[116] The DPS Report goes further by also concluding that greater degrees of ratepayer advocacy independence are synonymous with less public accountability.[117] Both conclusions are complete falsehoods.

All ratepayer advocates across the U.S. are ultimately accountable to the electorate whether that be through the election of a governor, an attorney general, or a group of legislators that many be responsible for these advocates' appointment and removal. The fact that Vermont's governor is elected on a two-year basis is relatively immaterial, particularly as it relates to utility regulatory issues. The DPS Report provides no empirical evidence to support the assertion that ratepayer advocates appointed by more frequently-elected governors (or other elected officials) are more responsive to ratepayer interests and are more accountable. This is simply one of the numerous unsupported assertions in the DPS Report that is a function of misguided opinion, not fact.

Further, the DPS Report reaches its independence and accountability conclusions by simply tallying the organizational structure of each ratepayer advocate,

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[116] An Evaluation of Ratepayer Advocate Structures Pursuant to Act 56, Section 21(b): A Report to the Vermont Hose Committee on Commerce and Economic Development and the Senate Committee on Finance (February 22, 2016), Vermont Public Service Department, p. 20.

[117] *Ibid.*

and then overlaying a number of unsupported opinions and absurd assumptions (like the appointment of a climate change denier) to suggest that accountability and independence are mutually exclusive.[118] The DPS Report does not undertake a thorough investigation of each state ratepayer advocacy organization: and how each advocate is appointed; how oversight is maintained; the financial resources utilized; the number and type of reporting requirements; and any professional qualifications required to hold office.

Even more egregious is the fact that the DPS Report does not attempt to survey the best practices of each state and compile, on a composite basis, a model for ratepayer advocacy that would improve the current structure's effectiveness. There appears to be a very simple answer to this deficiency: the DPS Report is a results-driven product designed to maintain the status quo. The Department clearly has no desire to change since it believes no change is necessary. The underlying theme in the DPS Report's "research" is that no change is needed since Vermont already has the most unique, and best model for ratepayer advocacy. Such a conclusion is misplaced.

Currently, there are 43 state ratepayer advocacy entities from 42 states across around the U.S. (see below): 20 states have independent agencies (47 percent); three are located within a regulatory commission (9 percent); 16 are located within an Attorney General's office (37 percent), and three are located within other state administrative agencies. In other words, nearly three-quarters of the ratepayer advocacy agencies in the U.S are either in independent agencies or are part of an AG's office. No state, as even the DPS Report recognizes, has an organizational structure comparable to Vermont.

[118] *Ibid.*, p. 21.

Table 3. Summary of State Ratepayer Advocates Organizational Structure.

Independent Agency	Within Public Utility Commission	Within other Government Agency: Attorney General	Within other Government Agency: Department of Commerce	Within other Government Agency: Department of State
Arizona	California	Alabama	Hawaii	Delaware
Colorado	North Carolina	Alaska	Utah	
Connecticut	West Virginia	Arkansas		
D.C.	Wyoming	Illinois		
Florida		Iowa		
Illinois		Kentucky		
Indiana		Massachusetts		
Kansas		Michigan		
Maine		Minnesota		
Maryland		Nevada		
Missouri		New Mexico		
Montana		North Carolina		
Nebraska		Ohio		
New Hampshire		Rhode Island		
New Jersey		Tennessee		
Ohio		Washington		
Oregon				
Pennsylvania				
Texas				
Wisconsin				

Note: North Carolina is included twice as it has a Consumer Services Division within the Public Utility Commission, and a Utilities Section within the Office of Attorney General.

Contrary to the DPS Report's incorrect conclusions, many of these ratepayer advocates have very high degrees of independence and accountability. Also, in contradiction to the conclusions of the DPS Report, there are a number of attractive organizational and oversight requirements that have been utilized by these states that could be combined to create an exceptionally effective, independent, and accountable ratepayer advocate in Vermont.

Consider, as an example, the current structure of the New Hampshire Office of the Consumer Advocate ("OCA") who is appointed by the governor of that state for a four year term that is not necessarily coincident with that of the governor. In addition, there is a residential ratepayer advisory board that advises the ratepayer advocate on matters concerning residential ratepayers. The advisory board has nine members that serve three-year terms.

- Three members are appointed by the speaker of the house. One represents the interests of residential ratepayers; one represents the elderly; and one is a member of the public.
- Three members are appointed by the senate president. One represents the interests of residential ratepayers; one represents the disabled; and one represents environmental concerns.
- Three members are appointed by the governor and council. One represents the interests of persons of low income; one represents the interests of small business owners; and one represents the interests of residents of low-income housing.

The OCA meets with its advisory board at least quarterly or at the call of the chairperson or three board members. The Consumer Advocate must be present for all board meetings to inform the board of the actions of the office of the consumer advocate and to respond to the board's inquiries. In addition, the Board recommends to the governor and council whether to reappoint the consumer advocate. If the Board does not recommend reappointment, or the governor and council do not accept the Board's recommendation to reappoint, the Board shall then recommend three persons to the governor and council to fill the position.

A structure similar to New Hampshire's would represent a significant improvement to the current structure of consumer advocacy in Vermont. The New Hampshire Consumer Advocate is appointed by the Governor, thereby undermining one of the arguments offered by the Department in its Final Report. The Governor however, gets important direction from the constituency group primarily impacted by the OCA's activities, which is ratepayers. An advisory board of this nature would represent a considerable improvement to the current Vermont structure. Further, the OCA's advisory board is appointed by both the Governor and the Legislature, thereby expanding the degree of independence and accountability, not reducing it. Independence is improved since advice, counsel, and oversight are provided by a governing board that represents ratepayer constituencies and accountability is maintained is the Board is selected by both the Governor and the Legislature. In other words, a structure of this nature has enhanced accountability since it is required to answer to: (1) the Governor; (2) the Legislature; and (3) ratepayers.

The organizational structure of the Ohio Consumer Counsel ("OCC") provides another important example of ratepayer advocacy. The OCC's mission is to explicitly represent residential ratepayers: there is no ambiguity of the mission. Here, the Attorney General appoints a nine-member governing board that serve three-year terms representing represent farmers, residential customers, and organized labor. No more than five members of the board can be from the same political party and each board member is required to be confirmed by the state senate. The governing board appoints the OCC and deputy OCC and provides guidance to the OCC on regulatory matters and policy.

Again, the Ohio example represents a differing approach that enhances both accountability and independence that could provide a number of alternatives to ratepayer advocacy in Vermont. The ratepayer advocate in Ohio is appointed by the Attorney General rather than the Governor. The results of the DPS Report suggests that having an AG appoint a ratepayer advocate is less accountable than one appointed by a Governor. However, this is a misplaced conclusion. First, AGs in most states are elected officials, just like a governor. Second, AGs are elected to be a state's lead legal representative and advocate. An equally strong argument could be made that since the regulatory process is one primarily associated with litigation, it is more appropriate to have the state's lead legal officer selecting appointed advocates rather than an individual governor. The broader public interest considerations of the "public interest" are not diminished by a structure of this nature. Consider that a Governor can still ensure that his energy policy and planning goals are communicated through the use of his SEO. More importantly, in most states, the regulatory commission itself is appointed by the Governor and will likely have some deference to his or her policy positions and/or preferences and is typically required to review evidence, and make decisions, that are in the public interest.

Kansas also utilizes a ratepayer advocacy organizational and governance structure that includes some type of oversight committee. Residential and small commercial ratepayers in Kansas are represented by the Citizens Utility Ratepayer Board ("CURB"), which was legislatively authorized in 1989, and re-approved in 1991. CURB is an independent agency in Kansas. The consumer advocate in Kansas is appointed by CURB's Board of Directors, which itself is comprised of five members each of whom are appointed by the Governor. Each board member represents one of Kansas' congressional districts, with one at-large member. CURB is a relatively cost-efficient agency, comprised of a relatively small internal staff that includes the consumer counsel, two supporting attorneys, one technical staff member (accountant/economist), and two administrative staff.

The Kansas model reflects another example of a collective appointment and governance model for consumer advocacy. The mission for CURB is clearly focused on residential and small commercial customers. CURB has a Board of Directors that represents the broad, geographic diversity of the state. The governor has influence over the appointment of individual board members. Further, CURB's internal staff is limited, reducing direct employee costs. Instead, the office relies on the expertise of outside consultants in litigated matters. This allows CURB to hire experts with a particular set of expertise rather than holding a large staff that could be idle during periods in which the number of active litigation matters is limited.

Arizona offers another potential model for alternative ratepayer advocacy organization and governance. In Arizona, residential ratepayer interests are represented by the Residential Utility Consumer Office ("RUCO"), formed by legislation in 1983. The RUCO director is appointed by the governor and is required to have some experience in utility regulatory issues. Like the Kansas CURB (as well as the CUB in Illinois), RUCO has a relatively small staff and relies on outside consultants for technical expertise on an as-needed basis. This creates litigation flexibility since it allows RUCO to select the best technical experts based upon the issues at hand rather than (1) holding a large staff of technical experts that cover a wide range technical issues arising in regulation or (2) having a smaller staff that may have mismatched technical skills relative to the regulatory issues at hand.

4.4 The DPS Report Recommendations are Meaningless

The DPS Report makes three rather meaningless recommendations which, by themselves, will do nothing for residential and small commercial ratepayer advocacy in Vermont.[119] All three recommendations are offered to address what the DPS Report believes is a public perception problem with many of the Department's past actions

[119] *Ibid.*, p. 35.

before the Board.[120] The DPS Report finds that any concerns regarding the Department's actions are not attributable to the Department itself, but instead are due to the presumption that residential ratepayers are incapable of understanding their own best interests and how those interests should be advocated before the Board.

The DPS Report's first recommendation is that the Department submit an annual report that communicates the Department's prior-year's activities before the Board.[121] The submission of an annual report will likely do nothing to improve ratepayer advocacy in Vermont. First, it is not uncommon for ratepayer advocates in other parts of the country to prepare annual reports to their respective governing bodies. The fact that the Department has not already been preparing such reports speaks volumes about its ongoing accountability to ratepayers. The Department should be doing this as a normal course of business, not as some type of "reform" initiative designed to increase ratepayer advocacy effectiveness in Vermont.

Second, the DPS Report's recommendation to prepare an annual report is offered in a somewhat cavalier, offhanded manner: it does not identify any specific type of report format, the type of specific information that will be provided, and it fails to identify any review and input process for the report.[122] For instance, the DPS Report does not recommend a reporting requirement and input process similar to the best practices associated with other ratepayer advocates (nor does it even define any best

[120] An Evaluation of Ratepayer Advocate Structures Pursuant to Act 56, Section 21(b): A Report to the Vermont Hose Committee on Commerce and Economic Development and the Senate Committee on Finance (Draft dated January 15, 2016), Vermont Public Service Department, p. 19; see also, An Evaluation of Ratepayer Advocate Structures Pursuant to Act 56, Section 21(b): A Report to the Vermont Hose Committee on Commerce and Economic Development and the Senate Committee on Finance (February 22, 2016), Vermont Public Service Department, p. 35.

[121] An Evaluation of Ratepayer Advocate Structures Pursuant to Act 56, Section 21(b): A Report to the Vermont Hose Committee on Commerce and Economic Development and the Senate Committee on Finance (February 22, 2016), Vermont Public Service Department, p. 36.

[122] *Ibid.*, p. 37.

reporting practices). Ratepayers will be disserved if the current DPS Report is any indication of quality and type of critical self-examination that is expected to result from the Department's proposed annual reporting process.

Lastly, the preparation of an after-the-fact report will provide little consolation to ratepayers after the proverbial "cow is out of the barn." There will be no performance consequences associated with any of the Department's prior year activities. Developing a report that simply lists the Department's "cooperative" activities with utilities, without any accountability, is simply meaningless.

The DPS Report's second recommendation is that the Department hold a public hearing prior to the Board's public hearing in order to improve its "public outreach."[123] However, the proposed recommendation will in reality provide very little public involvement, likely coming too late in the evidentiary process for the Department to act in any meaningful fashion. By the point in the evidentiary process when public hearings are typically held, the majority of the discovery in the case will have already been served, litigation strategy will have already been formulated, experts will have been secured, and a good portion of the first round of pre-filed expert testimony will have been prepared.

Second, it is doubtful that a "second" public hearing will do much to change or modify the Department's actions in litigated matters before the Board. The DPS Report fails to identify what goals will be set for these public hearings, what information will be solicited, how the Department will act upon this information or public testimony, and whether or not, and how, the Department will be bound by the information and concerns submitted to them in these newly-proposed public hearings. The Department's

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[123] *Ibid.*, p. 37.

recommendation is nothing more than providing an "open mic" for the public to speak directly to the Department, it will have little to no impact particularly given the Department's reception of the public input provided in the development of the instance DPS Report. Thus, the DPS Report's recommendation to hold a second public hearing is relatively meaningless.

The DPS Report's third recommendation is for the Department to submit evidence showing why any settlement, or MOU, that it enters into with utilities is in the public interest.[124] This recommendation is simply redundant to standard evidentiary practice before the Board. Under Board practices, all parties are required to provide evidence in any contested or uncontested settlement to support why a particular settlement is in the public interest.[125] Unfortunately, this filing requirement did not prevent the Department from entering into a settlement agreement with VGS and creating a SERF thereby denying ratepayers a natural gas cost refund in which they were entitled.[126] Instead those refunds were diverted to a special ratemaking fund that effectively serves as a utility investment hedge fund. Again, this recommendation is relatively meaningless since, like the other two recommendations, it is one that should be (or is) the normal course of business in Vermont regulatory proceedings.

[124] *Ibid.*, p. 38.

[125] See, 30 V.S.A. § 218d(a)(2).

[126] See, Request of Vermont Gas Systems, Inc. to establish a System Expansion and Reliability Fund with funds provided by reductions in the quarterly Purchase Gas Adjustment rate under the Alternative Regulation Plan, Vermont Public Service Board Docket No. 7712, Order Amending Alternative Regulation Plan, p. 5.

5 Conclusions and Recommendations

Ratepayer advocacy in Vermont would be best served by a number of reforms that enhance the independence and vigor in which residential and small commercial ratepayer interests are protected before the Vermont Public Service Board. This Report recommends that the Legislature eliminate the Division of Public Advocacy and the position of the Public Advocate in the Department of Public Service. In its place, the Legislature should create an independent Ratepayer Advocate ("RA") that supervises an Office of Ratepayer Advocacy ("ORA").[127]

For administrative purposes, the RA and ORA can be housed in any relevant state agency, including the Department or the Office of the Attorney General, provided that a high degree of independence included in the recommendations below, or some version of the recommendations listed below, are adopted. If the RA/ORA functions are removed, the Department should continue to conduct its statewide energy planning and policy activities like any other state energy office. Further, the dollars associated with the RA's activities should be eliminated from the Department's future budget. The Department should be allowed to intervene, as a separate state agency intervenor, in matters before the Board, provided the Department has the internal budget to support such activities and it makes clear that its intervention is predicated on representing the Governor's energy policy positions and goals and not ratepayer interests.

Three areas of recommendation for the RA/ORA are provided below: one addresses the mission and emphasis of the new entity, one addresses the

[127] This new office can remain in the Department if certain organizational, independence, and accountability reforms are undertaken. If the Legislature were to choose to keep this new ratepayer advocate in the Department, the "elimination" of the current PA would effectively consist of a name, mission, and organizational change, rather than a true "elimination." Likewise, a movement to another agency could also be seen as effectively "transferring" rather than eliminating.

organizational structure of the new entity and one area addresses other relevant administrative and reporting issues.

5.1 Mission Recommendations

One of the most important policy recommendations that can be made to the Legislature in this matter is to clearly and unambiguously identify the RA's mission as being one dedicated to:

- Representing and forcefully advocating for residential and small commercial ratepayer interests.
- Supporting low-income and disadvantaged utility customers.
- Being fuel and technology neutral, focusing on securing the lowest cost, most reliable utility service possible.
- Defending residential and small commercial ratepayers from assuming utility business, financial, and regulatory risk without appropriate and reasonable compensation.

5.2 Organizational Recommendations

The RA and the ORA need an independent organizational and oversight structure. This can be accomplished through the following recommendations:

- A volunteer stakeholder committee (Committee for Ratepayer Advocacy or "Committee") should be established that provides guidance on ratepayer advocacy and governance issues.
    - o The committee should be comprised of six members: two appointed by the Governor; one appointed by the Senate President Pro Tempore; one appointed by the Speaker of the House; and two appointed by the Committee itself.
    - o Members will serve staggered four-year terms and should represent a balanced, cross-section of stakeholder groups, including small business groups, consumer groups, low-income groups, and environmental groups.
    - o Committee members can be removed by a majority vote of other committee members.
- The Committee shall solicit qualified RA candidates that have prior consumer advocacy experience. The RA does not have to be an attorney.

- The Committee will submit three RA candidates to the Governor for selection. The Governor will appoint the RA who will also be confirmed by the Senate Finance Committee.
- The RA will serve a four year term and can be re-nominated and re-confirmed for additional terms.
- The RA can be removed for cause by a recommendation of the Governor provided that recommendation is approved by both the majority of the Committee and the Senate Finance Committee.
- The RA and ORA may operate within any state agency. However, the RA and ORA shall be completely independent of any agency Secretary, Commissioner, or other type of administrative director. The RA and ORA will have a separate line item budget from the agency in which it is housed that will be funded through regulatory assessment fees.
- The ORA shall be comprised of a moderate-sized staff that is composed primary of attorneys with one attorney serving as a Director of Litigation.
    - The RA can serve as the Director of Litigation if she/he is a Vermont Bar-certified attorney in good standing.
    - The ORA should be comprised of a small number of professional staff members such as economists, engineers, accountants, and other policy/utility analysts to assist in case management and non-docketed regulatory matters.
    - The RA/ORA will primarily rely on outside consultants for litigated matters. The RA will be limited to a total consulting budget not to exceed $125,000 per docket. The RA can increase this expenditure to $175,000 per docket upon a showing of special circumstances provided this amount is approved by the Committee. Consulting fees will be recovered through the regulatory assessment fee, or a direct utility reimbursement, and will not be part of the ORA's normal operating budget.

5.3 Other Recommendations

- All settlement agreements, memoranda of understanding, or other agreements entered into by the RA with other parties (including utilities) in litigated proceedings before the Board must be approved by the Committee.
- The RA will brief the Committee on a quarterly basis. At least two of these briefings will be on an in-person basis.
- The RA shall prepare an annual report that will be submitted to the Committee that will also be submitted to the Governor and the Senate Finance Committee. The report will explicitly discuss: the RA's actions during the prior year; the specific positions taken by the RA on each major proceeding during the prior year and how those positions compare to the Board's final decision in each matter; an explicit discussion regarding the

rationale and basis for any settlements or memoranda of understanding entered into by the RA during the prior year (prepared in a fashion that does not compromise the statutorily-required confidentiality of such agreements); the RA's position and status associated with any pending proceedings; and a discussion and analysis of the value delivered to ratepayers during the course of the prior year. Assumptions, caveats, and other conditions associated with the analysis of ratepayer value and any quantification of this value shall be clearly provided in the report.

<u>Exhibit 4</u> - Hempling 2014 Article re: Alternative Regulation and Return on Equity (ROE)

Are Regulators Allowing Returns on Equity Above the Real Cost of Equity?

Scott Hempling, Attorney at Law[1]

Presentation to the
NARUC Consumer Affairs Committee
July 13, 2014

1. **Context and Concepts**
2. **Five Utility Strategies**
3. **Regulatory Omissions**
4. **Regulatory Solutions**

* * *

I. Context and Concepts

A. ***The purpose of utility finance:*** To obtain from capital markets the mix of equity and debt capital that supports the utility's obligatory infrastructure at the lowest long-term cost to consumers.

B. ***The purpose of regulation:*** To align private behavior with public interest, by setting standards for performance and compensating consistent with performance.

C. ***Utility profit:*** three perspectives

1. "Authorized return on equity"

a. In cost-based ratemaking, we set the utility's annual revenue requirement by applying a simple equation: Annual revenue requirement = expenses plus cost of capital.

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(1) expense items: operating expenses, fuel, depreciation and taxes

(2) cost of capital items

(a) contractual interest rate x debt
(b) commission-authorized ***return on equity*** x equity

b. The ***authorized*** return on equity is what the commission finds the utility is entitled to earn, if the utility operates prudently and if commission's projections for costs and sales are accurate.

> "The return on equity in traditional regulation is a residual. That is, under normal regulation the return on equity or the profit a utility earns is what remains after all other operating expenses have been met (operating expenses, interest expenses, taxes, salaries, pension expense, etc.). Because both revenues and expenses may be more or less than anticipated, the residual—the rate of return on equity or profit to the firm—will vary or fluctuate. It is this variance or volatility of the return that makes utility common equity a more risky investment than utility debt...."[2]

2. "Real cost of equity"

a. FERC's careful answer: "the rate of return required by investors to invest in a company - otherwise known as the capital attraction rate of return, or the market cost of equity capital."[3]

b. U.S. Supreme Court: "[A] public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally

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[2] Testimony of Stephen G. Hill, *In Re Joint Application of Entergy Louisiana and ITC Holdings, et al.*, Louisiana Public Service Commission Docket No. U-32538 at pp. 30-31 (Apr. 10, 2013) (hereinafter, "Hill Testimony").

[3] *Coakley, et al. v. Bangor Hydro, et al.*, 147 FERC para. 61,234 at para. 14 (June 19, 2014).

> being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties."[4]

3. "Actual return on equity"

> This is the end-of-year figure on the utility's books indicating what actually was earned. The actual return on equity is a "residual": the money left over when all expenses are paid or booked.

4. ***Relationship among the three concepts:*** The ***authorized*** return on equity is supposed to track the real ***cost*** of equity. Whether the ***actual*** return on equity matches the ***authorized*** return on equity depends on how the utility and the economy actually perform over the year.

D. Distinction between competitive markets and regulatory monopoly markets

1. ***Competitive markets:*** Since the market sets prices, you make money by beating competitors

2. ***Regulated monopoly markets:*** Since the regulators set prices, you make money by persuading regulators.

II. Five Utility Strategies for Persuading Regulators to Authorize Return on Equity Above the Real Cost of Equity

A. Move assets from state jurisdiction to FERC jurisdiction

1. Cost-based rates for transmission (and sometimes, generation)

   a. Higher base ROEs

   b. Higher equity-debt ratio: 60-40 has been approved; whereas around 50-50 is more common. (*AUS Utility Reports*, Feb. 2013 stated that 47% equity was the average common equity ratio for electric utilities.)

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[4] *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, 692-93 (1923).

c. Transmission "incentives" per Federal Power Act section 219[5]

2. Market-based rates for generation

B. Use debt to fund equity: the magic of double leveraging

1. Double leveraging defined

a. When a holding company purchases stock in the utility, the holding company is purchasing the utility's equity. If the holding company uses borrowed money (debt) to buy the equity, the holding company has leveraged its investment (just like someone who borrows money to buy a home or car). Since the utility also has debt (as all utilities do), we call the result double leveraging.

b. Double-leveraging is profitable because in the regulated utility setting, the cost of debt (the interest rate) is lower the authorized return on equity.

(1) "[A]lleged 'double leveraging' occurs when a purchaser of stock uses debt to finance the purchase. In effect, the purchaser leverages the investment by using lower cost debt to obtain a higher return on equity.").[6]

(2) "The theory's basic concept is that the true cost of a subsidiary's equity capital is the overall cost of the parent's capital. Accordingly, the cost of the subsidiary's equity should be computed as the weighted average of the parent's debt and equity costs. Otherwise, says the theory, shareholders of the parent receive not only the higher equity returns associated with the parent's equity, but an

[5] FERC’s main pronouncement s are in *Promoting Transmission Investment through Pricing Reform*, 116 FERC ¶ 61,057 (July 20, 2006); *Promoting Transmission Investment Through Pricing Reform Policy Statement*, 141 F.E.R.C. ¶ 61,129 (Nov. 15, 2012) (hereinafter cited as "2012 Policy Statement"); and in the many cases applying the principles in those documents. *See also* Adam Pollock, *How Can FERC Improve the Transmission Incentive Policy? Ways to Improve Clarity, Transparency, and Performance* (National Regulatory Research Institute 2009).

[6] *Williams Natural Gas*, 80 FERC para. 61,158 (1997).

artificial (doubly leveraged) return on the subsidiary's equity."[7]

2. Double bonus: Use double leveraging while moving assets to FERC

a. "[International Transmission Company's] business plan "unlocks" the profit potential in transmission by first (a) converting assets historically used for bundled state-jurisdictional service into assets used for unbundled FERC-jurisdictional service, then (b) providing that FERC-jurisdictional service through subsidiaries whose equity comes from debt incurred by the holding company.43 ITC thus earns high FERC returns on equity financed with lower-cost debt. Without making a single change (or commitment) in transmission planning, maintenance, repairs or operations, ITC not only increases the market value of the assets it acquires (thus allowing it to pay a price for the assets that produces a gain for the selling company's shareholders); it also locks in an opportunity to earn the new higher FERC profits on future investments within the selling company's service area. (Those future investments are certain to occur, due to load growth, replacements and/or upgrades.) This latter profit opportunity comes not only from FERC's base return on equity and its capital structure policies (allowing a return on equity financed in part with holding company debt, with the return on equity applied to a 60-40 equity-debt ratio), but also from the "incentives" potentially available under FERC's Order No. 679."[8]

3. Double leveraging imposes extra costs on ratepayers

a. The problem for utility customers arises because they are paying a high-cost return on equity that was funded with low-cost debt. Example from ITC's situation:

(1) The utility subsidiary, after the acquisition would have an equity-debt ratio of 60-40.

(2) The subsidiary's equity would be funded by the holding company parent.

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[7] *Missouri Public Service Commission v. FERC*, 215 F.3d 1 (D.C. Cir. 2000).

[8] Direct Testimony of Scott Hempling, Mississippi Public Service Commission Docket No. 2012-UA-358 (June 20, 2013).

(3) If we assume that subsidiary's equity is funded by the parent with equal amounts of equity and debt, then the utility subsidiary's 60 percent equity is actually made up of 30 percent equity and 30 percent debt.

(4) In effect then, the subsidiary's capital structure is 30 percent equity and 70 percent (30 + 40) debt.

b. An effective 30-70 ratio is less costly than an asserted 60-40 ratio, because the cost of debt is less than the cost of equity. (According to Stephen Hill, the cost of equity to ratepayers can be as much as 3 times the cost of debt (compare, for example a 9% cost of equity with a 5% cost of debt, then take into account that interest is tax deductible whereas equity return is taxed, which tax cost ratepayers pay along with the equity cost)).

c. This logic shows that when a rate regulator accepts double leveraging, ratepayers pay more to ultimate equity holders than their actual cost of the equity invested in the utility. As FERC stated (summarizing) the customers' position in ITC's proposed acquisition of Entergy's transmission assets:

> "Joint Customers state that they "do not find fault with [ITC Holdings'] financing strategy" because "the extremely low risk of the Commission-regulated, cost-of-service formula rate based transmission service can reasonably be financed with relatively low equity levels." However, Joint Customers argue that ITC Holdings attempt to perpetuate a myth that its transmission businesses are financed with 60 percent equity, when in fact, they are financed with approximately 30 percent equity, and that ITC Holdings continues to seek to have ratepayers charged an equity return on borrowed funds. Joint Customers argue that the Commission should require that the real sources of the funds used to finance the rate bases of the operating companies and their actual costs be used in the transmission formula rates of the operating companies."[9]

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[9] *ITC Holdings Corp., Entergy Corporation,* 143 F.E.R.C. para. 61,256 at para. 68 (2013) (footnotes omitted).

4. FERC's response

"[T]he Commission's policy is to use the capital structure of the pipeline subsidiary when the pipeline is responsible for its own financing and issues its own debt." *Williams Natural Gas*, 80 FERC para. 61,158 (1997).

"[I]n choosing between the capital structure of the parent and the pipeline, the Commission will continue to look to whether the pipeline issues its own debt, but will also require a determination of whether the pipeline's equity ratio falls within the range of equity ratios of the proxy companies used in the DCF analysis...." *Id.*

"The rate of return to a pipeline should not depend on who owns the pipeline, nor on how that owner, whether a holding company or individual stockholders, financed its investment.... There is no reason why [the customers' proposal to ignore double leveraging] should not apply equally as well if the owner of the operating company is one wealthy individual or a group of individual investors. In the latter case, the Commission would have to inquire into the leverage used by the individual investors to finance their stock purchase in order to arrive at a reasonable rate of return." *Id.* at text accompanying n.22 (1997).

a. FERC repeated this policy in its 2013 approval of ITC's proposed acquisition of Entergy's transmission assets. (The proposal died after the Mississippi Commission rejected it.)

b. Norman Bay's response to Sen. Murkowski's Question 26, part of larger packet of responses to Senate Committee questions, dated June 4, 2014

> "'By eliminating the competition for capital between generation and transmission functions and thereby focusing only on transmission investment, the transco model responds more rapidly and precisely to market signals indicating when and where transmission investment is needed.' Additional transmission investment leads to improved electric reliability, improved access to power markets, and ultimately, reduced overall costs of delivering electric power. Second, the Commission has 'long recognized that the [transco] business model can bring significant benefits to the industry. Their for-profit nature

with a focus on the transmission business is ideally suited to bring about: 1) improved asset management including increased investment, 2) improved access to capital markets given a more focused business model than that of vertically-integrated utilities, 3) development of innovative services, and 4) additional independence from market participants.' Finally, a transco's financial model may lead to stronger credit ratings that attract a larger pool of investors. Those ratings produce immediate off-setting benefits in the form of cheaper debt."

c. Commentary on Mr. Bay's response

(1) ***Competition for capital:*** In financial markets, there will always be competition for capital because capital is a scarce resource. The premise that there is a distinct, destructive competition for capital within a vertically integrated structure is unsupported. Capital from outside the company will flow into the company, whether vertically integrated or not, if the regulators authorize a return sufficient to attract capital. A prudently managed utility with an obligation to serve (including an obligation to build transmission) will seek that return, and a commission making lawful, public interest decisions will grant it. So if there is insufficient flow of capital to a particular utility obligation, the fault is either with the regulators for failing to approve sufficient rates, or with the utility management for failing to manage prudently so as to win sufficient confidence from capital markets. The "competition for capital" argument is only argument; it lacks both logic and facts.

(2) ***Importance of transmission investment:*** As just explained, when transmission investment is a utility obligation, capital will flow if regulators and utility managers act appropriately. Capital flows to transmission investments now, as it has for a century, regardless of whether the investments are made by vertically integrated or transmission-only companies. Somehow vertically integrated utilities in the Southeast are managing to raise capital for nuclear plants far riskier than transmission.

(3) ***Benefits of the Transco model:*** This is a ***non sequitor***. Assuming, for purposes of argument, that the Transco model has benefits not available from vertical integration, those benefits do not depend on either double leveraging or a holding company structure. As Mr. Bay separately pointed out, holding companies and double leveraging exist in contexts other than Transcos; further, Transcos can exist without holding companies or double leveraging. In any event, the notion of a "more focused business model" is a double-edged sword. A transmission-only company makes money only through transmission; thus its profitability depends on persuading decision-makers to approve transmission. A traditional utility, in contrast, has an obligation to serve its customers at least-cost, taking into account all possible solutions to find the most cost-effective mix of generation, transmission, distribution, energy efficiency and demand response.

Caution: There is real public interest value in making transmission ownership and control independent of generation, such as preventing discrimination. But those arguments do not need double-leveraging. Mr. Bay has bootstrapped double leveraging onto Transco benefits, just because Transcos benefit from double leveraging. As for the possibility that Transcos can provide more innovative services, there is no proof. Innovation depends on company culture and regulatory expectations, which can vary with human nature; it does not necessarily vary with corporate form.

(4) ***Financial model leads to stronger credit ratings:*** This is an obscure way of stating the obvious: The more money regulators force ratepayers to pay, the happier are the creditors. That fact of life also is independent of double leveraging and holding company form.

5. Leveraging, whether or not double leveraging, is risky

a. ITC itself stated, in its filings with the Securities and Exchange Commission:

> "[ITC's] substantial indebtedness can have several important consequences, including, but not limited to, the

> following: If future cash flows are insufficient, ITC may not be able to make principal or interest payments on its debt obligations, which could result in the occurrence of an event of default under one or more of those debt instruments....A substantial portion of the dividends and payments in lieu of taxes ITC receives from its regulated operating subsidiaries will be dedicated to the payment of interest on its indebtedness, thereby reducing the funds available for working capital expenditures and the payment of dividends on its common stock....ITC's ability to secure additional financing prior to or after existing [debt] facilities mature, if needed, and in connection with the merger may be substantially restricted by the existing level of ITC's indebtedness and the restrictions contained in ITC's debt instruments. ITC's substantial indebtedness could place it at a competitive disadvantage and make it more vulnerable to general adverse economic conditions."[10]

b. Ironically, a 60-40 equity ratio implies financial strength; that is what ratepayers should be getting, given their high rate payments. But as the quotes about leveraging's risks make clear, they are not getting that benefit. Double leveraging makes the company weaker.

C. Seek supranormal returns to perform obligatory tasks

1. The purpose of rate regulation is to provide compensation for performance. The typical "incentive" proposal fails this test.

2. Utility incentive proposals usually amount to an increase, in some form, in the dollars that would be produced by the traditional revenue requirements formula. (As Peter Bradford famously said, "regulation is incentive regulation.) This increase in compensation is not matched by an increase in performance, but the performance obligation is rarely defined. The proposal is for a supranormal return without any commitment to supranormal performance. (This can only happen in a regulated, monopoly market. In a competitive market, sellers have no choice but to match returns with performance-or-lose customers.)

3. Example: One prudent transmission practice is to build transmission when necessary. A second prudent transmission practice is to use the best

[10] ITC's SEC Form S-4 Registration Statement at p.64 (Dec. 3, 2012).

available technology. A third prudent transmission practice is, where transmission ownership induces anticompetitive behavior, to turn ownership over to a third party—selected because it is the party most likely to create benefits for consumers (as opposed to that third party willing to pay the most to the seller). Prudent utility practice deserves normal rates of return, not extra cash. Yet FERC grants extra money for each of these actions. (It is true that Federal Power Act Section 219 requires FERC to grant "incentives," but the statute grants FERC sufficient discretion that it need not require ratepayers to pay extra for actions the utilities should be doing anyway—especially where the state commissions are sufficient alert to require those actions.)

D. Shift normal business risks to ratepayers

1. Risk of bad luck

a. "Prudent actions can produce uneconomic outcomes. A new pipeline overruns its budget, due to unpredicted and unavoidable siting disputes. A new power plant ends up with excess capacity, because customer demand falls below reasonable forecasts. A trusted fuel supplier goes bankrupt, forcing the utility to buy high-cost substitutes on the spot market. A gas company's financial hedges become unnecessary (expensively so), because fuel prices drop. An experimental power plant technology fails, forcing the utility to abandon construction. When prudence combines with disappointment, who bears the extra cost—shareholders or customers?"[11]

b. Regulators have no constitutional obligation to impose the cost of bad luck on the customers.[12] Note, though, that state statutes could grant shareholders protection than the Constitution does. Putting business risk on the customer separates decisional authority from decisional accountability. It relieves utilities of normal business risk, undermining a culture of conservatism and care within the company.

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[11] Quoted from Scott Hempling, *Regulating Public Utility Performance: The Law of Market Structure, Pricing and Jurisdiction* at Chapter 6.D (American Bar Association 2013).

[12] *See Duquesne Power & Light v. Barasch*, 488 U.S. 299 (1989) (rejecting utility's view that the Constitution requires recovery of prudent investment, regardless of the investment's usefulness).

2. Risk of business shrinkage

a. Customers are seeking and finding alternatives to the traditional utility. I have long argued that these customers have to pay off the past: the utility's costs, not yet recovered, prudently incurred to meet the historic obligation to serve.

b. But future investment is another story. If large numbers of customers find alternatives to the traditional utilities, those utilities will be smaller. This happens to any business whose former customers substitute self-supply for purchases. It happens to bakeries when people bake their own bread and groceries when people grow their own tomatoes. In the utility context, this shrinkage, if handled carefully, will reduce costs for all. It may be sad news for utility shareholders who bought stock betting on constant growth. But that's not regulation's concern. In regulation, we care about compensating the utility fairly for its investment but we don't cover shareholder bets.[13]

E. Reduce business risks without reducing authorized return equity

1. In utility ratemaking, the annual revenue requirement is based, in large part, on projected costs. A key shareholder risk is that actual costs will exceed projected costs. To reduce this risk, utilities are proposing, and commissions are approving a, mix of devices. They include riders, cost trackers, surcharges, pre-approvals and decoupling. The most risk-reducing of these devices is the formula rate.

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[13] *See Market Street Railway Co. v. Railroad Commission of California*, 324 U.S. 548, 554, 557, 567 (1945), showing no constitutional no sympathy for a company whose services are no longer needed:

> [I]f there were no public regulation at all, this appellant would be a particularly ailing unit of a generally sick industry. The problem of reconciling the patrons' needs and the investors' rights in an enterprise that has passed its zenith of opportunity and usefulness, whose investment already is impaired by economic forces, and whose earning possibilities are already invaded by competition from other forms of transportation, is quite a different problem. . . .
>
> The due process clause has been applied to prevent governmental destruction of existing economic values. It has not and cannot be applied to insure values or to restore values that have been lost by the operation of economic forces.

2. A formula rate, in its most advanced form, combines the features of all the other devices. Its main purpose is to convert return on equity from a residual into a guarantee. As Stephen G. Hill has explained:

> "The return on equity in traditional regulation is a residual. That is, under normal regulation the return on equity or the profit a utility earns is what remains after all other operating expenses have been met (operating expenses, interest expenses, taxes, salaries, pension expense, etc.). Because both revenues and expenses may be more or less than anticipated, the residual—the rate of return on equity or profit to the firm—will vary or fluctuate. It is this variance or volatility of the return that makes utility common equity a more risky investment than utility debt. With a debt instrument, the monetary stream to the [debt] investor is known with certainty. Normally, with a common equity investment, the residual return to the investor is volatile—under FERC's formula rate, it is not."
>
> "The FERC formula rate allows the utility's return on equity to be collected in rates like an expense and [at the end of the year] trued up so that the earned return will always equal the allowed return. The FERC formula rate of return on equity, therefore, will not vary and is, in effect, a guaranteed return that the utility will earn with certainty."[14]

3. If a commission approves a risk-reducing device, but does not commensurately reduce the risk-related return on equity, the utility will overearn. FERC has recognized this point, at least conceptually, as Hill points out: ". . . FERC has recognized that a formula rate structure in which the return on common equity is recovered with no variance substantially reduces risk and calls for a much lower return on equity than is normally allowed under traditional regulation." *Id.*

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[14] Testimony of Stephen G. Hill, *In Re Joint Application of Entergy Louisiana and ITC Holdings, et al.*, Louisiana Public Service Commission Docket No. U-32538 at pp. 30-31 (Apr. 10, 2013).

III. Regulatory Omissions

A. Accept aspirations rather than compel commitments.

Example from FERC's decision approving ITC's acquisition of Entergy's transmission:

> "Although Applicants have acknowledged that the Proposed Transaction will have an effect on rates due to the use of an actual capital structure targeting 60 percent equity and 40 percent debt, agree with Applicants' conclusion that those effects are offset by the benefits of independent transmission company ownership over the Entergy transmission facilities. As Applicants note, the Proposed Transaction will benefit customers in the Entergy footprint and bring an independent transmission company to a region that has not experienced the benefits of independent transmission ownership. We agree with Applicants that transferring Entergy's transmission facilities to ITC Holdings will strengthen the Entergy Operating Companies' focus on generation and distribution. Further, we note that the benefits discussed below are over and above any benefits that will result from Entergy's integration into MISO. In other words, these benefits are due to ownership of Entergy's transmission assets by an independent transmission company, and are benefits that are not attributable to Entergy's integration into MISO."[15]

B. Accept, uncritically, the view that bigger is better.

Concerning ITC's proposed acquisition of Entergy's transmission:

> "ITC is an acquisition company. Its business model is to leverage and acquire. (*See* ITC's S-4: "ITC is highly leveraged and will assume and incur substantial additional leverage in connection with the merger, which may have an adverse effect on ITC's business and the value of ITC common stock.") With each leveraged acquisition, it pays premiums based on the assumption that transmission will be (a) relatively free of competition and (b) well-compensated under FERC ratemaking. But its ratings advantage could reverse itself under plausible changes in those

[15] *ITC Holdings Corp.*, *Entergy Corporation*, 143 F.E.R.C. para. 61,256 at para. 124 (2013) (footnotes omitted).

assumptions. Transmission's monopoly role could be disrupted by new technologies like storage and other "non-transmission alternatives," which FERC's Order 1000 seeks to encourage. The high compensation levels could come down, as FERC is signaling in its 2012 Policy Statement on Transmission Pricing. ... And there could be more challenges to the prudence of transmission investments, as FERC is signaling in its May 2013 Order requiring revisions to formula rates for MISO and all its transmission owners, including ITC."[16]

IV. Regulatory Solutions

A. Context: Repeal of the Public Utility Holding Company Act of 1935.

PUHCA 1935 imposed conservatism on utility holding companies by limiting the amount of nonutility businesses, by requiring financing to match the requirements of utility service, by preventing utilities from using ratepayers to finance non-utility businesses, by reviewing in advance and limiting interaffiliate financial transactions (including limiting double leveraging), and by limiting geographic expansion. All these financially conservative limits are now gone. States have to replace those regulatory protections with visions and standards.

B. **Regulators should establish a vision for corporate structure**, by addressing each possible utility action, and determining whether to prohibit it, permit it without review, or subject it to reviews and conditions. See attached table.

[16] Direct Testimony of Scott Hempling, Mississippi Public Service Commission Docket No. 2012-UA-358 (June 20, 2013).

Corporate Restructuring by Public Utilities: How Should Regulators Prepare and Respond?

	Regulatory Action		
Corporate Event	**Prohibition?**	**Reviews, Limits and Conditions?**	**Permission w/o Review?**
1. Utility merger with another utility			
a. operationally integrated			
b. not operationally integrated			
2. Utility acquisition of nonutility			
a. for utility purpose			
b. not for utility purpose			
3. Nonutility acquisition of utility			
a. acquirer has operational relationship to utility			
b. acquirer has no operational relationship to utility			
4. Interaffiliate transactions			
a. goods and services: sale to utility			
b. goods and services: sale by utility to nonutility			
c. financing: loan or guarantee to utility			
d. financing: loan or guarantee from utility to nonutility			
5. Issuance of debt or equity			
a. at the holding company level, for utility purposes			
b. at the holding company level, for nonutility purposes			
c. at the utility level, for utility purposes			
d. at the utility level, for nonutility purposes			
e. at the nonutility level, for utility purposes			
f. at the nonutility level, for nonutility purposes			
6. Divestiture or spin-off			
a. of utility assets serving your state			
b. of utility assets serving other states			
c. of nonutility assets or businesses			
7. Use of utility assets for non-utility business			
a. utility assets in your state			
b. utility assets in other states			

Exhibit 5 - **Relevant portion of the Brief filed by the Vermont Department of Public Service (Department) with the Vermont Public Service Board (Board)in Docket 5428 (1990-91).**

STATE OF VERMONT
PUBLIC SERVICE BOARD

Docket No. 5428

Tariff Filing of Green Mountain Power Corporation requesting a 15.69% increase in rates, to take effect June 4, 1990	))))

BRIEF OF THE VERMONT DEPARTMENT OF PUBLIC SERVICE ON BEHALF OF THE PUBLIC

VERMONT DEPARTMENT OF
PUBLIC SERVICE

James Volz
Director for Public Advocacy

Robert V. Simpson, Jr.
Geoffrey Commons
Special Counsel

Dated: December 7, 1990

Brief of the Vermont
Department of Public Service On Behalf
Of The Public

Introduction

A. Statement of the Case

The Vermont Department of Public Service (the "Department") submits this Brief in opposition to the 15.69% rate increase requested by Green Mountain Power Corporation ("GMP") on April 20, 1990.

The Department has analyzed GMP's filing and has concluded that the record does not support a rate increase. Although the Company has requested additional revenues of $17,223,000 for a total revenue requirement of $127 million, the Department recommends downward adjustments which demonstrate that the Company does not need a rate increase because its current rates are adequate. Although the Company requested total revenues of $127 million, the record itself does not justify a revenue requirement of more than $109.241 million. Since GMP's current revenues are $109.777 million, the Company's existing rates are more than sufficient.

The $109.241 million is reached by making four basic adjustments to the test year: (1) Company sponsored adjustments ($3.335 million); (2) Power Cost Adjustments ($6.681 million); (3) Cost of Service adjustments ($5.454 million) and (4) Revenue adjustments due to adjustments to rate base and cost of capital ($2.289 million).

The Department makes these adjustments fully aware that the economy of the state, region and indeed the country is entering a recession. Consumers and businesses everywhere are cutting back on unnecessary expenditures and challenging whether even normal practices can't be shaved a bit to weather these difficult times. Regulators must bear some of the responsibility for challenging perks, expenditures and business practices of regulated companies. Regulation must act as a substitute for the harsh discipline of the market. Regulators and managers together must challenge costs, and cut unnecessary expenditures.

Were regulation to ignore its responsibility, to act with management to create the discipline normally imposed by impersonal market forces, regulation would become a pipeline for passing on higher costs with great harm to consumers and businesses. Indeed, a criticism often levelled at regulated enterprises such as GMP is that they abuse the regulated environment and become bloated with inflated salaries and costs. If GMP is granted a rate increase, it will be such an enterprise.

In spite of the economic difficulties faced by the rest of the state, over the past 12 months GMP has requested a total of more than 22% in rate increases. In this docket, the Company actually pushed its 15.69% requested increase to nearly 19% during the course of the proceedings when it asked for an additional $4 million because of estimated oil price increases in the rate year. (The Board rejected this attempt to add $4 million to the rate case in orders dated November 5, 1990 and November 26,1990.) Since GMP was granted a 3.88% increase in December, 1989, this means that in less than one year the Company has asked for total rate increases of over 22%.

In spite of the economic difficulties faced by the rest of the state, GMP has not been reluctant to ask ratepayers to provide for management comfort as part of its requested increase. The Company has asked ratepayers to fund management bonuses totalling $246,634 for the rate year (1991). These bonuses may be paid to managers when the Company earns more than 85% of its allowed rate of return. The bonuses help to make GMP executives among the highest paid in the industry. According to an EEI study provided by the Company (DPS Exhibit ZZ), the Company's Chief Executive Officer, its top Administrative Executive and its Controller are the highest paid in their job categories of all utilities earning revenues of $249 million or less. (GMP is asking for annual revenues of $127 million in the rate year.) Its Chief Legal Officer is in second place and two of its other officers are in the "top ten."

In spite of this extremely generous executive compensation, the Company has asked that its officers receive a 6% increase in the rate year while its hourly employees receive a 3.5% increase. In addition GMP has asked for $259,000 to fund a "supplemental plan" which is a retirement package which provides benefits for officers above the normal pension plan provided most of GMP's employees, GMP also wants ratepayers to continue to fund a transportation fleet which provides each of the Company's 13 officers with exclusive use of an automobile which they may take home at the end of the day.

GMP agreed near the end of hearings to remove some $30,000 from its cost of service <u>in this case</u> which it said was attributable to first class air travel and spousal travel expenses. Yet, it expressly stated that it was not prepared to abolish a policy which asks ratepayers to pay for travel, meals and accommodations of spouses of GMP executives who accompany their husbands and wives on trips to utility conferences.

The Department is also concerned that the ratepayers are being asked to subsidize management's diversification projects. Department experts Scott Hempling and Seymour Laskow question whether GMP is fairly allocating costs between the utility and its unregulated subsidiaries. Mr. Hempling challenges GMP's practice of charging its subsidiaries "book cost" rather than "fair market" value for GMP assets and services which these unregulated subsidiaries use. As a result of this practice, GMP ratepayers paid "outside" lawyers approximately $1 million in 1989 (Keyes, 9/10/90. p. 86), while "in house" lawyers were available to GMP's unregulated subsidiaries at "cost".

As for power costs, GMP also asks ratepayers to pay for as many as 690,000 kW months of capacity in excess of the Company's test year Capability Responsibility (CR). Although ratepayers are to pay for this capacity, the Company claims that it is worth nothing now and will continue to be worth nothing in the rate year because the resale market is "nonexistent and likely to get worse." GMP has overlooked the fact that (1) it has projected 5.3% customer growth in the rate year which will provide a built-in market for the excess capacity, and (2) it is hardly "known and measurable" that there is no resale market in light of the fact that GMP recently made a resale for $54/kw yr.

As indicated earlier, the Department has concluded that GMP has not demonstrated a need for a rate increase. This conclusion is based on: (1) an accurate statement of the Company's cost of service (Part I) and rate base (Part II); (2) a reasonable return on equity for an appropriate capital structure (Part VI); (3) a more appropriate treatment of power costs, including imputing a value to excess capacity (Part IV); and Downward adjustments to DSM (Part V). GMP's cost of service will be reduced further if the Board rejects GMP's method of allocating costs between the utility and its non-regulated subsidiaries (Part VI). The DPS also asks the Board to clarify certain Company policies relating to executive expenses (Part III).

This brief contains both a "Findings" and a "Discussion" section. The "Findings" set forth proposed findings of fact in numbered paragraphs pursuant to P.S.B. Rule 2.222. The proposed findings contain citations to supporting evidence in the record. The "Discussion" sections then state the Department's argument, but do not repeat citations to the record for propositions stated in the proposed findings. (Attached are 10 L&A Cost of Service exhibits and 4 rate base adjustment exhibits.)

B. Procedural Background

On April 20, 1990, GMP filed a petition for an increase in rates with the Public Service Board (Tariff No. 1070). On May 4, 1990, GMP filed a second, revised petition for a rate increase. The Company proposed a revenue requirement of $127 million. An increase of some $17 million over the test year revenues of $109.77 million.

The Department and the Board questioned GMP witnesses supporting the proposed increase at hearings on August 22, 1990 and September 5-7, 1990, as well as September 10, 1990. On September 21, 1990, the Department filed prefiled testimony in which it supported a revenue requirement of $110.486 million. GMP and the Board questioned Department witnesses at hearings on October 16, 17 and 18, 1990 as well as November 1, 5 and 6, 1990. Rebuttal and surrebuttal hearings were held on November 26, 27 and 28, 1990.

C. Adjustments to the 1989 Test Year

The Department has analyzed the Company's proposed cost of service in light of the Board's rate-making policy as stated in In Re GMP, Docket No. 4661, Order of 12/20/82, at 3-4:

> Two types of adjustments are regularly made to test year figures: they are "normalized" by removing abnormal occurrences in order to reflect the probable future operation of the Company, and they are adjusted for known and measurable changes, in other words, for changes in costs which are certain or highly likely to occur outside the test year.

The Department has found that GMP's filing is deficient with respect to both categories of adjustment. In several instances the Company failed to "normalize" test year expenditures by removing abnormal occurrences. In several other instances where GMP proposed upward adjustments to the test year, these proposed adjustments did not meet the "known and measurable" standard. The Department has also challenged certain expenses as excessive or unwarranted in that they do not provide a benefit to ratepayers.

D. Burden of Proof

In order to be entitled to an increase in rates, "a utility must prove that expenses it proposes to have reflected are reasonable." In Re Central Vermont Public Service, Docket 5132, order of 6/20/86, 76 PUR4th 517 at 519.

GMP acknowledged that it has the burden of proof with respect to its proposed "known and measurable" adjustments to test year expenditures. It claimed, however, that it does not bear any burden with respect to those expenditures which are subject to the second type of adjustment referred to above. That is, the Company maintained that it did not have to prove that test year expenditures have been "normalized" by removing abnormal occurrences.

It pointed out that its test year expenditures had been "audited;" and, it maintained, in light of this, that those who challenge these expenditures must bear the burden of proving that these expenditures were not "reasonable."

This misstates the issue. The question is not whether the expenditures were "reasonable" for the test year. Instead, the issue is whether it is reasonable to project these expenditures into the rate year. There may have been abnormal events in the test year which made it reasonable to make these expenditures then. But, the very fact that these expenditures were prompted by abnormal events may make it unlikely that the need for this level of expenditure will recur in the rate year. There is no authority for the proposition that a utility does not have the burden of showing that the expenditures it proposes for the rate year are normal and recurring.

In any event, GMP would still bear the burden of proof even if the "reasonableness of test year expenditures" was the matter in issue. A utility seeking a rate increase "bears the burden of persuasion on the question of whether expenditures claimed to support rates were reasonable and prudent." In Re Central Vermont Public Service, Docket 5132, order of 5/15/87, 83 PUR4th 532, 566.

This burden always remains with the utility. While there is a presumption that the utility's expenditures have been reasonable, it is a rebuttable presumption. This presumption does not shift the burden of proof. It simply means that those who challenge the reasonableness of these expenditures must come forward with sufficient evidence" to permit (not necessarily to require) a finding that the expenditure in question is not reasonable. Rocque v. Cooperative Fire Insurance Association of Vermont, 140 Vt. 321, 438 A2d 383 (1981) . . . " In Re Central Vermont Public Service Corporation, Docket 5132, order of 6/20/86, 76PUR 4th 517, 519.

In the Rocque case cited by the Board, the Vermont Supreme Court further clarified the quantum of proof necessary to "burst" the presumption of reasonableness:

> Under Vermont law the effect of such a presumption is to place the burden of going forward with evidence on the party against whom it operates, but the presumption itself is without any independent probative value. When any evidence is introduced from which facts to the contrary may be found, the presumption disappears and is wholly without effect.

140 Vt at 326.

In each instance where the Department has made an adjustment, it has introduced evidence "from which" it is possible to conclude that the GMP expenditure is unwarranted as proposed. Therefore, assuming for the sake of argument that the "presumption of reasonableness" applies to the adjustments in issue, the Department has effectively rebutted this presumption and the burden of persuasion remains with the Company.

<u>Exhibit 6</u> - Relevant portion of the Brief filed with the Vermont Supreme Court (Docket No. 92-353) by the Department in its appeal of the Board decision in - *In Re Green Mountain Power Corporation* – on October 1, 1992. The decision in the matter is reported as *In Re Green Mountain Power Corp.* 162 Vt. 378 (1994)

IN THE SUPREME COURT OF THE STATE OF VERMONT

In Re:	)	
	)	
Green Mountain Power Corporation	)	Supreme Court
	)	Docket No. 92-353

Appeal
from the
Public Service Board of Vermont
Docket Number 5532

BRIEF OF THE APPELLANT
DEPARTMENT OF PUBLIC SERVICE

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October 1, 1992

STATEMENT OF THE CASE

Appellee (Cross - Appellant) Green Mountain Power Corporation ("GMP") filed for a 10% rate increase on July 19, 1991. The proposed rate increase would have increased GMP's annual revenue from retail ratepayers by $11.704 million to $128.5 million. In Re Green Mountain Power, Docket 5532, 4/2/92 order at 6; Appendix 1, page 1; DPS Supplemental Printed Case "A" at 1. Appellant (Cross Appellee) Vermont Department of Public Service ("DPS") challenged the proposed increase on several grounds, arguing that GMP could only justify an increase of 2.65% - a $3.090 million increase in annual revenues.

The Vermont Public Service Board ("Board") heard evidence and argument on the proposed rate increase in a series of hearings from November, 1991 - April, 1992. The Board eventually granted GMP a rate increase of approximately 5.6% -- enabling it to collect an additional $6.55 million per year from its ratepayers. In Re Green Mountain Power, Docket 5532, 5/21/92 order at 2 fn. 1, P.C. at 49.

During the course of hearings, the DPS made more than 25 specific challenges to various components of GMP's "rate case" filing. Docket 5532, 4/2/92 order at 2-4, P.C. at 12-14.

The DPS has preserved two of the DPS challenges, which were rejected by the Board, for review by this court.

<u>Exhibit 7</u> – 2015 Larkin Report

VERMONT

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August 14, 2015

Susan M. Hudson, Clerk
Vermont Public Service Board
1 12 State Street
Montpelier, VT 05620-2701

Re: Tariff No. 8580 – Green Mountain Power Base Rate Filing – Larkin Report

Dear Mrs. Hudson:

Enclosed for filing with the Public Service Board is the Report of Larkin & Associates, PLLC (with exhibit) regarding its review of the Base Rate filing made on July 31, 2015 by Green Mountain Power Corporation (GMP). This filing is made pursuant to section (III)(E) of GMP's Alternative Regulation Plan.

Thank you for your attention to this matter. If any additional information would be helpful, please let me know.

Sincerely,

Timothy M. Duggan
Special Counsel

Enclosures

cc: Charlotte Ancel, Esq., Green Mountain Power Corporation
Robert A. Bingel, Green Mountain Power Corporation
Philene Taormina, AARP

LARKIN & ASSOCIATES, PLLC

REPORT ON ANALYSIS OF RATE YEAR ENDING SEPTEMBER 30, 2016

GREEN MOUNTAIN POWER CORPORATION

COST OF SERVICE REQUEST AND COST OF CAPITAL REQUEST UNDER ALTERNATIVE REGULATION

August 14, 2015

GREEN MOUNTAIN POWER CORPORATION

ALTERNATIVE REGULATION PLAN REPORT

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GREEN MOUNTAIN POWER CORPORATION

ALTERNATIVE REGULATION PLAN REPORT

EXECUTIVE SUMMARY

Successor Plan

On December 20, 2013 Green Mountain Power Corporation ("GMP") filed two petitions seeking Board approval of base rate decrease and approval of a successor Alternative Regulation Plan. The Board opened Docket 8190 for the Rate Docket and Docket 8191 for the Plan Docket. After several rounds of discovery, testimony, meetings, and a workshop, agreements were reached between the Vermont Department of Public Service ("DPS" or "the Department"), International Business Machines (“IBM”), AARP, Associated Industries of Vermont (“AIV”) and GMP. The Memorandum of Understandings ("MOU") dated May 30, 2014 and as amended on June 4, 2014 presents the agreements between the Petitioners and the Parties including revisions to the provisions related to shared savings between GMP and ratepayers as part of the Earnings Sharing Adjustor Band, a definition of Major Storm, an agreement to flow through to ratepayers any Vermont Yankee Revenue Sharing Funds to which GMP is entitled to through September 30, 2017, a reduction of $573,045 to incentive compensation included in Base O&M, continuation of the Alternative Regulation Plan ("Alt Reg") referred to as the Successor Plan (“Plan”), and a Transmission Rate Freeze.

The Successor Plan allows GMP to adjust its rates annually based on four rate adjustment mechanisms. The mechanisms include a Base Rate Adjustment mechanism, Earnings Sharing Adjustor, Exogenous Change Adjustment and a Power Adjustor. Larkin would note that under Alt Reg the Company is operating under a different ratemaking theory than what historically has been referred to as traditional ratemaking. Under traditional ratemaking the Company is afforded an opportunity to earn a reasonable rate of return. Under Alt Reg, which includes four separate rate mechanisms, the Company is essentially guaranteed a return with minimal risk. This difference in regulation is discussed in more detail later as it is an important factor considered as part of the review process.

Vermont Public Service Board Order in Docket Nos. 8190 & 8191

The August 25, 2014, Vermont Public Service Board's Order in Docket No. 8190 and 8191 included the approval of the Memorandum of Understanding dated May 30, 2014 and June 04, 2014. This Order and MOU provided for a 1.46% base rate reduction effective October 1, 2014 and an agreement as to a Successor Plan as discussed above.

Vermont Public Service Board Order in Docket No. 7770

On June 15, 2012, the Vermont Public Service Board's Order in Docket No. 7770 included the approval of the Memorandum of Understanding dated March 26, 2012. This Order approved the acquisition of CVPS by a subsidiary of Gaz Métro in addition to the merger of CVPS and GMP. GMP is the surviving corporation after the merger; therefore, the Combined Company will be referred to as GMP in this report.

The Order provides that GMP will guarantee at least $144 million in savings to retail customers as a result of the merger during the ten years beginning October 1, 2012. If savings are less than that amount, GMP will credit the difference to customers under a plan that will be subject to the Board's approval. The Order provides that GMP will provide credits to GMP's base rate cost of service in the aggregate amounts of $2.5 million, $5.0 million and $8.0 million in years 1, 2 and 3, respectively. In years 4,5,6,7 and 8, GMP's base-rate cost of service will be credited $10.5 million, $12.0 million, $13.0 million, $14.0 million and $14.5 million, respectively. To the extent that these amounts are different from 50% of actual savings in each year a billing adjustment will be made in conjunction with the next ESAM filing.

In the first eight years subsequent to the merger GMP and its ratepayers will share O&M cost savings that result from the merger. During the first three years, GMP will credit its base-rate cost of service with the amount of annual guaranteed savings due to its customers for that year before it receives any applicable O&M cost savings resulting from the merger for that year. The benefits of applicable merger-related cost savings in years 4 through 8 will be split evenly between GMP and its customers. GMP's customers will receive all of the O&M merger-related cost savings after the 8th year. For a minimum of ten years following the merger, GMP will also be required to file an annual report of savings that result from the merger.

GMP will be required to exclude any costs or savings related to the deployment of Smart Grid and Advanced Meter Infrastructure (AMI), the Kingdom Community Wind Project, CVPS's acquisition of the assets of Vermont Marble Power Division of Omya, Inc., and any CVPS staff reductions associated with the Docket 7496 MOU from base O&M costs. In each future base-rate adjustment in which merger savings are shared, the Order states that base O&M costs are subject to change "to reflect the change in the Consumer Price Index for All Urban Consumers (CPI-U) Northeast Region, any

Exogenous Costs and the impact of the Non-Power Cost Cap as defined in GMP's Alt Reg Plan, and any further changes agreed upon by GMP and the Department and approved by the Board." And as noted above, GMP and the Department agreed to such a change with respect to the appropriate level of incentive compensation costs.

Summary

The Company's rate base and cost of service included in the proposed filing were reviewed by Larkin & Associates, PLLC (Larkin). The analysis performed took into consideration the Vermont ratemaking principles, precedents and previous Board Orders. The analysis evaluated the development and the reasonableness of the cost of service, including rate base, capital structure and cost of capital for the rate year ending September 30, 2016. The Company was consulted and had indicated agreement with some proposed adjustments or variations of those adjustments. The proposed adjustments determined by Larkin, whether made or not, are discussed within the report. As part of the process the Department and the Company had a number of discussions to resolve differences with the proposed adjustments. As part of this process the Company offered to increase the merger savings from $12.5 million to $13.3 million. The Company also proposed to adjust the capital structure by increasing debt and decreasing equity by an equal amount. A third offer to mitigate the increase was the Company's proposal to accelerate the write-off of Contributions In Aid of Construction from the asset life to two years. This adjustment reduced depreciation/amortization expense $5.1 million in the current rate year, with the expectation of a similar reduction in the following rate year. While not all of Larkin's recommended adjustments were adopted by the Company, the Department believes that with the mitigation adjustments the filing under the alternative regulation process is sufficient for establishing just and reasonable rates to be effective October 1, 2015. Larkin has reviewed the proposed revised filing and has determined that the changes agreed upon by the Department and the Company have been made and properly flowed through.

Included in the report is the Department's conclusion that the projected Category A and Category B expenses as presented in the cost of service for power supply and transmission costs are reasonable. This portion of the review was conducted in accordance with the MOU and final order in Docket No. 8389, in which the Department and Larkin committed to jointly review whether certain cost categories should be reflected in O&M costs rather than in the power adjustor.

THE PROPOSED FILING

The Company has based its cost of service (Company Schedule 2.3/2) filing on the twelve months ended March 31, 2015. The cost of service was adjusted to reflect the platform costs approved in the Docket No. 8190 for the rates effective October 1, 2014. The filing adjusts the test year to the FY2014 platform costs using a negative .4% CPI for New England, changes to power costs, transmission costs and other non-base O&M costs. The Company has based its rate base filing (Company Attachment B, Schedule 2) on the average twelve months ended March 31, 2015, adjusted for projected plant additions and projected changes to other rate base categories for the rate period ending September 30, 2016.

GMP provided a filing that included all of its schedules and almost all the work papers. Additional information was requested for amounts linked to workpapers that were hard coded (i.e. income tax papers for ADIT) and that information was provided in a timely manner.

In past reviews it was noted that supporting documentation to meet the known and measurable standard was insufficient in many cases. To resolve this issue, the Company and Department agreed as a condition of the MOU in Docket Nos. 8190/8191 that the Successor Plan would include Attachment 7, which set forth the documentation standards for proposed plant additions and the ramifications of not satisfying them. Attachment 7 was included as part of the Successor Alternative Regulation Plan filed on June 4, 2014. With Attachment 7 the Company has specific direction as to what is required to be included in the filing as supporting documentation. This documentation should be available at the time the proposed filing is submitted for review and not have to be requested during the review or developed and/or obtained subsequent to preparation. This is true whether it is for plant additions or cost of service items. There was a significant improvement in providing cost documentation for the projected plant additions, however, there was still some project detail (i.e. project description and financial analysis) that while supplied after the initial information was supplied, was considered less than sufficient. This will be discussed in more detail as part of the review section of the report.

Recommendations

1. The Company should continue to file its schedules with links to other files in a single folder for ease of review and to assure that all the linked files are accessible. If hard coded workpapers are the source of the linked information an excel workpaper showing the development of the hard coded numbers should also be provided. The Company should also continue to provide a hard copy of the filing as is maintained by the Company for the review.
2. Company personnel should be required to familiarize themselves with the known and measurable requirements as memorialized in Attachment 7.
3. Larkin suggests that the Company in developing its schedules that are printed for filing with the Board and as part of the initial hard copy provided to the Department for review note on the Schedules and/or workpapers the electronic file where the detail can be located. This will aid the review process and should provide a measure of consistency from filing to filing.

REVIEW

The review analyzes the cost of service and rate base as presented by the Company. The cost of service review will include analysis of O&M and other expenses in the test year on a very limited basis. The majority of costs, other than power costs, depreciation and taxes are within the platform and any changes to those costs would not impact rates. Those changes would impact the amount of cost savings that occurred in the test year. The Department and Larkin did perform a detailed review of power costs, depreciation and taxes.

The rate base review included an analysis of historical plant additions since the last review, a comparative analysis of budget to actual of projected additions included in the last filing, an analysis of selected test year costs, a comparison of selected historical costs to the test year, analysis of adjustments to the test year, identification of concerns regarding costs reflected in the filing, and an assessment of the reasonableness of the Company's rate request for the year ended September 30, 2016. For projected additions to plant, a selection of 134 specific projects was made for a more specific review and/or verification of projected/actual costs on a test basis. Blanket and joint owner project projections were also reviewed for reasonableness. After reviewing the information supplied, discussions took place with Company personnel regarding concerns with some costs and/or cost estimates. The Company either resolved some of the concerns with an explanation and/or additional detail, or the Company made some adjustment to the proposed filing to eliminate and/or reduce the concern. Issues were generally resolved.

Specifics of Review

The review undertaken for this filing consisted of essentially an evaluation of seven different cost components. To be reviewed was the Capital budget of GMP, other rate base amounts, the select non base O&M costs for GMP, the Exogenous costs excluded from the test year, the Power Adjustor costs for the first and second quarter of the rate year ended September 30, 2015, test year costs and the calculated increase to the Base O&M Platform. Multiple discussions also took place regarding the filing, the establishing of the O&M Base Platform and the cost to be included, vegetation management, Smart Grid costs, questioned costs included in the Power Adjustor filings, Exogenous costs, the accounting for the Net Operating Loss (NOL) for tax purposes and its impact on Accumulated Deferred Income Taxes (ADIT) and various other issues as they were identified during the review process.

Review Process

The intent of the review process under the Plan is for the Department's consultant to analyze the proposed projects for the rate year covered by the proposed rate filing and to identify any major concerns prior to the Company completing the initial draft of GMP's proposed rate filing. The next step is the review of the initial draft of GMP's proposed rate filing, evaluate the reasonableness of support, evaluate the propriety of costs classifications and suggest revisions to the filing prior to the finalizing of the proposed change in rates that will be submitted to the Board. During this time frame the Department and Larkin are also reviewing the costs included in the Power Adjustor and the Exogenous cost filings. The review process allows for an analysis of historical information included in the test year and the Company's proposed adjustments made to develop a rate year cost of service.

During the review, the Company and the reviewer(s) are to attempt to resolve any potential issues, prior to the Company's filing for a proposed change in rates. Throughout the review process the Company has allowed the Department and the Department's consultant unrestricted access to Company personnel ultimately responsible for various cost components in the filing. Also there are periodic conference calls to discuss the current status of the review or any specific issues identified. Requests for information were responded to by the Company in a timely manner. We encourage the Company to continue this practice as it enhances the Alternative Regulation process.

Time Period of Review

This report concerns the Company's annual filing for a change in base rates effective October 1, 2015 for the year ended September 30, 2016. The review of costs impacting the rate year beginning October 1, 2015 and ending September 30, 2016 began in March 2015 and continued through July 2015. The timeline of the review was as follows:

- The Company's filing of the 1st Quarter Power costs on January 30, 2015.
- Discussion between the Company, the Department and Larkin in March 2015 regarding the capitalization and accounting for exogenous storm costs.
- The Company's filing of the 2nd Quarter Power costs on April 30, 2015.
- The Company files the Exogenous Change Adjustment on April 30, 2015.
- Larkin's receipt of project listing for proposed capital projects to be added to plant and included in the proposed base filing on April 29, 2015 and Larkin's selection of projects for review was sent on May 1, 2015.
- Larkin is provided a flash drive with selected project folders and performs an on-site review at GMP South (formerly CVPS) from May 5th through 7th of 2015.
- The Company files an amended Exogenous Change Adjustment on May 26, 2015.
- The Company files a version of the proposed filing on June 1, 2015 and that version was the basis of our review.
- The Company provides an updated version of the proposed filing reflecting specific adjustments as of July 1, 2015.
- On July 31, 2015 the Company files its official 2016 base rate filing.

Projected Capital Additions

GMP provided the projected capital additions budgets for the respective departments on April 29, 2015. The projected capital additions selected for review were sent to the Company on May 1, 2015. The Company's original project listing included a request for $141,778,905 of project additions and $21,950,586 of plant retirements. The $141,778,905 of additions included $50,261,780 for blanket work orders and $5,017,766 for joint owner capital additions. There were a total of 206 specific projects totaling $86,499,359. Larkin selected 134 of the 206 projects (65%) for review for a total of $83,904,933 of costs or 97% of the project specific costs. The support for the $50,261,780 of blanket work orders and $5,017,766 of joint owner capital additions was also reviewed for reasonableness based on historical cost trends and the use of the five average cost standard. That equates to $139,184,479 of the $141,778,905 (98.2%) of the requested project costs being evaluated for reasonableness. Attached as Exhibit HWS-1, is a summary of the projects with some notable observations from the review. GMP provided Larkin with a flash drive of the project folders and copies of other supporting documentation for the projected capital additions during the on-site review. The project request provided for review by Larkin identified capital additions to plant for the interim period April 1, 2015 through September 30, 2015 and for the twelve months ended September 30, 2016.

The budget consisted of sixteen classifications. The classifications are communications, computer hardware, computer software, distribution lines, distribution substations, general plant, joint ownership, meters, new initiatives, production, property and structures, regulators and capacitors, transformers, transmission lines, transmission substations, and transportation. During the on-site review supporting documentation for the selected projects was reviewed and discussions with Company personnel took place to clarify questions that arose and to discuss the process. The reviewed documents consisted of work order forms, various cost summaries that tie into respective lines on the work order forms, supporting documents for the costs included on the respective cost summaries and documents identified as a "Financial Analysis". Support for internal labor costs was based on a labor rate summary for the year. Costs for materials and supplies were based on a materials and supplies inventory summary. Direct materials costs were based on a cost manual that included quotes, estimates and/or actual invoices. The direct materials in the cost summaries were coded so the cost could be readily traced to the cost manual. Contract labor and fixed contracts were based on various types of documents including quotes and/or estimates, external email quotes or invoices from the project or prior projects similar in nature. The joint ownership requested was based on the joint owner budgets. Direct materials purchases and contract labor were based on various types of documents including quotes and/or estimates, external email quotes or invoices from the project or prior projects similar in nature.

Prior to the on-site, GMP provided a sample of the "Financial Analysis" document that was to be included with each project. Larkin noted the selected project was a reliability project so the required information may be different from the information included for other projects. The Company informed Larkin that a complete book of the selected project Financial Analysis would be subsequently provided. The project book of Financial Analysis was reviewed in detail for project justification, whether alternatives were considered and for financial analysis as required by Attachment 7 for projects between $300,000 and $3,000,000. A number of the projects generated a concern. Larkin deemed the financial analysis on the documents provided was insufficient. Larkin has noted some of the concerns on Exhibit HWS-1. Under strict application of Attachment 7 to the Successor Plan a large number of the projects could have been excluded from the request. Larkin identified the numerous concerns and noted that while an adjustment could be made, only selected recommended adjustments were being proposed. Larkin notes that because this is the first testing under Attachment 7, and in light of the Company's improvement in providing underlying supporting cost documentation, some allowances were made. This discussion of the issue should be considered as notice to the Company that future allowances will have to be justified.

Exhibit HWS-1 was prepared using the original project listing. Columns were added as part of the review process and Larkin has identified the added columns with a yellow highlight. Specifically, the column "Start Month Per Project Analysis" was added to verify the start date that was identified in the filing. While not depicted, Larkin also verified the in-service date and project cost to the Installation and Retirement Work Order form. The Column "Spending through 5-31-15" was added to determine whether projects that were supposed to have started did start and to determine the progress of projects.

The next three columns were added as part of the review of the Financial Analysis form. Because a large number of projects stated the project would have no O&M impact, that no cost savings would occur, and that no alternatives were considered, Larkin summarized the findings. As shown on Exhibit HWS-1, 64.93% of the Financial Analysis forms indicated that there would be no O&M cost impact. Based on experience Larkin believes that number to be overstated. Even with new equipment, whether it be conductor, new or replacement poles, or other equipment, some added costs would be expected for more of the additions. Even more concern exists when 88.81% of the projects will not generate a cost savings. That figure is troublesome since a number of projects are replacing old, worn out equipment that no doubt has had to have some maintenance. There is also the concern the projects undertaken to improve performance did not have any cost savings. Finally, 55.22% of the projects were undertaken without any alternatives considered. This is a real concern since that means the project cost cannot be proven to be reasonable. Because so many of the cost related questions were responded to with “NO,” the Financial Analysis for the projects is considered less than sufficient. As discussed above no adjustment was made because this was the first review under Attachment 7 and there was the significant improvement in cost documentation for the projects estimated cost.

The Company, after discussion, revised its request by eliminating selected projects that were questioned and by adjusting the in-service dates for a number of projects due to concerns noted by Larkin regarding slippage. Based on a review of the revised summary, GMP made all the recommended adjustments proposed by Larkin.

Cost of Service

General

On June 1, 2015, Larkin received the entire GMP base rate filing for the year ended September 30, 2016. The filing indicated a revenue deficiency of $7.021 million requiring a 1.26% increase in revenues. The filing reflected a lower revenue requirement than would have been included due to the $12.5 million ratepayer share of the merger-related shared savings being factored in, which is $2 million more than the $10.5 million provided for under the MOU in Docket No. 7770.

A subsequent revenue requirement was provided on July 1, 2015 indicating a revenue deficiency of $9.412 million requiring a 1.69% increase in revenues. The change was primarily related to the elimination of an investment and the estimated return reflected in other earnings. It should also be noted that there was a change in the information summarized. The initial filing showed the revenue deficiency as being the difference between the "Total Cost of Service to Ultimate Consumers" and "Revenue from Ultimate Consumers." The July 1st filing shows the revenue deficiency of $9.412 million as being the difference between the "Total Cost of Service to Ultimate Consumers" of $603.427 million and the "Revenue from Ultimate Consumers" of $593.034 million, less the "Increase in Revenue due to Smart Power Implementation" of $981,000. This change was the result of reclassifying as a separate line Smart Power revenue previously included in the Revenue from Ultimate Consumers line.

The final revenue requirement filed on July 31st indicates a revenue deficiency of $473,000 requiring a .08% increase in revenues. The change was the result of changes to project costs included in rate base, adjustments to various costs outside the platform, elimination of a request for a new working capital component, the Company's proposal to write-off one half of the unamortized CIAC balance, an increase of $800,000 in the merger savings and a change to the capital structure. Again it should be noted that this revenue requirement calculation was consistent with the July 1st presentation but different from the initial filing on June 1st. While the initial filing showed the revenue deficiency as being the difference between the "Total Cost of Service to Ultimate Consumers" and "Revenue from Ultimate Consumers," the July1st filing and the July 31st filing show the revenue deficiency as being the difference between the "Total Cost of Service to Ultimate Consumers" and the "Revenue from Ultimate Consumers" less the "Increase in Revenue due to Smart Power Implementation."

GMP

GMP provided an electronic copy of its proposed filing and workpapers on June 1, 2015. The use of the platform primarily limits the review to non-base O&M costs. The review focused on depreciation, income taxes, the non-base O&M costs for KCW, and Smart Grid. Power costs were reviewed by the Department except Larkin assisted in review of the costs charged to power costs as part of the Power Adjustor filings.

PROJECTED PLANT ADDITIONS

As discussed earlier, Larkin was provided a summary of proposed plant additions and selected 134 specific projects for review. In past reviews, GMP was advised of the importance of having sufficient supporting documentation to meet the known and measurable standard as required under traditional Vermont ratemaking and yet there continued to be issues in assembling sufficient support. The review of the current filing found there was a significant improvement compared to previous filings with respect to the supporting detail for estimating the cost of specific projects. Larkin is encouraged with the improvement and the concern by the Company with the quality of cost documentation. However, as discussed earlier there is concern that project detail was not sufficient, specifically with respect to the financial analyses. The Company's compliance with the known and measurable standard from a cost perspective is improved but project justification in the form of analysis of cost impact and alternatives considered continues to be a concern, especially with the provision in the Successor Plan that requires compliance with Attachment 7.

As part of the review, Larkin requested a comparison of the project request filing in Docket No. 8190 and the current status of the projects using a June 30, 2015 cut-off. The results raised a great concern as to the reasonableness of the Company's projections. The major issue identified was that in-service dates identified in the filing were overly optimistic as a vast number of projects recorded in-service dates that were later than projected. This is an issue because ratepayers begin paying for the plant and depreciation based on the Company estimated in-service date, and the delays noted provide the Company with free cash working capital. Another issue identified was that there were a number of projects that not only did not go into service on time, but there were no project costs for the project even though the filing indicated it would be in-service as of June 30, 2015. A third issue is project substitution. This is particularly an issue with IT projects.

The listing shows that a number of projects were not done or the cost requested exceeded the actual cost incurred because costs were transferred to another project. The other projects were not part of the review process therefore no determination can be made as to the appropriateness of the cost. The findings from the review of past projects will be discussed in more detail in the respective project categories.

GMP Capital Additions

GMP initially projected for the year ended September 30, 2016, a net increase of \$142.167 million to plant in service and a decrease of \$60.881 million to Construction Work in Progress (CWIP). The Company focused heavily on complying with Attachment 7 to the Successor Plan by communicating with the Department and Larkin regarding the detail to be presented as support for the projected additions. As was done in the past, our review consisted of an on-site review allowing Larkin to review information readily and providing the opportunity for interaction with the Company.

During the review, a request was made for a budget to actual comparison of the projects included in the base case filing in Docket No. 8190 to assess the reasonableness of the past projections and to establish a confidence level in the projected additions in the current filing. This analytical procedure is critical and provides evidence as to the reliability of the Company's projection process. The review of the budget to actual showed a significant number of variances in cost and even more so in projected in-service dates. The cost variances were both under and over budget. The variance explanations were limited but provided sufficient information to assess the issue and reach a conclusion. Some deferrals were identified but the cost amount was not considered material. The major concern identified and communicated to the Company was the slippage that occurred in the completion of the projects and the fact that projects not completed had costs assigned to other projects not previously identified and/or reviewed. The concern with the Company's optimistic projected in-service dates is ratepayers are funding plant investment ahead of the point where the investment becomes used and useful. The Company did revise some current project in-service dates in response to our concern. As will be discussed later, most of the projects in the Docket No. 8190 base case filing had met the known and measurable requirements but due to changes in planning and delays, the project estimates and completion dates have been too optimistic. This factored into our analysis of projects and our recommendations.

The projected additions for 2015 and 2016 incorporated in the filing for the establishment of rates for FY 2016 were reviewed based on a sampling of one hundred and thirty-four of the two hundred and six projects, excluding blankets, on the list provided by GMP. The one hundred and thirty-four projects selected for review totaled to $83.905 million. The sample did not include blankets since blankets are evaluated based on historical spending. The sample was 65.0% of the Company's requested projects excluding blankets and approximately 97% of the requested cost excluding blankets. The reasonableness of the amounts requested was verified to supporting cost documentation and/or historical cost information. The Company projected the costs for blanket work orders based on an indexed five year average of costs closed to plant.

The projected additions analyzed were reviewed for cost development and substantiation of cost estimates to quotes, estimates, historical averages, actual costs to date and/or similar historical cost detail. A full complement of detail was provided with the Company caveat that the Financial Analysis provided will be supplemented in full at a later date. This practice, except for the supplementing, should be continued in future filings. In our review of the selected projects, we noted that most projects had estimate sheets for direct materials, direct internal labor, contract labor, contract costs, etc. Documentation was provided as support for the contract labor and the contract costs that were included in the project cost estimate. Testing of direct internal labor costs, stock materials and direct materials was done using project cost reference documents. For example, the cost for the materials and supplies was tested to the Company's materials and supplies inventory listing. Overhead costs were based on various overhead rates as summarized and provided by the Company.

Observations

The Company was requested to provide a summary of projects included in the filing for 2015 and 2016. The plant addition summary provided was used to determine the sample test for projected plant costs. In an attempt to expedite the review process, a sample listing was provided to the Company in advance. The selected project files were downloaded to a flash drive and made available upon our arrival at the Company. The documentation supporting the projected capital addition direct external costs was generally included with an exception for the updated Financial Analysis as discussed earlier. The readily available information is a reflection of the progress made by GMP and is an indication that the alternative regulation process is working to encourage compliance with filing requirements.

The current process allows for review of project costs being requested prior to the filing of a proposed change in rates. This provides the Company the opportunity to assemble information and support for the requested plant additions that it may not have been afforded in a typical rate proceeding. This fact was a major factor in determining whether an adjustment would be proposed.

Concerns

1. As noted above, we are concerned that there are cost variances between budget and actual for the numerous projects included in rates. We are also concerned with the slippage of project completion dates.
2. A concern exists with the fact that in compliance with Attachment 7 to the Successor Plan, numerous projects should include a financial analysis that provides substantive financial information and does not simply answer questions regarding cost impact and cost savings with a simple yes or no without explanations. The Board in the past has excluded the costs for projects that should have been evaluated with a cost benefit analysis and Attachment 7 provides that failure to meet the documentation requirements could result in a cost disallowance.
3. We tested the reasonableness of general blanket work orders to the Company's calculated actual five year average and the average utilizing the CPI inflation index. While most of the amounts appeared reasonable based on the indexed

historical averages using a CPI index, we do not believe indexing is justified based on actual historical costs. We note the Company did estimate the blanket costs based on a CPI index but because the estimates were at least in part based on the escalated values we continue to note our concern.

Recommendations

1. The Company should provide, *as part of each prospective filing*, a summary of plant additions as requested in the previous rate request that compares the "as requested" amount to actual for jobs completed and jobs still in process. The summary should also identify the as-projected date of completion and the actual completion date, or the latest estimated completion date. Because of the Alternative Regulation Process and the use of the ESAM we believe this should be a standard part of the Company filing and should not have to be requested each filing by the Department. For projects that are completed, the Company should provide a *detailed* explanation for any cost variances of 10% or more. For projects in process or not yet started, the Company should provide a *detailed* explanation for any estimated changes in the cost projection and explain any changes in the estimated date of completion. This analysis will provide valuable information to the Board and the Department for evaluating the reasonableness of the Company's current estimates incorporated in the current filing.
2. To address Larkin's concern with slippage and variances the Company should factor in the variances and slippage when establishing the new budgets for plant additions.

3. The Company should continue to use the master material and supplies inventory, labor summary and overhead summary in developing the project estimates. The Company should continue to reference the applicable pages from the master list in the project folder.
4. We are concerned that projects not completed had costs assigned to other projects not previously identified and/or reviewed. It is recommended that the Company include with its initial filing submitted for review a list of all projects that were undertaken during the test year that were not subject to review in the prior filing. This summary should include the cost, date started, date completed (if completed) and an explanation why the project was undertaken. The same detail made available for the projected additions should also be available for review for these projects.

Communications

The August 1 filing includes $1.349 million for Communication projects. Larkin reviewed the cost for one project that totaled $1.224 million of the $1.349 million requested. The AMI Gatekeeper LTE project was a prime example of the concern with respect to the Financial Analysis prepared by the Company. The analysis indicated the project had no O&M impact, no cost savings were identified and no alternatives were considered. Since the project cost of $1.224 million is related to smart meters it is hard to conceive how there would be no cost impact, whether it be added cost or cost savings, and why there is no explanation why there was no alternative considered. Larkin also evaluated the timing of the projects and recommended that another project due to be completed in October 2015 have the in-service date extended 3 months. The Company agreed to the in-service date adjustment.

Computer Hardware

The projected addition for computer hardware reflected in the initial filing was $7.721 million for specific projects and $652,998 for blankets. As noted earlier there are concerns with projections for computer hardware because of the number of changes and the timing of in-service. Some examples include, but are not limited to, the Plant NW Switch, the Conference Room Video Displays and Dell Blade Enc. The Plant NW Switch projected in service November 2013 at a cost of $150,293. The response to DPS 3-12 indicates the project was closed for $63,707 with an in-service date of June 2014. The Conference Room Video Displays was projected in service January 2014 at a cost of $12,995. The response to DPS 3-12 indicates the project was closed for $1,081 with an in-service date of June 2014. And the Dell Blade Enc was projected to be in service February 2014 at a cost of $1,185,406. The response to DPS 3-12 indicates the project was closed for $781,091 with an in-service date of July 2014. These 3 projects were the first 3 projects on an extensive list and they all were less than projected and went into service at least 5 months after they were supposed to. The explanation for the projects for the unused funds was that the remaining funds were moved to another project. The issues with IT are perennial and are a major concern. While documentation existed to justify the projected cost in many of the projects, the quality of that cost documentation and the estimates will now be questioned. The shifting of funds is also a major concern because the project funding for wherever the funds were shifted to has not been subject to a review which means there is no assurance that the project is an appropriate cost to be passed onto rate payers. The optimism of in-service has always been an issue with GMP for IT projects. In future reviews, the in-service date will be viewed with skepticism until the Company can prove its estimates are reasonable.

Larkin recommended that 5 of the project in-service dates be shifted by 3 months and a project for $555,424 be deleted. The deleted project was for security cameras and the start date was April 2015 and as of June 2015 there was no action taken. This is another concern since a project described as being for safety/security is not done when it is supposed to be. From a review perspective a question now exists as to whether the labeling of projects as necessary can be relied on. The Company agreed to make the changes recommended.

Computer Software

GMP requested $8.220 million for computer software projects. The Company's original request consisted of 28 projects ranging from $15,475 to $1,867,248. Due to past concerns Larkin analyzed 25 of the 28 projects totaling $8.137 million. Similar to the Computer Hardware projects there were delays and spending that did not occur with projections made for Docket No. 8190. A project labeled Room Wizards with an in-service date of November 2013 actually went into service March 2015. Another project identified as CIS Enablement for $146,105 with a projected in-service date of December 2013 went into service March 2015 at a cost of $53,060. A third project issue is the project identified as Cross Bow for $177,338 due to be in-service January 2014. The project was canceled and the funds were moved to another project. This is a sample of the first three of many projects where costs did not occur or the date in-service date was overly optimistic.

Another issue was the Financial Analysis, where 20 of the 25 projects indicated there was no impact on O&M expense. Then, in review of the cost savings question there were 2 where it was indicated the savings can't be calculated, 6 indicated the any savings would be reallocated, 11 indicated efficiencies would result without any quantification, 5 indicated there were no savings, and 1 indicated a savings of $162 per incident. To add to the inadequacy of support for the acquisition, 11 Financial Analyses indicated that no alternatives were considered and 5 indicated that an alternative was considered but provided no explanation why that alternative was not selected or why it was rejected. With the requirements listed in Attachment 7 to the Successor Plan the next review will be less lenient in evaluating the appropriateness of the IT requests.

Larkin recommended that 4 projects totaling $1,060,117 be deleted and 1 project move its in-service date 3 months. The Company agreed with the recommendation.

Distribution Lines

The GMP request for Distribution Lines totaled $36.242 million. The request is based on 18 months of additions for April 2015 through September 2015 and all of FY2016. The escalated five year average was annualized for the interim period and the rate effective period. Based on historical spending the amount requested appears reasonable.

Distribution Substation

The initial capital request provided consisted of $9.567 million for specific projects and blanket expenditures of $1.008 million. The specific projected expenditures consisted of 24 projects. Larkin reviewed 11 of the 24 specific projects with the 11 totaling $9.035 million. The workorder 34 amount for blankets was considered reasonable based on past historical spending that averaged $675,859. On an annualized basis for the interim period and the rate effective period the blanket would be approximately $1.008 million. Again Larkin identified an issue with slippage. The Company filing in Docket No. 8190 included 11 specific projects and for 6 of the 11 the in-service date slipped. Adding to the concern is that 2 of the projects were to be completed in 2014 and are still not in service. No adjustments were recommended but there is justification for making a change.

General Plant

The Company projections for General Plant are different from past filings. Past filings included equipment and vehicle purchases but this year the costs consist of amortization of communication equipment, computer equipment, laboratory equipment and various other categories. The $5.138 million is not included in capital costs but is a charge to retirements. The cost categories of communication and computer equipment did not reflect any retirements so the amount here is a reclassification. Larkin did not take issue with the retirement amounts here but in future requests the continuation of classifying the costs here may be questioned.

Joint Ownership

The initial request for the current filing included $5.018 million for joint owner projects. The Company uses the owner budgets to estimate costs. Reliance on past budgets has not proven to be a reliable way of estimating costs. The Company and Larkin discussed the issue and agreed to begin with a 3 year average of performance and move to a 5 year average as more information becomes available. No changes were recommended.

Meters

The meter blanket request in the filing is $1.067 million. The escalated average is for a year is $538,090. Annualized for the 18 month period April 2015 through September 2016 is $807,135. While an adjustment of approximately $260,000 could have been recommended Larkin determined based on the cyclical changes the amount is reasonable.

New Initiatives

New Initiatives consists of 6 specific projects totaling $9.778 million. The projects were all to begin in April 2015 but only 3 were started with 2 of the 3 having expended approximately 25% of the project budget. Larkin recommended that the 3 projects not started be deleted. The Company requested that one of the projects remain but with a later in-service date. A new quote was provided as support for this request. Larkin agreed to the September 2016 in-service date as long as the Company reduced the cost $200,240 based on the new quote. The Company agreed with Larkin's recommendation.

Production

GMP's initial request was for $20.969 million for specific projects and $991,974 for blanket projects. Two of the listed projects totaling $13.651 million are essentially the same project. The cost to date totaled $13.275 million indicating the project should be on target. Larkin reviewed 24 of the 27 specific projects for a total review of $20.819 million of project costs. The 5 year average cost for production blankets is $500,167. Annualized for the 18 month period the cost would be $750,250 indicating a possible excess of approximately $240,000. Since there is a downward trend in blanket spending the Company is put on notice that there should not be any excess in future filings. No specific project costs were recommended for adjustment. However, in review of the projected additions from Docket No. 8190 it was noted that of 43 specific projects that were to be in-service before or by June 2015, 23 were not in-service by the filing in-service date and another 13 projects were either canceled or not started yet. This is a major concern due to the dollars involved. Larkin notes that 13 of the current projects have not had any spending as of June 2015. Because of the concern Larkin recommended that 7 project in-service dates should be moved to March 2016 which is later than initially indicated. Larkin recommends the Company consider a more in-depth evaluation of the projects in the future because a continuation of the trend from the rate case would prompt a recommendation that some project costs be deleted.

Property and Structures

The FY 2016 request for property and structures in the initial filing was $7.047 million. The initial request included 29 projects of which 7 were for the purchase of land. The issue with this request was the inclusion of the land purchases for some prospective future plant project, 13 of the projects indicated there was no O&M impact, 15 projects indicated there was no cost savings and another 16 projects were planned without considering any alternatives. Adding to the concern was of the 23 projects in Docket No.

8190 that had an in-service date of or prior to June 2015, 4 did not occur and 12 have slippage with the in-service date. Larkin conservatively recommended the land purchase be removed and one project have its in-service date moved from June 2015 to September 2015. The Company agreed to the recommendations.

Regulators/Capacitors and Transformers

The blankets for regulators, capacitors and transformers is $8.410 million. The 5 year average for blankets is $4.241 million. The Company request is excessive because they included a full year for the six month period April 2015 through September 2015. Larkin did not recommend an adjustment because Larkin did not identify the excess for 6 months FY 2015 until after the Department and GMP reached an agreement on the filing. The request should have been adjusted by approximately $2 million. The over-all impact is mitigated by the fact that the Company used a year end in-service date instead of monthly or quarterly in-services dates which means the rate base impact for the $8.41 million was $4.496 million.

Transmission Lines

The Transmission line request of $10.376 million included 17 projects. Larkin selected 14 projects totaling $10.265 million for review. Larkin noted that of the 18 projects in Docket No. 8190 there were 13 that were to be completed and in-service by June 2015. Only four of the projects were done by the filed in-service date leaving 13 projects with an in-service date that was beyond the date used in the filing. Larkin recommended that 1 project be removed from the filing and 3 projects have the in-service date set back. The Company agreed to remove the project and change the in-service dates.

Transmission Substations

GMP requested $4.114 million for specific Transmission Substation projects and $1.888 million for blanket work order 32. There were 26 specific projects and Larkin selected 9 projects totaling $3.286 million for review. The Financial Analysis provided had indicated there was “No Loss Savings” for 8 of the projects. Again there is a concern as to whether the projects have been properly justified. In reviewing the status of the 16 projects in Docket No. 8190 Larkin observed that 10 were to be in-service by June 2015 yet one was not being done until a future date and 7 were put in-service after the date used in the filing. As noted before this means ratepayers are paying for plant that is not used and useful and this is a major concern. The five year escalated average spending was $1.266 million. When annualized for the 6 month interim period (April 2013/September 2013) and the rate effective period this equals $1.899 million. The requested blanket amount is reasonable. Larkin recommended that 3 project in-service dates be set back because the projects were done when they were supposed to be and the Company agreed to the change.

Transportation

The five projects requested for transportation vehicles totals $7.359 million. The replacement vehicles according to the Financial Analysis would not provide any cost savings and no alternatives were considered for any of the acquisitions. In Docket No. 8190 the Company had nine projects with eight of the projects having an in-service date prior to June 2015. Five of the projects in-service dates had slippage. In the current filing two of the acquisitions were to have occurred and the vehicles were to be in-service. No acquisitions have occurred as of June 2015. Larkin recommended the two acquisitions that did not meet the in-service date be set back to March 2016. The Company agreed to make the changes.

Concerns:

1. The Company assembly of documents has improved significantly compared to past filings. However, the Company's optimism with in-service dates is not supported by a comparison of actual historical in-service dates to projected in-service dates. In addition, the Financial Analyses prepared by the Company are not considered sufficient. With the high level of "No" responses to the questions regarding costs and alternatives considered there is significant concern that the least cost alternative may have not been acted upon and the financial justification does not exist for undertaking the project. It is Larkin's opinion, that the Company must improve the Financial Analysis process or more costs will be recommended for exclusion in future filings.
2. As indicated above, there is concern with the in-service dates being overly optimistic. This optimism is costing rate payers because plant is included in rate base before it becomes used and useful.
3. The Company had one project that required a cost benefit analysis. The analysis provided was in PDF format and because of that that assumptions and calculations could not be reviewed.

Recommendations:

1. The Company should instruct employees as to what the purpose of the Financial Analysis is and direct the employees to provide information of substance. Some analysis must exist as to whether there is an O&M impact and how the impact was determined should be explained. The same process applies to determining whether a cost savings will occur. It is the cost savings that can be used to justify the financial investment in the project. Finally, the consideration of alternatives is significant. Employees do not just walk in and write a check for any car, they review the options and look at different makes and models. This same process should be applied when the Company undertakes a project. After that alternative is considered, the analysis should indicate why the one alternative was selected and the others were not.
2. To the extent a cost benefit analysis is prepared, the analysis should be included with the supporting cost documentation, in electronic form, along with a reference and/or explanation regarding how the cost savings were reflected in the filing.

OTHER RATE BASE ITEMS

Other rate base additions include items such as Investments in Affiliates, Special Deposits, Unamortized Discounts, Preliminary Surveys, Regulatory Assets, Low Income Payments, Efficiency Fund Payments, Storm Deferrals, Retired Meters, the Community Energy & Efficient Development Fund (CEED), Capital Expense, AMI Investment and the Working Capital Allowance. Other rate base deductions include Accumulated

Depreciation, Customer Deposits and Advances For Construction, Capital Leases, Accumulated Deferred Income Taxes, Accrued Pension Expense, Accrued Post Retirement Expense and Other Current Liabilities (Deferred Credits). This report will discuss the respective additions and/or reductions to rate base where issues were identified and discussed with the Company. Larkin not taking issue with certain rate base items should not be construed to mean there is no issue. Due to time constraints not all costs are looked at in the same level of detail.

Working Capital

Prior to the merger, CVPS and GMP working capital allowance calculations were done differently when the annual filings were prepared under Alternative Regulation and in past litigated proceedings. CVPS submitted a working capital allowance that included a lead lag approach, the average materials and supplies inventory, Millstone fuel inventory, prepayments and an adjustment for accrued interest. GMP used what is commonly referred to as the formula method or one-eighth of operating expense allowance plus the average materials and supplies inventory, fuel inventory, prepayments and an adjustment for accrued interest. During the merger and subsequent to the merger, the Company filed a working capital request based on the one-eighth of operating expense method. The use of a lead lag study was discussed, and as discussed in prior reports the Company, the Company opted to use the formula method because it would have been burdensome to prepare a lead lag study due to the fact that the information for the test year was on two systems. Larkin agreed under the circumstances that use of the formula would be best and indicated that while a lead lag approach is preferred, due to the circumstances identified it would okay to utilize the formula method at the time. However, Larkin did advise in their report for the rate year ending September 30, 2014 that the Company in future filings should prepare a lead lag study especially with the filing for the year ended September 30, 2015 being of a more traditional nature. The Company verbally agreed with this recommendation during discussions. As noted in the direct testimony of Helmuth Schultz in Docket No. 8190 the Company again used the formula approach instead of a lead lag study. Once again it was stated "that it should be clear that in a future filing the Company should use a lead lag study."[1] After each of the last filings based on representations by Company personnel, it was Larkin's understanding that the Company would use a lead lag analysis in the next filing. GMP has failed to comply with its commitment. If this filing were to be litigated, Larkin would recommend that no cash working capital allowance be allowed because of the Company's failure to comply. Larkin is recommending that the Company be ordered to prepare a lead lag analysis in the next filing or risk a full disallowance of the formula amount.

Accumulated Deferred Income Taxes

The Company's original filing included an accumulated deferred income tax ("ADIT") offset to rate base of $304,242,096. This deferred balance is net of a deferred tax asset of $31,550,430 for net operating losses ("NOL") that the Company has not been able to utilize. This offset prompted a concern because there is a question as to whether

[1] Prefiled Testimony of Helmuth Schultz III in Docket No. 8190 at page 89.

the offset is appropriate given the fact that even though the Company pays no income taxes to the Internal Revenue Service ("IRS"), ratepayers paid the deferred income taxes to the Company. In the initial filing submitted for review this income tax was $33,203,000. The Company's accounting for this unique issue is critical because in some cases recognition of the NOL may not be appropriate and ratepayers are not properly credited for the advance payment of taxes.

When identified as a potential issue, the Company stated that if the NOL is not recognized GMP would have a normalization violation. The Company also supplied the Department with summaries of 4 Private Letter Rulings ("PLR") that they believe would support the Company's accounting treatment for ratemaking. The concern is that the while the Company places reliance on the Internal Revenue Code ("Code") and the Internal Revenue Regulations ("Regs") that discuss normalization requirements there is no specific discussion on the treatment of an NOL. The only discussion in the Code and Regs is that a determination should be made by the Internal Revenue Service as to how to account for an NOL. Private Letter Rulings are company specific and have to be requested. No such request or determination has been made for GMP. Larkin notes that there is a recent PLR that states based on the facts the NOL offset to deferred income taxes would not be a normalization violation. This is also critical because while it is not precedent, nor are the other PLRs cited by the Company, it shows that the determination is made on a case by case basis. The Company and Larkin had extensive discussions on the issue and various analyses and scenarios were reviewed. The Company did state that they viewed the issue as being an equity issue more than a normalization issue. Based on information supplied Larkin determined that the deferred income taxes on the books of GMP have been accounted for in a manner that would reflect a zero impact on rate base from the NOL asset being netted against the deferred tax liability. This issue has been a major topic of discussion in the regulatory process in many jurisdictions. Based on current tax law bonus depreciation is scheduled to expire which would purportedly eliminate the NOL issue. However, because this tax election has been extended in the past and current legislation exists to extend it, NOLs may continue to be an issue in the future. The accounting by GMP in future filings will be scrutinized for consistency and to provide assurance that ratepayers are not being deprived of the appropriate credit for taxes paid to the Company but not remitted to the IRS.

Another issue identified with the ADIT is the Company calculation of the balance for the test year is based on a 13 month average while the rate year balance is based on year end averages adjusted by a formula that supposedly provides a hybrid 13 month average. Larkin believes that since other rate base components are calculated based on a true 13 month average this balance should also be calculated based on a 13 month average. The Company indicated that information was not available to make a true 13 month average calculation. If not calculated using a 13 month average, Larkin recommends the use of a simple average of the projected beginning and ending balance of the rate year. In the current filing, Larkin recommended and the Company agreed to adjust the rate year balance based on the Larkin recommendation. Based on the information currently available, the net deferred tax credit, as revised, appears reasonable. Larkin will review this treatment further during the Company's next filing to further confirm the appropriateness of the accounting for the NOL.

Contributions In Aid of Construction

The Company's initial request reflected a reduction to rate base of $10.746 million for contributions in aid of construction (CIAC). The CIAC is ratepayer funds advanced to the Company prior to construction specifically for the customer. The Company has been amortizing the balance in CIAC over the expected life of the asset constructed as a credit in other revenue which reduces the cost of service. The Company proposed a change in accounting for the CIAC and suggested a write-off of the $10.746 million over 2 years. This accelerated write-off mitigates the increase that would have been required had the Company continued its current method of accounting.

The Department agreed to the proposed treatment but is concerned that the offer to change the accounting for CIAC was not presented until after the Department had identified the adjustments it was proposing to the Company filing. The Department and Larkin recommend that the Company propose any such changes when the filing is made and not when discussions are taking place regarding the Departments proposed adjustments.

TEST YEAR EXPENSES

Base and Non Base O&M Expense

The use of the platform eliminated much of the review of expenses included in the cost of service. Larkin verified the platform costs to the previous filing and tested the calculated decrease for the (.4%) inflation factor applied. Larkin verified the O&M

expenses to the Company's summary of revenue and expenses by FERC account. The test year O&M costs were reduced by $15.283 million for the Company's requested exogenous adjustment.

Joint Owner Cost

The initial Company filing reflected a total joint owner expense of $9,705,875 reflecting an increase of $944,886 over the test year expense of $8,760,988. The costs are classified as O&M, Property Taxes and Property Insurance. Since insurance is a cost included in base O&M costs, the actual adjustment in the filing is $781,954. Larkin took exception to the increase because historically projected joint owner costs have exceeded actual costs. The Company in the updated filing of July 1 reduced the request to $686,675 due to an owner change in projected costs. The Company agreed to eliminate the request for the additional $686,675.

Non Base O&M Costs – KCW

The test year expense for Non Base O&M Costs – KCW was $678,000. The initial Company filing did not reflect a change in the KCW costs for the rate year. Included in the KCW costs are $587,760 specifically related to the synchronous condenser. The Department and Larkin opined that the costs for the synchronous condenser are separate from KCW costs. Approval of the synchronous condenser and the KCW costs were separate and therefore treatment should be separate. In addition, the KCW costs when initiated did not include costs for the synchronous condenser, instead the cost were the result of systems impact study conducted by ISO-NE. The decision in Docket No. 7770, dated June 15, 2012, specifically mentions Kingdom Community Wind costs with no reference to the synchronous condenser costs. The reason the synchronous condenser is not mention is because that project start date based on the Company work order from the Alternative Regulation filing for the FY 2014 was October 2013. Larkin is of the opinion that the assumption that the synchronous condenser is part and parcel of the KCW costs referred to in Docket No. 7770 would be akin to assuming any other connecting lines after the fact as being KCW costs. Larkin believes the synchronous condenser costs are separate and distinct and should be considered as such.

The Company disagreed, and provided a memorandum supporting its position that O&M costs associated with the synchronous condenser should be considered non-base O&M (KCW) costs, excluded from the platform. The Company and the Department discussed the issue and no specific adjustment was made. As discussed earlier a global adjustment was made to address some of the specific concerns not adjusted, including this one.

Smart Power Cost

The test year expense for Smart Power was $2,333,042. The Company proposed increasing the test year by $420,710 to $2,753,752. The Company provided the supporting detail for the rate year expense in response to Informal Request DPS 1-11. The response provided a summary of the outside costs for various vendors. The sum total for outside vendors was $2,191,401. The Company also provided an Attachment to the response summarizing the vendor and cost and that total was $2,041,401, a $150,000 difference from the written response. The $562,351 difference between the $2,753,752 requested and the $2,141,401 is for internal labor and overheads. The test year vendor cost and internal labor costs were $1,935,996 and $397,046, respectively.

Larkin and the Department reviewed the cost projection and supporting detail and recommended adjustments for various costs. Larkin recommended three adjustments totaling $328,493. The first adjustment was for the $150,000 difference between the written response and the schedule of vendor costs in the attachment to the response. The Company in discussions indicated the written response was the proper number. The second adjustment was a net reduction of $25,100 that Company identified in the response to Informal Request DPS 1-11 as being needed. The final adjustment was $153,393 for the labor related costs. Larkin noted there were no changes in the employees from the test year to the rate year so the test year labor costs were simply escalated by 3% to get a rate year labor cost of $408,957. The Department recommended various other adjustments to the vendor costs. The Department and the Company ultimately agreed to reduce the initial request of $2,753,752 to $2,114,174 a reduction of $639,578.

<u>Other O&M Expense</u>

The review of other operation and maintenance expense included verification of the depreciation expense to the plant addition model and a review of the income tax calculation. Additionally, Larkin reviewed the Equity in Earnings of Affiliates and Other Operating Revenues.

POWER COSTS AND TRANSMISSION COSTS

The DPS Finance and Economics Division along with Larkin examined GMP's forecasted power supply requirements and transmission expense for the base rate period. The projected Category A and Category B expenses as adjusted in the Cost of Service for power supply and transmission costs are reasonable.

As part of the review, Larkin assisted the Department in analyzing costs included in the Power Adjustor. The review performed was in accordance with Finding No. 6 of the Order in Docket Nos. 8389 and 8456, dated March 20, 2015. The Department with the assistance of Larkin reviewed the 2015 First and Second Quarter Power Adjustor costs of GMP (Joint Review). The review consisted of an analysis of the proposed power cost filings as submitted by GMP, multiple rounds of discovery and some discussion with the Company. The information reviewed included account summaries, invoices, responses to informal discovery and cost classifications. The findings of the Joint Review are as explained in detail as to whether costs should be excluded from the Power Adjustor.

Larkin observed that while the parameters of the Power Adjustor have been previously set, that the recovery of power costs for GMP are significantly different from power cost mechanisms elsewhere. The GMP power costs include FERC Accounts 500-556 and 560-574. Power clauses and/or mechanisms typically provide for recovery of costs in Account 501 (Fuel); Account 518 (Nuclear Fuel Expense); Account 547 (Fuel) and Account 555 Purchased Power. In some cases, fuel handling charges may also be included. The various other operational and maintenance accounts, allowed GMP, are not automatically passed through a recovery mechanism in other jurisdictions. This difference in treatment has resulted in other costs being charged to the production O&M costs that would and should be charged elsewhere. This shifting of costs is attributed to interpreting FERC account definitions to allow for miscellaneous costs not specified in the FERC description to be charged to production O&M accounts. The Department is not proposing a change to what accounts are included in the Power Adjustor but is taking issue with some costs charged to Power Adjustor accounts, as opposed to other, more appropriate O&M accounts, and reserves the right to challenge other costs as part of evaluations in future filings.

Account 549 Miscellaneous other power generation expenses.

Legal Fees

The Power Adjustor filing included $20,064 charged to Account 54930 for legal fees to Sheehey Furlong & Behm PC in the first Quarter and $33,185 charged to Account 54930 for legal fees to Sheehey Furlong & Behm PC in the second Quarter. Account 549 is a miscellaneous account and nowhere in the description of costs are attorney fees identified. A review of the FERC account description for the broad range of accounts that are included in the Power Adjustor could not find any reference to attorney fees. Account 923 “Outside Services Employed” references attorney fees. The Company was asked to explain why this charge to Account 549 was appropriate. The explanation was the description for Account 549 allows for charging costs not captured in other accounts. Specifically, the Account 549 description states “This account shall include the cost of labor, materials used and expenses incurred in the operation of other power generating stations which are not specifically provided for or not readily assignable to other generation expense accounts."[2] The Department disagreed with the Company's broad interpretation. The FERC Account 549 description also identifies various costs to be included that include minor costs such as first aid supplies, office supplies, meals, hand held tools, etc. No mention of legal fees and no mention of outside consulting services.

In addition to the misclassification of the legal fees it was noted that two of the invoice amounts included errors. One was a payment of a net past due amount of $405 that could not be traced to any bill and the second error was a payment of $2,003.56 for the March 16 fees of $906.62 plus the previous months balance due of $1,096.94 which was already included separately. Larkin notes that when the platform rates were set, legal fees were included in the platform and no legal fees were included in power costs.[3] By charging legal costs to the Power Adjustor, the Company understates O&M expense in the ESAM. This means to the extent legal fees were charged to the Power Adjustor the Company's shareholders benefited from the overstated savings twofold. First because ratepayers assumed responsibility for those costs as a direct pass through and secondly by flowing through the overstated savings to shareholders. The 2015 First and Second Quarter Power Adjustor costs should be reduced by $53,249 and any reclassification should be limited to $51,747 due to the payment errors. The Company agreed to adjust

[2] Company response to Power Adjustor informal requests Q. 1DPS 2-4.

[3] Company response to informal Base Rate request DPS 2-3.

the power costs in the filing by reclassifying test year legal fees totaling $156,430 from Production Power to the platform.

Monitoring

The First Quarter included an expense of $28,598 for sound monitoring and $28,987 for bird and bat monitoring at KCW. The Second Quarter included an expense of $5,259 for sound monitoring and $12,964 for bird and bat monitoring at KCW. The Company believes the cost are properly charged to Account 54930 because they are for "Miscellaneous Labor" and are not readily assignable to other generation expense.[4] As discussed above outside services should be charged to Account 923 and there is no provision in the description for Account 549 for outside services to be charged to this power generation expenses account. The Company agreed to reclassify the test year expense of $297,548 from Production Power costs to Non Base O&M Costs – KCW.

Community Outreach

The First Quarter and Second Quarter included expenses of $1,500 and $4,500, respectively for a location for landowner meetings and running summer tours for KCW. Larkin is of the opinion the costs are clearly image building and promotional in nature and should be excluded from both the Power Adjustor and base O&M expense. The Department and the Company agreed to reclassify the test year expense of $17,050 from Production Power costs to Non Base O&M Costs – KCW.

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[4] Company response to Power Adjustor informal requests Q. 1DPS 2-17 and 2-18.

<u>Good Neighbor Fund</u>

The Company paid 5 municipalities $188,617 for what is labeled "Good Neighbor Fund" in the Second Quarter. The payments are made based on "Memo Invoices" that are internally generated. During the First Quarter, the Company indicated that no payment was made but that $45,000 was accrued. The Company in past discussions has suggested the costs are operating costs of the facility and are comparable to the landowner lease/royalty payments. That claim presents a different issue because landowner payments are charged to Account 555 (Rent). The Department objects to the classification and description of the "Good Neighbor Fund" payments and recommends the costs be included in the non-platform KCW costs. The Company agreed to reclassify the test year expense of $188,617 from Production Power costs to Non Base O&M Costs – KCW.

<u>Utility Charges</u>

The Company has included First Quarter and Second Quarter charges of $54,255 and $56,659, respectively, from Vermont Electric Cooperative. The charges are labeled KCW Expenses and except for one payment are for usage at Lowell. One billing for $12,731 is for maintenance that is a monthly charge generally charged to the Non-platform KCW costs. The maintenance billing is charged to this account in error and should be reclassified to Non-platform KWC costs. The Company agreed to reclassify the test year expense of $12,731 from Production Power costs to Non Base O&M Costs – KCW.

Cleaning

GMP receives a monthly bill for $950 for "Lowell Office Cleaning." An invoice error was noted. The January invoice includes January's charge plus an overdue balance of $950 for December. December's invoice was also paid and so was included twice. There should be a reduction of $950 for this expense and it should be excluded from the cost of service. The Department and the Company agreed to reclassify the test year expense of $950 from Production Power costs to Non Base O&M Costs – KCW.

Mitigation Surveys

GMP was questioned on the engineering expense in Quarter 1 of $7,450 and the response stated that these surveys were performed on various portions of the mitigation parcels as a requirement of the Wind Farm Easement agreement which had to be completed once the project was completed. The survey identified portions of land that were no longer needed by GMP and could be returned to the landowner. The costs were charged to 549 as Care of Grounds – or a necessary expense related to the grounds of the project. Account 549 lists 'care of grounds as 'Care of grounds, including snow removal, cutting grass, etc.' and not outside consulting of this nature. The total expense for the 1st and 2nd quarters is $10,625 and should be charged to outside services and reflected as Non-platform KCW expenses. The Company agreed to reclassify the test year expense of $18,936 from Production Power costs to Non Base O&M Costs – KCW.

Other

A consulting invoice for $2,483 for "KCW Wind Farm, includes $250 having a description of "review of ANR certified mail letters for notices of violations at KCW and

W. Danville. File search and sent pertaining documents to GMP and VHB." At the very least the $250 of costs pertaining to violations should be more appropriately assigned to an administrative account for outside services. The Company agreed to reclassify the test year expense of $250 from Production Power costs to Non Base O&M Costs – KCW.

Account 554 Maintenance of miscellaneous other power generation plant.

During the First Quarter this account included a charge to Account 55430 for $4,013 that was for "Outreach" and "Performance Monitoring" and the Second Quarter included a charge of $1,351. The charges were questioned and the Company explained the costs were for tours and performance monitoring[5]. The tours explanation for the Outreach is clarified but there is no clear indication what monitoring is performed. The title for Account 554 is "Maintenance of Miscellaneous Other Power Generation Plant (Major only)" and there is no indication the costs are for maintenance, especially plant tours. Plant tours are essentially promotional in nature and are questionable costs for recovery whether in Power Costs or in O&M expense. The costs should not be included in the Company's Power Adjustor and Larkin believes the cost should be charged below the line to the extent they are promotional. The Department and the Company agreed to reclassify the test year expense of $10,728 from Production Power costs to Non Base O&M Costs – KCW.

[5] Company response to Power Adjustor informal requests Q.1 DPS 2-7.

EXOGENOUS COST and ADJUSTMENT

On April 30, 2015, the Company filed its proposed Exogenous Change Adjustment of $15,288,734 for the period October 1, 2014 through March 31, 2015 pursuant to Section III(C) of the Alt Reg Plan[6] and as specified in the Order in Docket Nos. 8190/8191. On May 26, 2015, the Company filed an amended calculation of the proposed Exogenous Change Adjustment for the period October 1, 2014 through March 31, 2015. The revised requested amount was $15,282,683. Based on the Company's request, the December 9, 2014 storm had costs totaling $16,095,743 from which the Company deducted an exogenous factor threshold of $600,000 and $213,060 of joint owner costs collected. The Company summary identified the major cost component for storm restoration to be the $12,739,778, paid for outside services. Those costs were subject to a detailed review as well as a high level review of other costs to evaluate the propriety of costs requested.

The review consisted of two sets of discovery and verification of costs incurred to supporting documentation. Larkin identified five specific cost issues and one overall cost concern. The cost issues are as follows:

- The $600,000 threshold adjustment instead of the $1,200,000 threshold,
- Non-incremental overtime included in the storm costs,
- Payment of bonuses to exempt employees,
- An excessive payroll tax rate,

[6] Alternative Regulation Plan approved in Docket Nos. 8190/8191 decision dated August 25, 2014.

- Undocumented costs and
- The level of costs incurred and the impact on costs due to lack of an aggressive vegetation maintenance program.

Threshold

In order to qualify as an exogenous storm event the costs for the storm must exceed $1,200,000. This requirement is specifically identified in Alt Reg Plan[7] and the Board Order in Docket Nos. 8190/8191.[8] The Company only reduced the storm costs by $600,000 (one-half of the $1,200,000) because the storm costs are for a storm within the six month period from October 1, 2014 through March 31, 2015. Larkin is of the opinion this reduction to the threshold is contrary to the Alt Reg Plan and the Order in Docket Nos. 8190/8191. It is clear from the Alt Reg Plan and the Board's decision that the only way the costs qualify as an exogenous event is because the total storm costs exceed $1,200,000 not the $600,000 recognized by GMP.

The Alt Reg Plan specifically states:

> 2. Exogenous Storm Changes shall consist of increased costs experienced by the company relating to the incremental maintenance expenses incurred for Major Storms (as defined in the Company's Service Quality & Reliability Performance, Monitoring & Reporting Plan (the "SQRP")), and further defined as a storm that causes the Company to incur maintenance expenses in excess of $1,200,000, adjusted annually for inflation ($1.2M x (1+ CPI_U Northeast)), to the extent the aggregate amount in any year exceeds $1,200,000 adjusted annually for inflation ($1.2M x (1 + CPI-U Northeast). In the event that the Company has not exceeded the amount related to storm costs included in Base O&M Costs, Exogenous Storm

[7] Alternative Regulation Plan filed June 4, 2014 Section III(c) (2).

[8] Vermont Public Service Board Order dated August 25, 2014, pages 9 and 22.

Changes shall be reduced by such difference.[9]

There is no specific provision for modification of the $1,200,000 storm requirement even though the Alt Reg Plan specifically references the first Exogenous Change Adjustment period as being from October 1, 2014 through March 31, 2015.

In addition, the Boards Order explains the calculation as follows:

> The mechanics work as follows: *if any single major storm* during the year causes damage expenses in excess of $ 1,200,000, *then the costs in excess of $ 1,200,000 will be deferred* and fully recovered in the next year's rates, provided GMP had exceeded the amount provided for storm costs in its base rates. For example, if GMP experiences five storms in a year, each of which meets the definition of a major storm but each of which only causes GMP to incur maintenance expenses of $ 1,000,000, then GMP would need to cover those expenses with existing rates. However, if GMP experiences a major storm that causes the Company to incur $1,300,000, then the Company could defer and recover later the $100,000 above the ESAF threshold, provided that GMP had exceeded the amount provided for storm costs in its base rates.[10] (Emphasis added)

This explanation makes no provision for the deferral of costs over $600,000. The Order specifically states “any single major storm” and that the costs to be deferred are those in excess of $1,200,000. The Company is correct that the period covered is not a year. However, in Larkin’s opinion, the basis for classification is not a year but the cost level of a storm or storms during the period being observed and there is no specific provision for limiting the storm in this exogenous adjustment to $600,000. It is our opinion and was our recommendation that the costs should be reduced by $1,200,000 instead of the $600,000 reduction reflected by the Company. The Company disagreed

9 Alternative Regulation Plan filed June 4, 2014 Section III(c) (2).

10 Vermont Public Service Board Order dated August 25, 2014 at 22.

with this recommendation. This adjustment was not made, as it was ultimately resolved pursuant to a global agreement.

Non-incremental overtime

The Company storm cost request included $1,689,927 of overtime costs. In reviewing the costs there was a concern as to whether the overtime reflected non-incremental overtime. Larkin has found in reviewing storm costs in other jurisdictions that with the increased storm activity that overtime typically incurred and included in base rates is being shifted to storm work. The result of that shift is the test year cost for overtime is less than the amount allowed in base rates. Absent an accounting for that differential ratepayers will pay for the same labor dollars twice, once for the overtime in base rates and not charged in the test year and then a second time as part of the storm costs. Based on the information supplied by the Company, Larkin determined that the test year overtime was $62,711 lower than the amount allowed in rates for the test year. Larkin recommended that the exogenous adjustment be made reducing the deferred amount by the $62,711 and the associated payroll taxes of $5,644. The Company agreed to make this adjustment.

Storm Bonuses

The exogenous request includes bonus payments of $770,410 to exempt employees for extra time during the storm events. Exempt employees are salaried employees that are not eligible for overtime. This amount was included in a line with the description "Payroll: Other Earnings." There is also a line in the cost summary labeled as

"Bonuses" that totaled $10,333. The Company justification for bonus payments is that the salaried employees worked "more than 5 hours during the storm"[11] and management determined that the employees should be compensated for this added effort. The Company was questioned whether this was a formal policy and in response the Company provided a document labeled "Storm Restoration Bonus-Salaried Employees."[12] The document identifies a level of payment based on a range of hours worked and the document specifically states "Storm Bonuses are at the sole discretion of GMP's management."

Larkin took issue with the $770,410 of storm bonuses included in the "Payroll: Other Earnings" category. Ratepayers are being inconvenienced due to the impact of the significant storm and will pay most if not all the cost associated with the restoration effort. The costs for this storm event are significant and for ratepayers to have to pay bonuses to salaried employees who are expected, as part of a salaried employees job, to work extra hours as needed is not appropriate. First, the bonuses are discretionary so if management believes they are justified then shareholders should share some responsibility for these costs since the damage impacts shareholders and they are benefitted by the restoration effort. A second consideration is whether payment of employees bonuses are appropriate for ratepayers to pay when the level of damage and the cost associated could be attributed in part to the Company's decisions with respect to preventative maintenance. This is a concern discussed in more depth later. Larkin does

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[11] Company response to Informal Request DPS 1-5.

[12] Company response to Informal Request DPS 2-2, Attachment 2-2c.

not dispute that a need exists for employees to step up in storm conditions but the discretionary cost of that effort should not be at ratepayer's expense, and at the very least, should not be at the ratepayer's *sole* expense. Larkin recommended the $770,410 plus the associated payroll taxes of $69,337 be excluded from the deferral and the Company rejected this recommendation. This adjustment was not made, as it was ultimately resolved pursuant to a global agreement.

Payroll Tax Rate

The Company calculated payroll taxes using a 9.00% tax rate. Based on the response to Exogenous Informal Request DPS 2-3 the effective payroll tax rate for the test year was 7.35% and the Company agreed that rate should be used. Larkin recommended an adjustment of $16,854 to remove the excess taxes from the Company's request for deferral. The Company agreed to make the adjustment.

Undocumented Cost

The Company included $11,976 in the request for which no supporting documentation was available. Larkin recommended the $11,976 be removed from the storm cost deferral and the Company agreed with the recommendation.

VEGETATION MANAGEMENT IMPACT

The storm damage and cost from the December 2014 snow storm was significant. In response to Exogenous Informal Request DPS 1-11, the Company indicated that it was estimated that 95% of the storm damage was due to trees brought down by heavy snow. Heavy snow on trees causes damage either by having untrimmed trees along the right of way making contact due to the added weight or from trees outside the right of way because of the added weight and the condition of the trees outside the right of way. In response to Exogenous Informal Request DPS 2-5, the Company indicated that "a large percentage of the trees that impacted these areas during the storm event were from outside the right of way" and then provided pictures showing examples of the damage. The pictures corroborated the explanation. Tree maintenance is critical in mitigating storm damage. The International Society of Arboriculture ("ISA") has numerous manuals on vegetation maintenance and some are specifically related to utilities. For example, a June 1993 edition of "A Handbook of Hazard Tree Evaluation for Utility Arborists" identifies what trees should be considered for site management. Specifically, the handbook states that any tree that could strike a target, such as a pole or line, should be evaluated even if it is off the right-of-way. GMP has not proactively done this and as evidenced by the date of the handbook this is a practice that should have been in existence years ago.

As part of Docket Nos. 8389 and 8456 vegetation management was identified as an issue. The Larkin Report, in Docket No. 8389, identified and discussed 3 issues with the exogenous storm costs.[13] The current filing reflects an improvement in addressing the first concern which was recouping of costs from companies with pole attachments. Larkin was advised of the agreements and while it is an improvement, Larkin informed the Company that that sharing by the telephone companies was lower than he has seen in other jurisdictions. The Company has also addressed the second concern with the capitalization of storm costs by applying a 3 factor to labor costs to reflect the increase in cost associated with storm restoration. The third concern was the Company's vegetation maintenance. In the Larkin Report, it was indicated that with the increase in storm activity companies have taken a new approach in vegetation maintenance to mitigate storm costs. The approach is a shorter trim cycle and an aggressive enhanced maintenance program that focuses on danger and hazard trees. These trees are generally found on the outer edge of the right-of-way or just outside the right-of-way. The report noted that absent a proactive program, the level of storm cost restoration is increased and may not be justified. The recommendation was for GMP to perform or have performed a newer tree growth study that can be relied on for improving the maintenance on the system. As part of MOU in Docket Nos. 8389/8456, the Company agreed to perform a growth study and would determine whether an increased or expanded enhanced vegetation management program would provide a benefit.

During the review process of the current filing the Company provided a discussion on a proposed vegetation plan and in response to Exogenous Informal Request DPS 2-6 the Company provided the agreed upon growth study. The study did indicate

[13] Larkin Report filed on February 17, 2015 at pages 11-17.

that a six year cycle could be maintained. The results provided a growth analysis by species and an annual growth rate at which the current 10 foot clearance would be exceeded by regrowth. There are 4 species which make up the largest frequency/or density (48.7%) on the system. The sugar maple which is considered one of the hardest maples is 17.6% and its 10 foot regrowth is from 6 to 7 years. Next is the eastern white pine at 10.7% with a 10 year regrowth rate of 7 years. That is followed by the ash and red maple that together are 20.4% and have a regrowth rate of 4-5 years. Based on the results, the Company's current trim cycle of 7.8 years is inadequate, and the Company should shorten the trim cycle just for basic reliability purposes. The study did not address hazard and danger trees which as noted are the primary cause of damage during storms.

The Company and the Department did discuss a plan to address the cycle issue and to aggressively address the hazard/danger tree issue that is causing the damage during storms. These discussions remain ongoing, and are noted here to provide context for Larkin's concern. It is Larkin's opinion that the current level of exogenous costs could have been adjusted to account for the Company not proactively addressing the hazard/danger tree issue as other companies have. Failure to address the hazard/danger tree issue will only increase storm damage and costs in the future and that increased cost should not be inappropriately recovered in full from ratepayers. Ultimately, an adjustment was not made on this basis, however, this discussion should put the company on notice that improvements to vegetation management programs are necessary and will be examined in connection with future storm recovery costs proposed for recovery as Exogenous Events.

CONCLUSION

This review showed a significant improvement in the Company's compliance with providing supporting documentation for the projected costs. The Company did try to mitigate the rate impact with the suggested accounting change for CIAC, a global reduction to costs and the increase in merger savings offset. The Company provided timely responses to questions asked and promptly made personnel available to discuss issues identified. However, there still remain some areas of concern that are significant in nature. The Company should improve on the financial analyses that are provided as justification for projects and the Company should consider being less optimistic about the in-service dates especially based on its history of actual dates when compared to projected dates. Exogenous storm events have resulted in significant costs to ratepayers and because the ratepayers are ultimately responsible for this cost the Company should focus on vegetative management practices that will mitigate the costs. Under the current Alt Reg Plan, this year's base rate review process was considered positive and the resulting rates are considered reasonable.

Green Mountain Power

Exhibit HWS-1

Projects include in Filing as of 4/27/2015

	Construction Summary by Category and Project		Start Month Per Filing	Start Month Per Project Analysis	Per Filing In Service Month	Per Filing In Service Year	Addition	Retirement	Spending Through 5-31-15	O&M Impact	Cost Savings	Alternatives Considered	Recommend
1	141542: AMI Gatekeeper LTE Retro	Communications	Oct-14	Jan-15	9	2016	1,224,168		517,374	No	None ID	No	
	143692: RNMS	Communications			4	2016	29,519						
	143700: SCADA Head-End Comm	Communications			10	2015	95,249						Move 3 months
	IT Blanket 2015	Computer Hardware		Sep-15	9	2015	323,742		205,617				
2	140455: CALAMP/AVL	Computer Hardware	Jul-14	Jan-15	9	2015	815,668		775,767	$59k + $66k	Efficiency - No $	$Diff	
3	141671 : 2015 Laptop Refresh	Computer Hardware	Oct-14		7	2015	480,958		358,394	No	No	No	
4	141673: Continuation of Colchester Visualization	Computer Hardware		Oct-15	3	2016	1,213,007			$31k	Efficiency - No $	Yes	
5	141810: 2015 District Repeaters	Computer Hardware	Oct-14		5	2015	107,609		143,131				
6	143200: Core Network Upgrade	Computer Hardware		###########	6	2016	756,979			$12k	No	Yes*	
	143202: Upgrade Wireless Controllers	Computer Hardware			3	2016	45,832						
	143203: Brattleboro Phone/Network	Computer Hardware	Apr-15		4	2016	47,428		920				
	143204: RDSC Phone/Network	Computer Hardware	Mar-15		10	2015	17,825		20,604				
	143205: EMAC Phone/Network	Computer Hardware			1	2016	43,846						
7	143206: Replace Video Conferencing	Computer Hardware		Jun-16	8	2016	281,641			No	Efficiency - No $	Yes*	
8	143207: Replace Security Camera Systems	Computer Hardware		Apr-15	12	2015	555,424		#	No	No	No	Delete
9	143210: Zeacom Web Chat	Computer Hardware		Nov-15	12	2015	21,028		#	No	Efficiency - No $	No	
10	143211: Cell Boosting	Computer Hardware		Oct-15	9	2016	415,578			No	No	No	
	143212: Replace Rutland Internet Routers	Computer Hardware			4	2016	14,220						
	143220: Replace Conference Phones	Computer Hardware			10	2015	22,566		#				Move 3 months
	143223: UPS Unit Replacements	Computer Hardware			12	2015	39,274		#				Move 3 months
11	143224: Solar Back Up for UPS Units	Computer Hardware		Oct-15	9	2016	160,216			No	Efficiency - No $	No	
12	143225: Packet Shaper	Computer Hardware		Nov-15	12	2015	207,203		#	No	Efficiency - No $	No	Move 3 months
13	143242: Hadoop Infrastructure (Redundancy and DR)	Computer Hardware		Jan-16	2	2016	256,424			$960	Efficiency - No $	No	
14	143243: Backup and Recovery (data protector and Tivoli) Solutic	Computer Hardware		Dec-15	2	2016	297,045			No	No	Yes w/Cost Detail	
15	143244: Physical Server Replacements	Computer Hardware		Jan-16	5	2016	39,708			No	No	No	
16	143245: Storage - NetApp	Computer Hardware		Mar-16	3	2016	429,177			No	No	No	
17	143251: FS for Rutland	Computer Hardware	###########	Jul-16	7	2016	206,729		178	$26k	No	No	
18	143252: SRM	Computer Hardware		Feb-16	3	2016	132,859			No	No	No	
19	143253: Security Event Correlation	Computer Hardware		Nov-15	11	2015	188,077		#	No	No	Yes*	
20	143262: Technology Device Refresh	Computer Hardware		Oct-15	9	2016	474,159			No	Efficiency - No $	No	
21	143264: Colchester Multi Media Refresh	Computer Hardware		Jan-16	4	2016	140,889			$1,025	Efficiency - No $	Yes*	
	143265: 4K TV Applications	Computer Hardware			11	2015	38,204		#				Move 3 months
	143266: Kiosk	Computer Hardware			11	2015	20,200		#				Move 3 months
	143267: Electronic Signage	Computer Hardware			1	2016	60,354						
	143268: Control Center Polycom	Computer Hardware			11	2015	70,694		#				Move 3 months
22	143945: Personal Beacon Locators	Computer Hardware	###########	###########	5	2015	120,459		119,650	No	No	-	
	IT Blanket 2016	Computer Hardware			9	2016	329,246						
23	141166: Customer Self Service Web Site	Computer Software	Sep-14	Apr-15	9	2015	217,167		319,630	No	Can't be calculated	Yes/w higher costs	
24	141681: BI for Engineering	Computer Software	Oct-14	Oct-14	9	2015	477,492		200,850	No	Efficiency - No $	No	
25	142859: iFactor mobile app enhancements	Computer Software	Jan-15	###########	9	2015	172,523		121,430	$6,300	Savings Reallocated	Yes*	
	143201: APC Datacenter Management Software	Computer Software			6	2016	15,475						
	143208: Zeacom Upgrade	Computer Software			12	2015	39,441		#				Move 3 months
26	143229: Mobile APP Enhancements	Computer Software		Mar-16	9	2016	226,434			No	Savings Reallocated	Yes*	
27	143230: CSS Enhancements 2016	Computer Software		Apr-16	9	2016	123,506			No	Savings Reallocated	Yes/w higher costs	
28	143232: Notifi Enhancements	Computer Software		Apr-16	9	2016	144,656			No	Savings Reallocated	Yes/w higher costs	
29	143233: NMS RGI 2015	Computer Software		###########	9	2015	125,751		#	No	No	-	Delete
30	143237: GMP API Enhancements/Opportunities	Computer Software	Apr-15	Oct-15	9	2016	371,479		1,382	No	Efficiency - No $	Yes*	
31	143257: BI - 2016	Computer Software		Oct-15	9	2016	616,987			No	Savings Reallocated	Yes*	

	Construction Summary by Category and Project		Start Month Per Filing	Start Month Per Project Analysis	Per Filing	Per Filing			Spending Through 5-31-15	O&M Impact	Cost Savings	Alternatives Considered	Recommend
32	143258: UI Cap Budget & Forecasting	Computer Software		Nov-15	2	2016	332,078			No	Efficiency - No $	Yes*	
33	143259: Light Notice App Solution	Computer Software		Nov-15	4	2016	483,167			$60k	Savings Reallocated	No	
34	143260: GIS Upgrade 2016	Computer Software		Nov-15	11	2015	110,153		#	No	Efficiency - No $	No	
35	143406: NRG Account Summary Emails	Computer Software	Feb-15	Feb-15	9	2015	247,547		104,293	No	Efficiency - No $	No	
36	143548: Vegetation Management	Computer Software		Apr-15	9	2015	559,065		#	$40k	Efficiency - No $	No	Delete
37	143646: Controller	Computer Software	Apr-15	Apr-15	7	2015	97,156		53,060	No	No	Yes	
38	143657: BI Power Supply	Computer Software		Oct-15	9	2016	499,560			No	Efficiency - No $	No	
39	143658: BI Technology Upgrade	Computer Software		Apr-16	9	2016	198,907			No	Efficiency - No $	No	
40	143659: Bromium	Computer Software		Mar-16	3	2016	130,347			No	No	Yes	
	143661: Hunk	Computer Software			1	2016	28,620						
41	143664: 2015 GMP Mobile App	Computer Software	###########	Apr-15	9	2015	259,726		21,859	$6,300	Efficiency - No $	Yes	
42	143665: 2015 GMP API Project	Computer Software		Mar-15	9	2015	229,283		#	No	Efficiency - No $	Yes	Delete
43	143667: Work Management for Substations	Computer Software	Apr-15	Jun-15	4	2016	1,867,248		269	No	No	No	
44	143679: Tripwire	Computer Software		Mar-15	3	2016	69,358			No	No	No	
45	143682: NRG Simply Smart Account Summary	Computer Software		Oct-15	3	2016	340,418			No	Can't be Calculated	No	
46	143691: Crossbow	Computer Software		Jan-16	1	2016	90,831			$5,700	$162 per incident	No	
47	143988: Daily Work	Computer Software		Mar-15	9	2015	146,018		#	No	Efficiency - No $	Yes	Delete
	Distribution Lines	Distribution Lines			1	2016	2,024,733	270,378					
	Distribution Lines	Distribution Lines			2	2016	2,024,733	270,378					
	Distribution Lines	Distribution Lines			3	2016	2,024,733	270,378					
	Distribution Lines	Distribution Lines			4	2016	2,024,733	270,378					
	Distribution Lines	Distribution Lines			5	2016	2,024,733	270,378					
	Distribution Lines	Distribution Lines			6	2016	2,024,733	270,378					
	Distribution Lines	Distribution Lines			7	2016	2,024,733	270,378					
	Distribution Lines	Distribution Lines			8	2016	2,024,733	270,378					
	Distribution Lines	Distribution Lines			9	2016	2,024,733	270,378					
	Distribution Lines	Distribution Lines			4	2015	1,990,888	265,858	2,963,602				
	Distribution Lines	Distribution Lines			5	2015	1,990,888	265,858	2,120,022				
	Distribution Lines	Distribution Lines			6	2015	1,990,888	265,858					
	Distribution Lines	Distribution Lines			7	2015	1,990,888	265,858					
	Distribution Lines	Distribution Lines			8	2015	1,990,888	265,858					
	Distribution Lines	Distribution Lines			9	2015	1,990,888	265,858					
	Distribution Lines	Distribution Lines			10	2015	2,024,733	270,378					
	Distribution Lines	Distribution Lines			11	2015	2,024,733	270,378					
	Distribution Lines	Distribution Lines			12	2015	2,024,733	270,378					
	135213: South Shaftsbury RTU	Distribution Substations	Apr-14		6	2016	71,542	6,953	17,732				
48	138164: Waterbury Substation	Distribution Substations	Mar-14	Oct-14	11	2015	1,953,679	233,766	672,203	No	$483	Yes	
	139030: GILMAN - SUB SECURITY	Distribution Substations	Nov-14		6	2015	34,696		21,892				
	141590: Dorset Street Security	Distribution Substations	Dec-14		6	2015	48,223		41,312				
	141592: Queen City Security	Distribution Substations	Dec-14		6	2015	50,406		31,128				
	141593: Middlebury Lower Security	Distribution Substations	Nov-14		7	2015	40,065		27,104				
49	141596: Vergennes Substation Security	Distribution Substations	Oct-14	Jan-15	6	2015	47,817		49,567	No	No Loss Savings	Yes	
	141605: Bay Street Substation Security	Distribution Substations	Oct-14		5	2015	29,956		35,605				
	141606: Fair Haven Substation Security	Distribution Substations	Nov-14		5	2015	39,416		15,461				
	141607: Hewitt Road Sub Security	Distribution Substations	Oct-14		5	2015	46,337		22,361				
	141609: 141609-Weybridge Security	Distribution Substations	Apr-15		7	2015	42,129		16,926				
50	141614: 2015 White River Jct Rebuild	Distribution Substations	Jan-15	Oct-14	11	2015	2,079,928	185,005	628,964	$1,928	$11,414	Discussed	
	141619: Telecom Test Equipment 2015	Distribution Substations	Nov-14		9	2015	29,810		1,538				
51	141621: Brownsville Fence	Distribution Substations	###########	Oct-14	5	2015	135,173	1,996	59,749	No		No - Had to do	
52	143110: South Rutland RGI	Distribution Substations	Apr-15	Apr-15	8	2015	564,828	61,695	53,504	($1,220)	No Loss Savings	Same Discussion	
53	143112: Gas Turbine RGI breakers relay scada	Distribution Substations	Feb-15	Mar-15	10	2015	276,655	25,349	28,167	($915)	No Loss Savings	Same Discussion	
54	143113: Lalor RGI relay scada	Distribution Substations	Apr-15	Oct-14	9	2015	156,604	23,438	29,301	($178)	No Loss Savings	Same Discussion	
55	143288: Wallingford Transformer Upgrade Substation & Securit	Distribution Substations		Oct-15	5	2016	589,643	31,640		($216)	$1,599	Discussed	
56	143291: Airport Distribution Substation	Distribution Substations	Apr-15	Oct-15	9	2016	1,994,871		1,625	$1,576	$6,655	Discussed	

	Construction Summary by Category and Project		Start Month Per Filing	Start Month Per Project Analysis	Per Filing	Per Filing			Spending Through 5-31-15	O&M Impact	Cost Savings	Alternatives Considered	Recommend
	143295: Substation Security - Montpelier	Distribution Substations			6	2016	35,909						
	143296: Georgia Substation Security Purchase and Install	Distribution Substations			5	2016	43,038						
	143307: Spare 15kV Breaker	Distribution Substations			2	2016	20,533						
57	143308: 15/28MVA 69/46-12.47kV Spare Transformer	Distribution Substations		Oct-15	5	2016	848,282			No	No Loss Savings	No	
58	143309: 15/28MVA 34.5-12.47kV Spare Transformer	Distribution Substations		Oct-15	6	2016	387,437			No	No Loss Savings	No	
	Distribution Substation Minor Adds 2015	Distribution Substations			4	2015	55,380	9,111	#				
	Distribution Substation Minor Adds 2015	Distribution Substations			5	2015	55,380	9,111	#				
	Distribution Substation Minor Adds 2015	Distribution Substations			6	2015	55,380	9,111					
	Distribution Substation Minor Adds 2015	Distribution Substations			7	2015	55,380	9,111					
	Distribution Substation Minor Adds 2015	Distribution Substations			8	2015	55,380	9,111					
	Distribution Substation Minor Adds 2015	Distribution Substations			9	2015	55,380	9,111					
	Distribution Substation Minor Adds 2016	Distribution Substations			1	2016	56,322	9,266					
	Distribution Substation Minor Adds 2016	Distribution Substations			2	2016	56,322	9,266					
	Distribution Substation Minor Adds 2016	Distribution Substations			3	2016	56,322	9,266					
	Distribution Substation Minor Adds 2016	Distribution Substations			4	2016	56,322	9,266					
	Distribution Substation Minor Adds 2016	Distribution Substations			5	2016	56,322	9,266					
	Distribution Substation Minor Adds 2016	Distribution Substations			6	2016	56,322	9,266					
	Distribution Substation Minor Adds 2016	Distribution Substations			7	2016	56,322	9,266					
	Distribution Substation Minor Adds 2016	Distribution Substations			8	2016	56,322	9,266					
	Distribution Substation Minor Adds 2016	Distribution Substations			9	2016	56,322	9,266					
	Distribution Substation Minor Adds 2016	Distribution Substations			10	2015	56,322	9,266					
	Distribution Substation Minor Adds 2016	Distribution Substations			11	2015	56,322	9,266					
	Distribution Substation Minor Adds 2016	Distribution Substations			12	2015	56,322	9,266					
	Communications Equip Amort	General Plant			9	2015		######### ##					
	Communications Equipm Amort	General Plant			9	2016		445,624					
	Computer Equipment Amort	General Plant			9	2016		748,453					
	Computer Equipment Amort	General Plant			9	2015		######### ##					
	Laboratory Equipment Amort	General Plant			9	2016		21,779					
	Laboratory Equipment Amort	General Plant			9	2015		322,359					
	Miscellaneous Equipment Amort	General Plant			9	2015		36,100					
	Office and Equipment General Amort	General Plant			9	2016		121,536					
	Office and Equipment General Amort	General Plant			9	2015		701,673					
	Stores Amort	General Plant			9	2016		108,395					
	Stores Amort	General Plant			9	2015		237,670					
	Tools, Shop and Equipment Amort	General Plant			9	2016		125,214					
	Tools, Shop and Equipment Amort	General Plant			9	2015		210,924					
	120024 : Stony Brook	Joint Ownership	On-going		6	2016	11,639	5,000	563,814				9/30/2016
	120025: Highgate JO 2010	Joint Ownership	On-going		6	2015	1,239,970	250,000	1,548,673				9/30/2015
	120025: Highgate JO 2010	Joint Ownership		Oct-14	6	2016	502,323	100,000					9/30/2016
	120026 : McNeil Capital	Joint Ownership	On-going		6	2015	725,317	100,000	1,063,218				9/30/2015
	120026 : McNeil Capital	Joint Ownership		Oct-14	6	2016	1,093,965	250,000					9/30/2016
	126487: Millstone 3 Construction	Joint Ownership	Nov-12		6	2015	597,018	100,000	2,261,184				9/30/2015
	126487: Millstone 3 Construction	Joint Ownership		Oct-14	6	2016	683,210	100,000					9/30/2016
	126488: Wyman	Joint Ownership	Nov-12		6	2015	67,127	25,000	83,909				9/30/2015
	126488: Wyman	Joint Ownership		Oct-14	6	2016	97,197	25,000					9/30/2016
	Meter Blanket 2015	Meter		Jan-15	9	2015	529,095	11,018	398,783				
	Meter Blanket 2016	Meter			9	2016	538,090	11,205					
59	134298: Heat Pump Rental Pilot	New Initiatives	Aug-13	Apr-15	9	2016	3,845,553		908,606	$15k	-	No	
60	137316: eVGO	New Initiatives	Jan-14	Apr-15	9	2016	1,143,103		296,073	$5k	-	Yes*	
61	143534: eHome	New Initiatives		Apr-15	9	2016	1,676,049		#	$15k	-	No	Delete
62	143535: Heat Pump Water Heaters	New Initiatives	###########	Apr-15	9	2016	1,434,812		14,547	$3k	-	No	
63	143537: eGenerator	New Initiatives		Apr-15	9	2016	236,169		#	$5k	-	Best Pricing	Delete
64	143677: DERMS Circuit 51	New Initiatives		Apr-15	10	2015	1,441,932		#	$100k	No	High Level Research	Delete
65	126631 : Proctor Mech Mod ###	Production	Nov-12	Jan-15	5	2015	9,051,802	######### ##	9,035,116	$277k yr plus	#Benefits in Cost	Discussed	

	Construction Summary by Category and Project		Start Month Per Filing	Start Month Per Project Analysis	Per Filing	Per Filing			Spending Through 5-31-15	O&M Impact	Cost Savings	Alternatives Considered	Recommend
66	126632 : Proctor Elec Mod ###	Production	Nov-12	Jan-15	5	2015	4,599,062		4,240,144	Tax & Ins. of $100k	Benefit Analysis	Discussed	
67	140385: T4 Searsurg Gearbox Rebuild	Production	Jul-14	Apr-15	9	2015	128,429	12,800	60,774	No	-	No	
	141602: Vergennes Plant Yard Security	Production	Oct-14		9	2015	43,894		26,862				
68	141772: Essex Dam Resurface	Production		Mar-15	10	2015	673,082	100,000	#	No	No	No	3/31/2016
69	141777: Gorge GT Upgrades	Production	Mar-15	Jan-15	10	2015	459,096	75,000	659,736	No	No	Discussed	
70	141779: 2015 Middlesex Unit 1 Mechanical Upgrades	Production		Jul-15	10	2015	220,489	25,000	#	No	No	Discussed	
71	141780 : Peacham Pond Level Indication	Production		Mar-15	8	2015	67,715		#	No	No	No	3/31/2016
72	141843: Proctor Intake Modernization & FERC Post License	Production	Nov-14	Mar-15	11	2015	553,808		2,478	No	No	No	
73	142381: KCW Reveg	Production		Apr-15	9	2015	77,943		#	No	No	-	3/31/2016
74	142742: Weybridge Arch	Production	Jan-15	Jan-15	1	2016	166,263		38,027	No	No	No	
75	142744: Vergennes Archeology oblig	Production	Dec-14	Jan-15	1	2016	136,559		20,067	No	No	No	
76	143334: Arnold Falls Fishing Access	Production	Feb-15	###########	9	2015	147,405		16,763	No	No	Discussed	
77	143336: Belden Hydraulic Grapple & Ferc Rec Improvements	Production		Jan-16	9	2016	109,952			No	No	Discussed	
78	143341: Cavendish Unit 1 & 2 Exciter Control Replacement	Production		Dec-15	3	2016	76,196	5,000		No	No	Discussed	
79	143355: Essex Transformer Containment Upgrades	Production		Sep-15	12	2015	214,149	30,000	#	No	No	No	
80	143356: Fairfax Bearing, Runner, Rotor & Exciter Upgrades	Production		Jun-16	9	2016	129,275	10,000		No	No	No	
81	143364: Marshfield SCADA and Switchgear Upgrades	Production		Jun-15	11	2015	772,786	80,000	#	No	No	No	3/31/2016
82	143367: Middlesex Sluice Gate Rebuild	Production	###########	Mar-15	10	2015	414,380	50,000	527	No	No	No	3/31/2016
83	143375: Silver Lake Generator Rewind	Production		Nov-15	6	2016	342,305			No	No	No	
84	143376: Silver Lake Trashracks and Spillway Upgrades	Production	Apr-15	Mar-16	9	2016	648,650	65,000	1,091	No	No	No	
85	143388: Berlin GT Manifold Upgrades	Production	###########	Apr-15	7	2015	255,595	30,000	6,587	No	No	Discussed	3/31/2016
86	143389: Berlin PLC & HMI Upgrades	Production		Apr-16	9	2016	554,462	50,000		No	No	Yes*	
	143621: Belden Archaeology	Production			1	2016	43,323						
87	143793: Marshfield Roof Upgrades	Production		Jun-15	8	2015	172,566	20,000	#	No	No	No	3/31/2015
	143795: KCW Reveg 2016	Production	Apr-15		9	2016	62,270		221				
88	144147 Stafford Additional Battery Storage and Conduit	Production	Apr-15	Apr-15	8	2015	847,115		8,837	No	No	No	
	Hydro Blanket 2015	Production		Sep-15	9	2015	491,807	33,197	454,943				
	Hydro Blanket 2016	Production		Sep-16	9	2016	500,167	33,761			No	No	
89	138967: New Brattleboro S.C.	Property and Structures	###########	Jan-15	12	2015	2,401,658	######### ##	377,422	$18,335	No	Discussed	
90	141447: 2015 Facility Blanket	Property and Structures	Oct-14	Jan-15	9	2015	183,039		75,612	5yr avg	No	No	
	141632 : Col. boiler replacement	Property and Structures			6	2015	11,003	2,136	#				
91	141633: Colchester switchgear replacement	Property and Structures		Aug-15	9	2015	186,481		#	$500	No	Discussed	
92	141635 : Middlebury office Remodel	Property and Structures	Mar-15	Mar-15	6	2015	443,056	35,000	246,336	No	$5,000	No	9/30/2015
93	141637: Westminster conf. room	Property and Structures		Jun-15	9	2015	38,070		#	No	No	No	
94	141639: Purchase Dover Land	Property and Structures		Jan-15	8	2015	113,990		#	No	No	No	Delete
95	143162: 2016 Capital Blanket	Property and Structures		Oct-15	9	2016	186,151			5yr avg	No	No	
	143179: Replace Fire Alarm System	Property and Structures			12	2015	5,940	1,000	#				
	143313: HVAC data closets	Property and Structures			12	2015	13,838		#				
	143314: Security System Upgrades	Property and Structures			5	2016	23,979	2,000					
	143467: Poultney Lighting upgrade 16	Property and Structures			3	2016	6,271	3,000					
96	143539: Purchase Land for Burl Sub	Property and Structures	###########	Jan-15	9	2015	115,310		253	No	No	No	Delete
97	143540: Purchase Land Hinesburg	Property and Structures		Oct-15	7	2016	113,844			No	No	No	Delete
98	143541: Purchase Land in Websterville	Property and Structures		Oct-15	7	2016	113,825			No	No	No	Delete
99	143543: Purchase Land in Windsor	Property and Structures		Oct-15	7	2016	113,863			No	No	No	Delete
100	143544: Purchase Land in Bennington	Property and Structures		Oct-15	7	2016	113,823			No	No	No	Delete
101	143545: Purchase Land in Barre	Property and Structures		Oct-15	9	2016	115,063			No	No	No	Delete
102	143551: New OH Door's at WRJ	Property and Structures		Oct-15	7	2016	46,144			No	No	No	
	143552: Canopy Addition WRJ	Property and Structures			9	2016	15,171						
103	143553: DDC Upgrade	Property and Structures		Oct-15	9	2016	57,240	8,000		No	$120/trip	No	
	143555: EMF-Oil Filled Equipment Containment Area	Property and Structures			9	2016	29,549	5,000					
	143556: Springfield DDC System Additions	Property and Structures			9	2016	23,166	1,000					
	143557: Sunderland DDC Additions	Property and Structures			9	2016	21,708	1,000					
	143560: Operations Headquarters-Covered Vehicle Storage	Property and Structures			9	2016	51,072						
	143575: Montpelier/Colchester Fuel Island	Property and Structures			2	2016	143,664	15,000					

	Construction Summary by Category and Project		Start Month Per Filing	Start Month Per Project Analysis	Per Filing	Per Filing			Spending Through 5-31-15	O&M Impact	Cost Savings	Alternatives Considered	Recommend
104	143576: Colchester Data Center	Property and Structures		Oct-15	9	2016	1,812,912	50,000		$1,000	No	No	
105	143577: White River District Pavement install	Property and Structures		Oct-15	2	2016	408,615			No	$5,000 yr	No	
106	143649 Middlebury Generator	Property and Structures		Oct-15	10	2015	138,573	30,000		No	No	No	
	Regulators and Capacitor	Regulators and Capacitor			9	2016	848,319	13,470					
	Regulators and Capacitor	Regulators and Capacitor			9	2015	834,139	13,245	#				
	Transformers	Transformers			9	2016	3,392,582	53,868					
	Transformers	Transformers			9	2015	3,335,873	52,968	3,391,526				
	135212 : So Shaftsbury SCADA MOABs	Transmission Lines	Apr-14		6	2016	22,065	7,610	8,409				
107	138957: 2016 Marble Street to Danby Reconstruction	Transmission Lines		Oct-15	9	2016	1,569,335	187,231		No	No Loss Savings	Discussed	
108	141651: TL Line 36 Reconstruction 2015	Transmission Lines	Oct-14		9	2015	841,762	97,271	435,260	No	No Loss Savings	Discussed	
109	141653 : Milton to Wyeth Reconductor	Transmission Lines	Nov-14	Feb-15	5	2015	1,158,234	115,000	198,815	No	No Loss Savings	Discussed	3/31/2016
110	141654 : White River Tap 46kV Transmission Line	Transmission Lines	Nov-14	Feb-15	9	2015	1,386,985		134,808	$2,224	No Loss Savings	Discussed	3/31/2016
111	141655 : 3309 Line Reconstruction for 16Y3	Transmission Lines	Nov-14	Feb-15	4	2015	533,466	53,000	420,689	No	No Loss Savings	Discussed	6/30/2015
112	141656: 2015 Loadbreaks and Motor Operators	Transmission Lines		###########	9	2015	94,540		#	No	No Loss Savings	No	Delete
113	141657 : Purchase 46kV Transmission Line from VELCO	Transmission Lines		Sep-15	9	2015	2,203,272		#	$4,538	No Loss Savings	Discussed	
114	143180: Smead Rd to Quarry Rd 46kV Partial Reconductor	Transmission Lines		Jun-16	6	2016	100,350	10,000		No	$5k over 20yrs.	Discussed	
115	143181: Smead Rd to Silver Lake 46kV Reconductor	Transmission Lines		Jun-16	8	2016	493,582	48,000		No	$45k over 20yrs.	Discussed	
116	143182: Claremont to Charlestown Partial Reconductor	Transmission Lines		###########	5	2016	252,765	11,000		No	$17k over 20yrs.	No	
117	143183: East Jamaica Tap 236 and 827 Motor Operators	Transmission Lines		Aug-16	8	2016	192,769	20,000		$502	No Loss Savings	Discussed	
118	143184: Sherburne Tap Loadbreaks and Motor Operators	Transmission Lines		Jun-16	6	2016	272,945	7,000		$502	No Loss Savings	Discussed	
	143506: Husky Tap RTU	Transmission Lines			4	2016	40,338	7,610					
	143507: North Elm Tap RTU	Transmission Lines			4	2016	47,821	7,610					
119	143570: Fiber to Marshfield Dam	Transmission Lines		Oct-14	7	2016	94,179			No	-	Yes*	
120	143694 : Ascutney to Claremont Partial Reconductor	Transmission Lines		Jun-16	9	2016	1,071,126	100,000		No	-	No	
121	132935: Ballard Road Substation	Transmission Substations	Jul-13	Jan-15	5	2015	1,253,179		1,368,737	$1,992	$22,294	Discussed	
	138411: HSCAT 3303 87L	Transmission Substations	Jun-14		5	2015	34,727		23,289				9/30/2015
	138413: HSCAT 3326 87L	Transmission Substations	Jul-14		2	2016	35,598		12,305				
	138415: HSCAT 3325 PUTT	Transmission Substations	Apr-14		2	2016	25,981		12,633				
	138416: HSCAT 3321 PUTT	Transmission Substations	Apr-14		4	2015	76,722		97,534				
	138418: HSCAT 3309 PUTT	Transmission Substations	Apr-14		7	2015	53,495		32,207				
	138419: HSCAT 3312 87L	Transmission Substations	Apr-14		7	2015	34,794		8,200				
	138420: HSCAT 3302 87L	Transmission Substations	Apr-14		9	2015	27,613		8,339				
	138422: HSCAT 3313 PUTT	Transmission Substations	Jul-14		3	2016	48,624		11,673				
	138423: HSCAT 3304 Putt	Transmission Substations	Feb-15		3	2016	70,710		5,025				
	138424: HSCAT 3306 Putt	Transmission Substations	Feb-15		3	2016	71,869		6,707				
	139035: JOHNSON - SUB SECURITY	Transmission Substations	Aug-14		6	2015	35,338		19,293				
	139962: Sand Rd 3302 Relocation	Transmission Substations	Jul-14		6	2015	144,165		126,738				9/30/2015
	141608: Smead Road Sub Security	Transmission Substations	Oct-14		5	2015	40,966		17,003				9/30/2015
122	141613: Gorge 16Y3 Breaker Reactors	Transmission Substations	###########	Jun-15	11	2015	336,536		73,083	$413	No Loss Savings	Discussed	
	143297: Transmission Breaker Change Out Essex 3314	Transmission Substations			1	2016	98,619	50,874					
123	143299: Transmission Breaker Change Out Digital 3330 & 3332	Transmission Substations		Oct-15	4	2016	176,507	29,086		($432)	No Loss Savings	Discussed	
124	143301: Transmission Breaker Change Out Cavendish B-17	Transmission Substations		Oct-15	4	2016	116,289	43,212		($216)	No Loss Savings	Discussed	
125	143303: Fence Job - Ascutney	Transmission Substations	Apr-15	Oct-15	11	2015	110,022	3,877	820	No	No Loss Savings	Fence not current	
126	143305 : Middlesex Substation #2 Security	Transmission Substations		Jan-15	5	2016	37,068			No	No Loss Savings	Motion Detectors	
127	143311: VELCO Irasburg H14	Transmission Substations		Oct-15	10	2015	38,182	9,694	#	($89)	No Loss Savings	No	
128	143312: VELCO Fairfax Capacitor Bank	Transmission Substations		Oct-15	10	2015	932,509		#	$89	No Loss Savings	Discussed	
	143498 : ADAS Montpelier	Transmission Substations			1	2016	9,501						
	143502: ADAS Little River	Transmission Substations			2	2016	10,323						
	143503: ADAS Vergennes	Transmission Substations			3	2016	9,502						
129	143584: Line VT Replacements	Transmission Substations		Oct-15	2	2016	285,521	6,084		No	No Loss Savings	No	
	Transmission Substation Minor Adds 2015	Transmission Substations			4	2015	103,738	9,882	#				
	Transmission Substation Minor Adds 2015	Transmission Substations			5	2015	103,738	9,882	#				
	Transmission Substation Minor Adds 2015	Transmission Substations			6	2015	103,738	9,882					
	Transmission Substation Minor Adds 2015	Transmission Substations			7	2015	103,738	9,882					

	Construction Summary by Category and Project		Start Month Per Filing	Start Month Per Project Analysis	Per Filing	Per Filing			Spending Through 5-31-15	O&M Impact	Cost Savings	Alternatives Considered	Recommend
	Transmission Substation Minor Adds 2015	Transmission Substations			8	2015	103,738	9,882					
	Transmission Substation Minor Adds 2015	Transmission Substations			9	2015	103,738	9,882					
	Transmission Substation Minor Adds 2015	Transmission Substations			10	2015	105,502	10,050					
	Transmission Substation Minor Adds 2015	Transmission Substations			1	2016	105,502	10,050					
	Transmission Substation Minor Adds 2015	Transmission Substations			2	2016	105,502	10,050					
	Transmission Substation Minor Adds 2015	Transmission Substations			3	2016	105,502	10,050					
	Transmission Substation Minor Adds 2015	Transmission Substations			4	2016	105,502	10,050					
	Transmission Substation Minor Adds 2015	Transmission Substations			5	2016	105,502	10,050					
	Transmission Substation Minor Adds 2015	Transmission Substations			6	2016	105,502	10,050					
	Transmission Substation Minor Adds 2015	Transmission Substations			7	2016	105,502	10,050					
	Transmission Substation Minor Adds 2015	Transmission Substations			8	2016	105,502	10,050					
	Transmission Substation Minor Adds 2015	Transmission Substations			9	2016	105,502	10,050					
	Transmission Substation Minor Adds 2015	Transmission Substations			11	2015	105,502	10,050					
	Transmission Substation Minor Adds 2015	Transmission Substations			12	2015	105,502	10,050					
130	141919: 2015 Fleet	Transportation		Oct-14	9	2015	2,872,109	######### ##	#	$98k	No	No Alternatives	3/31/2016
131	143561: 2016 Pur Buckets and Diggers	Transportation	Mar-15	Oct-15	6	2016	2,858,694	######### ##	75	$69k	No	No Alternatives	
132	143562: 2016 Pur Trailers	Transportation		Jan-15	10	2015	124,768		#	$814	No	No Alternatives	3/31/2016
133	143563: 2016 Pur Small Trucks	Transportation		Oct-15	3	2016	1,282,841	323,802		$52k	No	No Alternatives	
134	143565: Fleet Fuel System	Transportation		Jan-16	3	2016	220,261	161,020		$4k	No	No Alternatives	
							141,778,905	21,950,586	38,625,941				
	No cost or cost savings or alternatives considered									87	111	71	
	Not addressed										8	3	
		Not started as noted or no start date.					**# - No 2015 costs**		Percentages	64.93%	88.81%	55.22%	

* No explanation why alternative was not selected.

Cost benefit analysis provided is in PDF so it is impossible to review computation and assumptions.

Exhibit 8 – 2016 Larkin Report

LARKIN & ASSOCIATES, PLLC

REPORT ON ANALYSIS OF RATE YEAR ENDING SEPTEMBER 30, 2017

GREEN MOUNTAIN POWER CORPORATION

COST OF SERVICE REQUEST AND COST OF CAPITAL REQUEST UNDER ALTERNATIVE REGULATION

August 15, 2016

GREEN MOUNTAIN POWER CORPORATION

ALTERNATIVE REGULATION PLAN REPORT

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GREEN MOUNTAIN POWER CORPORATION

ALTERNATIVE REGULATION PLAN REPORT

EXECUTIVE SUMMARY

The Company's rate base and cost of service included in the proposed filing were reviewed by Larkin & Associates, PLLC (Larkin). The analysis performed took into consideration the Vermont ratemaking principles, precedents and previous Board Orders. The analysis evaluated the development and the reasonableness of the cost of service, including rate base, capital structure and cost of capital for the rate year ending September 30, 2017. The Company was consulted and had indicated agreement with some proposed adjustments or variations of those adjustments. The proposed adjustments determined by Larkin, whether made or not, are discussed within the report. As part of the process the Department and the Company had a number of discussions to resolve differences with the proposed adjustments. While not all of Larkin's recommended adjustments were adopted by the Company, the Department and Larkin believe that the filing under the alternative regulation process is sufficient for establishing just and reasonable rates to be effective October 1, 2016. Larkin has reviewed the proposed revised filing and has determined that the majority of changes agreed upon by the Department and the Company have been made and properly flowed through. Some differences exist and are discussed in the respective sections of the report.

Included in the report is the Department's conclusion that the projected Category A and Category B expenses as presented in the cost of service for power supply and transmission costs are reasonable.

The Company's initial draft of the filing reflected a base rate revenue deficiency of $14.217 million requiring a 2.57% increase in revenues and a Power Supply Adjustor revenue increase of $5.342 million (.96%). This resulted in a total proposed revenue increase of $19.559 million (3.53%). After discussion regarding the detailed review of the projected capital additions and other cost contributors the Department and the Company were able to agree to various adjustments resulting in the August 1, 2016 filing reflecting a base revenue sufficiency of $142,000 (-.03%) and a Power Supply Adjustor revenue increase of $5.342 million (.96%), for a total increase of $5.2 million (.93%).

GREEN MOUNTAIN POWER CORPORATION

ALTERNATIVE REGULATION PLAN REPORT

HISTORY OF PLAN

Successor Plan

On December 20, 2013 Green Mountain Power Corporation ("GMP") filed a petition seeking Board approval of a successor Alternative Regulation Plan and the Board opened Docket 8191 for the Plan Docket. After several rounds of discovery, testimony, meetings, and a workshop, agreements were reached between the Vermont Department of Public Service ("DPS" or "the Department"), International Business Machines (“IBM”), AARP, Associated Industries of Vermont (“AIV”) and GMP. The Memorandum of Understandings ("MOU") dated May 30, 2014 and as amended on June 4, 2014 presents the agreements between the Petitioners and the Parties including revisions to the provisions related to shared savings between GMP and ratepayers as part of the Earnings Sharing Adjustor Band, a definition of Major Storm, an agreement to flow through to ratepayers any Vermont Yankee Revenue Sharing Funds to which GMP is entitled to through September 30, 2017, a reduction of $573,045 to incentive compensation included in Base O&M, continuation of the Alternative Regulation Plan ("Alt Reg") referred to as the Successor Plan (“Plan”), and a Transmission Rate Freeze.

The Successor Plan allows GMP to adjust its rates annually based on four rate adjustment mechanisms. The mechanisms include a Base Rate Adjustment mechanism, Earnings Sharing Adjustor, Exogenous Change Adjustment and a Power Adjustor. Larkin would note that under Alt Reg the Company is operating under a different ratemaking theory than what historically has been referred to as traditional ratemaking. Under traditional ratemaking the Company is afforded an opportunity to earn a reasonable rate of return. Under Alt Reg, which includes four separate rate mechanisms, the Company is essentially guaranteed a return with minimal risk. This difference in regulation is discussed in more detail later as it is an important factor considered as part of the review process.

Vermont Public Service Board Order in Docket No. 7770

On June 15, 2012, the Vermont Public Service Board's Order in Docket No. 7770 included the approval of the Memorandum of Understanding dated March 26, 2012. This Order approved the acquisition of CVPS by a subsidiary of Gaz Métro in addition to the merger of CVPS and GMP. GMP is the surviving corporation after the merger; therefore, the Combined Company will be referred to as GMP in this report.

The Order provides that GMP will guarantee at least $144 million in savings to retail customers as a result of the merger during the ten years beginning October 1, 2012. If savings are less than that amount, GMP will credit the difference to customers under a plan that will be subject to the Board's approval. The Order provides that GMP will provide credits to GMP's base rate cost of service in the aggregate amounts of $2.5 million, $5.0 million and $8.0 million in years 1, 2 and 3, respectively. That represents the Fiscal Years Ended (“FY”) September 30, 2013; September 30, 2014 and September 30, 2015. Beginning with the FY September 30, 2016, the years 4,5,6,7 and 8, GMP's base-rate cost of service will be credited $10.5 million, $12.0 million, $13.0 million, $14.0 million and $14.5 million, respectively. To the extent that these amounts are different from 50% of actual savings in each year a billing adjustment will be made in conjunction with the next ESAM filing.

In the first eight years subsequent to the merger GMP and its ratepayers will share O&M cost savings that result from the merger. During the first three years, GMP will credit its base-rate cost of service with the amount of annual guaranteed savings due to its customers for that year before it receives any applicable O&M cost savings resulting from the merger for that year. The benefits of applicable merger-related cost savings in years 4 through 8 will be split evenly between GMP and its customers. GMP's customers will receive all of the O&M merger-related cost savings after the 8th year. For a minimum of ten years following the merger, GMP will also be required to file an annual report of savings that result from the merger.

GMP will be required to exclude any costs or savings related to the deployment of Smart Grid and Advanced Meter Infrastructure (AMI), the Kingdom Community Wind

Project, CVPS's acquisition of the assets of Vermont Marble Power Division of Omya, Inc., and any CVPS staff reductions associated with the Docket 7496 MOU from base O&M costs. In each future base-rate adjustment in which merger savings are shared, the Order states that base O&M costs are subject to change "to reflect the change in the Consumer Price Index for All Urban Consumers (CPI-U) Northeast Region, any Exogenous Costs and the impact of the Non-Power Cost Cap as defined in GMP's Alt Reg Plan, and any further changes agreed upon by GMP and the Department and approved by the Board." And as noted above, GMP and the Department agreed to such a change with respect to the appropriate level of incentive compensation costs.

THE PROPOSED FILING

The Company has based its cost of service (Company Schedule 2.3/2) filing on the twelve months ended March 31, 2016. The cost of service was adjusted to reflect the platform costs consistent with those approved in the Docket No. 8190. The filing adjusts the test year to the FY2016 platform costs using a .6% CPI for New England, changes to power costs, transmission costs and other non-base O&M costs. The Company has based its rate base filing (Company Attachment B, Schedule 2) on the average twelve months ended March 31, 2016, adjusted for projected plant additions and projected changes to other rate base categories for the rate period ending September 30, 2017. This filing incorporated two additional factors for consideration. The first factor is the new Plan provides for the recognition of any impact from the prior year’s ESAM to be recognized as part of the cost of service for rates effective October 1, 2016. The second factor is the carryover of the issues with vegetation management costs and storm costs.

Initially, GMP provided a flash drive with what was identified as supporting information for the capital projects to be included in the filing and subsequently a complete filing was provided that included the lead schedule and all of the supporting schedules for the filing. In past reviews Larkin has noted that supporting documentation to meet the known and measurable standard was insufficient in many cases. To resolve this issue, the Company and Department agreed as a condition of the MOU in Docket Nos. 8190/8191 that the Successor Plan would include Attachment 7, which set forth the documentation standards for proposed plant additions and the ramifications of not satisfying them. Attachment 7 was included as part of the Successor Alternative Regulation Plan filed on June 4, 2014. With Attachment 7 the Company has specific direction as to what is required to be included in the filing as supporting documentation. This documentation should be available at the time the proposed filing is submitted for review and not have to be requested during the review or developed and/or obtained subsequent to preparation. This is true whether it is for plant additions or cost of service items. This filing, as more recent filings, showed an improvement in providing cost documentation for the projected plant additions, however, there were still issues identified, most notably, financial analysis. While reviewing the projects it was noted that, in general, the financial analysis provided would simply state there would be some cost savings or there would not be cost savings or there was an explanation provided that was designed to provide justification for the project. There was no indication what was done or how the conclusion was reached. A financial analysis does not simply make a statement without some form of supporting detail and/or explanation. The Company did immediately offer to provide revised financial analysis and updated files were provided on June 1, 2016.

Recommendations

1. Company personnel should be required to familiarize themselves with the known and measurable requirements as memorialized in Attachment 7. Emphasis should be placed on understanding what the requirements are for the preparation of a financial analysis.
2. Larkin suggests that the Company in developing its initial hard copy provided to the Department for review include a reference on the respective Schedules and/or workpapers that references the electronic file where the detail can be located.

This will aid the review process and should provide a measure of consistency from filing to filing.

REVIEW

The review analyzes the rate base and cost of service as presented by the Company. Due to the merger, the primary cost driver in any filing will be changes to rate base. The cost of service review will include analysis of O&M and other expenses in the test year on a very limited basis. The majority of costs, other than power costs, depreciation and taxes are within the platform and any changes to those costs would not impact rates. Those changes would impact the amount of cost savings that occurred in the test year. The Department and Larkin did perform a detailed review of power costs, depreciation and taxes.

The rate base review included an analysis of historical plant additions since the last review, a comparative analysis of budget to actual of projected additions included in the last filing, an analysis of selected test year costs, a comparison of selected historical costs to the test year, analysis of adjustments to the test year, identification of concerns regarding costs reflected in the filing, and an assessment of the reasonableness of the Company's rate request for the year ended September 30, 2017. For projected additions to plant, a selection of 155 specific projects was made for a more specific review and/or verification of projected/actual costs on a test basis. Blanket and joint owner project projections were also reviewed for reasonableness. After reviewing the information supplied, discussions took place with Company personnel regarding concerns with some costs and/or cost estimates. The Company either resolved some of the concerns with an explanation and/or additional detail, or the Company made some adjustment to the proposed filing to eliminate and/or reduce the concern. Issues were generally resolved.

Specifics of Review

The review undertaken for this filing consisted of essentially an evaluation of nine different cost contributors. To be reviewed was the Capital budget of GMP, other rate base amounts, capital structure, the select non base O&M costs for GMP, the Exogenous costs included in the rate year, the accounting for vegetation maintenance costs, the Power costs for the rate year ended September 30, 2016, test year costs and the calculated increase to the Base O&M Platform. Multiple discussions also took place regarding the filing, vegetation management, Power costs, Exogenous costs, and various other issues as they were identified during the review process.

Review Process

The intent of the review process under the Plan is for the Department's consultant to analyze the proposed projects for the rate year covered by the proposed rate filing and to identify any major concerns prior to the Company completing the initial draft of GMP's proposed rate filing. The next step is the review of the initial draft of GMP's proposed rate filing, evaluate the reasonableness of support, evaluate the propriety of costs classifications and suggest revisions to the filing prior to the finalizing of the proposed change in rates that will be submitted to the Board. The review process allows for an analysis of historical information included in the test year and the Company's proposed adjustments made to develop a rate year cost of service.

During the review, the Company and the reviewer(s) are to attempt to resolve any potential issues, prior to the Company's filing for a proposed change in rates. Throughout the review process the Company has allowed the Department and the Department's consultant virtually unrestricted access to Company personnel ultimately responsible for various cost components in the filing. Also there are periodic conference calls to discuss the current status of the review or any specific issues identified. Requests for information were responded to by the Company in a timely manner. We encourage the Company to continue this practice as it enhances the Alternative Regulation process.

Time Period of Review

This report concerns the Company's annual filing for a change in base rates effective October 1, 2016 for the year ended September 30, 2017. The review of costs impacting the rate year ending September 30, 2017 essentially began with the Company's filing of the ESAM in November 2015 and continued through July 2016. The timeline of the review was as follows:

- The Company's filing of the ESAM on November 20, 2015.
- Discussion between the Company, the Department and Larkin and discovery requests to the Company from approximately November 2015 through May 2016 regarding the vegetation concerns identified in the Larkin reports.
- The Company's filing of the 4th Quarter Power costs on October 30, 2015.
- The Company's filing of the 1st Quarter Power costs on January 28, 2016.
- The Company's filing of the 2nd Quarter Power costs on April 29, 2016.
- Larkin's receipt of project listing for proposed capital projects to be added to plant and included in the proposed base filing on May 3, 2016 and Larkin's selection of projects for review was sent on May 4, 2016.
- Larkin is provided a flash drive with selected project folders and performs an on-site review at GMP South from May 24th through 26th of 2016.
- On June 1, 2016 GMP provided Larkin with its initial proposed filing for the cost of service.
- On July 12, 2016 the Company provided the Department with proposed changes to the June 1, 2016 filing.
- Discussions were on going through the weeks of July 18th and 25th.
- On August 1, 2016 the Company filed its official 2017 base rate filing.

Projected Capital Additions

GMP provided the projected capital additions budgets for the respective departments on May 3, 2016. The projected capital additions selected for review were sent to the Company on May 4, 2016. The Company's original project listing included a request for $188,223,339, an increase of 32.8% or $46,444,434 more than the September 30, 2016 request of $141,778,905 of project additions. The September 30, 2017 projected plant retirements was $15,970,256 compared to the $21,950,586 of projected plant retirements for the Fiscal Year Ended September 30, 2016. The differences between the respective filings is significant and was factored in Larkin's assessment in this review due to the issues identified in the September 30, 2015 ESAM report, attached as Exhibit HWS-1, where the actual to projected variances are identified as a major concern by Larkin. The $188,223,339 of additions included $51,970,931 for traditional blanket work orders and $3,399,002 for joint owner capital additions. There were a total of 228 specific projects totaling $132,853,406 compared to 206 specific projects at a cost of $86,499,359 in the September 30, 2016 filing. Larkin selected 155 of the 228 projects (68%) for review for a total of $127,130,599 of costs or 95.7% of the project specific costs. The support for the $51,970,931 of blanket work orders and $3,399,002 of joint owner capital additions was also reviewed for reasonableness based on historical cost trends and the use of the five-year average cost standard. That equates to $182,500,532 of the $188,223,339 (97.0%) of the requested project costs being evaluated for reasonableness. GMP provided Larkin with a flash drive of the project folders and copies of other supporting documentation for the projected capital additions during the on-site review. The project request provided for review by Larkin identified capital additions to plant for the interim period April 1, 2016 through September 30, 2016 and for the twelve months ended September 30, 2017.

The budget consisted of twenty-one classifications. The classifications are communications, computer hardware, computer software, distribution lines, distribution substations, general plant, hydro - new hydro dams, joint ownership, Kingdom Community Wind, meters, production, property and structures, regulators and capacitors, solar, transformers, transmission lines, transmission substations, transportation, Vermont Marble hydro, Vermont Marble transmission lines and wind generation. It should be noted that the Solar designation is misleading since project costs included costs for heat pump and TESLA programs. During the on-site review supporting documentation for the selected projects was reviewed and discussions with Company personnel took place to clarify questions that arose and to discuss the process. The reviewed documents consisted of work order forms, various cost summaries that tie into respective lines on the work order forms, supporting documents for the costs included on the respective cost summaries and documents identified as a "Financial Analysis". Support for internal labor costs was based on a labor rate summary for the year. Costs for materials and supplies were based on a materials and supplies inventory summary. Direct materials costs were based on a cost manual that included quotes, estimates and/or actual invoices. The direct materials in the cost summaries were coded so the cost could be readily traced to the cost manual. Contract labor and fixed contracts were based on various types of documents including quotes and/or estimates, external email quotes or invoices from the project or prior projects similar in nature. The joint ownership requested was based on the joint owner budgets. Direct materials purchases and contract labor were based on various types of documents including quotes and/or estimates, external email quotes or invoices from the project or prior projects similar in nature.

The Financial Analysis were reviewed on-site and in detail, for project justification, whether alternatives were considered and for financial analysis as required by Attachment 7 for projects between $300,000 and $3,000,000. The vast majority of the projects generated a concern. Larkin deemed the financial analysis on the documents provided was insufficient. This finding was relayed to the Company. The Company informed Larkin that a complete revision of the selected project Financial Analysis would be subsequently provided. Larkin noted that and indicated that the updating would not be given the weight that would be given to Financial Analysis supplied with the filing as required by Attachment 7 and based on Board precedent. The purpose of the Financial Analysis is to determine whether there is a benefit associated with the project that justifies the undertaking of the project. This is a tool in making a decision on the appropriateness of the project and is not something to be done after the decision has been made to proceed with the project or to appease the Departments consultant. Under strict application of Attachment 7 to the Successor Plan a large number of the projects could have been excluded from the request. Despite the Company's failure to comply, Larkin focused more on the supporting cost detail and the justification provided with the work orders. Larkin notes that because this is the second testing under Attachment 7 where the Company failed to provide proper Financial Analysis. That said, consideration was given as to the Company's improvement in providing underlying supporting cost documentation but with caution that the supporting documentation and work order information are only part of the Attachment 7 requirements and future failures will require stricter application with the filing requirements in future reviews.

Exhibit HWS-2 was prepared based on the original project listing. Columns were added as part of the review process. Specifically, the column "Start Month Per Project Analysis" was added to verify the start date that was identified in the filing. While not depicted, Larkin also verified the in-service date and project cost to the Installation and Retirement Work Order form. The Column "Spending through 5-31-15" was added by GMP as part of the response to DPS.GMP.1-1 to determine whether projects that were supposed to have started did start and to determine the progress of projects. The Comment column was prepared by GMP and the Larkin Comment column is Larkin's recommendation to GMP on what should be done with the project requested.

The Company, after discussion, revised its request by eliminating selected projects that were questioned and by adjusting the in-service dates for a number of projects due to concerns noted by Larkin regarding slippage. Some of the concerns and recommendations were explained or additional information was provided justifying the in service dates. Some Larkin recommendations regarding in service date changes were not made due to consideration given on additional information provided by GMP. The Company removed $37,325,116 from its capital project request based on the recommended adjustments to cost or in service dates as proposed by the Department and Larkin.

<u>Cost of Service</u>

<u>General</u>

On June 1, 2016, Larkin received the entire GMP base rate filing for the year ended September 30, 2017. The filing indicated a base revenue deficiency of $14.217

million requiring a 2.57% increase in revenues plus a $5.342 million increase associated with the Power Supply Adjustor for a total increase of $19.559 million or 3.53%. The filing reflected a lower revenue requirement than would have been included due to the $1.5 million ratepayer share of the estimated FY 2016 merger-related shared savings being factored in, which is in addition to an estimated $15 million merger savings reflected in the filing.

Revisions to the revenue requirement were provided on July 12, 2016 identifying some proposed adjustments the Company wanted to reflect indicating a base revenue deficiency of $14.179 million requiring a combined 3.51 % increase in revenues (i.e. inclusive of the Power Adjustor increase). The changes were primarily related to the increased equity earnings, higher cost of capital due to added equity, higher transmission by other expense, higher revenue forecast and power costs. The proposed added adjustments were factored into the ultimate revenue requirement determination.

The final revenue requirement filed on August 1st indicates a base rate revenue sufficiency of $142,000 requiring a .03% decrease in revenues. The change was the result of changes to project costs included in rate base, adjustments to various costs outside the platform, elimination of a request for a new working capital component, the Company's proposal to write-off one half of the unamortized CIAC balance, an increase of $1.335 million in the merger savings and a change to the capital structure.

PROJECTED PLANT ADDITIONS

As discussed earlier, Larkin was provided a summary of proposed plant additions and selected 155 specific projects for review. The review of the current filing found there was an improvement compared to previous filings with respect to the supporting detail for estimating the cost of specific projects. Larkin is encouraged with the improvement and the concern by the Company with the quality of cost documentation. However, as discussed earlier there is concern that project detail was not sufficient, specifically with respect to the financial analyses. The Company's compliance with the known and measurable standard from a cost perspective is improved but project justification in the form of analysis of cost impact and alternatives considered continues to be a concern, especially with the provision in the Successor Plan that requires compliance with Attachment 7.

As part of the review process GMP provided the Larkin requested comparison of the project request filing in FY September 30, 2016 and the current status of the projects using a March 31, 2016 cut-off. The results continue to raise concern as to the reasonableness of the Company's projections. The major issue identified was that in-service dates identified in the filing continue to be overly optimistic as a number of projects recorded in-service dates that were later than projected. This is an issue because ratepayers begin paying for the plant and depreciation based on the Company estimated in-service date, and the delays noted provide the Company with free cash working capital. Another issue identified was that there were projects that not only did not go into service on time, but there were no project costs for the project even though the filing indicated it would be in-service as of March 31, 2016. A third issue is project substitution. This is particularly an issue with IT projects.

GMP Capital Additions

GMP initially projected for the year ended September 30, 2017, a net increase of $134.432 million to plant in service and a decrease of $35.160 million to Construction Work in Progress (CWIP). Larkin notes that the Company indicated from the beginning that it is focused on complying with Attachment 7 to the Successor Plan regarding the detail to be presented as support for the projected additions. As was done in the past, our review consisted of an on-site review allowing Larkin to review information readily and providing the opportunity for interaction with the Company.

The projected additions for 2016 and 2017 incorporated in the filing for the establishment of rates for FY 2017 were reviewed based on a sampling of one hundred and fifty-five of the two hundred and twenty-eight specific projects. The specific projects exclude blankets and joint owner capital project costs that are on the list provided by GMP. The one hundred and fifty-five specific projects selected for review totaled to

$127.131 million. The sample did not include blankets since blankets are evaluated based on historical spending. The sample, excluding blankets and joint owner costs, was 67.5% of the Company's total of requested projects. The sample, with blankets and joint owner costs, was 97% of the Company's total requested cost of $188.223 million. The reasonableness of the amounts requested was verified to supporting cost documentation and/or historical cost information. The Company projected the costs for blanket work orders based on an indexed five year average of costs closed to plant.

The projected additions analyzed were reviewed for cost development and substantiation of cost estimates to quotes, estimates, historical averages, actual costs to date and/or similar historical cost detail. A full complement of detail was provided with the Company voicing concern whether the Financial Analysis provided was sufficient. After Larkin noted the financial analysis were considered insufficient the Company supplemented the financial analysis but little weight was given to the supplement. This practice, except for the supplementing, should be continued in future filings. Most projects had estimate sheets for direct materials, direct internal labor, contract labor, contract costs, etc. Documentation was provided as support for the contract labor and the contract costs that were included in the project cost estimate. Testing of direct internal labor costs, stock materials and direct materials was done using project cost reference documents. For example, the cost for the materials and supplies was tested to the Company's materials and supplies inventory listing. Overhead costs were based on various overhead rates as summarized and provided by the Company.

Observations

The Company provided a summary of projects to be included in the filing for 2016 and 2017. The plant addition summary provided was used to determine the sample test for projected plant costs. The selected project files were downloaded to a flash drive and made available upon our arrival at the Company. The documentation supporting the projected capital addition direct external costs was generally included with an exception for the Financial Analysis as discussed earlier. The availability of information is a reflection of the progress made by GMP.

Concerns

1. As noted above, we are concerned that there are cost variances between budget and actual for the numerous projects included in rates. We are also concerned with the slippage of project completion dates.
2. A concern exists with the fact that in compliance with Attachment 7 to the Successor Plan, numerous projects should include a financial analysis that provides substantive financial information and does not simply answer questions regarding cost impact and cost savings with a simple yes or no without explanations. The Board in the past has excluded the costs for projects that should have been evaluated with a cost benefit analysis and Attachment 7 provides that failure to meet the documentation requirements could result in a cost disallowance.
3. We tested the reasonableness of general blanket work orders to the Company's calculated actual five year average and the average utilizing the CPI inflation index. While most of the amounts appeared reasonable based on the indexed historical averages using a CPI index, we do not believe indexing is justified based on actual historical costs. We note the Company did estimate the blanket costs based on a CPI index but because the estimates were at least in part based on the escalated values we continue to note our concern.

Recommendations

1. The Company should continue to provide, *as part of each prospective filing*, a summary of plant additions as requested in the previous rate request that compares the “as requested” amount to actual for jobs completed and jobs still in process. The summary should also identify the as-projected date of completion and the actual completion date, or the latest estimated completion date. For

projects that are completed, the Company should provide a *detailed* explanation for any cost variances of 10% or more. For projects in process or not yet started, the Company should provide a *detailed* explanation for any estimated changes in the cost projection and explain any changes in the estimated date of completion. This analysis will provide valuable information to the Board and the Department for evaluating the reasonableness of the Company's current estimates incorporated in the current filing.

2. To address Larkin's concern with slippage and variances the Company should factor in the variances and slippage when establishing the new budgets for plant additions. Larkin notes that a slippage allowance was factored into the cost of service for FY September 30, 2017.
3. The Company should continue to use the master material and supplies inventory, labor summary and overhead summary in developing the project estimates. The Company should continue to reference the applicable pages from the master list in the project folder.
4. Larkin continues to be concerned that projects not completed had costs assigned to other projects not previously identified and/or reviewed. It is recommended that the Company include with its initial filing submitted for review a list of all projects that were undertaken during the test year that were not subject to review in the prior filing. This summary should include the cost, date started, date completed (if completed) and an explanation why the project was undertaken.

Communications

The initial project listing included $2.289 million for seven Communication projects. Larkin reviewed the cost for six of the seven projects totaling to $2.276 million of the $2.289 million requested. The Company indicated in the response to the selection made that work order 143692, RNMS had been cancelled. This project was budgeted at $29,648. Larkin, as indicated earlier had concerns with a majority of the financial analysis provided. The financial analysis for work order 148528, Elster Outage Enhance had the following explanation for added costs or cost savings:

> Ultimately when GMP has an enhanced integration between the AMI system and the Outage Management systems it is anticipated there will be savings in several areas including the time necessary to identify where electrical outages are and to confirm when power has been restored. These savings will be in the Field and System Operations areas related to improvements in determining where, and to what magnitude, electrical outages have occurred. The AMI data will supplement current information received from customers and other GMP systems.

This suggests that the project would have an O&M impact but the work order detail made no attempt to estimate the savings. The project said no alternatives were considered. Adding to the concerns of Larkin was the project has a start date of April 2016 and a closing date of September 2017 with no costs incurred as of May 2016. Larkin noted the project appears to have slipped and the Company agreed to remove the $990,354 out of the request because the slippage moved the in service date beyond the end of the September 2017 rate year. Another example of a less than sufficient financial analysis was the one provided for project 148549, Conversion to VTEL. The explanation for added costs or costs savings said there would be no added costs and that the project will allow GMP to end several costs. No detail of the specific costs or the estimated costs was provided. Other than the issue with the financial analysis Larkin did not recommend any other adjustments to Communications.

Computer Hardware

The projected addition for computer hardware reflected in the initial filing was $7.179 million including $535,637 for blankets. As noted in previous reports and as part of the ESAM report there are concerns with projections for computer hardware because of the number of changes and the timing of in-service. The issues with IT are perennial and are a major concern. While documentation existed to justify the projected cost in many of the projects, the actual completion of the project remains in question. The shifting of funds is also a major concern because the project funding for wherever the funds were shifted to has not been subject to a review which means there is no assurance that the project is an appropriate cost to be passed onto rate payers. The optimism of in-service has always been an issue with GMP for IT projects.

Larkin recommended that two of the project in-service dates be shifted and that the $535,637 of costs for blanket projects be deleted. The Company agreed to move the in service date for project 143212, Replace Rutland Internet Routers from May 2016 to August 2016 and also agreed to move the in service date of project 143202, Upgrade Wireless Controllers from July to September. The date listed in the filing was July 2017 but it was determined it should have been July 2016. Larkin confirmed that the work order and listing were in error by reviewing the cost schedule which indicated costs were to be incurred in April of 2016. The blanket project costs were removed from the request.

Computer Software

GMP requested $13.826 million for computer software projects. This is a 68.2% increase over the 2016 request of $8.220 million. The Company's request consisted of 52 projects ranging from $3,226 to $1,454,117. Larkin analyzed all 52 projects. As noted the Financial Analysis were less than adequate. For project 143667, WM for Substations 2015-2016 the following explanation was provided with respect to added costs or savings:

> Improve reliability and elimination of manual processes.

The explanation provides no information with respect to the cost impact or savings for undertaking this million dollar plus project. Another common statement for other cost and benefits was will create business efficiencies. In 2016 20 of the 25 projects reviewed indicated there was no impact on O&M expense. That statement, by itself, was considered less than adequate as it seemed to be a quick response to the inquiry of cost impacts. In the current filing two stated no cost impact and two others made a reference to either not adding costs or a reduction of costs. The explanation provided for added cost or benefits was more of an attempt to justify the project than to quantify any resulting cost impacts associated with the project. The document where the explanations were provided is supposed to be a financial analysis and after reviewing all 52 projects Larkin is of the opinion no financial analysis were provided. Under strict application of the requirements listed in Attachment 7 to the Successor Plan all the projects could have been recommended for disallowance. Cost detail was provided supporting the costs requested, work orders were provided as required but that only is part of the requirements provide for in Attachment 7. In order for the alternative regulation process to work the Company must make a better effort to meet the requirements of Attachment 7.

Larkin recommended that three Computer Hardware projects have the in-service date moved. The Company agreed with the recommendation for two of the projects and provided evidence that the third was in process and would be completed as scheduled.

Distribution Lines

The GMP request for Distribution Lines totaled $41.461 million compared to $36.242 million in the FY2016 filing. The request is based on 18 months of additions for April 2016 through September 2016 and all of FY2017. The initial estimate included $3,500,000 for danger tree removal. Over the past year there have been discussions with how to treat the costs associated with danger tree removal. The Company proposed that the costs be capitalized. Larkin indicated to the Department and the Company that this has been done in some jurisdictions but that FERC says that this is not appropriate. The Company removed the $3,500,000 reducing its request to $37.961 million. The escalated five year average was annualized for the interim period and the rate effective period. Based on the actual historical spending the 18 month average would be $36.380 million. The costs fluctuate from year to year which, in Larkin's opinion, suggests the escalation is not necessary. Based on the requested for FY2015 and the actual amount spent in FY 2015, the amount requested for FY 2017 appears reasonable.

Distribution Substation

The initial capital request provided consisted of $7.096 million compared to $9.567 million in FY 2016 for specific projects and blanket expenditures of $.935 million compared to $1.008 million in FY 2016. The specific projected expenditures consisted of

9 projects. Larkin reviewed 6 of the 9 specific projects totaling $6.922 million. The workorder 34 amount for blankets was considered reasonable based on past historical spending that averaged $626,133 on an escalated basis and $596,393 on an actual basis. Annualized for the interim period and the rate effective period the average escalated blanket would be approximately $926,816 and the average actual would be $894,589. Again Larkin identified an issue with slippage. As discussed in more detail in the ESAM Report, the Company filing in Docket No. 8190 included 16 specific projects, for 6 of the 16 the in-service date slipped and 3 projects were not done at all. In addition, there were 3 projects completed that were not the subject of review. This was factored into Larkins evaluation. For FY 2017 Larkin took exception to two of the project costs. Project 143292; Graniteville Substation Rebuild was lacking support for $278,699 of costs and Project 143308; Spare Transformer was completed for $34,878 less than projected. The Company agreed to reduce the request by the $313,577.

General Plant

As reported in FY 2016 the Company projections for General Plant continues to be different from past filings. Past filings included equipment and vehicle purchases but the current request consists of miscellaneous equipment. Amortizations (i.e. retirement amounts) that were included in general plant as part of retirements in FY 2016 are now reflected in Computer Hardware. Separate categories exist for Property & Structures and Transportation Equipment. Inconsistencies make comparisons more difficult and should be avoided going forward.

The current request is for 4 projects totaling $295,437. Larkin selected 2 projects for review totaling $245,962. An issue was raised concerning the in service date for both projects since the projects were to start in January and February 2016 but no cost had been incurred as of May 2016. The Company rejected the recommendation to move the in-service date explaining the acquisitions are for equipment and the time allowed for in service was sufficient to make the purchase and simply plug in the equipment to put it into service. Larkin accepted the explanation and did not pursue the issue further. No adjustments were made to General Plant.

Hydro – New Hydro Dams

The Company requested a plant addition of $23,009,217 for the acquisition of 17 dams in New England. The cost was broken down into two phase. The Vermont phase is $7.785 million and the non-Vermont phase was $15.215 million. Of the 17 dams, 4 were located in Vermont and the remaining 13 are out of state. The Company indicated that Company staff will maintain the Vermont plants and three of the New Hampshire plants located near the Vermont-New Hampshire border and the other plants would be maintained with contract labor[1]. Multiple issues exist with allowing the cost as plant in service. Larkin advised the Department that there were concerns with the costs for operation and maintenance of the plants as well as future capital requirements. The project detail required under Attachment 7 lacked support for the cost. The $23 million cost was an estimate and the Company is still in the process of determining the actual cost[2]. Another concern is whether the project cost reflected on the books should be book value or fair market value. Larkin did not see information that was considered adequate for establishing what book value was or fair market value was. The Company did have a due diligence analysis performed and did prepare a cost benefit analysis. Larkin advised the Department that concerns exist based on review of the due diligence report and that the cost benefit analysis as prepared was not considered adequate. There is also concern with the Company having to file a request for approval of the acquisition which had not been completed.

It was recommended that the cost be removed from the filing. The Company agreed to remove the cost from the filing but requested that the Vermont dam cost be allowed deferred recovery pending evaluation of the cost and the appropriateness of the acquisition. The Department agreed on the condition that it did not preclude the Department from taking exception to the acquisition being included in rates in the future.

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1 Company response to DPS.GMP.1-31.

2 Company response to DPS.GMP.1-34.

Larkin believes the condition protects ratepayers should it be determined that the purchase is not in the best interest of ratepayers. Larkin recommends that an in-depth review of the proposed purchase be performed talking into consideration costs for upgrades that have been required for GMP's existing dams.

Joint Ownership

The initial request for the current filing included $3.399 million for joint owner projects compared to $5.018 million in FY 2016. The work order detail supplied stated that the Company uses the owner budgets to estimate costs. Larkin believes that based on experience with the joint owned costs that reliance on budgets has not proven to be a reliable way of estimating costs. Previously the Company and Larkin discussed the issue and agreed to begin with a 3 year average of performance and move to a 5 year average as more information becomes available. It is not apparent that the averaging approach was used from information reviewed and based on the work order explanations. No changes were recommended because based on historical spending the amounts were considered reasonable.

Kingdom Community Wind

The Company requested $63,057 for a single project for Kingdom Community Wind. Larkin reviewed the detail provided and did not take issue with the project costs requested.

Meters

The meter blanket request in the filing is $909,280 compared $1.067 million for FY 2016. The actual and escalated five year annual average is $580,258 and $609,227, respectively. The actual and escalated average annualized for the 18 month period April 2016 through September 2017 is $870,387 and $913,840, respectively. Larkin determined based on the cyclical changes the amount requested is reasonable.

Production

GMP requested $27.640 million for 22 specific projects compared to $20.969 million in FY 2016. The request also included 2 blankets for $852,421 compared to $991,974 for blanket projects in FY 2016. Larkin reviewed 15 of the 22 specific projects for a total review of $26.936 million of project costs. Based on past history with the 5 year average cost for production blankets Larkin believes the blanket spending may be high but did not recommend an adjustment for blankets. Larkin is advising the Company that in the FY 2018 filing any excess over the historical average will be recommended for disallowance unless known and measurable support can be provided.

Larkin identified issues and recommended changes to the in service date or exclusion of the cost for 6 of the projects reviewed. The in service date of production remains a concern as noted in the ESAM Report. In FY 2015 the Company request included 50 projects and only 11 were completed on time and 6 were never done. Because cost had not been expended for the 150kW E farm and the Project 143344; St. Albans e Farm was running behind schedule and still had hearings to complete it was recommended the $11.506 million of costs be excluded from the Company's request. The Company agreed to the recommendation. The Company agreed to move the in service date for the 3 of the other 4 projects as recommended by Larkin. The remaining project date was not moved because the project was completed. Larkin is recommending the Company evaluate its process for determining an service date for Production Projects by taking into consideration the recent history of slippage. If the trend continues and the Company does not factor in slippage a recommendation that some project costs be deleted may be required.

There is one additional concern Larkin has with the high level of the project costs associated with dams that is included in this request. The concern is whether the $4.053 million for penstock and trashracks at Glen Falls is indicative of what amount of added investment may be required for GMP's proposed acquisition of 17 existing dam structures. Over the approximately 24 years of reviewing project cost in Vermont it is obvious that capital dam maintenance cost and relicensing cost can be significant.

Property and Structures

The FY 2017 request for property and structures in the initial project listing was $5.799 million. This request is $1.248 million less than the $7.047 million request for FY 2016. The initial request included 27 projects of which 4 were for the purchase of land and 2 blanket projects. The primary issue with this request was the inclusion of the land purchases for some prospective future plant project and the in service date for the Colchester Data Center project has been ongoing for some time. Adding to the concern was of the 46 projects requested in FY 2015, 6 did not occur and 18 were put into service late.

Larkin conservatively recommended that 3 of the land purchases be removed and the Colchester Data Center project have its in-service date moved. The fourth land purchase occurred as of May 2016. The Company agreed to remove the 3 land purchase totaling $741,552. However, in reviewing the August 1st filing Larkin noted that the Company did not remove Project 148806; West Rutland land purchase with a cost of $98,843. With respect to the change to the in-service date for the Colchester Data Center the Company provided updated information supporting the acceleration of the project, thereby eliminating the need to move the date. Larkin notes that blankets for Property and Structures were not traditionally allowed and should not be reflected in future filings. The alternative regulation process itself allows for recovery without the regulatory lag that existed under traditional ratemaking but it should not be viewed as a blank check for unknown projects in future filings.

Regulators/Capacitors

The FY 2017 request for blankets for regulators, capacitors and transformers is $1.582 million. The 5 year actual and escalated average for blankets is $757,997 and $881,905, respectively. Annualizing the actual and escalated average for the six month period April 2016 through September 2016 and for the FY 2017 results is $1.137 million and $1.323 million, respectively. Despite the possible excess of $250,000 Larkin did not recommend an adjustment.

Solar

The category label Solar used by the Company is misleading. The category label in FY 2016 was New Initiatives. The Company's request for FY 2017 was $11.925 million compared to $9.778 million in FY 2016. Larkin and the Department advised the Company that there are concerns with the costs but are not accepting or challenging the cost in the filing based on merit and expressly reserving the right to challenge the costs in future filings. The various projects could be subject to separate tariffs because the projects are not normal operating activities. Essentially the programs are trial programs.

The Department took initial issue with Project 147165; 2016 Power Pack Kiosk for $24,571 and the Company agreed to exclude the costs. Larkin selected for review 12 line items totaling $10.997 million. Larkin recommended 1 project be removed and the in service date changed for the 11 remaining projects reviewed. The Company agreed to remove $412,205 for the project identified as EVGO.107:2017EVGO. The Company moved the in-service date for Project 143677; Derm 51 Circuit. However, the Company disagreed with moving the remaining 10 project in-service dates and instead proposed to change the level of spending for quarterly cost estimates. Larkin agreed to the spending change.

In reviewing the Company's August 1st filing it was noted that the amount in the filing for one of the 10 projects was $249,452 less than what was agreed on. The Tesla cost agreed on of $605,041 was supposed to be in-service as of September 2017 and instead the Company reflected an amount of $475,968 in-service as of December 2016. While the dollar amount is less the impact on rate base is greater because the December 2016 in-service date adjusts the average rate base $366,129 whereas the September 2017 in-service date would adjust the average rate base $46,542. The added amount in rate base results in an approximate increase of $22,499 in the return on utility rate base reflected in the cost of service. This added return is a cost to ratepayers that was not agreed on.

Transformers

For the FY 2017 GMP requested $5.225 million for distribution transformers. In FY 2016 a request for $6.728 million was identified in the Larkin Report for Regulators and Capacitors. The annual actual and escalated five year average for transformers (wo 36) is $3.335 million and $3.501 million, respectively. Annualized for the interim period and the FY 2017 the actual and escalated average is $5.003 million and $5.251, respectively. The Company's request is considered reasonable based on the averages. No adjustment was recommended by Larkin.

Transmission Lines

In FY 2016 the Transmission line request of $10.376 million included 17 projects. In the FY 2017 the Company's request for $5.604 million includes 14 projects totaling $3.745 million and the transmission minor additions blanket for $1.859 million. This is another change made by the Company in grouping costs by category. In FY 2016 the blankets costs were included in Transmission Substations. This changing makes comparisons more difficult and should not be done. Larkin selected 8 projects totaling $3.261 million for review. No recommendations were made for the specific projects requested. Larkin compared the blanket request of $1.859 million to the actual and escalated annualized 5 year averages and determined the request to be reasonable. The annualized actual and escalated 5 year averages were $1.779 million and 1.868 million, respectively.

Transmission Substations

In FY 2016 GMP requested $4.114 million for specific Transmission Substation projects and $1.888 million for blanket work order 32. As noted above the work order 32 blanket is included in Transmission Lines in FY 2017. In FY 2017 the Company requested $4.247 million for 17 specific projects and Larkin selected 6 projects totaling $3.559 million for review. Larkin recommended that 4 of the projects' cost be adjusted to the actual since the projects were complete. The Company agreed to a $95,125 reduction in Transmission Substation request for FY 2017. With the adjustment Larkin believes the cost request is reasonable.

Transportation

The Company requested $8.544 million for 7 transportation projects in FY 2017. In FY 2016 GMP had a request for five projects totaling $7.359 million. Larkin selected all projects for review. Larkin discussed the purchasing of vehicles with the Company because it has been noted that in recent years purchase have been significant. The response was that a number of vehicles are past their expected life and GMP is trying to modernize the vehicle inventory. For heavy equipment (i.e. bucket trucks and digger trucks) the Company indicated it is trying to replace the vehicles based on a 10 year useful life. Larkin reviewed the inventory of vehicles and noted to the Company that the purchases scheduled for FY 2017 would essentially update the inventory for heavy equipment to the 10 year life cycle. The Company agreed that is what the records indicate but Larkin was cautioned that some of the vehicles listed represented the purchase date of vehicles previously under lease so there could be more replacements in the future. Initially Larkin did indicate concern with the 2 large vehicle replacement projects totaling $6.005 million. After discussion with the Company Larkin agreed no adjustment was necessary. Larkin will be monitoring the vehicle replacement program closely in future filings.

Vermont Marble – Hydro

The Company has requested $14.372 million for 7 projects associated with the Vermont Marble dam. Larkin selected 4 projects totaling $13.964 million for review. The one project of concern was the $6.281 million for Project 148860; Huntington U3 & Intake Modernization because spending indicated it was behind schedule. The Company was adamant the spending would accelerate but it was still agreed to move the in service date. No other adjustments were proposed. The most notable concern to Larkin with the high level of the project costs is if the requirements here could be an indicator of what amount of added investment may be required for GMP's proposed acquisition of 17 existing dam structures.

Vermont Marble – Transmission Lines

The FY 2017 request by GMP is for $1.439 million for Project 147380; 2016 Marble Street to Danby Reconstruction. Larkin questioned whether the in-service date should be adjusted because spending had not occurred for a project with a start date of October 2015. The Company clarified that cost had been incurred but they were reflected under a different project number. Larkin accepted the Company's support and agreed that a change in-service date was not required.

Wind Generation

GMP requested $531,778 for Project 143579; 2016 NPS 100 Wind Turbine. Larkin did not identify an issue with this request.

Concerns:

1. The Company assembly of documents has continued to improve. However, Larkin does not share the Company's optimism with in-service dates after reviewing actual historical in-service dates to projected in-service dates. In addition, the Financial Analyses prepared by the Company are not considered sufficient. The Company financial analysis are more project justifications than a true financial analysis that identifies added costs or cost savings. Of greater concern was the cost benefit analysis for the $23 million of hydro dam purchases was found to be inadequate. There was also a concern with the development of the cost benefit analysis of the digesters. It is Larkin's opinion, that the Company must improve the Financial Analysis process or more costs will be recommended for exclusion in future filings. As discussed earlier, Financial Analysis for projects are to be prepared before a determination is made on whether to proceed with a project and not after the fact.

2. As indicated above, there is concern with the in-service dates being overly optimistic. This optimism is costing rate payers because plant is included in rate base before it becomes used and useful.

Recommendations:

1. The Company should instruct employees as to what the purpose of the Financial Analysis is and direct the employees to provide information of substance. Some analysis must exist as to whether there is an O&M impact and how the impact was determined should be explained. The same process applies to determining whether a cost savings will occur. It is the cost savings that can be used to justify the financial investment in the project. Finally, the consideration of alternatives is significant. After that alternative is considered, the analysis should indicate why the one alternative was selected and the others were not.
2. To the extent a cost benefit analysis is prepared, the analysis should include all available information with respect to future costs and a cost benefit analysis should not reflect assumptions of a non-financial nature.

OTHER RATE BASE ITEMS

Other rate base additions include items such as Investments in Affiliates, Special Deposits, Unamortized Discounts, Preliminary Surveys, Regulatory Assets, Low Income Payments, Efficiency Fund Payments, Storm Deferrals, Retired Meters, the Community Energy & Efficient Development Fund (CEED), Capital Expense, AMI Investment and the Working Capital Allowance. Other rate base deductions include Accumulated Depreciation, Customer Deposits and Advances For Construction, Capital Leases, Accumulated Deferred Income Taxes, Accrued Pension Expense, Accrued Post Retirement Expense and Other Current Liabilities (Deferred Credits). This report will discuss the respective additions and/or reductions to rate base where issues were identified and discussed with the Company. Larkin not taking issue with certain rate base items should not be construed to mean there is no issue. Due to time constraints not all costs are looked at in the same level of detail.

Working Capital

The Company's request for a working capital allowance of $46.769 million included a lead/lag working capital requirement of $15.813 million, $20.499 million for the average materials and supplies inventory, $2.613 million for Millstone fuel inventory, and $7.844 million for prepayments. For years GMP used what is commonly referred to as the formula method or one-eighth of operating expense allowance plus the average materials and supplies inventory, fuel inventory, prepayments and an adjustment for accrued interest. Larkin has repeatedly recommended the use of a lead/lag study and the Company through an agreement as part of the FY 2016 filing finally prepared the requested study. As part of the Company's filing, the formula method was also included to provide a comparison of the two methods. The Company indicated that the formula method resulted in a lower working capital requirement thereby justifying the use of the formula method. The formula working capital requirement according to the Company's calculation was $35.015 million or $11.681 million less than the working capital allowance that included the lead/lag calculation. After review Larkin identified a $7.594 million error in the working capital allowance that was included as part of the formula method reducing the variance significantly. Larkin then took issue with the lead/lag calculation itself. Three major concerns were identified by Larkin. The concerns identified were the reduction to expenses for the synergies for shareholders, the failure to account for a lead for payment of dividends and/or on the return included in the cost of service and failure to reflect a lead for income tax expense.

The Company reduced the total expense included in the lead calculation by $15.000 million for both the synergies that were estimated to flow through to shareholders and also for the synergies assumed for customers. Larkin indicated that shareholder synergies reduction was not appropriate because the $15.000 million was not part of the O&M expenses reflected in the cost of service and was not an offset to the expense in the cost of service similar to the offset reflected for customer synergies. The Company agreed that the lead/lag calculation should be adjusted.

The next issue was whether the return to shareholders and/or dividends should have a lead applied to the amount reflected. The revenue that is reflected in the lag calculation includes not only the recovery of expenses but also recovery of the return to shareholders. It would be inequitable to ratepayers if they had to pay a second return on the return being paid to shareholders. Larkin advised the Company that in his experience that either a lead should be calculated on the return reflected in the cost of service or at a minimum on the dividends paid out. The Company questioned whether that should be reflected and indicated that there was a limited familiarity with how this should be done. Larkin notes that the Company's affiliate calculated a lead on the return. Larkin was adamant that one or the other should be reflected and recommended at a minimum that the $59 million of dividends reflected in the filing for FY 2017 be reflected in the calculation. The Company after agreeing that the dividend lead would be reflected but instead used a dividend amount of $38.956 million because it was the Company's intention that in the revised filing they would exclude an added investment and also exclude the projected special dividend. For the purposes of progressing with the possibility of settling issues Larkin agreed to accept the change as long as the earlier assumption of investment and payment of the special dividend were revised.

The last issue that was discussed was the failure to reflect an income tax lead. Larkin again stated that a lead should be reflected because the taxes are included in the revenue amount where the lag is calculated and that by not reflecting the tax lead shareholders are getting a return on working capital it is not entitled to. Larkin also advised GMP that its affiliate did reflect a lead on income taxes in its lead/lag study. GMP claimed that because taxes are not paid, due to a net operating loss for tax purposes, the lead should not be reflected because rate base already reflects an offset in the form of deferred income tax credit. Larkin explained the deferred tax offset is an average for the year and is required due to the fact that tax expense is recovered from ratepayers as part of the cost of service and is separate and distinct from the working capital requirement that is a different line item in rate base. The theory behind working capital is the

Company is utilizing shareholder funds to operate the Company and are entitled to a return on the difference in time between the time the funds are collected and the time the expense are paid out. As an example assuming tax expense collected from rate payers is $12 million and the Company does not remit any of that to the tax authorities. The Company has $12 million of funds to use at their discretion. Rate base will reflect an average of $7 million in deferred income taxes as an offset to rate base for the funds collected throughout the year, assuming it is collected at $1 million a month. This is important because despite ratepayers paying the Company $12 million, the resultant average credited to rate base is only $6 million ($12/2). Now, following the Company's position there is also a request for the Company to recover a return on the $12 million included in revenue based on the number of days there is a net lag in collection. There is no offset in the lead/lag calculation for the revenue collection so ratepayers are being charged for a collection lag without any offset. Because they are two separate rate base components, this is, in effect, a double recovery and is not appropriate. After lengthy discussion it was agreed that Larkin and the Company would disagree. Larkin advised the Department that there is a willingness to proceed as long as the Company files a lead/lag analysis in the next Alt Reg filing, the issue is reviewed further and resolved in the next filing. This is considered to be positive step forward because it means the Company will file a lead/lag study in the next filing instead of reverting back to filing using the formula approach. If not resolved in the next filing Larkin will recommend the issue be litigated.

Larkin would note that according to the Company filing on August 1, 2016 the lead/lag working capital allowance was $3.198 million less than the formula working capital allowance and $7.868 million less than the initial filing made on June 1, 2016. Larkin recommends that going forward the lead/lag study be a requirement as part of the Company's filing.

Deferred Regulatory Credit

As discussed in the ESAM report the Company failed to expend the amount of vegetation maintenance costs included in the platform in FY 2015. Larkin reflected a regulatory credit in the calculation of the ESAM and recommended the credit be reflected in the FY 2017 estimate until such time the funds are ultimately expended as intended. The underspending being reflected from the FY 2015 ESAM is $1,190,248.

Previously, Larkin advanced concerns that the Company had failed to expend what was allowed in rates and that the Company's trim cycle is not adequate. The Board ruled in Docket Nos. 6946 and 6988 that to the extent the CVPS did not expend what was allowed in rates, a regulatory credit should be established to carryforward the unspent funds to be utilized in the following years. This practice was followed by CVPS and GMP for years. GMP has contended that the accounting does not apply since the merger created a platform and even suggested it did not apply to GMP. As was stated by Larkin, GMP did follow this practice, as this was observed by Larkin in past reviews and as evidenced by the 2008 Alt Reg filing by GMP (pre-merger) where GMP reflected a deferred regulatory asset because it had overspent in a prior year. Larkin disagrees that the merger and platform eliminated this Board requirement. Larkin is not aware of any specific language in the merger order or MOU that specifically eliminates the Board requirement. The merger platform is designed to reflect merger related savings and the Company's forbearance in spending should not be a factor in determining merger savings that flows to shareholders, especially when the Company has not maintained an appropriate trim cycle.

As discussed in previous Larkin Reports there is a concern that the Company's failure to maintain a minimum trim cycle and failure to address the danger/hazard trees along the right of way has contributed to additional storm costs. The Company has identified that in the most recent snow storm that an estimated 95% of the damage was due to trees brought down by the heavy snow[3]. The Company also indicated that the

3 Company response to Exogenous Filing question 1-11.

major damage was caused by failure of trees outside the right of way[4]. The Company has indicated that it does not believe addressing the danger/hazard trees outside the right of way would have made a difference. Larkin believes that the trees did impact the level of storm damage and notes that multiple New England utilities have over the past years since 2008 undertaken programs to address the danger/hazard trees to mitigate storm damage. This is a critical issue and only further emphasizes the importance that the Company expends what is allowed in base rates.

The Company was reluctant to allow the credit as part of the filing but ultimately agreed to allow the credit and utilize the credit for vegetation maintenance. The Company in its filing included a summary of the changes that occurred during the review process. On page 2.6.3 the outcome of the treatment of the deferred liability is described as follows:

> $1.2 million carried forward as a platform amount to be applied to incremental trimming beyond 7-year requirement in ‘17. Further agreement to discuss and agree on plan for incremental trimming of approx. $1.2-3 million total to be applied to incremental cycle trim or enhanced danger trim through FY 18. Incremental amounts beyond first $1.2 million to be a non-platform expense. GMP to trim minimum 1/7 total system miles by end of CY 16 (resource dependent – will carry over spend if not able to hit by end of FY16) and going forward, in manner consistent with 2015 growth study.

Larkin recommends that the Board review the issue and provide guidance as to whether the accounting should continue as was previously ordered.

<u>Vegetation Management Impact</u>

The storm damage and cost from the December 2014 snow storm was significant. In response to Exogenous Informal Request DPS 1-11, the Company indicated that it was estimated that 95% of the storm damage was due to trees brought down by heavy snow. Heavy snow on trees causes damage either by having untrimmed trees along the right of way making contact due to the added weight or from trees outside the right of way

4 Company response to Exogenous Filing question 2-5.

because of the added weight and/or the condition of the trees outside the right of way. In response to Exogenous Informal Request DPS 2-5, the Company indicated that "a large percentage of the trees that impacted these areas during the storm event were from outside the right of way". Tree maintenance is critical in mitigating storm damage. Other utilities in the New England region have implemented enhanced vegetation programs to address the danger and/or hazard trees that threaten the system. This is done to mitigate storm costs that have occurred due to the increase in storm activity. As part of Docket Nos. 8389 and 8456 vegetation management was identified as an issue. The Larkin Report, in Docket No. 8389, identified and discussed 3 issues with the exogenous storm costs.[5] Some improvements have transpired but the concern with the Company's vegetation maintenance remains. The Company has yet to achieve a 7 year trim cycle and there is no definite program in place for enhanced tree removal that focuses on danger and hazard trees. As discussed above, the Company has made a commitment to achieve the 7 year cycle by the end of CY 2016. The danger and hazard trees are generally found on the outer edge of the right-of-way or just outside the right-of-way. Absent a proactive program, the level of storm cost restoration will continue and the expectation that if it occurs, ratepayers can pay for it is not appropriate. As part of the MOU in Docket Nos. 8389/8456, the Company agreed to perform a growth study and would determine whether an increased or expanded enhanced vegetation management program would provide a benefit. The study made reference to a 6 year trim cycle yet the Company has not yet achieved a 7 year cycle. The findings of the study are discussed in more detail in the FY 2016 Larkin Report. It is Larkins opinion that a 7 year cycle is not sufficient but recognizes that the 7 year cycle is what is set forth in the IRP. But of more significance is the limited attention given to danger and hazard trees is a major concern that should be addressed.

The Company and the Department have had discussions on a plan to address the cycle issue and to aggressively address the hazard/danger tree issue that is causing the damage during storms but no resolution was achieved. As noted earlier Larkin

[5] Larkin Report filed on February 17, 2015 at pages 11-17.

recommended that a credit be reflected in rate base to account for the Company's underspending of the vegetation maintenance costs included in base rates and the Company agreed to reflect the credit and utilize to address the vegetation concerns. The failure to expend what was allowed is unjustified given the Company has not been able to achieve, let alone, maintain a 7 year trim cycle and/or address more proactively the danger and hazard tree risk that exists. Larkin believes the resolution agreed to by the Company and the Department is a step in the right direction to achieving better vegetation maintenance. Larkin continues to recommend that the Company be required to develop a written proactive plan to address the danger and hazard tree risks that exist.

CAPITAL STRUCTURE

The Company proposed a capital structure that consisted of 50.77% equity, 44.48% of long term debt and 4.75% short term debt. Larkin identified various concerns with the capital structure and with the projected debt issuance. Larkin, as discussed in the ESAM report, noted that the Company failed to record the dividend declaration and instead recorded dividends when paid. This is not in accordance with Generally Accepted Accounting Principles (GAAP) and overstates the average equity for the year. The Company agreed this accounting is not GAAP[6]. An additional concern is the Company reflects equity based on the sum of all the Company's equity accounts. This is a concern because the Company has some non-utility operations and plant. The equity earned and the investment in non-utility plant should be excluded from the equity reflected in the capital structure. Finally, the Company is a wholly owned subsidiary and the level of equity is based on earnings and parent company investment. To the extent the parent invests added funds in GMP the equity balance is increased. If the funds invested are from borrowed funds this creates a profit mechanism for the parent because the return on equity is significantly higher than any debt rate the parent incurs to make that investment. It is not uncommon for the capital structure to reflect a 50/50 split

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6 Company response to DPS.GMP.5-3.

between debt and equity when a subsidiary is the utility requesting a change in rates. Larkin recommends that the Company reflect the 50/50 split to account for the non-utility investment, the non GAAP accounting and to reduce the possible inequity of parent debt being invested to generate earnings for the parent. The Department and GMP discussed the issue at length and it was ultimately agreed that GMP would reflects a 50.30% equity, a reduction of 47 basis points from the initial request of 50.77%. Larkin believes the reduction is reasonable for the current filing. The Company in response to DPS.GMP.5-12 explained it monitors its infusion of equity and investments so GMP maintains a 50/50 debt to equity structure over a 13 month average ratio. The response explains why this is necessary and given the concerns identified above Larkin recommends that future filings be based on a 50/50 capital structure.

Larkin also identified an issue with the long term debt raised proposed by the Company for the upcoming issuance of debt. The Company agreed to reduce the debt rate on that issue of debt and that effectively resolved the concern with the overall long term debt rate.

TEST YEAR EXPENSES

Base and Non Base O&M Expense

The use of the platform eliminated much of the review of expenses included in the cost of service. Larkin verified the platform costs to the previous filing and tested the calculated decrease for the (.6%) inflation factor applied. Larkin verified the O&M expenses to the Company's summary of revenue and expenses by FERC account.

Other O&M Expense

The review of other operation and maintenance expense included verification of the depreciation expense to the plant addition model and a review of the income tax calculation. Additionally, Larkin reviewed the Equity in Earnings of Affiliates and Other Operating Revenues.

Depreciation and Amortization Expense

Depreciation and amortization expense as reflected in the initial filing for review was $49.581 million. The $49.581 million consisted of $53.634 in depreciation expense, $1.778 million of amortization for the CEED program and a net amortization credit of $5.831 million associated with the various regulatory deferred debits and regulatory deferred credits. The August 1st filing reflected depreciation and amortization expense of $48.709 million. The $48.709 million consists of $52.909 in depreciation expense, $1.778 million of amortization for the CEED program and a net amortization credit of $5.978 million. The $725,000 decrease in depreciation expense is due to the removal of capital projects as recommended by Larkin. The change in net amortization credit reflects the Company agreeing to reduce the exogenous amortization by the $600,000 remaining from the $1,200,000 exogenous deductible, the Company agreeing to remove the amortization of the $761,962 ESAM amortization, the Company agreeing to the removal of the $147,522 of rate design costs from amortization expense and reflecting it as part of the platform costs, the Company's agreeing to eliminate the $1,500,000 synergy credit proposed to be reflected in amortization expense as an advance of the 2016 estimated synergy savings (i.e. this increased the cost of service) and the addition of a $112,220 credit for net metering as negotiated by the Department.

The $600,000 change will be discussed in more detail as part of the Exogenous section of the report. The ESAM adjustment reflects the fact that as described in the ESAM Report, Larkin determined that the revenue shortfall calculated by the Company should be adjusted and after the adjustment the shortfall fall is within the non-sharing band width. Larkin took exception to the Company requesting the rate design costs as a separate item from the platform costs. Regulatory related costs are reflected in the platform and since the rate design costs are associated with a previous rate filing the costs belong in the platform. Finally, Larkin advised the Department and the Company, that despite the Company's good intentions to advance synergy savings from FY 2016, it would not be considered to be a known and measurable adjustment because the FY 2016 has not been completed. In addition, if the credit were allowed and the results were not as was optimistically projected, then ratepayers would have to return the advanced synergy to the Company increasing rates in the FY 2018.

MERGER SAVINGS

The June 1st filing reflected a merger savings adjustment to the cost of service of \$15.0 million. The FY 2017 merger savings are to be shared equally between ratepayers and shareholders. Larkin recommended that since the difference between the test year and the platform for the rate year is representative of merger savings that the merger savings adjustment should be based on 50% of the platform adjustment. The Company initially pushed back on the recommendation but when in taken into consideration with Larkins recommendation to eliminate a somewhat related adjustment proposed by the Company where a synergy credit was proposed to be flowed through amortization expense an agreement was reached to reflect a 50% synergy savings in the cost of service. The August 1st filing reflects a \$16.335 million synergy savings to the cost of service. This is an increase of \$1.335 million.

SETTLEMENT ADJUSTMENT

As part of the discussions at resolving issues Larkin suggested that the Company consider a slippage adjustment similar to that which was included in a prior filing. This is to provide some rate relief to offset the fact that the GMP in-service dates have proven to be overly optimistic. The Department continued the push for an adjustment and for ease of accounting purposes it was agreed to reflect an offset to the cost of service for \$300,000. As part of the agreement it was agreed that to the extent Larkin proposes an ESAM adjustment for FY 2017 similar to that reflected in the FY 2015 ESAM that the Company receives credit for the slippage allowance. The adjustment and agreement are considered reasonable.

EXOGENOUS COST and ADJUSTMENT

On April 30, 2015, the Company filed its proposed Exogenous Change Adjustment of $15,288,734 for the period October 1, 2014 through March 31, 2015 pursuant to Section III(C) of the Alt Reg Plan[7] and as specified in the Order in Docket Nos. 8190/8191. On May 26, 2015, the Company filed an amended calculation of the proposed Exogenous Change Adjustment for the period October 1, 2014 through March 31, 2015. The revised requested amount was $15,282,683. Based on the Company's request, the December 9, 2014 storm had costs totaling $16,095,743 from which the Company deducted an exogenous factor threshold of $600,000 and $213,060 of joint owner costs collected. Larkin identified five specific cost issues and one overall cost concern. The cost concern is the application of a $600,000 deductible instead of the $1,200,000. With the amortization being reflected as part of FY 2016 and being completed in FY 2017 the initial issue remains. The Department has identified an added issue with respect to actual storm costs reflected in fiscal periods ending subsequent to the deferral of costs that are applicable to the period in which the deferral occurred. The cost issues are as follows:

- The Company's applying a $600,000 threshold adjustment instead of the $1,200,000 threshold per storm as required under the exogenous factor terms and
- The application of any underspending of base O&M storm costs to the exogenous storm amounts as provided for in the Alt Reg Plan Attachment 8 filed December 17, 2014.

<u>Threshold</u>

In order to qualify as an exogenous storm event the costs for the storm must exceed $1,200,000. This requirement is specifically identified in the Alt Reg Plan[8] and

7 Alternative Regulation Plan approved in Docket Nos. 8190/8191 decision dated August 25, 2014.

8 Alternative Regulation Plan filed June 4, 2014 Section III(c) (2).

the Board Order in Docket Nos. 8190/8191.[9] As part of its filing for FY 2016 (based on the test year ended March 31, 2015) the Company reflected the deferred the storm costs but only reduced the storm costs by $600,000 (one-half of the $1,200,000). The theory espoused by the Company was because the storm costs are for a storm within the six month period from October 1, 2014 through March 31, 2015 only a half year of the deductible should apply. The deferral was to be amortized over two years beginning with FY 2016. Larkin disagreed with the Company's position stating that this reduction to the threshold is contrary to the Alt Reg Plan and the Order in Docket Nos. 8190/8191. Larkin stated that under Alt Reg and based on the Board's decision, the only way costs would qualify as an exogenous event is if the total storm costs exceed $1,200,000, not the $600,000 recognized by GMP.

The Alt Reg Plan specifically states:

> 2. Exogenous Storm Changes shall consist of increased costs experienced by the company relating to the incremental maintenance expenses incurred for Major Storms (as defined in the Company's Service Quality & Reliability Performance, Monitoring & Reporting Plan (the "SQRP")), and further defined as a storm that causes the Company to incur maintenance expenses in excess of $1,200,000, adjusted annually for inflation ($1.2M x (1+ CPI_U Northeast)), to the extent the aggregate amount in any year exceeds $1,200,000 adjusted annually for inflation ($1.2M x (1 + CPI-U Northeast). In the event that the Company has not exceeded the amount related to storm costs included in Base O&M Costs, Exogenous Storm Changes shall be reduced by such difference.[10]

There is no specific provision for modification of the $1,200,000 storm requirement even though the Alt Reg Plan specifically references the first Exogenous Change Adjustment period as being from October 1, 2014 through March 31, 2015.

In addition, the Boards Order explains the calculation as follows:

> The mechanics work as follows: *<u>if any single major storm</u>* during the year causes damage expenses in excess of $ 1,200,000, *<u>then the costs in excess of $ 1,200,000</u>*

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9 Vermont Public Service Board Order dated August 25, 2014, pages 9 and 22.

10 Alternative Regulation Plan filed June 4, 2014 Section III(c) (2).

> *will be deferred* and fully recovered in the next year's rates, provided GMP had exceeded the amount provided for storm costs in its base rates. For example, if GMP experiences five storms in a year, each of which meets the definition of a major storm but each of which only causes GMP to incur maintenance expenses of $ 1,000,000, then GMP would need to cover those expenses with existing rates. However, if GMP experiences a major storm that causes the Company to incur $1,300,000, then the Company could defer and recover later the $100,000 above the ESAF threshold, provided that GMP had exceeded the amount provided for storm costs in its base rates.[11] (Emphasis added)

This explanation makes no provision for the deferral of costs over $600,000. The Order specifically states "any single major storm" and that the costs to be deferred are those in excess of $1,200,000. The measurement is not related to a time period but is related to a specific event. Larkin recommended that the costs should be reduced by $1,200,000 instead of the $600,000 reduction reflected by the Company. The Company disagreed with this recommendation. Because a global settlement was reached for setting rates in FY 2016, the issue remained unresolved.

The current filing reflects the second year of amortization and Larkin recommended at a minimum the $600,000 not applied must be applied to the amortized costs in the rate year. The Department advanced an added theory that if the Company wants to apply the deductible based on a period in time then for the FY 2017 the full $1,200,000 deductible should be applied. The Company was not receptive to either recommendation. Larkin opined to the Department that both recommendations had merit and if the Company rejects the single event theory of applying a deductible because of time periods then the Company should not be able to reverse that application when the costs are being reflected in another time period making the $1,200,000 deductible application appropriate. Larkin believes the Company made the proper choice for FY 2017 in agreeing to the $600,000 adjustment because the deductible is based on an event and not based on a period of time. The Department and the Company may want to consider drafting clarifying language to the exogenous provision to avoid further issues.

[11] Vermont Public Service Board Order dated August 25, 2014 at 22.

Another issue identified by the Department with respect to the exogenous costs being requested is the application of subparts 2 and 4 of the Exogenous Change Adjustment section in the current Alt Reg Plan. The last sentence in subpart 2 states "In the event that the Company has not exceeded the amount related to storm costs included in Base O&M Costs, Exogenous Storm Changes shall be reduced by such a difference". The storm occurred in December 2014 which places it within the FY 2015. While the deferral was established shortly after the storm occurred there was no way that the actual Base O&M Costs for storms cost could be determined because the FY 2015 was not yet completed. Adding to the ambiguity of how the cost application can be applied is the fact that rates set for FY 2016 are based on the March 31, 2015 test year and again FY 2015 actual result are still not known and measurable. It is only when the FY 2015 ESAM was filed and reviewed that a determination could be made whether the Company recovered more storm costs in Base O&M rates than what was actually incurred. Based on a response to DPS 1-5 in the vegetation maintenance review the Company identified the September 30, 2015 total storm cost to be $20,967,684 of which $15,785,497 was designated as exogenous leaving Base O&M storm cost to be $5,182,187. The response to DPS 1-6 in the vegetation review identified the Base O&M storm amount included in the platform as $7,441,522. The difference of $2,259,335, as defined by subpart 2 of the Exogenous Change section of the Alt Reg Plan, should then be applied to the exogenous storm amount being requested for recovery. The Department advanced that subpart 4 should be applied in this rate application and that the exogenous amount included in the FY 2017 filing should be reduced by an additional $2,259,335. The Company did not agree with this recommendation. The Departments recommendation has some merit in that subpart 4 states "Over/under collections of the Exogenous Change Adjustment, due to a variance between projected and actual revenues, shall be deferred and included in the next base rate adjustment". The next base rate adjustment arguably could be the FY 2017 or it could apply retroactively to the ESAM for FY 2015 since the cost are in effect costs associated with the FY 2015 or the application could be applied to FY 2016 which is the first year of amortization of the Exogenous Change Adjustment made for FY 2015 where the cost were deferred. Larkin is of the opinion that according to the subparts of the

Exogenous Change section of the Alt Reg Plan that the Company must recognize a deferral of the Base O&M storm costs allowed in rates but not expended in FY 2015. The basis for that determination is the Exogenous Change (i.e. the storm) occurred in FY 2015 and the Company expended only $5,182,187 of the $7,441,522 allowed in Base O&M storm costs in FY 2015, therefore, in compliance with subparts 2 and 4 of the Exogenous Change section of the Alt Reg Plan a deferral of $2,259,335 is required. There is no ambiguity there. The ambiguity is what is the "next base rate adjustment" referred to by subpart 4. Typically if the exogenous change was deferred in the fiscal year of occurrence (i.e. FY 2015) and was to be written off in the next base rate filing (i.e. instead of over two years) which would be FY 2016, the underspending would not yet be known and factored into rates because base rates set for FY 2016 use a March 2015 test year and FY 2015 is still not complete. The earliest application would be the FY 2016 ESAM when the deferral is expensed and the FY 2015 storm costs are known and measurable. This is the first period in which an actual base rate O&M adjustment will be made and the first period in which the adjustment is known and measurable. An alternative would be the FY 2017 rate filing as advocated by the Department. Technically this also could be considered as the first period in which a base rate adjustment is made since it is the first base rate filing subsequent to the known and measurable difference being determined. Larkin recommends that the Board make a determination of how the provision should be applied or instruct the Department and GMP to clarify the language in the Alt Reg Plan and determine when to apply the adjustment since it is clear an adjustment is required. Larkin would recommend the adjustment be applied as part of the FY 2016 ESAM because that is the first period of time where the application of the known and measurable dollar amount to O&M expense could be reflected.

CONCLUSION

An improvement in the Company's compliance with providing supporting documentation for the projected costs was observed as part of the review. The Company did try to mitigate the rate impact with the suggested accounting change for CIAC (i.e. recommended in FY 2016 and continuing into FY 2017), a global reduction to costs and the increase in merger savings offset. The Company provided timely responses to questions asked and at making personnel available to discuss issues identified. Under the current Alt Reg process the resulting rates are considered reasonable. As discussed in detail, GMP initially was seeking an increase in base rates of $14.217 million (2.57%) and the review process ultimately resulted in a base rate decrease of $142,000 (-.03%). This is considered significant and serves as an indication that the process can work if the parties make an effort to resolve any issues at hand.

However, there still remain some areas of concern that are significant in nature. The Company should improve on the financial analysis that are provided as justification for projects and the Company should consider being less optimistic about the in-service dates especially based on its history of actual dates when compared to projected dates. Exogenous storm events have resulted in significant costs to ratepayers and because the ratepayers are ultimately held responsible for this cost the Company should focus on vegetative management practices that will mitigate the costs. Absent a more proactive vegetative program that focuses on danger/hazard trees the Company should be held responsible for future storm costs. The Company has made a commitment to address some of the concerns so it is now more important than ever to monitor the commitment to make sure the improved vegetation practice is achieved.

<u>Exhibit 9</u> - June 4, 2014 Memorandum of Understanding (MOU) which is GMP's current (2014-2017) Alternative Regulation Plan

GREEN MOUNTAIN POWER CORPORATION
ALTERNATIVE REGULATION PLAN
Filed June 4, 2014

This successor Alternative Regulation Plan (the "Plan") constitutes an alternative form of regulation for Green Mountain Power Corporation ("GMP" or the "Company") under 30 V.S.A. § 218d. The Plan governs the manner in which the electric rates of GMP will be regulated by the Public Service Board (the "Board") during the term of the Plan and shall be filed as a compliance tariff.

I. TERM

The Plan shall take effect on October 1, 2014. The Plan shall terminate, unless further extended, on September 30, 2017; provided, however, that rates incorporating adjustments relating to the Power Adjustor, Exogenous Change Adjustment and Earnings Sharing Adjustor shall continue beyond the termination date, as provided in Section III(F), below. The Plan may be terminated or modified upon request of the Company and the Department of Public Service ("Department") and approval by the Board.

II. PLAN EXTENSION

The Company shall have the option to petition for a one-year extension beginning October 1, 2017 subject to prior review by the Department and approval of the Board. No later than December 30, 2016, the Company shall file with the Board and Department its intentions regarding a successor plan or plan extension, if any.

III. RATE ADJUSTMENTS

No general rate adjustment other than described herein (and as provided for in the previously-approved Alternative Regulation Plan) will be effective before October 1, 2017, except that the Company may seek temporary rate increases pursuant to 30 V.S.A. § 226(a) and the Company may file modified or new tariffs for new services or adjustments on a revenue-neutral basis subject to Board approval pursuant to 30 V.S.A. §§ 225, 226, 227.

A. BASE RATE ADJUSTMENTS

Under the Plan, the Company will propose to revise its base rates annually on a service-rendered basis commencing October 1, 2015, and will support each such proposal with cost of service information filed with the Board by August 1 of the same year.

The rate year cost of service filing shall be calculated in a manner consistent with the traditional Vermont rate making principles (*i.e.*, exclude the Company's disallowed costs and results of unregulated operations (but business services included in cost of service)), consistent with the provisions of this Plan, and **Attachment 7** hereto (setting out supporting cost documentation requirements for each capital project proposed as a rate year addition to plant), except that no adjustments due to the merger of Central Vermont Public Service Corp. ("CVPS") and GMP will be made to the accounts included in Synergy Savings described in **Attachment 6** ("Base O&M Costs"). Base O&M Costs shall not include savings and costs related to Smart Grid and Advanced Meter Infrastructure, Kingdom Community Wind, cost reductions associated with the MOU in Docket 7496, and the CVPS acquisition of OMYA, which shall be reflected in rates consistent with traditional ratemaking principles (except to the extent approved by the Board, such as recovery of the OMYA acquisition premium). The Base O&M Costs included in the October 1, 2012 base rate adjustment will be subject to change, in each future base rate adjustment in which merger savings are shared with customers, to reflect the change in the Consumer Price Index for All Urban Consumers, Northeast Region ("CPI-U Northeast")[1], any Exogenous Changes and the impact of the Non-Power Cost Cap, and any further changes agreed upon by GMP and the Department and approved by the Board, and in particular;

1. The test year shall be based on the 12-month period ending March 31 of the year of the base rate filing.

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[1] "CPI-U Northeast" means Consumer Price Index All Urban Consumers- Northeast for the test year, expressed as a percentage increase or decrease over the prior 12-month period.

2. The percentage base rate change will be determined by comparison of forecasted rate year total cost of service to the revenues that would be raised by existing base rates and projected rate year sales as projected in accordance with the Company's Forecast Methodology, attached hereto in **Attachment 1**.

3. The base rate adjustment shall reflect the rate treatment of merger savings approved by the Board in Docket 7770.

4. Except as provided in Section 6 below, any change in base rates shall be implemented by a uniform percentage change in each rate element for each rate class; provided that any change in base rates shall not apply to the Commercial and Industrial Transmission Service Rate ("Transmission Rate") or to rates or fees that have historically not been subject to general rate increases or decreases (for instance the adder portion of Voluntary Renewables Service Rider, Curtailable Rider Buy-Through Rate, special charges/fees, wholesale power market rates included in the ski area service tariff) ("Exempt Charges").

5. The amounts recoverable in base rates associated with all costs other than those recoverable under the Power Adjustor ("Non-Power Supply Costs") shall be limited by a Non-Power Cost Cap expressed in the following formula:

   ((Current Non-Power Costs) x (1 + CPI-U Northeast -1% Productivity Adjustment + Non-Power Supply Cost Incentive Adjustment)) + Capital Spending Adjustment + Exogenous Changes (if any) + Incremental ROE Adjustment (if any).

   "Current Non-Power Costs" means the amount of Non-Power Supply Costs included in the previous base rate adjustment.

"Non-power Supply Cost Incentive Adjustment" means the productivity factor adjustment set forth in **Attachment 5** hereto.

"Capital Spending Adjustment" means the return, taxes and depreciation/amortization expense on (1) the incremental rate year utility plant in service investment, (a) net of retirements and any incremental investments subject to AFUDC, and (b) adjusted for the change in accumulated depreciation and accumulated deferred income tax resulting from the incremental rate year utility plant in service investment, (2) incremental rate year GMP Efficiency Fund and CEED Fund spending, and (3) incremental rate year Preliminary Survey costs.

"Exogenous Changes" means the amount of any Exogenous Changes in the rate year calculated in accordance with the provisions of this Plan.

"Incremental ROE Adjustment" means the difference between the allowed return on equity in the current base rates and the return on equity included in the proposed base rates.

The allowed return on equity component shall be adjusted by a percentage amount equal to 50% of the difference between the average ten-year Treasury note yield to maturity (a) as of the last twenty trading days ending two weeks prior to the filing, and (b) as of the twenty trading day period used for the last adjustment to the return on equity component.

6. The Commercial and Industrial Transmission Service Rate ("Transmission Rate") charges that becomes effective October 1, 2014 as a result of Board Orders issued in Dockets 8190 and 8191 shall remain in effect without change for the three year term of the Plan. No changes or adjustments shall be made to the Transmission Rate charges that become effective October 1, 2014 for any reason, including but not limited to any specified Plan Rate Adjustments (as such term is defined in the

Plan) and changes resulting from any rate design proceeding, during the three-year term of the Plan.

B. <u>EARNINGS SHARING ADJUSTOR</u>

Commencing October 1, 2014, the Company's rates will be subject to an Earnings Sharing Adjustor collected at the time of the next base rate adjustment. No later than 60 days after the end of each rate year ("ESA Measurement Period"), the Company shall file with the Board and Department its Actual Earnings for the ESA Measurement Period, the proposed Earnings Sharing Adjustor calculation, the proposed Earnings Sharing Adjustor, and supporting information. Actual Earnings will be calculated on a regulatory basis based on the same methodology as the earnings cap calculation reflected in the Board's Order in Docket Nos. 6946/6988 (*i.e.*, exclude the Company's disallowed costs and results of unregulated operations (but business services shall be included in cost of service)). Actual Earnings shall include the earnings impact of any variance within the Power Adjustor Efficiency Band, but shall not include the earnings impact of excluding merger-related adjustments to Base O&M Costs. The Variance Amount (as defined below) shall be deferred and amortized during the following base rate year ("ESA Adjustment Period").

The Earnings Sharing Adjustor shall be calculated as follows:

1. <u>Calculation of Variance Amount</u>

i. If Actual Earnings reflect a rate of return on equity that is within a range equal to 50 basis points below and 35 basis points above the Board-approved rate of return on equity during the ESA Measurement Period ("Earnings Sharing Band"), there will be no Earnings Sharing Adjustor and the Company shall contribute 10% of Earnings Sharing Band earnings in excess of the Board-approved rate of return on equity to the Company's Power Partners Program;

ii. If Actual Earnings reflect a rate of return on equity that is below the Earnings Sharing Band, a positive Earnings Sharing Adjustor will collect from ratepayers an amount reflecting (a) the revenue impact of a 50/50 sharing of the lower earnings (below the Earnings Sharing Band), down to a level equal to 200 basis points below the Board-approved rate of return on equity during the ESA Measurement Period, and (b) the entire revenue impact of the lower earnings (below 200 basis points); and

iii. If Actual Earnings reflect a rate of return on equity that is above the Earnings Sharing Band, a negative Earnings Sharing Adjustor will refund to ratepayers an amount reflecting (a) the revenue impact of a 50 (Company)/40 (customers)/10 (Power Partners) sharing of the higher earnings (above the Earnings Sharing Band), up to a level equal to 55 basis points above the Board-approved rate of return on equity during the ESA Measurement Period.

If Actual Earnings reflect a rate of return on equity that is 56 basis points, a negative Earnings Sharing Adjustor will refund to ratepayers an amount reflecting (a) the revenue impact of a 25 (Company)/65 (customers)/10 (Power Partners) sharing of the higher earnings (above the Earnings Sharing Band), up to a level equal to 200 basis points above the Board-approved rate of return on equity within the Upper Bound; and (b) the entire revenue impact of the higher earnings (above 200 basis points).

2. Calculation of Earnings Sharing Adjustor

i. The Earnings Sharing Adjustor shall be a positive or negative fraction equal to (a) the dollar Variance Amount derived in Section III(B)(1) above, divided by (b) projected revenues from Company charges during the ESA Adjustment Period, based on the Forecast Methodology.

ii. The Earnings Sharing Adjustor fraction shall be applied to each rate element for each rate class other than Exempt Charges and Transmission Rate.

iii. Over/under collections of the Earnings Sharing Adjustor, due to a variance between projected and actual revenues, shall be deferred and included in the next base rate adjustment.

A sample calculation is attached as **Attachment 2**.

C. EXOGENOUS CHANGE ADJUSTMENT

The Exogenous Change Adjustment shall equal the sum of any (a) Exogenous Non-Storm Changes, plus any (b) Exogenous Storm Changes (collectively, "Exogenous Changes") as provided below. Any Exogenous Changes in the 12-month period ending March 31, positive or negative, will be deferred and recovered in full (i.e., not subject to the Earnings Sharing Band) as part of the base rate adjustment in the next base rate year, unless the Department and the Company agree to a longer recovery period based on deferral amount, customer rate impact or for other reasons; provided that the period associated with the first Exogenous Change Adjustment shall be based on the period between October 1, 2014 and March 31, 2015.

1. Exogenous Non-Storm Changes shall consist of material cost or revenue changes relating to the following, to the extent the aggregate amount in any year exceeds $1,200,000 adjusted annually for inflation ($1.2M x (1 + CPI-U Northeast).

i. Changes in tax laws that impact the Company.
ii. Changes in Generally Accepted Accounting Principles.
iii. Any Federal Energy Regulatory Commission or New England Independent System Operator rule changes affecting the Company.
iv. Other regulatory, judicial or legislative changes affecting the Company.
v. Net loss of major customer(s) load not related to weather.

vi. Major unplanned maintenance costs or investments, such as those incurred due to unexpected major maintenance (unrelated to storms) and major repairs to Company-owned power plants.

2. Exogenous Storm Changes shall consist of increased costs experienced by the company relating to the incremental maintenance expenses incurred for Major Storms (as defined in the Company's Service Quality & Reliability Performance, Monitoring & Reporting Plan (the "SQRP")), and further defined as a storm that causes the Company to incur maintenance expenses in excess of $1,200,000, adjusted annually for inflation ($1.2M x (1+ CPI_U Northeast)), to the extent the aggregate amount in any year exceeds $1,200,000 adjusted annually for inflation ($1.2M x (1 + CPI-U Northeast). In the event that the Company has not exceeded the amount related to storm costs included in Base O&M Costs, Exogenous Storm Changes shall be reduced by such difference.

3. The calculation of any Exogenous Change Adjustment shall be provided to the Department as soon as available, but no later than May 1.

4. Over/under collections of the Exogenous Change Adjustment, due to a variance between projected and actual revenues, shall be deferred and included in the next base rate adjustment.

D. <u>POWER ADJUSTOR</u>

Commencing October 1, 2014, the Company's rates will be subject to a Power Adjustor effective on a service-rendered basis collected at the time of the next base rate adjustment. Thereafter and within 30 days after the end of each quarter ("PA Measurement Quarter"), the Company shall file for informational purposes with the Board and Department, (1) the Company's actual power costs (calculated in a manner consistent with the principles underlying the annual cost of service filings, and reflecting the provisions set forth below), and (2) the variance between the actual (*i.e.* recorded in the Company's accounts) power costs and the forecasted power costs included in the

Company's rates for the PA Measurement Quarter. At the time of the next base rate filing, the Company will file a Power Adjustor aggregating the results of the calculation from the previous four (4) quarters ending March 31 and propose a Power Adjustor to be collected during the rate year ("PA Adjustment Period"); provided that the PA Measurement Period associated with the first Power Adjustor shall be based on the period between October 1, 2014 and March 31, 2015.

The Power Adjustor shall reflect a positive or negative rate adjustment equal to the following:

1. Calculation of Quarterly Variance Amount:
    i. Component A, which includes the dollar amount of any variation between (1) actual Committed Costs for the PA Measurement Quarter and (2) the Committed Costs included in the cost of service underlying the Company's base rates for the corresponding quarter; plus

    ii. Ninety percent (90%) of Component B, which includes the amount, if any, by which (1) the dollar amount of any variation between (a) actual total Open Position Costs for the PA Measurement Quarter and (b) total Open Position Costs included in the cost of service underlying the Company's base rates for the corresponding quarter, and adjusted for any change in retail sales by multiplying such change times the amount/kWh of power costs included in base rates, exceeds (2) $307,000 ("Power Efficiency Band");

Committed Costs consist of demand charges, transmission costs and ancillary charges (net of interchange (resales)). Open Position Costs consist of all other power costs (net of interchange (resales)). A list of the Company's current Committed Costs and Open Position Costs is attached as **Attachment 3**.

2. Calculation of Annual Power Adjustor:

The Power Adjustor shall be a uniform positive or negative adjustment per kWh equal to (1) the Annual Variance Amount divided by (2) projected MWh sales during the Collection Year based on the Forecast Methodology, where the Annual Variance Amount shall equal the sum of the previous four (4) Quarterly Variance Amounts plus any previous PA Adjustment Period over or under collections of the Power Adjustor due to variance between projected and actual sales.

A sample calculation is attached as **Attachment 4**.

3. The Annual Variance Amount shall be calculated based on the same methodology used for the Earnings Sharing Adjustor and shall be applied to each rate element for each rate class other than Exempt Charges, Transmission Rate, and rate elements not subject to a kWh charge. For accounting purposes, the Annual Variance Amount shall be deferred and amortized in the PA Adjustment Period in an amount equal to the revenue increases or decreases that recover or repay the amortized amount.

4. The Company shall maintain separate accounts for Component A and Component B costs.

E. <u>NOTICE AND REVIEW OF FILINGS; EFFECTIVE DATE</u>

Each Base Rate Adjustment, Earnings Sharing Adjustor, Exogenous Change Adjustment and Power Adjustor (collectively, “Plan Rate Adjustments”) shall be effective on October 1. The Company shall provide individual customer notice through normal bill or other mailings of each Plan Rate Adjustment not less than 30 days before service is rendered.

a. A draft of each Plan Rate Adjustment shall be filed with the Board and Department as follows: (1) draft Earnings Sharing Adjustor no later than December 1, (2) draft Power Adjustor and Exogenous Change Adjustment no later than May 1, and (3) draft of all Plan Rate Adjustments (including base rate adjustment) no later than June 1. The June 1 filing shall be posted on the Company's web site, and the Company shall hold a public workshop after the June 1 draft base rate filing.

All Plan Rate Adjustments shall be accompanied by a narrative explanation of information reasonably needed to assist in understanding the filing.

For all Plan Rate Adjustments, the Department shall be able to retain, at the Company's expense and subject to the Company's reasonable consent, an independent third party with accounting and ratemaking expertise ("Third Party") to review each filing under the Plan for, (1) accuracy, (2) completeness, (3) compliance with traditional rate making and existing Board Orders regarding Cost of Service filings including the calculation of regulated earnings and (4) consistency with the Company's actual costs and with the Plan. Unless the Board grants an extension at the request of the Department, the Third Party shall file a report with the Board and Department no later than two weeks after the rate adjustment is submitted to the Board on August 1.

The Base Rate Adjustment is subject to Board suspension and review, pursuant to 30 V.S.A. §§ 225, 226, 227. Any Board decision in the proceeding resulting from Board's suspension shall be based on contested case procedures and shall be issued within four months after the applicable base rate filing was scheduled to take effect. This deadline shall not apply to any investigation relating to the Company's existing rates described in Section V(B).

In the event that a Plan Rate Adjustment filing results in a partial settlement, with one or more disputed issues, the Company or the Department may request that the Board issue an order putting rates reflecting the parties' agreement(s) into effect October 1 subject to further revision, and establishing a schedule for expedited procedures to resolve the remaining issue(s) in dispute. To the extent the resolution of any such issues results in rates different from those put into effect October 1, the Board shall require the Company to adjust its rates to account for the difference, in a manner similar to other Plan Rate

Adjustments and as determined by the Board to be just and reasonable in the particular circumstances.

The Earnings Sharing Adjustor, Exogenous Change Adjustment and Power Adjustor are not subject to Board suspension, but the Board may open an investigation and to the extent it finds, after notice and hearing, that the calculation was inaccurate or reflected costs inappropriate for inclusion in rates, it may require a modification to the extent necessary to correct the deficiencies.

There will be no issue preclusion or claim preclusion if any person or entity unsuccessfully seeks to initiate an investigation.

F. RESIDUAL ADJUSTMENTS

The Power Adjustor, Earnings Adjustor, and Exogenous Adjustment shall continue through the last billing cycle in September 2018. Any uncollected balance remaining after the adjustors are terminated shall be deferred and addressed in a future rate case.

IV. OTHER PLAN COMPONENTS

A. SERVICE QUALITY

The Company's SQRP, as it may be amended from time to time, is hereby incorporated into and made a part of this Plan.

B. LOW INCOME

. The Company shall match contributions by its customers to the Company's Warmth Program, and the amount of the Company's match shall not be included in rates.

C. INTEGRATED RESOURCE PLAN UPDATES

The Company shall provide the Board and the Department an update to the Action Plan included in the most recently filed Integrated Resource Plan ("IRP") no later than March 31st of each year of this Plan.

D. VERMONT ENERGY PLAN INVESTMENT

The Company shall continue to support Vermont's statewide energy goals by advancing promising technologies (e.g. electric vehicles, heat pumps, energy storage, solar power, etc.) and by exploring new services to facilitate efficient, low carbon energy choices by electric customers and consistent with least cost principles.

E. SERVICE CHOICES

The Company will continue to work with the Department to explore and implement additional innovative service choices, including as the result of the implementation of advanced automated meter reading technologies and infrastructure.

F. PLAN EVALUATION

Beginning March 31, 2016 and continuing each year thereafter under the Plan, the Company shall file a report with the Board and Department evaluating the effectiveness of the Plan's performance in achieving the goals of 30 V.S.A. § 218d. In advance of filing the reports, the Company shall confer with the Department with respect to the measurement criteria to be used in the reports. The Company will continue to use the criteria jointly agreed-upon with the Department in the annual reports assessing the Plan's effectiveness.

V. MISCELLANEOUS

A. During the term of the Plan, the application of 30 V.S.A. §§ 218(a), 225, 226, 227 and 229 to GMP shall be modified by the provisions of the Plan and the Board order approving the Plan.

B. The Company shall continue to file concurrently with each base rate adjustment, Power Adjustor, Exogenous Change Adjustment and Earnings Sharing Adjustor filing, the documentation currently filed with respect to each type of filing.

C. The Company shall describe the Plan in a separate mailing at least one month prior the first rate adjustment under the Plan and shall work with the Department in the development of customer communications and materials to be provided to customers.

D. Nothing in the Plan will be interpreted as preventing the Department from requesting a Board investigation into the Company's rates or the Board from undertaking such an investigation. The retroactive effect of any such investigation, and of any investigation pursuant to Section III(E), shall be consistent with 30 V.S.A. § 227(b).

Attachment 1

GREEN MOUNTAIN POWER CORPORATION
ALTERNATIVE REGULATION PLAN
LOAD FORECAST METHODOLOGY

The Alternative Regulation Plan Load Forecast incorporates the Company's Annual Customer, Sales and Revenue Forecast ("Annual Forecast") provided each year in connection with the annual budget prepared for the board of director's. The Company issues the services of Itron, Inc., an outside consultant with expertise in the field of energy forecasting, to assist in developing each year's Annual Forecast. Itron also implements an hourly load forecasting application, which the Company uses daily to forecast short-term system loads.

The Annual Forecast incorporates projections of (1) number of customers, (2) sales, and (3) revenues. Each of these is addressed in turn.

1. Number of Customers. Customers Forecasts are generated within a linear regression framework that relates class-level customer data to economic drivers. For the Residential class, the major economic drive in the model is a forecast of the number of households in the region. For the non-Residential non-Time of Use ("TOU") class, the primary economic driver is regional non-manufacturing employment. The forecast for the TOU customers is driven primarily by the total employment in the region.

2. Sales. The sale forecast is based on statistical models that relate specific end-use categories (e.g., residential electric heating, residential water-heating, residential non-heating, etc.) to weather, economics, saturation/efficiencies of various end-uses, and trends in electric prices. Monthly forecasts values are calculated on a billing-month basis. Cycle-weighted heating and cooling degrees day values are developed based on the meter-reading schedule, in order to align the weather data with the billing cycle. The models incorporate various forecasted economic data, including household income, people-per-household, and non-manufacturing output, based in large part on various third-party sources. Inputs concerning energy usage

patterns is based on Energy Information Administration ("EIA") data, macroeconomic data is obtained from Economy.corn and Weatherbank.com provides climate information for the Company's service area.

3. Revenues. The revenue projection is based on a reconciliation of the sales to the Company's billing protocol. In particular, the forecast aggregates billed-month sales and prior-month unbilled sales to convert the Company's billing cycles, which drive revenues, to the calendar month, on which the sales information is based. After conciliation, revenues are calculated by multiplying the consumption units (mWh, number of customers, kW, etc) by the appropriate tariff to determine the monthly amount of revenue that the Company will recognize for the upcoming year.

The Company reviews the sales, customer, and revenue forecast, and makes adjustments where warranted. The final results are used for the budget, for financial forecasts and for developing expected power supply requirements.

Example: Proposed Earnings Sharing Adjustor **Attachment 2**

(all revenues/costs in $000)

	Year 1 Benchmark	Year 1 Actual	Year 1 first Block	Year 1 Second Block	Year 1 Third Block
Retail Sales (kWh)	2,000,000,000	2,000,000,000	2,000,000,000	2,000,000,000	2,000,000,000
			Revenue required	Revenue required	Revenue required
Total Retail Revenue	$224,000	$224,000	$227,475	$226,525	$223,675
Total Expenses	$201,520	$205,000	$205,000	$205,000	$205,000
Operating income	$22,480	$19,000	$22,475	$21,525	$18,675
Interest	$4,000	$4,000	$4,000	$4,000	$4,000
Net income pre-tax	$18,480	$15,000	$18,475	$17,525	$14,675
Income tax	$5,800	$4,700	$5,800	$5,500	$4,600
Net income	$12,680	$10,300	$12,675	$12,025	$10,075
Net equity *	$130,000	$130,000	$130,000	$130,000	$130,000
Return on equity	9.754%	7.923%	9.750%	9.250%	7.750%
Revenue requirement @9.75%			227,475		
Revenue requirement @9.25%				226,525	
Revenue requirement @7.75%					223,675

Earnings Sharing Calculation

First Block - Retained 100% by Company	
100% shortfall retention limit % (ROE - 0.50%)	9.25%
100% shortfall retention limit ($227,474 - $226,525)	$950
100% shortfall retained	$950
Second Block - Shared 50/50 with Customers	
50% sharing shortfall limit % (ROE - 2.00%)	7.75%
50% sharing shortfall limit ($226,525 - $224,000)	$2,525
50% retained by Company	$1,263
50% collected from Customers	$1,263
Third Block - Collected 100% from Customers	
100% shortfall collected = ($223,675 - $224,000)	$0
Total shortfall to be collected from Customers	$1,263
Total shortfall borne by Company	$2,213
Projected Retail Sales (Year 2)	2,020,000,000
ESM Rate Change per kWh (Year 2)	$0.0006
ESM Rate Change %age	0.56%

Attachment 3

Summary of GMP Power Supply Expenses

	Additional description	Proposed PSA Component	FERC Account Number	Rationale
Jointly Owned Units - Non-fuel O&M				
Operation – Supervision & Eng	Steam	A	500	Little/no GMP control
Steam Expense	Steam	A	502	" "
Steam From Other Sources	Steam	A	503	" "
Steam Transfer Credit	Steam	A	504	" "
Electric Expenses	Steam	A	505	" "
Misc Steam Expenses	Steam	A	506	" "
Rents	Steam	A	507	" "
Allowances	Steam	A	509	" "
Maintenance Supervision & Eng	Steam	A	510	" "
Maintenance of Structures	Steam	A	511	" "
Maintenance of Boiler Plant	Steam	A	512	" "
Maintenance of Electric Plant	Steam	A	513	" "
Maintenance of Misc Steam Plant	Steam	A	514	" "
Maintenance of Steam Production Plant Non-Major	Steam	A	515	" "
Operation – Supervision & Eng	Nuclear	A	517	" "
Fuel	Nuclear	B	518	" "
Coolants and Water	Nuclear	A	519	" "
Misc Nuclear Power Expense	Nuclear	A	520	" "
Steam from Other Sources	Nuclear	A	521	" "
Steam Transferred-Cr	Nuclear	A	522	" "
Electric Expenses	Nuclear	A	523	" "
Misc Nuclear Power Expenses	Nuclear	A	524	" "
Rents	Nuclear	A	525	" "
Maintenance Supervision & Eng	Nuclear	A	528	" "
Maintenance of Reactor Plant Eq	Nuclear	A	529	" "
Maintenance of Electric Plant	Nuclear	A	530	" "
Maintenance of Misc Steam Plant	Nuclear	A	531	" "
Maintenance of Misc Nuclear Plant	Nuclear	A	532	" "
Operation – Supervision & Eng	Other	A	546	" "
Generation Expense	Other	A	548	" "
Misc	Other	A	549	" "
Rents	Other	A	550	" "
Maintenance of Supervision & Eng	Other	A	551	" "
Maintenance of Structures	Other	A	552	" "
Maintenance of Misc	Other	A	553-554	" "
GMP Owned Units - Non-fuel O&M				
Operation – Supervision & Eng	Hydro	B	535	Under GMP control
Water of Power	Hydro	B	536	" "
Hydraulic Expenses	Hydro	B	537	" "
Electric Expenses	Hydro	B	538	" "
Misc Hydraulic power gen expense	Hydro	B	539	" "
Rents	Hydro	B	540	" "
Maintenance Supervision & Eng	Hydro	B	541	" "
Maintenance of Structures	Hydro	B	542	" "
Maintenance of Reservoirs, Dams, etc	Hydro	B	543	" "
Maintenance of Electric Plant	Hydro	B	544	" "
Maintenance of Misc Hydraulic plant	Hydro	B	545	" "
Operation – Supervision & Eng	Other	B	546	" "
Fuel	Other	B	547	" "
Generation Expense	Other	B	548	" "
Misc	Other	B	549	" "
Rents	Other	B	550	" "
Maintenance of Supervision & Eng	Other	B	551	" "
Maintenance of Structures	Other	B	552	" "

Certain subaccounts include costs subject to the Savings Sharing mechanism and therefore will be excluded from the Power Adjustor.

Maintenance of Misc	Other	B	553-554	" "
Purchased Transmission and related	**FERC Account 565. Primarily ISO-NE and VELCO costs. Smaller fractions of Phase 1/2 support costs, NEPCO, NYPA.**	A	565	Little/no GMP control, likely volatility.
ISO-NE OATT, Market Services				
Transmission by Others	VELCO VTA, Regional Network Service (NOATT 1 and 9), Phase I/II support costs, National Grid (OATT, G-33, Ashuelot), SPEED, VEC, etc	A	565	Little/no GMP control
Schedule 2 VAR Charges/Credits	Reactive power and voltage support	A	561.4	Little/no GMP control
Schedule 16 Black Start Credits/Charges	System restoration payments to GMP for its units with black start capability	A	561.8	" "
ISO Sched 1 RNS	Scheduling, system control & dispatch for RNS load	A	561.4	" "
ISO Sched 1 Through & Out	Scheduling, system control & dispatch for Through or Out load	A	561.4	" "
ISO Sched 2	Administrative charges for energy market administration	A	575.7	" "
ISO Sched 3	Reliability market administration	A	561.8/575.7	" "
ISO Sched 4	Allocated FERC charges	A	575.7	" "
ISO Sched 5	NESCOE Charge	A	575.7	" "
Interest and Late Fees		A	565	Booked as Energy charge
NEPOOL Expenses	attorney fees for NEPOOL activities	A	565	
Rents Trans		A	567	Little/no GMP control
Highgate O&M				
Supervision Eng High Oper		A	560	" "
Load Dispatching High Oper		A	561	" "
Station Expenses High Oper		A	562	" "
Overhead Line Exp High Oper		A	563	" "
Rents other Highgate		A	567	" "
Supervision Eng High Maintenance		A	568	" "
Maintenance of Structures (Major Only)		A	569	" "
Station Equip High Maintenance		A	570	" "
Overhead Lines High Maintenance		A	571	" "
GMP Owned Units - Fuel	Includes hydro units, peaking units and Searsburg	B	547	All energy costs in B
Jointly Owned Units - Fuel	Includes Wyman 4, Stony Brook , McNeil, Millstone	B	501/518/547	" "
Power Transaction related accounts				
Existing Long-term Contracts - Energy Charges	Energy in A, Capacity in B	B	555	All energy costs in B
Existing Long-term Contracts - Capacity Charges	Energy in A, Capacity in B	A	555	Changes fundamentally not under GMP control.
Existing Long-term Sales for Resale - Energy Revenues	Energy in A, Capacity in B	B	447	All energy costs in B.
Existing Long-term Sales for Resale - Capacity Revenues	Energy in A, Capacity in B	A	447	Changes fundamentally not under GMP control.
Future bilateral purchases & sales of Energy - Energy Charges	Energy in A, Capacity in B	B	555, 447	All energy costs in B.
Future bilateral purchases & sales of Energy - Capacity Charges	Energy in A, Capacity in B	A	555, 447	
Future bilateral purchases & sales of capacity	Energy in A, Capacity in B	A	555, 447	
Financial Hedging Instruments (for energy costs)		B	555	Used to hedge energy costs
REC sale revenues (or purchase costs)	Renewable energy credits	B	447	All energy costs in B
ISO Market Settlement Accounts				
Day Ahead Energy	Includes cost of GMP load obligation & revenue from all GMP resources	B	555	Energy Component Only -All Energy in B
Real Time Energy	Includes cost of GMP load obligation & revenue from all GMP resources	B	555	Energy Component Only -All Energy in B
Energy losses	The loss component of LMP costs to serve GMP load & LMP revenues from GMP resources.	A	555	Marginal Loss Component - Little/no GMP control
Congestion	The congestion component of LMP costs to serve GMP load & LMP revenues from GMP resources	B	555	Can be partially hedged
Emergency Purchases	Made by ISO-NE	A	555	
Emergency Sales	Made by ISO-NE	A	447	
ICAP/FCM Capacity (charges and credits)		A	555	
Reliability Must Run ("RMR") charges		A	555	
Load response	ISO-NE load response program	A	555	
Regulation		A	555	

Certain subaccounts include costs subject to the Savings Sharing mechanism and therefore will be excluded from the Power Adjustor.

DA NCPC Charges	Operating reserves	**A**	**555, 447**	Matches costs when GMP units or joint-owned units are run for reliability and fuel expense appears as Component B. Non-GMP unit or joint-owned unit NCPC charges/credits will remain in Component A.
DA NCPC Credits	Operating reserves	**B**	**555**	Little/no GMP control
RT NCPC Charges	Operating reserves	**B**	**555, 447**	Matches costs when GMP units or joint-owned units are run for reliability and fuel expense appears as Component B. Non-GMP unit or joint-owned unit NCPC charges/credits will remain in Component A.
RT NCPC Credits	Operating reserves	**B**	**555**	Little/no GMP control
Forward Reserve Credits/Charges	Operating reserves	**A**	**555**	
Synchronous Condenser credits/charges	Operating reserves	**A**	**555**	
Cancelled Starts	Operating reserves	**A**	**555**	
OR Resources available in DA not dispatched in RT	Operating reserves	**A**	**555**	
DA NCPC credits for dispatchable load pumps	Operating reserves	**A**	**555**	
RT NCPC credits for dispatchable load pumps	Operating reserves	**A**	**555**	
NCPC credits for resources postured for relaibility	Operating reserves	**B**	**555, 447**	Matches costs when GMP units or joint-owned units are run for reliability and fuel expense appears as Component B. Non-GMP unit or joint-owned unit NCPC charges/credits will remain in Component A.
Special Constraint Resource charges/credits	Operating reserves	**B**	**555, 447**	Matches costs when GMP units or joint-owned units are run for reliability and fuel expense appears as Component B. Non-GMP unit or joint-owned unit NCPC charges/credits will remain in Component A.
FTR/ARR		**B**		
LT On Peak ARR Credit	Revenues From FTR Auctions	**A**	**555**	Little/no GMP control
Monthly On Peak ARR Credit	Revenues From FTR Auctions	**A**	**555**	" "
LT Off Peak ARR Credit	Revenues From FTR Auctions	**A**	**555**	" "
Monthly Off Peak ARR Credit	Revenues From FTR Auctions	**A**	**555**	" "
FTR Auction Credits/Charges	Cost of FTR's in auction	**B**	**555**	Used to hedge congestion costs
Monthly FTR Congestion Credits/Charges	monthly congestion revenue paid to FTR holders	**B**	**555**	" "
Negative Congestion Adjustment	Charge if FTR congestion revenue is negative	**A**	**555**	Little/no GMP control
Annual FTR Adjustments	Disbursement of Excess FTR congestion revenue	**B**	**555**	only paid to FTR holders
NEPOOL GIS Fees	GIS transaction fees, and GMP share of NEPOOL GIS overhead costs.	**A**	**555**	

Excluded from the Power Adjustor:
Transmission for Others (this is mostly subtransmission service for VT utilities)

Certain subaccounts include costs subject to the Savings Sharing mechanism and therefore will be excluded from the Power Adjustor.

Attachment 4

Benchmark Power Cost Calculation

	Benchmark Quarter 1	Benchmark Quarter 2	Benchmark Quarter 3	Benchmark Quarter 4	Total
Retail Sales - kWh	1,050,000,000	1,250,000,000	950,000,000	1,100,000,000	4,350,000,000
Component A Costs	$25,000,000	$23,000,000	$26,000,000	$18,000,000	$92,000,000
Component B Costs	$70,000,000	$75,000,000	$60,000,000	$65,000,000	$270,000,000
	========	========	========	========	
Total	$95,000,000	$98,000,000	$86,000,000	$83,000,000	$362,000,000
	Retail Power Cost per kwh				**$0.0832**

Operation of Power Adjustor for Quarter 1
Example - Effect of Incremental Revenues on Power Adjustor Calculation

Power Cost in Retail Rate $0.08322 $/kwh (derived in benchmark calculation)

	Benchmark Quarter 1	Actual Quarter 1	Variance from Benchmark	Bandwidth	Add. 10% bandwidth	Variance to be Collected/Refunded
Retail Sales - kWh	1,050,000,000	1,075,000,000	25,000,000			
Component A Costs	$25,000,000	$25,000,000	$0	$0		$0
Component B Costs	$70,000,000	$75,000,000	$5,000,000			
Incremental Revenues as Offset to Component B			**$2,080,460**			
Net Component B variance			$2,919,540	$307,000	$261,254	$2,351,286
	========	========				========
Total	**$95,000,000**	**$100,000,000**				**$2,351,286**

Attachment 5

NON-POWER SUPPLY COST INCENTIVE ADJUSTMENT

1. The Non-Power Supply Cost Incentive Adjustment shall equal amounts set forth in the tables below, based on GMP's ranking among the Benchmarked Utilities listed below in Benchmarked Expenses per Customer, as calculated from data reported in each utility's FERC Form 1 for the most-recently completed calendar year.

a. Non-Power Supply Cost Incentive Adjustment:

GMP Ranking	Adjustment
1st Quartile (i.e. ranked in top 5 companies)	0.75%
2nd Quartile	0.50%
3rd Quartile	0.25%
4th Quartile	0%

2. Definitions:

Benchmarked Expenses means (1) the sum of:

TOTAL Administrative & General Expenses	FERC p.323
TOTAL Customer Accounts Expenses	FERC p.322
TOTAL Customer Service and Information Expenses	FERC p. 323
TOTAL Sales Expenses	FERC p. 323
TOTAL Distribution Expenses	FERC p. 322
TOTAL Transmission Expenses less Transmission of Electricity by Others	FERC p. 321

divided by the average number of customers per year
FERC p. 301

Benchmarked Utilities means

Bangor Hydro-Electric
Unitil Energy Systems, Inc.
Granite State Electric Company
Northern States Power Company (WI)

Green Mountain Power
MDU Resources
The Empire District Electric Co.
Maine Public Service Co.
Fitchburg Gas & Electric
Western Massachusetts Electric Co
Rochester Gas & Electric
Madison Gas & Electric
CH Energy
Black Hills Power, Inc.
Upper Peninsula Power Company
Public Service Company of New Hampshire
Otter Tail
The United Illuminating Co (UL Holdings)
Rockland Electric Company
Allete (Minnesota Power,SWL&P)

In the event any Benchmark Utility ceases to exist as a separate investor-owned electric distribution utility filing an annual FERC Form 1, or ceases to be an appropriate benchmark as agreed by both the Company and the Department, it shall be replaced by an investor-owned electric distribution utility with relevant attributes similar to the Company. In the event the Department and the Company are unable to agree on a replacement, they shall submit the issue to the Board for resolution.

<u>Examples of the Non-Power Supply Cost Incentive Adjustment</u>

If GMP's rank were 10 out of the 20 Benchmarked Utilities in Benchmarked Expenses, it would rank in the second quartile of Benchmarked Utilities. This results in a 0.50% Non-Power Supply Cost Incentive Adjustment, reducing the 1% Productivity Adjustment to 0.50%.

If GMP's rank were 16 out of the 20 Benchmarked Utilities in Benchmarked Expenses, it would rank in the fourth quartile of Benchmarked Utilities. This results in a 0% Non-Power Supply Cost Incentive Adjustment, with no effect on the 1% Productivity Adjustment.

O&M ACCOUNTS TO BE INCLUDED IN SYNERGY SAVINGS

Synergy Savings for existing accounts are limited to the highlighted accounts in the table below.

Certain subaccounts of the highlighted accounts include costs subject to the power cost adjustment mechanism and therefore will be excluded from the Synergy Savings calculations, and vice versa. The two accounts with asterisks are treated differently by GMP and CVPS under their power adjustors; this will be addressed in the filings requesting changes to the Alternative Regulation Plans.

Acct #	1. POWER PRODUCTION EXPENSES
	A. Steam Power Generation:
500	Operation - Supervision & Eng
501	Fuel
502	Steam Expense
503	Steam From Other Sources
504	Steam Transfer Credit
505	Electric Expenses
506	Misc Steam Expenses
507	Rents
509	Allowances
510	Maintenance Supervision & Eng
511	Main't of Structures
512	Main't of Boiler Plant
513	Main't of Electric Plant
514	Main't of Misc Steam Plant
	TOTAL Power Production - STEAM Power
	B. Nuclear Power Generation
517	Operation - Supervision & Eng
518	Fuel
519	Coolants and Water
520	Misc Nuclear Power Expense
521	Steam from Other Sources
522	Steam Transferred-Cr
523	Electric Expenses
524	Misc Nuclear Power Expenses
525	Rents
528	Maintenance Supervision & Eng
529	Main't of Reactor Plant Eq
530	Main't of Electric Plant
531	Main't of Misc Steam Plant
532	Maint of Misc Nuclear Plant
	TOTAL Power Production - NUCLEAR Power
	C. Hydraulic Power Generation:

535	Operation - Supervision & Eng
536	Water of Power
537	Hydraulic Expenses
538	Electric Expenses
539	Misc Hydraulic power gen expense
540	Rents
541	Maintenance Supervision & Eng
542	Main't of Structures
543	Main't of Reservoirs, Dams, etc
544	Main't of Electric Plant
545	Main't of Misc Hydraulice plant
	TOTAL Power Production - HYDRO Power
	D. Other Power Generation:
546	Operation - Supervision & Eng
547	Fuel
548	Generation Expense
549	Misc
550	Rents
551	Maintenance Supervision & Eng
552	Main't of Structures
553-554	Main't of Misc
	TOTAL Power Production - OTHER Power
555	Purchased Power
556	System Control and Load Dispatch
557	Other Expense
	TOTAL Power Production Expense
	2. TRANSMISSION EXPENSES
	Operation:
560	Operation - Supervision & Eng
561	Load Dispatching
561.2	Load Dispatching - Monitor and Operate
561.4	Scheduling, System Control, Dispatch
561.5	Reliability, Planning and Standards Dev'l
561.8	Reliability Planning & Standards Development Services
562	Station Expenses
563	Overhead Lines
564	Underground line expenses
565	Transmission of Electricity by Others
566	Misc Transmission Expense
567*	Rents
568	Maintenance Supervision & Eng
569	Main't of Structures
569.1	Main't of Computer Hardware
569.2	Main't of Computer Software
570	Main't of Station Equipment
571	Main't of Overhead Lines
572	Main't of underground lines
573	Maintenance of Misc Transmission plant

	TOTAL Transmision
	3. REGIONAL MARKET EXPENSES
	Operation:
575.6*	Market Monitoring and Compliance
575.7	Market Facilitation, Monitoring, and Compliance Services
	TOTAL Regional Transmission & Market Ops
	4. DISTRIBUTION EXPENSES
	Operation:
580	Operation - Supervision & Eng
581	Load Dispatching
582	Station Expenses
583	Overhead Lines
584	Underground Line Expenses
585	Street Lighting & Signal System Expense
586	Meter Expense
587	Customer Installation Expenses
588	Misc
589	Rents
	Total Operation
	Maintenance:
590	Maintenance Supervision & Eng
591	Main't of Structures
592	Main't of Station Equipment
593	Main't of Overhead Lines
594	Main't of Underground Lines
595	Main't of Line Transformers
596	Main't of Street Lighting and Signal Systems
597	Main't of Meters
598	Misc Distribution plt.
	Total Maintenance
	TOTAL Distribution Expense
	5. CUSTOMER ACCOUNTS EXPENSE
	Operation:
901	Supervision
902	Meter Reading Expenses
903	Customer Records & Collections Expense
904	Uncollectible Accounts
905	Misc Customer Accounts Expense
	Total Customer Accounts Expense
	TOTAL Customer Servic & Information Expense
	6. CUSTOMER SERVICE & INFORMATIONAL EXPENSE
	Operation:
907	Supervision

908	Customer Assistance Expense
909	Informational & Instructional Expense
910	Misc
	Total Customer Service & Information Expense
	TOTAL Customer Servic & Information Expense

	7. SALES EXPENSE
	Operation:
911	Supervision
912	Demostrating & Selling Expense
913	Advertising Expense
916	Misc
	Total Sales Expense
	TOTAL Sales Expense

	8. ADMINISTRATIVE & GENERAL EXPENSE
	Operation:
920	Administrative & General Salaries
921	Office Supplies and Expenses
922	Administrative Expense Transferred
923	Outside Services Employed - Non Audit
923	Outside Services Employed - Audit
924	Property Insurance
925	Injuries and Damages
926	Employee Pensions and Benefits
928	Regulatory Commission Expense
930	General and Miscellaneous Expenses
931	Rents
	Total Operation
935	Maintenance of General Plant

Attachment 7

In its annual June 1 Base Rate Adjustment filing, made on June 1 of each year of the plan, GMP will include **Supporting Cost Documentation** for each capital project proposed as a rate year addition to plant. All **Supporting Cost Documentation** for each capital project will be included in a folder dedicated to that project. **Supporting Cost Documentation** folders can be provided either electronically or in hard copy, as agreed to by GMP and PSD. Any **Supporting Cost Documentation** that is not provided in the relevant folder at the time of the June 1 filing will be excluded from consideration and the associated project will be excluded from rates.

Supporting Cost Documentation shall include:

1. A Capital Project Summary Sheet with amounts tying out to the amount requested

2. A Work Order with a project description & the reason GMP is undertaking it plus the projected start and end dates of the project and the Oracle Project Number.

3. Any capital projects over $3 million will contain a cost/benefit analysis. Any capital project less than $3 million will contain either a financial analysis or a cost/benefit analysis. Capital Projects under $300,000 may include a qualitative analysis if adequately justified, so long as there is a sufficient explanation as to why a quantitative analysis was not performed. Documentation for reliability projects shall include a description of the reliability issue being addressed and a summary of alternatives considered and rejected.

   A "cost-benefit analysis" means an analysis that describes:

   - how the project advances customer service, reliability, safety, operational efficiency and/or state energy policy
   - why the project is appropriate at this time
   - the capital, estimated O&M and retirement costs associated with the project
   - a quantitative comparison of costs and benefits where such costs and benefits should reasonably be quantified in monetary value
   - a qualitative comparison of costs and benefits where such costs and benefits include factors that should not reasonably be converted to monetary value
   - what alternative(s) was/were considered and the cost associated with alternative(s)

4. Actual Costs and Cost Estimates:

   a. if developed on external labor and/or materials, will be supported by either:

(i) external current quotes/estimates; or

(ii) recent similar invoices or GMP project costs with a written explanation on a standardized form of why the projects are similar;

(iii) any use of escalation on quotes, estimates or recent project cost documentation must be justified with an explanation and documentation that shows the costs have increased;

b. if developed on GMP's materials, will be supported by the GMP materials list;

c. if developed on GMP labor, will be supported by GMP payroll information with an explanation as to how the hours were estimated;

d. if developed on direct overhead costs, will be supported by a description of each direct overhead rate and how it is calculated (any studies performed in determining overhead rate will also be provided);

e. if developed on indirect overhead costs, will be supported by a documented study;

f. if developed on blanket work orders, will be supported by five-year GMP historical averages inflated by the CPI;

g. for projects with costs already incurred, each project folder will contain an actual cost summary reflecting the actual costs recorded in GMP's financial system detailing labor, materials, contractor costs and overhead costs. Actual invoices will be included for costs over $5,000;

h. if actual costs related to projects carried over from year-to-year have a variance of more than 20% from the original projected costs, an explanation will be provided as to what caused the variance.

5. All project folders will include the documentation listed in 1 – 4 above whether the project is completed or not, and whether or not actual costs are available.

Attachment 8 Filed December 17, 2014

GMP – Non-Tariffed Alternative for Innovative Pilots and Services

Eligibility:

The Non-Tariffed Alternative shall be available for products or services, beyond the sale of basic electric service, that advance achieving the goals of Vermont's Comprehensive Energy Plan of meeting 90% of energy supply with renewable resources by 2050 and reducing fossil fuel consumption and reducing greenhouse gas emissions 75% below 1990 levels by 2050 ("Innovative Services").

New Innovative Pilots

GMP shall file 15 days advance notice with the Department and the Board, with a copy to Efficiency Vermont, before commencing pilot programs to provide Innovative Services ("Innovative Pilot").[1] The notice shall include a narrative explanation of the Innovative Pilot and how it is consistent with the eligibility requirements, the number of customers it will be made available to and how those eligible customers were selected, expected costs and revenues, why the proposal does not conflict with work performed by Efficiency Vermont, a certification that GMP has collaborated with Efficiency Vermont regarding the proposal in advance of the filing, and the frequency by which GMP shall provide status reports to the Board and Department on the Innovative Pilot's progress.

New Innovative Services

GMP shall file a proposal to provide "new" Innovative Services with the Department and the Board ("Proposal"), with a copy to Efficiency Vermont. The Proposal shall include a narrative explanation of the proposal and how it is consistent with the eligibility requirements, a summary of projected costs and revenues, why the proposal does not conflict with work performed by Efficiency Vermont, a certification that GMP has collaborated with Efficiency Vermont regarding the proposal in advance of the filing, as well as a proposed standard contract, as applicable, with pricing, terms, and conditions.

The Department shall file a recommendation regarding the Proposal within 30 days and the Board shall issue an order within 15 days from the Department's recommendation. The investigation and suspension provisions of 30 VSA 226 and 227 shall apply.

Amendments to Terms and Conditions of Innovative Services

GMP shall file 7 days advance notice of changes to Innovative Services' pricing, terms, or conditions with the Department, Efficiency Vermont, and the Board. GMP shall also provide written notice of all such changes to affected participating customers. The investigation provisions of 30 VSA 226 and 227 shall apply.

[1] The term of any New Innovative Pilot is limited to eighteen months.

Attachment 8

On-Going Review of Innovative Pilots and Services

GMP shall include the costs and revenues of Innovative Pilots and Services in Base Rates, subject to Department review and Board approval. The annual Base Rate filing shall include a schedule setting forth the costs and revenues of all Innovative Pilots and Services offered.

Exhibit 10 –Larkin Report on GMP's proposed Earnings Sharing Adjustment (ESAM) for in the 2016 Rate Adjustment Filing.

Exhibit HWS-1

LARKIN & ASSOCIATES P.L.L.C.

REPORT ON THE ANALYSIS OF THE GREEN MOUNTAIN POWER – 2015 EARNINGS SHARING ADJUSTOR

August 15, 2016

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EXECUTIVE SUMMARY

Green Mountain Power Corporation (GMP or the Company) filed its draft Earnings Sharing Adjustor (ESAM) for the year ended September 30, 2015 on November 20, 2015. Under the current Alternative Regulation Plan (Plan), the results of the ESAM will be reflected in the base rates scheduled to be implemented on October 1, 2016. The Company draft indicates that for the fiscal year ended September 30, 2015 the Company under earned, and as part of the 50/50 sharing provision in the Plan, is entitled to collect 50% of the $1,524,000 variance from ratepayers. Larkin & Associates P.L.L.C. (Larkin) was to perform an analysis of the filings on behalf of the Vermont Department of Public Service (Department) to determine the reasonableness of the filings. Through discussion with the Department it was determined that focus should be placed on the causes for the $1.5 million shortfall subject to sharing and also whether there are any issues with actual reported costs. An initial review of the filing revealed two primary causes of the shortfall: (1) actual rate base exceeded projected rate base by $44 million; and (2) the actual platform adjusted cost of service was $16 million greater than the projected cost of service. The excess actual platform adjusted cost of service was partially offset by actual revenues being $9.6 million greater than projected revenues.

Larkin's review of the filing consisted of the following:

- an evaluation of the filing and supporting documents supplied;
- four sets of formal information requests; and
- a comparison of what was projected when the base rates were set to the actual results for the year ended September 30, 2015.

During the review process, Larkin identified areas of concern with the Department. Those concerns and recommendations are explained in the report. The concerns and recommendations by Larkin are based on our experience with specific issues as well as consideration of Vermont ratemaking principles, precedents and previous Board Orders. The analysis evaluated the reasonableness of the ESAM filing, and is made with due consideration of the merger savings generated by the Company in the fiscal year ended September 30, 2015 as well as the merger savings as shown in GMP's "NARRATIVE DESCRIPTION OF MATERIAL CHANGES IN ACTUAL O&M COSTS ACCOUNTS FROM OCTOBER 1, 2012 THROUGH SEPTEMBER 30, 2014."

ALTERNATIVE REGULATION

The Alternative Regulation (Alt Reg) process affords GMP a unique situation since it all but eliminates the risk traditionally associated with regulated utilities. First, under Alt Reg, GMP is allowed to reset its base rates by way of expedited (two-month) annual proceedings. This minimizes the extent to which GMP's costs and revenues can become unaligned by the regulatory lag associated with traditional regulation. Second, Alt Reg provides GMP with two additional mechanisms—power adjustor and the ESAM—that all but ensure cost recovery (within established deadbands) within each year. The power adjustor allows GMP to recover from (or give back to) ratepayers the quarterly variances in defined power and non-power expenses. The ESAM allows GMP to recover from (or give back to) ratepayers the annual variance between approved earnings (at the Board-approved ROE) and actual earnings at year's end. Third, GMP's Plan incorporates the Merger Savings Plan, approved in Docket No. 7770, which allocates merger-related savings among GMP's ratepayers and shareholders. The Merger

Savings Plan is designed to allow GMP to recover the acquisition premium reflecting the above-book-value price it paid to acquire CVPS, while at the same time providing a mechanism through which ratepayers are provided some of the savings associated with the merger.

A key feature of Alt Reg in Vermont and GMP's Plan in particular, which distinguishes it from other jurisdictions, is that essentially all costs are covered by at least one of these sharing mechanisms. The power adjustor allows for not only recovery of direct power costs but also costs in accounts that are related to production and/or purchased power. This is significant since the power clause or power cost mechanism in other jurisdictions is typically limited to actual production and/or purchase power costs. This extra allowance removes risk since costs that are not direct power costs can be recovered through the power adjustor even if they exceed the previously estimated costs to a degree where they may not have been recoverable under traditional regulation. The ESAM provides a similar benefit, especially when viewed in tandem with the Merger Savings Plan, in that it minimizes the Company's risk in a manner that would not exist under traditional ratemaking.

In addition to allowing the Company to reduce risk associated with regulatory lag, the annual Base Rates proceedings provide an important control, that is, the review process that the Company is subject to as part of establishing rates on an annual basis. That process establishes requirements, commonly part of traditional ratemaking, that include meeting the known and measurable standard. In the past, the Company has had difficulty in meeting this standard, which has necessitated the inclusion of Attachment 7 in the Plan—a document setting forth the requirements and consequences in detail. Attachment 7 was a result of an MOU in the traditional rate filing and request for a new Plan addressed in Docket Nos. 8190 & 8191. (This ESAM relates to the 2015 base rates set in that proceeding.)

The known and measurable standard applies on a forward looking basis and allows costs that will be incurred during the future rate year to be recovered from ratepayers. In this way, it does not strictly apply to an ESAM filing, which is a backward looking filing in which the Company sets forth its actual costs during the past year. The standard is still relevant in an ESAM filing. For example, it would be inappropriate for the Company to recover under earnings from ratepayers (or avoid paying over earnings) by including costs in the ESAM for plant that had not been previously reviewed and approved. To allow recovery of costs associated with such un-approved plant, as part of the ESAM, would be to expand beyond established ratemaking standards and result in a process that loses the validation principle for setting reasonable rates. This is a concern that has arisen as part of this ESAM review.

ESAM FILING

In the analysis of the ESAM filing, Larkin verified the per books amounts to the September 30, 2015 trial balance provided by the Company. The platform adjustment was based on the September 30, 2014 escalated platform costs being increased an additional 1.8% for the year ended September 30, 2015. The result was a total cost of service of $605,782,000, less the $8,000,000 guaranteed savings, for an adjusted total cost of service of $597,782,000. This total cost of service included a return of $86,890,000 on utility rate base of $1,164,743,000. The ESAM filed cost of service is $614,027,000 net of the $8,000,000 guaranteed merger savings. The calculated ceiling and floor were $617,589,000 and $608,939,000, respectively. The base cost of service included a return of $88,809,000 on a utility rate base of $1,209,350,000. With the higher rate base the calculated return is $1,919,000 higher than projected, which is in addition to a synergy savings of $19,814,000 ($27,814,000 - $8,000,000) that is flowing through to shareholders. This is the context in which GMP seeks to recover an additional $762,000 from ratepayers through the ESAM (i.e., 50% of the $1,524,000 shortfall).

Larkin has identified various issues with the filing and is recommending adjustments that, in total, eliminate the proposed adjustment to rates by bringing the shortfall within the ESAM deadbands. Larkin first made a comparison of the rate filing for the year ended September 30, 2015 (i.e., the rates established in the most recent traditional rate case – Docket No. 8190) to the ESAM filing. This comparison identified areas of concern regarding the Company's claim of an earnings shortfall. Below is a summary of Larkin's concerns.

Common Equity

The Company calculates its 13 month average for common equity using various equity related accounts. The result is 100% of the equity of GMP is factored into this calculation. In reviewing the filing, Larkin noted two areas of concern. The first is the Company has erroneously recorded dividends as a reduction to equity when the dividend is paid. Proper accounting standards requires dividends be recorded when they are declared. The Company acknowledged this error in response to ESAM GMP 1-2. To properly reflect the 13 month average equity balance, the Company equity balance in the Cost of Capital – Allowed ROE[1] needs to be reduced by $2,659,107. This adjustment is required because the accounting is in error.

A second area of concern is that the equity balance assumes that 100% of GMP operations are regulated. This is a wrong assumption. The Company has different non-regulated operations that had to be funded by some means and that would be with shareholder equity. Areas of non-regulated operations include a net plant investment of $2,970,486 for water heater rentals, a net plant investment in non-utility miscellaneous plant of $1,861,211, a net plant

[1] Company Attachment 2, Page 3.

investment in Catamount of $244,383 and a net plant investment in Northern Water Resources of $450,699. There is also the concern that total equity reflects the income earned over the years from non-utility operations. The response to ESAM GMP 2-27 indicated that non-utility net income for the year ended September 30, 2015 was $1,553,025. To the extent that non-utility income is included in the equity, ratepayers are over paying on the Return on Utility Rate Base that is included in the cost of service. Again the $1,553,025 amount is for one year only so the total over a period of time could be significantly more. Larkin is of the opinion that an argument could be made and justified for reducing equity by another $6,303,292. This represents the 13 month average amounts of non-utility net plant investment plus 50% (i.e. the simple average of) of the fiscal year ended September 30, 2015 non-utility net income. This adjustment is not made here, because making the adjustment would not lead to any change in the end result for ratepayers, i.e., it would not result in an over-recovery that would require GMP to return money to ratepayers, and other adjustments made eliminate the claimed under-recovery that would have required ratepayers to make additional contributions to GMP's earnings. GMP is now on notice that this change will be required in the future.

Plant and Accumulated Depreciation

The Company earnings shortfall is driven in large part by the significant difference in the actual plant reflected in the ESAM over the amount of projected plant reflected in the base rate filing. Larkin finds this variance to be significant when factoring in the purpose of the Alt Reg plan and the process for setting rates under Alt Reg. As noted earlier, Alt Reg significantly reduces the risk associated with the regulatory process as the Company is allowed to adjust rates annually. As part of that process, plant is included in base rates on the assumption the plant will be built and/or acquired during the rate year. The reason for this assumption is that for plant additions to be allowed in rates, they must meet the known and measurable standard. This allowance for plant additions goes beyond what would be allowed under traditional ratemaking which would limit additions to non-growth and reliability/safety projects.

Larkin has noted, in previous reports on the base rate filings, the Company's failure to complete projects as projected. Larkin has also noted in past ESAM reviews its concern regarding the Company's practice of substituting and adding projects that were not part of the base rate filing and not subject to the review process that is an integral part of the Alt Reg process. While some minor changes in projected to actual plant may occur, the extent to which the Company's actual plant additions deviate from its projections continue to undermine the Alt Reg process. A noted area of concern with plant is that 137 projects totaling $25.214 million were reflected as additions to plant in the FY ended September 30, 2015 that were not included in the base rate filing for the projected year ended September 30, 2015[2].

As part of the review, Larkin noted various factors that drove the actual results when compared to the base rate filing. As noted above and as shown on ESAM Exhibit-DPS- LA-2, Page 2, actual plant exceeded projected plant by $24.186 million. Another driver was the fact that actual accumulated depreciation was $16.885 million below projected accumulated depreciation. This in effect was an increase of $41.071 million over the projected rate base. Both changes have the effect of driving higher returns to shareholders. The intriguing thing is that projected depreciation expense, the major contributing factor to accumulated depreciation, was on target. The primary reason that accumulated depreciation was below what was projected was actual retirements were $11.121 million greater than projected. This means that the variance

[2] Company response to ESAM DPS.GMP.2-70.

between projected and actual plant is actually much greater than $24.186 million because actual plant was credited for retirements that were not projected.

It is worth emphasizing that the plant additions projected in the underlying rate proceeding were all subject to the known and measurable standard, which means that they "are measurable with a reasonable degree of accuracy and have a high probability of being in effect in the adjusted test year."[3] Larkin and the Department have long expressed concerns with the Company's willingness and ability to adhere to this stringent standard with respect to projected plant additions. During the annual base rate proceedings, projected plant additions often reflect primary areas of disagreement between the Company and the Department. This is a difficult issue given that projected plant additions are inherently just that—projections—and are therefore impossible to prove or disprove conclusively. While the Department requires certain supporting cost documentation for a plant addition to meet the known and measurable standard, there still remains some measure of uncertainty that the project will be completed in accordance with the projected schedule and budget provided.

In light of this necessary uncertainty, there has to be some level of trust in the Company's ability and willingness to realize its projections. This is only fair as ratepayers are subject to the full value of such projections in rates beginning on Day 1, while the Company remains in full control of whether such projections are realized. Below, Larkin will break out the different categories of plant additions and describe the Company's ability to realize its projected plant additions, with recommendations at the end of the section.

<u>Production</u>

The Company request under Alt Reg included 50 projects. Based on the response to ESAM 1-8, the Company only completed 11 on time, another 32 were late (3 had an in-service

[3] *In re Green Mountain Power Corp.*, 162 Vt. 378, 381 (1994).

date beyond September 30, 2015, and so were never in service during the relevant rate year) and 7 were not done at all. Ultimately, 48 projects were completed within the fiscal year, some of which were not reviewed as part of the base rates filing. It is a concern that ratepayers are paying for the project prior to completion, paying for projects that are not completed, and now being asked to pay for projects that were not subject to the base rate filing review. The ESAM reflects 7 projects completed at a cost of $1,799,895 that were not in the base rates request and subject to review. In response to ESAM 2-70 the Company acknowledged that the 7 were never reviewed. The Alt Reg process as well as traditional ratemaking requires that costs be reviewed prior to being included in rates. The subsequent additions have not been through the process and should not be included in rates as part of the ESAM, which at its core is a true-up filing, rather than an initial rate request. It should also be noted that in response to discovery questions, GMP indicated that certain delays of plant in service dates were due to issues with planning and miscommunication. Ratepayers should not be required to hold GMP harmless for its own poor performance regarding planning and communications. However, that is the essence of what GMP asks of the Alt Reg process when it repeatedly misses in-service projections while nonetheless recovering the costs of the associated projects from day 1. Adding to the issue is the Company estimated retirements of $1.2 million at the time of the base rates filing, but then reflected $1.9 million in the actual amounts. This has the effect of masking the increase in plant that is increasing depreciation expense.

Transmission

Transmission Substations

The Company request under Alt Reg was for $9,934,997 of plant additions and $1,460,596 of retirements. The actual amounts as identified in the response to ESAM 1-8 was

$12,006,070 and $1,725,622 for plant additions and retirements, respectively. Of the 15 projects requested, 7 were completed late, 2 were blankets, and 6 were done on time. The Company added 7 projects not included in the base rate review process for the year ending September 30, 2015 for a total of $1,861,536 and $126,504 of retirements. In response to ESAM 2-70, the Company noted that two of the seven were not subject to a previous review and of the other five, one was reviewed in the FY 9/30/12 filing, three were reviewed in the FY 9/30/13 filing and the remaining project was reviewed in the FY 9/30/14 filing. This illustrates Larkin's long-running concern that the Company's projected in-service dates are overly optimistic. It also reinforces the concern with projects being proposed in the base rates filing as "known and measurable" but then not being completed during the intended rate year. If a project was not done and/or completed when it was supposed to be completed, the project should be included in subsequent requests (i.e. the Company has done this for some projects) and not simply closed to plant as part of the ESAM. This inconsistent treatment, of including some projects and not including others, results in the Company's base rate requests being misleading. When a project that was to be completed in one year (i.e. FY2014) is included in the next base rate filing (i.e. FY 2015) it identifies the delay and puts all parties on notice that project forecasting issues exist. However, when plant that is not completed and is omitted from the next base rate filing it suggests the planned project did not occur and it is not included in rates being set. That leads to the issue at hand where ratepayers are surprised by plant increasing more than anticipated (i.e. as reflected in the base rate filing) resulting in the Company then asking for more funds due to a revenue shortfall. Over time, facts and circumstances change, as do cost estimates. An example of one project, not listed as an addition in the initial filing that we did verify as being previously reviewed, was the Marble Street Upgrade. The cost was significantly different as it was estimated at $337,535 in FY 2014 and the actual cost was $116,538 when added to plant in FY 2015.

Transmission Lines

The Company request under Alt Reg was for 20 projects totaled $9,606,189 with $317,098 of retirements. The response to ESAM 1-8 showed a request of $9,941,216 (i.e. the amounts in the response were different than the original request) because the Company changed the dollar amount on 3 projects. The total actual costs in the ESAM were $12,753,139 with $39,716 of retirements. The cost increase in plant additions was due to the $411,743 cost change for 3 projects, a previous project with a cost of $1,192,529, not included in the 9/30/15 Alt Reg review, and the $1,565,461 overrun for a project that is still not completed. That project was again included in the 9/30/16 filing. The added project was in fact a project reviewed as part of the FY 9/30/13 base rate filing but was just recorded as in service in the current period. This project was not included in the 9/30/15 base rate request as it should have been.

Distribution

Distribution Substations

The Company request under Alt Reg was for 18 distribution substation projects totaling $11,768,983 with $1,738,612 of retirements. The actual additions were $9,937,801 with $562,692 of retirements. The Company completed 7 projects on time, 6 projects were completed later than projected, 2 projects were blankets and 3 projects were not done. During the rate year, the Company added 3 projects that were not part of the 9/30/15 review process. Those 3 projects added $1,717,864 to plant and $328,150 to retirements. In response to ESAM 2-70 the Company indicated one project was not subject to review and the other added projects were reviewed as part of the base rate filing for FY 9/30/13 and FY 9/30/14. This fact was confirmed but it was noted that both projects were completed at a greater cost than projected. The added costs were not subject to any review and there is a concern that the costs were not part of the FY 9/30/15 base rate filing. The arbitrary late addition of projects not previously done when indicated creates an issue for ratepayers. That the plant was included previously under the Alt Reg process but not completed suggesting that the need for that project no longer existed. Ratepayers paid for that plant for the year it was supposed to be completed even though it did not get completed. Absent continued inclusion of the cost in subsequent base rates proceedings creates an accountability problem by allowing the Company to essentially suggest the project is not going to be done and then surprising ratepayers with its completion in a subsequent ESAM filing.

Distribution Purchase and Lines

The blanket work orders for distribution purchases and lines consisted of $9,884,551 and $44,231,580 of costs, respectively. The respective retirements projected were $2,885,224 and $8,421,108. Actual plant costs for purchase and lines were $11,248,801 and $55,210,739, respectively. Actual retirements were zero for purchases and $18,204,298 for lines. Blankets do not have in-service dates per se so the timing is not discussed (i.e. the estimate is prorated monthly or quarterly). The differences are significant. Blankets are allowed in base rates based on historical averages as the projects are numerous and smaller in nature. Fluctuations can occur but if fluctuations are significant, as they were in FY 9/30/15, the Company should advise the Board and the Department as to why the differences are occurring. The Company has not done so here.

Property & Structures

The Company's request under Alt Reg was for $19,233,328 of additions and $17,362,543 of retirements. The actual additions were $18,698,828 and actual retirements were $20,187,059.

Of the 46 projects requested 18 were put into service late (3 were beyond the rate year), 6 were not done and 22 were completed on time. The actual cost of the completed projects (including the 3 projects not completed in the rate year) totaled $587,126 that were not reviewed as part of the 9/30/15 filing and actual retirements included $5,132,991 not projected. The Company acknowledged that one of the projects was not subject to any prior review and the two retirements were not part of any previous review process. The other two projects completed were identified by the Company as FY 9/30/14 projects but could not be readily identified in the Company's previous filing. This could be due to a change in the name and/or amount requested being different. If the projects were part of a previous review and either not done or not completed on time they should have been part of the FY 9/30/15 filing.

Communications

The Company's Alt Reg request was for $3,443,802 of plant additions and $2,642,841 of retirements. The actual additions were $4,296,669 with no retirements. That $4,296,669 included $3,051,294 for 21 projects not included in the 9/30/15 Alt Reg review. Of the $3,051,294, 12 projects totaling $2,289,667 were identified as projects that were supposed to have closed in FY2013[4]. According to the response to ESAM 2-70, ten of the projects were not subject to any review and the remaining eleven were purportedly part of the FY 9/30/13 review However, only four could be readily confirmed as part of the FY 9/30/13 review and there were significant cost differences. There was no indication in the FY 9/30/15 filing that these project costs would be included in plant in FY 9/30/15. Of the 22 projects requested the Company completed 3 projects on time, 7 were cancelled, 4 projects did not have a closing date because their dollars were purportedly included with a different plant category when closed, 1 project was not provided a closing date, and 7 projects were closed after they were supposed to be. The

[4] Response to ESAM 1-8.

question that now comes before the Board and the Department is whether the cancelled or not completed projects can be completed at some future date and included in an ESAM filing without any further notification. The answer should be no.

General

General plant originally requested by the Company consisted of vehicles and equipment totaling $3,352,874 with $1,787,475 of retirements. Due to lack of support some adjustments were made to the request. The actual amounts ultimately allowed in base rates for plant and retirements were $2,572,576 and $600,000, respectively. Actual plant additions and retirement reflected in the ESAM filing were $6,523,184 and $2,397,022, respectively. The actual additions included $1,617,905 for 22 projects and 1 retirement of $1,025,563 not subject to review in the 9/30/15 Alt Reg review process. The response to ESAM 2-70 indicated that none of the 22 new additions were subject to any review process. Of the 9 requested projects, 5 were not completed on time, 3 were completed on time and 1 was not done.

Information Technology

Software

The IT request in the 9/30/15 Alt Reg filing was for 12 hardware projects totaling $6,322,191. The Company expended $2,232,466 on 7 of the requested projects. The other 5 projects were not done but the Company indicated it used the funds for other projects. As an added note, 5 of the 7 requested projects were not completed on time. Instead of the requested projects the Company expended $2,735,974 on 25 different projects not part of the 9/30/15 Alt Reg review process. While the cost added to plant was less than what was budgeted, the changing of projects is a great concern and undermines the Alt Reg process and the reliance that this consultant can put on the information supplied as support for plant additions in a base rate filing. In response to ESAM 2-70 the Company indicated that 7 of the 25 projects were not ever reviewed and it was indicated that of the other 18 projects, 15 were the subject of review in FY 9/30/13 and 3 were subject to review in FY 9/30/14. Five of the FY 9/30/13 projects appear to have been part of the review process. The other projects could not be readily identified to the previous filings. Again, it is a problem when costs included in plant in a previous year is not completed when it was projected to be completed and then subsequently included in an ESAM filing 2 years later. If the costs are to be included in base rates and have yet to be closed to plant they should be part of the current base rate filing. In discussing the issue of timeliness the Company attempted to justify the changes by suggesting that technology changes impacts the project. Larkin is not convinced by that argument since purportedly 15 FY 2013 projects that were completed in FY 2015 were purportedly subject to some level of review previously.

Software

The Alt Reg request for software was for 35 projects at a cost of $12,295,591. Of the 35 projects 10 were completed late, 8 were completed on time and 17 (totaling $1,053,779) were not done. The Company indicated in a number of instances that they offered the dollars to another property budget. This is not an appropriate under the Alt Reg process. The 18 completed were done at a cost of $11,645,140. In place of the 17 projects not done, the Company supplemented 46 projects at a cost of $10,649,841. Many reports have addressed the IT budget process as a concern and the blank check approach applied in the FY 9/30/15 adds even more concern for the lack of respect for the favorable regulatory process provided to GMP under Alt Reg. In response to ESAM 2-70 the Company indicated that 29 of the 46 projects were not subjected to the review process and that of the remaining 17 projects, 10 were reviewed in FY 9/30/13, 4 were reviewed in FY 9/30/14 and 3 were subject to review in FY 9/30/15. The suggestion that 3 were subject to review in FY 9/30/15 is not possible since the projects were in question in the first place because they were not part of the FY 9/30/15 project listing. Four of the FY 9/30/13 were traced to similar named projects but none of the remaining FY 9/30/13 or any of the FY 9/30/14 could be readily traced to the respective years project listing. Once again the issue for projects that may have been previously reviewed and included in plant when rates were set but were not in fact in-service as projected suddenly appearing in an ESAM filing when there was no indication in the FY 9/30/15 base rate filing that these projects would suddenly become part of rate base. This is like having two bites at the proverbial apple. Without question the inclusion of projects not subject to any review is also inappropriate. The ESAM is a comparison of projected to actual based on assumptions, that are accepted in good faith, that the plant will go into service.

Plant Recommendation

As discussed above, the Company's claimed ESAM shortfall is driven in large part by the amount of plant added over what was included in the base rate filing. Larkin has often noted in previous reports concerns with the Company's failure to complete projects and the substitution of projects that were not part of the base rate review. This occurred, once again, in the fiscal year September 30, 2015. The Alt Reg process provides a significant benefit to GMP since it provides an opportunity to earn a return on plant as it is put into service as part of a base rate filing instead of after the fact. The Company's continued inability and/or unwillingness to at least generally achieve its projections is contrary to the Alt Reg process. Including plant in the ESAM that was not subject to the base rates review process suggests that the Company does not understand the importance of demonstrating that rates are just and reasonable, reflecting only costs that have been reviewed as part of Alt Reg. Also including in the ESAM filing plant that may have been reviewed in earlier years that were not completed on time without including those projects in the most current request creates a surprise in the ESAM by increasing plant more than anticipated and it does not allow for changes in that plant request that have occurred due to the Company's delay in completing the project. This in effect is as if the Company has a capital project rate mechanism in addition to the Alt Reg process. This is inappropriate since it expands the Alt Reg beyond the intention of the parties.

As noted in the above discussion, the Company's actual capital additions compared to those projected and upon which the Company's rates are based are significantly different. Even more concerning is that the above-discussion comparing the actual plant additions (in the ESAM) to the projected plant additions (in the underlying rate case) was based on the Company's initial filing in Docket No. 8190. That filing was settled and the Company's plant request was in effect reduced by approximately $21.1 million as part of that settlement. So the rate filing to ESAM variance is even greater when viewed in light of what the Company originally agreed to as just and reasonable for underlying rates. To allow the cost of added projects as part of the ESAM would essentially undo the adjustments that formed the basis of the Docket No. 8190 settlement and undermine the Alt Reg review process by giving the Company an automatic return on those assets without the rigors of the review process.

The Company, as noted above, in response to discovery indicated that some of the projects and project costs included in the ESAM but not in the FY 9/30/15 base rate filing were in fact reviewed in earlier years. While to some extent a project number or description may have been reviewed at that time (mostly 2013), there were changes in cost and certainly the timing of the in-service date since that review. The fact remains, even if previously reviewed the facts and circumstances as well as the dollars change and the Company did not include the projects in the FY 9/30/15 filing. The base rate filing under Alt Reg serves as the basis of what plant will be in-service during the year that rates are in effect (this is similarly true where a "traditional" rate filing, such as the Docket No. 8190 filing, forms the basis of a Alt Reg rate year subject to the ESAM, Power Adjustor, and other Plan features). The inclusion in the ESAM of new projects not previously subject to review or projects that for one reason or another were lost in space is not appropriate and results in an inappropriate surprise to ratepayers. The ESAM request is essentially an apples to oranges comparison because not only does the Company change the level of some of the reviewed projects but they add new projects (i.e. the projects in the review are not the same as the ESAM projects). The use of the ESAM as a blank check should not be allowed for automatic recovery from ratepayers. Larkin is recommending the plant additions that were not the subject of review in the FY 9/30/15 base rate filing be excluded from the ESAM measurement. The Company response to ESAM 2-70 has indicated that the additions added an average of $16,364,407 to plant and removed $3,268,030 of retirements not projected for the FY 9/30/15. Plant should be reduced by a net $13,096,377 and accumulated depreciation should be increased by $3,268,030.

Cash Working Capital

The ESAM filing reflects a working capital allowance of $38,112,000. The allowance is made up of an average fuel inventory of $8,048,000, an average materials and supplies inventory of $11,936,000, an average Millstone Nuclear Fuel Inventory of $1,343,000, an average balance of prepayments of $5,298,000, the 1/8th O&M expense allowance of $15,363,000 and offsetting credit of $3,876,000 for 1/8 of the bond interest expense. In addition to Larkin's ongoing concern with the use of the 1/8th O&M allowance, Larkin also identified concerns with the fuel balance and the prepayment amount.

In the past Larkin has taken issue with the use of the 1/8th O&M expense calculation instead of a lead/lag study. The Board has accepted the use of the 1/8th O&M but the Board has also required companies to perform a lead/lag study to determine whether the 1/8th O&M is a reasonable surrogate. Larkin in a past traditional rate filing has advocated that the 1/8th O&M be adjusted to account for some expenses that are reflected in accounts payable through the year and this recommendation has been adopted in at least one rate proceeding. The justification is that the expenses used are assumed to be paid for during the year but in reality some of those expenses are in accruals or accounts payable at month end therefore no working capital is required at that time. Larkin recommends that when the 1/8th O&M is utilized in future filings that an average of accounts payable be determined for the expenses that are included in the 1/8th O&M factor and that average offset the allowance as determined by the formula. No adjustment has been proposed to the current ESAM for this oversight.

Larkin identified an error in the calculation of the working capital allowance where costs are being duplicated. Included in the prepayment amount are O&M expenses that are reflected in the 1/8th O&M calculation. Including the expensed amounts as prepayments and as O&M expense included in the 1/8th formula is a duplication of costs. The Company acknowledged this in response to ESAM GMP 3-25 and 3-26 noting that an adjustment to prepayments of $4,438,344 should be made. The Company did however also note that the prepaid balance did not include property taxes of $3,361,525 that should have been included because taxes are not included in O&M. The net impact is a reduction of $1,076,819 to the prepayments included in the working capital allowance.

Other Rate Base Issues

During the year ended September 30, 2015 the Company was allowed in rates, as part of the platform costs, $10,005,208 for vegetation management. The Company expended $8,814,960 during the year and the number of miles maintained was less that what would be required to achieve a 7 year cycle. The 7 year cycle is what the Company should be maintaining as a maximum cycle to be somewhat consistent with other utilities in the New England region as well as GMP's own IRP. In a past Board order it was determined that to the extent that actual vegetation maintenance was over or under what was allowed in rates that difference was to be reflected as a regulatory asset or liability and either utilized or applied in a future period[5]. This order also referenced a past decision that stated the Board expects that funds approved for specific a program (i.e. tree trimming) be spent exclusively on the program[6]. In discussions with the Company it has been suggested that the treatment dictated by the Board in Docket Nos. 6946 and 6988 is exclusive to Central Vermont Public Service Company (CVPS) and not to GMP. This suggestion ignores two important facts. The first is that CVPS is now part of GMP and absent any special exclusion, the accounting requirement should continue to apply. The second important fact is that GMP's base rate filing for 2008 included a deferred regulatory asset of $345,794 for tree trimming in the thirteen month average rate base. My recollection of past Alt Reg filings and the second fact noted are considered clear evidence that GMP did in fact follow the Board requirement in the past. To properly account for the $1,190,248 shortfall in spending I recommend that a deferred regulatory liability be reflected in the September 30, 2015 rate base for the ESAM calculation.

[5] Order entered on March 29, 2005 in Docket Nos. 6946 and 6988, at pages 134-136.
[6] Order entered on December 8, 1978 in Docket No. 4230.

Another issue identified concerns the exogenous costs deferral for FY 2015. As part of the Exogenous Change Adjustment section in the current Alt Reg Plan specifically subparts 2 and 4 the Company should have reflected a regulatory credit to offset the exogenous cost deferred and to be amortized in the future. The last sentence in subpart 2 states "In the event that the Company has not exceeded the amount related to storm costs included in Base O&M Costs, Exogenous Storm Changes shall be reduced by such a difference". The storm occurred in December 2014 which places it within the FY 2015. While the deferral was established shortly after the storm occurred (i.e. during the FY 2015) there was no way that the actual Base O&M Costs for storms cost could be determined because the FY 2015 was not yet completed. It is only when the FY 2015 ESAM was filed and reviewed that a determination could be made whether the Company deferral for more storm costs was excessive. Based on a response to DPS 1-5 in the vegetation maintenance review the Company identified the September 30, 2015 total storm cost to be $20,967,684 of which $15,785,497 was designated as exogenous leaving Base O&M storm cost to be $5,182,187. The response to DPS 1-6 in the vegetation review identified the Base O&M storm amount included in the platform as $7,441,522. The difference of $2,259,335, as defined by subpart 2 of the Exogenous Change section of the Alt Reg Plan, should then be applied to the exogenous storm amount being requested for recovery. Subpart 4 states "Over/under collections of the Exogenous Change Adjustment, due to a variance between projected and actual revenues, shall be deferred and included in the next base rate adjustment". The time for deferral is when the cost variance becomes known and measurable and that is the ESAM for FY 2015. Larkin is of the opinion that according to the subparts of the Exogenous Change section of the Alt Reg Plan that the Company must recognize a deferral of the Base O&M storm costs allowed in rates but not expended in FY 2015. The basis for that determination is the Exogenous Change (i.e. the storm) occurred in FY 2015 and the Company expended only $5,182,187 of the $7,441,522 allowed in Base O&M storm costs in FY 2015, therefore, in compliance with subparts 2 and 4 of the Exogenous Change section of the Alt Reg Plan a rate base deferral of $2,259,335 is required.

Below the Line Costs

Larkin sample tested various O&M accounts as part of the review and found certain costs that should be charged to account 426 and booked below the line instead included in the O&M costs above the line. As part of previous reviews of GMP filings under Alternative Regulation, Larkin has identified this as an issue in multiple reports on the Company's base rating filings. In fact as part of Docket No. 8389, where the current ESAM fiscal year base rates were addressed, the Company and the Department entered into an MOU which specifically addressed this very concern. The MOU stated as follows:

> 6. Certain expenses - GMP shall account for all image-building, charitable, and lobbying expenses below-the-line in the present filing (as proposed in the Larkin report) and in all rate filings made pursuant to Alternative Regulation going forward; except that to the extent GMP seeks to include any such expenses above-the-line, GMP shall separately identify all such expenses in a separate schedule and provide a justification as to why they are properly booked above-the-line.

The Company included below-the-line costs in the current ESAM filing and the Company did not provide a separate schedule of those costs with any explanation as why GMP believes the cost should be booked above-the-line, this in violation of the MOU. Not only has the Company failed to comply with the MOU, the Company has failed to comply with their past agreement, as noted in multiple Larkin reports, to remove the costs that are inappropriately charged above-the-line. Larkin continues to be concerned that GMP is not following a ratemaking standard accepted in Vermont and other jurisdictions. The costs in question are chamber dues (considered as image building) and lobbying related costs. While the costs in question, which total $40,346, may not be considered material in nature, the continued practice of deviating from well-established ratemaking standards is considered material. The cost is from a sampling of accounts and subaccounts, and therefore may not reflect all the costs that should be recorded in account 426.

The sampled costs include $9,087 of lobbying costs that GMP acknowledges should be below the line and $31,259 of chamber dues and other image building costs that should be below the line. In addition, Larkin has identified on ESAM Exhibit LA-1, Schedule 5, $61,939 of questionable costs. Included in the questionable costs not adjusted are Hack Vermont costs. The Company co-sponsored this event to develop an app that the Company claims could potentially benefit Vermont. In the rate effective period the net cost recorded in fiscal year September 30, 2015 and reflected as an O&M expense in the ESAM is $40,017. This event is considered promotional and image building and the cost should not have been included in the ESAM. The Company has indicated that charging guidelines will be developed in the near future to correct for this problem. Larkin has taken issue with this problem for years with no changes being implemented. This is despite the fact that the Company agreed to charge lobbying costs and image building costs below the line in Docket No. 8389 and the Company agreed to the extent that such costs are not charged below the line that the Company would provide a schedule identifying the costs that were not charged below the line. The Company did not do either requirement and is therefore in violation of the terms of the MOU in Docket No. 8389.

It has been well documented that GMP did not charge the costs below the line as evidence in past Larkin Reports. The issue is that the Board has disallowed the costs and they are supposed to be charged below the line. Furthermore, GMP's accounting for these costs is inconsistent with FERC and the IRS regulations for lobbying and the MOU in Docket No. 8389. Therefore, it is recommended the cost be adjusted and that GMP be directed to comply with traditional Vermont ratemaking standards in its future reporting. As part of the adjustment the platform adjustment should not be adjusted in a manner that would effectively eliminate the impact of this adjustment. To do so would be the equivalent of rewarding the Company for including costs not approved in the platform and for continuing to account for costs improperly despite their agreeing not to do so.

<u>Questionable Costs</u>

Lobbying

The Company only charges one employees time to lobbying and that was only for part of the year. Expenses charged to lobbying for time periods where there were no payroll costs charged. Some lobbying related expenses were noted in O&M as the expense was for meeting with elected government officials. The expense for 2 employees meeting with legislatures was included in account 921. The happened upon expense was minimal (i.e. less than $100) but the fact that it was recorded above the line is significant and in violation of the MOU in Docket No. 8389. It was also noted that employee payroll charged below the line for lobbying was only $4,946 plus overheads.[7] The Company stated that they follow FERC guidance for lobbying[8]. In response to ESAM 2-73 the Company stated that the mismatch noted above (expenses and payroll) was an oversight. In response to ESAM 3-27 the Company provided its guidelines for

[7] Response to ESAM 2-35.
[8] Response to ESAM 2-19.

determining what is considered to be lobbying that is to be charged to account 426.4. The response identifies the FERC definition as its guideline as follows:

> This account shall include expenditures for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation, or ordinances (either with respect to the possible adoption of new referenda, legislation or ordinances or repeal or modification of existing referenda, legislation or ordinances) or approval, modification, or revocation of franchises; or for the purpose of influencing the decisions of public officials, but shall not include such expenditures which are directly related to appearances before regulatory or other governmental bodies in connection with the reporting utility's existing or proposed operations.

The definition as presented as the FERC definition is not at issue. At issue is whether the state of Vermont's definition should have precedent over the FERC when establishing rates. Vermont statute is as follows:

> **LOBBY or LOBBYING** means: (A) to communicate orally or in writing with any legislator or administrative official for the purpose of influencing legislative or administrative action; (B) solicitation of others to influence legislative or administrative action; (C) an attempt to obtain the goodwill of a legislator or administrative official by communications or activities with that legislator or administrative official intended ultimately to influence legislative or administrative action; or (D) activities sponsored by an employer or lobbyist on behalf of or for the benefit of the members of an interest group, if a principal purpose of the activity is to enable such members to communicate orally with one or more legislators or administrative officials for the purpose of influencing legislative or administrative action or to obtain their goodwill.
> **LOBBYIST** means a person who receives or is entitled to receive, either by employment or contract, $500.00 or more in monetary or in-kind compensation in any calendar year for engaging in lobbying, either personally or through his or her agents, or a person who expends more than $500.00 on lobbying in any calendar year.[9]

A noted difference is the reference to an administrative official and legislatures and influencing administrative action. This definition expands on what is included in the FERC definition and to the extent the Company interacts with legislators and administrative officials to influence what costs should be allowed in rates that would be lobbying that should not be charged to ratepayers. Larkin is recommending that because of the limited costs charged by GMP to lobbying that the Board should advise the Company that future filings should be consistent with Vermont statutes.

[9] Vermont Code Title 2 Chapter 11,Section 261

Consulting Costs

The Company has included in the ESAM payments totaling $162,120 to a former employee for eight months of consulting[10]. This individual was also compensated as an employee for part of the year[11]. The costs are considered more of golden retirement payments and should be excluded from the ESAM calculation. The Company is supposed to control costs under Alt Reg and the level of spending and the rates paid for various consultants raises a concern as to whether the platform is being used to pass through costs without regard to the impact it has on ratepayers. The cost were not reflected as an adjustment for new costs as part of the FY 9/30/15 base rate filing. The platform should not be used as a catch all for whatever new costs the Company decides it wants to pay. Larkin recommends the $162,120 be excluded from the ESAM filing with no adjustment allowed to the platform adjustment already reflected.

The Company has indicated in response to ESAM 3-4 that certain costs in the FY 9/30/15 are merger related costs. The cost in question total $134,718 is for legal services. Merger related costs are to be excluded from the cost of service. The total cost of $134,718 should not be included as part of above the line costs and should be excluded.

The reported O&M cost in the ESAM include legal fees associated with a questions involving FERC. The questions arose due to the affiliation between Gaz Metro and a foreign entity. These are costs that should be borne by GMP affiliate and not GMP ratepayers[12]. The cost in question is $5,186.

The filing includes $21,600 that are for reading SAP computer detail from the former CVPS operations. Larkin has not recommended an adjustment but notes that the costs could be considered merger related costs and possibly excluded from the reported O&M expense.

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[10] Company response to ESAM 2-20(b).
[11] Company response to ESAM 2-22.
[12] Company response to ESAM 3-11.

Officer Payroll

The response to ESAM 2-22 indicates that basically all officer time is charged to O&M with one exception and that employee left the employ of the Company for a related company. In addition as part of the response to ESAM 2-22 the Company was to provide time reports for officers. The response provided a summary that shows a full day allocation of payroll to an O&M account. No detail exists supporting the 100% allocation to O&M. Past Board decision took issue with full allocation of time to O&M and to less than actual time reporting. The Company has apparently forgotten past Board rulings on this issue. Some time and cost should be charged below the line for lobbying, non-utility operations and for image building. The response to ESAM 2-24 shows only $12,231 of branding costs and $5,920 of advertising charged below the line. The costs are exceptionally low for a Company like GMP. While no adjustment has been recommended the allocation of costs in future filings will be scrutinized.

Conclusion

Larkin has adjusted for costs that are deemed as inappropriate for the measurement of the projected base rate filing for the year ended September 30, 2015. After adjusting for those costs, as reflected in ESAM Exhibit DPS-L&A-1, the Company still has under earned but that under earning falls within the dead band. Based on that analysis the request for recovery of a $762,000 revenue shortfall should be denied. Pursuant to discussions with GMP the Company removed the revenue shortfall from its FY 2017 base rate filing. With this agreement Larkin considers the FY 2015 ESAM filing issues resolved. The level of review of the September 30, 2015 ESAM was more in depth than previous reviews which were limited due to the time constraints imposed by filing requirements. Under the new Alt Reg it was agreed that the ESAM impact, if any, would be reflected in the subsequent base rate filing. This is considered a positive improvement to the Alt Reg process. As with this ESAM filing, future ESAM filings will now allow for more than a cursory review to verify the level of synergies achieved which is more important now that the savings will be shared equally between ratepayers and the Company.

Exhibit 11 - GMP Schedule 3 dated 8/1/2016

Schedule 3

GREEN MOUNTAIN POWER CORPORATION
August 1, 2016

Rate Year October 2016 - September 2017
COST OF CAPITAL
TEST YEAR ENDED March 31, 2016

Effective Tax Rate = 0.40525

$ in 000s	Invested Capital Per Books	Proforma Adjustments	Invested Capital Proforma	Proportion of Total Percentage	Cost Rate Percentage	Cost of Component Percentage	Cost of Pre Tax % Percentage
Long-Term Debt Bonds	605,848	62,372	668,220	44.58%	5.34%	2.38%	2.38%
Short-Term Debt Bank Loans	56,080	20,596	76,675	5.12%	2.27%	0.12%	0.12%
Total Debt	661,928	82,968	744,895	49.70%	5.02%	2.50%	2.50%
Common Equity	656,840	97,115	753,955	50.30%	9.02%	4.54%	7.63%
Total Capital	1,318,768	180,082	1,498,850			7.04%	10.13%

<u>Exhibit 12</u> - Transcript of the Board's September 13, 2016 Work Shop in GMP's 2016 Rate Adjustment Filing.

STATE OF VERMONT
PUBLIC SERVICE BOARD

IN RE: TARIFF FILING 8618
2017 GMP BASE RATE FILING

September 13, 2016
1:30 p.m.
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112 State Street
Montpelier, Vermont

Workshop held before the Vermont Public Service Board, at the Susan M. Hudson Conference Room, People's United Bank Building, 112 State Street, Montpelier, Vermont, on September 13, 2016, beginning at 1:30 p.m.

P R E S E N T

PSB STAFF: George E. Young, Deputy General Counsel
Ann C. Bishop, Chief Economist
Kevin Fink, Policy Analyst
Jake Marren, Staff Attorney
James Volz, Chairman

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Carol Flint, DPS
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Philene Taormina, AARP
Charlotte Ancel, Esq., GMP
Josh Castonguay, GMP
Kristin Carlson, GMP
Rob Bingel, GMP
Matt Haley, GMP
Doug Smith, GMP
Brian Otley, GMP
Eddie Ryan, GMP

MR. YOUNG: This is a workshop in re: Tariff filing 8618 which is Green Mountain Power's 2017 base rate filing under the Alternative Regulation Plan. The Board has assigned a number of staff; myself, George Young; Ann Bishop, Kevin Fink to staff this proceeding -- this workshop today. As you can see the Chairman is also here.

Why don't we just start by taking appearances and get all the parties down and/or since it's technically not parties, interested participants down, and then we will move on to the next stage. Mr. Duggan.

MR. DUGGAN: Thank you. Good afternoon. Timothy Duggan for the Department of Public Service. With me today at the table is John Woodward from our planning division. Also here are John Copans our deputy commissioner; Brian Winn, our director of finance and economics; and Carol Flint our director of consumer affairs.

MR. DUMONT: James Dumont for AARP. With me is Philene Taormina.

MR. BINGEL: I'm Rob Bingel from Green Mountain Power. With me are Brian Otley and Charlotte Ancel. Also we have Matt Haley, Doug Smith, Josh Castonguay, Eddie Ryan, and I believe myself too.

MR. YOUNG: Other participants who wish to be identified?

MR. BINGEL: I did forget Kristin Carlson. Sorry about that.

MR. YOUNG: Great. The purpose of this is to -- what we have been doing annually for the last, I don't know, four years or so under the Alternative Regulation Plan which is to have a workshop after the filing of Mr. Larkin's report to go over issues or questions that we have, questions that other parties may -- participants may have. And I will slip into the parties constantly here, but we are not at a stage where we actually have parties, so I'll be trying to correct myself each time I do it. But so it's really informational.

And let me just start, Mr. Duggan, off the record you were indicating that Mr. Larkin is not available.

MR. DUGGAN: Mr. Schultz is not available.

MR. YOUNG: Correct. So and he's not available at all. So if we have questions for Mr. Schultz, is there somebody from the Department who might be able to answer those?

MR. DUGGAN: I'm happy to take a stab at them. And if that doesn't work out, then I'm happy to take those questions back to Mr. Schultz or proceed in any other manner that would be helpful to Board staff.

CHAIRMAN VOLZ: It would have been helpful to know about this ahead of time because part of the purpose of the workshop was to have the discussion with the people who had the knowledge. And so now that he's not here at the last minute, it's kind of frustrating.

MR. DUGGAN: Understood. My apologies for that.

CHAIRMAN VOLZ: Yeah.

MR. YOUNG: We will have some questions that we will certainly ask Green Mountain Power that are raised by Mr. Schultz in his report. And we will see how that -- how it plays out.

Have anybody discussed about how you want to proceed today?

MR. DUMONT: Just on what you've just addressed, I'm concerned about what the Chairman just was concerned about. And I think so to ensure that it continues to be a public process going forward, that if there is any kind of information exchange it be posted on the Board's Web site or something like that.

CHAIRMAN VOLZ: Everything that's filed is public. We will share it with all the parties. And it will be -- I think normally we would have stuff like this on our web page, I think.

MR. YOUNG: Not necessarily.

MR. DUMONT: If it's in discovery it isn't posted, so you know --

MR. YOUNG: I guess since AARP has traditionally had an interest in these, to the extent there is a follow up, I'll ask Mr. Duggan to please provide Mr. Dumont with a copy.

MR. DUGGAN: Happy to do so.

MS. ANCEL: I'll add Green Mountain Power -- on behalf of Green Mountain Power we post everything related to the base rate on our Web site, and we are pleased to also post --

MR. DUMONT: If you'll put it on your Web site then that takes care of it.

MS. ANCEL: We will.

MR. YOUNG: We will make sure that you have access to copies, and if it's on Green Mountain Power's Web site --

MR. DUMONT: I wasn't just concerned

about AARP but the public generally, and I think Charlotte has taken care of that.

MR. YOUNG: Fair enough. I know last year there was a nice presentation to sort of frame the issues. Is Green Mountain Power planning the same?

MR. BINGEL: Yes, we are.

MR. YOUNG: Cool. Why don't you start.

MR. BINGEL: Here are copies. Everybody have a copy? Okay.

So this is our 2017 base rate filing. Second slide we are requesting a rate change of .93 percent. That includes a change to our base rate filing, and also our power supply adjustor for the year ended right before we did this filing.

As you can see, the change to the base rates is minus .03 percent which is almost de minimis, and the power supply adjustor is a recovery of $5.3 million. So it's a roughly -- base rates are roughly flat, and then we have recovery of the power supply adjustor.

Slide number 3. Investment highlights. We have $102 million of the plant placed in service in this fiscal year. And Bill Schultz of Larkin & Associates did review our capital that we submitted in the one June filing.

Moving on to slide four. We do have an investment in TransCo, and that capital investment is reflected in this filing as are the accompanying equity and earnings. And those flow back to customers as a reduction in the cost of service. We do also have investments for innovative services, primarily heat pumps, heat pump water heaters and Tesla batteries. And we do have the revenue and the costs associated with them in this filing as well.

MR. YOUNG: Mr. Bingel, may I jump in?

MR. BINGEL: Sure.

MR. YOUNG: You say here it's 1.4 million in revenue associated with this project, projects. Do you remember what the cost of service -- the cost side of that is between the capital return and everything else?

MR. BINGEL: Yes. So we have $350,000 approximately of O&M costs. We have six hundred thousand dollars of depreciation. And we have seven hundred thousand dollars of return on rate base.

A couple of things to note is that we participants in these lease tariffs are charged the same rate throughout their participation in the program. And the costs become lower as time goes on because the item gets more and more depreciated.

Additionally, what we have in here is we did not include incremental sales accompanying heat pumps and that sort of equipment. Heat pumps add roughly two to four megawatthours per unit per year in additional sales. And those contribute to lowering our cost of service as well. Those are embedded in the Itron forecast and the reduction associated with those approximately $250,000 or so, rough estimate though.

MS. ANCEL: I would also note, Mr. Young, that all of the detail regarding the innovative services, so the heat pumps, heat pump water heaters, Tesla batteries is set forth on workpaper number 2.3.1-19.

MS. BISHOP: Can you help me understand how -- where those numbers get rolled up when I'm looking at your cost of service and your rate base summary spreadsheets?

MS. ANCEL: Absolutely.

MR. BINGEL: So -- if you go to 2.3.1 we have them. The other operating revenue contains the revenue associated with these items. Depreciation, amortization, contains the expenses. Return on rate base is the $700,000 return on rate base, and that also -- federal and state taxes those lines in cost of service. O&M expense is located in the black font items. So that is where it is embedded in this filing.

MS. BISHOP: Thank you.

MR. YOUNG: So it's basically close to a whole lot of sub lines that you've got to look a few layers down to find the specifics.

MR. BINGEL: Yes.

MR. YOUNG: Okay. As I was doing my quick math on your presentation of the costs and the revenues, it looks like as of right now if you include the incremental heat pump revenues the programs are approximately breaking even.

MR. BINGEL: Yes. They are.

MR. YOUNG: And you're expecting that that's going to improve over time.

MR. BINGEL: Yes. I think as you install more units, you're going to have -- as you're in growth phase of this program, you're going to have costs that are going to be incurred up front, but then eventually you reach a switch-over point in which it becomes a cash cow essentially, and that benefit goes back to customers, non-participating customers.

MR. YOUNG: Right. I guess I sort of anticipated that trend from the innovative programs. It's just your numbers seem to suggest you've hit it already, which is a little quicker than some new initiatives you might expect.

MS. ANCEL: And the philosophy behind the innovative services is that they are a mechanism to bring revenues back into the business that go a hundred percent to non-participating customers as a way to decrease rates and also to replace sales, kilowatthour sales that we have lost as a result of net metering which if we do nothing, would also drive up rates. So they are intended as a way to offset any of that sales loss and keep rates low.

MS. BISHOP: A question on rate base. And I apologize if you said that to me while I was still looking at the cost of service page. Are these -- they are recorded in your plant in service accounts; correct?

MR. BINGEL: Yes.

MS. BISHOP: Are they considered distribution or general, or what kind of plant do you consider these to be?

MR. BINGEL: So they are -- actually Matt?

MR. HALEY: When we functionalize these based on the FERC primary plant accounts, we put them in 364, 5, sub account which is in distribution.

MS. BISHOP: Thank you.

MR. HALEY: Yup.

MR. YOUNG: I'll turn it back to you.

MR. BINGEL: Okay. Thank you.

MR. YOUNG: I'd say sorry for the interruption, but it's going to happen again.

MR. BINGEL: No, we welcome it. So slide number five. We do have investments in five PV solar projects.

MR. SMITH: Hi. Doug Smith, power supply director. Just a brief context on these projects. They are fundamentally long-term investments. Their output goes to help GMP serve the power requirements of our customers both electricity, energy and capacity, as well as renewable attributes. So just a brief context on those.

On this slide you'll see a few details on how GMP has made the transaction work. Basically through a joint venture with the tax equity partner, and an initial phase of operation where the output is purchased through a PPA, the point of that is to harvest the tax benefits to lower the cost of this power to our customers, but the rationale for it is long term.

The effective price of this solar power over 25 years is estimated as about 12 cents or a little bit more. So that's a flat price levelized over 25 years. That's among the lowest cost solar PV sources that we have seen in Vermont so far. And in addition to that, after that period, we will have an owned solar plant that can provide additional value for our customers either through continued operation of a depreciated but still useful plant, or repowering it with then current panels and technologies.

So fundamentally this is a solid investment in local renewables for our customers. And as we turn to this filing, the power from this resource provides energy, reduces our load, and reduces capacity costs. It provides renewable energy certificates. These benefits which get discussed at a lot more length in the Certificate of Public Good cases for each of these, these benefits do flow through into the power and transmission and other costs in the filing.

MS. BISHOP: Can I ask you a question about your last bullet on this page? Are you -- is this bullet intended to say that each year the equity and earnings and the solar development fee is offsetting the rate base return for that year, or is it over that entire time period the sums net out?

MR. RYAN: It's over the entire time period for this particular project. Although the actual equity earnings and developer are front load, you actually have a reduced cost of service as a result of the front loading of these two benefits.

MS. BISHOP: So it's a lower cost of service now, and in a few years it will be a higher cost of service?

MR. RYAN: Slightly higher. But if you look at it over the five-year period they just about net each other out. Yes.

MS. BISHOP: Thank you.

MR. YOUNG: And the equity in earnings and solar development fee, were those factored into Mr. Smith's estimate that the power would be about 12 cents over its life?

MR. SMITH: I don't believe that the equity in earnings is. Can I check that?

MS. ANCEL: Yeah, please, subject to check. The developer fee is not either. So when you include that impact of the developer fee to customers, the levelized cost of these projects over 25 years is actually below 12 cents to customers. And then of course that doesn't include the fact that they will have additional benefit to customers. They will go beyond 25 years, and during that time customers will get their output for no cost.

MR. YOUNG: If there is an easy way to do it, I would be just curious as to how much you think it drops it down from 12.

MS. ANCEL: Yeah.

MR. YOUNG: Ball park. You know, it's more curiosity just to try to understand what's going on. And I know Mr. Smith just indicated that, you know, 12 cents is one of the lower power price. I believe the last couple standard offer projects that made it through the standard offer program actually came in at lower prices.

MR. SMITH: Yeah. I think to be more specific, I think these are the lowest cost solar projects that have been built. You are absolutely right, that there have been some bids both to Green Mountain Power through a bilateral like an RFP request for proposals, or -- and through the standard offer program that have been at least for the first 25 years a little bit lower. But those for various reasons have not made it on line yet.

And as the Board is probably familiar, that is a feature sometimes of procurements that are done through an RFP or standard procurement. Sometimes it's the winner's curse and the best price bids don't always make it essentially to commercial on line. So that's why I was choosing my words to say the lowest cost built to date.

MR. YOUNG: Thank you. Mr. Bingel.

MR. BINGEL: Okay. So the next slide, slide number six. Other major inputs. Itron puts together the sales forecast. They are showing that we have rate pressure because our sales are decreasing. So we are experiencing growth in the number of customers within our service territory. It's growing by about .5 percent a year.

We are also getting growth in income, and that sort of thing, but it's being adversely or excuse me, it's being reduced by improvements in energy efficiency appliance standards, the efforts of Efficiency Vermont, and also we are having greater net metering.

Third point is that in the 2016 cost of service, Itron forecasted sales growth for our industrial customers. That growth has not materialized. And so that is also causing upward rate pressure this year.

Second bullet we have -- we expect 60 megawatts solar net metering to be installed in calendar year 2016. And in the second year that reflects what we have in our queue. And in 2017, we are forecasting 30 megawatts being installed in our service territory. For this particular cost of service filing, because we have our fiscal year that overlaps both years, we are expecting to have 46 megawatts of solar installed and that will -- we expect those units to produce about 68,000 megawatthours of power.

Mr. Smith will take us through transmission by others.

MR. YOUNG: Actually before we jump to him, why don't we -- a couple questions on the previous.

In your preliminary filing that you submitted in June, one of the bullets said the only impact of net metering in this filing was around two percent. Is that still true in the final base rate filing?

MR. BINGEL: It's slightly less because we did remove seven megawatts per discussion with the

DPS. There is some volatility as far as when these units get installed, and there is also some timing differences here as well. So we have -- when people produce solar, it either reduces their bill, or if they produce more than they use, we have to book it as an expense in the period in which it's produced.

The way our fiscal year is set up, most of the installations, of course, produce power in the April to September time frame, and so a lot of these units as they come on line are producing power at the end of our fiscal year, and then they are using the credits during the darker months of the year which are, of course, October through February.

We also get some benefits from solar reduction in transmission costs and a reduction in some capacity requirements, but those are delayed as well. So the impact for solar rough estimates probably for this particular cost of service is approximately one to one and-a-half percent. I would say actually -- excuse me. It's one and-a-half percent.

MR. YOUNG: And that factors in all those timing differences you're talking about?

MR. BINGEL: Yes, it does.

MR. YOUNG: In terms of like the

transmission avoidance.

MR. BINGEL: Yes.

MR. YOUNG: And other facts -- one and a half percent.

MR. BINGEL: Excuse me. It's only the impact on the cost of service in 2017. So the benefits associated with capacity and transmission are largely delayed until 2018.

MR. YOUNG: Okay. So would it be fair to say that at least as presented here, I mean your preliminary filing said two percent. That was an overstatement of what the effect of net metering has been so far in your cost of service.

MR. BINGEL: A little bit, but it's still significant.

MS. ANCEL: And that the change from the roughly two percent to one and-a-half percent reflects the downward adjustment that we made by virtue of the talks with the Department of Public Service. That's forecasting what we expect is going to go on line for net metering in rate year '17, so coming in the year that will start October first, 2016 for us and go through September 30, 2017.

That's -- it's an estimate and a projection going forward. We don't know exactly how much net metering installations will go in. There could be more going in than we have projected. And so that downward adjustment to be clear was -- reflects the downward adjustment that we made to the projections.

MR. MARREN: Jake Marren. I'm a staff member at the Board. What was the assumed capacity that led to the 1.7 percent cost estimate?

MR. BINGEL: Excuse me?

MR. MARREN: What was the installed capacity and net metering?

MR. BINGEL: 46 megawatts additional.

MR. MARREN: Additional. What is the total amount of installed?

MR. BINGEL: So let me see. By the end of calendar year '16 we estimate approximately 120. So by the end of fiscal year '17, 140 megawatts. So estimate.

CHAIRMAN VOLZ: Of installed net metering?

MR. BINGEL: Yes.

CHAIRMAN VOLZ: In your service territory?

MR. BINGEL: Yes.

MS. ANCEL: And our projections assumed

-- we used the draft rule that was available at the time we made the filing on June 1 which at that point assumed a four percent pacing mechanism year over year. So if that pacing mechanism is exceeded, our projections would be understated, and there would be additional impact to the power adjustor going forward.

MR. FINK: So sort of questioning the Itron report. I guess first I had a clarifying question. I'm looking at figure 14 on there. The -- it's on page 23 which is labeled monthly solar capacity forecast. There is a similar chart in there.

MR. DUMONT: Could you speak up a little bit?

MR. FINK: Apologies. I'll try to project a little better. On page 23 of the Itron report it's labeled figure 14. There is a graph labeled Monthly Solar Capacity Forecast, and there is a graph earlier in the report that's labeled something to the effect of Net Metering Capacity or something along that lines.

I wanted to first just clarify, is figure 14 there reflecting just net metering capacity or --

MR. BINGEL: Yes.

MR. FINK: It appears to be in context, but I just wanted to understand.

MR. BINGEL: Yes, it is. As opposed to --

MR. FINK: Other services of solar.

MR. BINGEL: Yes.

MR. FINK: Actually you just sort of touched on this, and you may have sort of foreshadowed what the answer is, but obviously that has a breakdown of size facilities, and I'm curious, I mean I would imagine you anticipate that potentially looking different based on the final net metering rule.

MR. BINGEL: Yes. There has been -- it's been very difficult to forecast solar installations.

MS. ANCEL: But our forecast was refined and updated to reflect the draft rule that we had as of June 1 which did reflect the various incentives for projects based on size.

MR. FINK: Okay. And then I had another question. If we go down a couple pages in the same report and go to the allocation of own use versus excess use section, it's on page 25. I'm just curious especially with the residential section here, correct me if I am wrong, but I'm reading that to suggest that in that instance -- the projection is that something like 75 percent of production is actually used on-site for residential customers? Am I reading that graph correctly or that table? Table nine.

MR. BINGEL: Table nine.

MR. FINK: Page 25.

MR. BINGEL: Yeah.

MR. FINK: So I'm looking at you have a total residential generation megawatthours.

MR. BINGEL: Yes.

MR. FINK: And then you have residential own use, I believe it is residential access.

MR. BINGEL: Yes.

MR. FINK: So it looks to me like the lion's share is own use, which I took to mean is used on-site. Is that --

MR. BINGEL: It could be. It could also be participants are in a group, they can also use it as well. This really reflects the timing of when people use solar net metering versus when they accrue the benefit associated with it.

MR. FINK: So that's not strictly what's behind the meter or --

MR. BINGEL: No. You have group net metering in there as well.

MR. FINK: Okay.

MS. BISHOP: So how is it then that the industrial class as a whole has nothing that is considered own use for net metering?

MR. BINGEL: It has to deal with the accounting and how you treat the different rates, and where the source of the net metering is coming from. So these group net metering arrays you do get units where they are produced by say C&I small customers, and they are transferred to industrial customers as well.

MS. BISHOP: So if I were an industrial customer, and I had put in a net-metering facility on my property, that was a group system because I had multiple accounts, is that all considered excess then? Under this chart it would seem that all of that is excess.

MR. BINGEL: Yes. I believe I should follow up with you on this one though.

MS. BISHOP: Okay. And also to understand how that works with residential customers who are in groups. I'm trying to understand if this is -- if it's -- is it a group system that's creating the issue or is it timing?

MR. BINGEL: The accounting is very tricky for group net metering, especially depends on whether you're collocated with the meter or not. If you have a stand-alone array, then for say time-of-use customers, the power that's produced by that stand-alone array is booked as power supply expense. Your bill is still recognized as revenue, but the two then offset on the bill itself.

So you have the generation again is considered an expense, the amount of power that you use is considered revenue, and then on your bill they offset. Whereas with some residential group net-metering projects it becomes -- you get a certain percentage of the power from the group net-metering project. If your usage exceeds that amount, then it's a reduction in your -- in the revenue. But if the production exceeds the consumption, it's considered an expense because you have more of a credit than you're using.

MR. FINK: So I should read excess on this page to understand that that is essentially when a customer is receiving a credit above what their bill would be, not --

MR. BINGEL: It's actually two different mechanisms. So for -- it can mean one of two things. Either the consumption is less than the production so then you have excess, or it can mean for certain types of customers time of use, and I believe that's the industrial, but I just want to verify that, if you have a stand-alone array, then you are -- you get residential rates applied to that.

And so because of the complexity of time of use and when you are actually using the power, it's recognized in two separate ways. So the first way is whatever is produced by your array is considered a power supply expense, your usage is calculated, you know, time of use, and hours you use the power, that sort of thing, and then because it's so complicated the revenue is booked separately but the two offset. So that the excess can mean either production exceeds consumption, or it's a time-of-use customer.

MS. BISHOP: And so the commercial then those are time-of-use customers or are they --

MR. BINGEL: Some of them are. Some of them aren't. We have a wide range of customers in the C&I small category.

MR. FINK: But I think maybe what Ann is trying to understand, I mean so again if I go back to this table the proportion of total generation that is labeled as own use for commercial is substantially less because a much larger share of commercial customers is time of use, is that essentially what you're saying?

MR. BINGEL: That's part of it. It's also the fact that these units are coming on, they are producing power, and they are generating these credits that are then going to be used in later periods when the darker months occur.

MR. YOUNG: So on the commercial -- well these are annual numbers; correct?

MR. BINGEL: Yes.

MR. YOUNG: And so what I hear you saying which is basically they are going to bank the summer production for use in the winter.

MR. BINGEL: Correct.

MR. YOUNG: This is recognizing the production but not the usage. That later usage drawing down the bank.

MR. BINGEL: Correct.

MR. YOUNG: And so these aren't really excess because they are really taking advantage of the net-metering program's ability to basically bank for a period of time, is that what I'm getting out of that?

MR. BINGEL: There is a timing difference for a portion of that, but again they are also time-of-use customers embedded in there that are actually using the power that is being produced in the same month.

MR. YOUNG: So on the commercial side it's safe to say I shouldn't read anything into these numbers because there is a whole lot of accounting issues here.

MR. BINGEL: Yes, but for residential you are correct.

MR. YOUNG: Let's go to residential then. Residential customers.

MR. BINGEL: Yes.

MR. YOUNG: If I produce excess power on my solar panels this month, is that going to be counted as residential excess even if I use it in October?

MR. BINGEL: Yes, it is. Yes, it is, because you have produced that power, we have the obligation to give you that credit, so we have to recognize that obligation in the month in which it's produced.

MR. YOUNG: And this chart doesn't recognize that netting the fact that you gave me that power back in October.

MR. BINGEL: No. Because that's the next fiscal year, yes.

MR. YOUNG: Oh, okay. Sorry. You caught me up on -- I walked right into that one. Let's assume it was October, November. And so we are in the same fiscal year. Would this chart be recognizing that?

MR. BINGEL: It would not -- in this particular chart would not have that. But what happens is that the Itron forecast would still show higher revenue.

MR. YOUNG: Okay.

MR. BINGEL: Because again you're using the bill credit to offset the revenue that you are incurring.

MR. YOUNG: So when I look at this number in general, all I'm getting out of the residential excess is that -- this is the cumulative amount from residential systems that in any particular month was excess and might be banked and used later on.

MR. BINGEL: Yes.

MR. YOUNG: Or it might go back to GMP's benefit because the customer didn't use all the credits within a year.

MR. BINGEL: Correct.

MR. YOUNG: But I can't tell which is which.

MR. BINGEL: No. It's just showing the obligation that we have to incur. As far as the excess credits go, in the month of July we had approximately 20,000 expire. And the month of August we had about 38,000 credits expire. And those will flow through the power supply adjusted and the benefit associated with that.

MS. ANCEL: Meaning they will go back a hundred percent to customers.

MR. YOUNG: Right. If I just mentally do the math of those numbers and compare these numbers which are in megawatthours, most of this stuff is actually used, this is just banked and used in a different period of time.

MR. BINGEL: Yes, it is.

MS. ANCEL: Yes.

MR. YOUNG: Okay. Thank you. Sorry. It's difficult for us to follow this.

MR. BINGEL: It's a very complicated subject so --

MS. BISHOP: So when I was looking at the kilowatthour sales, this is on schedule 2.2.

MR. BINGEL: Okay.

MS. BISHOP: And it was a summary of revenues under current and proposed rates. And it has -- I'll give you a minute to get there.

MR. BINGEL: Schedule 2.2?

MS. BISHOP: Yes.

MR. BINGEL: Okay.

MS. BISHOP: And so it has average number of customers by class and kilowatthour sales per class.

MR. BINGEL: A-hum.

MS. BISHOP: And when I was looking at this for residential, that kilowatthour sales number, please correct me if I am wrong, does not include the own-use net-metering residential number.

MR. BINGEL: You're absolutely right because it looks to us like they didn't even occur, yes.

MS. BISHOP: Okay. But it would include excess.

MR. BINGEL: Yes.

MS. BISHOP: Okay. Now what about for commercial and industrial? Does it also look to you like it didn't occur even if they actually are consuming it in the same month?

MR. BINGEL: No. It would look to us like given the fact that there is so much excess it would be embedded in the Itron forecast as higher revenue as well, except it depends on the type of business, so if you have a small say convenience store, you're not time of use, then you would be almost more like a residential customer.

MS. BISHOP: So should I look at this kilowatthour sales number for small commercial and industrial, and large commercial and industrial, is the net metering -- is all the net metering in here, or is it not in here?

MR. BINGEL: So to look at our forecast from Itron if you wanted to know what it would be if there was no solar you would add in the own use. And that would get you like if there was no solar in our service territory.

MS. BISHOP: Okay.

MR. BINGEL: Everything else is basically either a timing difference or it's been offset by revenue that's in the forecast.

MS. BISHOP: Okay. So I would do that for each customer class.

MR. BINGEL: Yes.

MS. BISHOP: Thank you.

MR. BINGEL: You're welcome.

MR. YOUNG: I believe we have been preventing Mr. Smith from talking about transmission by others.

MS. BISHOP: Actually before we get to transmission by others, I'm still back on the solar piece. I'm looking at page 24 of the Itron report. And there are solar load factors by month. And it says that the system hourly load profile was developed by GMP. Is this based on your actual historic experience or is it weather normalized or --

MR. BINGEL: It's not weather normalized. I believe this particular chart is probably about five years old or so. It was when we were first developing solar adder. That's where this came from. But it's just reflecting expected production throughout the year on -- and it all sums to a hundred percent.

MS. BISHOP: And do you know how closely it matches your more recent actual experience in terms of production?

MR. BINGEL: Not down to the precision of hundreds of a decimal point, but I do know that April before the leaves come on is a high period, and then May, June, July and August are all very intense as well.

MS. BISHOP: Thank you.

MR. YOUNG: Mr. Smith.

MR. SMITH: The next item, transmission by others is one --

MR. DUMONT: Excuse me. Do you want questions from the rest of us to wait or not?

MR. YOUNG: You know, the interesting thing is I was just trying to figure out how I was going to sequence that. If you have a question that's germane to this, why don't you jump in right now.

MR. DUMONT: On page six the second bullet point about 30 megawatts of solar net metering installed in calendar year 2017. I'm just wondering how my client or the rest of us or the Board can address used and useful test when applied to 30 megawatts.

MS. ANCEL: I'm pleased to take that. So the 30 megawatts reflected the draft rule for net metering for the pricing program that would start in

2017 that was in effect as of June 1. And then I also would add that with respect to these expenses, they flowed through the power adjustor, so to the extent that there is variance in either direction, that variance is returned to customers.

MR. DUMONT: I think I understand some of that.

MR. YOUNG: We will give you plenty of other opportunity to ask questions. If you have follow up now --

MR. DUMONT: I have no follow up now.

MR. YOUNG: Mr. Smith.

MR. SMITH: The transmission by others topic is one that the Board is probably fairly familiar with as it's been a meaningful retail rate driver for Green Mountain Power and other Vermont utilities in recent years. This is basically the -- the primary component of this labeled here as RNS or regional network service. That's basically the cost for Green Mountain Power as a load-serving entity to obtain bulk transmission service to an every day basis match up its loads and resources. It gets charged to GMP and other users of the bulk system on a monthly basis, and the increase that's cited here in the chart, the dollars per kilowattyear reflect the mid to hopefully late stages of a major regional build out in bulk transmission facilities.

This is basically transmission owners in all the New England states including in Vermont, building reliability-driven transmission projects of various sorts, and the charge here -- the one that will become $103.77 per kilowattyear -- is essentially a monthly charge per kilowatt of maximum usage each month. So that factor that has been increasing by a few dollars per kilowattyear for most of this decade and it contributes several million dollars to the transmission by others category in this rate year, fiscal '17.

I should add that in addition to the price or the rate for this there are measures we can take and are taking to try to mitigate those costs. We talked earlier about distributed generation like the GMPSolar plants. Net metering, some other distributed resources to the extent they reduce the peak draw, if you will, of Green Mountain Power from the system, they can help mitigate such charges, and that's one of the reasons that when you hear us talk about our resource strategy management of peak, is one of the factors that we mention because there is a good bit of charging associated with those peak hours of consumption. It's not so much energy, it's transmission bills.

MS. BISHOP: So can I follow up on that for a second? When you talked about one of the strategies to help mitigate those costs being increased use of solar, so what happens then if it's a cloudy day on the day that's the ISO system peak, what did that just do to your strategy to mitigate costs?

MR. SMITH: Interesting way to put it. In short, the contribution and the amount of mitigation does depend when we have a distributed resource like -- and by that I mean one that serves to reduce our load. It's not an ISO-registered generator that has an administratively determined capacity value, but rather it's one that chips away at the consumption that GMP requires from the bulk grid, that type of resources contribution to lowering those costs does depend on actual production during the time of peak hours.

I can tell you though that in recent years for this purpose transmission peaks as well as the regional capacity charges which are allocated based on ISO New England's maximum hour of demand per year, Vermont and GMP shared those charges, capacity and transmission has been noticeably cut as a result of distributed generation, mostly solar that's been producing during summer afternoons.

So in other words we see it in our load curves on a day-to-day basis, but the other implication of this is as solar both here and Vermont becomes more and more prevalent, we are seeing our peak loads on the system begin to shift into the evening. So the next hundred megawatts of solar or the hundred after that will logically probably have diminishing returns on this particular peak load.

MS. BISHOP: Are there other implications of the increased penetration of intermittent resources on your system for our power supply strategies?

MR. SMITH: There are. And we are looking at that through a couple of lenses, but the short story is that on a day-to-day basis, we see quite a bit of variance in output from our distributed renewables. But it does not have a major impact on our net power costs as of now. Because the penetration of those mostly distributed solar in the region is modest.

So on a day where it is very sunny versus one where it's cloudy, we see a difference in our load curve and what that difference means is the difference in the amount we need to buy each hour from ISO New England. But the cost to do that or the value of extra solar we have on a day when it's very sunny, those differences are modest today, typically quite modest. Over time though as the penetration of solar increases in our state, and particularly across the region, it is reasonable to expect some what I would call integration costs or diminishing returns in the value of solar, because on the days that are best for our solar, produce the most energy, they will often be the best for solar production in neighboring states, and that will drive down the market price for energy a little bit.

So the bottom line, the primary impact we see of the intermittence right now is a significant day-to-day and sometimes hour-to-hour variance in how much power we need from the New England market. The financial cost of that has not been very large so far, but it's a risk topic that we need to watch and manage. And we are looking towards resources like storage and responsive demand that can be price responsive to help us manage that as the amount of intermittent power supply grows.

MS. BISHOP: Is there a difference

between wind and solar when you're thinking about the intermittent resources and the ways of managing the risk associated with them?

MR. SMITH: Yes. In short, they each share one common characteristic which is that from a time frame of even a day ahead, 24 hours, there can be quite significant variances between a forecast quantity of production and actual in a way that is not present for some of our other intermittents such as hydroelectric fleet. We don't get the same hour-to-hour fluctuation in hydro as we do for wind and solar.

The other characteristic with the solar is simply that as you can imagine the production of solar generators is concentrated in the hours of sunlight so that the variance we see in output between cloudy and sunny hours or surprises in the forecast of cloudiness, it's concentrated during the daytime hours in a way that wind's output is spread more randomly across the day. So the impact of intermittents are less concentrated I would say, at least in our portfolio for wind. They are spread across the whole day in other words.

MR. YOUNG: You were talking about the system peak and the shift in system peak. And I know we have had this discussion with Green Mountain Power, I don't remember whether it was last year or some other proceeding in between. Is ISO seeing the same shift in terms of its peak or is the penetration of solar not as great at the ISO New England level so that there is a little more of a mismatch?

MR. SMITH: I would say that ISO is seeing that effect but more gradually. For Green Mountain Power over the last three or four years we have seen a marked increase in the number of hours in the sunny months in which the maximum net load or residual demand on our system actually occurs in the evening because the distributed solar production has reduced what would have been our peak during the sunny daytime.

At ISO we see a migration beginning to occur where the net system peak is migrating toward hours 16, 17, 18. So 4 p.m., 5 p.m., 6 p.m. in the afternoon. Whereas five or six years ago from memory, those peak hours for ISO might have been two, maybe even three hours earlier. So it's not as pronounced, but we are seeing the beginnings at ISO New England as well.

MR. YOUNG: And I don't expect an answer -- that you are necessarily going to have an answer for this, this is just throwing a thought out. Which is -- I mean to date there has been a certain benefit of the timing of solar in terms of being able to reduce your loads. As you said, when you get the load shifting so that your peak is now at a time when solar is not really working very well, is there something the Board or frankly the Department should be doing in the context of various proceedings or the valuation to take into account a changing value for some of the solar? And as I said, that's more rhetorical right now, just to start triggering a thought process, you know, you're free to jump in. But do we need to be thinking about these things differently and how, and I just wanted to throw that out.

MR. SMITH: I guess in short, it does matter. The value of the output does matter. In the context of the joint venture or GMPSolar projects that we mentioned earlier, I updated -- Green Mountain Power updated its estimates, lowered its estimates noticeably of what the output of that solar power would be in part because of this very issue. When we took a look this year at the coincidence, particularly for the Vermont peak, it was somewhat less than we had been assuming, so we reduced by a couple of cents per kilowatthour our estimate of the value of that solar power.

I think it would be appropriate for the Board to weigh among the -- the many factors that weigh on an appropriate pace -- bear on the appropriate pace for solar development in the net metering realm, to weigh the estimated value taking into account the evolutions and things like power market prices, timing of peaks and all that. And I think the Board has started that dialogue, and so has the Department as well.

MR. YOUNG: Okay. I'll turn it back to you for next topic.

MR. SMITH: The next slide entitled Major Inputs, Revenue and Power Supply, this is a summary of some of the largest influences both upward and downward on the power costs that are reported. The punch line is the bottom bullet there. If you look at the net of power costs which include several sub components, the net of all these changes for this rate filing, this fiscal year is about a one percent upward pressure on GMP's estimated retail rate requirement. And the major drivers are as follows.

We have talked about net metering at some length, but we may not need to go too deeply into that here. I can if you would like, but I would say the primary take away is the one that you -- the Board discussed a little bit with Mr. Bingel before that is -- there is a major meaningful item in the power supply costs called net-metering excess. And that consists of, as Mr. Bingel discussed, several drivers of what are accounted for as excess net-metering consumption on a monthly basis, even if that is often from a well-sized solar facility that just happens to produce more in the summer.

The other content in that row though is the so-called solar adder which reflects several vintages and is differentiated presently by the size of solar facility. The point I want to make is simply that that item in the power cost which is about 23 and change million dollars consists of both of those things. The dollar figure is both the solar adder which is a meaningful contributor as well as so-called excess solar on a monthly basis. So if you divide the dollars by the kilowatthours and wonder why it produces an extremely large number, that's why. It's got the solar adder for all net-metered production and the kilowatthours and booking of excess solar production for the portion that each month is excess to its associated customers' usage.

So that has become -- I simply want to point out it's become a meaningful item in our revenue requirement that was not really present in the same degree even a couple years ago.

MS. BISHOP: Are you able to break those two numbers out, those two components of that number?

MR. SMITH: Not right at this moment. But we can. Yes.

MS. BISHOP: No.

MR. BINGEL: Roughly speaking it's the six cents or 60 dollars per megawatthour times the total generation that's found on page 25 of the Itron report. 60 dollars times 162,735 megawatthours roughly.

MR. SMITH: The second item is capacity. Capacity is the ability to deliver reliably and on-demand energy. And this is really important for our grid operator ISO New England to be able to ensure that accounting for the profile of consumption of power, outages of generating plants and so forth, they are sufficient capacity resources to be available.

So the short story is three years ahead ISO New England conducts a forward capacity auction.

There are subsequent reconfiguration auctions as they call them, but these annual auctions each winter make sure that there is sufficient supply and demand-side resources to provide capacity to serve the ISO New England system. And that is separate from the dispatch, the operation each day an hour of those resources which will occur on a real-time basis, based on economic dispatch principles.

For GMP the reason this matters is as a load-serving obligation we are responsible for our proportional share of those capacity reserves in New England. As an order of magnitude GMP is responsible to either provide or purchase I think 900 or 900 something megawatts as an indicative GMP share of the total regional capacity requirements. And the reason we called it out here is that forward capacity auction eight, this was the first -- this was completed several years ago, for capacity to be delivered starting next summer, next June. And this is the first auction in which New England transitioned from a surplus regime on the order of 10 percent more capacity resources than was the estimated minimum requirement to one that was quite balanced and the price roughly doubled.

So bottom line there are several

million dollars of upward pressure in our net power costs in capacity which show up starting next June and will really show up across in load-serving entities pretty much across the region at that time. The impact on GMP is significantly blunted because of the contribution that our own power plants, hydroelectric, combustion turbines, even wind plants, they act as sources that meet a significant part of our capacity needs. But still, even though GMP is a supplier of a substantial amount of its own capacity, this is a meaningful rate driver, and I think you'll see it for other Vermont utilities in the next couple of years as well. Okay.

MR. DUMONT: Can I ask a question?

MR. YOUNG: Sure.

MR. DUMONT: This is probably in the category of stupid questions. You just said it's a powerful or important part of a driver of rate. How does that relate to the .96 and .03 percent on page two?

MR. SMITH: In short, the first row that you cited there on page two, the one that culminates in a rate impact of negative .03 percent, what I'm saying is that that negative .03 percent is -- consists of or driven by many components that we have been discussing today, but the capacity market increases in price are one of the influences that essentially causes this number to be lower than it might have been.

So the point -- negative .03 is a net of many things, but this here is driven in part by capacity.

MS. ANCEL: And to add to that, Jim, the capacity costs are part of the forecasted power costs expected to occur in the next year, so they are part of the base rate. Whereas the power adjustor are a true-up of the variance between projected power costs in the last rate filing and then what they actually ended up being.

So this capacity is part of the projection going forward for next year.

MR. DUMONT: On the bottom of page seven it says: The net impact of these changes drive about 1.8 percent of GMP's estimated rate need.

MR. SMITH: Good place to look is page ten, I believe, of today's packet which tries to visually show the effects of this -- I mentioned several offsetting impacts.

On page 10 the second item from the left shows a positive 1.8 percent. It's Labeled FY

'17 power supply. What I'm saying is that power supply alone, if you looked at that only, that contributes upward rate pressure and would have caused our rates to need to go up by about 1.8 percent. But the other factors shown on that page, particularly operating savings, net out to roughly zero.

MR. DUMONT: Okay. Thank you. That last page puts the pieces together. Thank you.

MR. SMITH: A smaller contributor, but one that's notable from a net cost and policy perspective is the next one, renewable energy credit sale revenue.

The short story there is that as the Board knows, GMP sells -- presently sells a significant volume of renewable energy certificates or RECs to entities to comply with Renewable Portfolio Standards in neighboring states. RECs or renewable energy certificates are basically the right to claim certain volumes of power as being associated with a certain type of generation and a certain emission profile. So GMP is a meaningful seller of RECs from projects that were built recently; solar, wind, other types. We sell those attributes at least on a temporary basis, in this case here, and credit the significant market revenues to reduce net power costs.

So you'll see a line in our net power costs, a net credit or reduction of 22 or 3 million dollars in this year, and the point here is that that's similar to past years but a little bit lower for two reasons. Regional market prices for renewable energy certificates for the most -- the highest priced classes of RPS have dropped a little bit in the last year or so.

And secondly, this is the first year where our power supply costs show a few months of compliance costs with the new Vermont Renewable Energy Standard. That is the retirement of renewable energy certificates particularly associated with tiers one and two. So these factors net to produce a reduction of a couple of million dollars in the net revenue line for this year.

MS. BISHOP: So I'm trying to think ahead in terms of what does this mean for the year after when I -- and your statement about how this reflects the first few months of compliance with the tier one and tier two standards. What portion of this couple million dollars' difference was associated with that change? In other words, what's coming down the pike for the following year?

MR. SMITH: I don't have a particular breakdown for future years right now. But the lion's share of the reduction in net REC revenue that I just mentioned is associated with the market prices or revenues that we are able to achieve, oh, and the compliance costs or retirement of RECs only pertains for, I believe, one quarter's worth or three months of this rate year.

I don't have a good estimate right now for the future years. But it's in the order of millions of dollars a year. Not tens. But we would expect to see millions of dollars of compliance costs begin to show up once a full year of RES is in place in our next rate filing.

MR. FINK: Following up on a similar vein, I'm curious sort of just in general what the company's REC market risk profile looks like over the next sort of several years. And it's my impression, correct me if I am wrong, that the company is somewhat long on RECs at least in the earlier years of the RES at this point.

MR. SMITH: It's a good question. The short story is as we just discussed there is a selling side and a buying side. On the selling side the one that produces the 20 something million dollars' net credit today, we use a layered forward-sale program similar to what we do on the purchasing side in which we have a length of RECs that are eligible for high value classes of RPS in neighboring states. Think order of magnitude, depending on the year, 700,000 megawatthours. We try to sell those forward from one to four years forward on a layered-sale program.

So for 2016 calendar year we are largely sold right now. And we are substantially sold for '17 and a chunk of 2018 as well. But that's roughly the profile on the sell side. To the extent regional REC market prices go up or down, and I'm more worried about the down side on behalf of our customers, the exposure gets greater say three to four years out, much greater than it is next year.

On the purchasing side which is tier one total renewables and tier two distributed renewables, I would say simply that the mix of procurement activities are in place from net metering, the standard offer program, the GMPSolar projects that we discussed earlier, and other bilateral PPAs should have us in good shape for the first several years of compliance with tier two. And a lot of it will simply depend on frankly how much and how fast net metering continues to develop and how many customers choose to claim their net-metered power as renewable for their own consumption as opposed to assigning it to the utilities for use in compliance with the Renewable Energy Standards.

MR. FINK: Is there a sense that over time particularly as the Vermont requirements ramp up that the company will become -- essentially will be selling less RECs on the market in the future, or do you -- obviously they are coming on as projects that are not necessarily eligible for a tier two of the rates. And I assume those might continue to be sold.

MR. SMITH: There is. In the long run we envision these sources -- take a solar project that was recently developed, or the Granite Reliable Wind Project in New Hampshire, we have a PPA. We would envision in the long run those would become part of the mix of resources that are claimed as renewable consumption by Vermont customers.

It's a little bit of a balancing act in terms of the timing of that because, as you probably know, in recent years, that renewable attribute has had a substantial value on the order of four or five even more cents per kilowatthour. So it is a productive use of those RECs to sell and lower rates. But in the long run I don't know exactly what that date means, and we are working on that strategy. We do envision those becoming part of the power mix that's claimed as renewable for Vermont customers. Yes.

MR. FINK: So essentially over the long term the company doesn't envision sort of being -- playing the same role in the REC market that it perhaps has over the past several years where it's almost primarily a seller in terms of --

MS. ANCEL: I'll speak to that. Yeah, our energy portfolio strategy is to long term. And when we say long term we think of about -- think of on average about a decade or so from these projects going into service give or take some amount of time is something that our team is looking at right now. We will retire the RECs from every renewable project that we have in our portfolio.

MR. FINK: Okay.

MR. SMITH: The only thing I would add is we will be REC buyers and retirers. As the Board is aware, the Renewable Energy Standard does contemplate the mechanism of demonstrating compliance as retiring renewable energy certificates, and it's very clear on that. We do have a need over, you know, the next decade for both particularly tier one but also tier two, and as we discussed we will be retiring those RECs as well.

MR. FINK: Thanks.

MR. SMITH: The last item I wanted to note is simply that the power market environment regional wholesale power prices play a part in our retail rates. Lately GMP's rate path has been relatively flat and power -- net power costs have been relatively flat. Expiring of several purchase power contracts in this period that 2016, '17 period, is putting some downward pressure on our net power costs. The most notable of that is the expiration of the last schedules, excuse me, of the Hydro-Quebec Vermont Joint Owners long-term power purchase agreement and its replacement with a smaller and differently priced purchase from Hydro-Quebec U.S.

That is the -- the net of that is a -- represents a downward pressure of several million dollars in our net power costs during this period. And also, some other purchases that were made earlier in the decade, I think 2011, 2012, in part to hedge the risk of Vermont Yankee retirement. Some of those purchases on the order of five to six or even more cents per kilowatthour are being replaced by contracts in the fours now. And that is also a moderate downward pressure on the net power costs.

MR. YOUNG: So two things. I just wanted to follow up -- finish up on the whole RES discussion. And as I'm looking at this I realize these are imprecise numbers, but from what Ms. Ancel and Mr. Smith were saying, it looks like you've reflected about a quarter of a year in this filing attributable to RES compliance. If I do a rough back-of-the-envelope, would that be approximately it's going to cost you one percent on cost of service for RES compliance? You used the number of $2 million. Some of that was lower REC prices, but some of it was RES compliance. If I just do a rough multiply that by four or account a little bit differently, I end up around one percent.

MR. SMITH: It would be a bit less than that. I don't have an exact number but single millions of dollars. Take the first year. The first year tier-two requirement for RES is one percent of sales. For GMP that is in round numbers 40,000 megawatthours. If we were to forego the sale of a regional class one renewable energy certificate let's say from a solar plant here in Vermont and retire that toward tier two, the rough math would be 40,000 megawatthours times -- I'll use an illustrative four cents per kilowatthour or 40 dollars per megawatthour price. That's 1.6 million dollars for tier two. Tier one we have much larger volumes to purchase.

But those prices we have much more flexibility on the type and vintage of renewables to procure. I would expect that to also be in the couple million dollars range. So overall, I would say less than one percent for the first year or two of compliance with tiers one and two. I haven't done the same exercise for tier three. But I note that that has -- that contains both measures that reduce electric consumption as well as cost effective electrification, so it doesn't represent only an upwards pressure from retail rate perspective. It can push both ways.

MR. YOUNG: Okay. Based upon those numbers it's more like half a percent.

MR. SMITH: As an illustrative figure, yes, that's what I'm saying.

MR. YOUNG: We are not holding you to this. I'm just trying to get some, you know, this is my chance to actually learn something for a change.

Different question. Mr. Larkin's or

Mr. Schultz's report on behalf of Larkin & Associates page 21 talks about the new hydro dams. And I don't know whether this is Mr. Smith or somebody else who should be answering this. And one question reflected in here, I mean it looks like for the moment there is an agreement to disagree and not put it in the cost of service, but there is a discussion item on how the project costs should be reflected.

Is there -- is that an outstanding issue still?

MS. ANCEL: I can speak to that. The -- no cost related to the proposed hydro purchase are included in this rate filing. And we will take it up in the next rate filing.

MR. YOUNG: Okay. So all issues about how it's going to be valued, everything else we will see next year.

MS. ANCEL: Yup. And the value meaning the levelized cost to customers will come before the Board and the Department and other interested parties as part of the 248 for -- that's required for the purchase of the out-of-state plants.

MR. YOUNG: Right. I was actually differentiating between -- from the levelized price, Mr. Schultz has a line: Another concern is whether the project costs reflected on the books should be book value or fair market value, which is more an accounting issue than a valuation issue.

MS. ANCEL: That issue will come before the Board and the Department in the next rate filing.

MR. YOUNG: Okay. In that case I'm not going to worry about it now. We will turn it back to -- are we on to page eight?

MS. BISHOP: Let me just ask one more sort of big picture question. We have talked a lot about net metering and smaller power supply resources. Are there -- setting aside the dams for a second, are there other larger power supply issues or concerns that we should be thinking of? And I'm thinking, for example, a couple of years ago we had talked about the integration of the different power supply strategies between CVPS and GMP and how you were making some resource decisions that were moving the company as a whole toward the approach that you wanted to take. And I'm just kind of curious where -- taking a step back from the big picture, I mean is it really all about net metering now and the small or smaller projects? Or are there still some of those big picture purchases, et cetera, that are going on?

MR. SMITH: Short story, the GMP's been

operating as an integrated company for several years. So that example that you correctly recalled of essentially reconciling two companies is several years in the rear-view mirror, and we are operating as one integrated company basically from day one in our ISO New England accounts, and our strategies all reflect one perspective.

I guess I would answer it; others on our team may supplement. But I would answer it that it is yes, distributed resources and smaller ones are more prevalent. That's partly by our strategy at Green Mountain Power, and partly by the evolution and clarity of strategy of statewide renewable strategy to focus on in-state renewables and distributed ones.

So in some sense it's logical that the procurement issues that we are talking about, costs, benefits, revenues derive and focus on distributed resources. So that's logical.

The final thing I would say is nonetheless as we discussed here today, there are broader factors, the wholesale power market, regional capacity prices, fossil fuel prices. These still have meaningful impacts on GMP's net power supply and retail rates, and a good bit of what our management needs to focus on is the when and how to purchase at low cost from the regional market and the distributed resources. They are definitely part of that.

Looking forward I bet you storage on both the load and -- storage plant side will evolve. But the wholesale market still is a meaningful driver. It happens to be relatively flat the last year or two. So there is not a lot to talk about except for a moderate down draft which has enabled us to replace power purchases as I discussed a few minutes ago at fairly favorable rates.

MS. ANCEL: And I just would add there are also another significant opportunity in terms of changing the way we think about how we manage our power supply needs as coming down the pike. We have seen certainly a precipitous decline in the cost of manufacturing and installing solar. And we are starting to see the similar decline that we think will start to become very rapid with respect to the costs of storage both commercial and residential scale.

And also, significantly enhance the way that we can manage and control devices, so water heaters; heat pumps; an ice bear, which is basically like a really big ice cube that you let melt and serve as air conditioning. And those -- the combination of those things, combining them together are -- help us shave our peak which will reduce our capacity needs and our RNS needs, can help us avoid transmission and distribution upgrades. And also has the potential to provide even more reliable service because we can take a distributed generation plant and pair it with storage and use that to create a micro grid, an island, a certain group of customers, so that they have service even if we have an outage on the T&D.

We see an intersection there with how we plan and plan for our supply portfolio, and that's something that our team is doing a significant amount of work. We see definite significant benefit in the future to our customers in terms of how we manage our costs there.

MS. BISHOP: Thank you.

MR. BINGEL: Okay. Moving along to slide eight. We have an allowed ROE of the 9.02 percent. That's down from the current ROE of 9.44 percent. It's based on the average of 10-year treasury bond rates in the month of June and July. And it reflects the Brexit vote which drove 10-year treasury rates lower. It went from 2.36 on average to 1.52 I think it was, and that changed our ROE.

We have an assumed capital structure of 50.3 percent equity and 49.7 percent debt. And then the platform was adjusted upward by .6 percent for CPI New England. That's roughly $700,000 that was added to our cost of service.

Accompanying that is on page nine, so that even though the platform went up by $700,000, we are returning to customers $16.3 million in operational savings for fiscal year 2017. That's a $3 million increase over what we had in the cost of service for 2016. And then you can see on this slide as well by the end of the fiscal year 2017, 45 million dollars in cumulative savings will be returned to customers.

MS. BISHOP: Can I ask a question about where you see this savings heading in the future? Are these savings that you're expecting to continue on, or is there anything in here that you are projecting at some point this savings ends? You know, the savings would shrink, or you see it only getting only as a larger number going forward.

MS. ANCEL: I can take that one. So we have a Board-ordered obligation to deliver 144 million in guaranteed savings as a result of the merger. We are projecting that we will significantly exceed that guarantee meaning that the amount of overall merger savings will be significantly -- that flow to customers will be significantly above 144 million. And we are expecting and forecasting year over year those savings are additive, meaning once we get a savings, it sets a new bar, and year over year we build on that. And we are projecting those savings amount will continue to increase through the end of the measurement period, 2022.

MS. BISHOP: Thank you.

MR. BINGEL: The next two items. Eddie, can you describe those?

MR. RYAN: There were two additional items on page nine. One is 3.5 million of plant removal costs. We do collect the appreciation accrual rate or removal costs for customers. We have between 35 and 40 million dollars we have collected to far. So we are going to return seven million dollars over two years or 3.5 million dollars each year.

And then the last bullet on that page on that result is making some improvements to our hydroelectric dams. We are eligible to receive some production tax credits, so there is a retroactive piece to that. It goes back to the date improvements were made. So we set up that 1.2 million dollars as a regulatory liability. And we are going to be returning that to customers in fiscal year '17.

MR. BINGEL: That leads us to chart 10. Slide 10. As you can see we discussed this already, but it's the reduction for the base rates of minus .03 percent. There are some factors that go in either direction. We discussed revenue power supply and transmission. Capital expenditures. We have an increase in depreciation and property taxes. We have a return on rate base in there. And then we have the higher equity and earnings associated with primarily TransCo.

You can see the big minus 3.9 percent drop for operations. That reflects largely the day one JV solar benefit that was described earlier, and the 3.5 plant removal cost being returned to customers as well. And there were some other components in there as well.

Yes, I'm sorry. Also includes the additional $3 million of merger savings.

MS. BISHOP: So I had a couple of questions about items that I know they are in the platform. But I just would like to understand what's involved with them. And when I looked at -- this is the summary cost of service schedule, and I saw the adjustment to distribution costs, it struck me as a large percentage increase. And I'm just trying to understand what's driving that, what's behind it.

MR. BINGEL: That is the difference between -- so the pro forma balances taking the 2013 platform and adjusting it by the CPI New England for those couple years, so it's the first one happened in 2013. So the change in CPI New England for 2014, '15, '16 and '17. On the per books balance we are actually showing what the costs are for those accounts. So they are the actual costs in there. So those costs because of the savings we have achieved, they are lower than what we have for the platform going forward.

MS. BISHOP: Okay. And so then is that the same answer for the administrative and general?

MR. BINGEL: Yes, it is.

MS. BISHOP: Thank you. Can I ask one more question about transmission and distribution capital investments? And is my understanding correct that those investments do not include costs that are associated with changes that are necessary because of constrained areas that are newly developed as a result of net metering or other distributed generation that's newly built?

MS. ANCEL: We would like to have our team answer that. Let me make sure I just clarify so we understand what you're asking.

MS. BISHOP: Sure.

MS. ANCEL: You're asking do our proposed transmission and distribution plant additions for this year, for rate year '17, do they include any projected upgrades on the T&D side to deal with circuits that are overloaded as a result of net metering?

MS. BISHOP: Net metering or other distributed generation, new distributed generation resources.

MR. CASTONGUAY: Yeah. Josh Castonguay. GMP. No, so anything related to distributed generation, interconnection or -- it's resolved during study processes and gets paid for by the developer of that distributed generation project.

MS. BISHOP: Okay. Are there -- are there new issues that GMP is thinking about or are there new issues that are arising as a result of large amounts of generation on certain circuits and the potential for generation to flow backward or the flow of electricity to kind of go reverse direction so to speak?

MR. CASTONGUAY: Good question. Yeah. We do. We have sections of the system around the state that have a lot more DG than others. And what ultimately currently happens is when we start to approach those limits, we essentially have to stop the development of additional resources until a solution is put in place.

At this time, so you know, the next generation resource coming in could be responsible for a substation upgrade, for example. So those are a few of the issues. We are also looking at the -- you mentioned earlier the intermittency nature as an impact to power supply. It potentially impacts the system as well. And what are the solutions for those. It's something we are actually pursuing as well in terms of storage or other control of our resources.

MS. BISHOP: Is all -- are all of those issues still largely focused on the distribution system, or are there any that are potentially significant enough that they end up having the potential to affect the bulk power system?

MR. CASTONGUAY: You know for distribution level generation, not yet. There certainly could come a time where there is -- I would call this subtransmission level which is where GMP sort of -- it's the 34,000 volt system, there could come a point where we have to watch protection and some certain things there.

At the bulk level of the 115 there is still quite a bit of head room before you start to see significant issues at that level. So we are not there yet, but it's definitely something we are watching. And when we do planning studies and look at the system that's something that's taken into account.

MS. BISHOP: So in other words the issues are still basically at a GMP or distribution utility level. They haven't yet gotten to the point where you're needing to involve VELCO in your studies is that --

MR. CASTONGUAY: We are definitely involving VELCO in terms of just keeping an eye on all of this stuff. In aggregate there is a significant amount of solar we are watching as there is more and more and more, a significant swing. What happens if you lose a lot of solar at once. What do these things do. So we are actively working together. It hasn't come up as a significant issue yet, but something we have got to keep a very close eye and plan for.

MR. SMITH: I would just add that's a topic which I would expect to arise and get some exploration in VELCO's next long-range transmission plan. That's an example of what the planners at VELCO are thinking about.

I agree with Josh's summary entirely. I just wanted to note that the dialogue has begun. We are heavy collaborators with VELCO in the Vermont Weather Analytic Center work. And one of the things that does is shed light on how close are certain circuits and under what combinations of conditions might flows be different from what they were in the past. So it's definitely a topic that is on planners' minds, but I think of it as -- I think so far it's more of a proactive look than addressing a problem really that's manifested so far.

MS. BISHOP: Thank you.

MR. YOUNG: Did you want -- I think we actually covered the last slide unless you want to go back over it. Anything else you want to add before we -- I know I have a few more questions. And I'm going to throw it open to others first.

MS. ANCEL: We will be pleased to take

them.

MR. YOUNG: Mr. Duggan, you have been quiet. I don't know, the Department's obviously had a chance to look at this and discuss with GMP the questions you wanted to jump in on at this point.

MR. DUGGAN: We don't have questions today as throughout the course of this we have conducted five rounds of discovery, had many discussions back and forth with the company. And so that, as you know, is the process where we inquire. And so at this point, no, we don't have any questions, but thank you for the opportunity.

MR. YOUNG: And your formal recommendation I believe is due Thursday.

MR. DUGGAN: Thursday.

MR. YOUNG: Mr. Dumont, do you have other questions? As I said we will have a few more, but I want to make sure I get others the opportunity.

MR. DUMONT: Well I have questions for Mr. Larkin. Maybe if I could have a minute with Attorney Ancel we can shorten this up.

CHAIRMAN VOLZ: You could feel free to ask them even though he's not here, and the Department should try to answer them.

MR. DUGGAN: Happy to do so.

MR. DUMONT: It might be better if I E-mail them later.

CHAIRMAN VOLZ: Okay. All right.

(A discussion was held off the record.)

MR. YOUNG: Are you ready to go back on the record?

MR. DUMONT: In a minute.

CHAIRMAN VOLZ: Would it be helpful to go after we finish asking our questions? It doesn't matter to me.

MR. DUMONT: Sure.

CHAIRMAN VOLZ: Maybe we will ask some that will help you reduce the number of questions you need.

MR. YOUNG: Okay. Let me touch on a few that came out of Mr. Schultz's report. And let's see, which one do we want to start with. Why don't we start with what's been a recurring theme.

We have talked about this at multiple workshops. Mr. Schultz once again highlights that there seems to be a number of projects that are put into the cost of service that aren't being built or aren't being built within the estimated time period. And I guess there are two parts to the question.

Number one is one sort of more for the

future. Is there something that we need to start building into future alternative regulation plans, assuming there are future alternative regulation plans, to better address this issue, because we talk about it every year at this time. And so that's one question.

The second is, the way it's working now is that creating an upward bias in rates for consumers? Because presumably there aren't a lot of -- I mean because you're putting money -- putting things into the cost of service and starting to recover a return on them as if they were being built and then the costs aren't actually incurred. And I think that's partially a question for Mr. Schultz who is not here to answer it. But it's also for the company.

CHAIRMAN VOLZ: But if the Department could answer it anyway.

MR. YOUNG: Oh.

CHAIRMAN VOLZ: It's for the Department. The fact that they don't have one of their people here is not our problem. They need to deal with that.

MR. YOUNG: Fair enough. I agree.

CHAIRMAN VOLZ: Thank you.

MR. DUGGAN: The first question is it something that should be built into future plans, I think the Department is certainly open to it. We are still evaluating the success of attachment seven. And I think one thing that you'll see in Mr. Schultz's report, and that I believe I've observed is consistent improvement from the company once attachment seven has gone into place. So from that perspective, that's a good sign. So is something more than attachment seven as it presently exists needed for a future plan? Perhaps. But I think that would have to be evaluated in the context of an overall future plan and frankly not ready to do so at this time.

Second question, is the way that this is working out is it creating upward bias in rates. Hard to say. I think there -- what we do in our analysis is we try to make sure that whatever is going into rates in a given year is just and reasonable, and that there is sufficient indicia that project is known to take place in the rate year with a reasonably high degree of certainty. So what you saw in this year was a concern with the initial financial analyses, but then a response from Mr. Schultz that said notwithstanding that, he looked at it, he relied on his experience with this company and his knowledge of what the company's doing, their capital investments, and where he believed that there was a sufficiently reliable indication from the totality of the documentation that was being provided, there was a sufficient -- there was sufficient, you know, evidence there that it was reasonable for rate recovery at this time.

But as you saw, you know what happened in this rate year, we urged the company and they agreed to reduce a significant amount of that plant in service. We also negotiated a general slippage adjustment off the cost of service to account for the fact that plants slip. So absent having a crystal ball, I think the outcome that was achieved by the work of Mr. Schultz and the negotiations that we had with the company reflect rates and proposed capital projects that are just and reasonable, and you know, and that we have a reasonably solid basis for believing we will take -- will be made in the rate year.

MS. ANCEL: I would like to respond also. So the question relates to projects and when they go into service. We project our capital projects to go into service on, you know, over a yearly basis. Sometimes there are projects -- we have people working, our field team working, they are sometimes affected. Projects are affected, like a substation replacement or rebuild is impacted by weather. So weather may change the construction pattern of that.

Sometimes our team may get taken off certain construction projects to go to other ones that have urgency for our customers because they are a reliability or safety issue. So that is another factor. And I would add just as Mr. Duggan said on the second issue about whether there is impact to customers, there is not in this rate filing.

We made adjustments to reflect some in-service dates backwards at the -- back at the Department's urging, and then we also made for the first time a global adjustment for a global slippage adjustment meaning even in addition to those changes we made to in-service dates, another adjustment assuming that there would be even a little bit more correction there for when projects actually go into service versus when they are projected to.

So that was a significant adjustment that we made this year, and it's the first time we made that adjustment, and it's intended to reflect the timing issues that arise.

MR. YOUNG: And I will say I wasn't stating an opinion on the subject. It is more I read these things every year and the same comments get made and expressed as a concern by Mr. Schultz. And I think what I'm hearing is at least you two parties -- it's adequately addressed for this filing in any case.

MR. DUGGAN: I would say it's adequately addressed, and the trend is positive, which is another important thing to note. That the -- as you probably noticed the greater concerns related to the ESAM evaluation which, of course, is an after-the-fact evaluation where you do have perfect, pretty much, knowledge. So our experience with this -- Mr. Schultz's experience with this as reflected in the report is with steady improvement in documentation in the past few years.

MR. YOUNG: Great. Let me just mention one other thing. Again some of these things -- I'm simply throwing out some questions that have arisen and have recurred. I am cognizant of the fact that typically by the time a new Alternative Regulation Plan hits the Board, the Department and Green Mountain Power at least in the recent past have already agreed to it and the framework is set. So to the extent these are issues that we see that are recurring, I think at least part of my thinking is just a reminder, hey, you guys keep talking about these.

Different issue, because Mr. Duggan you raised the attachment seven. On page 10 of Mr. Larkin's report, and this is going into the financial analysis which is a lot of what's coming out of attachment seven. There is the statement halfway through the page, the vast majority of the projects generated a concern. And this is about the financial analysis accompanying the projects. And at least as I read Mr. Schultz's report, what he's concerned is a before-the-fact cost/benefit analysis is what he's looking for, not an after-the-fact justification.

Again I don't see a lot of recommendations on how that should be -- that anything needs to be done in the context of this filing, but is that something that should be looked at or better melded into future reviews or future alternative regulation plans? And I don't need an answer to that. But I did want to -- his statement is pretty specific.

MR. DUGGAN: If I may, I would like to

answer it.

MR. YOUNG: Sure.

MR. DUGGAN: That is something that the Department does agree with. And that we -- I mean that's the very reason why the Larkin report is published so that we can have the benefit of Schultz's review, and that we sort of inform the company about where we believe the future year's proceeding should go. And issues that we see in one year the hope is through the negotiation process in one year and putting it out in a recommendation in subsequent year these issues become addressed. And I think we have seen that in certain areas.

And so from where I sit that's a positive aspect of alternative regulation.

MR. YOUNG: One other question that came to mind to me, and I'm trying to find the exact quote from Mr. Schultz's report. I thought I had it. And this related to the ROE. And I recognize the ROE is -- per the presentation is now down to slightly over nine percent.

At the bottom of page two Mr. Schultz says: Under alt reg which includes four separate rate mechanisms, the company is essentially guaranteed a return with minimal risk.

And again, in the context of the current alt reg plan in this base rate filing, I don't think there is any question I have, but what this question sort of triggered in my mind is if we have a return on equity that is basically set, you know, in the traditional way, and I realize we have built in an adjustment to it over time to reflect changes in long bonds, but you know, essentially a premium -- risk premium above the long bond, and the risk is drastically reduced, is there, you know, should there be further adjustments? And at this point treat that as rhetorical, a question that's for the future. I don't think I'm looking for an answer to that.

Mr. Dumont, did you have any other questions that have come to mind?

MR. DUMONT: Questions and comments. Last year following the workshop I engaged in discussions with a company's counsel to come up with --

CHAIRMAN VOLZ: I'm not sure that's on. Just speak up.

MR. DUMONT: Last year following the workshop on behalf of AARP I engaged in discussions with a company's counsel to agree upon wording that we agreed should be put in the Board's order. The Board issued its order before we could submit that stipulation. This year we don't have Mr. Larkin present. Much of what we are talking about revolves around his report.

I do feel the need to follow up with the questions for Mr. Larkin.

CHAIRMAN VOLZ: You mean Mr. Schultz?

MR. DUMONT: I'm sorry. Mr. Schultz.

CHAIRMAN VOLZ: Thanks.

MR. DUMONT: The author of the Larkin report. He should call it the Schultz report. And then submit language to the -- or concerns to the Board.

So perhaps my first question is for the Board. What is your proposed or contemplated schedule?

MR. YOUNG: Well under the Alternative Regulation Plan the rates take effect unless suspended on October 1. I believe -- I don't remember, and I'll ask Ms. Ancel to correct me if I am wrong, but I don't know that we set out separate time frames from the statutory ones for purposes of suspension or anything else. So you're subject to the Department making its recommendation 15 days before the proposed effective date, the Board must suspend under Section 226(a) at least six days prior to the proposed effective date. So we would have to suspend the rate filing approximately a week before -- you know, the 24th of September if I'm doing my math at all correctly.

MR. DUMONT: About nine days from now.

MR. YOUNG: I haven't applied that to a calendar. Well that's the way the plan reads. That's the way it works. We are in the normal situation that if we are asked to open an investigation, the three Board members will be presented with the question of whether to investigate, and obviously even if we are not asked to, the Board members may choose for whatever reason to open an investigation or otherwise.

But those are the applicable dates. Ms. Ancel, did I get that right?

MS. ANCEL: Yes.

MR. YOUNG: Thanks.

MR. DUMONT: We -- I still have questions about the value and the rate impact of the concerns that the Larkin report and its author raised, and the -- how much of those concerns ended up in the compromise that has now been submitted to the Board. Attorney Ancel has pointed me to a page of his attachments which may answer those questions, but it's not clear to me that it does. So I really want to ask Mr. --

MS. ANCEL: And actually just to be clear, Jim, there are actually two attachments, two schedules to the final August 1 filing. And then they are also reflected in Mr. Schultz's report.

MR. DUMONT: So --

MS. ANCEL: And those two schedules were prepared specifically at your request from last year.

MR. DUMONT: So hopefully I can get some clarification from Mr. Schultz about those. And we will try and get the questions to you as quickly as possible in writing; hopefully tomorrow morning.

MR. DUGGAN: That would be fine. I'm also happy to engage a call if you would like, and I do regret the scheduling conflict that happened today. I think it is always to ratepayers' benefit, Mr. Schultz is talking, but this was unfortunate and unavoidable.

To the extent you have any questions, I would welcome them and -- but at this point given the schedule that Mr. Young articulated --

MR. DUMONT: Sure. Attorney Ancel has helped me part way through this. But my questions will be focused on those attachments to his report, and I'll try to get them to you tomorrow morning.

MR. DUGGAN: Sure.

MR. DUMONT: And then we will submit something to the Board before the last possible second. And I understand the last possible second is the 24th.

CHAIRMAN VOLZ: We have to issue an order on the 24th. If you want us to take into consideration your comments, you need to file it before that.

MR. DUMONT: Before that. Yes.

MR. YOUNG: And just to be a little bit helpful, I pulled up a calendar. The 24th is a Saturday. So essentially to meet the six day for suspension, again the Board can open an investigation, allow it to take effect and open an investigation, in which case it's not suspended and there is not necessarily a time limit on that. But if one wanted to investigate this particular filing and seek to have it suspended, the Board would need to act no later than the 23d as I'm looking at the calendar year.

MR. DUMONT: Don't work on Saturdays? Not officially.

MR. YOUNG: I don't think I need to answer that question, but let me just say I think under the rules Saturday doesn't count whether I work on it or not. So it's immaterial.

MR. DUGGAN: One thing I might offer, Mr. Dumont, the bulk of what we have been discussing here today really does focus on power supply. And we have here Mr. Woodward who does power supply work for the Department. So to the extent there is any questions on that area, you know, we would welcome that, and we could address them at this point. So but as you know, as following the Power Point that Mr. Bingel was presenting, it did seem to focus on that area. So if those are the primary concerns, happy to discuss now if that's helpful.

MR. DUMONT: I think we are okay for now.

CHAIRMAN VOLZ: Just to be as helpful as possible, it would be helpful to the Board if we had your recommendation before the 21st of September.

MR. DUMONT: That makes sense.

CHAIRMAN VOLZ: Okay. Thanks. So by the close of business on the 20th would be ideal which is a week from today.

MR. DUMONT: We will get something to you on by the close of business on the 20th.

CHAIRMAN VOLZ: Okay.

MR. YOUNG: I believe we have actually -- Mr. Fink has a few additional questions.

MR. FINK: Just one. I did quickly want to ask, in the Larkin report Mr. Schultz talks at some length about GMP's vegetative management plan and some concerns around that specifically related to hazard trees, and I was wondering if GMP could just very briefly update us on its perspective on some of those issues and what's going on there.

MR. OTLEY: Yeah. Brian Otley from Green Mountain Power. So we have had a lot of discussions with both Mr. Schultz and the Department on this issue. A lot of issue stems from the December 2014 snowstorm which had major impacts statewide. And there has been a lot of discussion about just the traditional preventive vegetative management trimming program as well as -- I think I forget how Mr. Larkin or Mr. Schultz terms it, but an advanced danger tree removal program I think. Does that sound --

MR. DUGGAN: Enhanced.

MR. OTLEY: Enhanced. Thank you. And so we have got as part of the settlement, we have got a plan to do accelerated preventive trimming on an annual basis that puts us on a seven-year trim cycle. We would attain that, the first year of that seven-year trim cycle by the end of this year, and then catch up on past years within a year after that. The advanced or the enhanced danger tree program is something we are interested in, but we are not structured and signed off on yet.

As we look at the impacts of the December 2014 storm, our conclusion is an enhanced danger program would not have had a significant benefit during that storm just because of the magnitude of the weather effects. That storm was, you know, once in a 20-year storm. It had substantial impact to the canopy and no danger tree program was going to prevent the impacts that we saw.

That being said, we are interested in exploring that more under a different structure with collaboration with the Department.

MR. FINK: Okay. And has that taken any form at this point, or is that -- I mean in terms of how you're looking at exploring that?

MR. OTLEY: No. You know, we have

scheduled some discussions with the Department already.

MR. FINK: All right.

MR. YOUNG: I think we are done. Let me just ask. Is there anything else from anybody here who would like -- any other issues people want to raise?

Mr. Duggan.

MR. DUGGAN: Selfishly on the question of the Department's homework. I just -- if the questions were not answered satisfactorily when I answered them to the Board, I'm happy to bring them back to Mr. Schultz as well. Otherwise, we can report back on Mr. Dumont's questions when provided. But I just want to make sure that I'm providing everything needed in a timely way.

MR. YOUNG: Let me flip that around to you.

MR. DUGGAN: Yes.

MR. YOUNG: Which is you provided an answer. If you and Mr. Schultz look at the transcript or the two of you consult and you think you need to add something, please add something. Otherwise we got your answer.

MR. DUGGAN: Okay great. Thank you.

MR. YOUNG: So the responsibility is yours rather than mine.

MR. DUGGAN: Great.

MR. YOUNG: Anything further?

(No response)

MR. YOUNG: Thank you all for your time. I do want to thank Green Mountain Power, this has been very helpful. Even though we diverted you from what you intended to get into lots of other things as usual, it's helpful for us to understand what's in your filing and to actually understand more about what's going on. So we appreciate that. Thank you, and we are adjourned.

(Whereupon, the proceeding was adjourned at 3:31 p.m.)

C E R T I F I C A T E

I, Kim U. Sears, do hereby certify that I recorded by stenographic means the Workshop re: Tariff Filing 8618 at the Susan M. Hudson Hearing Room, People's United Bank Building, 112 State Street, Montpelier, Vermont, on September 13, 2016, beginning at 1:30 p.m.

I further certify that the foregoing testimony was taken by me stenographically and thereafter reduced to typewriting and the foregoing 89 pages are a transcript of the stenograph notes taken by me of the evidence and the proceedings to the best of my ability.

I further certify that I am not related to any of the parties thereto or their counsel, and I am in no way interested in the outcome of said cause.

Dated at Williston, Vermont, this 16th day of September, 2016.

Kim U Sears

<u>Exhibit 13</u> – GMP Schedule 4 dated 8/1/2016

Schedule 4

CALCULATION OF INCOME TAX EXPENSE
TEST YEAR ENDED March 31, 2016

GREEN MOUNTAIN POWER CORPORATION
August 1, 2016

$ in 000s	PRO FORMA
Total rate base investment	1,352,771
Return % (Total Cost of capital	7.04%
Return on utility rate base	95,235
Add back:	
Federal income tax	26,245
State income tax	8,145
Return before taxes	129,625
Less interest (Wtd. Cost of Debt X Rate Base)	33,819
Subtotal	95,806
Additions & deductions for income tax purposes:	
Non-taxable portion of equity in earnings of VELCO	(344)
Non-taxable portion (100%) of equity in earnings of Vermont Yankee	(70)
Non-taxable portion (70%) of equity in earnings of MY, CY, YA, NEHT and NEHTE	0
Non-deductible AFUDC-equity	405
Non-depreciable ITC basis reduction	109
Non-deductible meals expense	111
Domestic production activities deduction	0
Total additions & deductions	210
Balance	96,016
Less state income tax (8.5% of Line 27)	8,161
Taxable income	87,855
Federal Income Tax Calculation:	
Federal income tax before credit at 35%	30,749
Investment credit amortization	(14)
Production Tax Credit	(4,451)
CAFC Perm	(60)
FAS 109 ITC Basis Adjustment	12
AFUDC Deferred Tax Adjustment	10
Federal income tax	26,245
Excess Deferred Tax & Con Adj	0
Total Federal Income Taxes	26,245
State Income Tax Calculation:	
Taxable income at 8.5%	8,161
Vermont income tax rate change adjustment	9
Vermont Solar ITC	(32)
ITC Basis Adj	3
AFUDC Deferred Tax Adj	3
Total State Income Taxes	8,144
TOTAL STATE AND FEDERAL INCOME TAX	34,390

Exhibit 14 – GMP Schedule 4 dated 5/31/2014

CALCULATION OF INCOME TAX EXPENSE
TEST YEAR ENDED September 30, 2013

GREEN MOUNTAIN POWER CORPORATION
30-May-14

	PRO FORMA
Total rate base investment	1,164,743
Return % (Total Cost of capital	7.46%
Return on utility rate base	86,890
Add back:	
Federal income tax	22,889
State income tax	7,257
Return before taxes	117,036
Less interest (Wtd. Cost of Debt X Rate Base)	30,982
Subtotal	86,054
Additions & deductions for income tax purposes:	
Non-taxable portion (80%) of equity in earnings of VELCO	(936)
Non-taxable portion (100%) of equity in earnings of Vermont Yankee	(334)
Non-taxable portion (70%) of equity in earnings of MY, CY, YA, NEHT and NEHTE	(66)
Non-deductible AFUDC-equity	338
Non-depreciable ITC basis reduction	98
Non-deductible meals expense	341
Amort. of Cap. Return on Equity - VY & MY	0
Medicare Part D	0
Domestic production activities deduction	0
Total additions & deductions	(559)
Balance	85,495
Less state income tax (8.5% of Line 27)	7,266
Taxable income	78,229
Federal Income Tax Calculation:	
Federal income tax before credit at 35%	27,380
Investment credit amortization	(139)
Production Tax Credit	(4,269)
CAFC Perm	(70)
FAS 109 ITC Basis Adjustment	30
AFUDC Deferred Tax Adjustment	17
Federal income tax	22,949
Excess Deferred Tax & Con Adj	(60)
Total Federal Income Taxes	22,889
State Income Tax Calculation:	
Taxable income at 8.5%	7,267
Vermont income tax rate change adjustment	9
Vermont Solar ITC	(32)
ITC Basis Adj	8
AFUDC Deferred Tax Adj	5
Total State Income Taxes	7,257
TOTAL STATE AND FEDERAL INCOME TAX	30,146

Exhibit 15 - **Relevant Portion of the Brief filed by the Department with the Board in Docket 5532 (February 25, 1992)**

FILE COPY

STATE OF VERMONT
PUBLIC SERVICE BOARD

Docket No. 5532

Tariff filing of Green Mountain Power)
Corporation requesting a 9.96% overall)
increase in rates, and revisions to its)
Rules, Regulations and existing tariffs,)
to take effect September 2, 1991)

BRIEF OF THE VERMONT DEPARTMENT OF PUBLIC SERVICE ON BEHALF OF THE PUBLIC

VERMONT DEPARTMENT OF
PUBLIC SERVICE

James Volz
Director for Public Advocacy

George E. Young
Robert V. Simpson, Jr.
Special Counsel

Dated: February 24, 1992

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lbr5532.50

INTRODUCTION

GMP filed for a 9.96% rate increase on September 10, 1991. The Department filed its testimony on December 5, 1991. It maintains that GMP is only entitled to an increase of approximately 2.5%.

I. RATE BASE

The Company had originally requested a rate base of $164.544 million. The Department's proposed adjustment would reduce that amount by $8.633 million to make it $155.911 million. Schultz prefiled, 12/5/91, Revised Schedule 1C and Schultz surrebuttal, 2/3/92 at pp.23-24 as well as 2/18/92 GMP response to 2/7/92 "transcript request", Kvedar at p. 267.

Less than one third of the total rate base reduction requested by DPS arises from challenges to future Company projects. In fact, most of the reduction the Department requests is not based on the argument that the ratepayers will be "paying for something they may not get." Instead, it is based on the premise that they should receive credit in rates for payments they have already made. For instance, the largest single adjustment proposed by the Department is for Accumulated Depreciation - $3.076 million. Another $2.176 of the proposed reduction is to give ratepayers credit for "cost free capital" they have provided

<u>Exhibit 16</u> - Pre-filed testimony (dated 8/22/2016) of Helmuth W. Schultz III of Larkin Associates on behalf of the Department in Vermont Gas proceedings.

STATE OF VERMONT
PUBLIC SERVICE BOARD

Investigation into Vermont Gas Systems Inc. request for approval of a new Alternative Regulation Plan to take effect October 1, 2017	)))	Docket No. 8698

PREFILED TESTIMONY OF
HELMUTH W. SCHULTZ III

ON BEHALF OF THE
VERMONT DEPARTMENT OF PUBLIC SERVICE

August 22, 2016

Summary: Mr. Schultz makes recommendations with respect to Vermont Gas's request for a new Alternative Regulation Plan.

I. INTRODUCTION

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

A. My name is Helmuth W. Schultz, III. I am a Certified Public Accountant, licensed in the State of Michigan, and a Senior Regulatory Analyst in the firm of Larkin & Associates P.L.L.C., 15728 Farmington Road, Livonia, Michigan 48154.

Q. PLEASE DESCRIBE THE FIRM LARKIN & ASSOCIATES.

A. Larkin & Associates P.L.L.C. is a Certified Public Accounting and Regulatory Consulting firm. Larkin & Associates performs independent regulatory consulting primarily for public service utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin &Associates has extensive experience in the utility regulatory field as expert witnesses in over 500 regulatory proceedings including numerous electric, gas, water and sewer, and telephone utilities.

Q. HAVE YOU PREPARED AN APPENDIX WHICH DESCRIBES YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. I have attached Appendix I, which is a summary of my experience and qualifications.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. Larkin & Associates was retained by the Vermont Department of Public Service ("Department"), to review the proposed Alternative Regulation Plan (“ARP” or “Plan”) of Vermont Gas Systems, Inc. ("VGS" or “the Company”). Accordingly, I am appearing on behalf of the Department and Vermont Gas Systems, Inc. ratepayers.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Our firm was requested by the Vermont Department of Public Service to analyze the request by Vermont Gas Systems, Inc. to implement a new Alternative Regulation Plan effective October 1, 2017. Larkin in conjunction with Department staff witness, Joanna (Joan) E. White, are testifying on behalf of the Department to provide an analysis of the Company’s request and offer recommendations that assume a new Plan does go into effect and offer recommendations should it be determined that traditional ratemaking will be resumed.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN VERMONT?

A. Yes, I testified in a number of Dockets on behalf of the Vermont Department of Public Service regarding various ratemaking issues since 1990.

II. ANALYSIS

ORGANIZATION

Q. PLEASE EXPLAIN HOW YOUR TESTIMONY HAS BEEN ORGANIZED.

A. My testimony will address, in order, the following:

- Pros and Cons of Alternative Regulation
- Comments on VGS's Proposed Plan
- Response to Company Testimony

PROS AND CONS OF ALTERNATIVE REGULATION

Q. WHAT, IN YOUR OPINION ARE SOME OF THE PROS OF THE VERMONT ALTERNATIVE REGULATION PLANS OVER THE PAST 9 YEARS?

A. First, I want to be clear while I have worked on prior Vermont Gas cases, my recent experience with alternative regulation in Vermont is with electric companies. However, while there are differences between the plans applicable to Vermont Gas and the electric utilities, there are structural similarities, such as annual base rates filings, earnings sharing, etc. So I think experience with the electric utilities in Vermont translates to Vermont Gas. In any event, I am speaking generally about alternative regulation here.

The major positive aspect about alternative regulation is that it can offer rate stability for ratepayers and all but eliminate risk for the Company. However, for ratepayers to realize their end of the bargain, Plan terms must be clearly understood and strictly complied with, with penalties for non-compliance.

Q. WOULD YOU DISCUSS HOW THE PLAN OFFERS RATE STABILITY?

A. The costs generally are adjusted annually instead of every two, three or four years, so any change, up or down, should generally be small in comparison to what could occur under periodic traditional filings. Under traditional filings when a company prepares a rate application the increase in rates typically may be 5% or more. When changes are made more frequently, as under the Plan, they are generally smaller. The fact that rate changes are generally smaller, ratepayers are not shocked by the change and can plan their personal or business budgets accordingly.

Q. PLEASE CONTINUE WITH YOUR DISCUSSION REGARDING RATE STABILITY.

A. Alternative regulation also mitigates the risk and impact of changes in weather and gas supply costs in a way that provides for greater rate stability. Changes in weather and gas supply costs can have a significant impact on revenues. The risk is all but eliminated because there is reasonable assurance that fluctuations in power cost will not have as significant impact on earnings as it could under traditional rate making. At the same time, customers are protected because when costs decline the company does not reap a benefit from higher estimated costs being built into base rates as they would in a traditional rate filing and absent a gas cost mechanism.

Q. ARE THERE OTHER BENEFITS THAT EXIST UNDER ALTERNATIVE REGULATION?

A. Costs are reviewed on an annual basis and while there is a cost to that review it can be done at a significantly lower cost than a traditional rate filing. By reviewing costs annually the ratepayer benefits because productivity and technological gains may reduce costs and the cost reduction can be reflected in rates on a more current schedule. The Company benefits because cost increases are reflected in rates more quickly, reducing regulatory lag.

Another benefit is with the recovery mechanisms in place credit agencies will recognize the very limited risk and that results in a favorable credit rating. The Company has the opportunity to obtain better financing arrangements as a result of the better ratings. Under traditional ratemaking credit agencies have a tendency to assume that the high return has a risk of not being achieved because of outside factors that can impact the return.

Q. WHAT ARE SOME OF THE CONS WITH ALTERNATIVE REGULATION?

A. Abuse and complacency can occur, resulting in higher rates. The abuse that can occur is that a company can develop what I think of as a “blank check” approach in planning. The attitude that “if money is spent, it can be recovered from ratepayers” can develop because the level of scrutiny is limited under Alternative Regulation.

A prime example is that under traditional ratemaking companies should perform compensation reviews by comparing the compensation of its employees with compensation surveys. If a company has the blank check attitude there is less effort to control costs because the costs just get passed on to ratepayers through the annual filing.

My experience in Vermont is the schedule has been a factor on the review process, limiting what can be analyzed as opposed to a traditional rate filing. A limited review means that some costs that would not typically be allowed in rates can fall through the cracks and get passed on and into rates. With an ARP, the review of costs is even more important because of the ability to pass on costs so readily.

Q. WHY IS REVIEW OF COSTS MORE IMPORTANT BUT BASICALLY LIMITED AND DIFFICULT?

A. The proposed Plan provides for a review to be performed in approximately 59 days and another 21 days to make sure the filing of the Annual Base Rate Adjustment is consistent the preliminary information supplied and subject to review and discussion. This timeline makes it exceedingly difficult to review the initial proposed filing, to discover details, and to review plant and O&M costs for conformance with the known and measurable standard.. Arguments over the extent of permissible updating throughout the two-month review period exacerbate the problem.

Q. WHAT IS THE COMPLACENCY THAT YOU REFER TO?

A. The complacency occurs when traditional rate making requirements are compromised by attempting to resolve issues in alternative regulation proceedings. Once the issues get resolved through compromise, subsequent filings will test the leniency of the requirements more and more and costs that would not be allowed under traditional ratemaking get allowed. Compromise can be good but when it erodes the standards of ratemaking someone is harmed. That someone most often will be rate payers. Additionally, there is the problem that settlements to not produce binding and instructive Board precedent. Under traditional regulation, when the Department and a utility litigate an issue, the Board resolves the matter and everyone has to follow it afterward. That does not happen with settlements under alternative regulation. And while litigation is possible under alternative regulation, the plans are just not set up for litigation; they are set up for cases to be resolved through settlement. I think the erosion of a body of developing Board ratemaking precedent is one of the unanticipated results of alternative regulation that can result in the complacency I discuss above.

Q. WHAT OTHER NEGATIVE ATTRIBUTES HAVE YOU IDENTIFIED WITH THE ALTERNATIVE REGULATION PROCESS?

A. Traditional regulation existed for years and was intended to offer a utility the *opportunity* to achieve a reasonable return for its shareholders on the investment they have made. The Alternative Regulation Plans have in effect taken that one step beyond and provide shareholders with *closer to a guaranteed* return, barring significant imprudence. The use of the bandwidths in the Earning Sharing Adjustment ("ESA") minimizes of the possibility of the Company earning below a set return and in effect eliminates any possibility of achieving below what could be deemed a reasonable return. This is significant because it protects the Company from the ramifications of excessive spending and possibly imprudence that would not be offered under traditional ratemaking.

Q. HOW IS THE COMPANY PROTECTED WHEN IT WOULD NOT BE PROTECTED UNDER TRADITIONAL RATEMAKING?

A. The Earnings Sharing Adjustor provides for a dead band 25 basis points above and 50 basis points below the authorized return. There is no earnings sharing within the dead band. The ESA will allow recovery, from ratepayers, of excess costs beyond the 50 basis points and a sharing will occur with ratepayers of excess revenues when the authorized return is exceeded by 25 basis points. For example, if the ROE is set at 8.5% and the Company achieves a 7.75% ROE the ESA will reflect a revenue impact that will bring it up least 50% of the difference between the 7.75% and 8.5% so there is, in effect, a guaranteed ROE of 8.12%. Under traditional ratemaking if the Company earns a 7.75% ROE, that is what it earned and there is no guaranteed floor. The guarantee provides an earnings floor that may create a disincentive to minimize costs and may impact the efficiency of operations. Under traditional ratemaking there is an incentive to avoid inefficient operations and an incentive to minimize costs. The incentive is the fear of failing to earn the allowed return, with no ability to pass a portion of that off to ratepayers.

Q. ARE YOU AWARE OF ANY OTHER JURISDICTION THAT HAS AN ALTERNATIVE REGULATION PLAN SIMILAR TO WHAT VGS HAS?

A. No. The term alternative regulation is used to describe various alternative approaches to ratemaking that are not considered as traditional ratemaking. Typically an alternative in other jurisdictions allows for a tracker, a rider or some mechanism that allows recovery of certain costs more quickly and with more certainty. The value of the various alternatives is they reduce the concern with regulatory lag and it reduces credit agencies concerns with risk. Some jurisdictions may have a fuel clause or power cost clause that allow for true ups, some may have storm cost mechanisms or reserves, some may have specific capital recovery provisions. I am not aware of any other state that has all of the features of the Plan in existence or proposed by VGS.

VGS'S PROPOSED PLAN

Q. WOULD YOU IDENTIFY THE RESPECTIVE SECTIONS OF THE PROPOSED PLAN AND COMMENT?

A. Yes. The proposed Plan sections and attachments are as follows:

- Section 1. Term of the Plan
- Section 2. Regulatory Framework
- Section 3. Cost of Service
- Section 4. Purchased Gas Adjustments
- Section 5. Annual Base Rate Adjustments
- Section 6. System Expansion and Reliability Fund and Rate Stabilization or Customer Innovation Mechanisms
- Section 7. Service Quality and Reliability Plan
- Section 8. Management of Gas Supply
- Section 9. System Expansion
- Section 10. Dispute Resolution
- Section 11. Amendment of Plan
- Attachment 1. Known and Measurable Standards
- Attachment 2. Evaluation Criteria

Q. DO YOU RECOMMEND THAT VGS'S PROPOSED PLAN BE ADOPTED?

A. No. The Company is proposing that the Plan it now has in place, with some changes, be extended through September 30, 2019. I do not recommend that the Plan be extended.

Q. WHY ARE YOU RECOMMENDING THE PLAN NOT BE EXTENDED?

A. The Company has undertaken a significant expansion project that has a significant impact on base rates. The determination of prudence and the actual in service date are unknown at this time. In addition to the Addison Project, the Company has requested a more than normal level of other plant additions in Docket No. 8710. The cost impact and the recoverability from ratepayers should be determined prior to allowing any extension of the Plan. As I indicated earlier there are concerns under Alternative Regulation with complacency and the accelerated pass through of project costs. Until the Addison Project is completed and in service and evaluated for prudence there should not be an ARP for the base cost of service. Even when plant costs are reviewed for the known and measurable standard, the actual plant costs for the period that rates were set can vary significantly. That variance is due to cost overruns and/or projects being cancelled and other projects being supplemented. The proposed Plan provides insufficient protection for ratepayers if the Company over expends its plant projections or decides to change its capital spending from a reviewed project to one that has not been reviewed or even made subject to a possible review.

Q. HAVE YOU REVIEWED THE PROPOSAL MADE BY DEPARTMENT WITNESS WHITE REGARDING WHAT SHE REFERS TO AS A PGA-ONLY PLAN? WHAT IS YOUR VIEW OF THAT PLAN?

A. Yes. I think it is a reasonable approach, and certainly much more preferable than the Plan proposed by VGS. Power cost and gas adjustment clauses and/or mechanisms are common practice. The use of a PGA reduces the Company's risk and can provide more stable rates for customers. As discussed by Department witness Joan White, the Plan provisions for gas cost recovery should be continued.

RESPONSE TO COMPANY TESTIMONY

Q. WHAT ARE SOME OF THE ISSUES THAT YOU HAVE FOUND IN YOUR REVIEW OF THE COMPANY'S TESTIMONY?

A. At page 2, Company witness Eileen Simollardes states that "alternative regulation is superior to traditional rate regulation." I have been reviewing alternative regulation since its inception and I am not convinced it is superior. That is my opinion but as evidence of my opinion there is the fact that the plans in effect have been on a temporary basis and always subject to review and possible renewal. If superior I would think that the Department and the Board would have fully endorsed the process and traditional ratemaking would be something of the past. Furthermore, as noted earlier, the review process does not allow for as efficient a review as traditional ratemaking allows for because of the time constraints and because the Company generally has to provide supplemental information to justify the cost requested. The reduced time table means project review is done based more on sampling than evaluating the complete large number of projects requested.

Q. WHAT ABOUT THE CLAIM THAT ALTERNATIVE REGULATION ENCOURAGES EFFICIENT OPERATIONS?

A. The Company's attributing its expansion to five new communities while maintaining stable rates, I believe, may be stretching the facts. The stabilization of rates during the expansion is more the result of lower gas costs. The fact that gas costs have declined is unrelated to the ARP being in place.

Q. IS THE COMPANY'S CLAIM THAT ALTERNATIVE REGULATION RESULTS IN MORE EFFICIENT REGULATORY REVIEW AND REDUCED REGULATORY COSTS ACCURATE?

A. Not totally. I would tend to agree that the cost is less because of the time constraints imposed and, as the Company suggests, it does not have to hire external consultants. However, as described above, I do have a concern that the expedited review process under alternative regulation may not be as efficient as the traditional rate process. Additionally, I have a different opinion of what is sufficient support for an alternative regulation filing, and believe it to be more similar to a traditional filing. Based on the level of detail that should be provided under either scenario, I do not envision that the preparation time is significantly less under ARP than under a traditional filing.

Q. AT PAGE 5 OF HER PREFILED TESTIMONY, COMPANY WITNESS SIMOLLARDES STATES THAT UNDER TRADITIONAL REGULATION THERE IS NOT A FRAMEWORK TO RETURN FINANCIAL PERFORMANCE AND GAS COST SAVINGS TO CUSTOMERS. DO YOU AGREE WITH THAT STATEMENT?

A. No. The savings passed back to customers under ARP are there because the ARP was written up to provide for that savings. The fact is the many jurisdictions have power cost and gas clauses under traditional rate making. Vermont could adopt such a rate making provision and still operate under traditional rate making. And to the extent there is some legal barrier that would prevent this from happening in Vermont, the ARP could be amended in a manner proposed by Department witness White to accomplish the same idea under alternative regulation. Additionally, while it is not a common practice, I do recall an occasion of sharing of operational cost savings under traditional rate making.

Q. HOW DO YOU RESPOND TO THE COMPANY'S CLAIM THAT RATES ARE MORE PREDICTABLE AND STABLE UNDER ARP?

A. As I indicated earlier that is a benefit that can occur. But that is not always true as other factors can impact the level of rates whether traditional rate making exists or whether ARP exists. For example, the addition to rate base of the Addison Project would impact rates significantly under traditional rate making and under ARP. The rate making system in place is what you make it and traditional rate making can be tailored for fuel clauses and for specific undertakings just like an ARP. This is essentially what the Department's proposed alternative regulation plan does, which is one reason why I support that plan over the one proposed by VGS.

Q. IS THE COMPANY'S COST BASED ARGUMENT APPROPRIATE?

A. As stated earlier, alternative regulation can promote rate stability and may prevent under earning and over earning. But traditional rate making (or a revised alternative regulation plan such as the one recommended by the Department) can include a gas clause that will mitigate the possible under-earning and over-earning concerns noted by the Company.

I also want to emphasize a concern with the Company's statement that alternative regulation eliminates any incentive to over-state costs during a traditional ratemaking proceeding. Just the suggestion of the possibility of this occurring has to raise a concern with the Board. It certainly does for me. In my opinion, if the Company is willing to over-state costs in a traditional filing, it would be willing to do so in an alternative regulation filing because with the bandwidths in place, the Company can still benefit from over earning.

Q. ARE THEREANY OTHER CHANGES TO THE ARP THAT ARE OF CONCERN?

A. Yes. First and foremost I would reiterate that I believe the ARP should not be renewed except for the PGA provision. One recommendation of great concern is where Company witness Eileen Simollardes has recommended that the language in the previous Attachment 5 be changed to that of Attachment 1, which now proposes that a cost of service exclusion, due to failure to provide supporting documentation in a timely manner, be discretionary rather than mandatory. This suggests the Company may be looking to make the ARP process a blank check approach to rate making. The Company cannot meet the known and measurable standard without providing supporting documentation and if any leniency takes place that should be solely at the discretion of the Department and ultimately the Board. The standard exists for a purpose. Making the result of the Company's failure to comply with the supporting documentation requirement discretionary undermines the likelihood of compliance with the known and measurable standard. This recommendation is not appropriate and should not be adopted.

Q. OTHER THAN THE ALLOWING THE PGA CONTINUE WOULD YOU EVEN CONSIDER RECOMMENDING THE CONTINUATION OF THE PLAN ON A TRIAL BASIS?

A. No. The Company is not requesting the ARP be continued on a trial basis. According to the response to DPS.VGS.1-31 the ARP as presented by the Company does not provide for or mention a traditional rate filing in the future because the Company is requesting the ARP replace traditional rate filings. I am not convinced that the ARP is better than traditional rate making especially with VGS and the current expansion that is on-going and planned for the future.

Q. Does this complete your testimony?

A. Yes.

<u>Exhibit 17</u> –GMP Schedule 4, 8/1/2015

Schedule 4

CALCULATION OF INCOME TAX EXPENSE
TEST YEAR ENDED March 31, 2015

GREEN MOUNTAIN POWER CORPORATION
August 1, 2015

$ in 000s	PRO FORMA
Total rate base investment	1,260,062
Return % (Total Cost of capital	7.31%
Return on utility rate base	92,111
Add back:	
Federal income tax	24,921
State income tax	7,774
Return before taxes	124,806
Less interest (Wtd. Cost of Debt X Rate Base)	33,140
Subtotal	91,666
Additions & deductions for income tax purposes:	
Non-taxable portion of equity in earnings of VELCO	(343)
Non-taxable portion (100%) of equity in earnings of Vermont Yankee	(68)
Non-taxable portion (70%) of equity in earnings of MY, CY, YA, NEHT and NEHTE	(82)
Non-deductible AFUDC-equity	327
Non-depreciable ITC basis reduction	8
Non-deductible meals expense	109
Domestic production activities deduction	0
Total additions & deductions	(49)
Balance	91,617
Less state income tax (8.5% of Line 27)	7,787
Taxable income	83,830
Federal Income Tax Calculation:	
Federal income tax before credit at 35%	29,341
Investment credit amortization	(64)
Production Tax Credit	(4,309)
CAFC Perm	(67)
FAS 109 ITC Basis Adjustment	22
AFUDC Deferred Tax Adjustment	13
Federal income tax	24,937
Excess Deferred Tax & Con Adj	(15)
Total Federal Income Taxes	24,922
State Income Tax Calculation:	
Taxable income at 8.5%	7,787
Vermont income tax rate change adjustment	9
Vermont Solar ITC	(32)
ITC Basis Adj	6
AFUDC Deferred Tax Adj	3
Total State Income Taxes	7,774
TOTAL STATE AND FEDERAL INCOME TAX	32,696

<u>Exhibit 18</u> - Hempling 2008 Article re: "pre-approvals"

National Regulatory
Research Institute

Pre-Approval Commitments: When And Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects?

Scott Hempling, Esq.
Scott H. Strauss, Esq.

November 2008

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EXECUTIVE SUMMARY

Until the last quarter of the 20th century, utility regulators commonly made cost recovery decisions concerning new capital projects only after construction was completed and the facility had entered commercial operation. The key aspect of this traditional approach is timing -- *i.e.*, that whatever regulatory decision is made with respect to the rate-making treatment of construction costs occurs "after-the-fact," *i.e.*, after the utility has incurred the costs at issue. Deciding only after a project is completed whether to allow rate recovery means that (1) cost recovery does not begin until the utility seeks and obtains a rate increase; and (2) during construction, the utility has to obtain outside (*i.e.*, non-ratepayer) sources of funds to finance the project.

Some state commissions, based on traditional statutes or recent amendments, are breaking from this traditional approach, thereby providing some level or form of cost recovery assurance prior to commercial operation (and sometimes prior to commencement of construction). Stimulating these new approaches are multiple factors: growing demand, aging infrastructure, environmental requirements, an increasing call for the construction of renewable projects, and shrinking credit markets. These considerations have led utilities to seek upfront regulatory commitments before expressing a willingness to pursue even much needed major capital projects.

This paper addresses the many and conflicting considerations raised when a utility asks a commission to commit to cost recovery in advance of the regulated utility's completion -- or, perhaps, even the initiation -- of construction of a major capital project. For shorthand purposes, we term these commitments as "pre-approvals," and define them as:

> ***An official government declaration that constrains future government decision-making, issued (a) by the commission pursuant to state statute, or (b) by statute directly. The declaration is issued at some point in time before (a) the utility obligates itself to incur project costs, or (b) the project enters commercial operation. The declaration provides that the utility (a) will receive, or (b) will have an opportunity to assert that it should receive, at some point or points in time, dollars from ratepayers, with some level of certainty, to cover some or all of the project costs.***

In evaluating whether to make a pre-approval commitment, there are many potential options and real-life examples to consider. These include state commission determinations that a specific capital project is a prudent choice, that pre-construction costs can be recovered in rates, or that some of the costs to be incurred in constructing a project can be included in rates, on either a contemporaneous or post-completion basis. Any of these approaches involves some upfront shifting, from regulated utilities to ratepayers, of the economic and timing risks associated with implementing a major capital project.

Examples of these mechanisms, which are not mutually exclusive, include:

- Recovery of construction costs during, rather than only after, construction;

- Approval of specific projects in advance of completion (sometimes, though not always, subject to conditions such as meeting scheduled milestones or imposing cost recovery caps);

- "Adjustment clauses" (allowing for recovery of specified costs as incurred, *e.g.*, on a monthly or annual basis);

- Approval of "formula" rate structures, which allow for automatic recovery of certain types of costs, including capital costs;

- Single issue rate increases (*e.g.*, involving consideration of only a capital improvement) rather than general rate cases (involving consideration of all of a utility's costs, whether increased or decreased since the last general rate case);

- Riders and surcharges, allowing for the recovery of pre-approved, specific cost increases without the need for a general rate case; and

- "Securitization" (a rock-solid, often statute-based, government guarantee of cost recovery, which is intended to reduce financing costs by eliminating the risk of non-recovery).

While the paper contains a review of these and other possibilities, its larger purpose is to identify the considerations that the regulator should take into account before moving forward with any form of an in-advance -- rather than after-the-fact -- approval of utility actions or costs. Consideration of advance commitments requires that the commission determine the terms on which risks may be shifted as between a utility's shareholders and its customers, and the benefits provided in response to any approved risk-shifting. In addressing these issues, the regulator must weigh multiple, and occasionally conflicting, concerns, including those involving management effectiveness, regulatory effectiveness, and rates. Some of the considerations involved in addressing pre-approval issues are arrayed sequentially in Figures 1 and 2 to this paper.

While the issues are, of course, fact-specific, the paper presents certain general guidelines that the regulator can apply in evaluating potential pre-approval opportunities. In general, the regulator should ensure that:

- Any pre-approvals are granted only upon a supported showing that regulatory action will benefit customers.

- Regulatory actions are based on full review of the relevant facts, and are supported by evidentiary showings.

- Whatever regulatory action is taken is appropriately limited or conditioned. Approval of an option as a "prudent" choice is not the same thing as approving the inclusion in rates of whatever dollars are expended to pursue it. Approving the recovery of "preliminary" or "planning" costs should not construed as approving the recovery of later-incurred dollars. The key is to be certain that regulator flexibility and discretion are retained to the greatest extent possible.

- The regulator has adequate resources to conduct appropriate reviews of whatever is requested. The commission will need assured access to sufficient technical resources if it is inclined to consider the request of a utility seeking, for example, a determination that building a new nuclear plant is a "prudent" response to the need for new capacity.

- The roles of the regulator and the utility remain properly defined. While it may be appropriate to require that a utility provide periodic reports on the progress of a construction project, the regulator's oversight should not leave it as the party with responsibility for managing the project.

Consideration is given to offsetting adjustments. If pre-approval will reduce the utility's going-forward risk profile, consider whether an adjustment to the utility's return on equity should be ordered in connection with whatever pre-approval is granted.

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Pre-Approval Commitments: When And Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects?

I. Introduction

Every regulated public utility has a statutory obligation to satisfy its customers' needs, reliably and cost effectively. To meet that obligation, the utility must, among other things, forecast demand accurately and commit to appropriate capital projects. Those projects must then be completed on time and constructed in a prudent and cost-effective manner. [1]

Achieving these public interest objectives — accurate forecasts, prudent capital project commitments, cost-effective and timely project implementation — requires a number of decisions by both the regulated utility and the regulatory commission. Common to these decisions is the commitment of dollars. Using its legal powers to approve projects, sites, and rates, the regulatory commission commits ratepayer dollars to the project. Using its legal powers to enter contracts, the regulated utility condemns land, borrows money, issues stock, and commits corporate resources — and ultimately shareholder dollars — to the project.

Taken together, these corresponding commitments present a multi-billion dollar, multi-part question: When a public utility proposes to undertake a major capital project, at what point in time should a commission provide assurance that the utility will recover its investment? What conditions, if any, should be placed on whatever assurance is provided? Phrased differently, how much ratepayer money should regulators commit, when should regulators commit it, and under what conditions should such commitments be made?

This paper focuses on commitments made by regulatory commissions in advance of the regulated utility's completion — or, perhaps, even the initiation — of construction of a major capital project. When faced with a request for approval of a project-related regulatory commitment in advance of project completion, a commission will face several basic questions:

a. What types of regulatory commitments should be considered?

b. At what point in the construction process should the regulator make a commitment to a new capital project?

[1] In this paper, "public utility" or "utility" refers to an entity having a legal obligation to serve. This obligation can arise from legislative or commission mandate. The policy origins of such a mandate are normally a determination that (a) the service is essential to the public welfare and (b) the provider is a monopoly or near-monopoly, such that customers have few alternatives and thus need regulation to ensure high-quality service. The application of this term will vary across states and across industries. At the state level, a regulated utility's obligation to serve typically amounts to a responsibility to provide a defined product (*e.g.*, reliable electric, gas, or water service) in a quantity sufficient to satisfy all demand within an assigned service territory. We do not address the more complex issue of utility obligations where there is competition for the right to supply customers.

c. Assuming the commitment involves cost recovery, should the commitment be bounded through the imposition of conditions, and, if so, how should those conditions be structured?

Consideration of advance commitments requires that the commission determine the terms on which risks may be shifted as between a utility's shareholders and its customers, and the benefits provided in response to any approved risk-shifting. In answering the questions presented above, the regulator must weigh multiple, and occasionally conflicting, concerns, including those involving management effectiveness, regulatory effectiveness, and rates.

While these questions can be considered sequentially, real-world decision-making is not so orderly. In a given set of circumstances, the answers to each of the questions posed will be interrelated and interdependent. For this reason, it is important for a regulator to observe the entire array of choices systematically, before making commitments at any particular stage.

Some of the considerations that may be posed by a request for a regulatory commitment are reviewed in this paper, are displayed in Figures 1 and 2 to this paper, and are applied in the "examples" presented below in Section III.

A. The Situation: Needed New Investment in Capital Projects Poses Challenges for Utilities and Regulators

Facing a combination of growing demand, aging infrastructure, environmental requirements, an increasing call for the construction of renewable resources, and shrinking credit markets, utilities are seeking upfront regulatory commitments before expressing a willingness to pursue even much needed major capital projects.

Consider the situation currently facing service providers in the electricity, gas and water industries:

a. Electricity

Infrastructure needs are growing for electric utilities. Some utilities are seeing capacity margins shrink as demand continues to grow in the face of plant retirements. Others have deferred investments in aging transmission and distribution systems. Utilities are voluntarily (or by mandate) investing in advanced metering and data management systems while facing the need to comply with new renewable energy and energy efficiency directives. Some utilities are considering investing in a new generation of nuclear plants, while others are proposing to meet customer needs by entering into long-term purchase power agreements. Those involved in construction projects have seen increases in the cost of raw materials used as project inputs. Licensing remains a challenge for any major project in an era of NIMBY (not in my backyard) and NIMTOO (not in my term of office). Utility financial capabilities and the availability of capital in today's markets also constrain capital investment projects.

b. Gas

During the past five years, gas utilities spent roughly $5 billion per year on capital investments. This spending trend is on the upswing. The American Gas Association (AGA) estimates that during the next twenty years, annual capital expenditures will increase to $6.5-$9 billion,[2] with funds expended on new main and service pipes, replacement pipes, and compliance with new federal safety regulations.[3]

In some states, gas utilities are petitioning their state commissions to approve accelerated recovery of capital expenditures.[4] As of the end of 2007, eleven state commissions allow gas utilities to "use expense trackers or accounting deferrals to recover costs expended to replace infrastructure in a timely manner."[5] Similar mechanisms are pending before other state commissions.

c. Water

In the years immediately following World War II, the unprecedented industrial, business, commercial and residential development experienced in the U.S. was accompanied by water and wastewater infrastructure to support that development. Many of the water and wastewater facilities constructed during that period are now at the point where they must be upgraded or replaced. Absent action, communities risk adverse economic consequences, such as unplanned system failures, increased maintenance costs, and unbudgeted repair and replacement costs. Water and wastewater utilities are also facing increasingly stringent water quality regulations, which will require large capital investments in water treatment facilities and processes. United States Environmental Protection Agency surveys indicate that over the next two decades, the level of

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[2] Cynthia J. Marple, Facilitating Energy Efficiency and Conservation: Non-Volumetric Rate Designs, Presentation Before the Virginia SCC and LDC Conference (Oct. 1, 2008).

[3] For example, the Pipeline Safety Improvement Act of 2002 (Pub. L. No. 107-355, 116 Stat. 2985 (codified as amended in scattered sections of 49 U.S.C.)) and the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (Pub. L. No. 109-468, 120 Stat. 3486 (codified as amended in scattered sections of 49 U.S.C.)) require gas utilities to increase their pipeline maintenance and safety investments. The latter legislation requires gas utilities to spend additional money on excavation damage prevention, distribution integrity management, excess flow valves and pipeline control room operations. In addition, state regulators can impose standards that are more stringent than federal safety mandate minimums.

[4] In general, state public utility commissions approve the construction of distribution facilities and intrastate pipelines, which include main distribution lines and service lines, metering systems, and storage facilities located within a utility's service area. Commissions review the economics and need (*e.g.*, requirement for meeting federal safety regulations) for these facilities before issuing a certificate. Moreover, state commissions may require that gas utilities under their jurisdiction provide reliable and safe service, which can include, for example, imposition of the obligation that a utility replace some of its existing pipes to comply with safety standards or construct new service lines to accommodate new customers.

[5] American Gas Association, "Infrastructure Cost Recovery Mechanisms," *Natural Gas Rate Round-Up*, December 2007. Commissions have approved trackers for pipeline integrity management programs and pipeline replacement costs.

needed investment in water and wastewater infrastructure improvement and replacement is between $500 billion and $1 trillion.[6]

B. The Traditional Approach: Determine Cost Recovery at Project Completion

Until the last quarter of the 20th century, regulators commonly made cost recovery decisions concerning new capital projects when construction was completed and the facility had entered commercial operation.[7] Under this traditional approach, referred to as the "prudent investment rule," cost recovery was available only on satisfaction of two conditions: costs were prudently incurred, and the project was "used and useful," *i.e.*, providing actual benefits to the public.[8]

The mechanics of the traditional approach are straightforward: once the plant enters commercial operation, the utility, for accounting purposes, puts its construction and associated financing costs into its rate base and books associated depreciation. The utility then seeks a rate increase to pay for the plant. In computing its proposed new rates, the utility includes the net book value (*i.e.*, original investment less booked depreciation) in its proposed rate base and includes annual depreciation of the investment in its proposed annual expenses. The depreciation expense gives the utility the return <u>of</u> its investment, while the cost of capital applied to the rate base gives the utility a return <u>on</u> its investment.[9]

In connection with the proposed rate increase, the regulator engages in several assessments, the aim of which is to determine whether the costs proposed for inclusion in rates were prudently incurred and whether the resulting utility plant is used and useful for serving the public. Those assessments include: (1) examining the utility forecasts that supported the decision to build the project, thereby satisfying itself that the project was, in fact, needed; (2) assessing the project choice,

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[6] David Denig-Chakroff, Nat'l Regulatory Research Inst., The Water Industry at a Glance (2001), http://nrri.org/pubs/water/Water_industry_at_a_glance.pdf.

[7] In setting utility rates, Commissions typically do not guarantee cost recovery, but rather provide a reasonable opportunity for recovery. That reasonable opportunity exists when the regulator includes the designated costs in the utility's revenue requirement when setting rates. Whether the utility actually collects that full revenue requirement depends on the extent to which its actual expenses and sales volumes match the levels assumed in the Commission-approved revenue requirement. Guaranteed cost recovery, which is the exception but not unprecedented, requires a distinct device, such as a fixed line item amount on each customer's bill, or a "pass through clause" that allows for periodic true-ups, or, most formally, a statutorily-defined "securitization" mechanism in which the state government promises full payment.

[8] For background on this concept, see Justice Brandeis's dissenting opinion in *Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission*., 262 U.S. 276 (1923); and James Bonbright, <u>Principles of Public Utility Rates</u> 159-61 (1961).

[9] In a state which defers cost recovery until construction is complete, the technical accounting works like this: While construction is ongoing, the utility records its construction costs as Construction Work in Progress, or CWIP. It also records an Allowance for Funds Used During Construction, or AFUDC, which represented the cost of financing the outstanding CWIP. The AFUDC rate varies: it may be the utility's weighted average cost of capital, or it may be the cost of debt, or the cost of short-term debt. When the plant is complete, the utility stops recording CWIP and AFUDC, moves the CWIP to plant-in-service accounts, and begins depreciating the plant and including it in rate base. For purposes of this discussion, the important point is that during construction the utility does not obtain a cash return of or on the investment, but books the costs for later recovery in rates.

including reviewing whether potentially less expensive alternatives were considered and, if so, why they were not pursued; (3) evaluating whether the methods and sources of plant financing reflect prudent decision-making; and (4) conducting a review of the reasonableness of construction costs and the timeliness of completion. Upon completing this review, the regulator disallows costs that it finds were caused by the utility's imprudence.

For purposes of this discussion, the key aspect of the traditional approach is *timing* — *i.e.*, that whatever regulatory decision is made with respect to the rate-making treatment of construction costs occurs "after-the-fact," i.e., after the utility has incurred the costs at issue. Deciding only after a project is completed whether to allow rate recovery means that (1) cost recovery does not begin until the utility seeks and obtains a rate increase;[10] and (2) during construction, the utility has to obtain outside (*i.e.*, non-ratepayer) sources of funds to finance the project.

Supporters of the traditional approach assert that it offers customers important benefits, including encouraging utility management to complete the project on schedule and on budget (if not sooner than forecast and less expensively). Moreover, in an after-the-fact cost recovery review, regulators have access to all relevant construction facts before making prudence and rate recovery decisions.

C. Is the Traditional Approach Optional Where Needed Financing is Difficult to Obtain?

Beginning in the 1970s, the factual bases for the traditional approach began to change. In the electric industry, for example, until the 1970s, the combination of economies of scale and increasing demand growth permitted utilities to size facilities to a level that would both meet expected demand and reduce unit costs, while also allowing for additional sales. However, the combination of inflation and fuel cost increases meant that internal utility funds were less available for use on construction projects. Moreover, access to needed capital became more difficult as construction projects grew larger, employed new technologies, required longer construction periods, and had to meet new and uncertain regulatory requirements (such as those emanating from the Nuclear Regulatory Commission for electric utilities and the Environmental Protection Agency for water utilities). These facts made capital markets less optimistic about whether, and when, ratepayers would pay up. In response, capital — both shareholder capital and debt capital — became more expensive and less available.

State law and practices concerning the timing and processing of rate increase requests subjected utilities to additional financial stress. Some states had statutory "stay-out" provisions, limiting the frequency of the utility's general rate increase requests. Regulators also had a non-statutory preference for infrequent rate cases, due to resource limits and public relations challenges. For small utilities, the transaction costs of a full rate case could compare unfavorably to the size of the revenue increase associated with the likely outcome.

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[10] One clarification of the phrase "seeks and obtains": some states allow the utility to institute some or all of its proposed rate increase before the commission has decided the case. Practitioners label such rates "interim subject to refund." If the Commission ultimately approves rates lower than those placed into effect, the utility must refund the excess amounts.

Critics of the traditional approach have asserted that this combination of circumstances has had negative effects, including: delays in needed utility investments (thereby increasing the risk of shortages, blackouts, brownouts and other service concerns); decreasing the frequency of rate filings (and conditioning customers to unchanging (meaning below-cost) utility rates even as other costs of living rose)[11]; and deferring projects until "crisis" conditions prevailed (leaving insufficient time for commission examination of potential alternatives).

Regulators have responded to these concerns by considering certain modifications to the traditional approach, many of which are short-term and project-specific. Examples of these mechanisms, which are not mutually exclusive, include:

1. Recovery of construction costs during, rather than only after, construction (known as recovery of Construction Work in Progress or "CWIP");

2. Approval of specific projects in advance of completion (sometimes, though not always, subject to conditions such as meeting scheduled milestones or imposing cost recovery caps);

3. "Adjustment clauses" (allowing for recovery of specified costs as incurred, *e.g.*, on a monthly or annual basis);

4. Approval of "formula" rate structures which allow for automatic recovery of certain types of costs, including capital costs;

5. Single issue rate increases (*e.g.*, involving consideration of only a capital improvement) rather than general rate cases (involving consideration of all of a utility's costs, whether increased or decreased since the last general rate case);

6. Riders and surcharges, allowing for the recovery of pre-approved, specific cost increases without the need for a general rate case; and

7. "Securitization" (a rock-solid, often statute-based, government guarantee of cost recovery, which is intended to reduce financing costs by eliminating the risk of non-recovery).

Some of these mechanisms were mandated by legislative action, which might single out a particular technology or cost category for favorable (*i.e.*, certainty-enhancing) treatment. However, approval of any of these cost recovery mechanisms could unreasonably shift risk from shareholders to ratepayers if not limited (*e.g.*, by imposing a cap on cost recovery, which could be exceeded if certain showings were made).

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[11] Eventual – and generally substantial – rate cases could engender customer and media attention that undermined public trust in both the commission and the utility. Bonbright, in his Principles of Public Utility Rates, *supra*, at 291 (bullet point 5), emphasizes the value of rate stability (including gradual rate increases) over sudden, large rate increases.

D. The Framework for a New Approach

The present regulatory landscape at the state commission level features an apparent mismatch between (a) the magnitude of investment dollars necessary for essential infrastructure expansion and replacement essential to the nation's well-being, and (b) the clarity and predictability of the regulatory treatment of those investment dollars. These concerns are present regardless of the perspective from which the situation is viewed. For example:

Regulators and utility executives are unclear about largely the same things: what decisions are theirs to make, which decisions will be mandated or guided by legislators, what risks they incur in taking particular actions, and, therefore, how best to identify and balance the managerial, financial, technical, economic, and political factors that affect construction of needed large capital projects.

Investors are unclear about when regulatory commitments will be made, how those regulatory actions will allocate responsibility for project costs and risks, when dollars will flow, through what ratemaking mechanism, and how regulatory commitments might change with unanticipated events.

Customers are unclear about (a) what to expect in terms of the cost consequences of utility investments on their behalf; and (b) whom to hold accountable — legislators, regulators, utility executives, capital markets, or all of the above — for outcomes that vary from these expectations.

In short, there is a need for clarity and predictability, in the form of systematic, but not rigid, decision-making. Systematic decision-making seeks clarity and predictability, the prerequisites for which include alertness to all relevant facts, identification of all legitimate values, attention to both long-term and short-term consequences, and analytic transparency. A framework embodying these features will allow for improvisations, changes of heart and mind, and creative modifications.

In considering how and when to approve the recovery of the costs associated with large capital projects, achievement of the public interest requires at least three ingredients:

- First, whatever regulatory commitments are made should be well-founded, *i.e.*, based on a substantial evidentiary record.

- Second, the commission must have the capacity (including skills, experience and resources) to evaluate anticipated utility performance, to monitor performance throughout the course of the project (including a review of utility rationales for schedule slips and cost overruns), and to take actions in response to unanticipated events.

- Third, whatever regulatory action is taken must be designed to both motivate the utility to excel (*i.e.*, operate efficiently) and to penalize the utility for poor performance.

In regulatory dialogue, these concepts can be captured in the term "pre-approval." This term has been given multiple meanings. Here is a suggested definition that covers many of them:

> ***An official government declaration that constrains future government decision-making, issued (a) by the commission pursuant to state statute, or (b) by statute directly. The declaration is issued at some point in time before (a) the utility obligates itself to incur project costs, or (b) the project enters commercial operation. The declaration provides that the utility (a) will receive, or (b) will have an opportunity to assert that it should receive, at some point or points in time, dollars from ratepayers, with some level of certainty, to cover some or all of the project costs.***

The concept can be viewed with more clarity when the description's separate components are parsed:

> ***a. An official government declaration that constrains future government decision-making, issued (a) by the commission pursuant to state statute or (b) by statute directly,***

Whether the commission issues an order or the legislature enacts a statute, the action is "official" because it declares rights and obligations. The declaration, the content of which is addressed below, can issue from the commission, acting pursuant to statutory authority, or directly from the legislature (which can either direct or authorize a result). However, unless the declaration constrains future government decision-making, it is legally meaningless.

> ***b. at some point in time before (a) the utility obligates itself to incur project costs, or (b) the project enters commercial operation,***

Utilities seek "pre-approval" to reduce the risk non-recovery of costs, and also to reduce the time lag between expenditure and cost recovery. "Pre-approval" can address one or both of these goals. Risk reduction occurs if a government makes a cost recovery commitment before the utility incurs a cost. Time lag reduction occurs if cost recovery under a pre-approval structure occurs sooner than would be the case if the utility has to file an after-the-fact rate case.

> ***c. that the utility (a) will receive, or (b) will have an opportunity to assert that it should receive,***

This phrase goes to the heart of what the government is, in fact, approving. If the government approves cost recovery, then it is promising that the utility "will receive" some amount of dollars at some point, predicated on the fulfillment of certain conditions (such as prudent conduct, timely completion of construction, or completion within a specified budget).

Another, and more limited type of "approval" does not commit to cost recovery specifically, but somewhat constrains future commission decisions on cost recovery. Assume, for example, that a commission determines that a utility's demand forecasts are accurate and that new capacity is necessary to meet those forecasts. If action is taken by the utility based on that finding, then the commission presumably cannot — absent a material change in factual circumstances — find later that the capacity addition was unnecessary. This type of pre-approval constrains the regulator to stick to its original "need" finding. However, depending on the scope of the action, the regulator remains free to question (a) the utility's choice of a particular project as the means of meeting the acknowledged need; (b) the reasonableness of the costs incurred in constructing the additional capacity; and (c) the utility's continuation of the project despite material changes in underlying facts.

d. at some point or points in time

In the context of pre-approvals, the point in time when the utility receives ratepayer dollars can vary widely. Dollars can flow either as or after the utility incurs costs, and each of these options themselves involve multiple choices. "As incurred" can mean in each monthly bill or pursuant to an annual true-up. "After incurred" could be at the next rate case if the costs were "deferred" (meaning that the commission has allowed the utility to preserve the right to argue later for recovery of costs incurred in the past).

e. dollars from ratepayers,

This portion of the description reflects that the main purpose of "pre-approval" is either to (a) create a government-authorized flow of dollars from ratepayers to the utility as compensation for utility service, or (b) have the commission bless a particular option (thus precluding a later finding that the option was imprudent), while leaving the specific dollar amount for subsequent determination.

f. with some level of certainty,

A regulatory approval granted prior to project completion may shift, but does not necessarily eliminate, cost recovery risk. Cost recovery certainty depends on several factors, including the scope of the regulator's decision. The regulator might determine that a particular project selection is prudent, but remain silent on the prudence of particular project costs. Such a decision creates certainty, in that prudent costs associated with the decision will be recoverable, but leaves uncertain what level of costs is prudent. The regulator might find that the utility's forecast of future needs is accurate but not address the type of project (*e.g.*, power plant vs. demand-side management) that will meet that need prudently, leaving that important question for later determination.

g. to cover some or all of the project costs.

The certainty of cost recovery is distinct from the amount of that recovery. A regulator could find, in advance, that all costs up to a stated amount are deemed prudent and therefore recoverable. On the other hand, as concerns additional costs, the regulator may find that costs above that limit (a) are not recoverable (making the stated amount a ceiling), or (b) the utility may argue later that the costs should be recovered because they were prudently incurred (making the stated amount a floor).

Having now set forth, in conceptual terms, the parameters of a pre-approval approach, we turn to a review of how various state commissions are putting these concepts into action.

II. Pre-Approval Mechanisms in Action: Examples from across the Nation

Pre-approval opportunities are typically triggered by a specific action taken by the utility, which results in a request for some type of imprimatur from a regulator. We begin by reviewing potential pre-approval triggers and then move into a discussion of specific regulatory actions that might be taken. This discussion will address the considerations that may be weighed in reviewing a specific request and provide examples of how regulators and state legislatures across the country are dealing with these issues.

A. Triggering Actions

1. Forecast customer requirements

The utility forecasts customer peak demand and annual consumption requirements. In order to do so, the utility measures economic trends and customer behavior (including price responsiveness and propensity to adopt efficiency opportunities). The utility may ask the regulator to "approve" the forecast or to bless actions to be taken in response to it.

2. Incur specific pre-commitment costs

Prior to committing to a capital project, a utility may incur costs necessary to preserve the option. Examples are paying a fee to an equipment supplier to reserve a place in its queue, initiating site development or seeking a construction license from the NRC. Such steps are time consuming and involve cost incurrence; their purpose is not to initiate a project, but to ensure that if the utility subsequently selects that option, it can move forward without undue delay. The utility might seek approval, in advance of the commencement or completion of a project, to recover such "pre-commitment" costs in rates.

3. Commit to a project and initiating construction

After assessing supply and demand options, the utility might ask the commission to approve the utility's commitment to an option that it asserts best matches the forecasted customer requirements (whether from the perspective of size, timing, reliability, environmental or siting effects) and cost (whether construction cost, running cost over its useful life, or decommissioning cost). In this context, "commitment" means that the utility binds itself contractually to the contractors and suppliers of the equipment, technology and other cost drivers required to construct the project.[12]

[12] For a detailed discussion of the multiplicity of generation choices, organized according to their characteristics, *see* J.

4. Continue construction

While a utility's commitment to a project may create some unavoidable cost obligations, there will always be avoidable costs as the project moves through various stages of development. Before committing to each stage of cost commitment, a prudent utility will compare the project's prospective costs and benefits, taking into account factors like cost escalations beyond those assumed in original projections, changes in forecasted customer requirements, and alternate options. The utility may ask the commission to approve continued (or modified) efforts.

5. Change in project plans

During construction, changes in circumstances may warrant project changes. Examples include: downsizing or upsizing to reflect changes in forecasted customer requirements, design changes to comply with new regulatory requirements, and modifications to fuel supply arrangements due to changes in availability or price. Any such change might shift the project's cost-benefit ratio, and may lead to the utility seeking commission approval of associated project modifications.

6. Abandon a project

Prior to completion, circumstances may change the cost-benefit ratio so drastically as to justify project abandonment.[13] Abandonment itself may cause the incurrence of new costs (*e.g.*, decommissioning, attorney fees to renegotiate supplier costs, payment of liquidated damages to shed contract commitments). The utility could seek authorization to recover abandoned plant costs before any such decision is made, or seek abandonment cost protection in advance of a decision whether to pursue a particular project.

B. Pre-Approval Regulatory Commitments that Constrain Future Decisions but Do Not Commit Ratepayer Dollars to Immediate Cost Recovery

For major capital projects, cost recovery is not the only regulatory decision. Under most state statutory schemes, a utility must obtain approvals relating to need, suitability, and environmental effects — often before incurring projects costs. Examples of these approvals include obtaining:

(1) A Certificate of Public Convenience and Necessity ("CPCN"), demonstrating that the proposed project is necessary to serve the public;

McGarvey et al., Nat'l Regulatory Research Inst., *What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria* 3 (2007), http://nrri.org/pubs/electricity/07-03.pdf.

[13] Factors leading to an abandonment decision may include: decline in forecasted customer requirements; emergence of new alternatives; unanticipated cost increases relating to fuel supply or regulatory requirements; and unavailability of key equipment components.

(2) A determination that a proposed project is consistent with an integrated resource plan;

(3) Permission to exercise the power of eminent domain (*i.e.*, the taking of private property for utility purposes);

(4) Permission to site utility facilities in particular locations, including (in some states) permission to preempt local zoning restrictions;

(5) Approval of compliance with federal or state environmental restrictions, such as installation of pollution control equipment or other actions associated with electric generating plants, transmission lines, gas and oil pipelines;

(6) Approval of a plan to address reliability problems arising from insufficient resources;

(7) Approval of critical infrastructure protection plans in response to national security challenges;

(8) Approval of plans for repair and replacement of aging facilities;

(9) Approval of bidding or procurement programs; and

(10) Permission to issue debt and equity securities.

Consideration of any of these actions raises at least two questions: (a) What purposes does the approval action serve?, and (b) Does the action constrain future regulatory decision-making, including cost recovery decisions?

1. What are the purposes of an approval that does not directly involve cost recovery?

Any of the above-listed approvals may serve several purposes.

Action at an early stage may provide the regulator with an opportunity to better match the utility's private interest with the public interest. There are plenty of opportunities for mismatch. A utility may prefer to build its own facilities (so as to earn a return on the investment), rather than relying on purchases from others (which might be lower cost, but will not produce a profit for the utility). A utility may seek to maximize sales of its product, even if promoting actions to reduce consumption would be a better choice for the public. Considering regulatory action at an early, pre-cost stage may identify areas in which private and public interest diverge and create opportunities for interest matching – identified through the development of an evidentiary record and implemented through, for example, conditional approvals.

Similarly, consideration of pre-approval actions that do not directly involve cost recovery give the regulator the opportunity to balance multiple factors besides cost. In the specific context of integrated resource planning, project choices involve multiple options with varied possible impacts on the consuming public – including cost, environmental, and economic development impacts — all on both a short-term and potentially longer-term basis. An early open planning process, culminating in some type of regulatory commitment, facilitates a public investigation of these effects and a weighing of the many public preferences and values.

Even where the issue before the regulator does not involve cost recovery, a pre-approval process can create a useful template for future consideration of cost recovery issues. In the case of pollution control infrastructure, some state statutes authorize their jurisdictional electric utilities to file compliance plans for meeting with state or federal emissions requirements. By approving the plan, the commission may effectively be committing to cost recovery of utility funds spent carrying out the plan, assuming a subsequent showing by the utility that such funds were prudently incurred.

Consider Indiana Code 8-1-27-8(1)(A), which directs the Indiana Utility Regulatory Commission to consider an electric utility's Clean Air Act Amendment compliance plan in terms of whether it is efficient, reliable, economic, and constitutes a reasonable least cost strategy over the life of the investment. The electric utility can seek recovery of its original cost estimate for the plan, an approved revised cost estimate, or additional costs, if it can show that they were necessary and prudent. The commission also has authority to modify or withdraw its original pre-approval if there have been substantial changes in the need for, or estimated cost of, an approved environmental compliance plan.[14] A similar arrangement is in place in Pennsylvania.[15]

2. To what extent does approval of a non-cost mechanism constrain a commission's future cost recovery decisions?

The short answer to this question is that it depends on what the commission says in its approval order. Some utilities have sought, prior to the incurrence of major costs, commission or legislative findings that the construction of a specific project is prudent. Such findings can vary in their degree of regulatory commitment to eventual cost recovery. At one end, a ruling on a specific project might not promise cost recovery at any particular cost level, but would insulate the utility from a subsequent finding that its project selection was imprudent. The North Carolina Commission has ruled, for example, that it has authority to issue a declaratory, pre-expenditure ruling regarding the prudence of a proposal.[16] However, some commission orders state expressly that approval of a project choice is not an approval of any cost recovery.[17]

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[14] Ind. Code §§ 8-1-27-18,-19. *See, e.g.*, *In re Indianapolis Power & Light Co.*, 145 P.U.R.4th 513 (Ind. Util. Regulatory Comm'n 1993); *In re S. Ind. Gas & Elec. Co.*, 137 P.U.R.4th 231 (Ind. Util. Regulatory Comm'n 1992). *See, e.g.*, *In re Indianapolis Power & Light Co.*,145 P.U.R.4th 513 (Ind. Util. Regulatory Comm'n 1993); *In re S. Ind. Gas & Elec. Co.*, 137 P.U.R.4th 231 (Ind. Util. Regulatory Comm'n 1992).

[15] *See* Pennsylvania statutes, Pa. Stat. Ann. § 530(d)(2) (requiring utility to show that amounts spent to fulfill the plan were reasonable in amount and prudently incurred as determined in an appropriate rate or other proceeding, for costs to be reflected in rates).

[16] *In re Duke Power Co.*, 256 P.U.R.4th 215, 232 (Commission finds authority to issue declaratory ruling providing

That said, the initial "approval" may constrain later regulatory decisions to the extent that actions the utility takes on the basis of that approval. In other words, the regulator can criticize a utility's implementation of an approved plan, but cannot simply announce after-the-fact that it is reversing that approval absent finding that the relevant facts have materially changed and that the utility should have taken the fact changes into account.[18] However, the commission's approval does not authorize the utility to take imprudent and unnecessarily costly actions to obtain the needed capacity, or to ignore changes in facts that undermine the basis for the original approval. The utility has a continuing obligation to act in a cost-effective manner, and the commission should remain free to enforce that obligation. For this reason, some states require utilities to file periodic updates of demand forecasts and project progress, allowing for a continuous reassessment of project premises.

C. Moves toward Pre-Approved Cost Recovery: "Deferral" of Costs for Later Consideration

Under traditional, embedded cost ratemaking, commissions use a "test year" to match utility cost and revenue increases and decreases. A "historic test year" is a 12-month period experienced by the utility, in which test year costs and revenues are those actually incurred by the utility during that period. Along with adjustments for inflation and other predictable changes (called "known and measurable changes"), these costs and revenues become the basis for the utility's new rates. A "future test year" approach bases rates on expected costs and revenues, rather than adjusted historic costs and revenues. The extent of any difference between the historic test year and future test year approaches depends on the nature of the predictions and adjustments.

After rates are set, if the utility incurs costs not anticipated in the test year, some commissions will permit the utility to "defer" these costs, meaning the utility records them on its

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"general assurance" concerning nuclear plant assessment activities), *clarified*, No. E-7, Sub 819, 2007 WL 2790658, *clarified*, No. ID 153282, E-7, Sub 819, 2007 WL 3273546 (N.C. Utils. Comm'n 2007); and *In re Duke Energy Carolinas LLC*, No. E-7, Sub 819 (N.C. Utils. Comm'n 2008), *available at* http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=EAAAAA36180B&parm3=000125794.

[17] Consider this 1999 Idaho PUC ruling:

> The Commission further finds that the general purposes to which the proceeds will be put are lawful purposes under the Public Utility Law of the State of Idaho and are compatible with the public interest. However, the Commission finds that this general approval of the general purposes to which the proceeds will be put is neither a finding of fact nor a conclusion of law that any particular program of Rockland which may be benefited by the approval of this Application has been considered or approved by this Order, and this Order shall not be construed to that effect.
>
> Further, the issuance of an Order authorizing the proposed loans does not constitute agency determination/approval of the type of financing or the related costs for ratemaking purposes, which determination the Commission expressly reserves until the appropriate proceeding.

In re Direct Commc'ns Rockland, Inc., Order No. 27914, No. ROK-T-99-1, 1999 Ida. PUC LEXIS 36, at *6-*7 (Idaho Pub. Utils. Comm'n 1999).

[18] For example, if the regulator finds that the utility needs to install or otherwise procure 500 MW of new capacity, then utility actions taken to obtain that capacity cannot be imprudent on the sole ground that the utility does not need the capacity. On other hand, the utility does not get a "free pass" if it continues to pursue the 500 MW in the face of later evidence that it no longer needs the capacity.

books and thereby preserves the opportunity to request recovery in future rates. By definition, such cost deferrals are deviations from the typical test year approach; deferral preserves the utility's option to argue for later recovery, even though costs were incurred prior to the test year. In permitting the deferral, the commission order makes no promise about cost recovery.[19]

Some state commissions are authorized to permit cost recovery deferrals for capital projects, but only where the project meets certain identified criteria. For example, under Nevada regulations, Nev. Admin. Code § 704.9484, the Commission may designate a "critical facility," thus making the utility eligible for special incentives for its construction, operation and maintenance, including authority to "defer" construction costs in a regulatory asset account for possible later cost recovery.[20] During the deferral period, the utility also can include put into rates "construction work in progress" (which is addressed separately below) associated with the designated facility.[21]

D. Options for Implementing Pre-Approved Cost Recovery

The most immediate, certain form of cost recovery is to permit a utility to include costs in rates contemporaneous with expenditure incurrence. Regulatory options are reviewed below.

1. Construction Work In Progress ("CWIP")

Under the traditional approach, a commission addresses cost recovery of a capital project in the utility's general rate case, submitted when the project enters commercial operation. If the costs are prudent, the commission allows them in rate base and establishes a depreciation rate, allowing

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[19] *See*, for example, *In re Idaho Power Co.*, Order No. 29904, No. IPC-E-05-21, 2005 Ida. PUC LEXIS 225 (Idaho Pub. Utils. Comm'n 2005) (clarifying the conditions under which a utility can treat preliminary survey and investigation costs as construction work in progress); *Phila. Elec. Co.*, 57 Pa. P.U.C. 114 (Pa. Pub. Util. Comm'n 1983). Similarly, in approving a Settlement that provided for a cost recovery deferral, the Pennsylvania Commission noted that in exchange for this treatment, the Settlement provided for early flow-through to consumers of the benefits derived from certain off-system transactions. *See In re Metro. Edison Co.*, Nos. G-900240, P-900485, P-910502, C-913373, P-910502C001, 1992 Pa. PUC LEXIS 87, at *73 (Pa. Pub. Util. Comm'n 1992) ("Affiliated Interest Agreements").

[20] The recovery would occur pursuant to subsection 3 of Nev. Admin. Code § 704.9523 (costs may be deferred between rate cases, and must include application of a carrying charge at the rate of 1/12 the authorized overall rate of return; account balances may be recovered via amortization over a period determined by the Commission in a general rate case, with a return at the authorized return plus 5 percent). Nev. Admin. Code § 704.9484(3)(cross-reference explanation supplied).

[21] In order to be eligible for these special cost recovery protections, the Commission (under Nev. Admin. Code § 704.9484(2)) must find that the facility will

1. protect reliability,
2. promote diversity of supply and demand side sources,
3. develop renewable energy resources,
4. fulfill specific statutory mandates,
5. promote retail price stability, or
6. fulfill any combination of the above.

for the gradual recovery of the investment.[22] Thus, cost recovery commences only when the plant enters commercial operation. By contrast, some states allow rate recovery of construction costs during the construction process. Known as "construction work in progress," the technique involves a commission finding that the utility's project selection decision, and the costs incurred to date, are prudent. This regulatory action eliminates the risk of non-recovery, and allows for recovery earlier. The technique both reduces non-recovery risk and aids in cash flow during construction. Providing CWIP may also reduce a utility's finance costs, as construction financing will be provided by ratepayers rather than lenders or shareholders.

Until the investment is moved from CWIP to a plant-in-service account, the utility is permitted to apply a rate of return to the investment amount (which covers its financing costs, *i.e.*, a return on investment). The utility is not permitted, however, to apply a depreciation rate to the investment amount, meaning that the shareholders will not start to see a return of their investment until the plant enters service and satisfies the commission's prudence review.[23] When a utility completes construction and the plant enters operation, accounting rules require the utility to (a) cease accruing an AFUDC on the investment; (b) place the CWIP associated with the plant into a plant-in-service account; and (c) begin amortizing (*i.e.*, reducing) that plant-in-service account by treating a portion of it as depreciation expense. Of course, there are limits to the impact of a decision to allow CWIP in rate base. While the action provides a current return during construction, it does not necessarily preclude the regulator from reviewing the prudence of the underlying investment once the project begins operation.

Proponents have argued, and some commissions have found, that permitting a utility to recover CWIP funding can reduce a project's total net present value cost, compared to booking construction costs as AFUDC and then placing those costs in rate base upon commercial operation.[24] CWIP has been justified on the ground that it removes any utility incentive to rush completion of a nuclear plant imprudently (so as to get its costs into rates) and in doing so risks errors and safety lapses.[25] On the other hand, including CWIP means that customers pay for a plant before it provides benefits, raising intergenerational inequity issues. Some states ban it. *See*, *e.g.*, *Barasch v. Pa. Pub.*

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[22] For example, if the plant cost $900 million and has an expected useful life of 30 years, and if the commission uses a straight line depreciation rate, the rates will recover a depreciation expense of $30 million, as well as a return on the undepreciated $870 million.

[23] In other words, putting CWIP in rate base does not allow the utility to recover the CWIP costs themselves. The utility instead recovers only the financing costs associated with the CWIP. The CWIP amount earns a return at the utility's Weighted Average Cost of Capital ("WACC"). Further, where CWIP is put in rate base with an AFUDC offset, the only dollar cost recovery created is CWIP times the excess of the allowed return over the AFUDC rate. This amount is substantial only where the AFUDC rate is based primarily on debt, particularly short-term debt, rather than a measure of the utility's WACC.

[24] *See* also the Oklahoma Commission's recitation of the competing views of witnesses in the Red Rock pre-approval case. *In re Okla. Gas & Elec. Co.*, Order No. 545240, No. PUD 200700012, 2007 Okla. PUC LEXIS 249 (Okla. Corp. Comm'n 2007) (utility's early approval request denied on other grounds).

[25] *See*, *e.g.*, *Phila. Elec. Co.*, 103 P.U.R.4th 430 (Pa. Pub. Util. Comm'n 1989)("early window" treatment allowed when the Company filed for rate increase just before fuel was loaded into the Limerick 2 Nuclear Unit); and *Pa. Power & Light Co.*, 47 P.U.R.4th 274 (Pa. Pub. Util. Comm'n 1982)("early window" treatment allowed where the Company filed two months before receiving an operating license for Susquehanna Nuclear Unit I).

Util. Comm'n, 532 A.2d 325 (Pa.1987), *aff'd sub nom. Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989).[26] Similarly, the Pennsylvania Commission denied "early window" treatment in a case in which the utility sought such authority three years before it acquired its proposed ownership interest in one plant and five years before it began construction of a related transmission line.[27]

2. Riders, surcharges and "single issue" rate increases

A commission's inclusion of costs in the utility's revenue requirement rates does not *guarantee* recovery (because other cost increases, or declines in sales, can leave the utility earning less than its authorized return on equity). One method for increasing the probability of cost recovery is the use of a rider or surcharge, added to each customer's bill on top the "normal" charges (*i.e.*, charges based on the revenue requirement). These riders or surcharges are typically applied to the quantity consumed; thus, as actual consumption may vary from estimates, the utility is still subject to some revenue recovery uncertainty. The probability of full cost recovery is greater if the charge is a fixed, per customer charge (meaning, it does not vary with the customer's consumption). While the typical forum for addressing surcharges is the utility's general rate case, some commissions have established them in so-called "single-issue" rate proceedings, in which recovery of a particular investment is the sole issue.

Certain surcharges are designed to increase over time through automatic "step increases" according to a pre-determined schedule or, as the utility's project costs rise, with periodic adjustments to avoid under- or over-recovery. For example, since 1997 Pennsylvania's water utilities have been allowed by statute to recover the costs of certain system improvements through a "Distribution System Infrastructure Charge" or "DSIC."[28]

The New Hampshire Commission has, in specific circumstances, granted step increase pre-approvals to gas and water utilities to recover the costs of infrastructure remediation, while providing certain safeguards to limit cost recovery. The gas utility filed a plan for gas main

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[26] Alternatively, some state commissions developed standards for inclusion of CWIP in rate base. *See*, *e.g.*, Nev. Admin. Code § 704.9484(3). In allowing CWIP for a portion of the construction costs associated with the North Valmy coal-fired plant, the Nevada Commission supported its decision by citing to intangible benefits associated with higher quality earnings, a federal policy of promoting coal over oil and natural gas, and the assertion that completion of the plant would advance the goal of fuel diversity. *In re Nev. Power Co.*, No. 06-06051, 2007 Nev. PUC LEXIS 22, at *114-15 n.11 (Nev. Pub. Serv. Comm'n 2007).

[27] *See* earlier discussion of Affiliated Interest Agreements. The Commission also denied "early window" treatment where neither size nor safety were important considerations. *Re W. Penn Power Co.*, 66 P.U.R.4th 337 (Pa. Pub. Util. Comm'n 1985) and *Re Pa. Power Co.,* 68 P.U.R.4th 357, 361 (Pa. Pub. Util. Comm'n 1985).

[28] *See* Section 1307(g) (66 Pa. Stat. Ann. § 1307(g)) to the Pennsylvania utility code, which states:

> **[Q]uality, fire protection reliability and long-term system viability**.—Water utilities may file tariffs establishing a sliding scale of rates or other method for the automatic adjustment of the rates of the water utility as shall provide for recovery of the fixed costs (depreciation and pretax return) of certain distribution system improvement projects, as approved by the commission, that are completed and placed in service between base rate proceedings. The commission, by regulation or order, shall prescribe the specific procedures to be followed in establishing the sliding scale or other automatic adjustment method.

replacement under which the utility, operating under an approved schedule, would replace bare steel gas mains (bare steel pipes lacking cathodic protection) with either cathodically-protected steel pipes or PVC piping. The purpose was to avert ongoing corrosion and gas main leaks associated with the unprotected bare steel pipe.[29] Similarly, the New Hampshire Commission awarded step increase treatment to address local water utilities' difficulties in financing improvements needed to address long-developing infrastructure deficiencies.[30] At the same time, the Commission, in each instance, provided for review and audit of construction costs incurred under the plan and review of the prudence of such costs, before the step increases would take effect.[31]

California has allowed water utilities to obtain step increases pursuant to an approved water infrastructure development plan. Once the plan is approved, the utility implements related annual rate increases by filing so-called "advice letters." In each letter, the utility notifies the Commission that investments that are required as preconditions for the step increase have been made and files the resulting new rates for application in the next year.[32]

In Washington State, the Commission gave Puget Sound Energy, Inc. authority to recover the costs of new power sources in the utility's reconciling Power Cost Adjustment, upon the approval of the new source in a so called Power Cost Only Rate Case (or PCOCR).[33]

Similarly, a Florida statute encouraging construction of new nuclear and Integrated Gasification Combined Cycle ("IGCC") plants, and the Commission regulations implementing the statute provide for annual construction cost recovery based on estimates of upcoming construction activities, together with a reconciliation of the most recent year's expenditures against the estimates upon which the earlier charges were based.[34]

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[29] *See*, *e.g.*, *Re N. Utils., Inc.*, Order No. 20,546, No. DR 91-081 (N. H. Pub. Utils. Comm'n 1992) and *Re N. Utils., Inc.*, Order No. 23, 052, No. DR 98-169 (N.H. Pub. Utils. Comm'n 1998) (approving the sixth step increase under Northern Utilities' bare steel main replacement plan).

[30] In that case, the Commission found that the deficiencies at issue

> pose a threat of backflow and cross-contamination to the drinking water supply. [The utility's witness] explained that this threat exists because much of the infrastructure is greater than 100 years old and consists of unlined cast-iron pipe which is subject to corrosion and failure. In addition, over 78% of the system has no post-treated storage. Also, increased traffic on the roadways, under which much of the distribution system is located, exerts additional pressure on these already weak pipes.

In re Hanover Water Works Co. Order No. 23,007, No. DF 98-076 (N.H. Pub. Utils. Comm'n 1998). Hanover Water Works serves approximately 8500 customers. Citydata.com, http://www.city-data.com/city/Hanover-New-Hampshire.html (last visited Oct. 3, 2008).

[31] The review proceedings differ from full rate cases in that they do not look at any other potential changes in revenues, costs and rates of return.

[32] *See*, *e.g.*, *In re San Gabriel Valley Water Co.*, 258 P.U.R.4th 65 (Cal. Pub. Utils. Comm'n 2007).

[33] Twelfth Supplemental Order, *Wa. Utils. & Transp. Comm'n v. Puget Sound Energy* , Nos. UE 011570, UG 011571, (Wa. Utils. & Transp. Comm'n 2002), *available at* http://www.wutc.wa.gov/rms2.nsf/vw2005OpenDocket/CB033A64A4C98B5688256BDE007D6AAE?OpenDocument.

[34] *See* Div. of Policy Analysis & Intergovernmental Liaison, Fla. Pub. Serv. Comm'n, Distribution System Improvement Charges for the Florida Water and Wastewater Industry 1 (2001),

3. Formula rates

The traditional test year approach to determining a utility's revenue requirement allows for a consideration of all cost increases and decreases. Regulators have designed a method for preserving the integrity of the test year while expediting analysis of a proposed rate increase necessitated by a capital addition. The approach allows the utility to update its rate base with increments of completed capital investment by filing an annual update of the inputs to a rate formula. The utility supplies the new cost data in accordance with the accounts of costs and revenues filed with the Federal Energy Regulatory Commission on the annual FERC Form 1, with (perhaps) some particular pre-approved adjustments. Because the regulator has approved the formula (and the input form) in advance, the regulatory review is confined to scrutiny of the prudence of particular input items or to arguments that the utility has misapplied the formula (*e.g.*, by including inaccurate or erroneous formula inputs).

4. Securitization

Securitization attaches a statutory commitment to cost recovery, thereby eliminating all risk of non-recovery. Reducing risk reduces the cost of capital to the customer.

E. Conditions That Can Accompany Pre-Approval Mechanisms to Ensure Consistency with the Public Interest

To ensure that risk-shifting pre-approval regulatory commitments promote the public interest, regulators have conditioned such commitments, including through the application of screening mechanisms. We review examples of such conditions below.

1. Consistency with regulator-approved resource plans

An integrated resource planning process identifies the public's needs and the investment options that may satisfy them cost-effectively. Once the plan has been approved, a commission will be more inclined to grant some form of pre-approval to projects that are consistent with the terms of the plan. Conversely, denying pre-approval to projects that are inconsistent with the plan properly leaves project risk with the utility.

2. Cost cap

Imposing a cost cap on the pre-approved amount limits the economic risk to ratepayers and shifts that risk to the utility. Similarly, some states have permitted the inclusion of CWIP or

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http://www.psc.state.fl.us/publications/pdf/pai/dsic4ww.pdf.

accelerated cost recovery only up to a defined dollar cap.[35] A cap can be set as a dollar amount or as a percentage of forecasted costs.

While a cap encourages utility cost-control measures, it can also have unintended and potentially adverse consequences. For example, a strict cap can induce the utility to cut corners or even abandon a project prematurely. Some regulators avoid this problem by making the cap a floor — *i.e.*, approving a cost level as prudent and leaving the utility free to argue for recovery of additional expenditures, if prudent. To protect ratepayers, the regulator might subject above-cap costs to some form of heightened scrutiny or require an enhanced demonstration of need and prudence before approving recovery.

3. Project must be near completion

Since pre-approval provides some cost recovery certainty, commissions may seek to ensure ratepayer benefits by implementing corresponding performance conditions. One approach is to limit pre-approval to projects that have a high probability of completion. An indicator of likely success is whether the project has met certain milestones.

The Oklahoma Commission authorized a rider for early recovery of the costs of a wind farm, providing a completion condition was met.[36] Similarly, a rider might be authorized only where the project will likely enter service within a short period of time (*e.g.*, six months). Or the commission (or the legislature) could require that a specified percentage of the costs of the project be incurred before the early recovery mechanism takes effect.[37]

4. Regulatory "oversight" of project activities

Where early cost recovery is authorized, the commission can keep track of the course of construction by requiring the utility to provide detailed status reports. The Florida Commission, by rule, requires utilities seeking current cost recovery for nuclear or IGCC plants to submit periodic reports on:

(a) the feasibility of finishing the plant;

(b) the technology selected by the utility including, but not limited to, a review of the technology and the factors leading to its selection;

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[35] *See*, *e.g.*, *Ariz. Pub. Serv. Co.*, Decision No. 54247, at 19-20 (Ariz. Corp. Comm'n 1984). In this case, the utility was rapidly accruing CWIP because of its construction of the Palo Verde nuclear power plant. The Commission allowed approximately $200 million of the utility's $600 million CWIP balance to go into rate base, before the plant was complete, to address the utility's cash-flow deficiency, and also to soften the rate increases that would occur if the entirety of the nuclear plant entered in rate base at one time.

[36] The condition was that at least 73 of the 80 contemplated required turbines had to be operational. *See In re Chermac Energy Corp.*, Order No. 524078, Nos. PUD 2005-00059, PUD 2005-00177 (Okla. Corp. Comm'n 2006).

[37] *See*, *e.g.*, Ohio Rev. Code. Ann. § 4909.15 (allowing the commission to approve CWIP in rate base if the plant is at least 75 percent complete, and the investment represents a defined percentage of the rate base).

(c) contracts executed in excess of $1 million, including the nature and scope of the work, the dollar value and term of the contract, the method of vendor selection, the identity and affiliation of the vendor, and current status of the contract;

(d) monthly expenditures incurred for major tasks performed within site selection, pre-construction and construction categories, and annual variance explanations, comparing the current and prior period to the most recent projections for those periods filed with the Commission; and

(e) monthly expenditures for major tasks performed within site selection, preconstruction and construction categories.[38]

5. Limit approval to specified investments

Some capital investments, such as pollution control equipment, are mandated by law. Where required by statute, and where no additional evidentiary showing is needed, the commission might grant pre-approval of cost recovery (at least up to a cap) or take other actions to reduce the risk of non-recovery.[39]

For example, Indiana's Environmental Compliance Plan Pre-Approval Act, Ind. Code § 8-1-27, allows the Commission to limit challenges to Commission-approved environmental compliance costs to issues of fraud, concealment or gross mismanagement. The Commission will grant pre-approval for these costs if they are part of an Environmental Compliance Plan that will "constitute[] a reasonable and least cost strategy over the life of the investment consistent with providing reliable, efficient and economical electric service."[40]

6. Preliminary project investments only

A commission (or legislature) may wish to encourage preliminary steps towards undertaking a capital project, while declining to commit ratepayer dollars to the full cost of the project before the completion of needed planning, investigation or engineering activities.

In 2008, the North Carolina Legislature enacted a statute providing for early recovery of so-called "project development" costs for potential nuclear power plants.[41] The legislation includes

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[38] Fla. Admin. Code Ann. r. 25-6.0423(5)(c)(5), (8)(b)-(e).

[39] These cases arise most frequently where a state requires the utility to file a pollution control or environmental compliance plan for commission review and approval. Such plans may include additions to infrastructure, as well as retrofits to existing infrastructure. Other examples are scrubbers on generators, leak detection programs for gas utilities, and treatment plants for water utilities, and post-9/11 security enhancements.

[40] The Florida Legislature enacted Section 366.93, Fla. Stat. § 366.93, providing early cost recovery for the siting, design, licensing, and construction of nuclear and integrated gasification combined cycle power plants.

[41] N.C. Gen. Stat. § 62-110.7 (effective January 2, 2008) states:

two conditions on recovery. First, the costs must be for preliminary activities in connection with a nuclear generating plant. Second, the costs must be incurred before certain dates or events have occurred. The statute also contains a non-exclusive list of examples of the types of activities that are included in the term "preliminary activities."[42]

The North Carolina Commission has approved Duke Power Company's requests for early approval of nuclear power development costs. The Commission approved a cost cap consistent with Duke's estimate of the costs it would incur in the relevant year for development efforts recoverable under the statute.[43] The Commission found that if Duke did not incur those expenses now, then long-lead time items needed to build the facility might not be available to Duke in a timely manner.[44]

7. Reduced ROE to reflect risk reduction

Some commissions have allowed early recovery where the utility's weakened financial condition would otherwise preclude projected completion or trigger certain specific adverse financial events, such as a bond rating reduction below investment grade, reduction in interest coverage ratios below a specified level, or insufficient cash flow to ensure adequate service.[45] In other cases, early recovery has been denied.[46] Any approval based on claimed financial weaknesses should be based on specific evidentiary showings, including the likelihood that the requested relief will alleviate the utility's financial problems.

> § 62-110.7. Project development cost review for a nuclear facility.
>
> (a) For purposes of this section, "project development costs" mean all capital costs associated with a potential nuclear electric generating facility incurred before (i) issuance of a certificate under G.S. 62-110.1 for a facility located in North Carolina or (ii) issuance of a certificate by the host state for an out-of-state facility to serve North Carolina retail customers, including, without limitation, the costs of evaluation, design, engineering, environmental analysis and permitting, early site permitting, combined operating license permitting, initial site preparation costs, and allowance for funds used during construction associated with such costs.

[42] As set out in the North Carolina statute, these can include the costs of evaluation, design, engineering, environmental analysis and permitting, early site permitting, combined operating license permitting, and initial site preparation costs, among others.

[43] These include: review by, and responses to, the NRC, purchases of land and rights-of-way, site preparations, project planning and engineering, and payments to fabricators to hold the utility's place in line for obtaining long-lead-time material and equipment such as reactor coolant pumps, containment vessel, reactor pressure vessel, steam generators, control rod drive mechanisms, and condenser circulating water piping.

[44] *In re Duke Power Co.*, 256 P.U.R.4th 215 (N.C. Utils. Comm'n 2007).

[45] In *Sierra Pacific Power Co.*, Docket No. 959, Order issued July 21, 1977, the Nevada Commission allowed SPCC to include CWIP associated with the Valmy generation project in rate base once the capital costs exceeded $27.7 million, in part on the theory that cash earnings would be higher quality earnings for the utility. In 1979, the Nevada Commission authorized SPPC to include $ 31.966 million of Valmy 1 and any common facilities CWIP in to rate base. *In re Nev. Power Co.*, No. 06-06051, 2007 Nev. PUC LEXIS 22, at *114-15 n.12 (Nev. Pub. Serv. Comm'n 2007).

[46] See Affiliated Interest Agreements (Pennsylvania Commission denies request for early approval and cost recovery where the estimated expenditure was no more than 15% of the total capital expenditures of the utility applicants over the next ten years).

Because pre-approvals reduce utility risk, commissions awarding some form of pre-approval cost recovery should consider whether a corresponding reduction in the utility's authorized return on equity is appropriate.

F. Criteria for Selecting among Pre-Approval Mechanism Options

As shown, a regulator considering some form of pre-approval commitment has many options. Indeed, even where the state legislature has already made certain choices, there will likely remain room for commission discretion.[47] We here offer criteria that a regulator may consider applying in making choices among competing options. The application of these criteria requires the regulator to match subjective concepts to the facts at hand.[48]

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[47] *E.g.*, Fla. Stat. § 366.93 (providing for cost recovery for certain changes relating to nuclear or IGCC plants, but leaving PSC free to "establish … cost recovery mechanisms.")

[48] The criteria are an outgrowth of questions developed by James Bonbright, and set forth in Principles of Public Utility Rates. Bonbright, *supra*, at 152-58, articulated five criteria for judging the appropriateness of a utility's rate:

1. The capital-attraction criterion: "[P]rinciples of rate control are best designed to permit well-managed, soundly financed public utility companies to attract needed capital."
2. The management-efficiency criterion: "[D]esigned, not just to enable a company to attract capital but also to reward efficiency and discourage inefficiency of management.
3. The rate-level stability criterion: "[W]hether or not an attempt to secure cyclical flexibility in the right direction is desirable and feasible remains a highly controversial question."
4. The consumer-rationing criterion: "[E]ach rate should be designed to encourage all consumption for which consumers are ready to pay escapable, marginal costs, and so as to deter any consumption for which consumers are not prepared to pay these costs."
5. The fairness-to-investors criterion: "Market acceptability may thus be thought to become, at one and the same time, the test of fairness and of corporate financial need….But…the principle is subject to serious qualifications…."

Bonbright (*supra*, at viii) noted the impossibility of meeting all five criteria at one time with any on rate-making approach:

> Reasonable public utility rates, like reasonable prices in general, are rates designed to perform with reasonable effectiveness multiple functions as instruments of social control. But a system of rates that would be best designed to perform any one of these functions is unlikely also to be the best that could be designed to perform any of the others. Hence, to a substantial extent, sound ratemaking policy is a policy of reasonable compromise among partly conflicting objectives.

Commissions and legislatures have added to Bonbright's list. *See, e.g.*, Michael Dworkin et al., *The Environmental Duties of Public Utility Commissions*, 18 Pace Envtl. L. Rev. 325 (2001). And *see* 2 Alfred E. Kahn, The Economics of Regulation xii (1971) (stating a regulatory goal of encouraging a utility to "engage in product or service innovation with an intensity" the same as its pursuit of efficiency).

1. Utility effectiveness criteria

(a) **Alignment of public and private interest:** The regulator should assess whether a proposed commitment will align the utility's commercial interest with the public interest. The utility must satisfy the multiple customer needs of reliable, safe and timely service at reasonable cost, while earning a reasonable return. Whatever pre-approvals are granted by the Commission should provide clear signals, in the form of both rewards and penalties, and should avoid conflicting messages. The regulator should consider whether pre-approval will promote broader objectives, such as construction of renewable resources.

(b) **Efficient utility management:** The regulator should consider whether granting the incentive will promote efficient utility management and discourage inefficient management. Will regulatory reduction of shareholder risk, through advance approval, reduce management's incentive to act cost-effectively? Conversely, if the regulator refrains from commitment, will the utility choose shorter-term, smaller, or more conventional projects over possibly more efficient but larger projects that involve greater risk?

(c) **Alignment of responsibility and risk:** Does the regulatory decision allocate responsibilities, risks, and benefits logically? Does it align decisional responsibility with management knowledge? Does the decision involve regulatory approval of a detailed, technical solution where the detailed regulatory knowledge is locked within utility management? Do the regulatory conditions involve the regulators so deeply in project management as to relieve the utility's project management experts of responsibility and risk? To the extent regulatory approval is conditioned on the commission oversight of the construction process, does the commission have the requisite technical expertise?

(d) **Sound planning and timely investment:** Will the decision encourage sound planning and timely investment? Some argue that the traditional regulatory practice of giving the utility no cost assurance until a plant is complete causes conservatism, lack of innovation, reliance on "what everyone else is doing." Others argue that the traditional practice, which includes not only no cost assurance but also no cost expectations, encourages a utility to overspend, because if the project cost is large enough, a "too big to fail" situation will pressure regulators to disallow no costs. Still others argue that without cost assurance upfront, the utility will tend to "wait until the last minute" to propose a project, in the hopes that the surrounding urgency will induce the regulator to approve the project for cost recovery without examining alternatives. All these tendencies, if the facts support them, deserve attention as regulators design approval methods. A useful approach is the integrated resource plan, approved well in advance of a project request, containing general guidelines about need, appropriate resources, and timing. A process allowing pre-authorization of a project consistent with a plan ensures two opportunities – the first one conceptual, the second one practical, to ensure utility effectiveness.

(e) **Access to capital:** How does the regulatory decision affect the utility's ability to attract necessary capital on reasonable terms? If the regulatory has refrained from promising cost recovery, will capital be available on reasonable terms? Conversely, if the commission has promised cost recovery, has the commission accurately reflected that risk reduction in the authorized return on equity?

(f) **Pre-approvals versus utility errors:** Is the request for a pre-construction commitment the result of utility errors or inappropriate delays? In other words, to what extent is the utility itself at fault for the need to consider a pre-approval commitment? Would granting the approval create a "moral dilemma" by rewarding (and encouraging for the future) sub-optimal practices?

2. Regulatory effectiveness criteria

(a) **Clarity:** "Pre-approval" encompasses a range of regulatory commitments. Choose your metaphor – palette of colors, symphony of sounds, tool chest of tools, algebraic equations with multiple variables – the regulator has choices about the level of certainty, the timing of decision, the depth of detail, and the intensity of oversight. Common to all the options is clarity: A regulatory commitment should be express as to its limits, thereby avoiding any later claim that the commission has "implicitly" approved recovery of subsequently-incurred costs.

(b) **Information and expertise:** A regulatory commitment can be no more detailed than the regulator's mastery of the details. In reaching a decision, the regulator should have access to information and expertise, including delaying or qualifying a decision, where feasible, until needed facts are available. Data concerns are increasingly prevalent as utilities operating in competitive markers have sought protection from public disclosure of cost data and other key information concerning proposed capital projects.

(c) **Timing affects information:** Pre-approvals are, by definition, approvals that precede knowledge about outcomes. In response to that informational gap, the regulator must focus its limited resources on a myriad of hypothetical concerns. Opponents of pre-approval object that this focus on hypotheticals produces less informed decisions than after-the-fact reviews: knowing the events that precipitated excess costs, the regulator can better assess management's handling of those facts. An argument against after-the-fact review is the risk that the regulator improperly imputes to utility management knowledge of facts that were not known when management made decisions.

(d) **Do precedents and consistency matter?** Regulatory statutes do not require identical, or even comparable, treatment of different projects. Provided the commission has a rational, evidentiary basis for each decision, treatments can vary, generally in accordance with material factual differences. But in sending signals to an investment community considering financing utility projects across four industries (electricity, gas, telecommunications, water), consistency has a value. The importance of consistency should be weighed against the need to address individual projects on the basis of the specific facts that are presented. Amplifying this tendency are legislative enactments that single out a particular industry, or even a particular expenditure, for pre-approval opportunity.[49]

(e) **Post-approval oversight:** How deeply does the regulatory commitment involve the commission in project oversight? Is the commitment an efficient use of commission resources? Does the commission possess the technical resources to monitor and enforce its conditions? Will

[49] *See* earlier discussions of Fla. Admin. Code Ann. r. 25-6.0423; and N.C. Gen. Stat. § 62-110.7.

the commission need to curtail other regulatory activities to free up the necessary resources? Will the utility cooperate in the commission's efforts to obtain the necessary resources?

3. Rates criteria

(a) **Economic efficiency:** Prices that reflect the cost of consumption induce consumer and producer behavior that maximizes benefits for the economy. In choosing the timing and type of pre-approval, and the method of cost recovery, regulators should seek rate solutions that send proper price signals.

(b) **Gradualism:** Sudden jumps in rates for a commodity product produced through large fixed costs with long lives make customers skeptical of the sellers and the regulators. Methods of pre-approval and cost recovery that give weight to gradualism without distorting economic efficiency deserve regulatory attention.

(c) **Investor risk:** As discussed throughout this paper, pre-approval is about identifying and allocating risk of uneconomic results. More sophisticated but clearer methods and procedures for calibrating the proper debt-equity ratios and authorized returns on equity for various types of pre-approvals may be necessary. This is an area deserving additional research.

(d) **Intergenerational equity:** Will the regulatory decision create a cost-benefit mismatch among generations of ratepayers? Early cost recovery requires customers taking service during the period of construction work in progress to pay for plant investments, the use of which they may never enjoy, or will enjoy for only part of the project's life. It also means that customers paying towards the investment during the construction period may pay more for the plant than customers who paid nothing during the construction, even if they are on the system for the same length of time. Yet this problem is not unique. A city collects taxes from today's parents for buildings that will benefit future students. Taxpayers pay today for mass transit projects that will benefit tomorrow's riders. Intergenerational equity need not be a requirement for each project if there is intergenerational sharing overall.

III. Application of the Framework to Hypothetical Examples

The criteria and other considerations addressed in Sections I and II are summarized in a chart entitled, "Pre-Approval: Options and Considerations," which is appended to this paper.

Here we illustrate how these criteria/considerations can be applied in the context of three hypothetical situations that may come before a state commission. We do not examine these examples to explain how they should be resolved. Our purpose is to identify the types of questions and considerations that may be weighed in deciding whether to provide some form of pre-approval, including cost recovery authorization. Specific answers will depend on the specific facts at issue and the weight commissions give to different considerations in the particular circumstances.

A. Example #1: A relatively small water utility seeks pre-approvals in connection with a relatively large — but otherwise routine — investment

Assume that a small water utility is required by statute or regulation to undertake a relatively large capital investment. The investment concerns a program that, while substantial for the utility, is routine for the industry. An example could be the development of a leak detection and mitigation program, which may include the removal and repair or replacement of a large portion of the utility's underground plant. The utility asserts that it needs upfront assurances that would not be available under the traditional approach of cost recovery after-the-fact.

The small utility might request two kinds of pre-approvals: one involving cost recovery and one involving approval without addressing cost recovery. An example of the former would be the utility arguing that it has no access to the level of financing required to complete the project, and that it cannot proceed absent assurance of contemporaneous cost recovery. An example of the latter would be seeking the regulator's blessing of the proposed program as a prudent course of action. Given the commission's statutory obligation to support any decision with substantial evidence, it must require that the utility document the specific challenges. If a utility wants advance approval, it must demonstrate that the program is the best option available. Identifying a statutory mandate, state or federal, would serve this purpose if the mandate specifies the solution.

The commission will need to consider whether conditions should be imposed on pre-approval, including these questions:

- Should the pre-approval, if granted, be contingent on the receipt of periodic progress reports?

- Should any cost recovery be capped at no more than the estimated price tag for the program? Should that cap be a hard cap, or one that the commission can raise or lower depending on future facts?

- Does the small utility have the technical resources sufficient to undertake a major capital project? If not, should the commission condition pre-approval on the utility procuring engineering and project management assistance? To what extent should or must the commission become involved in monitoring project progress? [50]

- Will a pre-approval aimed at shifting regulatory risks involve other associated adjustments? For example, should the utility's return on equity be adjusted if assurances are provided that result in changes in the utility's risk profile?

Each of these questions have a common theme: cost-benefit analysis. The commission should be satisfied that the risks associated with providing approvals in advance — including the constraints on the commission's ability to take action after the fact because of approvals granted

[50] To the extent the commission is involved in monitoring progress, the commission staff or an outside consultant will have to examine the progress of the project, measure it against whatever standards are available, and help the commission render a judgment as to whether the job is being done adequately.

before-the-fact — are outweighed by the benefits derived from the timely implementation of the infrastructure upgrade. Then the commission should ensure that those benefits arrive.

B. Example # 2: A utility with reasonable access to capital seeks pre-approvals in connection with a routine investment

In this example, the utility has ready access to capital on reasonable terms, and the needed capital project presents few new or unusual challenges. Unlike the first example, there is no reasonable claim that, absent pre-approvals, the project cannot be financed. As in the first example, the project will provide substantial benefits for customers, assuming efficient implementation.

The utility here seeks the same two types of pre-approvals: one that directly involves cost recovery and one that does not. For the pre-approval that does not directly involve cost recovery, the utility must demonstrate that its selected project is the best feasible option.

As to pre-approval of cost recovery, the utility's access to capital requires assessment of at least the following issues:

- The utility can make the investment without a pre-approval commitment. One question is whether pre-approval of cost recovery will lower the cost of capital while having no effect on management's incentive to act efficiently.

- The commission can address the efficiency issue directly by considering whether any advance authorization should be capped at the estimated cost of the project and, if so, whether the cap is hard (no later adjustments) or soft (later adjustments, up or down, possible based on fact changes). If the authorization is entirely "upside" for the utility, it may lack sufficient incentive to manage the project efficiently.

- As in the first example, the commission might consider conditioning cost recovery commitments on the submission of periodic project status reports. Continued regulatory supervision should encourage management to conduct construction of the project in a cost-efficient manner. Moreover, regulatory oversight can readily catch and prevent glaring inefficiencies and errors, especially as concerns routine infrastructure repair and replacement projects.

- The commission should consider why a utility with access to capital needs pre-approval of cost recovery. Is the utility seeking pre-approval to rectify prior management neglect? Was this project, for example, something that should have been pursued several years ago? Is early approval and cost recovery in such situations merely a reward to a utility that may have unreasonably delayed making necessary repairs and improvements to its system? To the extent there is evidence of management imprudence, the commission might consider combining early approval and cost recovery with reductions to the allowed return on equity to reflect (a) the lower risk to the utility where its costs are approved or recovered before project completion, as well as (b) management imprudence in delaying necessary investments.

C. *Example #3: A utility seeks pre-approvals in connection with a risky and discretionary investment intended to serve its customers*

In this example, a utility seeks pre-approvals in connection with a potentially risky capital project, such as a nuclear plant or "clean coal" facility that is needed to meet load (but for which there are other more conventional, proven technology options). The utility might be pursuing this option in a partnership, thereby spreading the risk.[51] Given the uncertain nature of project costs and timelines, it will be difficult for the commission to marshal sufficient facts to support upfront cost recovery. And the request for approval might not involve cost recovery directly, but might still have substantial cost recovery implications (*e.g.*, a determination that the decision to build a nuclear plant instead of pursuing other options is "prudent"), as well as daunting cost recovery requests (*e.g.*, recovery of planning costs, or costs to maintain the project as an option that could be pursued on a timely basis).

If the commission believes the utility would pursue this risky investment absent some form of pre-approval, there is not a clear basis for commission assistance. But if the project could benefit ratepayers yet is too uncertain for the utility to bet its own money, the commission faces a hard question: To what extent should it devote ratepayer money to experiments where, in the absence of ratepayer commitment, the experiments will not occur? To insist on never betting ratepayer money is to risk continued dependence on yesterday's technology. While new technologies can receive stimuli from Congressional authorizations, universities and ratepayer-funded joint research organizations like the Electric Power Research Institute, the involvement of local utilities and their state commissions can also influence technological development. Still, in these situations, the commission can insist that the utility first seek private sources.[52]

A commission may be asked to bless a potentially risky option as a "prudent" choice under the circumstances. This determination will involve both evidentiary showings and policy considerations. The resources identified as potential means to meet forecasted electricity needs for electricity, including energy efficiency, are all characterized by some level of uncertainty. The public may or may not prefer to take on the uncertainties of future carbon mitigation costs, generation construction cost overruns, safety and health consequences, and other risks affecting nuclear and IGCC generation, rather than the uncertainties as to the extent of achievable energy efficiency, or cost-competitive renewable power. Either way, and absent express intervention by the legislature, in addressing a pre-approval proposal, the commission will have the responsibility to make a policy call.[53]

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[51] On the regulatory treatment of joint venture investments in demonstration projects, see S. Hempling, *Joint Demonstration Projects: Options for Regulatory Treatment*, 21 Electricity J. 30, 30-40 (2008).

[52] The mere fact that such projects are estimated to have very high costs does not necessarily render them incapable of attracting private capital. Paul D. Phillips et al., *Financing the Alaskan Project: The Experience at SOHIO*, 8 Fin. Mgmt. 7, 7-16 (1979).

[53] Analysts have observed the somewhat symbiotic relationship at issue in the context of large and risky capital projects, highlighting the need for ratepayer support of such projects in order for the financial markets to make investments in such technologies. *See*, *e.g.*, Ellen Lapson, Managing Director, Utilities, Power & Gas, FitchRatings, Construction of Coal-

Depending upon the evidence, a regulator could determine that the decision to go forward with an expensive and risky generation option was not the product of sound planning, and that the plant was not needed to serve the public. Utilities proposing nuclear, IGCC, and similar plants will presumably have the expertise, staff, and external resources needed to carry out forecasting, construction management, commissioning, and operation of the plants. Compared to the huge firms involved in nuclear and IGCC plant development, regulators will lack sufficient resources to make the myriad decisions involved in the development process. Thus, additional (internal and external) resources may be needed to conduct extensive reviews of such utility proposals. Of course, this concern is not unique to pre-approvals and would be equally applicable present under the traditional approach.

Even where the commission restricts early approval and cost recovery to pre-construction costs, or to costs incurred within a single year, such decisions must be drafted carefully to avoid to constraining subsequent decision-making flexibility. If, for example, the commission is limiting recovery to "preliminary" or "pre-construction" costs, it must define these terms tightly. For emphasis, the commission could consider including in its approval order a specific definition and/or an express dollar amount.

Unlike routine infrastructure replacements, nuclear and IGCC projects (for example) are enormously complicated undertakings, dealing with technologies that may still be in experimental phases. In such circumstances, the commission must retain the flexibility to address changing conditions. This can be accomplished in part by requiring periodic reports from the utility and by retaining staff with sufficient technical expertise to review them and to advise the regulator. However, and as mentioned earlier, care should be taken to make clear that the provision and review of reports does not leave the commission in the role of supervising day-to-day project construction activities.

Fired Generation: Evaluating the Utility Credit Implications, Presentation Before the National Association of Regulatory Utility Commissioners (July 17, 2007) (presentation available at http://www.narucmeetings.org/Presentations/Construction%20of%20Coal-Fired%20Generation.ppt); Michael Degernes, Aberdeen Asset Management, Integrated Gasification Combined Cycle: Financing the Next Generation of Coal Plants, Presentation Before the Oregon Advanced Coal Workshop (May 24, 2006) (presentation available at http://www.oregon.gov/PUC/meetings/pmemos/2006/052406/Degernes.pdf); Kevin Genieser, Managing Director, Morgan Stanley, Putting Capital to Work to Achieve CO_2 Reduction¸ Presentation before the Electric Power Research Institute (Aug. 7, 2007) (presentation available at http://mydocs.epri.com/docs/SummerSeminar07/Presentations/EPRI_Summer_Seminar_07_Geneiser.pdf); and Ari Kagan, Director, Global Power Group, FitchRatings, Presentation Before the National Association of Regulatory Utility Commissioners Energy Resources and the Environment Committee: Credit Rating: Issues Associated with Nuclear Investment (July 27, 2005) (presentation available at http://www.narucmeetings.org/Presentations/ERE_Kagan_s05.pdf).

IV. Conclusions: Recommendations for Regulators

This paper has examined options a regulator can consider when faced with a "pre-approval" request — *i.e.*, an upfront request for approval of a utility's proposed course of conduct or for rate recovery of the costs that it plans to incur. The purpose of the paper has not simply been to provide a catalogue or description of potential options, though such a listing can be quite useful. The larger purpose has been to identify the considerations that the regulator should take into account before moving forward with any form of in-advance – rather than after-the-fact — approval of utility actions or costs.

The advice presented in this paper can be summarized as follows:

Where empowered to do so, the regulator can consider breaking from the traditional approach to rate recovery and shifting toward the provision of some in-advance security to the utility. That security can take many forms, including rulings that an option is prudent, that pre-construction costs can be recovered in rates, or that some of the costs to be incurred in constructing a project can be included in rates, on either a contemporaneous or post-completion basis. Any of these approaches involve some upfront shifting, from regulated utilities to ratepayers, of the risks associated with implementing a major capital project. Thus, in considering such approaches, the regulator should ensure that:

- Any pre-approvals are granted only upon a supported showing that regulatory action will benefit customers.

- Regulatory actions are based on full review of the relevant facts. For example, if a utility seeks the commission's blessing that a particular project is "prudent," require the applicant to explain why other options were rejected (and not simply why the applicant's option is appropriate).

- Whatever regulatory action is taken is appropriately limited or conditioned. Approval of an option as a "prudent" choice is not the same thing as approving the inclusion in rates of whatever dollars are expended to pursue it. Approving the recovery of "preliminary" or "planning" costs should not construed as approving the recovery of later-incurred dollars. The key is to be certain that regulator flexibility and discretion are retained to the greatest extent possible.

- The regulator has adequate resources to conduct appropriate reviews of whatever is requested. The commission will need assured access to sufficient technical resources if it is inclined to consider the request of a utility seeking, for example, a determination that building a new nuclear plant is a "prudent" response to the need for new capacity.

- Roles remain properly defined. For example, while it may be appropriate to require that a utility provide periodic reports on the progress of a construction project, the regulator's oversight should not leave it as the party with responsibility for managing the project.

- Consideration is given to offsetting adjustments. If pre-approval will reduce the utility's going-forward risk profile, consider whether an adjustment to the utility's return on equity should be ordered in connection with whatever pre-approval is granted.

Figures 1 and 2

-

Figure 1

Pre-Approval:
Options and Considerations

What utility action is being proposed?

- Forecast customer requirements
- Incur specific pre-commitment costs
- Commit to a project and initiate construction
- Continue construction
- Change project plan
- Abandon project

For each proposed action:

What are possible regulatory commitments?

- Approve for purposes other than cost recovery (e.g., financing, siting)
  - What are the purposes of these regulatory actions?
  - Does an approval action constrain the commission's future recovery decisions?
- Approve for purposes of cost recovery, with varying certainty
- Approve deferral of costs for later consideration

When might a regulator make a commitment?

- Before utility commits to any costs
- At one or more points in time during construction
- After the project has entered commercial operation

At what points in time, and over what time period, might cost recovery occur?

- As incurred (monthly)
- As incurred (annually)
- Upon commercial operation

What cost recovery devices are available?

- CWIP
- Riders, surcharges, and "single-issue" rate increases
- Formula rates
- Securitization

What conditions might the commission impose?

- Consistency with regulator-approved resource plan
- Cost cap
- Project must be near completion
- Regulatory oversight of project activities
- Limit approval to specified investments
- Preliminary project investments only
- Reduced ROE to reflect risk reduction

-

Figure 2

Pre-Approval:
Options and Considerations

Utility Effectiveness

- Alignment of public and private interest: Is the utility's interest aligned with the public interest in all relevant respects?
- Efficient utility management: Will the proposed regulatory action (or inaction) add (or subtract) certainty; to what extent, if any, will the utility have less incentive to act cost□effectively?
- Alignment of responsibility and risk: Does the approval allocate responsibilities, risks and benefits logically?
- Sound planning and timely investment: Will the decision encourage sound planning and timely investment?
- Access to capital: Will the decision allow the utility to attract necessary capital on reasonable terms?
- Pre-approvals versus utility errors: Would granting the approval create a "moral dilemma" by rewarding (and encouraging for the future) suboptimal practices?

Regulatory Effectiveness

- Clarity: Is the regulatory commitment express as to its limits, thereby avoiding any later claim that the commission has implicitly approved recovery of subsequently-incurred costs?
- Information and expertise: Does the regulator have effective access to the information and expertise necessary to make an appropriate decision?
- Timing affects information: To what extent does a pre-approval require the regulator to focus on hypotheticals and produce decisions based on imperfect information?
- Precedents and consistency: Will the regulatory decision create a precedent favoring a particular type of action and disfavoring others?
- Post-approval oversight: Does the regulatory action make efficient use of commission resources?

Rates

- Economic efficiency: What rate solutions will send proper price signals?
- Gradualism: Does the decision avoid unnecessary jumps in rate levels?
- Intergenerational equity: Will the regulatory decision create a cost□benefit mismatch among generations of ratepayers?

General Concerns

- Has the utility demonstrated that a pre-approval will benefit customers?
- Is the decision based on a full review of relevant facts?
- Is the regulatory action appropriately limited or conditioned?
- Does the regulator have adequate resources to conduct appropriate reviews of whatever is requested?
- Are the roles of the utilities and the regulator properly defined?
- Are there any offsetting adjustments that should be made?

-

Exhibit 19 - 2001 Vermont Judiciary Statistics re: felony jury trials in Chittenden County

DC - TABLE 1

DISTRICT COURT OF VERMONT
SUMMARY
For Year Ending June 30, 2001

Type of Case	Pending Start of Year	Added During Year	Reopened During Year	Disposed During Year	Adj.	Pending End of Year	Change in Pending	% Change in Pending
CRIMINAL	**10,642**	**18,862**	**119**	**19,508**	**12**	**10,127**	**-515**	**-4.8%**
Felonies	2,696	3,215	28	3,280	-34	2,625	-71	-2.6%
Misdemeanors	7,946	15,647	91	16,228	46	7,502	-444	-5.6%
CIVIL SUSPENSION	**299**	**1,830**	**28**	**1,940**	**53**	**270**	**-29**	**-9.7%**
TRAFFIC	**26**	**278**	**43**	**298**	**0**	**49**	**23**	**88.5%**
TRAFFIC APPEALS	**80**	**156**	**3**	**180**	**0**	**59**	**-21**	**-26.3%**
SNOWMOBILE/ BOATING AND FISH & GAME	**104**	**273**	**0**	**285**	**3**	**95**	**-9**	**-8.7%**
TOTAL	**11,151**	**21,399**	**193**	**22,211**	**68**	**10,600**	**-551**	**-4.9%**

DC-Table 2

DISTRICT COURT OF VERMONT
COMPARISON OF CASES ADDED AND PENDING
For Year Ending June 30, 2001

COURT Type of Case	Cases Added* during Quarter Ending: 6/30/00	6/30/01	Cases Added* during Year Ending: 6/30/00	6/30/01	Cases Pending as of 6/30/00	6/30/01
ADDISON						
Felonies	30	26	110	111	65	75
Misdemeanors	256	164	875	690	319	283
Civil Suspension	16	24	67	64	6	12
Traffic	0	0	1	1	0	0
Traffic Appeals	0	2	12	8	0	2
Fish & Game	8	8	48	32	16	16
TOTAL	310	224	1,113	906	406	388
BENNINGTON						
Felonies	54	55	228	217	211	260
Misdemeanors	332	251	1,338	1,050	562	650
Civil Suspension	34	19	102	92	12	8
Traffic	3	9	7	19	2	3
Traffic Appeals	4	2	4	4	2	4
Fish & Game	5	1	11	5	0	0
TOTAL	432	337	1,690	1,387	789	925
CALEDONIA						
Felonies	41	38	161	135	91	78
Misdemeanors	243	213	1,131	817	396	307
Civil Suspension	12	20	78	66	14	8
Traffic	1	1	7	15	0	1
Traffic Appeals	3	3	7	6	3	2
Fish & Game	1	0	19	7	4	4
TOTAL	301	275	1,403	1,046	508	400
CHITTENDEN						
Felonies	326	286	1,173	1,139	932	885
Misdemeanors	1150	1133	4,948	4,565	2,274	2,125
Civil Suspension	112	140	522	509	57	94
Traffic	9	26	27	76	4	20
Traffic Appeals	74	0	90	70	15	16
Fish & Game	31	15	36	22	31	24
TOTAL	1,702	1,600	6,796	6,381	3,313	3,164

* Includes new filings and reopened cases

DC - Table 3 (e)

DISTRICT COURT OF VERMONT
FELONY CASE DISPOSITIONS
For Year Ending 06/30/01

	CONVICTION				DISMISSAL/ACQUITTAL					TRANSFERRAL		
	Plea to	Plea to	By Trial		Dismissed		Diversion	By Trial		Juv.	Change	
Court	Felony	Misd.	Jury	Court	by State	by Court	Complete	Jury	Court	Court	of Venue	TOTAL
Addison	62	8	0	0	18	3	4	1	0	0	1	97
Bennington	103	36	6	0	13	1	5	1	0	0	2	167
Caledonia	105	28	0	0	8	0	5	0	0	0	0	146
Chittenden	503	356	19	2	191	36	33	4	1	6	5	1,156
Essex	23	5	0	0	1	0	0	0	0	0	0	29
Franklin	128	106	4	0	71	9	3	4	0	1	1	327
Grand Isle	7	11	0	0	2	2	0	0	0	0	2	24
Lamoille	71	31	0	0	15	4	6	2	0	0	1	130
Orange	32	13	2	0	13	1	6	0	0	1	3	71
Orleans	67	36	3	0	7	11	1	0	0	0	2	127
Rutland	167	50	3	1	34	4	13	1	0	1	3	277
Washington	121	48	3	1	21	3	13	0	0	2	2	214
Windham	144	63	10	0	33	7	14	3	0	2	2	278
Windsor	86	100	0	1	32	2	9	2	0	2	3	237
Total	**1,619**	**891**	**50**	**5**	**459**	**83**	**112**	**18**	**1**	**15**	**27**	**3,280**

DC - Table 3 (f)

DISTRICT COURT OF VERMONT
MISDEMEANOR CASE DISPOSITIONS
For Year Ending 06/30/01

	CONVICTION				DISMISSAL/ACQUITTAL					TRANSFERRAL		
	Plea by	Plea in	By Trial		Dismissed		Diversion	By Trial		Juv.	Change	
Court	Waiver	Court	Jury	Court	by State	by Court	Complete	Jury	Court	Court	of Venue	TOTAL
Addison	15	472	1	0	93	9	128	3	0	1	8	730
Bennington	26	772	6	6	66	2	75	5	2	2	0	962
Caledonia	202	483	4	1	78	58	70	1	2	2	3	904
Chittenden	158	2,666	10	5	1,372	154	336	2	1	33	11	4,748
Essex	3	94	4	2	3	3	7	0	0	0	0	116
Franklin	163	744	2	4	385	51	57	3	1	7	1	1,418
Grand Isle	3	64	2	0	23	2	3	2	0	0	0	99
Lamoille	54	376	0	1	72	33	110	0	0	2	0	648
Orange	27	241	1	1	71	3	40	1	0	1	1	387
Orleans	61	433	0	1	91	66	53	2	0	1	10	718
Rutland	38	838	3	2	246	9	171	1	0	3	6	1,317
Washington	66	895	1	1	109	11	151	1	0	1	2	1,238
Windham	342	641	3	1	224	51	197	6	2	9	5	1,481
Windsor	264	695	0	2	267	29	190	2	0	6	7	1,462
Total	**1,422**	**9,414**	**37**	**27**	**3,100**	**481**	**1,588**	**29**	**8**	**68**	**54**	**16,228**

<u>Exhibit 20</u> - GMP Schedules August 1, 2016 – includes summary of resolution of issues raised in negotiations – pp. 114-119, 2016 "global agreement."

Schedule I

Green Mountain Power Corporation
Fiscal Year (FY) 2017 Total Rate Impact

$ in 000's	Revenue Deficiency	Rate Impact
FY 2017 Change in Base Rates	$ (142)	-0.03%
FY 2017 Power Supply Adjustor	$ 5,342	0.96%
	$ 5,200	0.93%

FY 2017 Change in Base Rates will apply to all rate classes starting October 1, 2016, except for the Transmission Class customer. The change includes a 9.02% allowed rate of return, which reflects the formulaic result associated with mid-July 10-year Treasury Bond rates. Please note that Base Rates include the second year of the two-year Exogenous Change Adjustment collection. This adjustment, consisting primarily of the Major Storm Adjustment of $15.2 M for the period October 1, 2014 through March 31, 2015 offset partially by application of the Vermont Yankee Revenue Sharing proceeds of $7.9 M, results in a collection of $3.1 M in FY 2017.

FY Power Adjustor includes recovery of an under-collection of $5.3 M for the period April 1, 2015 to March 31, 2016.

BASE O&M CALCULATION
2017 Base Rate (filed August 1, 2015)

Prior Year Base O&M Costs	$	120,703,671
CPI-U Northeast Adjustment[1]	$	724,223
Current Year Base O&M Costs	$	121,427,894

[1] Based on latest available report as of April 30

Description of 2017 Non-Base O&M Costs – Support Schedule I(B-1)

The purpose of this document is to discuss the following components of the 2017 Cost of Service:

Rate Year 2017 COST OF SERVICE - $ in 000s	PER BOOKS BALANCES (1)	ADJUSTMENT COL3-COL1 (2)	PROFORMA BALANCES (3)
Non Base O&M Costs - AMI	1,935	(1,193)	742
Non Base O&M Costs - KCW	930	27	957
Non Base O&M Costs - VMPD	263	(150)	113
Non Base O&M Costs - 7496 MOU	0	0	0

These costs are considered O&M in nature, but are not included in the platform. Please note that in addition to platform costs and the non-base O&M costs shown above, the company's internal generation costs are found in the "Production" line of the summary cost of service.

Non-Base O&M Costs – AMI -These are costs associated with the implementation of SmartMeters within the GMP territory. While the Test Year value of $1.935 MM is spending associated with SmartMeters, the Rate Year value of $0.742 MM also contains a netting effect due to savings resulting from the adoption of this technology. The 2017 savings of $1.566 MM reflect costs originally embedded within the 2013 platform –adjusted by the platform inflation - that have been eliminated due to the implementation of AMI. The 2017 Rate Year spending for AMI is $2.307 MM. The change between the Rate Year value of $2.307 MM and the Test Year value of $1.935 MM is due largely to an infrastructure buildout-associated amortization of $0.266 MM in FY17 that began in April, 2016.

Non-Base O&M Costs – KCW - This line represents costs associated with the synchronous condenser built to support the Kingdom Community Wind Farm. Per an agreement with the DPS, GMP has moved some KCW-related expenses from the Production line in the Cost of Service to this non-platform, non-Power Supply Adjustor line. The increase of $0.027 MM from $0.930 MM in the Test Year to $0.957 MM in the Rate Year reflects those DPS agreement-affiliated expenses that were embedded in the Production Test Year that were then moved to this line in the Cost of Service.

Non-Base O&M Costs – VMPD – This line represents costs associated with tree trimming to reclaim the entire Danby transmission line from Huntington Falls to Danby Quarry.

Non-Base O&M Costs – 7496 MOU – No longer applicable.

Exh. EFR-5

GREEN MOUNTAIN POWER CORPORATION

SUMMARY OF REVENUES UNDER CURRENT AND PROPOSED RATES

RATE YEAR OCTOBER 1, 2016 - SEPTEMBER 2017

-0.03%

	AVERAGE NO OF CUSTOMERS	KWH SALES	REVENUE AT CURRENT RATES	REVENUE AT PROPOSED RATES	DIFFERENCE	PERCENT INCREASE
Residential	221,698	1,482,869,239	$253,479,926	$253,415,556	($64,370)	-0.03%
Small Commercial & Industrial	41,054	1,551,016,166	220,572,870	$220,516,857	(56,014)	-0.03%
Large Commercial & Industrial						
Other Large	70	783,844,005	80,968,762	$80,948,200	(20,562)	-0.03%
Transmission Class	1	399,012,519	35,681,000	35,681,000	-	0.00%
Total Large C& I	71	1,182,856,524	116,649,762	116,629,200	(20,562)	
Street Lighting and Other	160	5,064,681	2,742,337	$2,741,641	(696)	-0.03%
Total Retail Sales	**262,983**	**4,221,806,611**	**$593,444,895**	**$593,303,253**	**($141,642)**	**-0.03%**

GREEN MOUNTAIN POWER CORPORATION
Calculation of Rate Increases
$ in 000's

Total Cost of Service to Ultimate Consumers		593,303
Remove VY Outage Reserve Impact:		0
Net Cost of Service for Non-Transmission Class Consumer:		593,303
Revenue from Ultimate Consumers		593,445
Transmission Class	35,681	
All Other Classes:	557,764	
	593,445	

Total Cost of Service to Ultimate Consumers	593,303
2017 Transmission Class Revenue:	$35,681
Total Cost of Service for Non-Transmission Class Customers:	557,622
Total Revenue from Non-Transmission Class Customers (2016 Rates)	557,764
Revenue Deficiency from Non-Transmission Class Customers:	(142)
Rate Increase for Non-Transmission Class Customers	**-0.03%**

Check:

593,303 Total Cost of Service to Ultimate Consumers

	35,681	=	Transmission Class Revenue at 2016 Rates.
	0.00%	=	FY 2017 Rate Increase
35,681	35,681	=	FY 2017 Transmission Class Revenue
	557,764	=	Non-Transmission Class Revenue at 2016 Rates.
	-0.03%	=	FY 2017 Rate Increase
557,622	557,622	=	FY 2017 Non-Transmission Class Revenue

593,303 = Total FY 2017 Revenue

0 = Difference

Knowledge to Shape Your Future

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Green Mountain Power
2017 Budget Forecast Report

Prepared for:

Green Mountain Power

Prepared by:

Itron, Inc.
20 Park Plaza
Boston, MA 02116-4399
617-423-7660

July 28, 2016

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2017 BUDGET FORECAST: FORECAST SUMMARY

The 2017 budget-year forecast was completed in June 2016. The forecast is based on actual sales and customer data through May 2016. The forecast has also been updated to reflect the February 2016 state economic outlook, current energy efficiency program savings projections from Vermont Energy Investment Corporation (VEIC), updated solar load projections, and expected increase in heat pump saturation as a result of VEIC and GMP promotion of cold climate heat pumps.

Sales forecasts are generated at the customer class level and include residential, commercial, industrial and street lighting. Class level sales forecasts are then allocated to rate schedules and billing determinants for the purpose of estimating revenues. Sales, customers and revenues are projected through 2026.

The sales and customer forecasts are based on statistical models (linear regression) that relate monthly class sales (average use in the residential sector) to monthly weather conditions, population growth, economic activity, prices and end-use efficiency improvements. The sales forecast is adjusted for factors not reflected in historical data including expected changes in energy requirements for the largest commercial and industrial customers, solar load penetration, and cold climate heat pumps. Impact of future efficiency programs are incorporated into the end-use intensity projections that drive the class sales forecasts. Over the next 10-years, sales are expected to be flat. Table 1 shows the customer class sales forecast.

Table 1: Customer Class Sales Forecast (MWh)

Year	Residential	Chg	Commercial	Chg	Industrial	Chg	Other	Chg	Total	Chg
2016	1,480,023		1,528,335		1,172,925		5,096		4,186,379	
2017	1,482,869	0.2%	1,551,016	1.5%	1,182,857	0.8%	5,065	-0.6%	4,221,807	0.8%
2018	1,468,375	-1.0%	1,557,717	0.4%	1,189,175	0.5%	5,065	0.0%	4,220,332	0.0%
2019	1,452,155	-1.1%	1,561,728	0.3%	1,193,493	0.4%	5,065	0.0%	4,212,440	-0.2%
2020	1,428,216	-1.6%	1,563,121	0.1%	1,193,583	0.0%	5,065	0.0%	4,189,985	-0.5%
2021	1,407,962	-1.4%	1,560,101	-0.2%	1,192,359	-0.1%	5,065	0.0%	4,165,488	-0.6%
2022	1,400,397	-0.5%	1,562,887	0.2%	1,192,341	0.0%	5,065	0.0%	4,160,689	-0.1%
2023	1,396,486	-0.3%	1,567,415	0.3%	1,192,705	0.0%	5,065	0.0%	4,161,671	0.0%
2024	1,397,923	0.1%	1,573,504	0.4%	1,192,537	0.0%	5,065	0.0%	4,169,029	0.2%
2025	1,394,753	-0.2%	1,575,381	0.1%	1,192,316	0.0%	5,065	0.0%	4,167,515	0.0%
2026	1,396,384	0.1%	1,580,843	0.3%	1,192,458	0.0%	5,065	0.0%	4,174,750	0.2%
16-26		-0.6%		0.3%		0.2%		-0.1%		0.0%

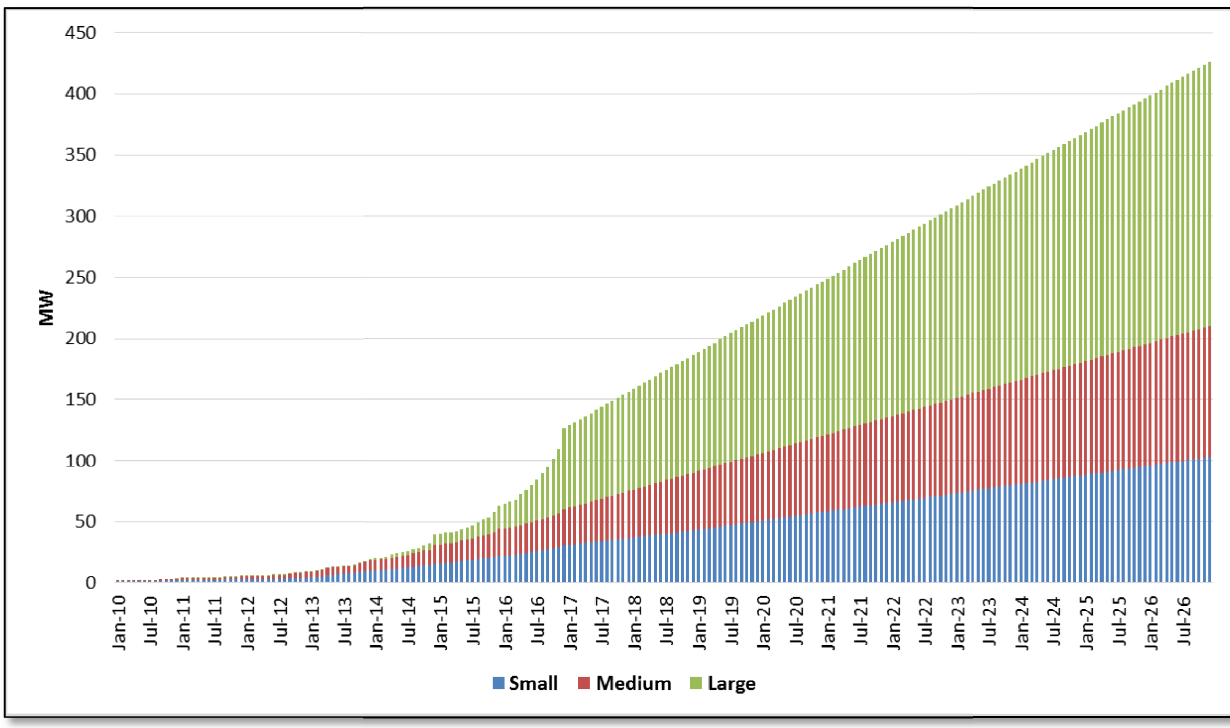
* All sales forecasts are on a "booked" or calendar-month basis by fiscal-year (Oct to Sep).

While customers have averaged 0.5% annual growth since 2005, sales have averaged 0.2% decline. This implies that average customer use has been declining 0.7% per year. This strong decline in customer usage is largely the result of improvements in end-use efficiency due to new standards and aggressive state-wide energy efficiency activity.

One of the most significant factors impacting sales is the growth in net metering. GMP is experiencing a sharp increase in PV installations, driven by declining solar system costs, extension of federal tax incentives, and GMP rate incentives.

Figure 1 shows net metering capacity projection by system size category. Between 2010 and the end of 2015, total net metering capacity has increased from virtually nothing to over 60 MW of installed capacity. Given current permits and activity level, an additional 60 MW is expected to be installed in 2016, doubling the total installed solar capacity.

Figure 1: Historical and Projected Net Metering Capacity



1. Class Sales Forecast

Monthly customer-class sales and customer forecasts are based on regression models that relate monthly sales to population projections, economic conditions, weather, price, and changes in end-use energy intensities. Models are estimated with monthly billed sales and customer counts from January 2006 to May 2016.

The forecast is based on Moody's Analytics February 2016 state economic forecast, price projections (with an assumption of flat real prices), and the Energy Information Administration (EIA) end-use intensity projections for New England. End-use intensity projections are adjusted to reflect end-use saturations for Vermont and state-wide energy efficiency (EE) program savings projections. EE savings projections are provided by VEIC and are based on the VEIC's current funding level. The EIA's New England heat pump saturation forecast is also adjusted upwards to reflect expected growth in heat pumps as part of VEIC and GMP's efforts to promote adoption of cold-climate heat pumps in homes whose primary heating fuel is propane or heating oil.

Class sales forecasts, which are derived from the statistical models, are adjusted for expected net metering impacts, and other large exogenous load changes based on the expected activity of specific large customers.

Residential

Residential customer average use has been trending downward for the last ten years. Since 2005, weather-normalized annual average use has declined from 7,650 kWh per customer to 6,900 kWh per customer; this translates into a 1.0% annual decline. The decline in usage is largely the outcome of improved efficiency driven by new appliance standards and strong energy efficiency (EE) program activity. In the last few years, net metering has also been contributing to usage decline. In the near-term, GMP will see even stronger declines in residential usage as the impact of new lighting standards coupled with other appliance standards, Efficiency Vermont's EE efforts, and net metering roll forward. Usage decline is somewhat mitigated by customer growth with population growth expected to translate into 0.4% annual residential customer growth. The combination of average use and customer forecasts results in residential sales projections of 0.6% annual decline over the next ten years. Table 2 shows the residential sales forecast.

Table 2: Residential Customer and Use Forecast

Year	Average Use (kWh)	Chg	Customers	Chg	Sales (MWh)	Chg
2016	6,703		220,803		1,480,023	
2017	6,689	-0.2%	221,698	0.4%	1,482,869	0.2%
2018	6,590	-1.5%	222,816	0.5%	1,468,375	-1.0%
2019	6,484	-1.6%	223,944	0.5%	1,452,155	-1.1%
2020	6,348	-2.1%	224,970	0.5%	1,428,216	-1.6%
2021	6,235	-1.8%	225,807	0.4%	1,407,962	-1.4%
2022	6,179	-0.9%	226,650	0.4%	1,400,397	-0.5%
2023	6,139	-0.6%	227,483	0.4%	1,396,486	-0.3%
2024	6,123	-0.3%	228,290	0.4%	1,397,923	0.1%
2025	6,087	-0.6%	229,139	0.4%	1,394,753	-0.2%
2026	6,072	-0.2%	229,978	0.4%	1,396,384	0.1%
16-26		-1.0%		0.4%		-0.6%

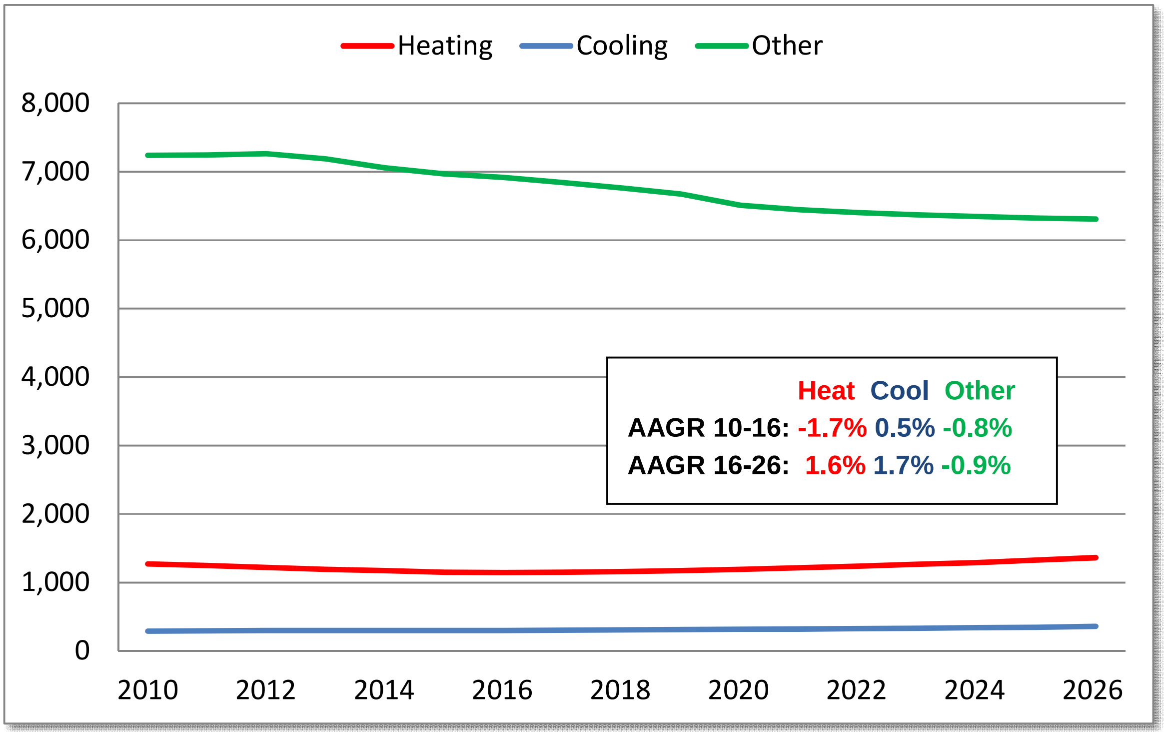
Residential sales are partly driven by state household and household income forecasts. We expect to see relatively moderate economic growth over the next five years, with households averaging 0.3% annual growth and real income per household increasing 0.7% annually. Table 3 summarizes key residential economic drivers.

Table 3: Residential Economic Drivers

Year	Population (Thou)	Chg	Households (Thou)	Chg	RPI (Mil $)	Chg	Household Income (Thou $)	Chg
2010	625.8		256.8		24,720		96.3	
2011	626.5	0.1%	257.4	0.2%	25,605	3.6%	99.5	3.3%
2012	626.1	0.0%	258.4	0.4%	26,064	1.8%	100.9	1.4%
2013	626.9	0.1%	258.9	0.2%	26,179	0.4%	101.1	0.3%
2014	626.6	0.0%	258.6	-0.1%	26,624	1.7%	103.0	1.8%
2015	627.1	0.1%	258.5	0.0%	27,317	2.6%	105.7	2.6%
2016	629.3	0.4%	259.5	0.4%	27,876	2.0%	107.4	1.7%
2017	631.3	0.3%	260.4	0.4%	28,349	1.7%	108.9	1.3%
2018	633.3	0.3%	261.6	0.4%	28,687	1.2%	109.7	0.7%
2019	635.2	0.3%	262.7	0.4%	28,966	1.0%	110.3	0.5%
2020	637.1	0.3%	263.7	0.4%	29,183	0.7%	110.7	0.4%
2021	639.0	0.3%	264.5	0.3%	29,469	1.0%	111.4	0.7%
2022	640.8	0.3%	265.3	0.3%	29,804	1.1%	112.3	0.8%
2023	642.6	0.3%	266.1	0.3%	30,133	1.1%	113.2	0.8%
2024	644.4	0.3%	266.9	0.3%	30,440	1.0%	114.1	0.7%
2025	646.1	0.3%	267.7	0.3%	30,748	1.0%	114.9	0.7%
2026	647.9	0.3%	268.5	0.3%	31,073	1.1%	115.7	0.8%
10-16		0.1%		0.2%		2.0%		1.9%
16-26		0.3%		0.3%		1.1%		0.7%

Even with stable population and economic growth, residential sales will continue to decline with improving end-use efficiency. Figure 2 shows the end-use intensity trends.

Figure 2: Residential End-Use Indices (Annual kWh per Household)



Overall, total residential intensity is expected to decline 0.4% annually over the next ten years with the non-weather sensitive end-uses seeing the largest improvement in efficiency, averaging 0.9% decline through 2026. The strong decline in other use is largely the outcome of statewide EE programs promoting LED lighting, along with future end-use appliance standards. Heating and cooling intensities actually increase over the forecast period as a result of statewide program to promote high efficiency (cold-climate) heat pumps.

Commercial Sales

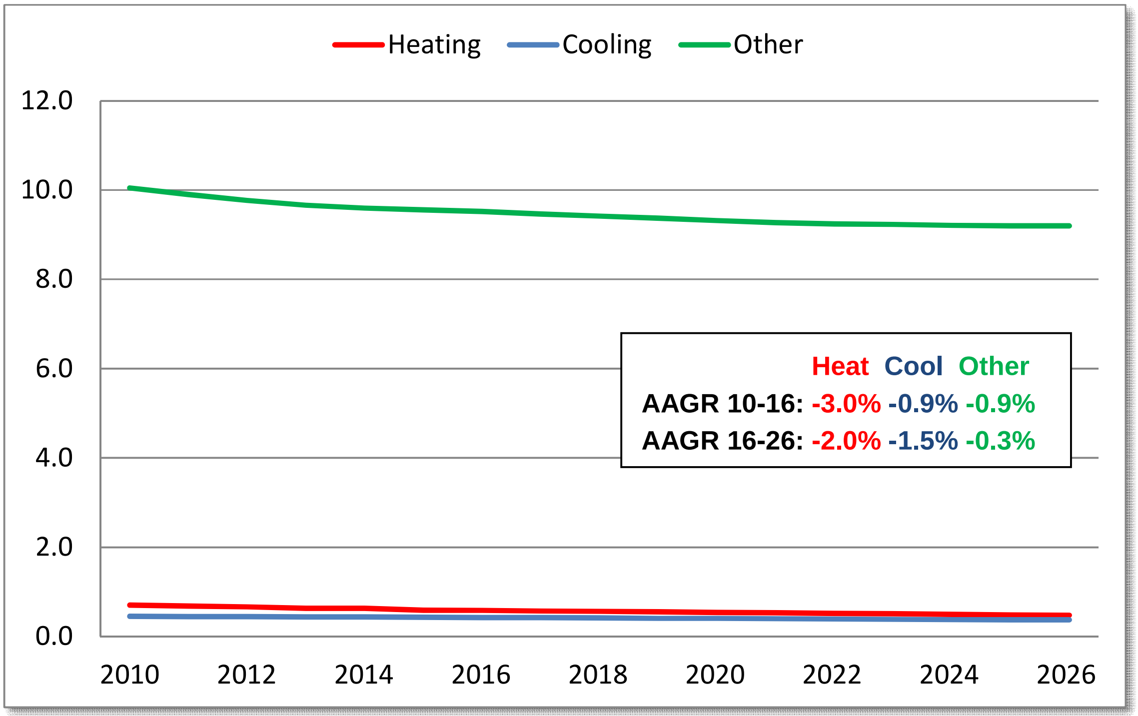
Commercial sales are projected to increase 0.3% per year through 2026. This is largely the result of strong customer growth. Table 4 shows a breakdown of the commercial sales forecast into average-use and customers.

Table 4: Commercial Customer Usage Forecast

Year	Average Use (kWh)	Chg	Customers	Chg	Sales (MWh)	Chg
2016	37,865		40,363		1,528,335	
2017	37,780	-0.2%	41,054	1.7%	1,551,016	1.5%
2018	37,552	-0.6%	41,481	1.0%	1,557,717	0.4%
2019	37,268	-0.8%	41,906	1.0%	1,561,728	0.3%
2020	37,116	-0.4%	42,114	0.5%	1,563,121	0.1%
2021	36,946	-0.5%	42,226	0.3%	1,560,101	-0.2%
2022	36,848	-0.3%	42,415	0.4%	1,562,887	0.2%
2023	36,760	-0.2%	42,639	0.5%	1,567,415	0.3%
2024	36,731	-0.1%	42,839	0.5%	1,573,504	0.4%
2025	36,606	-0.3%	43,036	0.5%	1,575,381	0.1%
2026	36,554	-0.1%	43,247	0.5%	1,580,843	0.3%
16-26		-0.4%		0.7%		0.3%

Average-use declines over the longer term as a result of improving end-use efficiency and solar load growth. Total commercial intensity (kWh per square foot) is expected to decline 0.5% annually, resulting from new commercial end-use standards and state EE programs. Figure 3 shows commercial energy intensity by major end-use.

Figure 3: Commercial End-Use Intensities (kWh/sqft)



Moderate economic growth mitigates some of this decline. GDP is expected to average 1.4% and employment 0.7% growth over the next ten years. Manufacturing employment is incorporated into the Industrial sales model along with GDP. Table 5 shows commercial and industrial model economic drivers.

Table 5: State GDP and Employment Forecast

Year	GDP (Mil $)	Chg	Emp (Thou)	Chg	ManEmp (Thou)	Chg	NManEmp (Thou)	Chg
2010	26,235		297.8		30.6		267.2	
2011	26,923	2.6%	300.7	1.0%	31.1	1.6%	269.6	0.9%
2012	27,089	0.6%	304.3	1.2%	31.8	2.3%	272.5	1.1%
2013	26,991	-0.4%	306.7	0.8%	31.8	-0.2%	275.0	0.9%
2014	27,147	0.6%	309.9	1.0%	31.2	-1.6%	278.7	1.3%
2015	27,728	2.1%	314.3	1.4%	30.8	-1.4%	283.5	1.7%
2016	28,375	2.3%	319.5	1.7%	30.6	-0.6%	288.9	1.9%
2017	28,976	2.1%	324.6	1.6%	30.8	0.8%	293.7	1.7%
2018	29,408	1.5%	329.0	1.4%	31.0	0.4%	298.0	1.5%
2019	29,766	1.2%	332.2	1.0%	30.9	-0.2%	301.3	1.1%
2020	30,044	0.9%	333.6	0.4%	30.5	-1.2%	303.0	0.6%
2021	30,412	1.2%	334.6	0.3%	30.1	-1.5%	304.5	0.5%
2022	30,845	1.4%	336.1	0.4%	29.7	-1.4%	306.4	0.6%
2023	31,270	1.4%	337.7	0.5%	29.3	-1.3%	308.5	0.7%
2024	31,668	1.3%	339.2	0.4%	28.9	-1.4%	310.3	0.6%
2025	32,069	1.3%	340.7	0.4%	28.5	-1.3%	312.2	0.6%
2026	32,493	1.3%	342.2	0.4%	28.2	-1.2%	314.1	0.6%
10-16		1.3%		1.2%		0.0%		1.3%
16-26		1.4%		0.7%		-0.8%		0.8%

Industrial and Other Sales

The "industrial" class includes GMP's largest customers. After recent re-classification, there are now 72 customers that are defined in this rate class. While this class is dominated by industrial load, it also includes some of GMP's largest commercial customers. The two largest customers, Global Foundries and OMYA, account for half the industrial sales. Global Foundries and OMYA sales are expected to be flat over the forecast horizon.

The rest of the industrial sales are estimated using a general econometric model that relates sales to state-level GDP and manufacturing employment.
Given the current projections for the overall VT economy and for Global Foundries and OMYA in particular, sales growth should be slightly positive in the near-term. Longer term, industrial sales growth is flat with continued solar load growth, and expected efficiency program savings. The net adjustment for other specific-customer activity is relatively small with a 900 MWh annual positive adjustment.

Other use primarily consists of street lighting sales, but also includes public authority sales. Total sales are expected to be flat as continued efficiency gains outweigh new street-lighting fixture growth.

Table 6 summarizes industrial and other use sales forecast.

Table 6: Industrial Sales Forecast

Year	Industrial (MWh)	Chg	Other (MWh)	Chg
2016	1,172,925		5,096	
2017	1,182,857	0.8%	5,065	-0.6%
2018	1,189,175	0.5%	5,065	0.0%
2019	1,193,493	0.4%	5,065	0.0%
2020	1,193,583	0.0%	5,065	0.0%
2021	1,192,359	-0.1%	5,065	0.0%
2022	1,192,341	0.0%	5,065	0.0%
2023	1,192,705	0.0%	5,065	0.0%
2024	1,192,537	0.0%	5,065	0.0%
2025	1,192,316	0.0%	5,065	0.0%
2026	1,192,458	0.0%	5,065	0.0%
16-26		0.2%		-0.1%

2. Forecast Assumptions

Economic Drivers

Historical and forecasted economic drivers are incorporated into the residential, commercial, and industrial sales forecasts via the forecast model specification. The primary economic variables are households, household income, GDP, total employment, and manufacturing employment. State actual and forecasted economic data is provided by Moody's Analytics; the forecast is based on the February 2016 outlook.

End-Use Saturation and Efficiency Trends

Improvements in end-use efficiency have had a significant impact on customer usage. It is impossible to explain the decline in customer usage without accounting for efficiency. Improvements in end-use efficiency are the result of new appliance standards coupled with strong state-wide EE program activity.

Historical and end-use intensity estimates are directly incorporated into the forecast models. Starting end-use energy intensities are based on the Energy

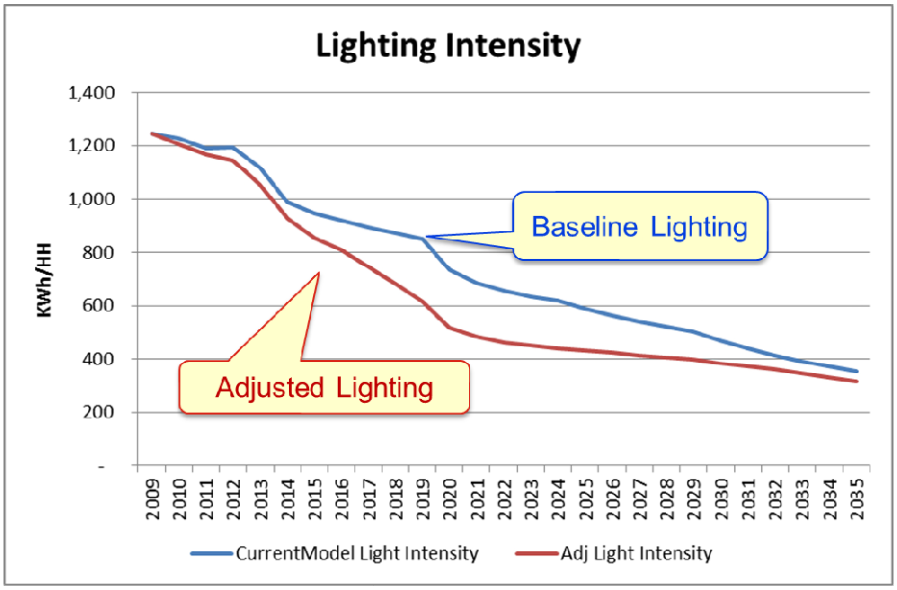
Information Agency's (EIA) 2014 Annual Energy Outlook for the New England Census Division. To better reflect the GMP service area, residential end-use saturations are calibrated into the 2013 and 2007 statewide residential appliance saturation surveys and earlier survey work conducted by Burlington Electric.

Adjusting for State EE Program Impact. End-use intensities are further adjusted to account for expected savings from state energy efficiency (EE) program activity. The current set of end-use intensity estimates were developed as part of the Vermont Electric Power Company (VELCO) long-term forecast. Itron worked with Vermont Energy Investment Corporation (VEIC) and other members of the Vermont System Planning Forecast Subcommittee (*Forecast Committee*) to develop a set of end-use intensity projections that reflect both Federal efficiency standards and the impact of future EE program savings. The end-use intensities were updated in the June 2016 forecast to reflect changes in VEIC's EE program savings projections.

The process for incorporating the program savings projections entails first developing baseline end-use sales forecasts, which reflect new standards, economics and price forecasts, weather conditions, and embedded EE program activity. Future cumulative EE program savings are then subtracted from the baseline forecast at the end-use level and used to construct EE adjusted end-use intensity forecasts.

As the state has been aggressively pursuing efficiency programs for the last ten years, there is significant efficiency improvements already embedded in the baseline forecast. To avoid "double counting" future EE savings; future EE program savings are adjusted to account for EE savings already embedded in the baseline forecast. The one exception is residential lighting. The *Forecast Committee* felt that the new lighting program promoting LED adoption was not reflected in past usage trends. A new lighting intensity to account for the LED program was developed using a stock accounting model based on annual LED bulb projections provided by VEIC. Figure 4 compares the baseline lighting intensity and program-adjusted lighting intensity.

Figure 4: Lighting Intensity Comparison



In the residential sector, end-use intensities that are adjusted for future EE program impacts include water heating, cooling, refrigeration, lighting, dryers, kitchen/laundry, and miscellaneous use. In the commercial sector, program efficiency adjustments are made to indoor lighting, outdoor lighting, refrigeration, cooling, ventilation, water heating, and miscellaneous use.

Customer Specific Load Adjustments

Customer load adjustments are also made for large expected shifts in usage that would not be captured by a regression model. These predominantly include expected load losses or increases for large commercial and industrial customers and are provided by GMP staff. The adjustments this year were relatively small as expected load losses were roughly equal to expected load gains. There is a slight positive adjustment in this year's forecast with about 2,000 MWh added to the commercial forecast and another 900 MWh added the industrial sales forecast.

Other Exogenous Forecasts

GMP provides monthly forecasts for their large transmission customers (Global Foundries/IBM and OMYA). Sales projections for these two companies are flat.

Solar Load Forecast

GMP is experiencing a significant ramp-up in solar load and is expecting this trend to continue over the next few years. GMP solar capacity projections are translated to total solar generation (MWh) and allocated between customer own-use and excess-use (that which is sold back to the Company). The allocation of solar generation to own-use and excess-use is based on historical solar generation data. Table 7 shows the cumulative solar generation forecast. Own Use reduces customer consumption and is subtracted from the sales forecasts. Excess Use (the difference between generation and own-use) is treated as a power purchase cost.

Table 7: Solar Generation (FY Basis)

Year	Total Generation	Res Gen MWh	Res Own MWh	Res Excess MWh	Com Gen MWh	Com Own MWh	Com Excess MWh	Ind Gen MWh	Ind Own MWh	Ind Excess MWh
2016	94,817	37,773	28,632	9,141	50,573	3,689	46,883	6,472	0	6,472
2017	162,735	61,221	46,475	14,746	94,660	6,704	87,956	6,853	0	6,853
2018	201,467	73,743	56,069	17,674	119,010	8,410	110,600	8,714	0	8,714
2019	237,546	86,285	65,608	20,677	140,857	9,943	130,914	10,404	0	10,404
2020	274,170	100,160	76,233	23,927	162,026	11,440	150,586	11,984	0	11,984
2021	309,702	113,667	86,505	27,163	182,523	12,890	169,633	13,512	0	13,512
2022	345,781	127,374	96,965	30,409	203,343	14,363	188,980	15,064	0	15,064
2023	381,859	141,081	107,426	33,654	224,163	15,835	208,328	16,616	0	16,616
2024	418,779	155,099	118,182	36,916	245,476	17,342	228,134	18,205	0	18,205
2025	454,016	168,494	128,348	40,146	265,802	18,780	247,022	19,720	0	19,720
2026	490,094	182,201	138,809	43,392	286,622	20,253	266,369	21,272	0	21,272

3. Methodology

Class Sales Forecast

The sales forecast is based on estimated linear regression models that relate monthly historical sales to economic conditions, price, weather conditions, and long-term appliance saturation and efficiency trends. Saturation and efficiency trends are combined to construct annual energy intensity projections that are then adjusted for future EE program savings projections. Once models are estimated, assumptions about future conditions are executed through the models to generate customer and sales forecasts.

Separate forecast models are estimated for the primary revenue classes. Models are estimated for the following:

- Residential
- Commercial
- Industrial
- Other

For the 2017 budget forecast, class sales data for legacy GMP companies (North and South) were combined and modeled as a single company. The former North GS and TOU revenue classes were included in a total commercial class, and the North CIL and Station Service revenue classes were both mapped to the industrial revenue class.

Residential and commercial models are constructed using an SAE modeling framework. This approach entails constructing generalized end-use variables (Heating, Cooling, and Other Use) that incorporate expected end-use saturation and efficiency projections as well as price, economic drivers, and weather. The SAE specification allows us to directly capture the impact of improving end-use efficiency and end-use saturation trends on class sales.

Residential

The residential forecast is generated using separate average use and customer forecast models. The average use model is estimated using an SAE specification where monthly average use is estimated as a function of a heating variable (*XHeat*), cooling variable (*XCool*) and other use variable (*XOther*) as shown below:

$$AvgUse_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m$$

XHeat is calculated as a product of a variable that captures changes in heating end-use saturation and efficiency (HeatIndex), economic and other factors that impact stock utilization (HDD, household size, household income, and price). *XHeat* is calculated as:

$$XHeat_{y,m} = HeatIndex_y \times HeatUse_{y,m}$$

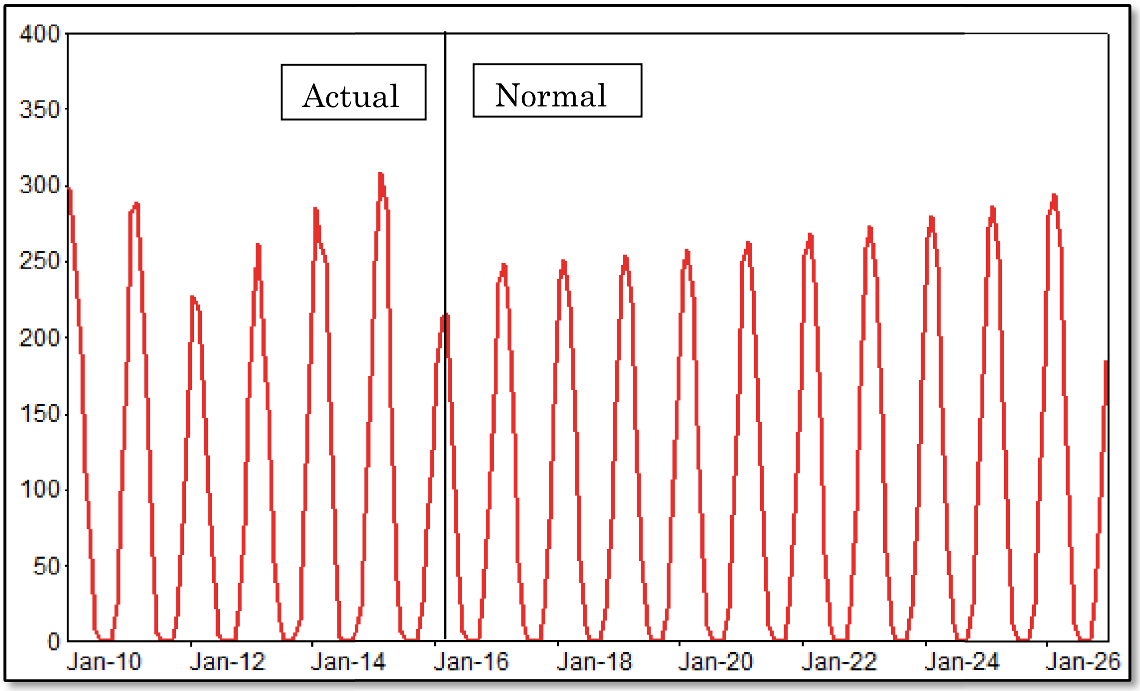
Where:

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{09}}\right) \times \left(\frac{HHSize_y}{HHSize_{09}}\right)^{0.20} \times \left(\frac{Income_y}{Income_{09}}\right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{09}}\right)^{-0.10}$$

The heat index is a variable that captures heating end-use efficiency and saturation trends, thermal shell improvement trends, and housing square footage trends. The index is constructed from the EIA's annual end-use residential forecast for the New England census division. The economic and price drivers are incorporated into the HeatUse variable. By construction, the $HeatUse_{y,m}$ variable sums close to 1.0 in the base year (2009). This index value changes through time and across months in response to changes in weather conditions, prices, household size, and household income.

The heat index (*HeatIndex*) and heat use variable (*HeatUse*) are combined to generate the monthly heating variable XHeat. Figure 5 shows the calculated XHeat variable.

Figure 5: XHeat Variable



The strong increase in the XHeat is largely driven by expected saturation growth in heat pumps. The increase in heat-pumps is a result of state-wide effort to promote cold-climate heat pumps where homes are currently heating with fuel oil or propane.

Similar variables are constructed for cooling (*XCool*) and other end-uses (*XOther*). Figure 6 and Figure 7 show XCool and XOther.

Figure 6: XCool Variable

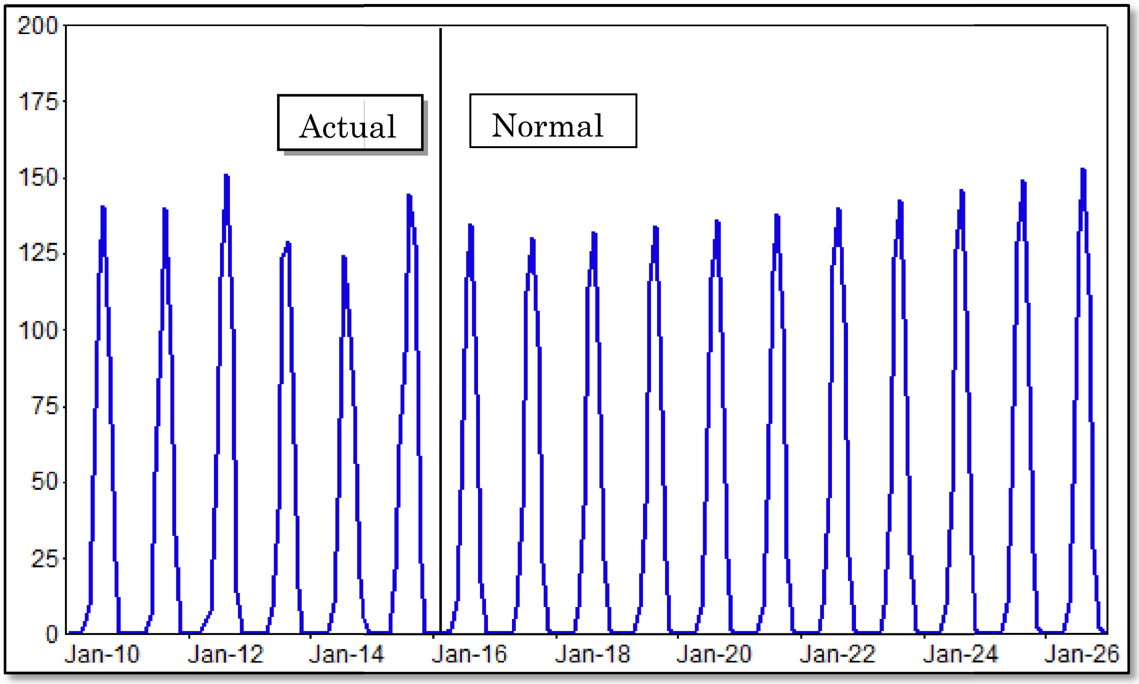
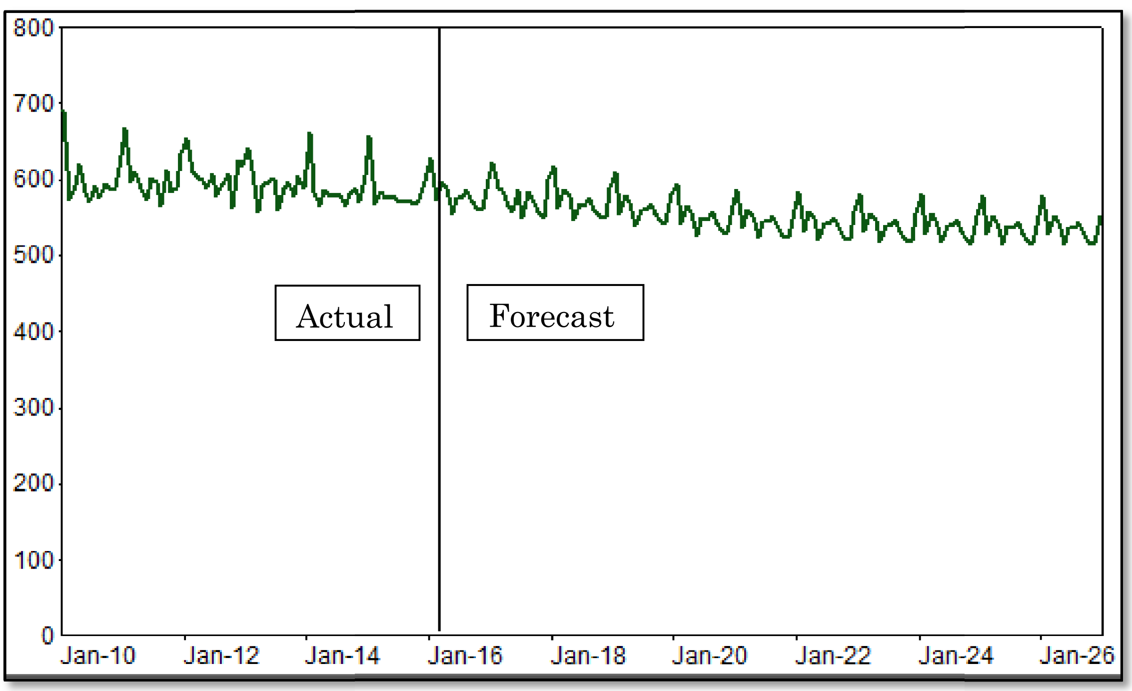


Figure 7: XOther Variable

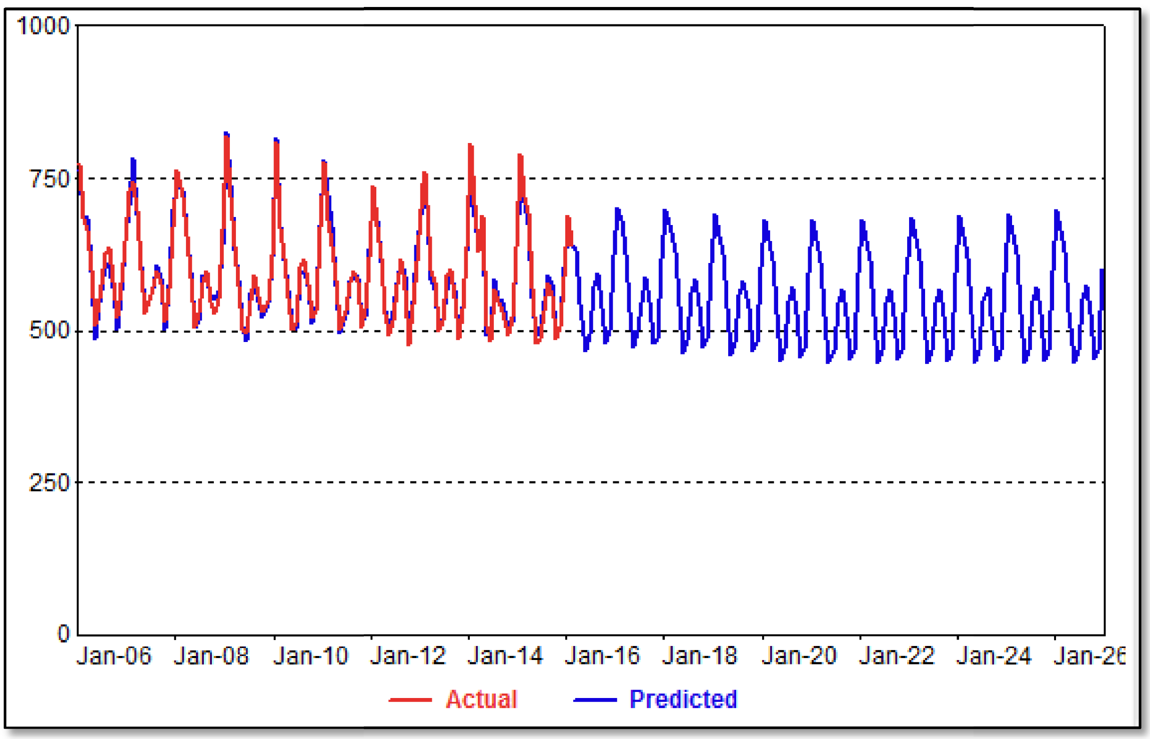


While cooling intensity is relatively small, cooling per household increases over the forecast period largely as a result of increasing in heat-pump saturation.

XOther (non-weather sensitive use) declines over the forecast period. The monthly variation in XOther reflects variation in the number of monthly billing days, lighting requirements, and monthly variation in water heater use. While both heating and cooling intensities are increasing, end-use intensities across all the other end-uses are declining at a faster rate. As a result, XOther declines faster than increase in XHeat and XCool driving total average use downwards.

The end-use variables are used to estimate the residential average use model. Figure 8 shows actual and predicted residential average use.

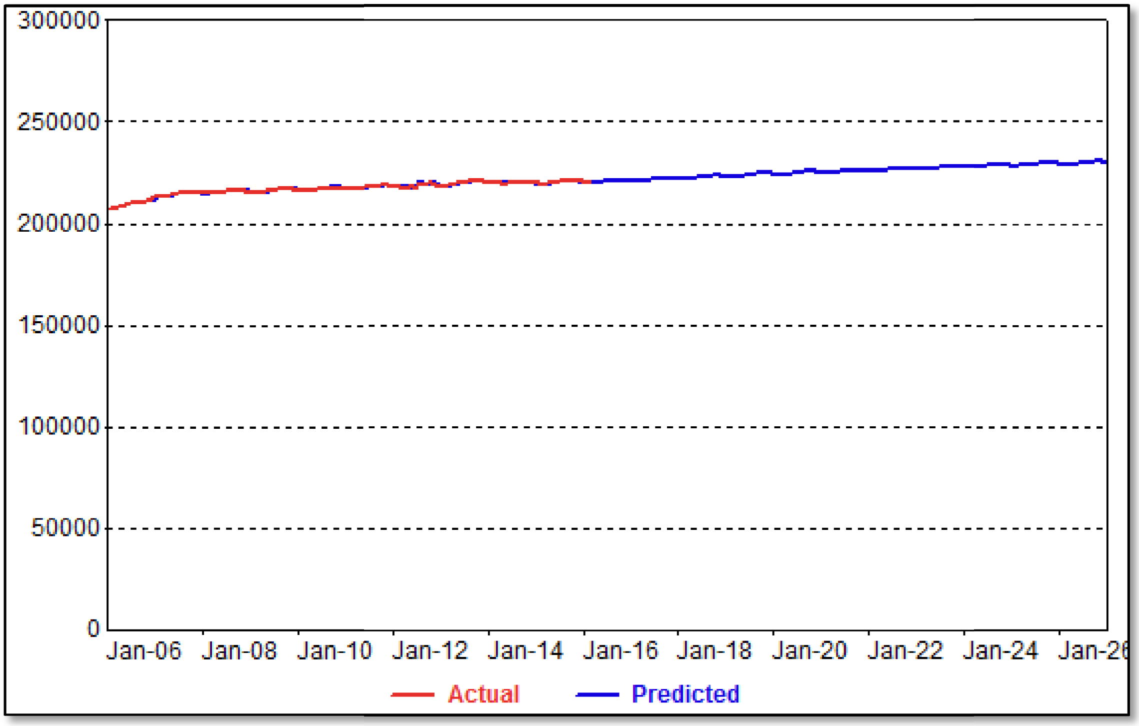
Figure 8: Residential Average Use (kWh)



The model explains historical monthly sales variation well with an Adjusted R-Squared of 0.97 and a MAPE of 1.9%.

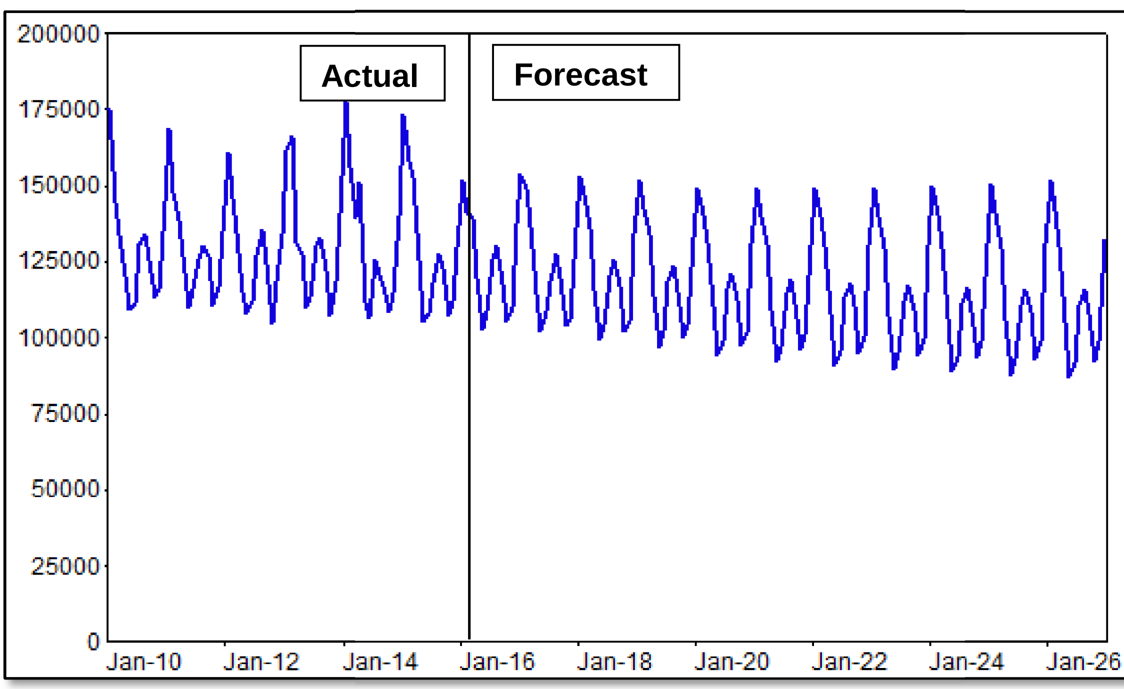
Residential customer projections are based on state household projections. The models explain historical customer growth well with an Adjusted R-Squared of 0.98 and MAPE of 0.1%. Figure 9 shows actual and predicted customers for GMP.

Figure 9: Residential Customer Forecast



Customer and average use forecasts are combined to generate monthly billed sales forecast. Figure 10 shows the monthly residential forecast for the combined GMP.

Figure 10: Residential Sales Forecast (MWh)



Commercial

The commercial model is also based on SAE specification. Monthly commercial class sales and customers are derived adding the former North GS (general service) and TOU revenue class and the former GMP South commercial sales.

The SAE commercial model captures the impact of changing end-use intensity as well as economic conditions, price, and weather in the constructed model variables. As in the residential model, end-use variables XHeat, XCool, and XOther are constructed from end-use saturation and efficiency trends, regional output, price, and weather conditions. The commercial SAE model is defined as:

$$ComSales_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m$$

The SAE model variables are constructed similarly to that of the residential model, the primary differences is that the end-use intensities are measured on a kWh per square foot basis (vs. kWh per household in the residential model), and output and employment are used to capture economic activity (vs. household income and population in the residential model).

The GMP commercial class is forecasted using a total sales model where XCool is defined as:

$$XCool_{y,m} = CoolEI_y \times CoolUse_{y,m}$$

Where:

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{CDD_{04}}\right) \times \left(\frac{ComVar_y}{ComVar_{04}}\right) \times \left(\frac{Price_{y,m}}{Price_{04}}\right)^{-0.10}$$

.

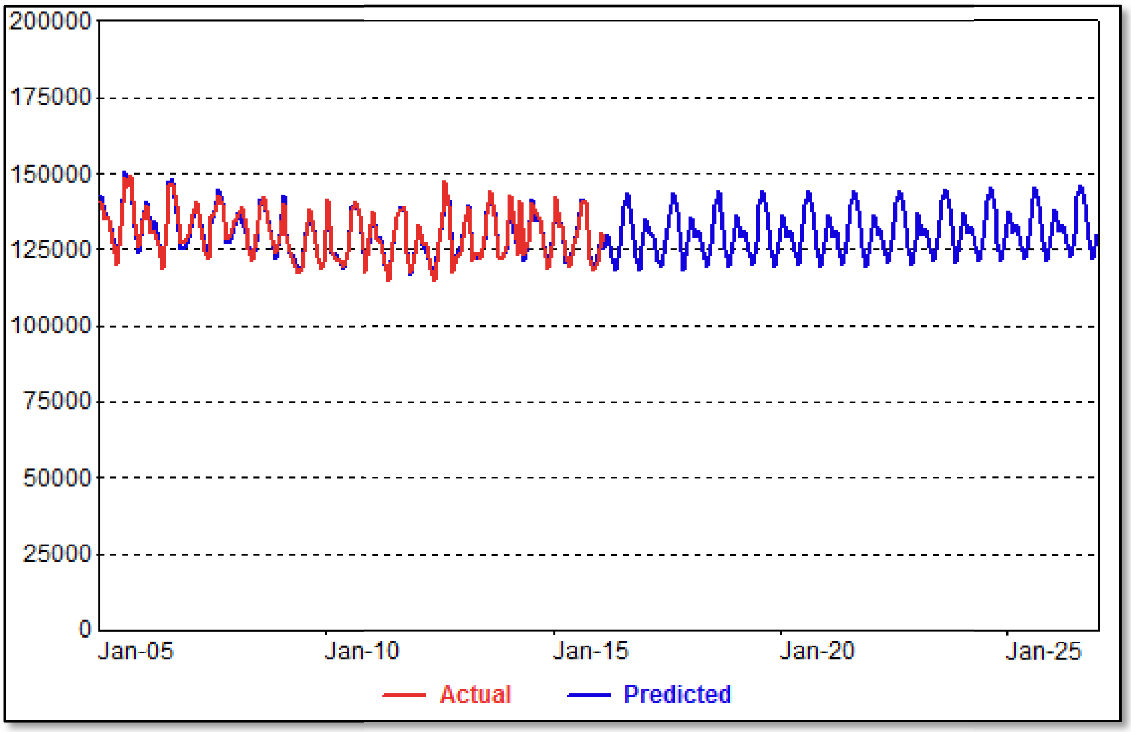
And

$$ComVar_{y,m} = \left(\frac{Emp_{y,m}}{Emp_{04}}\right)^{0.50} \times \left(\frac{GDP_{y,m}}{GDP_{04}}\right)^{0.50}$$

In the constructed economic variable output and employment are weighted equally reflecting the relationship between economy and sales in the last five years.

A monthly variable is constructed for heating (XHeat) and other use (XOther) similar to that of XCool. The model variables are used to drive total sales through an estimated monthly regression model. Figure 11 shows the commercial sales model results.

Figure 11: Commercial Sales Forecast (MWh)



This model fits commercial data well with an Adjusted R-Squared of 0.96 and model MAPE of 1.0%. Model statistics can be found in the Appendix A.

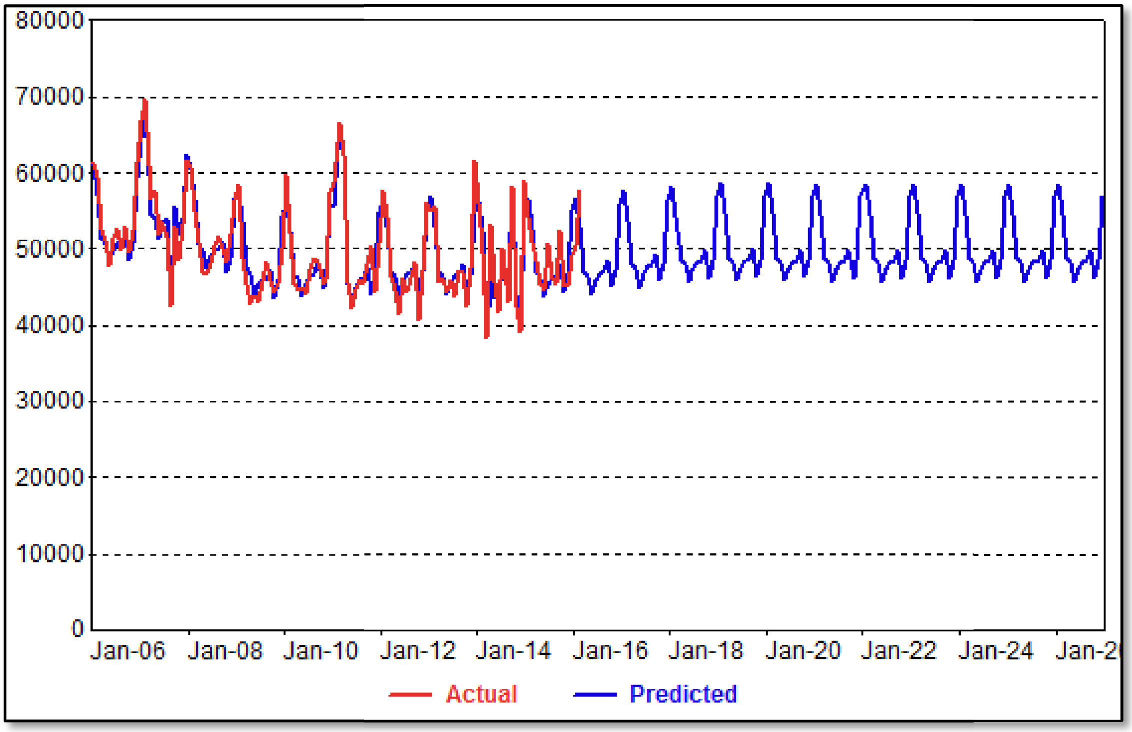
Industrial

Industrial sales are estimated using a generalized (vs. SAE model) model specification that is driven by economic projections. The economic variable includes both manufacturing employment projections and state GDP where half of the weight is on manufacturing employment (0.5). The constructed economic variable is summarized below:

$$IndVar_{y,m} = \left(\frac{ManEmp_{y,m}}{ManEmp_{04}}\right)^{0.50} \times \left(\frac{GDP_{y,m}}{GDP_{04}}\right)^{0.50}$$

Seasonal load variation is captured through a set of monthly binary variables. The industrial model excludes IBM and OMYA sales as GMP provides an independent forecast for these customers. Figure 12 shows actual and predicted industrial sales.

Figure 12: Industrial Sales Forecast (kWh)

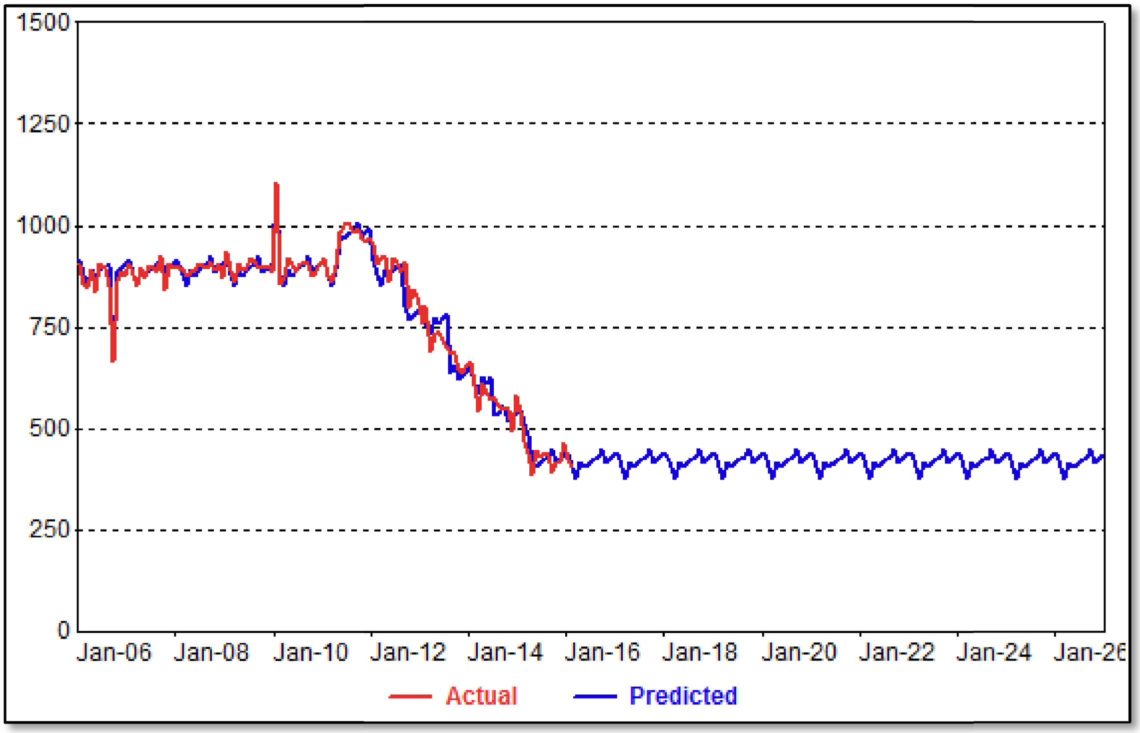


This model Adjusted R-Squared is 0.81 and the MAPE is 3.5%. The lower, relative to other models, Adjusted R-Square is due to the large variation in monthly billed sales data. There is significant month-to-month variation driven by customer-specific activity and billing adjustments that cannot be totally accounted for by economic drivers and weather conditions.

Other Use

Other Use sales are estimated using a simple regression model constructed to capture seasonal effects and shifts in the data. This class is dominated by street lighting, but also includes a small amount of other public authority sales. GMP has seen a significant drop in street lighting sales as existing lamps were replaced with high efficiency lamps. We assume some additional savings in the near-term and project flat sales after the savings adjustments. Figure 13 shows actual and forecasted sales for this revenue class

Figure 13: Other Sales Forecast (MWh)



4. Solar Load Forecast

The 2017 Budget Forecast includes the impact of expected rooftop net metering and community/group solar generation. GMP is experiencing strong solar market penetration and expects this trend to continue through the forecast period. Strong solar load growth is driven by two major law changes; the extension of the Federal Investment Tax Credit (ITC) and Vermont's Net Metering Cap. The Federal ITC, which provides a 30% tax credit on solar systems, has been extended at its current rate until 2020, at which point it begins to decline. The Vermont Net Metering Cap, which was set to 15% of a utility's total load, has been removed. The other factor contributing to strong solar demand growth is the sharp rise in "group-based" solar generation systems. These are effectively stand-along solar generation systems up to 500 kW that have been incentivized by effectively providing them the same incentives as a retail roof-top installation.

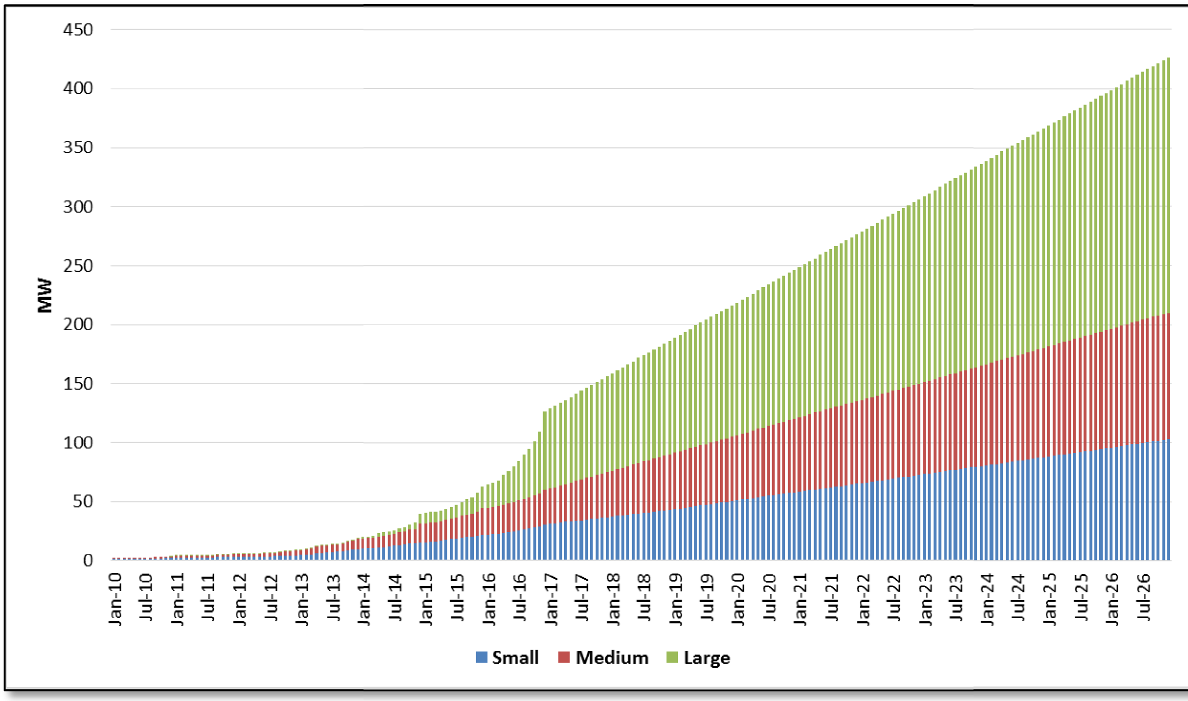
Solar Capacity (MW) Forecast

System solar capacity forecast is based on current PV applications through 2016 and an additional 30 MW of capacity in 2017. While rooftop adoption is still relatively strong, we expect most of the future capacity growth to come from "group-based" stand alone solar systems. The capacity forecast is broken into three classifications:

- **Small Systems**: <15kW in size
- **Medium Systems**: 15-150kW in size
- **Large Systems**: >150kW in size

Figure 14 shows the monthly capacity forecast by system size.

Figure 14: Monthly Solar Capacity Forecast



The forecast is adjusted for additional solar load generation beginning June 2016 – the first forecast month.

The capacity forecast is translated into a total monthly generation forecast, which is then allocated to the residential, commercial, and industrial classes. Total monthly generation is derived by applying monthly solar load factors to the capacity forecast. Table 8 shows the solar generation load factors.

Table 8: Solar Load Factors

Month	MonthlyLdFct
Jan	0.08
Feb	0.11
Mar	0.14
Apr	0.19
May	0.20
Jun	0.21
Jul	0.20
Aug	0.20
Sep	0.16
Oct	0.12
Nov	0.08
Dec	0.06

The monthly load factors are derived from engineering-based solar hourly load profile for 1 MW solar system load. The load shape is a weighted profile, which assumes 33% of systems are roof-mounted, 57% are fixed-tilt, and 10% 2 are axis trackers. The system hourly load profile was developed by GMP.

The solar generation forecast (MWh) is derived by applying the load factors to solar capacity projections. The following equation shows an example of how 1 MW of capacity is translated into June generation.

$$1MW_{june} \times 0.21LdFct_{june} \times 720hrs_{june} = 151\ MWh_{june}$$

Allocation of Solar Generation to Rate Classes

For revenue purposes, the monthly generation forecast is disaggregated to residential, commercial, and industrial revenue classes based on historical system adoption data. We assume the following:

- **Small Systems (less than 15 kW):** 100% of generation is residential.
- **Medium Systems (15 kW to 150 kW):** Generation is split between commercial and industrial, 75% and 25% respectively.
- **Large Systems (greater than 150 kW):** The majority of the new systems in this bin will be group net-metering systems, which will sign up residential, commercial, and industrial customers. Based on the community group solar billing data, the average split is 22% residential, 73% commercial, and 5% industrial.

Allocation to Own Use vs. Excess Use

Solar generation is either consumed by the solar customer (*own use*) or returned to the connected power-grid (*excess*); own-use reduces billed revenues, while excess is treated as power purchase cost. Historical solar billing data is used to determine the month share that is own-use and excess. The split between own use and excess varies by revenue class and month; own-use share is typically smaller in the summer months with a larger percentage of the generation sent to the grid. Table 9 shows the forecasted generation by own-use and excess use.

Table 9: Solar Generation (FY Basis)

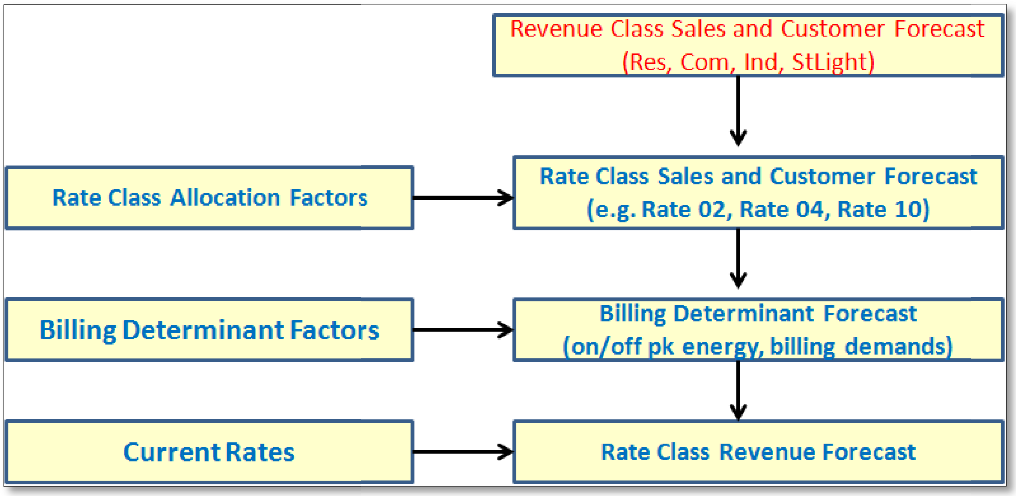
Year	Total Generation	Res Gen MWh	Res Own MWh	Res Excess MWh	Com Gen MWh	Com Own MWh	Com Excess MWh	Ind Gen MWh	Ind Own MWh	Ind Excess MWh
2016	94,817	37,773	28,632	9,141	50,573	3,689	46,883	6,472	0	6,472
2017	162,735	61,221	46,475	14,746	94,660	6,704	87,956	6,853	0	6,853
2018	201,467	73,743	56,069	17,674	119,010	8,410	110,600	8,714	0	8,714
2019	237,546	86,285	65,608	20,677	140,857	9,943	130,914	10,404	0	10,404
2020	274,170	100,160	76,233	23,927	162,026	11,440	150,586	11,984	0	11,984
2021	309,702	113,667	86,505	27,163	182,523	12,890	169,633	13,512	0	13,512
2022	345,781	127,374	96,965	30,409	203,343	14,363	188,980	15,064	0	15,064
2023	381,859	141,081	107,426	33,654	224,163	15,835	208,328	16,616	0	16,616
2024	418,779	155,099	118,182	36,916	245,476	17,342	228,134	18,205	0	18,205
2025	454,016	168,494	128,348	40,146	265,802	18,780	247,022	19,720	0	19,720
2026	490,094	182,201	138,809	43,392	286,622	20,253	266,369	21,272	0	21,272

The sales forecast is adjusted for solar load impacts by subtracting cumulative new solar own use generation from the appropriate class sales forecasts. By 2026, solar generation reduces residential sales by 138,809 MWh, which represents reduction of 603 kWh per customer. Commercial sales are reduced by 20,253 MWh. All Industrial solar is treated as excess.

5. Revenue Forecast

The revenue forecast is derived at the rate schedule level. Class sales forecasts are allocated to rate schedules and within rate schedules to billing determinants (i.e., customer, on and off-peak use, and billing demands). Revenues are then generated by multiplying rate schedule billing determinants by the current tariff rates. Figure 15 provides an overview of the revenue model.

Figure 15: Revenue Model



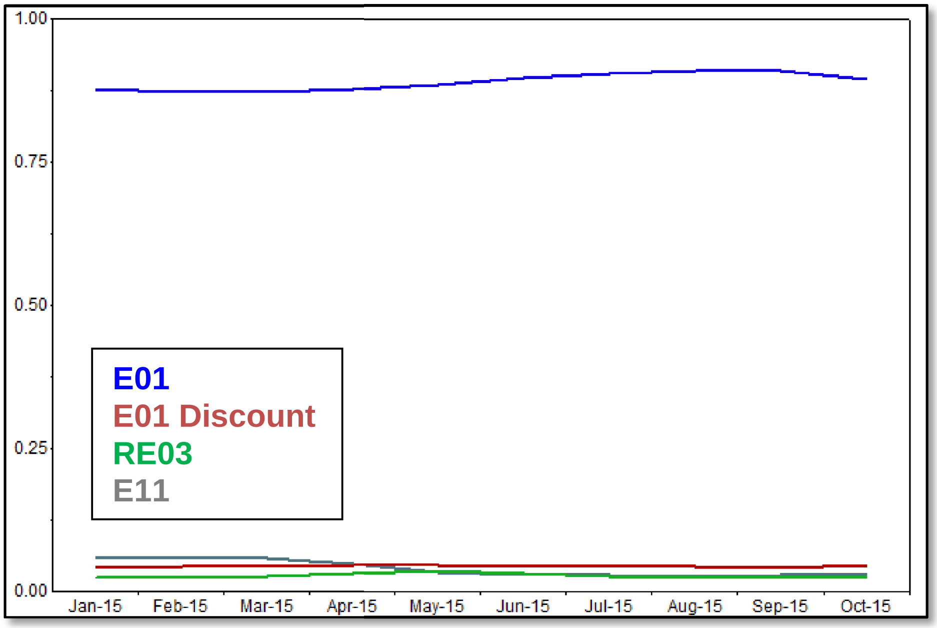
The process is described below.

Step 1: Derive Rate Class Monthly Sales Forecast

Revenue class sales and customer forecasts are first allocated to the underlying rate schedules based on projected monthly allocation factors. The allocation factors are derived from historical billing data and simple regression models that allow us to capture any seasonal variation in the rate class shares. Residential class sales, for example, are allocated to rate schedules - E01, RE03, and E11 rate classes. Figure 16 shows historical and forecasted residential rate class sales shares.

2.2.1

Figure 16: Residential Rate Class Share Forecast (%)



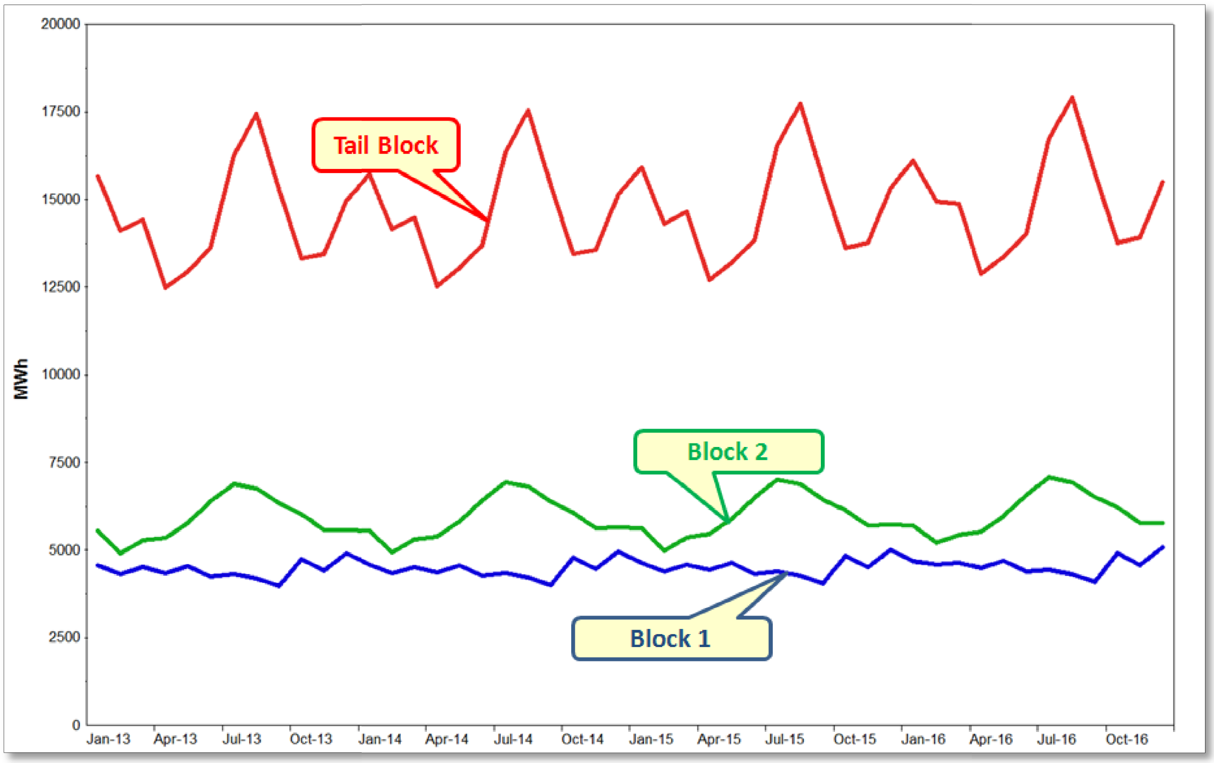
Approximately 97% of residential sales are billed under rate E01. The percentage is slightly lower in the winter months as the electric heat rate (E11) is higher in these months.

Step 2: Estimate monthly billing determinants

In the next step, rate class sales (and customers counts for some rates) are allocated to billing blocks, time-of-use billing periods, and on and off-peak billing demand blocks. Billing block and demand factors are derived from historical billing data. For example, residential rate E11 has on-peak and off-peak energy billing periods that are priced differently. Rate E11 monthly sales are allocated to TOU periods based on historical on-peak and off-peak sales data.

Some of the rates are complex. The commercial rate RE02, for example, includes non-demand and demand billed sales and customers, load factor kWh blocks (for demand customers), and different demand charges for demand below 5 kW and demand above 5 kW. Figure 17 shows the resulting sales block forecasts for rate RE02 Demand Customers.

Figure 17: Rate RE02 Demand Customer - Sales Billing Block Forecast



Step 3: Calculate Rate Schedule and Revenue Class Revenues

Once the billing determinants are derived, revenues are generated by multiplying the forecasted billing determinants by the current customer, energy, and demand charges. Revenues are aggregated by rate schedule and month. Rate schedule revenues are then aggregated to revenue classes: residential, commercial, industrial and street lighting.

Step 4: Model Rate Restructuring

Starting in April 2016, GMP will gradually merge most of the legacy GMP South rates into modified GMP North rates or completely new rates for the entire company. The rate restructuring occurs over the next five-years with the final rate tariffs effective April, 2020. Major restructuring include:

- Legacy South RE02 non-demand rate customers migrate to modified rate E06.
- Legacy South RE02 demand rate customers migrate to modified rates E06, E63, and new rate E08 based on the individual customer load characteristics.
- Legacy North E06 rate is split between rates E06 and E08.
- Legacy South RE10 customers will migrate to rates E06 and E63.

- Legacy South RE04, RE05, RE16 customers will join existing E63 customers in the modified company-wide rate E63.

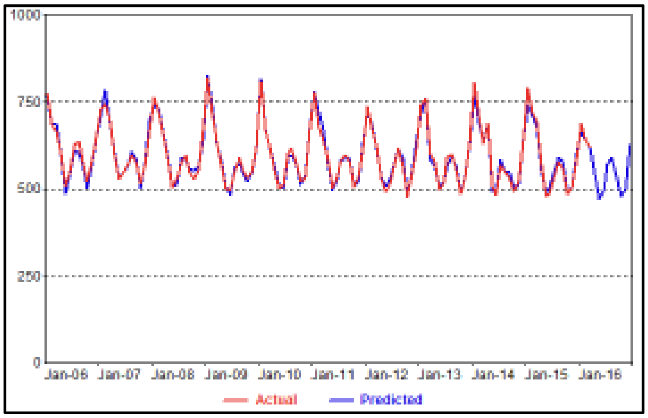
New rates E06, E08 and E63 which are scheduled to begin in April 2016 combine parts of pre-existing rates, but have no historical billed data of their own. The new rates are estimated by allocating sales to the new rate schedules based on allocation factors provided by GMP. Revenue is then calculated by applying billing determinant factors to rate class sales.

Step 5: Validate and Calibrate Revenue Calculation

To validate the revenue calculations, calculated revenues are compared to actual revenues on a per kWh basis. Because of the rate restructuring, the non-residential rate classes are validated against expected average rates based on GMP's rate design work.

APPENDIX A: MODEL STATISTICS AND COEFFICIENTS

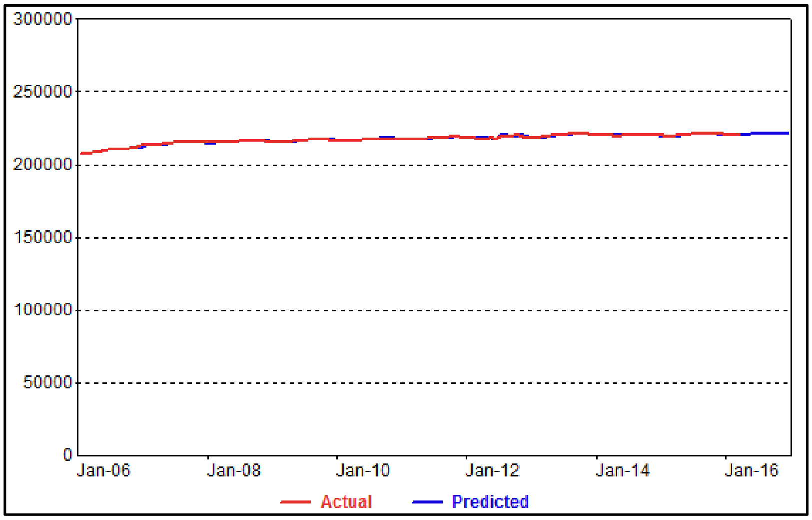
Figure 18: Residential Average Use Model



Variable	Coefficient	StdErr	T-Stat	P-Value
mStructRev.XHeat	0.779	0.035	22.305	0.00%
mStructRev.XCool	0.808	0.071	11.437	0.00%
mStructRev.XOther	0.844	0.013	66.007	0.00%
mBin.Mar	-28.556	5.427	-5.262	0.00%
mBin.Apr	-45.077	5.926	-7.607	0.00%
mBin.May	-37.525	6.954	-5.396	0.00%
mBin.Jun	-27.023	6.596	-4.097	0.01%
mBin.Oct	-18.971	7.264	-2.612	1.02%
mBin.Nov	-32.805	6.856	-4.785	0.00%
mBin.Feb13	44.639	15.895	2.808	0.59%
mBin.Apr14	122.231	16.388	7.459	0.00%
mSales.Savings_PerCust	-0.111	0.043	-2.603	1.05%

Model Statistics	
Iterations	1
Adjusted Observations	125
Deg. of Freedom for Error	113
R-Squared	0.969
Adjusted R-Squared	0.966
Model Sum of Squares	844,889.90
Sum of Squared Errors	27,273.20
Mean Squared Error	241.36
Std. Error of Regression	15.54
Mean Abs. Dev. (MAD)	11.43
Mean Abs. % Err. (MAPE)	1.90%
Durbin-Watson Statistic	1.842

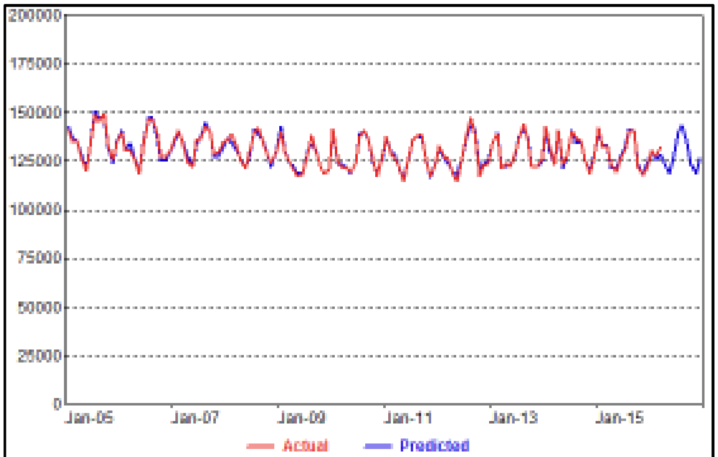
Figure 19: Residential Customer Model



Variable	Coefficient	StdErr	T-Stat	P-Value
mBin.TrendVar	146.719	104.693	1.401	16.38%
Economics.HHs	848.142	2.025	418.848	0.00%
mBin.Dec	-333.896	135.177	-2.47	1.50%
mBin.Jan	-624.55	172.805	-3.614	0.05%
mBin.Feb	-614.688	186.05	-3.304	0.13%
mBin.Mar	-660.121	185.925	-3.55	0.06%
mBin.Apr	-731.098	171.828	-4.255	0.00%
mBin.May	-362.714	138.637	-2.616	1.01%
mBin.Jun12	-2045.417	390.352	-5.24	0.00%
mBin.Jul12	1019.856	382.193	2.668	0.87%
AR(1)	0.863	0.037	23.147	0.00%

Model Statistics	
Iterations	11
Adjusted Observations	124
Deg. of Freedom for Error	113
R-Squared	0.982
Adjusted R-Squared	0.981
Model Sum of Squares	1,202,163,628.33
Sum of Squared Errors	21,616,630.35
Mean Squared Error	191,297.61
Std. Error of Regression	437.38
Mean Abs. Dev. (MAD)	305.81
Mean Abs. % Err. (MAPE)	0.14%
Durbin-Watson Statistic	2.119

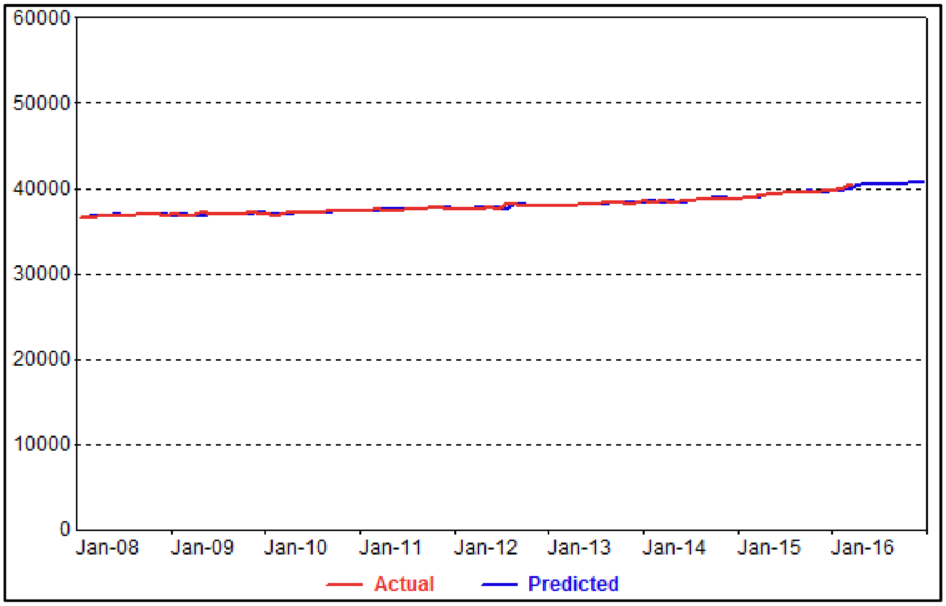
Figure 20: Commercial Sales Model



Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	44367.42	4407.911	10.065	0.00%
mStructRev.XHeat	89807.018	4027.321	22.299	0.00%
mStructRev.XCool	109497.251	3204.73	34.167	0.00%
mStructRev.XOther	7109.653	424.784	16.737	0.00%
mBin.Jan	1389.621	639.462	2.173	3.17%
mBin.Apr	-1781.026	540.971	-3.292	0.13%
mBin.Sep	2140.307	611.423	3.501	0.07%
mBin.Oct	3482.666	592.333	5.88	0.00%
mBin.Dec08	5541.299	1703.692	3.253	0.15%
mBin.Feb13	7222.843	1732.324	4.169	0.01%
mBin.Mar14	-5906.018	1818.132	-3.248	0.15%
mBin.Apr14	16315.339	1851.055	8.814	0.00%
mBin.May16	-5650.697	1846.95	-3.059	0.27%
mBin.Sep12Plus	3303.708	521.172	6.339	0.00%
mBin.Apr15Plus	-2806.485	745.085	-3.767	0.03%
MA(1)	0.289	0.093	3.098	0.24%

Model Statistics	
Iterations	15
Adjusted Observations	137
Deg. of Freedom for Error	121
R-Squared	0.962
Adjusted R-Squared	0.957
F-Statistic	202.761
Prob (F-Statistic)	0
Model Sum of Squares	9,268,199,194.38
Sum of Squared Errors	368,726,496.00
Mean Squared Error	3,047,326.41
Std. Error of Regression	1,745.66
Mean Abs. Dev. (MAD)	1,318.15
Mean Abs. % Err. (MAPE)	1.01%
Durbin-Watson Statistic	1.969

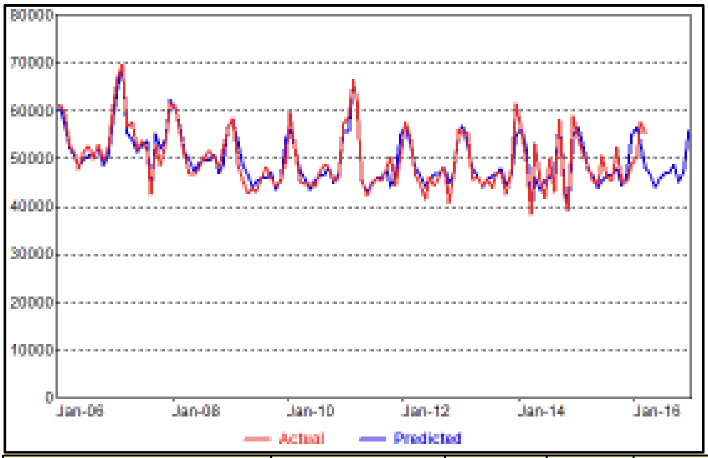
Figure 21: Commercial Customer Model



Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	-3052.185	7291.62	-0.42	67.65%
Economics.Emp	135.442	23.627	5.733	0.00%
AR(1)	0.922	0.031	30.08	0.00%

Model Statistics	
Iterations	10
Adjusted Observations	100
Deg. of Freedom for Error	97
R-Squared	0.974
Adjusted R-Squared	0.974
F-Statistic	1836.019
Prob (F-Statistic)	0
Model Sum of Squares	94,399,976.07
Sum of Squared Errors	2,493,655.89
Mean Squared Error	25,707.79
Std. Error of Regression	160.34
Mean Abs. Dev. (MAD)	111.78
Mean Abs. % Err. (MAPE)	0.29%
Durbin-Watson Statistic	2.515

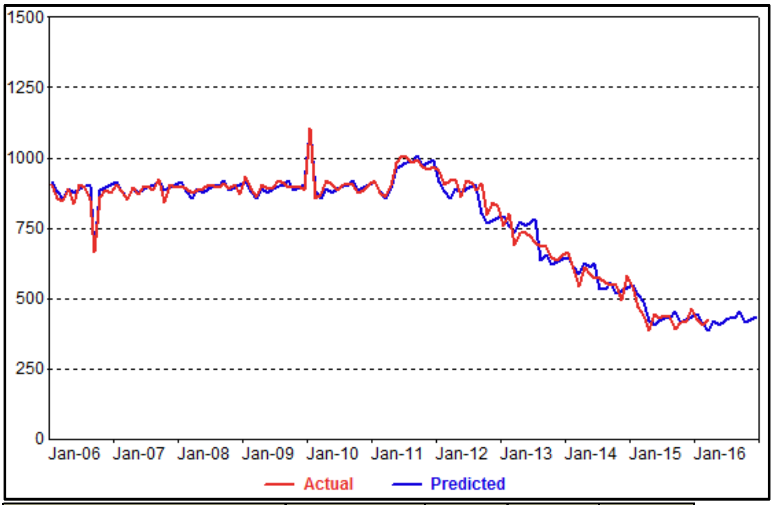
Figure 22: Industrial Sales Model



Variable	Coefficient	StdErr	T-Stat	P-Value
mEcon.IndVar	54070.766	922.319	58.625	0.00%
mBin.Yr07	3561.155	941.462	3.783	0.03%
mBin.Jan11Plus	-1592.824	518.123	-3.074	0.27%
mBin.Jan	3887.485	1202.413	3.233	0.16%
mBin.Mar	-4969.727	1263.58	-3.933	0.02%
mBin.Apr	-6511.523	1201.815	-5.418	0.00%
mBin.May	-8947.046	1201.649	-7.446	0.00%
mBin.Jun	-7275.08	1228.163	-5.924	0.00%
mBin.Jul	-6382.64	1227.874	-5.198	0.00%
mBin.Aug	-6169.813	1256.411	-4.911	0.00%
mBin.Sep	-4760.452	1260.284	-3.777	0.03%
mBin.Oct	-8346.823	1226.956	-6.803	0.00%
mBin.Nov	-6190.028	1259.638	-4.914	0.00%
mBin.Dec	2185.425	1226.501	1.782	7.77%
mBin.Feb07	9169.547	2957.488	3.1	0.25%
mBin.Aug07	-11554.105	2958.763	-3.905	0.02%
mBin.Feb11	14600.112	2824.431	5.169	0.00%
mBin.Mar11	15578.616	2834.929	5.495	0.00%
mBin.Mar14	-9255.279	2834.564	-3.265	0.15%
mBin.Sep14	10340.745	2834.404	3.648	0.04%
mBin.Nov14	-7197.788	2834.354	-2.539	1.26%

Model Statistics	
Iterations	1
Adjusted Observations	125
Deg. of Freedom for Error	104
R-Squared	0.84
Adjusted R-Squared	0.809
Model Sum of Squares	3,904,473,673.97
Sum of Squared Errors	744,863,544.44
Mean Squared Error	7,162,149.47
Std. Error of Regression	2,676.22
Mean Abs. Dev. (MAD)	1,770.20
Mean Abs. % Err. (MAPE)	3.54%
Durbin-Watson Statistic	1.844

Figure 23: Other Sales Model



Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	906.36	9.83	92.207	0.00%
mBin.MayDec11	84.959	11.354	7.483	0.00%
mBin.Sep12Plus	-118.762	9.719	-12.219	0.00%
mBin.AftAug13	-146.77	12.775	-11.489	0.00%
mBin.AftJul14	-101.689	13.536	-7.512	0.00%
mBin.Apr15Plus	-103.634	12.943	-8.007	0.00%
mBin.Jan	6.754	13.385	0.505	61.49%
mBin.Feb	-27.748	13.085	-2.121	3.63%
mBin.Mar	-51.752	13.085	-3.955	0.01%
mBin.Apr	-16.898	13.141	-1.286	20.13%
mBin.May	-29.981	13.088	-2.291	2.40%
mBin.Jun	-15.988	13.38	-1.195	23.48%
mBin.Jul	-6.097	13.372	-0.456	64.93%
mBin.Aug	-5.927	13.372	-0.443	65.85%
mBin.Sep	15.807	13.706	1.153	25.14%
mBin.Oct	-19.656	13.337	-1.474	14.35%
mBin.Nov	-9.898	13.337	-0.742	45.96%
mBin.Sep06	-254.949	31.586	-8.072	0.00%
mBin.Jan10	189.879	31.363	6.054	0.00%

Model Statistics	
Iterations	1
Adjusted Observations	125
Deg. of Freedom for Error	106
R-Squared	0.977
Adjusted R-Squared	0.973
F-Statistic	248.643
Prob (F-Statistic)	0
Model Sum of Squares	3,980,497.00
Sum of Squared Errors	94,274.51
Mean Squared Error	889.38
Std. Error of Regression	29.82
Mean Abs. Dev. (MAD)	20.56
Mean Abs. % Err. (MAPE)	2.94%
Durbin-Watson Statistic	1.706

COST OF SERVICE
TEST YEAR ENDED March 31, 2016

GREEN MOUNTAIN POWER CORPORATION
August 1, 2016

Rate Year 2017

COST OF SERVICE - $ in 000s	PER BOOKS BALANCES (1)	ADJUSTMENT COL3-COL1 (2)	PROFORMA BALANCES (3)
Operating Expenses:			
Purchased Power, Net	$249,023	$7,261	$256,284
Production	25,845	(1,101)	24,744
Other Power Supply	967	2,226	3,193
	--------	-------	--------
Purchased Power and Production	275,835	8,386	284,221
Transmission	94,397	1,123	95,520
Transmission - Other	3,550	2,085	5,635
Distribution	31,907	12,652	44,559
Customer Accounting	9,079	1,160	10,239
Customer Service and Information	2,573	33	2,606
Sales	13	(13)	0
Administrative and General	40,669	14,527	55,196
Non Base O&M Costs - AMI	1,935	(1,193)	742
Non Base O&M Costs - KCW	930	27	957
Non Base O&M Costs - VMPD	263	(150)	113
Non Base O&M Costs - 7496 MOU	0	0	0
Acct 929	128	(472)	(344)
Business Development	556	0	556
Depreciation & Amortization	52,829	(4,120)	48,709
Taxes - Federal and State	32,887	1,503	34,390
- Municipal	24,908	2,974	27,882
- Other, excluding Revenue Taxes	2,924	(49)	2,875
Accretion Expense	231	17	248
Capital Costs (Credit Facility Fees)	445	(348)	97
	--------	-------	--------
Total Operating Expenses	576,057	38,143	614,200
Return on Utility Rate Base	84,113	11,123	95,235
	--------	-------	--------
Total Cost of Service Before Credits	660,170	49,265	709,435
Less:			
Equity in Earnings of Affiliates	62,066	21,092	83,158
Other Operating Revenues	22,526	(763)	21,763
Business Development	742	(0)	742
VY Insurance	0	0	0
Interest Due From ISO-NE	0	0	0
Resales	0	0	0
	--------	-------	--------
Total Credits	85,334	20,329	105,662
Cost of Service to Ultimate Consumers	574,836	28,936	603,772
Gross Revenue & Fuel Gross Receipts Taxes	6,137	29	6,166
	--------	-------	--------
Total Cost of Service to Ultimate Consumers	580,973	28,965	609,938
Merger savings			(16,335)
Settlement Adjustment			(300)
Total Cost of Service to Ultimate Consumers			593,303
Revenue from Ultimate Consumers			592,464
Increase in Revenue due to SmartPower Implementation			981
Revenue Deficiency from Ultimate Consumers			(142)
Revenue Adjustment Percent			**-0.03%**

Bolded, italicized text indicates functional categories in Base O&M Costs. excludes psa

psa impact >> 0.96% 2.3/1

RATE BASE INVESTMENT
TEST YEAR ENDED March 31, 2016
$ in 000s

GREEN MOUNTAIN POWER CORPORATION
August 1, 2016

	13 MONTH AVG BALANCES (1)	ADJUSTMENT COL3-COL1 (2)	PRO FORMA BALANCES (3)
Production	$502,293	$30,304	$532,597
Transmission	211,029	6,947	217,976
Distribution	725,480	53,605	779,085
General	171,925	24,023	195,948
Utility Plant in Service	1,610,727	114,879	1,725,606
Community Energy & Efficiency Development Fu	14,408	2,055	16,463
Subtotal	1,625,135	116,934	1,742,069
Construction Work in Progress	43,195	(34,317)	8,878
Investment in Affiliates			
Generation Vermont Yankee	933	(0)	933
Generation Maine Yankee	49	0	49
Generation Connecticut Yankee	33	(0)	33
Generation Yankee Atomic	52	(0)	52
Green Lantern	1,041	(0)	1,041
Transmission NE Hydro Trans	174	(174)	0
Transmission NE Hydro Trans Electric	458	331	789
Transmission VELCO - Common	10,556	0	10,556
JV Solar	1,405	48,170	49,574
Transmission TRANSCO LLC	419,300	60,284	479,584
SUBTOTAL	2,102,331	191,227	2,293,558
Special Deposits	658	0	658
Unamortized Debt Discount and Expense	5,160	(54)	5,106
Millstone 3 Energy and Capacity	452	37	488
17420~Renewable Energy Certificates	3,930	0	3,930
18225~Gorge Repowerment	454	(227)	227
18230~Regulatory Asset-Asset Retirement Oblig	340	(46)	294
18235~Reg Asset - Vmpd Value Sharing Pool	401	(191)	210
18233~Reg Asset - 2013 Nta Study	95	(95)	0
18236~Reg Asset - Depreciation Study	65	(29)	35
18238~Reg Asset - Deerfield Wind Costs	856	(408)	448
18250~Reg Asset - Retired Meter Cost	6,721	(3,360)	3,360
18611~Jv Solar Abandoned Sites	46	57	103
18612~Def Asset-Low Income Disc Payments	400	(150)	250
18613~Def Asset-Efficiency Fund Payments	4,477	(1,320)	3,157
18640~Cv Hq Cont Rochester	1	(1)	0
18647~Rate Design	309	(309)	0
18652~Vtel Smartgrid Payt	1,550	843	2,393
Net Plant Removal	0	6,462	6,462
Tax FAS 109	5,329	443	5,772
Subtotal	31,242	1,652	32,894

Working Capital Allowance:			
Material and Supplies Inventory includ	20,499	0	20,499
Millstone III Nuclear Fuel Inventory (I	1,919	9	1,928
Construction Blanket Work Orders			
Prepayments	7,844	0	7,844
Less: 1/8 Bond Interest Expense (inclu	(3,727)	0	0
Lead -Lag Working Capital Allowance	15,601	(504)	8,623
Subtotal Working Capital	42,136	(495)	38,894
DEDUCT:			
ACCUMULATED DEPRECIATION/AMORT.	586,405	53,256	639,661
Customer Advances for Construction	5,923	(5,632)	291
DEFERRED CREDITS			
Accumulated Deferred Income Taxes	287,976	60,155	344,291
Accumulated Deferred Investment Tax Credit	1,653	(249)	1,404
25352~Unclaimed Prprty-Cust Refunds	48	0	48
25353~Unclaimed Prprty-A/P Checks	0	0	0
25392~Insurance Settlements	3,475	0	3,475
25393~Health Insurance Reserve	1,213	0	1,213
22820~Accum Prov-Injuries And Damages	0	0	0
25343~Reg Liab - Vynpc Val Allow	283	(283)	0
25361~Reg Liab-Neil Vy	474	0	474
25363~Reg Liab-Brattleboro Environ Reserve	0	0	0
25379~ESTIMATED EXCESS CUSTOMER SYNERGY	50	(50)	0
25380~Reg Liab Cow Power Marketing	1	0	1
25381~Def Rev-So2 Emission Allowances	7	0	7
25390~Reg Liab Smartpower Overcoll-In Current	0.0	0	0
25358~Reg Liab-Earnings Sharing	2	(2)	0
24216~Misc Curresidual-Fin 45 Leas	18	(18)	0
24230~Vmpd Phase-In Current	359	(186)	173
23000~Asset Retirement Liability	5,289	0	5,289
23480~Nothern Water Res- Accounts Payable	5,305	0	5,305
24206~Misc Cur Workers Comp Major	1,863	0	1,863
25378~Ciac Reg Liability	4,100	(1,450)	2,650
25402~Reg Liab Production Tax Credit	95	523	618
2XXXX~REG LIAB JV SOLAR SMOOTHING	0	8,430	8,430
253XX-PLANT REMOVAL	0	4,712	4,712
CVPS - CIS Credit	0	56	56
Enhanced Veg Management	0	1,200	1,200
SERP	3,839	(96)	3,743
Accrued Pension Expense	(13,627)	347	(13,280)
Acc. Post-Ret. Medical Expense FAS 106	678	(735)	(57)
Acc. Other Post-Employment Ben. Exp. FAS 1	1,129	(121)	1,008
SUBTOTAL	896,559	119,856	1,012,575
TOTAL RATEBASE INVESTMENT	1,279,151 1,224,082	72,527	1,352,771

Schedule 3

GREEN MOUNTAIN POWER CORPORATION
August 1, 2016

Rate Year October 2016 - September 2017
COST OF CAPITAL
TEST YEAR ENDED March 31, 2016

Effective Tax Rate = 0.40525

$ in 000s	Invested Capital Per Books	Proforma Adjustments	Invested Capital Proforma	Proportion of Total Percentage	Cost Rate Percentage	Cost of Component Percentage	Cost of Pre Tax % Percentage
Long-Term Debt Bonds	605,848	62,372	668,220	44.58%	5.34%	2.38%	2.38%
Short-Term Debt Bank Loans	56,080	20,596	76,675	5.12%	2.27%	0.12%	0.12%
Total Debt	661,928	82,968	744,895	49.70%	5.02%	2.50%	2.50%
Common Equity	656,840	97,115	753,955	50.30%	9.02%	4.54%	7.63%
Total Capital	1,318,768	180,082	1,498,850			7.04%	10.13%

Schedule 4

CALCULATION OF INCOME TAX EXPENSE
TEST YEAR ENDED March 31, 2016

GREEN MOUNTAIN POWER CORPORATION
August 1, 2016

$ in 000s	PRO FORMA
Total rate base investment	1,352,771
Return % (Total Cost of capital	7.04%
Return on utility rate base	95,235
Add back:	
Federal income tax	26,245
State income tax	8,145
Return before taxes	129,625
Less interest (Wtd. Cost of Debt X Rate Base)	33,819
Subtotal	95,806
Additions & deductions for income tax purposes:	
Non-taxable portion of equity in earnings of VELCO	(344)
Non-taxable portion (100%) of equity in earnings of Vermont Yankee	(70)
Non-taxable portion (70%) of equity in earnings of MY, CY, YA, NEHT and NEHTE	0
Non-deductible AFUDC-equity	405
Non-depreciable ITC basis reduction	109
Non-deductible meals expense	111
Domestic production activities deduction	0
Total additions & deductions	210
Balance	96,016
Less state income tax (8.5% of Line 27)	8,161
Taxable income	87,855
Federal Income Tax Calculation:	
Federal income tax before credit at 35%	30,749
Investment credit amortization	(14)
Production Tax Credit	(4,451)
CAFC Perm	(60)
FAS 109 ITC Basis Adjustment	12
AFUDC Deferred Tax Adjustment	10
Federal income tax	26,245
Excess Deferred Tax & Con Adj	0
Total Federal Income Taxes	26,245
State Income Tax Calculation:	
Taxable income at 8.5%	8,161
Vermont income tax rate change adjustment	9
Vermont Solar ITC	(32)
ITC Basis Adj	3
AFUDC Deferred Tax Adj	3
Total State Income Taxes	8,144
TOTAL STATE AND FEDERAL INCOME TAX	34,390

Schedule 5

GREEN MOUNTAIN POWER CORPORATION
COST OF SERVICE ANALYSIS
TEST YEAR ENDED March 31, 2016
$ in 000s

GREEN MOUNTAIN POWER CORPORATION
August 1, 2016

Adj. No.	Description	Total	Purchased Power	Power Supply Production	Other Power Supply	Power Adjustor Trans-mission	Other Trans-mission	Distri-bution	Customer Accounting	Customer Service	Sales	Admin. & General	Deprec-iation	Income Taxes	Municipal Taxes	Other Taxes	Other
1	Purchased Power, net	7,261	7,261														
2	Production Fuel	(261)		(261)													
3	Joint Ownership Costs	(900)		(900)		-									-		
4	Transmission by Others	676				676											
5	ISO New England Charges	447				447											
6	Wholly-Owned Production	60		60													
7	Base O&M Adjustment	32,670			2,226		2,085	12,652	1,160	33	(13)	14,527					
8	Non Base O&M Costs / Benefits - SmartPower	(1,193)															(1,193)
9	Non Base O&M Costs - VMPD Tree Trimming	(150)															(150)
10	Non Base O&M Costs - KCW & Synch Condenser	27															27
11	Vermont Unemployment	4														4	
12	Social Security Taxes	(53)														(53)	
13	Depreciation Expense	5,561											5,561				
14	Federal & State Income Taxes	1,503												1,503			
15	CEED amortization	611											611				
16	Equity in Earnings of Affiliates	(21,092)															(21,092)
17	Property Taxes	2,974													2,974		
18	Business Development - Revenue	0															-
18	Business Development - Expense	0															-
19	Other Operating Revenues	763															763
20	Reg Assets, Deferred Debits & Reg Liabilities	(8,456)											(8,456)				
21	Accretion Expense	17															17
22	Credit Facility Fees	(348)															(348)
23	Acct 929 Generation Company use of Electricity	(472)															(472)
24	Removal of Regulatory Deferrals in Test Year	(1,836)											(1,836)				
25	Gross Revenue & Fuel Gross Receipts Taxes	29															29
26	Return on Utility Rate Base	11,123															11,123
	Total Cost of Service Adjustments	$28,964	$7,261	($1,101)	$2,226	$1,123	$2,085	$12,652	$1,160	$33	($13)	$14,527	($4,120)	$1,503	$2,974	($49)	($11,297)

GREEN MOUNTAIN POWER CORPORATION
RATE BASE ANALYSIS
TEST YEAR ENDED March 31, 2016
Rate Year October 2016 - September 2017

GREEN MOUNTAIN POWER CORPORATION
August 1, 2016

Adj. No.	Description	13 MONTH AVERAGE BALANCES	Rate Base Adjustment	PRO FORMA BALANCES
1	Production	$502,293	$30,304	$532,597
2	Transmission	211,029	6,947	217,976
3	Distribution	725,480	53,605	779,085
4	General	171,925	24,023	195,948
5	Community Energy & Efficiency Development Fund	14,408	2,055	16,463
6	Investment in Affiliates	434,001	108,610	542,611
7	Special Deposits	658	0	658
8	Unamortized Debt Discount and Expense	5,160	(54)	5,106
9	Construction Work In Progress	43,195	(34,317)	8,878
10	TY 2015-16 Millstone 3 Energy/Capacity	452	(452)	0
11	RY 2017 Millstone 3 Energy/Capacity	0	488	488
12	Working Capital Allowance	42,137	(38)	42,099
13	Reg Assets, Deferred Debits	18,094	(6,080)	12,014
14	Vtel Contract	1,550	843	2,393
15	Change in Net Plant Removal	0	6,462	6,462
16	Tax FAS 109	5,329	443	5,772
17				
18	Less:			
19	Accumulated Depreciation	586,405	53,256	639,661
20	Customer Advances for Construction CIAC	5,923	(5,632)	291
21	Accumulated Deferred Income Taxes	284,136	60,155	344,291
22	Accumulated Deferred Investment Tax Credits	1,653	(249)	1,404
23	Reg Liabilities	17,277	11,676	28,953
24	Northern Water Res - Accounts Payable	5,305	0	5,305
25	Accrued Pension Expense	(13,627)	347	(13,280)
26	Acc. Post-Ret. Medical Expense FAS 106	678	(735)	(57)
27	Acc. Other Post-Employment Ben. Exp. FAS 112	1,129	(121)	1,008
28	Supplemental Executive Retirement Benefits (SERP	3,839	(96)	3,743

Green Mountain Power Corporation

For the Test Year Ended March 31, 2016

Line No.	Description	Per Books 12 mo 3/31/16
	Operating Expenses:	
1	Purchased Power , net	249,023,147.94
2	Production	25,844,975.89
3	Other Power Supply	966,718.88
4	Purchased Power and Production	
5	Transmission	93,767,734.92
6	Transmission - Other	5,040,404.00
7	Distribution	31,907,403.80
8	Customer Accounting	9,078,880.20
9	Customer Service and Information	2,598,283.69
10	Sales	13,102.33
11	Administration and General	42,909,336.91
12	Non Base O&M Costs - AMI	
13	Non Base O&M Costs - KCW	
14	Non Base O&M Costs - VMPD	
15	Non Base O&M Costs - FERC Acct 929	127,833.15
16		
17	Business Development Expense	555,624.21
18	Depreciation and Amortization	52,829,347.10
19	Taxes - Federal and State	32,886,731.00
20	- Municipal	24,907,762.65
21	- Other, Excluding Revenue Taxes	2,924,212.54
	Accretion Expense	231,141.29
22	Capital Costs	444,729.37
23	Total Operating Expenses	
24	Return on Utility Rate Base	
25	Total Cost of Service Before Credits	
		-
	Less:	
26	Equity in Earnings of Affiliates	(62,065,519.53)
27	Other Operating Revenues	(22,525,915.03)
28	Business Development	(742,194.35)
29	Total Credits	

30	Cost of Service to Ultimate Consumers	
31	Gross Revenue & Fuel Gross Receipts Taxes	6,137,210.53
32	Total Cost of Service to Ultimate Consumers	
33	Merger Savings	
34	Total Cost of Service to Ultimate Consumers	
35	Revenue from Ultimate Consumers	(593,538,634.66)
36	Revenue Deficiency (Sufficiency) from Ultimate Consumers	

TO RECONCILE	
Non Operating Expense	5,373,190.61
Non Operating Revenue	(4,101,298.67)
Interest costs collected through Return on Ratebase	34,385,808.18
TOTAL	(61,019,983.05)
from Trial bal 3/31/16	(61,019,983.05)
difference	0.00

Exh. EFR-6

GREEN MOUNTAIN POWER CORPORATION
RATE BASE AND COST OF SERVICE
TEST YEAR ENDED March 31, 2016
DEPRECIATION /AMORTIZATION

	Test Year	Adjustment	Rate Year September 2017	
TOTAL AMORTIZATION CHARGED AGAINST INCOME				
Depreciation & Amortization	$52,829,347	($4,120,000)	$48,709,347	
Adjustments:				
Depreciation Expense	47,347,916	5,560,651	52,908,567	adj 13
CEED Amortization	1,167,224	610,601	1,777,825	adj 15
Reg Assets, Deferred Debits & Reg Liabilit:	2,478,015	(8,455,836)	(5,977,821)	adj 21
Other unadjusted	1,836,192	(1,835,416)	776	
Check Total	52,829,347	(4,120,000)	48,709,347	
	=========	=========	=========	

Green Mountain Power Corporation
RATE BASE AND COST OF SERVICE
TEST YEAR ENDED March 31, 2016
Rate Year October 2016 - September 2017

PROPERTY TAX

Taxes Other than Income - Operating	Test Year	Adjust	Rate Year
408 Municipal Property:			
Other - Vermont *	$22,546,351	$2,930,649	$25,477,000
Dam Purchase ***	0	0	0
KCW	1,102,386	43,614	1,146,000
McNeil **	379,627	(0)	379,627
Highgate **	522,622	0	522,622
Total Vermont	24,550,985	2,974,264	27,525,249
Maine - Wyman **	36,260	(0)	36,260
Mass. - MMWEC **	81,454	(0)	81,454
Conn. - Millstone **	239,063	0	239,063
Total Property Taxes	24,907,763	2,974,263	27,882,026

*Additional $260,000 included in VT for major sub upgrades and Montpelier service center upgrade in FY2017
**Joint Owned figures equal test year amounts

GREEN MOUNTAIN POWER CORPORATION
RATE BASE AND COST OF SERVICE
TEST YEAR ENDED March 31, 2016
GROSS REVENUE TAX CALCULATION

Exh. EFR-7

2016

GROSS REVENUE TAX RATE t=	1.04%	Adjusted
$ in 000s		
GENERAL FORMULA: GRT=	(t*(COS-GRT))/(1-t)	

	PROFORMA
COST OF SERVICE TO ULT CUST (COS)	593,604
LESS GROSS REVENUE TAX (GRT)	6,167
	587,437
TIMES GROSS REV TAX RATE (t)	1.04%
	6,102
DIVIDED BY 1 MINUS TAX RATE (1-t)	98.96%
GROSS REVENUE TAX TOTAL (GRT)	6,166

	MAR-2016	FEB-2016	JAN-2016	DEC-2015	NOV-2015	OCT-2015	SEP-2015	AUG-2015	JUL-2015	JUN-2015	MAY-2015	APR-2015	MAR-2015	13 Month Average	Production 13 month avg	General 13 month avg
Electric Plant in Service:																
Intangible	64,219,124	64,479,503	64,455,030	63,448,616	63,448,616	63,047,479	63,009,489	60,676,008	60,676,008	60,338,376	60,410,275	60,317,492	60,257,213	62,214,095		
Steam Production	34,353,435	34,353,435	34,353,435	34,353,435	34,353,435	34,353,435	34,353,435	34,353,435	34,353,435	36,163,715	35,257,069	35,257,069	35,257,069	34,701,218		
Nuclear Production	81,388,435	81,388,435	81,388,435	81,388,435	81,388,435	81,388,435	81,388,435	81,388,435	81,388,435	81,388,435	80,796,679	80,796,679	80,796,679	81,251,876		
Hydro Production	200,407,863	199,092,720	197,938,473	197,685,026	196,755,165	196,755,165	196,757,911	196,429,597	196,429,221	196,065,981	194,252,002	183,000,525	182,980,728	194,965,414		
Other Production	193,926,327	192,524,293	192,424,297	192,501,093	191,093,340	190,845,969	190,839,991	190,840,973	190,840,973	190,636,568	190,617,429	190,574,524	190,202,908	191,374,514	502,293,022	
Transmission	217,104,715	216,889,867	215,807,228	213,460,791	213,360,147	213,403,655	213,352,990	208,893,479	208,061,376	207,990,417	206,017,375	204,598,297	204,437,559	211,029,069		
Distribution	750,364,495	739,922,025	736,604,873	731,108,008	730,173,282	728,183,817	726,830,724	718,312,761	716,979,147	715,575,082	712,812,396	712,306,836	712,071,271	725,480,363		
Transportation	24,680,244	24,238,336	24,238,336	23,571,762	23,571,762	23,570,301	23,571,388	20,417,914	21,443,477	21,375,973	21,373,603	21,364,902	21,150,760	22,659,135		
General	89,415,870	87,773,100	87,288,697	87,019,045	86,975,325	86,382,923	86,344,417	84,387,297	87,930,834	87,322,419	87,264,889	86,807,318	86,765,499	87,052,126		171,925,355
Total Plant in Service	1,655,860,509	1,640,661,714	1,634,498,804	1,624,536,211	1,621,119,507	1,617,931,178	1,616,448,780	1,595,699,898	1,598,102,906	1,596,856,966	1,588,801,717	1,575,023,643	1,573,919,685	1,610,727,809		
Nuclear Fuel, net	2,480,765	2,581,980	2,676,651	1,585,862	1,686,986	1,785,003	1,885,945	1,740,400	1,826,049	1,933,699	2,045,964	2,147,401	575,921	1,919,433		
Accum Prov for Depreciation & Amortization																
Intangible	(24,626,758)	(25,487,214)	(24,803,209)	(24,133,084)	(23,462,959)	(22,799,520)	(22,136,715)	(21,512,800)	(20,888,886)	(20,270,798)	(19,651,512)	(19,033,773)	(18,417,038)	(22,094,174)		
Steam Production	(30,486,838)	(30,392,435)	(30,298,033)	(30,203,630)	(30,109,227)	(30,014,824)	(29,920,422)	(29,826,019)	(29,731,616)	(30,267,338)	(30,170,316)	(30,073,294)	(29,976,273)	(30,113,097)		
Nuclear Production	(46,952,433)	(46,869,022)	(46,785,611)	(46,702,200)	(46,618,789)	(46,535,378)	(46,451,966)	(46,368,555)	(46,285,144)	(46,201,733)	(46,118,928)	(46,036,124)	(45,953,319)	(46,452,246)		
Hydro Production	(72,995,794)	(72,612,664)	(72,137,087)	(71,564,747)	(71,652,795)	(71,082,621)	(70,514,559)	(70,083,148)	(69,514,628)	(68,957,827)	(68,413,468)	(69,691,010)	(69,149,126)	(70,643,806)		
Other Production	(50,295,402)	(49,658,953)	(49,022,940)	(48,386,755)	(47,753,176)	(47,148,974)	(46,544,787)	(45,940,574)	(45,336,361)	(44,757,241)	(44,153,575)	(43,550,046)	(42,947,769)	(46,576,658)		
Transmission	(66,519,413)	(66,300,624)	(65,985,768)	(65,689,255)	(65,397,122)	(65,163,596)	(64,852,504)	(64,686,023)	(64,383,391)	(64,090,313)	(63,868,741)	(63,574,727)	(63,275,545)	(64,906,694)		
Distribution	(282,510,867)	(281,557,561)	(280,721,546)	(280,551,106)	(279,502,183)	(278,697,018)	(277,924,867)	(277,486,462)	(276,490,566)	(275,405,043)	(274,487,677)	(273,746,071)	(272,535,415)	(277,816,645)		
Transportation	(10,280,322)	(10,158,003)	(10,035,684)	(9,917,060)	(9,798,436)	(9,679,820)	(9,561,197)	(9,454,564)	(10,371,798)	(10,241,947)	(10,125,003)	(10,008,060)	(9,892,253)	(9,963,396)		
General	(19,349,237)	(18,975,673)	(18,753,350)	(18,382,518)	(18,011,833)	(17,645,858)	(17,288,279)	(16,948,980)	(20,147,987)	(19,817,044)	(19,470,970)	(19,117,025)	(18,763,193)	(18,667,073)		
Retirement Work in Progress	714,976	648,980	719,073	844,769	1,041,463	1,065,672	872,910	997,430	625,300	441,494	511,932	1,157,748	1,127,378	828,394		
Total Deprec & Amort.	(603,302,088)	(601,363,169)	(597,824,154)	(594,685,586)	(591,265,057)	(587,701,938)	(584,322,385)	(581,309,694)	(582,525,076)	(579,567,789)	(575,948,258)	(573,672,382)	(569,782,553)	(586,405,395)		
Construction Work in Progress	38,496,544	47,073,130	47,688,751	52,672,225	49,434,026	46,883,611	40,373,855	48,023,418	40,299,090	34,775,408	35,142,242	43,009,028	37,665,918	43,195,173		
Investment in Assoc Cos																
VT Yankee	934,034	945,709	939,872	934,034	945,709	939,872	934,034	940,597	934,760	929,672	923,834	917,997	912,159	933,253		
Conn Yankee	33,786	33,641	33,532	33,532	33,468	33,322	33,207	33,149	33,023	32,881	32,702	32,642	32,482	33,182		
Mass Yankee	52,149	52,161	52,226	52,226	52,331	52,330	52,330	52,549	52,414	52,416	52,687	52,793	52,793	52,416		
Maine Yankee	45,473	45,238	45,109	45,109	51,047	50,819	50,588	50,427	50,225	49,997	49,814	49,593	49,372	48,678		
Green Lantern	1,011,437	1,022,623	1,024,351	1,024,465	1,026,893	1,031,662	1,037,173	1,042,706	1,054,650	1,059,873	1,065,099	1,068,445	1,069,638	1,041,463		
VELCO	10,377,506	10,568,039	10,709,936	10,592,352	10,896,884	10,511,107	10,464,701	10,638,153	10,556,370	10,440,867	10,600,227	10,478,274	10,389,629	10,555,696		
NE Hydro Trans Co	185,560	183,844	181,949	180,054	178,159	176,264	174,369	172,474	170,579	168,684	166,789	164,894	162,999	174,355		
NE Hydro Trans Electric	502,515	495,829	488,237	480,645	473,053	465,461	457,869	450,277	442,685	435,093	427,501	419,909	412,317	457,799		
Transco LLC	430,221,838	425,109,838	419,933,754	427,055,720	421,943,720	417,850,449	424,859,235	416,002,235	411,074,494	418,569,055	413,641,752	408,585,189	416,051,107	419,299,876		
JV Solar	2,205,169	1,858,236	1,765,909	1,930,554	1,694,057	1,662,138	1,494,875	1,382,923	1,311,580	980,242	826,713	583,706	563,400	1,404,577		
Total Invest in Utility Assoc Co	445,569,468	440,315,157	435,174,874	442,328,690	437,295,322	432,773,425	439,558,381	430,765,491	425,680,780	432,718,780	427,787,118	422,353,441	429,695,895	434,001,294		
Special Deposits	2,484,479	1,983,799	1,983,192	2,009,908	9,908	9,908	9,908	9,908	9,908	9,908	9,908	9,908	9,908	657,735		
Deferred Charges																
Unamortized Debt Discount	5,231,160	5,260,877	5,290,465	5,294,372	5,008,704	4,996,344	5,033,267	5,068,392	5,105,412	5,141,380	5,178,265	5,215,040	5,252,119	5,159,677		
17420~Renewable Energy Certificates	3,822,749	4,276,274	3,612,936	2,996,883	4,036,342	3,410,700	2,816,549	4,515,327	4,229,651	3,847,282	5,069,382	4,539,391	3,922,992	3,930,497		
18225~Gorge Repowerment	378,028	390,629	403,230	415,831	428,432	441,032	453,633	466,234	478,835	491,436	504,037	516,638	529,239	453,633		
18233~Reg Asset - 2013 Nta Study	47,259	55,136	63,012	70,889	78,765	86,642	94,518	102,395	110,271	118,148	126,024	133,901	141,777	94,518		
18235~Reg Asset - Vmpd Value Sharing Pool	349,497	361,147	372,797	384,446	396,096	407,746	419,396	419,396	419,396	419,396	419,396	419,396	419,396	400,577		
18236~Reg Asset - Depreciation Study	54,370	52,510	55,255	58,000	60,745	63,490	66,235	67,800	69,364	70,928	72,493	74,057	75,621	64,682		
18238~Reg Asset - Deerfield Wind Costs	746,597	771,484	796,370	821,257	846,143	871,030	895,917	895,917	895,917	895,917	895,917	895,917	895,917	855,715		
18250~Reg Asset - Retired Meter Cost	5,600,523	5,787,207	5,973,891	6,160,575	6,347,259	6,533,943	6,720,627	6,907,311	7,093,995	7,280,680	7,467,364	7,654,048	7,840,732	6,720,627		
18255~Nuclear Def Outage Costs	-	75,267	150,535	225,802	301,069	376,337	451,604	526,872	602,139	677,406	752,674	827,941	903,208	451,604		
18652~Vtel Smartgrid Payt	1,550,000	1,550,000	1,550,000	1,550,000	1,550,000	1,550,000	1,550,000	1,550,000	1,550,000	1,550,000	1,550,000	1,550,000	1,550,000	1,550,000		
18611~Jv Solar Abandoned Sites	198,324	198,324	198,324	-	-	-	-	-	-	-	-	-	-	45,767		
18612~Def Asset-Low Income Disc Payments	350,035	358,369	366,703	375,037	383,372	391,706	400,040	408,374	416,708	425,042	433,377	441,711	450,045	400,040		
18613~Def Asset-Efficiency Fund Payments	4,009,679	4,090,632	4,161,776	4,247,871	4,318,943	4,398,503	4,469,647	4,549,083	4,629,581	4,710,187	4,791,538	4,870,270	4,954,564	4,477,098		
18628~Ceed Fund Def Chg	15,571,965	15,229,921	15,208,739	15,121,481	14,853,944	14,639,510	14,119,443	14,041,969	13,918,983	13,848,289	13,518,425	13,590,614	13,642,777	14,408,158		
18647~Rate Design	442,565	407,170	393,970	391,939	384,117	380,223	345,633	332,156	327,691	324,780	289,970	-	-	309,247		
18640~Cv Hq Cont Rochester	-	-	175	351	526	702	877	1,053	1,228	1,403	1,579	1,754	1,930	891		
Total Deferred Charges	38,352,750	38,864,946	38,598,179	38,114,733	38,994,457	38,547,908	37,837,386	39,852,277	39,849,172	39,802,275	41,070,440	40,730,678	40,580,317	39,322,732		
18230~Regulatory Asset-Asset Retirement Obligation	324,997	327,577	330,156	332,735	335,315	337,894	340,474	343,053	345,632	348,212	350,791	353,370	355,950	340,474		
	324,997	327,577	330,156	332,735	335,315	337,894	340,474	343,053	345,632	348,212	350,791	353,370	355,950	340,474		
ADIT																
19010~Accum Deferred Income Tax-Fed	111,588,291	115,869,240	115,737,811	116,220,016	70,590,542	71,414,553	75,187,161	70,301,481	72,278,100	74,415,266	77,584,157	74,030,662	74,945,648	86,166,379		
19011~Deferred Tax Asset Current Portion	-	-	-	-	31,893,684	30,569,971	31,808,405	35,535,220	34,291,121	32,612,080	31,260,375	29,350,369	28,901,191	22,017,109		
19015~Def Tax Asset Allowance Fed	931,193	932,871	934,058	935,880	887,403	936,339	935,731	933,503	939,278	935,474	952,485	951,410	970,322	936,611		
19020~Accum Deferred Income Tax-Stat	8,738,439	10,196,321	10,317,100	10,598,645	10,818,941	10,598,401	11,837,695	11,346,933	11,367,110	11,308,472	11,852,399	10,095,997	10,097,363	10,705,679		
19025~Def Tax Asset Allowance State	347,718	343,295	339,285	334,455	330,050	326,267	322,471	335,778	331,009	327,325	321,167	317,141	311,002	329,766		
19031~Unfunded Future Income Tax Fed	452,424	448,610	444,796	440,982	437,168	433,354	429,540	432,576	435,613	438,649	441,686	444,722	447,759	440,606		
19032~Unfunded Future Income Tax St	120,081	119,069	118,056	117,044	116,032	115,019	114,007	114,813	115,619	116,425	117,231	118,037	118,843	116,944		

	MAR-2016	FEB-2016	JAN-2016	DEC-2015	NOV-2015	OCT-2015	SEP-2015	AUG-2015	JUL-2015	JUN-2015	MAY-2015	APR-2015	MAR-2015	13 Month Average	Production 13 month avg	General 13 month avg
19041~Unfunded Current Income Tax Fd	45,079	47,435	49,794	52,150	54,507	56,865	59,222	66,326	73,432	80,536	87,641	94,745	101,850	66,891		
19042~Unfunded Current Income Tax St	11,964	12,590	13,215	13,841	14,467	15,092	15,718	17,604	19,489	21,375	23,261	25,147	27,032	17,753		
	122,235,189	127,969,431	127,954,115	128,713,013	115,142,794	114,465,861	120,709,950	119,084,234	119,850,771	120,255,602	122,640,402	115,428,230	115,921,010	120,797,739		
28210~Def Inc Tax-Fed Inc-Other Prop	(232,758,196)	(231,426,349)	(230,111,025)	(228,758,459)	(213,376,682)	(212,907,686)	(212,439,407)	(212,005,244)	(211,677,023)	(211,593,959)	(210,547,432)	(203,955,047)	(203,836,905)	(216,568,724)		
28211~Deferred Tax Liability Current Portion	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
28220~Def Inc Tax-St Inc-Other Prop	(37,953,195)	(37,641,581)	(37,334,356)	(37,017,245)	(36,708,207)	(36,385,459)	(36,062,903)	(35,711,365)	(35,390,666)	(35,136,142)	(34,842,340)	(32,680,687)	(32,413,018)	(35,790,552)		
28231~Unfunded Lt Fedrl Inc Tax Liab	(86,065)	(87,397)	(88,728)	(90,060)	(91,392)	(92,724)	(94,055)	(95,858)	(97,662)	(99,465)	(101,269)	(103,072)	(104,875)	(94,817)		
28232~Unfunded Lt State Inc Tax Liab	(22,843)	(23,196)	(23,550)	(23,903)	(24,257)	(24,610)	(24,964)	(25,443)	(25,921)	(26,400)	(26,878)	(27,357)	(27,836)	(25,166)		
28241~Unfunded Curr Fed Inc Tax Liab	(18,811)	(19,283)	(19,755)	(20,227)	(20,698)	(21,170)	(21,642)	(22,209)	(22,776)	(23,343)	(23,910)	(24,477)	(25,044)	(21,796)		
28242~Unfunded Curr St Inc Tax Liab	(4,993)	(5,118)	(5,243)	(5,368)	(5,494)	(5,619)	(5,744)	(5,894)	(6,045)	(6,195)	(6,346)	(6,496)	(6,648)	(5,785)		
28310~Def Inc Tax Fed Op Current	-	-	-	-	(8,929,507)	(9,392,018)	(7,081,339)	(4,778,226)	(4,295,607)	(4,042,960)	(4,759,883)	(5,657,084)	(6,897,804)	(4,294,956)		
28311~Def Inc Tax-State Inc-Oper	(21,038,287)	(22,018,299)	(22,000,176)	(22,029,391)	(21,641,699)	(21,194,170)	(22,205,818)	(20,841,028)	(20,317,802)	(19,884,276)	(19,896,190)	(19,934,306)	(19,954,053)	(20,996,576)		
28312~Excess Deferred Taxes - Fed	652,597	651,345	650,093	648,841	647,589	646,337	645,085	640,077	635,069	630,061	625,053	620,045	615,038	639,018		
28315~Def Inc Tax-St Inc-Other Inc	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
28317~Def Inc Tax-St Inc-Nonop	(5,777,311)	(5,777,311)	(5,777,311)	(5,777,311)	(5,777,311)	(5,777,311)	(5,777,311)	(5,777,311)	(5,777,311)	(5,777,311)	(5,777,311)	(5,777,311)	(5,777,311)	(5,777,311)		
28318~Def Inc Tax-Fed Inc-Nonop	(26,022,029)	(26,022,029)	(26,022,029)	(26,022,029)	(26,022,029)	(26,022,029)	(26,022,029)	(26,022,029)	(26,022,029)	(26,022,029)	(26,022,029)	(26,022,029)	(26,022,029)	(26,022,029)		
28320~Def Inc Tax State Current	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
28321~Def Inc Tax-Federal Inc-Oper	(103,632,942)	(107,329,611)	(107,265,656)	(107,380,056)	(96,994,189)	(94,849,873)	(100,976,413)	(98,748,292)	(97,268,846)	(95,980,750)	(95,308,716)	(94,555,121)	(93,388,801)	(99,513,790)		
25371~Accrued State Tax Longterm	(326,308)	(326,308)	(326,308)	(326,308)	(326,308)	(326,308)	(326,308)	(272,267)	(272,267)	(272,267)	(272,267)	(272,267)	(272,267)	(301,366)		
	(426,988,383)	(430,025,137)	(428,324,044)	(426,801,516)	(409,270,184)	(406,352,640)	(410,392,848)	(403,665,089)	(400,538,886)	(398,235,036)	(396,959,518)	(388,395,209)	(388,111,553)	(408,773,850)		
Total ADIT	(304,753,194)	(302,055,706)	(300,369,929)	(298,088,503)	(294,127,390)	(291,886,779)	(289,682,898)	(284,580,855)	(280,688,115)	(277,979,434)	(274,319,116)	(272,966,979)	(272,190,543)	(287,976,111)		
25510~Accum Def Inv Tax Cr-Oper 6	(1,508,607)	(1,517,292)	(1,596,162)	(1,610,162)	(1,624,162)	(1,638,163)	(1,652,163)	(1,672,849)	(1,693,535)	(1,714,221)	(1,734,907)	(1,755,593)	(1,776,279)	(1,653,391)		
CAFC																
25221~Cafc-Old Tarriff Line Extensn	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
25222~Cafc-Docket 5282-Line Extensin	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
25223~Cafc-Tax Surcharge-Line Extens	-	(3,082)	-	-	-	-	-	-	(7,752)	-	-	10	-	(833)		
25224~Cafc-Spare Conduit-Line Extens	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
25225~Cafc-Conduit Credt-Line Extens	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
25226~Cafc- Loop Credit -Line Extens	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
25227~Cafc-Refunds Existing Line Ext	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
25228~Cafc-Street Light Contrib	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
25229~Cafc Tax Surcharge Comm Connects Liab	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
25297~Cafc Tax Perm Diff	(354,309)	(359,864)	(365,418)	(370,973)	(376,528)	(382,082)	(387,637)	(393,493)	(399,348)	(405,204)	(411,059)	(416,915)	(422,770)	(388,123)		
25298~Finance Charge (Linex)	-	-	-	-	-	-	(10,400,472)	(10,302,661)	(10,239,529)	(10,261,893)	(10,208,183)	(10,232,572)	(10,292,986)	(5,533,715)		
	(354,309)	(362,946)	(365,418)	(370,973)	(376,528)	(382,082)	(10,788,109)	(10,696,154)	(10,646,629)	(10,667,097)	(10,619,242)	(10,649,477)	(10,715,756)	(5,922,671)		
Deferred Credits																
25351~Unclaimed Prprty-Dividend Cks	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
25352~Unclaimed Prprty-Cust Refunds	(43,603)	(44,771)	(46,778)	(46,778)	(46,778)	(46,778)	(46,778)	(46,778)	(46,778)	(46,767)	(47,999)	(48,070)	(60,251)	(47,608)		
25353~Unclaimed Prprty-A/P Checks	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
25392~Insurance Settlements	(3,743,887)	(3,262,792)	(3,262,792)	(3,241,792)	(3,495,580)	(3,495,580)	(3,459,867)	(3,580,820)	(3,580,820)	(3,705,820)	(3,460,505)	(3,460,505)	(3,424,996)	(3,475,058)		
25393~Health Insurance Reserve	(1,217,058)	(1,191,994)	(1,191,994)	(1,191,994)	(1,167,449)	(1,167,449)	(1,167,449)	(1,258,770)	(1,258,770)	(1,258,770)	(1,234,453)	(1,234,453)	(1,234,453)	(1,213,466)		
22820~Accum Prov-Injuries And Damages	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
	(5,004,548)	(4,499,557)	(4,501,564)	(4,480,564)	(4,709,807)	(4,709,807)	(4,674,094)	(4,886,368)	(4,886,368)	(5,011,357)	(4,742,957)	(4,743,028)	(4,719,700)	(4,736,132)		
22830~Long Term Disability Obligation	(961,695)	(971,950)	(981,900)	(991,850)	(1,002,106)	(1,012,056)	(1,022,311)	(923,758)	(932,860)	(942,267)	(951,370)	(960,472)	(969,879)	(971,113)		
24221~Curr Liab - Long Term Disability	(150,935)	(150,935)	(150,935)	(150,935)	(150,935)	(150,935)	(150,935)	(165,219)	(165,219)	(165,219)	(165,219)	(165,219)	(165,219)	(157,528)		
	(1,112,630)	(1,122,885)	(1,132,835)	(1,142,785)	(1,153,041)	(1,162,991)	(1,173,246)	(1,088,977)	(1,098,079)	(1,107,486)	(1,116,589)	(1,125,691)	(1,135,098)	(1,128,641)		
25343~Reg Liab - Vynpc Val Allow	-	-	-	-	-	-	-	(175,111)	(350,222)	(525,333)	(700,444)	(875,555)	(1,050,666)	(282,872)		
25361~Reg Liab-Neil Vy	(690,306)	(408,731)	(408,731)	(408,731)	(408,731)	(429,369)	(429,369)	(449,369)	(469,369)	(461,161)	(481,229)	(539,873)	(577,202)	(474,013)		
25363~Reg Liab-Brattleboro Environ Reserve	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
25379~Reg Liab Cvps Esam Overcollection	(600,000)	26	26	26	26	26	26	(2,090)	(4,207)	(6,323)	(8,439)	(10,555)	(12,671)	(49,548)		
25380~Reg Liab Cow Power Marketing	(377)	(377)	(377)	(13,577)	(377)	(377)	(377)	(377)	(377)	(377)	(377)	(377)	(1,168)	(1,453)		
25381~Def Rev-So2 Emission Allowances	-	-	-	-	(2,060)	(4,119)	(6,179)	(8,239)	(10,298)	(12,358)	(14,418)	(16,477)	(18,537)	(7,130)		
25390~Reg Liab Smartpower Overcoll-In Current	454	454	-	-	-	-	-	-	-	-	-	-	-	70		
25358~Reg Liab-Earnings Sharing	-	-	-	-	-	(6,450)	(6,450)	(1,600)	(1,600)	(1,600)	(1,600)	(1,600)	(1,600)	(1,731)		
24216~Misc Curresidual-Fin 45 Leas	-	-	-	-	(25,485)	(25,485)	(25,485)	(25,485)	(25,485)	(25,485)	(25,485)	(25,485)	(25,485)	(17,644)		
23000~Asset Retirement Liability	(5,422,880)	(5,363,315)	(5,363,315)	(5,363,315)	(5,306,123)	(5,306,123)	(5,306,123)	(5,248,931)	(5,248,931)	(5,248,931)	(5,191,739)	(5,191,739)	(5,191,739)	(5,288,708)		
24206~Misc Cur Workers Comp Major	(2,253,069)	(2,140,241)	(2,233,370)	(2,064,907)	(2,114,614)	(1,964,501)	(2,000,000)	(1,502,829)	(1,582,361)	(1,610,877)	(1,672,382)	(1,531,140)	(1,551,476)	(1,863,213)		
25378~Ciac Reg Liability	(7,800,354)	(8,233,707)	(8,667,060)	(9,100,413)	(9,533,766)	(9,967,119)	-	-	-	-	-	-	-	(4,100,186)		
24230~Vmpd Phase-In Current	(346,270)	(346,238)	(346,205)	(346,996)	(350,503)	(354,038)	(357,643)	(361,122)	(365,962)	(370,778)	(375,827)	(380,943)	(385,867)	(359,057)		
23480~Nothern Water Res- Accounts Payable	(5,547,603)	(5,547,603)	(5,547,603)	(5,547,603)	(5,547,603)	(5,547,603)	(5,547,603)	(5,022,274)	(5,022,274)	(5,022,274)	(5,022,274)	(5,022,274)	(5,022,274)	(5,305,144)		
25402~Reg Liab Production Tax Credit	(1,236,191)	-	-	-	-	-	-	-	-	-	-	-	-	(95,092)		
Pension																
18635~Prepaid Pension Offset Account	(13,820,385)	(13,885,441)	(13,566,497)	(14,015,553)	(12,640,134)	(13,264,715)	(13,889,296)	(13,878,632)	(13,867,969)	(13,857,306)	(13,846,643)	(13,835,980)	(13,825,317)	(13,707,221)		
18636~Accrued Benefit Asset-Pension	13,820,385	13,885,441	13,566,497	14,015,553	12,640,134	13,264,715	13,889,296	13,878,632	13,867,969	13,857,306	13,846,643	13,835,980	13,825,317	13,707,221		
18696~Reg Asset - Make Up Plan	31,857	32,315	32,773	33,231	33,689	34,147	34,605	35,063	35,521	35,979	36,437	36,895	37,353	34,605		
18698~Regulatory Asset 158 Pension Funding Offset	57,858,254	58,190,849	58,523,444	58,856,039	59,193,804	59,531,569	59,869,334	47,558,293	47,808,461	48,058,629	48,308,797	48,558,965	48,809,133	53,932,736		
22832~Non-Curr Make Up Plan Other	(66,986)	(67,955)	(66,534)	(67,504)	(67,278)	(65,857)	(65,631)	(50,416)	(50,190)	(49,964)	(51,714)	(51,879)	(50,457)	(59,413)		
22833~Non Current Liab Make Up Fas 158	(31,857)	(32,315)	(32,773)	(33,231)	(33,689)	(34,147)	(34,605)	(35,063)	(35,521)	(35,979)	(36,437)	(36,895)	(37,353)	(34,605)		

	MAR-2016	FEB-2016	JAN-2016	DEC-2015	NOV-2015	OCT-2015	SEP-2015	AUG-2015	JUL-2015	JUN-2015	MAY-2015	APR-2015	MAR-2015	13 Month Average	Production 13 month avg	General 13 month avg
22834~Pension Obilagation Other	13,820,386	13,885,442	13,566,498	14,015,554	12,640,135	13,264,716	13,889,297	13,878,633	13,867,970	13,857,307	13,846,644	13,835,981	13,825,318	13,707,222		
25398~Pension Funding Liability Fas 158	(57,858,254)	(58,190,849)	(58,523,444)	(58,856,039)	(59,193,804)	(59,531,569)	(59,869,334)	(47,558,293)	(47,808,461)	(48,058,629)	(48,308,797)	(48,558,965)	(48,809,133)	(53,932,736)		
24222~Misc Curr Liab - Make Up Plan	(14,343)	(14,343)	(14,343)	(14,343)	(14,343)	(14,343)	(14,343)	(29,332)	(29,332)	(29,332)	(29,332)	(29,332)	(29,332)	(21,261)		
Net Pension Asset	13,739,057	13,803,144	13,485,621	13,933,707	12,558,514	13,184,516	13,809,323	13,798,885	13,788,448	13,778,011	13,765,598	13,754,770	13,745,529	13,626,548		
Working Capital - Fuel																
15110~Mands Fuel-Diesel Plants	2,057,586	2,063,230	2,156,852	2,313,029	2,317,940	2,307,426	2,361,654	2,377,771	2,391,534	2,386,380	2,401,268	2,401,342	2,403,573	2,303,045		
15120~Mands Fuel-Gas Turbine Plants	3,712,126	3,731,899	3,765,434	3,786,928	3,693,110	3,691,159	3,697,129	3,910,881	4,029,489	4,048,888	4,060,119	4,037,410	4,033,661	3,861,403		
15121~Mands Fuel-Mcneil General Plant	376,374	385,846	457,777	486,213	533,506	535,343	236,455	399,992	456,526	250,424	127,966	58,158	160,476	343,466		
15122~Mands Fuel-Mcneil G Plt-Swanton	216,942	237,024	129,088	194,538	123,557	118,780	77,237	59,339	32,277	147,695	246,545	221,078	246,743	157,757		
15123~Mands Fuel-Mcneil Gen Plt-Oil	50,554	33,313	37,190	40,858	44,349	48,499	51,681	56,127	59,895	63,055	66,279	67,630	71,190	53,125		
15130~Mands Fuel-Steam Plants	803,615	936,712	1,001,844	1,015,611	815,321	714,386	665,004	701,476	745,174	746,030	752,739	754,912	862,230	808,850		
15210~Fuel Hndling-Steam Plant #24	36,503	39,586	52,508	55,984	62,058	61,007	31,529	54,131	60,888	31,547	16,562	4,196	17,675	40,321		
15220~Fuel Hndling-Steam Plant #24	28,376	36,155	21,236	25,618	17,252	22,972	17,237	14,221	4,380	32,517	42,423	30,381	44,263	25,926		
	7,282,077	7,463,765	7,621,929	7,918,779	7,607,093	7,499,571	7,137,926	7,573,938	7,780,162	7,706,536	7,713,902	7,575,108	7,839,811	7,593,892		
Working Capital - Inventory																
15410~Plt Mtls And Oper Supp-General	10,143,675	10,075,992	9,918,901	10,011,442	10,008,663	9,709,676	9,232,112	9,289,413	9,411,108	9,193,563	8,620,594	8,311,168	8,182,637	9,392,996		
15411~Mat & Suppl - Millst Mcneil & Misc	2,790,888	2,727,239	2,744,148	2,732,010	2,763,527	2,739,540	2,704,339	2,322,019	2,323,096	1,970,331	2,195,976	2,019,344	2,016,722	2,465,322		
15420~Plt Mtls And Oper Supp-Assoc Stk	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
15430~Orange Tag Inventory-Col / Mont	-	-	-	-	-	-	-	12,949	25,899	38,848	51,798	64,747	77,696	20,918		
15510~Merchandise	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
15810~Renewable Energy Credits Inventory Allowance	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
16310~Stores Hndling Exp-Undistribut	(3,226,038)	(3,158,523)	(3,083,944)	(2,994,758)	(2,959,175)	(2,773,912)	(2,738,353)	(2,519,272)	(2,419,262)	(2,365,056)	(2,230,099)	(2,162,921)	(2,091,247)	(2,670,966)		
16320~Sales And Use Tax On Store Purch	3,897,972	3,893,825	3,924,304	3,839,157	3,714,576	3,642,310	3,584,351	3,461,851	3,374,823	3,310,895	3,213,417	3,157,176	3,071,907	3,545,120		
15412~Tesla Battery Inventory	1,765,045	208,010	-	-	-	-	-	-	-	-	-	-	-	151,773		
	15,371,543	13,746,543	13,503,410	13,587,852	13,527,591	13,317,613	12,782,449	12,566,960	12,715,665	12,148,582	11,851,687	11,389,514	11,257,716	12,905,163		
Working Capital -Prepayments																
16511~Prepayments-Ins General	775,027	910,355	1,045,682	1,181,010	1,141,948	1,137,169	4,472	144,777	286,671	427,770	567,876	709,964	852,052	706,521		
16512~Prepayments-Employee Medical	(1,663,732)	(1,484,421)	(1,542,426)	(1,418,175)	(666,132)	(292,453)	-	(269,475)	380,244	589,024	445,615	389,619	217,735	(408,814)		
16513~Prepayments-Ins Life	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
16514~Prepayments-Ins Liability	103,087	120,268	137,449	154,630	171,313	188,445	-	16,446	32,892	49,338	65,784	82,230	98,676	93,889		
16515~Prepayments-Worker'S Comp	-	-	-	-	-	-	-	-	16,789	92,641	123,424	154,276	185,128	44,020		
16516~Prepayments-Excess Liability	590,885	714,854	814,452	915,970	208,584	(166,082)	-	45,499	150,839	280,279	403,720	541,831	713,532	401,105		
16517~Prepayments-D.O.L.I.	272,352	284,699	297,047	309,394	286,335	298,950	311,565	324,178	336,791	349,404	362,017	374,630	387,243	322,662		
16521~Prepayments-Purchase Power	-	-	-	0	144,445	288,889	433,333	577,778	722,222	830,197	974,641	1,119,086	1,625,226	516,601		
16522~Prepayments-Rec Brokerage Fees	146,569	145,188	137,688	137,688	137,688	109,438	109,438	115,126	115,126	115,126	124,076	124,076	124,076	126,254		
16531~Prepayment-Other	2,412,659	2,553,381	787,842	1,078,932	1,426,553	1,568,842	1,858,199	1,810,034	2,101,935	2,346,401	2,606,947	2,792,138	3,125,560	2,036,109		
16532~Prepayments-Mmwec	(487,511)	(120,285)	(109,998)	16,996	109,841	(105,514)	(675,959)	(929,450)	(443,629)	(381,378)	(196,154)	(7,300)	(249,231)	(275,352)		
16535~Prepayments-Medicare Prhc Receivableres Conservtn Cor	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
16537~Prepaid-Other Expense	-	-	-	-	-	-	-	-	-	-	-	18,354	36,708	4,236		
16538~Prepayments-Mcneil	959,413	1,027,697	1,095,523	1,198,481	1,184,456	1,033,244	1,149,723	1,166,427	1,191,076	772,170	770,817	430,077	363,237	949,411		
16539~Prepayments-Highgate	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
16540~Ap Property Tax Liability	38,150,479	37,929,692	36,148,263	33,198,634	32,829,049	32,124,704	26,212,967	22,611,568	19,259,144	16,300,923	16,234,802	15,850,794	14,272,123	26,240,242		
16542~Prepayments-Property Taxes	(35,101,370)	(32,982,143)	(30,954,165)	(28,828,117)	(26,761,045)	(24,735,034)	(22,656,126)	(20,533,787)	(18,851,711)	(16,941,336)	(15,011,131)	(13,174,797)	(11,335,757)	(22,912,809)		
	6,157,857	9,099,286	7,857,358	7,945,445	10,213,036	11,450,598	6,747,613	5,079,120	5,298,390	4,830,558	7,472,436	9,404,978	10,416,307	7,844,076		
Post Retirement Medical																
18661~Non-Curr Prepaid Prw	-	-	-	-	-	-	-	(691,786)	(699,020)	(898,839)	(759,817)	(902,428)	(910,126)	(374,001)		
18662~Non-Curr Prepaid Prw - Sfas 158	-	-	-	-	-	-	-	4,492,046	4,472,830	4,453,614	4,434,398	4,415,182	4,395,966	2,051,080		
18692~Reg Asset Prhc	745,729	770,999	796,269	821,539	846,809	872,079	897,349	-	-	-	-	-	-	442,367		
26381~Prw 158 Liability Non Current	(745,729)	(770,999)	(796,269)	(821,539)	(846,809)	(872,079)	(897,349)	-	-	-	-	-	-	(442,367)		
26382~Prw Non Current Liab Other	(332,519)	(391,899)	(441,418)	(494,261)	(274,681)	(278,173)	(278,740)	-	-	-	-	-	-	(191,668)		
25344~Reg Liab - Opeb Aoc1	-	-	-	-	-	-	-	(4,492,046)	(4,472,830)	(4,453,614)	(4,434,398)	(4,415,182)	(4,395,966)	(2,051,080)		
14325~Employee Benefit Plans	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
24259~Retiree Med Curr Liab	(209,542)	(209,542)	(209,542)	(209,542)	(209,542)	-	-	-	-	-	-	-	-	(80,593)		
Proforma Adjustment	-	-	-	-	-	(209,542)	(209,542)	-	-	-	-	-	-	(32,237.2)		
	(542,061)	(601,441)	(650,960)	(703,803)	(484,223)	(487,715)	(488,282)	(691,786)	(699,020)	(898,839)	(759,817)	(902,428)	(910,126)	(678,500)		
SERP																
18691~Reg Asset Serp Non Current	989,321	999,434	1,009,547	1,019,660	1,029,701	1,039,742	1,049,783	1,868,441	1,892,943	1,917,445	1,941,947	1,966,449	1,990,951	1,439,643		
18697~Reg Asset Serp Liability Current Portion	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
24256~Serp Curr Liab Other	(366,469)	(366,469)	(366,469)	(366,469)	(366,469)	(576,011)	(576,011)	(451,545)	(451,545)	(451,545)	(451,545)	(451,545)	(451,545)	(437,972)		
26311~Serp 158 Liability	(989,321)	(999,434)	(1,009,547)	(1,019,660)	(1,029,701)	(1,039,742)	(1,049,783)	(1,868,441)	(1,892,943)	(1,917,445)	(1,941,947)	(1,966,449)	(1,990,951)	(1,439,643)		
26312~Gmp Serp Liability Non-Current	(3,268,725)	(3,282,697)	(3,249,557)	(3,263,529)	(3,250,950)	(3,214,816)	(3,285,774)	(3,782,811)	(3,719,400)	(3,655,988)	(3,620,912)	(3,561,357)	(3,477,323)	(3,433,372)		
26360~Minimum Serp Liability	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
26365~Serp Current Liab Fas 158	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
Proforma Adjustment (reclass to Retiree Medical)	-	-	-	-	-	209,542	209,542	-	-	-	-	-	-	32,237		
	(3,635,194)	(3,649,166)	(3,616,026)	(3,629,998)	(3,617,419)	(3,581,285)	(3,652,243)	(4,234,356)	(4,170,945)	(4,107,533)	(4,072,457)	(4,012,902)	(3,928,868)	(3,839,107)		
FAS 109																
18231~Future Revenue Due To Inc Tax	108,908	110,593	112,278	113,963	115,649	117,334	119,019	121,301	123,583	125,865	128,147	130,429	132,712	119,983		
18232~Current Revenue Due To Inc Tax	23,804	24,401	24,998	25,595	26,192	26,789	27,386	28,103	28,821	29,538	30,256	30,973	31,691	27,581		
18251~Sfas 109 Reg Asset Cv	6,027,479	5,988,423	5,949,439	5,910,455	5,871,470	5,832,486	5,793,502	5,861,472	5,806,235	5,750,347	5,694,458	5,638,570	5,582,682	5,823,617		

	MAR-2016	FEB-2016	JAN-2016	DEC-2015	NOV-2015	OCT-2015	SEP-2015	AUG-2015	JUL-2015	JUN-2015	MAY-2015	APR-2015	MAR-2015	13 Month Average	Production 13 month avg	General 13 month avg
24411~Future Rev Reduction - Inc Tax	(572,506)	(567,679)	(562,853)	(558,026)	(553,200)	(548,373)	(543,547)	(547,389)	(551,232)	(555,074)	(558,917)	(562,759)	(566,602)	(557,551)		
24412~Curr Rev Reduction - Inc Tax	(57,042)	(60,025)	(63,008)	(65,991)	(68,974)	(71,957)	(74,940)	(83,930)	(92,921)	(101,911)	(110,902)	(119,892)	(128,882)	(84,644)		
	5,530,643	5,495,713	5,460,854	5,425,996	5,391,137	5,356,279	5,321,420	5,379,557	5,314,486	5,248,765	5,183,042	5,117,321	5,051,601	5,328,986		

GREEN MOUNTAIN POWER CORPORATION
COMPUTATION OF WORKING CAPITAL
TEST YEAR ENDED March 31, 2016
2017
Lead Lag Cash Working Capital

Description	Per Books	Adjustments	Adjusted	000's Ratebase Adjustment
Material and Supplies Inventory including Fuel	20,499,055	0	20,499,055	
Millstone III Nuclear Fuel Inventory (Net)	1,919,433	8,648	1,928,081	
Prepayments	7,844,076	0	7,844,076	
Lead /Lag Working Capital Allowance	11,874,000	(3,244,120)	8,629,880	8,623
Total Working Capital	42,136,564	(3,235,472)	38,901,092	

Rate Year - $ in 000's

Description	**Base Filing**	**Lead /(Lag) Days**	**Dollar Days**	**Working Capital Provided / (Required)**	
Revenues					
Retail Revenues	593,303	(40.19)	(23,842,222)	(65,321)	
Cost of Service					
Purchase Power, Net	$256,284	33.08	8,479,006	23,230	
Production	24,744	0.95	23,526	64	
Transmission	95,520	53.90	5,148,799	14,106	
O&M (Platform, Non-base O&M & Acct 929)	122,895				
Less Customer Synergies	(16,335)				
Less Investor Synergies	0				
O&M (Platform, Non-base O&M & Acct 929)	106,560	17.31	1,844,237	5,053	
Business Development Expense	556				
Depreciation and Amortization	48,709	-	-	-	
Accretion Expense	248	-	-	-	
Taxes - Income Taxes	34,390	-	-	-	
- Municipal Taxes	27,882	-	-	-	
- Other Payroll Taxes	2,875	8.5	24,439	67	
Capital Costs	97		-	-	
Total Operating Expenses	$ 597,865	25.96	$ 15,520,008	$ 42,521	
Equity-in-Earnings of Affiliates	(83,158)	-	-	-	
Other Operating Revenue	(21,763)	48.66	(1,059,010)	(2,901)	
Business Development	(742)	-	-	-	
Gross Revenue Taxes	6,166	175.4	1,081,244	2,962	
Merger Savings (included above)					
Capital Costs					
Interest on LTD and STD	36,791	90.5	3,330,788	9,125	
Return	58,445	45.63	1,819,286	4,984	39,870 << Recurring Dividends based on discovery set
Cost of Service	$ 593,603	34.86	$ 20,692,316	56,691	
Working Capital Requirement				(8,630)	

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Green Mountain Power Corporation
Analysis of Return on Rate Base
Test Year ending March 31, 2016

Net Income applicable to Common Stock	$ 61,019,983
09 Catamount Resources Equity in Earnings	0
63 Northern Water Works Equity in Earnings	(14,841)
Equity Income	**(14,841)**
RWH / Rental Income, net	1,584,011
Synergies Savings	19,136,633
NonOperating Income	2,060,042
Below the Line Accounts	(4,901,103)
Sub-total - Unregulated Income (expense)	17,864,741
Tax benefit (expense)	(6,912,427)
Total Unregulated income (expense)	10,952,314
Net Regulatory Income:	
Net Income applicable to Common Stock	61,019,983
Remove: Unregulated income/(Expense)	(10,952,314)
Total Regulatory Income	50,067,669
Interest / Fee Charges	
First Mortgage Bonds	33,372,713
Debentures	
Notes Payable	672,170
Total Book Return on Rate Base	$84,112,551
Tax Calculation:	
Unregulated Income (expense)	$17,864,741
Remove: Life Insurance	305,453
Remove: Non Deductible Lobbying	4,168
Remove: Non Deductible Fees	(221,897)
Remove: AFUDC Equity	(910,114)
Remove: Equity income	14,841
	17,057,193
Effective Tax Rate - 40.525%	($6,912,427)
Reconciliation	
Trial Balance	
Net Income	61,019,983
Non-Operating Expenses	5,373,191
Non-Operating Revenue	(4,101,299)
First Mortgage Bonds	33,372,713
Notes Payable	672,169.57
	96,336,757
Tax (Benefit)/Expense from Above	6,912,427
Synergy Savings From Above	(19,136,633)
	84,112,551
Check	$0.00

		4-2015 - 9-2015 test year 6 months FY 2014	10-2015 - 3-31-2016 test year 6 months FY 2015	Total Test Year Synergy Savings	Customer Share	Investor Share
Total Test Year Synergies		15,173,380	15,926,506	31,099,886	11,963,253	19,136,633
Guaranteed Annual FY 2015 Customer Synergy Savings		8,000,000	-			
Test Year Portion of FY 2015 Customer Synergy Savings		4,000,000	-		4,000,000	11,173,380
Customer Synergies 50% Sharing	50%		7,963,253		7,963,253	7,963,253

Green Mountain Power Corporation
Equity & Bank Loan Balances

	3/31/2015	4/30/2015	5/31/2015	6/30/2015	7/31/2015	8/31/2015	9/30/2015	10/31/2015	11/30/2015	12/31/2015	1/31/2016	2/29/2016	3/31/2016
TOTAL COMMON STOCK EQUITY	642,451,366	644,912,642	647,891,200	645,212,009	650,238,532	656,236,100	656,997,452	660,913,887	664,932,753	663,171,465	667,329,024	670,354,693	668,283,002
13-Month Average Common Equity													**656,840,317**
COMPANY BANK LOANS	69,565,993	54,604,945	56,109,280	71,359,880	56,044,286	59,917,380	71,173,565	64,785,763	69,132,899	45,067,297	33,884,993	38,968,188	38,421,198
13-Month Average Bank Loans													**56,079,667**

Green Mountain Power Corporation
Equity & Bank Loan Balances

	---------------- RATE YEAR ----------------												
	9/30/2016	10/31/2016	11/30/2016	12/31/2016	1/31/2017	2/28/2017	3/31/2017	4/30/2017	5/31/2017	6/30/2017	7/31/2017	8/31/2017	9/30/2017
Initial Filing Equity Balance	696,823,958	702,451,943	707,083,712	755,504,796	761,948,255	766,428,986	763,818,788	767,960,270	751,290,845	748,486,986	753,868,756	759,302,761	759,445,182
Accelerated Equity Investment	39,000,000	39,000,000	39,000,000	(11,000,000)	(11,000,000)	(11,000,000)	(11,000,000)	(11,000,000)	(11,000,000)	(11,000,000)	(11,000,000)	(11,000,000)	(11,000,000)
Do not Provide $20 Return of Capital									20,000,000	20,000,000	20,000,000	20,000,000	20,000,000
TOTAL COMMON STOCK EQUITY	735,823,958	741,451,943	746,083,712	744,504,796	750,948,255	755,428,986	752,818,788	756,960,270	760,290,845	757,486,986	762,868,756	768,302,761	768,445,182
13-Month Average Common Equity													**753,955,018**
Initial Filing Bank Loan Balances	45,228,890	77,328,311	78,687,235	80,725,019	77,159,889	76,142,440	79,545,641	16,412,177	66,584,058	82,120,945	73,969,423	75,418,686	77,457,062
Increase in STD	-	-	-	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000
COMPANY BANK LOANS	45,228,890	77,328,311	78,687,235	89,725,019	86,159,889	85,142,440	88,545,641	25,412,177	75,584,058	91,120,945	82,969,423	84,418,686	86,457,062
13-Month Average Bank Loans													**76,675,367**
Additional Interest Expense on higher STD Balance	-	-	-	-	17,025	17,025	17,025	17,025	17,025	17,025	17,025	17,025	17,025
Combined Company - interest on Short term borrowing	-	114,897	146,265	149,449	148,017	143,721	145,958	89,960	77,809	139,411	146,335	140,051	143,321
Rate Year Total Interest Expense													1,738,419
Average Interest Rate													2.27%
Initial Change in Equity Structure		5,627,985	4,631,769	(1,578,916)	6,443,459	4,480,731	(2,610,199)	4,141,483	3,330,574	(2,803,859)	5,381,770	5,434,005	142,421

Green Mountain Power Corporation
Long Term Debt

DEBT BALANCES

Description	Maturity	Interest	3/31/2015	4/30/2015	5/31/2015	6/30/2015	7/31/2015	8/31/2015	9/30/2015	10/31/2015	11/30/2015	12/31/2015	1/31/2016	2/29/2016	3/31/2016	4/30/2016
			---------- TEST YEAR ----------													
11th Supplemental FMB	9/01/2020	9.64%	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000
12th Supplemental FMB	3/01/2022	8.65%	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000	10,500,000	10,500,000	10,500,000
14th Supplemental FMB	11/01/2018	6.70%	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000
17th Supplemental FMB	12/1/2017	6.04%	18,000,000	18,000,000	18,000,000	18,000,000	18,000,000	18,000,000	18,000,000	18,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000
18th Supplemental FMB	7/1/2036	6.53%	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000
19th Supplemental FMB	12/01/2037	6.17%	16,000,000	16,000,000	16,000,000	16,000,000	16,000,000	16,000,000	16,000,000	16,000,000	16,000,000	16,000,000	16,000,000	16,000,000	16,000,000	16,000,000
20th Supplemental FMB	4/01/2019	5.98%	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000
21st Supplemental FMB	4/01/2035	varies	56,405,046	56,405,046	56,405,046	56,405,046	56,405,046	56,405,046	56,405,046	56,405,046	56,405,046	56,405,046	56,405,046	56,405,046	55,665,046	55,665,046
22nd Supplemental FMB	11/18/2041	varies	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000
23rd Supplemental FMB	11/18/2041	5.89%	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000
23rd Supplemental FMB	12/15/2031	8.91%	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000
23rd Supplemental FMB	12/15/2023	6.90%	17,500,000	17,500,000	17,500,000	17,500,000	17,500,000	17,500,000	17,500,000	17,500,000	17,500,000	17,500,000	17,500,000	17,500,000	17,500,000	17,500,000
23rd Supplemental FMB	6/15/2019	5.72%	55,000,000	55,000,000	55,000,000	55,000,000	55,000,000	55,000,000	55,000,000	55,000,000	55,000,000	55,000,000	55,000,000	55,000,000	55,000,000	55,000,000
23rd Supplemental FMB	5/15/2028	6.83%	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000
24th Supplemental FMB	12/01/2042	3.99%	85,000,000	85,000,000	85,000,000	85,000,000	85,000,000	85,000,000	85,000,000	85,000,000	85,000,000	85,000,000	85,000,000	85,000,000	85,000,000	85,000,000
25th Supplemental FMB	1/09/2029	4.07%	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000
25th Supplemental FMB	12/16/2033	4.39%	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000
25th Supplemental FMB	12/16/2043	4.89%	43,000,000	43,000,000	43,000,000	43,000,000	43,000,000	43,000,000	43,000,000	43,000,000	43,000,000	43,000,000	43,000,000	43,000,000	43,000,000	43,000,000
26th Supplemental FMB	12/15/2027	3.31%	0	0	0	0	0	0	0	0	0	18,000,000	18,000,000	18,000,000	18,000,000	18,000,000
26th Supplemental FMB	12/15/2045	4.26%	0	0	0	0	0	0	0	0	0	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000
New Debt		4.50%	0	0	0	0	0	0	0	0	0	0	0	0	0	
Total Long-Term Debt Balance			$592,905,046	$592,905,046	$592,905,046	$592,905,046	$592,905,046	$592,905,046	$592,905,046	$592,905,046	$586,905,046	$636,905,046	$636,905,046	$636,405,046	$635,665,046	$635,665,046
13-Month Average Long-Term Debt															**$605,848,123**	

INTEREST EXPENSE

			3/31/2015	4/30/2015	5/31/2015	6/30/2015	7/31/2015	8/31/2015	9/30/2015	10/31/2015	11/30/2015	12/31/2015	1/31/2016	2/29/2016	3/31/2016	4/30/2016
11th Supplemental FMB		9.64%														
12th Supplemental FMB		8.65%														
14th Supplemental FMB		6.70%														
17th Supplemental FMB		6.04%														
18th Supplemental FMB		6.53%														
19th Supplemental FMB		6.17%														
20th Supplemental FMB		5.98%														
21st Supplemental FMB		see below														
22nd Supplemental FMB		see below														
23rd Supplemental FMB		5.89%														
23rd Supplemental FMB		8.91%														
23rd Supplemental FMB		6.90%														
23rd Supplemental FMB		5.72%														
23rd Supplemental FMB		6.83%														
24th Supplemental FMB		3.99%														
25th Supplemental FMB		4.07%														
25th Supplemental FMB		4.39%														
25th Supplemental FMB		4.89%														
26th Supplemental FMB		3.31%														
26th Supplemental FMB		4.26%														
New Debt		4.50%														
Monthly Total Interest Expense			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate Year Total Interest Expense																
Average Interest Rate																

VEDA 1 - 21st Supplemental Schedules:

	Principle	Interest	Sinking Funds*
	22,120,046		
2012		3.00%	$655,000
2013		2.85%	$675,000
2014		4.30%	$695,000
2015		4.30%	$715,000
2016		4.36%	$740,000
2017		4.45%	$755,000
2018		3.00%	$780,000
2019		3.25%	$800,000
2020		3.25%	$830,000
2021		3.50%	$855,000
2022		3.60%	$885,000
2023		3.75%	$915,000
2024		3.75%	$0
2025		3.75%	$0
2026		3.75%	$0
2027		3.75%	$0
2028		4.50%	$5,205,000
2029		4.50%	$0
2030		4.50%	$0
2031		4.50%	$0
2032		4.50%	$0
2033		4.50%	$0
2034		4.50%	$0
2035		5.00%	$9,640,000

** Paid April 1st*

4.4068%

VEDA 2

Principle	Interest	
5,000,000	6.00%	*300,000.00*

VEDA Exchange

Principle	Interest	
30,000,000	5.00%	*1,500,000.00*

Supplemental Sinking Fund Schedules:

17th Supplemental FMB	Dec. 1, 2017	6.04%	$6M Annually beginning 12/1/11; paid in December
12th Supplemental FMB	Mar. 1, 2022	8.65%	$500K Annually beginning 2012; paid in March

22nd Supplemental Schedule	Principle	Interest Rate
1st Tranche	50,000,000	4.56%
2nd Tranche	25,000,000	4.61%

5/31/2016	6/30/2016	7/31/2016	8/31/2016	9/30/2016	10/31/2016	11/30/2016	12/31/2016	1/31/2017	2/28/2017	3/31/2017	4/30/2017	5/31/2017	6/30/2017	7/31/2017	8/31/2017	9/30/2017
				---- AVERAGE 13 MONTH RATE YEAR ----												
9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000	9,000,000
10,500,000	10,500,000	10,500,000	10,500,000	10,500,000	10,500,000	10,500,000	10,500,000	10,500,000	10,500,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000	10,000,000
15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000
12,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000
30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000
16,000,000	16,000,000	16,000,000	16,000,000	16,000,000	16,000,000	16,000,000	16,000,000	16,000,000	16,000,000	16,000,000	16,000,000	16,000,000	16,000,000	16,000,000	16,000,000	16,000,000
15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000
55,665,046	55,665,046	55,665,046	55,665,046	55,665,046	55,665,046	55,665,046	55,665,046	55,665,046	55,665,046	54,910,046	54,910,046	54,910,046	54,910,046	54,910,046	54,910,046	54,910,046
75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000	75,000,000
40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000	40,000,000
15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000	15,000,000
17,500,000	17,500,000	17,500,000	17,500,000	17,500,000	17,500,000	17,500,000	17,500,000	17,500,000	17,500,000	17,500,000	17,500,000	17,500,000	17,500,000	17,500,000	17,500,000	17,500,000
55,000,000	55,000,000	55,000,000	55,000,000	55,000,000	55,000,000	55,000,000	55,000,000	55,000,000	55,000,000	55,000,000	55,000,000	55,000,000	55,000,000	55,000,000	55,000,000	55,000,000
60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000
85,000,000	85,000,000	85,000,000	85,000,000	85,000,000	85,000,000	85,000,000	85,000,000	85,000,000	85,000,000	85,000,000	85,000,000	85,000,000	85,000,000	85,000,000	85,000,000	85,000,000
12,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000	12,000,000
20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000	20,000,000
43,000,000	43,000,000	43,000,000	43,000,000	43,000,000	43,000,000	43,000,000	43,000,000	43,000,000	43,000,000	43,000,000	43,000,000	43,000,000	43,000,000	43,000,000	43,000,000	43,000,000
18,000,000	18,000,000	18,000,000	18,000,000	18,000,000	18,000,000	18,000,000	18,000,000	18,000,000	18,000,000	18,000,000	18,000,000	18,000,000	18,000,000	18,000,000	18,000,000	18,000,000
32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000	32,000,000
				0	0	0	0	0	0	0	82,000,000	82,000,000	82,000,000	82,000,000	82,000,000	82,000,000
$635,665,046	$635,665,046	$635,665,046	$635,665,046	$635,665,046	$635,665,046	$635,665,046	$629,665,046	$629,665,046	$629,665,046	$628,410,046	$710,410,046	$710,410,046	$710,410,046	$710,410,046	$710,410,046	$710,410,046
																668,220,046
					72,300	72,300	72,300	72,300	72,300	72,300	72,300	72,300	72,300	72,300	72,300	72,300
					75,688	75,688	75,688	75,688	75,688	72,083	72,083	72,083	72,083	72,083	72,083	72,083
					83,750	83,750	83,750	83,750	83,750	83,750	83,750	83,750	83,750	83,750	83,750	83,750
					60,400	60,400	30,200	30,200	30,200	30,200	30,200	30,200	30,200	30,200	30,200	30,200
					163,250	163,250	163,250	163,250	163,250	163,250	163,250	163,250	163,250	163,250	163,250	163,250
					82,267	82,267	82,267	82,267	82,267	82,267	82,267	82,267	82,267	82,267	82,267	82,267
					74,750	74,750	74,750	74,750	74,750	74,750	74,750	74,750	74,750	74,750	74,750	74,750
					226,555	226,555	226,555	226,555	226,555	223,758	223,758	223,758	223,758	223,758	223,758	223,758
					286,042	286,042	286,042	286,042	286,042	286,042	286,042	286,042	286,042	286,042	286,042	286,042
					196,333	196,333	196,333	196,333	196,333	196,333	196,333	196,333	196,333	196,333	196,333	196,333
					111,375	111,375	111,375	111,375	111,375	111,375	111,375	111,375	111,375	111,375	111,375	111,375
					100,625	100,625	100,625	100,625	100,625	100,625	100,625	100,625	100,625	100,625	100,625	100,625
					262,167	262,167	262,167	262,167	262,167	262,167	262,167	262,167	262,167	262,167	262,167	262,167
					341,500	341,500	341,500	341,500	341,500	341,500	341,500	341,500	341,500	341,500	341,500	341,500
					282,625	282,625	282,625	282,625	282,625	282,625	282,625	282,625	282,625	282,625	282,625	282,625
					40,700	40,700	40,700	40,700	40,700	40,700	40,700	40,700	40,700	40,700	40,700	40,700
					73,167	73,167	73,167	73,167	73,167	73,167	73,167	73,167	73,167	73,167	73,167	73,167
					175,225	175,225	175,225	175,225	175,225	175,225	175,225	175,225	175,225	175,225	175,225	175,225
					49,650	49,650	49,650	49,650	49,650	49,650	49,650	49,650	49,650	49,650	49,650	49,650
					113,600	113,600	113,600	113,600	113,600	113,600	113,600	113,600	113,600	113,600	113,600	113,600
					-	-	-	-	-	-	153,750	307,500	307,500	307,500	307,500	307,500
0.0	0.0	0.0	0.0	0.0	2,871,967	2,871,967	2,841,767	2,841,767	2,841,767	2,835,366	2,989,116	3,142,866	3,142,866	3,142,866	3,142,866	3,142,866
																$ 35,808,046.62
																5.34%
					25,000											
					125,000											
					76,555											

GREEN MOUNTAIN POWER CORPORATION
RB 15 Accumulated Deferred Income Taxes

		9/30/2017 Rate Year 13 mo avg	3/31/2016 Test Year 13 mo avg	Change
TRANS	Investment in Associated Companies	(120,025,752)	(97,838,270)	(22,187,482)
Deferred Charges				
18121	INT RATE SWAP/BOND DISCOUNT	173,877	195,230	(21,353)
18225	GORGE REPOWERMENT	(91,918)	(183,835)	91,917
18233	REG-ASSET-2013 NTA STUDY	3	(38,304)	38,307
18235	REG ASSET - VMPD VALUE SHARING	(84,981)	(155,797)	70,816
18236	REG ASSET - DEPRECIATION STUDY	(16,292)	(26,340)	10,048
18238	REG ASSET - DEERFIELD WIND COST	(242,048)	(151,280)	(90,768)
18255	NUCLEAR DEF OUTAGE COSTS	227,581	(183,013)	410,594
18611	JV SOLAR ABANDONED SITES	(36,582)	(40,186)	3,604
18612	DEF ASSET-LOW INCOME DISC PAYME	(101,324)	(162,117)	60,793
18613	DEF ASSET-EFFICIENCY FUND PAYME	(1,290,934)	(1,816,381)	525,447
18628	CEED FUND Def chg	(6,485,391)	(5,919,637)	(565,754)
18647	RATE DESIGN	(149,580)	(89,675)	(59,905)
18651	DEERFIELD WIND	60,512	(181,535)	242,047
ARO		0	0	0
18230	REGULATORY ASSET-ASSET RETIREME	(119,162)	(137,978)	18,816
CAFC		0	0	0
25297,25298	FINANCE CHARGE (LINEX)	(28,597)	2,071,257	(2,099,854)
Deferred Credits		0	0	0
23000	ASSET RETIREMENT LIABILITY	2,283,638	2,152,033	131,605
23515	UNEARNED REVENUE	83,696	76,701	6,995
24206	MISC CUR WORKERS COMP MAJOR	902,727	770,896	131,831
25343	REG LIAB - VYNPC VAL ALLOW	0	212,892	(212,892)
25358	REG-LIAB-earnings sharing	0	324	(324)
25361	REG LIAB-NEIL VY	279,747	256,829	22,918
25378	CIAC REG LIABILITY	1,074,008	1,580,547	(506,539)
25379	REG LIAB CVPS ESAM OVERCOLLECTI	60,788	124,143	(63,355)
25380	REG LIAB COW POWER MARKETING	(32)	313	(345)
25381	DEF-REV-SO2 EMISSION ALLOWANCE	0	3,756	(3,756)
25390	REG LIAB SMARTPOWER OVERCOLL-IN	(77)	(170)	93
25392	CONTINGENCY RESERVES	1,523,209	1,452,595	70,614
25393	HEALTH INSURANCE RESERVE	493,213	496,738	(3,525)
25397	ELECTRICITY ASSISTANCE PROGRAM	0	1,363,020	(1,363,020)
25400	REG LIAB VYNPC REV SHAR AGRMT	0	2,270,333	(2,270,333)
25402	REG LIAB PRODUCTION TAX CREDIT	250,483	250,483	0
FAS 112	FAS 112 liability	446,860	455,446	(8,586)
PENSION		(7,604,207)	(6,663,442)	(940,765)
W Cap	Working Capital	(1,188,539)	(641,827)	(546,712)
P R Med	Post Retirement Medical	201,183	294,250	(93,067)
SERP		1,477,035	1,532,656	(55,621)
TAX FAS 109		(5,772,123)	(5,278,963)	(493,160)
WC Prepayments	Working Capital Prepayments	(591,959)	(1,135,350)	543,391
FA	Plant related items	(290,208,963)	(248,296,783)	(41,912,180)
CAP S EQUITY	Capital Structure Equity	0	29,138	(29,138)
NOL	Net Operating losses	52,752,245	49,416,978	3,335,267
25394	COST OF REMOVAL REGULATORY LIAB	9,115,885	9,825,072	(709,187)
PTC	Production Tax Credits	18,670,348	11,701,497	6,968,851
18250	REG ASSET - RETIRED METER COST	(1,361,821)	(2,723,535)	1,361,714
VY Contra VA		1,282,643	1,280,118	2,525
FIN48	FIN48	114,208	104,751	9,457
12801NQ	Millstone non-qualified trust	549,011	536,415	12,596
20	AMORT OF HQ (89-90 AUDIT) now North & South	2,632	8,181	(5,549)
East Barnet		(916,275)	(934,457)	18,182
	Items in Rate Base	(344,291,025)	(284,136,283)	(60,154,742)

Accumulated Deferred Investment Tax Credits (memo WP)

	Projected
Average for Post - 1980 Additions (Regular)	
Average for - McNeil	0
- East Barnet	225,034
- Bradford	133,681
- Highgate	151,757
- Millstone	893,919
Total	1,404,391
Total Rounded	1,404,000

Green Mountain Power Corporation
Community Energy & Efficiency Development Fund (CEED)
TEST YEAR: 4/1/15 - 3/31/16
RATE YEAR: 10/1/16 - 9/30/17

	Deferred Charges (18628) BEGINNING BALANCE	Investments	AMORTIZATION	ENDING BALANCE
Test Year and Interium:				
March 2015	13,546,764	168,205	(72,189)	13,642,780
April	13,642,780	20,026	(72,189)	13,590,618
May	13,590,618	-	(72,189)	13,518,429
June	13,518,429	402,052	(72,189)	13,848,293
July	13,848,293	142,883	(72,189)	13,918,987
August	13,918,987	195,174	(72,189)	14,041,972
September	14,041,972	149,663	(72,189)	14,119,447
October	14,119,447	642,416	(122,349)	14,639,514
November	14,639,514	336,782	(122,349)	14,853,947
December	14,853,947	389,886	(122,349)	15,121,485
January 2016	15,121,485	209,607	(122,349)	15,208,743
February	15,208,743	143,530	(122,349)	15,229,924
March	15,229,924	464,392	(122,349)	15,571,968
April	15,571,968	159,421	(122,349)	15,609,040
May	15,609,040	159,421	(122,349)	15,646,113
June	15,646,113	159,421	(122,349)	15,683,185
July	15,683,185	159,421	(122,349)	15,720,257
August	15,720,257	159,421	(122,349)	15,757,330
September 2016	15,757,330	159,421	(122,349)	15,794,402
Rate Year:				
October 2016	15,794,402	514,981	(148,152)	16,161,231
November	16,161,231	514,981	(148,152)	16,528,060
December	16,528,060	514,983	(148,152)	16,894,891
January 2017	16,894,891	72,333	(148,152)	16,819,072
February	16,819,072	72,333	(148,152)	16,743,253
March	16,743,253	72,333	(148,152)	16,667,435
April	16,667,435	72,333	(148,152)	16,591,616
May	16,591,616	72,333	(148,152)	16,515,797
June	16,515,797	72,333	(148,152)	16,439,978
July	16,439,978	72,333	(148,152)	16,364,160
August	16,364,160	72,333	(148,152)	16,288,341
September 2017	16,288,341	72,333	(148,152)	16,212,522
Rate year amortization			(1,777,825)	

Rate Base:		13 month total	**13 month avg bal**
Test Year:	4/1/14- 3/31/15	187,306,107	**$14,408,162**
Rate Year:	10/1/15 - 9/30/16	214,020,758	**$16,463,135**

Incremental Innovative Services Support Worksheet

Revenues and Expenses

$1,428,835	= Total Revenue	(A)
$342,503	= Total Incremental O&M Expenses	(B)
$590,866	= Total Depreciation Expense	(C)
$663,703	= Return on Rate Base	(D)

Please note: Rate base higher at beginning of leases , so expenses for a given lease are highest in first year.

Business Development Revenue Associated with eCompany for FY17

Leases	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	FY17
Heat Pump	$55,919	$57,323	$58,727	$62,268	$65,808	$72,035	$82,718	$93,645	$106,099	$119,407	$133,631	$146,084	$1,053,664
Heat Pump Water Heater	$8,348	$8,827	$9,305	$9,963	$10,622	$11,280	$11,938	$12,626	$13,315	$14,003	$14,691	$15,349	$140,267
EVGo	$727	$727	$727	$727	$727	$859	$991	$1,190	$1,322	$1,454	$1,586	$1,718	$12,756
Tesla Lease	$4,313	$4,950	$5,588	$5,775	$5,963	$6,525	$7,275	$8,063	$9,000	$9,938	$10,875	$11,813	$90,075
Electric Thermal Storage	$631	$631	$631	$631	$631	$631	$631	$631	$631	$631	$631	$631	$7,572

Sales (Please note that these numbers reflect margin on sales)	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	FY17
Tesla	$4,088	$4,088	$4,088	$4,088	$4,088	$4,088	$4,088	$20,440	$16,352	$16,352	$16,352	$6,132	$104,244
ConnectDER	$1,736	$1,736	$1,158	$1,158	$1,158	$1,158	$2,315	$2,315	$2,315	$2,315	$1,736	$1,158	$20,257

Source: "FY17 EIC Revenue"

Total Revenue for EIC Initiatives in FY17: $1,428,835 (A)

Department	Expense Class	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	TY
37: Customer Programs - EIC	260: Outside Services	28,542	28,542	28,542	28,542	28,542	28,542	28,542	28,542	28,542	28,542	28,542	28,542	342,503

Source: UI Budgeting Software Output downloaded into "Incremental EIC O&M Expenses"

Total O&M Expenses for EIC Initiatives in FY17: 342,503 (B)

	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	TY	
Monthly Depreciation Expense	$ 36,602	$ 36,602	$ 39,063	$ 41,524	$ 41,524	$ 44,768	$ 48,012	$ 48,012	$ 55,700	$ 63,388	$ 63,388	$ 72,283	$ 590,866	(C)

					$885,640			$1,167,156			$2,766,186			$3,200,621		
		Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17		
Rate Base	Plant in Service	$6,533,342	$6,533,342	$6,533,342	$7,418,982	$7,418,982	$7,418,982	$8,586,138	$8,586,138	$8,586,138	$11,352,324	$11,352,324	$11,352,324	$14,552,945		
	(Accum. Depr.)	-$240,617	-$277,219	-$313,821	-$352,884	-$394,408	-$435,932	-$480,700	-$528,712	-$576,724	-$632,424	-$695,812	-$759,200	-$831,483		
	Subtotal:	$6,292,725	$6,256,123	$6,219,521	$7,066,098	$7,024,574	$6,983,050	$8,105,438	$8,057,426	$8,009,414	$10,719,900	$10,656,512	$10,593,124	$13,721,462	$8,438,874	
	Accum. Book Depr.	$240,617	$277,219	$313,821	$352,884	$394,408	$435,932	$480,700	$528,712	$576,724	$632,424	$695,812	$759,200	$831,483		
	Accum. Tax Depr.	-$3,540,901	($3,614,487)	($3,688,074)	($4,152,842)	($4,235,161)	($4,317,479)	($4,918,282)	($5,015,071)	($5,111,860)	($6,463,627)	($6,620,866)	($6,778,104)	($8,596,904)		
	Net	-$3,300,284	-$3,337,268	-$3,374,253	-$3,799,958	-$3,840,753	-$3,881,547	-$4,437,582	-$4,486,359	-$4,535,136	-$5,831,203	-$5,925,054	-$6,018,904	-$7,765,421		
	Deferred Taxes on Depr	-$1,337,440	-$1,352,428	-$1,367,416	-$1,539,933	-$1,556,465	-$1,572,997	-$1,798,330	-$1,818,097	-$1,837,864	-$2,363,095	-$2,401,128	-$2,439,161	-$3,146,937		
	Net Rate Base	$4,955,285	$4,903,695	$4,852,105	$5,526,165	$5,468,109	$5,410,053	$6,307,108	$6,239,329	$6,171,550	$8,356,805	$8,255,384	$8,153,963	$10,574,525	$6,551,852	(D)

Innovative Services Support Worksheet

Installations and Cumulative Inventories, by Program Type

Units Installed Each Month

	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	FY17
Heat Pump	23	23	23	58	58	102	175	179	204	218	233	204	1,500
Heat Pump Water Heater	16	16	16	22	22	22	22	23	23	23	23	22	250
EVGo	0	0	0	0	0	2	2	3	2	2	2	2	15
Tesla Lease	25	17	17	5	5	15	20	21	25	25	25	25	225
Tesla Sales	4	4	4	4	4	4	4	20	16	16	16	6	102
ConnectDER	30	30	20	20	20	20	40	40	40	40	30	20	350

Cumulative Inventory

	Opening Balance	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17
Heat Pump	893	916	939	962	1020	1078	1180	1355	1534	1738	1956	2189	2393
Heat Pump Water Heater	263	279	295	311	333	355	377	399	422	445	468	491	513
EVGo	11	11	11	11	11	11	13	15	18	20	22	24	26
Tesla Lease	90	115	132	149	154	159	174	194	215	240	265	290	315
Electric Thermal Storage	1	1	1	1	1	1	1	1	1	1	1	1	1

GREEN MOUNTAIN POWER CORPORATION

Allowed ROE for Base Rate Filing 8/1/2016

10-Year Treasury Yields:

	Prior Yr Average	Current Yr Average		Change in Treasury Yield	50% Change
6/19/2015	2.26%	1.67%	6/20/2016		
6/22/2015	2.37%	1.71%	6/21/2016		
6/23/2015	2.42%	1.69%	6/22/2016		
6/24/2015	2.38%	1.74%	6/23/2016		
6/25/2015	2.40%	1.57%	6/24/2016		
6/26/2015	2.49%	1.46%	6/27/2016		
6/29/2015	2.33%	1.46%	6/28/2016		
6/30/2015	2.35%	1.50%	6/29/2016		
7/1/2015	2.43%	1.49%	6/30/2016		
7/2/2015	2.40%	1.46%	7/1/2016		
7/6/2015	2.30%	1.37%	7/5/2016		
7/7/2015	2.27%	1.38%	7/6/2016		
7/8/2015	2.22%	1.40%	7/7/2016		
7/9/2015	2.32%	1.37%	7/8/2016		
7/10/2015	2.42%	1.43%	7/11/2016		
7/13/2015	2.44%	1.53%	7/12/2016		
7/14/2015	2.41%	1.48%	7/13/2016		
7/15/2015	2.36%	1.53%	7/14/2016		
7/16/2015	2.36%	1.60%	7/15/2016		
7/17/2015	2.34%	1.59%	7/18/2016		
Average Yield	2.36%	1.52%	<<Avg		
Change				-0.84%	-0.42%

Current ROE	9.44%
Benchmark Adjustment	0.00%
FY 2016 Allowed ROE	**9.02%**

U.S. DEPARTMENT OF THE TREASURY

Resource Center

Daily Treasury Yield Curve Rates

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2016 ▼ Go

Date	1 Mo	3 Mo	6 Mo	1 Yr	2 Yr	3 Yr	5 Yr	7 Yr	10 Yr	20 Yr	30 Yr
01/04/16	0.17	0.22	0.49	0.61	1.02	1.31	1.73	2.06	2.24	2.64	2.98
01/05/16	0.20	0.20	0.49	0.68	1.04	1.32	1.73	2.06	2.25	2.67	3.01
01/06/16	0.21	0.21	0.47	0.67	0.99	1.26	1.65	1.98	2.18	2.59	2.94
01/07/16	0.20	0.20	0.46	0.66	0.96	1.22	1.61	1.94	2.16	2.56	2.92
01/08/16	0.20	0.20	0.45	0.64	0.94	1.20	1.57	1.91	2.13	2.55	2.91
01/11/16	0.19	0.21	0.48	0.63	0.94	1.20	1.58	1.94	2.17	2.59	2.96
01/12/16	0.22	0.21	0.47	0.62	0.93	1.18	1.55	1.88	2.12	2.51	2.89
01/13/16	0.22	0.22	0.46	0.60	0.91	1.15	1.51	1.85	2.08	2.47	2.85
01/14/16	0.22	0.25	0.43	0.55	0.90	1.14	1.52	1.87	2.10	2.51	2.90
01/15/16	0.19	0.24	0.37	0.49	0.85	1.08	1.46	1.79	2.03	2.44	2.81
01/19/16	0.21	0.26	0.37	0.48	0.88	1.11	1.49	1.82	2.06	2.45	2.82
01/20/16	0.26	0.26	0.35	0.43	0.85	1.06	1.44	1.76	2.01	2.41	2.77
01/21/16	0.27	0.28	0.38	0.44	0.84	1.06	1.44	1.77	2.02	2.42	2.79
01/22/16	0.26	0.31	0.41	0.47	0.88	1.11	1.49	1.81	2.07	2.46	2.83
01/25/16	0.25	0.31	0.42	0.47	0.88	1.10	1.47	1.79	2.03	2.42	2.80
01/26/16	0.29	0.31	0.45	0.47	0.85	1.07	1.45	1.76	2.01	2.41	2.79
01/27/16	0.28	0.32	0.43	0.47	0.84	1.07	1.43	1.76	2.02	2.42	2.80
01/28/16	0.26	0.35	0.45	0.47	0.83	1.05	1.40	1.75	2.00	2.41	2.79
01/29/16	0.22	0.33	0.43	0.47	0.76	0.97	1.33	1.67	1.94	2.36	2.75
02/01/16	0.19	0.35	0.47	0.47	0.81	1.01	1.38	1.72	1.97	2.38	2.77
02/02/16	0.26	0.34	0.47	0.54	0.75	0.93	1.28	1.61	1.87	2.27	2.67
02/03/16	0.27	0.33	0.46	0.54	0.72	0.91	1.27	1.61	1.88	2.30	2.70
02/04/16	0.24	0.29	0.43	0.52	0.70	0.90	1.25	1.60	1.87	2.29	2.70
02/05/16	0.23	0.30	0.45	0.55	0.74	0.91	1.25	1.58	1.86	2.27	2.68
02/08/16	0.21	0.32	0.42	0.51	0.66	0.83	1.16	1.48	1.75	2.17	2.56
02/09/16	0.27	0.30	0.43	0.52	0.69	0.85	1.15	1.47	1.74	2.16	2.55
02/10/16	0.27	0.31	0.42	0.52	0.71	0.85	1.15	1.46	1.71	2.13	2.53
02/11/16	0.27	0.28	0.39	0.47	0.64	0.81	1.11	1.39	1.63	2.06	2.50
02/12/16	0.26	0.30	0.39	0.51	0.71	0.89	1.20	1.50	1.74	2.15	2.60
02/16/16	0.23	0.30	0.42	0.51	0.74	0.91	1.23	1.53	1.78	2.19	2.64
02/17/16	0.28	0.30	0.43	0.53	0.74	0.93	1.26	1.57	1.81	2.24	2.68
02/18/16	0.28	0.30	0.45	0.53	0.71	0.88	1.21	1.51	1.75	2.17	2.62
02/19/16	0.26	0.31	0.46	0.53	0.76	0.91	1.24	1.53	1.76	2.17	2.61

02/22/16	0.28	0.33	0.46	0.55	0.78	0.92	1.25	1.54	1.77	2.18	2.62
02/23/16	0.28	0.32	0.47	0.55	0.76	0.90	1.23	1.51	1.74	2.16	2.60
02/24/16	0.28	0.33	0.46	0.55	0.75	0.90	1.21	1.52	1.75	2.16	2.61
02/25/16	0.27	0.32	0.46	0.56	0.72	0.85	1.16	1.47	1.71	2.14	2.58
02/26/16	0.26	0.33	0.47	0.60	0.80	0.93	1.23	1.55	1.76	2.20	2.63
02/29/16	0.23	0.33	0.49	0.62	0.78	0.91	1.22	1.52	1.74	2.19	2.61
03/01/16	0.29	0.33	0.50	0.68	0.85	0.98	1.31	1.62	1.83	2.28	2.70
03/02/16	0.28	0.36	0.48	0.67	0.85	1.00	1.34	1.65	1.84	2.27	2.69
03/03/16	0.25	0.28	0.46	0.65	0.85	0.99	1.33	1.63	1.83	2.23	2.65
03/04/16	0.25	0.29	0.47	0.67	0.88	1.04	1.38	1.69	1.88	2.29	2.70
03/07/16	0.27	0.32	0.49	0.67	0.91	1.08	1.42	1.72	1.91	2.30	2.71
03/08/16	0.27	0.29	0.48	0.68	0.88	1.04	1.34	1.64	1.83	2.22	2.63
03/09/16	0.27	0.30	0.47	0.68	0.90	1.07	1.39	1.69	1.90	2.27	2.68
03/10/16	0.27	0.32	0.50	0.69	0.93	1.11	1.45	1.75	1.93	2.29	2.70
03/11/16	0.27	0.33	0.51	0.70	0.97	1.16	1.49	1.79	1.98	2.34	2.75
03/14/16	0.28	0.34	0.52	0.70	0.97	1.15	1.49	1.78	1.97	2.33	2.74
03/15/16	0.29	0.34	0.52	0.71	0.98	1.16	1.50	1.78	1.97	2.33	2.73
03/16/16	0.28	0.31	0.47	0.66	0.87	1.05	1.41	1.72	1.94	2.32	2.73
03/17/16	0.29	0.29	0.47	0.64	0.87	1.04	1.39	1.70	1.91	2.28	2.69
03/18/16	0.27	0.30	0.44	0.62	0.84	1.00	1.34	1.66	1.88	2.26	2.68
03/21/16	0.26	0.31	0.46	0.63	0.87	1.05	1.38	1.70	1.92	2.31	2.72
03/22/16	0.28	0.30	0.46	0.64	0.91	1.08	1.42	1.74	1.94	2.32	2.72
03/23/16	0.27	0.30	0.46	0.64	0.87	1.03	1.37	1.67	1.88	2.25	2.65
03/24/16	0.24	0.30	0.46	0.63	0.89	1.05	1.39	1.70	1.91	2.28	2.67
03/28/16	0.19	0.29	0.49	0.65	0.89	1.04	1.37	1.68	1.89	2.26	2.66
03/29/16	0.18	0.23	0.45	0.63	0.78	0.94	1.29	1.59	1.81	2.20	2.60
03/30/16	0.14	0.20	0.39	0.61	0.76	0.91	1.26	1.60	1.83	2.24	2.65
03/31/16	0.18	0.21	0.39	0.59	0.73	0.87	1.21	1.54	1.78	2.20	2.61
04/01/16	0.20	0.23	0.40	0.62	0.76	0.90	1.24	1.56	1.79	2.20	2.62
04/04/16	0.18	0.23	0.38	0.59	0.75	0.88	1.22	1.53	1.78	2.19	2.60
04/05/16	0.19	0.23	0.36	0.56	0.72	0.85	1.17	1.49	1.73	2.13	2.54
04/06/16	0.19	0.23	0.36	0.55	0.73	0.88	1.20	1.52	1.76	2.17	2.58
04/07/16	0.20	0.23	0.36	0.52	0.70	0.83	1.14	1.46	1.70	2.10	2.52
04/08/16	0.20	0.23	0.34	0.54	0.70	0.84	1.16	1.47	1.72	2.13	2.55
04/11/16	0.19	0.23	0.34	0.53	0.70	0.85	1.16	1.48	1.73	2.14	2.56
04/12/16	0.21	0.22	0.34	0.54	0.74	0.90	1.22	1.54	1.79	2.18	2.61
04/13/16	0.21	0.23	0.36	0.55	0.75	0.90	1.22	1.53	1.77	2.16	2.58
04/14/16	0.21	0.22	0.37	0.55	0.77	0.92	1.26	1.57	1.80	2.18	2.61
04/15/16	0.19	0.22	0.37	0.53	0.74	0.87	1.22	1.52	1.76	2.14	2.56
04/18/16	0.16	0.22	0.35	0.52	0.75	0.90	1.24	1.54	1.78	2.17	2.58
04/19/16	0.18	0.21	0.36	0.53	0.77	0.92	1.26	1.57	1.79	2.19	2.60
04/20/16	0.18	0.23	0.36	0.54	0.80	0.97	1.32	1.63	1.85	2.25	2.66
04/21/16	0.19	0.23	0.37	0.56	0.82	0.98	1.35	1.65	1.88	2.29	2.69
04/22/16	0.19	0.23	0.38	0.56	0.84	1.01	1.37	1.67	1.89	2.30	2.70
04/25/16	0.17	0.25	0.40	0.57	0.85	1.01	1.38	1.69	1.91	2.32	2.72
04/26/16	0.19	0.24	0.43	0.61	0.86	1.04	1.40	1.72	1.94	2.35	2.76
04/27/16	0.18	0.24	0.40	0.58	0.83	0.99	1.33	1.64	1.87	2.30	2.71
04/28/16	0.17	0.22	0.39	0.56	0.78	0.93	1.28	1.60	1.84	2.27	2.68
04/29/16	0.16	0.22	0.40	0.56	0.77	0.92	1.28	1.60	1.83	2.26	2.66

05/02/16	0.11	0.22	0.41	0.55	0.80	0.96	1.32	1.64	1.88	2.31	2.71
05/03/16	0.18	0.21	0.40	0.53	0.75	0.92	1.25	1.57	1.81	2.24	2.66
05/04/16	0.18	0.19	0.39	0.52	0.75	0.89	1.23	1.55	1.79	2.22	2.64
05/05/16	0.20	0.20	0.39	0.51	0.72	0.87	1.20	1.52	1.76	2.17	2.60
05/06/16	0.20	0.19	0.39	0.51	0.74	0.90	1.23	1.55	1.79	2.20	2.62
05/09/16	0.21	0.24	0.38	0.51	0.72	0.86	1.20	1.51	1.77	2.18	2.61
05/10/16	0.25	0.24	0.36	0.52	0.72	0.88	1.20	1.52	1.77	2.18	2.61
05/11/16	0.25	0.26	0.37	0.53	0.74	0.87	1.20	1.51	1.73	2.15	2.58
05/12/16	0.25	0.27	0.37	0.54	0.76	0.92	1.24	1.54	1.75	2.18	2.60
05/13/16	0.25	0.29	0.38	0.55	0.76	0.91	1.22	1.51	1.71	2.14	2.55
05/16/16	0.21	0.28	0.38	0.57	0.79	0.94	1.26	1.55	1.75	2.18	2.59
05/17/16	0.25	0.28	0.40	0.58	0.82	0.97	1.29	1.57	1.76	2.18	2.59
05/18/16	0.25	0.30	0.43	0.63	0.90	1.08	1.41	1.69	1.87	2.27	2.67
05/19/16	0.25	0.31	0.43	0.64	0.89	1.06	1.38	1.67	1.85	2.24	2.64
05/20/16	0.26	0.33	0.46	0.67	0.89	1.05	1.38	1.65	1.85	2.24	2.63
05/23/16	0.26	0.35	0.48	0.69	0.91	1.05	1.38	1.65	1.84	2.23	2.63
05/24/16	0.28	0.35	0.48	0.69	0.92	1.08	1.41	1.68	1.86	2.25	2.65
05/25/16	0.24	0.33	0.47	0.67	0.92	1.08	1.40	1.69	1.87	2.27	2.67
05/26/16	0.17	0.31	0.46	0.65	0.87	1.03	1.35	1.65	1.83	2.24	2.64
05/27/16	0.23	0.32	0.47	0.68	0.90	1.06	1.39	1.67	1.85	2.25	2.65
05/31/16	0.27	0.34	0.49	0.68	0.87	1.03	1.37	1.66	1.84	2.23	2.64
06/01/16	0.27	0.30	0.49	0.70	0.91	1.07	1.39	1.67	1.85	2.22	2.63
06/02/16	0.19	0.29	0.48	0.68	0.89	1.03	1.36	1.63	1.81	2.17	2.58
06/03/16	0.19	0.30	0.43	0.60	0.78	0.92	1.23	1.50	1.71	2.09	2.52
06/06/16	0.19	0.28	0.43	0.60	0.80	0.94	1.25	1.53	1.73	2.12	2.55
06/07/16	0.20	0.28	0.43	0.59	0.78	0.94	1.23	1.51	1.72	2.10	2.54
06/08/16	0.20	0.24	0.43	0.60	0.78	0.93	1.23	1.51	1.71	2.08	2.51
06/09/16	0.21	0.26	0.43	0.59	0.77	0.91	1.22	1.49	1.68	2.05	2.48
06/10/16	0.18	0.26	0.42	0.57	0.73	0.87	1.17	1.44	1.64	2.02	2.44
06/13/16	0.23	0.27	0.40	0.55	0.73	0.84	1.14	1.42	1.62	2.01	2.43
06/14/16	0.24	0.27	0.41	0.55	0.74	0.85	1.15	1.42	1.62	2.00	2.43
06/15/16	0.23	0.26	0.37	0.52	0.69	0.81	1.10	1.38	1.60	1.99	2.43
06/16/16	0.23	0.27	0.36	0.53	0.70	0.81	1.10	1.37	1.57	1.96	2.39
06/17/16	0.22	0.27	0.37	0.51	0.70	0.83	1.13	1.41	1.62	1.99	2.43
06/20/16	0.23	0.28	0.41	0.56	0.74	0.87	1.17	1.45	1.67	2.03	2.47
06/21/16	0.25	0.27	0.41	0.57	0.76	0.89	1.22	1.49	1.71	2.07	2.50
06/22/16	0.25	0.27	0.40	0.56	0.75	0.88	1.20	1.49	1.69	2.06	2.50
06/23/16	0.27	0.31	0.43	0.58	0.78	0.92	1.25	1.54	1.74	2.12	2.55
06/24/16	0.24	0.27	0.38	0.48	0.64	0.76	1.08	1.35	1.57	1.96	2.42
06/27/16	0.22	0.27	0.35	0.45	0.61	0.70	1.00	1.26	1.46	1.83	2.28
06/28/16	0.25	0.26	0.35	0.45	0.61	0.71	1.00	1.26	1.46	1.83	2.27
06/29/16	0.18	0.26	0.35	0.46	0.62	0.74	1.03	1.30	1.50	1.86	2.30
06/30/16	0.20	0.26	0.36	0.45	0.58	0.71	1.01	1.29	1.49	1.86	2.30
07/01/16	0.24	0.28	0.37	0.45	0.59	0.71	1.00	1.27	1.46	1.81	2.24
07/05/16	0.27	0.28	0.35	0.44	0.56	0.66	0.94	1.19	1.37	1.72	2.14
07/06/16	0.26	0.27	0.36	0.46	0.58	0.69	0.95	1.20	1.38	1.72	2.14
07/07/16	0.27	0.29	0.37	0.47	0.58	0.69	0.97	1.21	1.40	1.72	2.14
07/08/16	0.26	0.28	0.36	0.48	0.61	0.71	0.95	1.19	1.37	1.69	2.11
07/11/16	0.28	0.31	0.40	0.50	0.66	0.77	1.03	1.27	1.43	1.73	2.14

07/12/16	0.29	0.29	0.40	0.52	0.69	0.81	1.10	1.35	1.53	1.82	2.24
07/13/16	0.29	0.31	0.40	0.51	0.68	0.80	1.07	1.32	1.48	1.77	2.18
07/14/16	0.29	0.32	0.41	0.53	0.68	0.82	1.10	1.36	1.53	1.84	2.25
07/15/16	0.27	0.32	0.42	0.52	0.71	0.87	1.15	1.42	1.60	1.90	2.30
07/18/16	0.26	0.32	0.44	0.52	0.68	0.85	1.14	1.40	1.59	1.90	2.30
07/19/16	0.29	0.31	0.44	0.56	0.70	0.84	1.12	1.38	1.56	1.88	2.27
07/20/16	0.28	0.32	0.44	0.56	0.73	0.86	1.15	1.41	1.59	1.91	2.30
07/21/16	0.28	0.32	0.44	0.54	0.70	0.82	1.11	1.38	1.57	1.90	2.29
07/22/16	0.29	0.33	0.44	0.55	0.71	0.84	1.13	1.40	1.57	1.90	2.29
07/25/16	0.28	0.32	0.44	0.55	0.72	0.87	1.15	1.41	1.58	1.90	2.29
07/26/16	0.24	0.31	0.43	0.55	0.75	0.87	1.15	1.40	1.57	1.89	2.28
07/27/16	0.25	0.31	0.40	0.53	0.73	0.83	1.10	1.35	1.52	1.84	2.23
07/28/16	0.19	0.25	0.39	0.53	0.72	0.82	1.09	1.35	1.52	1.83	2.23

* 30-year Treasury constant maturity series was discontinued on February 18, 2002 and reintroduced on February 9, 2006. From February 18, 2002 to February 8, 2006, Treasury published alternatives to a 30-year rate. See Long-Term Average Rate for more information.

Treasury discontinued the 20-year constant maturity series at the end of calendar year 1986 and reinstated that series on October 1, 1993. As a result, there are no 20-year rates available for the time period January 1, 1987 through September 30, 1993.

Treasury Yield Curve Rates. These rates are commonly referred to as "Constant Maturity Treasury" rates, or CMTs. Yields are interpolated by the Treasury from the daily yield curve. This curve, which relates the yield on a security to its time to maturity is based on the closing market bid yields on actively traded Treasury securities in the over-the-counter market. These market yields are calculated from composites of quotations obtained by the Federal Reserve Bank of New York. The yield values are read from the yield curve at fixed maturities, currently 1, 3 and 6 months and 1, 2, 3, 5, 7, 10, 20, and 30 years. This method provides a yield for a 10 year maturity, for example, even if no outstanding security has exactly 10 years remaining to maturity.

Treasury Yield Curve Methodology. The Treasury yield curve is estimated daily using a cubic spline model. Inputs to the model are primarily bid-side yields for on-the-run Treasury securities. See our Treasury Yield Curve Methodology page for details.

Negative Yields and Nominal Constant Maturity Treasury Series Rates (CMTs). Current financial market conditions, in conjunction with extraordinary low levels of interest rates, have resulted in negative yields for some Treasury securities trading in the secondary market. Negative yields for Treasury securities most often reflect highly technical factors in Treasury markets related to the cash and repurchase agreement markets, and are at times unrelated to the time value of money.

As such, Treasury will restrict the use of negative input yields for securities used in deriving interest rates for the Treasury nominal Constant Maturity Treasury series (CMTs). Any CMT input points with negative yields will be reset to zero percent prior to use as inputs in the CMT derivation. This decision is consistent with Treasury not accepting negative yields in Treasury nominal security auctions.

In addition, given that CMTs are used in many statutorily and regulatory determined loan and credit programs as well as for setting interest rates on non-marketable government securities, establishing a floor of zero more accurately reflects borrowing costs related to various programs.

For more information regarding these statistics contact the Office of Debt Management by email at debt.management@do.treas.gov.

2015 GMP Benchmarked Performance

Rank	Peer Group Ferc Ref	State State(s)	2015 $$$ per Customer	2014 $$$ per Customer	2013 $$$ per Customer	Transmission Expense p. 321, ln 112	Transmission of Electricity by Others p. 321, Ln 96	Total Trans Exp less TBO Col (h) - (i)	Distribution p. 322, ln 156	Customer Srvc Total Customer Accounts p. 322, ln 164	Customer Srvc Total Cust Svc & Info Expense p. 323, ln 171	Customer Srvc Total Sales Expense p. 323, ln 178	Total Customer Service Related Col (l) + (m) + (n)	Administrative p. 323, ln 197	Total Customers p. 301, ln 10
1	Emera Maine (Bangor Hydro & ME Public Service) *	Maine	$291	$277	$232	$ (17,907,130)	$ (24,022,972)	$ 6,115,842	$ 16,511,720	$ 7,915,906	$ 223,428	$ -	$ 8,139,334	$ 18,528,799	169,355
2	Unitil Energy Systems, Inc.	NH	$318	$320	$327	$ 25,401,190	$ 24,936,682	$ 464,508	$ 9,010,331	$ 3,697,008	$ 2,469,443	$ -	$ 6,166,451	$ 9,124,580	77,844
3	Maine Public Service Co.*	Maine	$325	$325	$325	$ 2,649,952	$ -	$ 2,649,952	$ 3,606,095	$ 1,754,639	$ 36,435	$ -	$ 1,791,074	$ 3,640,521	36,000
4	MDU Resources	Mont/Dak/WY	$363	$360	$370	$ 13,469,108	$ 4,687,579	$ 8,781,529	$ 15,746,672	$ 4,146,987	$ 253,014	$ 154,353	$ 4,554,354	$ 21,965,677	140,690
5	Green Mountain Power	VT	$371	$386	$400	$ 98,294,767	$ 90,006,769	$ 8,287,998	$ 32,541,326	$ 9,145,056	$ 2,571,740	$ 27,898	$ 11,744,694	$ 43,845,172	260,216
6	Northern States Power Co (WI)	Wis	$393	$387	$386	$ 46,131,267	$ 36,711,609	$ 9,419,658	$ 24,951,094	$ 9,835,156	$ 11,158,306	$ 72,065	$ 21,065,527	$ 44,910,611	255,036
7	Madison Gas & Electric	Wis	$421	$426	$483	$ 36,331,545	$ 36,320,848	$ 10,697	$ 14,140,666	$ 5,368,713	$ 8,158,080	$ 213,568	$ 13,740,361	$ 34,372,618	147,728
8	Granite State Electric Co (Liberty Utilities)	NH	$426	$475	$459	$ 19,673,205	$ 19,117,443	$ 555,762	$ 7,022,450	$ 3,660,224	$ 205,667	$ 48,565	$ 3,914,456	$ 7,132,684	43,705
9	Public Service Company of New Hampshire	NH	$440	$431	$460	$ 33,959,257	$ 22,525,519	$ 11,433,738	$ 64,752,854	$ 34,225,939	$ 16,025,583	$ 23,615	$ 50,275,137	$ 95,308,584	504,071
10	Rochester Gas & Electric **	NY	$508	$508	$545	$ 11,111,872	$ 324,170	$ 10,787,702	$ 46,079,730	$ 27,917,130	$ 46,386,877	$ 2,759,651	$ 77,063,658	$ 55,068,442	372,237
11	The Empire District Electric Co.	Ark	$549	$566	$537	$ 23,667,303	$ 17,720,679	$ 5,946,624	$ 29,022,564	$ 8,624,288	$ 2,986,029	$ 194,682	$ 11,804,999	$ 46,209,166	169,346
12	Western Massachusetts Electric Co	Mass	$622	$630	$653	$ 6,962,115	$ (608,351)	$ 7,570,466	$ 21,811,836	$ 18,278,625	$ 41,900,550	$ 10,048	$ 60,189,223	$ 40,171,484	208,606
13	Black Hills Power, Inc.	SD	$639	$698	$678	$ 23,463,615	$ 19,065,613	$ 4,398,002	$ 9,615,432	$ 3,239,329	$ 1,716,625	$ 3,704	$ 4,959,658	$ 26,140,980	70,560
14	Fitchburg Gas & Electric	Mass	$661	$605	$552	$ 8,025,950	$ 7,378,384	$ 647,566	$ 3,679,956	$ 3,618,779	$ 4,772,160	$ 1,200,563	$ 9,591,502	$ 5,397,362	29,218
15	Otter Tail	Minn, Dak	$685	$695	$675	$ 27,080,231	$ 16,995,586	$ 10,084,645	$ 15,514,298	$ 12,791,342	$ 8,864,128	$ 312,768	$ 21,968,238	$ 42,025,282	130,822
16	Upper Peninsula Power Co	Mich	$718	$555	$555	$ 18,268,616	$ 18,033,546	$ 235,070	$ 13,330,480	$ 3,506,782	$ 2,660,912	$ -	$ 6,167,694	$ 17,555,970	51,942
17	Rockland Electric Company	NJ	$721	$715	$724	$ 2,125,414	$ -	$ 2,125,414	$ 16,292,619	$ 4,839,255	$ 8,953,971	$ 6,162	$ 13,799,388	$ 20,296,250	72,871
19	CH Energy (Central Hudson)	NY	$767	$807	$767	$ 11,511,582	$ 2,190,040	$ 9,321,542	$ 44,593,941	$ 20,136,126	$ 48,387,469	$ 54,384	$ 68,577,979	$ 67,456,885	247,750
18	The United Illuminating Co	CT	$908	$770	$710	$ 139,122,793	$ 93,078,369	$ 46,044,424	$ 98,347,065	$ 47,508,853	$ 44,581,872	$ -	$ 92,090,725	$ 65,125,257	332,221
20	Allete	Minn	$927	$1,000	$921	$ 73,534,084	$ 50,653,854	$ 22,880,230	$ 24,186,895	$ 5,473,122	$ 8,401,534	$ 126,714	$ 14,001,370	$ 73,415,863	145,054

* Bangor Hydro and Maine Public Service merged so we need a new utility in the peer group.

** Rochester Gas & Electric have not filed yet. These are the 2014 figures.

Green Mountain Power
Alternative Regulation Plan Base Rate Filing
2017 Base Rate Adjustment
Description of Methodologies

The summary below describes the methodologies and assumptions underlying the adjustments to Green Mountain Power's ("GMP" or the "Company") base rate filing pursuant to its Alternative Regulation Plan.

The Test Year is April 1, 2015 through March 31, 2016. The Rate Year is the Company's fiscal year ended September 30, 2017. The Company developed the Rate Year Cost of Service ("COS") by making known and measurable adjustments to the Test Year costs and rate base.

CAPITAL STRUCTURE

Based on long-term debt, short-term debt, and common equity, adjusted for projections through the end of the Rate Year of new debt and equity issues and retirements, net income, dividends and other miscellaneous items impacting common equity.

RETURN ON EQUITY

The Company's allowed return on equity effective October 1, 2015 (9.44%) adjusted by 50% of the change in the 10-year Treasury Bill yields to maturity measured over the last 20 trading days ending July 18, 2016. For this filing, the result is a 9.02% ROE.

RATE YEAR REVENUE

Based on Rate Year sales and customer forecast incorporating such factors as self-generation, conservation, efficiency, AMI smart meter efficiency, load management and customer growth and reflecting: (1) the elimination of voluntary renewable service rider ("GMP Cow Power™") revenue; (2) any general rate change taking place before the beginning of the Rate Year; (3) revenues from retail customers coming onto or leaving GMP such as acquisitions or customer growth; (4) volume changes included in the retail sales forecast; and (5) rate change applicable to instant docket to reflect that the resulting Rate Year revenue will recover the allowable Rate Year revenue requirement with no change to the Commercial and Industrial Transmission Service Rate. Forecast produced by Itron, Inc.

NON-POWER COST CAP 'NPCC'

The amount of Current Non-Power Cost recoverable in base rates is limited by a NPCC. The level of non-power costs can increase from the level currently allowed in rates by changes to CPI-U Northeast (less a 1% productivity adjustment plus cost incentive adjustment) and adjustments made for Capital Spending, Exogenous Changes and incremental ROE impacts. The Capital Spending adjustment includes incremental changes in ratebase and their ancillary impact on cost of service expenses.

Green Mountain Power
Alternative Regulation Plan Base Rate Filing
2017 Base Rate Adjustment
Description of Methodologies

COST OF SERVICE ADJUSTMENTS

The Cost of Service Adjustments were developed in a manner consistent with traditional Vermont ratemaking principles and consistent with the provisions of GMP's Alternative Regulation Plan.

Purchased Power-net: developed in the same manner as in other recent GMP rate cases, costs are developed using projected Rate Year loads and either contractual or forecast prices and volumes for power. Projected Rate Year information related to energy and capacity prices, unit availability, market prices, etc. are input into a power cost model that simulates ISO New England operations and settlement. A new expense was added this year to better reflect the cost of ISO purchases and sales because our forecasting model does not account for the full impact of hourly (versus monthly net on- and off-peak amounts) interchange on energy costs.

Production Fuel: reflects the cost of fuel used to produce energy from company-owned (whole or joint) units. The price used for Millstone 3 nuclear unit is an estimate of the current fuel-cycle amortization rate. The prices used for Stonybrook, Wyman, and GMP peakers are based on very recent NYMEX futures prices. McNeil's projected price reflects fiscal year 2015 actual prices.

Joint Ownership Costs: O&M was calculated based on a five year average and property tax reflects test year.

Transmission by Others: the value for NEPOOL Open Access Transmission Tariff (NOATT) charges is based on projected rates (6/16-5/17 and 6/17-5/18) times projected GMP network loads, less projected NOATT credits for our PTF facilities. The value for FY 2017 VELCO VTA charges is based on a projection of costs from VELCO, adjusted for NOATT, Specific Facility, and other credits. Other TbyO values were projected using recent values or general trends.

ISO-NE and NEPOOL Charges: projections of ISO New England and NEPOOL tariff charges are based on the best available data, including the published rate for the latest period available, which includes part of the rate year for most tariffs

Wholly-Owned Production: the Rate Year is based on the Company's updated FY2017 Budget projections.

Base O&M: Increase Year 4 (2016) Base O&M platform by CPI-U of 0.6% to arrive at Year 5 (2017) Base O&M platform. There are no other adjustments to the Base O&M platform in this filing. CPI-U reflects 12 months ending March, 2016 using data available as of April 30, 2016.

Green Mountain Power
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Non Base O&M Costs - SmartPower: includes SmartPower O&M Rate Year costs and amortizations and removes incremental Rate Year savings.

Non Base O&M Costs – VMPD Tree Trimming – Danby Line: reflects the Company's expected Rate Year level of costs.

Non Base O&M Costs - Kingdom Community Wind Project (KCW): Rate Year level of Non Power adjustor O&M costs is consistent with Test Year level of expense plus KCW costs charged to Power Supply Adjustor accounts in the Test Year but will be charged to Non Base O&M Costs – KCW in the Rate Year.

Vermont Unemployment: the Rate Year O&M amount was calculated by multiplying the Test Year to Rate Year change in the taxable wage base times the Rate Year number of regular employees multiplied by the O&M allocation factor.

Social Security Taxes: The Test Year to Rate Year percentage change in the number of employees, multiplied by the Test Year O&M Social Security tax to determine the adjustment to Test Year payroll taxes.

Depreciation Expense: reflects the impacts of Interim Period and Rate Year plant in service additions and retirements. The depreciation rates reflect the most recent GMP Depreciation Study that was approved by the Public Service Board.

Federal & State Income Taxes: calculation based on the statutory income tax rate adjusted for permanent differences.

Gross Revenue and Fuel Gross Receipts Taxes: The gross revenue tax is 0.5% of retail electric revenue, other operating revenue and Rec revenue. The fuel gross receipts tax is 0.5% of retail electric revenue. A weighted average rate of 1.04% was calculated and applied to just the rate year retail electric revenue to calculate the rate year gross operating and fuel gross receipts taxes.

Business Development: reflects Test Year level of revenues and expenses.

Community Energy & Efficiency Development Fund Amortization: is the Rate Year amortization for weatherization and thermal efficiency improvements funded by the CEED fund.

Return on Utility Rate Base: weighted average cost of capital applied to the Rate Year 13-month average rate base.

Equity in Earnings of Affiliates: reflects Rate Year equity in earnings of Vermont Yankee, Maine Yankee, Connecticut Yankee, Green Lantern, NE Hydro Trans, NE Hydro Trans Electric, VELCO, VT TRANSCO LLC, and JV-Solar.

Property Taxes: Rate Year level is developed utilizing an annual escalation factor based on recent trends.

Other Operating Revenue: removes items charged to Other Operating Revenue that were prior-period adjustments or will not be recurring in the Rate Year, and adds items to be charged to Other Operating Revenue in the Rate Year that did not occur in the Test Year.

Reg Assets, Deferred Debits and Reg Liabilities: includes Rate Year amortization of regulatory assets, deferred debits and regulatory liabilities.

Accretion Expense: Includes the rate year expense related to asset retirement obligations.

Credit Facility Fees: Includes Rate Year fees paid for Letter of Credits outstanding under the credit facility and for the un-used portion of the $110 million revolving credit facility.

Non Base O&M Costs – Acct 929 Electric Company Usage Credit: Includes credit for the Rate Year costs of company electric usage that is included in the wholly-owned production expense.

Removal of Regulatory Deferrals in Test Year: Removes the Test Year Regulatory Deferrals associated with Hydro Production Tax Credits and the estimated customer synergies in excess of the amount included in the FY 2016 base rate filing.

RATE BASE ADJUSTMENTS

The Rate Base (“RB”) Adjustments were developed in a manner consistent with traditional Vermont ratemaking principles and consistent with the provisions of GMP’s Alternative Regulation Plan.

Production: reflects the capital additions and retirements from the end of the Test Year to the beginning of the Rate Year (“Interim Period”) and Rate Year capital additions and retirements that meet the documentation requirements as outlined in Attachment 7 of the Alternative Regulation Plan.

Transmission: reflects the Interim Period and Rate Year capital additions and retirements that meet the documentation requirements as outlined in Attachment 7 of the Alternative Regulation Plan.

Green Mountain Power
Alternative Regulation Plan Base Rate Filing
2017 Base Rate Adjustment
Description of Methodologies

Distribution: reflects the Interim Period and Rate Year capital additions and retirements that meet the documentation requirements as outlined in Attachment 7 of the Alternative Regulation Plan.

General: reflects the Interim Period and Rate Year capital additions and retirements that meet the documentation requirements as outlined in Attachment 7 of the Alternative Regulation Plan.

Community Energy & Efficiency Development Fund: the Rate Year 13-month average balance for investments levels identified in the DPS MOU for weatherization improvements and thermal efficiency improvements for those who do not qualify for the weatherization improvements.

Construction Work in Progress: CWIP 13-month average balance, excluding AFUDC projects and excluding those plant items that are not closed to plant before the end of the Rate Year.

Investment in Affiliates: Test Year to Rate Year change in investment balances.

Special Deposits: Test Year 13-month average balance of cash deposits with ISO-NE.

Unamortized Debt Discount and Expense: Rate Year 13-month average balance of unamortized deferred issuance costs for debt securities and capital stock.

Rate Year Millstone 3 Energy and Capacity: Rate Year 13-month average balance of unamortized nuclear replacement energy and capacity costs for the Millstone 3 outage.

Reg Assets, Deferred Debits: Rate Year 13-month average balance of unamortized regulatory assets, deferred debits and regulatory liabilities.

Vtel Contract: Rate Year 13-month average balance of the prepaid Vtel wireless communication net work access fee.

Change in Net Plant Removal Costs: Rate Year 13-month average balance of the net plant removal cost asset created by returning $7M of plant removal costs to customers over 2 years beginning October 1, 2016. This net asset is partially offset by a regulatory liability (253XX-Reg Liab PLANT REMOVAL)

Tax FAS 109: Rate Year 13-month average balance of the FAS 109 net asset. This amount is offset by an amount included in Accumulated Deferred Income taxes.

Working Capital Allowances: Includes Test Year 13-month average balance for Material and Supplies and Prepayments including prepaid property taxes but excluding prepaid income taxes, Rate Year 13-month average balance for Millstone III Nuclear Fuel and a cash working capital requirement calculated base on a lead-lag study.

Accumulated Depreciation: includes Interim Period and Rate Year retirements and depreciation expense related to current plant balances, plant additions and plant retirements.

Accumulated Deferred Income Taxes: reflects beginning and ending Rate Year average deferred income tax asset and liability balances. Includes the impacts of various Rate Base adjustments and known tax law in effect during the Rate Year.

Accumulated Deferred Investment Tax Credits: Rate Year 13-month average balance of deferred investment tax credits accounted for in accordance with Option 1 of IRC Section 46(f).

Reg Liabilities: Rate Year 13-month average balance of unamortized regulatory liabilities.

Northern Water Res (NWR) – Accounts Payable: Test Year 13-month average balance of the NWR Accounts Payable resulting from NWR losses utilized by GMP and offset by a GMP deferred tax asset.

CIAC: Reflects return of 50% of CIAC tax adder liability to customers in FY17. The CIAC tax adder collected from customers is being recorded to operating income.

SERP: reflects the Rate Year 13-month average Supplemental Executive Retirement Plan liability.

Accrued Pension Expense: Rate Year 13-month average overfunded pension asset.

Accumulated Post-Retirement Medical Expense FAS 106: reflects the Rate Year 13-month average post-retirement medical expense liability.

Accumulated Other Post-Employment Benefit Expense FAS 112: reflects the Rate Year 13-month average for other post-employment benefits expense asset.

GREEN MOUNTAIN POWER CORPORATION

NON-POWER COST CAP CALCULATION

$ in 000's

		Amount	
1	2016 Non Power Costs	233,375	2016 Base Case (filed August 1, 2015)
2	Plus CPI-U Northeast - (1% Productivity - Non-Power Supply C	0.35%	CPI-NE 12 months ended March 2016 less Productivity A
3		----------	
4	2017 Non Power Cost of Service subtotal	234,192	
5			
6	Capital Spending Adjustment	2,043	Capital Spending Adjustment 2/4
7	Exogenous Changes	3,082	2015 ESAM collection; Storm recovery that was no t pa
8	ROE	(3,216)	ROE Adjustment 4/4
9		----------	
10	2017 Proforma Non Power Cost of Service Cap	236,101	
11			
12	Non Power Cost of Service to Ultimate Consumers	217,055	Non Power Cost of Service Calculation 3/4
13		----------	
14	Amount (above) or below the cap	19,046	

Capital Spending Adjustment Calc

Calculation of Capital Spending Adjustment Revenue Requirement

	Rate Year	In Rates *	Incremental Difference
Utility Plant in Service	1,725,606	1,644,419	81,187
CWIP	8,878	8,036	842
Accumulated Depreciation	(639,661)	(602,083)	(3,426)
ADIT			(26,654)
AFUDC			0
Efficiency Fund and CEED Fund	19,620	19,362	258
Preliminary Survey Costs	0	0	0
	----------	----------	----------
Rate Base subject to Capital Spending Adjustment	1,114,443	1,069,734	52,207
Depreciation and Amortization			(4,518)
Municipal Taxes		1.54%	1,253
Return and Associated Income Taxes on Rate Base		10.13%	5,289
			0
Gross Receipts Tax		1.00%	20

Capital Spending Adjustment Revenue Requirement			2,043

* From 2016 Settled Case

Line	Description	2016 Non Power Cost of Service	2017 Non Power Cost of Service
1	**Non Power Cost of Service Calculation 3/5**		
6	Operating Expenses:		
7	Purchased Power, Net		
8	Production		
9	Other Power Supply	3,174	3,193
10			
11	Purchased Power and Production	3,174	3,193
12	Transmission		
13	Transmission - Other	5,601	5,635
14	Distribution	44,294	44,559
15	Customer Accounting	10,178	10,239
16	Customer Service and Information	2,590	2,606
17	Sales	0	0
18	Administrative and General	54,866	55,196
19	Non Base O&M Costs - AMI	558	742
20	Non Base O&M Costs - KCW	1,225	957
21	Non Base O&M Costs - VMPD	135	113
22	Non Base O&M Costs - 7496 MOU	0	0
22	Non Base Acct 929	(147)	(344)
23	Business Development	562	556
24	Depreciation & Amortization	50,145	48,709
25	Taxes - Federal and State	32,696	34,390
26	- Municipal	24,911	27,882
27	- Other, excluding Revenue Taxes	2,844	2,875
	Accretion Expense	193	248
28	Capital Costs	142	97
29		--------	--------
30	Total Operating Expenses	233,969	237,652
31	Return on Utility Rate Base	92,111	95,235
32		--------	--------
33	Total Cost of Service Before Credits	326,079	332,887
34			
35	Less:		
36	Equity in Earnings of Affiliates	62,816	83,158
37	Other Operating Revenues	21,669	21,763
38	Business Development	864	742
39	VY Insurance	0	0
40	Interest Due From ISO-NE	0	0
41	Resales	0	0
42		--------	--------
43	Total Credits	85,349	105,662
44			
45	Non Power Cost of Service	240,731	227,225
46			
47	Gross Revenue & Fuel Gross Receipts Taxes	5,944	6,166
48		--------	--------
49	Non Power Costs	246,675	233,391
50	Merger savings	(13,300)	(16,335)
51			
52	Total Non Power Costs	233,375	217,055
53			

ROE Adjustment

Equity Return 2017	4.54%
Equity Return 2016	4.68%
Difference	-0.14%
Rate Base	1,352,771
Change in equity return	(1,894)
Change in income Tax	(1,290)
Change in Gross revenue tax	(32)
Total ROE Adjustment	(3,216)

Green Mountain Power
Functional Categories of Plant Additions
As they are being recovered in FY17 base rates

$ in 000s	Q3 2016 (Apr - Jun)	Q4 2016 (Jul - Sep)	Q1 2017 (Oct - Dec)	Q2 2017 (Jan - Mar)	Q3 2017 (Apr - Jun)	Q4 2017 (Jul - Sep)	Total Additions	Retirements	Net Total in Case
Communications	$ -	$ -	$ -	$ 183	$ 43	$ 1,043	$ 1,269	$ -	$ 1,269
Computer Hardware	242	3,744	189	639	362	1,386	6,561	-	6,561
Computer Software	121	5,087	9	1,968	653	5,988	13,826	-	13,826
Distribution Lines	6,263	6,263	6,359	6,359	6,359	6,359	37,961	5,606	32,355
Distribution Substations	1,132	154	157	1,996	181	396	4,016	253	3,763
General Plant	-	-	186	109	-	-	295	4,836	(4,540)
Joint Ownership	-	1,692	-	-	-	1,707	3,399	6,224	(2,825)
Meter	150	150	152	152	152	152	909	150	759
New Initiatives	61	1,605	886	2,720	2,766	3,201	11,239	-	11,239
Production	136	643	7,853	8,791	13,701	830	31,954	1,807	30,147
Property and Structures	510	1,863	-	107	1,706	1,020	5,207	396	4,811
Regulators and Capacitor	-	785	-	-	-	797	1,582	17	1,565
Transformers	862	862	875	875	875	875	5,225	56	5,169
Transmission Lines	877	2,993	1,494	311	503	502	6,681	419	6,262
Transmission Substations	581	70	-	-	1,235	2,265	4,152	339	3,812
Transportation	-	3,722	-	169	296	4,307	8,494	1,700	6,794
	$ 10,936	$ 29,634	$ 18,159	$ 24,379	$ 28,833	$ 30,828	$ 142,769	$ 21,804	$ 120,966

Green Mountain Power
FY 2017 Alt Reg Project listing

Construction Summary w/End Date	Start Date	In-Service Date	Additions	Retirements	Balance at 5/31/16	Comment	Comment	GMP Response
Communications								
Install								
148528: Elster Outage Enhance	16-Apr	Sep 2017	990,354		-		Not started on time move In-service	Amount removed from the case
			990,354					
Computer Hardware								
Install								
143202: Upgrade Wireless Controllers	16-Apr	Jul 2017	45,985		-		Not started on time move In-service	Moved to September 2016
143212: Replace Rutland Internet Routers	16-Apr	May 2016	14,189		-	Updated inservice date to August 2016 to coincide with the completion of the data center		Moved to August 2016
143263: Misc. IT Blanket 2016	15-Oct	Sep 2016	176,755		52,260		**IT includes small projects in budget; blankets n**	Amount removed from the case
148494: 2017 IT Blanket	16-Oct	Sep 2017	358,882		-		**IT includes small projects in budget blankets nc**	Amount removed from the case
			595,811					
Computer Software								
Install								
143208: Zeacom Upgrade	16-May	Jul 2016	56,519		-		Start delay move in service	Moved to September 2016
143691: Crossbow	16-May	Jun 2016	127,562		-	In Service date will be moved to July due to minor delays.		Moved to September 2016
148525: UI Enhancement - Rolling Capital Forecast	16-Apr	Sep 2016	191,546		-		Start delay move in service	No Change, in service date will be hit
			375,627					
Distribution Lines Large Cap								
Install								
Distribution Lines - Danger Tree Removal		Oct 2016	291,667				**Remove**	Amount removed from the case
Distribution Lines - Danger Tree Removal		Nov 2016	291,667				**Remove**	Amount removed from the case
Distribution Lines - Danger Tree Removal		Dec 2016	291,667				**Remove**	Amount removed from the case
Distribution Lines - Danger Tree Removal		Jan 2017	291,667				**Remove**	Amount removed from the case
Distribution Lines - Danger Tree Removal		Feb 2017	291,667				**Remove**	Amount removed from the case
Distribution Lines - Danger Tree Removal		Mar 2017	291,667				**Remove**	Amount removed from the case
Distribution Lines - Danger Tree Removal		Apr 2017	291,667				**Remove**	Amount removed from the case
Distribution Lines - Danger Tree Removal		May 2017	291,663				**Remove**	Amount removed from the case
Distribution Lines - Danger Tree Removal		Jun 2017	291,667				**Remove**	Amount removed from the case
Distribution Lines - Danger Tree Removal		Jul 2017	291,667				**Remove**	Amount removed from the case
Distribution Lines - Danger Tree Removal		Aug 2017	291,667				**Remove**	Amount removed from the case
Distribution Lines - Danger Tree Removal		Sep 2017	291,667				**Remove**	Amount removed from the case
Sub-Total Install			**3,500,000**	**-**				
Distribution Substation								
Install								
143292: Graniteville Substation Rebuild	16-Jan	Jan 2017	1,752,326	104,929	87,403		**No invoices deduct $278,699**	$278,699 removed from ask amount, need to look at.
143308: 15/28MVA 69/46-12.47kV Spare Transformer	15-Oct	Apr 2016	450,552		415,674	Closed	**Adjust to closed amount**	Amount adjusted
Sub-Total Install			**2,202,878**	**104,929**				
General Plant								
Install								
149612 - CMC 356 Test Set.107: CMC 356 Test Set	16-Feb	Jan 2017	108,998		-		No cost; delayed move date	No Change, items have been ordered
146701 Meter Test Boards: 146701 Meter Test Boards	16-Jan	Dec 2016	136,964		-		No cost; delayed move date	No Change, items have been ordered
Sub-Total Install			**245,962**	**-**				
Hydro - New Hydro Dams								
Install								
Generation Purchase	16-Mar	May 2017	23,009,217		-		**Remove: Cost is estimate & need CPG**	Removed
Sub-Total Install			**23,009,217**	**-**				
Jt Ownership								
Install								
Kingdom Community Wind								
Install								
Meters								
Install								
Production								
Install								
Generation Upgrades		Sep 2016	281,290	18,987	187,500			
2017 150kW eFarm 1	16-Aug	Sep 2017	2,024,252		-		**No cost, need approval Remove**	Amount removed from the case
143344: eFarm - St. Albans	15-Sep	Mar 2017	9,481,896		1,016,283		**Question inservice w/ pending hearings**	Amount removed from the case
143362: Glen Penstock & Trashracks	15-Oct	Dec 2016	4,053,031	100,000	113,273		Running behind move in service	In service date moved to 3/2017
143374: Salisbury Penstock Replacement at Bridge	15-Sep	Sep 2016	592,695	10,000	44,550		Running behid move in service	Moved to December 2016
145353: Milton Solar	15-Oct	May 2016	135,866		150,841	Will close in May delayed by accounting to create depreciation group.		No Change, project is complete
148890: Panton Grid Scale Energy Storage	16-May	Jan 2017	3,028,069		3,918		Below planned cost - Move in service	Moved to March 2017
Sub-Total Install			**19,597,099**	**128,987**				
Property & Structures								
Install								
143539: Purchase Land for Burl Sub	15-May	Sep 2017	543,866		70,247		**Remove until sale is final**	Amount removed from the case
143540: Purchase Land Hinesburg		Sep 2017	98,843		-		**Remove until sale is final**	Amount removed from the case
143576: Colchester Data Center	15-Oct	Sep 2016	1,405,326		29,521		Move In Service	No Change, project is underway and on target
148806: Purchase Land in West Rutland	16-Oct	Jul 2017	98,843		-		**Remove until sale is final**	Amount removed from the case
Sub-Total Install			**2,146,879**	**-**				
Regulators and Capacitors								

2.4a

Construction Summary w/End Date	Start Date	In-Service Date	Additions	Retirements	Balance at 5/31/16	Comment	Comment	GMP Response	
Install									
Solar									
Install									
143677: DERM 51 CIRCUIT	15-Apr	Sep 2016	1,552,654		897,706		**If final close @ $897,706 or move in service**	Dollars the same, in service moved to 2/2017	
37.2017EVGO.107: 2017 EVGO	16-Mar	Sep 2017	412,205				Delayed start- Move In Service	Amount removed from the case	
37.2017HEATPUMP.107: 2017 HEAT PUMPS	16-Apr	Sep 2016	895,252				No cost to date - Move In Service	No change	
37.2017HEATPUMP.107: 2017 HEAT PUMPS	16-Apr	Dec 2016	1,398,831				No cost to date - Move In Service	Amount updated - in service date remains	257,385
37.2017HEATPUMP.107: 2017 HEAT PUMPS	16-Apr	Mar 2017	1,398,831				No cost to date - Move In Service	Amount updated - in service date remains	813,187
37.2017HEATPUMP.107: 2017 HEAT PUMPS	16-Apr	Jun 2017	1,398,831				No cost to date - Move In Service	Amount updated - in service date remains	2,081,461
37.2017HEATPUMP.107: 2017 HEAT PUMPS	16-Apr	Sep 2017	1,398,831				No cost to date - Move In Service	Amount updated - in service date remains	2,443,291
37.2017TESLA.107: 2017 TESLA	16-Apr	Sep 2016	726,049				No cost to date - Move In Service	No change	
37.2017TESLA.107: 2017 TESLA	16-Apr	Dec 2016	453,781				No cost to date - Move In Service	Amount updated - in service date remains	475,966
37.2017TESLA.107: 2017 TESLA	16-Apr	Mar 2017	453,781				No cost to date - Move In Service	Amount updated - in service date remains	201,680
37.2017TESLA.107: 2017 TESLA	16-Apr	Jun 2017	453,781				No cost to date - Move In Service	Amount updated - in service date remains	532,436
37.2017TESLA.107: 2017 TESLA	16-Apr	Sep 2017	453,781				No cost to date - Move In Service	Amount updated - in service date remains	605,041
Sub-Total Install			**10,996,608**	**-**					
Transformers									
Install									
			-						
Transmission Lines			-						
Install			-						
Transmission Substations									
Install									
138423: HSCAT 3304 Putt	Jan-15	May 2016	131,296		78,381	Closed	**Change to actual spent**	Amount updated to Closed amount	
143299: Transmission Breaker Change out Digital 3330 & 3332 - INTERIM	Oct-15	May 2016	239,241	273,384	262,003	Closed	**Change to actual spent**	Amount updated to Closed amount	
143301: Transmission Breaker Change out Cavendish B-17 - INTERIM		May 2016	156,333	37,077	34,241	Closed	**Change to actual spent**	Amount updated to Closed amount	
143584: Line VT Replacements		Apr 2016	88,443	1,000	145,564	Closed	**Change to actual spent**	Amount updated to Closed amount	
Sub-Total Install			**615,314**	**311,461**	**520,189**				
Transportation									
Install									
143561: 2016 Pur Buckets and Diggers	15-Oct	Aug 2016	3,008,385	600,000	13,562		Based on existing stock consider excessive	No change based on replacement plan.	
148958: 2017 Bucket and Digger Trucks	16-Oct	Jul 2017	2,996,260	600,000	6,891		Based on existing stock consider excessive	No change based on replacement plan.	
Sub-Total Install			**6,004,645**	**1,200,000**					
Vermont Marble - Hydro									
Install									
148860: Huntington U3 & Intake Modernization	15-Apr	May 2017	6,280,259	220,000	495,998		Cost are a concern for timing	In service date moved to June 2017	
Sub-Total Install			**6,280,259**	**220,000**					
Vermont Marble - Transmission Lines									
Install									
147380: 2016 Marble Street to Danby Reconstruction	15-Oct	Sep 2016	1,438,642	250,000	-		No cost shown - Move In Service	No change, project costs were transferred to another project. This will be closed in August.	
Sub-Total Install			**1,438,642**	**250,000**					
Wind Generation									
Install									

2.4a

Green Mountain Power
FY 2017 Alt Reg Project listing

Construction Summary by Category and Project	Functional Category	Additions	Retirements	In-Service Month	Quarter	In-Service Year
148587: Parallel Protect Device	Communications	182,629		2	Q2	2017
148581: 2017 Sec Camera Chit Dam	Communications	13,464		4	Q3	2017
148580: Security cameras-OH	Communications	29,568		5	Q3	2017
148549: Conversion to VTEL	Communications	1,003,877		9	Q4	2017
148919: Lowell Wind cameras	Communications	39,481		9	Q4	2017
		1,269,018	-			
149202: 2016 Internal Cloud Infra	Computer Hardware	241,677		6	Q3	2016
143212: Replace Rutland Internet Routers	Computer Hardware	14,189		8	Q4	2016
141673: Colchester Visualization	Computer Hardware	1,404,189		9	Q4	2016
143200: Core Network Upgrade	Computer Hardware	983,930		9	Q4	2016
143202: Upgrade Wireless Controllers	Computer Hardware	45,985		9	Q4	2016
143211: Cell Boosting	Computer Hardware	410,561		9	Q4	2016
143262: Technology Device Refresh	Computer Hardware	313,412		9	Q4	2016
148414: 2016 Col New Datacenter Tech	Computer Hardware	572,063		9	Q4	2016
148987: 2017 Exadata Memory Upgrade	Computer Hardware	90,074		11	Q1	2016
148515: 2017 PWNIE Express	Computer Hardware	9,036		12	Q1	2016
148551: 2017 Digital Fault Recorders	Computer Hardware	35,072		12	Q1	2016
148552: 2017 Montpelier NetApp Rep	Computer Hardware	54,358		12	Q1	2016
148513: 2017 Portable Radios	Computer Hardware	71,289		1	Q2	2017
148516: Radio Infrastruct Upgrade	Computer Hardware	44,743		1	Q2	2017
148521: Security Subsystems	Computer Hardware	137,505		1	Q2	2017
148474: 2017 Cell Amp Sys Districts	Computer Hardware	175,913		2	Q2	2017
148493: ISO New England RTU	Computer Hardware	162,046		2	Q2	2017
148517: SCADA DMZ Server Rplmnt	Computer Hardware	47,393		2	Q2	2017
148484: 2017 Dist Server Tech	Computer Hardware	56,776		5	Q3	2017
148519: SCADA Network IDS	Computer Hardware	305,516		5	Q3	2017
148522: 2017 Server Replacements	Computer Hardware	310,797		7	Q4	2017
143206: Replace Video Conferencing	Computer Hardware	286,772		9	Q4	2017
148475: 2017 Cell Amp Sys P & S	Computer Hardware	101,687		9	Q4	2017
148511: 2017 Plant Networking	Computer Hardware	135,402		9	Q4	2017
148512: 2017 Plant Wireless Networking	Computer Hardware	32,652		9	Q4	2017
148524: 2017 Technology Refresh	Computer Hardware	518,227		9	Q4	2017
		6,561,263	-			
143260: GIS Upgrade 2016	Computer Software	120,819		6	Q3	2016
143259: Light Notice App Solution	Computer Software	452,373		7	Q4	2016
148767: Salesforce - Phase I	Computer Software	43,012		7	Q4	2016
143682: NRG Simply Smart Enh	Computer Software	330,697		8	Q4	2016
143208: Zeacom Upgrade	Computer Software	56,519		9	Q4	2016
143210: Zeacom Web Chat	Computer Software	21,219		9	Q4	2016
143229: Mobile APP Enhancements 2016	Computer Software	230,732		9	Q4	2016
143230: CSS Enhancements 2016	Computer Software	278,881		9	Q4	2016
143232: Notifi Enhancements	Computer Software	217,778		9	Q4	2016
143237: GMP API Enhancements/Opportunities	Computer Software	392,735		9	Q4	2016
143257: BI - 2016	Computer Software	286,200		9	Q4	2016
143658: BI Technology Upgrade	Computer Software	214,045		9	Q4	2016
143666: Website Refresh 2016	Computer Software	347,341		9	Q4	2016
143667: WM for Substations 2015-2016	Computer Software	1,017,656		9	Q4	2016
143679: Tripwire	Computer Software	69,851		9	Q4	2016
143691: Crossbow	Computer Software	127,562		9	Q4	2016
146568: BI for Power Supply 2016	Computer Software	573,738		9	Q4	2016
148525: UI Enhancement - Rolling Capital Forecast	Computer Software	191,546		9	Q4	2016
148766: 2016 M2C Enhancements	Computer Software	235,374		9	Q4	2016
148983: 2017 Field Observations and Inspections	Computer Software	5,914		12	Q1	2016
148985: eBenefits Marketplace - HR Intelligence	Computer Software	3,226		12	Q1	2016
148495: 2017 Logsheet Enhance	Computer Software	31,184		1	Q2	2017
148589: 2017 Splunk Log Monitoring	Computer Software	37,109		1	Q2	2017
148492: 2017 GMP Web Framework	Computer Software	153,504		2	Q2	2017
148498: 2017 Network Monitor Utility	Computer Software	4,846		2	Q2	2017
148501: 2017 EBS Upgrade & Enhance	Computer Software	490,092		2	Q2	2017
148527: 2017 Work Mgmt Enhance	Computer Software	162,436		2	Q2	2017
148555: VDI POD Architecture	Computer Software	287,397		2	Q2	2017
148576: 2017 Print Server Upgrade	Computer Software	24,188		2	Q2	2017
148584: Salesforce - Phase II	Computer Software	43,012		2	Q2	2017
148585: Asset Designer for iPad	Computer Software	90,848		2	Q2	2017
148586: 2017 EBS Fixed Asset Enhance	Computer Software	46,249		2	Q2	2017
148845: 2017 EBS 106 Comp	Computer Software	212,682		2	Q2	2017
148514: 2017 Products & Svcs Web Pay	Computer Software	40,656		3	Q2	2017
148523: 2017 Tableau Software	Computer Software	108,324		3	Q2	2017
148582: 2017 Backup and Rec Solution	Computer Software	235,000		3	Q2	2017
148473: 2017 BI for Renew Energy Cr	Computer Software	127,605		4	Q3	2017
148499: ODM System Enhancements	Computer Software	47,421		4	Q3	2017
148526: 2017 Veg Mgmt Software	Computer Software	308,160		4	Q3	2017
148550: Multispeak for SCADA	Computer Software	124,661		5	Q3	2017
148553: MDM Enhancements	Computer Software	45,485		5	Q3	2017
148469: 2017 NRG-Spirae Wave Peak Load Management	Computer Software	475,959		7	Q4	2017
148471: 2017 BI for GIS	Computer Software	136,127		7	Q4	2017
148479: 2017 Controller Enhancements	Computer Software	183,202		9	Q4	2017
148480: 2017 Cust Self Service Enh	Computer Software	579,899		9	Q4	2017
148489: 2017 GMP API	Computer Software	1,170,580		9	Q4	2017
148491: 2017 GMP Mobile App	Computer Software	445,515		9	Q4	2017
148496: M2C Enhancements	Computer Software	314,060		9	Q4	2017
148500: 2017 Oracle NMS	Computer Software	1,454,117		9	Q4	2017
148554: MWM Upgrade	Computer Software	211,410		9	Q4	2017
148583: CCB Upgrade to Ver 2.5 Software	Computer Software	533,189		9	Q4	2017

Construction Summary by Category and Project	Functional Category	Additions	Retirements	In-Service Month	Quarter	In-Service Year
149444: 2017 Distrib Gen Tracking	Computer Software	483,722		9	Q4	2017
		13,825,855	-			
Distribution Lines	Distribution Lines	2,087,798	308,341	4	Q3	2016
Distribution Lines	Distribution Lines	2,087,798	308,341	5	Q3	2016
Distribution Lines	Distribution Lines	2,087,798	308,341	6	Q3	2016
Distribution Lines	Distribution Lines	2,087,798	308,341	7	Q4	2016
Distribution Lines	Distribution Lines	2,087,798	308,341	8	Q4	2016
Distribution Lines	Distribution Lines	2,087,798	308,341	9	Q4	2016
Distribution Lines	Distribution Lines	2,119,533	313,028	10	Q1	2016
Distribution Lines	Distribution Lines	2,119,533	313,028	11	Q1	2016
Distribution Lines	Distribution Lines	2,119,533	313,028	12	Q1	2016
Distribution Lines	Distribution Lines	2,119,533	313,028	1	Q2	2017
Distribution Lines	Distribution Lines	2,119,533	313,028	2	Q2	2017
Distribution Lines	Distribution Lines	2,119,533	313,028	3	Q2	2017
Distribution Lines	Distribution Lines	2,119,533	313,028	4	Q3	2017
Distribution Lines	Distribution Lines	2,119,533	313,028	5	Q3	2017
Distribution Lines	Distribution Lines	2,119,533	313,028	6	Q3	2017
Distribution Lines	Distribution Lines	2,119,533	313,028	7	Q4	2017
Distribution Lines	Distribution Lines	2,119,533	313,028	8	Q4	2017
Distribution Lines	Distribution Lines	2,119,533	313,028	9	Q4	2017
		37,961,184	5,606,382			
141723 - Distribution Minor Additions	Distribution Substations	51,397	8,137	4	Q3	2016
143308: 15/28MVA 69/46-12.47kV Spare Transformer	Distribution Substations	415,674		4	Q3	2016
141723 - Distribution Minor Additions	Distribution Substations	51,397	8,137	5	Q3	2016
135213: South Shaftbury RTU (@ sub) & Security - INTERIM	Distribution Substations	88,176		6	Q3	2016
141723 - Distribution Minor Additions	Distribution Substations	51,397	8,137	6	Q3	2016
143295: Substation Security - Montpelier	Distribution Substations	62,401		6	Q3	2016
143309: 15/28MVA 34.5-12.47kV Spare Transformer - INTERIM	Distribution Substations	411,152		6	Q3	2016
141723 - Distribution Minor Additions	Distribution Substations	51,397	8,137	7	Q4	2016
141723 - Distribution Minor Additions	Distribution Substations	51,397	8,137	8	Q4	2016
141723 - Distribution Minor Additions	Distribution Substations	51,397	8,137	9	Q4	2016
141723 - Distribution Minor Additions	Distribution Substations	52,178	8,261	10	Q1	2016
141723 - Distribution Minor Additions	Distribution Substations	52,178	8,261	11	Q1	2016
141723 - Distribution Minor Additions	Distribution Substations	52,178	8,261	12	Q1	2016
141723 - Distribution Minor Additions	Distribution Substations	52,178	8,261	1	Q2	2017
143292: Graniteville Substation Rebuild	Distribution Substations	1,473,627	104,929	1	Q2	2017
148596: Sharon Substation Rebuild - GMP	Distribution Substations	366,257		1	Q2	2017
141723 - Distribution Minor Additions	Distribution Substations	52,178	8,261	2	Q2	2017
141723 - Distribution Minor Additions	Distribution Substations	52,178	8,261	3	Q2	2017
141723 - Distribution Minor Additions	Distribution Substations	52,178	8,261	4	Q3	2017
148602: Randolph Center Substation Security	Distribution Substations	24,100		4	Q3	2017
141723 - Distribution Minor Additions	Distribution Substations	52,178	8,261	5	Q3	2017
141723 - Distribution Minor Additions	Distribution Substations	52,178	8,261	6	Q3	2017
141723 - Distribution Minor Additions	Distribution Substations	52,178	8,261	7	Q4	2017
	Distribution Substations	52,178	8,261	8	Q4	2017
141723 - Distribution Minor Additions	Distribution Substations	52,178	8,261	9	Q4	2017
143601: 5MVA 46-34.5/12.47kV Spare Transformer - Interim	Distribution Substations	239,863		9	Q4	2017
		4,015,768	252,883			
Communications Equipm Amort	General Plant		445,624	9	Q4	2016
Computer Equipment Amort	General Plant		742,389	9	Q4	2016
Laboratory Equipment Amort	General Plant		21,779	9	Q4	2016
Office and Equipment General Amort	General Plant		121,536	9	Q4	2016
Stores Amort	General Plant		108,395	9	Q4	2016
Tools, Shop and Equipment Amort	General Plant		125,214	9	Q4	2016
149613 - EZCT 2000 Test Set.107: EZCT 2000 Test Set	General Plant	21,918		11	Q1	2016
146701 Meter Test Boards: 146701 Meter Test Boards	General Plant	136,964		12	Q1	2016
149614 - Fiber Trailer	General Plant	27,557		12	Q1	2016
149612 - CMC 356 Test Set.107: CMC 356 Test Set	General Plant	108,998		1	Q2	2017
Communications Equipm Amort	General Plant		454,187	9	Q4	2017
Computer Equipment Amort	General Plant		2,610,215	9	Q4	2017
Laboratory Equipment Amort	General Plant		74,365	9	Q4	2017
Miscellaneous Equipment Amort	General Plant		2,485	9	Q4	2017
Office and Equipment General Amort	General Plant		56,743	9	Q4	2017
Stores Amort	General Plant		28,070	9	Q4	2017
Tools, Shop and Equipment Amort	General Plant		44,804	9	Q4	2017
		295,437	4,835,806			
145124: Highgate Joint Owned	Joint Owned	-	5,883,465	6	Q4	2016
120024: Stony Brook	Joint Owned	85,122	8,512	9	Q4	2016
143142: Wyman-2015	Joint Owned	25,037	2,504	9	Q4	2016
145122: Millstone Joint Owned	Joint Owned	651,068	65,107	9	Q4	2016
145123: McNeil Joint Owned	Joint Owned	285,340	28,534	9	Q4	2016
145124: Highgate Joint Owned	Joint Owned	645,026	64,503	9	Q4	2016
120024: Stony Brook	Joint Owned	86,416	8,642	9	Q4	2017
143142: Wyman-2015	Joint Owned	25,418	2,542	9	Q4	2017
145122: Millstone Joint Owned	Joint Owned	651,068	66,096	9	Q4	2017
145123: McNeil Joint Owned	Joint Owned	289,677	28,968	9	Q4	2017
145124: Highgate Joint Owned	Joint Owned	654,830	65,483	9	Q4	2017
		3,399,002	6,224,356			
143663: 2016 Meter Purchases	Meters	150,026	25,000	6	Q3	2016
143663: 2016 Meter Purchases	Meters	150,026	25,000	9	Q4	2016
148953: 2017 Meter Purchases	Meters	152,307	25,000	12	Q1	2016
148953: 2017 Meter Purchases	Meters	152,307	25,000	3	Q2	2017
148953: 2017 Meter Purchases	Meters	152,307	25,000	6	Q3	2017
148953: 2017 Meter Purchases	Meters	152,307	25,000	9	Q4	2017
		909,280	150,000			
143536: ETS Capital	New Initiatives	61,250		5	Q3	2016
37.2017HEATPUMP.107: 2017 HEAT PUMPS	New Initiatives	895,252		9	Q4	2016
37.2017HPWH.107: 2017 HEAT PUMP WATER HEATERS	New Initiatives	233,916		9	Q4	2016
37.2017TESLA.107: 2017 TESLA	New Initiatives	475,966		9	Q4	2016

Construction Summary by Category and Project	Functional Category	Additions	Retirements	In-Service Month	Quarter	In-Service Year
37.2017HEATPUMP.107: 2017 HEAT PUMPS	New Initiatives	257,385		12	Q1	2016
37.2017HPWH.107: 2017 HEAT PUMP WATER HEATERS	New Initiatives	152,289		12	Q1	2016
37.2017TESLA.107: 2017 TESLA	New Initiatives	475,968		12	Q1	2016
143677: DERM 51 CIRCUIT	New Initiatives	1,552,654		2	Q2	2017
37.2017HEATPUMP.107: 2017 HEAT PUMPS	New Initiatives	813,187		3	Q2	2017
37.2017HPWH.107: 2017 HEAT PUMP WATER HEATERS	New Initiatives	152,289		3	Q2	2017
37.2017TESLA.107: 2017 TESLA	New Initiatives	201,680		3	Q2	2017
37.2017HEATPUMP.107: 2017 HEAT PUMPS	New Initiatives	2,081,461		6	Q3	2017
37.2017HPWH.107: 2017 HEAT PUMP WATER HEATERS	New Initiatives	152,289		6	Q3	2017
37.2017TESLA.107: 2017 TESLA	New Initiatives	532,436		6	Q3	2017
37.2017HEATPUMP.107: 2017 HEAT PUMPS	New Initiatives	2,443,291		9	Q4	2017
37.2017HPWH.107: 2017 HEAT PUMP WATER HEATERS	New Initiatives	152,289		9	Q4	2017
37.2017TESLA.107: 2017 TESLA	New Initiatives	605,041		9	Q4	2017
		11,238,643	-			
145353: Milton Solar	Production	135,866		5	Q3	2016
141780: Peacham Pond Level Indicator	Production	59,541		7	Q4	2016
143356: Fairfax Bearing	Production	97,134	5,000	9	Q4	2016
143378: 2016 Weybridge Gate Upgrades	Production	83,318	17,000	9	Q4	2016
148851: Ascutney Standby Generator	Production	58,393		9	Q4	2016
148853: KCW Reveg Phase II	Production	63,057		9	Q4	2016
Generation Upgrades	Production	281,290	18,987	9	Q4	2016
143336: Belden Hydraulic Grapple & Ferc Rec Improvements	Production	141,303		10	Q1	2016
143369: Passumpic Fish Passage & Portage Access Improvements	Production	449,685		10	Q1	2016
143375: Silver Lake Generator Rewind	Production	297,335	61,000	10	Q1	2016
143376: Silver Lake Goshen Spillway, Itake Rack and Diversion Dan	Production	884,449	32,000	10	Q1	2016
148852: Proctor Recreational Improvements	Production	157,773		10	Q1	2016
148855: Beldens #3 Excitation Upgrade	Production	109,267	50,000	10	Q1	2016
148862: Marshfield Lube Oil Upgrade	Production	38,126		10	Q1	2016
143355: 2016 Essex Transfrmr Contain	Production	307,816	8,000	11	Q1	2016
143387: Ascutney GT HMI/PLC Upgrages	Production	470,905	75,000	11	Q1	2016
143579: 2016 NPS 100 Wind Turbine	Production	531,778		11	Q1	2016
141779: Middlesex U1 U2	Production	1,299,883	34,600	12	Q1	2016
143343: Clark Falls Electrical Modernization	Production	1,837,797	175,000	12	Q1	2016
143374: Salisbury Penstock Replacement at Bridge	Production	592,695	10,000	12	Q1	2016
148858: Huntington Substation Upgrades	Production	734,368	15,000	12	Q1	2016
148857: Smith Gearbox	Production	70,591	20,000	1	Q2	2017
143338: Bolton Falls Electrical Modernization	Production	1,639,436	152,000	2	Q2	2017
143362: Glen Penstock & Trashracks	Production	4,053,031	100,000	3	Q2	2017
148890: Panton Grid Scale Energy Storage	Production	3,028,069		3	Q2	2017
148861: Huntington U1 & U2 Modernization	Production	6,739,537	700,000	4	Q3	2017
148898: Otter Creek FERC Oblig	Production	209,980		4	Q3	2017
143389: Berlin PLC & HMI Upgrades	Production	471,241	75,000	6	Q3	2017
148860: Huntington U3 & Intake Modernization	Production	6,280,259	220,000	6	Q3	2017
148899: Lamoille FERC Oblig	Production	258,769		8	Q4	2017
Generation Upgrades	Production	571,131	38,551	9	Q4	2017
		31,953,823	1,807,138			
146154: St J Cold Storage Heat	Property and Structures	37,181		4	Q3	2016
149187: Hartford Real Estate Purchase	Property and Structures	473,132		4	Q3	2016
143577: White River District Pavement install	Property and Structures	366,782	73,386	8	Q4	2016
143162: 2016 Facilities Blanket	Property and Structures	91,026	12,500	9	Q4	2016
143576: Colchester Data Center	Property and Structures	1,405,326		9	Q4	2016
148728: Conference Room at O.H.	Property and Structures	5,267		1	Q2	2017
148781: St Johnsbury Fuel Island Replacement	Property and Structures	55,076	20,000	1	Q2	2017
143315: St Albans lighting upgrade	Property and Structures	27,968	15,000	2	Q2	2017
148731: Sunderland Fire Alarm	Property and Structures	18,401	5,000	3	Q2	2017
143545 Fuel Management System: 143545 Fuel Management Syst	Property and Structures	50,596		4	Q3	2017
143630: Montpelier Renovation	Property and Structures	977,109	50,000	4	Q3	2017
148730: Colchester Fire Suppression	Property and Structures	30,611	17,582	4	Q3	2017
148805: Montpelier Transportation Lift	Property and Structures	187,119	35,000	5	Q3	2017
148835: Colchester Control Center	Property and Structures	394,062	18,000	5	Q3	2017
148837: RDSC Cooling Tower	Property and Structures	23,717	21,297	5	Q3	2017
143555: EMF-Oil Filled Equipment Containment Area	Property and Structures	43,084	8,000	6	Q3	2017
148725: Springfield unit heaters	Property and Structures	15,175	12,000	7	Q4	2017
148736: Montpelier Roof Replacement	Property and Structures	10,329	406	7	Q4	2017
148806: Purchase Land in West Rutland	Property and Structures	98,843		7	Q4	2017
148723: St. Johnsbury Cold Storage Building	Property and Structures	168,649		8	Q4	2017
148724: Royalton Cold Storage Facility	Property and Structures	170,460		9	Q4	2017
148732: 2017 Facilities Blanket	Property and Structures	184,818	25,000	9	Q4	2017
148734: Springfield Roof	Property and Structures	354,343	70,000	9	Q4	2017
148838: Saint Albans HVAC	Property and Structures	17,430	12,500	9	Q4	2017
		5,206,502	395,671			
141719: Regulators and capacitors	Regulators and Capacitors	785,183	8,401	9	Q4	2016
141719: Regulators and capacitors	Regulators and Capacitors	797,118	8,529	9	Q4	2017
		1,582,301	16,930			
141720: Distribution Transformers Install	Transformers	862,115	9,260	6	Q3	2016
141720: Distribution Transformers Install	Transformers	862,115	9,260	9	Q4	2016
141720: Distribution Transformers Install	Transformers	875,219	9,401	12	Q1	2016
141720: Distribution Transformers Install	Transformers	875,219	9,401	3	Q2	2017
141720: Distribution Transformers Install	Transformers	875,219	9,401	6	Q3	2017
141720: Distribution Transformers Install	Transformers	875,219	9,401	9	Q4	2017
		5,225,106	56,124			
141721: Transmission Minor Additions	Transmission Lines	102,217	2,143	4	Q3	2016
141721: Transmission Minor Additions	Transmission Lines	102,217	2,143	5	Q3	2016
143506: Husky Tap RTU	Transmission Lines	50,631		5	Q3	2016
143507: North Elm Tap RTU	Transmission Lines	55,296		5	Q3	2016
135211: Sherburn Tap SCADA	Transmission Lines	464,670		6	Q3	2016
141721: Transmission Minor Additions	Transmission Lines	102,217	2,143	6	Q3	2016
141721: Transmission Minor Additions	Transmission Lines	102,217	2,143	7	Q4	2016
147274: Claremont to Charlestown Partial Reconductor	Transmission Lines	380,311	40,000	7	Q4	2016

Construction Summary by Category and Project	Functional Category	Additions	Retirements	In-Service Month	Quarter	In-Service Year
141721: Transmission Minor Additions	Transmission Lines	102,217	2,143	8	Q4	2016
143570: Fiber to Marshfield Dam	Transmission Lines	187,564		8	Q4	2016
141721: Transmission Minor Additions	Transmission Lines	102,217	2,143	9	Q4	2016
145182: Gilman Tap MOAB	Transmission Lines	319,987		9	Q4	2016
147380: 2016 Marble Street to Danby Reconstruction	Transmission Lines	1,438,642	250,000	9	Q4	2016
148773: Rock of Ages Line 3306	Transmission Lines	186,598	10,000	9	Q4	2016
148776: Graniteville Line 3305	Transmission Lines	173,647	10,000	9	Q4	2016
141721: Transmission Minor Additions	Transmission Lines	103,770	2,176	10	Q1	2016
141721: Transmission Minor Additions	Transmission Lines	103,770	2,176	11	Q1	2016
141721: Transmission Minor Additions	Transmission Lines	103,770	2,176	12	Q1	2016
147273 : Ascutney to Claremont Partial Reconductor	Transmission Lines	1,182,351	50,000	12	Q1	2016
141721: Transmission Minor Additions	Transmission Lines	103,770	2,176	1	Q2	2017
141721: Transmission Minor Additions	Transmission Lines	103,770	2,176	2	Q2	2017
141721: Transmission Minor Additions	Transmission Lines	103,770	2,176	3	Q2	2017
141721: Transmission Minor Additions	Transmission Lines	103,770	2,176	4	Q3	2017
143180: Reconductoring: Line 69 (E. Midd to Smead Rd)	Transmission Lines	191,837	20,000	4	Q3	2017
141721: Transmission Minor Additions	Transmission Lines	103,770	2,176	5	Q3	2017
141721: Transmission Minor Additions	Transmission Lines	103,770	2,176	6	Q3	2017
	Transmission Lines	103,770	2,176	7	Q4	2017
148604: Wyeth Tap RTU	Transmission Lines	50,888		7	Q4	2017
148605: Silk Road Tap RTU	Transmission Lines	42,734		7	Q4	2017
141721: Transmission Minor Additions	Transmission Lines	103,770	2,176	8	Q4	2017
143989: Haystack Fiber	Transmission Lines	97,384		8	Q4	2017
141721: Transmission Minor Additions	Transmission Lines	103,770	2,176	9	Q4	2017
		6,681,081	418,970			
138415: HSCAT 3325 PUTT	Transmission Substations	37,482		4	Q3	2016
143584: Line VT Replacements	Transmission Substations	145,564	1,000	4	Q3	2016
138423: HSCAT 3304 Putt	Transmission Substations	78,381		5	Q3	2016
143299: Transmission Breaker Change out Digital 3330 & 3332 - IN	Transmission Substations	262,003	273,384	5	Q3	2016
143301: Transmission Breaker Change out Cavendish B-17 - INTER	Transmission Substations	34,241	37,077	5	Q3	2016
135212: South Shaftbury SCADA MOAB 426 & 222 (RTU upgrade) ·	Transmission Substations	23,623		6	Q3	2016
138411: HSCAT 3303 87L	Transmission Substations	22,830		8	Q4	2016
143311: VELCO Irasburg H14 Relay Replacement	Transmission Substations	47,424		9	Q4	2016
143454: VELCO Hartford H82 Breaker Replacement	Transmission Substations	537,347		4	Q3	2017
138419: HSCAT 3312 87L	Transmission Substations	45,079		5	Q3	2017
138422: HSCAT 3313 PUTT	Transmission Substations	79,353		5	Q3	2017
148601: Ascutney Substation Security	Transmission Substations	91,563		6	Q3	2017
148603: Digital #43 Substation Security	Transmission Substations	63,726		6	Q3	2017
149349: Spare 46-34.5kV 20MVA Autotransformer	Transmission Substations	417,977		6	Q3	2017
148592: VEC Cambridge Substation	Transmission Substations	1,290,189		9	Q4	2017
148598: Marble street substation reconductor	Transmission Substations	31,385	3,000	9	Q4	2017
149351: Lowell Substation Upgrades	Transmission Substations	943,367	25,000	9	Q4	2017
		4,151,534	339,461			
143561: 2016 Pur Buckets and Diggers	Transportation	3,008,385	600,000	8	Q4	2016
149010: 2016 Relay and EMAC Trucks	Transportation	713,206	100,000	8	Q4	2016
148961: 2017 Purchase Trailers	Transportation	169,466		3	Q2	2017
148962: Purchase Tracked Vehicle	Transportation	295,874		6	Q3	2017
148958: 2017 Bucket and Digger Trucks	Transportation	2,996,260	600,000	7	Q4	2017
148959: 2017 Small Vehicles	Transportation	1,310,331	400,000	9	Q4	2017
		8,493,523	1,700,000			
		142,769,321	21,803,721			
		428,307,964				

V.P.S.B.DOCKET NO. **Exh. DCS-2**
Attachment D, Schedule 1 **Rate Year Summary**
August 1st, 2016

GREEN MOUNTAIN POWER CORPORATION
ALTERNATIVE REGULATION PLAN
POWER SUPPLY COST SUMMARY
TWELVE MONTHS ENDED SEPTEMBER 2017

	Description	RY Avg. Nominal Capacity MW	Avg '$/ KW-yr	Capacity Source	Energy MWH	Capacity Costs ($000)	Energy Source	Energy Costs ($000)	Total Costs ($000)
	Purchase Power								
1	Hydro Quebec C4-a	2	$228.67	LTC-1	11,044	442	LTC-1	385	827
2	HQUS PPA				1,001,228		LTC-1	52,400	52,400
3	NextEra Seabrook PPA	60	$54.33	LTC-1	467,928	3,260	LTC-1	23,343	26,603
4	VEPPI	30	$0.00		88,983		LTC-1	11,779	11,779
5	Other Renewable purchases				133,821		LTC-1	13,048	13,048
6	Ryegate	17	$0.00		143,083		LTC-1	14,748	14,748
7	SPEED standard offer	52	$0.00		85,920		LTC-1	18,258	18,258
8	Granite Reliable	81	$4.53		215,774	369	LTC-1	16,024	16,394
9	JP Morgan				230,425		LTC-1	13,471	13,471
10	NextEra System				109,150		LTC-1	4,322	4,322
11	Citigroup				306,600		LTC-1	15,943	15,943
12	Shell				503,120		LTC-1	22,854	22,854
13	BP				263,400		LTC-1	17,254	17,254
14	Net Metered Excess				109,556		LTC-1	23,657	23,657
15	Moretown	3		LTC-1	14,298	180	LTC-1	1,222	1,402
16	Ancillary Services			AS-1		750	AS-1	2,031	2,781
17	Congestion & Losses						Cl-1	3,945	3,945
18	ISO-NE			AS-1	43,454	23,738	R-1	1,324	25,062
19	Other	15		LTC-1	13,437	583	LTC-1	635	1,218
									0
	Sub-Total	261			3,741,220	29,323		256,643	285,966
	Owned Entitlements (Cap Cost is O&M only)					**8,683**			
20	GMP G.T. & Diesel	98	$6.01	UOM-1	3,708	587	UOM-1	571	1,157
21	GMP Hydro	99	$40.18	UOM-1	381,165	3,959	UOM-1	0	3,959
22	GMP Wind and Solar	62	$66.40	UOM-1	202,248	4,138	UOM-1	0	4,138
23	McNeil	16	$136.41	UOM-1	91,925	2,114	UOM-1	6,673	8,787
24	Stony Brook	30	$25.53	UOM-1	14,628	776	UOM-1	641	1,417
25	Wyman #4	18	$18.58	UOM-1	4,844	335	UOM-1	322	658
26	Millstone 3	21	$149.04	UOM-1	181,090	3,185	UOM-1	1,444	4,628
	Sub-Total	344			879,608	15,094		9,650	24,744
						6,410			
	Trans. Rent and Trans by others								
27	Velco Specific Facilities					5,265	TBO-1		5,265
28	VELCO Common Charges					10,594	TBO-1		10,594
29	ISO - NOATT 1&9					66,833	TBO-1		66,833
30	ISO - Other					5,915	TBO-1		5,915
31	NEP					1,889	TBO-1		1,889
32	Phase I and II	81				3,392	TBO-1		3,392
33	Others					702	TBO-1		702
34	rents					300	TBO-1		300
35	Highgate					629	TBO-1		629
	Sub-Total	81				95,520			95,520
	Resales								
36	NEPOOL				(138,470)			(5,068)	(5,068)
37	KCW				(23,571)			(3,172)	(3,172)
38	NCPC Credits							(591)	(591)
39	RECs							(22,998)	(22,998)
	Sub-Total				(162,042)	-		(31,828)	(31,828)
40	ISO ANI Adjustment						R-1	2,146	2,146
41	Recovery of Q3 FY15 through Q2 FY16 undercollection							5,342	5,342
42	Sub-Total					0		7,488	7,488
43	**Total**	**686**			**4,458,786**	**139,936**	<Gross	**241,954**	**381,890**
	NPC Only (no PSA adj)				*4,458,786*	*29,323*		*236,612*	*265,934*
	w/ Purchased Capacity							*265,934*	*376,548*

GREEN MOUNTAIN POWER CORPORATION
ALTERNATIVE REGULATION PLAN
POWER SUPPLY COST SUMMARY
TWELVE MONTHS ENDING MARCH 2016

	Description	Avg. Nominal Capacity MW	Avg $/ kW-yr	Capacity Source	Energy MWh	Capacity Costs ($000)	Energy Source	Energy Costs ($000)	Total Costs ($000)
	Purchase Power								
1	NextEra Nuclear	71	$37	page 3	447,751	2,636	page 2	21,594	24,230
2	HQ VJO Sched B	93	$220	page 3	542,517	20,572	page 2	18,516	39,088
3	HQ VJO Sched C-3	27	$228	page 3	158,215	6,115	page 2	5,424	11,538
4	HQ VJO Sched C-4a	23	$229	page 3	155,422	5,308	page 2	5,312	10,620
5	HQUS PPA				398,165	0	page 2	22,669	22,669
6	Granite Reliable				192,862	0	page 2	14,076	14,076
7	Small Power Producers	27		page 3	142,964	(57)	page 2	16,123	16,066
8	Ryegate	17			128,976	0	page 2	13,460	13,460
9	Standard Offer	40			75,276	0	page 2	16,592	16,592
10	Net Metered				44,143	0	page 2	10,226	10,226
11	Moretown	3	$60	page 3	17,382	180	page 2	1,487	1,667
12	Ampersand				25,584	0	page 2	2,402	2,402
13	JP Morgan				234,280	0	page 2	16,068	16,068
14	Citigroup				177,080	0	page 2	7,801	7,801
15	Shell Energy				73,945	0	page 2	3,186	3,186
16	BP				221,200	0	page 2	14,295	14,295
17	Cargill				84,335	0	page 2	5,780	5,780
18	NextEra System				333,400	0	page 2	15,890	15,890
19	Exgen				7,840	0	page 2	261	261
20	Stony Brook	14		page 3	0	1,096	page 2	330	1,426
21	HQ 9701			page 3	0	401	page 2	768	1,169
22	Other Misc	6		page 3	12,345	(1,121)	page 2	74	(1,047)
23	Amort/Deferral			page 3	0	(897)	page 2	326	(571)
24	ISO Energy			page 3	664,702	17,095	page 2	20,476	37,570
25	-								
26	Congestion						page 2	771	771
27	Losses						page 2	2,813	2,813
28	ISO Ancillary			page 3		638	page 2	2,008	2,646
	Sub-Total	321			4,138,386	51,966		238,727	290,692
	Owned Entitlements (Cap Cost is O&M only)								
29	Hydro	99	$40	page 4	391,513	3,923	page 5	0	3,923
30	GT/Diesel	97	$6	page 4	1,697	587	page 5	707	1,293
31	Wind	62	$66	page 4	183,744	4,066	page 5	0	4,066
32	Other owned	1	$47	page 4	12,812	47	page 5	0	47
33	Stonybrook	31	$25	page 4	14,846	776	page 5	968	1,744
34	Wyman	17	$20	page 4	2,831	335	page 5	623	958
35	McNeil	16	$148	page 4	91,802	2,384	page 5	6,280	8,664
36	Millstone	21	$180	page 4	181,870	3,815	page 5	1,334	5,149
	Sub-Total	344			881,115	15,934		9,911	25,845
	Trans. Rent and Trans by others								
37	VELCO - Spec. Fac.			page 6		4,467			4,467
38	VELCO - Common			page 6		14,892			14,892
39	ISO NE			page 6		61,547			61,547
40	National Grid			page 6		2,157			2,157
41	Phase I			page 6		242			242
42	Phase II	81		page 6		3,582			3,582
43	Misc. Utilities			page 6		813			813
44	ISO/NEPOOL Tariffs			page 6		5,768			5,768
45	Rents			page 6		300			300
46	Highgate O&M			page 6		629			629
	Sub-Total	81				94,397			94,397
						ok			ok
	Resales								
47	ISO NE #				-577,916		page 7	-14,412	-14,412
48	System				-594		page 7	-44	-44
49	Unit				-24,191		page 7	-3,618	-3,618
50	Capacity			page 7		-20	page 7		-20
51	RECs						page 7	-23,575	-23,575
	Sub-Total				-602,700	-20		-41,649	-41,669
52	**Total**	**746**			**4,416,801**	**162,277**		**206,988**	**369,265**

Includes energy, congestion, losses, and NCPC credits

GREEN MOUNTAIN POWER CORPORATION
TEST YEAR POWER SUPPLY COSTS AND REVENUES
MONTHLY SUMMARY

Month	Own Load MWh	Purchased Energy	Fuel	Total Energy $000	Demand $000	Resales incl RECs $000	Trans-mission $000	O & M $000	Total PSA $000	Total PSA $/MWh
Apr	341,510	$19,735,669	$396,476	$20,132,145	$5,779,545	-$1,809,520	$7,894,416	$989,609	$32,986,195	$96.59
May	346,701	$15,984,628	$1,365,188	$17,349,815	$5,421,806	-$1,396,858	$9,274,308	$1,172,213	$31,821,284	$91.78
Jun	348,336	$17,542,749	-$3,359	$17,539,390	$6,056,247	-$8,082,115	$7,055,663	$1,894,529	$24,463,713	$70.23
Jul	387,225	$20,846,010	$849,522	$21,695,532	$5,113,585	-$1,497,412	$8,986,654	$1,717,979	$36,016,337	$93.01
Aug	391,003	$21,089,184	$1,214,203	$22,303,387	$7,004,375	-$1,376,914	$6,532,597	$1,210,227	$35,673,672	$91.24
Sep	360,230	$18,691,527	$599,245	$19,290,772	$5,612,839	-$7,503,470	$6,617,352	$1,206,055	$25,223,549	$70.02
Oct	350,779	$16,870,303	$859,801	$17,730,104	$5,720,786	-$1,038,863	$4,202,911	$1,171,728	$27,786,666	$79.21
Nov	350,392	$17,654,574	$695,049	$18,349,623	$1,449,235	-$1,226,877	$9,124,937	$1,207,376	$28,904,295	$82.49
Dec	378,198	$23,755,521	$808,661	$24,564,182	$2,323,967	-$8,757,410	$10,459,038	$1,125,319	$29,715,097	$78.57
Jan	416,362	$23,657,204	$1,183,705	$24,840,909	$2,465,686	-$1,315,568	$8,661,795	$1,652,086	$36,304,908	$87.20
Feb	380,614	$22,659,251	$884,610	$23,543,861	$2,518,394	-$1,265,613	$8,462,016	$1,305,999	$34,564,658	$90.81
Mar	365,454	$20,239,949	$1,057,999	$21,297,948	$2,499,409	-$6,398,676	$7,125,259	$1,280,755	$25,804,695	$70.61
Total	4,416,803	$238,726,568	$9,911,100	$248,637,668	$51,965,875	-$41,669,295	$94,396,943	$15,933,876	$369,265,067	$83.60

GREEN MOUNTAIN POWER CORPORATION
TEST YEAR POWER SUPPLY COSTS
PURCHASED POWER ENERGY
Page 2 of 7

Energy $000	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
NextEra Nuclear	1,749,872	1,895,757	2,038,342	2,352,847	2,386,674	1,708,851	(6,486)	1,015,601	2,353,967	2,213,121	2,198,803	1,686,478	21,593,828
HQ VJO Sched B	2,478,156	2,316,690	2,756,767	3,087,673	3,061,855	2,187,821	2,627,747	(354)	-	-	-	-	18,516,356
HQ VJO Sched C-3	745,253	679,095	802,506	898,633	892,887	638,950	765,781	545	-	-	-	-	5,423,649
HQ VJO Sched C-4a	350,771	334,031	399,655	447,676	443,300	313,905	380,671	482,020	592,976	498,825	528,140	540,122	5,312,092
HQUS PPA	235,807	243,654	235,794	243,654	243,654	235,794	243,654	4,142,174	4,280,246	4,280,246	4,004,101	4,280,246	22,669,024
Granite Reliable	1,381,946	1,218,007	918,902	833,001	615,604	741,985	1,351,877	1,441,150	1,277,783	1,403,759	1,532,635	1,359,127	14,075,775
Small Power Producers	2,715,283	972,254	1,933,248	1,167,352	535,382	321,831	485,910	1,048,129	2,228,874	1,225,991	1,467,201	2,021,615	16,123,069
Ryegate	987,509	586,024	1,077,011	1,054,488	1,244,149	1,236,019	1,191,803	1,258,657	1,290,338	1,154,219	1,148,300	1,231,846	13,460,362
Standard Offer	1,524,008	1,755,300	1,706,859	1,829,883	1,742,354	1,624,125	1,310,194	1,049,599	701,191	812,130	936,129	1,600,390	16,592,162
Net Metered	708,768	898,962	1,040,558	995,156	1,121,503	1,146,144	976,223	743,500	559,746	434,587	542,050	1,058,935	10,226,131
Moretown	149,917	130,634	147,409	148,109	144,395	130,543	141,359	130,284	5,232	102,343	129,425	126,888	1,486,537
Ampersand	197,700	267,102	260,435	213,598	154,151	93,938	172,881	110,470	255,728	225,637	167,176	283,229	2,402,048
JP Morgan	1,972,868	2,041,350	1,975,500	2,041,350	2,041,350	1,975,500	2,041,350	1,978,244	2,041,350	(2,041,350)	-	-	16,067,512
Citigroup	180,320	831,040	-	2,435,608	2,583,168	1,770,720	-	-	-	-	-	-	7,800,856
Shell Energy	-	-	-	-	-	-	863,060	-	-	364,000	382,200	1,576,272	3,185,533
BP	-	-	-	-	-	-	-	-	4,190,180	4,979,798	5,124,918	-	14,294,896
Cargill	-	-	-	-	-	-	-	-	-	3,315,450	1,191,900	1,272,388	5,779,738
NextEra System	438,472	505,196	1,734,824	1,782,484	2,259,084	2,173,296	467,068	859,072	1,353,544	1,772,952	1,658,568	885,285	15,889,844
Exgen	-	-	-	-	-	-	261,072	-	-	-	-	-	261,072
Stony Brook	8,575	4,113	59,339	85,094	141,445	(62,473)	(8,036)	1,838	11,461	69,458	14,775	4,757	330,347
HQ 9701	(108,017)	109,471	109,471	109,471	109,471	109,471	109,471	109,471	109,471	0	-	-	767,749
Other Misc	3,151	2,220	2,711	2,453	2,839	3,086	2,705	2,873	2,747	2,208	2,388	44,689	74,071
Amort/Deferral	27,155	27,156	27,155	27,156	27,155	27,156	27,155	27,156	27,155	27,156	27,155	26,980	325,691
ISO Energy	2,220,896	1,458,616	575,085	800,988	1,085,010	2,026,908	3,185,463	3,793,616	662,893	2,166,920	871,784	1,627,455	20,475,634
-	-	-	-	-	-	-	-	-	-	-	-	-	
Congestion	1,403,621	65,425	(533,472)	7,655	4,398	(42,734)	(33,985)	(189,325)	7,507	31,754	4,140	46,400	771,384
Losses	190,201	242,666	182,036	254,347	186,136	262,350	253,773	244,787	220,720	354,859	198,038	223,464	2,813,377
ISO Ancillary	173,436	(600,134)	92,614	27,334	63,219	68,342	59,593	(594,931)	1,582,412	263,140	529,424	343,384	2,007,833
Other	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	$19,735,669	$15,984,628	$17,542,749	$20,846,010	$21,089,184	$18,691,527	$16,870,303	$17,654,574	$23,755,521	$23,657,204	$22,659,251	$20,239,949	$238,726,568

Energy MWh	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
NextEra Nuclear	43,200	44,640	43,183	44,640	44,640	39,682	7	22,272	44,631	41,987	41,760	37,110	447,751
HQ VJO Sched B	72,877	67,839	80,725	90,408	89,666	64,065	76,956	-	(19)	-	-	-	542,517
HQ VJO Sched C-3	21,220	19,886	23,499	26,324	26,136	18,710	22,407	-	33	-	-	-	158,215
HQ VJO Sched C-4a	10,565	9,782	11,703	13,106	12,981	9,268	11,156	14,030	17,238	14,514	15,366	15,715	155,422
HQUS PPA	3,754	3,879	3,754	3,879	3,879	3,754	3,879	73,300	75,743	75,743	70,857	75,743	398,165
Granite Reliable	19,044	16,765	12,485	11,185	8,283	10,344	18,599	19,939	17,547	19,258	21,113	18,301	192,862
Small Power Producers	19,872	10,933	17,875	9,874	5,023	2,878	5,687	8,495	16,078	10,538	15,490	20,220	142,964
Ryegate	9,478	5,617	10,338	10,122	11,945	11,867	11,226	11,731	12,056	11,298	11,240	12,059	128,976
Standard Offer	6,916	7,600	7,556	7,760	7,335	6,878	5,914	4,993	3,929	4,199	4,748	7,450	75,276
Net Metered	2,990	4,021	4,839	4,413	4,687	4,650	3,773	3,291	2,442	1,991	2,400	4,645	44,143
Moretown	1,749	1,528	1,724	1,732	1,689	1,527	1,653	1,524	60	1,258	1,454	1,484	17,382
Ampersand	2,298	2,748	2,762	2,308	1,692	1,055	1,769	1,222	2,589	2,411	1,791	2,940	25,584
JP Morgan	28,800	29,760	28,800	29,760	29,760	28,800	29,760	28,840	29,760	(29,760)	-	-	234,280
Citigroup	3,680	16,960	-	56,120	59,520	40,800	-	-	-	-	-	-	177,080
Shell Energy	-	-	-	-	-	-	20,360	-	-	8,000	8,400	37,185	73,945
BP	-	-	-	-	-	-	-	-	65,600	77,000	78,600	-	221,200
Cargill	-	-	-	-	-	-	-	-	-	48,360	17,400	18,575	84,335
NextEra System	9,200	10,600	36,400	37,400	47,400	45,600	9,800	18,025	28,400	37,200	34,800	18,575	333,400
Exgen	-	-	-	-	-	-	7,840	-	-	-	-	-	7,840
Stony Brook	-	-	-	-	-	-	-	-	-	-	-	-	0
HQ 9701	-	-	-	-	-	-	-	-	-	-	-	-	0
Other Misc	622	1,125	1,083	1,724	2,969	1,580	680	510	580	609	404	459	12,345
Amort/Deferral	-	-	-	-	-	-	-	-	-	-	-	-	0
ISO Energy	68,990	60,768	35,481	29,877	23,938	58,582	84,548	114,002	39,680	52,173	24,193	72,470	664,702
Total	325,254	314,451	322,208	380,632	381,543	350,040	316,013	322,175	356,347	376,777	350,015	342,930	4,138,386

Energy $/MWh													Total
NextEra Nuclear	$40.51	$42.47	$47.20	$52.71	$53.46	$43.06	($968.07)	$45.60	$52.74	$52.71	$52.65	$45.45	$48,227.28
HQ VJO Sched B	$34.00	$34.15	$34.15	$34.15	$34.15	$34.15	$34.15	N/A	$0.00	N/A	N/A	N/A	$34.13
HQ VJO Sched C-3	$35.12	$34.15	$34.15	$34.14	$34.16	$34.15	$34.18	N/A	$0.00	N/A	N/A	N/A	$34.28
HQ VJO Sched C-4a	$33.20	$34.15	$34.15	$34.16	$34.15	$33.87	$34.12	$34.36	$34.40	$34.37	$34.37	$34.37	$34.18
HQUS PPA	$62.81	$62.81	$62.81	$62.81	$62.81	$62.81	$62.81	$56.51	$56.51	$56.51	$56.51	$56.51	$56.93
Granite Reliable	$72.57	$72.65	$73.60	$74.47	$74.32	$71.73	$72.69	$72.28	$72.82	$72.89	$72.59	$74.26	$72.98
Small Power Producers	$136.64	$88.93	$108.15	$118.22	$106.58	$111.81	$85.44	$123.39	$138.63	$116.34	$94.72	$99.98	$112.78
Ryegate	$104.19	$104.33	$104.18	$104.18	$104.15	$104.15	$106.16	$107.29	$107.03	$102.17	$102.17	$102.16	$104.36
Standard Offer	$220.36	$230.96	$225.88	$235.82	$237.56	$236.13	$221.56	$210.21	$178.47	$193.43	$197.16	$214.83	$220.42
Net Metered	$237.05	$223.54	$215.04	$225.49	$239.26	$246.48	$258.75	$225.92	$229.23	$218.24	$225.86	$227.96	$231.66
Moretown	$85.74	$85.50	$85.50	$85.50	$85.50	$85.50	$85.50	$85.49	$86.91	$81.39	$88.99	$85.50	$85.52
Ampersand	$86.03	$97.21	$94.29	$92.55	$91.11	$89.03	$97.72	$90.39	$98.79	$93.61	$93.32	$96.35	$93.89
JP Morgan	$68.50	$68.59	$68.59	$68.59	$68.59	$68.59	$68.59	$68.59	$68.59	$68.59	N/A	N/A	$68.58
Citigroup	$49.00	$49.00	N/A	$43.40	$43.40	$43.40	N/A	N/A	N/A	N/A	N/A	N/A	$44.05
Shell Energy	N/A	N/A	N/A	N/A	N/A	N/A	$42.39	N/A	N/A	$45.50	$45.50	$42.39	$43.08
BP	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$63.87	$64.67	$65.20	N/A	$64.62
Cargill	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$68.56	$68.50	$68.50	$68.53
NextEra System	$47.66	$47.66	$47.66	$47.66	$47.66	$47.66	$47.66	$47.66	$47.66	$47.66	$47.66	$47.66	$47.66
Exgen	N/A	N/A	N/A	N/A	N/A	N/A	$33.30	N/A	N/A	N/A	N/A	N/A	$33.30
Stony Brook	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
HQ 9701	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Other Misc	$5.06	$1.97	$2.50	$1.42	$0.96	$1.95	$3.98	$5.64	$4.74	$3.63	$5.91	$97.40	$6.00
Amort/Deferral	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
ISO Energy	$32.19	$24.00	$16.21	$26.81	$45.33	$34.60	$37.68	$33.28	$16.71	$41.53	$36.03	$22.46	$30.80
Average	$60.68	$50.83	$54.45	$54.77	$55.27	$53.40	$53.38	$54.80	$66.66	$62.79	$64.74	$59.02	$57.69

GREEN MOUNTAIN POWER CORPORATION
V.P.S.B. DOCKET NO.
Attachment D, Schedule 2
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August 1st, 2016

Test Year Power Supply Costs

Purchase Power Capacity

Capacity $000

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
Yankees	(125,572)	(65,638)	(19,099)	(69,978)	(68,981)	(473,705)	(22,275)	(44,052)	(120,214)	(60,013)	(65,722)	(20,094)	$ (1,155,343)
Nextara Nuclear	-	-	-	524,836	263,925	263,925	263,925	263,925	263,925	263,925	263,925	263,925	2,636,236
HQ VJO B	2,938,855	2,938,855	2,938,855	2,048,855	3,828,855	2,938,855	2,938,855	(0)	-	-	-	-	20,571,987
HQ VJO C-3	873,536	873,536	873,536	873,536	873,536	873,536	873,536	-	-	-	-	-	6,114,752
HQ VJO C-4a	442,114	442,114	442,114	442,114	442,114	444,676	442,114	442,114	442,114	442,114	442,114	442,114	5,307,933
HQUS PPA	-	-	-	-	-	-	-	-	-	-	-	-	-
Granite	-	-	-	-	-	-	-	-	-	-	-	-	-
9701	121,532	34,974	34,974	34,974	34,974	34,974	34,974	34,974	34,974	-	-	-	401,322
Moretown	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	-	30,000	15,000	180,000
Stonybrook	93,387	93,387	93,387	93,387	93,386	93,387	93,387	93,387	93,387	93,387	76,968	85,177	1,096,011
Ampersand	-	-	-	-	-	-	-	-	-	-	-	-	-
SPP's	(127)	(8,301)	(5,982)	(2,790)	(9,525)	(5,620)	(5,644)	(6,756)	(5,314)	(2,526)	(2,242)	(2,235)	(57,063)
Ryegate	-	-	-	-	-	-	-	-	-	-	-	-	-
SPEED	-	-	-	-	-	-	-	-	-	-	-	-	-
NYPA	2,839	2,838	2,838	2,838	2,838	2,838	2,838	2,838	2,838	2,838	2,838	2,838	34,057
JP Morgan	-	-	-	-	-	-	-	-	-	-	-	-	-
NextEra Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
HQ/BP Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
Constellation	-	-	-	-	-	-	-	-	-	-	-	-	-
Misc Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
Amort/Def./Misc	(99,660)	(99,660)	(99,660)	(99,660)	(99,660)	(99,660)	(99,660)	(99,660)	(99,660)	-	-	-	(896,937)
ISO NE Ancillary	74,760	93,097	71,855	57,841	97,642	146,492	75,831	51,510	(5,540)	18,829	(11,399)	(32,667)	638,251
ISO NE Capacity	1,442,881	1,101,605	1,708,430	1,192,631	1,530,270	1,378,141	1,107,905	695,955	1,702,458	1,707,132	1,781,911	1,745,351	17,094,669
													-
Total	$5,779,545	$5,421,806	$6,056,247	$5,113,585	$7,004,375	$5,612,839	$5,720,786	$1,449,235	$2,323,967	$2,465,686	$2,518,394	$2,499,409	$ 51,965,875

Estimated Nominal Generating Capacity MW (FCM will be less)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
Yankees	0	0	0	0	0	0	0	0	0	0	0	0	0
Nextara Nuclear	0	0	85	85	85	85	85	85	85	85	85	85	71
HQ VJO B	160	160	160	160	160	160	160	0	0	0	0	0	93
HQ VJO C-3	46	46	46	46	46	46	46	0	0	0	0	0	27
HQ VJO C-4a	23	23	23	23	23	23	23	23	23	23	23	23	23
HQUS PPA	0	0	0	0	0	0	0	0	0	0	0	0	0
Granite	0	0	0	0	0	0	0	0	0	0	0	0	0
9701	0	0	0	0	0	0	0	0	0	0	0	0	0
Moretown	3	3	3	3	3	3	3	3	3	3	3	3	3
Stonybrook	14	14	14	14	14	14	14	14	14	14	14	14	14
Ampersand	5	5	5	5	5	5	5	5	5	5	5	5	5
SPP's	27	27	27	27	27	27	27	27	27	27	27	27	27
Ryegate	17	17	17	17	17	17	17	17	17	17	17	17	17
SPEED	31	31	31	33	34	34	48	48	48	48	48	48	40
NYPA	1	1	1	1	1	1	1	1	1	1	1	1	1
JP Morgan	0	0	0	0	0	0	0	0	0	0	0	0	0
NextEra Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0
HQ/BP Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
Constellation	0	0	0	0	0	0	0	0	0	0	0	0	0
Misc Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0
Amort/Def./Misc													0
ISO NE Ancillary													0
ISO NE Capacity													0
HQICC													0
Total	327	327	412	414	415	415	429	223	223	223	223	223	321

Demand $/kW-Mo.

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
Yankees	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Nextara Nuclear	N/A	N/A	$0.00	$6.17	$3.11	$3.11	$3.11	$3.11	$3.11	$3.11	$3.11	$3.11	$37.22
HQ VJO C-3	$18.37	$18.37	$18.37	$12.81	$23.93	$18.37	$18.37	N/A	N/A	N/A	N/A	N/A	$220.41
HQ VJO C-4a	$18.99	$18.99	$18.99	$18.99	$18.99	$18.99	$18.99	N/A	N/A	N/A	N/A	N/A	$227.88
HQ VJO B	$19.06	$19.06	$19.06	$19.06	$19.06	$19.17	$19.06	$19.06	$19.06	$19.06	$19.06	$19.06	$228.79
HQUS PPA	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Granite 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
9701	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Moretown	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$0.00	$10.00	$5.00	$60.00
Stonybrook	$6.56	$6.56	$6.56	$6.56	$6.56	$6.56	$6.56	$6.56	$6.56	$6.56	$5.40	$5.98	$76.94
Ampersand	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SPP's	$0.00	-$0.31	-$0.22	-$0.10	-$0.35	-$0.21	-$0.21	-$0.25	-$0.20	-$0.09	-$0.08	-$0.08	-$2.11
Ryegate	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SPEED	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
NYPA	$4.73	$4.73	$4.73	$4.73	$4.73	$4.73	$4.73	$4.73	$4.73	$4.73	$4.73	$4.73	$56.76
JP Morgan	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
NextEra Purchase	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
HQ/BP Purchases	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Constellation	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Misc Purchase	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Macquarie	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Amort/Def./Misc	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
ISO NE Ancillary	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
ISO NE Capacity	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
HQICC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

GREEN MOUNTAIN POWER CORPORATION
V.P.S.B. DOCKET NO.
Attachment D, Schedule 2
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August 1st, 2016

Test Year Power Supply Costs

Owned Generation O&M

Generation O & M $000

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
Hydro	$ 304,235	$ 286,874	$ 431,327	$ 201,266	$ 401,630	$ 253,618	$ 365,322	$ 348,271	$ 363,657	$ 312,261	$ 304,482	$ 350,002	$ 3,922,945
GT/Diesel	19,787	75,422	91,173	47,365	31,286	45,716	42,413	53,303	66,668	42,238	30,537	40,827	586,735
Wind	452,941	237,603	280,721	344,732	279,049	284,895	328,306	304,779	206,375	691,547	375,727	279,641	4,066,317
Other owned	18,890	1,554	(6,758)	(1,767)	3,312	1,771	5,395	14,953	4,489	2,620	1,732	1,264	47,456
Stonybrook	72,144	50,343	62,835	86,277	42,859	87,084	98,737	51,473	52,628	81,856	38,686	50,980	775,902
Wyman	(272,684)	19,999	449,397	14,830	10,333	92,739	(48,994)	(24,054)	38,941	14,048	25,004	15,737	335,296
McNeil	122,150	180,130	279,543	731,297	142,535	121,758	112,643	172,718	116,592	164,771	144,601	95,564	2,384,300
Millstone	272,146	320,286	306,291	293,978	299,223	318,475	267,906	285,933	275,970	342,745	385,229	446,740	3,814,926
Total	$ 989,609	$ 1,172,213	$ 1,894,529	$ 1,717,979	$ 1,210,227	$ 1,206,055	$ 1,171,728	$ 1,207,376	$ 1,125,319	$ 1,652,086	$ 1,305,999	$ 1,280,755	$ 15,933,876

Owned Company-owned Nominal MW (FCM will be less)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
Hydro	99	99	99	99	99	99	99	99	99	99	99	99	99
GT/Diesel	98	97	97	97	97	97	97	97	97	97	97	97	97
Wind (net)	62	62	62	62	62	62	62	62	62	62	62	62	62
Other owned													-
Stonybrook	31	31	31	31	31	31	31	31	31	31	31	31	31
Wyman	18	17	17	17	17	17	17	17	17	17	17	17	17
McNeil	16	16	16	16	16	16	16	16	16	16	16	16	16
Millstone	21	21	21	21	21	21	21	21	21	21	21	21	21
Total	246	244	244	244	244	244	244	244	244	244	244	244	245

Owned O & M $/kW-Mo.	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
Hydro	$ 3.09	$ 2.91	$ 4.38	$ 2.04	$ 4.08	$ 2.57	$ 3.71	$ 3.53	$ 3.69	$ 3.17	$ 3.09	$ 3.55	$ 39.81
GT/Diesel	0.20	0.78	0.94	0.49	0.32	0.47	0.44	0.55	0.69	0.44	0.31	0.42	6.05
Wind	7.27	3.83	4.53	5.56	4.50	4.60	5.30	4.92	3.33	11.15	6.06	4.51	65.56
Other owned	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Stonybrook	2.30	1.62	2.02	2.78	1.38	2.80	3.18	1.66	1.69	2.64	1.25	1.64	24.97
Wyman	(15.11)	1.18	26.44	0.87	0.61	5.46	(2.88)	(1.41)	2.29	0.83	1.47	0.93	19.62
McNeil	7.88	11.17	17.34	45.37	8.84	7.55	6.99	10.71	7.23	10.22	8.97	5.93	148.39
Millstone	12.74	15.11	14.45	13.87	14.12	15.03	12.64	13.49	13.02	16.17	18.17	21.08	179.86

Test Year Power Supply Costs

Generation Fuel

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
Hydro	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GT/Diesel	(4,071)	(22,687)	17,264	28,341	132,371	257,639	78,995	71,229	12,226	76,883	34,450	23,966	706,604
Wind	-	-	-	-	-	-	-	-	-	-	-	-	0
Other owned	-	-	-	-	-	-	-	-	-	-	-	-	0
Stonybrook	16,416	196,891	(22,626)	153,462	309,835	(136,925)	(17,651)	4,020	25,100	152,097	32,354	255,513	968,486
Wyman	26,958	697,977	(424,861)	45,835	17,028	51,412	2,775	3,948	12,686	77,980	176,260	(65,422)	622,578
McNeil	257,879	376,639	300,193	506,522	654,593	316,216	679,892	503,408	642,640	781,006	532,941	727,830	6,279,759
Millstone	99,293	116,368	126,670	115,362	100,376	110,903	115,790	112,444	116,009	95,739	108,606	116,113	1,333,673
Total	$ 396,476	$ 1,365,188	$ (3,359)	$ 849,522	$ 1,214,203	$ 599,245	$ 859,801	$ 695,049	$ 808,661	$ 1,183,705	$ 884,610	$ 1,057,999	$ 9,911,100

Generation Fuel MWh

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
Hydro	44,504	36,416	54,428	34,662	10,031	4,559	16,105	22,330	42,055	36,295	39,335	50,793	391,513
GT/Diesel	13	(2)	39	85	287	647	146	151	5	158	73	94	1,697
Wind (1)	19,270	17,643	13,010	12,861	10,236	8,984	18,255	18,514	14,553	18,480	18,586	13,354	183,744
Other owned	1,306	780	725	561	530	534	1,312	1,283	1,340	1,709	1,537	1,196	12,812
Stonybrook	90	2,122	849	2,864	5,402	2,268	296	127	295	464	5	64	14,846
Wyman	-	0	-	301	113	272	60	1	66	482	1,537	-	2,831
McNeil	2,900	4,998	5,490	7,867	9,363	4,311	9,415	9,415	8,992	10,344	9,736	8,972	91,802
Millstone	13,541	15,869	15,310	15,732	15,653	15,120	15,782	15,334	15,820	13,066	14,811	15,834	181,870
Total	81,623	77,826	89,848	74,934	51,615	36,693	61,372	67,156	83,126	80,996	85,619	90,307	881,115

Generatino Fuel $/MWh

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
Hydro	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
GT/Diesel	(313.18)	13,345.34	446.10	331.86	460.58	398.39	541.43	470.78	2,495.10	485.98	470.62	253.88	416.29
Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Other owned	-	-	-	-	-	-	-	-	-	-	-	-	-
Stonybrook	181.79	92.78	(26.67)	53.58	57.36	(60.38)	(59.57)	31.63	85.06	328.01	6,343.89	3,973.76	65.24
Wyman	N/A	##########	N/A	152.22	150.96	189.16	46.56	2,924.70	191.63	161.88	114.70	N/A	219.89
McNeil	88.94	75.37	54.69	64.39	69.91	73.35	72.21	53.47	71.46	75.51	54.74	81.12	68.41
Millstone	7.33	7.33	8.27	7.33	6.41	7.33	7.34	7.33	7.33	7.33	7.33	7.33	7.33

Notes: (1) Includes resale volume

GREEN MOUNTAIN POWER CORPORATION
V.P.S.B. DOCKET NO.
Attachment D, Schedule 2

August 1st, 2016

Test Year Power Supply Costs

Purchased Transmission plus Highgate O&M

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
VELCO - Spec. Fac.	$ 302,446	$ 324,726	$ 442,563	$ 363,450	$ 418,109	$ 371,682	$ 454,302	$ 366,404	$ 311,681	$ 385,147	$ 366,173	$ 360,039	$ 4,466,723
VELCO - Common	2,167,704	3,306,264	969,309	2,263,535	(594,325)	(327,648)	(1,828,415)	2,261,297	3,010,840	1,326,355	1,172,187	1,164,486	14,891,589
ISO NE	4,415,694	4,275,788	4,415,849	5,303,055	5,702,751	5,543,969	4,624,862	5,185,807	5,580,321	5,870,378	5,665,031	4,963,095	61,546,601
National Grid	302,627	142,382	177,067	66,433	43,100	85,235	70,734	124,722	575,718	37,091	407,713	124,348	2,157,168
Phase I	11,949	14,422	15,532	15,593	12,984	21,813	12,474	90,305	14,009	15,310	3,115	14,889	242,395
Phase II	269,540	360,303	332,389	330,207	290,252	309,923	324,741	821,186	61,711	164,674	115,962	201,424	3,582,313
Misc. Utilities	101,388	357,004	66,129	60,401	64,230	31,481	69,578	52,294	97,007	93,018	64,176	(243,436)	813,270
Sub-Total	$ 7,571,348	$ 8,780,889	$ 6,418,839	$ 8,402,674	$ 5,937,101	$ 6,036,455	$ 3,728,276	$ 8,902,015	$ 9,651,287	$ 7,891,974	$ 7,794,357	$ 6,584,844	$ 87,700,059
ISO/NEPOOL Tariffs	273,097	437,644	470,827	520,034	527,731	489,638	338,407	151,425	763,188	674,224	628,582	493,024	5,767,821
Rents	20,441	32,983	22,104	26,838	26,620	27,145	20,952	23,600	27,447	21,507	26,313	23,906	299,855
Highgate O&M	29,530	22,792	143,893	37,107	41,146	64,114	115,276	47,897	17,115	74,090	12,765	23,484	629,208
Total	$ 7,894,416	$ 9,274,308	$ 7,055,663	$ 8,986,654	$ 6,532,597	$ 6,617,352	$ 4,202,911	$ 9,124,937	$ 10,459,038	$ 8,661,795	$ 8,462,016	$ 7,125,259	$ 94,396,943

Test Year Power Supply Costs

Resales ($000)

Resales Energy $	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Total**
System	$ (3,416)	$ (3,040)	$ (3,355)	$ (3,247)	$ (3,739)	$ (3,542)	$ (3,234)	$ (3,883)	$ (4,016)	$ (4,158)	$ (4,536)	$ (4,253)	$ (44,420)
Unit	(276,659)	(283,894)	(261,250)	(275,499)	(293,006)	(577,983)	(244,464)	(267,545)	(263,549)	(277,477)	(326,085)	(270,386)	(3,617,797)
ISO NE	(1,662,140)	(1,179,733)	(1,112,730)	(1,324,784)	(1,279,970)	(1,042,398)	(787,089)	(933,650)	(1,024,303)	(1,075,229)	(1,139,514)	(1,021,654)	(13,583,195)
NCPC	-	-	-	-	-	-	-	-	(1,571,670)	-	-	(278,825)	(1,850,495)
Congestion	64,903	16,161	43,322	18,654	12,232	19,655	323	580	12,042	8,383	61,476	4,795	262,526
Losses	69,295	55,230	81,378	89,099	189,251	44,206	(2,859)	(20,570)	56,743	34,797	144,763	17,704	759,037
Total	$ (1,808,017)	$ (1,395,276)	$ (1,252,635)	$ (1,495,777)	$ (1,375,232)	$ (1,560,062)	$ (1,037,323)	$ (1,225,068)	$ (2,794,753)	$ (1,313,685)	$ (1,263,896)	$ (1,552,620)	$ (18,074,342)

Resales Other $	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Total**
Demand	(1,353)	(1,422)	(1,342)	(1,466)	(1,514)	(1,523)	(1,367)	(1,612)	(1,599)	(1,680)	(1,532)	(1,474)	(17,886)
Transmission	(149)	(160)	(149)	(169)	(168)	(178)	(173)	(197)	(191)	(203)	(185)	(172)	(2,093)
Total	$ (1,503)	$ (1,582)	$ (1,492)	$ (1,635)	$ (1,682)	$ (1,700)	$ (1,540)	$ (1,809)	$ (1,790)	$ (1,883)	$ (1,717)	$ (1,646)	$ (19,979)

Resales REC's $	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Total**
Total	$ -	$ -	$ (6,827,989)	$ -	$ -	$ (5,941,707)	$ -	$ -	$ (5,960,867)	$ -	$ -	$ (4,844,411)	$ (23,574,974)

Resales Total $	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Total**
Total	$ (1,809,520)	$ (1,396,858)	$ (8,082,115)	$ (1,497,412)	$ (1,376,914)	$ (7,503,470)	$ (1,038,863)	$ (1,226,877)	$ (8,757,410)	$ (1,315,568)	$ (1,265,613)	$ (6,398,676)	$ (41,669,295)

Resales Energy MWh	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Total**
System	(45)	(41)	(47)	(49)	(50)	(46)	(45)	(52)	(55)	(55)	(56)	(52)	(594)
Unit	(2,556)	(2,447)	(2,240)	(1,652)	(1,633)	(1,300)	(1,141)	(2,318)	(2,348)	(1,848)	(2,347)	(2,360)	(24,191)
ISO NE	(62,767)	(43,089)	(61,433)	(66,640)	(40,471)	(25,158)	(25,420)	(36,568)	(58,873)	(39,508)	(52,618)	(65,372)	(577,916)
Total	(65,368)	(45,577)	(63,720)	(68,341)	(42,154)	(26,504)	(26,606)	(38,938)	(61,276)	(41,411)	(55,021)	(67,784)	(602,700)

Green Mountain Power Corporation
Load at Retail and System Boundary

L-1

Retail Sales (1)

Period	Total	2016 Oct	Nov	Dec	2017 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
On-Peak	2,174,611	167,821	175,204	189,750	193,921	184,579	190,119	158,997	170,251	188,750	180,475	205,697	169,047
Off-Peak	2,047,196	162,229	168,472	189,545	198,373	173,597	165,807	162,818	153,607	154,136	188,693	163,549	166,370
All	4,221,807	330,050	343,676	379,296	392,295	358,176	355,925	321,815	323,858	342,886	369,168	369,245	335,417
GMP Est. Losses	5.3%	5.1%	5.3%	5.5%	5.6%	5.5%	5.3%	5.1%	5.1%	5.3%	5.4%	5.4%	5.2%

System Boundary Load - Including Losses

Period	Total	2016 Oct	Nov	Dec	2017 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
On-Peak	2,296,697	176,821	184,990	200,773	205,404	195,301	200,738	167,524	179,381	199,293	190,757	217,415	178,300
Off-Peak	2,162,161	170,930	177,882	200,556	210,119	183,681	175,068	171,550	161,845	162,746	199,443	172,866	175,477
All	4,458,858	347,751	362,872	401,328	415,522	378,982	375,806	339,073	341,226	362,038	390,200	390,282	353,778

	Total	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Contracts	3,674,195	275,528	270,635	323,815	346,430	316,601	284,617	245,593	295,129	314,376	354,124	348,834	298,515
Units	879,608	65,181	76,304	83,449	84,789	74,209	84,995	84,825	83,015	70,976	66,223	56,036	49,605
Total	4,553,803	340,709	346,939	407,264	431,219	390,810	369,611	330,418	378,144	385,352	420,346	404,871	348,119
Surplus/(Deficiency) (2)	94,945	(7,042)	(15,933)	5,935	15,696	11,828	(6,194)	(8,656)	36,918	23,314	30,147	14,589	(5,658)

Notes
(1) Includes 540 MWh of wholesale requirements sales
(2) Surplus/Deficiency values differ slightly (73 MWh annual total) with those from April 21, 2016 Output due to modeling requirements

GREEN MOUNTAIN POWER CORPORATION
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Green Mountain Power Corporation
Ancillary Service Costs and Credits

		TOTAL	2016 Oct	Nov	Dec	2017 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
DEMAND RESPONSE	1	$120,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
RESERVES	1	630,000	52,500	52,500	52,500	52,500	52,500	52,500	52,500	52,500	52,500	52,500	52,500	52,500
Demand Sub-total		$ 750,000	$ 62,500	$ 62,500	$ 62,500	$ 62,500	$ 62,500	$ 62,500	$ 62,500	$ 62,500	$ 62,500	$ 62,500	$ 62,500	$ 62,500
FORWARD CAPACITY MARKET	1	23,738,013	1,306,839	1,374,942	1,374,942	1,374,942	1,374,942	1,374,942	1,434,162	1,404,552	3,179,437	3,179,437	3,179,437	3,179,437
Demand Total		$ 24,488,013	$ 1,369,339	$ 1,437,442	$ 1,437,442	$ 1,437,442	$ 1,437,442	$ 1,437,442	$ 1,496,662	$ 1,467,052	$ 3,241,937	$ 3,241,937	$ 3,241,937	$ 3,241,937
ENERGY RT REG SETTLEMENT	2	679,944	38,554	47,275	87,699	100,960	92,004	55,300	41,180	38,287	44,315	46,491	48,936	38,944
OPERATING RESERVE - NCPC	2	1,249,036	22,444	125,003	177,211	275,953	120,522	185,703	2,065	6,610	89,944	90,380	129,670	23,529
AUCTION REVENUE RIGHTS	2	(120,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)
OTHER	2	221,855	-	-	281,250	281,250	263,105	-	(603,750)	-	-	-	-	-
Energy Total		$ 2,030,835	$ 50,998	$ 162,279	$ 536,160	$ 648,163	$ 465,631	$ 231,004	$ (570,505)	$ 34,897	$ 124,259	$ 126,871	$ 168,606	$ 52,473
Total Cost		$ 26,518,848	$ 1,420,338	$ 1,599,721	$ 1,973,603	$ 2,085,606	$ 1,903,074	$ 1,668,446	$ 926,157	$ 1,501,949	$ 3,366,196	$ 3,368,808	$ 3,410,543	$ 3,294,410
OPERATING RESERVE CREDIT	3	$ (591,000)	$ (50,000)	$ (50,000)	$ (50,000)	$ (36,667)	$ (36,667)	$ (36,667)	$ (43,667)	$ (43,667)	$ (43,667)	$ (66,667)	$ (66,667)	$ (66,667)

1 = demand; 2 = Energy, 3 = Resale Energy $ 1,439,835

GREEN MOUNTAIN POWER CORPORATION
V.P.S.B. DOCKET NO.
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August 1st, 2016

Green Mountain Power Corporation
Forward prices used in model

			2016			2017								
		Avg	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
FY2015	On-Peak	$ 43.87	$ 32.85	$ 38.50	$ 50.65	$ 68.25	$ 68.25	$ 46.86	$ 40.11	$ 32.25	$ 36.50	$ 40.75	$ 40.75	$ 30.75
	Off-Peak	$ 31.72	$ 23.00	$ 28.00	$ 39.50	$ 53.75	$ 53.75	$ 36.90	$ 30.40	$ 22.00	$ 23.50	$ 24.25	$ 24.25	$ 21.40
	Flat	$ 37.37	$ 27.45	$ 32.89	$ 44.54	$ 60.47	$ 60.47	$ 41.71	$ 34.85	$ 26.85	$ 29.86	$ 31.88	$ 31.88	$ 25.56

GREEN MOUNTAIN POWER CORPORATION
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Green Mountain Power Corporation
Congestion & Losses Expense (1)

Production	Total	2016 Oct	Nov	Dec	2017 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
On-peak	$ 1,040,528	$ 29,381	$ 71,867	$ 138,988	$ 266,371	$ 232,495	$ 131,497	$ 64,384	$ 35,878	$ 17,451	$ 32,141	$ 22,877	$ (2,802)
Off-peak	(1,553,901)	(125,808)	(122,417)	(114,167)	(106,571)	(88,112)	(83,095)	(103,518)	(124,676)	(145,113)	(206,992)	(178,044)	(155,387)
Total	$ (513,373)	$ (96,427)	$ (50,549)	$ 24,821	$ 159,800	$ 144,383	$ 48,402	$ (39,134)	$ (88,799)	$ (127,662)	$ (174,851)	$ (155,167)	$ (158,189)

Load	Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
On-peak	2,296,697	176,821	184,990	200,773	205,404	195,301	200,738	167,524	179,381	199,293	190,757	217,415	178,300
Off-peak	2,162,161	170,930	177,882	200,556	210,119	183,681	175,068	171,550	161,845	162,746	199,443	172,866	175,477
Total	$ 4,458,858	$ 347,751	$ 362,872	$ 401,328	$ 415,522	$ 378,982	$ 375,806	$ 339,073	$ 341,226	$ 362,038	$ 390,200	$ 390,282	$ 353,778

Net	Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
On-peak	3,337,224	206,202	256,857	339,761	471,774	427,796	332,235	231,908	215,259	216,744	222,899	240,292	175,498
Off-peak	608,261	45,122	55,466	86,388	103,548	95,569	91,973	68,031	37,169	17,633	(7,550)	(5,178)	20,090
Total	$ 3,945,485	$ 251,324	$ 312,322	$ 426,149	$ 575,322	$ 523,365	$ 424,208	$ 299,939	$ 252,428	$ 234,377	$ 215,349	$ 235,114	$ 195,588

Notes: (1) Losses and Congestion were estimated together by resource and load
(2) Excess Marginal Losses are calculated hourly by the Pool as the difference between the sum of marginal loss costs and actual (average) costs, and are allocated back to utilities

GREEN MOUNTAIN POWER CORPORATION
V.P.S.B. DOCKET NO.
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August 1st, 2016

Green Mountain Power Corporation
Generation Entitlements (1)

NAME	VINTAGE	EST. PLANT SIZE AVG MW (2)	GMP % SHARE	AVG GMP SHARE MW (2)	GMP CUM MW (2)	TYPE	FUEL	LOCATION
Kingdom	2012	64.5	87.3%	56.3	56.3	Wind	Wind	VT
Searsburg	1997	6.0	100.0%	6.0	62.3	Wind	Wind	VT
Granite Reliable	2012	99.0	82.3%	81.5	143.8	Wind	Wind	NH
McNeil	1984	50.0	31.0%	15.5	159.3	Steam	Wood/Gas/Oil #2	VT
Ryegate	1989	21.0	81.0%	17.0	176.3	Steam	Wood	VT
Wyman #4	1978	618.0	2.9%	18.0	194.3	Steam	Oil #6	ME
Standard Offer		67.0	78.0%	52.3	246.6	Renewable	Renewable	VT
GMP Solar		4.0	100.0%	4.0	250.6	Renewable	Renewable	VT
Solar PPA's		36.0	100.0%	36.0	286.6	Renewable	Renewable	VT
Seabrook		1,246.0	4.8%	60.0	346.6	Nuclear	Nuclear	NH
Millstone 3	1987	1,235.0	1.7%	21.4	368.0	Nuclear	Nuclear	CT
Moretown	2008	3.0	100.0%	3.0	371.0	Landfill	Methane	VT
Essex #19	1917	7.2	100.0%	7.2	378.2	Hydro	Water	VT
Deforge #1	1986	7.0	100.0%	7.0	385.2	Hydro	Water	VT
Waterbury #22	1953	5.5	100.0%	5.5	390.7	Hydro	Water	VT
Marshfield #6	1927	5.0	100.0%	5.0	395.7	Hydro	Water	VT
Gorge #18	1928	3.0	100.0%	3.0	398.7	Hydro	Water	VT
Middlesex #2	1928	3.2	100.0%	3.2	401.9	Hydro	Water	VT
Vergennes #9c	1912	2.4	100.0%	2.4	404.3	Hydro	Water	VT
W. Danville #15	1917	1.0	100.0%	1.0	405.3	Hydro	Water	VT
SPP's		32.0	78.0%	25.0	430.2	Hydro	Water	VT
Ampersand		5.0	100.0%	5.0	435.2	Hydro	Water	VT?
Fairfax Falls	1920	4.2	100.0%	4.2	439.4	Hydro	Water	VT
Clark Falls	1937	3.0	100.0%	3.0	442.4	Hydro	Water	VT
Milton	1929	7.5	100.0%	7.5	449.9	Hydro	Water	VT
Peterson	1948	6.4	100.0%	6.4	456.3	Hydro	Water	VT
Pierce Mills	1928	0.3	100.0%	0.3	456.5	Hydro	Water	VT
Arnold Falls	1928	0.4	100.0%	0.4	456.9	Hydro	Water	VT
Gage	1919	0.7	100.0%	0.7	457.6	Hydro	Water	VT
Passumpsic	1928	0.7	100.0%	0.7	458.3	Hydro	Water	VT
E Barnet	1983	2.2	100.0%	2.2	460.5	Hydro	Water	VT
Smith	1984	1.5	100.0%	1.5	462.0	Hydro	Water	VT
Silver Lake	1916	2.2	100.0%	2.2	464.2	Hydro	Water	VT
Salisbury	1917	1.3	100.0%	1.3	465.5	Hydro	Water	VT
Middlebury Lower	1920	2.3	100.0%	2.3	467.7	Hydro	Water	VT
Beldens	1913/1988	5.9	100.0%	5.9	473.6	Hydro	Water	VT
Huntington Falls	1911/1989	5.5	100.0%	5.5	479.1	Hydro	Water	VT
Weybridge	1951	3.0	100.0%	3.0	482.1	Hydro	Water	VT
E Pittsford	1914	3.6	100.0%	3.6	485.7	Hydro	Water	VT
Glen	1920	2.0	100.0%	2.0	487.7	Hydro	Water	VT
Patch	1921	0.4	100.0%	0.4	488.1	Hydro	Water	VT
Ctr Rutland	1898	0.3	100.0%	0.3	488.3	Hydro	Water	VT
Proctor	1905/1984	6.9	100.0%	6.9	495.2	Hydro	Water	VT
Carver Falls	1894	2.3	100.0%	2.3	497.5	Hydro	Water	VT
Cavendish	1908	1.4	100.0%	1.4	499.0	Hydro	Water	VT
Taftsville	1942	0.5	100.0%	0.5	499.5	Hydro	Water	VT
North Hartland		4.0	100.0%	4.0	503.5	Hydro	Water	VT
Colchester #16	1965	17.0	100.0%	17.0	520.5	Gas Turbine	Oil #2	VT
Ascutney	1961	12.5	100.0%	12.5	533.0	Gas Turbine	Oil #2	VT
Rutland 5	1962	12.5	100.0%	12.5	545.5	Gas Turbine	Oil #2	VT
Berlin #5	1972	46.5	93.7%	43.6	589.1	Gas Turbine	Oil #1/Kero	VT
Vergennes #9	1964	4.0	100.0%	4.0	593.1	Diesel	Oil #2	VT
Essex #19	1947	8.0	100.0%	8.0	601.1	Diesel	Oil #2	VT
HQ-C4a	1995	1.9	100.0%	1.9	603.0	Contract	System	HG/Phase II
NYPA		0.6	100.0%	0.6	603.6	Contract	System	NY
Stonybrook	1981	353.9	12.9%	45.6	649.2	CC/SC	Oil #2/Gas	MA

Notes: (1) Table represents nominal capacity value of resource
(2) MW are installed values, not ICAP

GREEN MOUNTAIN POWER CORPORATION
V.P.S.B. DOCKET NO.
Attachment D, Schedule 3

August 1st, 2016

Green Mountain Power Corporation
Power Supply Reconciliation

			2016			2017					R-1			
		Total	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**
Net deficiency/(surplus)		(95,017)	7,036	15,927	(5,941)	(15,702)	(11,834)	6,188	8,650	(36,924)	(23,320)	(30,153)	(14,595)	5,652
MWH														
Purchases	On	10,545	1,936	1,755	-	-	-	1,916	2,733	-	-	-	-	2,205
	Off	32,909	5,100	14,172	-	-	-	4,272	5,917	-	-	-	-	3,448
Resales	On	(67,885)	-	-	(981)	(10,087)	(7,063)	-	-	(22,904)	(8,612)	(14,788)	(3,451)	-
	Off	(70,585)	-	-	(4,961)	(5,616)	(4,772)	-	-	(14,020)	(14,708)	(15,365)	(11,144)	-
Net ISO		(95,017)	7,036	15,927	(5,941)	(15,702)	(11,834)	6,188	8,650	(36,924)	(23,320)	(30,153)	(14,595)	5,652
Dollars														
Purchases	On	$398,378	$63,605	$67,561	$0	$0	$0	$89,803	$109,617	$0	$0	$0	$0	$67,790
	Off	925,355	117,297	396,823	-	-	-	157,617	179,836	-	-	-	-	73,783
Resales	On	(3,016,343)	-	-	(49,671)	(688,406)	(482,017)	-	-	(738,668)	(314,350)	(602,610)	(140,622)	-
	Off	(2,051,195)	-	-	(195,948)	(301,849)	(256,489)	-	-	(308,437)	(345,630)	(372,595)	(270,248)	-
ISO ANI Adjustment		2,146,384	130,933	158,051	213,585	289,121	289,333	199,507	165,586	129,128	142,416	151,222	154,607	122,895
Net ISO		($1,597,421)	$311,836	$622,435	($32,033)	($701,134)	($449,173)	$446,927	$455,040	($917,977)	($517,564)	($823,983)	($256,263)	$264,469

GREEN MOUNTAIN POWER CORPORATION
V.P.S.B. DOCKET NO.
Attachment D, Schedule 3

August 1st, 2016

Green Mountain Power Corporation
Operations & Maintenance

		Source	Total	2016 Oct	Nov	Dec	2017 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	UOM-1 Sep
J C McNeil Wood	1	Budget/Forecast	2,114,300	176,192	176,192	176,192	176,192	176,192	176,192	176,192	176,192	176,192	176,192	176,192	176,192
Stonybrk CC	2	Forecast	775,902	64,659	64,659	64,659	64,659	64,659	64,659	64,659	64,659	64,659	64,659	64,659	64,659
Wyman 4	3	Forecast	335,296	27,941	27,941	27,941	27,941	27,941	27,941	27,941	27,941	27,941	27,941	27,941	27,941
Millstone 3	4	Forecast	3,184,926	265,410	265,410	265,410	265,410	265,410	265,410	265,410	265,410	265,410	265,410	265,410	265,410
Other owned	5	GMP Budget	96,706	9,499	19,057	8,593	6,724	5,837	5,368	22,995	5,658	(2,653)	2,337	7,417	5,875
G.T./Diesel & Other	6	GMP Budget	586,735	42,413	53,303	66,668	42,238	30,537	40,827	19,787	75,422	91,173	47,365	31,286	45,716
Util Hydro*	7	GMP Budget	3,959,102	368,335	351,284	366,670	315,274	307,495	353,015	307,248	289,887	434,340	204,279	404,643	256,631
Wind	8	GMP Budget	4,040,900	326,188	302,661	204,256	689,429	373,609	277,523	450,823	235,485	278,602	342,614	276,931	282,777
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Total			15,093,866	1,280,638	1,260,507	1,180,390	1,587,867	1,251,680	1,210,935	1,335,054	1,140,655	1,335,664	1,130,797	1,254,478	1,125,201

Green Mountain Power Corporation
Fuel Expense

		Source	Total	2016 Oct	Nov	Dec	2017 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Util Hydro	9	Production MWh	381,165	23,538	32,918	37,664	34,205	28,900	39,514	49,770	45,305	33,965	26,821	16,216	12,350
	9	Variable Production Costs $	-	0	0	0	0	0	0	0	0	0	0	0	0
		Average Variable Cost $/MWh	-	-	-	-	-	-	-	-	-	-	-	-	-
J C McNeil Wood	10	Production MWh	91,925	8,784	8,827	8,241	8,661	9,198	10,174	2,946	5,855	7,175	6,976	8,705	6,383
	10	Variable Production Costs $	6,672,708	637,639	640,750	598,232	628,716	667,650	738,496	213,860	424,972	520,786	506,374	631,902	463,332
		Average Variable Cost $/MWh	$72.59	$72.59	$72.59	$72.59	$72.59	$72.59	$72.59	$72.59	$72.59	$72.59	$72.59	$72.59	$72.59
Stonybrk CC	11	Production MWh	14,628	369	169	398	2,284	2,437	685	92	1,071	668	2,868	2,342	1,245
	11	Variable Production Costs $	641,235	10,476	6,379	26,356	172,480	184,231	45,238	2,939	24,052	15,932	70,662	55,380	27,109
		Average Variable Cost $/MWh	$43.84	$28.40	$37.69	$66.17	$75.53	$75.61	$66.07	$32.09	$22.47	$23.84	$24.64	$23.64	$21.77
Wyman 4	12	Production MWh	4,844	12	57	250	1,923	1,683	434	57	0	34	235	111	49
	12	Variable Production Costs $	322,357	766	3,632	16,215	126,380	112,197	29,301	3,812	0	2,328	16,396	7,827	3,501
		Average Variable Cost $/MWh	$67.93	$63.13	$73.05	$65.18	$67.04	$67.94	$67.53	$67.33	$68.16	$84.85	$73.59	$70.55	$71.19
Millstone 3	13	Production MWh	181,090	15,380	14,884	15,380	15,380	13,892	15,380	14,884	15,380	14,884	15,380	15,380	14,884
	13	Variable Production Costs $	1,443,518	122,600	118,645	122,600	122,600	110,736	122,600	118,645	122,600	118,645	122,600	122,600	118,645
		Average Variable Cost $/MWh	$7.97	$7.97	$7.97	$7.97	$7.97	$7.97	$7.97	$7.97	$7.97	$7.97	$7.97	$7.97	$7.97
Kingdom (gross)	14	Production MWh	185,625	15,378	17,705	19,848	20,189	16,199	16,950	15,487	13,825	12,701	12,159	11,950	13,233
Searsburg	15	Production MWh	11,725	1,169	1,187	1,351	1,242	1,174	1,200	1,014	828	667	637	557	699
Other GMP	16	Production MWh	4,897	430	260	187	195	263	432	485	526	567	567	514	472
GMP G.T. & Diesel	17	Production MWh	3,708	121	297	129	709	464	226	91	225	316	581	260	288
		Variable Production Costs $	570,511	18,660	45,504	19,627	101,579	65,029	33,206	15,345	34,173	49,670	94,399	44,775	48,544
		Average Variable Cost $/MWh	$156.89	$156.94	$153.60	$154.19	$146.21	$143.89	$164.44	$168.85	$151.82	$159.74	$163.66	$175.13	$169.75
Total		Production MWh	879,608	65,181	76,304	83,449	84,789	74,209	84,995	84,825	83,015	70,976	66,223	56,036	49,605
		Variable Production Costs $	$9,650,329	790,142	814,911	783,031	1,151,756	1,139,842	968,841	354,602	605,797	707,361	810,431	862,483	661,131

Green Mountain Power Corporation
Power Contracts

Energy			2016			2017								
		Total	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
VEPPI	1 Production MWh	88,983	6,445	9,430	8,189	6,799	5,442	9,356	14,520	11,145	6,417	4,349	3,662	3,229
	1 Variable Production Costs $	11,778,596	708,109	1,301,993	1,131,104	1,009,321	808,605	1,387,370	2,150,827	1,264,695	729,917	496,034	418,295	372,327
	Average Variable Cost $/MWh	$132.37	$109.87	$138.07	$138.13	$148.45	$148.60	$148.29	$148.13	$113.48	$113.75	$114.05	$114.22	$115.30
Other Renewable	2 Production MWh	133,821	6,018	7,153	7,540	7,959	7,813	12,336	17,161	17,931	17,521	14,178	10,337	7,875
	2 Variable Production Costs $	13,048,042	543,510	626,786	721,993	832,380	873,438	1,315,037	1,391,267	1,556,457	1,571,903	1,472,974	1,222,050	920,247
	Average Variable Cost $/MWh	$97.50	$90.31	$87.62	$95.76	$104.59	$111.79	$106.60	$81.07	$86.80	$89.72	$103.89	$118.22	$116.85
Ryegate	3 Production MWh	143,083	12,152	11,777	12,152	12,152	10,976	12,136	11,760	12,152	11,760	12,152	12,152	11,760
	3 Variable Production Costs $	14,747,970	1,241,411	1,214,869	1,253,563	1,253,563	1,132,433	1,251,881	1,213,186	1,253,563	1,213,186	1,253,563	1,253,563	1,213,186
	PPA Price Charged $/MWh	$103.07	$102.15	$103.16	$103.15	$103.15	$103.17	$103.15	$103.16	$103.15	$103.16	$103.15	$103.15	$103.16
HQUS	4 Production MWh	1,001,228	75,743	83,127	85,898	85,898	77,586	85,898	83,127	85,898	83,127	85,898	85,898	83,127
	4 Variable Production Costs $	52,399,643	4,280,347	4,322,093	4,466,162	4,466,162	4,033,953	4,466,162	4,322,093	4,466,162	4,322,093	4,466,162	4,466,162	4,322,093
	Average Variable Cost $/MWh	$52.34	$56.51	$51.99	$51.99	$51.99	$51.99	$51.99	$51.99	$51.99	$51.99	$51.99	$51.99	$51.99
Net Metered Excess	5 Production MWh	109,556	5,785	3,835	3,148	4,258	5,461	8,376	11,579	13,525	14,168	14,534	13,962	10,924
	5 Variable Production Costs $	23,656,755	1,277,897	863,632	701,915	955,160	1,230,071	1,858,732	2,521,537	2,877,734	3,000,478	3,081,383	2,967,169	2,321,047
	Average Variable Cost $/MWh	$215.93	$220.91	$225.22	$222.95	$224.31	$225.24	$221.92	$217.77	$212.77	$211.78	$212.01	$212.51	$212.47
NextEra Seabrook PPA	6 Production MWh	467,928	43,301	41,962	43,301	43,301	39,110	43,243	0	43,301	41,904	43,301	43,301	41,904
	6 Variable Production Costs $	23,342,756	1,911,519	1,955,339	2,336,301	2,336,301	2,110,207	2,015,002	0	1,911,519	2,100,615	2,387,700	2,387,700	1,890,554
	Average Variable Cost $/MWh	$49.89	$44.15	$46.60	$53.96	$53.96	$53.96	$46.60	$0.00	$44.15	$50.13	$55.14	$55.14	$45.12
Granite	7 Production MWh	215,774	18,548	21,316	22,000	22,481	21,463	23,467	17,163	17,843	13,631	10,834	12,265	14,764
	7 Variable Production Costs $	16,024,241	1,370,493	1,568,784	1,615,059	1,659,065	1,590,063	1,733,370	1,291,770	1,338,260	1,023,723	809,454	922,484	1,101,716
	Average Variable Cost $/MWh	$74.26	$73.89	$73.60	$73.41	$73.80	$74.09	$73.86	$75.26	$75.00	$75.10	$74.71	$75.21	$74.62
SPEED Standard Offer	8 Production MWh	85,920	6,354	5,351	4,621	5,082	5,468	6,964	9,393	9,410	8,972	8,724	8,374	7,208
	8 Variable Production Costs $	18,257,640	1,341,789	1,055,006	858,063	994,970	1,165,077	1,484,858	1,975,896	2,007,972	1,970,518	1,951,122	1,875,167	1,577,202
	Average Variable Cost $/MWh	$212.49	$211.16	$197.18	$185.69	$195.79	$213.06	$213.22	$210.35	$213.40	$219.63	$223.66	$223.92	$218.82
JP Morgan System	9 Production MWh	230,425	33,480	32,445	33,480	14,880	13,440	14,860	14,400	14,880	14,400	14,880	14,880	14,400
	9 Variable Production Costs $	13,471,473	2,096,964	2,032,139	2,096,964	822,864	743,232	821,758	796,320	822,864	796,320	822,864	822,864	796,320
	Average Variable Cost $/MWh	$58.46	$62.63	$62.63	$62.63	$55.30	$55.30	$55.30	$55.30	$55.30	$55.30	$55.30	$55.30	$55.30
NextEra System	10 Production MWh	109,150	0	0	0	12,400	11,200	12,350	12,000	12,400	12,000	12,400	12,400	12,000
	10 Variable Production Costs $	4,322,340	0	0	0	491,040	443,520	489,060	475,200	491,040	475,200	491,040	491,040	475,200
	Average Variable Cost $/MWh	$39.60	$0.00	$0.00	$0.00	$39.60	$39.60	$39.60	$39.60	$39.60	$39.60	$39.60	$39.60	$39.60
Citigroup System	11 Production MWh	306,600	26,040	25,235	26,040	26,040	23,520	26,005	25,200	26,040	25,200	26,040	26,040	25,200
	11 Variable Production Costs $	15,943,200	1,354,080	1,312,220	1,354,080	1,354,080	1,223,040	1,352,260	1,310,400	1,354,080	1,310,400	1,354,080	1,354,080	1,310,400
	Average Variable Cost $/MWh	$52.00	$52.00	$52.00	$52.00	$52.00	$52.00	$52.00	$52.00	$52.00	$52.00	$52.00	$52.00	$52.00
Shell System	12 Production MWh	503,120	30,480	29,330	30,480	30,480	27,200	29,790	29,600	30,160	64,960	68,000	67,040	65,600
	12 Variable Production Costs $	22,853,645	1,488,643	1,432,477	1,488,643	1,488,643	1,328,448	1,454,944	1,445,664	1,473,014	2,750,006	2,884,392	2,837,506	2,781,264
	Average Variable Cost $/MWh	$45.42	$48.84	$48.84	$48.84	$48.84	$48.84	$48.84	$48.84	$48.84	$42.33	$42.42	$42.33	$42.40
BP System	13 Production MWh	263,400	0	0	47,400	74,400	67,200	0	0	0	0	37,200	37,200	0
	13 Variable Production Costs $	17,254,242	0	0	2,915,574	4,801,524	4,340,304	0	0	0	0	2,598,420	2,598,420	0
	Average Variable Cost $/MWh	$65.51	$0.00	$0.00	$61.51	$64.54	$64.59	$0.00	$0.00	$0.00	$0.00	$69.85	$69.85	$0.00
KCW Resale	14 Production MWh	(23,571)	(1,953)	(2,248)	(2,520)	(2,564)	(2,057)	(2,152)	(1,967)	(1,756)	(1,613)	(1,544)	(1,518)	(1,680)
	14 Variable Production Costs $	(3,171,630)	(264,302)	(264,302)	(264,302)	(264,302)	(264,302)	(264,302)	(264,302)	(264,302)	(264,302)	(264,302)	(264,302)	(264,302)
	Average Variable Cost $/MWh	$134.55	$135.34	$117.56	$104.87	$103.10	$128.48	$122.79	$134.39	$150.55	$163.87	$171.18	$174.17	$157.29
Moretown	15 Production MWh	14,298	1,388	1,345	1,388	1,152	1,077	1,150	1,115	1,152	1,115	1,152	1,152	1,115
	15 Variable Production Costs $	1,222,441	118,636	114,969	118,636	98,468	92,115	98,336	95,292	98,468	95,292	98,468	98,468	95,292
	Average Variable Cost $/MWh	$85.50	$85.50	$85.50	$85.50	$85.50	$85.50	$85.50	$85.50	$85.50	$85.50	$85.50	$85.50	$85.50
Other Net	16 Production MWh	24,481	11,747	578	699	1,712	1,701	838	542	1,048	814	2,025	1,688	1,088
	16 Variable Production Costs $	1,019,915	414,552	28,035	38,202	118,728	120,357	47,637	25,915	36,869	32,166	64,826	55,106	37,524
	Average Variable Cost $/MWh	$41.66	$35.29	$48.53	$54.65	$69.35	$70.74	$56.81	$47.85	$35.17	$39.51	$32.01	$32.64	$34.47
Total, Net	Production MWh	3,674,195	**275,528**	**270,635**	**323,815**	**346,430**	**316,601**	**284,617**	**245,593**	**295,129**	**314,376**	**354,124**	**348,834**	**298,515**
	Variable Production Costs $	246,171,269	**17,883,647**	**17,564,038**	**20,831,957**	**22,417,968**	**20,970,561**	**19,512,104**	**18,751,064**	**20,688,395**	**21,127,515**	**23,968,180**	**23,505,771**	**18,950,070**
		246,171,269	*17,883,647*	*17,564,038*	*20,831,957*	*22,417,968*	*20,970,561*	*19,512,104*	*18,751,064*	*20,688,395*	*21,127,515*	*23,968,180*	*23,505,771*	*18,950,070*
Demand														
NextEra Seabrook	17 Contract formula	3,260,074	269,695	269,695	269,695	269,695	269,695	269,695	269,695	269,695	275,628	275,628	275,628	275,628
Yankee Plants	18 Forecasts	(351,975)	(35,365)	(35,365)	(35,365)	(27,320)	(27,320)	(27,320)	(27,320)	(27,320)	(27,320)	(27,320)	(27,320)	(27,320)
Stony Brook	19 Forecast	905,009	75,000	75,000	75,000	75,000	75,000	75,000	75,000	75,000	75,000	80,009	75,000	75,000
Moretown	20 Contract terms	180,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000	15,000
NYPA	21 Forecast	30,000	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
Granite	22 Contract terms	369,410	30,555	30,555	30,555	30,555	30,555	30,555	31,013	31,013	31,013	31,013	31,013	31,013
HQ VJO	23 Contract formula	442,114	442,114	0	0	0	0	0	0	0	0	0	0	0
Other, Net	24	(0)	0	0	0	(0)	(0)	(0)	0	0	(0)	0	(0)	(0)
	Total	4,834,632	799,499	357,385	357,385	365,430	365,430	365,430	365,888	365,888	371,822	376,830	371,822	371,822
		29,322,645	*2,168,839*	*1,794,827*	*1,794,827*	*1,802,872*	*1,802,872*	*1,802,872*	*1,862,551*	*1,832,941*	*3,613,759*	*3,618,767*	*3,613,759*	*3,613,759*

GREEN MOUNTAIN POWER CORPORATION
V.P.S.B.DOCKET NO.
Attachment D, Schedule 3
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August 1st, 2016

Green Mountain Power Corporation
REC Revenue

			2016			2017							
		Total	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Net REC Revenue	**$**	**(22,997,796)**	**-**	**-**	**(5,282,026)**	**-**	**-**	**(4,870,079)**	**-**	**-**	**(6,448,223)**	**-**	**-**	**(6,397,467)**

GREEN MOUNTAIN POWER CORPORATION
V.P.S.B.DOCKET NO.
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August 1st, 2016

Green Mountain Power Corporation
Purchased Transmission plus Highgate O&M

Purchased Transmission	Total	2016 Oct	Nov	Dec	2017 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
VELCO Spec Facilities	$5,265,479	$432,883	$426,465	$374,687	$457,186	$451,219	$448,778	$444,965	$432,221	$448,697	$453,349	$447,365	$447,665
VELCO VTA - Common	10,593,699	365,814	2,339,870	2,212,541	1,065,407	1,801,236	1,960,425	2,216,763	2,692,340	1,469,358	(1,115,423)	(2,456,471)	(1,958,162)
ISO - NOATT	66,833,362	5,072,015	5,600,656	6,031,108	6,096,509	5,722,132	5,339,225	4,815,993	4,840,005	5,674,228	6,187,866	5,829,710	5,623,916
ISO - Other Total	5,914,825	451,389	492,556	517,080	544,630	506,818	490,735	453,194	444,946	461,412	496,687	598,783	456,596
NEP	1,889,020	130,335	205,335	180,335	155,335	155,335	155,335	180,335	205,335	180,335	130,335	105,335	105,335
Phase I	95,544	7,962	7,962	7,962	7,962	7,962	7,962	7,962	7,962	7,962	7,962	7,962	7,962
Phase II	3,296,280	274,690	274,690	274,690	274,690	274,690	274,690	274,690	274,690	274,690	274,690	274,690	274,690
Other	702,203	58,513	58,515	58,517	58,517	58,517	58,517	58,517	58,518	58,518	58,518	58,518	58,518
Rents (567)	300,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000	25,000
Total	$94,890,413	$6,818,601	$9,431,049	$9,681,921	$8,685,235	$9,002,909	$8,760,667	$8,477,419	$8,981,017	$8,600,200	$6,518,984	$4,890,891	$5,041,520
Highgate O&M	$ 629,208	$52,434	$52,434	$52,434	$52,434	$52,434	$52,434	$52,434	$52,434	$52,434	$52,434	$52,434	$52,434
ISO Other													
ISO Schedule 1	1,501,931	112,944	124,680	134,176	140,499	131,960	123,130	110,999	111,869	124,314	135,773	128,002	123,585
ISO Schedule 2	1,951,978	148,203	159,819	169,385	183,069	163,129	165,978	153,159	153,159	159,568	173,099	169,538	153,871
ISO Schedule 3	1,589,864	118,978	131,340	141,344	148,962	139,908	130,546	117,685	118,607	131,802	143,951	135,711	131,029
ISO Schedule 4	120,000	-	-	-	-	-	-	-	-	-	-	120,000	-
ISO Schedule 5	20,929	1,757	1,940	2,088	-	2,114	1,985	1,853	1,670	1,683	1,870	2,043	1,926
Load Response	0	-	-	-	-	-	-	-	-	-	-	-	-
NOATT Schedule 2	888,934	77,985	81,671	78,390	80,455	78,769	78,339	78,623	71,682	65,842	64,307	65,426	67,444
NOATT Schedule 16	(158,811)	(8,478)	(6,894)	(8,304)	(8,355)	(9,063)	(9,244)	(9,125)	(12,042)	(21,798)	(22,314)	(21,937)	(21,259)
Other	0	-	-	-	-	-	-	-	-	-	-	-	-
Total ISO - Other	$5,914,825	$ 451,389	$ 492,556	$ 517,080	$ 544,630	$ 506,818	$ 490,735	$ 453,194	$ 444,946	$ 461,412	$ 496,687	$ 598,783	$ 456,596
Total Purchased	$94,890,413	$6,818,601	$9,431,049	$9,681,921	$8,685,235	$9,002,909	$8,760,667	$8,477,419	$8,981,017	$8,600,200	$6,518,984	$4,890,891	$5,041,520
Total w/ Highgate O&M	$95,519,621	$6,871,035	$9,483,483	$9,734,355	$8,737,669	$9,055,343	$8,813,101	$8,529,853	$9,033,451	$8,652,634	$6,571,418	$4,943,325	$5,093,954

STATE OF VERMONT
PUBLIC SERVICE BOARD

Petition of Champlain VT, LLC d/b/a TDI New England for a Certificate of Public Good, pursuant to 30 V.S.A. §248, authorizing the installation and operation of a high voltage direct current (HVDC) underwater and underground electric transmission line with a capacity of 1,000 MW, a converter station, and other associated facilities, to be located in Lake Champlain and in the Counties of Grand Isle, Chittenden, Addison, Rutland, and Windsor, Vermont, and to be known as the New England Clean Power Link Project ("NECPL")	)	Docket No. 8400

Stipulation between Champlain VT, LLC, the Vermont Public Service Department, the Vermont Agency of Natural Resources, and the Vermont Division for Historic Preservation

This Stipulation (the "Stipulation"), dated the 17th day of July, 2015, sets forth Stipulations reached by the Vermont Public Service Department ("PSD" or "Department"), the Vermont Agency of Natural Resources ("ANR" or "Agency"), the Vermont Division for Historic Preservation ("DHP"), and Champlain VT, LLC d/b/a TDI New England ("TDI-NE" or Petitioner), a Delaware limited liability company with its principal office at 600 Broadway, Albany, NY 12207, collectively, the "Parties," in connection with the above-captioned Vermont Public Service Board ("Board") docket.

WHEREAS, TDI-NE filed a Petition in December 2014 with the Board requesting permission to develop, construct, and operate the New England Clean Power Link ("NECPL" or "Project"), a proposed electric transmission line; and

WHEREAS, TDI-NE asserts that the electricity shipped through NECPL will be generated by renewable energy sources in Canada and will be delivered to Vermont and the New England electric grid. The transmission line will utilize high voltage direct current (HVDC) technology, capable of transmitting 1,000 megawatts (MW) of electricity; and

WHEREAS, the Department believes that in order to meet Vermont and New England energy and environmental policy goals, the NECPL should only ship renewable energy; and

WHEREAS, the transmission line will begin at a converter station in the Province of Québec, Canada and transmit electricity from Alburgh, Vermont to Ludlow, Vermont, where it will tie into a new converter station. The Ludlow converter station will convert the electrical power from direct current ("DC") to alternating current ("AC") and then connect to the 345 kV Coolidge Substation in Cavendish, Vermont that is owned by the Vermont Electric Power Company ("VELCO");

WHEREAS, the underwater portions of the transmission line, approximately 97 miles in length, will be buried in the bed of Lake Champlain, except at water depths of greater than 150 feet where the cables will be placed on the bottom. The terrestrial portions of the transmission line, approximately 57 miles in length, will be buried underground within existing public rights-of-way ("ROWs");

WHEREAS, the Vermont Department of Taxes has determined that the portion of the Project in Lake Champlain is not subject to property taxation under Vermont law; and it is TDI-NE's, the Department's, and ANR's understanding that the portion of the Project in Lake Champlain is not subject to any other impact fee, surcharge, tax, or other similar assessment imposed by the State of Vermont for the placement of the transmission line in Lake Champlain; and TDI-NE, ANR, and the Department recognize that these determinations affect project economics and have resulted in an increase to public benefit payments under this Stipulation; and TDI-NE, the Department, and ANR agree to explain to the Vermont General Assembly the mutual understanding related to project economics, the necessity in the public benefit payments in reaching this Stipulation, and the Board's order should a legislative matter arise that affects the Parties understandings in reaching the terms of this Stipulation.

WHEREAS, the Parties have engaged in discussions concerning the Project and, subject to the terms of this Stipulation, agree that the Project will promote the general good and otherwise meet the criteria of section 248, and consequently that the Board should approve TDI-NE's petition to construct and operate the NECPL.

STIPULATIONS

THEREFORE, in consideration of the foregoing and, provided that the PSB approves the Project consistent with TDI-NE's Petition and this Stipulation, and TDI-NE chooses in its sole discretion to construct and operate the Project, the Parties agree as follows:

1. The Parties agree that provided TDI-NE fulfills the terms of this Stipulation, the Project will promote the general good and otherwise meet the criteria of section 248, and consequently the Board should approve the Project and issue an Order and Certificate of Public Good ("CPG") in this matter in accordance: (i) with the plans and specifications submitted with TDI-NE's petition; and (ii) and with the terms and conditions of this Stipulation and any supplemental prefiled testimony and exhibits to be submitted by TDI-NE in connection herewith.

2. TDI-NE shall file supplemental testimony and exhibits that memorialize, as necessary, the conditions of this Stipulation.

3. Public Good Benefits.

   a. TDI-NE agrees to revise the public benefits plan contained in its section 248 filing as follows and as provided in more detail in Attachment I hereto:

      i. VT Electric Ratepayer Benefit (through VELCO) – remains the same as in the section 248 Petition, i.e., an average of $3.4 million/year for 40 years.

      ii. VT Renewables Programs (through the CEDF) – a total of approximately $109 million over a forty year period. The payments shall be $5 million per year for the first 20 years and the balance payable evenly for the remaining 20 years. TDI-NE agrees to make payments to the Clean Energy Development Fund as reflected in Attachment I hereto, beginning on July 1 of the initial year of commercial operations of the Project and continuing annually thereafter for the subsequent 39 years.

      iii. Lake Champlain Pollution Abatement and Restoration Fund.

         I. TDI-NE agrees to deposit: (i) $1 million on the fiscal close of the Project; (ii) $6 million on July 1 of the initial year of commercial operations of the Project; and (iii) $5 million on July 1 of each year thereafter for 39 years.

         II. Funds shall be deposited into a dedicated account of the Clean Water Fund established pursuant to 10 V.S.A. § 1388. Funds deposited into this account shall be managed in accordance with and used for the purposes established in 10 V.S.A. Chapter 47, Subchapter 7 except that the use of the funds shall be limited to the Lake Champlain watershed.

         III. ANR and TDI-NE may enter an agreement to accelerate payments to the Fund.

         IV. If monies required by this Section 3.a.iii. are used for any purpose other than the purposes established by 10 V.S.A. Chapter 47, Subchapter 7 or as otherwise agreed to in writing by the Parties, TDI-NE shall not be required to make additional payments under this Section 3.a.iii.

iv. Lake Champlain Enhancement and Restoration Trust Fund

I. There shall be established a Fund to be known as the Lake Champlain Enhancement and Restoration Trust Fund ("Fund"), established for the following purposes: (i) to promote recreational access to Lake Champlain; (ii) for acquisition and development of lands and facilities associated with municipal, state, and non-profit public recreation opportunities and habitat conservation within the Lake Champlain watershed; (iii) for recreational, cultural, historical, environmental, and educational activities, programs and opportunities associated with the Lake Champlain watershed; and (iv) to promote research and development and habitat restoration programs and projects related to the Lake Champlain watershed.

II. The Fund shall be governed by an advisory entity called the Lake Champlain Enhancement and Restoration Trust Fund Advisory Board (the "Advisory Board") to approve the expenditure of funds consistent with the purposes of the Fund. The Advisory Board shall consist of TDI-NE, the Conservation Law Foundation, the Commissioner of Forests, Parks, and Recreation, the Commissioner of Fish and Wildlife, one "at-large" representative chosen by the Governor, and two "at-large" representatives chosen by TDI-NE. When selecting its representatives, TDI-NE shall take into consideration regional diversity of members from the Lake Champlain Basin. With respect to the three "at-large" members, they shall serve staggered terms of three years with the Governor's appointee serving an initial three year term and the TDI-NE appointees serving an initial one and two year term and then three year terms thereafter. The purpose of the Advisory Board is to establish policies, priorities, procedures, and guidelines for the use of the Fund, select the Administrative Agent, review funding proposals and consider and approve projects for funding, and direct the Administrative Agent (defined below) in the administration of the Fund consistent with its purposes.

III. The Fund shall be administered by a not-for-profit entity selected by the Advisory Board ("the Administrative Agent"). The Administrative Agent shall manage the day to day functions of the Fund, provide administrative support to the Advisory Board, and make recommendations on the proper administration of the Fund for the approval of the Advisory Board.

IV. TDI-NE agrees to deposit to the Fund: (i) $1 million on the closing of the construction financing of the Project; and (ii) $1.5 million annually beginning on July 1 of the initial year of commercial operations and continuing annually thereafter for the subsequent 39 years. Monies deposited into the Fund shall be used for the purposes established in Section 3.b.iv.I. This section does not preclude loan structuring opportunities where the payments would be made to service any debt borrowed up front against the collateral of guaranteed ongoing payments. Further TDI-NE agrees to provide information to a TDI-NE qualified third party as may be necessary to borrow against the collateral of future payments.

V. The Advisory Board may enter into an agreement with TDI-NE to accelerate payments to the Fund.

VI. The administrative costs paid to the Administrative Agent and the Advisory Board shall be allocated from the Fund in an amount not to exceed a total of five (5) percent of the annual payment made to the Fund unless otherwise agreed to by the Advisory Board in writing. The Advisory Board shall consider existing organizations with experience in administering similar funds to assist in the administration of the Fund.

VII. TDI-NE shall, in consultation with the State, prepare an implementation plan for the Fund which, among other things, identifies the members of the Advisory Board and the Administrative Agent. The plan shall be submitted as a post-CPG compliance filing for PSB review and approval.

b. The Department, ANR, and TDI-NE agree that these public good benefits, in conjunction with the other direct and indirect economic benefits enumerated in the section 248 Petition, demonstrate that the Project provides an economic benefit to the State and its residents under section 248(b)(4) and will promote the general good of the State under section 248(a)(2)(A).

c. TDI-NE and ANR acknowledge that the Stipulation between the Vermont Department of Fish and Wildlife ("DFW") and TDI-NE allowing the use of the Korean Veterans Access Area in Alburgh to construct a portion of the Project facilities will provide other public good benefits, including TDI-NE providing $350,000 for a new boat ramp at the Access Area. TDI-NE agrees to abide by the terms and conditions of the license for the use of the Korean War Veterans Access Area.

d. The Parties acknowledge that the Project may operate beyond the 40 year period that TDI-NE has estimated based upon the manufacturer's warranty, understanding that the CPG will not have an expiration date. The Parties further acknowledge that these benefit payments are being or may be used in several regulatory obligations of TDI-NE which are necessary for the completion of this Project. The Parties further acknowledge that the benefit fund payments due under this Stipulation are for a term of forty years, after which the Parties agree to negotiate in good faith regarding whether any additional payments are appropriate and if so in what amount and amendments to this Stipulation, subject to PSB review and approval.

4. <u>Electrical System.</u>

a. TDI-NE and the Department acknowledge that ISO-New England's review process for the NECPL -- an Elective Transmission Upgrade -- is ongoing, and that the final System Impact Study (SIS) and I.3.9 approval is controlled by ISO-NE.[1]

b. TDI-NE and the Department agree that TDI-NE shall submit the final SIS and I.3.9 approval as soon as they are individually available. If the final SIS and I.3.9 approval are first available prior to the Board issuing a CPG for this project, then they shall be reviewed by the Board and Parties as part of this proceeding. If the final SIS and I.3.9 approval are not available at such time, TDI-NE and the Department agree that the CPG should be conditioned upon the Board review of each as a post-CPG compliance filing, subject to review and comment by the Department, VELCO, Green Mountain Power, and Burlington Electric Department regarding: (i) any issue germane to ongoing section 248(b)(3) compliance; or (ii) whether any identified subtransmission or transmission system upgrades require further review and/or approval by the PSB.

c. The Parties agree that TDI-NE and/or the affected transmission system owners will initiate separate proceeding(s) under section 248, or section 248(j) as appropriate, for the transmission or subtransmission upgrades to be required in Vermont as a result

[1] TDI-NE will, after consulting with the DPS, file supplemental testimony from witness Larry Eng or another qualified witness that adequately addresses the issues raised in Bill Jordan's June 12, 2015 testimony, consistent with the schedule in this docket.

of the NECPL. The Parties further agree that TDI-NE's pending Petition can be acted upon by the Board, subject to the condition that construction cannot commence until those collateral section 248 approvals for the transmission and subtransmission upgrades are obtained. All collateral transmission or subtransmission upgrades shall be reviewed independently under the applicable section 248 criteria and no party to this Stipulation waives any of its rights to participate in, or raise issues in connection with, those separate proceedings. The Parties recognize that in order for the Project to proceed to construction and for the benefit payments to commence, any collateral section 248 proceedings for transmission or subtransmission upgrades will need to be conducted as expeditiously as possible. The Parties agree to use their best efforts to facilitate an appropriate, efficient, and time-sensitive review process.

d. TDI-NE agrees that it will be obligated to pay for all transmission system and subtransmission system upgrades that are necessitated due to the Project, (i) as determined by ISO-NE pursuant to the interconnection process administered by ISO-NE; and (ii) those additional subtransmission upgrades as determined by Vermont Utilities and TDI-NE and approved by the Board. To the extent that Vermont Utilities and TDI-NE disagree that the subtransmission upgrades are necessary as a result of the NECPL, the Vermont utilities and TDI-NE will bring the dispute to the PSB. The Parties recognize that these upgrades may be different than the preliminary list provided by TDI-NE to the Department, and may require further review of the NECPL under PSB rules regarding amendments to a section 248 Petition if the upgrades materially change any finding or conclusion reached by the Board. TDI-NE cannot commercially operate the Project until the subtransmission mitigation measures are in service.

5. Environmental. TDI-NE and the Agency acknowledge that the review process for each of the underlying Agency permits is ongoing. However, based upon the currently available information in the Petition and in the Agency permit applications, the Agency agrees that the NECPL will not have an undue adverse effect under section 248(b)(5), subject to the following:

   a. TDI-NE shall submit all Agency permits that have not been issued at the time the Board issues a CPG as post-CPG compliance filings prior to commencement of construction. Submission of such permits shall be for notice purposes only and shall not give rise to further review or proceedings by the Board provided that such permit or permits do not require any material or substantial changes to the Project that have not yet undergone Board review.

b. TDI-NE agrees to the Project changes and CPG conditions specified in Attachment II.

6. Historic and Archaeological Resources. DHP has been involved with TDI-NE's consultation and outreach efforts beginning with the initial inter-agency scoping meeting in December 2013. DHP has reviewed the following documents from TDI-NE's Consultants: Phase I Archaeological Assessment in Support of the New England Clean Power Link Project-Lake Portion (November 2014); Phase IA Archaeological Reconnaissance Survey New England Clean Power Link Project-Overland Portion (November 2014); and Historic Architectural Reconnaissance Survey, New England Clean Power Link Project – Overland Portion, Grand Isle, Rutland-Windsor Counties, Vermont (November 2014). These documents and the prefiled direct testimony of Scott Dillon, James Duggan, Kristen Heitert, Stephen Olausen, and Christopher Sabick, provide baseline documentation of historic site concerns within the Project corridor. TDI-NE and DHP agree that provided that if all of the conditions in Attachment III regarding historic resources are met, the Project will not have an undue adverse effect on historic or archeological sites.

7. Proposed CPG Conditions

The Parties agree that the section 248 CPG should be conditioned as follows:

a. Submission of final design plans for review/approval prior to construction.

b. Compliance with all material representations made in the testimony and exhibits submitted to the PSB.

c. Submission, for notice purposes only, of all other applicable state and federal permits that are required for construction of the Project. If any other permit reflects material changes to the Project as submitted prior to issuance of the CPG, such permit(s) shall be subject to Board review after comment by the Parties.

d. If the final SIS and I.3.9 approval were not reviewed by the Board and the Department prior to issuance of the CPG, TDI-NE shall submit the final SIS and I.3.9 approval to the Board and Department for review prior to commencement of construction. TDI-NE shall be responsible for the costs of the transmission system and subtransmission system upgrades in Vermont that are necessary in order to address adverse impacts to system stability and reliability due to the Project, as determined by ISO-NE pursuant to the interconnection process administered by ISO-NE.

e. Construction schedule. Construction hours will be from 7:00 A.M. to 7:00 P.M. Monday through Friday and from 8:00 A.M. to 6:00 P.M. Saturdays. All construction activities and related deliveries shall cease on Sundays and state and federal holidays. TDI-NE may extend its construction hours as follows: (i) 24 hours per day seven days per week on the Lake during the construction window as identified in Attachment II (ANR Conditions); (ii) extenuating circumstances, beyond TDI-NE's reasonable control, that necessitate after-hours work to protect public safety, worker safety, and/or the convenience of the travelling public; (iii) certain horizontal directional drilling ("HDD") operations that may require extended hours in order to complete the operation; (iv) other extensions to the schedule for good cause, provided the Board approves them in advance.

f. Noise limits. Consistent with recent Board precedent, sound levels due to operation of the converter station will be measured at the exterior of the nearest surrounding residence and shall not exceed 45 dBA Leq(1-hour) (day or night). Prior to operation of the Project, TDI-NE shall submit for Board approval, after review and comment by the Department, a noise monitoring plan to confirm the Project complies with the noise limits. The plan shall be prepared and implemented under the direction of a qualified noise control engineer. If noise levels exceed 45 dBA Leq (1-hour)(day or night), TDI-NE shall install mitigation measures to ensure compliance with the limit.

g. Blasting Plan. Prior to commencement of construction of the Project, TDI-NE shall submit its final blasting plan for review and approval by the Board after comment of the parties. Any subsequent material changes to the plan will require further Board review and approval.

h. Decommissioning. Prior to the commencement of construction, TDI-NE shall file for Board review and approval a decommissioning plan that provides for the off-site removal of the converter station building and all structural steel components and the restoration of the converter station site to a stabilized condition allowing for natural revegetation. TDI-NE shall also provide a cost estimate for the decommissioning activities as part of the plan. For the duration of the project, TDI-NE agrees to file each contract with the Public Service Board for the use of the transmission line within 30 days of execution (redacted or under seal as necessary to protect confidential business information) as evidence that the facility is in use, and therefore that a decommissioning fund is not required. TDI-NE agrees to regularly monitor the contracts for use of the transmission line. If at any time TDI-NE's review of those contracts reveals that within two years, contracts for use of the transmission line will fall below 50% of total line capacity, TDI-NE will notify the Board and parties and the Board will initiate a proceeding to investigate the appropriateness of establishing a decommissioning fund. Should the Board determine that a decommissioning fund should be established, the decommissioning plan and cost figures shall be updated and TDI-NE shall be obligated to fully fund the decommissioning fund, either through a letter of credit or other financial mechanism acceptable to the Board, on a schedule established by the Board during that proceeding. Failure to use the converter station, other than during planned or unplanned outages or repairs, for a period of eighteen consecutive months, shall trigger Board review of whether the converter station should be decommissioned.

i. Other special conditions concerning specific environmental or historic resources.

j. This Stipulation, including all Attachments, shall be enforceable under the CPG.

k. All host town agreements entered into by TDI-NE shall be enforceable under the CPG.

l. Prior to operation of the Project, TDI-NE will become a member of Dig Safe System, Inc. and for the life of the project shall comply with the requirements of 30 V.S.A. Chapter 86 and PSB Rule 3.800.

m. Prior to operation of the project, TDI-NE will file an underground damage prevention plan with the Department.

n. Six months prior to the termination of the initial supply contracts for the Project, TDI-NE shall negotiate in good faith with the Vermont electric distribution utilities for up to 200 MW of transmission service on the NECPL for a term of up to 20 years. The price of such transmission service shall be determined at that time and shall be generally consistent with market prices; however, the price offered to Vermont utilities shall not exceed the price of transmission service for a contract of similar size and scope executed in the prior three years.

o. Confirmation of Renewable Energy. Prior to commencement of construction, TDI-NE shall file all contracts with energy suppliers who will utilize the NECPL. The purpose of the filing shall be solely to confirm TDI-NE's representations in the

Petition that energy to be shipped on the NECPL will be from hydro, wind, or other "renewable energy" sources, as defined under Vermont law. TDI-NE may submit redacted versions of such contracts to protect pricing and other business confidential and trade secret information.

p. <u>Aesthetics conditions:</u>

i. TDI-NE shall minimize tree removal along the entire route to the greatest extent practicable.

ii. TDI-NE shall take reasonable precautions during construction to limit impact to nearby trees and shrubs on private property. If trees or shrubs on private property are damaged due to construction, TDI-NE shall be responsible for replacements for a three year period after construction.

iii. At Shunpike Road, Shrewsbury, Vermont TDI-NE shall coordinate the tree planting plan with the property owner immediately adjacent to the Project, to the extent they agree to become involved, as well as with the local planning commission and/or conservation commission. If neither the landowner nor the local planning commission and or conservation commission elect to become involved in the tree planting plan for this location, TDI-NE will confer with the aesthetics consultant for the PSD to reach agreement on an appropriate aesthetic landscape mitigation plan for this location

iv. The converter station building shall be dark brown or dark gray in color. Other ancillary structures at the converter station site that are fabricated from galvanized steel (similar to the equipment and structures at the Coolidge Substation) are not required to be painted.

v. TDI-NE will conduct a post-construction site visit, in conjunction with the Department, to determine if additional mitigation in the form of vegetative screening is necessary at the converter station.

q. No later than January 1st of the 37th year of commercial operation of the Project, TDI-NE shall enter into discussions with ANR and the DPS, and shall negotiate in good faith, regarding continued payment of public good benefits and/or other amendments to the Stipulation (dated July 17, 2015) in the event commercial operation of the Project extends beyond the 40th year. No later than January 1 of the 39th year of commercial operation of the Project, TDI-NE shall file with the Board for review and approval a plan regarding the extension of benefit fund payments beyond the 40^{th} year of commercial operations. In the event this plan does not reflect an agreement reached with ANR and DPS, TDI-NE shall provide an explanation of the efforts it made to engage in good faith negotiations, and the Board shall open a docket and establish a schedule to determine: (i) whether continued public good benefits are appropriate; and (ii) a plan for the continued payment of public good benefits if determined appropriate. TDI-NE, ANR and DPS shall automatically be parties to the docket. TDI-NE shall be authorized to continue to operate the Project beyond the 40^{th} year during and after the proceedings concerning the public good benefits, provided that if payment of public good benefits ultimately are approved by the Board they shall be applied retroactively beginning in the 41^{st} year of operation of the Project.

8. <u>Other Provisions</u>

a. The Parties agree that the Board should accept into evidence the prefiled direct and supplemental testimony and exhibits of the Parties. The Parties so move.

b. The Parties agree that any action, whether formal or informal, that each may elect to take before any other federal, state, or municipal regulatory entity concerning the Project shall be consistent with this Stipulation.

c. The Parties acknowledge that this Stipulation does not concern regulatory decisions on any applications filed by TDI-NE for environmental permit programs administered by ANR or any of its departments.

d. This Stipulation represents the entire Stipulation between the Parties with respect to the Project. It may be modified only upon mutual written Stipulation by the Parties and is subject to any necessary Board approvals.

e. Other than as may be specifically provided herein, this Stipulation shall not constitute an admission of any fact or law by any Party concerning the Project or any impacts related to the Project. This Stipulation shall not be construed as having precedential impact in any future section 248 proceeding concerning the Project, except as necessary to implement this Stipulation or to enforce an order of the Board resulting from this Stipulation.

f. This Stipulation should not be construed by any party or tribunal as having precedential or any other impact on any other proceeding involving a different project, different subject matter, or other parties. With respect to such proceedings, the Parties reserve the right to advocate positions that differ from those set forth in this Stipulation.

g. This Stipulation pertains only to the Project as it is presently proposed at the time the Agreement is executed. Prior to CPG approval, if TDI-NE makes any changes to the Project that could materially impact any of the agreements contained in this Stipulation, the Parties shall negotiate in good faith to amend the Stipulation as necessary. The Parties acknowledge that should they fail to reach agreement to amend the Stipulation, any Party may present its position to the Board concerning such Project changes, provided such Party otherwise act in conformance with this Stipulation consistent with its statutory duties.

h. In the event of any disagreement over the interpretation of this Stipulation or the implementation of any provision of this Stipulation that cannot be resolved informally amongst the Parties, the disagreement shall be resolved in the following manner:

   i. The Parties shall meet and make a good faith effort to resolve any dispute. The Parties shall consider the use of alternative dispute resolution to resolve any dispute.

   ii. If the dispute cannot be resolved by the Parties, any Party can petition the Board for the resolution of the matter.

i. TDI-NE agrees to submit a section 231 Petition to the Board within 30 days of receiving section 248 approval of the Project.

j. This Stipulation is expressly conditioned upon the Board's acceptance of all of its provisions, without material change or condition. If the Board does not accept the Stipulation in all material respects, the Stipulation shall, at the option of any party, be deemed to be null and void and without effect, and shall not constitute any part of the record in this proceeding and shall not be used for any other purpose. In the event the Board makes such material modification or change and as a result a party exercises its option to void the Stipulation, each Party shall be placed in the position that it enjoyed in this proceeding before entering into the Stipulation. Exercise of the option to terminate this Stipulation shall be by written notice delivered to the Board and the Department no later than ten days after issuance of a Board Order triggering the option.

k. Any disputes arising under this Stipulation shall be resolved by the Board under Vermont Law.

l. Each of the state agency parties to this Stipulation will support issuance of a CPG by the Board, and will not take actions during the section 248 proceeding to oppose the Project or otherwise undermine this Stipulation, subject to each such Party's obligations under any applicable state law including without limitation the Department's obligations under Title 30 of the Vermont Statutes Annotated.

m. This CPG shall not be transferred without prior notice to all docket parties and approval of the Board.

[Remainder of Page Intentionally Left Blank; Signature Pages to Follow]

DATED this 17th day of July, 2015

By: ______________________________
Andrew N. Raubvogel
DUNKIEL SAUNDERS ELLIOTT RAUBVOGEL & HAND, PLLC
Attorneys for TDI New England

By: ______________________________
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Vermont Public Service Department
Special Counsel

By: ______________________________
Donald Einhorn
Vermont Agency of Natural Resources
Legal Counsel

By: ______________________________
Dale Azarai
Vermont Division for Historic Preservation
Legal Counsel

Green Mountain Power
FY 2017 Rate Changes
July 27, 2016 Proposal
$ in 000's

		Rate Increase
JUN 1 Filing.		3.53%
GMP Proposed Update Adjustments		
1)	Accelerated Transco Investment	
	Change in Equity-in-Earnings	-0.33%
	Pre-tax Return on higher 13 month avg investment	0.19%
	Higher Cost of Capital due to 13 month avg equity balance	0.10%
	Higher Transmission by Others Expense	0.31%
2)	Higher Starting Revenue due to updated Itron Forecast	-0.79%
3)	Net Power Changes	0.52%
4)	Change in Jv Solar Abandoned Cost Reg Amort (concession in DPS Set 4)	0.00%
	Ancillary Impacts	-0.01%
JUL 1 Update Filing.		3.51%
Adjustments		
1)	Plant Adjustments (rate impact includes return and depreciation) .	-0.47%
2)	Change due to Plant in Service Dates	-0.05%
3)	New LTD Interest Rate Lowered from 4.75% vs 4.5%	-0.03%
4)	Joint Owned O&M	-0.16%
5)	Lowered Cap Structure from JUL Filing	-0.22%
6)	Removal of Rate Redesign	-0.03%
7)	Exogenous Storm	-0.11%
8)	ESAM Removal	-0.14%
9)	Synergies Increased from $15.0M to $16.335	-0.24%
10)	Removal of $1.5M accelerated FY 2016 Synergies	0.28%
11)	Property Taxes (reflect just removal of ENEL Dams)	-0.04%
12)	Wholly-Owned O&M Reduced by digesters and ENEL	-0.13%
13)	Lead-Lag Study, accept synergy and modified return adj	-0.13%
14.)	Power Supply Changes	-0.17%
15.)	CVPS - CIS Credit	-0.02%
16.)	Reduction in Nuclear Fuel Balance in Rate Base	-0.02%
17.)	Enhanced Vegetation Management	-0.02%
	Total Changes	-1.69%
Other Changes		
Change in Allowed ROE from 9.44% to 9.02%		-0.87%
	Ancillary Impacts	-0.03%
Current Filing.		0.93%

GMP 2017 Base Rates Filing

Minimum Plant Adjustments per attached sheet. Should consider adding some slippage to plant in service dates as evidenced by past performance discussed IN 2016 Larkin Report and "Variance Analysis of Plant Additions" filed with lead schedules in this filing. Would be willing to make a generic adjustment for slippage as has been done in the past.

> Outcome – Specific Adjustments made per Project Spreadsheet. Significant items removed include Hydro – New Dams ($23 million) and Production – Digesters (collectively, $11.4 million). GMP may take a regulatory asset for return on Vt Dams once placed in service. Additional $300,000 for generic adjustment due to slippage.

The CWIP for 2016 is said to have been fully closed as of 9/16 therefore it does not belong in FY2017 13 month average balance. Also still have concern regarding the title of this file as it suggests it is for removal of danger trees. Adjust out $6,091,942.

> Outcome – Further conversation revealed that concern was based on a date errors in file. Also, further conversation revealed that no danger trees in CWIP balance. No change made.

GMP 5-3 says the posting of the dividend does not impact capital structure. I disagree because by moving the dividend to the month declared reduces retained earnings in that month and that impacts the 13 month average calculation. Not material but it does.

> Outcome – Disagreement between Larkin and Company on accounting for this. Amount not material. No change made.

GMP 5-4 says the rate used for debt "appeared reasonable at the time of the filing". The wording suggests now they may not. I believe rates are high. Also not sure what in 5-4 attachment indicates the rates they are using are appropriate.

> Outcome – LT Debt rate reduced from 4.75% to 4.5%.

Response to GMP 5-5 says that the $7.3 million for Joint Owners cost in O&M is reasonable based on 5 year average of $7 million. The COS Adjustment 3 shows Joint Owner Costs excluding taxes and insurance is $7.9 million. The $7.3 may exclude Highgate, but the averages include Highgate. An adjustment of at least $900,000 should be made to get the 5 year average.

> Outcome – Recommended Adjustment made.

Response to GMP 5-7 only explains what I know. It still does not explain the existence of $6.462 million deferred debit in rate base labeled Net Plant Removal.

> Outcome – Error in original explanation, subsequently explained by GMP to Larkin's satisfaction. Recommendation withdrawn.

Capital structure should be at minimum 50/50. See Company response to GMP 5-12. Additionally, equity should not include the net investment in non-utility operations.

> Outcome – Equity ratio reduced from 50.8% to 50.3%.

Rate design costs are platform costs and should be excluded (especially legal fees). Not aware of any provision in merger that allows for regulatory costs to be accounted for outside of platform.

> Outcome – Rate design costs moved inside platform and amortized over 2 years.

Veg Mgmt and storm costs to be appropriately reflected in Base Rates and ESAM.

Outcome – $1.2 million carried forward as a platform amount to be applied to incremental trimming beyond 7-year requirement in '17. Further agreement to discuss and agree on plan for incremental trimming of approx. $1.2-3 million total to be applied to incremental cycle trim or enhanced danger trim through FY 18. Incremental amounts beyond first $1.2 million to be a non-platform expense. GMP to trim minimum 1/7 total system miles by end of CY 16 (resource dependent – will carry over spend if not able to hit by end of FY16) and going forward, in manner consistent with 2015 growth study.

$600k reduction to carried over Exogenous amount of $3.7 million.

ESAM: remove ESAM amount of $761,962.

Outcome – Recommended adjustment made.

Merger Savings line is $15 million with change over to 50/50 sharing this should be increased to 50% of $32.67 million (i.e. 1.335 million) platform adjustment on line 7 of COS adjs.

Outcome – Recommended adjustment made. Essentially offsets concern re: advanced $1.5 million merger savings below. Combined effect of the two adjustments is to more accurately project merger savings and maintain merger savings schedule reflected in Merger Order.

Lead Lag.

The Company has not calculated a lead for income taxes and while I agree that one would not apply if the Company filed its own tax return and paid no taxes that exception does not apply since GMP is part of the parent return. My understanding is that stand alone returns are prepared and the parent files a return and the individual companies make payments to the parent for their share of taxes. This line should be adjusted to reflect the lead associated with income taxes unless the Company provides evidence that the facts stated are inaccurate.

Also have a concern with synergy adjustment on study since the rates are based on the collection of the platform and if any synergy is reflected it would only be the synergy used to adjust the cost of service. The synergy dollars are in the revenue that is in the lag so the costs must remain also.

There should be a lead on the return also as well as dividends.

Outcome – Lead/lag adjusted to reflect synergies and dividends. Income taxes not reflected.

Property Taxes were increased based on a 6% average of 2 years of increases. This is to limited an averaging period and recommend using the 3% in for 2016 over 2015 based on GMP 4-23.

Outcome – Further evidence provided to satisfaction of Larkin on this issue. Only change made to reflect removal of New Hydro from plant.

Wholly owned O&M associated with adjusted plant additions (e.g., digester and hydro) needs to come out per 4-26.

Outcome – Recommended Adjustment made.

Concern regarding advanced $1.5 million merger savings in this rate year.

Outcome – Recommended adjustment made. Essentially offsets concern re: merger savings above. Combined effect of the two adjustments is to more accurately project merger savings and maintain merger savings schedule reflected in Merger Order.

Solar NM installed capacity forecast should be reduced by 7.36 MW, allocated as shown below. For NM 1.0, this is to match attrition cap used in docket 8652. For NM 2.0 reflects elimination of Cat V from current NM rule and general uncertainty about development.

Project Size	MW Reduction	Share of Reduction
REDUCTION IN NM 1.0 CAPACITY		
<=15	0.18	2%
>15<=150	0.77	10%
>150<=500	5.32	72%
REDUCTION IN NM 2.0 CAPACITY		
<=15	0.01	0%
>15<=150	0.11	1%
>150<=500	0.97	53%

Outcome – Recommended Adjustments made.

Unit cost of monetary credits issued to NM 2.0 customers in exchange for RECs should be reduced from 6 cents per kWh to 3 cents per kWh.

Outcome – Adjustment made to REC calculation per further discussions between GMP and DPS. Approx. $100k reduction.

Reduce total NM Costs by the equivalent monetary value of 10% of FY16 excess production from group systems and 75% of FY16 production from individual systems. See 3-50. Some adjustment for expiring credits should be made.

Outcome – Adjustment for expiring credits of $150k made.

Remove the $2.3+ million ANI adjustment. GMP has been over-collecting, not under-collecting balancing costs. And use of more granular data is not appropriate in this context as it could reflect anomalous results. So adjustment is not appropriate.

Outcome – DPS revises proposed adjustment after further discussion with GMP. Result is an agreed upon adjustment of approx. $200k to ANI adjustment for a result of approx. $2.1 million.

JV Solar and Innovative Services – neither accepting nor challenging here (other than plant adjustments). Expressly reserving rights in future cases (e.g., tariffs for innovative services). (Except for kiosk, that is out per 5-19)

Outcome – Kiosk removed. Reservation of rights not necessary but acknowledged by GMP.

Green Mountain Power
FY 2017 Alt Reg Project listing

Construction Summary w/End Date	Start Date	In-Service Date	Additions	Retirements	Balance at 5/31/16	Comment	Comment	GMP Response
Communications								
Install								
148528: Elster Outage Enhance	16-Apr	Sep 2017	990,354		-		Not started on time move In-service	Amount removed from the case
			990,354					
Computer Hardware								
Install								
143202: Upgrade Wireless Controllers	16-Apr	Jul 2017	45,985		-		Not started on time move In-service	Moved to September 2016
143212: Replace Rutland Internet Routers	16-Apr	May 2016	14,189		-	Updated inservice date to August 2016 to coincide with the completion of the data center		Moved to August 2016
143263: Misc. IT Blanket 2016	15-Oct	Sep 2016	176,755		52,260		**IT includes small projects in budget; blankets n**	Amount removed from the case
148494: 2017 IT Blanket	16-Oct	Sep 2017	358,882		-		**IT includes small projects in budget blankets nc**	Amount removed from the case
			595,811					
Computer Software								
Install								
143208: Zeacom Upgrade	16-May	Jul 2016	56,519		-		Start delay move in service	Moved to September 2016
143691: Crossbow	16-May	Jun 2016	127,562		-	In Service date will be moved to July due to minor delays.		Moved to September 2016
148525: UI Enhancement - Rolling Capital Forecast	16-Apr	Sep 2016	191,546		-		Start delay move in service	No Change, in service date will be hit
			375,627					
Distribution Lines Large Cap								
Install								
Distribution Lines - Danger Tree Removal		Oct 2016	291,667				**Remove**	Amount removed from the case
Distribution Lines - Danger Tree Removal		Nov 2016	291,667				**Remove**	Amount removed from the case
Distribution Lines - Danger Tree Removal		Dec 2016	291,667				**Remove**	Amount removed from the case
Distribution Lines - Danger Tree Removal		Jan 2017	291,667				**Remove**	Amount removed from the case
Distribution Lines - Danger Tree Removal		Feb 2017	291,667				**Remove**	Amount removed from the case
Distribution Lines - Danger Tree Removal		Mar 2017	291,667				**Remove**	Amount removed from the case
Distribution Lines - Danger Tree Removal		Apr 2017	291,667				**Remove**	Amount removed from the case
Distribution Lines - Danger Tree Removal		May 2017	291,663				**Remove**	Amount removed from the case
Distribution Lines - Danger Tree Removal		Jun 2017	291,667				**Remove**	Amount removed from the case
Distribution Lines - Danger Tree Removal		Jul 2017	291,667				**Remove**	Amount removed from the case
Distribution Lines - Danger Tree Removal		Aug 2017	291,667				**Remove**	Amount removed from the case
Distribution Lines - Danger Tree Removal		Sep 2017	291,667				**Remove**	Amount removed from the case
Sub-Total Install			**3,500,000**	-				
Distribution Substation								
Install								
143292: Graniteville Substation Rebuild	16-Jan	Jan 2017	1,752,326	104,929	87,403		**No invoices deduct $278,699**	$278,699 removed from ask amount, need to look at.
143308: 15/28MVA 69/46-12.47kV Spare Transformer	15-Oct	Apr 2016	450,552		415,674	Closed	**Adjust to closed amount**	Amount adjusted
Sub-Total Install			**2,202,878**	**104,929**				
General Plant								
Install								
149612 - CMC 356 Test Set.107: CMC 356 Test Set	16-Feb	Jan 2017	108,998		-		No cost; delayed move date	No Change, items have been ordered
146701 Meter Test Boards: 146701 Meter Test Boards	16-Jan	Dec 2016	136,964		-		No cost; delayed move date	No Change, items have been ordered
Sub-Total Install			**245,962**	-				
Hydro - New Hydro Dams								
Install								
Generation Purchase	16-Mar	May 2017	23,009,217		-		**Remove: Cost is estimate & need CPG**	Removed
Sub-Total Install			**23,009,217**	-				
Jt Ownership								
Install								
Kingdom Community Wind								
Install								
Meters								
Install								
Production								
Install								
Generation Upgrades		Sep 2016	281,290	18,987	187,500			
2017 150kW eFarm 1	16-Aug	Sep 2017	2,024,252		-		**No cost, need approval Remove**	Amount removed from the case
143344: eFarm - St. Albans	15-Sep	Mar 2017	9,481,896		1,016,283		**Question inservice w/ pending hearings**	Amount removed from the case
143362: Glen Penstock & Trashracks	15-Oct	Dec 2016	4,053,031	100,000	113,273		Running behind move in service	In service date moved to 3/2017
143374: Salisbury Penstock Replacement at Bridge	15-Sep	Sep 2016	592,695	10,000	44,550		Running behid move in service	Moved to December 2016
145353: Milton Solar	15-Oct	May 2016	135,866		150,841	Will close in May delayed by accounting to create depreciation group.		No Change, project is complete
148890: Panton Grid Scale Energy Storage	16-May	Jan 2017	3,028,069		3,918		Below planned cost - Move in service	Moved to March 2017
Sub-Total Install			**19,597,099**	**128,987**				
Property & Structures								
Install								
143539: Purchase Land for Burl Sub	15-May	Sep 2017	543,866		70,247		**Remove until sale is final**	Amount removed from the case
143540: Purchase Land Hinesburg		Sep 2017	98,843		-		**Remove until sale is final**	Amount removed from the case
143576: Colchester Data Center	15-Oct	Sep 2016	1,405,326		29,521		Move In Service	No Change, project is underway and on target
148806: Purchase Land in West Rutland	16-Oct	Jul 2017	98,843		-		**Remove until sale is final**	Amount removed from the case
Sub-Total Install			**2,146,879**	-				
Regulators and Capacitors								
Install								
Solar								
Install								

Construction Summary w/End Date	Start Date	In-Service Date	Additions	Retirements	Balance at 5/31/16	Comment	Comment	GMP Response	
143677: DERM 51 CIRCUIT	15-Apr	Sep 2016	1,552,654		897,706		**If final close @ $897,706 or move in service**	Dollars the same, in service moved to 2/2017	
37.2017EVGO.107: 2017 EVGO	16-Mar	Sep 2017	412,205				Delayed start- Move In Service	Amount removed from the case	
37.2017HEATPUMP.107: 2017 HEAT PUMPS	16-Apr	Sep 2016	895,252				No cost to date - Move In Service	No change	
37.2017HEATPUMP.107: 2017 HEAT PUMPS	16-Apr	Dec 2016	1,398,831				No cost to date - Move In Service	Amount updated - in service date remains	257,385
37.2017HEATPUMP.107: 2017 HEAT PUMPS	16-Apr	Mar 2017	1,398,831				No cost to date - Move In Service	Amount updated - in service date remains	813,187
37.2017HEATPUMP.107: 2017 HEAT PUMPS	16-Apr	Jun 2017	1,398,831				No cost to date - Move In Service	Amount updated - in service date remains	2,081,461
37.2017HEATPUMP.107: 2017 HEAT PUMPS	16-Apr	Sep 2017	1,398,831				No cost to date - Move In Service	Amount updated - in service date remains	2,443,291
37.2017TESLA.107: 2017 TESLA	16-Apr	Sep 2016	726,049				No cost to date - Move In Service	No change	
37.2017TESLA.107: 2017 TESLA	16-Apr	Dec 2016	453,781				No cost to date - Move In Service	Amount updated - in service date remains	475,966
37.2017TESLA.107: 2017 TESLA	16-Apr	Mar 2017	453,781				No cost to date - Move In Service	Amount updated - in service date remains	201,680
37.2017TESLA.107: 2017 TESLA	16-Apr	Jun 2017	453,781				No cost to date - Move In Service	Amount updated - in service date remains	532,436
37.2017TESLA.107: 2017 TESLA	16-Apr	Sep 2017	453,781				No cost to date - Move In Service	Amount updated - in service date remains	605,041
Sub-Total Install			**10,996,608**	**-**					
Transformers									
Install									
			-						
Transmission Lines			-						
Install			-						
Transmission Substations									
Install									
138423: HSCAT 3304 Putt	Jan-15	May 2016	131,296		78,381	Closed	**Change to actual spent**	Amount updated to Closed amount	
143299: Transmission Breaker Change out Digital 3330 & 3332 - INTERIM	Oct-15	May 2016	239,241	273,384	262,003	Closed	**Change to actual spent**	Amount updated to Closed amount	
143301: Transmission Breaker Change out Cavendish B-17 - INTERIM		May 2016	156,333	37,077	34,241	Closed	**Change to actual spent**	Amount updated to Closed amount	
143584: Line VT Replacements		Apr 2016	88,443	1,000	145,564	Closed	**Change to actual spent**	Amount updated to Closed amount	
Sub-Total Install			**615,314**	**311,461**	**520,189**				
Transportation									
Install									
143561: 2016 Pur Buckets and Diggers	15-Oct	Aug 2016	3,008,385	600,000	13,562		Based on existing stock consider excessive	No change based on replacement plan.	
148958: 2017 Bucket and Digger Trucks	16-Oct	Jul 2017	2,996,260	600,000	6,891		Based on existing stock consider excessive	No change based on replacement plan.	
Sub-Total Install			**6,004,645**	**1,200,000**					
Vermont Marble - Hydro									
Install									
148860: Huntington U3 & Intake Modernization	15-Apr	May 2017	6,280,259	220,000	495,998		Cost are a concern for timing	In service date moved to June 2017	
Sub-Total Install			**6,280,259**	**220,000**					
Vermont Marble - Transmission Lines									
Install									
147380: 2016 Marble Street to Danby Reconstruction	15-Oct	Sep 2016	1,438,642	250,000	-		No cost shown - Move In Service	No change, project costs were transferred to another project. This will be closed in August.	
Sub-Total Install			**1,438,642**	**250,000**					
Wind Generation									
Install									