STATE OF VERMONT
PUBLIC UTILITY COMMISSION

Petition of Green Mountain Power Corporation for approval of its new Multi-Year Regulation Plan pursuant to 30 V.S.A. Sections 209, 218, and 218d	)))	Case No. 21-____-PET

PREFILED DIRECT TESTIMONY OF MATTHEW MCDONNELL & RONALD NELSON ON BEHALF OF GREEN MOUNTAIN POWER

September 1, 2021

Summary of Testimony

Mr. McDonnell's and Mr. Nelson's testimony provides a policy design and structural review of GMP's proposed Regulation Plan, and proposes recommendations for improvements to the current Plan. The testimony begins by summarizing key components of the proposed Plan including revenue adjustment mechanisms, performance mechanisms, other regulatory mechanisms, and GMP's proposed changes. The testimony then turns to an overview of performance-based regulation and national trends from a selected group of leading jurisdictions. We then conduct a qualitative analysis of GMP's proposed Plan to identify potential structural gaps and certain opportunities for refinement within GMP's current Plan. While we note a few areas for possible improvement, we conclude the proposed Regulation Plan is a sound, comprehensively designed and balanced performance-based regulatory framework. We close our testimony by providing recommendations to enhance the proposed Plan.

Exhibit List

Exhibit GMP-MM-RN-1 **Resume of Matthew McDonnell**

Exhibit GMP-MM-RN-2 **Resume of Ron Nelson**

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I. Introduction

Q1. Please state your name, title, and position.

A1. **McDonnell**: My name is Matthew McDonnell. I am the Managing Director of US Consulting at Strategen Consulting located at 2150 Allston Way Suite 400, Berkeley, California 94704.

Nelson: My name is Ronald Nelson. I am a Director at Strategen Consulting located at 2150 Allston Way Suite 400, Berkeley, California 94704.

Q2. On whose behalf are you testifying?

A2. We are testifying on behalf of Green Mountain Power ("GMP").

Q3. Please describe your formal education and professional experience.

A3. **McDonnell:** Currently, I am the Managing Director of US Consulting at Strategen Consulting. The Strategen team is nationally recognized for its thought leadership and deep expertise in regulatory innovation, performance-based regulation, rate design, renewable program development, grid modernization, and new grid technologies including distributed and centralized renewable energy, energy storage, smart grid technologies, and electric vehicles. At Strategen, I have worked with regulators and stakeholder groups on a wide-array of issues related to the ongoing energy transition, including, but not limited to, performance-based regulation ("PBR"), distributed energy resource ("DER") integration, and virtual net-metering tariff design.

Before joining Strategen in 2020, I served as Commission Counsel at the Hawaii Public Utilities Commission ("HPUC"), a regulatory body that is a global leader in market design for the deployment of clean energy technologies. I supported the thought leadership, organization, and execution for critical projects ranging from advanced DER program design, to establishing a statewide community solar framework, to articulating guidance for innovative grid modernization that earned the Hawaiian Electric Companies SEPA's 2018 Utility of the Year.[1]

After departing the HPUC, I served as an Associate Director at Navigant (n/k/a Guidehouse). At Navigant, I authored a report for the Edison Electric Institute ("EEI") that provides in-depth analysis of alternative regulatory mechanisms available to regulators, with a section dedicated to examining regulatory sandbox best practices. I am licensed to practice law in Arizona and Hawaii. I earned a Juris Doctor from the James E. Rogers College of Law at the University of Arizona and a B.A. in Finance from Michigan State University. My resume is attached as **Exhibit GMP-MM-RN-1.**

Nelson: Currently, I am a Director at Strategen Consulting. During my time at Strategen, I have worked with numerous consumer advocate, non-governmental organizations, and commissions on issues related to cost-of-service modeling, rate design, grid modernization, distributed energy resource valuation and integration, and performance-based regulation.

[1] Hawaiian Electric, *Hawaiian Electric Companies named 2018 Investor-Owned Utilities of the Year by Smart Electric Power Alliance* (June 12, 2018), available at https://www.hawaiianelectric.com/hawaiian-electric-companies-named-2018-investor-owned-utilities-of-the-year-by-smart-electric-power-alliance.

Before joining Strategen in early 2018, I worked for the Minnesota Attorney General's Office for almost five years, where I led that office's work on cost of service, rate design, renewable energy program design, performance-based regulation, and utility business model issues. Before that, I worked for two universities and the United States Geological Survey as an economic researcher. I have a Master of Science from Colorado State University in Agriculture and Resource Economics, and a Bachelor of Arts in Environmental Economics from Western Washington University where I minored in Mathematics. My resume is attached as **Exhibit GMP-MM-RN-2.**

Q4. Please summarize your professional experience regarding performance-based regulation.

A4. **McDonnell:** As Commission Counsel at the Hawaii Public Utilities Commission ("HPUC"), I have led a wide array of energy policy efforts—navigating uncharted waters with Hawaii on the leading-edge of the energy transition in the United States. I led the HPUC's investigation into performance-based regulation as process architect, project manager, and subject matter expert. I designed a regulatory process approach that won broad support from local stakeholders as well as national acclaim.[2]

I served as the lead author on all HPUC orders and staff concept papers through Phase 1 of the proceeding. I outlined a staff proposal for an advanced performance-based regulation framework for the State of Hawaii that emphasized the need to create space for

[2] Utility Dive, *A utility regulatory process for the 21st century gets a test run in Hawaii* (Mar. 19, 2019), available at https://www.utilitydive.com/news/a-utility-regulatory-process-for-the-21st-century-gets-a-test-run-in-hawaii/550146/#:~:text=Deep%20Dive-,A%20utility%20regulatory%20process%20for%20the%2021st,a%20test%20run%20in%20Hawaii&text=A%20new%20effort%20to%20bring,for%20the%20state's%20regulated%20utilities.

innovation and included the creation of an innovative pilot structure modeled after the Vermont approach. The staff proposal was ultimately adopted by the HPUC and a final framework implemented in December 2020. After departing the HPUC, I spent time at Navigant (n/k/a Guidehouse) where, among other efforts pertaining to regulatory innovation, I authored a report for the Edison Electric Institute ("EEI") that provides in-depth analysis of alternative regulatory mechanisms available to regulators, with a section dedicated to examining performance-based regulatory frameworks.

Now at Strategen, I am building on past research and experience, working with a wide array of clients to advance regulatory frameworks and performance-based approaches. I am currently working with the Connecticut Public Utilities Regulatory Authority ("PURA") to create a regulatory sandbox pilot framework that consists of a legal and regulatory structure, process design to surface novel pilot ideas and facilitate utility partnerships, and cost recovery mechanisms to enable the effective deployment of innovative pilots.

In recognition of my experience and expertise, the National Association of Regulatory Utility Commissioners ("NARUC") has asked me to serve as a "PBR Expert" to educate and inform various state regulatory utility commissions on PBR frameworks and opportunities in regulatory innovation.

Nelson: I have extensive experience testifying and participating as a stakeholder in PBR-related proceedings as well as designing and implementing PBR-related mechanisms, such as revenue decoupling and performance incentive mechanisms ("PIMs"). While at the Minnesota Attorney General's Office, I testified on PBR in multiple proceedings, including Xcel Energy's first significant multi-year rate plan proceeding (Docket 15-826). In that docket, I recommended that a new proceeding be created to more comprehensively discuss Minnesota's PBR framework, performance metrics, and PIMs. The Minnesota Public Utilities Commission adopted this recommendation and opened Docket 17-401. In that docket, a colleague and I drafted a comprehensive, step-by-step PBR framework for the Minnesota Commission to implement. This same framework was used to inform Hawaii's Phase I proceeding structure which I consulted on for the HPUC.

While at Strategen, I have testified or participated in PBR-related proceedings, covering decoupling, multi-year rate plans ("MYRPs"), formula rates, performance metrics, and PIMs, among other topics, in New Hampshire, North Carolina, Massachusetts, Minnesota, Oklahoma, and Hawaii.

Q5. Have you previously testified before the Vermont Public Utility Commission?

A5. **McDonnell:** I have not previously testified before the Vermont Public Utility Commission, but as noted above I have been involved in numerous Commission proceedings in Hawaii as Commission Counsel.

Nelson: I have not testified before the Vermont Public Utility Commission. However, I have testified in over 20 proceedings in Minnesota, Pennsylvania, Oklahoma, Illinois, Utah, New Hampshire, and Ohio. The issues covered in these proceedings include marginal and embedded cost-of-service studies, revenue apportionment, rate design, renewable program design, fuel clause adjustments, formula rates, decoupling, performance-based regulation, multi-year rate plans, performance metrics, DER interconnection, DER compensation, DER integration, and smart inverter specifications.

I have also assisted with testimonies and regulatory analysis in Hawaii Washington D.C., Maryland, Minnesota, Massachusetts, California, North Carolina, and the Federal Energy Regulatory Commission. The issues covered in these proceedings include electric vehicle rate design and infrastructure, wholesale market tariff design, cost-benefit analysis, community-based solar programs, rate design, cost and rate unbundling, integrated resource planning, energy storage integration, and DER interconnection.

Q6. What is the purpose of your testimony?

A6. GMP has asked us to provide a policy design and structural review of their proposed Multi-Year Regulation Plan (“Regulation Plan” or “Plan”). Specifically, GMP requested that we identify any opportunities for improvement within GMP’s proposed Plan, and make recommendations for addressing any gaps. Beyond this high-level guidance, we independently determined our analytical approach, the states that we selected for comparison, and areas we identified for improvement within the Regulation Plan.

To conduct our evaluation, we took a high-level analytical approach that compared GMP’s proposed PBR framework to best practices from PBR frameworks in other leading states. We selected a specific set of states for comparison based on those states having gone through recent, comprehensive performance-based regulatory proceedings. In Hawaii, the HPUC adopted a comprehensive, advanced PBR framework in December 2020.[3] In Massachusetts, the Department of Public Utilities approved a proposal from National Grid that reflected a material suite of performance-based regulatory mechanisms.[4] Xcel Energy in Minnesota operates under a multi-year rate plan and their Public Utilities Commission continues to investigate and develop a complimentary set of performance mechanisms, including metrics.[5] Rhode Island conducted a recent and thorough review of a proposed slate of performance incentive mechanisms.[6]

In addition to these states representing leading jurisdictions when it comes to performance-based regulation, we also possess deep, first-hand experience with both Hawaii's and Minnesota's PBR frameworks, having been involved directly in the proceedings that have led to their current respective structures.[7] To a lesser extent, we have also participated in Massachusetts PBR proceedings.

After investigating these modern PBR frameworks, we constructed an evaluative structure that contains the most critical, common mechanisms one finds in an advanced performance-based framework. We then assessed GMP's proposed Regulation Plan and

[3] *See* Hawaii Public Utilities Commission, *Decision and Order No. 37507* (Dec. 23, 2020). Docket No. 2018-0088. Available at https://puc.hawaii.gov/wp-content/uploads/2020/12/2018-0088.PBR_.Phase-2-DO.Final_.mk_.12-22-2020.E-FILED.pdf.

[4] *See* Massachusetts Department of Public Utilities, *Order* (Sep. 30, 2019). Docket No. 18-150. Available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/11262053.

[5] *See* Minnesota Public Utilities Commission, *Order Establishing Performance Metrics* (Sep. 18, 2019). Docket No. CI-17-401. Available at https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7b0082456D-0000-CA1F-9241-23A4FFF7C2FB%7d&documentTitle=20199-155917-01.

[6] *See* Rhode Island Public Utilities Commission, *Report and Order No. 23823* (May 5, 2020). Docket Nos. 4770 and 4780. Available at http://www.ripuc.ri.gov/eventsactions/docket/4770-4780-NGrid-Ord23823 (5-5-20).pdf.

[7] *See, e.g.*, Hawaii PUC Docket No. 2018-0088 and Minnesota PUC Docket Nos. 15-826 and 17-401.

conducted a gap analysis, highlighting elements aligned with best practices and identifying opportunities for refinement.

Q7. Provide a summary of your recommendations.

A7. Based on our review of GMP's proposed Regulatory Plan, we find it to be a comprehensively designed and balanced PBR framework that will benefit customers and has sufficient flexibility for GMP to foster further innovation and achieve its public policy goals. To further improve upon the GMP's Regulatory Plan and the regulatory framework, we make the following recommendations.

1. We recommend implementing additional alternative regulatory mechanisms to further equalize the treatment of capital expenditures ("CAPEX") and operating expenditures ("OPEX"). This includes changes to the regulatory treatment of service-based technology solutions which would allow for the capitalization of prepaid third-party contracts. This would bring greater parity to treatment of these costs compared to other capital-supported programs, and promote selection of the best, most cost-effective solutions for GMP's customers.
2. Consideration should be given to several improvements to the performance mechanisms over the course of this proceeding and before GMP's next Regulation Plan. We divide our performance mechanism recommendations into three stages:
    a. During this proceeding, we recommend that electrification-related metrics be expanded to include building electrification metrics and additional transportation electrification metrics.

b. Before the next Regulation Plan is filed, we recommend that the Commission consider a comprehensive evaluation of all innovation, performance, and reliability metrics with the purpose of streamlining and focusing all metrics into one report and explore opportunities for simple online publication of these metrics. Within the evaluation, we recommend that stakeholders focus on (i) restructuring performance mechanisms to follow hierarchal goals, outcomes, and metrics format; (ii) integrating traditional reliability and service quality metrics into the broader set of performance mechanism reporting; (iii) identifying and integrating equity-related metrics; (iv) continuing to push forward on grid service related metrics (i.e., advanced demand response and bidirectional load control metrics); and (v) investigate online publication of the adopted metrics, if determined to be cost-effective.

c. After the aforementioned evaluation, we recommend that the Commission consider elevating one or more grid service metrics to a scorecard or performance incentive mechanism.

II. <u>Overview of Green Mountain Power and the Multi-Year Regulation Plan</u>

Q8. Please briefly describe Green Mountain Power.

A8. Green Mountain Power serves approximately 270,000 residential and business customers in Vermont in an approximately 6,000-square mile service territory across Vermont. As of July 1, 2021, GMP has a total asset of approximately $2.6 billion and annual retail sales of $660 million. GMP has 16 offices across Vermont and just over 500 employees.

Today, GMP's annual energy supply is 100-percent carbon-free and the utility has committed to being 100-percent renewable by 2030.[8] We note that GMP is also a certified B Corporation which obligates GMP to consider the impact of decisions on their workers, customers, suppliers, community, and the environment.

Q9. What is the statute that enables GMP to file a multi-year regulation plan?

A9. 30 V.S.A.§ 218d describes the alternative regulation of electric and natural gas companies.

Q10. Based on your knowledge of other states' statutes that allow alternative forms of regulation, what are the most notable sections of 30 V.S.A. § 218d?

A10. The statute recognizes the importance of establishing a system of regulation that aligns the utility's financial risk profile with its customers' interests for a least cost system. The statute includes numerous requirements to ensure a new system of regulation achieves this goal. Of these requirements, there are several relevant subsections, which generally align with the goals of PBR we see in other states. Most notably, the statute states that the Commission shall find the alternative regulation plan, among other things, will:

- offer incentives for innovations and improved performance that advance state energy policy,
- encourage innovation in the provision of service,
- establish a balanced system of risks and rewards that encourages the utility to operate efficiently using sound management practices, and

[8] *See Investigation re: Renewable Energy Standard for program year 2020*, Case No. 21-1045-INV.

- allow for substantive changes to rate base-rate of return rate setting while still providing a reasonable opportunity for the utility to earn a fair rate of return.

Importantly, the statute also allows the Commission to amend the standards and procedures of the alternative forms of regulation as needed. This is an important condition as the Commission will mostly likely need to adapt its regulations as the utilities iteratively improve upon these plans. As noted below, we find that GMP's proposed Plan is well designed to meet these standards, and recommend areas for possible enhancement of the Plan to further these goals.

Q11. Please give us a high-level overview of GMP's proposed Multi-Year Regulation Plan.

A11. The proposed Multi-Year Regulation Plan's stated goals are to develop a smooth, stable rate path, support innovation for customers and create a more resilient grid that is better able to withstand the challenges of a changing climate. The proposed Regulation Plan looks substantively similar to the previous multi-year regulation plan approved in Vermont PUC Case No. 18-1633-PET. The base rate components can still be grouped into those that are fixed at the beginning of the Regulation Plan, those that are forecasted and adjusted annually, and those that are based upon an annual formula or calculation. The Plan continues to use a number of adjustors that will be described below.

Q12. When will the Regulation Plan take effect?

A12. The Plan will take effect on September 1, 2022, for rates effective October 1, 2022, and end on September 30, 2026, unless the Commission approves a one-year optional extension. The Plan may be terminated or modified upon request of GMP or the Vermont Department of Public Service ("DPS" or "Department") and subject to approval by the Commission.

Q13. How will annual base rates be established?

A13. GMP will file a traditional, cost-of-service rate case to set rates for fiscal year 2023 (October 1, 2022 – September 30, 2023) in January 2022. During that rate case, GMP will file its forecasted base rate changes for fiscal years ("FY") 2024–2026 to achieve the utility's goal of a projected, smoothed base rate for all four years of the Plan. For FY24–FY26 these annual forecasts will be updated in an Annual Base Rate Filing each year, consistent with the mechanisms in the Plan, in order to establish base rates for the coming fiscal year.

Q14. Please walk us through the structure of the Plan. What are the major components of base rates for the term of the Plan?

A14. The base rate components of the Plan are largely the same as the previous multi-year regulation plan. The proposed Plan categorizes the components into the four following groups:

1. Non-Power Costs, which are largely forecasted and fixed for the term of the Plan, subject only to certain exceptions. This grouping includes infrastructure costs, certain O&M costs, the cost of debt, earnings in affiliates, and other costs and revenues.

2. Power Supply Cost and Retail Revenue, which are forecasted and updated annually. This grouping includes retail revenue and power supply costs.
3. Income Taxes and Related Costs, including ADIT and gross revenue and fuel gross receipt taxes, which are forecasted and updated annually.
4. Financing Equity – The return on equity, which for FY23 is determined in the FY23 cost-of-service rate case, and then is updated annual in FY24-26 based on a formula previously approved by the Commission.

Q15. Please provide more detail on the first grouping, the Non-Power Costs.

A15. The Non-Power Costs are forecasted at the beginning of the Plan and are largely fixed for the duration of the Plan. The first major component is infrastructure costs. These are capital expenditures including depreciation expense, property taxes, and existing new initiative programs, which are forecasted and fixed, subject only to certain exceptions for unforeseen circumstances or strategic opportunities, which would require commission approval. In addition, for any tariff program for new initiatives that may be approved by the Commission during the term of the Plan, GMP proposes to book capital costs and returns and incremental operations and maintenance ("O&M") expenses and other operating revenue changes as a regulatory asset, but will not seek to recover through rates the cost-of-service impacts of these new capital projects until after the plant is in service and the Commission has specifically approved the project for base rates.

Q16. Please continue by describing the O&M cost component.

A16. O&M consist of a variety of costs that includes Other Power Supply, Transmission – Other, Distribution, Customer Accounting, Customer Service and Information, Sales and Administrative and General costs. Now that the Merger Savings Platform is expiring at the end of the current plan, all O&M costs will fall under the Plan. O&M costs will be categorized into three buckets and treated differently. First, O&M costs that GMP believes are more directly under their control will be fixed for the entirety of the Plan based on known and measurable costs. The second bucket are costs that will be updated annually using a formula based on inflation, such as customer service and administration. The third bucket are costs that GMP believes are largely outside of its control and will be re-forecasted and updated annually. These include pension, health care, and tree trimming. Under this proposed approach, approximately two-thirds of annual O&M costs will be either fixed or indexed under a formula to inflation. Approximately one-third of total O&M costs will be reforecast annually.

Q17. How does the Plan treat the cost of debt?

A17. GMP will forecast its anticipated debt costs at the beginning of the Plan for each fiscal year. The cost of debt will be based on forecasted long-term and credit facility borrowing balances, as well as changes in the average long-term debt interest rate. Although the cost of debt is initially fixed for the term of the Plan, it could change if the Commission approved any new expenditures during the Plan.

Q18. Please describe the Earnings in Affiliates component.

A18. All equity-in-earnings investments from affiliates will be forecasted and fixed for the term of the Plan, except for Vermont Transco LLC investments, which will be updated annually, so that customers receive the significant benefit of the investments from the time the investments are made.[9]

Q19. Please discuss the Unexpected Circumstances and Strategic Opportunities component.

A19. The Plan includes a placeholder for unexpected circumstances of as-yet-unknown strategic opportunities that will benefit customers. In these circumstances, the utility will bear the burden of demonstrating the proposed project is in the customers' best interest. If approved, the base rates would be adjusted the next quarter after approval by the Commission, or otherwise as ordered.

Q20. Finally, please discuss GMP's Cybersecurity Plan.

A20. The Plan indicates that GMP may file a Cybersecurity Plan during the term of the Plan that would include additional capital expenditures or O&M expenses. The Cybersecurity Plan would include a methodology for any proposed base rate adjustments; and shall be subject to Commission review.

[9] *See* Prefiled Direct Testimony of Edmund F. Ryan and Robert Bingel at 16–18.

Q21. Let's turn now to the second grouping, the Forecasted and Annually Updated Components, Power Supply Cost and Retail Revenue. Will you please explain each of these components?

A21. Like the fixed components, GMP will forecast each of these at the beginning of the Plan, but will also provide annual updates. The Retail Revenue Adjustor tracks actual retail revenue every quarter against the forecasted amount that was included in base rates.

The Power Supply Adjustor trues up actual power supply costs against forecasted costs, as adjusted by a Power Supply Efficiency Band, on a quarterly basis. GMP provides a more detailed description of the adjustor calculation in the Plan. However, it is worth pointing out that the Power Supply Adjustor uses an asymmetrical efficiency band weighted to the benefit of customers (+$150,000 retained by GMP and -$307,000 absorbed by GMP).

Q22. How does the Plan propose recovering the costs of these adjustors?

A22. The recovery of these two adjustors will use a methodology that also incorporates the Major Storm Adjustor, which is described later in our testimony. Each quarter, the variance[10] in the Retail Revenue, Power Supply, and Major Storm adjustors will be netted together to create a Quarterly Net Adjustment ("QNA"). If the QNA for the current quarter is in the opposite direction as the previous quarter QNA, then the two quarters will be netted against each other and carried forward into the future quarter as a regulatory asset or liability. If the QNA for the current quarter is the same direction as

[10] The variance is the difference between the actual amount and the forecasted amount for each quarter.

the previous quarter, and the prior quarter's amount is greater than +/- $1 million, then the total amount will be collected from or returned to customers over the subsequent 12 months, or as ordered by the Commission. If the prior quarter's amount was less than +/- $1 million, then the total amount is carried forward to the future quarter. The Plan will exclude the street lighting class from surcharge collections or returns associated with the Retail Revenue and Power Supply adjustors. The Plan foresees GMP using the Major Storm Restoration Fund, which is described later in our testimony, to mitigate rate impact volatility from these adjustors or other costs as approved by the Commission.

Q23. Please describe the third grouping, Income Taxes and Related Costs.

A23. GMP will annually forecast state and federal income taxes, ADIT, and gross revenue and fuel gross receipt taxes based on the authorized adjustments in overall income or power costs. GMP will update the forecast annually and include it in the Annual Base Rate Filing.

Q24. The fourth grouping has just one component, financing costs – cost of equity. Will you please describe this component?

A24. The Return on Equity ("ROE") will be updated annually based on a formula. GMP's ROE in 2024 will be indexed off the ROE approved during the 2023 rate case. The ROE in 2025 and 2026 will be indexed using the ROE of the previous year, using the same formula approved by the Commission for GMP's current Regulation Plan.

Q25. GMP states that one of the goals of the Plan is to develop a smooth rate path for customers. Will you please describe the proposed Rate Smoothing Mechanism?

A25. Yes. The Plan sets an Initial Rate Smoothing Mechanism ("IRSM") at the beginning of the Plan based on the 2023 rate case and the initial forecasted cost of service for 2024–2026. The IRSM will establish an amount that is either added to or subtracted from the revenue requirement for each year of the term of the Plan. Then GMP will set a uniform projected annual base rate change for four years of the Plan. GMP will create a regulatory asset or liability account at the beginning of the Plan to account for any adjustments to the forecasted costs or revenues in each fiscal year. The regulatory asset or liability will reverse over the term of the Plan to be zero at the end of the term. In years 2024, 2025, and 2026, the Plan gives GMP the opportunity to propose additional smoothing adjustments to base rates if it believes that it can minimize rate variation over the term of the Plan, subject to Commission approval.

Q26. The Plan also includes a number of rate adjustors, programs, and metrics. Let's go through these one by one. What is the Exogenous Change Adjustor?

A26. The Exogenous Change Adjustor has three parts to it: the non-storm exogenous events outside GMP's control (e.g., changes in federal tax law), Exogenous Major Storm events that occur during the term of the Plan, and a Major Storm Restoration Fund. For Exogenous Non-Storm Changes, GMP will consider cost or revenue changes material if the aggregate amount during a fiscal year exceeds $1.2 million.

Exogenous Major Storm changes are events that meet GMP's definition of a Major Storm, as defined in GMP's Service Quality and Reliability Performance, Monitoring & Reporting Plan, and incur costs in excess of $1.2 million. If GMP experiences one or more Major Storms in a year, it may recover those costs from customers minus a one-time annual $1.2 million deductible. GMP will file a report on each qualifying Major Storm in the quarter following receipt of invoices. The quarterly Major Storm Adjustor will use the same methodology as described for the Retail Revenue Adjustor and the Power Supply Adjustor described above.

The Major Storm Restoration Fund is a regulatory liability account for collecting funds from customers to off-set changes that may occur during the Plan from the Retail Revenue, Power Supply, and Major Storm Adjustors or other costs as approved by the Commission. The regulatory liability account will accrue interest on the balance based on GMP's credit facility interest rate.

Q27. What is the Earnings Sharing Adjustment Mechanism?

A27. The Earnings Sharing Adjustment Mechanism is a tool to share with customers the actual earnings above or below the approved rate of return annually. The mechanism first uses an efficiency band of 50 basis points above or below the Commission-approved ROE. If actual earnings are 50–125 basis points above or 50–150 basis points below the ROE, then 75% of the revenue benefit of the higher earnings is returned to, or 50% of the revenue impact of the lower earnings is collected from, customers. If actual earnings are more than 125 basis points above or more than 150 basis points below the ROE, all of the impact flows back to customers.

Q28. What is the Innovative Pilot Program?

A28. The Innovative Pilot Program is being carried over from the previous multi-year regulation plan, in substantially the same form, and is intended to advance the goals of Vermont's Comprehensive Energy Plan. Innovative Pilots and non-tariffed New Initiative programs developed during the term of the Plan will be included as plant additions during the term of the Plan, subject to GMP's proposed fixed capital amounts.

Q29. What does the Plan say about the measurement of Innovation and Performance Metrics?

A29. The Plan requires GMP to measure and annually report on more than 25 metrics pertaining to capital spending, power supply, distributed generation, storm costs, distributed energy resources, electric vehicles, and customer relations. The metrics are for tracking purposes only, and do not include penalties or incentives.

Q30. What does the Plan say about Low Income rate contributions?

A30. The Plan states that GMP's shareholders will match contributions made by the utility's customers to the Warmth Program. GMP will also contribute five percent of any excess earned utility net income above the allowed utility net incomes to its low-income customer support programs, after consulting with DPS.

Q31. Does the proposed Plan include an evaluation?

A31. GMP will provide a brief narrative evaluation of the effectiveness of the Plan's performance in achieving the goals of 30 V.S.A. § 218d at the time that it reports results on Innovation and Performance Metrics.

Q32. Did Green Mountain Power file an evaluation of its current Multi-Year Regulation Plan?

A32. Yes. GMP filed its "Analysis of Plan Performance" with the Commission on February 1, 2021.

Q33. Please provide a brief summary of GMP's Analysis of Plan Performance.

A33. GMP reports that the Plan generally operated as it was designed despite the unforeseen impact of COVID-19. GMP also reported that it found the Plan's structure to be effective and efficient and allowed GMP, the Department, and the Commission to adapt to the changing conditions. However, GMP noted some concern with its ROE formula during uncertain times, some unexpectedly high uncollectible receivables particularly related to the pandemic, and the challenge of incorporating new technology into regulatory policy. Later on in the testimony we will provide our analysis of GMP's Analysis of Plan Performance.

Q34. Do agree with GMP's assessment that the current regulation plan "generally operated as it was designed despite the unforeseen emergence of COVID-19"?

A34. Yes. It appears that the Plan provided much needed flexibility for adapting to an unpredictable global pandemic that had significant electricity usage and economic impacts. The Plan also provided stable rates for customers during an extremely uncertain economic period. For example, GMP reports that the Commission allowed it to revise the timing of the return and collector of adjustors to smooth out the impact to customers.

Rate stability during a period of economic uncertainty is one of the many benefits of a multi-year regulation plan and other associated mechanisms.

Q35. In your summary, you also noted that the Analysis of Plan Performance highlighted the challenge of incorporating new technology into regulatory policy. Will you please elaborate?

A35. Utilities are increasingly reliant on IT investment to operate the grid. As GMP points out, there is not only greater technological complexity to its operations but also to its cybersecurity needs. Utilities have two options: build and manage IT infrastructure or use cloud computing and software-as-a-service ("SaaS"), the latter of which is usually more efficient, flexible, secure, and cheaper. However, the traditional regulatory model incentivizes the utility to build capital projects and operate its own infrastructure. GMP's Analysis notes that the Commission should examine this regulatory policy as it exits it Merger Savings O&M Platform in 2023. We agree. We will discuss later in our testimony why operating expense and capital expense equalization is an important part of PBR.

III. Overview of Performance-Based Regulation

Q36. What is Performance-Based Regulation?

A36. PBR is an approach to regulation that combines a set of alternative regulatory mechanisms and processes with an aim to focus on the desired outcomes that matter to regulators, customers, and utilities. Stated simply, a PBR framework can provide clear incentives for the utility to manage costs without compromising service or reliability, while calibrating financial incentives with the public interest.

Q37. Why is PBR an increasingly important regulatory approach for the electric power industry?

A37. The electric power industry is in the midst of a significant transition from predominantly centralized fossil-fuel-based generation systems towards increasingly distributed and renewable generation systems. This transition includes the incorporation of large amounts of variable renewable generation resources, DER, including Demand Response or "DR" resources, and a considerable focus on enhancing customer choice. GMP has consistently demonstrated its support for this transition in Vermont and has been recognized nationally for its efforts.[11]

It is widely acknowledged that the factors driving this energy transition are of sufficient breath and magnitude that state regulatory frameworks must also continue to evolve to meet these new challenges, maintain safety and reliability, offer new opportunities to create value for customers, and result in affordable rates.

PBR enables regulators to enhance legacy regulatory structures to enable innovations within modern power systems. An old regulatory paradigm built to ensure safe and reliable electricity at reasonable prices from capital-intensive electricity monopolies is now adjusting to a new era of disruptive technological advances that

[11] Gold, Guccione, and Henchen, *Customer-Centric Energy System Transformation: A Case Study of the Opportunity with Green Mountain Power*. Rocky Mountain Institute (2017). Available at https://rmi.org/wp-content/uploads/2018/04/RMI_Green_Mountain_Power_Report.pdf. *See also*, De La Garza, *This Vermont Utility Is Revolutionizing Its Power Grid to Fight Climate Change. Will the Rest of the Country Follow Suit?* Time Magazine (July 26, 2021). Available at https://time.com/6082973/vermont-electric-grid/.

change the way utilities make money and what value customers expect from their own electricity company. PBR attempts to address some of the issues and disincentives inherent in traditional cost-of service regulation ("COSR") through a set of alternative regulatory mechanisms intended to focus utilities on performance and alignment with public policy goals, as opposed to growth in capital investments or other traditional determinants of utility earnings under COSR.

Q38. What are some core characteristics of a well-designed PBR framework?

A38. Well-designed PBR frameworks should result in a risk-sharing structure that encourages exemplary utility performance irrespective of the nature of its investments (e.g., investment in capital expenditures verses investment in efficiency measures). By encouraging specific outcomes and objectives, a PBR framework should provide a utility with the opportunity to earn a fair return in relation to its risk, based on a business model that is well aligned with the public interest. As demonstrated by experience in other jurisdictions, PBR can provide a variety of benefits, including: advancing regulatory goals; providing utilities with increased flexibility, opportunity, and accountability to pursue identified goals; and freeing up limited regulatory resources to focus on overseeing utility success in achieving public priorities.

Q39. Can you describe the types of alternative regulatory mechanisms that are typically used in PBR frameworks?

A39. While performance-based regulatory mechanisms can overlap, they may be grouped according to three broad categories:

- **Revenue adjustment mechanisms** focus on how an electric company's target revenues are determined, collected, and/or adjusted over time, and include policy tools that shift regulation away from a backward-looking focus on costs and sales to a more forward-looking approach that promotes cost control and improved performance.
- **Performance mechanisms** provide focused incentives for an electric company to reach performance targets aligned with policy and identified customer priorities through the public display of metrics or scorecards, or more overtly through financial reward for achieving certain levels of exemplary performance.
- **Other regulatory mechanisms** include those that provide electric companies an opportunity to earn revenues from the procurement of cost-effective, third-party solutions, such as cloud-based computing or aggregated DERs.

A summary of the specific alternative regulatory mechanisms that fall under each of the three categories listed above can be viewed in the following table:

Table 1 – Summary of Alternative Regulatory Mechanism Components

<table>
<tr><th colspan="2">Revenue Adjustment Mechanisms</th></tr>
<tr><td rowspan="2">Multi-Year Rate Plan and Attrition Relief Mechanism (“ARM”)</td><td>MYRPs permit utilities to operate for several years without a traditional, general rate case. The rate plan period typically lasts three to five years.</td></tr>
<tr><td>Between plan periods, ARMs automatically adjust rates or the revenue requirement according to a predetermined formula that adjusts rates in line with expected utility cost pressures without tracking its actual cost. ARMs are commonly based on cost forecasts, indexed trends in utility costs, or a combination of the two.</td></tr>
<tr><td>Revenue Decoupling (Revenue Regulation)</td><td>Revenue decoupling (revenue regulation) eliminates the throughput incentive by ensuring the utility recovery of allowed revenue regardless of megawatt-hour (MWh) and megawatts (MW) of utility system use. Allowed revenue is typically escalated using a predetermined formula. Under this approach, the impact on utility revenues between rate cases from energy efficiency, DR programs, and customer-sited distributed generation can be reduced or eliminated.</td></tr>
<tr><td>Earnings Sharing Mechanisms (“ESMs”)</td><td>ESMs divide surplus or deficit earnings between the utility and its customers, to provide customers with a share of savings achieved through operational efficiency or other measures, while maintaining utility incentives to pursue cost savings</td></tr>
<tr><th colspan="2">Performance Mechanisms</th></tr>
<tr><td>Performance Incentive Mechanisms</td><td>PIMs consist of performance metrics, targets, and financial incentives. PIMs have been employed for many years to address performance in areas such as reliability, safety, and energy efficiency. In recent years, PIMs have received increased attention as a way to provide utilities with regulatory guidance and align utility and customer interests regarding DER and the implementation of new technologies and practices.</td></tr>
</table>

Scorecards	Scorecard metrics permit the collection of information on utility performance or achievement of targets in specific areas compared to a peer group of other utilities. Typically, financial incentives are not initially linked to a scorecard, but scorecards can assist in defining baseline conditions and as a way to evaluate and measure changes to performance over time.
Reported Metrics	Reported Metrics can serve as a helpful reporting requirement, meaning that the data reflected by the unit of measurement is tracked and published to illuminate progress towards a prioritized outcome and, in turn, toward the attendant regulatory goal. The simple act of tracking and reporting metrics can encourage utilities toward stronger performance by using transparency as a regulatory tool.
Other Regulatory Mechanisms	
CAPEX/OPEX Equalization	Alternative regulatory mechanisms that explore development of other approaches to equalize treatment of CAPEX/OPEX, such as a return on service-based solutions and the capitalization of prepaid contracts**.**
Innovation	Mechanisms that support utility and third-party innovation, such as an expedited innovative pilot framework.

Q40. Could you speak to why a comprehensive and balanced performance-based regulatory framework is key to effectively achieving public policy goals?

A40. Developing an effective, performance-based regulatory framework necessitates a comprehensive approach composed of a balanced and holistic set of alternative regulatory mechanisms. A customer-centric regulatory framework cannot be constructed in an ad-hoc, “à la carte” manner. Rather, a suite of alternative regulatory mechanisms should be adopted in the right combination to achieve a balanced approach that is in the public interest.

Q41. Can you elaborate as to what you mean by a balanced approach?

A41. When we speak to the need for a balanced approach, we are speaking about assembling a set of regulatory mechanisms in a precise manner to ensure that neither customers nor the electric utility are left bearing a disproportionate and undue amount of risk within the regulatory framework. Moreover, balance means providing appropriate consumer protections and safeguards coupled with the right incentives to achieve public policy objectives on the one hand, while providing a reasonable opportunity to earn an appropriate return on equity for the utility.

Achieving balance within an advanced regulatory framework will involve some combination of the structural components across revenue adjustment mechanisms, performance mechanisms, and other regulatory mechanisms as outlined above. Our view is that creating a comprehensive set of structural components to create a productive regulatory framework is a singular, and foundational element of PBR. An appropriately structured PBR framework provides clear regulatory boundaries, highlights areas of focus, aligns utility interests with both customer interests and public policy goals, and creates fair, transparent risk sharing.

Q42. What are some guiding principles that should ground and inform performance-based regulatory frameworks?

A42. There are three guiding principles that should help inform development of performance-based regulatory frameworks: (1) customer-centric approach; (2) administrative efficiency; and (3) utility financial integrity.

Q43. Could you speak to each of these three guiding principles in turn?

A43. A **customer-centric approach** speaks to expanding opportunities for customer choice and participation in all appropriate aspects of utility system functions. **Administrative efficiency** reflects the potential that PBR frameworks offer to simplify the regulatory framework and enhance overall administrative efficiency. With regard to **utility financial integrity**, from the inception of utility regulation, a fundamental goal has been to ensure the utility's financial health. The financial integrity of the utility is essential to its basic obligation to provide safe and reliable electric service for its customers. Moreover, the utility is a critical community partner and serves as an integral role in achieving the State's energy policy goals and stands as an essential credit-worthy off-taker for non-utility power purchases and new and evolving grid services providers.

Q44. Do specific jurisdictional characteristics need to be considered when developing a performance-based regulatory framework and identifying an appropriate balance of mechanisms?

A44. Yes. Every jurisdiction and utility company service territory has unique features, and a well-designed performance-based regulatory framework should be tailored to the specific needs of the local context.

Q45. What types of localized context is most important when evaluating a performance-based regulatory framework design?

A45. Evaluation of regulatory frameworks should consider, among other factors: (1) utility characteristics (e.g., customer demographics, geography, etc.); (2) state regulatory characteristics; and (3) state legislation, including clean energy goals.

Q46. What utility characteristics should be considered when evaluating a prospective performance-based regulatory framework?

A46. A number of utility characteristics are important to consider when evaluating a regulatory framework: the size of the utility company in question in terms of peak system demand, the number of total customers, the level of customer load density, and other elements related to a utility company's service territory including, but not limited to, terrain and weather challenges. Whether a utility in question is permitted to own generation and whether the utility operates in a structured wholesale market are further factors that need to be weighed.

Q47. What type of consideration should be given to the existing regulatory environment when evaluating a prospective performance-based regulatory framework?

A47. A prospective performance-based regulatory framework should be evaluated against the specific context of the regulatory framework it would be modifying or refining. How well is the current regulatory framework operating today? How fairly is risk shared between the utility and customers and how well is the amount of risk borne by the utility reflected in its ROE or other incentives? Does it include a set of structures that facilitate achievement of the jurisdiction's regulatory goals and outcomes? How well has the utility been performing under the current regulation plan (e.g., cost containment, environmental performance, customer empowerment)?

Q48. What type of consideration should be given to state legislation?

A48. Evaluation of a prospective performance-based regulation plan must also consider the legal framework and public policy of the jurisdiction within which it will operate. Analysis in this category should likely include identifying any legal barriers to adopting certain alternative regulatory mechanisms as well as the particular needs and policy goals for which well-tuned mechanisms can help catalyze achievement.

IV. National Trends

Q49. Can you speak to national trends related to performance-based regulatory mechanisms being adopted?

A49. While we are aware that PBR related issues are evolving all over the country on a consistent basis, we are planning to focus our discussion on a few states. The states of Minnesota, Hawaii, Rhode Island, and Massachusetts have recently undergone significant PBR-related proceedings from which we can extract valuable lessons and insights. We directly participated in three of the four proceedings. We also plan to discuss Illinois and New York but consider these two processes to be relative outliers due to their unique structures and context, which we explain later.

A. Revenue Adjustment Mechanisms

Q50. Let's examine trends in regulatory mechanisms across the three categories you identified: revenue adjustment mechanism, performance mechanisms, and other regulatory mechanisms. We can begin by discussing specific revenue adjustment mechanisms. What is revenue decoupling?

A50. Revenue decoupling is a widely accepted regulatory mechanism that is intended to break the link between a utility's electricity sales to its customers and the revenue it collects from those customers, also known as the throughput incentive.[12] There are numerous decoupling approaches and variations on those approaches, but the goal remains the same.

Q51. Why is it important to address the throughput incentive?

A51. It is important to address the throughput incentive because utilities can better serve the public interest when its interests are better aligned with customers. Customers benefit when the utility is focused on controlling costs, rather than selling more power to increase its profits. Many of the states that have adopted revenue decoupling have done so to alleviate the utility's natural opposition to energy efficiency and conservation programs, which are designed to cost effectively reduce the cost of the utility system to ratepayers. But the underlying policy reason for decoupling is larger than just deploying

[12] Lazar, Wilson, Shirley, et al., *Revenue Regulation and Decoupling: A Guide to Theory and Application*. Regulatory Assistance Project (Nov. 8, 2016). Available at https://www.raponline.org/knowledge-center/revenue-regulation-and-decoupling-a-guide-to-theory-and-application-incl-case-studies/.

energy efficiency programs; it is about aligning interest toward highest value solutions for customers irrespective of the impact to electricity sales.

Q52. Are there other benefits attendant with a decoupling mechanism?

A52. Yes. Decoupling mechanisms can help facilitate utility financial integrity should electricity sales decline due to a sudden disruptive event or through customer adoption of technology that reduces consumption. Moreover, as decarbonization plans operate to electrify other sectors, such as transportation and heating, a decoupling mechanism can operate to share attendant benefits with customers in a timely manner. For instance, unanticipated increases in electricity sales that result in overcollection of revenue can be distributed back to customers through rate adjustments on a quarterly basis.

Q53. Have other states adopted revenue decoupling?

A53. Yes. Dozens of states have adopted some sort of revenue decoupling mechanism for electric or natural gas utilities, or both, including each of the states mentioned below.[13]

Q54. Is revenue decoupling alone sufficient to achieve the desired outcomes?

A54. No, it is an important component of an advanced PBR framework but needs to be paired with multiple other regulatory mechanisms to effectively achieve desired policy outcomes.

[13] Prepared for EEI by Guidehouse, *Electric Regulation for a Customer-Centric Future, Survey of Alternative Regulatory Mechanisms* at Table A-1 (2020), available at https://www.eei.org/issuesandpolicy/distribution/Documents/Guidehouse_Electricity-Regulation-for-a-Customer-Centric-Future_July-2020 FINAL.pdf.

Q55. What is a rate adjustor and what is its purpose?

A55. Rate adjustors are another commonly accepted regulatory mechanism. Sometimes called "cost trackers," they are mechanisms that provide expedited recovery of targeted costs. An account typically tracks costs that are eligible for recovery. These costs are then typically recovered via "rate riders" that use a separate line item on a customer's bill for costs that are in addition to the customer's electric rate charge. The purpose of the adjustor is to allow recovery of costs that are significant but are not significantly under the control of the utility.

Q56. Do other states use rate adjustors?

A56. Numerous states have adopted rate adjustors including all of the states discussed below.

Q57. What are some considerations the Commission should keep in mind when approving rate adjustors?

A57. A rate adjustor's impact on risk sharing is often underappreciated. Rate adjustor treatment is intended for costs that are large, volatile, and largely beyond the control of the utility. Allowing costs that do not fit this description to be recovered through a rate adjustor begins to shift risk onto customers and away from the utility by limiting regulatory lag, among other things. The Commission should take care to keep rate adjustors at a reasonable level to ensure that other PBR structure components work as intended. For example, a key feature of a MYRP is its incentive for cost control. However, a MYRP will not apply the same level of cost control incentive if a utility is permitted to introduce a distribution cost recovery adjustor for grid modernization in the middle of the term of the plan.

Q58. Have trends been observed as states switch to a MYRP?

A58. Although numerous states have transitioned to MYRPs, the structures of plans that have been approved differ significantly. MYRPs are common and are an important element within a performance-based regulatory framework. General rate cases are typically held every four or five years. Between rate cases, an attrition relief mechanism permits revenue (or rates) to grow in the face of cost pressures, without linking relief to all of a utility's specific costs. Some costs may be addressed separately using rate adjustors.

A core advantage of MYRPs is their potential to strengthen cost containment incentives. The ARM can provide timely, predictable rate modification that permits an extension of the period between rate cases. Modification is based on cost forecasts, industry cost trends, or both, rather than a utility's specific, historic-looking costs. Such an approach helps to create an operating environment more like that experienced in competitive markets.

Q59. Please elaborate on the MYRP structures that have been observed.

A59. The MYRP structures that we have observed include ARMs that escalate pursuant to (1) forecasted CAPEX, (2) an external index, such as inflation, or (3) formula rates. I will walk through examples of each of these structures.

In Minnesota, Xcel Energy's MYRP calculates rates based on a forecasted CAPEX method. Rates for a four-year rate plan were established based on 2016 weathernormalized sales and forecasted for the remainder of the rate period.[14] It is worth noting, however, that Xcel has numerous rate riders that undermine the cost containment incentives within its MYRP.

Hawaii and National Grid Massachusetts have MYRPs that calculate revenue requirements using an externally-indexed revenue cap approach, sometimes referred to as an "I-X" methodology. Simply stated, an I-X methodology adjusts the base revenue requirement annually accounting for inflation, less a productivity factor ("X-factor"), an adjustment for exogenous costs ("Z-factor"), and a customer dividend, with the utility retaining savings above the target. Productivity factors have largely been zero (e.g., Hawaii) or negative (e.g., National Grid, Massachusetts). Specifically, for National Grid, a productivity factor of -1.72 was approved[15] and a productivity factor of 0 was approved in Hawaii.[16] For small utilities, the externally-indexed revenue cap approach may unduly limit investment flexibility over the life of the regulation plan and deliver suboptimal outcomes for customers as compared to a well-designed forecasted CAPEX approach, depending upon the design of key parameters as well as the presence of complementary mechanisms.

Finally, Illinois utilizes a formula rate plan. In Illinois, the formulaic rates include cost recovery of the utility's actual capital structure, excluding goodwill; a legislatively-

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[14] *See* Minnesota PUC, *Findings of Fact, Conclusion and Order* at 36 (June 12, 2017). Docket No. GR-15-826. Available at https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7bECF405E1-C848-4D03-BBE3-91BA3DD17B96%7d&documentTitle=20176-132748-01.

[15] *See* Massachusetts DPU, *Order* at 60 (Sep. 30, 2019). Docket No. 18-150. Available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/11262053.

[16] *See* Hawaii PUC, *Decision and Order No. 37507 op. cit.* at 41.

set formula for purposes of calculating the allowed return on equity equivalent to a 580 basis-point premium above the 12-month average 30-year Treasury Bond yield; and recovery of pension-related costs, as well as recovery of certain incentive compensation expenses.[17]

In all the forms we have evaluated, we have found that formula rate plan frameworks often result in an undue shift of risk onto ratepayers.

B. Performance Mechanisms

Q60. Describe what a Performance Incentive Mechanism is.

A60. Performance Incentive Mechanisms tie a portion of utilities' earnings to desired regulatory outcomes.

Q61. What trends have emerged in proceedings relating to PIMs?

A61. Stakeholder or regulatory utility commission proceedings in many states have evaluated and proposed numerous PIMs for commissions' consideration. However, most states rely heavily on reporting metrics, and have not adopted the majority of PIMs that have been proposed.

Q62. Have any PIMs been successfully adopted?

A62. Recently, Hawaii, Minnesota, and Rhode Island all underwent extensive PIM processes. The Hawaii PUC has adopted several new PIMs: Grid Services, Interconnection

[17] *See* Illinois Commerce Commission, *Order* at 138 (May 29, 2012). Docket No. 11-0721. Available at https://www.icc.illinois.gov/docket/P2011-0721/documents/182671/files/322042.pdf.

Approval, LMI Energy Efficiency, AMI Utilization, and RPS Acceleration.[18] Minnesota adopted and is currently developing a DR PIM that encompasses a suite of DR types (e.g., shed, shift, shape, and shimmy).[19]

In Rhode Island, a suite of PIMs was proposed, but the Rhode Island Public Utilities Commission rejected them all except for a DR PIM.[20] Notably, Hawaii, Minnesota, and Rhode Island each have a PIM related to DR.

Q63. Can you further discuss these examples of a demand response PIM?

A63. The Grid Services PIM in Hawaii is designed to promote DER asset effectiveness and grid investment efficiency, by incentivizing the prompt acquisition of grid service capabilities from DERs. The incentive is measured per kW of capacity for certain grid services procured.[21] This PIM has financial reward opportunities with no penalties.

The Minnesota PIM relating to cost effective alignment of generation and load, or DR PIM, has not yet been implemented but several metrics for measuring DR effectiveness have been adopted by the Commission. These metrics include DR capacity, DR availability, and amount of DR called annually, among others.[22]

The Rhode Island System Efficiency PIM is measured based on MW of annual peak capacity savings.[23] Demand response is one of the key eligible resources that can

[18] *See* Hawaii PUC, *Decision and Order No. 37507 op. cit.* at 94.

[19] *See* Minnesota PUC, *Order Establishing Performance Metrics op. cit.* at 10.

[20] *See* Rhode Island PUC, *Report and Order No. 23823 op. cit.* at 29.

[21] *See* Hawaii PUC, *Decision and Order 37507 op. cit.* at 106.

[22] *See* Minnesota PUC, *Order Establishing Performance Metrics op. cit.* at 12.

[23] *See* Rhode Island and Providence Plantations PUC, *Report and Order No. 23823 op. cit.* at 68.

count towards capacity savings. The System Efficiency PIM includes minimum, mid, and maximum targets, with an increasing earning opportunity at each level. A maximum incentive cap is also specified. There is no penalty attached to this PIM. To date, National Grid has significantly exceeded the MW of capacity savings needed for the maximum PIM incentive.[24]

C. Other Regulatory Mechanisms

Q64. In addition to revenue adjustment mechanisms and performance mechanisms, are there other regulatory tools that regulatory commissions could use to help balance risk and align utility incentives?

A64. One area that is ripe for further development within advanced regulatory frameworks is treating capital expenditures (CAPEX) and operating expenses (OPEX) more equitably. Traditional utility regulation creates an inherent preference for company-owned capital investments over other solutions because utilities earn a rate of return on CAPEX but not OPEX. This disparate treatment of CAPEX and OPEX is increasingly problematic as traditional CAPEX solutions are not always the best or most cost-effective way to bring value to customers. Emergent solutions, such as cloud computing and virtual power plants, underscore the need for a framework that financially encourages a utility to pursue

[24] *See* The Narragansett Electric Company d/b/a National Grid, *2019 Performance-Based Incentive Mechanism 2019 Annual Report* at 1 (Feb. 28, 2020). Docket No. 4770. Available at http://www.ripuc.ri.gov/eventsactions/docket/4770-NGrid-PIM%20Annual%20Report%202019%20(2-28-2020).pdf. *See also* National Grid, *Performance Incentive Mechanism 2020 Annual Report* at 1 (Mar. 1, 2021). Docket No. 4770. Available at http://www.ripuc.ri.gov/eventsactions/docket/4770-NGrid-PIM%20Annual%20Report%20(PUC%203-1-2021).pdf.

not just the least-cost but the highest value solution for customers, irrespective of whether that solution would be classified as CAPEX or OPEX.

Q65. Can you provide an example?

A65. The information technology ("IT") transition from on-premise hardware and software to cloud-based computing is underway in the electric sector as energy providers seek out increased customer benefit. Regulatory commissions have recognized cloud and software-as-a-service solutions' ability to provide scalable, mobile, and resilient technology to utilities and their customers. Despite the many benefits of cloud computing and SaaS, these technologies are at a disadvantage when compared to on-premise IT investments. This is because, under traditional accounting and ratemaking rules, on-premises IT is treated as a capital asset, while cloud computing and SaaS solutions are treated as operating expenses. In order to fully take advantage of the benefits of cloud-based software, these technologies must be able to compete on more equal regulatory footing.

Q66. Have there been any regulatory developments to reduce this disparate treatment?

A66. Yes. As of 2018, Generally Accepted Accounting Principles ("GAAP") have allowed treatment of cloud computing expenses as capital expenses. This is a step in the right direction; however, it does not go far enough towards CAPEX/OPEX parity.

Q67. What other steps should the Commission consider to reach CAPEX/OPEX parity?

A67. One option is to allow the capitalization of a prepaid contract, which treats an expense (such as payments for a service) like a capital investment by placing it into the rate base, amortizing it and recovering costs over time. For example, a service payment would be prepaid for a number of years and would be amortized over the length of the contract. The electric company would collect its annual carrying costs, including repayment for the electric company expenditure and return on unamortized balances. With this option, the electric company earns a rate of return on the prepaid contract in a similar manner and at a similar level as traditional rate-based assets.

While this approach mitigates the electric company's bias toward capital solutions, the electric company should be encouraged to choose the most efficient approach, especially if the capital expenditure option provides an opportunity to place a larger asset in the rate base. The contract length is another factor that will influence electric company decision-making; longer-lived contracts will allow the electric company the opportunity to earn more for the same level of initial investment. Not all service-based solutions may be treatable as prepaid contracts, limiting the applicability of this solution. To that end, certain regulatory commissions have explored allowing utilities to treated SaaS solutions, which often have a short depreciation schedule, as a regulatory asset to help reduce a utility's preference to a more expensive capital-based solution.

Q68. Will you provide an example of a state regulatory commission's approach to parity treatment of SaaS solutions?

A68. The New York Public Service Commission ("NY PSC") issued a declaratory statement in its Reforming the Energy Vision ("REV") Track 2 order, that electric companies could capitalize pre-paid SaaS contracts. The tack that the NY PSC took, pre-paying the total cost of service contract and recording it as a regulatory asset in the rate base, is a simple solution that resolves the disincentive for electric companies to utilize cloud computing or third-party solutions and places these services on equal footing with on-premises, traditional solutions, allowing the electric company to select a solution that provides the most value to the system and to customers.

Q69. Is the equalization of CAPEX/OPEX only applicable to SaaS?

A69. No. Using the New York approach, electric companies can be encouraged to cost-effectively procure non-wire solutions ("NWS") or DER solutions instead of traditional electric company-owned assets; thereby unlocking savings for all customers. An electric company could enter into a power purchase agreement ("PPA") with a third-party DER aggregator (e.g., rooftop PV or distributed energy storage) and earn a return on that procurement. By prepaying for a 10-year PPA, an electric company could capitalize the expense and earn a return that is equivalent to what the electric company would have earned on a capital expenditure.

Q70. What is a regulatory sandbox?

A70. Regulatory sandboxes open the door to testing new approaches within a controlled environment. These sandboxes are effectively a limited waiver from normal regulations and requirements, allowing companies with new innovative ventures to test their products or services in a contained and safe environment.

Q71. Why does a regulatory sandbox provide value?

A71. Traditional regulatory systems and legal requirements aren't built to accommodate the fast pace of innovative new technologies, tools and products. Innovation requires testing unproven concepts and technologies, taking risks, and pursuing ideas that can fail. These tenets of innovation, though, are at odds with both the obligations of electric companies (which are encouraged to avoid risks for safety, security, and reliability) and the duty of regulators to ensure a well-run and efficient electricity system.

The flexibility of a regulatory sandbox is especially critical for the introduction of new customer offerings. It is not market responsive to conceive of a new customer solution and then wait a year or more for an adjudicated decision. In the time that traditional process takes place, the customer will, in many cases, find another option. This same dynamic occurred in the telecom industry as competition increased for the incumbent line companies. Alternative regulation plans established expedited approval and introduction of new customer products and solutions.

Q72. Discuss some examples of regulatory sandboxes in the U.S.

A72. GMP's Innovative Pilots is a notable example we cite in proceedings around the country. The program has enabled the utility to develop pilots outside of the traditional regulatory process in order to offer non-traditional services that generally would not be nimbly deployed under traditional cost-of-service regulatory process but that can advance the state's clean energy goals.[25] These pilots have been remarkably agile as the regulatory commission does not need to formally approve pilots before they are implemented; rather, the approved plan sets out a fixed budget for pilots with a limit of $5 million for any single initiative.

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[25] *See* Vermont PUC Docket No. 20-1401-PET.

Another example of a regulatory sandbox is Portland General Electric's ("PGE") Smart Grid Testbed (the "Testbed"), which announced a first-of-its-kind smart grid testbed in 2019.[26] This is a multi-year learning program, which focused on advanced communications capabilities and distribution system upgrades. Centered around customer needs and offerings, the Testbed aims to help PGE rethink how it uses energy through new technologies, programs, and products, while still allowing customers to have control over their comfort settings, use more renewable energy, and maintain reliability and affordability. This pilot is intended to be iterative and inform future program design to ultimately build PGE's roadmap to a virtual power plant—one powered by customer devices and behaviors rather than traditional generation. Initiatives undertaken within the Testbed are proposed by PGE and approved by the Oregon PUC before deployment. The Oregon PUC requires PGE to file a Smart Grid Report every two years. All prudently incurred costs are to be recoverable by PGE.

Finally, Connecticut is currently designing a regulatory sandbox—the Innovation Pilots Framework—with support from Strategen Consulting.[27] The Innovation Pilots Framework ("IPF") is intended to serve as a safe but monitored place to test new ideas and validate their benefits in the real world. Innovative pilot programs, technologies, products, and services will be deployed on a limited basis, investigated, and evaluated for

[26] PR Newswire, *Portland General Electric's ambitious Smart Grid Test Bed launches* (July 15, 2019), available at https://www.prnewswire.com/news-releases/portland-general-electrics-ambitious-smart-grid-test-bed-launches-300885175.html.

[27] *See* Connecticut Public Utilities Regulatory Authority, *Innovation Pilots Framework – Final Proposal* (July 23, 2021). Docket No. 17-12-03RE05. Available at http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/e876d4086d2f88ab8525871b006eaff8?OpenDocument.

overall impact, costs, and benefits, and scaled if ratepayer benefits are demonstrated. The Connecticut Public Utilities Regulatory Authority has issued a final straw IPF framework that outlines specific design principles and a programmatic approach drawing upon best practices from regulatory sandboxes in other jurisdictions, including the regulatory sandboxes implemented by GMP and PGE.

V. Evaluation of Green Mountain Power's Proposed Regulation Plan

Q73. Did you evaluate GMP's proposed Regulation Plan?

A73. Yes. We were able to conduct a high-level overview and assess key components of GMP's proposed Regulation Plan. We evaluated the proposed Regulation Plan structure, examined the Plan's core regulatory mechanisms, and qualitatively analyzed the Plan's regulatory mechanisms against the framework discussed above, which is informed by performance-based regulation implementation across leading jurisdictions in the United States. We further assessed whether the proposed Regulation Plan appeared to appropriately balance risk between GMP and its customers, whether it embodied sufficient flexibility over the life of the Plan, and whether it contained sufficient consumer guardrails.

Q74. Please describe your assessment of the proposed Plan's structural components.

A74. As noted, we first took a comprehensive view of the proposed Regulation Plan's design and structure—mapping the core components to the emergent best practices framework highlighted in Section III of this testimony. By mapping the GMP Regulation Plan core components to this qualitative framework, we were able to confirm key components of the Plan and identify potential gaps and highlight potential areas for structural enhancement or refinement going froward. We did not assess each individual Plan mechanism, but rather focused on those mechanisms we find to be central to advanced performance-based regulatory frameworks in the U.S. We also did not analyze GMP's regulatory mechanisms in a quantitative manner, nor did we evaluate the application of these mechanisms in practice—i.e., their past performance—though we did review GMP witness testimony that touched upon that performance. The focus here was primarily on the structure and design of the Plan and how well it would appear positioned to reasonably balance risk between GMP and customers, provide flexibility and integrity over the life of the Plan, encourage exceptional utility performance, and deliver optimal customer value. The table below summarizes our qualitative evaluation. We discuss each of the core components in turn.

Table 2 – Proposed GMP Regulation Plan Components

Revenue Adjustment Mechanisms	
Multi-Year Rate Plan and Attrition Relief Mechanism	Plan period of four years—or five years with Commission approval of optional fifth year.
	Hybrid ARM approach with forecasted CAPEX capped over the plan period and OPEX treated in one of three ways: forecasted and capped, capped and tied to an external inflation index, or reforecast annually.
Revenue Decoupling (Revenue Regulation)	Retail revenue adjustor that operates as a revenue decoupling mechanism, de-linking electricity sales from revenue collection through a quarterly true-up mechanism.

Earnings Sharing Mechanisms	Earnings sharing mechanism that operates annually and includes both "upside" and "downside" sharing of revenue. There is no sharing adjustment for any over- or under-earning within a +/- 50 basis point band tied to Commission-approved return on equity. If actual earnings reflect an ROE that +50 to 125 basis points above, or -50 to 150 basis points below the ROE, 75% of revenue benefits are returned to, or 50% of lower earnings is collected from, customers. If actual earnings are more than +125 above the ROE, or more than -150 below the ROE, all revenue benefit or impact are passed onto customers.
Performance Mechanisms	
Performance Incentive Mechanisms	None tied to revenue or financial adjustors.
Scorecards	None.
Reported Metrics	Set of Innovation and Performance Metrics measured on a fiscal year basis except where otherwise indicated
Other Regulatory Mechanisms	
CAPEX/OPEX Equalization	None.
Innovation	Innovative pilot framework that allows for expedited deployment of non-tariffed pilot offerings as well as flexibility to pursue unanticipated tariffed New Initiative offerings.

A. <u>Revenue Adjustment Mechanisms</u>

Q75. Can you identify the revenue adjustment mechanisms that you evaluated in GMP's proposed Regulation Plan?

A75. We examined the following revenue adjustment mechanisms: multi-year rate plan structure, including the functional attrition relief mechanism; revenue decoupling mechanism, known as the Retail Revenue Adjustor; earnings sharing mechanism; and other selected adjustors.

i. *Multi-Year Rate Plan*

Q76. Please describe your assessment of the MYRP duration in GMP's proposed Regulation Plan.

A76. As noted earlier in our testimony, GMP's proposed Regulation Plan outlines a four-year MYRP period to terminate in 2026, unless a one-year optional extension is approved by the Commission. The Plan's period duration is consistent with best practices identified in the literature[28] and is consistent with experience from leading jurisdictions.[29] A plan length of four to five years provides sufficient duration for a utility to experience the stability and financial benefits, while minimizing the administrative burden and cost of cost-of-service cases, and therefore aligns both GMP and customers' interests to pursue effective cost containment initiatives—some of which may take multiple years to fully implement. The Plan length is also sufficiently balanced such that it is not too long and permits reasonable review and course correction before the commencement of a successor regulation plan.

Experience in the United Kingdom ("UK") has shown that four to five years is an optimal MYRP length. In RIIO-1, the UK regulator, Ofgem, approved an eight-year MYRP for the regulated networks. Eight years proved to be too long a duration without a more fulsome review process and opportunity to course-correct. Accordingly, Ofgem has

[28] Guidehouse, *Electricity Regulation for a Customer-Centric Future, Survey of Alternative Regulatory Mechanisms op. cit*. *See also* Lowry, Makos, Deason, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities* (July 2017). Lawrence Berkeley National Lab. Available at https://gmlc.doe.gov/sites/default/files/resources/multiyear_rate_plan_gmlc_1.4.29_final_report071217.pdf.

[29] *See* Minnesota PUC Docket No. 15-826, Hawaii PUC Docket No. 2018-0088, and Rhode Island PUC Docket No. 4770.

moved to implement five-year MYRPs for networks under RIIO-2. The need to have a checkpoint at five years is increasingly important in an energy industry landscape that is rapidly changing—and one for which the rate of change appears to be increasing.

On the other hand, it is possible for MYRPs to be too short in duration. Experience in Hawaii demonstrated that a three-year MYRP was limited in its ability to create a structure that encouraged robust cost control and did not achieve meaningful administrative efficiency. Consequently, the HPUC approved a revised MYRP duration of five years as part of its advanced PBR framework implementation.

Here, GMP's proposed four- to five-year MYRP strikes the right balance between creating space within the Plan period to generate regulatory efficiency and encourage cost efficiency, while also not allowing the proposed Plan to run for too long without opportunity for meaningful review and course correction, if necessary. Such a MYRP duration helps to encourage better utility performance and administrative efficiency.

Q77. Can you speak to the Attrition Relief Mechanism utilized in the proposed GMP Plan?

A77. A core advantage of MYRPs is their potential to strengthen cost containment incentives. The Attrition Relief Mechanism can provide timely, predictable rate escalation that permits an extension of the period between general rate cases. Escalation is based on forecasts, industry trends, or both, rather than the utility's specific forecasts. The combination of a rate case moratorium and the ARM approach to rate modification can strengthen this cost efficiency and permit a well-run electric company to realize its allowed rate of return while materially reducing regulatory costs, which get passed along to customers. By loosening the link between an electric company's own cost and its revenue, an MYRP can encourage electric companies to operate more efficiently by allowing the company to share in additional savings from reduced operating costs.

In GMP's proposed Plan, the ARM utilized during the MYRP follows a hybrid approach, based on cost forecast for capital expenditures and, for operations and maintenance costs, a mixture of cost forecasts, externally-indexed, inflation-based escalation, and annually reforecast amounts depending upon the O&M cost category.

More specifically, with respect to capital expenditures, which include GMP's anticipated Plant Additions during each fiscal year of the MYRP period, ongoing new initiatives capital projects, and forecasted amounts for GMP's anticipated extension of the Energy Storage System ("ESS") program, the amounts would remain fixed in rates unless supplemented with approved additions across strategic and targeted areas like cybersecurity and broadband deployment.

With respect to O&M, this category of costs includes the Other Power Supply, Transmission – Other, Distribution, Customer Accounting, Customer Service and Information, Sales and Administrative, and General Categories of the cost of services. GMP has varied levels of control over certain of these cost types and very limited or no control over other cost types. Cost types that GMP has a level of control over will either be fixed or adjusted for inflation and cost types GMP has little or no control over will be reforecast based on updated actuarial reports, consultant reports, or GMP known and measurable costs.

Q78. What is your view of GMP's proposed hybrid ARM approach within the MYRP?

A78. Overall, we view GMP's proposed hybrid ARM as a sound and reasonable approach. A hybrid ARM that is applied in a targeted manner, such as the one proposed by GMP, is consistent with the literature and reflects a balanced risk-sharing approach. Generally, categories of costs that are more firmly under GMP's control are proposed to be forecast and fixed (e.g., capital expenditures), whereas those costs that fall largely outside of GMP's control are annually reforecast (e.g., pension, healthcare, and tree trimming). This reasonably enhances cost recovery certainty for those costs GMP has little to no control over and focuses cost containment on those cost types where GMP has agency and can respond to the cost containment opportunity present in the MYRP through operational savings that benefit GMP and customers.

We also view the handling of tariffed New Initiative offerings outside of the forecast and locked capital budget as a reasonable approach. As noted earlier in this testimony, sufficient flexibility over the life of the MYRP is an important feature of a well-designed performance-based regulatory framework. Unlike traditional capital investments, which often have a longer line-of-sight to when the need would be triggered, it is more difficult to forecast investment levels in initiatives that are driven by customer demand and adoption. This is particularly true over the course of four or five years in a dynamic and drastically changing industry environment—underscoring the difficulty of forecasting and anticipating customer needs a half decade from now. While we acknowledge that treating tariffed New Initiatives offerings outside of the locked capital budget may somewhat dilute cost containment within the MYRP, any dilution effect is outweighed by the value gained from an ability to respond nimbly to customer needs and quickly scale customer-facing offerings that should deliver net benefits to participating and non-participating customers alike. Further, because the Commission will have to review and approve any tariffed offerings, there is no real loss in administrative efficiency and there will be sufficient opportunity to impose reasonable consumer protections in place at the time of approval.

New Initiative capital projects, by design, should yield value for GMP customers over the life of the investment. Unlike other infrastructure and budget components, the exact scale and timing of these investments are largely driven by new market and technological opportunities as well as customer interest and adoption. Accordingly, GMP's proposed treatment of New Initiative capital projects would appear to have low downside risk, with the right amount of flexibility to take advantage of emergent, dynamic opportunities to create net benefits for all customers. That said, we expect GMP to be mindful of the cumulative impact tariffed New Initiatives may have to place any upward pressure on rates for customers over the life of the MYRP.

ii. <u>Decoupling - Retail Revenue Adjustor</u>

Q79. What is your view of GMP's Retail Revenue Adjustor in its proposed Regulation Plan?

A79. The Retail Revenue Adjustor operates as the revenue decoupling mechanism within GMP's proposed Plan. The Retail Revenue Adjustor shall collect or return to customers, on a bills-rendered basis, the difference between the actual retail revenue every

Measurement Quarter and the forecasted retail revenue amount included in base rates for that quarter.

We view the inclusion of a revenue decoupling mechanism as a critical component of a well-designed and balanced performance-based regulatory framework. As noted previously in this testimony, revenue decoupling addresses the utility throughput incentive by ensuring the electric company recovery of allowed revenue that is less dependent upon total megawatt-hours and megawatts of electric company system use. Under this approach, the impact on electric company revenues over the life of the MYRP from energy efficiency, DR programs, and customer-sited distributed generation can be reduced or eliminated. Moreover, the advance of electrification across sectors like transportation and heating can yield benefits for customers by placing downward pressure on rates. GMP's decoupling mechanism allows for the timely sharing of such customer benefits should they materialize.

Accordingly, we view favorably GMP's inclusion of the Retail Revenue Adjustor, given the importance of including a decoupling mechanism in a sound framework, but note that we have not analyzed the specific mechanics and application of the Retail Revenue Adjustor in practice.

Q80. Please explain why you view decoupling as a critical component of a PBR framework.

A80. The rate at which technology and policies are changing creates some uncertainty as to how certain state policy goals may ultimately be achieved. For example, decarbonization of other sectors, such as heating and transportation, could be significantly achieved through electrification, green hydrogen, or a combination of many technologies. Each of these outcomes could have significantly different implications for utility sales; therefore there is clearly risk and uncertainty for the utility and ratepayers. Continuing with the electrification example, electrification of transportation and heat could significantly increase electric utility sales. If the electric utility is decoupled, and is operating within a comprehensive PBR framework, a larger share of the benefits of increased sales will flow to ratepayers via the decoupling mechanism within the MYRP.[30] Decoupling can therefore ensure timely benefit sharing with ratepayers (e.g., on a quarterly basis) and consequently receive a larger share of benefits created through electrification than would be seen under traditional regulation.

iii. *<u>Authorized Return on Equity</u>*

Q81. Please describe your assessment of GMP's authorized return on equity.

A81. GMP's return on equity is adjusted by a set formula annually. The formula measures the change in daily average yield of the 10-year Treasury Note between February 15 and May 15, compared to the same period in the prior year. GMP's existing authorized ROE is then adjusted by 50 percent of the change in the average daily yield during the measurement period to establish the current year's ROE. This year, the formula has yielded an ROE of 8.57% which represents one of the lowest ROE of any electric utility in the country.

[30] While this statement is concerned with benefits accrued within the MYRP, electrification can create benefits that extend beyond the MYRP. Specifically, increased sales can lead to a decrease in rates, by spreading the utility revenue requirement over more sales units, all else being constant.

iv. Earnings Sharing Mechanism

Q82. Could you please describe your assessment of GMP's Earnings Sharing Mechanism?

A82. An ESM serves to share amounts of electric company earnings that fall outside a range as determined by regulators and is a key component of any PBR approach. ESMs are established to ensure that the electric company's earned return is neither excessive nor insufficient, by "sharing" this excess or insufficiency with the customer. An ESM can provide some assurance that company earnings will not excessively benefit or suffer from exogenous factors not under electric company control or from unintended results of other alternative regulatory mechanisms.

In GMP's proposed Plan, GMP's rates will be subject to an Earnings Sharing Adjustor Mechanism ("ESAM") for each rate period during the proposed Plan term.

We support the inclusion of an ESAM in GMP's proposed Plan as a mechanism to provide both "upside" and "downside" sharing of earnings that fall outside of a Commission-approved range. The ESAM would serve as a customer protection provision. To the extent that realized earnings exceed the "approved" levels in the most recent general rate case, increasing proportions of the realized earnings would be returned (shared) with ratepayers as a credit toward future revenue collection. Conversely, the ESAM can also effectively operate to ensure financial integrity over the life of the Regulation Plan, by ensuring GMP realizes a baseline, minimum threshold of earnings to enable it to continue to operate the power system in a safe and reliable manner that is consistent with the public interest.

B. Performance Mechanisms

Q83. Please provide your thoughts on GMP's performance mechanisms.

A83. Overall, the theme and spirit of GMP's performance metrics align with other states' approaches. There is a clear focus on cost control, clean energy, DERs, interconnection, and DR.

Notwithstanding the overall alignment with other states' approaches, we observe that the overarching structure of GMP performance mechanisms differ slightly from the states with which we are most familiar. A common and effective hierarchical structure is to begin with high-level policy goals, link these goals to specific regulatory outcomes, and develop metrics to track and measure achievement of the outcomes. This approach has been used in other states to ensure that the achievement of state and regulatory goals are explicitly tied to outcomes and therefore to each metric. While most of GMP's performance metrics appear to link to policy goals, the connections could be made clearer by undergoing a process that relies on a goals-outcomes-metrics hierarchical structure. Such a process could consolidate or refine the number of reporting metrics, depending on the approach. Undergoing the exercise of determining goals, outcomes, and metrics could produce state-specific insights and results, and perhaps GMP could work with the Department during the course of this proceeding to consider this framework or further develop a framework for later implementation.

Q84. Do you have other observations related to GMP's performance mechanisms?

A84. Yes. While we understand that GMP develops its reliability metrics through its Service Quality and Reliability Performance, Monitoring, and Reporting Plan and reports these metrics on a standardized basis, many states report all metrics within at least one annual or MYRP filing. The reason that reporting all metrics within one filing can be useful is to ensure that (1) all policy goals map to at least one metric, (2) synergy and relationships between metrics are considered, and (3) metrics are focused. The objective of the performance metrics process is to clearly and explicitly state goals and how progress towards these goals will be tracked over time. Because reliability is a core utility service, developing and tracking reliability metrics in coordination with performance metrics may add insight and clarity.

i. Scorecards and Performance Incentive Mechanisms

Q85. What is your perspective on the lack of scorecards or financial-based PIMs within GMP's Plan?

A85. There are numerous issues that influence the reasonableness of elevating a metric to a formal scorecard or PIM, many of which are contextualized to the individual state.

One key issue is that creating a focused scorecard or PIM that will create value for customers during this dynamic and fast-changing energy transition will take significant time and attention from stakeholders. While some states seem to be coalescing around development of DR-focused PIMs, very few have designed and implemented them. For example, Minnesota has determined they will implement a DR PIM but are still in the process of developing the PIM. Part of the reason for this is that Minnesota is attempting to create a DR PIM that better reflects the grid needs to address challenges presented by the energy transition. Given that GMP's performance and innovation has surpassed where most utilities find themselves along the energy transition path, it is unlikely that Vermont could directly adapt a DR PIM from another jurisdiction. Rather, stakeholders would need to think critically about whether such a PIM is needed here given GMP's performance in this area, and if so, how a PIM should be tailored to meet the specific needs of GMP's customers. If such a PIM is explored, we suggest framing the metrics as more of a suite of load flexibility or grid service metrics to acknowledge that GMP's performance is beyond traditional measures of DR, and the potential challenge of designing and implementing an emergent PIM.

A second key contextual issue is that at least two of these states had a history of frustration with the utility's performance in DR before adopting a DR PIM. For example, the Minnesota Commission ordered Xcel to procure 400 MW of DR capacity by 2023 in its 2015 IRP proceeding.[31] As of today, Xcel has failed to add DR capacity, and stakeholders are suggesting they have actually lost a significant amount of DR capacity since the Minnesota Commission's order.[32] Furthermore, while Xcel has a significant amount of DR, it is all emergency-only DR, hence why the Minnesota PUC adopted metrics that require Xcel to procure specific types of DR. To summarize, state-specific circumstances are important to consider in understanding the motivation behind creating PIMs.

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[31] *See* Minnesota PUC, *Order Approving Plan with Modifications and Establishing Requirements for Future Resource Plan Filings* at 10 (Jan. 11, 2017). Docket No. RP-15-21. Available at https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7b978E98E8-C6BD-4851-80E2-14ED10400D48%7d&documentTitle=20171-128000-01.

[32] *See* Advanced Energy Management Alliance, *Initial Comments* at 20. Minnesota PUC Docket Nos. M-21-101 and CI-17-401. Available at https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7b00FD207A-0000-CB12-806B-4D796DE90D34%7d&documentTitle=20216-175220-01.

With that said, we strongly support the use of scorecards and PIMs, especially when these tools are used to better align utility incentives around the utilization of DER to create grid services. While designing scorecards and PIMs can be challenging, the process will likely provide stakeholders with additional insight into a critically important area. We view both scorecards and PIMs as key areas worth further development as stakeholders progress through the clean energy transition, and will discuss actions that Commission could consider below.

C. <u>Other Regulatory Mechanisms</u>

Q86. In addition to revenue adjustment mechanisms and performance mechanisms, were there other regulatory mechanisms that you assessed within GMP's proposed Plan?

A86. Yes. We evaluated whether there were any mechanisms related to helping establish CAPEX/OPEX parity as well as creating space for innovation within the regulatory framework.

i. <u>CAPEX/OPEX Equalization</u>

Q87. Did your evaluation of GMP's proposed Plan identify any mechanisms that address CAPEX/OPEX parity?

A87. No. In our assessment, we did not identify any specific mechanisms that help equalize the treatment of CAPEX and OPEX within the regulatory framework. As noted elsewhere in this testimony, traditional utility regulation may include an inherent preference for utility-owned capital investments over other solutions because utilities are able to earn a rate of return on CAPEX but not OPEX. The net effect can be a loss of customer value. Stated simply, a utility may not identify, either consciously or subconsciously, the least cost, highest value solution if such a solution happens to be treated as an operating expense rather than a capital expenditure and an earning opportunity.

We do observe GMP's industry leadership when it comes to keeping customers at the heart of all decisions, decarbonizing the electricity system, and offering innovative customer-facing products and services. GMP's demonstrated success and customer-centric approach stands in contrast to many other investor-owned utilities in the United States. This is further reflected in GMP's status as a certified B Corporation. Certified B (Benefit) Corporations ("B Corps") use the power of business to solve social, environmental, and economic problems. Benchmarking and measuring a company's social impact allow customers and employees to know that a company is serious about doing good and doing well.

Notwithstanding GMP's past and continued success in delivering for customers, we view the category of CAPEX/OPEX parity to be one of the primary areas of opportunity when it comes to potential improvements to GMP's proposed Regulation Plan. In Section VI of our testimony, we outline recommendations for mechanisms that might be explored further.

ii. *Innovation Platforms*

Q88. Did your evaluation of GMP's proposed Plan identify any mechanisms that foster and facilitate innovation?

A88. Yes. GMP has an Innovative Pilots framework that permits an expedited pathway to pilot deployment, creating important space in the regulatory framework for innovation to benefit all customers. The Innovative Pilots framework has served as a model and case study for other jurisdictions nationally and has supported successful pilots and other programs that are at the forefront of energy transformation efforts in the United States. Some of the offerings GMP was able to implement include customer-facing offerings related to distributed energy storage and transportation electrification.

There is a growing need across the U.S. for flexible and adaptive regulatory frameworks that permit expedited deployment of innovative pilots. Such frameworks should include the ability to prototype customer-facing programs and services. We commend GMP and the Commission for being leaders in this space and demonstrating the potential for innovation frameworks to deliver customer value and new ways of engaging customers in a clean energy future.

That said, just as there is a need to expeditiously innovate with new customer-facing initiatives to trial new ideas and approaches, there is a pressing need to scale those solutions that have proven successful in the pilot stage and can deliver benefits to all customers. In that spirit, we support GMP's proposed regulation plan improvements when it comes to the treatment of tariffed New Initiatives. Experience has shown that when an innovative pilot proves very successful with strong customer interest, such as with the implementation of GMP's ESS tariff, the existing plan approach acted as somewhat of a barrier to nimble scaling, requiring GMP to request that the Commission authorize additional upfront capital investment to support the fully-subscribed program.

Going forward, GMP proposes that all new, unanticipated tariffed programs developed during the term of the proposed Plan that are approved by the Commission be treated separately outside of the capped capital amounts, in a manner similar to GMP's recent Climate Plan and Broadband Tariff Rider programs. On balance, we support GMP's proposed approach which should remove any artificial barriers to scaling innovative programs with strong customer interest that, by their very nature, are designed to create positive value for GMP's customers over the program life, whether through direct financial value or through improved reliability.

VI. Focus Areas to Enhance GMP's Proposed Regulation Plan

A. CAPEX and OPEX Parity

Q89. Do you have specific recommendations related to the area of CAPEX and OPEX parity?

A89. Yes. We recommend additional implementation of alternative regulatory mechanisms to further equalize the treatment of CAPEX and OPEX within the regulatory framework.

Q90. Why is CAPEX/OPEX parity important for customers?

A90. As mentioned earlier in this testimony, traditional electric company regulation creates an inherent bias for electric companies to prefer electric company-owned capital investments over other solutions because electric companies earn a rate of return on CAPEX but not

OPEX. This disparate treatment of CAPEX and OPEX is increasingly problematic as traditional CAPEX solutions are not always the best or most cost-effective way to bring value to customers. Over the long term, services that can improve the utilization of, defer, or replace capital investments may have the effect of reducing opportunities for utilities to generate earnings. Because many new technologies are offered only as a service, utilities may be discouraged from using them. Realizing that both customers and utilities stand to benefit from fairer accounting treatment, mechanisms that better equalize the earnings opportunities between traditional capital solutions and service solutions should be implemented.

i. Return on Service-Based Solutions

Q91. Do you recommend development of a mechanism that accommodates capitalized treatment of service-based solutions?

A91. Yes—we recommend the inclusion of an opportunity to capitalize service-based solutions within the next Regulation Plan. More specifically, we recommend accounting treatment of cloud computing and SaaS solutions in line with the latest GAAP guidance, which allows utilities and commissions to treat cloud computing expenses as capital expenses.

The information technology transition from on-premise hardware and software to cloud-based computing is underway in the electric company sector as energy providers seek out increased customer benefit. Regulatory commissions have recognized the ability of cloud and SaaS solutions to provide scalable, mobile, and resilient technology to electric companies and their customers. Despite the many benefits of cloud computing and SaaS, these technologies are at a disadvantage when compared to on-premises IT investments. This is because under traditional accounting and ratemaking rules, on-premises IT is treated as a capital asset that may earn a rate of return, while cloud computing and SaaS solutions are treated as operating expenses, with no ability to earn a return. In order to fully take advantage of the benefits of cloud-based software, these technologies must be able to compete on more equal regulatory footing.

The most discussed potential benefit of cloud computing to utilities and customers is lower costs. Because cloud services are accessed using a "pay-as-you-go," model, by moving to cloud solutions, utilities can pay for what they use. This approach is in contrast to a utility investing in on-premises hardware, which are built for peak usage days—even if those peak times occur only a handful of times over the life of the investment. Cloud solutions allow a utility to pay for what it needs and ramp up or down in response to changing conditions. This flexibility provides benefits to utilities and customers as it allows utilities to avoid over-spending on IT and to be more responsive to customer needs.

In 2016, the National Association of Regulatory Utilities Commissioners passed a resolution encouraging state regulatory commissions to consider allowing utilities to earn a rate of return or provide other incentives for the use of cloud computing solutions.[33] This resolution acknowledged the utility financial bias towards capital expenditures while recognizing the potential customer, environmental, societal, and grid benefits of cloud computing.

[33] NARUC, *Resolution Encouraging State Utility Commissions to Consider Improving the Regulatory Treatment of Cloud Computing Arrangements* (Nov. 16, 2016), available at https://pubs.naruc.org/pub.cfm?id=2E54C6FF-FEE9-5368-21AB-638C00554476.

Several states have already taken action on the regulatory accounting treatment for cloud computing solutions. In Ohio, the PUC made a general statement that it was in the public interest for utilities to capitalize cloud computing costs and invited utilities to propose cloud costs receive such treatment in rate cases.[34] In Pennsylvania, the Commission allowed for capitalization of cloud implementation costs even before the GAAP change.[35] Similarly, in Alabama, Alabama Power was granted the authority to capitalize cloud and related costs on an ongoing basis.[36]

We recommend a regulation plan that follows the guidance set forth by GAAP and NARUC as well as leading state jurisdictions and allows for capitalization of cloud computing and SaaS costs on an ongoing basis, beginning with the next Regulation Plan. Such costs could be folded into the forecasted and locked capital budget or be offered for Commission review and approval in the context of other plans that fall outside of GMP's capital budget.

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[34] Ohio Public Utilities Commission, *PowerForward: A Roadmap to Ohio's Electricity Future* (Aug. 29, 2018), available at https://puco.ohio.gov/wps/wcm/connect/gov/38550a6d-78f5-4a9d-96e4-d2693f0920de/PUCO+Roadmap.pdf?MOD=AJPERES&CONVERT_TO=url&CACHEID=ROOTWORKSPACE.Z18_M1HGGIK0N0JO00QO9DDDDM3000-38550a6d-78f5-4a9d-96e4-d2693f0920de-nawqRqj.

[35] Pennsylvania Public Utility Commission, *Recommended Decision* at 30 (Oct. 18, 2018). Docket Nos. R-2018-3000124, R-2018-3000829, C-2018-3001029, C-2018-3001074, C-2018-3001152, C-2018-3001566, C-2018-3001713, C-2018-3002424, and C-2018-3002755 *in re Pennsylvania Public Utility Commission, Office of the Consumer Advocate, Jason Dolby, Peoples National Gas Company LLC, Office of Small Business Advocate, Duquesne Industrial Intervenors, Leonard Coyer, and NRG Energy Center Pittsburgh LLC v. Duquesne Light Company*. Available at http://www.puc.state.pa.us/pcdocs/1590205.pdf.

[36] Alabama Public Service Commission, *Order*. Docket No. U-4732. Available at https://www.pscpublicaccess.alabama.gov/pscpublicaccess/ViewFile.aspx?Id=ab7ebd69-9e95-4112-9831-11d1e1a476c2.

ii. Capitalization of Prepaid Contracts

Q92. Do you recommend development of a mechanism that allows for the capitalization of prepaid third-party contracts?

A92. Yes—we recommend that opportunities to further equalization of CAPEX and OPEX treatment be explored by allowing for the capitalization of prepaid third-party contracts.

The capitalization of a prepaid contract treats an expense (such as payments for a service) like a capital investment by placing it into the rate base, amortizing it, and recovering costs over time. For example, a service payment could be prepaid for a number of years and amortized over the length of the contract. The electric company can collect its annual carrying costs, including repayment for the electric company expenditure and return on unamortized balances. With this option, the electric company earns a rate of return on the prepaid contract in a similar manner and at a similar level as traditional rate-based assets.

As noted previously in this testimony, the NY PSC issued a declaratory statement in its REV Track 2 order that electric companies could capitalize pre-paid service contracts. Using the New York approach, regulators can incentivize electric companies to cost-effectively procure non-wire solutions or DER solutions instead of traditional electric company-owned assets,; thereby unlocking value and savings for all customers. Under this approach, an electric utility can enter into a power purchase agreement (PPA) with a third-party DER aggregator (e.g. electric vehicles, rooftop PV, or distributed storage) and earn a return on that procurement. By prepaying a 10-year PPA, an electric company could capitalize the expense and earn a rate of return that is equivalent to what the electric company would have earned on a capital expenditure.

As the clean energy transformation continues to accelerate, so too will customer adoption of DER, be it EVs, rooftop solar PV, or distributed energy storage. Regulatory frameworks must evolve and adapt to better accommodate increasingly distributed clean energy systems. By enabling capitalization of prepaid service contracts in the right circumstances, a regulatory framework can better align interests toward leveraging all of these dynamic, flexible, customer-sited assets that will be coming onto GMP's power system. By leveraging these assets acquired largely through customers' capital, Vermont can meet grid needs and enhance system resilience in a manner that delivers cost savings to all customers.

B. <u>Performance Metrics</u>

Q93. Do you have thoughts on how the Commission could further improve and advance its utilization of performance metrics?

A93. Yes. We recommend exploration of a few areas for improvement with the performance mechanisms of the Regulation Plan. We divide our performance mechanism recommendations into three temporal stages. First, within this proceeding, we recommend that electrification-related metrics be expanded. Second, before GMP's next Regulation Plan, we recommend that the Commission consider a comprehensive evaluation of all innovation, performance, and reliability metrics with the purpose of streamlining and focusing all metrics into one report and explore opportunities for online publication. Lastly, after such an evaluation, we recommend that the Commission consider elevating one or more grid service metrics to a scorecard or incentive mechanism.

i. *Electrification Metrics*

Q94. Please explain your recommendation to expand the set of performance metrics to include additional electrification metrics.

A94. One goal that has been identified by GMP is electrification in support of decarbonization and lower overall customer costs through increased load. In the current set of the Regulation Plan's Metrics Report, transportation electrification is represented with some metrics and in GMP Witness Joshua Castonguay's testimony GMP is proposing to expand transportation metric to include fleet electrification. However, building electrification is currently absent. Explicitly articulating building electrification and beginning to develop useful indicators of GMP's progress in this area would add value to the Regulation Plan's Metrics Report.

Because GMP is excelling at transitioning its generation fleet to one that is largely carbon-free, the focus of some performance metrics may need to look forward towards other State policy goals for achieving the carbon reduction identified in the State's Comprehensive Energy Plan.[37] GMP's proposed Plan already includes five performance metrics for transportation electrification. The Commission should also consider creating performance metrics to achieve another State policy goal: building decarbonization. Building decarbonization can improve indoor and outdoor air quality, reduce emissions,

[37] Vermont Department of Public Service, *2016 Comprehensive Energy Plan*, available at https://publicservice.vermont.gov/publications-resources/publications/energy_plan/2016_plan.

and save customers money. Utility focus on building decarbonization could help unlock access to capital for customer investments and help solve the split incentive for landlords and tenants. For these reasons, we recommend that stakeholders work to agree on useful building electrification metrics within the instant proceeding.

Q95. Have other states adopted metrics related to building electrification?

A95. Yes. Minnesota has adopted an outcome of environmental performance with a metric of CO2 emissions avoided by electrification of buildings, agriculture, and other sections.

Q96. Are there metrics that should be considered that could complement electrification goals?

A96. Yes. While there is uncertainty as to how electrification will impact utility loads, the Commission should consider beginning to monitor seasonal loading conditions more closely and how DERs are utilized during these seasons. If GMP begins to electrify significant heating loads, the predominant summer peak could begin to shift to a dueling or predominantly winter peak. If this change were to occur, GMP may want to prioritize DER programs and services that ensure flexibility to cover winter peaks as well as summer. Additionally, low load periods in shoulder months with significant solar production may benefit from flexible resource increasing loads during specific events. We note that many of GMP innovative pilots likely provide flexibility in winter capacity but tracking these trends may provide useful insights for stakeholders.

ii. <u>Comprehensive Evaluation of Metrics</u>

Q97. Please explain your recommendation for the Commission to undergo a comprehensive evaluation of the current innovation, performance, and reliability metrics.

A97. In our discussion with GMP, we learned that they have talked with the DPS regarding ways to update GMP's SQRP during the period covered by this Regulation Plan. We view this as an opportunity to undertake a comprehensive review of the alignment of the SQRP with the current performance metrics structure and content. If the Commission determines such an evaluation would be valuable, we recommend a few areas of focus.

First, restructuring the metrics to follow hierarchal goals, outcomes, and metrics format could create numerous benefits. For example, we observed that there are a significant number of metrics tied to pilots, which may distract from a more focused set of metrics linked to policy goals and regulatory outcomes. Because the intent of pilot metrics appears related to innovation, a subset of metrics may well suffice. While it depends on the administrative preferences of the Commission and GMP, it could be appropriate to report these pilot metrics within pilot-specific dockets and incorporate these incremental changes into the system-wide MYRP performance metrics. Another possibility is that stakeholders may find that some of the other metrics do not clearly tie to an outcome. With that said, the evaluation could lead to more metrics being reorganized and added than eliminated.

Second, stakeholders should consider integrating traditional reliability and service quality metrics into the broader set of performance metrics for GMP. Traditional reliability metrics include SAIDI, SAIFI, and CAIDI as well as slightly more advanced reliability measures such as CELID, CEMI, ASAI, and MAIFI. In addition to traditional reliability metrics, the Commission and GMP should explore ways in which reliability and resilience metrics may capture distributed reliability and resilience investments and benefits. For instance, GMP's catalyzing deployment of customer-sited resources, such as distributed energy storage, can ensure uninterrupted power for those customers with distributed energy storage even where non-DER customers on the same feeder experience an outage. To that end, in a customer-centric electricity system, what we are ultimately concerned with measuring is the end-use, customer experience, which in a high-DER future could diverge materially from a simple top-down view of bulk power system performance. In other words, the system may experience an outage, but individual customers may not on account of their enjoying resilience and reliability benefits of distributed energy storage, for example. Accordingly, new reliability and/or resilience metrics should be developed to track both hours of outage avoided as well as outage events avoided, when customers are able to remain energized by DER through the duration of a traditional "outage event."

Third, GMP, the Commission, and stakeholders should identify and integrate equity-related metrics. GMP's proposed Plan includes some new metrics to better track the access of their program to customers with lower incomes. In addition, GMP and Commission should consider a means to deepen equity, perhaps through a process similar to the Resiliency Zone work highlighted in Mr. Castonguay's testimony that would encourage broader stakeholder participation, particularly by those organizations and community groups that may have been underrepresented in the past: for example, communities that have higher concentration of home heating oil usage, communities with industry transitions (quarries, dairy) or limited industry options, or communities with reduced access to transit options. Stakeholders could identify not only projects that may be undertaken but also the potential indicators and metrics that are worth measuring. For example, this may be tracking household energy burden, reduced outages, as well as job creation and other types of positive customer benefits. As with other performance metrics, parties could begin with high-level policy goals, and link these goals to specific regulatory outcomes and development metrics to track and measure achievement of the outcomes.

Fourth, stakeholders should continue to push forward on grid service-related metrics. The landscape for DER and associated grid services will look very different at the end of this coming Regulation Plan. Accordingly, stakeholders should be investigating opportunities to proactively advance load flexibility in a manner that creates the right regulatory conditions for leveraging DER to provide grid services and deliver value to all customers. Indeed, as the grid transitions toward one that is increasingly bidirectional, populated by variable renewable generation, DERs will increase system flexibility in both directions—that is, via imports as well as exports. For these reasons, a comprehensive suite of metrics should be used to inform performance related to grid service utilization.

Lastly, stakeholders should consider online publication of the adopted metrics, if determined to be cost-effective. An online metric dashboard can clearly and concisely demonstrate GMP's performance and innovative undertakings to customers.[38]

iii. Grid Services Scorecard and Incentive

Q98. Please explain your recommendation for the Commission to evaluate a grid services scorecard and prospective PIM.

A98. As GMP notes in its testimony, the Commission only has one year's worth of reported performance metrics at this time. For this reason, it would be preferrable to have a larger data set before a scorecard or PIM is developed to insulate both customer and GMP from excessive implementation risk. Additionally, if the Commission chooses to undergo a comprehensive evaluation of metrics, creating a scorecard or PIM should logically occur after this proceeding.

Given the potentially long regulatory cycles created by design with MYRPs, the Commission could permit GMP to develop a grid service scorecard or PIM at some point within the proposed Regulation Plan, if GMP determines such a benefit would be beneficial to customers. Our reasoning for this recommendation is that the proposed Regulatory Plan may go until 2027. If the Commission does not start a process for developing a target or incentive for grid services until GMP's next Regulation Plan

[38] The Hawaiian Electric Company provides a leading example of easily accessed performance metrics from the company's website. *See Key Performance Metrics* available at https://www.hawaiianelectric.com/about-us/key-performance-metrics.

(assuming GMP and Commission continue using a similar framework), it could be several years before a DR PIM could be implemented.

Q99. Could you explain what might be encompassed by a Grid Services metric, scorecard, or PIM?

A99. As the electric utility network continues to transform from one defined by central station generation and one-way power flow to a system in which there are thousands of DER and multi-directional power flows, there is an emergent and increasing need to ensure that these new resources are able to play an integral role in the functioning of the network. From a customer perspective, there are benefits to deferring traditional investment, increasing grid reliability and power quality, and procuring grid services in the most cost-effective manner. In other words, the focus here is on both flexible load, which could be modulated in a load building or load shedding manner, as well as on dynamic energy-injecting resources, all of which can be cost-effectively leveraged to support the grid and deliver benefits to all customers.

Grid Services metrics could include measurements that focus on advanced demand response and bidirectional load capabilities and utilization, which might be measured, among other ways, through megawatts of DER interconnected on the grid and enrolled in grid-supporting programs.

VII. Conclusion

Q100. Does this conclude your testimony?

A100. Yes, it does.