STATE OF VERMONT
PUBLIC UTILITY COMMISSION

Tariff filing of Green Mountain Power Corporation requesting a change in rates, effective October 1, 2026	)))	Case No. 26-____-TF
Petition of Green Mountain Power for approval of its new multi-year regulation plan pursuant to 30 V.S.A. §§ 209, 218, and 218d.	)))	Case No. 25-1955-PET

PREFILED DIRECT & SUPPLEMENTAL TESTIMONY OF ANDY EIDEN ON BEHALF OF GREEN MOUNTAIN POWER

January 16, 2026

Summary of Testimony

Mr. Eiden of Current Energy Group ("CEG") presents the benefit-cost analysis ("BCA") completed on behalf of Green Mountain Power ("GMP") which evaluated GMP's focused resiliency work for Fiscal Year 2027 ("FY27"). Mr. Eiden surveys and explains best-practices for resiliency BCA, including the use of jurisdiction-specific tests tailored to policy goals, and presents CEG's methodology, results, and analysis related to GMP's two resilience capital programs in this filing. Mr. Eiden's analysis establishes that both GMP's distribution system Resiliency Projects and its proposed Integrated Energy Storage Pilot will provide net positive benefits and he recommends the Commission approve this work as reasonable and cost-effective investments.

Exhibit List

Exhibit GMP-AE-1	CV
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PREFILED DIRECT & SUPPLEMENTAL TESTIMONY OF ANDY EIDEN ON BEHALF OF GREEN MOUNTAIN POWER

I. Introduction

Q1. Please state your name, affiliation, and business address.

A1. My name is Andy Eiden, and I am Senior Manager of Distribution System Planning and distributed energy resource ("DER") Integration at Current Energy Group, located at 4764 E Sunrise Drive, Unit #508, Tucson, AZ 85718.

Q2. On whose behalf are you testifying?

A2. I am submitting this testimony on behalf of Green Mountain Power ("GMP") in this proceeding.

Q3. Have you previously testified before the Vermont Public Utility Commission?

A3. No. This is my first time testifying before the Vermont Public Utility Commission.

Q4. Have you testified before any other state regulatory bodies?

A4. Yes. I have testified in the following states and proceedings: Illinois (Docket No. 25-0678) regarding Commonwealth Edison's (ComEd's) Virtual Power Plant and Smart Thermostat tariff proposals; Texas (Texas PUC Docket No. 58306) regarding Oncor Electric Company's 2024 Rate Case, focusing on distribution planning, DER interconnection, and T&D rate design; Oregon (Docket No. UM 2377) related to PGE's Marginal Cost of Service Study and issues concerning large load growth; Colorado (Proceeding No. 24A-0442E) covering issues within Public Service Company of

Colorado's 2024 Electric Resource Plan related to DER and large load growth forecasting and ratepayer risks, and T&D line extension policies; Kentucky (Case No. 2025-00045) regarding EE and DER potential modeling, including how DERs such as energy storage can be used to meet new resource adequacy capacity needs associated with large load growth; and Massachusetts regarding DER integration and T&D capital investment projects (D.P.U 25-31), as well as EV time of use rates and rate design (D.P.U. 23-84/D.P.U. 23-85).

Q5. Please describe your experience in the energy and utility industries and your educational and professional qualifications.

A5. I joined Current Energy Group in 2025, where I focus on utility system planning and DER integration across multiple states, including participation in regulatory proceedings on behalf of clients related to the newly enacted Electric System Planning regulations in Maryland, and the Long-Term System Planning Process in Massachusetts. CEG specializes in providing clients regulatory services in the areas of cost-of-service modeling, regulatory innovation, performance-based regulation, DER, rate design, renewable program development, grid modernization, new grid technologies, integrated resource planning, and electric vehicles ("EVs").

I currently serve as a member of the Advisory Board for Stanford University's Sustainable Systems Lab project called "ReliAdapt", which is an AI-driven platform that addresses the growing challenge of increasing power outages due to extreme weather events, I engage with industry thought leaders around tackling the challenge of reliability and resilience using data-driven methods.

Previously, I served as Senior Principal Planning & Strategy Analyst at Portland General Electric ("PGE"), leading company-wide DER forecasting and planning initiatives, collaborating with the Transmission and Distribution ("T&D") engineering teams to integrate DERs into grid modernization planning, and earning industry recognition for innovation in hosting capacity analysis and forecasting tools. While at PGE, I represented PGE within the Electric Power Research Institute's ("EPRI") ClimateREADi Initiative focusing on T&D Planning issues and Benefit Cost Analysis ("BCA") for resilience investments. Before PGE, I conducted program planning for energy efficiency ("EE") and renewable energy programs at Energy Trust of Oregon, where I also led targeted demand-side management pilots to defer T&D capacity needs with Pacific Power, and earlier, I conducted third-party evaluations of utility EE programs as a consultant at Cadmus Group. My work has been recognized with awards from EPRI and the Association of Energy Service Professionals,[1] and I have contributed to solar photovoltaic ("PV") forecasting studies with Pacific Northwest National Laboratory and served on Stanford University's technical advisory group for the Deep Solar project.

I hold dual Bachelor of Science degrees in Economics and Environmental Studies from Portland State University. I have taught graduate courses on the evolution of the Smart Grid, including T&D grid modernization topics, in the electrical engineering degree program at Oregon State University and the energy policy graduate certificate at

[1]

Portland State University. My educational and professional background is summarized more fully in **Exh. GMP-AE-1**.

II. Purpose and Summary of Recommendations

Q6. What is the purpose of your Direct Testimony?

A6. The purpose of my Direct Testimony is to present the results of the Benefit-Cost Analysis ("BCA") I conducted on GMP's Proposed FY27 Resilience Projects and its Integrated Energy Storage Pilot included in the current case. I also discuss the best practices in the industry related to conducting BCA for resilience investments and how the methodology utilized here to assess GMP's investments aligns with ongoing discussions in Vermont on integrating resilience into utility planning. For review along with my testimony, I also provide the BCA model with working formulas intact as **Exh. GMP-AE-2**.

Q7. How is your testimony organized?

A7. The remainder of this section provides an overview of GMP's Resilience Projects and Integrated Energy Storage Pilot and presents high-level BCA results. Section III describes the current state of the industry with respect to integrating value of resilience into utility planning and regulatory decision making and discusses best practices pertaining to conducting BCAs for utility resilience investments. Section IV provides an overview of GMP's Resilience Projects. Section V describes the BCA modeling I conducted for GMP's Resilience Projects and provides detailed modeling results. Section VI discusses conservative assumptions used in the current modeling approach and suggests areas of future improvement to refine GMP's value of resilience framework within the context of the wider arena of Vermont policy regarding resilience investments and planning. Section VII describes GMP's Integrated Energy Storage Pilot and the BCA modeling I conducted to evaluate that pilot program. Section VIII concludes my testimony.

Q8. Can you summarize the portfolio of prospective work that you have reviewed on behalf of GMP?

A8. As described by GMP witnesses Mike Burke and Josh Castonguay, GMP is proposing two areas of focused resiliency work for its Fiscal Year 2027 ("FY27"), which is the Rate Year for setting the cost of service in this filing. First, as described by Mr. Burke, are GMP's Resiliency Projects: approximately $76M of targeted T&D hardening work on the ten circuits on GMP's system experiencing the greatest outages during storms, treating approximately 121 miles in total. Second, GMP has developed an Integrated Energy Storage Pilot, a $7.2M targeted program involving the installation of 300 whole-home backup energy storage systems as a resiliency alternative on remote areas of the grid, as described further by Mr. Castonguay.

Q9. What are the top-line conclusions of your analysis?

A9. Overall, GMP's approach to estimating and including a value of resilience to inform its T&D investments is an innovative and useful step that is unique among industry peers. Based on my analysis, the $76M of Resilience Projects target feeders within GMP's service area with high historical outages and provide significant resilience benefits for customers. Figure 1 below shows the overall results from the BCA modeling CEG conducted, details of which are provided in Section V of my testimony. The overall Benefit-Cost Ratio ("BCR") for the Resilience Projects is 16.05, indicating that when considering the value of resilience alongside traditional utility system cost savings, the accelerated resilience investments yield incremental benefits that significantly outweigh the incremental costs of the Resilience Projects compared to the Baseline Scenario discussed further below. The Overhead Spacer Cable ("OH Spacer") project type on 3-phase has the highest BCR among the three project types. This is primarily due to two factors. The first is the higher relative number of customers impacted by these projects, which are predominantly in Zone 1 and 2. In Section V Subsection C I discuss the three project mitigation types in more detail and how the relative scoring within a given Zone are handled in the model. The second is the feeder backup value that I quantify for the Resilience Projects all fall within feeders that are 3-phase OH lines, and are therefore attributed to this project type in our modeling.

Figure 1. Overall Resilience BCA for FY27 Resiliency Projects

Project Type	Line Phases	(A) NPV Total Incremental Benefits	(B) NPV Total Incremental Costs	(C) (A ⁄ B) Benefit Cost Ratio
OH Spacer	1-Phase	$ 13,763,473	$ 2,268,584	6.07
OH Spacer	3-Phase	$ 222,896,675	$ 8,169,183	27.29
UG CIC	1-Phase	$ 39,194,096	$ 6,748,987	5.81
Total		**$ 275,854,244**	**$ 17,186,754**	**16.05**

I also analyzed the resilience value of GMP's Integrated Energy Storage Pilot as well as the utility system impacts. Figure 2 shows the overall resilience BCR results for the Integrated Energy Storage Pilot. The Integrated Energy Storage Pilot has an overall BCR of 1.11, indicating that the incremental benefits outweigh the incremental costs of implementing the program. The BCR is 1.09 even without considering the additional resilience value attributable to the program. I discuss the individual cost and benefit streams incorporated into my analysis in more detail in Section VIII of my testimony.

Figure 2. Overall Resilience BCA for Integrated Energy Storage Pilot

Project Type	(A) NPV Total Incremental Benefits	(B) NPV Total Incremental Costs	(C) (A ⁄ B) Benefit Cost Ratio
Integrated Energy Storage Pilot	$ 6,615,432	$ 5,941,546	1.11

Q10. Please summarize your recommendations.

A10. Based on the analyses presented in this testimony, I recommend that the Commission approve GMP's proposed FY27 Resilience Projects and the Integrated Energy Storage Pilot as reasonable, cost-effective, and consistent with the Commission's prior orders. This recommendation is based on a conservative application of best-practice resilience valuation principles, aligning with the National Standard Practice Manual, EPRI's Climate READi guidance, and other leading industry work.

Specifically, my analysis demonstrates that GMP's FY27 Resilience Projects produce substantial net benefits when evaluated using best-practice resilience valuation principles against a reasonable counterfactual baseline, with an overall benefit-cost ratio of 16.05 under a Total Resource Cost test. These results indicate that accelerating targeted system hardening on GMP's worst-performing circuits is highly cost-effective and materially reduces customer outage exposure, future restoration costs, and ongoing operational expenses compared to deferring this work.

I further recommend that the Commission view the Integrated Energy Storage Pilot as an appropriately scoped test of residential energy storage as a complementary resilience strategy in remote portions of GMP's system. Even without assigning additional value to long-duration outages or broader societal resilience impacts, the Pilot produces net benefits, with a benefit-cost ratio of 1.09, while providing significant outage protection to customers facing among the highest outage risk on the system.

III. Resilience Benefit-Cost Principles and Industry Status

Q11. What is the purpose of this section of your testimony?

A11. The purpose of this section of my testimony is to discuss the status of resilience valuation within utility planning and regulatory frameworks across the industry in order to situate the analyses I conducted for GMP's FY27 T&D Resilience Projects and the Integrated Energy Storage Pilot. I highlight research regarding BCA methodologies that apply to evaluating utility resilience investments and quantifying resilience value from mitigation investments like system hardening. I provide an overview of relevant approaches to monetize the value of resilience estimates and discuss these methodologies in the context of regulatory decision making and ongoing policy discussions in Vermont on the development of new methodologies to value and quantify resilience.

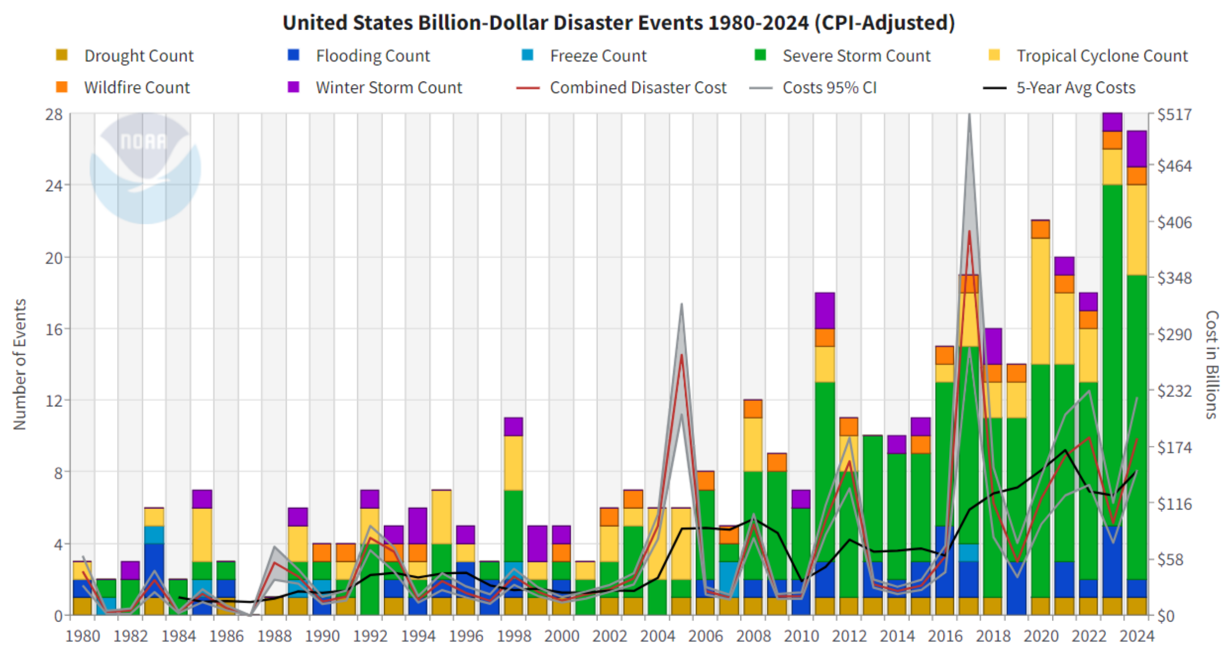
Q12. Can you summarize the current state of resiliency planning efforts in other jurisdictions?

A12. Climate-change driven impacts are significantly impacting utility infrastructure across the country. Weather events such as flooding, lightning, ice, extreme temperatures, and extreme winds already cause the vast majority of power outages in the United States.[2]

[2] E. Mills. "Extreme grid disruptions and extreme weather." *Lawrence Berkeley National Laboratory*, U.S. Disaster Reanalysis Workshop, May 3, 2012.

Damage from extreme weather events has been rising and is likely to have a bigger impact on electrical infrastructure moving forward. Analysis of National Oceanic and Atmospheric Administration ("NOAA") data show that billion-dollar disasters occur nearly five times more frequently than in the 1980s (see Figure 3).

Figure 3 The Number of Extreme Weather Events and the Cost to Recover From Them[3]



As a result, many different efforts across U.S. Department of Energy National Laboratories, electric industry trade groups, and academic research institutions have been approaching the impacts of climate change and resilience—in some cases for many years building on previous planning work for energy efficiency. EPRI is a leading electric industry organization that recognized the need to bring together industry leaders alongside academic and government researchers in order to provide assistance to utilities

[3] Adam Smith, "2024: An Active Year of U.S. Billion-Dollar Weather and Climate Disasters | NOAA Climate.Gov," January 10, 2025, https://www.climate.gov/news-features/blogs/beyond-data/2024-active-year-us-billion-dollar-weather-and-climate-disasters.

seeking to value their resilience investments and integrate resilience into planning. Through tools like the Climate READi Compass and its Benefit-Cost Analysis guidance, EPRI's initiative helps utilities capture resilience benefits through a quantified framework, compare them against costs, and justify proactive investments that reduce outage risks and long-term system costs.[4]

To date, utility led resilience planning focused on understanding the specific risks and benefits in a utility's territory is rarely done in other jurisdictions. Utilities in other states that have engaged in resilience planning exercises were usually forced into action by extreme weather events (e.g. Entergy after Hurricanes Katrina and Rita, Consolidated Edison ("ConEd") after Superstorm Sandy) without standardization to the process.[5] Regulators have so far been cautious to approve resiliency improvements without clear examples of first-movers and established methods in other jurisdictions.[6] Despite the fact that the approach to evaluating and valuing resilience is still developing, proactive regulators are nevertheless moving ahead prudently given the pace of major events and significant customer impacts occurring regionally and nationwide. The Commission's Order approving GMP's initial Zero Outages Initiative ("ZOI") investments acknowledges this uncertainty but also recognizes the imperative to act and authorized

[4] "Climate READi," Electric Power Research Institute, accessed December 17, 2025, https://www.epri.com/research/sectors/readi.
[5] *Id*.
[6] William McCurry and Elliot Nethercutt, *Developing a Shared Framework to Value Resilience Investments*, Ch 2, Energy Resilience Reference Guide (National Association of Regulatory Utility Commissioners, 2023), https://pubs.naruc.org/pub/458600D2-913F-CBF6-B8F3-BBF1A796F00E.

initial investments on the expectation that additional experience and data would inform resilience planning.[7]

However, as discussed throughout the remainder of this section, while resilience planning frameworks are new, substantial guidance does exist and can be brought to bear. The BCA principles and approaches that inform my testimony are grounded in longstanding frameworks used to assess utility investments and ratepayer benefits, such as those used to evaluate cost effectiveness of distributed energy resource investments. One of the most commonly cited resources is the National Standard Practice Manual ("NSPM") which elaborated key principles for conducting BCA that updated and expounded upon traditional guidance that has influenced utility decision-making and regulatory review of other investments, such as energy efficiency, including the California Standard Practice Manual ("CaSPM") developed in the 1990s.[8]

Q13. Have the principles in the NSPM been applied to resilience investments?

A13. Yes. A 2021 report by Sandia National Lab applied the principles outlined in the NSPM for conducting BCA of resilience investments.[9] The Sandia BCA report reiterates the continued importance of the eight fundamental NSPM principles when it comes to conducting BCA for resilience investments, which I include in Figure 4 here, and

[7] Case No. 23-3501-PET, Final Order of 10/18/2024 at 23-25, 30.
[8] National Energy Screening Project. *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*, (August 2020), available for download at: https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/.
[9] Jennifer Kallay et al., *Application of a Standard Approach to Benefit-Cost Analysis for Electric Grid Resilience Investments,* Sandia National Laboratories, Report, (May 2021), https://www.osti.gov/servlets/purl/1821803. (Hereinafter "the Sandia BCA Report").

highlights several new considerations when applying these principles to resilience investments.[10]

[10] Id. at 21-22.

Figure 4. Principles of BCA with Implications for Application to Resilience Investments

Principle	Description	Implications for Resilience
Treat Utility Resources Consistently	All utility resources should be compared using consistent methods and assumptions to avoid bias across resource investment decisions.	All resilience investment options should be evaluated using BCA.
Align with Policy Goals	Jurisdictions invest in or support energy resources to meet a variety of goals and objectives. The jurisdiction-specific BCA test should therefore reflect this intent by accounting for the jurisdiction's applicable policy goals and objectives.	If resilience is a policy goal, resilience costs and benefits should be captured.
Ensure Symmetry	Asymmetrical treatment of benefits and costs associated with a resource can lead to a biased assessment of the resource. To avoid such bias, benefits and costs should be treated symmetrically for any given type of impact.	If resilience costs are included, resilience benefits should be as well.
Account for Relevant Impacts	BCA tests should include all relevant impacts including those that are difficult to quantify or monetize.	Some resilience benefits may be hard to quantify but they should not be ignored or given no value.
Conduct Forward-Looking, Long-Term, Incremental Analyses	BCA should be forward-looking, long-term,[25] and incremental to what would have occurred absent the investment. This helps ensure that the investment in question is properly compared with alternatives. The analysis should consider the entire lifetime of the investment so it can capture the full costs and benefits associated with the solutions under consideration.	The benefits of resilience investments may not be experienced frequently or soon.
Avoid Double-Counting Impacts	BCA present a risk of double-counting benefits and/or costs. All impacts should therefore be clearly defined and valued to avoid double-counting.	The delineation by perspective can help avoid counting the same impact twice.
Ensure Transparency	Transparency helps ensure engagement and trust in the BCA process and decisions. BCA practices should therefore be transparent, where all relevant assumptions, methodologies, and results are clearly documented and available for stakeholder review and input.	Resilience costs and benefits should be clearly named and defined.
Conduct BCAs Separately from Rate and Bill Impact Analyses	BCA answer fundamentally different questions than rate and bill impact analyses, and therefore should be conducted separately from the rate and bill impact analysis.	As the cost of some resilience investments may be high, rate and bill impacts are an important, but separate consideration.

One principle from Figure 4 I note here is the need to "conduct forward-looking, long-term, incremental analysis." Section V of my testimony describes the BCA methodology I followed, including a detailed discussion of the baseline investment scenario constructed to weigh the "incremental" long-term costs and benefits of GMP's proposed resilience investments throughout their entire lifecycle.

Applying these core principles, Sandia recommends the creation of a "Jurisdiction-Specific BCA test," building upon but modifying the traditional BCA tests outlined in the CaSPM, such as the Total Resource Cost ("TRC") test, to best assess resilience investments. As described below, this test allows for typical system impacts to be included in a single BCA framework alongside regulatory perspectives unique to a jurisdiction, such as meeting policy goals outlined in legislation, existing regulations, or prior commission orders. This accounting for regulatory and policy goals is important with respect to resilience investments, which might indicate the need to incorporate a range of additional impacts, such as impacts to customers, communities, and society.[11]

Q14. What are the components of a jurisdiction-specific test as recommended by Sandia?

A14. The Sandia BCA Report provides a road map to follow with five steps to guide stakeholders in developing a Jurisdiction-Specific BCA Test. These are:[12]

1. Articulate Applicable Policy Goals
2. Include All Utility System Impacts
3. Decide which Non-Utility System Impacts to Include

[11] Id., at 24.
[12] Id., at 23-24.

4. Ensure that Benefits and Costs are Properly Addressed
5. Establish Comprehensive, Transparent Documentation

Q15. What are the types of benefits that might be valued in a jurisdiction-specific test?

A15. The Sandia BCA Report lists a subset of the overall benefits identified in the NSPM that are applicable to resilience investments. Figure 5 shows these benefits along with whether they apply to the utility system, the host customer, the community, or society.

Figure 5. NSPM Benefits Applicable to Resilience Investments (from Sandia BCA Report)[13]

Type	Impact	Utility System	Host Customer	Community	Society[31]
Generation, Transmission & Distribution: Energy and Capacity	Reducing Emergency Staff Deployment Costs	X			
	Avoiding Energy Infrastructure Damages	X			
Non-Energy: Economic[32]	Avoiding Damages to Goods and Infrastructure		X	X	X
	Avoiding Lower Revenues from Lower Production and Fewer Sales of Goods and Services		X		X
	Reducing Emergency Staff Deployment Costs		X	X	
	Avoiding Departure of Customers Important to the Community			X	
	Avoiding Lost Economic Development, Education, and Recreation Opportunities			X	X
Non-Energy: Public Health, Safety, and Security	Reducing Medical and Insurance Costs	X	X	X	X
	Avoiding Loss of Quality of Life	X	X	X	X

[13] Id., at 30.

In developing the resilience BCA used in this analysis, I incorporated utility system impacts as well as customer benefits in the form of improved resilience. I describe each cost and benefit included in the model in Section V.

Q16. Can robust estimates of the value of resilience be quantified?

A16. Yes. For example, Lawrence Berkeley National Laboratory ("LBNL") developed the Interruption Cost Estimate ("ICE") calculator v2.0, which uses customer damage functions that represent the economic cost of outages to customers as a function of a variety of inputs.[14] The ICE Calculator was developed by LBNL in order to help utilities assess the value of reliability and resilience improvements.

Q17. Please describe the inputs to the ICE Calculator v2.0.

A17. The tool takes several key inputs listed below in order to determine the value of resilience:

- Customer counts
- Customer class (residential, non-residential)
- Average interruption duration
- Energy consumption (kWh)
- Season (summer, fall, winter, spring)
- Time of Day
- Household income

[14] Peter H Larsen et al., "ICE Calculator 2.0: Final Report for Phase 1 of the National Initiative to Update the Interruption Cost Estimate (ICE) Calculator," 2025, https://escholarship.org/content/qt2x78m2q9/qt2x78m2q9.pdf.

- Other characteristics (e.g., work from home status, access to backup generator)

Q18. What do the ICE calculator results represent, and how does this inform the analysis of resilience projects?

A18. The ICE calculator results represent a proxy for the value of resilience in terms of reducing or avoiding an outage. The survey methodology asks residential customers a series of questions to derive their "willingness-to-pay" to avoid an outage, and is therefore a proxy for customer's stated value that they place on resilience. By comparison, the ICE tool's estimates of non-residential resilience value are based on direct cost of productivity losses such as lost revenue or impacts to GDP. The ICE v2.0 tool was recently updated by LBNL after a significant survey effort to include survey responses from more representative regions across the U.S. Importantly, there is now greater reflection of respondents in the Northeast, including New York and Massachusetts.

Q19. Have you reviewed Vermont developments on resilience valuation and planning?

A19. Yes. As part of my research into resilience planning efforts, I reviewed the Commission's open investigation into the resilience of Vermont's electric grid in Case No. 25-0339-PET, and the materials provided within that proceeding. I also reviewed the Commission's Order partially approving GMP's ZOI investments in Case No. 23-3501-PET ("ZOI Order").

Q20. What is your understanding of the purpose and status of the resilience proceeding in Case No. 25-0339-PET?

A20. This proceeding was opened at the request of the Vermont Department of Public Service ("Department") following the Commission's ZOI Order. It seeks to investigate the development of a common framework for defining, valuing, measuring, and planning for the resilience of Vermont's electric grid, through a series of informal stakeholder workshops led by the Department. Technical assistance has been provided by LBNL partnered with the University of Texas and participants included distribution utilities, members of Vermont's emergency management and resilience planning communities, and climatologists.

While this investigation remains open, I understand that the Department expects to submit a report with its findings and recommendations early in 2026.[15] Throughout the proceeding, LBNL staff have presented recommendations and in August 2025 the Department submitted a "straw proposal" developed with assistance from LBNL for planning, measuring, and valuing resilience within utility planning. I reviewed this straw proposal with its stated limitations as a draft for stakeholder discussion in mind.

Q21. How does the Department's straw proposal approach benefit-cost analysis for resilience work and how does this relate to the principles you discuss above?

A21. The Department's straw proposal identifies the core components recommended to be included within a resilience BCA framed in general terms to provide a draft for

[15] Case No. 25-0339-PET, 12/22/25 DPS Status Update.

refinement. From my review of the proceeding, I also understand that a potential common framework in Vermont would need to account for a range of distribution utility sizes with resulting differing approaches to planning tools, and therefore gather that the framework may need to leave flexibility for utilities to design analyses to meet the core requirements of the BCA framework, rather than prescribing specific approaches.

The five components of a BCA for system-enhancing resilience investments identified in the straw proposal require: 1) characterizing the resiliency projects under review and their expected benefits; 2) characterizing system risks; 3) projecting physical impacts of those risks, with and without intervention; 4) calculating the resulting power interruptions; and 5) quantifying the economic impacts of those interruptions. In this last step, economic impacts must include consideration of avoided customer interruption cost, avoided system restoration costs, and avoided costs from alternative resilience activities such as reduced vegetation management. Utilities may also include other benefits that are appropriate for BCA consideration.

As a general matter—and understanding that this is a draft framework—this proposed framework appears to outline options for a potential future jurisdiction-specific test approach. Specifically, accounting for avoided customer and system costs aligns with the modifications in the jurisdiction-specific test to address policy goals and identify the types of benefit—and from whose perspective they are evaluated—that are important to the analysis.

Q22. What is your understanding of the Commission's ZOI Order as it relates to this analysis?

A22. My understanding is that in the Commission's Order approving T&D investments under GMP's ZOI initiative, there is an expectation that further proposed resilience work should be supported by additional planning and seek to provide greater information regarding the performance of these projects and their relative costs and benefits.

Q23. What approach do you take in your BCA modeling in light of the best practices discussed above?

A23. In reviewing the available literature, examples of other utilities engaged in resilience investment planning, and the Department's straw proposal pertaining to BCAs for resilience, I have developed a resilience BCA methodology that follows the NSPM principles for evaluating resilience investments as outlined in the Sandia BCA Report and also mirrors EPRI's ClimateREADi guide to conducting BCA for resilience investments.[16]

Specifically, the BCA methodology I use in my analysis evaluates the full lifecycle costs and benefits of GMP's FY27 T&D Resilience Projects and the Integrated Energy Storage Pilot. I establish a baseline counterfactual scenario to identify the net costs and benefits, and quantify a monetized value of customer resilience using the ICE v2.0 calculator.

[16] EPRI ClimateREADi Investment Guide: Performing a CBA, https://apps.epri.com/climate-readi-investment-guide/en/cba.html.

Q24. Is your approach consistent with the Department's and LBNL's straw proposal?

A24. Yes. Broadly speaking, I find high-level agreement between the NSPM principles and EPRI's ClimateREADi guide for conducting BCA for resilience investments and components of the straw proposal. I have not applied the straw proposal in this BCA and have not formed a detailed opinion of the proposal in this case because it is still under development and disclaims that it is only a high-level framework for discussion. However, my work does address each of the five components identified in the straw proposal, which aligns with other methods I cite above, and which are set forth in greater detail in Section V, below. Specifically, I account for the three types of economic impacts called for in the straw proposal, identifying resilience value from the customer perspective, and projected avoided restoration costs and other operational utility cost savings.

Q25. Please summarize the findings from your review of the utility climate and risk planning and value of resilience literature as it pertains to the BCA modeling you conducted for GMP's T&D resilience investments.

A25. My review of the utility climate risk, resilience planning, and BCA literature supports three overarching conclusions relevant to the modeling conducted in this testimony.

First, while formal resilience planning and valuation frameworks are still emerging, there are existing BCA principles—particularly those articulated in the NSPM—that are both applicable and appropriate for evaluating resilience investments when adapted to account for forward-looking risk, uncertainty, and customer impacts. Reports from Sandia, EPRI, and LBNL consistently emphasize that resilience benefits should be evaluated incrementally against a clearly defined baseline and assessed over long time horizons, reflecting the infrequent but high-impact nature of extreme weather events.

Second, the literature demonstrates that customer-level resilience benefits can be credibly quantified using established tools such as the ICE calculator, particularly when combined with utility-specific outage data and engineering assessments of mitigation effectiveness. While these tools do not capture all dimensions of resilience—especially long-duration and widespread outages—they provide a defensible and conservative proxy for customers' economic value of avoided interruptions, and their use is increasingly common in regulatory proceedings.

Third, the literature reviewed in this section emphasizes that resilience investments should be evaluated using forward-looking, incremental analytical frameworks that compare system outcomes with and without mitigation, rather than relying solely on backward-looking metrics or short-term cost comparisons. As articulated in the Sandia BCA Report, best practice calls for explicitly characterizing risks, projecting outage impacts under alternative conditions, and quantifying the resulting economic consequences. These principles inform the comparative structure of the BCA methodology applied in my testimony.

Taken together, this body of literature supports the conclusion that the BCA methodology applied here represents a reasonable, conservative, and policy-aligned approach to evaluating GMP's proposed resilience investments, and that the resulting findings provide meaningful information to inform Commission decision-making.

IV. Overview of GMP's Proposed Resiliency Projects

Q26. What is the purpose of this section of your testimony?

A26. This section introduces the portfolio of work that I have analyzed for GMP, which is proposed to be completed during FY27. This work includes $76M of targeted T&D hardening work that represent accelerated investments to increase system resiliency, and also includes the Integrated Energy Storage Pilot program to further evaluate residential storage as an alternative to T&D resiliency investments in certain remote areas on GMP's circuits. I describe each set of investments below in this section, and they are further described in detail by GMP witnesses Michael Burke (T&D investments, known as "Resilience Projects" under GMP's proposed multi-year regulation plan) and Josh Castonguay (Integrated Energy Storage Pilot).

Q27. Please describe your understanding of GMP's Resilience Projects for increased T&D resilience.

A27. GMP's Resilience Project plan for FY27 builds from investments it made under its Zero Outages Initiative, in which the Commission approved $150M of accelerated capital investment through the end of FY26 on GMP's distribution system. This work focused on two circuits, portions of which were experiencing some of the worst outcomes on GMP's system at the time of that proceeding, identified as the East Jamaica EJ-G7 and Wilmington 56G1 circuits, as well as other hardening projects on GMP's list of 20 least reliable circuits. The FY27 Resilience Projects shift focus from the EJ-G7 and the 56G1 circuits to target the next ten least-reliable circuits on GMP's system (see Figure 7 below).

Two general categories of mitigations are used for this work: overhead storm-hardening with OH Spacer and the undergrounding of overhead lines with cable-in-conduit construction (“UG CIC”). The specific mitigation is selected by GMP based on a number of factors: OH Spacer projects are typically deployed on mainline feeders out of the substations, which are three-phase lines with larger conductor sizes and loads, and a greater number of taps, customer services, and total customers. CIC projects are typically used further out on the circuit where there are fewer taps and services and dense forest canopy is common.

Along with the storm-hardened construction, much of this work also relocates previous cross-country lines to roadside locations where restoration is faster and safer. Several of the mainline OH Spacer projects are also designed to provide feeder-back up capability, which means that they can provide backup to the substation or to a portion of a circuit in the event that a transmission fault occurs, or in the event of planned maintenance on the distribution substation. This adds resilience value to circuits that are radially fed.

Figure 6 below shows the FY27 proposed budget for each project type, along with the number of miles treated by each resilience measure and the total capital cost estimate.

Figure 6. FY 2027 T&D Resilience Projects Capital Cost Estimate ($2026)

Project Type	Line Phases	Circuit Miles Treated	Capital Cost Estimate
OH Spacer	1-Phase	19.95	$10,031,291
OH Spacer	3-Phase	51.32	$36,122,723
UG CIC	1-Phase	49.60	$29,842,862
Total		**120.87**	**$75,996,876**

Figure 7 below lists the summary cost in FY27 for each project by the total expenditure by feeder as well as the historical SAIFI score over the 5-year period 2020-2024.[17] Each feeder in the list is at the top of the 20-worst performing circuits list. I present the historical SAIFI over the 5-year period 2020-2024 in order to provide context, however in modeling future expected outage reductions for purposes of defining future customer resilience value I have adjusted the number of expected future outages based on the ratio of the current number of customers to the average historical customer counts included in the 2020-2024 historical SAIFI shown in the figure below. The biggest change has been on CH-G11 where there were 1,617 customers on average from 2020-2024, but moving forward 610 customers have been moved to a different feeder resulting in 1,007 customers served by CH-G11.[18]

[17] 2025 reliability metrics were not available yet when developing the study and therefore have not been included in calculating historical baseline.

[18] For purposes of modeling, I assume the change in customers in 2025 is a proxy for the change in expected future outages. In other words, this adjustment does not attempt to account for the impact on total outages experienced in the baseline by individual customers who have been added or removed from a feeder, but rather captures the average impact.

Figure 7. Total Estimated Capital Costs by Feeder in FY27 T&D Resilience Projects, with historical SAIFI[19] and Least Reliability Circuits Ranking [20]

Feeder	FY27 Capital Cost Estimate	SAIFI in Historical 5-year Period (2020-2024)	Rank in GMP Least Reliability Circuit List (based on SAIDI)
CH-G11	$ 5,509,379	6.65	1
DM-G6	$ 22,796,856	6.72	3
CV-G65	$ 7,578,187	4.71	4
SH-G35	$ 4,276,212	5.69	5
BV-G44	$ 7,149,940	6.53	6
BV-G43	$ 5,638,387	4.43	7
EL-G40	$ 7,243,022	7.36	8
SB-G91	$ 3,928,884	6.05	9
CS-G34	$ 7,281,076	4.30	10
TH-G16	$ 4,594,933	4.57	11
Total	**$ 75,996,876**	**5.93**	

In my modeling, the specific impacts attributable to each mitigation type (OH Spacer and CIC) are broken out for analysis so that the specific costs and benefits of each approach are reflected. I also separate projects within the portfolio depending on whether they are improving a single- or three-phase line. The number of phases and load on a given line has a substantial direct impact on material costs and, because these projects often occur on different areas of the circuit—which GMP has standardized as circuit

[19] This calculation represents the average SAIFI over the 2020-2024 historical period and accounts for changing number of customers by year. Therefore it may differ from the 5-year SAIFI included in GMP's Rule 4.900 Worst 40 Circuits reporting.
[20] SAIDI rankings taken from *Green Mountain Power PUC Rule 4.900 Electricity Outage Reporting, Calendar Year 2024*, submitted January 30, 2025.

"zones"—it is helpful to group by both project type and phase because the projected benefits are dependent on the location within a circuit.

Q28. Please describe your understanding of the resilience benefits resulting from these mitigations.

A28. In the FY27 Resilience Projects, GMP is installing primarily Hendrix spacer cable for its OH Spacer projects, which uses a steel messenger cable to protect the fully-insulated conductor line suspended below from tree contact, with occasional insulated tree-wire in limited single-phase sections. Spacer cable systems provide a range of benefits including reduced outages and increased line insulation, easier vegetation management, and improved power quality through reduced impedance and increased cable sizes, among other benefits.[21] For the evaluation of the OH Spacer projects, I am only including the benefits of reduced outages and improved line capacity resulting from the upgrades. While ease of vegetation management is an expected benefit of this hardening strategy—particularly when re-routing a cross-country line roadside where vegetation management is easier and clearances may be larger—I did not attempt to include a quantified value for it in my analysis. Therefore, the benefits of OH Spacer can be considered conservative.[22]

For underground projects, CIC allows for rapid construction by installing reels of conduit and conductor simultaneously with trenching and backfilling, saving on traditional costs of underground construction. Underground lines are expected to

[21] *See* https://marmonutility.com/overhead/spacer-cable/.
[22] In discussions with GMP the value of reduced vegetation management from installing OH Spacer was identified as a likely benefit but not readily quantifiable and varying based on line location. It was decided to leave this potential benefit out of the analysis. If future analysis demonstrates the incremental vegetation management cost reductions associated with the OH Spacer program then they could be included in future BCA updates.

significantly reduce outages from most causes and in particular extreme weather events, reduce vegetation management needs, and like the spacer cable projects, increases capacity and reduces line losses. My understanding is that these single-phase CIC projects are replacing small conductor size bare-wire relative to the CIC conductor installed, which are sized based on customer load and GMP Engineering Standards.

Q29. Please summarize the Integrated Energy Storage Pilot.

A29. The Integrated Energy Storage Pilot, as presented by GMP witness Josh Castonguay, is a targeted program to evaluate the use of residential-scale energy storage systems as an alternative to T&D on the remote ends of GMP's circuits, where customers are exposed to the greatest number of outages. This area is identified as Zone 4, and each Zone 4 customer within a targeted circuit would have a full-home backup battery energy storage system (BESS) installed following a GMP outreach program. The circuit targeted for this work is the EJ-G7 circuit, GMP's worst-performing circuit in storms in recent years leading up to the ZOI filing. This circuit is currently receiving comprehensive storm hardening on Zones 1-3; this pilot would allow GMP to test the value of a holistic full-circuit resiliency solution during storm response. I modeled this program based on approximately 300 BESS installations to the customers identified within Zone 4, and incorporated GMP's power supply modeling based on existing residential storage programs. The 300 BESSs in this pilot require $7.4M of capital.

Q30. What are the benefits expected for the BESS systems installed in this pilot?

A30. For the participating Zone 4 customer, the BESS provides full home backup power during all outages, including storms, blue sky events such as accidents, planned maintenance, and even large-scale outages on the transmission system or regional grid. During a storm event on the EJ-G7, these customers would remain on while GMP crews address any urgent outage needs. Because of the substantial hardening on this circuit, it is expected that restoration crews would be able to restore grid power to Zone 4 sooner, and also be able to use resources more efficiently knowing that these Zone 4 customers remain with power. My understanding is that the pilot program is designed to evaluate the potential benefits from these types of operational savings, among other potential benefits.

When not providing backup power, these systems are available for GMP to deploy for a range of power supply, power quality, and other use cases as described by Mr. Castonguay. Based on GMP's modeling, which I have reviewed and find reasonable and sound in methodology, these power supply benefits create enough value that each BESS installation is net positive over its useful life for all GMP customers. Below, I analyze the resilience value of this pilot.

V. Resilience Projects Benefit-Cost Analysis

Q31. What are the results of your BCA analysis and what does that signify for the FY27 Resilience Projects?

A31. For the FY27 Mitigation Scenario, I calculated an overall BCR of 16.05 under the TRC test, reflecting significant net benefits including utility future cost savings and increased customer resilience resulting from the accelerated investments reflected in GMP's proposal. Figure 8 shows the final overall portfolio BCA by project type.

Figure 8. Overall Resilience BCA for FY27 ZOI Projects

Project Type	Line Phases	(A) NPV Total Incremental Benefits	(B) NPV Total Incremental Costs	(C) (A ÷ B) Benefit Cost Ratio
OH Spacer	1-Phase	$ 13,763,473	$ 2,268,584	6.07
OH Spacer	3-Phase	$ 222,896,675	$ 8,169,183	27.29
UG CIC	1-Phase	$ 39,194,096	$ 6,748,987	5.81
Total		**$ 275,854,244**	**$ 17,186,754**	**16.05**

The BCR model provides net benefits for accelerating the portfolio of identified projects in FY27 over a baseline scenario. The baseline was developed with input from GMP as described in greater detail below and reflects the expected level of resilience investment that would occur without any accelerated Resilience Project spending. Therefore, the BCR provided here represents the costs and benefits of doing this work now rather than stretching lower investment levels over time. As can be seen in Figure 8 above, each of the types of T&D work included in GMP's proposal is beneficial to accelerate in FY27, with ratios of benefits to costs ranging from approximately 6:1 to 27:1, and an overall ratio of 16:1.

The benefits included in this total include: resiliency values as derived from the ICE 2.0 tool, storm and blue-sky restoration cost savings, operational cost savings, avoided line losses from improved conductors, and the value of implementing feeder-back up on certain circuits. Not included as quantified benefits are additional customer and community values for resiliency not captured in the ICE tool, including the value of increased safety for customers, emergency responders, and GMP's restoration crews, resiliency values for low-probability, high-risk events, broader economic benefits from making these accelerated investments, equity considerations beyond the ICE tool, and reduced brush fire risk. These real benefits are additional to the values I have calculated here, which represent a conservative analysis. These additional qualitative benefits are discussed in greater detail in Section VI below. Figure 9 shows the detailed breakout of the net benefits resulting from each category of expected future savings included in the model.

Figure 9. Overall Net Benefits of the Mitigation Scenario (net over the Baseline Scenario)

Project Type	Line Phases	NPV Reduced Storm Damages	NPV Reduced Non-Storm Damages	NPV Lower O&M Expenditures	NPV Customer Resilience Value - Circuit Hardening	NPV Customer Resilience Value - Feeder-Back Up	NPV Line Loss Reduction
OH Spacer	1-Phase	$ 522,169	$ 42,809	$ -	$ 13,196,383	$ -	$ 2,112
OH Spacer	3-Phase	$ 1,343,245	$ 482,518	$ -	$ 182,568,584	$ 37,855,625	$ 646,703
UG CIC	1-Phase	$ 1,396,935	$ 141,376	$ 747,508	$ 36,758,716	$ -	$ 149,562
Total		**$ 3,262,349**	**$ 666,703**	**$ 747,508**	**$ 232,523,683**	**$ 37,855,625**	**$ 798,376**

As I step through the methodology below, I address how each cost and benefit was calculated in the model, including data sources and assumptions utilized in the modeling.

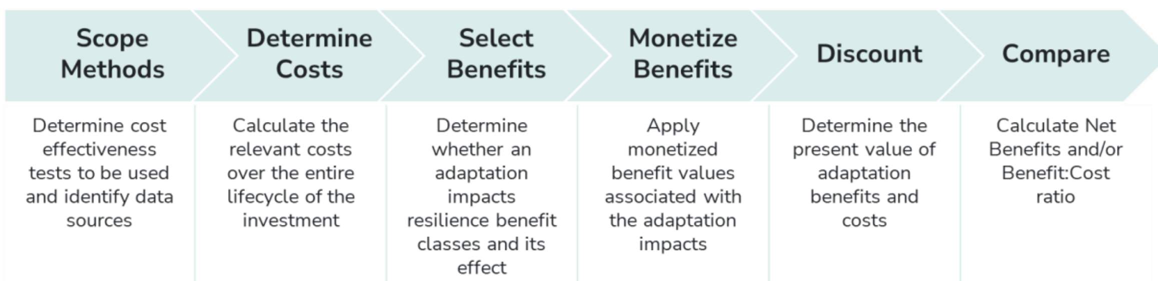
Q32. What conclusions do you draw with respect to the BCA results and your evaluation of GMP's proposed FY27 Resilience Projects?

A32. The results indicate that the proposed FY27 Resilience Projects are not marginal improvements but represent a category of investment for which the total benefits to customers are significant. The magnitude of the BCRs reflects both the concentration of historical outage risk on the targeted circuits and the compounding effects of deferred hardening under rising construction costs and increasing storm severity. From a regulatory perspective, the analysis demonstrates that accelerating these investments meaningfully reduces future cost exposure while delivering substantial customer resilience benefits.

Q33. Please explain the steps you followed to develop the resilience BCA framework.

A33. In developing the BCA framework for evaluating GMP's T&D resilience investments, I relied on two primary sources discussed elsewhere in my testimony: The Sandia BCA Report, and EPRI's ClimateREADi BCA roadmap.[23,24] Figure 10 below shows the high-level steps common to the two approaches.

Figure 10. High-Level Steps to Completing a BCA for Resilience Investments



Each subsection below details the methodology, assumptions, and summarizes key inputs and outputs of the different stages of completing a BCA for resilience investments depicted in Figure 10.

A. <u>Scope Methods—BCA Test Perspective and data source</u>

Q34. What BCA Test Perspective did you use in your analysis?

A34. There are a variety of different BCA tests described by the NSPM that show different perspectives of a proposed project. Figure 11 lists the different perspectives and what costs and benefits are typically included.

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[23] Jennifer Kallay et al., note 10, *supra*.
[24] EPRI ClimateREADi Investment Guide: Performing a CBA, https://apps.epri.com/climate-readi-investment-guide/en/cba.html.

Figure 11. NSPM Traditional Cost-Effectiveness Test Comparison[25]

Test	Perspective	Key Question Answered	Impacts Accounted For
Utility Cost	The utility system	Will utility system costs be reduced?	Includes the benefits and costs experienced by the utility system
Total Resource Cost	The utility system plus participating customers	Will utility system costs plus program participants' costs be reduced?	Includes the benefits and costs experienced by the utility system, plus benefits and costs to program participants
Societal Cost	Society as a whole	Will total costs to society be reduced?	Includes the benefits and costs experienced by society as a whole
Participant Cost	Customers who participate in a program	Will program participants' costs be reduced?	Includes the benefits and costs experienced by the customers who participate in the program
Rate Impact Measure	Impact on rates paid by all customers	Will utility rates be reduced?	Includes the benefits and costs that will affect utility rates, including utility system benefits and costs plus lost revenues

Consistent with the Commission's discussion in the ZOI Order[26] and the developing discussion of resilience valuation in Vermont, the focus of this analysis is on understanding the value of resilience investments, including the experience of customers, avoided storm restoration costs, and other related benefits. I utilized the TRC test to evaluate the costs and benefits of GMP's resilience projects. Using the TRC allows stakeholders to assess the impact of the investments to the utility system as well as the value of providing resilience benefits for impacted customers. A resilience BCA is not intended to be a direct rate analysis because it incorporates a broader set of benefits, but it does help inform the tradeoffs with incorporating a value of resilience into investment decision making by comparing a more comprehensive set of benefits and costs across

[25] National Energy Screening Project. *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*, (August 2020) at E-2, available for download at: https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/.
[26] Case No. 23-3501-PET, Final Order of 10/18/2024.

investment options. I discuss the framework used to quantify the resilience impacts used in the BCA test throughout this section.

Q35. What data sources did you rely on in conducting the BCA?

A35. My primary data sources for conducting the resilience BCA were utility-specific financial and cost inputs provided by GMP that are consistent with the current MYRP filing and reflect actual past incurred expenses, historical outage data from its Rule 4.900 reliability reporting database, and customer demographic data.

Q36. Can you explain in greater detail how you developed a counterfactual baseline to evaluate GMP's proposed resilience investments?

A36. EPRI's ClimateREADi guidance documentation for calculating a BCR for resilience investments highlights the importance of specifying a baseline scenario against which to evaluate the impacts of the mitigation.[27] Accordingly, I established a counterfactual investment pathway ("Baseline Scenario") against which I compared the net impacts of making accelerated resilience investments ("Mitigation Scenario").[28] Importantly, the Baseline Scenario is not a "do nothing" scenario, but rather assumes a continued, albeit lower, level of investment in circuit replacement and hardening. As a result, in the Baseline Scenario the mitigations of OH and UG still occur, but at a much slower pace of investment compared to the accelerated case represented by the Mitigation Scenario.

[27] EPRI ClimateREADi Investment Guide: Performing a CBA, https://apps.epri.com/climate-readi-investment-guide/en/cba.html.
[28] In both scenarios I calculate the full lifecycle costs and benefits and compare discounted present value dollar amounts to determine the final BCR. In the following sub-sections I describe the methodology for calculating future costs and benefits under each scenario.

Q37. Describe the investment levels reflected in the Baseline Scenario used for evaluating GMP's resilience investments.

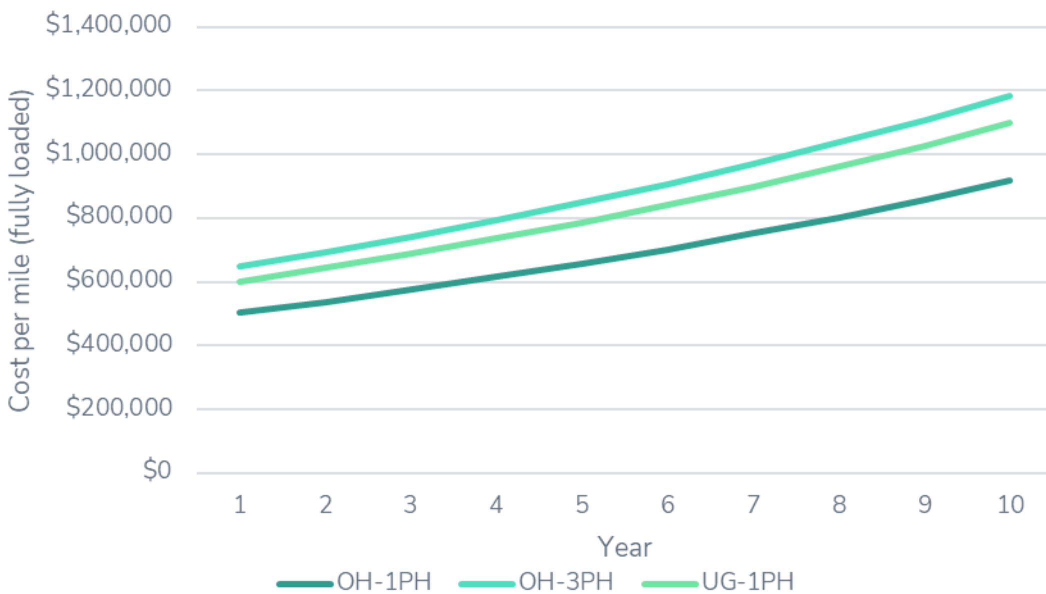
A37. The Baseline Scenario assumes that capital upgrades for T&D system hardening in the target feeders occurs at 10% of the Year 1 investments captured in the Mitigation Scenario. In subsequent years of the Baseline Scenario, the overall investment level is capped at this initial 10% and increased by inflation. The Baseline Scenario therefore aims to capture a similar overall capital expenditure of the Mitigation Scenario, as opposed to mirroring the same level of circuit miles treated in the Mitigation Scenario. This decision reflects the fact that with delayed circuit hardening, future capital investments will result in fewer line miles treated due to construction cost escalation.

Q38. Can you elaborate as to why delayed investment in system hardening will result in fewer future miles treated?

A38. Yes. To the extent that future construction costs for T&D projects increase faster than inflation, investments deferred into the future will cover relatively less units than in the Mitigation Scenario. To estimate this effect, I have scaled the cost per mile of implementing the two mitigations (OH and UG) based on the Handy-Whitman Index for the North Atlantic region. The Handy-Whitman Index is a supplier price index with annual electric industry data going back to 1925 and is commonly used to evaluate price changes in utility assets. I calculated the 10-year average percentage change in overall Distribution Plant costs over the 2015-2025 period of 6.9 percent and used this as an escalator for future construction cost increases.

Applying this escalation factor to escalate future GMP costs per mile in the Baseline Scenario results in a 1.8 times increase in per mile construction costs by the end of initial 10-year investment comparison window. Figure 12 shows the escalated cost per mile per year applicable the Baseline Scenario.

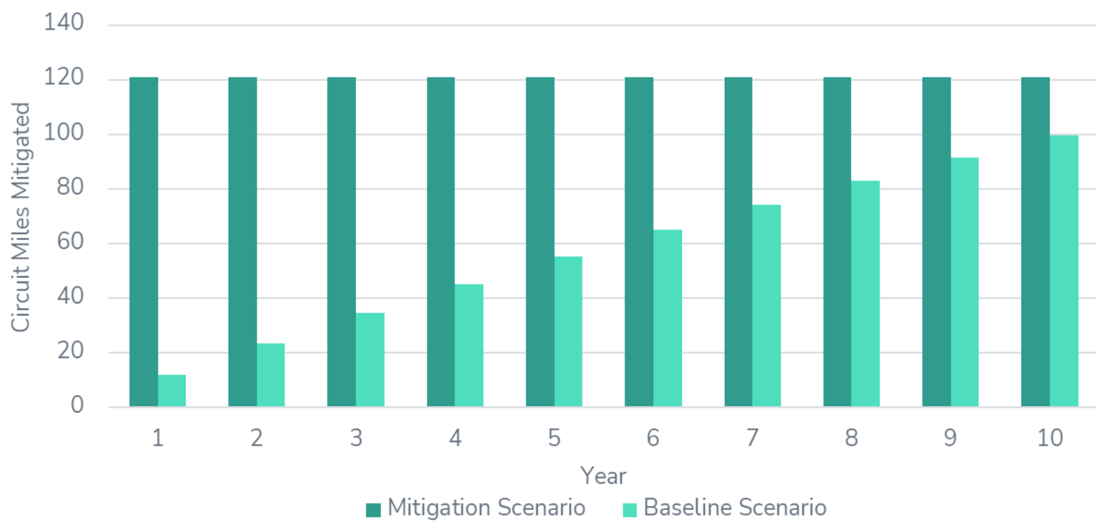
Figure 12. Escalated Construction Costs (Fully Loaded) in Baseline Scenario, by Project Type



Q39. Does the escalation of future construction costs in the Baseline Scenario lead to increased future risk exposure?

A39. Yes. The slower pace of capital investment assumed in the Baseline Scenario has the effect of delaying system hardening and therefore leaves more aging overhead assets exposed to the increasing climate risks discussed elsewhere in my testimony. Figure 13 shows the modeled circuit line miles that are hardened in the Mitigation Scenario and Baseline Scenario over the initial 10-year investment period.

Figure 13. Circuit Line Miles Hardened in the Mitigation Scenario and Baseline Scenario



As shown in Figure 13 above, by Year 10 of the initial investment period, the line miles treated in the Baseline Scenario are lower than in the Mitigation Scenario (100 miles versus 120 miles, respectively). The delayed investments in the Baseline Case leave more circuit miles exposed to increasing storm risks and associated restoration costs, increased exposure to hazards and safety risks for crews and emergency responders, increased wildfire risk, and continue to require elevated O&M expenditures for maintenance.[29] The result is that under the Baseline Scenario, the investments are never able to catch up to the Mitigation Scenario in terms of circuit miles treated. This has the effect of continuing the gap in related costs and benefits that are dependent on the number of treated circuit miles between the Baseline Scenario and Mitigation Scenario throughout the lifecycle analysis period.[30]

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[29] I discuss these increased O&M costs resulting from the delayed investments reflected in the Baseline Scenario in subsection B.

[30] For example, reductions in storm-related costs due to system hardening increase in the Baseline Scenario up until Year 10, and then level out. Given the lifetime of the equipment (47 years for OH and 56 for UG), the Mitigation Scenario continues to have lower storm-related costs throughout the entire analysis period.

Q40. How did you allocate the investment in the Baseline Scenario between the two different T&D resilience project types?

A40. I assumed that the capital expenditures in the Baseline Scenario would be allocated proportionately according to the relative shares of OH and UG investment in the Mitigation Scenario. The Mitigation Scenario reflects GMP's current prioritization of this work based on their selection criteria. This is a reasonable representation of where work would be expected to occur under the Baseline Scenario based on GMP's best judgment at this time. In the event some work moved in location based on unforeseen events over those ten years, it would be expected to be similar in total benefits and costs using the same prioritization criteria.

B. Determine Costs—Calculate relevant lifecycle costs of the investments

Q41. What categories of costs did you include in the calculation of the BCA?

A41. For each project in the FY2027 project list, I included both capital and O&M costs associated with the relevant scenario (i.e., Baseline Scenario and Mitigation Scenario). These high-level cost categories are further broken down into:

- All-in capital carrying costs (including depreciation, taxes, and GMP's weighted-average cost of capital)
- Property tax increases from replacing depreciated infrastructure
- Storm-related restoration costs (both Major and Minor storms)[31]

[31] Future projected storm restoration costs are based on total historical capital and expense costs related to Major and Minor Storm restoration. I do not attempt to split out the future storm costs by discrete category.

- Non-storm related outage restoration costs[32]
- Pole inspections costs
- Vegetation Management
- Customer response calls for Trouble Outages and Danger Trees[33]
- Reduced pole attachment revenue[34]

Q42. Were the costs applied equally in the Baseline Scenario and the Mitigation Scenario?

A42. Yes, all cost streams that I identify above were input into the model based on the first year the new plant would be placed in service, and subject to the same underlying financial assumptions including depreciation, taxes, inflation, and discount rates. A full list of financial assumptions used in the model can be found in **Exh. GMP-AE-2, "Assumptions" tab.**

Q43. Please summarize the Resilience Projects that are included in the BCA.

A43. I used the cost estimates for the FY27 period developed by GMP covering 45 distinct projects encompassing OH Spacer and UG CIC mitigation projects that together impact

[32] While the primary focus of the resilience projects is reducing exposure to increasing storms, the system hardening benefits still apply to reduce other non-storm related outages and commensurate costs. See Zamuda et al., (2019) "Monetization methods for evaluating investments in electricity system resilience to extreme weather and climate change", *The Electricity Journal,* 32(9), available at: https://www.sciencedirect.com/science/article/abs/pii/S104061901930185X.

[33] These cost categories are distinct from Vegetation Management costs and represent GMP response to customer calls regarding trees posing a danger by being close to wires, and other related issues. By comparison, Vegetation Management Costs are routine scheduled maintenance costs.

[34] Only applicable to undergrounding. In discussions GMP noted they are exploring possible contracts to share trenching costs with other service providers, and therefore this cost may reduce in the future. For now, I have left in to be conservative and reflect the current status of the one-sided reduction in pole attachment revenues due to undergrounding.

120 miles of circuit. These circuits are all within the 10-worst performing circuits and therefore face significant reliability issues, which I discuss more in the next subsection. As shown in Figure 13 above, for OH Spacer projects the total project costs in the Mitigation Scenario are $10,031,291 for single phase and $36,122,723 for three phase projects, and UG CIC single phase costs of $29,842,862 for a total FY27 Resilience Project total capital expenditure of $75,996,876. **Exh. GMP-AE-2, "FY27 Resilience Projects List" tab,** includes the individual project costs grouped by mitigation type and whether the project addresses three-phase or single-phase line segments.

Q44. How did you model the capital costs in the Baseline Scenario and the Mitigation Scenario?

A44. In each scenario I modeled the full revenue requirement of the capital investment based on the year the new plant would be placed in service, including accounting for depreciation, income taxes, and return on investment. As described above, in the Baseline Scenario I assumed 10 percent of the Mitigation Scenario investment levels, inflated by CPI for each year of the initial 10 year window. In Year 1 of the analysis this translates to $7,599,688 of capital investment in the Baseline Scenario, inflating to $9,243,869 in Year 10, for a total 10-year cumulative capital investment in the Baseline Scenario of $83,979,407. As I discussed above, the delayed investments in the Baseline Scenario are able to cover lower relative line miles, which I discuss more in the next subsection.

In calculating the BCR for the Resilience Projects, I compared the net lifecycle capital carrying costs by subtracting the present value of the discounted future costs of the Baseline Scenario from the Mitigation Scenario. I discuss discounting in subsection F below.

Q45. Describe how you modeled the costs associated with property tax of the proposed investments.

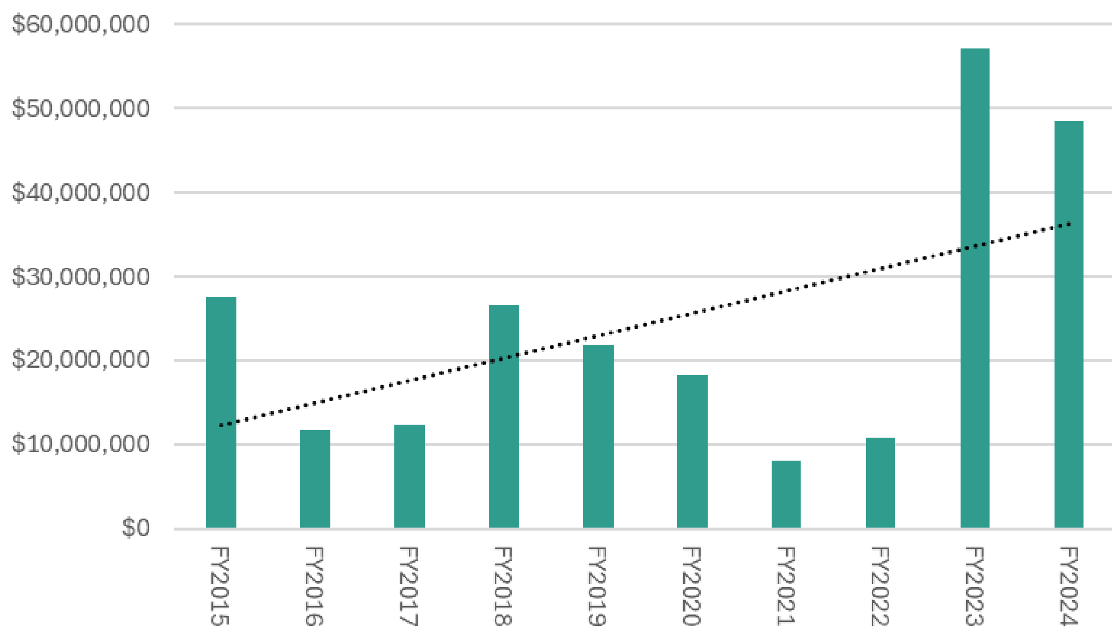
A45. I modeled property taxes as a statewide average annual cost of $1,700 per $1,000,000, or 1.7 percent, of new taxable capital investment in both the Baseline Scenario and the Mitigation Scenario. Based on input from GMP, the taxable amount of the new plant investment is assumed to be 95 percent. The accelerated investments reflected in the Mitigation Scenario result in an increase of overall property tax costs in the initial period of the lifecycle analysis, with $1.2 million in annual property taxes associated with the accelerated investments, compared to an average of $707,010 over the initial 10-year investment period in the Baseline Scenario.[35] While this cost is included in the BCR model as a cost, payment of additional property tax also yields substantial benefit to the local community or state receiving the payments as a form of revenue. Therefore, we have included in the model in order to be conservative. However, there is precedent to treat these as a benefit or a pass-through under a Societal Cost Test view as outlined in the NSPM, or as I previously discussed under a Vermont-specific Jurisdictional Specific Test.

[35] Property tax levels start at $108,288 in Year 1 of the Baseline Scenario and then increase at the same pace as the capital investments to a total of $1.2 million in Year 10. After the initial 10-year investment window, the property tax in both scenarios continues for the full depreciation period of any remaining net plant in service.

Q46. How did you model storm-related restoration costs?

A46. A primary benefit of implementing system hardening is the protection against severe weather and associated equipment damage and widespread outages. I collected historical storm-related outage restoration costs from GMP and analyzed cost trends over time in order to develop inputs to the BCA model. Figure 14 shows GMP's 10-year historical storm restoration costs by FY, including a linear trend line.

Figure 14. Annual Storm Related (Major and Minor) Restoration Costs, FY2015-2024.



The average annual storm costs over this period were $24.3 million, and increased on average by $2.6 million per year using the slope of the linear trend line. I used these two data points as inputs to the model to quantify future storm restoration costs in both the Baseline Scenario and the Mitigation Scenario based on the relative amount of circuit miles treated in each scenario. I have applied the annual linear trend to increase future expected storm costs to only the first ten years of the analysis period, and thereafter only apply inflation.

Q47. Explain how you associated the storm costs to the circuits included in the FY27 Resilience Project lists.

A47. The $24.3 million in average historical storm costs shown in Figure 9 above are an average over the entire GMP service area. In order to assess the proportion of storm costs that could be expected to be reduced from the mitigations targeted at the FY27 Resilience Project feeders I converted the average annual storm restoration costs and the average annual linear increase in storm costs from an annual systemwide average value to a per circuit mile value and then applied this to each individual project based on the circuit length treated in each project. To estimate the reduction in storm-related costs attributable to each project mitigation, I apply an "Effectiveness Score" reflecting the expected ability of the specific mitigation to reduce outages caused by hazard exposure. I describe the Effectiveness Score in more detail in Subsection C regarding discussion of benefits of reduced Customer Resilience.

Q48. In what ways is your method of assigning storm reduction costs conservative?

A48. This is a conservative approach because the historic storm costs that GMP has incurred are most likely concentrated more heavily in the 40-worst performing circuits, of which the FY27 Resilience Projects are a subset. However, my methodology normalizes the average historic costs equally over the whole service area and then applies this normalized dollar per mile cost to the target projects. Therefore, with more granular assessment of the heightened risk probability for storm outages in these circuits, the BCR would be expected to improve. I provide recommendations for refinements to the methodology used here to assess storm damage costs and the benefits from system hardening in Section VI of my testimony.

Q49. Describe how you modeled non-storm restoration costs.

A49. I modeled future expected non-storm restoration costs following the same logic as for the storm-related restoration costs, and applied an average non-storm restoration cost of $472 per incident to the Baseline Scenario and Mitigation Scenario based on historical outage cost data provided by GMP. Similar to the reduction in storm-related costs due to hardening, the non-storm related costs are modeled in the Baseline Scenario based on the share of asset line miles remaining at risk, versus those that have been mitigated. When modeling the expected reduction in non-storm outages from the different mitigations within each FY27 Resilience Project, I apply both the Effectiveness Score and the Applicability Score that are described in Subsection C.[36]

Q50. Describe how you modeled the costs associated with vegetation management.

A50. There are three categories of vegetation management that are reflected in the model: routine tree trimming costs, customer tickets, and danger trees.[37] Of these, the largest cost is the annual tree trimming cost, which is $13,087 per mile (in $2026 USD).[38] GMP segments its feeders into groups that are either on a five-year trimming cycle, or a seven-

[36] I apply only the Effectiveness Score to assess the expected reduction in storm-related costs because the universe of outage causes is by definition “applicable” (i.e., they are weather-related outages, which the interventions are intended to mitigate). By contrast, when assessing the expected impact of the mitigations on non-storm outage restoration costs, I additionally consider the Applicability Score in order to adjust for non-avoidable outages such as transmission faults, planned maintenance outages, etc. I discuss these two factors in Subsection C of my testimony below.
[37] Customer tickets and danger trees both refer to requests by customers who call GMP because of vegetation close to wires.
[38] This value includes traffic control costs.

year trimming cycle. Each of the feeders in the FY27 Resilience Projects list are on a seven-year cycle, therefore I have divided the $13,087 by seven for an average tree trimming cost of $1,870 per mile per year in the Baseline Scenario. In the Mitigation Scenario, the costs of tree trimming are reduced by undergrounding, however there are still some costs as not every pole is eliminated during undergrounding. The comparable cost of tree trimming for undergrounded lines is $129 per mile per year, representing a 93 percent reduction in costs.

The cost of customer tickets in 2025 were $2.6 million, and the cost of danger trees were $570,106. Based on GMP input, I assumed reductions of 75 percent and 90 percent of these costs after undergrounding, resulting in $262 per mile per year for customer tickets in the Baseline Scenario for OH lines, and $65 per mile per year after undergrounding. The danger tree costs are $57 per mile per year in the Baseline Scenario for OH lines and $5.70 after undergrounding. As with the case of tree trimming, I assumed no change for the OH Spacer projects and therefore did not include these costs.

Q51. Did you apply the vegetation management costs to all project types?

A51. No, I only applied the vegetation management costs to the UG CIC project types. This is because, for the OH Spacer project types the Baseline Scenario and the Mitigation Scenario are assumed to have the same costs before and after the mitigation and therefore there is no change. As I discussed above, there are likely benefits to vegetation management that result from installing OH Spacer Cable, but I did not attempt to quantify them for the purposes of this analysis. Therefore, the estimates are conservative from that perspective.

Q52. Describe how you modeled pole inspection costs.

A52. Historical pole inspection costs were provided by GMP and similar to vegetation management costs are only applied to the UG CIC case in both the Baseline Scenario and the Mitigation Scenario. The pole inspection costs were modeled as $476 per mile in the case of OH lines, and $323 per mile in the case of UG lines. Pole inspections take place every 10 years and so these values were divided by 10 for a final input value of $47.6 per mile per year for the OH case and $32.3 per mile per year for the UG case.

Q53. Describe the revenue reduction from reduced pole attachments.

A53. Poles that are above ground have a variety of attachments, such as telephone and cable equipment and wires, or municipal emergency management systems. Each of these attachments brings revenue to the utility, and therefore when poles are removed due to undergrounding, this represents a cost to the utility in the form of reduced revenue. I include a lost revenue amount of $154.67 per mile from undergrounding poles based on data provided by GMP.

Q54. What are the total costs and present value of the full lifecycle costs that fed into your BCA analysis?

A54. Figures 15 and 16 below show the Total FY27 construction costs (CAPEX),[39] alongside the net present value (NPV) of total costs and the constituent cost elements of utility

[39] Note the Total FY27 Columns for the Baseline and Mitigation scenarios shown in Figures 15 and 16 are included for consistency and to allow stakeholders to compare year 1 investment cost differences. However, as described above, the total capital investment in the Baseline Scenario over the 1-10 year window of the analysis period is $83,973,469. The "NPV Utility CAPEX" in column a is the appropriate comparison value for understanding the final inputs to the BCR related to the impact of capital investment costs between the two scenarios.

CAPEX, storm- and non-storm restoration, property tax increases, and O&M costs over the relevant analysis period for each cost type. For instance, CAPEX costs are analyzed based on the book and tax depreciation time periods for each asset type, whereas the O&M and restoration costs are evaluated over the useful life of the asset. The lighter shaded columns in the Figures below (labeled column a through e) roll up into the "NPV Total Costs" column.

Figure 15. Total Costs for Baseline Scenario

Project Type	Line Phases	Total FY2027 CAPEX (Fully Loaded)	NPV Total Costs (Sum of a-e)	(a) NPV Utility CAPEX	(b) NPV Property Tax from New CAPEX	(c) NPV Storm Restoration Costs	(d) NPV Non-Storm Restoration Costs	(e) NPV O&M Costs (Veg Mng and Inspections)
OH Spacer	1-Phase	$ 1,003,129	$ 12,461,948	$ 9,657,187	$ 1,998,373	$ 716,777	$ 89,610	$ -
OH Spacer	3-Phase	$ 3,612,272	$ 44,825,609	$ 34,775,573	$ 7,196,150	$ 1,843,860	$ 1,010,026	$ -
UG CIC	1-Phase	$ 2,984,286	$ 37,488,972	$ 28,729,912	$ 5,945,114	$ 1,499,384	$ 240,737	$ 1,073,826
Total		**$ 7,599,688**	**$ 94,776,530**	**$ 73,162,672**	**$ 15,139,638**	**$ 4,060,020**	**$ 1,340,373**	**$ 1,073,826**

Figure 16. Total Costs for Mitigation Scenario

Project Type	Line Phases	Total FY2027 CAPEX (Fully Loaded)	NPV Total Costs (Sum of a-e)	(a) NPV Utility CAPEX	(b) NPV Property Tax from New CAPEX	(c) NPV Storm Restoration Costs	(d) NPV Non-Storm Restoration Costs	(e) NPV O&M Costs (Veg Mng and Inspections)
OH Spacer	1-Phase	$ 10,031,291	$ 14,165,554	$ 11,525,963	$ 2,398,182	$ 194,608	$ 46,801	$ -
OH Spacer	3-Phase	$ 36,122,723	$ 51,169,029	$ 41,505,044	$ 8,635,862	$ 500,615	$ 527,508	$ -
UG CIC	1-Phase	$ 29,842,862	$ 41,952,140	$ 34,289,478	$ 7,134,535	$ 102,449	$ 99,361	$ 326,318
Total		**$ 75,996,876**	**$ 107,286,723**	**$ 87,320,485**	**$ 18,168,579**	**$ 797,672**	**$ 673,670**	**$ 326,318**

As I explained above, the BCA methodology takes the incremental cost into account when evaluating the final BCR. For purposes of clarity I am keeping the description of cost inputs to the model together because they are associated with the Baseline Scenario and Mitigation Scenario in terms of the modeling mechanics—in other words, the BCR model tracks the above described costs for each year of the analysis period based on the relative share of mitigated and un-mitigated circuit line miles in each scenario. However, I present the reduction in storm- and non-storm restoration costs, vegetation management costs, and inspections costs as a net benefit in the final BCR screening. Therefore, the net incremental costs that factor into the final BCR are the NPV Utility CAPEX (column a in Figures 15 and 16) and NPV Property Tax from New CAPEX (column b in Figures 15 and 16). Together, these reflect a net incremental cost of $17,186,754 in NPV terms associated with the accelerated investments reflected in the Mitigation Scenario over the full lifecycle of the analysis period.

C. Select Benefits—Determine which adaptations provide resilience benefits

Q55. What benefits did you include in the calculation of the BCA?

A55. CEG modeled the benefits of GMP's FY27 Resilience Projects as a function of both lower expected costs and increased benefits:

- Reduced future O&M costs
  - Reduced outage restoration costs (storm- and non-storm related)
  - Reduced pole inspection costs, and
  - Reduced vegetation management costs.
- Increased benefits
  - Customer resilience value from reduced outages due to circuit hardening
  - Customer resilience value from circuit backup, and
  - Reduced line losses due to the additional line capacity.

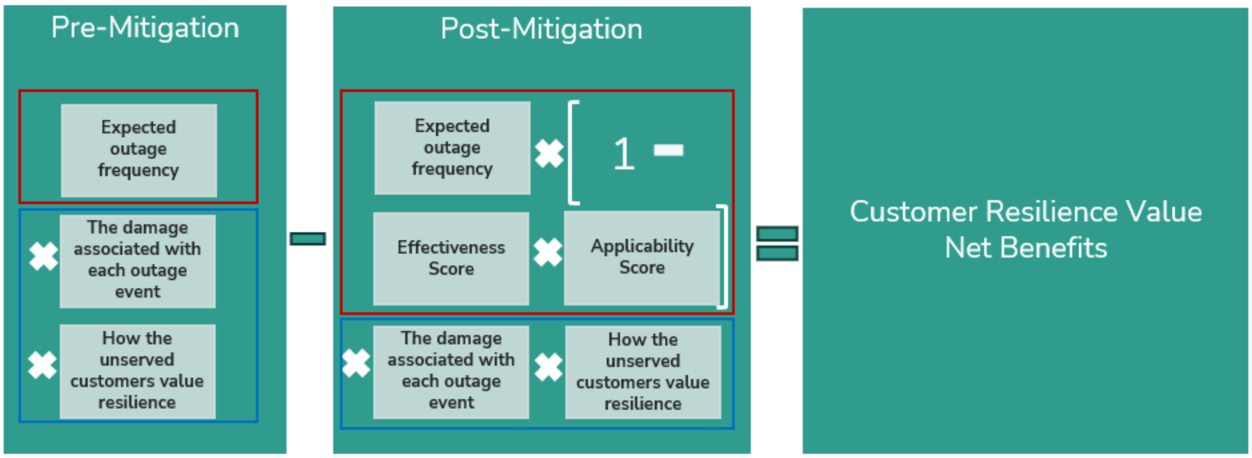
I discussed the benefits calculated as reduced O&M expenditures in subsection B of my testimony[40] and therefore focus the remainder of this section on describing the increased benefits included in the model.[41]

Q56. How did you model the expected outage reductions resulting from each Resilience Project?

A56. Based on best practices identified in the literature, I utilized a formulation that takes account of the frequency of the risk event (in this case, outages) and the potential consequences if the risk event takes place. This can be expressed by the formula: Likelihood of Risk Event x Consequence of Risk Event = Customer Resilience Risk Value. In keeping with the context of the resilience BCA framework comparing the Baseline Scenario to the Mitigation Scenario, I calculated the Customer Resilience Risk Value for both the Pre-Mitigation (i.e., Baseline Scenario) and the post-Mitigation Scenario cases to determine the total net Customer Resilience benefits due to the FY27 Resilience Projects. Figure 17 illustrates this overall process.

[40] See the total discounted future costs of the Baseline Scenario and Mitigation Scenario in Figures 15 and 16 in subsection B above for the Baseline Scenario and the Mitigation Scenario.
[41] I treat costs and benefits separately here in discussing the inputs as the categories most neatly fit a logical pattern. In the final BCR calculation, I include the present value of future O&M cost savings as a benefit for simplicity and ease of understanding. Trying to show the benefits of saving future O&M only as a net reduction of the relative costs obscures their contribution as a benefit of doing the project. However, mathematically these two treatments are equivalent.

Figure 17. Calculation Steps for Determining Customer Resilience Benefit from FY27 Resilience Projects



Starting with the left-hand side of Figure 17, I calculate the likelihood of the outages occurring pre-mitigation based on an average of historical outage data (the red box) and associate it with the damage caused by the outage (the blue box). Then I subtract the same customer impacts in the post-mitigation scenario after adjusting for the Effectiveness Score and the Applicability Score of the specific grid hardening project type.

The Effectiveness Score is expressed as a percentage and reflects the expected effectiveness of the mitigation in terms of reducing outages from various external hazards, such as tree contact or animal contacts with bare wire. The Applicability Score is expressed as a percentage and reflects the proportion of GMP's historical outages that can be assumed to be impacted by the mitigation.[42] I applied these two factors at the individual project level to GMP's historical outage data using the equation shown below.

$$\text{Outages}_{\text{Post-mitigation}} = \text{Outages}_{\text{Historical average}} \text{ x } (1 - \text{Effectiveness Score x Applicability Score})$$

[42] For example, some outages are caused by requests from the transmission provider to curtail load due to a fault on the transmission system, and therefore hardening the system would not likely reduce these outages. Likewise for planned maintenance and emergency outages.

Where the Outages $_{\text{Historical average}}$ = the 5-year average customer outages using GMP's Rule 4.900 Reliability Reporting data.

I assumed a 90 percent reduction in applicable outages after installing OH Spacer and a 98 percent reduction in applicable outages for UG CIC. To determine the Applicability Score to apply to each project type I analyzed GMP historical data and individual outage cause codes and calculated an average contribution to the overall Rule 4.900 outages attributable to each outage cause category. The weighted-average Applicability Scores for each project type are shown in Figure 18.[43]

Figure 18. Resilience Project Weighted Applicability Scores

Project Type	Weighted Applicability Score
OH Spacer	80%
UG CIC	83%

Q57. Were there any additional steps you followed to estimate the expected outage reduction resulting from the Resilience Projects?

A57. Yes, I needed to make two additional assumptions in order to appropriately assign expected outage reductions to the FY27 Resilience Projects. First, I needed to identify the proportion of customers on a given circuit that would be impacted by the project. This is important because while the projects target areas with the highest need, the projects do not harden every line mile of the circuit. For projects impacting areas of the grid in Zone 1 and Zone 2, I assume 100 percent of the outages that occur in those areas are impacted

[43] The difference between the two is due to including more applicable outages coded as "Accidents" in GMP's database.

by the mitigations.[44] This is justifiable because the Zone 1 and 2 projects occur close to the substation protective devices and cover all downstream outages within the zone. For projects impacting Zone 3, I assume 50 percent of the historical outages are impacted by the mitigation. While the Zone 3 projects will likely impact a greater share of historical outages, I assumed a conservative value until more work can be done to align the particular protective devices impacted by a project with the historical outage data. Therefore, the analysis I conducted on outage reduction value of the mitigations is conservative in this respect.

Second, in cases where there were multiple projects per feeder, I assigned a weight to each individual project to allocate the overall share of outage reductions and avoid double-counting the benefits.[45] I discuss how these outage reductions are translated in the model into quantitative monetized benefits in subsection D.

Q58. Explain how this method for estimating the benefits of outage reductions are conservative.

A58. An important conservatism built into this method is that I am using average expected future values for estimating pre- and post-mitigation SAIFI metrics, as described above, as well as average increases in major and minor storm restoration costs, as described in

[44] The assumptions I discuss here are related to the number of customers impacted by the mitigation, and is distinct from the Applicability Score I described above in my testimony. The latter has to do with the ability of a mitigation to reduce an outage, while this discussion of "customers impacted by a mitigation" is meant to isolate the customers that are in portions of the treated circuits that are likely to experience the reductions.

[45] This assumption is a function of the way the data were developed and is necessary to avoid double counting benefits across a circuit. It does not change the overall benefit but simply spreads the expected outage reduction benefit among each contributing project on a feeder.

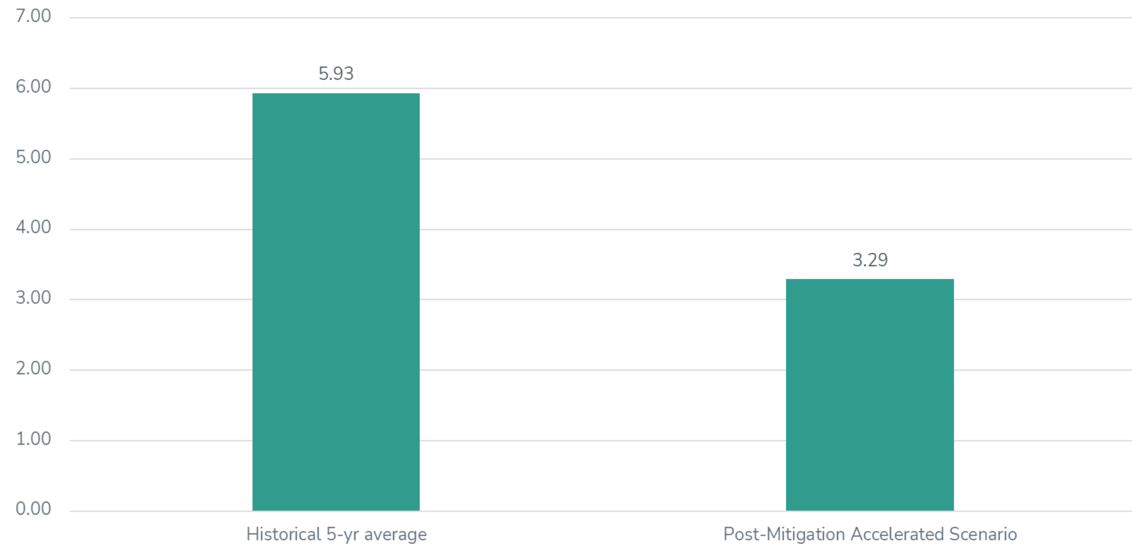
Subsection B.[46] These projections of *average expected costs* are useful for considering the average expected benefits from the mitigation, grounded in the historical and forecasted data. Not included within this average are the additional risks associated with high impact, low probability events, that are characteristic of climate-related disasters. These tail-risk events additionally justify this accelerated work. Though I have not quantified a monetary value in this model associated with events beyond the historical-based projection, in Section VI I discuss potential future analysis to evaluate the probability of increased tail-risk events and how this may impact the benefits associated with proactive resilience investments.

Q59. Can you describe the overall impact of the mitigations on expected future average outages, based on your modeling approach?

A59. After applying the methodology described above to each feeder (assessing baseline outage frequency, applying the Effectiveness Score and Applicability Score specific to each mitigation type, and accounting for the proportion of impacted customers in each Zone) I was able to calculate the pre-mitigation historical SAIFI and the post-mitigation SAIFI. The average pre-mitigation 5-year historical average SAIFI for the modeled feeders is 5.93, compared to a post-mitigation SAIFI of 3.89 (see Figure 19).

[46] For average expected future major and minor storm costs, I do escalate these by the observed average trend over the last 10 years, and adjust for future predicted climate change impacts associated with increased heavy precipitation. The methodology and data inputs for these future projections are discussed in subsection B above.

Figure 19. Average Pre- and Post-Mitigation SAIFI Comparison for the Circuits Treated by FY27 Resilience Projects[47]



Q60. Explain how you modeled reduced line losses.

A60. As GMP completes the OH Spacer and CIC in the FY27 Resilience Projects it is my understanding the new lines will provide additional capacity. This upgrade can provide many benefits in terms of improved power quality, capacity increases, and reduced energy losses. In my analysis I have only included the estimated reduction in energy losses as a result of the increased line capacity. However, the additional capacity will also allow more load growth to occur without the need for upgrades, potentially accommodating future load growth or electrification.

To estimate the reduction in line losses resulting from the upgrade, GMP conducted load flow modeling for the EJ-G7 feeder comparing the pre- and post-

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[47] The pre- and post-SAIFI comparison here only depicts the Mitigation Scenario compared to the historical 5-year average SAIFI for the target feeders.

mitigation losses for those Resilience Projects. The modeling consisted of five main steps, outlined below.

1. Run load flow of circuit with each individual project's upgrades included and determine downstream kVA losses from the feeder breaker.
2. From known load level and loss, determine an impedance factor. This impedance factor differs depending on the upgrade analyzed, with a bigger (less impedance) upgrade creating fewer losses and thus a lower impedance across the entire feeder.
3. Repeat steps 1 and 2 for each ZOI project on and for the feeder without any upgrades installed and determine the impedance factor for each scenario.
4. Apply impedance factor from step 3 to SCADA 15-minute data (net load at the feeder head) and determine the MWh losses for the bases circuit and all ZOI project scenarios.
5. Determine differences between base case and each ZOI project, then come up with a MWh savings per mile of reconductoring associated with each project.

I then took the average MWh reduction per line mile for each project type and applied this factor to the corresponding FY27 Resilience Projects according to the mitigation project type, resulting in a total MWh per year estimated reduction in line losses in the Mitigation Scenario.

Q61. Explain how you modeled feeder-back up.

A61. Certain projects in the FY27 Resilience Projects list will allow feeder ties into neighboring substations, which provide for feeder back up during an outage. The five feeder-back up projects included in the model are:

- CV-G65 – backs up 792 customers on BV-G44
- BV-G44 – backs up 339 customers on CV-G65
- TH-G16 – backs up 1,005 customers on EL-G40 and 722 customers on EL-G41
- DM-G6 – backs up 2,571 customers on EJ-G7
- CS-G34 – backs up 871 customers on the CS-34 and 1,877 customers on the BE-G29[48]

The only outages that can be switched are those that occur right outside the feeder breaker, which is labeled as Zone 1 using GMP's mapping nomenclature discussed above. Therefore, I calculated the benefits of implementing feeder backup as an increase to customer resilience value resulting from additional reductions in future expected outages that occur upstream of the feeder.

[48] Note that because of limited substation transformer capacity, CS-G34 will only be able to back up approximately 50 percent of the load from BE-G29. However, BE-G29 will be able to pick up 100 percent of the 871 customers on CS-G34. In order to be conservative with the analysis I only apply 50 percent of the feeder back up value when CS-G34 picks up load from BE-G29.

Q62. Can you clarify what you mean when you say the benefits of feeder-back up are the result of "additional" reductions in future expected outages?

A62. Yes, what this means is that in order to avoid double-counting customer resilience benefits resulting from feeder hardening, due to implementation of OH Spacer Cable and CIC discussed above, and the value of feeder-back up, it was necessary to apply the value for feeder-back up only to the future expected outages on a given feeder post-hardening. I quantified the number of remaining expected future outages after the project mitigations were in place using the methodology described above and assumed 100 percent of these remaining outages could be mitigated with feeder-back up. The hardening measures of OH Spacer and UG CIC reduced the average outages experienced by impacted customers[49] by 74 percent in our conservative analysis. Therefore, the feeder-back up applies to the portion of the remaining 26 percent of outages on that feeder, and de-rated by the percentage of the remaining outages that occurred in Zone 1.[50]

D. <u>Monetize benefits—where possible, monetize resilience benefits</u>

Q63. What benefits did you monetize in the calculation of the BCA?

A63. The benefits attributable to reduced utility costs are monetized already and have been discussed above in the costs section. They are essentially a reduction in costs, but as mentioned above, I categorize the reduction in future costs between the Baseline Scenario and Mitigation Scenario as a benefit within the BCA framework in order to more clearly view the relative costs and benefits of proactive resilience investments. In this subsection

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[49] See above for discussion of how I estimated the number of impacted customers for each project.
[50] This is because, as stated above, the only outages able to be switched at this time are those at the circuit breaker, which GMP defines as Zone 1.

I will discuss the methodology I followed to monetize the customer resilience value, which is applicable to both grid hardening and feeder-back up benefit streams, and the reduction in line losses from upgraded conductor.

Q64. How did you monetize the benefits of improved customer resilience?

A64. I utilized the ICE calculator version 2.0, supported by LBNL, in order to translate the improvements to customer reliability on the FY27 Resilience Project feeders into monetary inputs to the resilience BCA.[51] To do this I used the number of customers by customer class (residential and non-residential) on the impacted feeders, the baseline SAIFI and SAIDI for the feeders, and the ICE calculator's default values for Vermont-specific economic and demographic variables included in the ICE calculator (such as average household income and gross domestic product).

Q65. What are the values represented by the ICE tool?

A65. The fundamental outputs of the ICE tool are a representation of customers' value of resilience as approximated by their stated willingness-to-pay gathered through national surveys, as I discussed in Section III of my testimony. The survey asks customers to rate how much they would pay to avoid an outage of varying durations, represented in Figure 20 below. Figure 20 shows the underlying economic cost of outages derived from the recent ICE v2.0 modeling update for residential and non-residential customers across each outage duration included in the survey, and reflected in a number of different ways (e.g., Cost per Event, Cost per kW, etc.).

[51] https://icecalculator.com/interruption-cost/results

Figure 20. ICE v2.0 Economic Consequences for Different Durations of Interruption[52]

Duration of Power Interruption Event	Cost per Event	Cost per kW	Cost per Unserved kWh	Cost per CMI[4]
Residential				
Momentary	$1.80	$1.50	$18.03	$0.36
2 Hours	$10.49	$8.62	$4.31	$0.09
8 Hours	$25.55	$21.21	$2.65	$0.05
24 Hours	$54.52	$44.76	$1.86	$0.04
Non-residential				
Momentary	$609	$43	$521	$122
2 Hours	$2,839	$202	$101	$24
8 Hours	$6,172	$440	$55	$13
24 Hours	$12,646	$902	$38	$9

The ICE Tool guidance from LBNL recommends using the Cost per Event metric to apply during analysis and I have used that metric in developing the monetized customer resilience value for the BCA.

Q66. Does the ICE tool capture the full value of customer resilience?

A66. No it does not. The ICE tool only reflects outage costs up to 24 hours in duration. However, there are instances on the FY27 Resilience Projects list of feeders that experience substantial outage incidents for periods greater than 24 hours. Across all the feeders, there was an average of 116 incidents per year lasting greater than 24 hours over the 2020-2024 time period. This points to the importance of developing new methods to quantify the increased resilience benefits from preventing exposure to extra-long duration

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[52] Peter H Larsen et al., "ICE Calculator 2.0: Final Report for Phase 1 of the National Initiative to Update the Interruption Cost Estimate (ICE) Calculator," 2025, at xiii, https://escholarship.org/content/qt2x78m2q9/qt2x78m2q9.pdf.

outages. The assumptions used in developing the customer resilience value for this analysis are therefore conservative to the true cost of outages. I discuss this issue further in Section VI of my testimony below.

Q67. Is the ICE tool output a one time or ongoing value?

A67. The ICE tool provides outputs in terms of annual benefits reflective of the value of lost service, and therefore needs to be applied for each year of the useful life of the investment in question and discounted to the present value using a discount rate.[53]

Q68. How did you quantify a monetizable benefit of reduced line losses?

A68. I took the MWh per year of reduced line losses described above and multiplied the total annual MWh per project by the corresponding annual average of on- and off-peak forward wholesale energy prices provided by GMP. The real levelized value of the avoided future energy losses modeled are $71.78 per MWh.[54]

E. Discount—determine the present value of the costs and benefits

Q69. What discount rate did you use when discounting costs and benefits to determine the inputs into the final BCR.

A69. The final resilience BCR compares the NPV of the total benefits divided by the NPV of the total costs. I used the weighted average cost of capital (after tax) of 6.46 percent provided by GMP to discount all utility cost impacts. I used a societal discount rate of

[53] Sullivan, M. et al. (2013). *How to Estimate the Value of Service Reliability Improvements*, at 4, https://www.ourenergypolicy.org/wp-content/uploads/2013/08/REPORT-lbnl-3529e.pdf.
[54] In the model the average of on- and off-peak avoided energy costs are modeled for each year of the analysis period, but showing the real levelized value here for simplicity.

2.00 percent to discount the future customer resilience benefits due to the Resilience Projects.[55]

F. Compare—evaluate the discounted costs and benefits as net benefits or a BCR

Q70. How did you compare the discounted costs and benefits in the BCA?

A70. As I discussed above in my testimony, I have calculated the net benefits and the net costs to feed into the BCA following best practices outlined by the NSPM and EPRI. The net costs and net benefits are represented as a single NPV value and the BCR is simply the NPV benefits divided by the NPV costs. Results of the BCA are presented at the beginning of this section.

VI. Additional Considerations for Evaluating the Benefits and Costs of GMP's Resiliency Projects

Q71. What is the purpose of this section of your testimony?

A71. In this section I discuss further qualitative considerations relating to the resilience BCA results and methodology that I have utilized here. I specifically highlight areas where better data and more targeted analysis could refine some of the conservative assumptions to the analysis that I mention through my testimony. These areas for refinement in many instances represent values that would be additional to the model benefits above if quantified and are important for the Commission to consider.

Below, I address the treatment of property tax impacts; the need to study the differential impacts of long-duration outages, especially on vulnerable communities;

[55] Use of different discount rates to assess resilience investments is consistent with how the California utilities screen BCAs for resilience planning. See for example, Southern California Gas Company & San Diego Gas & Electric Company, *2025 Risk Assessment Mitigation Phase (RAMP) Report, Chapter RAMP-1: Overview,* at 13 (May 15, 2025), https://www.sdge.com/sites/default/files/regulatory/Vol1_Ch1_Joint_RAMP_Overview_.pdf.

methods to address risks of high-impact and low-probability events in resilience modeling; and considerations of additional societal value related to resilience investments.

Q72. What are the implications for how you treated property tax within the resilience BCA modeling?

A72. I included property tax as a cost in both the Baseline Scenario and the Mitigation Scenario. It is my understanding that Vermont has recently changed the way it assesses property tax on utility distribution infrastructure,[56] and this addition has a sizeable impact when installing new utility plant to replace heavily depreciated assets. This assessment of property tax significantly reduces the overall BCR of the Resilience Projects. While it could arguably be treated as a transfer payment, I retained it as a cost to be conservative in my analysis and because it is consistent with how GMP treats its overall T&D investments. However, there are real benefits associated with potential increases in property taxes that are important to consider when developing a Jurisdictional Specific Test. In other words, the significant increased net costs in the short-term associated with the accelerated investments will provide additional revenue to the local jurisdiction and the State, and therefore depending on the perspective taken in conducting a BCA could justifiably be treated as a pass-through cost or as a benefit via increased tax base for the town which impacts the community and society.

[56] See generally Vermont Department of Taxes, Utility Valuation, available at https://tax.vermont.gov/property/utility-valuation.

Q73. Are there other possible considerations related to the accelerated capital investments on the broader economic outcomes in Vermont?

A73. Yes, the accelerated capital investment modeled in the Mitigation Scenario has increased costs, which are captured in the current BCA modeling approach. However, I did not attempt to estimate the broader societal benefits of increased jobs that would be created from these accelerated investments. However, under a societal test perspective or a JST, inclusion of these benefits may be desirable. Many studies use economic planning software, such as IMPLAN, to assess the direct, indirect, and induced jobs that result from a net increase in spending associated with a given investment or program.

Q74. Explain what you mean by high-impact and low-probability events.

A74. This is sometimes referred to as "tail risk" because it refers to the outlier events at the end of a statistical distribution (i.e., the "tail" of the distribution being the areas under the curve of low probability). These outlier events have a substantial impact in terms of their scale and intensity measured either in terms of magnitude and duration of outages (for customer resilience value), excessive storm-related recovery costs and equipment damage, or both. As I mentioned above in my testimony, the resilience BCA modeling I conducted for GMP's FY27 Resilience Projects took a conservative approach to estimating future risks associated with storm-related outage costs. Instead of taking the average expected future value, as I have done, GMP could also calculate the impact of tail risk on expected future benefits of proactive system hardening, which would provide more information about potential risk avoided by system hardening.

Q75. What frameworks and methods have been used to assess the uncertainty and risk associated with tail risk?

A75. Researchers and practitioners can use probabilistic models and risk-based approaches to address uncertainty. One approach is using probabilistic models for outages caused by hurricanes and found that outage magnitude was the strongest predictor of recovery time, and that models for outage length depend heavily on county characteristics (urban/rural, vegetation).[57] Out of the models studied, regression techniques were found to perform relatively well. Another approach uses conditional value-at-risk (CvaR) to quantify system outage risk, and does probabilistic (e.g., Monte Carlo) simulations to inform an optimization formulation for distribution grid planning.[58] As an industry example, San Diego Gas & Electric recently modeled this type of tail risk in a supplemental analysis supporting their main BCA resilience modeling.[59]

Q76. Are there any limitations to the ICE tool that could be conservative?

A76. Yes, while the ICE tool produces values reflecting customers' willingness-to-pay to avoid an outage, which can be a measure of customer resilience value, there are shortcomings of using the tool to value longer-duration, widespread outages. For one thing, the tool itself does not value outages over 24 hours in duration due to difficulty experienced when

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[57] Willems, Nicholas, Bandana Kar, Samuel Levinson, Benjamin Turner, John Brewer, and Marija Prica. "Probabilistic Restoration Modeling of Wide-Area Power Outage." IEEE Access 12 (2024): 184431–41. https://doi.org/10.1109/ACCESS.2024.3509263.

[58] Poudyal, Abodh, Shiva Poudel, and Anamika Dubey. "Risk-Based Active Distribution System Planning for Resilience Against Extreme Weather Events." IEEE Transactions on Sustainable Energy 14, no. 2 (2023): 1178–92. https://doi.org/10.1109/TSTE.2022.3220561.

[59] Southern California Gas Company & San Diego Gas & Electric Company, *2025 Risk Assessment Mitigation Phase (RAMP) Report, Chapter RAMP-3: Risk Quantification Framework,* at 42 (May 15, 2025), https://www.sdge.com/sites/default/files/regulatory/Vol1_Ch3_Joint_ERM_Risk_Quantification.pdf.

asking customers to respond to that hypothetical scenario. More recent research by LBNL has been focused on developing a tool to capture the economic impact of longer-duration power outages.[60] I also note that the ICE tool is similarly limited in how it incorporates differences in community vulnerability or social burden. The ICE tool does not account for the relative differences among customer groups based on demographic or spatial differences, for example, access to emergency resources or alternative forms of shelter.

Q77. How can social burden differences be incorporated into these the value of resilience and resilience BCA frameworks?

A77. Methodologies to determine a direct economic estimate for socially-vulnerable communities can be expensive and difficult to implement for a variety of practical reasons. As a result, researchers have relied on proxy values and methods, such as modifying inputs to the ICE calculator, to reflect the fact that not all residences fare equally in power outages.[61] Prior academic literature justifies adjusting customer energy demand by community vulnerability index values to calculate monetized valuations.[62] Adopting approaches such as this could incorporate relative social burden into the benefit-cost frameworks that inform resilience decision making. At minimum, I understand that the portfolio of work GMP selected and I reviewed includes areas of the

[60]See LBNL, "Power Outage Economics Tool: A Prototype for the Commonwealth Edison Service Territory" (May 2024) at 28, available at: https://eta-publications.lbl.gov/sites/default/files/poet_final_report_6may2024.pdf.

[61] Jesse Dugan et al., "Social Vulnerability to Long-Duration Power Outages," *International Journal of Disaster Risk Reduction* 85 (February 2023): 103501, https://doi.org/10.1016/j.ijdrr.2022.103501.

[62] Arnav Gautam et al., "Grid-Aware Tradeoff Analysis for Outage Mitigation Microgrids at Emerging Resilience Hubs," *Policy and Regulation IEEE Transactions on Energy Markets* 2, no. 2 (2024): 186–99, https://doi.org/10.1109/TEMPR.2024.3383369.

state that score higher on social vulnerability metrics, in addition to being more remote—and thus removed from community supports.

Q78. Are there other resilience benefits of this work not captured within the ICE tool estimates?

A78. Yes, there are broader resiliency benefits to the community as a whole that are not the focus of the customer surveying underlying the ICE tool. For example, through storm-hardened and underground construction, events resulting in lines on roadways would be expected to decrease, improving travel and public safety during emergency response. And as discussed above, because the ICE tool does not account for geographic differences, it does not include the proportional impact on rural customers who may be some distance on snow covered roads from a hospital, municipal facilities, a grocery store or other community resources, access to which can be especially critical in emergency events.

Q79. How should the Commission interpret the conservative assumptions used in this BCA?

A79. The analyses presented in this testimony demonstrate that GMP's FY27 Resilience Projects and the Integrated Energy Storage Pilot represent measured, data-driven responses to demonstrable reliability challenges on the system. Under conservative and transparent assumptions, these investments are cost-effective today, align with emerging best practices nationally and in Vermont, and provide a sound analytical foundation for continued refinement of resilience valuation as experience and data accumulate. As a result, I have recommended that the Commission approve this accelerated work. The considerations above represent additional benefits that may be considered in this proceeding, or refined in future analyses.

VII. Integrated Energy Storage Pilot Benefit-Cost Analysis

Q80. Please summarize the results of your Benefit-Cost Analysis for GMP's proposed Integrated Energy Storage Pilot program.

A80. The overall BCR for the Integrated Energy Storage Pilot are presented in Figure 21. The BCR is a 1.11 indicating that the Pilot will provide overall net benefits.

Figure 21. Overall BCR for Integrated Energy Storage Pilot

Project Type	(A) NPV Total Incremental Benefits	(B) NPV Total Incremental Costs	(C) (A ÷ B) Benefit Cost Ratio
Integrated Energy Storage Pilot	$ 6,615,432	$ 5,941,546	1.11

Q81. Please explain the steps you took to develop this analysis, including any variation from the Resiliency Projects analysis.

A81. I followed the same principles and high-level methodology when conducting the BCA modeling for the Integrated Energy Storage Pilot as I did for the Resilience Projects described above. In the case of the Integrated Energy Storage Pilot, however, I compared the net incremental benefits against the net incremental costs against a "no investment" baseline where the Zone 4 storage would simply not be deployed.

Q82. Describe the costs and benefits that are included in your calculation of the BCA for the Integrated Energy Storage Pilot.

A82. The costs modeled include capital costs including equipment and installation costs, O&M costs, software fees, end of life removal, and the round-trip efficiency ("RTE") losses. The benefits modeled include customer resilience value from avoided interruptions and utility system benefits, including avoided wholesale energy costs, revenue from frequency response market participation, T&D asset deferral, regional network service ("RNS") transmission benefits, ISO-NE Forward Capacity Market ("FCM") capacity reduction benefits, increased renewable energy standard credits, and increased retail revenue resulting from RTE losses.

Q83. Describe the data sources you used in your BCA modeling.

A83. I used GMP's existing financial modeling of the Pilot as a starting point for my analysis. I performed a review of the inputs and assumptions in GMP's storage model and confirmed that it is reasonably constructed and conforms to commonly accepted practices for calculating BCA for DERs. Therefore, I incorporated these values into the BCA model and added the customer resilience value following the framework discussed for the T&D Resilience Projects in Section V, subsection C.

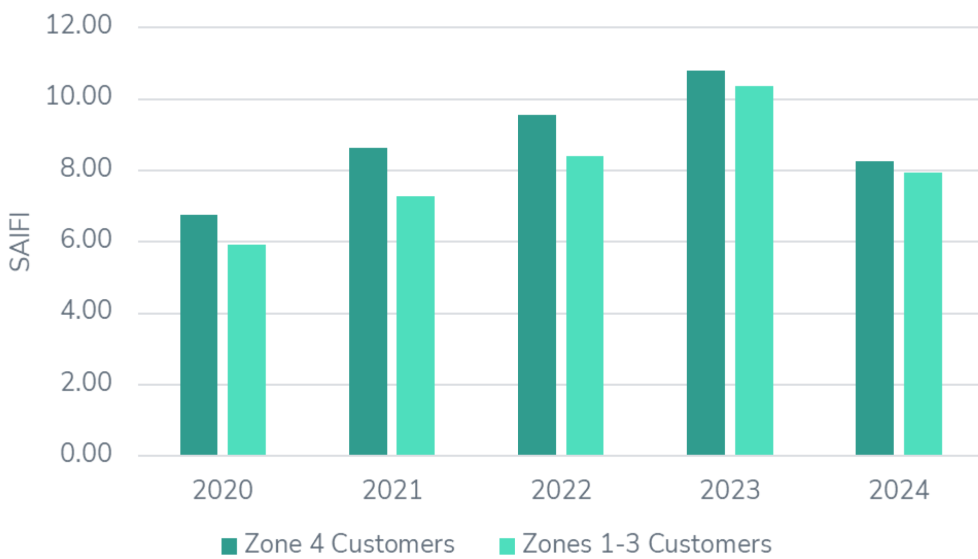
Q84. How were customer resilience values developed for these storage investments?

A84. I developed the customer resilience values using the same methodology as described above for the T&D Resilience Projects. Namely, I first calculated the pre-mitigation SAIFI, and then estimated the reduction in outages expected from the Integrated Energy Storage Pilot.

Q85. **Do customers in EJ-G7 Zone 4 face a higher number of outages from the rest of the customers on that feeder?**

A85. Yes, I analyzed the historic outage percentage by Zone on the EJ-G7 feeder, and the Zone 4 customers face the highest outage rates of any segment. Figure 22 shows the historical 5-year average SAIFI for EJ-G7 for Zone 4 customers versus the Zone 1-3 customers.

Figure 22. EJ-G7 Historical SAIFI for Zone 4 and Zone 1-3 customers



The average SAIFI for Zone 1-3 customers over the period 2020-2024 was 7.99, while the average SAIFI for Zone 4 customers was 8.80. But considering the system hardening improvements made to the circuit in Zone 1 through Zone 3, the outages affecting those customers are expected to greatly reduced by a combination of OH Spacer and UG CIC as a result of these previous projects. Zone 4 customers, therefore, while benefiting from work elsewhere on the circuit, are expected to continue to face a disproportionately high outage expectation.

Q86. How did you account for the previous work done on EJ-G7 when determining the resilience value of the Integrated Energy Storage Pilot?

A86. I controlled for the recent improvements made to Zones 1 through 3 of the EJ-G7 circuit by applying the same methodology discussed in Section V, Subsection C to determine the post-mitigation SAIFI for Zones 1 through 3 based on the share of previous GMP resilience work on EJ-G7 that was OH Spacer Cable and UG CIC. This allowed me to calculate the remaining outages projected to impact customers in Zone 4. I used this expected annual outage amount and applied the ICE calculator value described above to develop the monetized customer resilience value from the Integrated Energy Storage Pilot.

Q87. What were the NPV costs and benefits from the model?

A87. The NPV net incremental costs for the modeled Integrated Energy Storage Pilot are shown in Figure 23.

Figure 23. Integrated Energy Storage Pilot NPV Incremental Costs

NPV Total Incremental Cost	NPV Capital Carrying Costs	NPV End of Life Removal	NPV O&M	NPV Software Fees	NPV RTE Losses (Credit)
$ 5,941,546	$ 5,614,597	$ 28,341	$ 10,355	$ 67,327	$ 220,926

The NPV net incremental benefits for the Pilot are shown in Figure 24.

Figure 24. Integrated Energy Storage Pilot Net Incremental Benefits (utility system benefits only)

NPV Total Incremental Benefit	NPV ISO-NE FCM Capacity Reductions	NPV RNS Transmission Charge Reduction	NPV T&D Deferral Value	NPV Avoided Wholesale Energy	NPV RTE Losses (Revenue under Rate 1)	NPV Frequency Regulation Revenue	NPV DASI	Tier 3 RES Value
$ 6,454,954	$ 1,923,549	$ 3,237,563	$ 274,642	$ 459,064	$ 220,926	$ 183,705	$ 21,600	$ 133,907

As can be seen, the largest benefits are the RNS Transmission Charge reduction and the ISO-NE FCM capacity reduction benefit, followed by avoided wholesale energy costs.

Q88. What was the resilience value that you calculated for the Integrated Energy Storage Pilot?

A88. I calculated an NPV customer resilience value of $160,478 thus adding to the overall program benefits. The overall BCR with just the system benefits is 1.09, and with the additional value of customer resilience it is 1.11. The BCA is positive under both views, demonstrating that the Integrated Energy Storage Pilot is cost effective and will provide meaningful resilience improvements to the target customers while providing net benefits to all of GMP's customers.

VIII. Conclusion

Q89. Does this conclude your testimony?

A89. Yes.

I, Andy Eiden, declare that the testimony and exhibits that I have sponsored are true and accurate to the best of my knowledge and belief and were prepared by me or under my direct supervision. I understand that if the above statement is false, I may be subject to sanctions by the Commission pursuant to 30 V.S.A. § 30.

Dated at Portland, Oregon on the 16th day of January, 2026.

Andy Eiden