Powering through Change: Affordable Grid Resilience Amid Climate and Demand Pressures

Resilience Proceeding Findings and Recommendations – June 2026

Vermont Department of Public Service

Executive Summary

Vermont's climate is changing; 2010 through 2020 stand as the state's warmest 11 years on record and this trend is projected to continue.[1] Overall, it is "getting wetter and warmer"[2] with impacts felt across the state. These impacts include more heat and moisture, expected to continue driving increased deluges of rain with resultant flooding; wet snowfall; and higher wind velocities with greater numbers of downed tree limbs if not whole trees. This spring, for example, Vermont experienced its only April tornado on record – an EF1 that touched down in Williamstown.[3]

Such extreme weather events cause costly damage to homes, communities, and infrastructure of all types, including the state's electric grid. For example, Green Mountain Power incurred $243 million in storm costs from 2015-2024, with 44% of that occurring in 2023-2024 alone. The costs of these climate impacts are already being reflected in electric rates and constitute just one of a key handful of cost drivers pushing Vermonters' electric bills higher. These increases are occurring, moreover, as state policy – and some customer sentiment – seeks to expand Vermonters' reliance on electricity for daily necessities. Vermont must determine what level of additional, proactive grid resilience investment Vermonters can afford in the near term to avoid having to pay even more expensive storm recovery costs in the future.

Weather-based threats have left the Vermont bulk electric system virtually unscathed while the distribution system has felt the brunt of the disruptive weather. Reliable electric distribution service is addressed through state statute and regulatory requirements that have evolved over

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[1] Vermont Today, Vermont Agency of Natural Resources Climate Action Office, available at: https://climatechange.vermont.gov/vermont-today.

[2] *See Petition of Green Mountain Power Corp.*, Case No. 23-3501-PET, Order of 10/18/24 at 7.

[3] Gunnar Consol, *Williamstown tornado is Vermont's first April tornado in recorded history*, WCAX (Apr. 17, 2026, 5:55 PM), https://www.wcax.com/2026/04/17/williamstown-tornado-is-vermonts-first-april-tornado-recorded-history/.

time. Grid reliability is traditionally concerned with day-to-day performance, minimizing "typical" outages by ensuring available supply resources, sound preparation, efficient system restoration and overall consistent power delivery in the face of routine disturbances. However, the increasing frequency and severity of storms has created issues beyond the scope of effective general utility practice and established regulatory reliability practices. The existing body of reliability-driven protocols must adapt to ensure we are planning, building, and operating an electric grid prepared to withstand, adapt to, and rapidly recover from major disruptions like extreme storms or other high-impact events.

These types of disruptions are not new in and of themselves – it is the severity, frequency, and duration of impacts that are changing. In contrast to the massive blackouts of 1965 and 2003 that spurred national action on bulk power system reliability, there may never be one seismic event that catalyzes a nationwide resilience initiative – but the implications for cost and service quality are no less significant. [4]

Though resilience is a prominent topic in policy conversations across sectors,[5] and indeed the nation, Vermont has yet to meaningfully address grid resilience in practice. There is a gap in applicable statutes, regulatory standards, and guidance. States across the Northeast and beyond are grappling with the impacts of changing weather, what that means for the grid, and how regulators and utilities should respond.[6]

These issues implicate all Vermont utilities and were brought to the forefront when Green Mountain Power ("GMP") proposed large resilience investments through its "Zero Outages Initiative" ("ZOI"). In the ZOI proceeding, GMP showed that its storm costs were increasing precipitously. GMP also showed that current reliability criteria did not account for areas of its system particularly vulnerable to storm-related disruptions, despite the company meeting its utility-wide reliability targets. ZOI's premise is that significant investment in resilience measures would improve service and save GMP customers money in the long run by stabilizing costs,

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[4] The North American Reliability Council ("NERC") was formed after the 1965 Northeast blackout, caused by a misprogrammed protective relay at a hydroelectric station in Ontario, Canada, left 30 million people in the dark across Ontario and several U.S. states. Mandatory reliability standards were developed after the largest North American blackout occurred in 2003. *See* Lesser & Giacchino, Fundamentals of Energy Regulation 2d at 393 (Pub. Util. Reports, Inc. 2013); *see also* Fed. Energy. Reg. Comm., Reliability Explainer, available at https://www.ferc.gov/reliability-explainer.

[5] *See, e.g.*, 2022 Vermont Comprehensive Energy Plan at 90, available at: https://publicservice.vermont.gov/sites/dps/files/documents/2022VermontComprehensiveEnergyPlan_0.pdf.

[6] See Appendix F: Findings from other Northeast States. J.D. Power's Utilities Intelligence Report notes that extreme weather is to blame for half of all outages reported in the first half of 2025 in the U.S.: https://www.jdpower.com/business/resources/disasters-become-fact-life-many-us-electric-utility-customers.

improving reliability, and providing overall benefits. At the time, no benefit-cost analysis was presented to support this thesis. While the imperative to try to improve service quality for areas especially hard-hit by storms is evident, it is not yet clear that the additional immediate costs borne by the utility's customers to pay for these resilience measures provide the commensurate, incremental customer value necessary to justify their expense.

GMP's ZOI proposal brought the issue of resiliency into sharp regulatory focus and raised questions the answer to which affect all utilities and indeed all of Vermont's ratepayers. Thus, the Department petitioned the Commission to open a proceeding in Case No. 25-0339-PET "to investigate the development of a common framework for defining, valuing, measuring, and planning for the resilience of Vermont's electric grid" (the "Resilience Proceeding"). This report summarizes the Department's findings in that proceeding and makes recommendations for next steps to improve grid resilience planning, valuation, and measurement in Vermont.

Like other states, Vermont is in the early stages of considering grid resilience. Through the Resilience Proceeding, Vermont is advancing the conversation and is at the forefront of this emerging field. Resilience issues are complex and evolving, but given the impacts to ratepayers, we must take action to provide the highest quality, lowest cost service possible. The Department therefore recommends pursuing three initial action steps:

- **Secure a baseline grid resilience performance assessment.** Current system reporting and performance standards do not capture or evaluate the true service impacts from significant storms.
- **Establish a benefit-cost analysis framework.** Better analytical tools for evaluating the costs and benefits to ratepayers are necessary to make informed decisions on resilience investments.
- **Incorporate resilience into existing utility planning requirements**. Utilities balance many priorities and costs within their Integrated Resource Plans; resilience should be an explicit consideration in their reported decision-making processes.

Key Findings

Municipal and cooperative utilities operate very differently from Vermont's only investor-owned utility (IOU), GMP. The differences in structure, size, resources, and technical capacity are an important underlying consideration throughout the Department's findings and recommendations.

Performance measurement, mitigation planning, and valuation must evolve to prepare for extreme weather.	Current reliability targets do not directly reflect outcomes or customer experiences during major storms
	Vermont has no explicit requirements for resilience planning or performance.
	Utilities are starting to consider and experiment with climate modeling to assess extreme weather trends.
	Resilience valuation methods are still developing; some utilities are already using benefit-cost analysis (BCA) for projects.
Utilities are diverse and seek scaled, customized approaches.	There is no easy one-size-fits-all approach to distribution system resilience in Vermont.
	Utilities each have different reliability performance targets and seek similar flexibility for resilience.
	Many utilities plan investments to meet multiple goals at once, balancing needs and priorities within limited capital budgets.
	Municipal and cooperative utilities operate under additional layers of ratepayer governance.
Strategic support to utilities would help advance grid resilience statewide.	All utilities would benefit from shared analytical tools or resources, and smaller utilities need financial and technical assistance with BCA.
	Many utilities are open to additional reporting requirements, but seek to avoid inefficient or conflicting regulatory demands and to remove regulatory requirements that no longer provide value.

Recommendations

Given the findings in this report, the Department recommends action at the State, Commission, and Agency levels as described below:

State Actions:

1. ***Revise state policy*** to explicitly incorporate grid resilience by:
    a. Strengthening statutory resilience planning requirements in IRPs;
    b. Allowing longer IRP intervals for municipal and cooperative utilities (increase from 3 to 5 years), to accommodate new requirements and need for regulatory relief;
    c. Allowing for larger rate changes under the expedited process for rate changes under § 218d(o), with approved IRPs as a prerequisite.

Commission Actions:

1. ***Initiate a rulemaking to Revise Rule 4.900 to:***
    a. add system resilience metrics;
    b. add customer-focused resilience metrics;
    c. Require lessons-learned reviews after major storms;
    d. Determine the role of energy storage in outage reporting;
    e. Establish defining parameters for "reasonably adequate service."
2. ***Initiate a trial period for resilience metrics*** to run concurrently with the Rule 4.900 update process,
3. ***For Green Mountain Power, implement resilience performance standards. For other utilities, phase-in resilience performance standards*** after three years of informational reporting.
4. ***Require investor-owned utilities to use up-front benefit-cost analysis*** *from ratepayer and societal perspectives* to justify proposals for major resilience investments

Department Actions:

1. ***Update IRP Guidance*** to address climate risks and system vulnerabilities. This report includes initial proposed language, and the update process will begin in 2026 with engagement of utilities and other stakeholders.
2. ***Pursue Joint Initiatives*** for technical and financial support in resilience planning.
3. ***Convene Utilities in 2026*** to explore regulatory mechanisms for smaller utilities to set aside funds for resilience investments.

Current practices, tools, data, and experience will evolve as technology and knowledge improve. For example, emerging technologies offer the promise of combining climate

projections with utility infrastructure data to help identify risks, vulnerabilities, and relative costs and benefits of interventions. Implementing these recommendations will ensure that Vermont has a core framework in place to leverage any advances and keep pace with the changing weather, economic realities, and customer expectations.

I. Introduction

The 2022 Comprehensive Energy Plan (CEP) elevated two themes: equity and grid evolution.[7] It explored how grid resilience is defined, what differentiates it from reliability; and how metrics might be selected.[8] The CEP also set an overarching goal for the future: *A secure and affordable grid that can efficiently integrate, use, and optimize high penetrations of distributed energy resources to enhance resilience and reduce greenhouse gas emissions.* This is far easier said than done – there are tradeoffs inherent in achieving that goal which require informed choices about how to proceed. As decision points arise, cost-effectiveness evaluation plays a critical role:

> *"Any grid investments — whether in security, distributed energy resources, resilience, or reducing greenhouse gas emissions — must be evaluated in terms of cost-effectiveness; otherwise they may work at odds with affordability. It is essential to keep electricity affordable (including the cost increases driven by upgrading and maintaining the grid), not only for the sake of equity but so that customers are willing and able to choose electricity over fossil fuels for their heating and transportation needs"*[9]

In 2023, Green Mountain Power (GMP) proposed spending an initial sum of $280 million on undergrounding, hardening, and distributed energy storage to "lay a foundation for GMP's stated goal of zero customer outages by 2030."[10] After an exhaustive process, The Public Utility Commission (PUC or Commission) approved $150 million of this request, noting:

> *"We do not need to be convinced about the expected impacts of climate change. Instead, we need to be convinced that GMP has identified an appropriate solution to mitigating those impacts."*[11]

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[7] 2022 Vermont Comprehensive Energy Plan, available at: https://publicservice.vermont.gov/sites/dps/files/documents/2022VermontComprehensiveEnergyPlan_0.pdf.
[8] *Id.* at 90-94.
[9] *Id.* at 60.
[10] *Petition of Green Mountain Power Corp.*, Case No. 23-3501-PET, Order of 10/18/24 at 2.
[11] *Id*. at 22.

While the Commission's limited approval acknowledged the "need for immediate action on climate resiliency," it also highlighted the "thin financial detail and cost-benefit analysis that GMP has presented in support of the [Zero Outages Initiative] to date, and the need for "both the Commission and the Department to be able to scrutinize GMP's planning and spending to ensure that [Zero Outages Initiative] investments are cost-effective and that GMP's ratepayers are the ultimate beneficiaries of the program." As part of its newly proposed Multi-Year Regulation Plan (MYRP) and rate filing, GMP has now provided a benefit-cost analysis framework to support ongoing capital investments for its "Zero Outages Initiative" ("ZOI"). The framework highlights the contrast between traditional utility benefits that flow to all ratepayers, and societal benefits where some ratepayers receive significant benefit, while others see less. The structure of the BCA holds tremendous value for regulators and utilities alike as a concerted effort to quantify the costs (to ratepayers) and benefits (to ratepayers and/or society) of proactive resilience measures in Vermont, and to understand tradeoffs.

The questions raised in the ZOI proceeding are not unique to GMP. Vermont has 16 other distribution utilities, and while none of them are investor-owned utilities (all being municipal, cooperative, or self-managed utilities), they too are experiencing the impacts of increased severity and frequency of major storms.[12] Concurrently, customers are relying more than ever on electricity to power their everyday lives, including meeting transportation and thermal needs with the service (see Figures 1 and 2).

[12] While this is generally the case, there are exceptions. Burlington Electric Department, for example, has noted that due to its compact and highly undergrounded system, severe weather is not a significant cost driver.

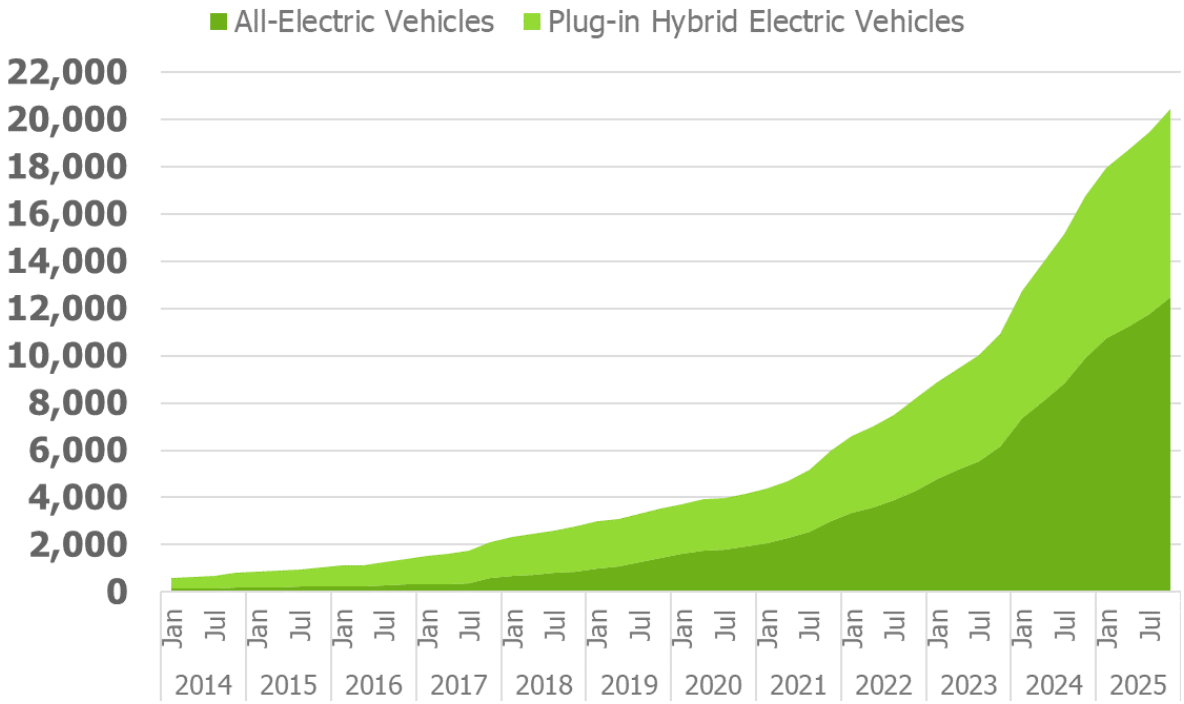

Figure 1: There were 20,424 registered electric vehicles in October 2024, an increase of 22% over the prior year. EVs comprise 10% of all new light-duty vehicle sales in Vermont. *Source: Drive Electric Vermont / October 2025 Vermont DMV data / VADA 2025 Q3 sales data.*

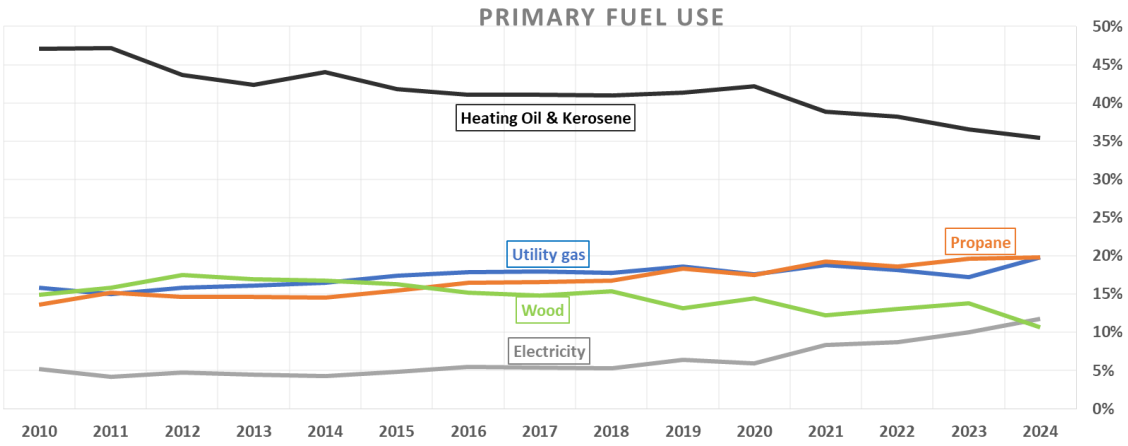

Figure 2: Residential use of heating oil and kerosene continues to drop as Vermonters' primary heating fuel. Electricity remains on the rise as a primary heating source with increased adoption of heat pumps. *Source: U.S. Census Bureau's American Community Survey.*

Several utilities report that their customers have increased expectations around reliability and resilience. At the same time, several years of consistent rate increases and rising costs have put affordability at the forefront. Vermont's utilities, and regulators, should strive to meet the right balance of service and affordability needs. In doing so, they are bound by least-cost planning requirements articulated in 30 V.S.A. § 218c. GMP's proposal for expansive hardening investments, while expensive in the near term, has *potential* to be a lower-cost solution than alternatives such as increased proactive vegetation management and reactive storm recoveries, *depending on assumptions including the frequency and severity of future major storms*. If that potential is realized, then proactive resilience investments by other Vermont utilities may also prove to be the least-cost solutions to support reliability and resilience. Nonetheless, the near-term rate impacts may be substantial and must be part of the decision-making process.

Because utility decisions around these investments and the overall resilience of the grid have implications for all Vermont ratepayers, the Department petitioned the Commission to open a resilience proceeding to help develop a *common framework for defining, valuing, measuring, and planning for resilience*.[13] The Department concurrently applied for and received technical assistance resources from Lawrence Berkeley National Laboratory (LBNL) to support the proceeding. As the Commission has said, "GMP is not alone in dealing with the recent uptick in severe weather and extended outages. All utilities in will need to begin to re-evaluate their distribution system planning to respond to evolving climate patterns. This issue is of particular concern as state energy policy continues to encourage greater reliance on electricity for heating and transportation."[14]

The Resilience Proceeding initiated under Case No. 25-0339-PET has unfolded through a series of Working Groups focused on resilience Planning, Valuation, and Measurement.[15] The Department is appreciative of the substantial time and effort that many stakeholders, including the Vermont distribution utilities, have devoted to participating. The utilities and other stakeholders have provided valuable insight into current resilience practices and priorities, as well as an understanding of the challenges and opportunities ahead.

After considering the content of the working group discussions and participant comments, the Department makes the findings below and recommends actions toward three outcomes: (1) assessing the resilience of the current grid, (2) identifying and prioritizing opportunities for

[13] Department Petition, Case No. 25-0339-PET.
[14] *Petition of Green Mountain Power Corp.*, Case No. 23-3501-PET, Order of 10/18/24 at 32.
[15] See Appendix A for a summary of the Resilience Proceeding process.

service improvement and cost containment, and (3) appropriately balancing the implications for ratepayers.

II. Key Findings from Working Groups, Utility Interviews, and Draft Feedback

The Department, LBNL, and UT-Austin worked together to distill existing knowledge and identify takeaways from the Working Groups, individual utility interviews, and submitted comments.[16] The high-level findings included here directly inform the Department's recommendations. The Department circulated a draft of this Report to stakeholders in March, 2026, and received constructive, detailed comments from several participants. Summaries of those comments and the Department's responses are included in Appendix B. Findings from other Northeast States are also included in Appendix F.

1. Performance measurement, mitigation planning, and valuation must evolve to prepare for extreme weather.

Current reliability targets do not directly reflect outcomes or customer experiences during major storms

Reliability focuses on the ability to meet load (avoid outages) on a routine, daily basis, while resilience is the ability to avoid long-duration outages and minimize or mitigate fallout from high-impact events.[17] In other words, for purposes of this report: **resilience is how well the power system handles and recovers from significant storm events.** While these events greatly impact customers, major storms[18] are excluded from the System Average Interruption Frequency Index ("SAIFI") and Customer Average Interruption Duration Index ("CAIDI")

[16] UT-Austin also distilled its own key takeaways from the working groups during this process, which can be found in Appendix D.

[17] FERC has proposed the following definition of resilience, which has been adopted by NERC: "The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event." *Grid Resilience in Reg'l Transmission Organizations & Indep. Sys. Operators*, 162 FERC ¶ 61,012 at P 7 (2018).

[18] In the reliability context, "major storm" is a specific category of events which are defined based on how they impact service. In the Working Groups, GMP also noted increasing impacts from non-major storms, i.e., highly significant storms where the utility was able restore enough customers in time to fall below the major storm threshold.

calculations underpinning current reliability performance targets in each utility's Service Quality and Reliability Plan ("SQRP").[19]

SAIFI and CAIDI values are system-wide averages that reduce the range of outcomes across the system to a single number. Perhaps unsurprisingly, customer level data provided during review of GMP's ZOI proposal showed that certain locations or groups of customers may see much longer or more frequent outages than others, even if the utility is meeting its reliability targets. Utilities know their systems and problem areas better than anyone, and Commission Rule 4.900 does require informational reporting on specific areas with the worst reliability. However, when it comes to actionable standards at the state level: the use of system-wide averages and the exclusion of major storms means that current reliability targets (1) do not necessarily reflect the actual customer experience, and (2) are not set up to gauge or regulate grid resilience.

Vermont has no explicit requirements for resilience planning or performance.

While the climate trends and implications for severe weather are broadly recognized,[20] Vermont utilities are not explicitly required to plan for resilience by statute or regulation. Under 30 V.S.A. § 218c, utilities must develop least-cost-integrated plans ("IRPs") that meet "the public's need for energy services, after safety concerns are addressed, at the lowest present value life cycle cost, including environmental and economic costs. . . ." The statutory provisions for IRPs do not directly mention resilience, nor is it referenced in State Energy Policy articulated by 30 V.S.A. § 202a. Though not explicit, resilience is implicated in language around adequacy and reliability of service: "To ensure to the greatest extent practicable that Vermont can meet its energy service needs in a manner that is **adequate, reliable**, **secure**, and sustainable."[21]

Utilities do have established reliability obligations, some which are set in their SQRPs and – as discussed above – are based on *system-wide averages net of major storms*. Resilience, by contrast, is *about significant storm events* and involves understanding growing risks and vulnerabilities that may be *masked by system-wide averages*. As noted in the CEP, "without imposition of a measurement or valuation framework, it is not particularly meaningful to describe a grid as resilient, or to describe a resource as providing grid resilience."[22]

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[19] The reliability targets incorporated in SQRPs carry financial penalties for underperformance. While SAIFI/CAIDI data for major storms is excluded for SQRPs, it is reported for informational purposes pursuant to Commission Rule 4.900.

[20] For a summary of relevant climate and storm data, see Appendix G.

[21] *See* 30 V.S.A. § 202a; *see also* 30 V.S.A. § 219.

[22] 2022 Vermont Comprehensive Energy Plan at 91, available at: https://publicservice.vermont.gov/sites/dps/files/documents/2022VermontComprehensiveEnergyPlan_0.pdf.

Utilities are starting to consider and experiment with climate modeling to assess extreme weather trends.

While grid resilience is not explicitly referenced in statute, it is an increasingly critical planning objective. Utilities recognize the risks and costs of extreme weather, and several are working to incorporate climate modeling in planning efforts, including through the development of the 2021 Northview report[23] and use of tools such as Rhizome's GridCAVA.[24]

Resilience valuation methods are still developing, and some utilities are already using benefit-cost analysis (BCA) for projects.

Several utilities have worked to assess the value of resilience or reliability measures, but these analyses have not been directly integrated into planning efforts. VEC, for example, has been developing an ex-post analysis to evaluate outage costs in terms of System Average Interruption Duration Index ("SAIDI") minute reduction per dollar invested, using societal benefits quantified in the Federal Emergency Management Agency ("FEMA") BCA tool.[25] VEC is also partnering with Rhizome to improve assessment of future risks.[26] GMP discussed its efforts to use the Interruption Cost Estimate ("ICE") calculator to estimate avoided costs of interruptions for resilience upgrades, although it did not use these results as inputs for planning associated with its "Zero Outages Initiative." Morrisville discussed its efforts to consider direct costs and benefits for projects, though not through a formal analysis converting benefits to dollars.

Some utilities that are eligible for FEMA funding after disasters (municipal and cooperative utilities) use BCA because it is required to access funds. However, utilities including VEC, Morrisville, and Stowe urged against state regulators requiring use of the FEMA BCA tool, primarily due to frustration with the exhaustive requirements and federal process surrounding its use. There is some receptivity to performing more complex forms of BCA if the analysis – like a streamlined version of the FEMA BCA tool – is likely to lead to receipt of resilience funding and can be kept streamlined. For GMP, which has proposed an expansive resilience-focused investment program, ex ante BCA will help transparently determine the overall cost-effective amount of proactive resilience spending, with project-level BCA helping to prioritize among alternatives. BCA should reflect multiple perspectives, allowing for costs and benefits to the

[23] https://vermontelectric.coop/client_media/files/K_VEC_NorthView_Weather_Final_Report_v2.pdf.
[24] https://www.rhizomedata.com/impact/impact-vermont-electric-cooperative-rhizome.
[25] The FEMA BCA Toolkit is available here: https://www.fema.gov/grants/tools/benefit-cost-analysis#toolkit.
[26] See VEC's presentation from the June 30, 2025, Planning Working Group meeting for more details on the VEC-Rhizome partnership: https://epuc.vermont.gov/?q=downloadfile/767879/203332.

utility system to be understood in relation to costs and benefits to particular customers, or society at large.

2. Utilities are diverse and seek scaled, customized approaches

There is no easy one-size-fits-all approach to distribution system resilience in Vermont

Vermont's distribution utilities are diverse, with considerable variation in size,[27] climate,[28] associated risks and vulnerabilities,[29] planning practices,[30] and institutional context.[31] While this is a simple observation, it creates significant challenges for a common approach to grid resilience. The extent of new risks for utilities from extreme weather is not clear. Considering Vermont's multiple micro-climates, regional/local topographical variation, and utility and customer characteristics, more information is needed to better understand the risks, including whether utilities necessarily have particularly vulnerable zones or circuits, and/or sub-sets of customers experiencing frequent and/or long-duration outages.

Some non-IOUs appear to be pursuing nationwide leading practices in resilience planning and analysis, particularly Vermont Electric Cooperative (VEC) and Stowe Electric Department (Stowe or SED) among electric cooperatives and municipal utilities respectively. By contrast, some use less advanced methods or are focused (sometimes by necessity) on other priorities. The regulatory and institutional environments under which the cooperative and municipal utilities operate place constraints on their decision-making that differ from those affecting IOUs like GMP – and this extends to capital budgeting, where smaller utilities often have a capital budget intended to address many priorities, from resilience to traditional asset condition to power supply investments. Many smaller utilities are resource-constrained such that they need external support to undertake new resilience-related planning. Substantial changes to their analysis of capital project portfolios may also be necessary to support mitigation projects at these smaller utilities, even if those projects are found to be cost-effective.[32]

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[27] E.g., number of customers, customers/line-mile, and geography.
[28] E.g., location-specific weather and topography
[29] For instance, location and climate-based variation in risks from heavy wet snow, floods, straight-line winds, fire, etc.; and system vulnerabilities like aging cross-country lines, or infrastructure located in floodplains.
[30] including evaluating relative costs and benefits of resilience investments (e.g., upfront costs of hardening, undergrounding, and relocating lines compared to long-term financial benefits associated with lower storm response costs, vegetation management costs, etc.)
[31] E.g., regulatory structure, capital structure, governance, and resources.
[32] See for example VEC's proposed 2025 Integrated Resource Plan at p.5, which notes they have $350 million of resiliency investment choices and $5 million to invest annually. https://vermontelectric.coop/client_media/files/2025_IRP_Section_1_Executive_Summary.pdf.

Utilities each have different reliability targets and seek similar flexibility for resilience

Each utility's SQRP has unique performance targets for reliability, which were developed in the early 2000s. In 1998, the utilities and Department voluntarily co-developed a process to capture outage data and calculate SAIFI and CAIDI values. Commission Rule 4.900 became effective on November 1, 2000 and formalized this process as "information-only" reporting. The Commission (then the Public Service Board) approved the first SQRP for an electric utility (GMP) in 2001[33] and subsequently approved SQRPs for all electric distribution utilities (except GF Power). The reliability performance targets were negotiated between each utility and the Department and were primarily based on the average of three years' SAIFI/CAIDI performance data.

SQRP tariffs allow "major storms" to be excluded from SAIFI/CAIDI calculations, and the definition of major storm differs between tariffs.[34] In Working Group meetings and follow-up correspondence, the participant consensus was that each utility should continue to have its own performance measures for reliability and resilience based upon its unique characteristics, rather than a one-size-fits-all approach.

Many utilities plan investments to meet multiple goals at once, balancing needs and priorities within limited capital budgets

Most Vermont utilities approach planning, operations, and assessments of infrastructure investments – including resilience measures – in a multi-criteria fashion: subject to multiple constraints and with multiple goals in mind. For cooperative and municipal utilities in particular, a resilience-specific framework would change current planning rubrics and potentially elevate resilience above other priorities established by their elected leadership. Strict planning

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[33] *See Tariff filing of Green Mountain Power Corp.*, Docket 6107, Order of 1/23/01 at 90-92.

[34] These definitions are not based on storm characteristics (e.g., wind speed, amount or type of precipitation), but rather on the *impacts* of the storm (damage to infrastructure, extent of outages). For Burlington Electric Department (BED), GMP, Ludlow, VEC, and WEC, a major storm is defined as a severe weather event that satisfies each of the following criteria:

1) Extensive mechanical damage to the utility infrastructure has occurred;
2) More than 10% of the customers in a service territory are out of service due to the storm or the storm's effects; and
3) At least 1% of the customers in the service territory are out of service for at least 24 hours.

For Barton, Enosburg Falls, Hardwick, Hyde Park, Jacksonville, Johnson, Lyndon, Morrisville, Northfield, Orleans, Stowe, and Swanton, the definition includes prongs (2) and (3) above, but not the criterion related to extensive mechanical damage. For these utilities, which take service from larger utilities, extensive "upstream" infrastructure damage in the larger utilities' service territory could occur that results in "downstream" outages for the smaller utilities.

requirements could also hamper their ability to adapt investment priorities based on emergent factors like funding opportunities or emergencies.

Most utilities in Vermont are not currently performing analysis to determine how much to spend overall on resilience measures. This is because cooperative and municipal utilities operate within a fixed capital budget and attempt to optimize for multiple objectives. For these utilities, selection and prioritization of projects can be driven by engineering studies, emergent circumstances (e.g., Morrisville Power and Light ("Morrisville")), or obligations to external funders such as the Rural Utilities Service (e.g., Washington Electric Cooperative) among other things. Vermont Electric Cooperative has developed a transparent prioritization process for projects, including a scoring rubric that incorporates reliability and consideration of worst-performing circuits, which they plan to revise in the future to include additional resilience criteria such as outage cost reduction and risk assessment efforts. This appears to be best practice. While approaches differ across utilities and the level of sophistication generally aligns with utility size, these decision-making processes are largely articulated in IRPs and should be refined to account for resilience.

Multi-objective planning remains appropriate, and the impacts of climate or storm-related trends and events should be addressed alongside traditional priorities through the planning process reflected in IRPs. Ancillary plans (e.g., GMP's MYRP) should reference the decision-making frameworks articulated in IRPs. It is also essential that utilities plan cooperatively with stakeholders. From a resilience perspective, this includes other entities involved in aspects of resilience planning, including Vermont Emergency Management, Regional Planning Commissions, and local governments, and other utilities.

Municipal and cooperative utilities operate under additional layers of ratepayer oversight

Vermont's two cooperative, and 14 municipal, distribution utilities are subject to oversight of their capital spending decisions by boards representing their ratepayer communities. Many cooperative and municipal utilities emphasized this in their comments on the Department's draft report, noting that these boards provide an additional layer of governance or supervision and can set the direction of spending priorities. The utilities also noted additional layers of requirements imposed by lenders (such as the Rural Utilities Service) and federal grant requirements. The Department acknowledges the additional oversight and obligations that municipal and cooperative utilities must consider in planning and prioritizing investments. While this does not change the regulatory relationship between these utilities and the

Department or the Commission, it does factor into the Department's recommendations – which do not mandate benefit-cost analysis for municipal or cooperative utility resilience investments and do not negate the broad latitude utilities are provided in formulating IRPs. The Department's proposed IRP guidance language enables utilities to determine and articulate their resilience decision-making frameworks within the fundamental pillars of risk assessment, evaluation of risk mitigation alternatives, and prioritization of solutions.

3. Strategic support to utilities would help advance grid resilience statewide

All utilities would benefit from shared analytical tools or resources, and smaller utilities need financial and technical assistance with BCA.

From the Working Groups it was clear that software tools and platforms to support resilience planning, valuation, and measurement are emerging and available for electric utilities. These tools are developed by the national labs (e. g., Argonne and LBNL) as well as commercial vendors, including the National Information Solutions Cooperative ("NISC") and Rhizome. A number of these have been or are being adopted in Vermont. However, commercial tools may be cost prohibitive for smaller Vermont utilities.

The Northview weather report was cooperatively commissioned by all the distribution utilities through Vermont Electric Power Company, exemplifying one way Vermont utilities can work together to develop planning tools that would otherwise be prohibitively expensive. Additional opportunities exist through the State and could benefit multiple sectors seeking tools to inform infrastructure resilience planning. These are explored further in the Recommendations section of this report.

Many utilities are open to additional reporting requirements but seek to avoid inefficient or conflicting regulatory demands and to remove regulatory requirements that no longer provide value.

Data collection methods for existing reporting requirements vary between utilities: for some the process is heavily automated and for others it is labor-intensive. Some utilities are collecting data and calculating additional metrics beyond those that are required.

In the Working Groups, the utilities were asked whether they were voluntarily utilizing certain additional metrics or assessments and if not, what effort and value would be associated with

calculating them. The discussion focused on metrics that are generally more granular than SAIFI/CAIDI, including:

- Customers Experiencing Multiple Interruptions ("$CEMI_n$"), which calculates the ratio of customers who experienced "n" interruptions to the total number of customers served.
- Customers Experiencing Long Interruption Durations ("CELID"), which calculates the ratio of individual customers that experience interruptions with durations longer than or equal to a given time, to the total number of customers served.
- Histograms of customer-level data for number of outages per year and total outage duration per year, similar to what GMP provided in the ZOI proceeding.
- Data by circuit segment i.e., the sub-circuit level.
- Momentary interruptions (< 5 minutes), such as Momentary Average Interruption Frequency Index (MAIFI).

Utility responses varied widely, from GMP seeing "great value" in these additional metrics[35] to the smaller utilities seeing either no value at all or not enough value to justify the additional staff resources to manually compile the data. The utilities are in different stages of adopting software tools to assess and improve system resilience. Some utilities already have the capability to do this, while others would require a costly software upgrade or extensive manual effort using spreadsheets. VEC struck a middle ground in its written comments, stating: "VEC does not have an issue adding CEMI and CELID as information-only metrics. . . . VEC opts for a trial period, outside of the rule, to provide this information in the next two Rule 4.900 reports to better understand how much additional costs/resources are needed."

The Working Groups also discussed the right amount of reporting to keep regulators informed without unduly burdening utilities. Some utilities were concerned about adding new reporting requirements: they questioned whether the Rule 4.900 reports submitted each year are reviewed by the Department and the Commission, because they do not receive feedback on them. While there is no formal feedback process, the Department does review every annual Rule 4.900 and SQRP report and follows up with those utilities that did not submit a report. The Department also maintains a spreadsheet of all utilities' annual SAIFI and CAIDI data, compared to each utility's SQRP performance measures.[36] Reliability metrics are currently addressed cooperatively during review of each utility's IRP. The exploration of additional, more granular, metrics is aimed at helping the Department, the Commission, and the state as a whole better understand (1) current grid performance and (2) customer experiences that may be masked by

[35] GMP is already reporting on these and other new metrics annually as part of its resilience work, though performance targets have yet to be established.
[36] See https://epuc.vermont.gov/?q=downloadfile/767816/203332.

system-wide averages as currently tracked – these are key considerations for resilience and safe, adequate service.

Other Rule 4.900 topics were addressed in the Working Groups as well, including new definitions and streamlining, consolidating, or removing requirements. Most utilities did not want to change the definition of "outage" or add a definition for "interruption," although GMP was supportive of this addition to account for the ability of energy storage[37] (batteries that can help mitigate the effects of certain outages), and VEC provided suggestions for both terms. All of the utilities opposed moving the definition of "major storm" from the SQRP tariffs to Rule 4.900, and all of the utilities also opposed making SQRP performance measures part of Rule 4.900, both of which the Department proposed to streamline outage reporting by putting it all in one place. The Department also raised the idea of including a formula in Rule 4.900 to determine the SAIFI/CAIDI performance measures used in SQRPs. This could provide a more efficient and consistent mechanism for setting performance targets. Most utilities opposed the idea, but SED supported a formula as long as it recognized the different characteristics of individual utilities' service territories. BED was concerned that formulaic standards would result in "setting targets that are unnecessarily stringent if based solely on improvement compared to current metrics."

III. Recommendations

After reviewing written and informal participant comments made throughout this proceeding, the discussions in the Working Groups, and feedback from the technical assistance team, the Department makes the following recommendations, organized by the entity that is recommended to take action: The State, the Commission, or the Department.[38]

State Action

Revise state policy to incorporate grid resilience

The Department proposes to incorporate and prioritize grid resilience in state policy and utility planning through the following statutory changes, which are intended to provide clear direction to utilities while allowing for better utilization of resources:

[37] An "outage" as currently defined is on utility infrastructure upstream of a customer's billing meter, and would not account for customer-sited energy storage that maintains some level of service to customers during outages.
[38] These recommendations include some components of the Draft Resilience Straw Proposal provided by LBNL and UT-Austin earlier in the Resilience Proceeding (Case No. 25-0339-PET).

a. Expand, streamline, and modernize requirements for utility Integrated Resource Plans (IRPs) to address resilience, reliability, and load management, while formalizing the process by which the Department issues IRP guidance as part of the Comprehensive Energy Plan.
b. Provide more time for municipal and cooperative utilities to prepare IRPs (increase cycle from 3 to 5 years), to help balance the burden of implementing new requirements by making the resource-intensive IRP process more efficient.
c. Allow for larger expedited rate changes under § 218d(o)[39] for utilities that have approved IRPs. This will appropriately link expedited rate requests to decision-making frameworks – including resilience decision-making frameworks – that have undergone review and approval by the Commission with higher permissible rate changes as a logical result.

This package is designed to address important statutory and planning gaps while offering some degree of regulatory relief, promoting a more efficient utilization of resources. Utilities have also expressed the need for additional support and reforms which neither the Department nor the Commission can fully provide. These include (1) Funding: consistent with recommendations made in the Climate Action Plan and Resilience Implementation Plan (see Appendix C), the size and regulatory structure of municipal and cooperative utilities means that non-ratepayer funding resources may be critical to their ability to make significant resilience investments. This is particularly true if those investments are not cost-effective. (2) Permitting: lengthy permitting can jeopardize utilities' ability to take advantage of external funding resources, such as FEMA Hazard Mitigation Grant Program funds. Cooperative and municipal utilities have 18 months from a declared disaster to complete projects, which can be especially challenging in the context of environmental permits that require seasonally specific studies.

The Department intends to work with utilities and other stakeholders to investigate actionable non-ratepayer funding avenues. For the fiscal year 2027 State Budget, for example, the Department proposed $10 million in funding to support municipal and cooperative utility resilience investments. Given other state priorities, this did not make it into the Administration's final budget. The Department has also been administering $8 million in Grid Resilience and Innovation Deployment Grants to utilities, funded through the U.S. Department of Energy under Section 40101 of the Bipartisan Infrastructure Law (BIL), and will pursue any similar funding opportunities.

[39] Increase the maximum allowable rate change for utilities with approved IRPs from 3% to 5% during any 12-month period, and cumulatively from 10% to 15% from rates last approved. Utilities without approved IRPs will continue to have access to 3% (10% cumulative) expedited rate changes.

Commission Actions

Update Rule 4.900 to address resilience

The Department recommends that the Commission update Rule 4.900 with a focus on resilience, to address outage reporting, severe weather impacts, and service quality. Implementing new reporting metrics at system-wide and customer-focused levels is a critical step in evaluating customer experiences and resilience needs or priorities, for each utility and across the state. Additional definitions and practices are also warranted to reflect the current context – the rule was last updated 25 years ago.

> *The Department recommends that the Commission update Rule 4.900 with a focus on resilience, to address outage reporting, severe weather impacts, and service quality.*

Specifically, the Department recommends that the Commission open a proceeding to investigate amending Rule 4.900, including:[40]

- **System-wide resilience metrics:** Discussed further below.
- **Customer-focused resilience metrics:** Discussed further below.
- **Major storm postmortems:** Rule 4.903(B)(3) requires "an overall assessment of system reliability" focusing on the areas with the most outages and the causes of most outages. The rule also calls for a description of short- and long-term actions and plans to address any problems identified. Most, but not all, utilities conduct the required analysis in Rule 4.900 reports. Because there is no enforced standard for reports to meet, the depth and subject matter of the reporting varies widely. Rule 4.903(B)(3) provides the opportunity for a narrative analysis of storm responses and lessons learned; however, the current

[40] In addition to these recommendations, the Department will independently explore:

- *Metrics dashboard:* Creating a public-facing dashboard of reported annual metrics for each utility would improve accessibility, transparency, and accountability. The Department is evaluating whether it has the capacity to provide this tool.
- *Linking Rule 4.900 and SQRP performance metrics:* A formula or set procedure for deriving performance standards would provide transparency and predictability when adding or revising performance metrics. Any formula or process should be flexible enough to account for the different characteristics of individual utilities and their service territories. The individuals who originally negotiated reliability performance targets in the early 2000s no longer work for the Department or the utilities, and there has been confusion about how those standards were generated.

rule does not specifically discuss resilience or major storm impacts. Resilience is focused on high-impact (and historically, low-frequency) storms, which are usually excluded from SQRP reliability metrics. If reliability standards do not capture these events, and therefore related outages are not factored into performance penalties, there is no practical requirement to address resilience. As a pragmatic step forward, the Department recommends: (1) enforcing a more consistent standard of detail for Rule 4.903(B)(3) narrative reporting; and (2) adjusting the rule language to explicitly include storm impacts and responses. This will require utilities to document their storm experience and explain how that information will be used to improve system resilience. The Department also recommends that the rule include a "postmortem" workshop to be held by the Commission each year, convening utilities to discuss major storms and their individual performances.[41]

- **Defining the role of energy storage:** Utility-provided energy storage may partially or wholly mitigate interruptions of service due to an outage on the utility system. As such, Rule 4.900 should explicitly discuss how energy storage is accounted for in outage reporting. The appropriate treatment of storage is a policy question warranting additional feedback from stakeholders, and consideration should be given to (1) the extent to which energy storage is equivalent to utility service,[42] and (2) metrics to track outage events mitigated by storage.
- **Parameters around "reasonably adequate service":** The Department sees value in adding criteria or guidance to inform the understanding of "reasonably adequate service" under 30 V.S.A. § 219. There is currently no definition of adequate service, and therefore no indicia beyond SQRP targets to measure performance in reliability or resilience. Parameters around adequate service should be considered at the system-wide and customer level, with and without major storms. One example would be an expectation for the maximum frequency and/or duration of outage any customer should experience within a given timeframe.

While the update process for Rule 4.900 unfolds, collection of system-wide and customer-specific trial metrics should begin. The Department recognizes that measuring resilience can be an art and a science – and the state of the art is still emerging. It is also true that Vermont's utilities differ widely in technical and staffing capacity. VEC's filed comments raised the idea of a trial period for some of the more granular data reporting under discussion. Considering the potential burden on some utilities, a trial reporting period across the board would provide

[41] Some utilities indicated that a dedicated "postmortem" workshop may be too formal and/or duplicative of other efforts. The Department sees value in convening utilities on a consistent basis but is open to exploring the most effective way to improve information sharing and analysis surrounding major storms.
[42] This may depend on the location of the installation and the degree of outage mitigation.

flexibility and inform decisions around permanent rule changes. Therefore, the Department recommends that the Commission issue an order in the Resilience Proceeding requiring a 2-year trial period[43] for the following system-wide and customer-specific trial metrics – while the update process for Rule 4.900 unfolds:

- **Systemwide resilience metrics: A rolling multi-year all-in (with major storms) SAIFI** and a metric assessing **time to restore 95% of affected customers for a given event**.[44] Including these or similar metrics would provide valuable insights for regulators and other stakeholders and may capitalize on existing external or internal reporting frameworks without extensive additional work or analysis for utilities.
- **Customer-focused resilience metrics: CEMI, CELID, and/or histograms** to indicate the range of customer experiences, particularly during high-impact storms or other resilience events. This would give the Commission and the Department insight into utility outage data at the customer level, rather than only at the system-average level. Customer-level outage data would also illuminate outcomes for potentially vulnerable customers and critical facilities, along with groups or communities of customers in specific locations.

Implementing a trial reporting period by order will serve two purposes: (1) it will allow the Commission to respond to emerging circumstances or new information, and (2) it will provide practical experience to inform the Rule 4.900 updates. Additionally, as noted by VEC, the trial period should be used to help to establish definitions; understand the burden on utilities; and consider how the metrics will inform regulatory decision-making. Each annual report during the trial period should include comments from the utilities discussing the practical impacts and value of data collection on an ongoing basis. The Department recommends that the Commission include the metrics above in the Rule 4.900 proceeding from the outset, to be adopted or modified based on any developments during the trial period.

Phase in resilience updates to Service Quality & Reliability Plans

Once new resilience reporting metrics are formally adopted as part of Rule 4.900, the Department recommends a phased approach to actionable resilience standards in SQRPs, implementing performance targets after three years of reporting. By that time, utilities and

[43] While some utilities suggested that a three-year trial period could be more beneficial, the Department would prefer to check in after two years and evaluate the need for an additional year.
[44] After the Working Groups concluded, the Smart Electric Power Association introduced these metrics, which consider both "resistance" – through tracking a rolling multi-year all-in (with major storms) SAIFI – and "restoration," through a metric assessing time to restore 95% of customers. See https://sepapower.org/resource/thread-is-beyond-the-baseline/.

regulators will have sufficient data and contextual information to develop appropriate utility-specific targets. This seeks to replicate the process by which SQRP targets for each utility were developed. GMP is already tracking resilience metrics for informational purposes through its SQRP. Given GMP's experience and level of resilience investment, actionable performance targets should be implemented much sooner, ideally through the implementation of the proposed Multi-Year Regulation Plan now under consideration.

Require investor-owned utilities to use strong, up-front benefit-cost analysis to justify major resilience investments

The Department recommends that the Commission require robust, ex ante[45] benefit-cost analysis (BCA) from investor-owned utilities seeking (1) to make large capital investments (projects, portfolios of projects, and/or programs) for system resilience, or (2) to achieve a level of resilience beyond existing reliability standards,[46] in order to demonstrate that the proposed investments will produce benefits in excess of costs.[47] BCAs should be centered around a ratepayer perspective, and should also consider impacts that accrue more broadly to Vermonters.

The CEP outlines four different benefit-cost tests that consider varying scopes of costs and benefits accruing to different parties.[48] By considering investments from multiple perspectives, any tradeoffs (for example, between costs to ratepayers and benefits to broader society) can be thoughtfully evaluated. Though many cost-benefit tests exist, the Department will expect that utilities seeking approval of large resilience investments provide BCAs featuring at least the **Utility Cost Test (UCT)** and the **Societal Test (SCT)**. The first assessment should be the UCT, which is centered around impacts to ratepayers. This test considers the direct costs to the utility (and therefore its ratepayers)[49] against the benefits of avoided costs related to system restoration and implementation of alternative reliability/resilience measures. The second assessment should be the SCT, which considers impacts to Vermonters and society more

[45] Ex ante means up-front, prior to the investment being made, as part of the justification to regulators for approval to make an investment – not after projects have been completed.
[46] As this report illustrates, current regulatory standards do not evaluate resilience and it is not clear how much additional investment may be needed for adequate least-cost service.
[47] As an example, GMP's ZOI would be a portfolio or a long-term program of investments, made up of specific project-level investments. GMP's ZOI should be evaluated with ex ante BCA, as should resilience spending proposed in its multi-year rate plan.
[48] These are the Utility Cost Test, Societal Test, Total Resource Test, and Participant Test. *See* Comprehensive Energy Plan at 41-42, available at: https://publicservice.vermont.gov/sites/dps/files/documents/2022VermontComprehensiveEnergyPlan_0.pdf.
[49] This would include the cost of the resilience project itself.

broadly.[50] The SCT considers total costs and benefits that accrue to all parties – even if those benefits come at a net expense to ratepayers. A Vermont-specific societal test (including non-electric benefits), confined to benefits that accrue within Vermont's borders, is also appropriate. Conducting multiple tests ensures that tradeoffs in costs and benefits to different groups can be examined, and is consistent with the current paradigm of least-cost planning, where economic costs (usually considered as ratepayer) and environmental (societal) costs must be considered.[51] Appendix H outlines components and steps for a rigorous BCA.

Figure 3: Core resilience planning practices with BCA.[52]

In addition to providing the BCA described above, a utility that implements a resilience project for which BCA was required should also conduct a post-implementation comparison of actual costs and benefits to the planned or estimated costs and benefits. If actual costs or benefits differ significantly from ex-ante estimates, then the utility should attempt to explain the discrepancy and outline how it will modify assumptions in future analyses.

The Department will reference these recommendations in policy discussions and dockets as part of its ratepayer advocacy. GMP has indicated that it "shall use the planning, valuation, and measurement recommendations that emerge from Case No. 25-0339-PET,"[53] and should be commended for its recent efforts in providing ex-ante BCA to justify Multi-Year Rate Plan

[50] Comprehensive Energy Plan at 41-42.
[51] *See* 30 V.S.A. §218c.
[52] *See* Appendix H for a detailed outline of BCA components and steps.
[53] GMP-DPS MOU in Case No. 24-3614-PET.

resilience budget proposals. Regardless of the merits of GMP's analysis, it will provide a wealth of information to bolster assessment of the economic and rate implications around resilience investments. It will also help pave the way for other utilities and the state at large to account for the value of resilience and improve least-cost planning.

Department Actions

Update the Department's IRP Guidance to address climate risks and system vulnerabilities

While grid resilience is a cross-cutting issue, it primarily implicates transmission and distribution issues in utility planning. Customers, regulators, and other stakeholders can see utilities' public-facing distribution planning through their Integrated Resource Plans ("IRPs"), which are currently updated on three-year cycles. GMP also has a Multi-Year Regulation Plan ("MYRP"), where additional resilience planning and budgeting is expected. The Department views the MYRP as a spending plan that should reflect priorities resulting from the detailed planning work undertaken in an IRP – including for transmission and distribution investments.

Beyond GMP, all utilities in their respective IRPs should be considering grid resilience in light of climate change and electrification. In the Department's view, there are three core grid resilience planning steps that each utility should take:

- Risk and vulnerability assessment;
- Evaluation of costs, benefits, and rate impacts of resilience projects or programs; and
- Identification of preferred or prioritized solution(s), with metrics to measure success.

This general sequence of steps, i.e., identifying needs, evaluating alternatives to meet those needs, and selecting a preferred solution, is familiar to utilities given the discipline of integrated resource planning. Most utilities have already committed to follow this general outline in their IRPs through memoranda of understanding (MOUs). For example:

> **Green Mountain Power (2024 IRP, Case No. 24-3614-PET)[54]**
>
> "*Resilience Investments:* GMP will include a decision-making framework for selection and prioritization of grid resilience investments, including a risk assessment that incorporates one or more long-term climate forecasts; evaluation of the costs, benefits, and rate impacts of potential resilience programs to mitigate those risks; and, proposed metrics for measuring the impacts of resilience

[54] GMP-DPS MOU in Case No. 24-3614-PET.

investments. GMP shall use the planning, valuation, and measurement recommendations that emerge from Case No. 25-0339-PET."

Washington Electric Cooperative (2024 IRP, Case No. 24-1106-PET)[55]

"*Resilience:* WEC will include a discussion of system resilience, including any anticipated resilience-focused investments, along with a methodology for quantifying the impact and financial value of those investments and proposed metrics for measuring the success of those investments. The discussion should include an assessment of potential distribution system resilience threats and vulnerabilities, as well as how WEC plans to address them through strategies to prevent, survive, and recover from major resilience events, i.e., generally, low-frequency, high-impact events impacting large geographic areas and lasting more than 24 hours. This should include a discussion regarding the overlap in benefits and costs between reliability and resilience-focused solutions plus a proposed least-cost analysis framework for selecting solutions including an analysis of alternatives."

Enosburg Falls (2024 IRP, Case No. 24-0489-PET)[56]

"*Resilience:* EFWL will include a discussion of system resilience, including a vulnerability assessment, description of proposed resilience programs or projects, and projected costs and rate impacts, utilizing the guidance, best practices, and template provided in *Lawrence Berkeley Lab's July 2024 publication, Grid Resilience Plans: State Requirements, Utility Practices, and Utility Plan Template* (https://emp.lbl.gov/publications/grid-resilience-plans-state) or equivalent authority, based on mutual agreement between EFWL and the Department. EFWL will also engage in any resilience initiatives convened by the Commission or Department."

The Department proposes updating its IRP Guidance with the language provided in Appendix I, which adds detail under each of the three core steps and moves toward standardized IRP Guidance language rather than utility-specific MOU conditions.

[55] WEC-DPS MOU in Case No. 24-1106-PET.
[56] Enosburg-DPS MOU in Case No. 24-0489-PET.

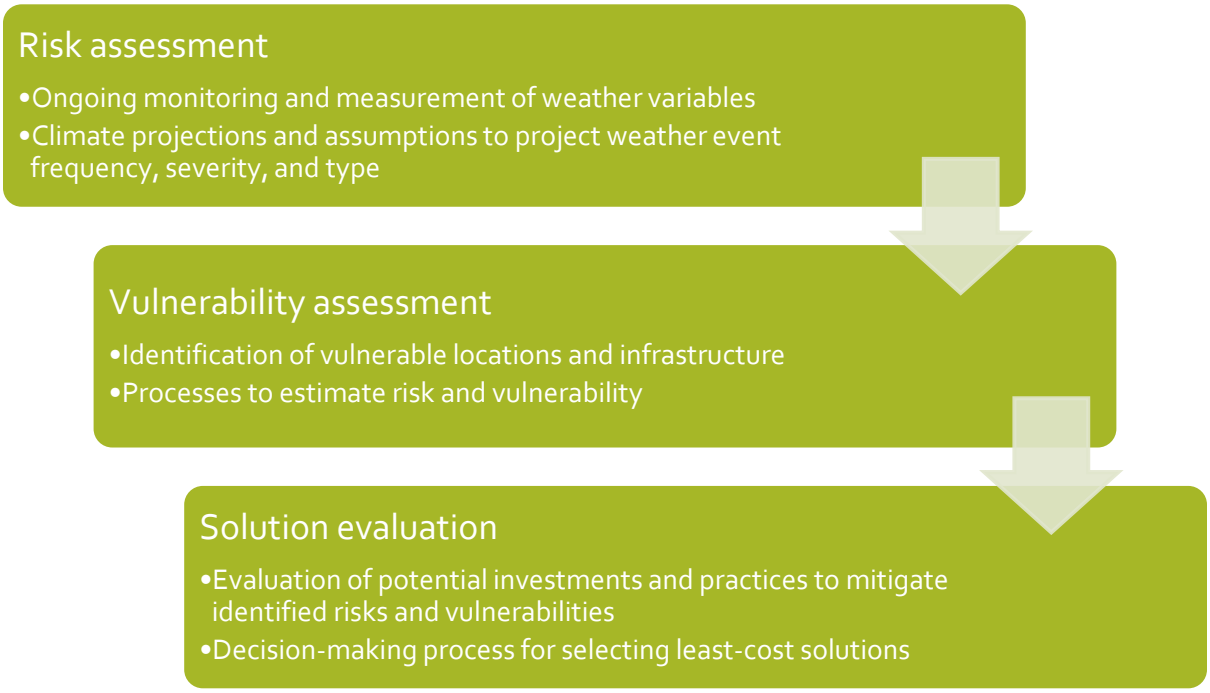

Figure 4: Core resilience planning practices[57]

As illustrated in the Working Groups, risk assessment is a particularly challenging area where additional support may be needed. Opportunities for cooperative action (jointly funded by utilities and/or with State funding) could include:

- Regular updates to the Northview Weather, LLC climate assessment (or similar product) indicating trends in extreme weather hazards. This would ideally be done for the whole state, and customized as needed for individual utilities, with projections formatted and mapped at a resolution consistent with the downscaled LOCA2 standard. In the absence of a statewide update, utilities should pursue individual updates or the equivalent.
- Updates to the Vermont Municipal Vulnerability Indicators Tool[58] to incorporate projections for hazards relevant to utilities (e.g. heavy, wet snow; icing; wind) in timescales commensurate with utility planning and infrastructure investment (20-50 years);

[57] See Appendix I for proposed IRP Guidance language. *Extensive resources, templates, and references are available to utilities seeking additional guidance from the following: Grid Resilience Plans: State Requirements, Utility Practices, and Utility Plan Template (Lawrence Berkeley National Lab, 2024); EPRI Climate READi Framework; Planning for Climate Resilience in the Power System: A Guide for Model Implementation (EPRI); IEEE Distribution Resiliency Working Group; Vermont Municipal Vulnerability Indicators Tool.*

[58] https://climatechange.vermont.gov/mvi.

- Development of an interactive online platform to provide and maintain downscaled, multi-risk hazard (e.g., heavy, wet snow; icing; wind) projections for use by utilities and other entities focused on infrastructure resilience;[59]
- Expansion of access to Rhizome or similar product offering hazard identification and vulnerability analysis;
- Pursuit of academic partnerships, such as with the State Climatologist and University of Vermont, including utilizing existing structures like the Inter-Agency Advisory Board to the Climate Action Office, where feasible.
- Facilitation of joint public/private/cooperative partnerships with industry and public power trade groups such as the Electric Power Research Institute ("EPRI"), ISO-NE, the American Public Power Association ("APPA") or the National Rural Electric Cooperative Association ("NRECA").

Risk and vulnerability assessments are key inputs to evaluate and prioritize solutions, as those steps illuminate the relative costs and impacts of specific projects. The value of resilience investments will depend on numerous variables and assumptions, from frequency and intensity of extreme weather to costs associated with storm recovery. Many costs and benefits associated with discrete resilience programs or projects will be at least utility-specific, and likely site-specific. All utilities should be attempting to determine whether they are making the right level and type of proactive investments in resilience as part of their least-cost planning frameworks and regularly re-evaluating their planning assumptions to inform decisions about the appropriate amount of overall investment.

All utilities should be attempting to determine whether they are making the right level and type of proactive investments in resilience as part of their least-cost planning frameworks and regularly re-evaluating their planning assumptions.

The Electric Power Research Institute ("EPRI") has recently developed a suite of tools – including investment evaluation tools - to assist utilities and regulators with resilience planning.[60] EPRI provides detailed guidance on selecting and conducting both benefit-cost analysis ("BCA") and Multi-Criteria Decision Analysis ("MCDA"). The Department encourages all utilities to employ one of these approaches, or a substantially similar approach, to evaluate and

[59] E.g., https://resilientma-mapcenter-mass-eoeea.hub.arcgis.com/; https://mitigateny.availabs.org/; https://hazardmitigation.ny.gov/; https://apps.epri.com/climate-data-user-guide/en/future-climate-data-sources.html
[60] https://apps.epri.com/climate-readi-investment-guide/en/.

support resilience investment decisions. All utilities should consider conducting BCA as part of their decision-making framework for evaluating resilience projects and it should be required of Green Mountain Power given its substantial ongoing investments.

Pursue joint initiatives for technical and financial support

The Department will actively seek funding, technical assistance, and partnership opportunities with other state agencies, academic institutions, industry, and utilities to facilitate and support collaborative action. A key objective is to develop tools and reports for climate hazard identification and vulnerability analysis. The technical assistance provided by LBNL and UT-Austin in this proceeding is one example of the kinds of opportunities that may exist. The Department has also applied for FEMA Hazard Mitigation Grant Program funding through Vermont Emergency Management, to develop a statewide hazard and threat assessment. This would inform vulnerability assessments for Vermont's cooperative and municipal utility infrastructure. Finally, the Department continues to seek additional rounds of funding for resilience project implementation from the Bipartisan Infrastructure Law.

Explore ways for smaller utilities to set aside funds for cost-effective resilience investment

Additionally, in response to the capital constraints faced by cooperative and municipal utilities, the Department will further explore voluntary regulatory mechanisms that may enable municipal and cooperative utilities to seek approval for advance collection of a "resilience capital reserve" for specific investments as warranted. With rigorous cost-benefit justification and appropriate financial screening, this could include approval of accounting treatment for a regulatory liability tracking advance funds collected for a resilience investment.

IV. Conclusion

The Resilience Proceeding and the recommendations here represent essential steps forward. The Department makes these recommendations after considering extensive input from distribution utilities and in recognition of the pressing need to confront and adapt to changing economic and environmental pressures. There are many challenges ahead, yet there are actions we can and should take today. Accelerated cycles of improvement are needed if the electric sector is to keep pace with the financial and physical impacts of climate trends, customer needs and expectations, and technological change. Taking the steps described in this report will provide experience, information, and tools to: (1) understand where the resilience of the grid currently stands; (2) identify and prioritize improvements in service and cost

containment; and (3) appropriately balance up-front costs with long-term benefits for ratepayers. With a foundation in place, Vermont will be positioned to work toward the best overall outcomes and take advantage of any new advances or opportunities.

The Department is very grateful to the utilities, participating stakeholders, the technical assistance team, and the Commission for their contributions and engagement in the work thus far. The Department will continue moving forward with actions available to it and respectfully asks the Commission and the utilities to do the same.

Acknowledgments

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- Steve Fitzhugh, Northfield Electric Department
- John Morley, Village of Orleans Electric
- Lynn Paradis, Village of Swanton

- Thomas Petraska, Village of Ludlow Electric Light Department
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- Erik Bailey, Village of Johnson Water & Light
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- Chris Campany, Windham Regional Commission
- Sam Lash, Central Vermont Regional Planning Commission
- Ann Janda, Chittenden County Regional Planning Commission
- Ted Brady, Vermont League of Cities & Towns
- Jonathan Dowds, Renewable Energy Vermont
- Marian Wolz, Agency of Natural Resources
- Caroline Paske, Vermont Emergency Management
- Dr. Jason Shafer, PowerOutage.US
- Dr. Lesley-Ann Dupigny-Giroux, University of Vermont

Appendix A: Process and Input

The Department structured the Resilience Proceeding Working Groups into three topic areas: Planning, Valuation, and Measurement. While the topics are interrelated, separating them allowed depth of discussion on each component. The first Working Group meeting was held on June 12, 2025, and the last on October 3, 2025. In all, two meetings were held on each topic, with an additional joint meeting of the Working Groups held at the midway point during which the Department's technical assistance partners, LBNL and their subcontractors at the University of Texas-Austin (UT-Austin), presented a draft straw proposal. In addition to the input received at each approximately 3-hour working group, opportunities for written comment were also provided at various points.[61]

Stakeholders attending the meetings comprised representatives of the distribution utilities, Vermont Electric Power Company (VELCO), several Regional Planning Commissions, the Vermont League of Cities & Towns, the Agency of Natural Resources, Vermont Emergency Management, Rhizome, Renewable Energy Vermont, Efficiency Vermont, and staff from several Department divisions (Planning, Engineering, Consumer Affairs and Public Information) in addition to LBNL and UT-Austin. Each meeting was attended by 30-50 individuals. Each meeting was recorded, with the recordings made available upon request. The presentations from the Working Groups were filed in Public Utility Commission Case No. 25-0339-PET.

Background and workshop/working group materials filed in Case No. 25-0339-PET are listed below:

- Department Slides for Workshop #1
- Working Groups Scope Outline for Workshop #1
- LBNL and UT Presentation for Workshop #1
- LBNL Technical Brief: The concept of resilience and its relationship with reliability in Vermont
- Resilience Working Group Primer
- Decision-Making Paradigms for Electricity Resilience Projects
- Approaches to Hazard Modeling, Vulnerability Assessments, and Mitigation Evaluation in Utility Grid Resilience Planning: Examples from Other Northeast Utilities
- Hardwick Electric Department Slides for Planning Working Group #1
- Vermont Electric Cooperative Slides for Planning Working Group #1
- Washington Electric Cooperative Slides for Planning Working Group #1
- Green Mountain Power Slides for Planning Working Group #1
- Stowe Electric Department Slides for Planning Working Group #1
- Green Mountain Power Slides for Valuation Working Group #2
- Department Slides for Measurement Working Group #1

[61] Written comments can be found at https://epuc.vermont.gov/?q=node/64/203332/FV-ALLOTDOX-PTL.

- Green Mountain Power Slides for Measurement Working Group #1
- Resilience Straw Proposal for Discussion
- LBNL-UT Slides for Joint Working Group Meeting
- Department Slides for Joint Working Group Meeting
- Dr. Jay Shafer Slides for Planning Working Group #2
- Department Slides for Measurement Working Group #2

Appendix B: Participant Comments and Department Responses Regarding the Draft Report.

Commenter	Comment	Department Response
Joint Letter: Vermont Public Power Supply Authority (VPPSA), Stowe Electric Department (SED), Washington Electric Cooperative (WEC)	Commenters object to additional requirements.	The recommendations take modest steps, tailored to utility type, to responsibly respond to growing severe weather threats. Currently, the Department and other stakeholders have no comprehensive mechanism to understand whether utilities are adequately planning for severe weather and associated costs, other than what has been agreed to piecemeal in IRP MOUs. Rather than continuing the inefficient piecemeal approach, the Department sees a need for a consistent, basic framework statewide for resilience planning and measurement. The commenters disagree with the Department's proposal given the potential regulatory burden, but thus far they have not articulated the degree of burden or presented an alternative that would provide adequate transparency on resilience investment decisions and performance.
SED/VPPSA/WEC	The report does not appropriately weigh the role of internal municipal & cooperative utility governance structures in strategic, capital, and operational planning	The Department is certainly mindful that municipal and cooperative utilities have distinct public or member-driven governance structures in addition to State regulatory oversight. Language has been added to that effect, acknowledging municipal and cooperative governance. The Department's recommendations are not intended to intervene in management decisions or supersede local priorities, but rather to ensure that emerging considerations are included in public-facing planning and decision-making processes. This has value not only to individual utilities and ratepayers, but to regulators and the state as a whole. The Commenters note they communicate their capital planning decisions to regulators in IRPs, financing notifications, innovative rate designs, and permits, where the Department

		and others have opportunities to respond. The Department agrees, which is why it sees value in modifying existing tools and processes (IRP, Rule 4.900) to account for resilience rather than implementing entirely new tools. Given the growing dependence on grid services and extreme weather threats, Vermont and its utilitiesshould be expressly considering resilience in addition to reliability. It is essential that regulated utilities, including municipal and cooperative utilities describe current and projected vulnerabilities and, show how resilience is accounted for in the planning process. Commenters also feel the report fails to consider how funding influences investment decisions for municipal and cooperative utilities. The report does recognize and support multi-objective planning, where investment decisions and grid upgrades can and should be responsive to current needs, opportunities, and constraints. The report is not recommending that resilience should be given a higher priority than other objectives. It is also worth noting that funding for resilience periodically flows through Department, and future funding opportunities will likely require more rigorous justification for projects than many utilities provided for the current GRID funding.
SED/VPPSA/WEC	The Department's definition of resilience is unclear, leading to ambiguity about when certain recommendations apply.	The Department agrees with the Commenters that there can be overlap between resilience and reliability, and that investments made for one purpose (i.e., safety, reliability, repair, cost savings) may also serve resilience functions. Specific to municipal and cooperative utilities, the Department's recommendations are primarily focused on (1) resilience planning steps and (2) informational reporting. For purposes of those recommendations, the Department references the FERC/NERC definition of resilience: "The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event."

		This is noted on p.10 of the report and explored in more detail in the 2022 Comprehensive Energy Plan (p. 90), which also explores the idea of reliability-to-resilience as a continuum. By making resilience (as defined above) a more explicit consideration in utility planning and tracking outcomes with more relevant measures than the current SAIFI/CAIDI data, we can work toward a more concrete operational definition of "resilience" governed by appropriate performance standards. Currently, the only differentiation in Vermont system metrics is whether or not major storms are included in a systemwide SAIFI or CAIDI average. However, major storms are defined based on system impacts rather than on the characteristics of the storm itself. Ideally, a resilience metric will measure the performance of the system during extreme weather decoupled from the impacts of extreme weather on that same system.
SED/VPPSA/WEC	Additional regulation and oversight in this area imposes an undue burden on small utilities and may discourage utilities from further work promoting resilience.	The Department has proposed and still supports a 5-yr IRP cycle if agreement on language can be found. The Department also plans to further streamline the IRP guidance and is open to detailed feedback regarding current regulatory burdens. While commenters have indicated the need for further relief, they have not been specific about which regulatory requirements could be modified without impacts to long-term provision of service. The Department's recommendations here can be implemented at same time as other regulatory burdens are alleviated to ensure minimal additional responsibilities. Commenters state that new reporting/data tracking requirements would be onerous; however, the objections are general rather than specific.. The Department remains open to more specific information on which proposed metrics are unduly burdensome to track and what the barrier is (e.g. time, software). Likewise, the Department remains open to specific alternative proposals.

		Comments state that the Department recommends revising SQRPs, many of which were recently updated. To be clear: the report recommends years of information-only reporting with 4.900 filings before any revisions to SQRPs is conducted. Commenters point to Case No. 23-0834-INV to show that Rule 4.900 already provides the information and tools the Department seeks – including the ability to review utility actions during storms. However, the quoted text clearly indicates more engagement has been expected through future proceedings of all stripes. While Rule 4.900 does provide certain tools, the Department sees a need to build in a more systematic focus on severe weather impacts, actions, and outcomes.
SED/VPPSA/WEC	The report does not sufficiently consider the costs or benefits of its recommendations relative to the current regulatory approach.	Least-cost planning is already required of all utilities, and the burden of proof is on the utilities to demonstrate the adequacy of their planning. If utilities are not including climate impacts in their IRPs, for example, they do not have robust decision-making frameworks. The Commenters suggest that the Department's planning recommendations represent a new paradigm of regulation. The Department views it differently: incorporating climate and resilience considerations into the existing planning process is critical to thoroughly vetting least-cost pathways under the existing regulatory framework. While these considerations may already be part of many utilities' decision-making, they are not always adequately reflected in IRPs. Commenters state that the Department's recommendations are based on speculative justifications including the "increase in major storms" and "lack of resilience planning requirements in VT.". The Department maintains that there is a clear need to evaluate future scenarios for major storms and recovery costs and consider whether certain mitigation & adaptation investments will be cost-effective than the status quo in the long term. Not doing this planning presumes it is more cost-effective to continue business as

		usual. Utilities should justify their planning assumptions, and given the clear trends, climate data, and exorbitant costs involved, they should consider alternatives that may save significant costs.
SED/VPPSA/WEC	Commenters do not agree with expanding Integrated Resource Plan MOUs	Commenters argue that evidence of MOU conditions around resilience should not be taken to mean those conditions can be applied universally – not all utilities have the same capacity. The Department agrees that there are significant differences between utilities, however, the examples cited in the report span IOUs, coops, and small munis, broadly representative of all utility types/scales in VT. Negotiating MOUs is inefficient for everyone and is imprecise: the Department would prefer to minimize MOUs and instead update the IRP guidance, which utilities have also expressed a desire for. The draft IRP guidance language in the report is proposed as a set of standardized provisions: the Department would greatly appreciate any comments on the substance of the language and whether or not it provides sufficient detail AND flexibility.
SED/VPPSA/WEC	Commenters support the development of DU resilience capital reserves	Commenters support regulatory changes to allow such reserves and also the use of them to assist with major storm recovery. If utilities have specific language or implementation mechanisms in mind, the Department would welcome that input as a starting point.
Stowe Electric Department (SED)	Department has not addressed concerns raised by utilities in written filings and oral comments	The Department has worked to incorporate utility feedback throughout this proceeding and understands that some concerns may remain. Additional comments, as specific as possible, would certainly be considered.
SED	Should take a measured approach to resiliency investments and avoid prescriptive measures that don't offer clear cost savings to Vermont electric ratepayers and increase	The report does not prescribe specific investments or planning outcomes. The Department's recommendations are scaled to utility type. Least cost planning – which is already required of all utilities – requires considering both short- and long-term costs and benefits. Robust least-cost planning should consider whether long-term benefits of resilience measures outweigh increased upfront costs.

	regulatory burden for small public power utilities	
SED	Does not agree with 4.900 rulemaking without specific issue to resolve. Feels that a trial period for metrics before deciding whether to make the trial period mandatory is "tantamount to regulatory creep that is not supported by any current Statute or Commission Rule." A trial period for metrics not an efficient use of resources. Department's IRP Guidance document is not a statutory or rule mandated document that the utilities are required to follow. Therefore the Department is free to update and amend the document, but it does not codify any of the recommendations for the purposes of the IRP."	The primarily issue is that current 4.900 metrics (SAIFI/CAIDI) only measure narrow aspects of reliability and do not account for or capture resilience attributes of the system. If we are not measuring resilience attributes and outcomes on the system, that implies that there is no consideration of resilience in operations or the decision-making framework. The Department is recommending a trial period for all utilities. The purpose of a trial period is to allow more flexibility – utilities can share their experience with implementation and have a dialogue with the Commission and/or the Department about what is working, what the challenges are, and what may need to change. All of this can inform the implementation of permanent mandatory metrics, if any. If a utility demonstrates that a metric is unduly burdensome, by indicating specifically why each metric is burdensome to collect and calculate, the Department would consider an opt-out provision for each metric. Regulations, regulatory guidance, and IRPs themselves need to evolve as conditions evolve. As Stowe itself is exploring with its Argonne work, the climate is changing and affecting weather patterns – which in turn impact operations and customers. Least-cost planning must consider these impacts and the costs and benefits of taking (or not taking) proactive steps (e.g., undergrounding, hardening) both in the short- and long term. Least-cost planning is already required of utilities. Planning outcomes, investments (if any), or strategies will vary by utility and should be explored in IRPs. Department IRP guidance articulates how the Department views the requirements of least-cost integrated resource

		planning and how it reviews IRPs for consistency with (1) state energy policy, (2) the CEP, and (3) least-cost principles. IRPs that do not align with the Department's guidance will likely require more significant review and investigation on the Department's part, to ascertain the decision-making process and determine whether the appropriate considerations have been adequately incorporated. This is not necessarily an efficient or beneficial use of Commission, utility, and Department staff time nor ratepayer funds.
SED	Does not support recommended metrics. Does support revisions to how SAIFI and CAIDI targets are calculated and discuss with each DU how their targets could be modified	See above response regarding the trial period. The Department is already convinced by GMP and work being done in other jurisdictions that SAIFI and CAIDI are not the right measurements for resilience. We have proposed some metrics that are more suitable and would be open to alternative suggestions. The Department is open to discussing with each DU how its SQRP performance measures for SAIFI and CAIDI are calculated.
SED	Funding to support veg management, replace end-of-life direct-buried conductor, install fault detection equipment, invest in modern tech, invest in loop feeds with D automation equipment	Noted, thank you.
SED	Recommends using restricted capital funds and 30 VSA 218d to establish grid modernization and resiliency investment funds	The Department is interested to hear what additional mechanisms (statutory, regulatory) or practices are needed to effectuate this, from the commenter's perspective.
Green Mountain Power (GMP)	Major storm postmortems already happen to some degree. 4.900 reports analyze major storms, and utilities share learnings & experiences through VEM	Most, but not all, utilities conduct the required analysis of outages in Rule 4.900 reports. Most utilities don't specifically analyze major storms. Language in the report was modified to address this. The Department is open to exploring the most effective way to do this.

	etc. Asks that the Department focus this request to avoid duplicative efforts.	
GMP	Parameters around "reasonably adequate service" may be helpful. SQRP and other mechanisms may be preferable to Rule 4.900 in order to provided needed flexibility and fact-specific analysis. If the Department continues with this Rule 4.900 recommendation, meaningful periods of baseline information gathering are needed before establishing a further definition.	Rule 4.900 and SQRP will be weighed for appropriateness. Rule 4.900 is generally better for providing analysis and narrative reporting, while SQRP is specific to each utility. It may be preferable for Rule 4.900 to provide general statewide parameters around adequate service, which could be the foundation of utility-specific measures more appropriate for SQRPs. The Department agrees that a meaningful period of baseline information gathering is appropriate in any case, and has suggested a trial period for new reporting metrics.
Burlington Electric Department (BED)	Additional regulation is not the preferred path forward; any additional information requirements must be balanced by a corresponding reduction in required IRP or 4.900 filings.	The Department has proposed a reduction in required IRP filings and remains supportive of that proposal. Commenter provided no specifics on recommended reduction in 4.900 filings. The Department welcomes specific recommendations.
BED	Sections 1 & 2 Climate impacts not a significant cost driver of BED's five most recent rate increases due to compact & resilient service territory Define "small utilities"	Added a footnote about BED's compact service territory, and will also take into consideration for any formula or competitive funding the Department pursues for utility resilience funding. "Small utilities" is not a defined term in statute or regulation. Appendix E of the report references how many customers a utility has. For the charts in Appendix E, the "large utilities"

	Clarify whether parameters for "reasonably adequate service" would be set statewide or by utility Clarify whether restoration parameters pertain to 95% of the system's total customers or 95% of the customers experiencing any given outage Regulatory mechanisms for DUs to set aside funds should be voluntary Review IRP requirements and remove outdated ones Proposed metrics would require manual calculations and new data tracking. CEMI & CELID would depend on which values calculated against. Histograms ok. Would monitoring of weather be regional/statewide or utility/customer-specific? IRP language should be associated with existing or new resilience metrics from 4.900 vs. standalone.	are GMP, BED, WEC, and VEC. These utilities all serve at least 10,000 customers/members. The thought was to set statewide parameters, but utility-specific parameters would be entertained. The restoration parameters would apply to 95% of the customers experiencing any given outage. The Department supports voluntary mechanisms for set-asides. Added to description in report. Agree with removing outdated IRP requirements. When Department updates IRP Guidance, specific recommendations for outdated provisions are welcome. Language in report originally included "expand and modernize" IRP requirements. Have added "streamline." The Department would like to better understand the burden of manual calculations for 95% of customers restored, CEMI, and CELID. The histograms would provide substantially the same information as CEMI and CELID, and it would be helpful if the Department could understand why histograms are easier to calculate than CEMI or CELID. RE: monitoring weather (assume this references the sub-bullet of the proposed IRP guidance around Assessing Risk: "Describe practices to monitor and measure weather variables.") The language leaves flexibility for the utility to monitor at the granularity that makes the most sense for it. RE: IRP language associated with existing or new resilience metrics: the Department agrees with this but until resilience metrics are agreed upon and implemented, it doesn't make sense to reference them in the IRP language.
BED	If move forward with metrics, trial period beneficial.	Noted, thank you. We are recommending a trial period.
BED	Most beneficial funding for storm hardening, D circuit	Noted, thank you.

	infrastructure enhancement, and grid-scale storage.	
BED	Seeks to maintain current flexibility to determine capital investment priorities and associated funding/financing sources at the local level.	The Department supports this as long as the decision-making framework is articulated in IRP and includes consideration of resilience.
Vermont Electric Cooperative (VEC)	Include a clear use case and appropriate timeframes for understanding metrics	See response below regarding Rule 4.900 and trial period.
VEC	Explicitly acknowledge that adding requirements increases regulatory burden or requires streamlining; add finding that added requirements must be balanced by removal of no longer relevant regulatory requirements	Added language to last finding that utilities also seek removal of regulatory requirements that are no longer needed. The Department has requested feedback on several occasions as to specific regulatory requirements which are "no longer relevant," We will continue to evaluate internally but welcome and encourage specific suggestions in this area.
VEC	Acknowledge existing oversight that already governs resilience-related decisions & add examples of this oversight; add finding that acknowledges munis & coops already operate under multiple layers of oversight & constraints	Added finding acknowledging this layer of oversight.
VEC	Modify the reason for extending IRP cycle to "making the resource-intensive IRP cycle more efficient"	Added this language.

VEC	Remove recommendation to require an "approved IRP" as prerequisite for expedited rate changes.	Modified recommendation to continue to allow existing expedited rate changes w/o an approved IRP but enable higher expedited rate changes for utilities with approved IRPs.
VEC	Emphasize that BCA not required for munis & coops.	The Department's recommendations would impose full BCA on IOUs only.
VEC	Adjust 4.900 recommendations: Formalizing major storm postmortems too much too fast. Perhaps begin more informally, e.g., hosting a post-storm all-DU call to focus on key lessons learned questions. Or ask for a few metrics to be shared with PSD after each storm. With respect to parameters around "reasonably adequate service," it is essential to clearly identify use-case, purpose, and timeframe of measurement for any metrics. Identify the review and removal of any requirements or metrics that no longer provide consumer value or utility or regulatory insight.	Most, but not all, utilities conduct the required analysis of outages in Rule 4.900 reports. Most utilities don't specifically analyze major storms. Language in the report was added to address this. The Department is open to exploring the most effective way to do this. As to reasonably adequate service: it may be that foundational parameters/definitions can be added to Rule 4.900, to be incorporated into utility-specific standards in SQRPs. We agree it is important to clearly identify use-case, purpose, and timeframe of measurement for any metrics. During the resilience proceeding, the Department asked the utilities to suggest any regulatory requirements that should be removed, and a Rule 4.900 amendment would be an additional forum for the utilities to make any suggestions.
VEC	Trial period: Appreciates doing within 4.900	Noted, thank you. The Department supports a 2-year trial period with a check-in to consider an additional year. The Department envisions a stakeholder process would be used to discuss trial results before any transition from Rule

	Supports trial as information-only, 3 years may be better Commit to establishing context and using a stakeholder process to ensure trial results not used to automatically set performance standards etc. Trial should establish data definitions, workload impacts, and how metrics will be used for regulatory decision-making. Define some early parameters and a process around evaluating results. The report assumes that trial metrics from Rule 4.900 reporting will be imported to SQRP metrics. Don't assume; it may be that after the trial period, Rule 4.900 is determined to be better fit for resiliency reporting than SQRPs.	4.900 information-only reporting to SQRP performance measures.
VEC	Initial metrics are appropriate for a trial period. Metrics should be tied to a use case showing regulatory and consumer value and be paired with clear definitions, consistent calculation approaches, and narrative context such as storm	Noted, thank you.

	severity, geography/terrain, and access constraints.	
VEC	Non-ratepayer funding helpful	Noted, thank you.
Agency of Natural Resources, Climate Action Office	Clarify whether recommendation calls for climate change hazard projections specifically, as distinct from historical hazard data Updates to Northview should (1) cover the entire state rather than a subset geography; and (2) produce projections formatted and mapped at a resolution consistent with the downscaled LOCA2 standard	Ideally utilities will use hazard projections to inform their assumptions about the type, frequency, and severity of extreme weather events (scenarios), though for resilience planning purposes extrapolating a (rolling) historical trend as a starting point is acceptable. For IOUs proposing large resilience investments, historical extrapolation is insufficient. Updated Northview language in the report.
Agency of Natural Resources, Climate Action Office	Specify which hazard projections are relevant to utility resilience planning, and at what planning timescale. If updates to MVI are to add forward-looking, clarify: • Which hazard projections are relevant (cited examples don't include projections for icing, wind, or heavy snow) • What timescale most useful	Added heavy, wet snow, icing, and wind as well as a 20- to 50-year timeframe. Deleted specific "home" of MVI.

	If Northview assessment and MVI updated, interactive platform at VEM may be unnecessary. Keep "home" of hazard projections generic.	
Agency of Natural Resources, Climate Action Office	Academic partnerships should tap into existing structures such as Inter-Agency Advisory Board to the CAO.	Added note to this effect.

Appendix C: Resilience Planning Recommendations

Resilience Implementation Strategy

The Governor's and Treasurer's Resilience Implementation Strategy (RIS), released September 17, 2025, includes the following actions related to this report:

- 12F: Build on utility efforts and outcomes of the grid resilience proceeding to help utilities develop capabilities to identify vulnerabilities to climate-related hazards, quantify risks, analyze costs and benefits of mitigation alternatives, prioritize investments, and measure the benefits of interventions.
- 13B: Provide grant funding to municipal and cooperative utilities to assist in the acquisition of software and hardware systems to enable real-time system and device visibility, communication, and control in support of demand management, including during periods of capacity or energy shortfalls.
- 13F: Explore potential funding and financing pathways, such as state programs, grant access, or pooled resources, to help municipal electric utilities and electricity co-ops fund major projects when third-party revenue is unavailable. Based on identified funding pathways, fund grid upgrades and other projects that increase stability and resilience.

  13G: If recommended as an outcome of the Public Utility Commission Resilience Proceeding, update utility grid reliability targets to include climate resilience and electrification, based on benefit-cost analysis, and create a mechanism for periodic review of these targets.

Climate Action Plan – Rural Resilience & Adaptation

The 2025 update to the Vermont Climate Action Plan includes recommendations specifically focused on grid resilience in the "Adaptation and Building Resilience in Communities and the Built Environment" section. These include the following actions related to this report:

- Priority Action: The State, through the Public Utility Commission (PUC) and Public Service Department (PSD), should complete the PUC resilience planning investigation underway, which is analyzing whether and how to define, value, measure, and set targets for grid resilience. Utilities should continue to integrate resilience planning into their operations.
- Action: Utilities should conduct benefit-cost analysis on resilience upgrades and seek non-ratepayer (e.g., federal, state, municipal, nonprofit, and private) funding for measures where costs exceed benefits.
- Priority Action: Expand upon the Municipal Vulnerability Indicators tool to create a Municipal Vulnerability Index that can be used by state agencies and others as a resource to assist in prioritizing infrastructure resilience investments across the state based on specific vulnerabilities or combinations of vulnerabilities. Ensure it includes currently missing data such as historic utility outage data, to the extent available, and

the Agency of Natural Resources' (ANR) Environmental Justice mapping tool, when complete.

- Action: Strategically integrate planning and preparedness across disciplines and geographies addressing the interdependencies of transportation, energy, communications, and other systems.
- Action: Utilities should deploy technology for management, control, and optimization of distributed energy resources, including energy storage, to improve reliability and resilience while reducing costs for all customers.
- Action: Evaluate the risks and opportunities created by potential climate change in-migration to Vermont's critical infrastructure.
- Priority Action: Replace or harden electric and communication infrastructure with the most appropriate resilient alternative when cost-effective. For example, for aging or unreliable lines, utilities should continue to evaluate improving resilience by relocating lines underground or through other options, where demonstrated to be feasible and cost-effective to electric customers. Planning frameworks, valuation tools, and metrics resulting from the Resilience Investigation (Case No. 25-0339-PET) being conducted by the Public Utility Commission (PUC) should be used to inform this evaluation.
- Action: Local and regional planners, utilities, transportation providers, and state agencies should collaborate to identify mission critical facilities and develop preparedness, survivability, and recovery plans, procedures, and investments that mitigate the impact of extreme weather events to services provided by these facilities.
- Action: Develop and fund programs to ensure continuous power for continuity of operations at water and wastewater facilities, including evaluation of solar/storage microgrids, anaerobic digesters (ADs), and other potential solutions.

State Hazard Mitigation Plan

The 2023 State Hazard Mitigation Plan includes the following mitigation actions related to this report:

- Coordinate State Energy Security Plan (due September 2023) with the SHMP - identifying the interdependency of other systems on the grid and additional risk analysis requirements.
- Increase Public Service Department capacity to maximize utilization of available federal dollars (including IIJA, IRA, ARPA, and EDA) towards utility resilience implementation work.
- Identify and evaluate microgrid feasibility for rural energy systems/hubs - including assessing locations for resilience hubs in coordination with utilities and RPC work under Act 174.
- Identify scales of resilience and opportunities across distribution utilities and appropriate opportunities to support equitable access to resilience - assessing disparity between utility providers re: grid resilience.

Appendix D: Working Group Findings (UT-Austin)

October 2025

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The University of Texas at Austin

Key Takeaways: Planning Working Group

Vermont Resilience Proceeding
Case No. 25-0339-PET

Nina Hebel and Benjamin Leibowicz
Operations Research and Industrial Engineering
The University of Texas at Austin

TEXAS
The University of Texas at Austin
WHAT STARTS HERE CHANGES THE WORLD

Notes:

- The takeaways presented here are focused on synthesizing the comments and insights from utilities during the Valuation Working Group meetings
- The presentations and proposals set forth by the PSD, LBNL, and UT are not summarized here, but provide additional material that is relevant to the PSD's recommendations
- While the takeaways are organized based on the Working Groups from which they arose, there are takeaways in the Valuation and Measurement Working Groups that are relevant to Planning

Many utilities periodically conduct a comprehensive system study and use this as the basis for planning.

- For smaller utilities, the planning process can essentially be distilled to replacing/modernizing old or damaged infrastructure
- Hardwick Electric currently performing engineering study (first since 1997) which will then be used to identify and prioritize capital projects
- Stowe conducted a comprehensive system study in 2020/2021
- WEC conducts a comprehensive study roughly every 10 years

→ These studies help maintain reliability and ensure conformance with engineering standards.

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Utilities contend that investment is often driven by state rules and regulations, even if indirectly.

- Net metering has impacted seasonal peak demand, driving new system needs and investment patterns
- Hardwick mentioned that they have doubled their ROW and vegetation management budgets, partially due to broadband initiatives and partially as a response to outage hotspots

Utilities note that they are paying attention to evolving weather trends, but it is not clear how this directly impacts planning.

- Hardwick mentioned using updated floodplain mapping in their planning
- WEC noted the increasing frequency/severity of weather events, mentioned better modeling of storm impacts as a “changing factor” for planning
- GMP cited the VELCO Climate Study, which it uses to identify areas that are likely to be impacted
- VEC is using Rhizome to enhance risk assessment
- Stowe participated in Argonne ClimRR study to understand climate risks

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WHAT STARTS HERE CHANGES THE WORLD

Commercial tools and external studies are available but there may be gaps that prevent them from being directly implemented for resilience planning purposes.

- Rhizome presented at first Planning WG meeting, sharing an overview of their commercial offerings and summarizing the service they provide to VEC
- Current work with VEC is limited to asset-based climate vulnerability assessment and does include full cost-benefit analysis, but Rhizome is also working with other utilities
- During second Planning WG meeting, when asked about the feasibility of updating the 2021 Climate Study, Jay noted that it is important to understand where there are gaps in translating climate risks into system risks (fragility models, etc.)

The weather threats faced by different utilities vary, and current practices largely rely on historical data to project future extreme weather events.

- Village of Hyde Park mentioned that, due to topography, its flood risk is much less significant than for many other Vermont utilities
- WEC and GMP both mentioned using historical storm data to project future weather events and impacts
- This can be somewhat augmented by the 2021 study, which provides coarse projections of how threats will evolve
- VEC also mentioned a more recent “Disastertech” study

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WHAT STARTS HERE CHANGES THE WORLD

Data collection practices and capabilities vary significantly across Vermont utilities.

- Stowe is currently working on implementing additional data collection/analysis tools, including AMI, GIS mapping, Pi Vision (VELCO), Operations Analytics (through NISC)
- GMP has a GIS tool that it uses to track reliability metrics, which also stores asset information, condition, and performance data
- *Editorial Note: Data collection and analysis are discussed in more detail in the Measurement Working Group*

	Hardwick Electric Dept.	Stowe Electric Dept.	Washington Electric Co-op	GMP
System Engineering Study	Currently undertaking first study since 1997	Conducted in 2021-2022	Conducted on a roughly 10-year basis	Not mentioned in presentation
Decision-Making Process	Current investments are often driven by evolving system conditions (e.g., net metering, new hazards), but no formal decision process in place	Director of Operations prioritizes projects, staff identifies funding opportunities/evaluates ratepayer impacts	Focus on greatest reliability gains first - Director of Operations uses outage/reliability data to identify problem areas	Projects selected based on criteria laid out (and approved) in IRP
GIS Mapping	No	Yes	No	Yes
Other Forms of Tools/Analysis	• Analysis to ensure NESC compliance • Looking to increase data availability/system visibility in the future	• AMI • Pi Vision Integration (VELCO) • ClimRR – working on climate resiliency plan w/ ORISE fellow • Operations Analytics & Distributed Energy Workstation • Flex Load Management	• Construction Work Plan – set out specific projects for 4+ years (covers all major planned work, including work not financed by RUS)	• Climate analysis conducted but doesn't seem to be directly integrated into planning process • GIS tool keeps track of daily performance, also contains information on asset condition (from field) • Track outage/reliability performance at different levels (customer – circuit)

October 2025

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Key Takeaways: Valuation Working Group

Vermont Resilience Proceeding
Case No. 25-0339-PET

Nina Hebel
Operations Research and Industrial Engineering
The University of Texas at Austin

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WHAT STARTS HERE CHANGES THE WORLD

Several utilities in VT have experience with FEMA BCA but are not in favor of using it outside of the FEMA process.

- Complaints from multiple small- and medium-sized co-ops and municipal utilities that the FEMA BCA tool is cumbersome and resource-intensive
  - VEC, Morrisville Water and Light, Stowe all mentioned this in first WG meeting
- The FEMA process requires BCA to get access to additional funding for resilience/reliability improvements – justifying the use of time and resources
- Another common complaint regarding FEMA's BCA process is that, while the core BCA was not necessarily burdensome, there was significant administrative bloat (e.g., additional modules) that accumulated over time

→ ***There seems to be some openness to using more complex forms of analysis for resilience valuation <u>if</u> the analysis leads to additional resources (e.g., access to resilience-specific funding) and it can be kept streamlined***

Utilities in VT have a range of different analyses that they use internally to prioritize among potential projects, with levels of sophistication that largely align with utility size.

- For many smaller utilities (e.g., Morrisville) project selection is driven by engineering system studies or response to recent interruptions/events
- VEC has a prioritization process that scores each project based on a series of criteria, including 25 points for reliability which are assigned based on whether the project is on one of the worst-performing circuits
- WEC uses RUS funding to supplement its capital budget, which comes with a specific set of requirements

→ ***As emphasized throughout the proceeding, it is important to ensure that the outcome of the proceeding is flexible for utilities of all sizes/capabilities***

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For larger utilities, the project prioritization process incorporates the identification of the worst-performing circuits (which they may include in Rule 4.900 filing).

- This is the starting point for GMP's project prioritization process
- VEC assigns reliability scores for projects based on whether circuit is a worst-performer (0 points for circuits outside of worst performers)
- WEC prioritizes line sections/feeders/substations with frequent outages, severe outages, and the most members served
- Stowe is working to develop a formal weighted prioritization tool; they are also implementing a variety of data collection and analysis tools to better identify "hot spots" on their system

A few utilities have done some analysis to assess the value of resilience or reliability, though these analyses are not currently directly integrated into planning efforts.

- VEC has been developing an ex-post analysis to quantify outage costs in terms of SAIDI minute reduction per $ invested, using societal benefits determined via FEMA CBA. Also pursuing partnership with Rhizome to improve assessment of future risks. *Planning to integrate these into their prioritization process in the future.*
- GMP used the ICE calculator to estimate avoided costs of interruptions for resilience upgrades, but this was to gather information, not a direct input into their planning process
- Morrisville mentioned that they consider direct costs and benefits for projects, but not in a formal analysis that converts benefits into dollars

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There are concerns that BCA may be unfavorable for projects in rural or isolated areas.

- GMP used the ICE calculator to estimate avoided interruption costs for planned resilience improvements, and noted that individual projects often have negative NPV in rural areas or if they serve primarily residential customers, though this effect is reduced by bundling projects together
- Similarly, VEC mentioned that certain (rural) projects need to be bundled together in order to “pass” FEMA BCA (positive Benefit-Cost Ratio)

→ ***Questions to consider: what is the acceptable/reasonable level of service quality for more isolated/expensive-to-serve customers? Are alternative cost recovery mechanisms appropriate for system hardening on isolated circuits?***

If possible, resilience valuation should be incorporated into existing planning processes, which balance reliability with other factors like project readiness and regulatory compliance

- VEC sought clarity around whether BCA would be used as a go/no-go decision point, or as part of a holistic decision-making approach (preferred)
- WEC asked about whether BCA would be limited to stretch goal projects, or if it would be expected to be integrated into budget allocation approaches

→ ***This is an example of how valuation and planning intersect. In developing guidance for integrating BCA into existing planning frameworks, it is important to consider how resilience should be balanced among other priorities.***

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There are concerns that conducting CBA or other forms of analysis on a very granular level will result in significant overhead costs without yielding benefits to customers.

- This has largely been reiterated by VEC during the working groups, but other smaller utilities have also mentioned their constraints in terms of administrative personnel and software availability
- Some utilities (e.g., Stowe) are actively working on increasing their capabilities, but expect that this transition will take several years

November 2025

Key Takeaways: Measurement Working Group

Vermont Resilience Proceeding
Case No. 25-0339-PET

Nina Hebel and Benjamin Leibowicz
Operations Research and Industrial Engineering
The University of Texas at Austin

Notes:

- The takeaways presented here are focused on synthesizing the comments and insights from utilities during the Measurement Working Group meetings
- The presentations and proposals set forth by the PSD, LBNL, and UT are not summarized here, but provide additional material that is relevant to the PSD's recommendations
- While the takeaways are organized based on the Working Groups from which they arose, there are takeaways in the Valuation and Planning Working Groups that are relevant to Measurement

To ground any recommendations around resilience, it is important to define what is meant by "good" resilience.

- This is reflected in some filed comments, where utilities express concern over being held to increasingly stringent requirements when they believe they are already operating with sufficient reliability/resilience
  - The comment from WEC notes that most VT utilities are "recording good customer service," so the need for new regulations addressing resiliency is unclear
- Note: "reasonably adequate service" is currently understood as corresponding to the baselines used in the SQRPs (per the PUC presentation in WG)

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The informational reporting from GMP on the ZOI metrics will be valuable for conversation about resilience metrics.

- There was interest in the informational metrics agreed upon in the ZOI proceeding; these could help to ground the conversation around metrics
- Some utilities were hesitant to weigh in regarding new metrics prior to seeing data and analysis from ZOI
- The reporting can help identify which metrics are most useful and worth the additional time and effort from utilities with limited resources

There is no clear consensus among utilities regarding whether there should be updates to Rule 4.900.

- Stowe indicates a desire to see updates to baseline targets, with more clarity, and to update the baseline with some regularity
  - Note: Whether this updating would occur through 4.900 or SQRP is not totally clear to us, but this is a procedural/implementation detail that does not affect the substance of Stowe's expressed desire for updating baseline targets
- WEC + VEC were both initially resistant to changing reporting requirements
- This was also addressed in recently filed comments, where VEC expressed an openness to a trial period for collecting new informational metrics
- In the filed comments, utilities were generally not in favor of making significant changes to 4.900

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There are divided opinions over whether current reporting and metrics adequately capture the "customer experience."

- GMP argues that frequency of interruptions is not adequately represented in current metrics – some of their customers are experiencing 0 outages, while others experience as many as 20+
  - Note: CAIDI goal from SQRP was missed by 0.1. Mike pointed out that several significant storm events led to outages that were just under the threshold of "major storm" classification
- However, many other utilities point out (both in WG meetings and filed comments) that they receive generally positive feedback from customers regarding the level of service, and don't see a need for additional metrics

Several utilities have some form of outage management system in place, either NISC or a legacy system.

- NISC: Stowe (currently transitioning), VEC, Enosburgh and other VPPSA members (planning to implement in the future)
- Northfield manages everything through spreadsheets, including outage information, and has not seen a need to invest in more advanced software up to this point
- GMP has outage management system, performs additional analysis for distribution outages via Oracle BI/Tableau

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In terms of ex-ante measurement of the impacts that resilience interventions would have, utilities seem to rely primarily on experience and rough estimates.

- GMP mentioned using historical/manufacturer data to estimate outage reductions from certain resilience interventions, like spacer cable
- VEC has discussed modeling outage reduction based on “educated guess”
- More generally, forward-looking estimation of impacts doesn’t really seem to be a focus for most utilities. Instead, the typical approach is to identify a poorly performing circuit and then improve it, balancing upgrades based on factors like cost, permitting status, and number of customers impacted

There is a learning curve associated with upgrading data capabilities and analysis tools.

- This was brought up by Stowe to make the point that even with new systems and tools available, it will take some additional time and effort to produce metrics on a more granular level
- Similar sentiments were reflected in many of the comments filed recently that responded to questions around data availability and granularity
- Smaller utilities, even when using the same software (e.g., NISC), may be more strained in preparing certain metrics/reports

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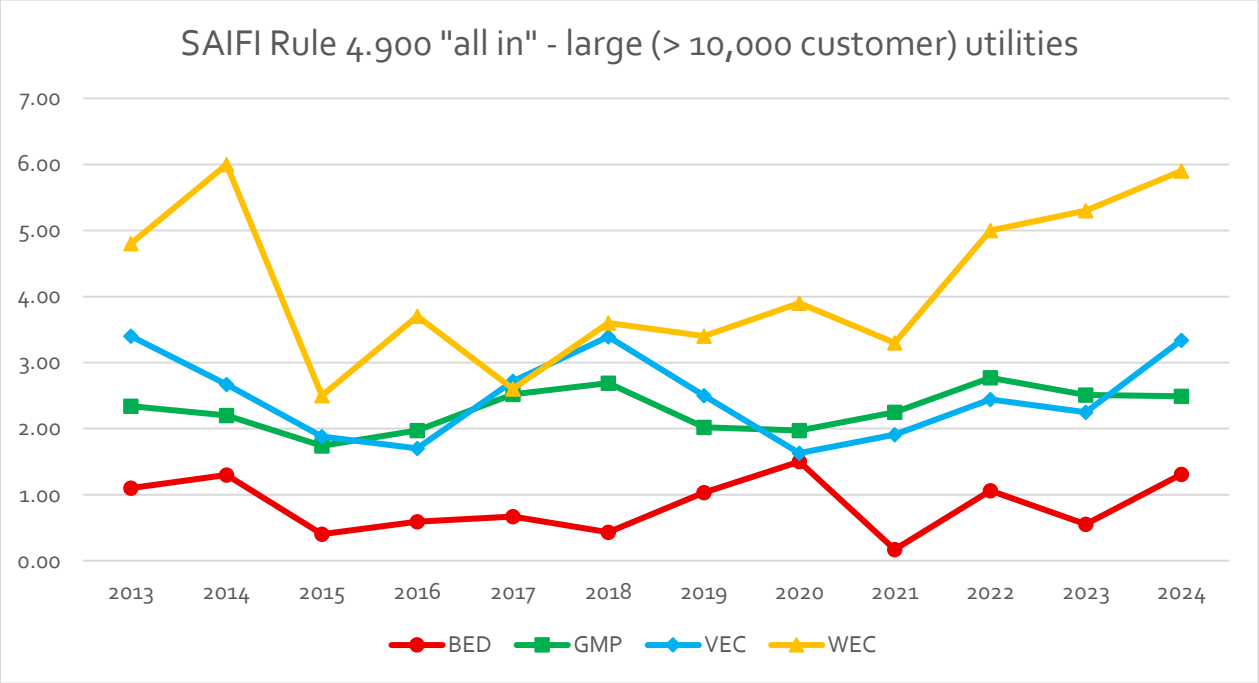
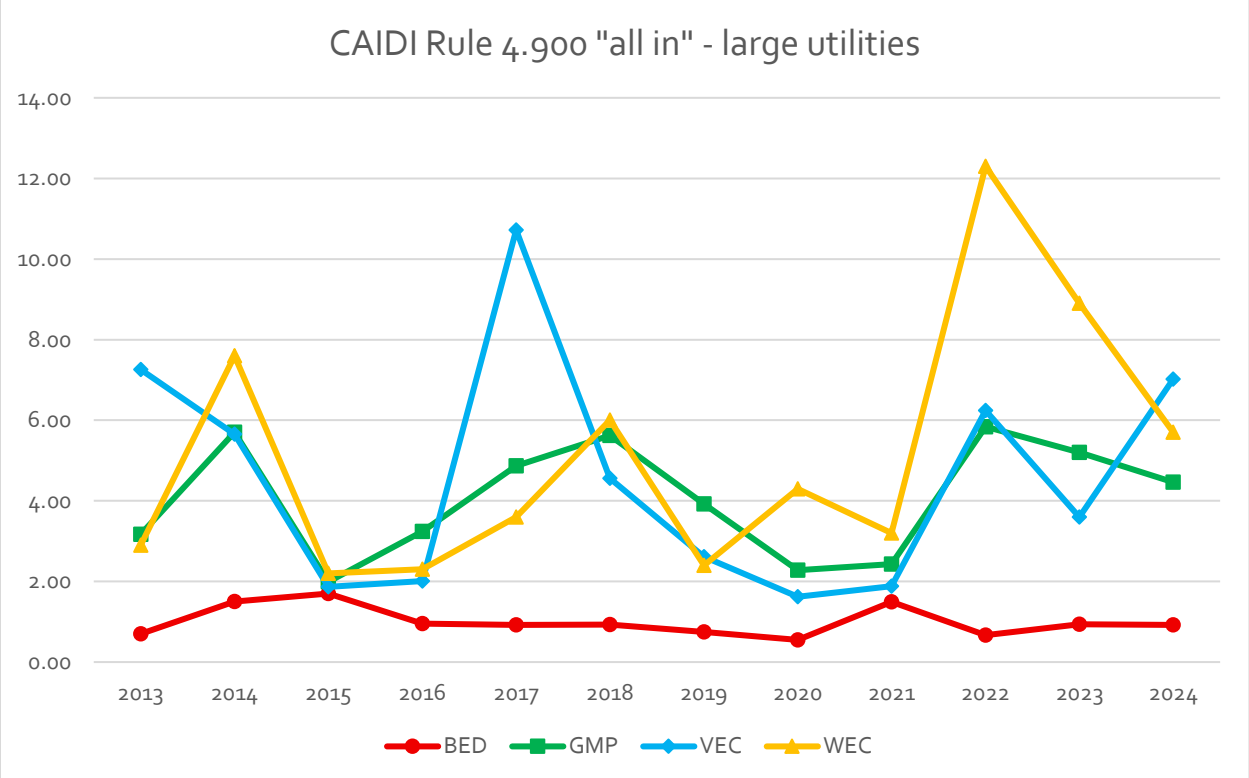
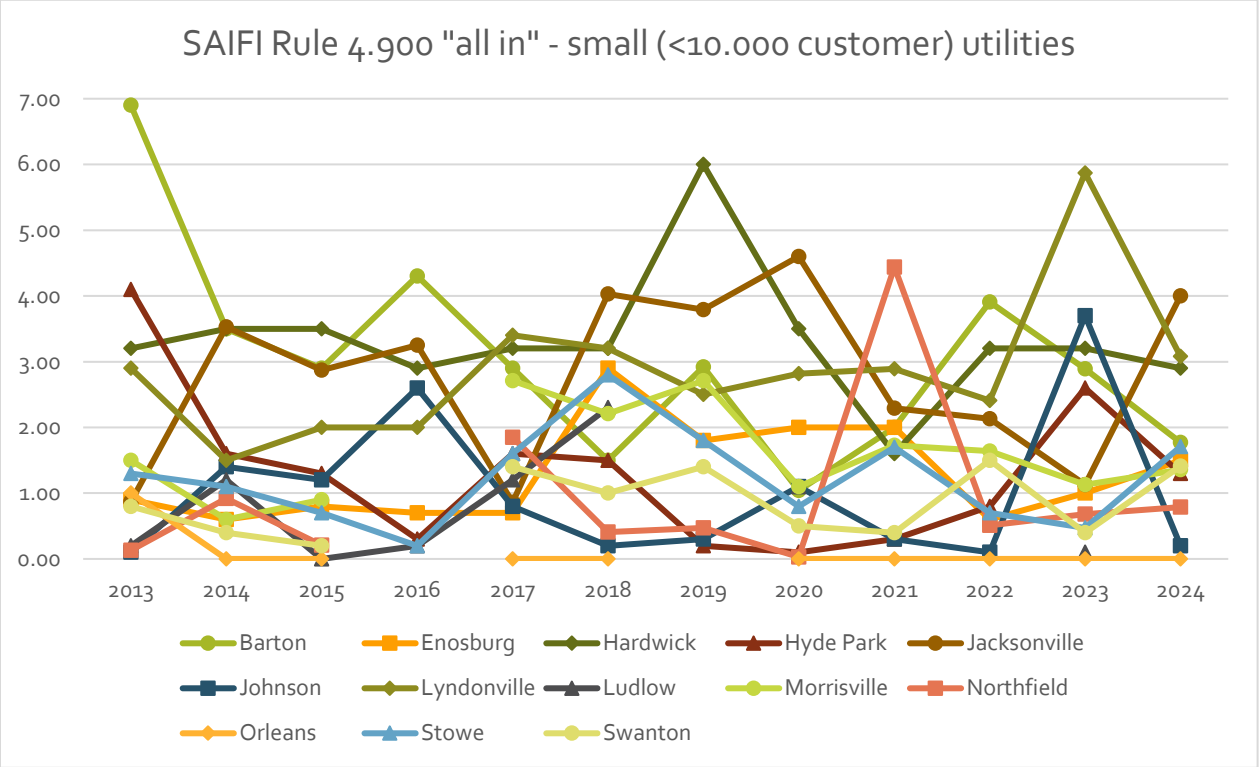
A clear understanding of the benefits of gathering additional metrics will encourage utility buy-in.

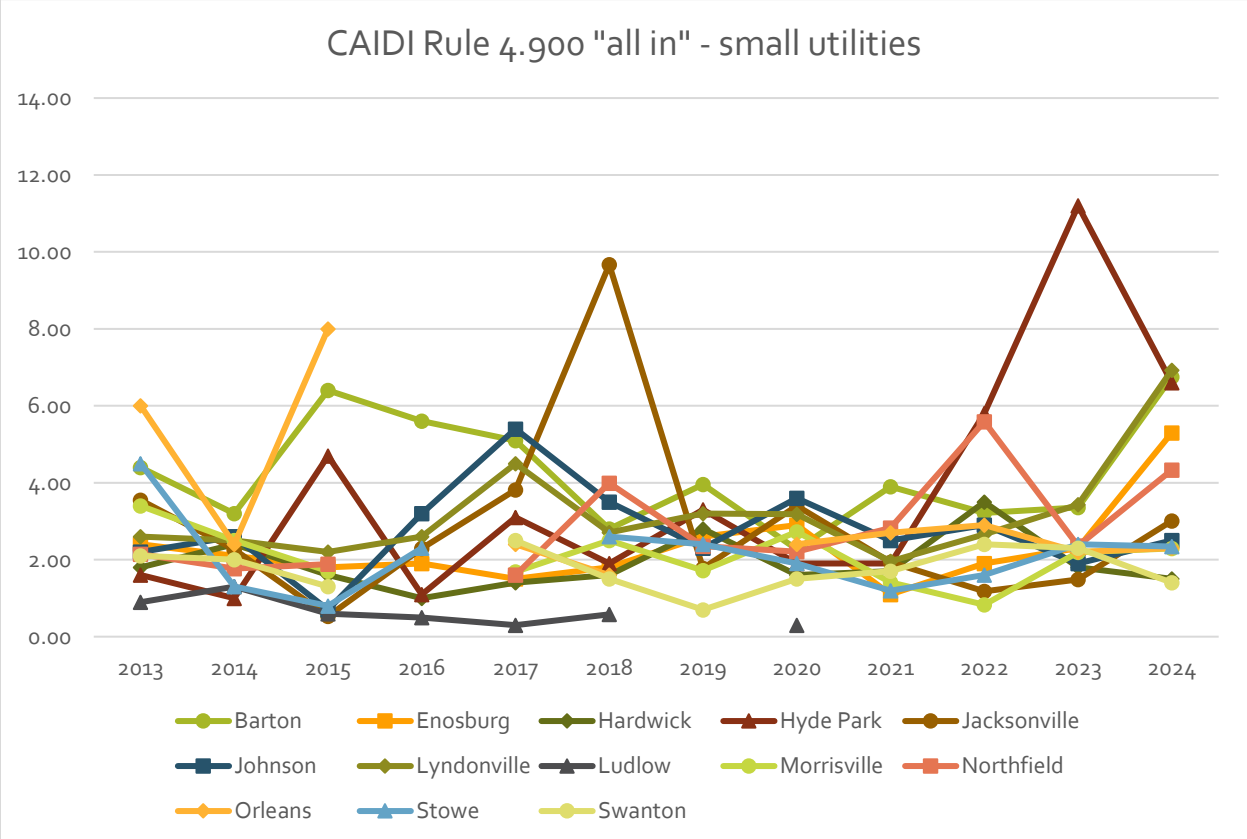
- As mentioned above, there may be significant resources involved in gathering or analyzing additional data
- To ensure that the customer is benefitting from this additional use of resources, it would be helpful to outline how new proposed metrics would fit into the broader planning context and result in improved system outcomes
- If metrics are intended to be purely informational, then it is important to consider what value that information brings and weigh it against the costs of obtaining that information

Appendix E: Utility Reliability Performance









Note: Stowe's 4.900 "all in" CAIDI in 2017 was 23.50, omitted from the above chart for visual ease.

Appendix F: Key Findings from Other Northeast States

As part of the proceeding, LBNL assisted the Department by reviewing the state of the art for resilience planning, valuation, and measurement in other northeastern states.[62] These states are at different stages of addressing investor-owned utility climate resilience. Municipalities and coops have largely not been the focus of state regulation in this space, primarily because of differences in their regulation. However, all their investor-owned utilities have developed or are developing resilience plans or are expected to do so in the near future, either as stand-alone plans (sometimes required by the state legislature) or in the context of larger grid modernization plans.

Investor-owned utilities in most states are required to conduct climate change vulnerability studies as the basis for resilience plans.

Investor-owned utilities in most states are required to conduct climate change vulnerability studies as the basis for resilience plans. Thus, all these utilities' resilience analyses have focused on the specific risks identified in those studies. Resilience proposals have broadly considered overhead hardening, e.g., reconductoring and/or pole upgrading/replacement, etc., as well as enhanced vegetation management, undergrounding, and automation.

Notwithstanding extensive regulatory activity and utility efforts, distribution system resilience regulation and planning continues to be a work-in-progress in these states, including:

- *Benefit-cost analysis:* BCA at the "high-risk zone" and/or circuit level has been conducted by several northeastern utilities over the years using the Berkeley Lab ICE Calculator 1.0. In addition, New York has for years had a general project-level BCA protocol for IOUs, including for resilience investments. However, regulators are now requiring comprehensive BCAs for grid modernization/resilience plans. Utilities in several states have stated though that current methods are insufficient for this purpose and regulators have agreed. Utilities are using different approaches to assess potential benefits of resilience proposals, including cost-effectiveness analysis and partially qualitative multi-criteria schemes. At least one utility – National Grid MA/NY – is adopting a commercial software platform (from Copperleaf, Inc.) for integrated distribution system planning and valuation.
- *Metrics:* As of June 2025, Connecticut is the only state in the Northeast to formally specify and require the use of resilience-specific "metrics" (though they have not defined

[62] See LBNL's June 30, 2025, presentation, "Approaches to Hazard Modeling, Vulnerability Assessments, and Mitigation Evaluation in Utility Grid Resilience Planning: Examples from Northeast Utilities," available at: https://epuc.vermont.gov/?q=downloadfile/767816/203332.

"resilience" in precise, operational terms). Neither of Connecticut's IOUs has yet filed distribution system planning proposals under the new guidelines. Regulators in other states point to the general lack of consensus among experts in and outside of the utility industry about what these should be. In practice, utilities are using "all-in" reliability metrics (SAIDI, etc.) and a few others such as Customer Interruption Duration, etc., with some exceptions where metrics are reported at a more granular level. Such metrics have at least been sufficient to develop resilience plans. In practice, most Northeast utilities do not yet make a categorical distinction between reliability and resilience; however, this is the topic of active investigation in several states, including Massachusetts, and the industry in general, and is worth revisiting in the near future.[63]

[63] See for example: the Massachusetts Department of Public Utilities active investigation into Service Quality Standards for Electric Distribution Utilities and Local Gas Distribution Companies, Docket #24-53, which included a technical conference that examined the establishment of resiliency performance metrics. Many states across the U.S, as well as industry groups (e.g., the IEEE Distribution Resiliency Working Group, https://sagroups.ieee.org/distreswg/resources) are in the process of examining or developing resilience metrics, including equity-focused resilience metrics (e.g., https://share.google/XQKcODFhqwIcMPoDi).

Appendix G: Summary Climate and Storm Data

Based on major storm restoration costs alone, exemplified by Figure 1 below, it is not possible to conclude with certainty that storm restoration costs are bound to rise. However, GMP reports that by enhancing restoration practices and grid hardening in recent years, it has reduced the number (and therefore total cost) of events that would otherwise have been classified as major storms. Over the longer-term, disaster declarations in Vermont – not necessarily indicative of grid outages, but a likely proxy over the course of many events – show an upward trend since the 1980s that reflect in part the consequences of climate change.

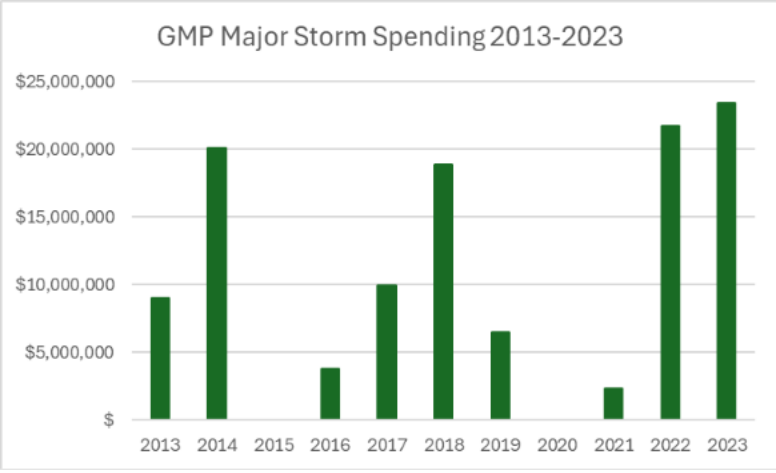


Figure 1: Green Mountain Power's storm restoration costs for major storms show ebbs and flows in magnitude from 2013-2023, with two consecutive years of high costs in 2022 and 2023. *Source: Green Mountain Power, Public Utility Commission proceeding 23-3501-PET.*

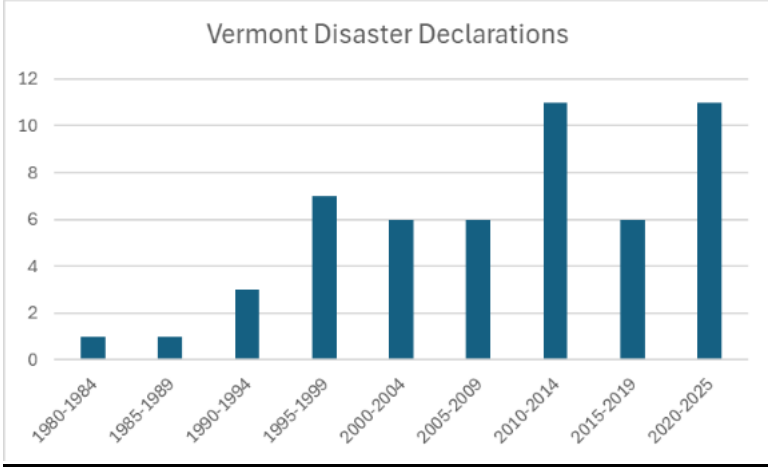


Figure 2: Vermont disaster declarations by five-year intervals from 1980 to the present, with an observable upwards trend. *Source: Disasters and Other Declarations, Federal Emergency Management Agency (FEMA).*

Crucially, long-term climate projections such as those shown in the 2021 Northview report when adequate translation to the resultant grid impacts is made – can positively demonstrate an expected upward trend in climate-related outage events. Some of the underlying climatological factors contributing to such conditions are seen in the figures below: increasing precipitation levels and air temperatures can cause the kinds of conditions that lead to icing of utility poles and of trees adjacent to utility rights of way.

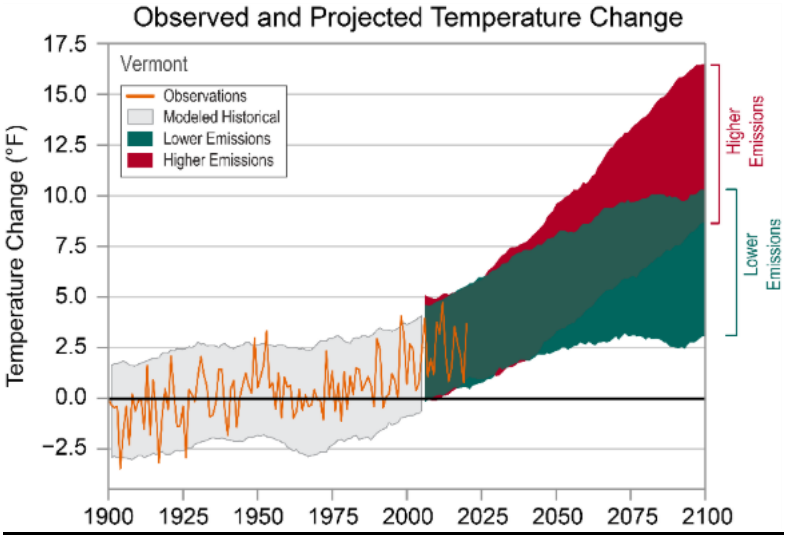


Figure 3: Vermont's air temperature over time, steady but increasing in the 1900s, has started increasing more rapidly in the 2000s with projections expecting continued increase. *Source: 2022 Vermont State Climate Summary, NOAA National Centers for Environmental Information.*

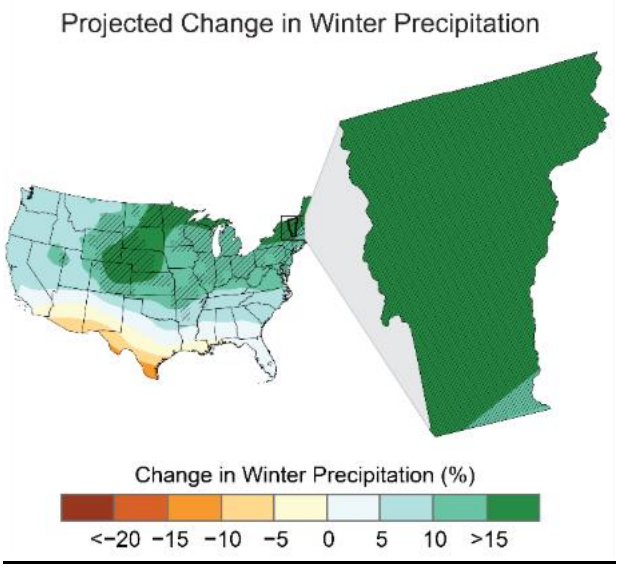


Figure 4: Vermont falls in a region of the United States expected to see an over 15% increase in winter precipitation. Paired with higher temperatures that can turn snow to sleet or freezing

rain, it is expected that negative impacts to power systems will result. Projection of those impacts can be undertaken to ascertain the opportunity for resilience projects as well as their value. *Source: 2022 Vermont State Climate Summary, NOAA National Centers for Environmental Information.*

Appendix H: Outline of BCA Components

A suitably rigorous BCA should include the following components:[64]

1) **Selection, Costs, and Impacts of Proposed Project:** Potential resilience projects should be characterized based on the resilience planning framework articulated above, including the specific risks and vulnerabilities being addressed and the expected outcomes: reductions in frequency and/or duration and/or scope of power interruptions, estimated cost, useful life, number and type of customers benefited, and expected mitigation potential in terms of MWh of energy not served (ENS), total and by customer for a feeder segment.

2) **Quantification of Impacts of Proposed Project:** At a minimum, the following three benefits must be quantified in monetary units that are directly comparable to estimated project costs (e.g., net present value of expected benefits in dollars):

    - **Avoided system restoration costs (all tests)**
        - Estimate how many fewer electric infrastructure assets would have to be repaired/replaced due to the proposed resilience project, along with estimated repair/replacement costs informed by experience.
    - **Avoided costs of implementing alternative reliability/resilience activities (all tests)**
        - If the proposed resilience project would save costs by reducing the need for existing reliability/resilience activities (e.g., undergrounding that reduces vegetation management needs), then those benefits should be quantified.
    - **Avoided customer interruption costs (SCT only)**
        - Multiply estimated reductions in ENS (MWh) from the proposed resilience project by an appropriate value of lost load (VOLL) estimate ($/MWh) or set of estimates (e.g., those found in the Interruption Cost Estimate Calculator 2.0[65])
    - **Other costs or benefits (applicable test will depend)**

[64] More detail on BCA methodology can be found here: https://apps.epri.com/climate-readi-investment-guide/en/cba.html.
[65] https://icecalculator.com/home.

- There may be other costs or benefits associated with proposed resilience projects, and utilities are welcome to identify and estimate those for inclusion in a BCA. Examples of additional benefits include the impact of reducing lost sales, reduced financial risk, or co-benefits of the project.

Appendix I: Proposed Grid Resilience Language for IRP Guidance

Each utility should describe its decision-making framework for resilience to extreme weather, including an evaluation of the overall balance of spending on prevention, survivability, and recovery, based on assumptions about weather trends, customer expectations, availability of mitigation or recovery funding, etc. A discussion of any barriers to achieving this balance should be provided. Plans should address the following elements:

- ***Assess Risk:*** *provide assumptions for extreme weather impacts, based on climate and geography:*
  - *Describe practices to monitor and measure weather variables*
  - *Provide Weather and Climate Projections (and sensitivities), including frequency, severity, and type of extreme events (documenting models, methods, data, and assumptions).*
- ***Assess Vulnerability:*** *provide assumptions for impacts to system given geography and system characteristics:*
  - *Identify high-risk or high-vulnerability areas of the utility's service territory (geographical) and infrastructure (physical/engineering) (documenting models, methods, data, and criteria used to identify areas).*
- ***Identify, evaluate, and select alternatives to mitigate risks:***
  - *Describe investments and practices that will be considered to mitigate identified risks and vulnerabilities, including: (1) proactive measures such as undergrounding, hardening, enhanced vegetation management, and deployment of energy storage; and (2) reactive measures including storm response.*
  - *Describe evaluation factors when considering individual projects and portfolios of resilience measures/investment, including selection and prioritization criteria (e.g., costs, cost-effectiveness, expected outcomes, input from, and impacts to, specific sets of customers and communities).*
- *Utilities that use multi-objective planning should articulate their decision-making framework for prioritizing various objectives, including improving resilience.*