



**Draft Meeting Minutes
January 21, 2026
South Burlington, Vermont**

The Vermont System Planning Committee held a quarterly meeting on January 21, 2026. Shana Louiselle, VSPC facilitator, called the meeting to order at 9:40 a.m. Ms. Louiselle reviewed the agenda for the meeting.

Ms. Louiselle asked if there were any corrections or objections to the October meeting minutes. Munir Kasti made a motion to approve and Taylor Newton seconded. The minutes were approved without objection.

Introductions

A list of attendees by sector appears at the end of these minutes.

Geographic Targeting Subcommittee Report

Ms. Louiselle reported that the Geographic Targeting Subcommittee met in November and received an update on the NTA Study Group’s evaluation of existing flexible load resources to clarify baseline reliability needs and determine whether additional NTAs are needed to address the 2024 LRTP transmission deficiency. Updated assumptions related to electric vehicle (EV) charging controls and active battery storage materially improved the reliability outlook, indicating that existing flexible resources may be sufficient to defer proposed transmission upgrades under current conditions. The subcommittee will reconvene in February to continue their coordinating with the lead and affected utilities on the development of the Reliability Plan that will be submitted to the Public Utility Commission in April.

Forecasting Subcommittee Report

Zakia El Omari, VELCO Transmission Planning Engineer, reported that the Forecasting Subcommittee met in November and December. Efficiency Vermont presented its Demand Resource Plan, emphasizing continued investment in heat pumps across residential and commercial sectors. Itron reviewed its updated load forecast assumptions, noting slower adoption rates for EVs and heat pumps compared to those used in the current Long-Range Plan. Itron is finalizing modeling assumptions for EVs, heat pumps, solar, and storage, and is requesting additional hourly heat pump data from utilities. Key milestones include delivery of hourly load data to Itron by March 12, a draft forecast report by April 3, and presentation of the final forecast at the April 29 VSPC meeting. The next subcommittee meeting will be scheduled in February.

Coordinating Subcommittee

Ms. Louiselle reported that the next VSPC quarterly meeting is on April 29, 2026 at the Middlebury Inn in Middlebury, VT.

2024 Vermont Long-Range Transmission Plan Update

2024 NTA Analysis Update: Kamran Hassan and Cam Twarog from GMP shared that the analysis of the northern and northwestern Vermont regions demonstrates that existing non-transmission resources—specifically managed electric vehicle charging and active battery storage already deployed by utilities—are sufficient under current assumptions to maintain system reliability and defer significant traditional transmission investments. The study concludes that these resources can address the identified peak load deficiencies, avoiding more than \$300 million in proposed transmission upgrades. VELCO’s updated time-series analysis showed that the reliability need is more limited in duration and shape than originally assumed, further supporting the viability of these non-transmission solutions.

GMP developed a draft project-specific action plan that document the analysis, assumptions, and conclusions for both regions. While the substantive analysis is unchanged from what was presented to the VSPC in October, the group acknowledged a process oversight in not initially circulating the draft to the full Geographic Targeting Subcommittee distribution list. That step has since been corrected, and additional feedback has been received from the Department of Public Service and Efficiency Vermont. These comments will be incorporated into a revised draft to strengthen clarity and transparency, before inclusion in the 2025 VSPC Annual Report.

The Study Group acknowledged that deferral of transmission does not eliminate the need for continued tracking and reporting metrics. These metrics will focus on participation and performance of EV managed charging programs, effectiveness of active storage in peak shaving, and continued validation of assumptions over time. It was also noted that lessons learned from this full application of the NTA process in over 10 years will inform refinements to the process flowchart for future planning cycles.

2025 VSPC Annual Report

Ms. Louiselle reported that the Committee will postpone the review and approval of the 2025 draft VSPC Annual Report to allow time for further input into the Project Specific Action Plan. The Coordinating Subcommittee will schedule a special meeting of the VSPC to vote on the revised 2025 VSPC Annual Report in February.

Large Load Interconnection – Reliability, Planning and Policy Considerations

Federal perspective: Christina Hayes, Executive Director of Americans for a Clean Energy Grid (ACEG), provided a national perspective on large load interconnection. Data centers are often sited based on access to fiber, power pricing, and resource availability, and much of this development is occurring outside New England. Unlike traditional customers, these large loads can be highly mobile and price-sensitive, with some sectors, such as crypto operations, lacking long-term stability. This creates forecasting challenges and increases the risk that utilities may overbuild infrastructure based on demand that does not materialize.

A key concern is how costs are allocated and when they are recovered. Utilities may invest in infrastructure ahead of actual load, with existing ratepayers bearing costs before new customers begin contributing, raising equity concerns. Proposed policy approaches, such as requiring large loads to supply their own generation or accept curtailment, attempt to limit system risk but often conflict with the need for constant, reliable service. Other strategies like co-location may reduce some exposure but can introduce inefficiencies and higher overall costs. Recent experience in PJM highlights the financial risks of rapid, data center-driven load growth without aligned planning and cost controls. The central issue is balancing timely interconnection with disciplined forecasting and ensuring that new large loads assume an appropriate share of system costs.

Regional perspective: Sarah Adams, External Affairs representative for Vermont at ISO New England, provided an update on how ISO-NE is approaching large load proposals, and how it is preparing in the event such projects begin advancing in New England. The presentation outlined ISO-NE's three phases of large load development: (1) initial contact with transmission owners and distribution companies, (2) formal service application and system impact studies, and (3) final commitment to construction, including executed contracts and financial commitments. Most known projects in New England remain in the first phase, with only a limited number in the second phase and none currently in the third phase. Ms. Adams emphasized that forecasting decisions should rely on projects that have reached a high level of commitment, generally aligned with phase three, to avoid overestimating load growth. This approach is being incorporated into the current forecasting cycle, with updates to be reflected in the next planning report.

In addition to refining forecasting criteria, the ISO- NE is coordinating with transmission owners to improve visibility into potential large load proposals, engaging with state policymakers regarding incentives or potential policy actions, and conducting research on expected load profiles to better understand actual consumption patterns. It is also participating in interregional forums, including NERC's Large Load Task Force and ISO/RTO Council planning efforts, to learn from regions experiencing faster growth. The overall objective is to ensure preparedness for potential large load additions while maintaining accurate planning assumptions and system reliability.

Transmission Perspective: Lucas Looman, Transmission Planning Engineer at VELCO, provided an overview of how large load interconnections would be evaluated in Vermont, noting that the state does not currently have a defined large load threshold. Any large load interconnection proposal would be reviewed under Section 248 criteria with requirements varying based on factors such as voltage level and location on the grid. Interconnection pathways depend on whether a project connects to the regional transmission network or other parts of the system, but all proposals would undergo structured technical review processes aligned with regional reliability standards.

At the core of this approach are two key studies that assess system impacts and proposed infrastructure changes, both subject to regional oversight and approval. These processes are designed to ensure reliability and proper system integration, while costs are recovered through established utility mechanisms rather than direct billing to individual customers. The analysis also highlighted that Vermont's ability to host large loads varies by region, with northern areas generally requiring more upgrades. Importantly, each project would be evaluated on its specific characteristics, including load behavior, to determine system impacts and necessary investments.

Distribution Perspective: Cam Twarog, Electrical Engineer at GMP, outlined three practical pathways for connecting new electric loads in Vermont, differentiated mainly by size and system voltage. Smaller loads under 5MW would connect at the distribution level through an Act 250 process, where the utility

evaluates whether it can reliably serve the load and identifies any required upgrades, which are generally paid for by the customer. As load size increases, projects shift to sub-transmission or transmission systems, triggering more rigorous review under Section 248 and, depending on voltage, additional regional study requirements. Across all pathways, interconnection is governed by existing regulatory frameworks designed to ensure reliability and appropriate cost responsibility.

Location, size, and load behavior drive both feasibility and cost. Engineering reviews assess system capacity, voltage performance, and protection needs, with outcomes varying significantly even for similar-sized projects in different locations. Non-traditional loads, such as data centers, introduce new challenges due to highly variable and rapid demand patterns, which differ from typical industrial profiles. Mr. Twarog noted that while large loads can require substantial infrastructure investment, they can also provide financial benefits by contributing to fixed system costs if sited and structured appropriately.

State Perspective: Lou Cecere, Electrical and Planning Engineer at the Vermont Department of Public Service, shared that the Department views data centers as a conditional opportunity that can benefit Vermont if managed within existing regulatory frameworks and aligned with state energy, environmental, and equity goals. Current processes under Section 248 and Act 250 are considered sufficient to evaluate impacts and ensure that new large loads fund necessary infrastructure, while Vermont is more likely to see smaller or flexible projects rather than large-scale developments seen elsewhere. At the same time, the state is closely monitoring regional market impacts, policy decisions in other states, and potential federal actions that could affect costs or jurisdiction, with an emphasis on maintaining strong guardrails to protect ratepayers and avoid unintended economic or community impacts.

Regional Planning Perspective: Chris Campany, Executive Director of Windham Regional Commission, and Taylor Newton, Planning Program Director at Chittenden County Regional Planning Commission, highlighted that data center development is creating significant uncertainty for long-term grid planning, with major concerns around inaccurate forecasting, potential overbuilding, and misaligned investments. Because planning and cost allocation are regional, decisions in one state can shift costs and reliability risks to others, underscoring the need for stronger coordination and consistent policy approaches. Key concerns include the risk of cost shifting to existing ratepayers if infrastructure is built ahead of demand, upward pressure on wholesale energy and capacity prices over time, and reliability challenges from large, inflexible loads. There is also concern that uneven state incentives could distort siting decisions and concentrate impacts, as well as that high water use for cooling could strain local water supplies, wastewater systems, and environmental resources if not carefully managed.

ISO-New England Regional Update

Sarah Adam, Senior External Affairs and Vermont Representative at ISO-New England, reported stable near-term system conditions, with sufficient resources expected to meet winter demand under typical scenarios and no projected energy shortfall risks. However, market signals show rising costs, driven in part by higher natural gas prices, and continued reliance on natural gas and nuclear generation. ISO also emphasized the importance of offshore wind projects such as Vineyard Wind and Revolution Wind for future reliability, particularly in winter, while noting that federal actions affecting these projects could introduce reliability and economic risks. At the same time, ISO is advancing capacity market reforms, shifting from a three-year forward auction to a more near-term “prompt” structure to improve forecasting accuracy and reduce risks tied to projects that fail to materialize.

From a planning perspective, ISO highlighted a fundamental shift toward increasing electricity demand after years of decline, driven by electrification and decarbonization policies, along with a transition toward winter peak demand. This is creating new pressure on transmission planning, interconnection processes, and long-term system investments. Reforms to the interconnection queue are intended to filter out speculative projects and prioritize viable resources, though this has significantly reduced the pipeline of proposed generation. Key concerns include growing cost pressures in regional markets, uncertainty around future resource development, and the need to ensure reliability as the system becomes more dependent on new technologies and policy-driven changes. The Day-Ahead Ancillary Services Initiative (DAASI) was also flagged, with stakeholders expressing concern about near-term cost impacts and volatility, while ISO noted it is still evaluating refinements to its design and forecasting approach. Key concerns overall include growing cost pressures in regional markets, uncertainty around future resource development, and the need to ensure reliability as the system becomes more dependent on new technologies and policy-driven changes.

Thermal Energy Networks and NTAs: What's Possible?

Representatives from Vermont Community Thermal Networks presented on thermal energy networks (TENS) as an emerging infrastructure approach that uses interconnected ground source heat pumps, piping loops, and multiple thermal resources (including waste heat, geothermal, and storage) to share heating and cooling across buildings. The presentation suggested that TENS can function as a grid-facing capacity resource by reducing peak electric demand associated with building electrification, while also improving efficiency through higher system-level performance when heat is strategically managed across connected buildings. The presenters emphasized that Vermont already has early-stage projects underway and a supportive legal framework (Act 142), with municipal and campus-scale deployments demonstrating practical feasibility in dense or planned growth areas.

The presentation proposed that widespread deployment of TENS could reduce required electric grid expansion, lower infrastructure costs, and support housing and economic development by enabling more flexible thermal energy supply options. The discussion highlighted significant potential system benefits, including avoided transmission and distribution investments and reduced wholesale electricity costs under certain scenarios, though results depend heavily on local design and density. Regional planners emphasized alignment with housing development, municipal infrastructure upgrades, and resilience planning, noting that TENS may be most viable in designated growth areas and redevelopment sites where water, sewer, and building density already support shared infrastructure models. Key uncertainties remain around governance, financing models, and how to integrate TENS into existing utility planning and non-wires alternatives frameworks, but the overall framing positioned them as a potentially meaningful tool for reducing peak load growth pressures on the electric system.

Attendance

* Indicates voting member

** Indicates alternate

Public Sector

- *Taylor Newton, Regional Planning Rep
- *Johanna Miller, Environmental Rep
- *Michael Kirick, Commercial representative
- **Molly Mahar, Commercial representative
- *Tim Duggan, Residential representative
- **Susan Paruch, Residential representative

Transmission Utility (VELCO)

- *Marc Allen, VELCO
- **Frank Etori, VELCO

Distribution Utilities Providing Transmission (GMP, VEC)

- *Kamran Hassan, GMP
- **Doug Smith, GMP
- **Michael Beaulieu, VEC

Large Transmission-Dependent Distribution Utilities (BED, WEC, GF)

- *JJ Vandette, WEC
- *Munir Kastj, BED
- **James Gibbons, BED

Transmission Dependent Distribution Utilities (Municipals)

- *Michael Gadway, Village of Ludlow
- *John Dasaro, Enosburg Falls
- *Jackie Pratt, Stowe Electric
- *James Weber, Village of Jacksonville
- **John Abbott, VPPSA
- *Chris Cole, GF Power

Supply & Demand Resources

- *Jonathan Dowds, Supply Representative
- *Tom Lyle, BED
- *Dave Westman, EVT

Non-Voting Members

- Lou Cecere, PSD
- TJ Poor, PSD

Staff

- Shana Louiselle, VELCO

Guests

- Ann Janda, CCRPC
- Barry Ahern, National Grid
- Betsy Bloomer, VELCO
- Brian Connaughton, VELCO
- Bill Barnes, Encore
- Brian Hall, VEC
- Bradley Williams, BED
- Cam Twarog, GMP
- Cara Robecheck, EAN
- Chris Company, WRPC
- Christina Hayes, ACEG
- Dave Carpenter, DRM
- David Mullett, All Earth Renewables
- Debbie New, VCTN
- Ed McGann, VELCO
- Emily Stebbins-Wheelock, BED
- Heather D’Arcy, VPPSA
- Jared Rodriguez, EUC
- Jay Pilliod, EVT
- Jayson Uppal, Community Decarbonization Partners
- Keara O’Laughlin, BEI
- Khalid Osman, VELCO
- Laura Coriell, FirstLight
- Lawrence Mott, Grid United
- Lucas Looman, VELCO
- Maddison Shropshire, VCTN

Marc Allen, VELCO
Mark Kleinginna, Integral Energy
Mark Sciarrotta, VELCO
Mary Jo Krolewski, PUC
Morgan Casella, DO
Paul Nadeau, BED
Paul Pikna, BED
Peter Fitzgerald, INS Engineering
Peter Sterling, REV
Sam Lash, CVRPC
Sarah Adams, ISO-NE
Tom Knauer, PUC
Zakia El Omari, VELCO