VERMONT ELECTRIC COOP

Filed via ePUC

July 15, 2025

Ms. Holly Anderson, Clerk
Vermont Public Utility Commission
112 State Street
Montpelier, VT 05620-2701

Re: 24-3351-INV Investigation into the potential need for transmission system improvements identified in the 2024 Vermont Long-Range Transmission Plan

Dear Ms. Anderson:

Vermont Electric Cooperative, Inc. (VEC) would like to provide the following feedback on the 05/27/2025 information request for 24-3351-INV.

<u>To understand the barriers to implementing locational adjustor fees, distribution utilities and VELCO are requested to provide an assessment of the drawbacks, barriers, opportunities, and usefulness of locational adjustor fee tariffs. Distribution utilities should address whether the barriers are administrative or technical, or if a determination has been made that such a fee would not help optimize the location of distributed generation. For example, the GMP Solar Map shows significant portions of the distribution system that are served by a substation transformer with less than 10% capacity remaining; GMP should address whether these parts of the grid are candidates for adoption of a locational adjustor fee tariff.</u>

Challenges: One of the primary challenges in implementing a locational adjustor fee is administrative complexity. VEC believes that while it may be feasible to structure the fee as a one-time, up-front charge, the process becomes significantly more difficult if the fee is collected on an ongoing basis or tied to generation output. There are also concerns about how to ensure that fees collected from specific members are reinvested in those same areas. This raises equity considerations, particularly since net-metering systems are often installed in higher-income areas. If the funds collected are returned to those same areas, it could result in disproportionate grid investment and exacerbate existing disparities.

Another barrier is the timing mismatch between when the fee is collected and the long-term nature of distributed generation assets, which typically last 20 to 25 years. Grid conditions are dynamic and will inevitably change over time. A fee assessed at the time of interconnection may later prove to be either insufficient or excessive, depending on how the grid evolves over the asset's lifespan.

Additionally, the tariff would need to be updated periodically to reflect current grid constraints. The frequency of these updates could become burdensome, both administratively and in terms of maintaining transparency and fairness.

Opportunities: If properly designed with predictability, low administrative burden, and cost alignment, VEC believes this fee could support the "cost causer pays" principle. This ensures that systems impacting the grid pay their share, rather than spreading costs to all members. The fee could also serve as a price signal for new distributed generation to areas with capacity, optimizing interconnections and potentially reducing infrastructure upgrades.

<u>Participants, including distribution utilities and VELCO, are requested to address whether there are other mechanisms to facilitate and enable a rational distribution of generation resources across the state with respect to distribution and transmission capacity.</u>

VEC does not have specific ideas regarding other mechanisms that would achieve this goal but appreciates that it is important to enable a rational and cost-effective distribution of generation resources. As distributed resources increase, this is becoming increasingly challenging, increasingly important, and critical that the utilities remain at the core of any mechanism given their role in managing the grid. VEC would be open to collaboratively exploring alternatives.

<u>In their comments, BED and VPPSA state that any mechanism relying on active control of distributed energy resource assets needs to occur at the distribution utility level to ensure that actions taken for statewide benefit do not lead to offsetting localized system or reliability problems or cause cost shifting among stakeholders. Participants are requested to address whether active control of distributed energy resource assets needs to occur at the distribution utility level and address the potential benefits, disadvantages, and costs of active control of these assets.</u>

VEC agrees with BED and VPPSA that the responsibility of management of member-owned resources should occur at the distribution utility level. If third-party aggregators are involved, assets must be visible to distribution operators. However, to support transmission NTA use cases VEC expects that VELCO could send signals or requests to the distribution utilities to dispatch DER resources under their management with a shared value proposition. This process and responsibilities are already identified in today's regional load shedding requests whereby VELCO receives a signal to shed load and then relays that request to the distribution utilities. The same process could be used with distribution level DER, balancing this use with other distribution needs for these same resources.

VEC understands that VELCO is still clarifying the time and duration of constraints in its long-range plan, making it challenging to determine how DER can help address them.

VEC believes many upgrades for electrification on the distribution system could be deferred or mitigated by effectively managing DER resources.

In its comments, VPPSA notes that the Plan discusses the desire to make use of non-transmission alternatives ("NTAs") and coordinate them with distributed generation siting and raises concerns about the reliance on active control or management of NTAs, including whether the active management of NTAs have the potential to negatively affect distribution level reliability, as loads are shifted locally or in time, and may result in significant cost shifting across stakeholders. Participants are requested to address the potential benefits, disadvantages, and costs that accompany active management of distributed energy resources and NTAs, including whether and how the shifting of costs or reliability problems across stakeholders can be avoided.

VEC believes that with clear communication, defined roles and data visibility any shifting of costs or reliability problems will be avoided. This practice is already in place in Australia where transmission operator's publicly identifies constraints that distribution operators can respond to. This has not only increased the amount of available capacity on the system but has also increased the reliability of the transmission network.

There are two primary challenges:

- **Bridging the data gap** between the transmission and distribution operators. Today Vermont distribution operators do not receive signals (time and location) from VELCO on where DER could be valuable. VELCO is unable to model how DER can contribute to the transmission system. Software platforms exist in the market but it takes time to select the proper tool and implement a solution.

  Additionally**,** VELCO currently lacks near real-time DER status, making it difficult to use DER to support transmission if operators can't assess available resources. While distribution utilities like VEC have near real-time data on 150+ batteries and 300 EV chargers, this aggregated information must be shared with VELCO in a usable format.

- **Managing Priorities of DER Values.** For an NTA to be a reliable alternative to an infrastructure investment, it must serve the transmission system as a primary use case. Balancing this use case with other use cases such as FCM/RNS peak shaving or distribution deferral could be challenging and needs to be better modeled and understood.

  For example, for a behind-the-meter battery to support VELCO transmission needs, the battery owner must prioritize those over-peak shaving for the utility and may not be available for peak shaving. A hierarchy of these DER use cases could look like:

  1. Transmission Use case
  2. Distribution Use case (reliability or asset deferral)
  3. Frequency regulation

4. Peak shaving

<u>In its comments, BED states that the Plan could benefit from additional analyses and discussion on the following issues: (1) duration, frequency, and load profile of transformer overloads under N-1-1 conditions; (2) rate of increase in the deployment of distributed generation and other distributed energy resources; (3) rate of increase in the deployment of electric vehicles and advanced heat pumps; (4) rate of increase in the deployment of energy storage in key areas of the state; (5) whether existing rate structures, such as electric vehicle rates, could alleviate forecasted overload conditions; and (6) whether future dynamic rate structures could alleviate forecasted overload conditions. Participants are requested to address how the Plan and state distribution and transmission planning can benefit from analysis of these issues and file any supplemental information, data, or analyses that would aid in the discussion of these issues.</u>

> VEC believes that the traditional top-down forecasting approach (substation level data) which has served VELCO and the state well in the past will soon be insufficient to accurately model future load. Due to the dynamic nature of electric vehicles, energy storage, solar and other distributed energy resources, a bottom-up meter level forecast should be implemented in the coming years. VEC understands that VELCO is already working through various approaches on how to achieve this.
>
> The most effective strategy is for distribution utilities to provide data to support this bottom-up meter level approach. This includes aggregated AMI data, data collected from flexible load programs such as electric vehicle management, and data from solar sites. The forecast in the LRP will only be as accurate as the data provided to VELCO through the work done by the VSPC Load Forecasting Subcommittee.

<u>As identified in the Department's comments, participants are requested to address the present condition of coordination of statewide distribution and transmission planning work, including strengths and weaknesses, and what steps are needed to ensure that NTAs are given full, fair and timely consideration as envisioned by Docket 7081. Responses should include a step-by-step recitation of how: (1) effective data and information gathering and collaboration will occur; (2) load growth, load controllability, and other key assumptions will be collectively determined; and (3) grid cost and resiliency factors can be better reflected in distributed generation siting and utility infrastructure investment decisions moving forward and incorporated in the next iteration of the Plan. Responses should also address: (1) any recommendations for changes to the Docket 7081 process to ensure NTAs are given full consideration; and (2) any recommendations for which entities are responsible for paying for transmission level upgrades that become necessary because of distributed generation growth, rather than load growth.</u>

> VEC supports the existing planning framework. The most important component of an NTA is understanding the challenge it solves in detail. At this point in time, the existing planning mechanisms are unable to effectively model how DER could support the transmission system and the duration of the constraints. VEC is aware that VELCO is exploring how to enhance these modeling efforts.

Sincerely,

Cyril Brunner

Cyril Brunner
Innovation and Technology Leader