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STATE OF VERMONT  
PUBLIC UTILITY COMMISSION

Case No. \_\_\_\_\_

Petition of Vermont Electric Cooperative, Inc. )  
 Requesting an Increase in Revenues of \$4,514,046 )  
 Or 4.84% to Take Effect January 1, 2025 )

PREFILED TESTIMONY OF  
DAN POTTER

ON BEHALF OF  
VERMONT ELECTRIC COOPERATIVE, INC.

November 15, 2024

### Summary of Testimony:

Mr. Potter's testimony will support the level of power costs included in the revenue requirement.

He sponsors the following exhibit, which will be submitted only in electronic format:

Exhibit VEC-DP-1: Electronic spreadsheet showing power costs projections for the Adjusted Test Year (Adjusted Test Year Power Cost Projections - Final.xlsx).

1     **I.     Introduction**

2     **Q1.     Please state your name and your position.**

3     **A1.**     My name is Dan Potter, and I am a Power Planning Analyst for Vermont Electric  
4     Cooperative, Inc. (VEC).

5     **Q2.     What is your educational and professional background?**

6     **A2.**     I received a Bachelor of Arts Degree in Community and International  
7     Development from the University of Vermont in 2009. In 2014, I received a Masters of  
8     Environmental Law and Policy from Vermont Law School. Prior to working at VEC, I was  
9     a Senior Energy Policy and Program Analyst for the Vermont Department of Public  
10    Service.

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

12    **A3.**     Yes, I have testified before the Public Utility Commission (PUC) numerous times  
13    while employed at the Department of Public Service and VEC. Most recently, I testified  
14    in Case No. 23-3943-TF, regarding VEC's 2024 Rate Case.

15    **Q4.     What is the purpose of your testimony?**

16    **A4.**     My testimony will support the \$38,200,901 of net power costs included in the  
17    revenue requirement and set forth on Schedule 2 of Exhibit VEC-CCM-1, which is  
18    included in the testimony of Caroline Mashia. My testimony and schedules focus on the  
19    \$822,868 projected decrease from the test year to the rate year.

20    **II. Power Cost Drivers**

21    **Q5. Power supply costs are decreasing from the Test Year to the Adjusted Test Year**

1 **(or Rate Year). Can you provide an overview of what is driving that decrease?**

2 **A5.** There are many moving pieces and changes in VEC's power supply costs between  
3 the Test Year (July 1, 2023 - June 30, 2024) (TY) and the Adjusted Test Year (calendar  
4 year 2025 (ATY). Having said that, there are two main items driving VEC's power cost  
5 decrease: (1) a decrease in the HQ US contract price, which results in \$119,875 in  
6 decreased costs, and (2) the expiration of the Mystic winter reliability contract  
7 administered by ISO NE, which results in \$860,200 in decreased costs. The remaining  
8 change is made up of all the combined puts and takes contained in all of the resources  
9 detailed on Schedule 2. These cost drivers are discussed in further detail in their  
10 respective questions and answers below.

11 **Q6. Before going through all the detailed adjustments from test year numbers to**  
12 **those proposed for the rate year, can you place all these power supply arrangements**  
13 **in the context of VEC's power supply philosophy?**

14 **A6.** There are many factors that influence VEC's power supply management  
15 strategies, including the timing and volume of energy consumed by VEC's members,  
16 statewide renewable energy mandates, the relative cost of various power supply  
17 products and services available in the region, and the risk and benefits of leaving some  
18 part of our power supply portfolio "open." While there is no industry standard formula  
19 hedging strategy, VEC's hedging strategy in the energy market is to be at least 90%  
20 hedged going into any given year and at least 80% hedged from 13-24 months prior to  
21 the beginning of a year; however, we allow flexibility in the timing of entering into

1 transactions so that we can take advantage of lower market prices. We believe this risk  
2 mitigation strategy protects VEC from rate impacts of rising markets and allows some  
3 ability to lock in lower prices. VEC's projected hedge level for 2025 is approximately 95%  
4 based on existing contracts and test year load.

5 **III. Net Power Costs for the Adjusted Test Year**

6 **Q7. Please summarize VEC's net power costs, as included in the revenue**  
7 **requirement.**

8 **A7.** Gross Purchased Power costs for the ATY are projected to be \$44,145,360, a  
9 decrease of \$1,112,131 compared to the TY. Power costs net of Sales for Resale and the  
10 sale of RECs are projected to be \$38,200,901, a decrease of \$822,868 compared to the  
11 TY. These are summarized on Exhibit VEC-CCM-1, Schedule 2. My testimony below  
12 provides additional context and information for those changes on Schedule 2 that result  
13 in a material impact to the ATY. Because many of our power supply arrangements are  
14 contracts with established escalators, I have simply adjusted the test year costs to  
15 reflect the contract price that will be in place during the ATY. Some of the annual  
16 contractual adjustments do not coincide with the calendar year, and I refer to the actual  
17 annual period covered by such contracts as the "Power Year."

18 All assumptions behind the development of the power costs are detailed in  
19 Exhibit VEC-DP-1 (Adjusted Test Year Power Cost Projections – Final.xls).

20 **Q8. How have you determined ATY adjustments for the solar generation projects**  
21 **within your power supply portfolio?**

1    **A8.**     Since the adoption of the Renewable Energy Standard (RES), VEC has entered  
2    into contracts for the output of five utility-scale solar projects:

- 3           1. The Alburgh facility (1.0 MW AC nameplate capacity),
- 4           2. The Magee Hill facility located in Hinesburg (1.3 MW AC nameplate capacity),
- 5           3. The Jericho Gravel Pit facility located in Jericho (1.15 MW AC nameplate
- 6                 capacity),
- 7           4. The Jericho Landfill facility also located in Jericho (1.65 MW AC nameplate
- 8                 capacity), and
- 9           5. The Grand Isle facility (4.99 MW AC nameplate capacity).

10           In determining costs projected for the ATY, I used each contract rate that will be  
11    in effect for the ATY. For MWh produced during the ATY, I have assumed TY actuals.  
12    The net impact of all 5 of these projects is an increase of \$31,810 from TY levels.

13    **Q9.     Turning to the wind projects in your portfolio, please explain your assumptions**  
14    **regarding Kingdom Community Wind.**

15    **A9.**     Under our power purchase agreement with Green Mountain Power (GMP), VEC  
16    is responsible for 8/63<sup>ths</sup> of the costs that GMP incurs in connection with the Kingdom  
17    Community Wind (KCW) Project. In return, VEC receives 8/63<sup>ths</sup> of the hourly output of  
18    energy, ancillary services, and renewable energy certificates, as well as the monthly  
19    value of capacity.

20           In the ATY, VEC assumes the same monthly MWh of actual generation during the  
21    TY. For 9 months of the ATY, I have assumed a monthly charge of \$232,123 and for 3

1 months of the ATY, I have assumed a monthly charge of \$228,641. These assumptions  
2 are based on GMP's forecast to own and operate the project in 2025, resulting in a net  
3 increase of \$14,093 in the ATY compared to the TY.

4 **Q10. Please explain your assumptions regarding capacity revenues from Kingdom**  
5 **Community Wind.**

6 **A10.** KCW also participates as a capacity resource in ISO New England's Forward  
7 Capacity Market (FCM). The FCM is the mechanism ISO New England uses to ensure  
8 there is enough capacity in the region to serve the projected peak load plus a reserve  
9 margin to account for potential unit outages during peak times. Through this market  
10 ISO-NE pays resources to commit to providing a certain amount of capacity, known as a  
11 capacity supply obligation (or CSO) in exchange for a fixed monthly payment. VEC is  
12 entitled to its 8/63<sup>th</sup> share of the revenue resulting from KCW's participation in the FCM.

13 In the ATY we expect to receive a credit of \$65,493 from GMP due to differences  
14 in CSO and the capacity rates between the TY and the ATY. This credit is slightly higher  
15 than the credit VEC received in the TY, which was \$52,920. This results in an increase in  
16 revenues in the ATY of \$12,573 as compared to the TY.

17 **Q11. Please explain energy costs associated with the First Wind Project in Sheffield.**

18 **A11.** The First Wind - Fixed Price contract expired on October 19, 2021, and VEC's 10  
19 MW entitlement under this contract was rolled into the Index to Market contract  
20 structure as required by the First Wind contract. VEC reached an agreement in 2022  
21 with Brookfield Renewable, LLC, the current owner of the First Wind project, to convert

1 5 MW of its current 20 MW entitlement under the Index to Market structure back to a  
2 Fixed Price structure. This contract contains energy and RECs, but not capacity, and  
3 began on January 1, 2023. I have projected 8,013 MWh associated with the Fixed Price  
4 portion of this contract in the ATY, which is based on VEC's TY actual MWh. During the  
5 TY VEC received a liquidated damages settlement from the owner of this project for  
6 \$18,638 due to the project failing to meet its minimum MWh guarantee. I have  
7 assumed this does not happen in the ATY, resulting in an increase of \$18,638 between  
8 the TY and the ATY.

9 The monthly ATY prices for the First Wind - Index to Market contract are based  
10 on the projected 7x24 LMP at the Hub, (the most commonly traded delivery point in the  
11 New England system) assuming average on-peak and off-peak forward prices on the  
12 Intercontinental Exchange (ICE) at the close of business on 11/05/2024 adjusted for the  
13 monthly basis to the Sheffield node from the TY. I used the forward energy prices from  
14 the ICE as it is published price information and is widely recognized as a reasonable  
15 source of forward energy prices. I have assumed 24,038 MWh in the Index to Market  
16 line item for this project which is the same MWH as the TY. These assumptions result in  
17 an increased cost of \$567,738 between the TY and the ATY.

18 **Q12. Please summarize VEC's contracts with Hydro Quebec.**

19 **A12.** VEC currently takes power from Hydro Quebec through two different contracts:  
20 (1) the HQ Energy Services – U.S contract (HQUS contract) with various Vermont  
21 distribution utilities and (2) VEC's contract for deliveries to the Block Load when that is

1 connected to HQ, called Assured Secondary Energy (ASE). However, during the TY VEC  
2 also had a three-year contract that VEC entered with HQ for energy and environmental  
3 attributes (HQ 2021-2023). The factors resulting in changed costs under the HQ  
4 contract include (1) the expiration of the 2021-2023 deal and (2) contract price changes.  
5 These changes are discussed further below.

6 **Q13. Please summarize ATY Adjustments associated with purchases from HQUS.**

7 **A13.** On August 12, 2010, VEC entered into a long-term agreement with HQUS and  
8 other Vermont utilities which includes prices that are set based on an agreed upon  
9 formula. In addition to VEC's own allotment defined in the contract, VEC has a separate  
10 agreement with WEC whereby VEC will purchase up to 4 MW of WEC's allotment under  
11 the same terms and conditions. Starting in June of 2023, WEC decided to take back 2  
12 MW of the 4 MW entitlement that it had previously assigned to VEC, which resulted in a  
13 downward adjustment to VEC's total MWh entitlement. The only change in MWh  
14 between the TY and the ATY is a decrease associated with removing the leap day from  
15 the ATY. This results in 352 fewer MWh in the ATY.

16 Under the contract's terms, the energy price changes each year based on a  
17 formula that is a function of forward market prices and historic LMPs, with a year-to-  
18 year price change "governor" (cap) of 15%. The price changes take effect November 1  
19 of each calendar year. For the ATY, the price for January 1 through October 31, 2025 has  
20 been set at \$67.20/MWh. For November 1 through December 31, 2025, I have assumed  
21 a price of \$69.22/MWh using an escalator of 3%. The pricing change and the decreased

1 amount of energy purchased result in a weighted average cost in the ATY of  
2 \$67.54/MWh compared to \$68.28/MWh in the TY, for a total adjustment of \$119,875,  
3 combined, under TY levels, as shown on Schedule 2 (lines 12 and 13).

4 **Q14. Please summarize ATY Adjustments associated with Hydro Quebec Assured**  
5 **Secondary Energy (ASE).**

6 **A14.** The ASE contract covers energy delivered by HQ to serve VEC's Block Load that is  
7 tied to Quebec. The general terms of the contract are set through a long-term  
8 agreement, but the prices are negotiated each year.

9 Load served through this contract is priced at the higher of On-Peak and Off-  
10 Peak Floor Prices or the Hourly Vermont Load Zone Locational Marginal Price (LMP) in  
11 the Real-Time market plus an adder to account for costs of capacity, reserves, and other  
12 ancillary services that VEC would have incurred had the load been connected to the ISO-  
13 NE control area (Ancillary Services Adder).

14 Although the prices have not been finalized for 2025 as of the preparation of my  
15 testimony, I have projected a decrease of \$309,983 from the TY to the ATY as a result of  
16 assumptions for: (1) lower spot market prices and (2) an increase in the adder to  
17 account for ancillary services we would have incurred had the load been on New  
18 England instead of Quebec.

19 In the ATY, I have assumed the same MWh per month as in the TY for every  
20 month except January and February. I adjusted the January and February MWh  
21 amounts, because in the TY, VEC intentionally kept this portion of our system tied to

1 Vermont and ISO NE, and in the ATY VEC expects to not need to keep this portion of our  
2 system tied to Vermont. To project the January and February MWh amounts, I started  
3 by calculating the MWh amount from the TY that VEC would have had on HQ were VEC  
4 to tie that load to HQ 100% of the time. I then assumed 50% of those MWh amounts for  
5 the ATY in January and February. The energy pricing terms that will be in effect from  
6 January 1, 2025 through December 31, 2025, are: the higher of (1) the Hourly Vermont  
7 Load Zone LMP in the Real-Time market plus an Ancillary Services Adder of \$4.41/MWh  
8 or (2) hourly Floor Prices of \$51.22/MWh in peak hours and \$41.57/MWh in off-peak  
9 hours.

10 **Q15. Please summarize ATY Adjustments associated the 2021-2023 short-term HQ**  
11 **contract.**

12 **A15.** The three year deal that VEC entered with HQ for energy and environmental  
13 attributes was for off-peak hours. From October-March, VEC purchased 15 MW/hour in  
14 hours ending 1-7 and hour ending 24. From April to September, VEC purchased 12  
15 MW/hour in hours ending 1-7 and hour ending 24. This contract expired on  
16 12/31/2023. As such, I have removed it from the ATY. This change results a decrease of  
17 19,887 MWh and \$655,277, as shown on Schedule 2 (line 15).

18 **Q16. Please explain your assumptions regarding the Standard Offer program shown**  
19 **on line 16 of Schedule 2.**

20 **A16.** For energy in the ATY I have modeled the purchase of 22,798 MWh at a total  
21 cost of \$3,858,120, including VEC's share of transmission costs, representing increases

1 of 11,410 MWh and \$1,366,275 from the TY. The increase is a combination of new  
2 facilities coming on line, price increases for the output of some existing projects, and a  
3 change in VEC's pro rata share of the output. VEC's pro rata share of Standard Offer  
4 output is a function of our share of total Vermont retail kWh sales. I assumed VEC's  
5 share of Standard Offer is 9.4648% beginning November 2024, based on information  
6 provided by the Standard Offer facilitator. This is an increase from VEC's 9.2688% that  
7 was effective November 1, 2023 – October 31, 2024.

8       ATY energy assumptions are based on information provided by the Standard  
9 Offer facilitator regarding projected online dates, monthly production and contract rates  
10 of projects that have been accepted as Standard Offer projects, and VEC's allocation of  
11 Standard Offer power effective November 1, 2024.

12       Additionally, in the ATY I have removed the costs associated with the Standard  
13 Offer – FCM Settlement as the Berkshire Cow Power project that historically provided a  
14 benefit in VEC's ISO NE Settlement that VEC then had to pass on to the other Vermont  
15 DU's has withdrawn from the Standard Offer Program. As such, VEC will no longer be  
16 reimbursing the other DUs for these revenues. This results in a decrease in costs of  
17 \$6,421.

18 **Q17. Please explain the purchases from Ryegate.**

19 **A17.** Since 2013, Ryegate has had a contract to sell power to most Vermont utilities  
20 on a pro-rata basis. This contract began November 1, 2013. Act 155 of the 2021/2022  
21 legislative session authorized the continuation of Ryegate's contract at the existing

1 levelized rate determined in Docket 7782. The cost of the power for ATY is based on the  
2 existing contract price of \$110/MWh.

3 I have assumed VEC's pro-rata share is 9.227% based on information provided by  
4 the Standard Offer Administrator on October 4, 2024. The monthly output of the  
5 Ryegate facility is based on historical average monthly production from 2019 through  
6 2023. These assumptions result in a decrease of 680 MWh purchased and a decrease of  
7 \$78,466 in total costs projected in the ATY as compared to the TY.

8 **Q18. Please explain your assumptions regarding Newport Hydro.**

9 **A18.** VEC has a contract to purchase all of the output from Newport Hydro effective  
10 September 1, 2017. The initial contract price of \$47.50/MWh escalates at rate of 2.8%  
11 annually and the contract ended on 8/31/2024. VEC negotiated a contract extension  
12 with the owner, Gravity Renewables, to 8/31/2034.

13 The weighted average energy cost of the Newport Hydro Contract is assumed to  
14 increase from \$60.65/MWh in the TY to \$67.99/MWh in the ATY. That is because the  
15 ATY will be comprised of eight months from the 2025 Power Year (9/1/2024 –  
16 8/31/2025), at an energy rate of \$67.50/MWh, and four months from the 2026 Power  
17 Year (9/1/2025–8/31/2026), at an energy rate of \$69.19/MWh, both as stated in the  
18 contract.

19 I have assumed TY MWh output in the ATY. These assumptions result in an  
20 increase of \$170,967 in total costs, as shown on Schedule 2.

21

1   **Q19.   Please summarize ATY Adjustments associated with the New York Power**  
2   **Authority (NYPA).**

3   **A19.**   NYPA provides power to VEC from projects on the St. Lawrence River (St.  
4   Lawrence) and Niagara Falls (Niagara). These are federally funded projects whose  
5   output is required to be allocated to public power systems in New York and any state  
6   that borders New York. Rates are based on New York Power Authority Service Tariff No.  
7   SL-1 Original Leaf No. 10, Section V.

8           For the ATY I have assumed TY MWh and utilized TY rates for Energy, Capacity,  
9   Congestion, Losses, Ancillary Services, and Administration to project costs in the ATY.  
10   These assumptions result in increased costs of \$37,781 in the ATY.

11   **Q20.   Please summarize the contract with PSEG as shown on line 22 of Schedule 2.**

12   **A20.**   VEC had a contract to purchase 10 MW of capacity from PSEG from June 2021  
13   through May 2024 at a price of \$6.90/kw-month for the full contract. This contract was  
14   in place during 11 months of the TY, July 2023 – May 2024. The expiration of this  
15   contract results in a decrease of \$759,000.

16   **Q21.   Please summarize the ATY Adjustments associated with NextEra – 2022-2025**  
17   **as shown on Schedule 2.**

18   **A21.**   This contract is for the purchase of energy at the schedule included below at a  
19   price of \$62.29/MWh. The contract was entered in November 2021 with a term of  
20   December 1, 2021 – December 31, 2025; thus, it was in place for the entire TY and will  
21   be in place for the entire ATY as well.

| Year | Month     | Peak MW | 2X16<br>MW | 7X8<br>MW |
|------|-----------|---------|------------|-----------|
| 2024 | January   | 9.5     | 8.3        | 15.2      |
| 2024 | February  | 10.4    | 8.5        | 17.3      |
| 2024 | March     | 5.1     | 2.2        | 14.6      |
| 2024 | April     | 1.2     | 0.0        | 10.6      |
| 2024 | May       | 0.0     | 0.0        | 10.0      |
| 2024 | June      | 3.4     | 0.0        | 12.8      |
| 2024 | July      | 6.6     | 3.8        | 15.3      |
| 2024 | August    | 3.6     | 1.0        | 12.9      |
| 2024 | September | 1.8     | 0.0        | 11.3      |
| 2024 | October   | 3.1     | 0.0        | 10.7      |
| 2024 | November  | 4.4     | 2.4        | 11.1      |
| 2024 | December  | 7.9     | 6.1        | 12.9      |
| 2025 | January   | 9.5     | 8.3        | 15.2      |
| 2025 | February  | 10.4    | 8.5        | 17.3      |
| 2025 | March     | 5.1     | 2.2        | 14.6      |
| 2025 | April     | 1.2     | 0.0        | 10.6      |
| 2025 | May       | 0.0     | 0.0        | 10.0      |
| 2025 | June      | 3.4     | 0.0        | 12.8      |
| 2025 | July      | 6.6     | 3.8        | 15.3      |
| 2025 | August    | 3.6     | 1.0        | 12.9      |
| 2025 | September | 1.8     | 0.0        | 11.3      |
| 2025 | October   | 3.1     | 0.0        | 10.7      |
| 2025 | November  | 4.4     | 2.4        | 11.1      |
| 2025 | December  | 7.9     | 6.1        | 12.9      |

1

2           However, MWh volumes by month change over the duration of the contract in  
 3   accordance with the schedule above. I have accounted for the changes in MWh  
 4   volumes by month according to the schedule above in the ATY. These adjustments  
 5   result in an additional 9,722 MWh purchased and an increase in costs of \$608,667 from  
 6   the TY to the ATY.

7   **Q22. Please summarize the ATY Adjustments associated with NextEra – Seabrook -**

1     **Energy as shown on Schedule 2.**

2     **A22.** VEC purchases 10 MW of unit contingent energy from NextEra's Seabrook Nuclear  
3     facility. TY costs are based on actual deliveries of 86,082 MWh at a weighted average  
4     contract price for the period of \$64.76/MWh. ATY costs are based on an assumed  
5     97.5% capacity factor in each month and a weighted average contract price of  
6     \$69.13/MWh.

7             These changes result in a 672 MWh decrease in energy purchased and a  
8     \$329,857 increase in costs.

9     **Q23. Please summarize the ATY Adjustments associated with NextEra – Seabrook -**  
10    **Capacity as shown on Schedule 2.**

11    **A23.** VEC also has two contracts with NextEra to purchase capacity from Seabrook.  
12    The first contract is for 10 MW at a weighted average price of \$4.263/kW-month in the  
13    TY and \$4.472/kW-month in the ATY. This contract was in VEC's settlement with ISO-NE  
14    in both the TY and the ATY.

15             The second contract is also for 10 MW but at a weighted average price of  
16    \$7.94/kW-month in the TY and \$8.33/kW-month in the ATY. This contract was in VEC's  
17    settlement with ISO-NE in both the TY and the ATY. Total impact from the two capacity  
18    contracts is an increase in the ATY of \$73,707.

19    **Q24. Please summarize the ATY Adjustments associated with NY Wind Project as**  
20    **shown on Schedule 2.**

21    **A24.** In October of 2022, VEC entered into a five-year contract for 40% of the output

1 of a wind facility located in New York State. The contract price is \$80/MWh with a 1%  
2 annual escalator. However, the price is shaped throughout the year to reflect a 1.25001  
3 multiplier in the winter months (November through March) and a 0.70263 multiplier in  
4 the Spring, Summer, and Fall months (April through October). VEC also modeled the  
5 basis charges between the NY ISO generator node and the NY ISO delivery node. Basis  
6 charges are the costs VEC expects to incur to bring the energy from the generator node  
7 to the delivery node and are the result of the difference in the Location Based Marginal  
8 Prices between those nodes. Including basis charges in NYISO, the average price per  
9 MWh for this contract during the ATY is projected to be \$89.25. I have used TY actual  
10 MWh output of the facility. These changes result in an increase of \$96,407 in the ATY.

11 **Q25. Please summarize costs associated with Losses, shown on line 35 of Schedule 2.**

12 **A25.** Losses are a charge or credit in the ISO New England settlement system based on  
13 the difference in price between the pricing node of the supply resource from which VEC  
14 purchases energy and the price of energy at the Vermont Load Zone. TY data are based  
15 on the net sum of all Losses charges and credits in the Day-Ahead and Real-Time market  
16 settlements incurred at each delivery point at which VEC has a settlement with ISO New  
17 England. ATY data are based on the projected MWh purchased and/or sold at each  
18 delivery point multiplied by the projected Losses component differential in the LMP  
19 between the delivery point and the Vermont Load Zone. The ATY Losses component  
20 differential for each delivery point is estimated by multiplying the Losses component  
21 differential as a percentage of the LMP at the Hub as occurred in the TY by the projected

1 monthly LMP at the Hub for each month of the ATY. I have assumed a \$89,094 increase  
2 in losses from the TY to the ATY as projected LMPs in the ATY are higher than actual  
3 LMPs in the TY.

4 **Q26. Please summarize the costs associated with Congestion shown on line 36 of**  
5 **Schedule 2.**

6 **A26.** Congestion is also a charge or credit in the ISO New England settlement system  
7 based on the difference in price between the pricing node of the supply resource from  
8 which VEC purchases energy and the price of energy at the Vermont Load Zone. TY data  
9 are based on the net sum of all Congestion charges and credits in the Day-Ahead and  
10 Real-Time market settlements incurred at each delivery point at which VEC had a  
11 settlement with ISO-NE. ATY data are based on the MWh purchased and/or sold at each  
12 delivery point multiplied by the projected Congestion component differential between  
13 the delivery point and the Vermont Load Zone. The ATY Congestion component  
14 differential for each delivery point is estimated by multiplying the Congestion  
15 component differential as a percentage of the LMP at the Hub as occurred in the TY by  
16 the projected monthly LMP at the Hub for each month of the ATY. I have assumed a  
17 \$82,453 increase in Congestion costs from the TY to the ATY as projected LMPs in the  
18 ATY are higher than actual LMPs in the TY.

19 **Q27. Please summarize costs associated with the Forward Capacity Market (FCM)**  
20 **shown on line 39 of Schedule 2.**

21 **A27.** The ATY power cost projections show an increase in costs related to FCM

1 settlement with ISO NE of \$1,124,190. In both the TY and the ATY, VEC's net costs for  
2 this line item are based on (1) VEC's actual capacity market charge and (2) revenues  
3 received from the ISO for VEC's capacity entitlements.

4 The difference in net costs is due to three things: (1) an increase in VEC's  
5 percentage share of New England's annual peak (its Capacity Load Obligation or CLO),  
6 (2) an increase in the clearing prices of the Forward Capacity auctions covering the ATY  
7 with respect to the TY, and (3) the expiration of a 10 MW Capacity contract (PSEG).

8 While the expiration of this higher priced contract will decrease overall costs for VEC, it  
9 increases the costs in this line item as VEC is settling more of its CLO on the market. VEC  
10 anticipates a reduction in costs of \$759,000 as a result of the contract expiration (see  
11 Q&A #20 above), but by settling this 10MW on the capacity market VEC will incur a cost  
12 of approximately \$301,020 with a net savings of \$457,980 from the TY to the ATY.

13 The monthly capacity market charge is determined by multiplying VEC's CLO by  
14 the monthly Net Regional Clearing Price. In the TY, VEC experienced 11 months with a  
15 monthly capacity load obligation of 52.890 MW and one month with a capacity load  
16 obligation of 68.787 MW. The ATY will see a significant increase in the capacity load  
17 obligation: 5 months with a monthly capacity load obligation of 68.787 MW and seven  
18 months with a monthly capacity load obligation of 69.326 MW.

19 More specifically, VEC's capacity load obligation is a function of the capacity  
20 requirement in the region and VEC's share of the load at the time of the ISO New  
21 England annual peak in the calendar year prior to the beginning of the commitment

1 period, which runs from June through May of the following year. The chart below  
 2 shows the relevant annual peaks and VEC's allocation based on those peaks for both the  
 3 test year and the ATY.

|                | Test Year      |                | Adjusted Test Year |                 |
|----------------|----------------|----------------|--------------------|-----------------|
| Period         | 7/1/23-5/31/24 | 6/1/24-6/30/24 | 1/1/25-5/31/25     | 6/1/25-12/31/25 |
| Peak Date/hour | 8/8/2022 1600  | 9/7/2023 1800  | 9/7/2023 1800      | 7/16/2024 1800  |
| NE Peak        | 24,395.518 MW  | 23,623.018MW   | 23,623.018MW       | 24,365.696 MW   |
| VEC Peak       | 38.007 MW      | 48.306 MW      | 48.306 MW          | 55.790 MW       |
| VEC share      | 0.1558%        | 0.2045%        | 0.2045%            | 0.2290%         |

4  
 5 As to the increase resulting from higher clearing price in the Forward Capacity  
 6 auctions, the TY includes 11 months of for Forward Capacity Auction (FCA) 14 (June 1,  
 7 2023 – May 2024) and one month of FCA 15 (June 2024 – May 2025). FCA 14 cleared at  
 8 \$2.001/kw-month, and FCA 15 cleared at \$2.477/kw-month (for the Northern New  
 9 England Zone), for a weighted average price of \$2.041/kw-month. The ATY includes five  
 10 months of the commitment period of FCA 15 (June 2024 – May 2025) at the \$2.477/kw-  
 11 month clearing price and seven months of the commitment period for FCA 16 (June  
 12 2025 – May 2026) at a clearing price of \$2.531/kw-month. This is a weighted average  
 13 price of \$2.509/kw-month.

14 The charges incurred in the capacity market are also a function of the amount of  
 15 capacity resources VEC has entitlement to and whether these resources are settled  
 16 through ISO-NE. The entitlements can change each commitment period as is explained

1 in several of my responses above; also subject to change is whether the resources are  
2 part of VEC's settlement with ISO-NE or with the supplier (for example KCW and VPPSA).

3 **Q28. Why do you show TY values for "ISO Re-Settlement" (line 41 of Schedule 2) and**  
4 **"VELCO Re-Settlement" (line 48 of Schedule 2) but no values for the ATY?**

5 **A28.** The values in the TY are from re-settlements the ISO conducts to fix errors in  
6 original settlements. For the ATY, I have assumed all original settlements are correct,  
7 and thus no re-settlement values are necessary.

8 **Q29. Please explain your assumptions regarding the Mystic Cost of Service as**  
9 **included in Schedule 2 (line 42).**

10 **A29.** In 2018, the owner of the Mystic Generating Station signaled its intent to  
11 permanently retire Mystic units 8 and 9 once their FCM obligations had been satisfied in  
12 May of 2022. ISO NE filed for a two-year special contract with the facility to address  
13 regional reliability concerns, which FERC approved. The contract requires Load Serving  
14 Entities within ISO NE to cover the facility's fixed and variable costs. While this  
15 contract was in place for the entire TY, it will not be in place during the ATY. These  
16 changes result in a decreased cost in the ATY over the TY of \$860,200.

17 **Q30. Please summarize costs associated with VPPSA Peaker (line 43 of Schedule 2).**

18 **A30.** VEC has entitlement to a portion of VPPSA's Swanton Gas Turbine. TY costs and  
19 MWh are actual data, while ATY costs those provided to VEC by VPPSA based on the  
20 2025 budget for the project. The result of these changes includes an increase in costs of  
21 \$10,160 from the TY to the ATY.

1   **Q31. Please summarize costs associated with VPPSA FCM Settlement (line 44 of**  
2   **Schedule 2).**

3   **A31.** Per the contract with VPPSA, VEC receives its pro-rata share of value the Peaker  
4   project generates in the Capacity Market. In a portion of the TY this value first passed to  
5   VPPSA through its settlement with ISO-NE. VPPSA then passed this value to VEC through  
6   the monthly invoice issued for the project. This is why the TY includes a credit.  
7   However, during the ATY, this value will flow directly through VEC's settlement with ISO  
8   NE as VEC has self-supplied its portion of the project. The \$393 charge included in the  
9   ATY is a function of a projected true up between Self Supply and the Project's Capacity  
10   Supply Obligation. The removal of the TY credit from this line item and the addition of  
11   the true up charge have a net impact of \$59,288.

12   **Q32. Why do you show an increase in VELCO FCM Settlement revenues of \$46,422**  
13   **(line 45 of Schedule 2)?**

14   **A32.** VELCO is the lead market participant in the Forward Capacity Market for Ryegate  
15   and NYPA. As lead market participant, VELCO receives Capacity Market revenues in  
16   their settlement with ISO-NE and passes through the capacity revenues on a monthly  
17   basis at the appropriate capacity payment rates. In the TY none of these resources were  
18   transferred into VEC's settlement, and thus they all flowed from ISO-NE to VELCO then  
19   to VEC. The same will be true in the ATY.

20           VEC's share of the NYPA CSO is 5.292 MW in 5 months of the ATY and increases  
21   to 5.783 MW for 7 months of the ATY, compared to 5.292 MW in each month of the TY.

1 For Ryegate I have assumed a monthly average CSO of 1.718 MW compared to 1.709 in  
2 the TY.

3 As discussed in responses to earlier questions regarding the Forward Capacity  
4 Market, the payment rate for the ATY is greater than the TY.

5 The higher payment rate and increases in CSOs for resources results in the higher  
6 revenues of approximately \$46,422 from VELCO in the ATY compared to the TY.

7 **Q33. Please summarize costs associated with Viridity Battery.**

8 **A33.** VEC entered an Energy Storage Services Agreement (ESSA) with Viridity for peak  
9 shaving services to reduce capacity market and NEPOOL RNS Transmission costs. VEC  
10 pays a monthly fee for the right to dispatch the battery for 400 hours per year, and will  
11 pay this fee in each month of the ATY. The ESSA became operational in July 2019;  
12 therefore, it was part of the TY and will also be part of the ATY. The savings from the  
13 battery flow through the Forward Capacity Market costs and Transmission costs,  
14 mitigating costs increases that would otherwise be higher in the capacity market. I have  
15 assumed TY actuals in the ATY resulting in no changes between the TY and the ATY.

16 Electricity used to charge the Viridity battery is billed at VEC's SC 5 rate, which  
17 passes along any real-time energy and ancillary services costs as well as capacity and  
18 transmission costs. Line 52 of Schedule 2 represents the total of these bills to Viridity  
19 for the Hinesburg battery for the TY. I have assumed TY actuals in the ATY resulting in  
20 no changes between the TY and the ATY.

21 **Q34. Please explain line 55, ISO NE IEP.**

1   **A34.**   ISO-NE has established a new, interim winter fuel security program called the  
2   Inventoried Energy Program (IEP). The program will run for the 2023/2034 and  
3   2024/2025 winters and will compensate generating resources for keeping three days'  
4   worth of fuel supply onsite. The program is anticipated to cost approximately  
5   \$170,000,000 each winter. These costs will be distributed to the load serving entities  
6   within ISO NE based on their share of load (MWh) each month. The program was active  
7   during December, January, and February of the TY. I have projected VEC's share of IEP  
8   related costs in the ATY by including TY actuals for January and February. These  
9   assumptions result in a decrease in the ATY of \$92,094 as compared to the TY.

10   **Q35.   Please explain your assumptions regarding Renewable Energy Certificates**  
11   **(RECs).**

12   **A35.**   For the ATY, in line 72 of Schedule 2, I project that revenues for renewable  
13   energy credits will decrease by \$501,468 compared to the TY due to changes in MWh  
14   volumes assumed from contracts that include RECs, changes in REC prices from the TY  
15   to the ATY, and the fact that I do not have the same sale of CES-E attributes modeled in  
16   the ATY. I explain each of these changes below.

17           I have assumed VEC will have entitlement to approximately 115,206 MWh of  
18   high-valued RECs (see the table below) that it can use to meet its RES requirements, to  
19   bank to meet future RES requirements, or to sell in order to reduce costs to our  
20   members. I have also assumed that VEC's Tier II requirement for 2025 will be 26,424  
21   MWh, and that 22,401 MWh will be met through net-metering, leaving a difference of

1 111,183 MWh of high-value RECs.

| Project/Source         | Projected ATY RECs (MWh) |
|------------------------|--------------------------|
| First Wind (Sheffield) | 8,013                    |
| NY Wind Project        | 41,832                   |
| Kingdom Community Wind | 19,841                   |
| Standard Offer         | 20,720                   |
| Ryegate                | 12,020                   |
| Alburgh                | 1,289                    |
| Magee Hill             | 1,525                    |
| Grand Isle             | 6,420                    |
| Jericho Gravel Pit     | 2,189                    |
| Jericho Landfill       | 1,357                    |
| Total                  | 115,206                  |

2

3 VEC has already contracted to sell 75,000 of these high value RECs, as shown in

4 the table below:

| REC Type | RECs Sold | Price (\$/REC) | Total Revenue |
|----------|-----------|----------------|---------------|
| MA I     | 10,000    | \$39.25        | \$392,500     |
| MA I     | 20,000    | \$38.20        | \$764,000     |
| RI I     | 10,000    | \$34.25        | \$342,500     |

|       |        |  |             |
|-------|--------|--|-------------|
| Total | 40,000 |  | \$1,499,000 |
|-------|--------|--|-------------|

1

2           This leaves approximately 75,206 high-value RECs yet to be sold. VEC typically  
3 retains some RECs until the end of the annual trading period in case its renewable  
4 resources produce less than expected. However, for purposes of the rate filing I have  
5 assumed these RECs will be sold at the end of the annual trading period. I have  
6 assumed a sales price of \$39.00 for the MA and CT Class I RECs. These revenues and  
7 committed sales outlined in the table above result in net revenues of \$4,227,298, a  
8 decrease of \$501,468. The decrease in revenues of \$501,468 is the net impact of two  
9 main factors:

- 10           1) The removal of the larger CES-E sale that occurred in the TY (explained in  
11           Q&A #37) and  
12           2) The fact that RECs in the ATY are assumed to be sold at higher prices than in  
13           the TY (several of the contracts covering the TY were entered in the years  
14           leading up to the TY when prices were lower than they are now).

15   **Q36. Please explain Line 56, VT Tier 1 REC Purchase.**

16   **A36.** In the TY after the sale of high-value Tier 1 RECs, VEC purchased additional low-  
17 value Tier 1 RECs. The total amount shown in line 56, \$902,247, includes some  
18 attributes that were purchased in Q3 & Q4 of 2023 as well as purchases made in 2024.  
19 The purchases included in this line item during the TY span multiple calendar years,  
20 which is the time-frame for REC settlements and RES compliance. Therefore, the

1 amount shown in this line includes RECs for both 2023 and 2024 RES compliance years.

2 In addition to its contractual entitlements to Tier 1 RECs, VEC anticipates needing to  
3 purchase approximately 191,157 additional Tier 1 RECs in the ATY to meet Tier 1 RES  
4 requirements and VEC's carbon free goals at a total price of \$716,837. This projected  
5 purchase results in a decrease of \$185,410 in the ATY.

6 **Q37. Please explain CES-E Purchases included in line 57.**

7 **A37.** During the TY, VEC entered a contract to sell 75,000 CES-E attributes resulting  
8 from its contract with NextEra for Seabrook output. However, only the first 2,500,000  
9 MWh generated by the Seabrook station qualify as CES-E attributes. Given this, VEC's  
10 share of those attributes did not cover the forward contract sale and VEC needed to  
11 purchase additional CES-E attributes. This line item represents the costs associated with  
12 those attribute purchases. The revenue from this sale was booked in the TY as part of  
13 the REC revenue discussed above and shown in line 72. During the ATY, I have assumed  
14 that VEC sells all 10,000 of its entitlement of CES-E attributes. This sale is included in the  
15 projected REC revenue in the ATY, also shown on line 72.

16 **Q38. Does this conclude your testimony?**

17 **A38.** Yes, it does.