

**STATE OF VERMONT
PUBLIC UTILITY COMMISSION**

Case No. 26-1130-TF

Petition of Town of Stowe Electric Department pursuant to 30 V.S.A. §§ 225 and 227(a) for a 14.6% rate increase to take effect on a service-rendered basis August 1, 2026	
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**PREFILED DIRECT TESTIMONY OF
MICHELLE COSCIA**

**ON BEHALF OF
THE TOWN OF STOWE ELECTRIC DEPARTMENT**

June 7, 2026

Summary of Testimony

The testimony of Ms. Coscia in support of the Town of Stowe Electric Department's Rate Increase request and explains the level of power costs included in the revenue requirement.

1 **Q1. Please state your name, position, and business address.**

2 A1. My name is Michelle Coscia. I am the Market Operations Manager at Energy New
3 England (“ENE”), LLC, a Massachusetts-based municipal electric and energy services
4 cooperative that serves public power utilities throughout New England. Established in
5 1998 to help public power entities stay competitive and efficient, ENE is the leading
6 wholesale risk management and energy trading organization for municipal utilities in the
7 Northeast. Our offices are located at 5 Hampshire Street, Suite 100, Mansfield,
8 Massachusetts 02048.

9
10 **Q2. Please provide a summary of your background and experience.**

11 A2. I hold a Bachelor of Science in Business Administration, with a minor in Economics,
12 from Saint Michael’s College, and a Master of Business Administration from Aspen
13 University. I began my career at Vermont Public Power Supply Authority as an Energy
14 Analyst. In 2009, I joined Energy New England, where I currently serve as Manager,
15 Market Operations. In this role, my responsibilities include ISO New England and
16 counterparty invoice reconciliation, budgeting and forecasting of power portfolios, and
17 load data analysis. My resume is attached for additional detail. Exhibit SED-MC-1.

18
19 **Q3. Have you previously testified before the Public Utility Commission (“Commission”
20 or “PUC”)?**

21 A3. Yes, I’ve previously testified before in various rate cases before the PUC.

22

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

2 A4. The purpose of my testimony is to present Stowe Electric Department's (SED) power
3 supply and transmission costs and cost of Vermont Renewable Energy Standard (RES)
4 compliance for the upcoming Rate Year in support of the requested rate increase. My
5 testimony will demonstrate that this increase is necessary due to rising power costs across
6 the ISO-New England market.

7

8 **Q5. Please summarize Stowe Electric Department's ("Stowe" or "SED") power supply
9 costs, as included in the revenue requirement.**

10 A5. As reflected in Exhibit SED-MC-2, total costs for SED during the Test Year were
11 \$11,511,339. After incorporating known and measurable adjustments, total costs are
12 projected to be \$13,852,871 in the Rate Year, representing an increase of \$2,341,532, or
13 20.3%, relative to the Test Year. With respect to snowmaking passthrough costs, the Test
14 Year amount was (\$1,253,655), while the Rate Year passthrough is projected at
15 (\$1,770,463). This reflects an increase in passthrough costs of \$516,808. After
16 accounting for these passthrough amounts, the net SED power cost for the Test Year was
17 \$10,257,684. The corresponding net power cost for the Rate Year is projected to be
18 \$12,082,408, which represents an increase of \$1,824,724, or 17.8%.

19

20 **Q6. Can you provide an overview of what is causing the increase?**

21 A6. Capacity and fixed cost category increased by \$100,506, due to McNeil Generating
22 Station's 2026 budget for fixed costs.

1 As reflected in Exhibit SED-MC-2, REC credits decreased by \$68,300, while Resource
2 REC purchases increased by \$202,635. The snowmaking passthrough REC component
3 reduces total SED RES costs by (\$24,529).
4

5 After incorporating these changes, the net SED RES REC cost is projected to increase by
6 \$270,935 in the Rate Year compared to the Test Year. Energy market costs are projected
7 to rise by \$1,136,826, reflecting an increase in forward energy prices compared to Test
8 Year actuals. The snowmaking passthrough energy component, totaling (\$1,262,886),
9 offsets a portion of this increase, resulting in a net energy cost increase of \$574,576.
10

11 Open Access Transmission Tariff (“OATT”) costs are increasing by \$909,982 due to
12 higher transmission rates. In addition, the VTA Common Facilities charge contributes to
13 an incremental increase of \$122,902. These transmission-related increases are partially
14 offset by the snowmaking passthrough of \$369,581.
15

16 **Q7. Are there any known and measurable changes that are reducing SED’s power**
17 **supply costs during the Rate Year?**

18 A7. Yes, Stony Brook Resource from the test year compared to the rate year has decreased by
19 \$173,945. The Stony budget is supplied by Massachusetts Municipal Wholesale Electric
20 Company.
21

1 **Q8. Please summarize the impact that Rate Year resource adjustments have on power**
2 **supply costs.**

3 A8. Please refer to column O of Exhibit SED-MC-2. In total, resource adjustments increased
4 power supply costs by \$ 2,341,532 As shown in Exhibit SED-MC-2, after accounting
5 for the snowmaking passthrough credit, the net impact of SED's resource adjustments is
6 an increase to power supply costs of \$1,8724,724 in the Rate Year compared to the Test
7 Year.

8
9 **Q9. What are the adjustments that apply to most of SED's Power Supply Resources,**
10 **Energy Rates, and Volume.**

11 A9. The adjustments that are made to forward energy prices have an impact on almost every
12 resource due to the changes in energy credit value. The energy rates reflected in the rate
13 year are based on the following assumptions and supporting exhibits. The resource
14 outputs and energy volumes reflected in the Rate Year have been developed using
15 historical data, contractual obligations, and known and measurable information, as
16 described below:

17
18 **1. Energy Rate Adjustments**

19 The New York Power Authority ("NYPA") energy rate is derived from Exhibit SED-
20 MC-3, which outlines NYPA's power rate plan. This plan includes an increased energy
21 rate of \$5.76 per MWh, as incorporated into the Rate Year. Capacity, transmission, and
22 output were held constant at Test Year levels.

1 The Ryegate energy rate is calculated by averaging the historical Ryegate energy costs
2 over the period from January 2024 through February 2026, as shown in Exhibit SED-
3 MC-4.

4
5 The Hydro-Québec PPA energy rate for the period March 2026 - October 2026 reflects
6 the current contract rate of \$73.87 per MWh. For the period from November 2026
7 through February 2027, the rate is escalated by 3%. This escalation is based on average
8 GDP percentage changes from 2025, as shown in Exhibit SED-MC-5.

9
10 The McNeil Plant's energy and fixed cost rate are based on the 2026 budget prepared by
11 Vermont Public Power Supply Authority, as shown in Exhibit SED-MC-6.

12
13 The Stony Intermediate Project's energy, fixed, and transmission rates are based on
14 budget information provided by MMWEC. Rates for the period from March 2026
15 through June 2026 reflect the budget posted on March 26, 2025 (Exhibit SED-MC-7),
16 while rates for July 2026 through February 2027 reflect the budget posted on March 25,
17 2026. *See* Exhibit SED-MC-8.

18
19 The Seabrook (NextEra) energy rate for March 2026 through May 2026 reflects the
20 current rate of \$63.10 per MWh. For the period from June 2026 through February 2027,
21 the rate includes an additional 3.776% adder. The capacity component was also adjusted

1 by the same adder. This adder represents the average contract year percentage changes
2 from June 2021 through May 2026, as detailed in Exhibit SED-MC-9.

3
4 The energy rates for Miller Hydro, Saddleback Ridge, and Great River are established
5 pursuant to their respective power purchase agreements and are applied as contractually
6 defined.

7
8 The snowmaking energy rate is, a load-following rate developed using a forward
9 energy curve (as of May 18, 2026) in conjunction with a historical snowmaking load-
10 following premium. This cost is treated as a direct passthrough and is billed through to the
11 Mountain invoices. Load for the Mountain was held constant at Test Year levels.

12
13 The open position, defined as ISO Energy Net Interchange, is priced based on the
14 on-peak and off-peak forward curve rates (as of May 18,2026) as shown in Exhibit SED-
15 MC-10.

16
17 **2. Energy Volume Adjustments**

18 Ryegate output is based on the average monthly capacity factors from 2015 to February
19 2026 as shown in Exhibit SED-MC-4.

20
21 McNeil output is based on the average monthly capacity factors from 2023 to February
22 2026 as shown in Exhibit SED-MC-11.

1 Stony Intermediate energy volume is derived from budget information provided by
2 MMWEC. Rates for the period from March 2026 through June 2026 reflect the budget
3 posted on March 26, 2025 (Exhibit SED-MC-7), while rates for July 2026 through
4 February 2027 reflect the budget posted on March 25, 2026, as shown in Exhibit SED-
5 MC-8.

6
7 Seabrook energy is based on the applicable power purchase agreements and is applied in
8 accordance with contractual terms. The primary variance occurs in April 2026, during
9 which Seabrook is scheduled for an outage, therefore, SED will not receive energy.

10
11 Cabot/Turners generation is based on the average monthly capacity factors from 2021
12 through September 2025 as shown in Exhibit SED-MC-13 and Exhibit SED-MC-14.

13
14 Miller generation was set to the average monthly capacity factors from 2018 through
15 August 2025 as documented in the following Exhibit (Exhibit SED-MC-15).

16
17 Saddleback generation was set to the average monthly capacity factors from 2018
18 through August 2025 as shown in Exhibit SED-MC-12.

19
20 Great River generation was set to the average monthly capacity factors for Great River B
21 (assets Moore 1, Moore 2, Moore 3, and Moore 4) from 2023 through September 2025 as

1 shown in Exhibit SED-MC-17. Great River A (asset Moore 5) is from 2024 through
2 September 2025 as shown in Exhibit SED-MC-16.

3
4 Shell Bilateral volumes are based on the applicable power purchase agreements and are
5 applied in accordance with contractual terms.

6
7 Open Market ISO Adjusted Net Interchange volumes are calculated as the actual Test
8 Year monthly totals less the MWh attributed to each resource in the Rate Year.

9
10 ISO ancillary costs comprising, NCPC, Regulation, Participant Expenses, Auction
11 Revenue Rights, GIS, and Other Load Settlement were held constant at Test Year levels.
12 The only adjustment made was to remove the resettlement credits associated with Mystic
13 and the Inventoried Energy Program, as these items are non-recurring and will not be
14 realized in the Rate Year.

15
16 The new ISO ancillary component, Day-Ahead Ancillary Services (“DAAS”), was
17 modeled using actual test year costs as the baseline. From that baseline, the monthly rates
18 were reduced by 30 percent to reflect the ISO Market Committee’s estimated Scenario 2
19 cost impact. The proposed adjustments to the Forecast Energy Requirements (“FER”),
20 Net Peak Forecast (“NPF”), and strike price collectively reduce the estimated costs from
21 first-year actuals by approximately \$292 million, or 30 percent, as shown in Exhibit
22 SED-MC-26.

1 **Q10. Please summarize the adjustments to capacity market costs.**

2 A10. ISO- New England Capacity costs (includes all resource capacity components) are to
3 increase to \$100,506. The associated charges and credits are calculated by subtracting
4 known self-supplied capacity from SED's ISO-NE peak load obligations, established on
5 July 16, 2024, Hour Ending 18 for Forward Capacity Market ("FCM") 16, and on June
6 24, 2025, Hour Ending 19 for FCM 17. The resulting megawatt obligation is then
7 multiplied by the applicable Forward Capacity Market cost allocation rates established by
8 ISO-NE for the Northern New England capacity zone. The FCM 16 rates are documented
9 in SED-MC-Exhibit 18, and the FCM 17 rates are shown in SED-MC-Exhibit 19.

10

11 SED's capacity market positions.

12 For FCM 16: The peak for FCM 16 was set on 7/16/2024 HE 18:

13 $12.952 \text{ MW} + 31.30\% \text{ (Reserve Margin)} = 17.006 \text{ MW} = \text{Cost of } 27,531/\text{month}$

14

15 For FCM 17: The peak for FCM 17 was set on 6/24/2025 HE 19:

16 $12.6958 \text{ MW} + 21.87\% \text{ (Reserve Margin)} = 15.792 \text{ MW} = \text{Cost of } 24,295 /\text{month}$

17

18 As reflected in Exhibit SED-MC-2, the snowmaking passthrough credit for the Test Year
19 was (\$63,840), compared to (\$62,346) in the Rate Year.

20

21 After accounting for this change, the net SED capacity cost reflects an overall increase of
22 approximately \$102,000 in the Rate Year relative to the Test Year.

1 **Q11. Please summarize the impact that Rate Year Transmission Adjustments have on**
 2 **power supply costs.**

3 A11. There are two adjustments reflected in transmission costs. The first adjustment is
 4 attributable to higher Schedule 9 rates for Regional Network Service (“RNS”) under the
 5 NEPOOL Open Access Transmission Tariff (“OATT”). The second adjustment reflects
 6 changes to the VELCO 1991 VTA Common Facilities charge.

7

8 **Q12. Please summarize the adjustments to the NEPOOL Open Access Transmission**
 9 **Tariff OATT charges.**

10 A12. The peaks used in this rate case are based on the monthly Test Year peak loads. Below is
 11 a comparison of the average four-year peaks to the Rate Year peaks. The RNS rate for
 12 calendar year 2026 under Schedule 9 was established on July 15, 2025, as documented in
 13 Exhibit SED-MC-20, at \$15.31 per MW-month. The Schedule 9 rate for calendar year
 14 2027 is set at \$16.42 per MW-month which is based on a forecast presented at the
 15 NEPOOL Reliability Committee/Transmission Committee Summer Meeting on August
 16 13, 2024, as documented in Exhibit SED-MC-21.

Customer SED - Stowe								
Average o Year								
month	2022	2023	2024	2025	2026	AVG 4 Years	Rate Year Pks	Difference
1	13,913	15,805	15,258	16,715	16,121	15,975	16,121	146
2	13,280	13,667	12,944	13,728	14,174	13,628	14,174	546
3	11,444	10,747	12,694	11,124	11,597	11,541	11,124	(417)
4	8,422	8,892	9,395	9,234	9,661	9,296	9,234	(62)
5	8,637	9,157	9,032	8,667		8,873	8,667	(206)
6	10,937	9,849	12,418	12,445		11,412	12,445	1,033
7	11,351	12,151	12,952	12,040		12,124	12,040	(84)
8	11,814	10,453	13,319	13,442		12,257	13,442	1,185
9	9,774	10,820	10,059	9,366		10,005	9,366	(639)
10	8,492	10,280	9,778	9,411		9,490	9,411	(79)
11	15,444	15,387	18,350	18,299		16,870	18,301	1,431
12	18,368	16,261	18,293	18,615		17,884	18,615	731
AVG	11,823	11,956	12,874	12,757	12,888	12,446	12,745	299

17

1 The transmission-related charges reflected in this filing include the following
 2 components. Schedule 1 RNS is applied at a rate of \$0.19 per MW-month, as
 3 documented in Exhibit SED-MC-22. The Transmission Out (“TOUT”) charge is applied
 4 at a rate of \$0.002 per MW-month, also as documented in Exhibit SED-MC-22. Schedule
 5 2 VAR is applied at a rate of \$0.09 per MW-month, as shown in Exhibit SED-MC-23.
 6 Additionally, the Interconnection Reliability Operating Limit (“IROL”) and Blackstart
 7 charges are based on Test Year actual costs.

ISO OATT	Jan-27	Feb-27	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26
Peak RNS	16.121	14.174	11.124	9.234	8.687	12.445	12.040	13.442	9.366	9.411	18.301	18.615
RNS Rate 9	\$ 16.42	\$ 16.42	\$ 15.31	\$ 15.31	\$ 15.31	\$ 15.31	\$ 15.31	\$ 15.31	\$ 15.31	\$ 15.31	\$ 15.31	\$ 15.31
Schedule 1 RNS	\$ 0.19	\$ 0.19	\$ 0.19	\$ 0.19	\$ 0.19	\$ 0.19	\$ 0.19	\$ 0.19	\$ 0.19	\$ 0.19	\$ 0.19	\$ 0.19
Tout	\$ 0.002	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00	\$ 0.00
Schedule 2 Var	\$ 0.09	\$ 0.09	\$ 0.09	\$ 0.09	\$ 0.09	\$ 0.09	\$ 0.09	\$ 0.09	\$ 0.09	\$ 0.09	\$ 0.09	\$ 0.09
IROL	\$ 2.97	\$ 6.10	\$ 7.03	\$ 8.08	\$ 9.07	\$ 4.96	\$ 5.23	\$ 5.66	\$ 5.16	\$ 5.60	\$ 6.74	\$ 5.77
BlackStart	\$ 0.19	\$ -	\$ 0.20	\$ 0.25	\$ 0.27	\$ 0.14	\$ 0.15	\$ 0.17	\$ 0.22	\$ 0.23	\$ 0.24	\$ 0.20
Estimate Trans \$/kw-mo	\$ 19.848	\$ 22.799	\$ 22.816	\$ 23.919	\$ 24.930	\$ 20.686	\$ 20.962	\$ 21.424	\$ 20.974	\$ 21.419	\$ 22.585	\$ 21.564
NET Trans Cost	\$ 319,973	\$ 323,150	\$ 253,805	\$ 220,867	\$ 216,071	\$ 257,557	\$ 252,378	\$ 287,975	\$ 196,446	\$ 201,573	\$ 412,983	\$ 401,416

8
9
10 **Q13. Please summarize the adjustments to the VTA Common Facilities charges.**

11 A13. The VTA charges are shown in Exhibit SED-MC-22 for SED’s Rate Year. VELCO
 12 provides an annual revenue forecast as well as the monthly allocation percentage for each
 13 utility. The VELCO 91 is a combination of the VTA 91 Common Revenue and the VTA
 14 91 Resettlement related to Return on Equity (ROE) Refund. The VTA increased
 15 \$122,902 or 13.7% over the test year. Major VELCO categories that are increasing the
 16 charges are: additions to the Plant (K42 rebuild, Fiber, Upgrades and Reliability), and
 17 plant depreciation and property taxes. To fund the capital expenditures there will be long
 18 term debt issued. The ’91 VTA charges assume VELCO will receive FERC approval to
 19 establish a Regulatory Asset for the ROE Refund.

1 **Q14. Please explain SED's RES costs during the Test Year.**

2 A14. SED Test Year had RES revenue of \$602,566. This was from REC arbitrage selling Class
3 I RECs and buying ME Class II's to cover Tier I obligations. SED sold RECs from
4 Ryegate, McNeil, Miller Hydro, Saddleback, and Great River (Moore #5). SED
5 purchased Tier I RECs for a cost of \$57,281.

6
7 **Q15. Please explain the known and measurable adjustments to SED's RES costs.**

8 A15. REC activity in the Rate Year results in a net increase in power costs. REC sales are
9 expected to decrease by \$68,300, while REC purchases are expected to increase by
10 \$202,635, which is a total net power cost increase of \$270,935. These changes are
11 primarily driven by recent statutory changes to the treatment of load which created a
12 difference between the obligation of load and retail sales. There have also been changes
13 in the value and qualification of resources. Beginning in the fourth quarter of 2025, SED
14 will sell McNeil generation as ME Class I RECs. In addition, starting in calendar year
15 2027, SED will bank Moore #5 generation for future use, with such volumes intended to
16 support Tier IV compliance beginning in 2030.

17
18 The increase in Tier II requirements from 10% by 2032 to 20% by 2032/2035 has
19 increased SED's need to procure Tier II RECs. RECs from Standard Offer (based on Test
20 Year), Net Metering and Nebraska (as documented in Exhibit SED-MC-25 Test Year)
21 will not fully satisfy SED's compliance requirement in the Rate Year, necessitating
22 additional market purchases. in the Rate year. SED's estimated Tier I Renewable Energy

1 Certificate (“REC”) costs are derived from Maine Class II market pricing, while Tier II
2 REC costs are based on Massachusetts Class I pricing. The REC sales associated with the
3 McNeil facility are valued using Maine Class I rates, consistent with the broker sheet
4 pricing presented in Exhibit SED-MC-24.

5
6 **Q16. Please summarize the Rate Year Power Supply Line Items Not Adjusted.**

7 A16. No adjustments were proposed for certain power supply components due to timing
8 constraints, as the associated costs are uncertain and not known and measurable at this
9 time. These components include Nebraska Valley Solar, the Standard Offer Program,
10 VELCO Administrative Fees, the Stowe Substation, and VELCO Phase I Transmission.

11
12 **Q17. Snowmaking Passthrough Charges**

13 A17. Portions of SED’s power costs are directly passed through to Stowe Mountain Resort
14 under the Interruptible Load Tariff pursuant to which the resort is billed. The
15 snowmaking-related power cost passthrough applies during the months of January
16 through April and October through December.

17
18 The passthrough consists of five components: (1) Energy (Load follow) with Ancillaries,
19 (2) VELCO 91 percent share based on Test Year, (3) ISO OATT percent share based on
20 Test Year, (3) Capacity (Peak based on Test Year), and (5) Renewable Energy Standard
21 costs based on applicable load percentages.

22

1 In the Test Year, the total passthrough amount was \$1,253,655. In the Rate Year, the
2 passthrough is projected to increase to \$1,770,463, resulting in an increase in cost to the
3 Mountain of \$516,808 (SED Revenue). The Snowmaking Tariff change will now include
4 a passthrough component for ISO Ancillary costs, whereas the Test Year energy only
5 included the load following agreement.
6

7 **Q18. Please summarize the adjustments to energy market costs**

8 A18. Please refer to Exhibit SED-MC-2, (line 26. The cost of energy in the Rate Year at the
9 Vermont Zone totals \$112.68/MWH. This is an increase of \$23.98/MWH compared to
10 the Test Year. This is a result of the adjustment to energy market prices which is
11 calculated using broker prices between the middle of December 2025 and early March
12 2026. The rate is the Energy Net Interchange divided by the open MWH total.
13

14 **Q19. Please explain the Day Ahead Ancillary Services costs and revenues.**

15 A19. The DAAS market is a new market in ISO that began March 1, 2025. This market
16 replaced the Forward Reserve Market, while maintaining all existing reserve products
17 and adding the new Energy Imbalance Reserve (“EIR”).
18

19 The EIR is the difference between the ISO forecasted load and the cleared day ahead
20 energy. If the cleared day ahead energy is less than the forecasted load, then that
21 difference clears in the DAAS market as EIR. The price at which EIR clears, the Forecast
22 Energy Requirement (“FER”) price, is then applied to all resources that clear in the Day

1 Ahead (“DA”) market as well. The cost of all DAAS products is applied to load based on
 2 the Real Time Load Obligation (“RTLO”). FER and EIR will increase costs for all load
 3 serving entities, which includes SED. SED’s resources that participate in DAAS are
 4 Stony Brook 1A, 1B, 1C and McNeil. SED’s resources that received FER benefits are
 5 McNeil, Miller Hydro, Ryegate, Saddleback and the three Stony Brook units.

6
 7 To calculate the cost to SED, the monthly rate in dollars per MWh for March 2025 –
 8 February 2026 is applied to the corresponding monthly ISO settlement load in the Rate
 9 Year. The DAAS market decreases SED’s costs by \$204,423 from test year due to the
 10 ISO restructuring the strike price floor. The breakdown per resource load that is included
 11 in the DAAS market rate is as such:

	Jan-27	Feb-27	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26
ISO Charges	Jan-26	Feb-26	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
Day-Ahead Ancillary Services	\$ 17.44	\$ 4.46	\$ 2.11	\$ 1.78	\$ 1.32	\$ 1.58	\$ 2.24	\$ 2.27	\$ 1.27	\$ 5.35	\$ 6.58	\$ 9.47
Load	\$ 38,698	\$ 11,303	\$ 3,608	\$ 3,459	\$ 2,341	\$ 4,062	\$ 6,022	\$ 5,494	\$ 2,747	\$ 8,675	\$ 10,062	\$ 16,534
J C MCNEIL	\$ (3,576)	\$ (1,223)	\$ (0,257)	\$ (0,031)	\$ (0,124)	\$ (0,615)	\$ (0,779)	\$ (0,646)	\$ (0,326)	\$ -	\$ (0,204)	\$ (1,085)
Miller Hydro	\$ (0,445)	\$ (0,091)	\$ (0,046)	\$ (0,059)	\$ (0,044)	\$ (0,036)	\$ (0,027)	\$ (0,020)	\$ (0,015)	\$ (0,050)	\$ (0,052)	\$ (0,073)
RYEGATE 1-NEW	\$ (0,718)	\$ (0,240)	\$ (0,106)	\$ (0,104)	\$ (0,095)	\$ (0,130)	\$ (0,104)	\$ (0,115)	\$ (0,057)	\$ (0,205)	\$ (0,201)	\$ (0,288)
SADDLEBACK RIDGE WIND	\$ (0,549)	\$ (0,245)	\$ (0,099)	\$ (0,140)	\$ (0,067)	\$ (0,067)	\$ (0,068)	\$ (0,041)	\$ (0,042)	\$ (0,240)	\$ (0,207)	\$ (0,313)
STONY BROOK GT1A	\$ (8,495)	\$ (3,137)	\$ (0,086)	\$ (0,588)	\$ (0,130)	\$ (0,960)	\$ (2,008)	\$ (1,435)	\$ (0,485)	\$ (0,534)	\$ -	\$ (1,241)

12
 13 **Q20. Does this conclude your testimony?**

14 **A20. Yes**

EXHIBIT LIST

Exhibit SED-MC-1	Michelle Coscia's Resume
Exhibit SED-MC-2	Test Year Power Costs & Rate Year Adjustments
Exhibit SED-MC-3	New York Power Authority's power plan
Exhibit SED-MC-4	Ryegate's historic output and average energy rate
Exhibit SED-MC-5	Hydro- Quebec Energy Rate adjustment
Exhibit SED-MC-6	VPPSA's McNeil 2026 Budget
Exhibit SED-MC-7	MMWEC's Stony Intermediate budget
Exhibit SED-MC-8	MMWEC's Stony Intermediate budget
Exhibit SED-MC-9	NextEra Seabrook Rate adjustment
Exhibit SED-MC-10	Forward Curve
Exhibit SED-MC-11	McNeil Historical Generation and Capacity Factors
Exhibit SED-MC-12	Saddleback Historical Generation and Capacity Factors
Exhibit SED-MC-13	Cabot Historical Generation and Capacity Factors
Exhibit SED-MC-14	Cabot Historical Generation and Capacity Factors
Exhibit SED-MC-15	Miller Hydro Historical Generation and Capacity Factors
Exhibit SED-MC-16	Moore 5 Historical Generation and Capacity Factors

Exhibit SED-MC-17	Moore 1 through Moore 5 Historical Generation and Capacity Factors
Exhibit SED-MC-18	FCM Cost allocation rate FCM 16
Exhibit SED-MC-19	FCM Cost allocation rate FCM 17
Exhibit SED-MC-20	Regional Network Service Rate Year 2026
Exhibit SED-MC-21	Regional Network Service Rate Year 2027
Exhibit SED-MC-22	VELCO 91 Forecast
Exhibit SED-MC-23	ISO OATT Rates
Exhibit SED-MC-24	Broker REC Sheet
Exhibit SED-MC-25	Historical Nebraska and Net Metering RECs
Exhibit SED-MC-26	DASI ISO rate changes (-30%)

DECLARATION OF MICHELLE COSCIA

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

June 7, 2026
Date

Michelle Coscia
Michelle Coscia,
Market Operations Manager
Energy New England (“ENE”)