3 Orchestrate Distributed Renewable Energy

3.1 Introduction

There are many factors that influence VEC's power supply management strategies, including the timing and volume of energy consumed by the membership, statewide renewable energy mandates, and the relative cost of various power supply products and services available in the region.

VEC's power supply analysis begins with an assessment of its needs. For 2024, VEC's retail sales were approximately 475,065 MWh, as measured at the members' meters; this number includes the impact of reduced sales due to net-metering. Accounting for line losses and VEC's own operational use, VEC had to purchase approximately 511,7600 MWh of electricity from various suppliers to meet its members' needs.

VEC's mission is to serve our Cooperative members with safe, reliable, sustainable and affordable energy services. With respect to Energy Supply, this mission requires meeting our members' energy needs in the most cost-effective manner possible given goals established by the Board of Directors, and adhering to the rules and decisions issued by the Public Utility Commission as well as the laws of the state of Vermont.

In February 2021, in support of the Cooperative doing its part to combat climate change and minimize its impact on the environment, the VEC Board of Directors passed a resolution directing VEC to:

- "…procure energy and/or environmental attributes from non-carbon emitting generating resources sufficient to cover 100% of VEC's annual energy requirement for each year."
- "…procure energy and/or environmental attributes from renewable resources sufficient to cover 100% of VEC's annual energy requirement for each year starting in 2030."

In response to the potential impacts of fossil fuel consumption on the environment, the state of Vermont has a Renewable Energy Standard (RES) that requires, in part, that utilities implement programs to convert fossil-fuel consuming end-uses to electric end-uses. These goals are established in Tier III of the RES. VEC expects to see noticeable load growth over the 20 years of the study horizon, mainly due to Electric Vehicle (EV) and Cold-Climate Heat Pump (CCHP) adoption by its members.

Under this backdrop, analyses in this section will:

- Review modeling assumptions in VEC's 2022 for load impacts of:
  - net metering projects
  - cold-climate heat pumps
  - electric vehicles

- Develop load forecast for 2026-2045 to project Tier I, Tier II and Tier IV requirements under the Vermont Renewable Energy Standard

- Perform Carbon Free, Tier I, Tier II and Tier IV analyses to:
  - Establish need assuming VEC's current resource mix
  - Identify potential options to serve shortfalls
  - Develop a 3-year Action Plan

- Analyze the value of renewable resource technology diversity.

3.1.1 Section Overview

<u>Forecast Overall Load Needs</u>

- Tier 1 and Tier 2 Analysis
- Member Energy and Capacity Needs
- Impact of Load on Peaks

<u>Existing Energy Makeup</u>

- Member Owned Generation
- ISONE Markets
- Power Purchase Agreements
- 100% Carbon Free

<u>100% Renewable on an Annual Basis by 2030</u>

- 100% Renewable – Energy and RECs from Existing Hydro
- 100% Renewable – Energy and RECs from Off Shore Wind
- 100% Renewable – New In-State Solar

<u>Explore 100% Renewable on an Hourly Basis</u>

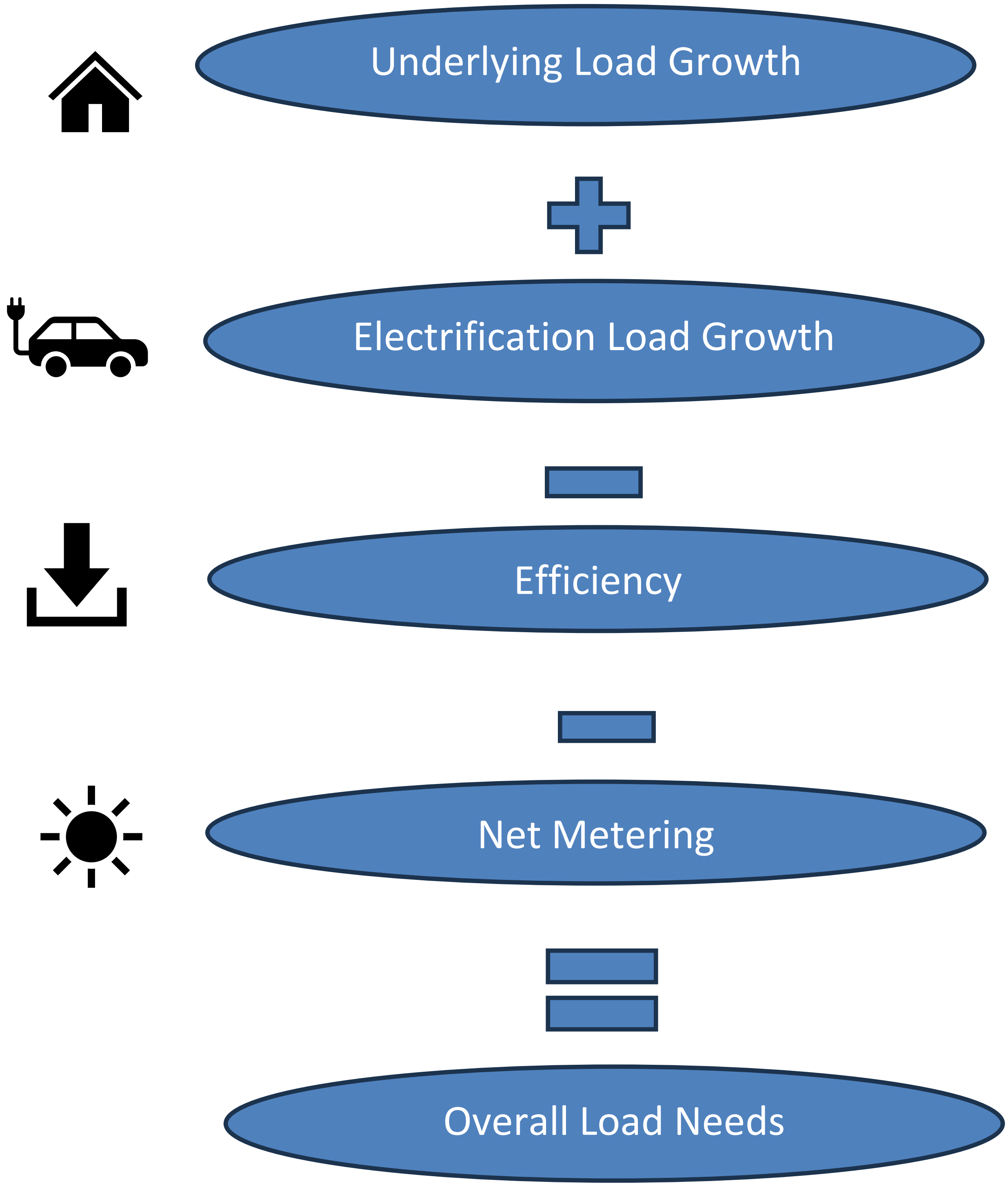
- Capacity factor analysis
- Costs of implementing renewables plus storage
- Takeaways

<u>Reduce Impacts of Distributed Generation on Infrastructure</u>

- Capacity factor analysis
- Costs of implementing renewables plus storage
- Takeaways

3.2 Forecast Overall Load Needs

3.2.1 Introduction of Energy Needs



One of the first challenges in managing a power supply portfolio is to develop a forecast of resource needs – which, on one hand, is necessary but, on the other hand is, by its nature, only an estimate of the future. VEC initially developed four individual forecasts which are then combined resulting in the final energy forecasts. It is important to note that these forecasts do not include potential impacts of federal legislation that was passed just prior to publication of this report reducing federal incentives which could potentially reduce efficiency, net metering, and electrification trends. Those four individual forecasts are:

- Underlying Load Forecast – this forecast was developed by establishing a trend-line based on actual system loads from 2014-2024, extending that trendline through 2045 and adding to that trendline 91% of the load from the newly installed Jay Peak boiler (because the Jay Peak boiler was in place for 1 of the 11 years used to develop the trendline). This is the load VEC projects prior to any impact from new Net Metering, Energy Efficiency and Tier III program activity on the system.
- New Energy Efficiency Forecast – this is forecasted load reduction resulting from VEC's estimated 9% of Efficiency Vermont's (EVT) projections for statewide efficiency measure installations for 2025-2043, and extrapolated through 2045.
- New Net Metering - forecasted load reduction from new net-metering to be installed on the VEC system – Base, High and Low forecasts were developed internally by VEC taking into consideration historic installations in VEC's territory and recent changes to Vermont's net metering laws.
- New Electrification Load - Load increase from electrification activity on the VEC system starting in 2025. Three forecasts were developed: one based on the number of Cold-Climate Heat Pumps (CCHP), All-Electric Vehicles (All-EV) and Plug-In Hybrid Electric Vehicles (PHEV) estimated to be needed in VEC's territory to meet Vermont's Climate Action Plan goals; a second based on 9% of the EVT's projections for CCHP installed statewide for 2025-2043 extrapolated through 2045 and the All-EV and PHEV assumed for 2025 developed by VEC with assistance from Pacific Northwest National Laboratory (PNNL); and a third based on VEC's estimated share of CCHPs and electric vehicles assumed in VELCO's 2023 Long-term Electric Energy and Demand Forecast Report.

  Each of these three electrification scenarios include a forecast for all other electrification programs based on recent installations for each individual end-use on the VEC system.

When combined, the four forecasts described above result in the following three final forecasts:

- Climate Action Plan Forecast: the Underlying Load Forecast, the New Efficiency Forecast, the Base Net Metering Forecast, *the Climate Action Plan CCHP Forecast*, *the Climate Action Plan EVs Forecast* and the All Other Tier III Programs Forecast;
- VEC Forecast: the Underlying Load Forecast, the New Efficiency Forecast, the Base Net Metering Forecast, *the EVT CCHP Forecast, the VEC Electric Vehicles Forecast* based on recent actual EVs purchased on the VEC system and an analysis done by PNNL, and the All Other Tier III Programs Forecast; and
- VELCO Forecast: the Underlying Load Forecast, the Efficiency Forecast, the Base Net Metering Forecast, *VEC' share of statewide CCHP and electric vehicles in its 2023 Long-Term Electric Energy and Demand Forecast Report* and the All Other Tier III Programs Forecast.

The two figures below show the resulting annual load forecasts for the three forecasts for the first 10 years of the study period and for the entire 20-year study period.

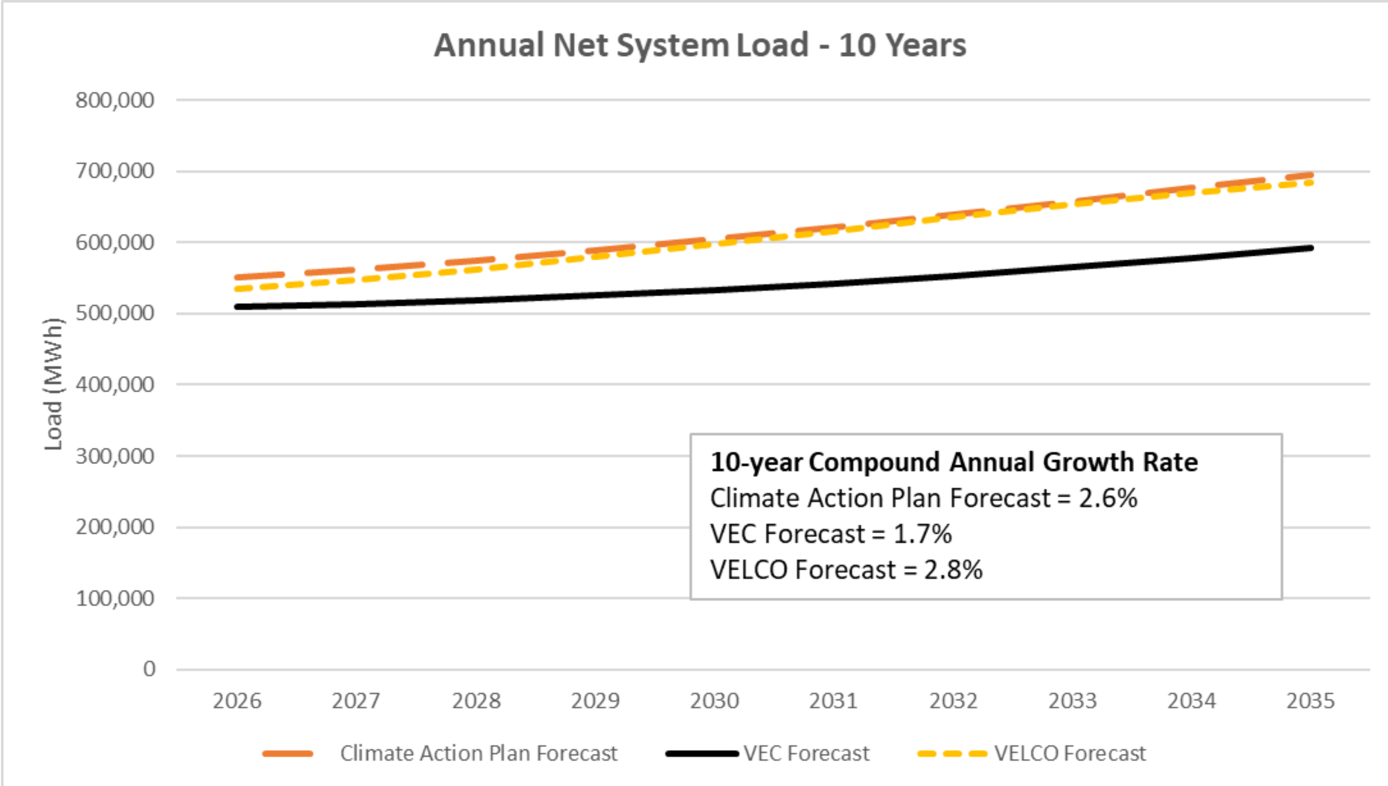


Figure 3.2.1.A - Net Load Forecast – 10 years

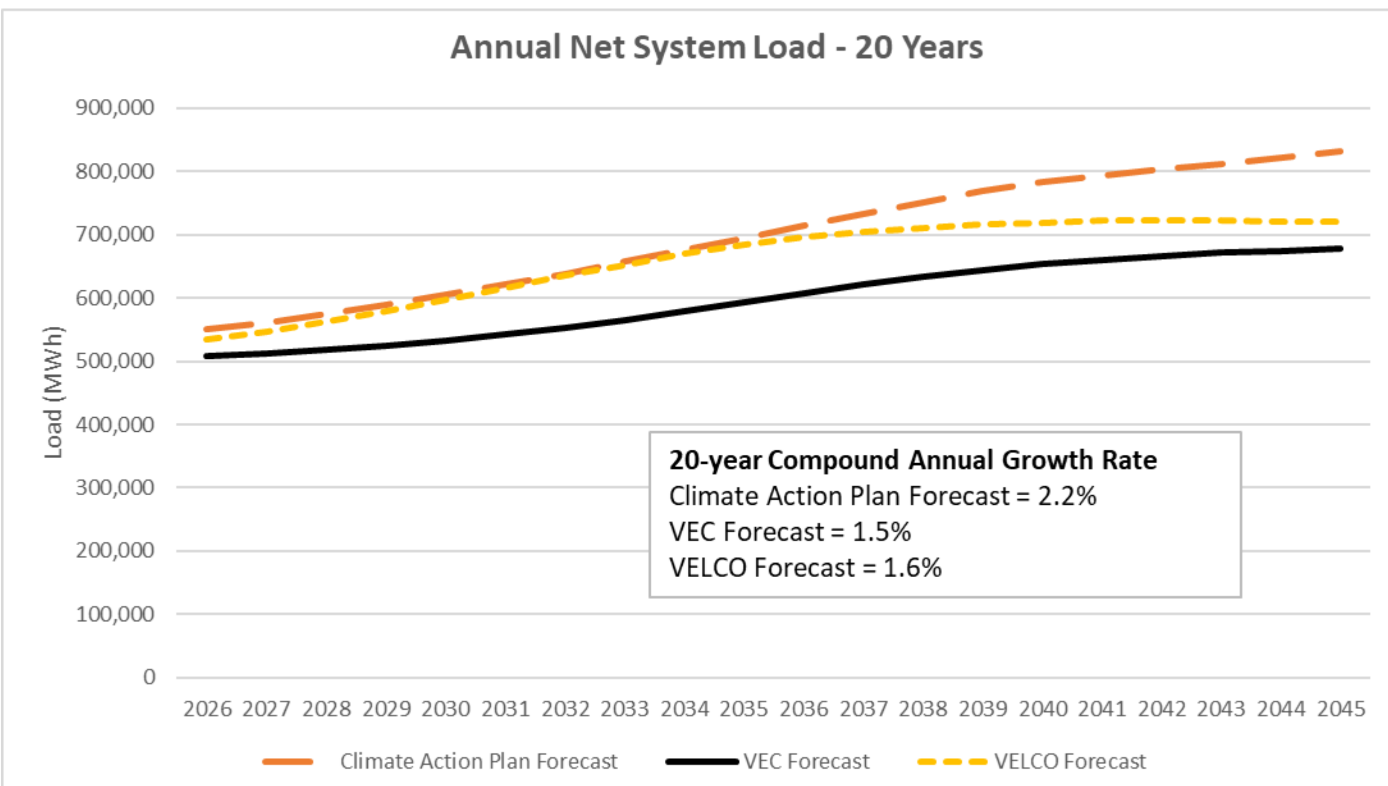


Figure 3.2.1.B - Net Load Forecast – 20 years

The data the plots are based on are shown in the table below.

Year	Climate Action Plan Forecast	VEC Forecast	VELCO Forecast
2026	551,119	509,047	534,404
2027	561,801	513,022	547,481
2028	574,238	518,348	562,334
2029	588,925	525,078	579,140
2030	604,371	533,254	597,537
2031	620,873	542,626	616,127
2032	638,688	553,259	634,675
2033	657,164	565,232	652,630
2034	676,251	578,445	669,824
2035	695,043	592,612	684,635
2036	713,975	606,943	696,153
2037	733,141	620,685	704,881
2038	751,528	633,250	711,331
2039	768,552	644,213	716,121
2040	782,588	653,338	719,621
2041	793,532	660,621	722,224
2042	803,177	666,547	723,087
2043	812,434	671,207	722,235
2044	821,737	674,974	721,107
2045	831,023	678,118	719,962

Table 3.2.1.C Net Load Forecasts

3.2.2 Underlying Load Forecast

VEC's load has been on a slight upward trend from 2014-2024. Growth from 2014-2019 was slight with loads being higher in years with more extreme cold and/or heat, and lower in years with more moderate temperatures.

During 2020 and 2021 VEC saw a significant increase in new construction in its service territory. VEC expects that much of this new construction drove the relatively high load in 2021 and will persist. In recognition of this; the fact that VEC's territory is still rural, thus minimal underlying load growth can return; a newly installed boiler at the Jay Peak Water Park that can operate on electric or propane, whichever is cheaper; and the belief that future loads will be impacted more by the rate of adoption of CCHPs, Electric Vehicles, Net Metering and other Beneficial Electrification, the underlying load forecast Pre-New Net Metering, Efficiency and Tier III Program Impact Forecast was established by calculating a trendline from 2014-2024 in Microsoft Excel and adding 91% of the load of the Jay Peak Boiler in 2024 (to recognize that the boiler was in operation for 1 of the 11 years of the trendline calculation), the equation for the Underlying Load Forecast is :

$$\text{Annual Load} = 473{,}410 + 2{,}369.2X + 91\% * \text{Jay Peak Boiler Load in 2024}$$

Where:

X = Year Value – 2013

Jay Peak Boiler Load in 2024 = 4,118.25 MWh

The results are graphically and in tabular form in the figure and table below.

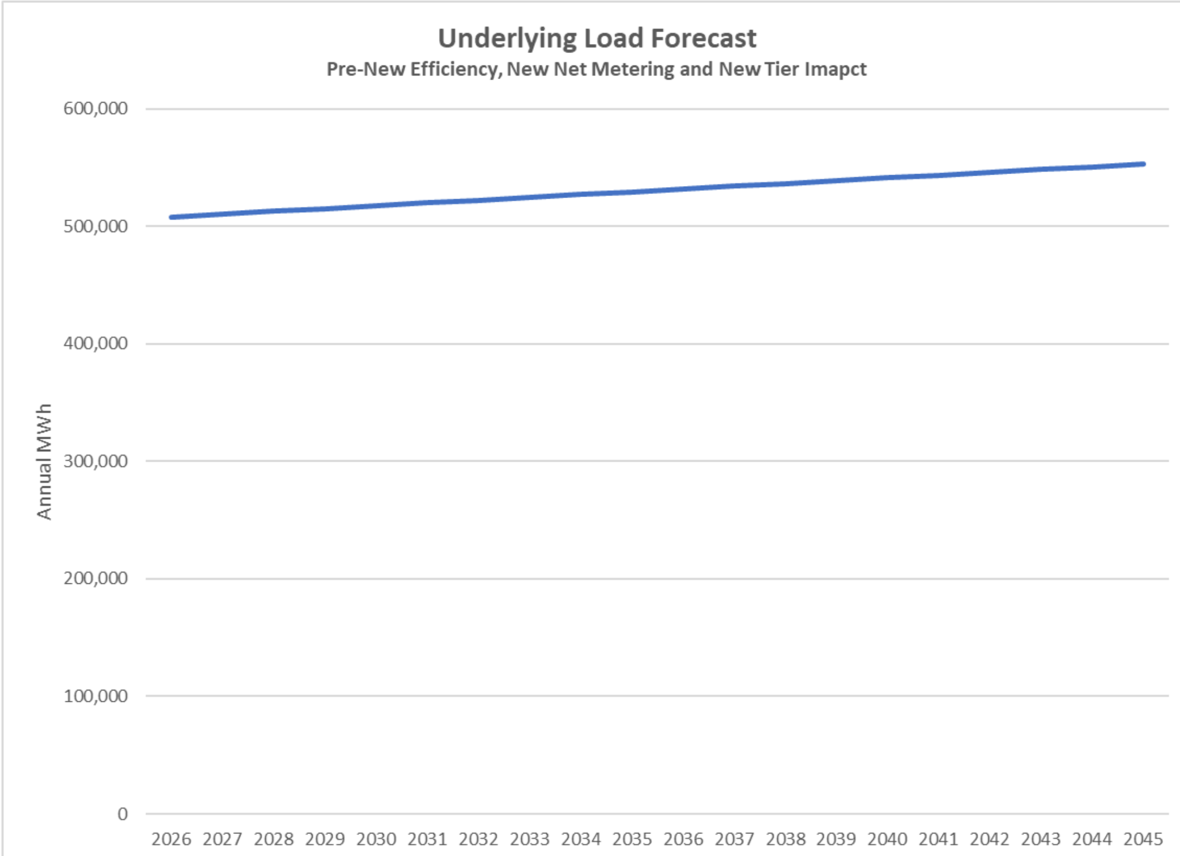


Figure 3.2.2. D – Annual Underlying Load Forecast: Pre-New Net Metering, New Efficiency and Tier III Impact

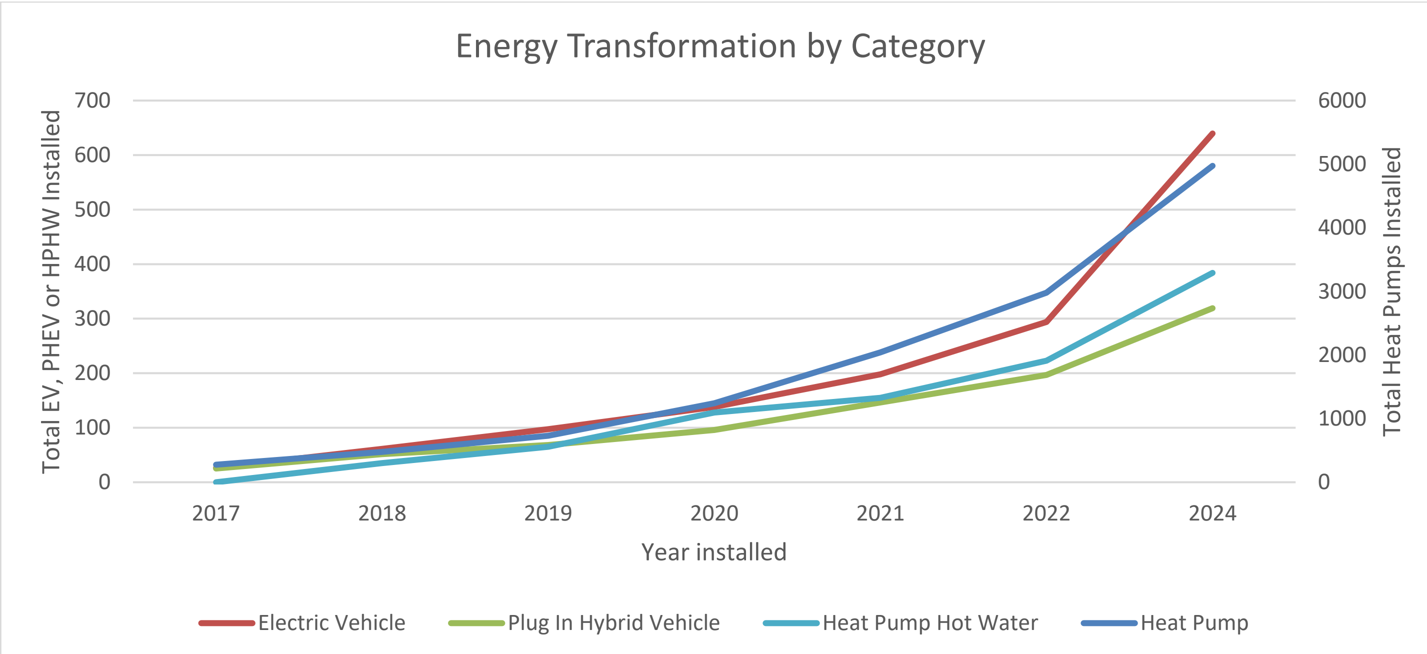
Year	Annual MWh
2026	507,953
2027	510,323
2028	512,692
2029	515,061
2030	517,430
2031	519,799
2032	522,169
2033	524,538
2034	526,907
2035	529,276
2036	531,645
2037	534,015
2038	536,384
2039	538,753
2040	541,122
2041	543,491
2042	545,861
2043	548,230
2044	550,599
2045	552,968

Figure 3.2.2.E - Annual Underlying Load Forecast: Pre-New Net Metering, New Efficiency and Tier III Impact

The underlying load forecast has a Compound Annual Growth Rate (CAGR) of 0.47%.

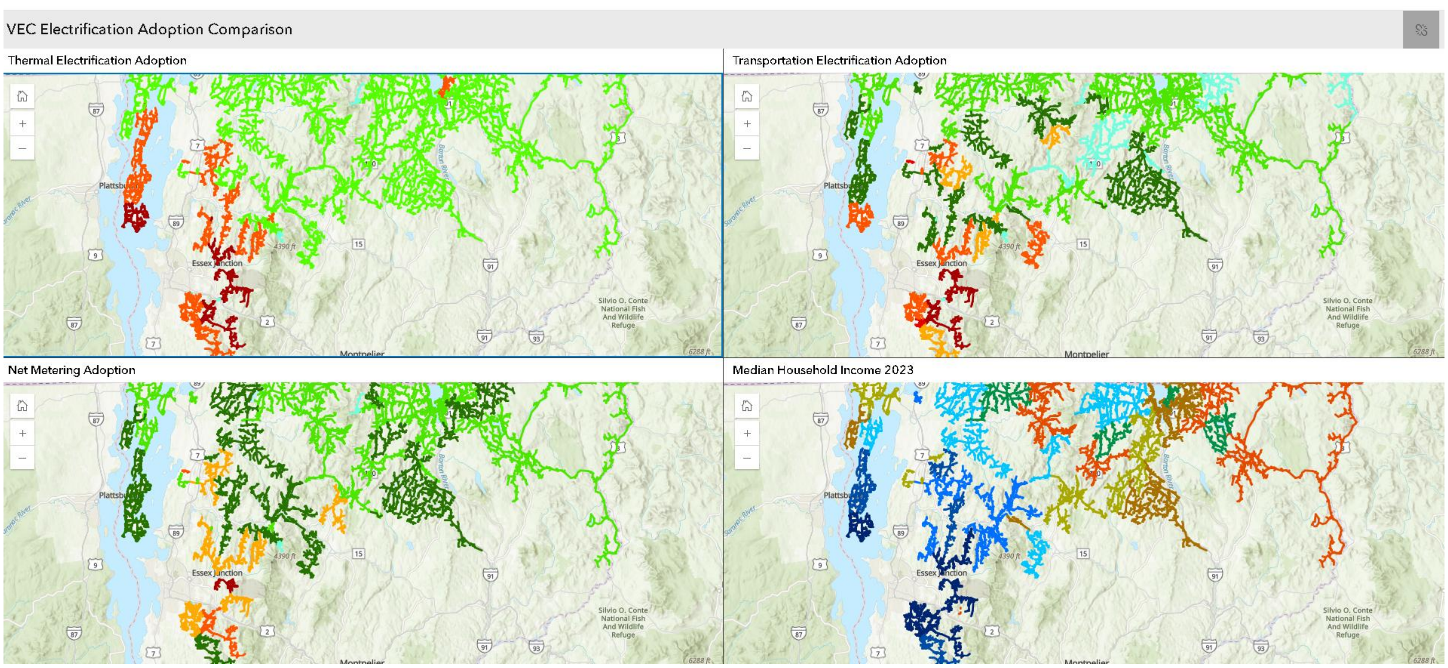
Overall Electrification Load Growth Impact Forecast

Adoption



Demographic Disparity in Adoption

VEC has found that several key demographic indicators, primarily political leaning and income, are driving electrification adoption. To illustrate this point VEC has created public maps that display thermal and transportation adoption as well as median income and political leaning.



VEC used the state treasurer results - https://electionresults.vermont.gov/#/state and Median Household data from the most recent census to build the income and political leaning charts.

In addition to the work VEC has done a 2023 research article in Energy Research & Social Science shows similar trends when looking at adoption.

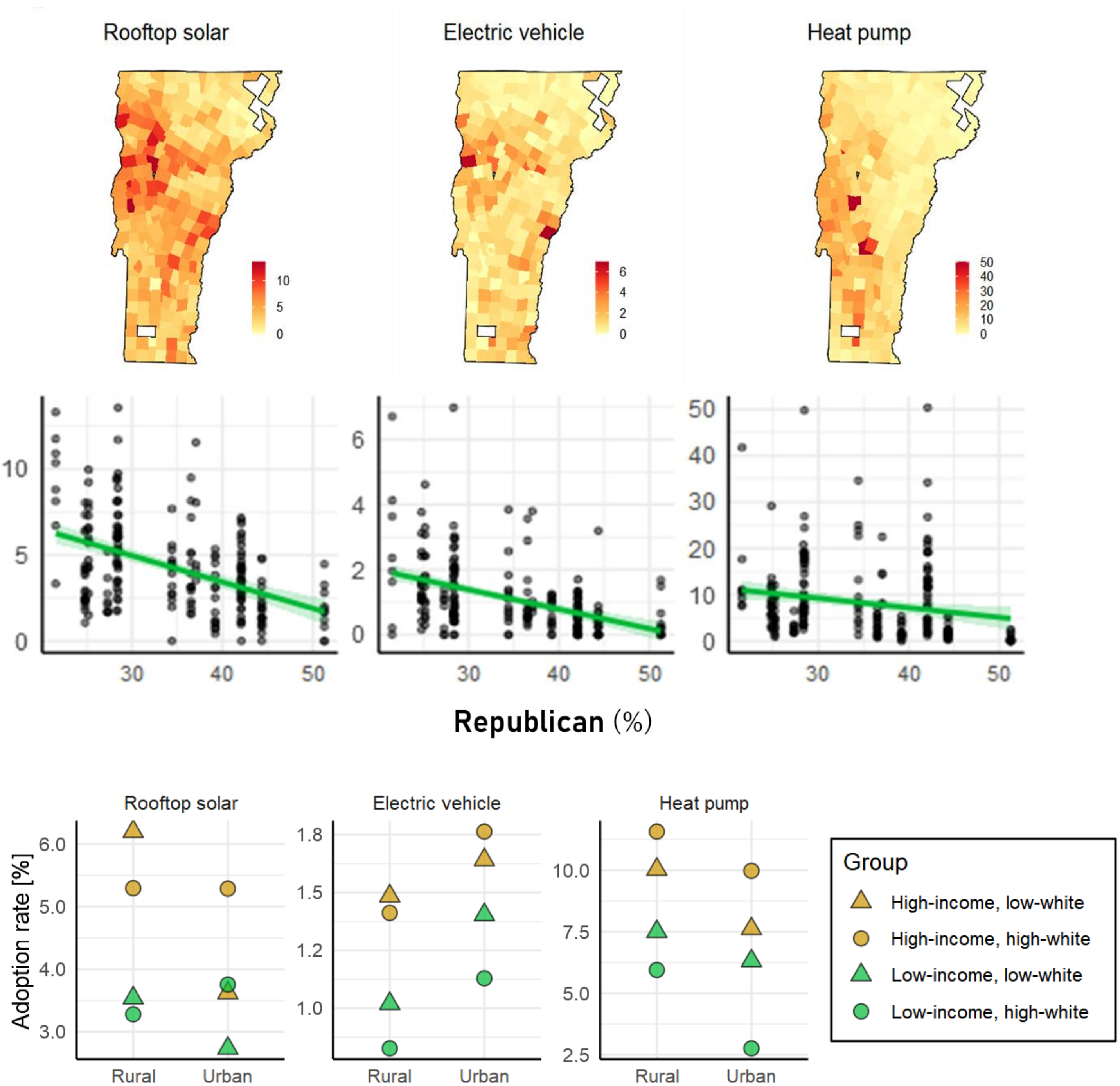


Figure 4.2.2.M – Min, Mayfield. 2023. Rooftop solar, electric vehicle, and heat pump adoption in rural areas in the United States". Energy Research and Social Science. https://doi.org/10.1016/j.erss.2023.103292

Overall Load Impact

Below is a plot of the combined annual load increase due to the various electrification categories described above for each of the three load forecast scenarios.

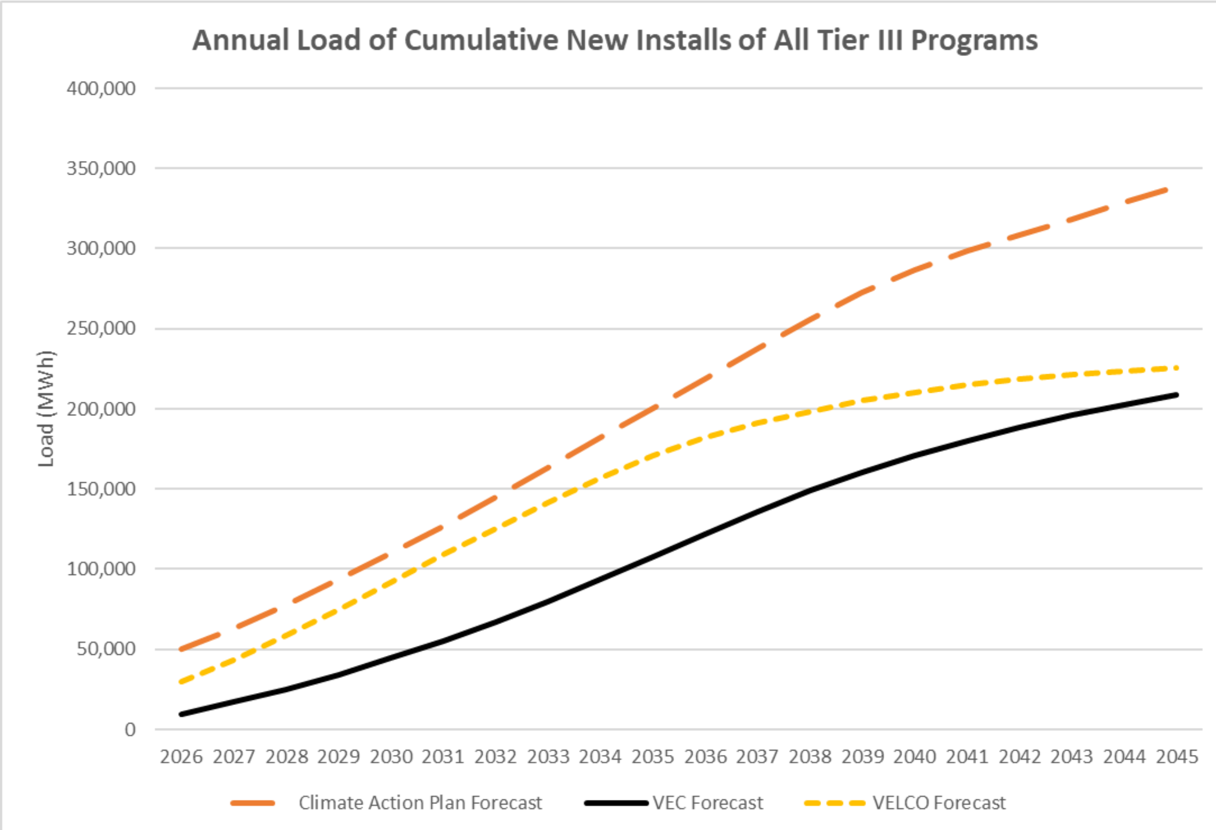


Figure 3.2.2.M – Annual Load Increase Due to Tier III Programs

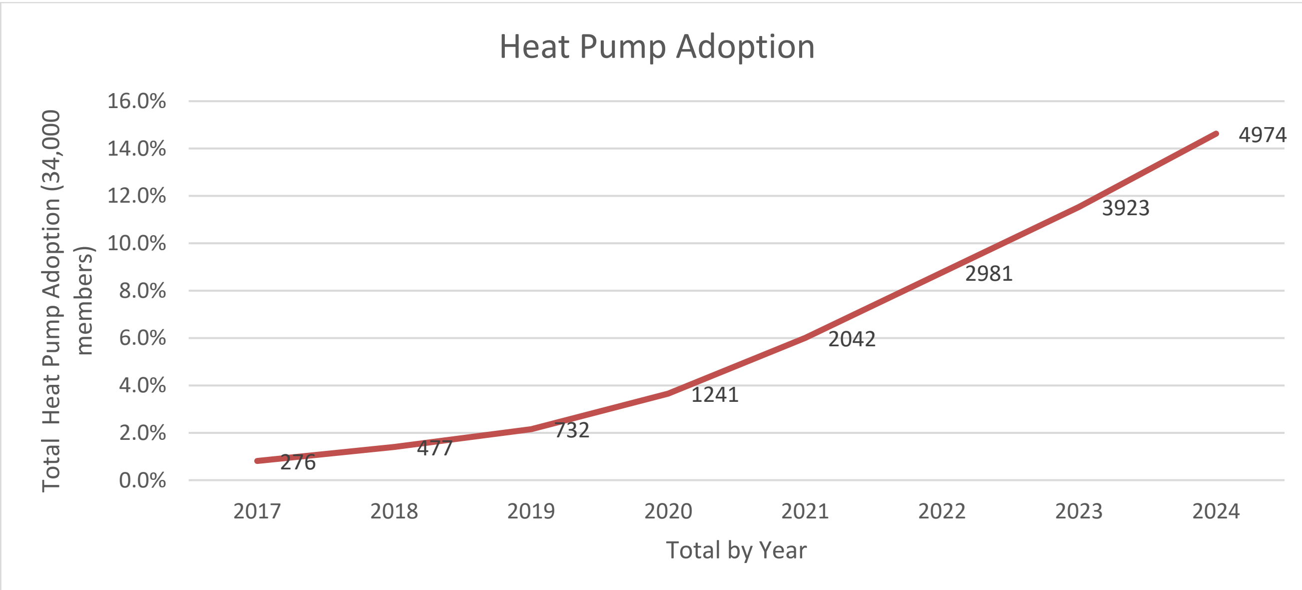
The chart is based on the following annual data:

Year	High NM MWh	Base NM MWh	Low NM MWh
2026	52,525	10,453	35,810
2027	67,096	18,316	52,776
2028	83,353	27,463	71,449
2029	101,792	37,945	92,007
2030	120,880	49,762	114,046
2031	141,020	62,772	136,274
2032	162,467	77,038	158,454
2033	184,512	92,579	179,978
2034	207,100	109,294	200,673
2035	229,389	126,958	218,980
2036	251,751	144,718	233,928
2037	274,334	161,877	246,074
2038	296,103	177,825	255,905
2039	316,497	192,158	264,066
2040	333,907	204,657	270,940
2041	348,259	215,348	276,950
2042	361,266	224,636	281,176
2043	373,956	232,729	283,757
2044	386,647	239,883	286,017
2045	399,337	246,431	288,275

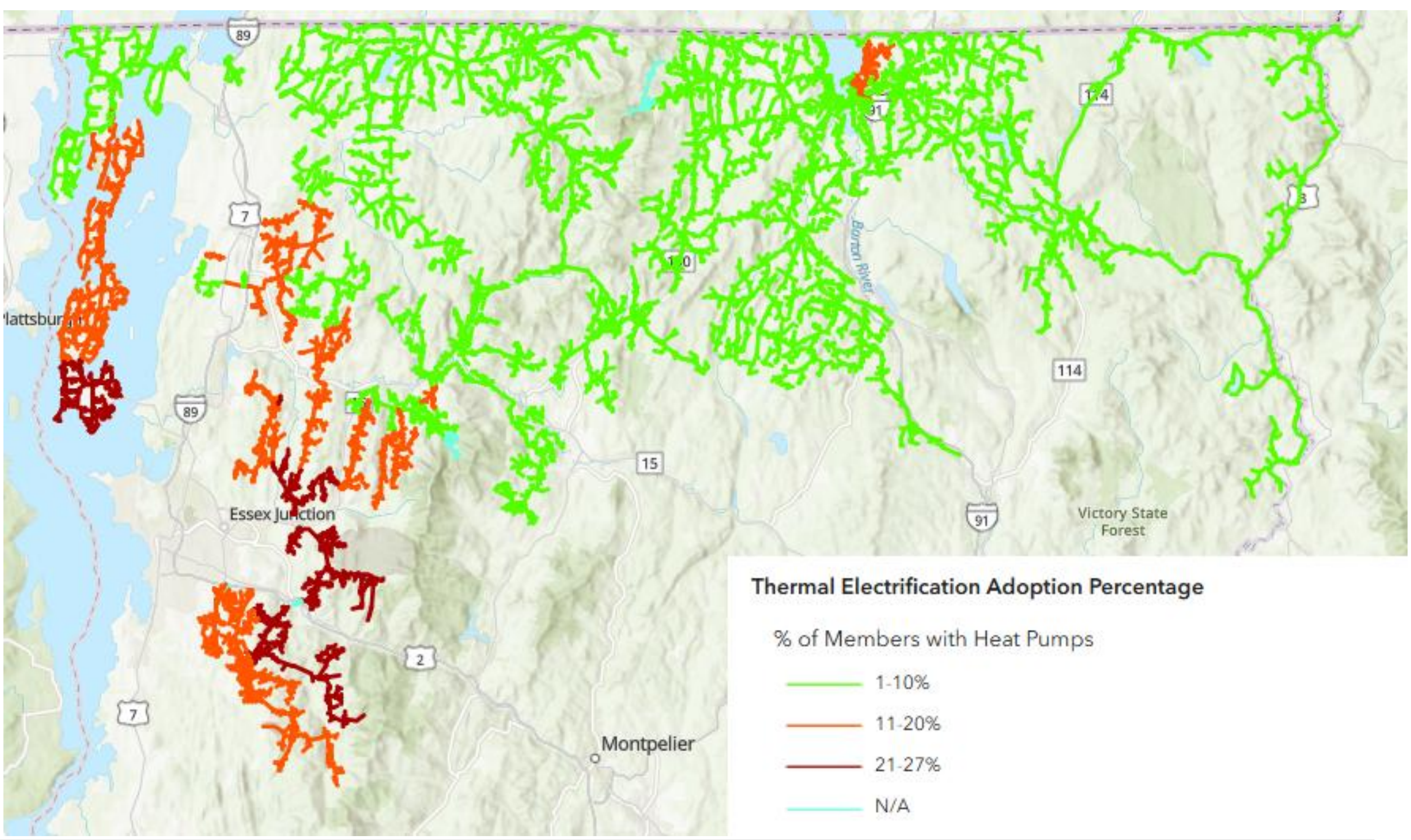
Heat Pumps

Current Heat Pump Adoption

As of January 1, 2025 VEC, has record of almost 5,000 heat pumps through tier 3 incentives which equates to almost 15% of members.



This adoption is located primarily in the western part of VEC's service territory where members with higher median incomes are located.



Future Heat Pump Projection

The three separate load forecast scenarios each had their own projections for annual CCHP installations on the VEC system.

The Climate Action Plan Forecast scenario is based on VEC's estimated 9% share of the annual CCHPs that Energy Ventures Network projected needed to be installed statewide in order for Vermont to meet its Climate Action Plan goals. This projection was adjusted to include the number of CCHPs that would need to be installed on the VEC system to make up for the shortfall of CCHPs actually installed from 2022-2024 compared to those that had been projected to be required to be installed in those years to meet the Climate Action Plan goals.

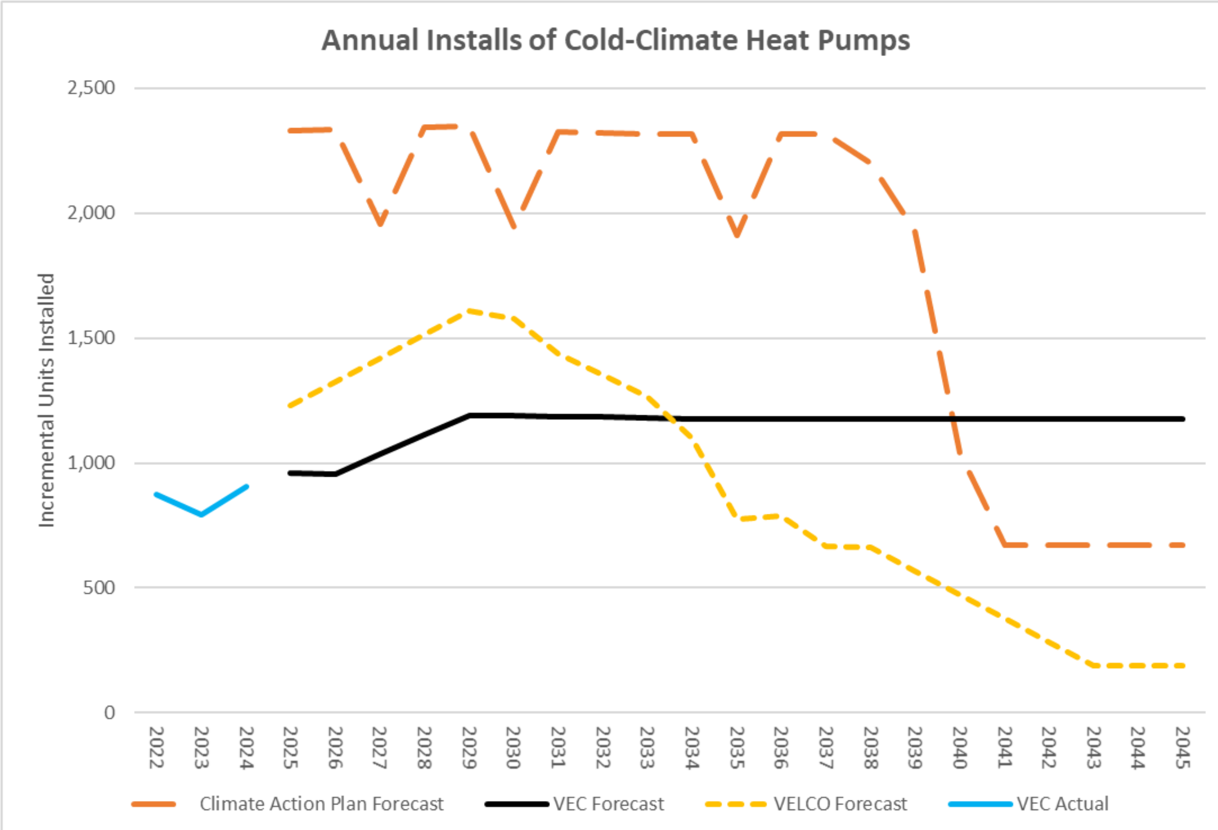
The VELCO Forecast scenario is based on VEC's estimated 9% share of the annual CCHPs for 2025-2045 VELCO assumed would be installed in its "2023 VELCO Long-Term Electrical Energy and Demand Forecast Report", with 2025 adjusted to include the number of CCHPs that would need to be installed on the VEC system to make up for the shortfall of CCHPs actually installed from 2022-2024 compared to those that had been projected to be required to be installed in those years to meet the assumptions of CCHPs installed by the end of 2025 in the VELCO plan.

The VEC Forecast scenario is based on data provided by EVT and is VEC's estimated 9% share of the annual CCPs for 2024-2045 under its current planning assumptions.

The annual installs for 2026-2045 for each forecast scenario are provided below:

Year	Climate Action Plan Forecast	VEC Forecast	VELCO Forecast
2026	2,336	955	1,323
2027	1,955	1,034	1,418
2028	2,344	1,112	1,512
2029	2,349	1,191	1,607
2030	1,944	1,188	1,577
2031	2,325	1,187	1,439
2032	2,319	1,185	1,354
2033	2,318	1,180	1,266
2034	2,315	1,178	1,101
2035	1,910	1,178	773
2036	2,314	1,178	788
2037	2,318	1,178	665
2038	2,201	1,178	662
2039	1,928	1,178	567
2040	1,039	1,178	473
2041	670	1,178	378
2042	671	1,178	284
2043	671	1,178	189
2044	671	1,178	189
2045	671	1,178	189

The plot below shows the data graphically, along with VEC's actual installations for 2022-2024:



Heat Pump Load Impact

One of the primary goals of this IRP is to analyze the incremental load per CCHP VEC is seeing on its system compared to what was assumed in the 2022 IRP.

In 2023 VEC contracted with Qilo to:

1. Create a baseline and profile using AMI data for VEC members before and after heat pump adoption
2. Identify the average annual change in usage across several groups and seasonal usage.
3. Create an 8760-hour load profile to be used for VEC planning efforts.
4. Group into several profiles that indicate the timing of use (summer, fall, winter, spring).

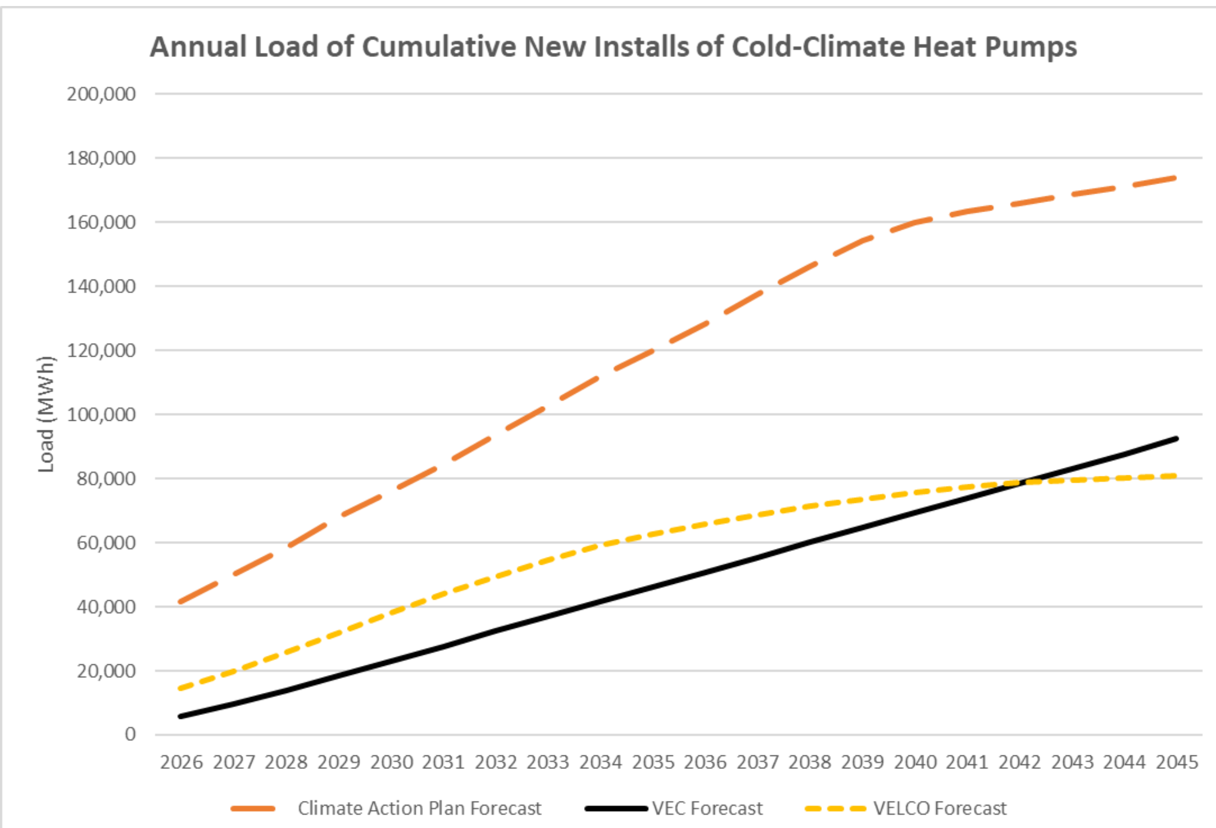
The results showed that the average annual change in usage ranges based on category. The average across all groups is ~ 3,672 kWh annual change in usage. This is noticeably higher than the 2,345 kWh assumed in the 2022 IRP and in all planning assumptions since.

Please see Appendix J for a discussion of the analysis.

Combining the new assumption of 3,672 kWh per CCHP and the annual installation leads to the following annual load impact for 2026-2045 resulting from all CCHPs projected to be installed on the VEC system from 2025-2045. The impact under each forecast scenario is shown numerically in the table below and graphically in the accompanying plot.

Year	Climate Action Plan Forecast (CCHP MWh)	VEC Forecast (CCHP MWh)	VELCO Forecast (CCHP MWh)
2026	41,738	5,730	14,564

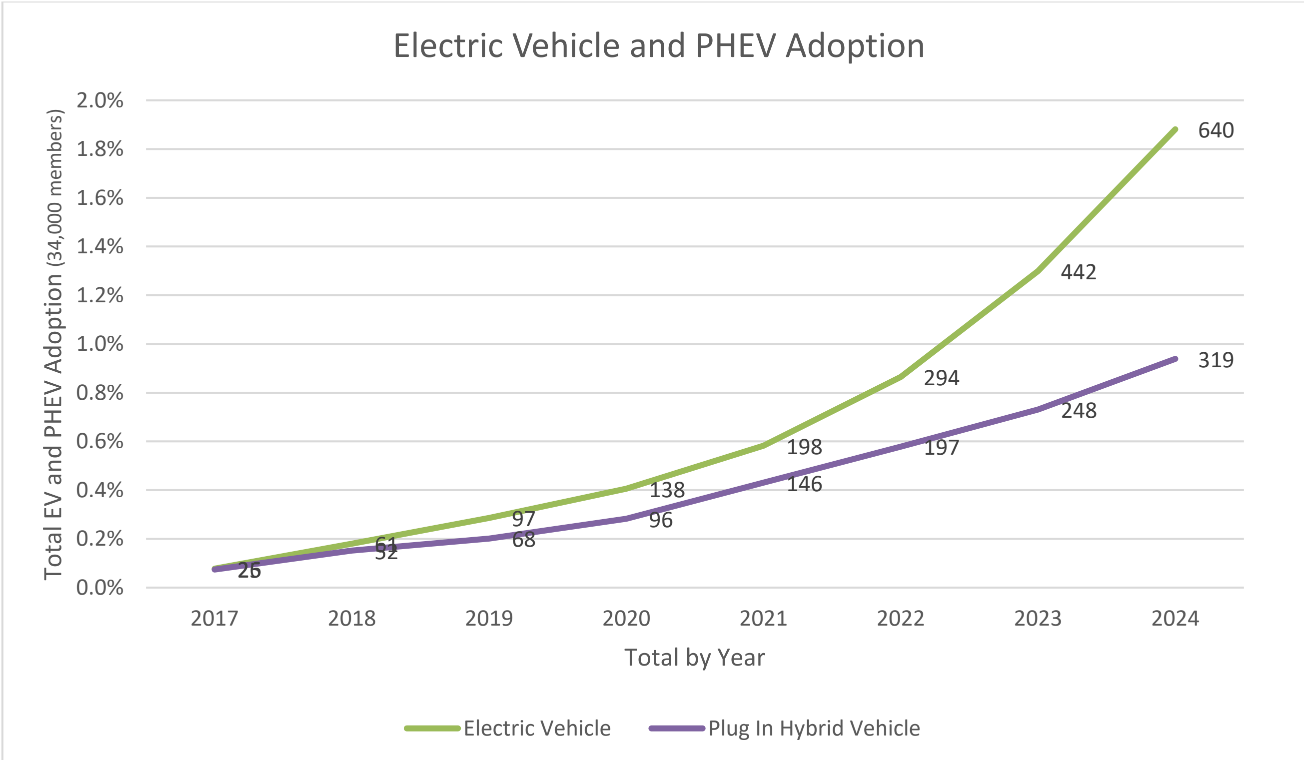
2027	50,103	9,635	19,943
2028	58,569	13,847	25,693
2029	67,763	18,368	31,812
2030	76,127	23,028	38,045
2031	84,533	27,680	43,938
2032	93,629	32,327	49,398
2033	102,713	36,959	54,520
2034	111,789	41,579	59,140
2035	120,023	46,194	62,775
2036	128,344	50,809	65,834
2037	137,419	55,425	68,668
2038	146,259	60,040	71,267
2039	154,319	64,656	73,663
2040	160,035	69,271	75,689
2041	163,342	73,887	77,345
2042	165,969	78,502	78,630
2043	168,598	83,118	79,546
2044	171,227	87,733	80,286
2045	173,855	92,348	81,027



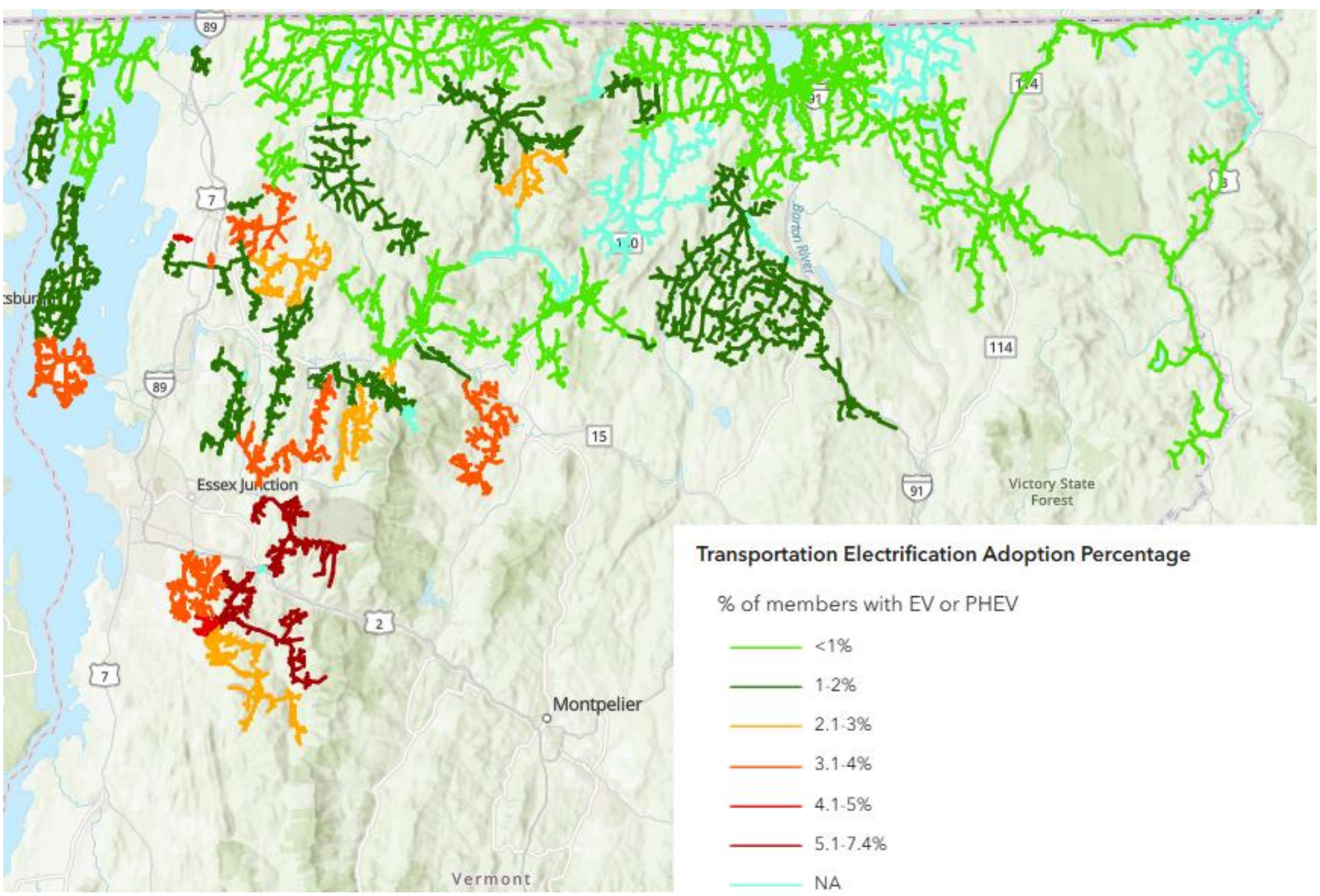
Electric Vehicles

<u>Current Electric Vehicle Adoption</u>

As of January 1, 2025 VEC, has record of almost 1,000 All Electric and Plug in Hybrid Electric vehicles. This data is sources through tier 3 incentives and EV detection which runs on VEC's AMI data.



This adoption is located primarily in the western part of VEC's service territory where members with higher median incomes are located and is also located where political leaning is most democrat.



Electric Vehicle Future Projection

The three separate load forecast scenarios each had their own projections for annual EV installations on the VEC system.

The Climate Action Plan Forecast scenario is based on VEC's assumed 9% share of the annual EVs that Energy Ventures Network projected needed to be installed statewide in order for Vermont to meet its Climate Action Plan goals. This projection was adjusted to include the number of EVs that would need to be installed on the VEC system to make up for the shortfall of EVs actually installed from 2022-2024 compared to those that had been projected to be required to be installed in those years to meet the Climate Action Plan goals.

The VELCO Forecast scenario is based on VEC's 9% share of the annual EVs for 2025-2045 VELCO assumed would be installed in its "2023 VELCO Long-Term Electrical Energy and Demand Forecast Report", with 2025 adjusted to include the number of EVs that would need to be installed on the VEC system to make up for the shortfall of EVs actually installed from 2022-2024 compared to those that had been projected to be required to be installed in those years to meet the assumptions of EVs installed by the end of 2025 in the VELCO plan.

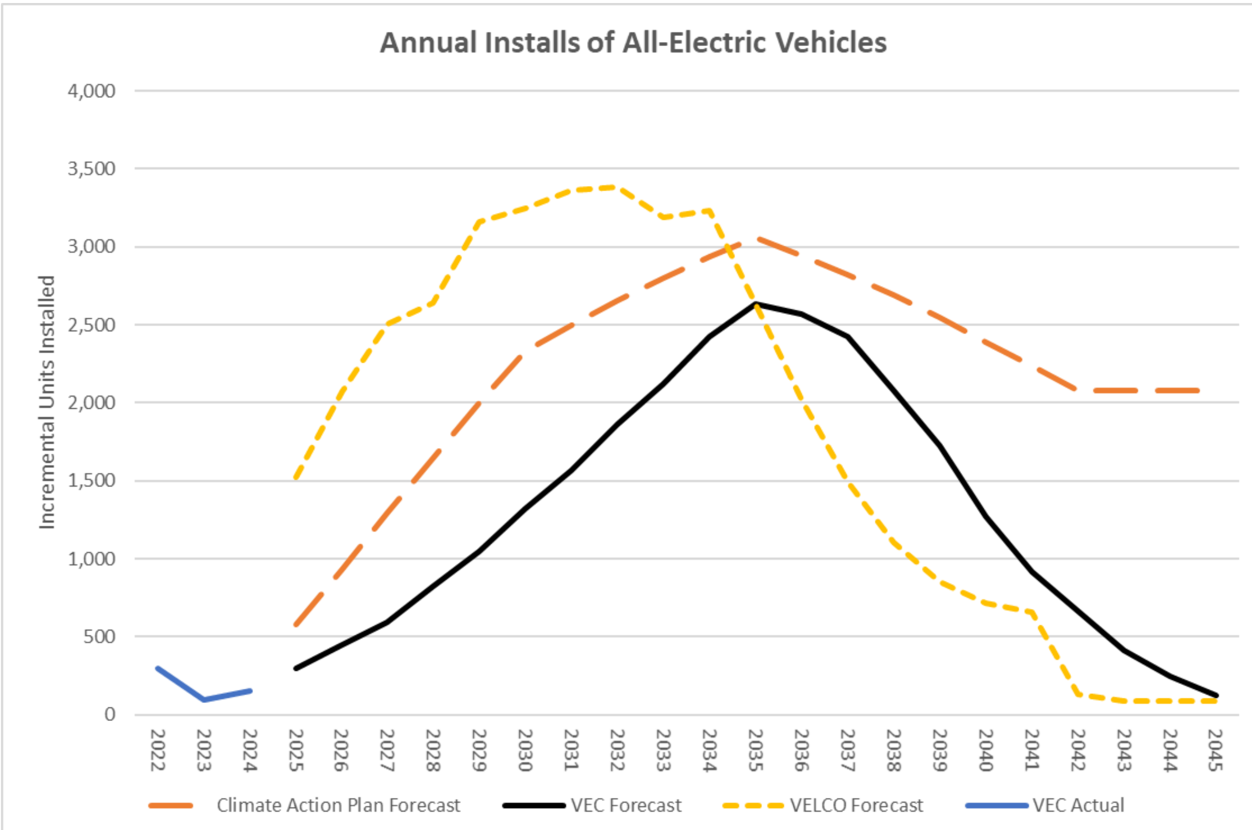
The VEC Forecast scenario is based on actual EVs known to be purchased by members and a projection prepared by Pacific Northwest National Laboratories, which is attached as Appendix K.

The annual incremental EVs for 2026-2045 for each forecast scenario are provided below:

Year	Climate Action Plan Forecast	VEC Forecast	VELCO Forecast
2026	933	451	2,073
2027	1,291	591	2,504
2028	1,648	826	2,640
2029	1,997	1,046	3,161
2030	2,329	1,321	3,244
2031	2,498	1,566	3,364
2032	2,658	1,860	3,385
2033	2,801	2,125	3,187
2034	2,933	2,425	3,232
2035	3,062	2,636	2,634
2036	2,945	2,570	2,019
2037	2,821	2,425	1,494
2038	2,689	2,081	1,106
2039	2,544	1,726	853
2040	2,390	1,273	713
2041	2,240	918	659
2042	2,081	664	134
2043	2,081	411	85
2044	2,081	245	85
2045	2,081	126	85

Note that incremental EVs are those EVs that are replacing a fossil-fuel vehicle. An EV that is replacing an EV is not counted in this data. Because of this, each forecast scenario shows incremental EVs decreasing in the mid-2030s. That does not mean fewer EVs are purchased each year, only that fewer EVs are replacing fossil-fuel vehicles.

The plot below shows the data graphically, along with VEC's actual installations for 2022-2024:



Each forecast scenario has a similar shape, with EVs on the system accelerating in the late-2020s through the mid-2030s. However, the timing is slightly different across the scenarios, with the VELCO forecast accelerating much more quickly than the Climate Action Plan and VEC forecasts.

EV Load Impact

One of the primary goals of this IRP is to analyze the incremental load per EV VEC is seeing on its system compared to what was assumed in the 2022 IRP.

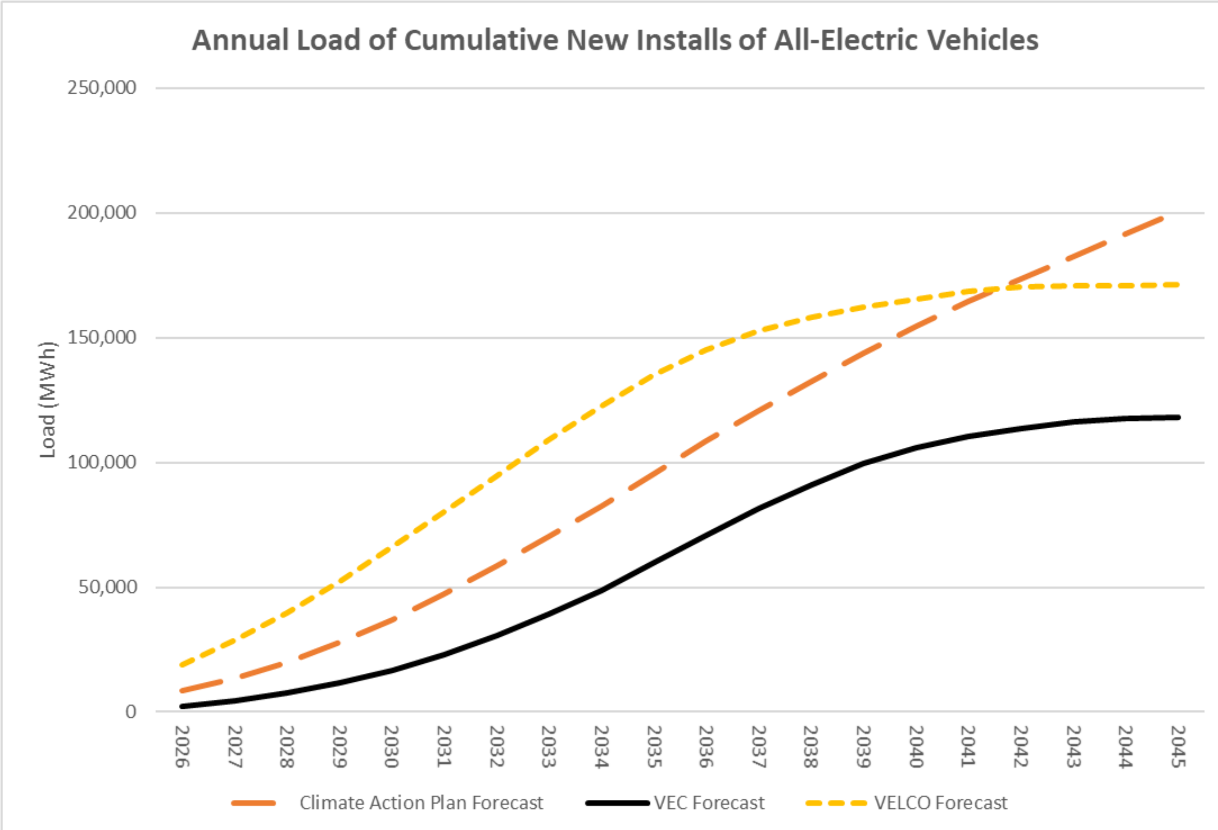
VEC performed this analysis in house by analyzing 2024 hourly charging data for 50 EVs and 23 PHEVs of members who received Tier III incentive data and had the charger installed prior to January 1, 2024.

The results showed that the average annual change in usage ranges based on category. The average across all groups is ~ 4,025 kWh annual change in usage. For reference, This compares to the 4,000 kWh assumed in the 2022 IRP and all planning assumptions since.

Please see Appendix K for a discussion of the analysis.

Combining the new assumption of 4,025 kWh per EV and the annual installation leads to the following annual load impact for 2026-2045 resulting from all EVs purchase by VEC members from 2025-2045. The impact under each forecast scenario is shown numerically in the table below and graphically in the accompanying plot.

Year	Climate Action Plan Forecast (EV MWh)	VEC Forecast (EV MWh)	VELCO Forecast (EV MWh)
2026	8,709	2,316	18,838
2027	13,531	4,572	28,723
2028	19,889	7,645	39,786
2029	27,762	11,692	52,310
2030	37,095	16,809	66,076
2031	47,483	23,039	80,283
2032	58,576	30,435	94,779
2033	70,317	39,027	108,865
2034	82,648	48,837	122,655
2035	95,539	59,733	135,175
2036	108,423	70,904	145,088
2037	120,789	81,612	152,565
2038	132,604	91,244	158,098
2039	143,823	99,372	162,272
2040	154,399	105,753	165,618
2041	164,322	110,413	168,557
2042	173,580	113,778	170,190
2043	182,518	116,054	170,654
2044	191,456	117,440	171,020
2045	200,393	118,221	171,387



3.2.3 Incremental Impact of Efficiency Vermont (EVT) Activity on VEC System

The Underlying Load Forecast was assumed to include the impact of EVT activity on the VEC system through December 2024 and must be adjusted by the incremental impact of EVT activity on the VEC system beginning January 1, 2025. This adjustment is based on data provided to VEC by EVT.

EVT provided data for the statewide annual MWh load reduction for both Commercial/Industrial and Residential efficiency measures projected to be installed in each year from 2025-2043 (VEC then projected installs for 2044 and 2045 by carrying forward 2043 assumptions). These measures include lighting, motors, refrigeration, space heating, air conditioning, industrial processes, ventilation systems and consumer electronics. VEC's approximately 9% share of Vermont load was applied to the statewide data to create a forecast specific to VEC's service territory.

The projected MWh load reduction assumed all installations occurred at the beginning of the year.

VEC converted the annual data to monthly cumulative data to arrive at the total projected load reduction each month for 2026-2045. VEC did not adjust for the impact of measure life based on the assumption that, as the measure life expires, members will replace the devices with another device of similar efficiency.

The plot below shows the annual **cumulative** load reduction of EVT activity in the VEC territory.

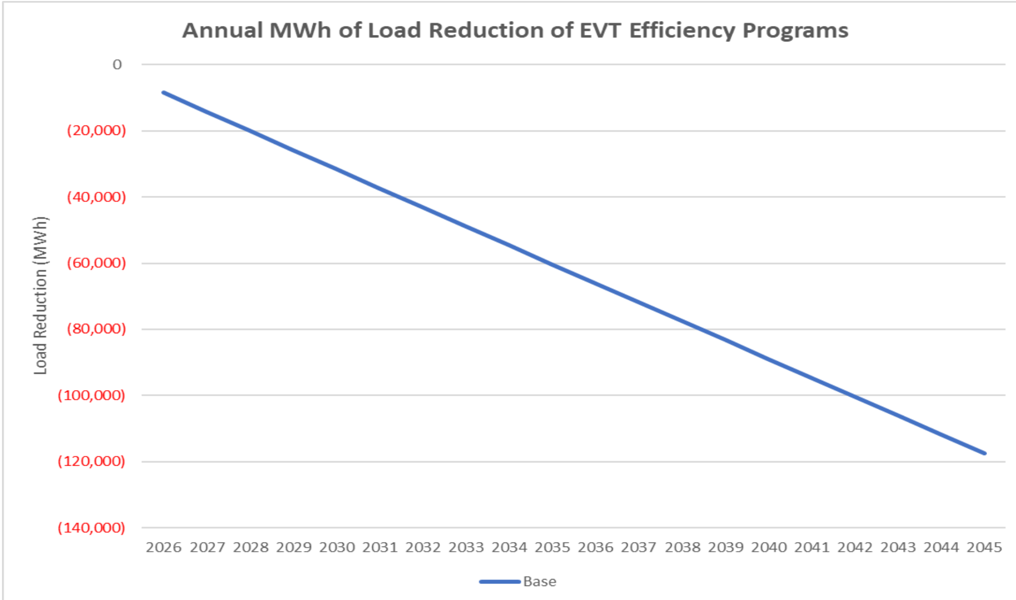


Figure 3.2.3.F – Cumulative MWh of Load Reduction Due to Efficiency

The chart is based on the following data:

Year	Load Impact (MWh)
2026	(8,523)
2027	(14,219)
2028	(20,007)
2029	(25,785)
2030	(31,540)
2031	(37,307)
2032	(43,110)
2033	(48,874)
2034	(54,627)
2035	(60,371)
2036	(66,071)
2037	(71,772)
2038	(77,483)
2039	(83,169)
2040	(88,876)
2041	(94,611)
2042	(100,316)
2043	(106,026)
2044	(111,758)
2045	(117,491)

Table 4.3.3.G – Cumulative MWh of Load Reduction Due to Efficiency

3.2.4 New Net Metering Forecast

The Underlying Load Forecast is limited to the impact of net-metering projects installed on the VEC system through December 2024 and must be adjusted by the Net Metering projects installed on the VEC system beginning January 1,

2025. The adjustment is based on actual projects installed from 2022-2024 and a forecast of new net-metering penetration for 2025-2045.

Net-metering rules in Vermont recently changed. The major change is that new Net-metering projects must be 150 kW AC or less or up to 500kw if a project serves co-located load. Net Metering rules have evolved over time and we expect will continue to evolve as the industry changes, making it difficult to predict with much certainty how much net-metering will be installed on the system during the study period.

VEC developed Base, High and Low net-metering scenarios which are described below based on current rules and possible scenarios we can envision today:

Scenario	Projects = 150 kW	Projects < 150 kW
High	No projects in 2025. 2026 includes 0.320 MW of projects with CPGs plus an additional 0.150 MW projects in August. 2027 and beyond assume one 0.150 MW project in August of each year.	Assumes the 1.444 MW that come on line in 2025, then 89% of previous year moving forward. (89% = 2023 Installed MW/2022 Installed MW)
Base	No projects in 2025. 2026 includes 0.320 MW of projects with CPGs plus an additional 0.150 MW project in August. 2027 and beyond assume one 0.150 MW project in August of every other year beginning in 2028.	Assumes the 1.264 MW that come on line in 2025, then 77.9% of previous year moving forward. (77.9% = average of 2023 Installed MW/2022 Installed MW and 2024 Installed MW/2023 Installed MW)
Low	No projects in 2025. 2026 includes 0.320 MW of projects with CPGs. 2027 and beyond assume no new projects.	Assumes the 1.087 MW that come on line in 2025, then 67% of previous year moving forward. (67% = average of 2024 Installed MW/2023 Installed MW)

Table 3.2.4.H – Low, Base, and High Net Metering Forecast Scenarios

As part of this IRP VEC wants to refine its monthly and annual Capacity Factor (CF) planning assumptions. VEC used actual monthly from its Meter Data Management system for 2024 and the kW of installed NM projects for all projects at the beginning of each month. This analysis shows an annual CF of 13.18%, compared to the 11.04% CF assumed in the 2022 IRP and since then.

The figure below shows the annual output of new net-metering projects for each of the three scenarios.

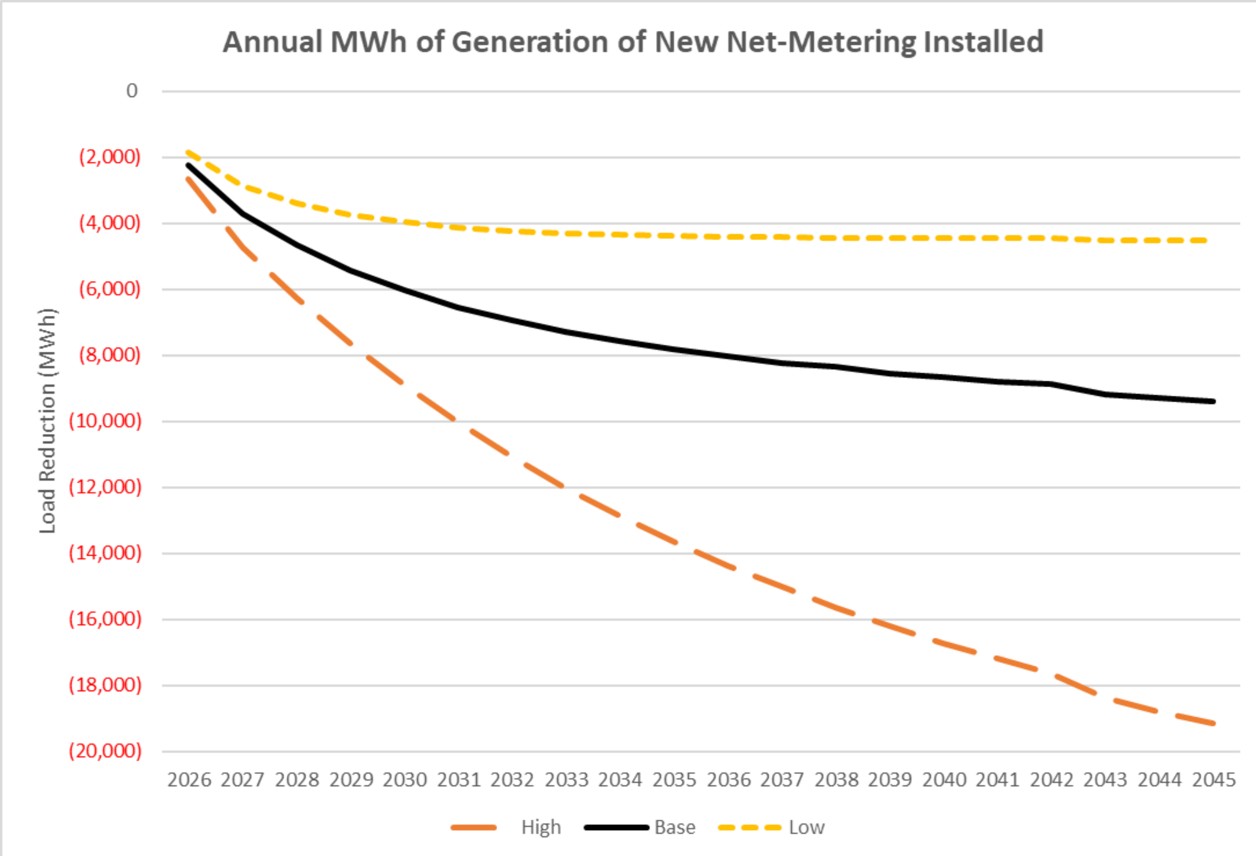


Figure 3.2.4.I – Annual MWh of New Net Metering

The plots are based on the data below.

Year	High NM MWh	Base NM MWh	Low NM MWh
2026	(2,675)	(2,246)	(1,843)
2027	(4,737)	(3,717)	(2,864)
2028	(6,282)	(4,652)	(3,395)
2029	(7,655)	(5,437)	(3,739)
2030	(8,908)	(6,024)	(3,974)
2031	(10,044)	(6,554)	(4,132)
2032	(11,097)	(6,949)	(4,246)
2033	(12,012)	(7,305)	(4,308)
2034	(12,867)	(7,560)	(4,355)
2035	(13,649)	(7,833)	(4,387)
2036	(14,394)	(8,029)	(4,418)
2037	(15,022)	(8,226)	(4,423)
2038	(15,627)	(8,359)	(4,432)
2039	(16,186)	(8,537)	(4,439)
2040	(16,738)	(8,660)	(4,452)
2041	(17,185)	(8,798)	(4,446)
2042	(17,633)	(8,887)	(4,448)
2043	(18,383)	(9,195)	(4,531)
2044	(18,784)	(9,275)	(4,532)
2045	(19,162)	(9,412)	(4,532)

Table 3.2.4.J Annual MWh of New Net Metering

Historically, only 30% of the net-metering generation on VEC's system has reduced sales at members' premises. The other 70% is either excess generation of small systems, or the entire output of group net-metering systems, which, instead of reducing load on the system is modeled similar to a purchase from a generator.

As a result, the load forecast is reduced by 30% of the total net-metering output shown above.

The plots below show the annual load reduction from new net-metering projects for each of the three scenarios.

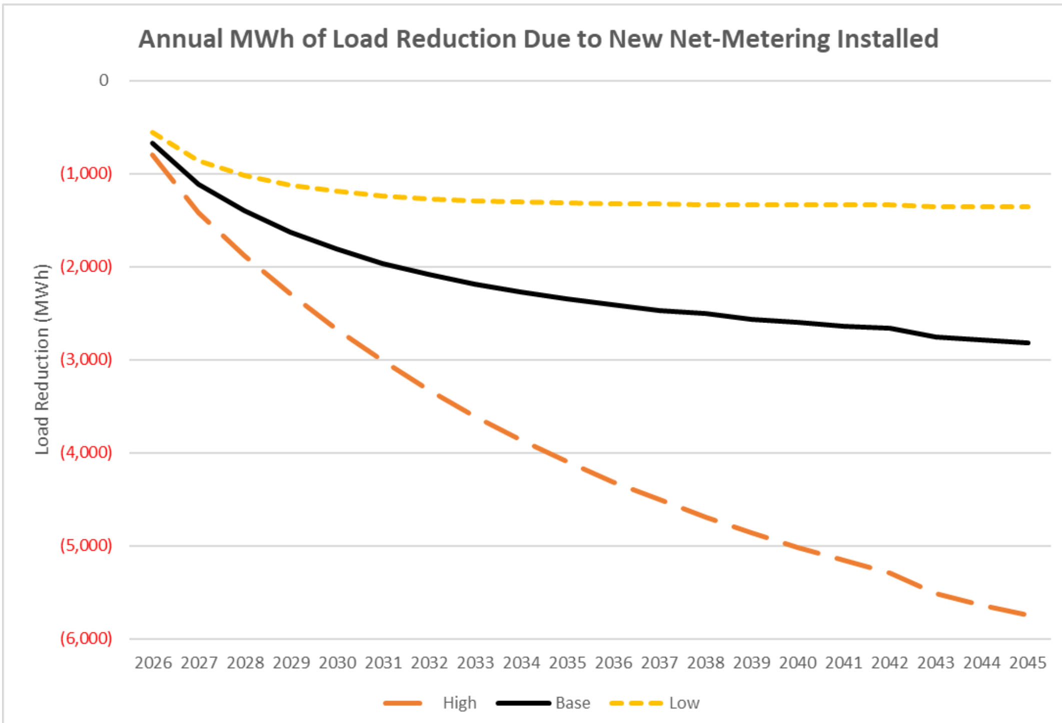


Figure 3.2.4.K – Annual MWh of Load Reduction Due to New Net Metering

The plots are based on the data below:

Year	High NM MWh	Base NM MWh	Low NM MWh
2026	(802)	(674)	(553)
2027	(1,421)	(1,115)	(859)
2028	(1,885)	(1,395)	(1,018)
2029	(2,297)	(1,631)	(1,122)
2030	(2,672)	(1,807)	(1,192)
2031	(3,013)	(1,966)	(1,240)
2032	(3,329)	(2,085)	(1,274)
2033	(3,604)	(2,191)	(1,292)
2034	(3,860)	(2,268)	(1,307)
2035	(4,095)	(2,350)	(1,316)
2036	(4,318)	(2,409)	(1,325)
2037	(4,506)	(2,468)	(1,327)
2038	(4,688)	(2,508)	(1,330)
2039	(4,856)	(2,561)	(1,332)
2040	(5,021)	(2,598)	(1,336)

2041	(5,155)	(2,640)	(1,334)
2042	(5,290)	(2,666)	(1,334)
2043	(5,515)	(2,759)	(1,359)
2044	(5,635)	(2,782)	(1,359)
2045	(5,749)	(2,824)	(1,360)

Table 3.2.4.L Annual MWh of Load Reduction Due to New Net Metering

For analyses performed in this IRP, VEC used the Base NM assumptions. To the extent that actual NM impacts are greater than the Base assumptions, VEC's energy, capacity and RES short positions will decrease (or long positions increase). To the extent that actual NM impacts are less than the Base assumptions, VEC's short positions will increase (or long positions decrease).

3.2.5 Overall Energy Needs

Prior to the establishment of a Renewable Energy Standard in Vermont, VEC managed its power supply as one large portfolio. Load was projected based primarily on historic usage trends adjusted for forecasts of external factors such as economic growth and energy efficiency implementation.

With the establishment of the RES, and its goals to have a 100% Carbon-Free energy portfolio, VEC must not only plan its portfolio to meet the entire needs of its members but also make sure that it meets its total renewables requirement, distributed generation requirement, and energy transformation requirement each year. VEC now views its portfolio from the following perspectives:

1. Total System Energy Requirements Portfolio
2. Carbon-Free Energy Portfolio
3. Tier I Portfolio – (Total Renewable Energy)
4. Tier II Portfolio - (Distributed Renewable Generation)
5. Tier III – (Energy Transformation)
6. Tier IV – (New Renewable Energy)

VEC typically has higher loads in the winter months (January, February and December) as colder temperatures and fewer daylight hours drive up residential usage. Usage typically decreases in the spring as warmer temperatures reduce heating load and more hours of daylight reduce lighting loads. Usage then typically rises in the summer as lower lighting loads from the long days are offset by cooling load brought on by higher temperatures.

The table below shows the energy purchased by VEC to meets its members' needs, the percentage of annual MWh purchased, and the peak load with the date and hour for each month of 2024:

Month	Load (MWh)	% of Annual Load	Peak (MW)	Peak Day of Week	Peak Day of Month	Peak Hour
Jan-24	49,302	9.6%	81.554	Mon	15	18
Feb-24	44,391	8.7%	77.049	Sun	11	18
Mar-24	46,956	9.2%	72.034	Thu	7	19
Apr-24	38,448	7.5%	69.297	Wed	3	18
May-24	36,690	7.2%	63.561	Wed	22	21
Jun-24	36,820	7.2%	73.443	Wed	19	21
Jul-24	45,609	8.9%	81.555	Mon	15	20

Aug-24	43,281	8.5%	79.951	Fri	2	21
Sep-24	37,459	7.3%	66.979	Mon	16	19
Oct-24	42,386	8.3%	68.888	Mon	14	18
Nov-24	41,662	8.1%	72.237	Sun	24	18
Dec-24	48,756	9.5%	81.895	Sun	22	18
Total	511,761	100.0%	81.895			

Table 3.2.5.A Purchased energy needs and peak hours

VEC's peak load of 81.895 MW occurred on December 22 in hour ending 6:00 PM, although the July peak load was only 0.440 MW lower. VEC is typically a winter-peaking system; 2021 is the only year since at least 2005 that the system peak load occurred in the summer. In 2024, the system peaked shortly before, or after, sunset, each month which is characteristic of a residential load shape.

Although total monthly energy usage changes on a year-to-year basis, the trend throughout the year has been similar for many years. Whether or not this trend continues will be greatly affected by the extent to which load is impacted by climate change; VEC members installing new net metering systems or their own generation behind the VEC meter, reducing the load on VEC's system; utility-initiated distributed generation with a nameplate AC capacity of less than 5.0 MW; battery storage under VEC's control or incentivized to operate in hours to reduce load at peak times; and increased load due to member adoption of electrification measures for cooling, heating, transportation and other household or business uses.

As a utility in New England, VEC (and many of its suppliers) has its load and generation entitlements settled through the Independent System Operator of New England (ISONE or ISO New England) settlement system. In addition, VEC participates in various New England Renewable Energy Certificates (REC) markets, based on its entitlements to RECs from several Vermont-based renewable generation projects, a wind project in New York; and contracts with Hydro-Quebec (HQ) and the New York Power Authority (NYPA). Each REC allows VEC to claim 1 MWh of renewable generation. VEC can retain RECs to meet its 100% Carbon-Free goal and/or the Vermont RES, or sell the RECs to another entity, thereby lowering VEC's costs, but doing so reduces the amount of renewable energy it can claim.

In developing and managing its power supply portfolio to meet its obligation to serve its members' electrical needs and/or managing its load at peak times, VEC's effective participation in the regional REC and ISONE Energy and Capacity Markets is important. There are several key external factors associated with these markets that VEC must anticipate and monitor in evaluating strategies for managing the portfolio.

Each of the components are explained below:

3.2.6 Seasonal Timing of Peaks

VEC developed its own peak load forecasts. This was done by multiplying the ratio of monthly-peak-load-to-monthly-energy for each month of 2024 by the projected monthly energy forecast for each of the load forecasts.

It is important to note that, as mentioned elsewhere in this document, the monthly peak forecasts assume no load management from electric vehicles and cold-climate heat pumps which more clearly identifies risks to not managing load and identify load shifting opportunities.

The resulting Winter Peak and Summer Peak forecasts are explained below.

Winter Peak

Under the Climate Action Plan Forecast, system winter peak demand is projected to increase from 89.354 MW in 2026, to 147.354 MW by 2045, implying a CAGR of 2.6%.   The CAGR for 2030-2035 of 93.4% is higher than that for 2026-2030 (3.0%), 2035-2040 (2.9%), and 2040-20245 (1.4%) because the adoption rates for CCHPs relative to the other periods.

Under the VEC Forecast the winter peak is projected to increase from 81.14 MW in 2026 to 111.63 MW, with a CAGR of 2.07%. As in the Climate Action Plan Forecast, the CAGR for 2030-2035 of 2.16% is higher than that for 2026-2030 (1.46%), 2035-2040 (2.04%), and 2040-20245 (1.12%) because the adoption rates for EVs relative to the other periods.

In the VELCO Forecast the winter peak is projected to grow from 82.58 MW in 2026 to 113.11 MW in 2045; with a CAGR of 2.0%.   The CAGR for 2026-2030 of 3.5% is higher than for 2030-2035 (3.0%), 2035-2040 (1.4%) and 2040-2045 (0.3%) because of the projected adoption rate of CCHPs and EVs in that period relative to the other periods.

The System Winter peak forecasts are shown graphically in the figure below:

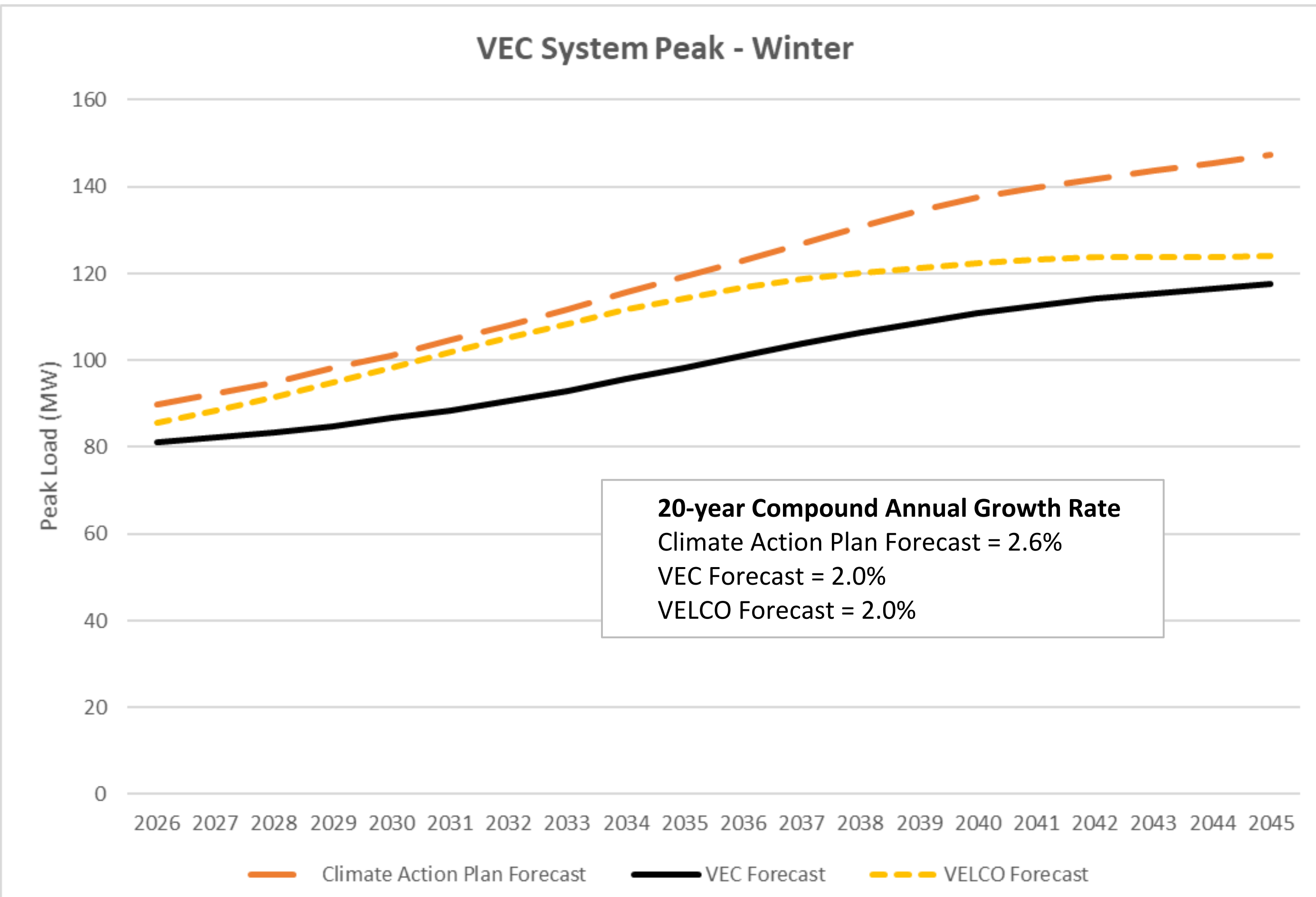


Figure 3.2.6.A – Projected System Winter Peak (MW)

The plots are based on the following data:

Year	Climate Action Plan Forecast (MW)	VEC Forecast (MW)	VELCO Forecast (MW)
2026	89.794	81.143	85.710

2027	92.251	82.196	88.466
2028	94.984	83.409	91.435
2029	98.110	84.886	94.852
2030	101.152	86.594	98.341
2031	104.609	88.519	101.803
2032	108.165	90.625	105.236
2033	111.829	92.996	108.474
2034	115.575	95.617	111.595
2035	119.344	98.358	114.240
2036	122.996	101.035	116.659
2037	126.904	103.751	118.645
2038	130.717	106.367	120.156
2039	134.323	108.727	121.381
2040	137.544	110.826	122.341
2041	139.888	112.598	123.104
2042	141.829	114.118	123.704
2043	143.674	115.449	123.871
2044	145.515	116.592	123.911
2045	147.354	117.621	123.949
2026-2045 CAGR	2.6%	2.0%	2.0%
2025-2030 CAGR	3.0%	1.6%	3.5%
2030-2035 CAGR	3.4%	2.6%	3.0%
2035-2040 CAGR	2.9%	2.4%	1.4%
2040-2045 CAGR	1.4%	1.2%	0.3%

Figure 3.2.6.B - Projected System Winter Peak (MW)

VEC Summer Peak

Under the Climate Action Plan Forecast, system summer peak demand is projected to increase from 85.769 MW in 2026, to 121.054 MW by 2045, implying a CAGR of 1.8%. The CAGR for 2030-2035 of 2.4% is higher than that for 2026-2030 (1.9%), 2035-2040 (2.0%), and 2040-20245 (1.1%) because of the adoption rates for CCHPs from 2030-2035 relative to the other periods.

Under the VEC Forecast the summer peak is projected to increase from 80.625 MW in 2026 to 101.792 MW, with a CAGR of 1.2%. The CAGR for 2030-2035 of 1.8% is higher than that for 2026-2030 (0.9%), 2035-2040 (1.6%), and 2040-20245 (0.6%) because the adoption rates for EVs relative to the other periods .

In the VELCO Forecast the system summer peak demand is projected to increase from 83.937 MW in 2026, to 107.499 MW by 2045, implying a CAGR of 1.3%. The CAGR for 2030-2035 of 2.3% is slightly higher than that for 2026-2030 (2.3%), and noticeably higher than 2035-2040 (0.8%), and 2040-20245 (>0.0%) because of the adoption rates for EVs relative to the other periods.

The system summer peak forecasts are shown graphically in the following figure:

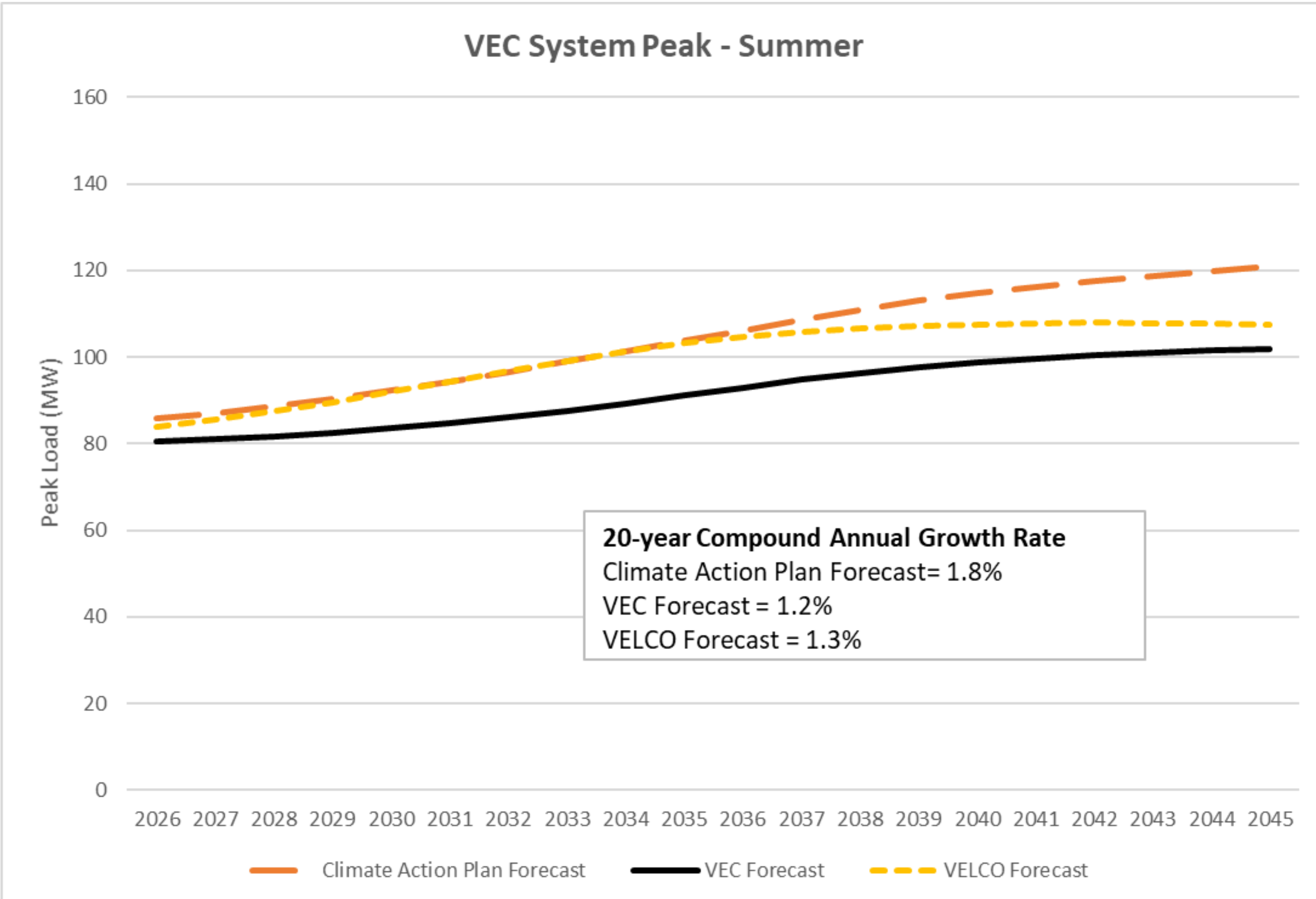


Figure 3.2.6.C – Projected System Summer Peak (MW)

The plots are based on the following data:

Year	**Climate Action Plan Forecast (MW)**	**VEC Forecast (MW)**	**VELCO Forecast (MW)**
2026	85.769	80.625	83.937
2027	87.032	81.064	85.576
2028	88.572	81.706	87.463
2029	90.385	82.524	89.610
2030	92.316	83.548	91.967
2031	94.394	84.723	94.345
2032	96.638	86.079	96.733
2033	98.963	87.604	99.032
2034	101.381	89.308	101.254
2035	103.753	91.127	103.139
2036	106.169	92.972	104.615
2037	108.583	94.725	105.711
2038	110.905	96.327	106.526
2039	113.043	97.706	107.115
2040	114.810	98.848	107.551
2041	116.202	99.736	107.864
2042	117.452	100.459	107.949
2043	118.650	101.008	107.820

2044	119.858	101.446	107.666
2045	121.054	101.792	107.499
2026-2045 CAGR	1.8%	1.2%	1.3%
2025-2030 CAGR	1.9%	0.9%	2.3%
2030-2035 CAGR	2.4%	1.8%	2.3%
2035-2040 CAGR	2.0%	1.6%	0.8%
2040-2045 CAGR	1.1%	0.6%	0.0%

Figure 3.2.6.D – Projected System Summer Peak (MW)

3.2.7 VEC's load in New England at the time of the Vermont Peak

VEC developed its own peak load forecast for its load at the time of the monthly Vermont Peak . This was done by multiplying the average ratio of VEC's load on NE at the time of the Vermont Peak-to-VEC's-monthly-peak-Total-system-load energy for each month of 2022-2024 by the projected monthly energy forecast for each of the three load forecast scenarios.

The figure below shows VEC's projected load at the annual average monthly load at the time of the Vermont monthly peak for year of the study period under the three forecast scenarios:

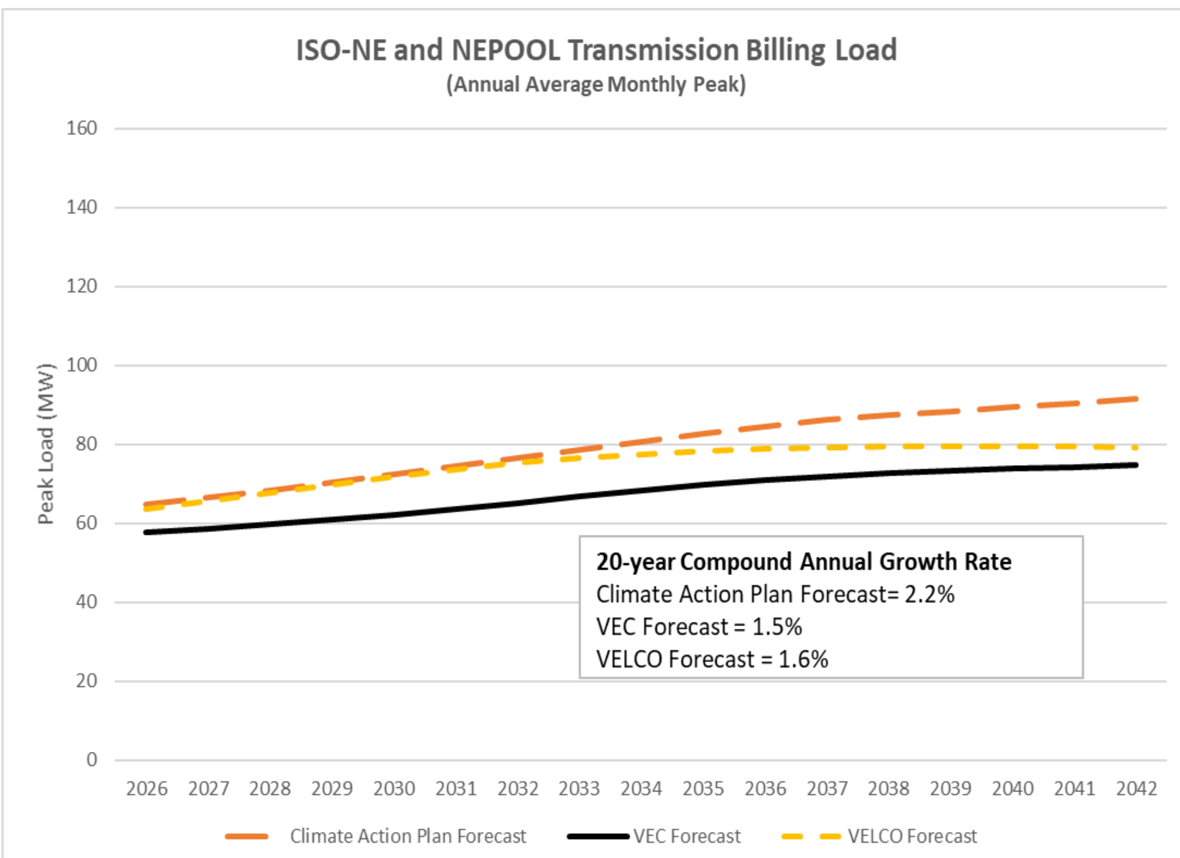


Figure 3.2.7.A – ISONE and NEPOOL Transmission Billing Peak

Under the Climate Action Plan Forecast, the average monthly peak demand for transmission billing purposes is projected to increase from 60.623 MW in 2026, to 91.481 MW by 2045, implying a CAGR of 2.2%. The CAGR for

2030-2035 of 2.8% is higher than that for 2026-2030 (2.3%), 2035-2040 (2.4%) and 2040-2045 (1.2%) because of the adoption rates for CCHPs relative to the other periods.

Under the VEC Forecast the average monthly peak demand for transmission billing purposes is projected to increase from 55.990 MW in 2026 to 74.646 MW, with a CAGR of 1.5%. However, the CAGR is higher from 2030-2035 (2.1%) than from 2026-2030 (1.2%), 2035-2040 (2.0%) and 2040-2045 (0.8%) due to the projected adoption of EVs in that time period relative to the other periods.

In the VELCO Forecast the average monthly peak demand for transmission billing purposes is projected to grow from 58.778 MW in 2026 to 79.248 MW in 2045. The 2026-2045 CAGR is 1.6%. The CAGR for 2026-2030 (>2.8%) is slightly higher than that for 2030-2035 (<2.8%) and noticeably higher than 2035-2040 (1.0%) and 2040-2045 (>0.0%) due to the adoption rates for EVs relative to the other periods.

The plots are based on the following data:

Year	Climate Action Plan Forecast (MW)	VEC Forecast (MW)	VELCO Forecast (MW)
2026	60.623	55.990	58.778
2027	61.802	56.430	60.219
2028	63.173	57.018	61.856
2029	64.792	57.761	63.707
2030	66.495	58.663	65.733
2031	68.313	59.697	67.782
2032	70.277	60.869	69.825
2033	72.313	62.189	71.804
2034	74.416	63.645	73.699
2035	76.488	65.206	75.332
2036	78.574	66.786	76.603
2037	80.686	68.300	77.567
2038	82.713	69.686	78.280
2039	84.590	70.896	78.810
2040	86.140	71.903	79.198
2041	87.347	72.708	79.487
2042	88.411	73.364	79.585
2043	89.431	73.879	79.494
2044	90.457	74.297	79.372
2045	91.481	74.646	79.248
2026-2045 CAGR	2.2%	1.5%	1.6%
2025-2030 CAGR	2.3%	1.2%	2.8%
2030-2035 CAGR	2.8%	2.1%	2.8%
2035-2040 CAGR	2.4%	2.0%	1.0%
2040-2045 CAGR	1.2%	0.8%	0.0%

Table 3.2.7.B – Projected Average Monthly Peak Demand 2026-2045

3.3 Existing Energy Makeup

3.3.1 Power Purchase Agreements

To this point, entering PPAs instead of building its own resources has been a strategic decision driven largely by:

- Lack of capital allocated for project development and ownership;
- Lack of internal expertise and labor bandwidth to oversee generation project development;
- Lack of appetite for development risk associated with spending member money for project development and permitting and having the project eventually not receive all necessary permits.

This strategy may change if/when VEC believes the regulatory and financial environments allow.

Below is a table showing the long-term PPAs in VEC's Energy Portfolio.

Resource	Fuel Type	PPA End Date	Contracted MW (Est)	Annual MWH (Est)	% of 2026 Load
Hydro Quebec	Large Hydro	10/2038	22.0	128,480	25.3%
NYPA	Large Hydro	12/2038	5.8	39,082	7.7%
Newport Hydro	Hydro	8/2034	4.0	14,251	2.8%
Brookfield	Hydro	12/2035	10.0	64,928	12.8%
Ryegate	Wood	10/2032	1.8	11,348	2.2%
KCW	Wind	10/2037	8.0	21,326	4.2%
Sheffield Wind	Wind	10/2031	20.0	31,290	6.2%
Howard Wind	Wind	12/2027	20.0	39,560	7.8%
VT Standard Offer	Various Renewables	12/2045	10.5	24,241	4.8%
Alburgh Solar	Solar	12/2041	1.1	1,502	0.3%
Magee Hill Solar	Solar	11/2042	1.3	1,962	0.4%
Grand Isle Solar	Solar	12/2042	4.9	7,101	1.4%
Jericho Gravel Pit	Solar	4/2045	1.5	2,433	0.5%
Jericho Land Fill	Solar	10/2046	1.7	2,669	0.5%
Net Metering Excess Gen	Solar	Various	36.3	30,476	6.0%
Seabrook	Nuclear	12/2034	10.0	78,390	15.4%
Swanton Peaker	Oil	12/2040	3.5	53	0.0%
Total			162.4	499,092	98.2%

The PPA for Sheffield Wind is made up of 10.0 MW at a Fixed-Price for the associated Energy and RECs; and 10.0 MW of associated Energy, but no RECs, at a price that fluctuates each hour based on a function of the Real-Time LMP at the Sheffield generation node. Because of this, VEC only considers 50% of the volume shown above as a hedge against price volatility and contributing to its Carbon-Free and Renewable goals.

Below is a table showing the long-term PPAs in VEC's energy portfolio that contribute to the Carbon-Free and Renewable goals, as well as the % of 2026 load those contracts serve.

Resource	Fuel Type	PPA End Date	Contracted MW (Est)	Annual MWH (Est)	% of 2026 Load
HQ US Energy Services	Large Hydro	10/2038	22.0	128,480	25.3%
NYPA	Large Hydro	12/2038	5.8	39,082	7.7%
Newport Hydro	Hydro	8/2034	4.0	14,251	2.8%

Brookfield	Hydro	12/2035	10.0	64,928	12.8%
Ryegate	Wood	10/2032	1.8	11,348	2.2%
KCW	Wind	10/2037	8.0	21,326	4.2%
Sheffield Wind	Wind	10/2031	10.0	15,645	3.1%
Howard Wind	Wind	12/2027	20.0	39,560	7.8%
VT Standard Offer	Various Renewables	12/2045	10.5	24,241	4.8%
Alburgh Solar	Solar	12/2041	1.1	1,502	0.3%
Magee Hill Solar	Solar	11/2042	1.3	1,962	0.4%
Grand Isle Solar	Solar	12/2042	4.9	7,101	1.4%
Jericho Gravel Pit	Solar	4/2045	1.5	2,433	0.5%
Jericho Land Fill	Solar	10/2046	1.7	2,669	0.5%
Net Metering Excess Gen	Solar	Various	36.3	30,476	6.0%
Seabrook	Nuclear	12/2034	10.0	78,390	15.4%
Swanton Peaker	Oil	12/2040	3.5	53	0.0%
Total			152.4	483,447	95.1%

The percentages assume an annual energy requirement of 508,000 MWh. On this assumption, VEC's energy portfolio in 2026 is projected to be approximately 95% carbon-free and 79% renewable on an annual basis. It should be noted that the hourly percentage of carbon-free and renewable resources will have a very wide range, with some hours below 20% and other hours over 100% depending on actual load, sunshine, wind speed and water flows.

3.3.2 VEC Owned Generation

At this point, VEC does not own any generation in its Energy Portfolio. Instead it relies on Power Purchase Agreements (PPA) with developers for the offtake of projects. Some of these projects are for the entire output of the project, while others are for only a fixed percentage of the output.

3.3.3 Co-op Community Solar

VEC offers members the option of sponsoring panels in our three solar arrays located in Hinesburg, Grand Isle, and Alburgh. Members pay a lump sum up-front and then are guaranteed fixed monthly bill credits on their electric bill. By the end of the term (either 10 or 20 years), the total of the credits exceeds the amount of the original up-front payment. One of the benefits of the program is that renters or homeowners who do not have a suitable site on their property can participate. If participants move out of VEC territory, they can get a refund based on the amount of time they have participated in the program.

Figure 3.3.4.A VEC board member John Ward promotes Community Solar

VEC has three community solar projects

- Alburgh Solar (3,996 panels, 1 MW, 100% sponsored)
- Magee Hill Solar (4,914 panels, 1.3 MW, 50% sponsored)
- Grand Isle Solar (19,490 panels, 4.8 MW)

We continue to see our members participating in our program and have sponsored 23% of the total capacity of the three sites. This equates to over 6,500 panels or about 1.7 MW. We continue to pursue funding to subsidize the enrollment of income-qualified members into VEC's Community Solar program. Participation in the program will provide direct benefits to members through monthly bill credits for a 10-year term, thus reducing their bills. Participation would also engage these members in our energy transformation future.

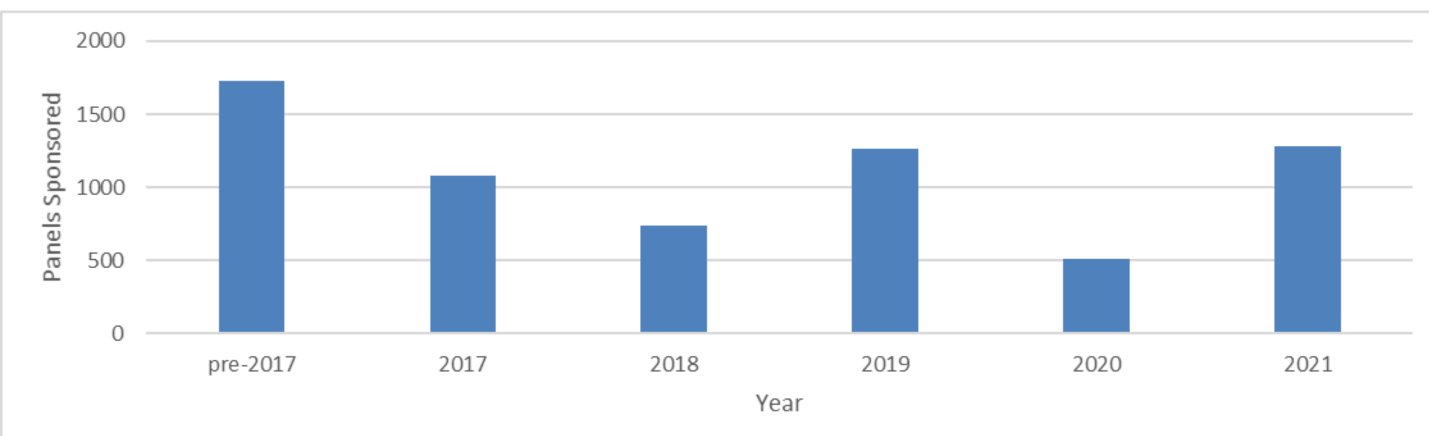


Figure 3.3.4.B Number of VEC Community Solar Panels sponsored by year

3.3.4 Member Owned Generation

VEC has seen a rapid increase of the amount of net-metering solar on its distribution system. Of the 22.8 MW total installed net-metering solar, larger net-metering projects 150kW and above (group-net metered) make up 30% (~6.7MW). Around 3.4 MW of solar is pending installation, with the clear majority (2.6MW) being projects less than 150kW. These larger interconnections generally have a bigger impact to VEC's distribution system and may cause constraints. If VEC identifies a constraint, the generation project developer is responsible to pay for the system upgrade per current PUC rules.

Around 3,000 of our members have net metering at their home (~8% of all homes in our service territory)

While there was a slight drop during the COVID pandemic VEC's quantity and capacity of net metering projects continue to increase. VEC closed its queue to new net-metering projects in early 2015 due to regulatory limits and then reopened its queue in 2017. Since 2017, VEC has seen around 326 applications annually.

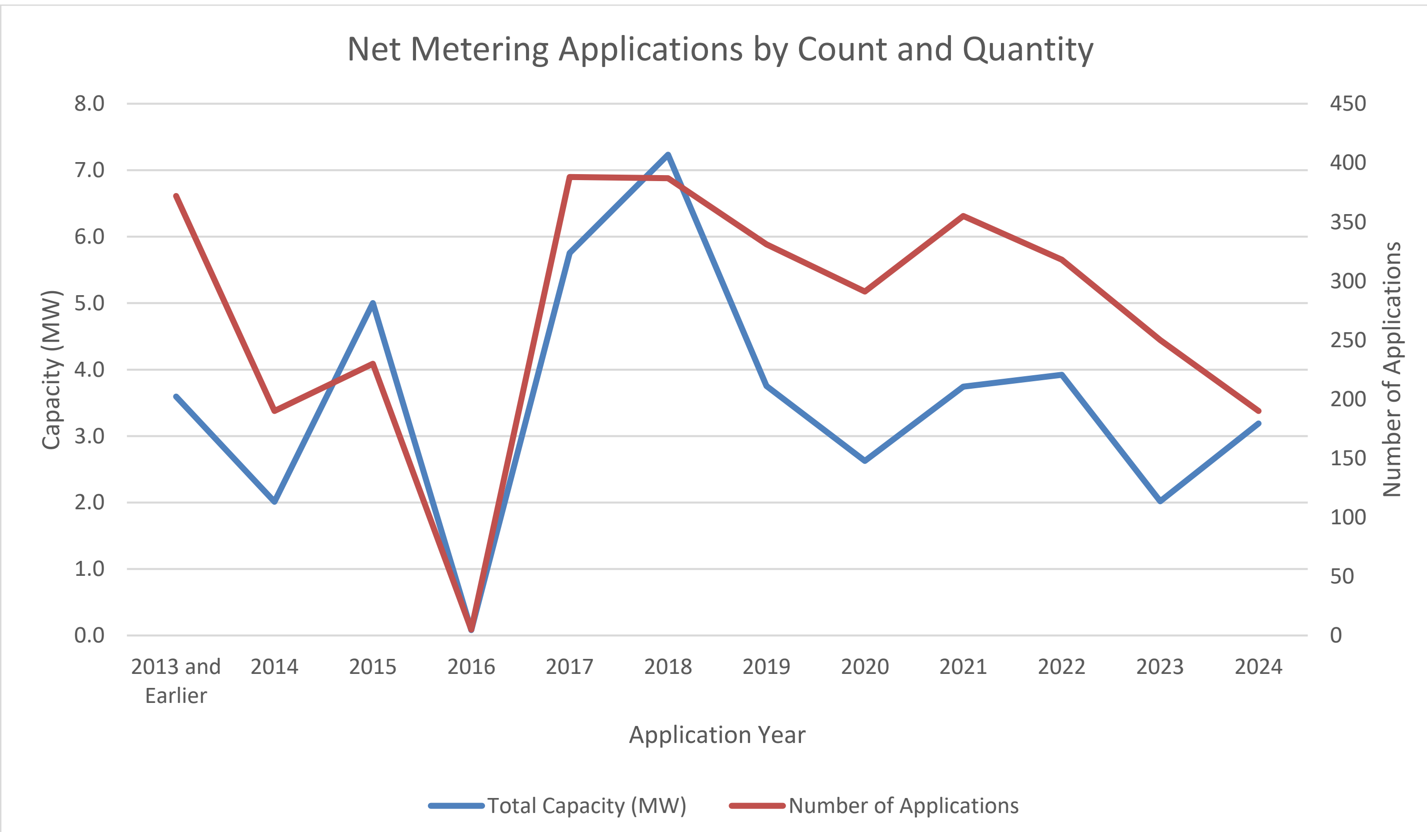
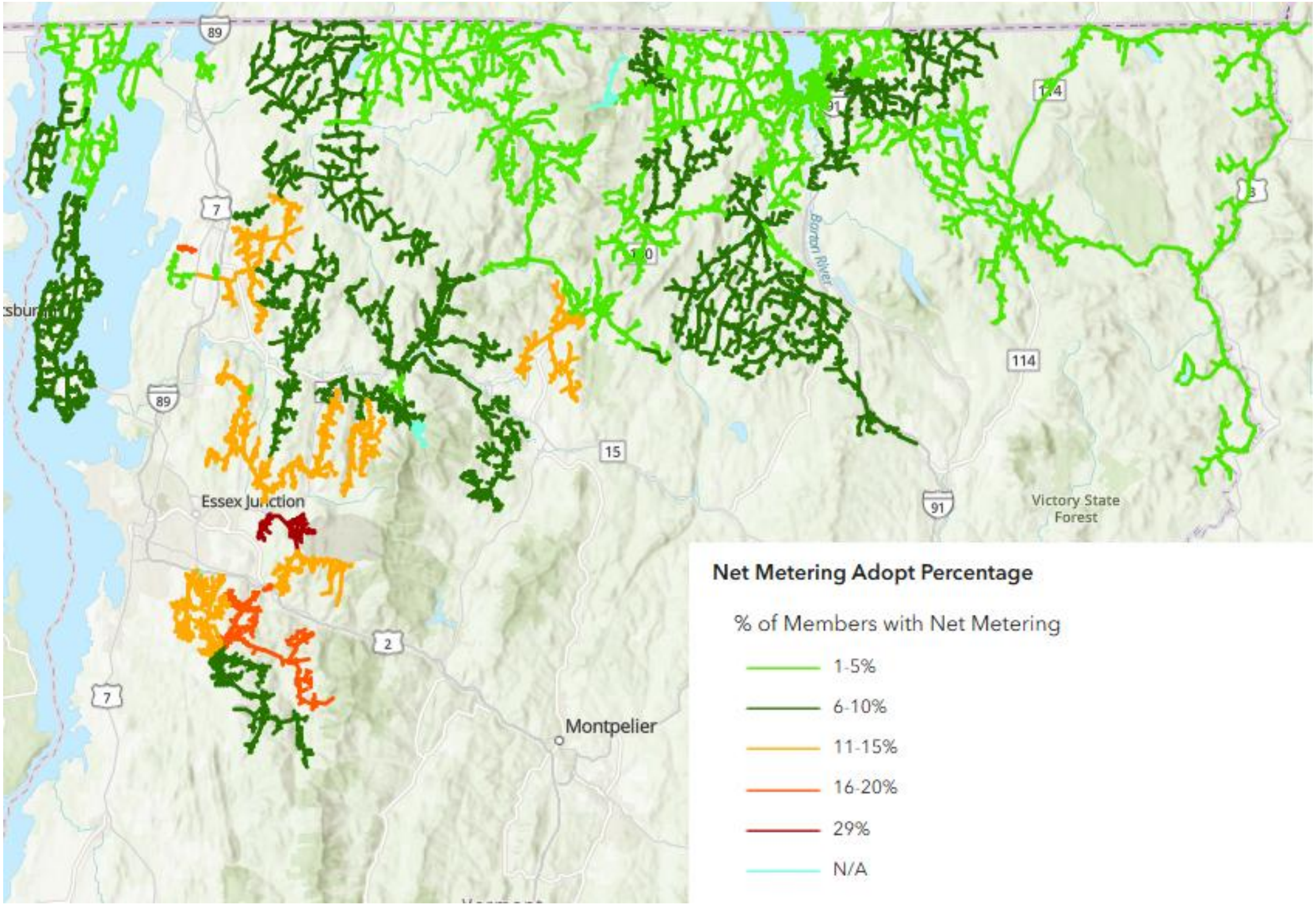


Figure 4.3.4.A Net-metering by size and Application (current as of 01/01/2025)

Location of Net Metering

Net metering projects have been primarily located off substations in Grand Isle, Chittenden, and Franklin Counties with the town of Hinesburg representing the largest quantity. The figure below shows these residential projects by feeder.



3.3.5 ISONE Energy Markets

VEC operates in the wholesale power markets administered by the ISONE. Fuel prices and locational supply and demand conditions in the New England power markets determine the cost of spot market energy and other longer-term bilateral energy purchases, while regional conditions affect the cost of other power requirements, such as capacity and ancillary services. Consequently, the economic viability of any resource that VEC might consider as part of its power supply portfolio is a function of conditions in the wholesale fuel and electricity generation markets. A utility can purchase power at these spot market prices or purchase from other sources at fixed prices to hedge against market volatility.

Hourly Locational Marginal Prices (LMPs) are developed and published by ISONE for energy delivered at specific points, or 'nodes' on the system, where generation or transmission connects to the bulk power grid. LMPs for each node are established for two energy markets operated by ISONE -- the Day-Ahead and the Real-Time markets -- to allow efficient economic dispatch of generators in the region. Each generating unit providing energy to the spot market at a given location (e.g., at the generator bus, or delivered into pool transmission facilities) receives a clearing price based on the LMP at that location. In general, the LMP reflects the bid price(s) of the most expensive source(s) providing energy to that location, adjusted for the marginal cost of transmission losses at each node. Under this market structure, generation suppliers have incentive to bid at or near their short-run variable costs of providing energy.

The ISONE market system for energy is 'multi-settlement', meaning there are separate settlements with ISONE for generators and dispatchable loads, on the one hand, and load-serving entities (including VEC), on the other.

Specifically, ISONE pays for generation and dispatchable load based on nodal, hourly LMPs at their specific location. In separate transactions with load-serving entities, it charges load based on the weighted average of nodal LMPs within the load zone in which the load resides. There are eight ISONE energy pricing zones, or load zones: one for each of the states of Vermont, New Hampshire, Maine, Rhode Island and Connecticut, and three within Massachusetts. VEC's cost to serve load is based on the Vermont Zonal LMP. These costs are offset by revenues received for VEC's supply resources based on the specific nodal LMPs where they are connected to the NEPOOL system.

LMPs are a function of many factors including New England-wide load net of efficiency and behind-the-meter generation, natural gas prices, oil prices, emissions pricing and the generation fleet in the region managed by ISONE.

To project energy market costs at the Vermont Load Zone, VEC developed forecasts in house using combinations of historic prices at the Vermont Load Zone and the MA Hub, the most liquid trading point in the ISO-NE settlement system; 2026-2032 prices for electricity on the Intercontinental Exchange, one of the most liquid trading platforms used by utilities to hedge spot market energy costs; and prices for Natural Gas on the New York Mercantile Exchange (NYMEX).

Four forecast scenarios were developed, with each consisting of monthly forecasts for Peak, Off-Peak and All Hours, where Peak hours are defined as Hours ending 0800-2300 Monday-Friday excluding NERC Holidays, Off-Peak hours are all those that are not Peak hours, and All Hours are the weighted average of the On-Peak and Off-Peak hours.

The four forecast scenarios are:

ICE Forwards at Nat Gas – the forecasts in this scenario are based on the forward market prices (those prices at which hedges against spot market prices can be purchased for) for January 2026 - December 2032 on the Intercontinental Exchange (ICE) as of the close of business on March 19, 2025. Prices for January 2033 and beyond were using the ICE prices for the corresponding month in 2032 and multiplying the increase in Natural Gas prices. ICE is one of the most liquid trading platforms for securing fixed prices for electricity, and, at least theoretically, consider projections of natural gas prices and new generation coming on-line in New England; but also have a risk premium built in for the potential for extreme weather to impact prices. Despite this risk factor, spot market prices are occasionally higher than the forward prices when unpredicted events take place that cause prices to spike.

VT Zone Historic at Nat Gas – Actual average spot market prices from January 2020 – December 2024 were averaged for each month of the year. Prices for January 2026 – December 2037 were projected using the ratio of forward Natural Gas prices on the NYMEX for the month compared to the average price for each month from January 2020 – December 2024. Prices beyond 2037 were projected using a 2.5% escalator applied to the price from the same month in the previous year.

The average monthly prices over the past four years were used as a starting point to capture and smooth out the volatility in market prices over that time.

NYMEX future prices were used because the marginal cost of electricity in New England is highly correlated to the daily price of natural gas, which itself is largely a function of weather and supply. The weather is difficult for the natural gas traders to predict, but, least theoretically, the forward price a risk premium for the potential for extreme weather events imbedded in it, as well as the latest knowledge regarding supply additions are subtractions. .

VT Zone Historic at 2.5% - Actual average spot market prices from January 2020 – December 2024 were averaged for each month of the year. Prices for January 2026 – December 2045 were projected by assigning a 2.5% annual escalator to the monthly prices beginning in 2025 through the remainder of the study period.

The average monthly prices over the past four years were used as a starting point to capture and smooth out the volatility in market prices over that time.

The 2.5% annual escalation was assumed to mimic long-term inflation. This method captures the seasonality of Natural Gas prices and electricity and the long-term trend of inflation. However, it does not capture the volatility of the natural gas market and is counter to the de-escalation in the NYMEX natural gas prices through the early 2030s.

Average of All 3 – The monthly prices of all three scenarios were averaged together. This method reflects the merits, drawbacks and trends of each scenario and, at least theoretically, provides a middle ground.

The "ICE Forwards at Nat Gas" and "VT Zone Historic at Nat Gas" forecasts have similar trends, applied to different starting points. The "VT Zone Historic at 2.5%" scenario starts at a noticeably lower level, but with a continuously increasing trend, resulting in it starting as the least expensive scenario, but becoming the most expensive scenario by 2031.

The following three figures show the resulting annual average On-Peak, Off-Peak, and Around-the-Clock energy prices at the Vermont Load Zone in nominal dollars for the three cases.

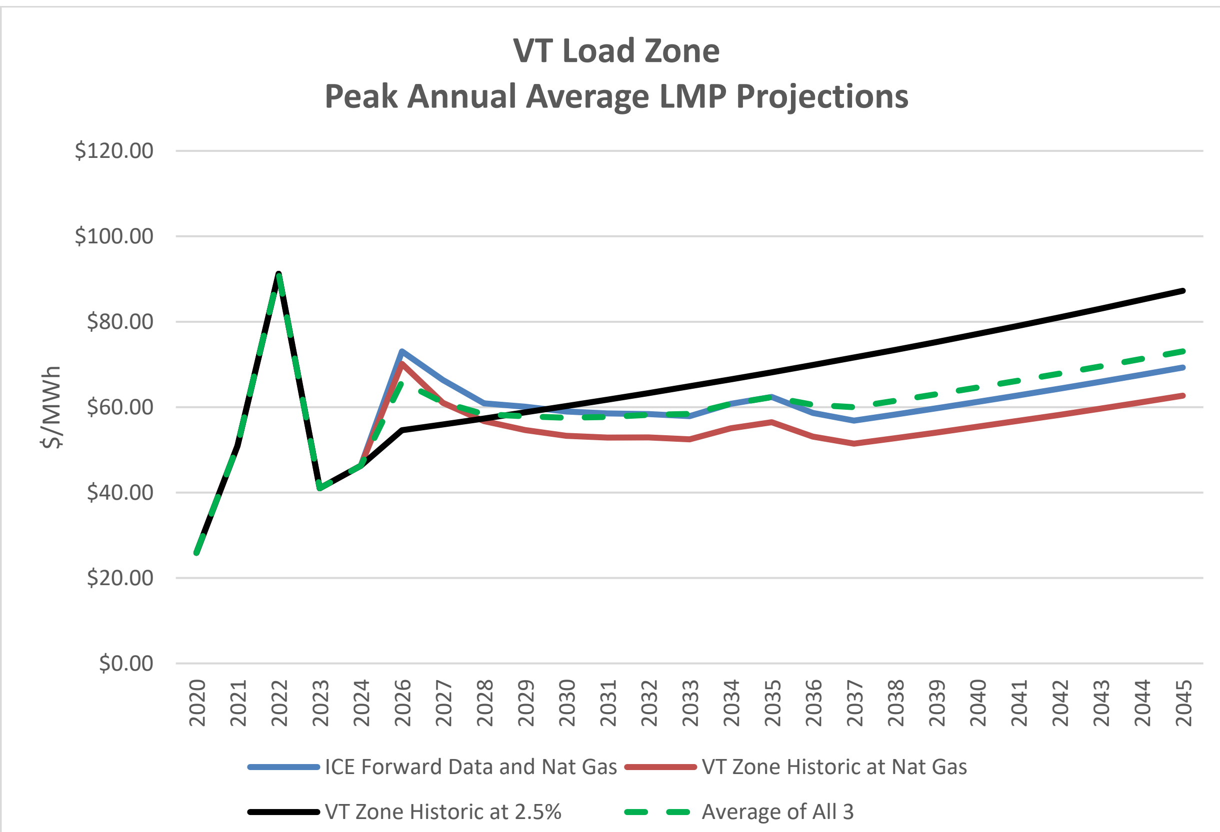


Figure 3.3.6.A – VT Load Zone On-Peak Annual Average LMP $/MWh

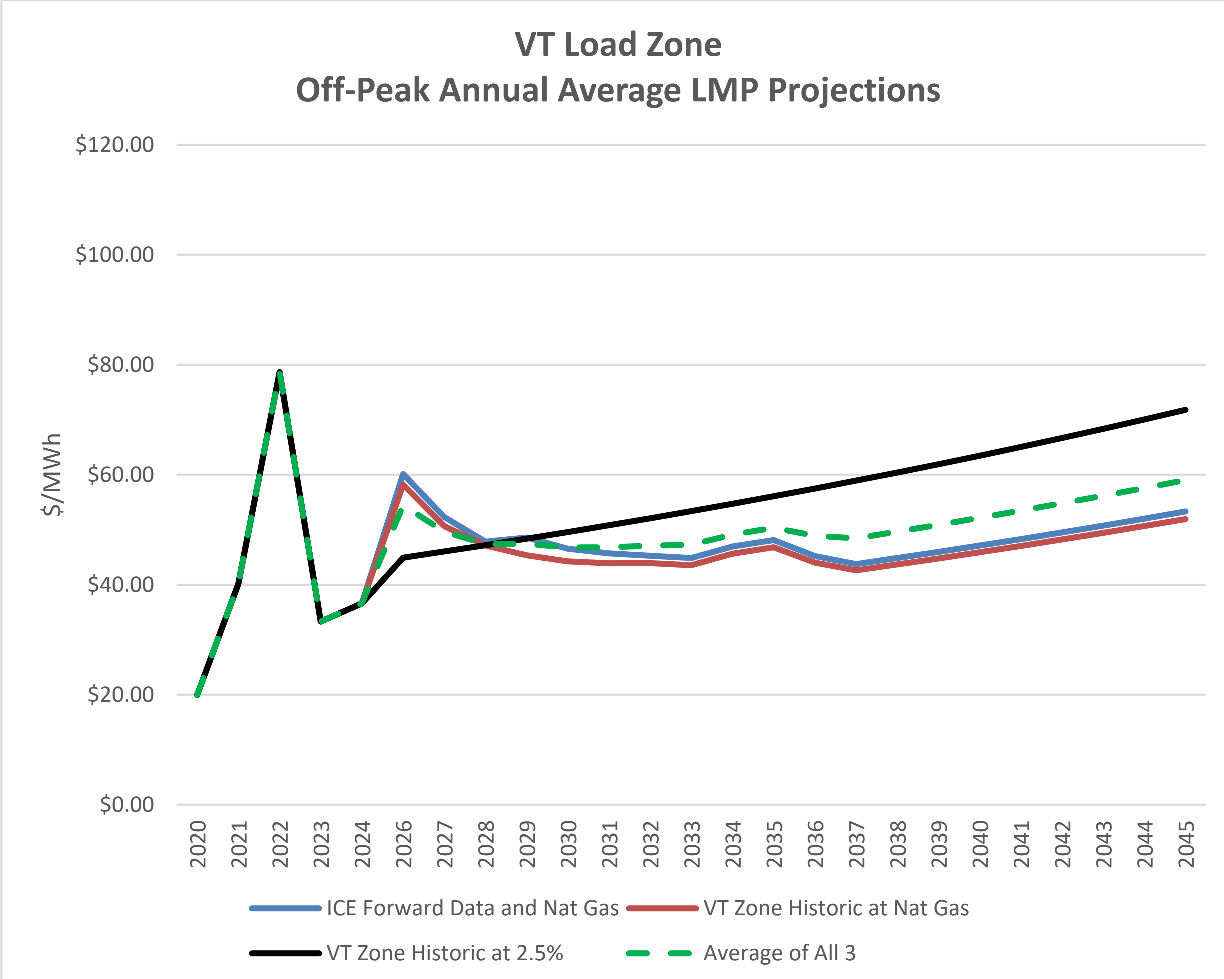


Figure 3.3.6.B – VT Load Zone Off-Peak Annual Averfage LMP $/MWh

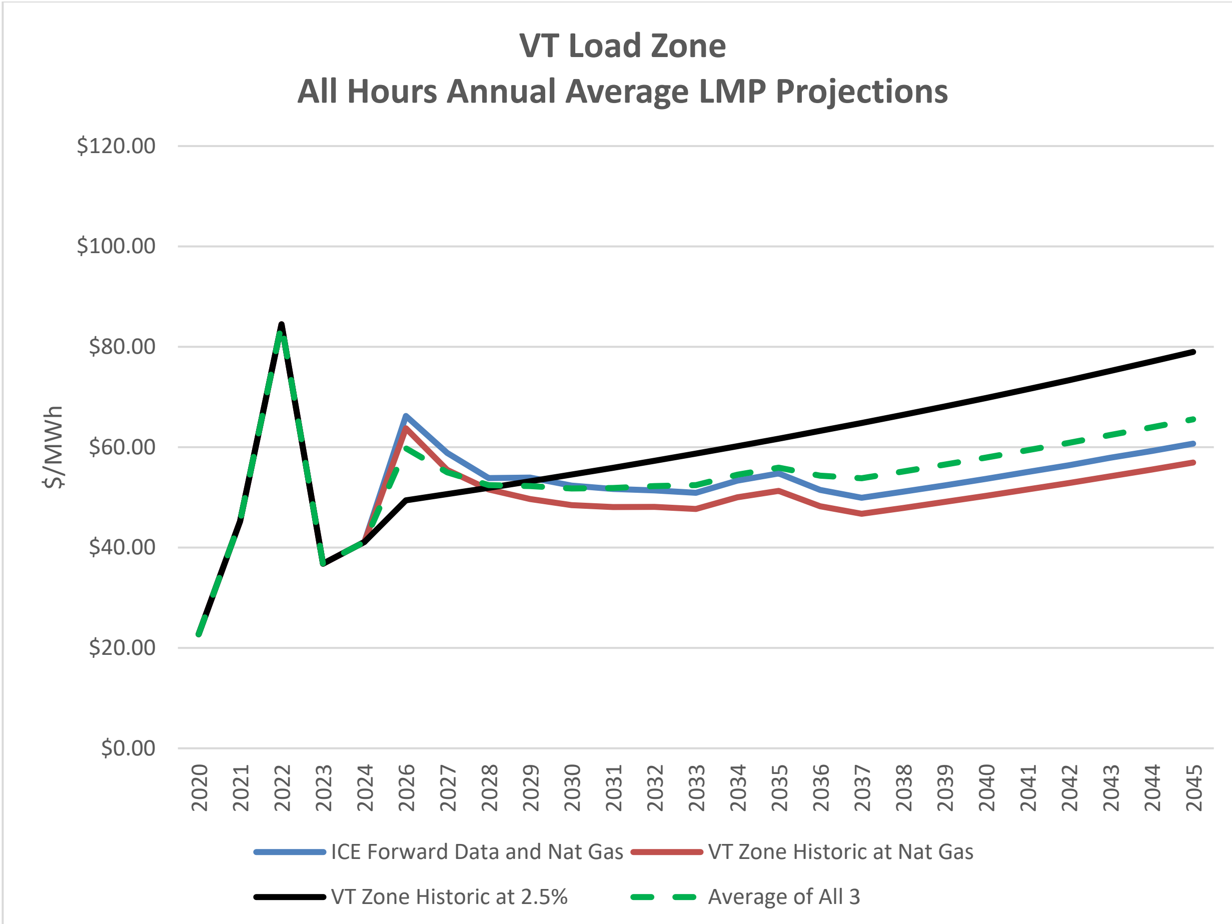


Figure 3.3.6.C – VT Load Zone Around-the-Clock Annual Average LMP $/MWh

It is important to note that long-term forecasts are intended to be predictors of potential trends. Because of the uncertainty involved in all of the factors, the trends of the forecasts are intended to be more reliable in the shorter term and less reliable as time goes on.

VEC will use all our forecast scenarios in its decision-making processes, with further analyses in this document being based on the "Average of All 3" scenario.

3.3.6 Vermont Renewable Energy Standard Rules

In 2015 the Vermont legislature passed Act 56. The Act established annual Renewable Energy Standard (RES) for Total Renewable Energy (Tier I), Distributed Renewable Energy (Tier II) and Energy Transformation Projects (Tier III) for VEC and most other utilities in Vermont beginning in 2017.

In 2024 the Vermont legislature passed H.289 which amended the Renewable Energy Standard beginning in 2025.

The Act defines existing renewables as those that came into service prior to January 1, 2010 and new renewables as those that came, or will come, into service after December 31, 2009 but excluding energy generated by a hydroelectric generation plant with a capacity of 200 MW or greater. Distributed Renewable Energy resources are defined as energy coming from a renewable energy project that has a plant capacity of 5 MW or less, is in Vermont, and came into service after December 31, 2009.

VEC is required to have total renewable energy (Tier I) equal to at least 63% of its annual retail sales beginning in 2025 escalating to 67% in 2028 and then to 100% in 2030. A utility that does not meet this requirement in any year must make a payment into the Vermont Clean Energy Development Fund equal to the product of the annual Alternative Compliance Payment (ACP) and the difference between the utility's annual total renewable energy requirement and the actual total renewable energy in the utility's portfolio in that year. The ACP for 2025 is $12.72 and escalates at the Consumer Price Index.

As a subset of its total renewable energy requirement, VEC is required to have at least 5.8% of its annual retail sales from distributed renewable energy (Tier II) in 2025, increasing by 2.0% each year through 2031, then maxing out at 20.0% in 2032. VEC's 2021 requirement was 3.4%. A utility that does not meet this requirement in any year must make a payment into the Vermont Clean Energy Development Fund equal to the product of the annual ACP and the difference between the utility's annual distributed renewable generation requirement and the actual distributed renewable generation in the utility's portfolio in that year. The ACP for 2025 is $76.35 and escalates at the Consumer Price Index.

In addition to the Tier I and Tier II renewable energy requirements, VEC also has an annual energy transformation (Tier III) requirement equal to 7.33% of its annual retail sales in 2025 increasing by 0.667% each year until reaching 12% in 2032. VEC's 2021 requirement was 4.67%. Distributed renewable generation in excess of the utility's distributed renewable generation (Tier II) requirement may be used to satisfy the utility's energy transformation (Tier III) requirement. A utility that does not meet its energy transformation requirement in any year must make a payment into the Vermont Clean Energy Development Fund equal to the product of the annual ACP and the difference between the utility's annual energy transformation (Tier III) requirement and the actual energy transformation (Tier III) credits acquired by the utility in a given year. As with distributed renewable (Tier II) generation, the ACP for 2025 is ___ and escalates at the Consumer Price Index .

In addition to the Tier I – Tier III categories that were included in the original RES, the amended RES added a fourth Category called Regional Renewable Energy. This category covers New Renewable Energy whose energy is either generated in, or can be shown to have been delivered into, New England. Under this requirement, VEC must have entitlement to energy from Regional Renewable Energy equal to at least 5% of its annual load beginning January 1, 2030 and 10% beginning January 1, 2035. Because VEC's Total Renewable Energy requirement is 100% beginning January 1, 2030, this new category does not increase VEC's renewable portfolio threshold, but instead provides it with more options to meet its requirements.

Value of Renewable Energy Certificates

VEC purchases generation and RECs from facilities that qualify as both Vermont Tier I resources and also as Class I resources in Massachusetts and Connecticut. The ACP essentially sets a cap on Tier I compliance costs. As a result, if VEC can sell RECs from Tier I eligible resources as Class I RECs in other states at a price that is higher than what it would have to pay for Tier I qualifying resources, or the Vermont ACP, its members are better off financially.

In the past 5 years Massachusetts and Connecticut RECs have traded in a range of approximately $10.00 - $45.00/REC. These REC prices can change drastically over a several year period, but also year-to-year and within a year by amounts that can have a substantial impact on VEC's annual budget and long-range financial plans.

The value of the RECs is beyond VEC's control; however, VEC can hedge against price swings by selling RECs in advance. Contracts are typically available for up to 3 years from the time the terms are agreed.

VEC monitors the price of RECs though information provided by brokers and through its consultant, Sustainable Energy Advantage (SEA).

The future value of RECs is a function of many factors including:

- The rate at which new renewable resources come on line;
- REC rules and requirements in each New England state as well as surrounding control areas;
- Load in each state; and
- The difference in energy and REC values in neighboring control areas, especially New York which impacts the volume of renewable imports into New England.

VT Tier I RECs

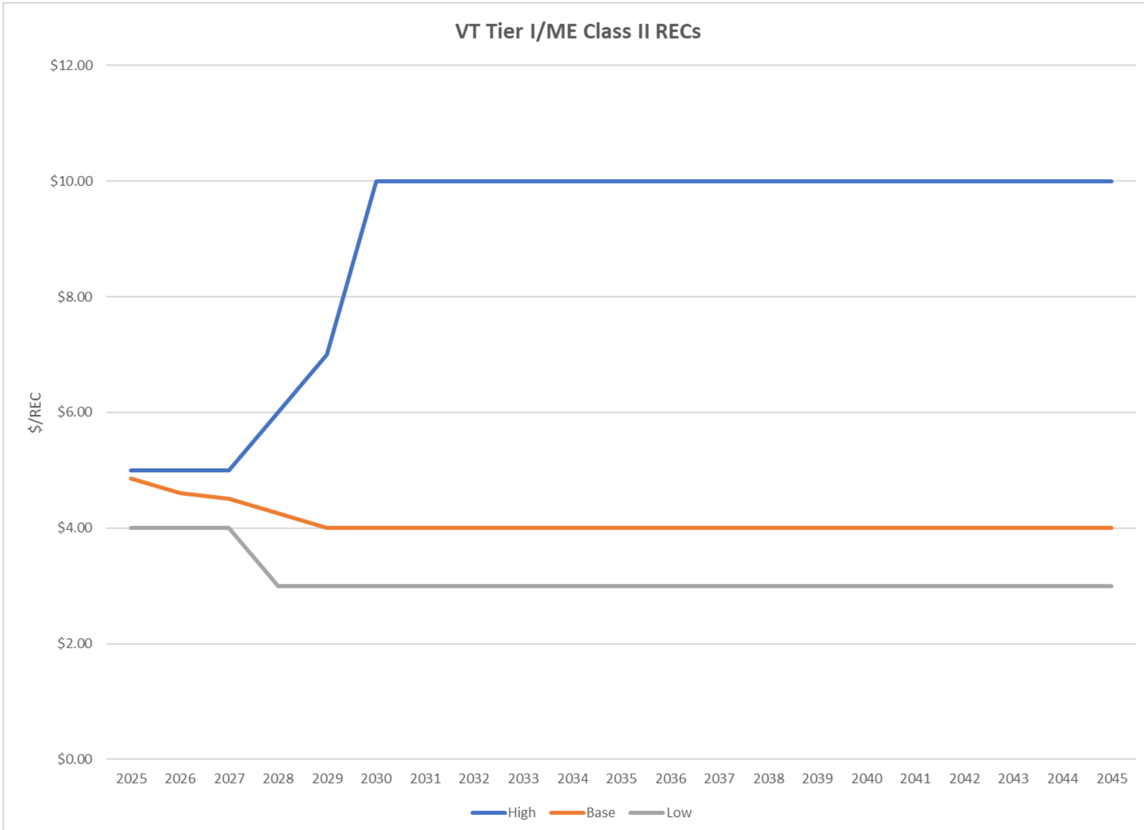
Vermont's Tier I requirement can be fulfilled with Existing Renewable Resources, which are those renewable resources that came on-line prior to January 1, 2010 and are located in, or can be shown to have had energy delivered into, New England.

Tier I RECs are similar to those that qualify as Maine Class II, and many Maine Class II resources are also registered as Vermont Tier I.

Currently the Vermont Tier I and Maine Class II pricing are very similar. In fact, VEC has used Maine Class II pricing as a proxy for Vermont Tier I because the Maine Class II REC market tends to be much more visible and liquid than VT Tier I. The main difference between the VT Tier I and the Maine Class II markets is in the ACP rates, which is a $/REC payment that each load serving entity can choose to pay for every MWh of shortfall in compliance with the RES requirement, instead of purchasing and retaining RECs.

The VT Tier I ACP began at $10.00 in 2017 and escalates each year based on inflation; the for 2025 was set in August 2024 at $12.72/REC. The ME Class II ACP rate is periodically set by the Maine PUC; the current ACP is $5.00/REC and was last changed in 2023. The ACP effectively serves as a cap on REC prices, although there have been times when REC prices have exceeded the ACP when REC supplies are low but LSEs do not want to be shown as not meeting the requirement. Presently, the VT Tier I market is not large enough to dictate the price; this can change in the future if legislatures in other states increase their existing renewable requirements.

Below are charts and tables of Tier I RECs prices under High, Base and Low Case Scenarios:



Year	High	Base	Low
2025	$5.00	$4.85	$4.00
2026	$5.00	$4.60	$4.00
2027	$5.00	$4.50	$4.00
2028	$6.00	$4.25	$3.00
2029	$7.00	$4.00	$3.00
2030	$14.39	$4.00	$3.00
2031	$14.75	$4.00	$3.00
2032	$15.12	$4.00	$3.00
2033	$15.50	$4.00	$3.00
2034	$15.89	$4.00	$3.00
2035	$16.28	$4.00	$3.00
2036	$16.69	$4.00	$3.00
2037	$17.11	$4.00	$3.00
2038	$17.53	$4.00	$3.00
2039	$17.97	$4.00	$3.00
2040	$18.42	$4.00	$3.00
2041	$18.88	$4.00	$3.00
2042	$19.35	$4.00	$3.00
2043	$19.84	$4.00	$3.00
2044	$20.33	$4.00	$3.00
2045	$20.84	$4.00	$3.00

The assumptions used to develop the High, Base and Low scenarios are:

Assumption	High	Base	Low
ME Class II ACP	Mimic VT in 2030	Status Quo	Status Quo
Existing Renewable Requirements in NE	Increase	Status Quo	Status Quo
Rainfall	Low	Moderate	High
Load Growth	High	Moderate	Low
New Renewable Requirements in NE	Decrease	Status Quo	Status Quo

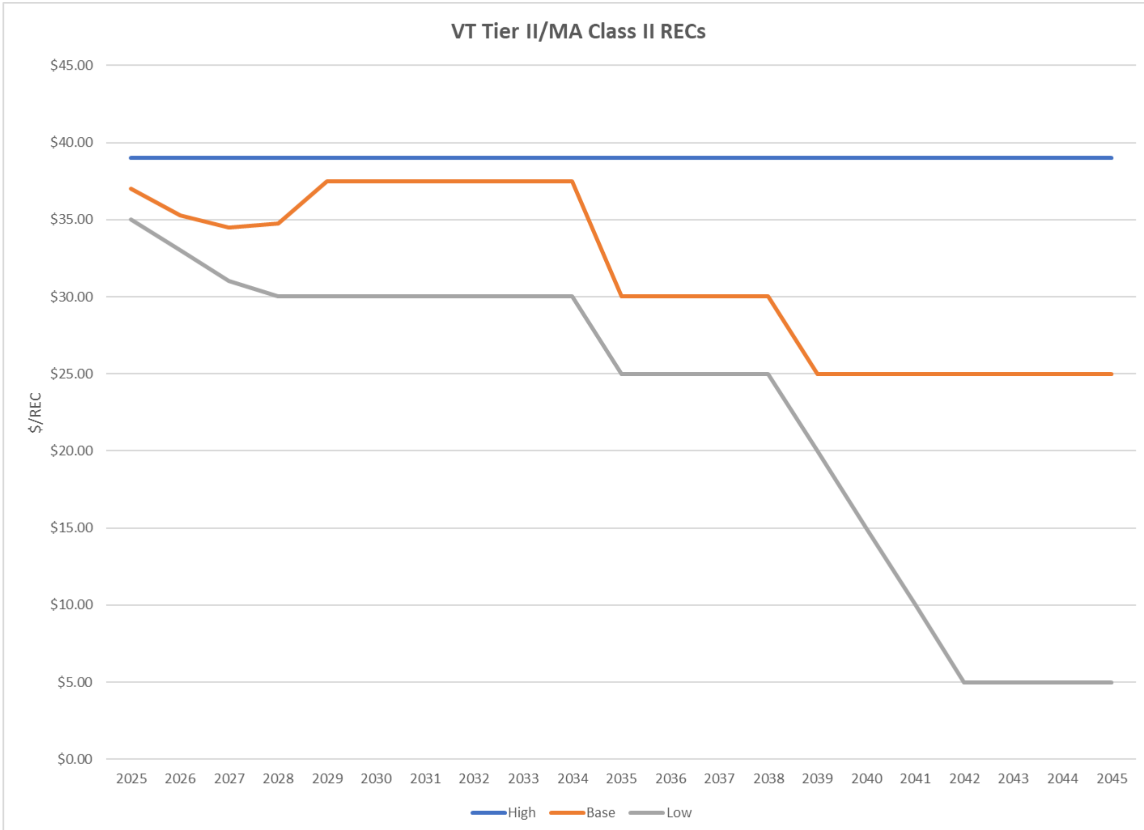
VT Tier II and MACT/RI Class I RECs

Vermont's Tier II requirement can be fulfilled with New Renewable Resources, which are those renewable resources with a plant capacity of 5 MW (AC) or less, is in Vermont, and came into service after December 31, 2009. Tier II RECs are similar to those that qualify as Massachusetts Class I, and many VT Tier II resources are also registered as MA Class I.

Currently the Vermont Tier II and MA Class I pricing are very similar. VEC uses MA Class I pricing as a proxy for Vermont Tier II because the MA Class I REC market tends to be much more visible and liquid. The main difference between the VT Tier I and the MA Class I markets is in the ACP rates, which is a $/REC payment that each load serving entity can choose to pay for every MWh of shortfall in compliance with the RES requirement, instead of purchasing and retaining RECs.

The VT Tier II ACP began at $63.00 in 2017 and escalates each year based on inflation; the for 2025 was set in August 2024 at $76.35/REC. The MA Class I ACP rate had been $50.00/REC in 2003 escalating at inflation. The MA ACP reached $71.57 in 2020, but legislation changed the rate to $60.00 in 2021, $50.00 in 2022, and $40.00 for 2023 and beyond. The ACP effectively serves as a cap on REC prices, although there have been times when REC prices have exceeded the ACP when REC supplies are low but LSEs do not want to be shown as not meeting the requirement. Presently, the VT Tier II market is not large enough to dictate the price; this can change in the future if legislatures in other states increase their existing renewable requirements.

Below are charts and tables of Tier I RECs prices under High, Base and Low Case Scenarios:



Year	High	Base	Low
2025	$39.00	$37.00	$35.00
2026	$39.00	$35.25	$33.00
2027	$39.00	$34.50	$31.00
2028	$39.00	$34.75	$30.00
2029	$39.00	$37.50	$30.00
2030	$39.00	$37.50	$30.00
2031	$39.00	$37.50	$30.00
2032	$39.00	$37.50	$30.00
2033	$39.00	$37.50	$30.00
2034	$39.00	$37.50	$30.00
2035	$39.00	$30.00	$25.00
2036	$39.00	$30.00	$25.00
2037	$39.00	$30.00	$25.00
2038	$39.00	$30.00	$25.00
2039	$39.00	$25.00	$20.00
2040	$39.00	$25.00	$15.00
2041	$39.00	$25.00	$10.00
2042	$39.00	$25.00	$5.00
2043	$39.00	$25.00	$5.00
2044	$39.00	$25.00	$5.00
2045	$39.00	$25.00	$5.00

The assumptions used to develop the High, Base and Low scenarios are:

Assumption	High	Base	Low
MA Class II ACP	Status Quo	Status Quo	Status Quo
Existing Renewable Requirements in NE	Status Quo	Status Quo	Increase
Off-Shore Wind Development	Slow	Moderate	High
Load Growth	High	Moderate	Low
New Renewable Requirements in NE	Status Quo	Status Quo	Status Quo

3.3.1 Total System Energy Requirements and Needs Assessment

Total System Energy Requirements refers to the total amount of energy consumed by VEC members in a given year. VEC can meet its requirements through generation that it owns, through power purchase agreements with suppliers, and/or through spot market purchases in the ISONE Day-Ahead and Real-Time energy markets.

The Total System Energy Requirements are compared to the energy projected to be supplied by the current committed and pending resources in VEC's power supply portfolio. The figure below provides a graphical comparison of the two with the resources grouped by fuel type. A table containing the data the graph is based on is included in "Appendix R: VEC Resource and Needs Projections."

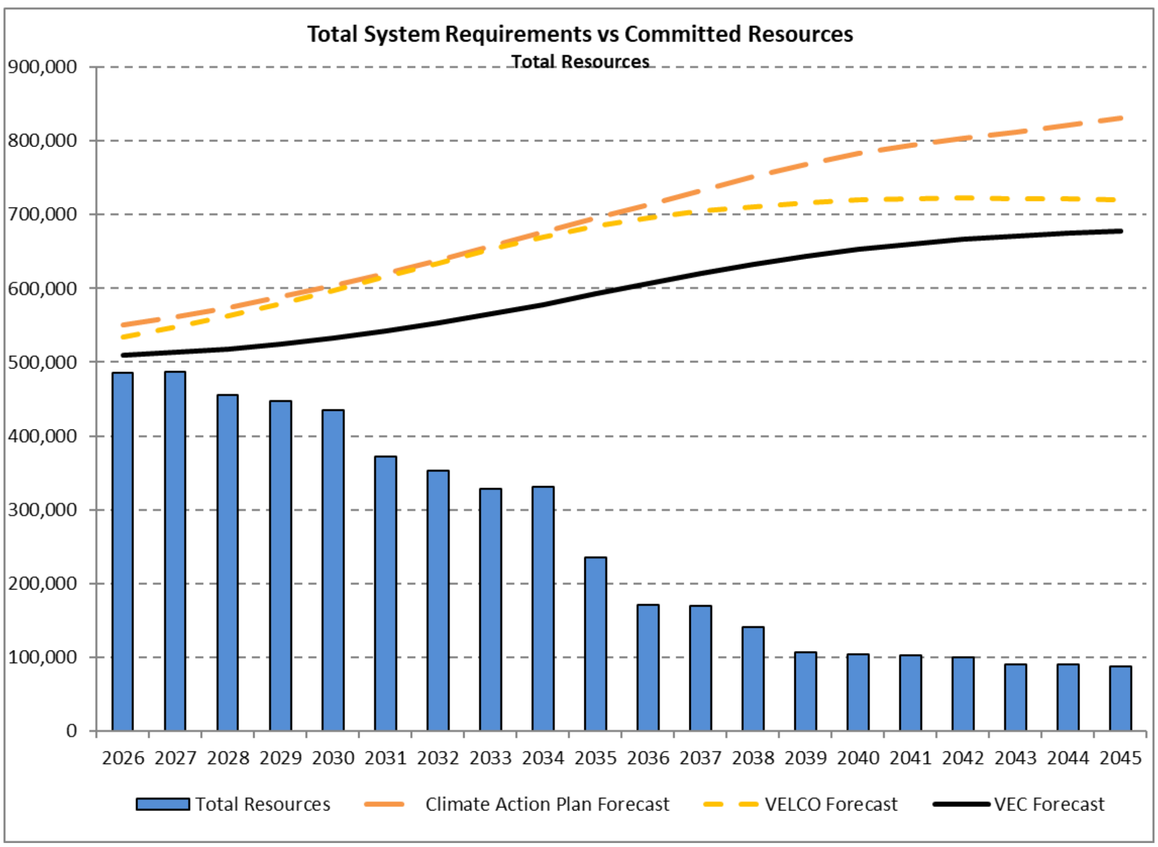


Figure 3.3.7.A – Total System Requirements vs Committed Resources

The following table shows VEC's annual projected hedged position with currently committed resources for the three load scenarios:

Year	Climate Action Plan Forecast	VEC Forecast	VELCO Forecast
2026	88.1%	95.4%	90.9%
2027	86.6%	94.8%	88.8%
2028	79.3%	87.8%	81.0%
2029	76.1%	85.3%	77.4%
2030	71.9%	81.5%	72.8%
2031	59.9%	68.5%	60.3%
2032	55.2%	63.7%	55.6%
2033	50.0%	58.1%	50.3%
2034	48.9%	57.2%	49.4%
2035	33.9%	39.8%	34.4%
2036	23.9%	28.1%	24.5%
2037	23.2%	27.4%	24.1%
2038	18.8%	22.3%	19.8%
2039	13.8%	16.5%	14.8%
2040	13.3%	15.9%	14.5%
2041	13.0%	15.6%	14.2%
2042	12.4%	15.0%	13.8%
2043	11.2%	13.5%	12.6%
2044	11.0%	13.4%	12.5%
2045	10.6%	13.0%	12.2%

Table 3.3.7.C Hedge Position of VEC's Energy Portfolio

There is no industry standard formula hedging strategy. In fact, the presence of different risk tolerances and market perspectives is the basis for liquid markets. VEC's current informal hedging strategy in the energy market is to be at least 90% hedged going into any given year and at least 80% hedged from 13-24 months prior to the beginning of a year; however, we allow flexibility in the timing in order to avoid having to enter transactions at a point when market prices are at unacceptable levels.

VEC is close to its self-imposed minimum hedge criteria of 90% through 2027 in all three load forecast scenarios

Renewable Energy Standard Requirements

The System Energy Requirements form the benchmark for assessing Tier I renewable energy requirements.

As noted above, H.289 requires that Vermont utilities retain RECs from resources that qualify to meet the total renewable energy requirement at a level that begins at 63% of total load in 2026 increasing to 67% in 2028 and 100% in 2030. Distributed Renewable Generation, or Tier II resources, must make up 7.8% of the total load in 2026 increasing by 2.0% every year to reach 17.8% in 2031, then increasing to 20.0% in 2032.

VEC refers to the difference between Total Renewable Energy and Tier II requirements as the Net Tier I Requirement.

The percentages of the Total Renewable Energy, Net Tier I, Tier II and Tier IV requirements are shown in the table below:

Year	Total	Net Tier I	Tier II	Tier IV

	Renewable Energy Requirement	Renewable Energy Requirement	Renewable Energy Requirement	Renewable Energy Requirement
2026	63.0%	55.2%	7.8%	0.0%
2027	63.0%	53.2%	9.8%	0.0%
2028	67.0%	55.2%	11.8%	0.0%
2029	67.0%	53.2%	13.8%	0.0%
2030	100.0%	84.2%	15.8%	5.0%
2031	100.0%	82.2%	17.8%	5.0%
2032	100.0%	80.0%	20.0%	5.0%
2033	100.0%	80.0%	20.0%	5.0%
2034	100.0%	80.0%	20.0%	5.0%
2035+	100.0%	80.0%	20.0%	10.0%

Table 3.3.7.D Total Renewable Energy, Tier I, Tier II and Tier IV requirements

Potential Resources To Meet Shortfalls

On-Shore Wind

On-shore wind resources are intermittent; however, unlike solar, they can provide power in any hour of the day and have energy production skewed to months in which solar output is lower due to the angle of the sun.

VEC is currently in discussion with three developers regarding wind projects that will qualify as Tier I/IV resources and also qualify as High-value RECs in MA and CT if VEC decided to sell the RECs and purchase strictly Tier I RECs to satisfy the Tier I requirement. Two of these projects are already on line, while the other has permits in place and expects to come on line in early 2027. Any of these projects can work as viable replacements to the Howard Wind project that expires at the end of 2027, and provide energy through the end of 2036 without the need for VEC to obtain a Certificate of Public Good[1] (CPG). However, VEC will likely need a CPG to purchase the output of the project that is not built yet, because that project will need 25-year contracts in order to obtain financing.

The owner of the Sheffield project is considering re-powering the facility after VEC's current contract expires in October 2031.

VEC, and other Vermont distribution utilities, are exploring participating in an RFP for on=-shore wind being issued by the Maine Public Utilities Commission (ME PUC). If details can be worked out with the ME PUC, VEC will participate as a potential off-taker of power generated by projects awarded contracts through the RFP.

For this IRP, VEC has assumed flat prices of $85 - $110//MWh for energy and associated RECs. The low end of the range is for prices from existing wind facilities, while the high end of the range is for new facilities. Both ends of the range have been informed by recent discussions with wind project developers and/or owners.

Biomass

Biomass compliments Hydro, Off-Shore Wind, On-Shore Wind and Solar by providing reliable baseload power without the need for battery storage. Biomass qualifies as a renewable resource under current Vermont RES rules and can be considered a Class I (high-value) REC in MA and CT, which allows for VEC to sell any RECs in excess of Tier II or Tier IV requirements and purchase lower-cost Tier I RECs in return, reducing member costs.

[1] Vermont utilities do not need to obtain a CPG for the output of renewable resources outside of Vermont unless the contract is for longer than 10 years.

The Tier I Requirements vs Resources chart and table above assume Ryegate's Standard Offer contract expires at the end of October, 2031. If this contract is renewed with a similar distribution among the Vermont utilities, VEC can expect to receive its current 1.8 MW share, that provides approximately 14,000 MWh of energy and RECs each year. If the Standard Offer contract is not renewed, it can provide an opportunity for VEC to negotiate a contract with the owner and add additional renewable baseload power to its resource mix.

Existing Biomass facilities in other states in New England are a potential source, if they have open positions in the future. VEC has assumed a price of $100/MWh escalating at 2% per year for Energy and associated RECs. This assumption is informed by the current Ryegate contract and offers received by VEC through a renewable energy RFP issued in the summer of 2024.

VEC is not aware of any Biomass facilities under construction or proposed to be built. All current Biomass facilities VEC is aware of qualify for Tier I, but not Tier II or Tier IV.

Off-Shore Wind

Off-shore Wind resources are intermittent, but have a considerably higher capacity factor than On-shore Wind due to the more-steady nature of ocean winds and larger turbines. ISO-NE modeling shows capacity factors of proposed projects in the 45%-50% range.

In the 2022 IRP, contract pricing for Off-Shore Wind projects assumed to be $80-$100/MWh, with no escalation. The low level of the range was based on PPA prices for energy and RECs that were executed in the early 2020s for Mayflower Wind. The high end of the range was to model potential prices increases for wind projects with characteristics that can drive the price up, for example: lower capacity factor, small land lease area that would lead to fewer turbines and potentially fewer MW, and equipment price increases.

Since the 2022 IRP was filed, off-shore wind developers have realized that the projects can not be developed at prices in the $80-$100/MWh range leading to many contracts being cancelled. Prices have increased significantly since then. In early 2024, the state of New York issued a press release stating that it had entered two contracts for Off-shore wind projects at an average price of $150.15/MWh.

In October 2023, Connecticut, Massachusetts and Rhode Island issued a multi-state RFP for off-shore wind. In addition, Rhode Island issued a separate RFP for 200 MW – 1,200 MW of off-shore wind through which developers can offer to provide to only Rhode Island, or the three states. Through these RFPs, Massachusetts and Rhode Island combined to entered PPA negotiations with developers of three projects for a combined total of 2,878 MW.

Although no information regarding prices has been officially released, prices are believed to be at least $140/MW for energy and RECs. This is a significant increase in price compared to what was modeled in the 2022 IRP. Recent RFPs issued by some New England states suggest the pricing of off-shore wind is now in the range of $140/MWh.

Solar

In recent years solar has been the least expensive NEW renewable resource for purchasing both energy and RECs from the same facility. However, solar also has the lowest capacity factor of all renewable options, mainly because it can only produce energy during daylight hours.

Prices had fallen significantly in the past decade. However, VEC has seen the price increase over the past 1-2 years. Recent offers for 25-year PPA are in the $85 - $90/MWh (depending on size and location) with a 1.75% annual escalator or a flat price of $100 - $110/MWh. These prices assume the projects still qualify for investment tax credits (ITC). Offers for flat pricing assuming no investment tax credits are $135 - $145/MWh.

VEC believes there is a high likelihood of the ITC going away as a result of the United States Congress negotiating a federal budget in 2025. If this does happen, developers expect to have 60-days, from the signing of the budget bill, to spend at least 5% of total project costs in order to qualify for current ITCs. With that assumption, it may be in VEC's best interest to move quickly on negotiating PPAs for in-state solar projects.

Hydro -

A typical hydro facility has an annual capacity factor of 25% - 35% depending on its location and annual precipitation. Although unit-specific output is intermittent, it does not change drastically from one hour to the next; the biggest uncertainty is precipitation related, and usually on seasonal and annual bases when there are extended dry spells or rainy spells.

However, because of VEC's size and the size of many hydro facilities in New England and Quebec, VEC has been able to enter PPAs with owners of existing facilities that provide reliable output, as long as its purchase is small compared to owner's hydro portfolio.

Because virtually all hydro facilities in New England are existing resources, their price for energy tend to be tied to the forward market for energy-only plus projections for a Tier I REC. Because of this, the cost for hydro energy and an associated REC is the same as the assumptions for a Market Price Energy + Tier I REC purchase.

3.3.2 100% Carbon Free Analysis

The System Energy Requirements form the benchmark for assessing 100 % Carbon Free energy requirements.

As stated earlier, In February 2021, in support of the Cooperative doing its part to combat climate change and minimize its impact on the environment, the VEC Board of Directors passed a resolution directing VEC to:

- "…procure energy and/or environmental attributes from non-carbon emitting generating resources sufficient to cover 100% of VEC's annual energy requirement for each year."

"…procure energy and/or environmental attributes from renewable resources sufficient to cover 100% of VEC's annual energy requirement for each year starting in 2030."

The figure below compares VEC's projected load to its current carbon-free committed and pending resources in each load scenario for 2026 - 2030. A table containing the data the graph is based on is included in "Appendix R: VEC Resource and Needs Projections."

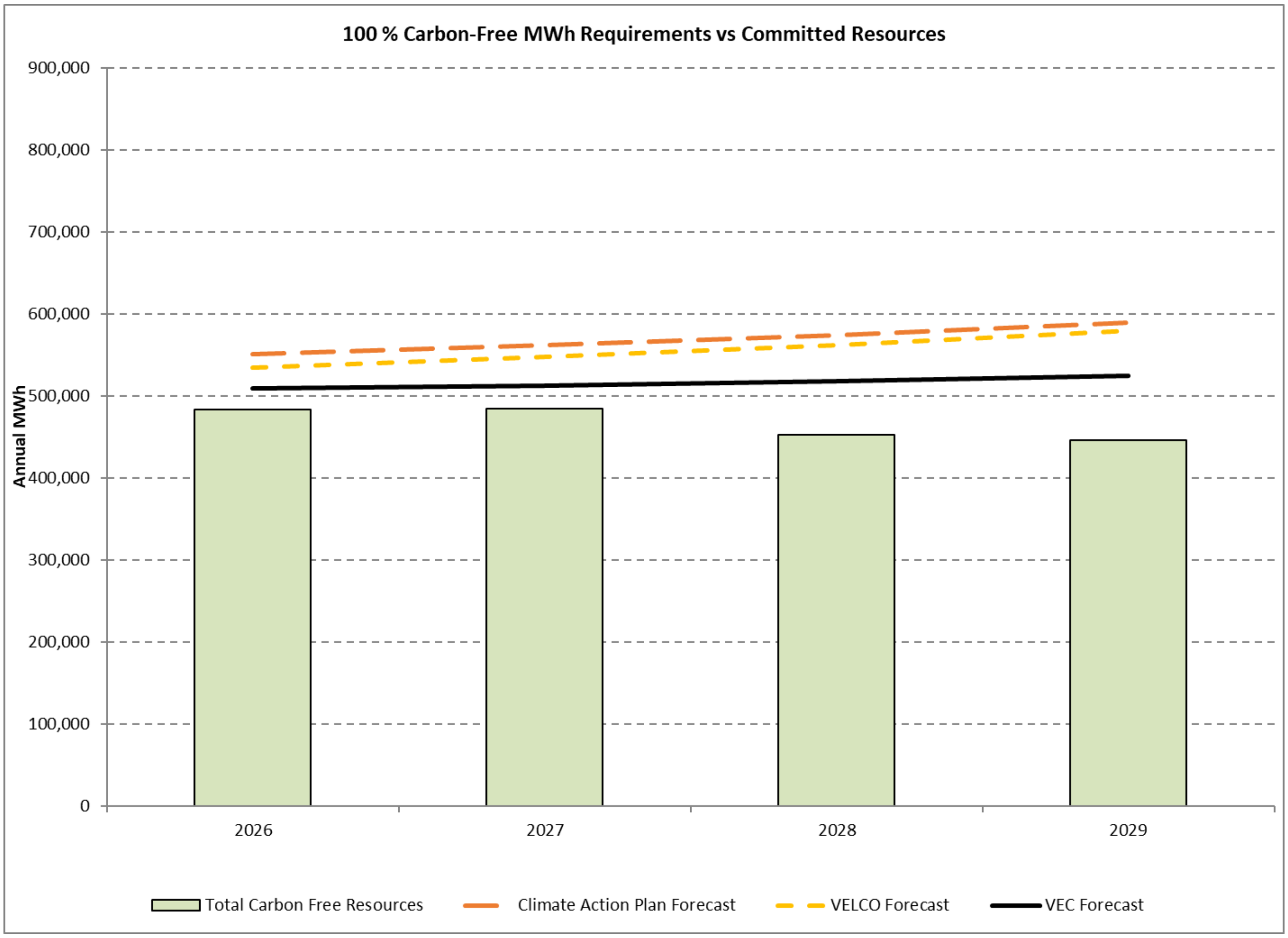


Figure 3.3.8.B – Tier I Pojrected Required MWh vs Resources Before Sale of High-Value REC

The annual carbon-free percentages are shown in the table below:

Year	Climate Action Plan Forecast	VEC Forecast	VELCO Forecast
2026	87.7%	95.0%	90.5%
2027	86.2%	94.4%	88.4%
2028	78.9%	87.4%	80.6%
2029	75.7%	84.9%	77.0%

VEC is projected to be slightly short carbon-free resources in all three forecast scenarios and through 2027 in all three forecast scenarios. The shortfalls increase in 2028 as the contract for Howard Wind expires.

Carbon-Free Potential Resources

Resources from which environmental attributes would likely be sourced from include: existing nuclear, instate-wind, hydro-facilities located in New England, Hydro-Quebec, and new In-state solar facilities.

The price for Energy and Environmental Attributes from existing facilities will be a function of the markets at the time a deal is reached. The value of the Environmental Attributes can vary depending on the fuel source of the generation project sourcing the attributes, for example those from a nuclear facility or Hydro-Quebec are typically less expensive than those from an existing hydro facility in New England. The RECs from existing hydro facilities in New England also tend to be more volatile than those from nuclear facilities or Hydro-Quebec because of typically higher demand and more variability in annual output.

Energy from the existing facilities are tied to market; however, if more utilities and states move to cleaner portfolios (from an emissions perspective) and move towards linking contracts for energy and environmental attributes, these facilities may be able to demand a premium for their energy and/or Environmental Attribute.

New in-state solar projects typically require a long-term commitment (Purchased Power Agreement or net-metering) at set prices for the purchase of both energy and the Environmental Attributes. Depending on whether the energy and Environmental Attributes come from a project that is a Net-Metering project, is developed by the utility, or is developed by a third-party developer, current prices can range from approximately $80/MWh to over $140/MWh. For the purposes of this analysis, prices are assumed to range from $70/MWh to $140/MWh.

Risks Associated With Management of the Carbon-Free Portfolio

There are a number of risks associated with the price of RECs and the volume of RECs needed to meet the Carbon-Free requirements with potential detrimental impacts on VEC's financial status. These include:

1. Load growth from CCHPs, electric vehicles and other electrification technologies – Deviation from assumed load growth will impact the volume of Tier I RECs VEC will need to retain to meet Vermont's RES standards. VEC will need to acquire more Tier I RECs than projected if load growth is faster than assumed in this analysis. Conversely, fewer RECs will be required if load growth is slower than assumed.

2. Net-metering adoption rate – The amount of net-metering installed on the VEC system will impact VEC's sales and the volume of Tier I RECs VEC will need to retain to meet Vermont's RES standards. VEC will need to acquire more Tier I RECs than projected if net-metering implementation is slower than assumed in this analysis. Conversely, fewer RECs will be required if net-metering implementation is faster than assumed.

3. Natural Gas Prices – Despite the increased volume of renewable energy on the New England system in the past decade or so, the five-minute and hourly marginal units in New England, which tend to dictate the price of spot market electricity prices in the ISO-NE control area, are primarily natural gas facilities. This is especially true in the winter, when solar and hydro output are lower than in other times of the year, and natural gas is relied upon for heating.

   This reliance on natural gas facilities causes the cost of Forward contracts for electricity (used to hedge against spot market prices) are tied to the forward prices for natural gas. As a result, VEC's open positions in its energy portfolio are tied to natural gas prices.

   In addition, the price of VEC's contract with HQ US Energy Services, which makes up approximately 25% of VEC's energy portfolio through 2030, changes every November based on the forward price of electricity for the next calendar year, linking a significant portion of VEC power supply costs to the cost of natural gas.

4. Prices for Nuclear emission-free certificates and Maine Class II and Vermont Tier I RECs Prices – the benchmark for any analyses for meeting the carbon-free requirement is typically the cost of Maine Class II

RECs, which are primarily existing hydro facilities. The cost of these RECs is largely a function of snowmelt runoff and rainfall. As of late-June 2025, ME Class II RECs for 2026-2029 are selling for approximately $4.50/REC. These RECs are fairly stable, but because of the weather impact, have traded for as low as $1.5-/REC and as high as $10.00/REC.

Other than weather, another factor that could drive prices higher is demand. VEC is at risk to prices increasing not only to a dry year, but also from Load Serving Entities deciding to increase their renewable portfolios by purchasing RECs, other New England states increasing the existing renewable requirements in the RES, and/or voluntary REC-market participants such as Google or Amazon to make their energy consumption look more renewable.

Carbon Free Action Plan

Over the next 1-2-years, VEC will:

- Monitor the adoption rate of Net Metering, Cold-Climate Heat Pumps, EVs, Clean Air Program projects and other Tier III on the system and change load forecasts and Tier I, II and IV requirements appropriately.
- Investigate extension of Howard Wind contract if a reasonable price can be obtained.
- Investigate converting remaining 10 MW of Sheffield contract that is a discount to LMP to a fixed price that includes RECs.
- Investigate long-term PPA for On-Shore Wind project PPA beginning in 2027.
    - This would require submittal of a CPG
- Investigate long-term PPA for existing hydro energy and RECs (anything longer than 10-years will require a CPG).
- Monitor the spread between VT Tier I and MA Class I RECs and take advantage of REC arbitrage when appropriate.
- Investigate receiving RECs for energy deliveries from HQ to VEC to serve VEC's Block load when it is connected to HQ.
- Work with HQ to develop a bi-directional energy pilot through which VEC and HQ can serve each other energy at different times and use resources on both sides of the border to serve both utilities.
- Consider acquiring nuclear energy environmental attributes to meet a portion of the carbon-free shortfall.
- Consider acquiring Vermont Tier to meet a portion of the carbon-free shortfall.

3.3.3 Tier I Analysis

The System Energy Requirements form the benchmark for assessing Tier I renewable energy requirements.

As noted above, H.289 requires that Vermont utilities retain RECs from resources that qualify to meet the total renewable energy requirement at a level that begins at 63% of total load in 2026 increasing to 67% in 2028 and 100% in 2030. Distributed Renewable Generation, or Tier II resources, must make up 7.8% of the total load in 2026 increasing by 2.0% every year to reach 17.8% in 2031, then increasing to 20.0% in 2032.

VEC refers to the difference between Total Renewable Energy and Tier II requirements as the Net Tier I Requirement.

The percentages of the Total Renewable Energy, Net Tier I, Tier II and Tier IV requirements are provided below.

Year	Total Renewable Energy Requirement	Net Tier I Renewable Energy Requirement	Tier II Renewable Energy Requirement	Tier IV Renewable Energy Requirement
2026	63.0%	55.2%	7.8%	0.0%

2027	63.0%	53.2%	9.8%	0.0%
2028	67.0%	55.2%	11.8%	0.0%
2029	67.0%	53.2%	13.8%	0.0%
2030	100.0%	84.2%	15.8%	5.0%
2031	100.0%	82.2%	17.8%	5.0%
2032	100.0%	80.0%	20.0%	5.0%
2033	100.0%	80.0%	20.0%	5.0%
2034	100.0%	80.0%	20.0%	5.0%
2035+	100.0%	80.0%	20.0%	10.0%

Table 3.3.9.A Total Renewable Energy, Tier I and Tier II requirements

With Act 56 (effective in 2017), Vermont joined every other New England state in having some form of renewable energy standard. However, even with the changes in H.289, each state has different categories of renewable resources and different definitions of what qualifies as a renewable resource. For example, Vermont defines existing renewable resources as those that came on line prior to January 1, 2010, and new renewable resources as those that come on line on or after January 1, 2010; while Massachusetts defines existing renewables as those that came on line before January 1, 1998, and new as those that came on line after December 31, 1997.

This is an important distinction that allows VEC to sell RECs from some Tier I resources (such as KCW, Ryegate and Sheffield) that are highly valued in other states and either replace them with RECs from resources that are lower valued in other states or pay the ACP.

The plot below compares VEC's projected Net Tier I requirement to its current Tier I committed and pending resources in each load scenario. A table containing the data the graph is based on is included in "Appendix R: VEC Resource and Needs Projections."

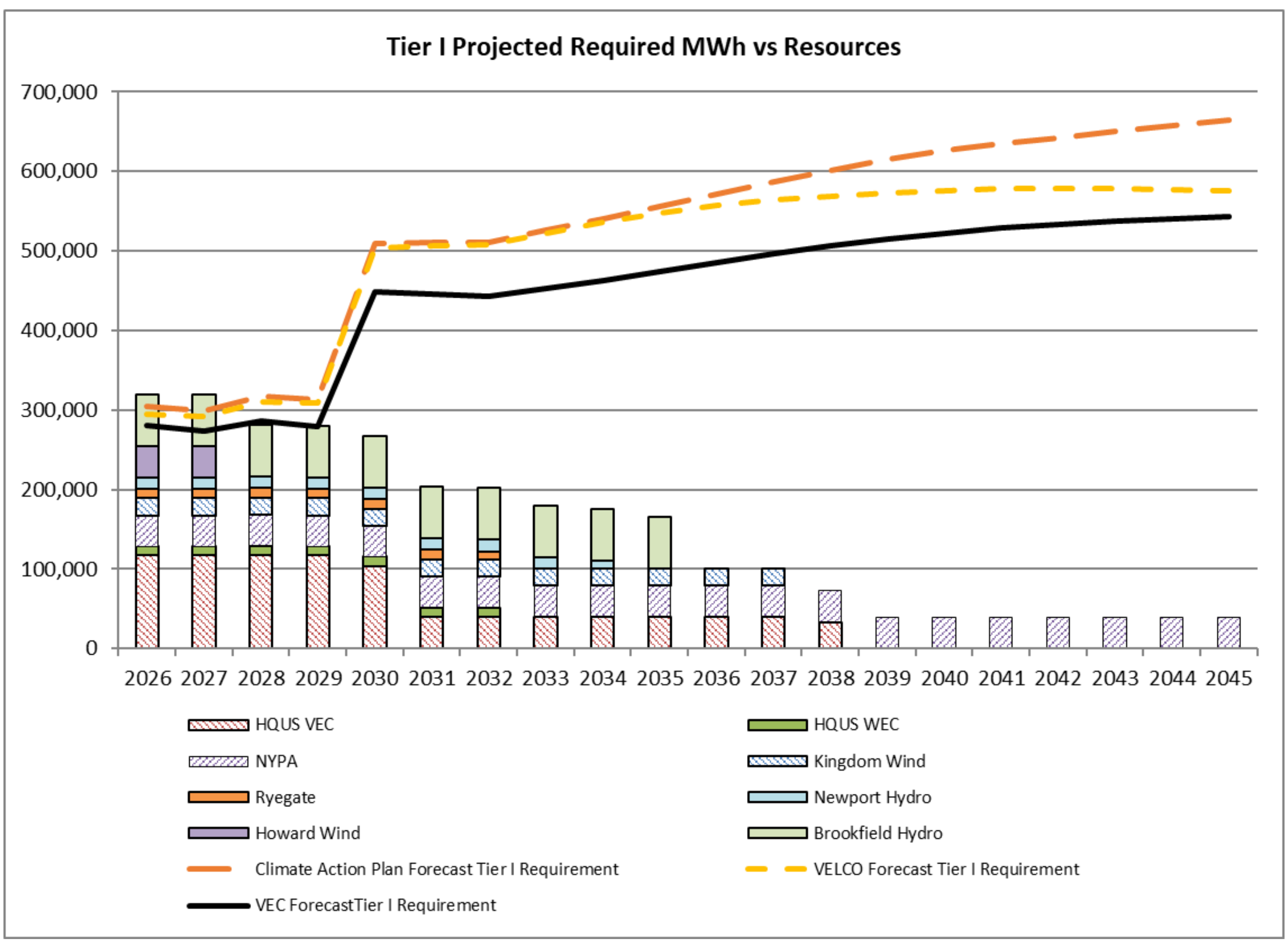


Figure 3.3.9.B – Tier I Pojrected Required MWh vs Resources Before Sale of High-Value REC

The shortfalls are shown numerically in the table below:

Year	Climate Action Plan Forecast	VEC Forecast	VELCO Forecast
2026	(31,319)	(54,542)	(40,545)
2027	(36,530)	(62,481)	(44,148)
2028	20,715	(10,136)	14,144
2029	17,524	(16,443)	12,318
2030	225,888	166,006	220,133
2031	296,781	232,461	292,879
2032	309,257	240,914	306,047
2033	346,425	272,878	342,797
2034	366,154	287,910	361,013
2035	390,915	308,971	382,589
2036	470,687	385,061	456,429
2037	486,267	396,302	463,659
2038	528,846	434,224	496,688
2039	575,759	476,288	533,814
2040	586,988	483,588	536,614
2041	595,743	489,415	538,697
2042	603,459	494,155	539,387
2043	610,865	497,883	538,706
2044	618,308	500,897	537,804
2045	625,736	503,412	536,887

VEC is projected to have enough resources to cover its Tier I energy requirement through 2027 in all three forecast scenarios and through 2029 in the VEC Forecast scenario. The shortfalls increase through the study period as load grows and contracts with HQUS, Sheffield, Ryegate, Newport Hydro and Brookfield Hydro expire.

The data assumes VEC retains the RECs from Kingdom Wind, Ryegate, Newport Hydro, and Howard Wind; all resources with high-value RECs but do not qualify at Tier II resources. As of the spring of 2025, VEC can sell 2026-2028 vintage RECs from these facilities as either CT Class I, MA Class I or NH Class III (in the case of Ryegate) for $37.00–$39.00/REC. In addition, 2026-2028-vintage Vermont Tier I eligible RECs currently sell for $4.00-$5.00/REC.

As long as the RECs from KCW, Ryegate, and Standard Offer projects can be sold in another state at a price that is higher than the ACP or the cost of other RECs that qualify for Tier I, VEC's members will be better served financially if VEC sells these RECs.

The following figure compares VEC's projected Tier I requirement to its current Tier I committed and pending resources in each load scenario after the sale of its high-value RECs. A table containing the data the graph is based on is included in "Appendix R: VEC Resource and Needs Projections."

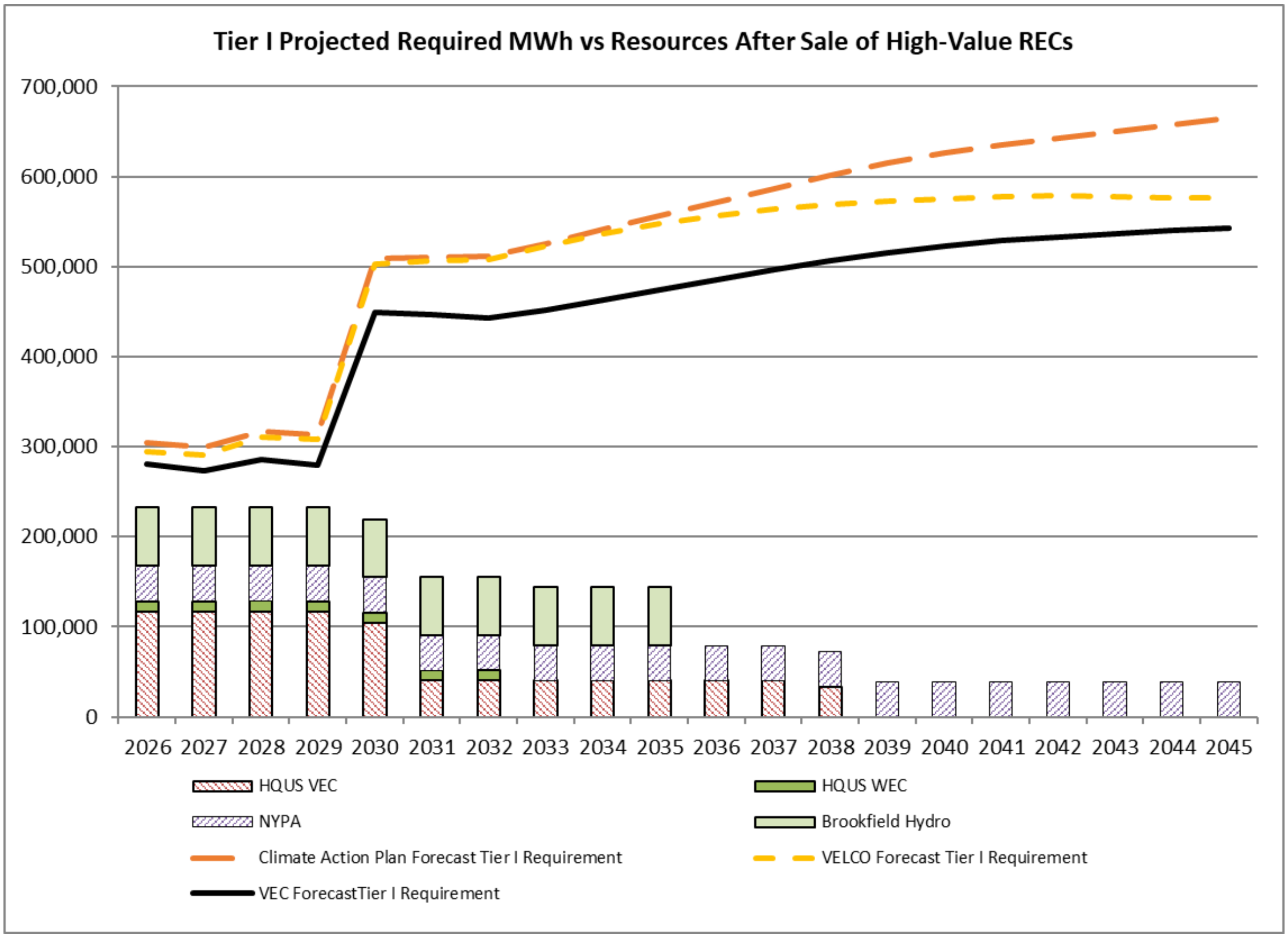


Figure 3.3.9.C – Tier I Projected Required MWh vs Resources After Sale of High-Value RECs

Risks Associated With Management of the Tier I Portfolio

There are a number of risks associated with the price of RECs and the volume of RECs needed to meet RES Tier I requirements with potential detrimental impacts on VEC's financial status. These include:

1. Difference in Value of MA Class I and CT Class I RECs compared to VT Tier I RECs – From 2026-2030 VEC expects to be able to have entitlement to approximately 50,600 RECs annually from KCW, Ryegate and Sheffield. This amount decreases by approximately 5,400 RECs in 2031 with the Sheffield contract expiring in October 2031; and by another 12,500 RECs in 2032 due as the Sheffield contract is not in the portfolio for the entirety of 2032, and the current Ryegate contract expires at the end of October 2032.

   If VEC can sell the RECs from these facilities and replace them with less-expensive Tier I qualifying RECs at the current price differential of $30/REC, it can decrease net costs for its members by approximately $$1,518,000 per year compared to retaining the RECs for Tier I compliance. This annual cost reduction changes by $50,600 for each $1.00/REC change in the price differential between the high-value RECs and the VT Tier I RECs.

   Because MA Class I REC prices are currently capped at $40.00/REC, VEC is exposed to much more risk to prices decreasing in the future than increasing, unless the cap is changed by the Massachusetts legislature. VEC is thus incentivized to sell as many of these RECs as possible.

2. Load growth from CCHPs, electric vehicles and other electrification technologies – Deviation from assumed load growth will impact the volume of Tier I RECs VEC will need to retain to meet Vermont's RES standards. VEC will need to acquire more Tier I RECs than projected if load growth is faster than assumed in this analysis. Conversely, fewer RECs will be required if load growth is slower than assumed.

3. Net-metering adoption rate – The amount of net-metering installed on the VEC system will impact VEC's sales and the volume of Tier I RECs VEC will need to retain to meet Vermont's RES standards. VEC will need to acquire more Tier I RECs than projected if net-metering implementation is slower than assumed in this analysis. Conversely, fewer RECs will be required if net-metering implementation is faster than assumed.

4. Natural Gas Prices – Despite the increased volume of renewable energy on the New England system in the past decade or so, the five-minute and hourly marginal units in New England, which tend to dictate the price of spot market electricity prices in the ISO-NE control area, are primarily natural gas facilities. This is especially true in the winter, when solar and hydro output are lower than in other times of the year, and natural gas is relied upon for heating.

   This reliance on natural gas facilities causes the cost of Forward contracts for electricity (used to hedge against spot market prices) are tied to the forward prices for natural gas. As a result, VEC's open positions in its energy portfolio are tied to natural gas prices.

   In addition, the price of VEC's contract with HQ US Energy Services, which makes up approximately 25% of VEC's energy portfolio through 2030, changes every November based on the forward price of electricity for the next calendar year, linking a significant portion of VEC power supply costs to the cost of natural gas.

Tier I Potential Resources and Analyses

Using the shortfalls from the VEC Forecast scenario, below is a table to MW needed each year of the various resource required to meet the annual Tier I shortfalls. Serving the entire shortfalls with one resource technology is not practical, nor is it advisable for cost-diversity and output-shape-diversity purposes. This table is only shown to provide context regarding the impact of the capacity factor of the various technologies.

Year	Biomass (90.0% CF)	Hydro (30.0% CF)	Market Purchases (60.0% CF)	Off-Shore Wind (47.0% CF)	On-Shore Wind (30.0% CF)	Solar (14.1% CF)
2026	0.0	0.0	0.0	0.0	0.0	0.0
2027	0.0	0.0	0.0	0.0	0.0	0.0
2028	0.0	0.0	0.0	0.0	0.0	0.0
2029	0.0	0.0	0.0	0.0	0.0	0.0
2030	21.1	63.2	31.6	40.3	63.2	134.8
2031	29.5	88.5	44.2	56.5	88.5	188.7
2032	30.6	91.7	45.8	58.5	91.7	195.6
2033	34.6	103.8	51.9	66.3	103.8	221.6
2034	36.5	109.6	54.8	69.9	109.6	233.8
2035	39.2	117.6	58.8	75.0	117.6	250.9
2036	48.8	146.5	73.3	93.5	146.5	312.6

2037	50.3	150.8	75.4	96.3	150.8	321.8
2038	55.1	165.2	82.6	105.5	165.2	352.6
2039	60.4	181.2	90.6	115.7	181.2	386.7
2040	61.3	184.0	92.0	117.5	184.0	392.6
2041	62.1	186.2	93.1	118.9	186.2	397.4
2042	62.7	188.0	94.0	120.0	188.0	401.2
2043	63.2	189.5	94.7	120.9	189.5	404.2
2044	63.5	190.6	95.3	121.7	190.6	406.7
2045	63.9	191.6	95.8	122.3	191.6	408.7

Tier I Action Plan

Over the next 3-years, VEC will:

- Monitor the adoption rate of Net Metering, Cold-Climate Heat Pumps, EVs, Clean Air Program projects and other Tier III on the system and change load forecasts and Tier I, II and IV requirements appropriately.
- Sell KCW, Sheffield and Howard RECs for 2026-2029 at as soon as practical in order to take advantage of prices that are reasonably high, and guard against potential reductions in new renewable requirements in other New England states which can drive prices down.
- Investigate extension of Howard Wind contract if a reasonable price can be obtained.
- Investigate converting remaining 10 MW of Sheffield contract that is a discount to LMP to a fixed price that includes RECs.
- Investigate long-term PPA for On-Shore Wind project PPA beginning in 2027.
  - This would require submittal of a CPG
- Participate in Request for Proposals for On-Shore Wind being issued by the Maine Public Utilities Commission for on-line date of mid-2030s.
- Investigate long-term PPA for existing hydro energy and RECs (anything longer than 10-years will require a CPG).
- Participate in discussions to extend up to 20 MW PPA with Sheffield wind if it repowers its facility.
- Monitor the spread between VT Tier I and MA Class I RECs and take advantage of REC arbitrage when appropriate.
- Investigate receiving RECs for energy deliveries from HQ to VEC to serve VEC’s Block load when it is connected to HQ.
- Work with HQ to develop a bi-directional energy pilot through which VEC and HQ can serve each other energy at different times and use resources on both sides of the border to serve both utilities.
- Investigating trading nuclear energy and environmental attributes for renewable energy and environmental attributes.

3.3.4 Tier II Analysis

The System Energy Requirements form the bench mark for assessing Tier II needs.

H.289 requires that each Vermont utility must acquire Distributed Renewable Generation resources at a level of 7.8% of the total load in 2026 increasing by 2.0% every year to reach 17.8% in 2031, then increasing to, and leveling off at, 20.0% in 2032. It changed the cap on the size of individual net-metering project from 500 kW to 150 kW beginning with CPG applications filed on or after January 1, 2025.

The percentages of Tier II requirements for each year of the study period are:

Year	Tier II Renewable Energy Requirement
2026	7.8%
2027	9.8%
2028	11.8%
2029	13.8%
2030	15.8%
2031	17.8%
2032+	20.0%

Table 3.3.10.A Tier II Renewable Energy Requirement

Vermont's definition of Distributed Renewable Generation requires that the projects have a name plate capacity of 5 MW or less, be located in Vermont, and reach commercial operation on or after January 1, 2010. Because of the in-state requirement, RECs from other states do not qualify to satisfy VEC's Tier II requirement. As a result, selling RECs from in-state Tier II projects and buying back lower-priced RECs from out of state is not an option.

VEC can use Tier II resources to satisfy its Energy Transformation/Tier III requirements. VEC has not modeled that scenario in this study, but will consider this strategy on an ongoing basis when developing its strategy to meet its Tier II and Tier III obligations.

Beginning with a rule change implemented in 2017, net-metering customers began receiving higher compensation for transferring RECs to the host utility as opposed to retaining the RECs. Since that rule change, almost 100% of net-metering customers have opted to transfer the REC to the utility in exchange for the higher compensation.

The figure below compares VEC's projected Tier II requirement to its current Tier II committed and pending resources in each load scenario assuming only those net metering projects that had filed for a CPG on or before December 31, 2024. A table containing the data the graph is based on is included in "Appendix R: VEC Resource and Needs Projections."

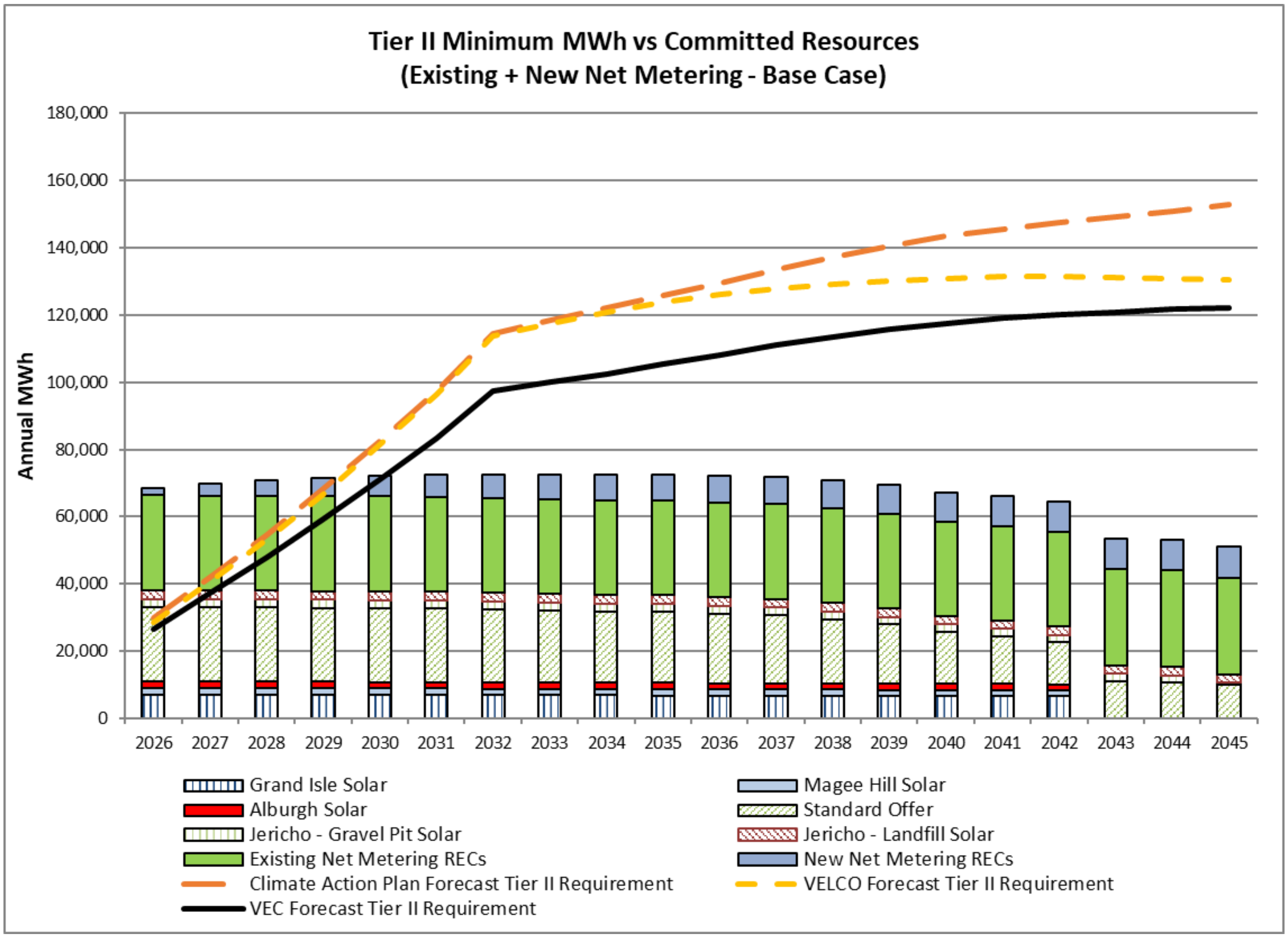


Figure 3.3.10.B VEC's projected Tier II requirement to its current Tier II committed and pending resources

The Shortfalls are shown numerically in the table below:

Year	Climate Action Plan Forecast	VEC Forecast	VELCO Forecast
2026	(38,711)	(41,993)	(40,015)
2027	(28,035)	(32,815)	(29,438)
2028	(16,273)	(22,868)	(17,678)
2029	(3,385)	(12,196)	(4,735)
2030	10,325	(912)	9,245
2031	25,027	11,099	24,182
2032	42,033	24,948	41,231
2033	45,746	27,359	44,839
2034	49,645	30,084	48,360
2035	53,210	32,723	51,128
2036	57,613	36,206	54,048
2037	62,068	39,577	56,416
2038	66,779	43,124	58,740
2039	71,620	46,752	61,134
2040	76,535	50,685	63,941
2041	79,953	53,370	65,691
2042	84,928	57,602	68,910

2043	95,529	67,284	77,489
2044	97,796	68,444	77,670
2045	101,712	71,131	79,499

VEC is projected to exceed its Tier II requirements through 2029 in all three load scenarios and 2030 in the VEC Forecast scenario.

The chart considers "Existing Net Metering" as projects on-line as of December 31, 2024, and new net metering as projects on line on or after January 1, 2025.

Solar has been the least expensive, and easiest to permit, Tier II resource over the past 10 years. The table below shows the annual incremental MW of New solar that would need to come on line each year to meet the Tier II requirements, assuming a 14.06% capacity factor, which is VEC estimate of net-metering projects on its system, and that VEC sells any excess RECs to reduce short-term costs to members, instead of banking them for future compliance years.

Year	**VELCO Forecast**	**Climate Action Plan Forecast**	**VEC Forecast**
2026			
2027			
2028			
2029			
2030	7.5	8.4	
2031	12.1	11.9	9.8
2032	13.8	13.8	11.2
2033	2.9	3.0	2.0
2034	2.9	3.2	2.2
2035	2.2	2.9	2.1
2036	2.4	3.6	2.8
2037	1.9	3.6	2.7
2038	1.9	3.8	2.9
2039	1.9	3.9	2.9
2040	2.3	4.0	3.2
2041	1.4	2.8	2.2
2042	2.6	4.0	3.4
2043	7.0	8.6	7.9
2044	0.1	1.8	0.9
2045	1.5	3.2	2.2

For the VEC Forecast, the sharp spike in required MW from 2030 to 2031 is the result of 2030 having only a slight shortfall. VEC Tier II MWh requirement increases from 71,257 MWh in 2030 to 83,622 MWh in 2031 (a 17.4% increase) due to Load growth (2.4%) and the RES requirement increasing from 15.8% to 17.8% (a 12.7% increase by itself).

The required MW increase in the VELCO and Climate Action Plan Forecast spikes in 2030 because the 2029 shortfall in those scenarios is very small.

In all three forecast scenarios, the required MW are much smaller beginning in 2032 because the Tier II percentage requirement does not increase after 2032, thus the only increase in Tier II required MM is the result of load growth through 2042. 2043 sees a spike in required MW in all three forecast scenarios because of the expiration of contracts with Grand Isle Solar and Magee Hill Solar.

Risks Associated With Management of the Tier II Portfolio

There are a number of risks associated with management of the Tier II. These include:

1. Net-metering adoption rate – The amount of net-metering installed on the VEC system will impact VEC's sales and the volume of Tier II RECs that VEC will need to retain to meet Vermont's RES standards. VEC will need to acquire more Tier II RECs than projected if net-metering implementation is slower than assumed in this analysis. Conversely, fewer RECs will be required if NM implementation is faster than assumed.

2. Load growth from CCHPs, electric vehicles and other electrification technologies – Deviation from assumed load growth will impact the volume of Tier II RECs VEC will need to retain to meet Vermont's RES standards. VEC will need to acquire more Tier II RECs than projected if load growth is faster than assumed in this analysis. Conversely, fewer RECs will be required if load growth is slower than assumed.

3. Tier II REC value – Utilities can either sell excess Tier II RECs, use them to meet Tier III requirements under the RES, or bank them to meet the Tier II requirement in later years. VEC's current plans are to sell the excess RECs in order to reduce net costs to members. This puts VEC at risk to the re-sale price of Tier II RECs, which is the price of Massachusetts Class I RECs (also, the same price as the higher-valued Tier I RECs).

4. The cost of new Solar facilities in Vermont – In mid-2024, proposals for 2.0- 5.0 MW distributed generation solar projects in the VEC territory were $70-90/MWh, with a mild annual escalator, depending on which Investment Tax Credits (ITC) the project is able to qualify obtain. However, those ITCs are now in question as the U.S. House of Representatives and Senate engage in budget discussions.

   In addition, the uncertainty regarding tariffs on products imported into the United States, especially on products from China, have put additional uncertainty on the price of solar panels and related materials imported into the United States. Although VEC does not have any recent formal offers for solar projects, discussions with potential developers suggest the cost can increase to close to $115/MWh, if all ITCs go away and 25% tariffs are in effect. Prices in this range can cause the annual cost of a 5.0 MW solar project with a 14.06% capacity factor, equating to 6,160 MWh, to increase by approximately $150,000 - $275,000 per year, compared to projects that would have otherwise been priced at $70/MWh and $90/MWh, respectively.

5. Legislative changes to the Tier II requirements – VEC is aware that in past legislative sessions it has been proposed to increase utilities' Tier II requirements as defined by the RES. VEC will participate in any future discussions. If any changes occur to increase or accelerate the Tier II requirements, VEC may be excess less than projected in the short term, and need to acquire more Tier II resources in the long term.

Tier II Action Plan

Over the next 3-years, VEC will:

- Consider and analyze entering into Solar PPAs immediately in order to guard against the impact to solar costs if ITCs are eliminated as a result of legislation passed by the United States Congress. This will require the analysis of VEC being even more excess Tier II RECs in 2027-2029 in order to reduce the PPA cost of the entire term of a 25-year solar PPA versus delaying the entering a solar PPA until it is needed, but possibly at a significantly higher PPA rate.

- Consider banking excess Tier II RECs in 2027-2029 to reduce the amount of new Tier II resources in 2030+. The decision to Bank excess RECs would have to consider the trade off between delaying the purchase of new resources and increasing the net cost to members prior to 2030 by not selling excess RECs.
- Consider using Market Purchases and either purchasing Tier II RECs from other VT utilities that are excess or paying the ACP rate in order to avoid overloading the Vermont distribution system with more generation than load in some hours of the summer.
- Analyze the impact of excess generation on the VEC system due to solar on VEC's settlement with ISO-NE as well as the stability of the VEC and VELCO systems.
- Investigate the potential for other Tier II resource technologies versus the cost of solar.

3.3.5 Tier IV (Regional Renewable Energy) Analysis

In addition to the Tier II and Net Tier I requirements, H.289 creates a Regional Renewable Energy requirement (Tier IV). This category covers New Renewable Energy (renewable energy that came on-line on or after January 1, 2010, whose energy is either generated in, or can be shown to have been delivered into, New England. VEC can use Tier II resources, or Tier I resources that meet the New Renewable Energy definition (for example, Howard Wind, KCW, or Sheffield) to satisfy its Tier IV requirements. However, any individual REC can only be used to meet on Tier requirement, in order to avoid double counting.

The table below shows the percentages of Tier IV requirements for each year of the study period.

Year	Tier II Renewable Energy Requirement
2026	0.0%
2027	0.0%
2028	0.0%
2029	0.0%
2030	5.0%
2031	5.0%
2032	5.0%
2033	5.0%
2034	5.0%
2035+	10.0%

Table 3.3.11.A Tier II Renewable Energy Requirement

The following figure compares VEC's projected Tier IV requirement to its current Tier IV committed resources that are not assumed to have been used to meet Tier II. A table containing the data the graph is based on is included in "Appendix R: VEC Resource and Needs Projections."

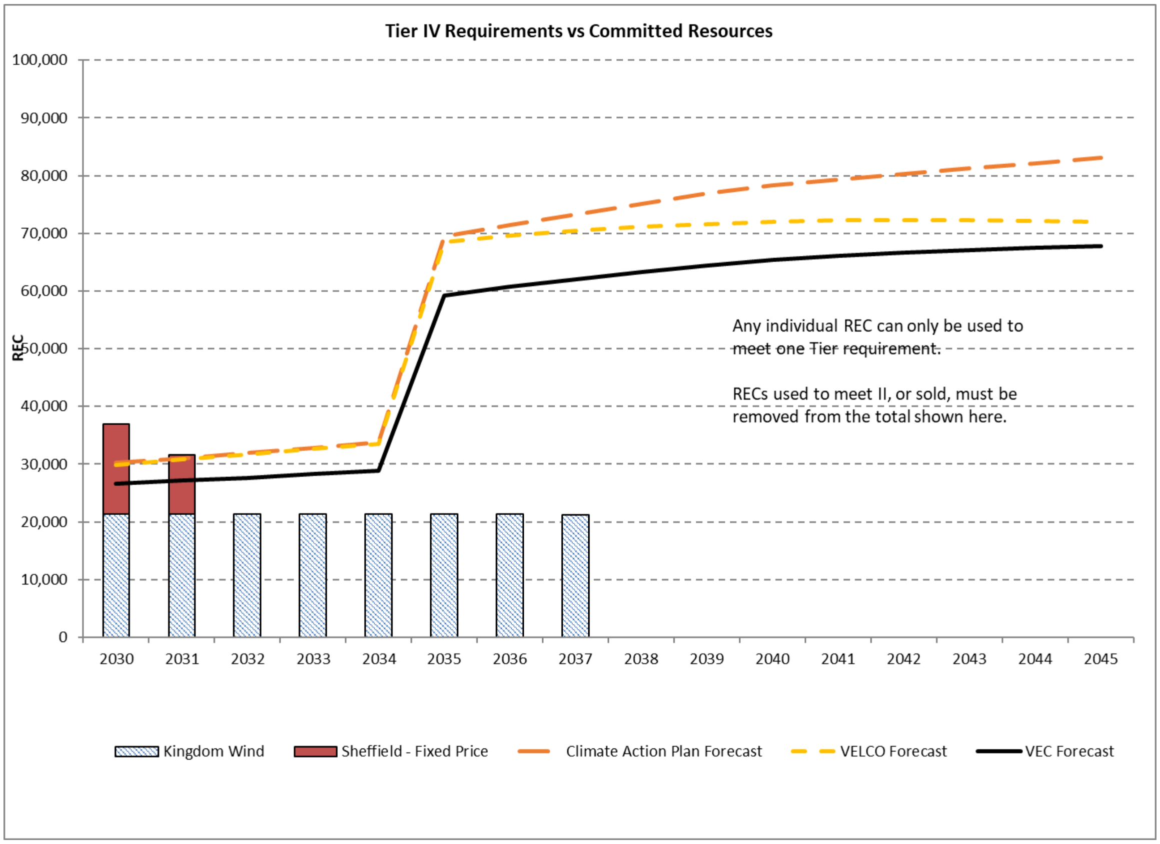


Figure 3.3.11.B VEC's projected Tier II requirement to its current Tier II committed and pending resources

The table below estimates the MWh shortfalls that correspond with the chart above.

Year	VELCO Forecast	Climate Action Plan Forecast	VEC Forecast
2026			
2027			
2028			
2029			
2030	(7,094)	(6,753)	(10,309)
2031	(735)	(498)	(4,410)
2032	10,407	10,608	6,337
2033	11,305	11,532	6,935
2034	12,165	12,486	7,596
2035	47,137	48,178	37,935
2036	48,289	50,071	39,368
2037	49,300	52,126	40,880
2038	71,133	75,153	63,325
2039	71,612	76,855	64,421
2040	71,962	78,259	65,334
2041	72,222	79,353	66,062
2042	72,309	80,318	66,655
2043	72,223	81,243	67,121
2044	72,111	82,174	67,497
2045	71,996	83,102	67,812

VEC is projected to exceed its Tier IV requirements through 2031 in all three load scenarios, and can meet the requirements through 2032 in the VEC Forecast scenario if RECs for 2030 and 2031 are banked. However, banking of RECs in 2030 and 2031 would result in higher costs to members in those years compared to selling the excess RECs.

Shortfalls can be filled with RECs from any New Renewable resource. The table below shows the annual incremental MW of various technologies needed each year to fill the shortfalls assuming load under the VEC Forecast and no banking of RECs. The spike in 2035 under all technologies is the result of the Tier IV requirement increasing from 5% to 10%.

Year	Biomass (90.0% CF)	Off-Shore Wind (47.0% CF)	On-Shore Wind (33% CF)	Solar (14.1% CF)
2026				
2027				
2028				
2029				
2030				
2031				
2032	0.8	1.2	1.5	2.4
2033	0.1	0.1	0.1	0.2
2034	0.1	0.1	0.2	0.3
2035	3.8	5.8	7.4	11.5
2036	0.2	0.3	0.3	0.5
2037	0.2	0.3	0.4	0.6
2038	2.8	4.3	5.5	8.5
2039	0.1	0.2	0.3	0.4
2040	0.1	0.2	0.2	0.3
2041	0.1	0.1	0.2	0.3
2042	0.1	0.1	0.1	0.2
2043	0.1	0.1	0.1	0.2
2044	0.0	0.1	0.1	0.1
2045	0.0	0.1	0.1	0.1

Risks Associated With Management of the Tier IV Portfolio

There are a number of risks associated with management of the Tier II. These include:

1. Net-metering adoption rate – The amount of net-metering installed on the VEC system will impact VEC's sales and the volume of Tier II RECs that VEC will need to retain to meet Vermont's RES standards. VEC will need to acquire more Tier II RECs than projected if net-metering implementation is slower than assumed in this analysis. Conversely, fewer RECs will be required if NM implementation is faster than assumed.
2. Load growth from CCHPs, electric vehicles and other electrification technologies – Deviation from assumed load growth will impact the volume of Tier II RECs VEC will need to retain to meet Vermont's RES standards. VEC will need to acquire more Tier II RECs than projected if load growth is faster than assumed in this analysis. Conversely, fewer RECs will be required if load growth is slower than assumed.
3. Probability of Sheffield Repowering – If the owners of Sheffield repower the facility, entering a new contract for 10 MW – 20 MW would be a simple way to help VEC meet both its Tier IV and Tier I requirements without the need of relying on a new facility being built.

4. Probability of KCW life extending beyond 2037 – VEC currently has the end of life for KCW modeled as December 31, 2037. This slightly over 25 years since its commercial operation date. If GMP repowers, or extends the project life, this can be a simple way to help fulfill Tier IV and Tier I requirements without the need of relying on a new facility being built.
5. Ability of new Off-Shore projects to get built – Many Off-Shore wind projects have been delayed because project developers can not meet the agreed-upon contract prices in the original PPAs due to cost increases after the PPAs were executed. Prices for currently proposed projects are in the $140 - $150/MWh range. These cost increases have many potential off-takers balking at the prices and several state legislatures considering lowering renewable energy requirements, thus putting into question how many off-shore projects will be built and when. Because of the large size of the projects, required to reach sufficient economies of scale, VEC cannot be a driver in whether or not a project can be built, but can only team up with other larger utilities, or states, who can be the primary off-takers required to ensure a project can get built.
6. Basis Risk associated with On-Shore Wind Projects in Maine – On-shore wind projects are having difficulty getting permitted, except in northern Maine. This is causing projects to be built in a limited geographical region causing SHEI-like congestion issues. Despite the congestion, and because of the remoteness of the area, new projects are still being proposed in the area. VEC needs to be cautious of purchasing at the project nodes, which can cause PPA prices to be higher than the value of the resources, but at the same time be aware of potential transmission upgrades that would be paid for through NEPOOL Regional Network Service rates and relieve congestion constraints, thus increasing the value of the PPA.

Tier IV Action Plan

Several of the current projects in VEC's current portfolio will qualify for both Tier I and Tier IV (Howard Wind, KCW and Sheffield). As a result, the action items for Tier I and IV are almost identical. Tier IV action items include:

- Investigate extension of Howard Wind contract if a reasonable price can be obtained.
- Investigate converting 10 MW of Sheffield contract that is a discount to LMP to a fixed price that includes RECs
- Investigate long-term PPA for On-Shore Wind project PPA beginning in 2027.
    - This would require submittal of a CPG
- Participate in Request for Proposals for On-Shore Wind being issued by the Maine Public Utilities Commission.
- Investigate long-term PPA for existing hydro energy and RECs.
    - Anything longer than 10 years will require a CPG
- Participate in discussions to extend up to 20 MW PPA with Sheffield wind if it repowers its facility.

3.3.6 Renewable Resource Technology Diversity

For many reasons, relying on one technology to meet load throughout the year is not prudent.

It is impossible at this point to determine what the optimum resource mix will be, but it is clear that the region's portfolio will need to have several different renewable technologies and some battery storage to reach its renewable goals. To examine how resource technologies can interact with each other to serve load we have looked at their output characteristics on both a monthly and hourly basis.

Complementary Resources by Month

Below is a chart showing monthly capacity factors for each of the technologies and assumed output shapes studied above.

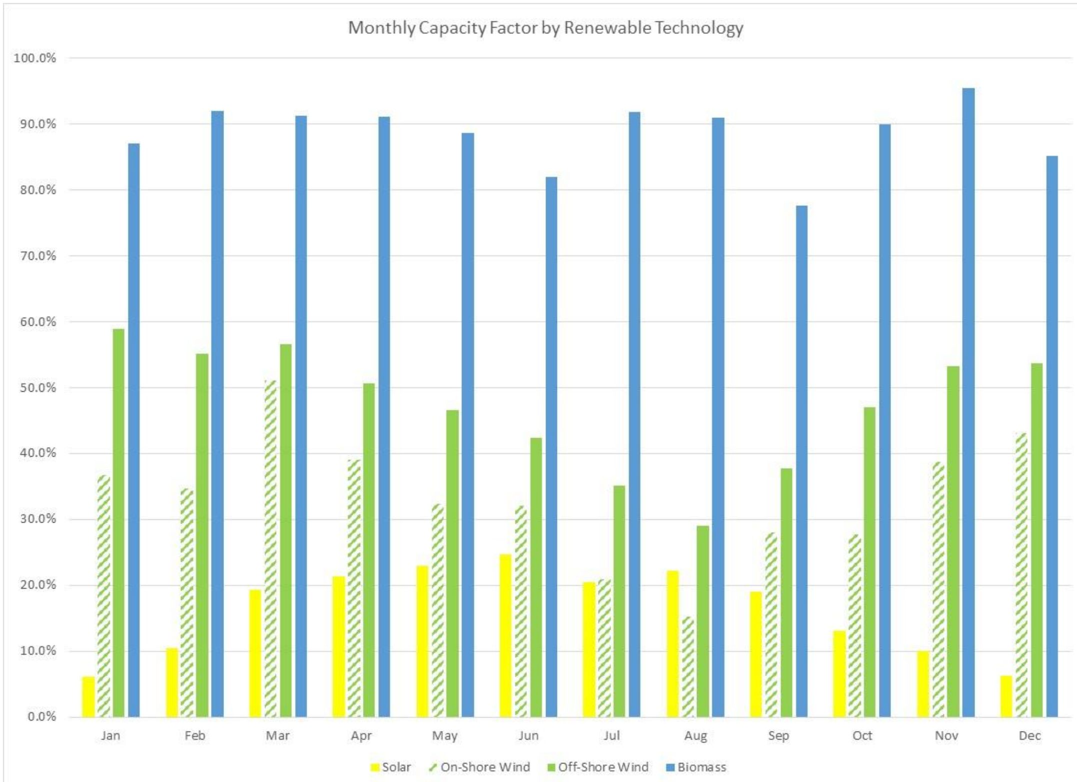


Figure 3.3.12.A – Monthly Capacity Factors by Renewable Technology

Biomass stands out as having the highest capacity factor of any month of the year, although it does vary slightly by month due to unit outages.

Off-Shore wind has the next highest capacity factor in every month of the year due to the stronger and more consistent wind compared to on-shore wind and the ability to generate at night that solar does not possess.

On-shore wind has the third-highest capacity factor in each month except July and August. Solar has the lowest capacity factor in all months except July and August due to its inability to generate at night and the short days in the winter.

Because these graphs are somewhat busy, below are plots of Solar versus each of Off-shore and On-Shore wind as well as a plot of Off-Shore wind vs On-Shore wind.

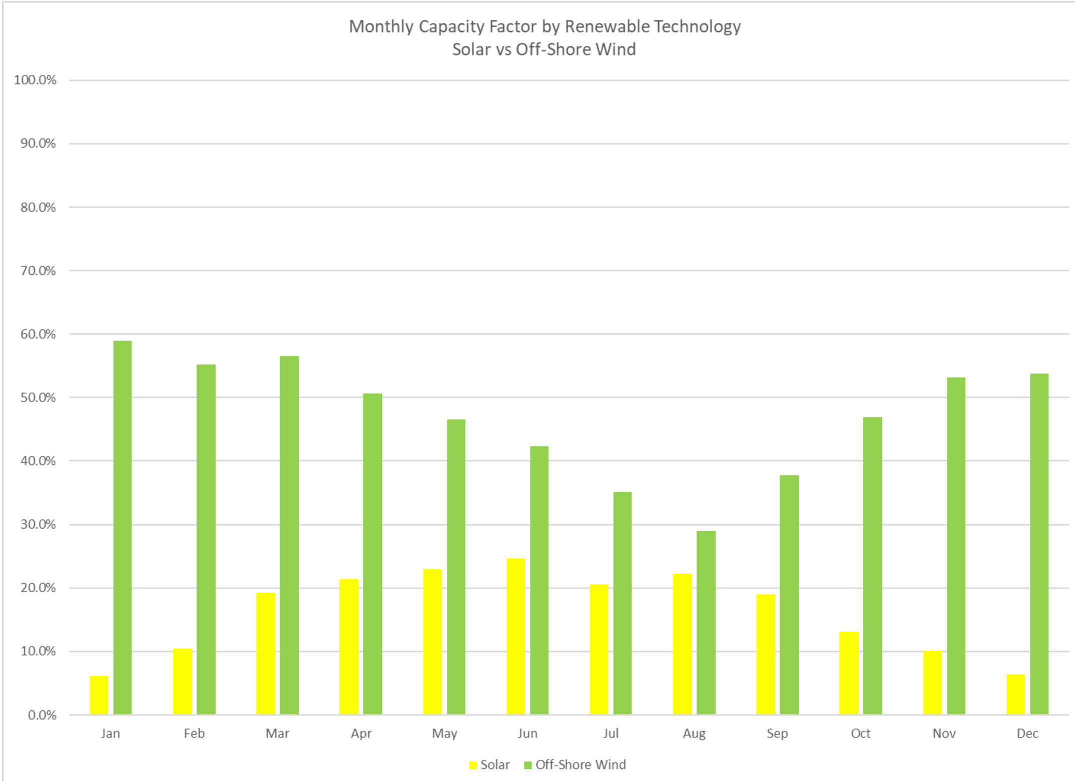


Figure 3.3.12.B – Solar and Off-Shore Wind Monthly Capacity Factor Comparison

This plot shows the complementary nature of Solar and Off-Shore wind as solar production tends to increase in the spring and summer months as wind generation decreases, and solar generation decreases in the fall and winter as the Off-shore wind generation increases. This suggests that solar and off-shore wind may pair together well, but solar would not be a good substitute for off-shore wind, while off-shore wind may be able to substitute for solar.

The figure below stacks the capacity factors on top of one another to provide an indication of the capacity factor of equal MW of resources.

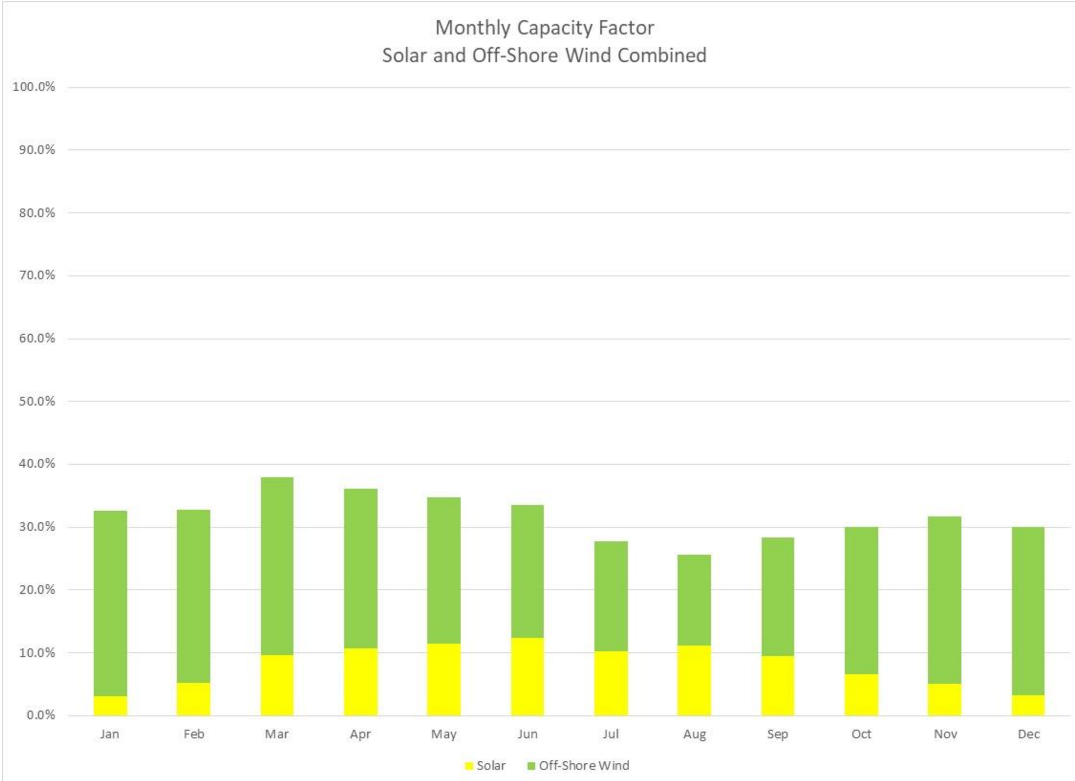


Figure 3.3.12.C – Solar and Off-Shore Wind Monthly Capacity Factor Stacked Comparison

The blending of these resources tends to flatten out the capacity factor through the year.

The figure below shows the monthly capacity factors for Solar and On-shore Wind.

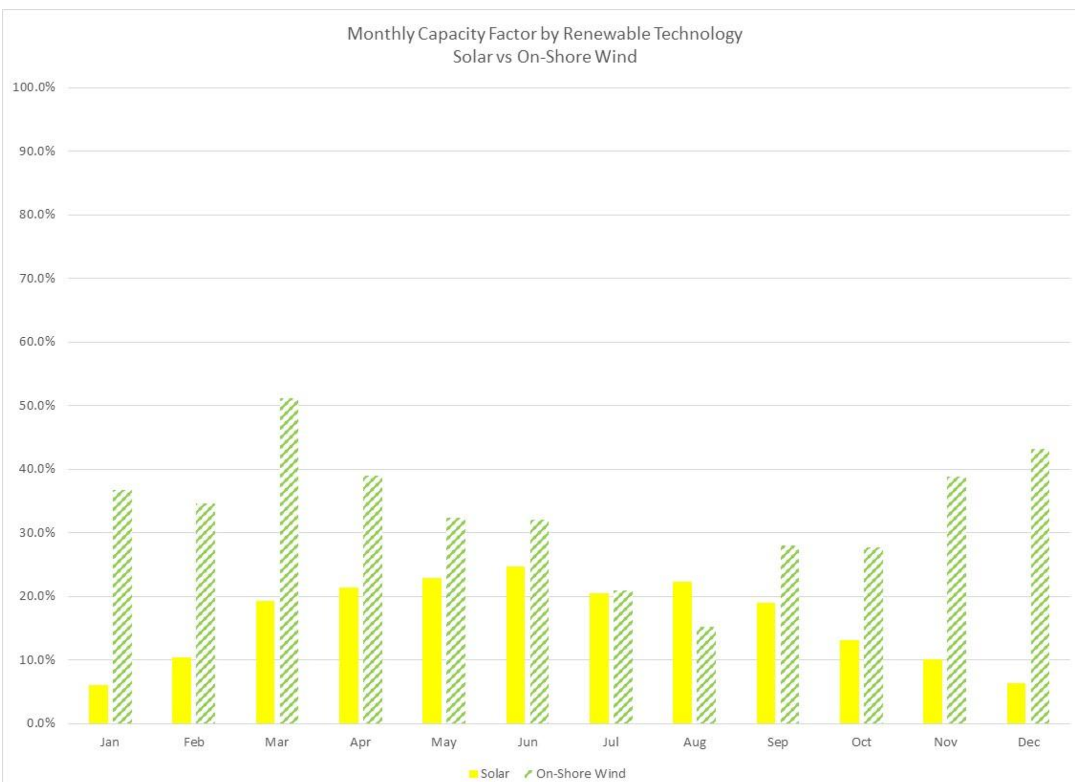


Figure 3.3.12.D – Solar and On-Shore Wind Monthly Capacity Factor Comparison

As with Solar and Off-Shore wind, the resources are somewhat complementary as solar production tends to increase in the spring and summer months as wind generation decreases, and solar generation decreases in the fall and winter as the Off-shore wind generation increases. This suggests that the solar and off-shore wind may pair together well, but solar would not be a good substitute for off-shore wind, while off-shore wind may be able to substitute for solar although not quite as well as Off-shore wind might.

Below is a plot stacking the capacity factors on top of one another to provide an indication of the capacity factor of equal MW of resources.

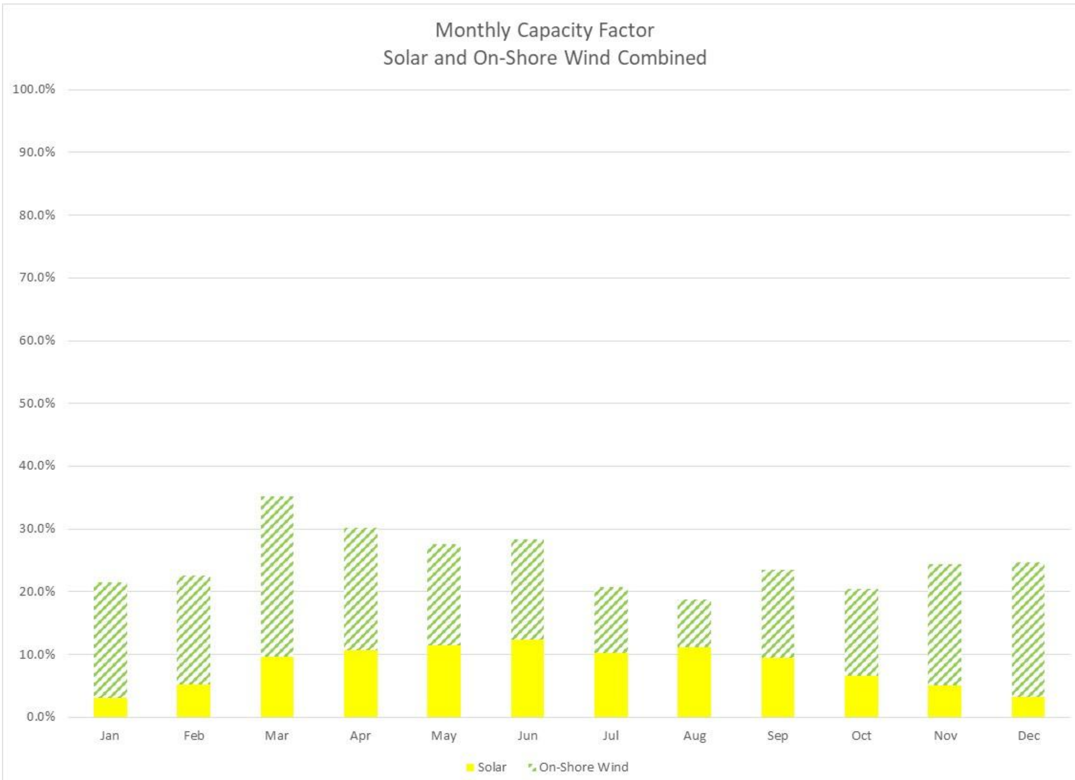


Figure 3.3.12.E - Solar and On-Shore Wind Monthly Capacity Factor Stacked Comparison

Similar to the case of Solar and Off-shore Wind, the blending of these resources tends to flatten out the capacity factor through the year; however, at a noticeably lower level.

Below is a plot of monthly capacity factors for Off-Shore Wind versus On-Shore Wind.

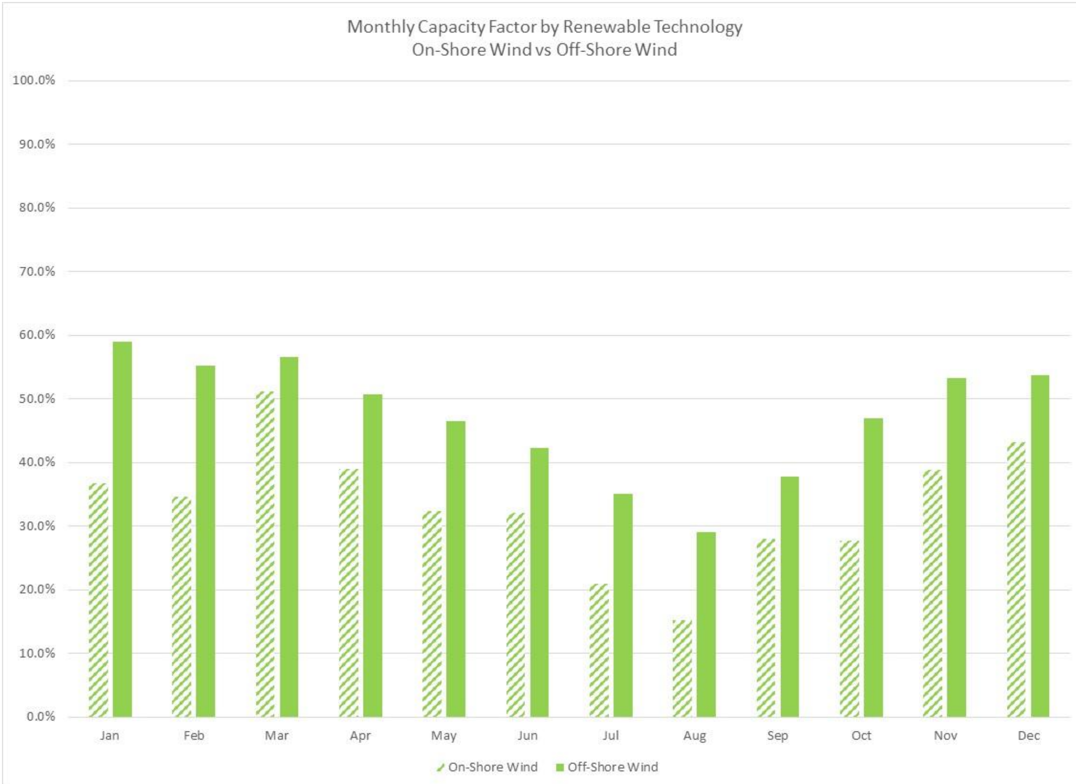


Figure 3.3.12.E – On-Shore and Off-Shore Wind Monthly Capacity Factor Comparison

The shapes of these plots are very similar meaning they are not very complementary to each other. Instead of being complementary they may be able to be replacements for one another.

Below is a plot showing the combined capacity factors of the two technologies:

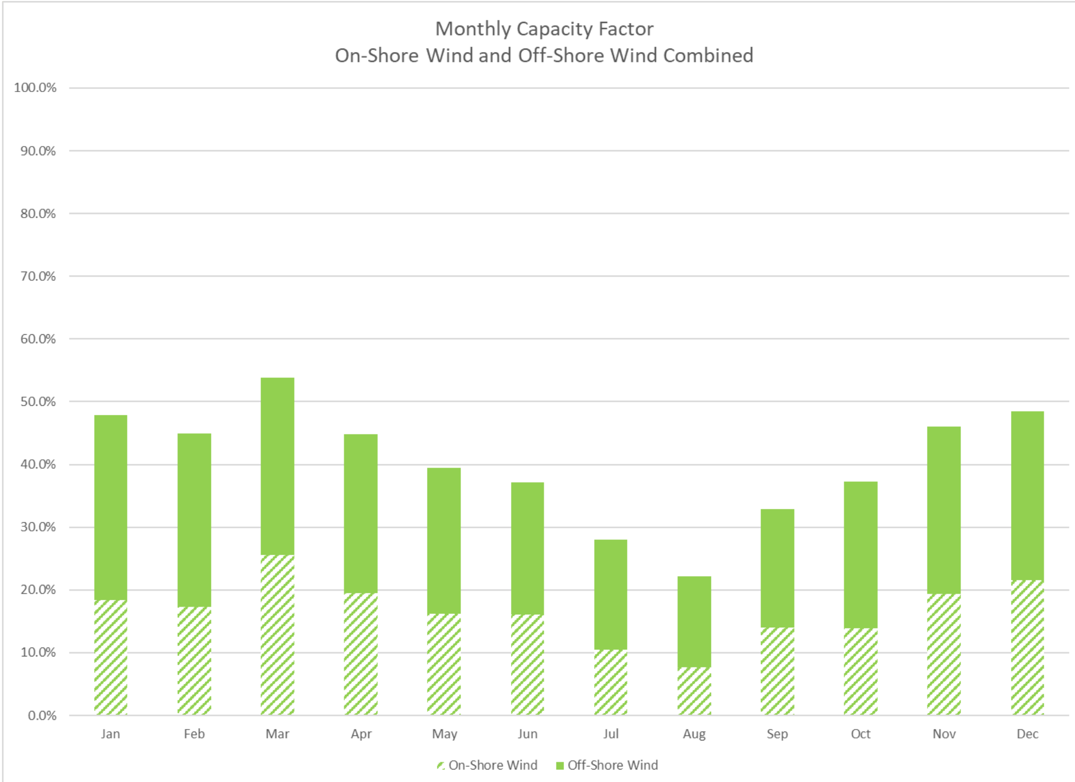


Figure 3.3.12.F - Figure 4.5.7.E – On-Shore and Off-Shore Wind Monthly Capacity Factor Stacked Comparison

The combined monthly capacity factors follow a similar shape throughout the year to both Off-Shore Wind and On-Shore wind, instead of being more stable as one would expect from complementary resources, further suggesting Off-Shore and On-Shore would be better replacements for each other than complements to each other.

Comparison of Renewable Technology Output by Hour

Comparing capacity factors by month provides some insight into how complementary various resources are. However, it is important to also compare the hourly output pattern of the various technologies. Below are plots for January, April, July and October of the average hourly output for each technology. Plots for all other months are in Appendix _.

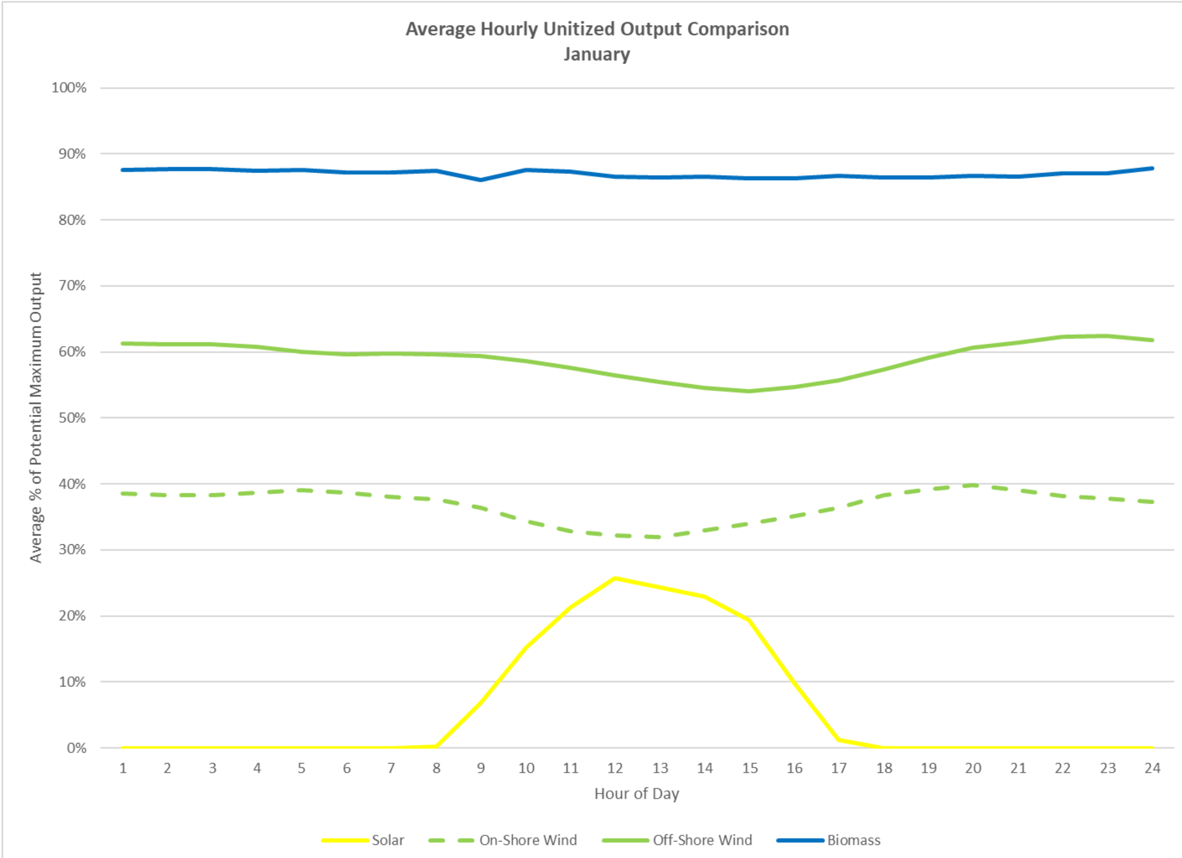


Figure 3.3.12.G – Average Hourly Unitized Output Comparison - January

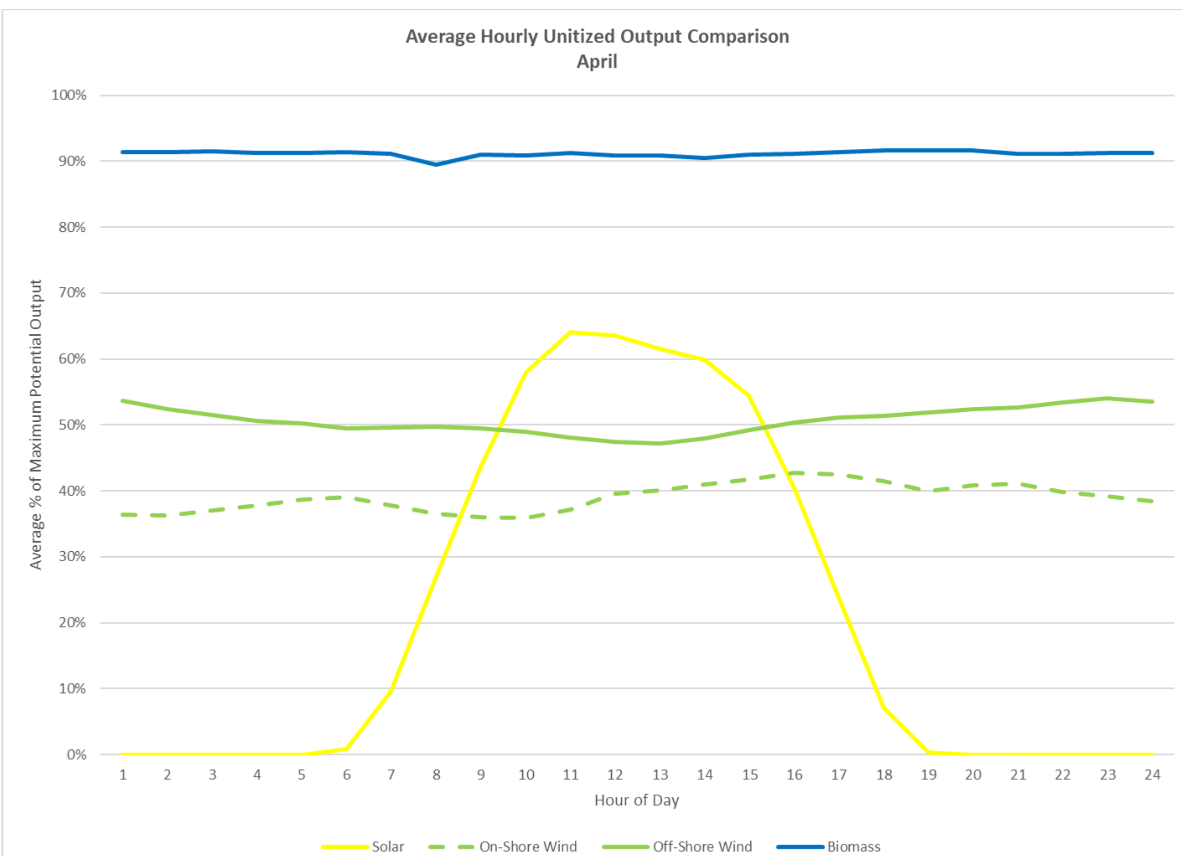


Figure 3.3.12.H – Average Hourly Unitized Output Comparison - April

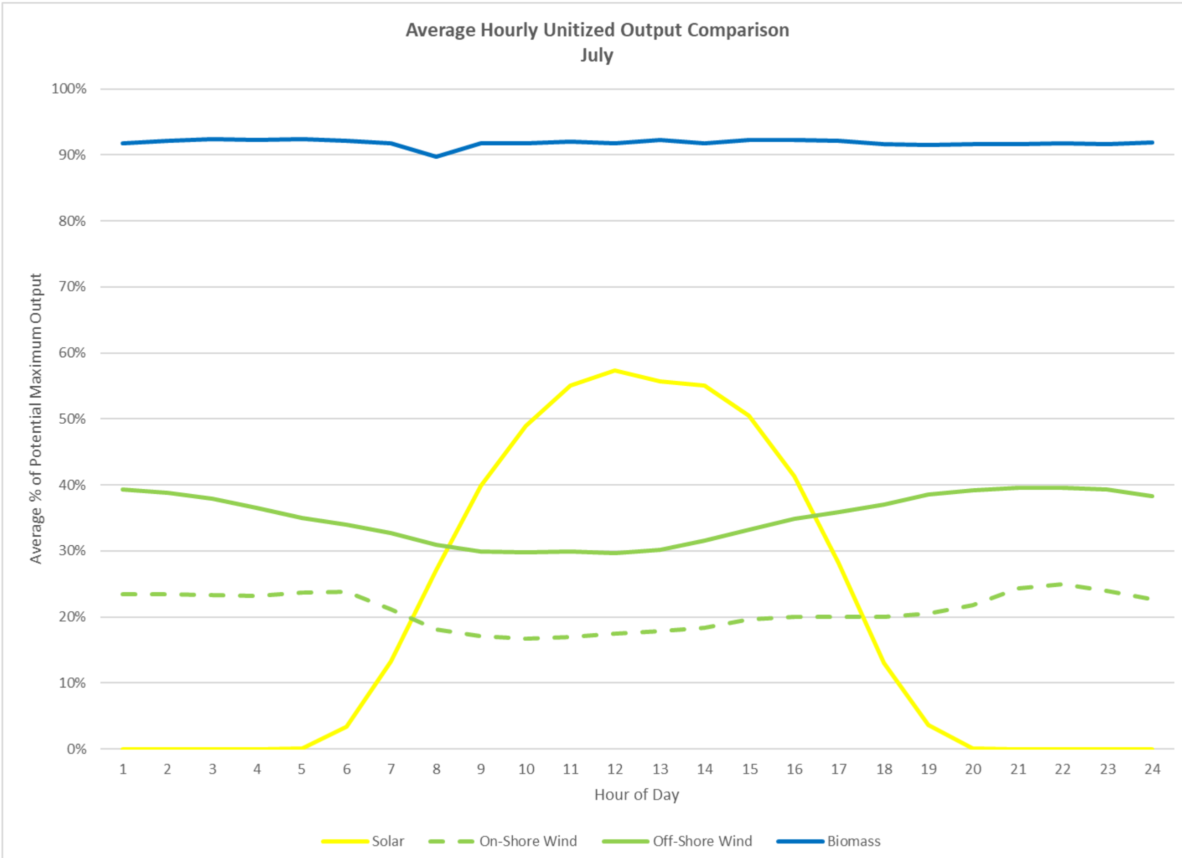


Figure 3.3.12.l – Average Hourly Unitized Output Comparison - July

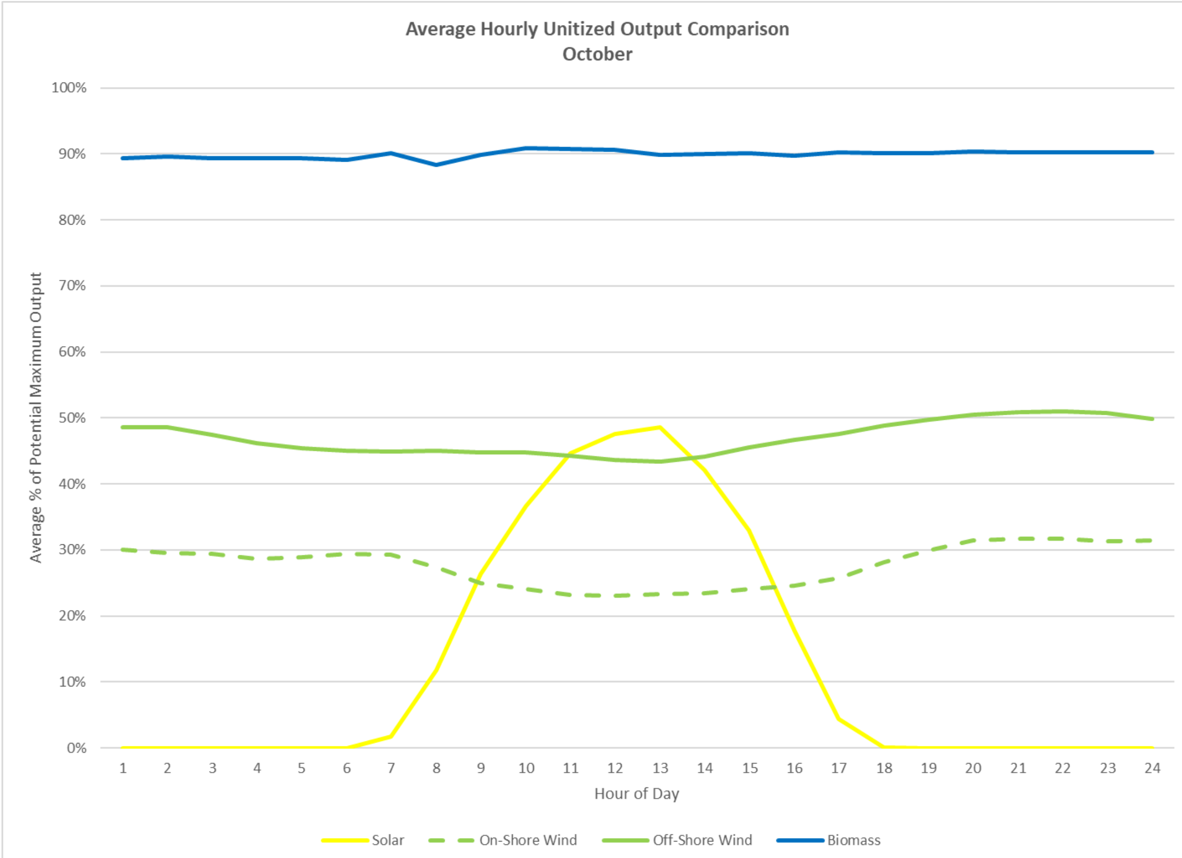


Figure 3.3.12.J– Average Hourly Unitized Output Comparison - October

These graphs make it clear that renewable resources that have the ability to operate around the clock can complement solar output and suggest that pairing solar with these other resources can reduce the amount of storage required, as well as costs to implement a 100% Renewable strategy.

3.3.7 The Benefits of Technology Diversity - Serving 1 MW of Load with Solar and Wind

To analyze the potential benefits of combining intermittent, renewable technologies with battery storage, VEC has done simplified analyses of the cost of serving 1 MW of load on an annual basis with different amounts of new solar, new On-shore Wind, and Batter storage.

VEC has developed a tool that can analyze different load and resource scenarios on an 8,760 hourly basis. This model can be used to determine the cost of different load and resource scenarios as well as VEC's risk to spot market prices by determining the number of hours and MWhs VEC is exposed to purchasing energy shortfalls or selling excess energy on the spot market, and value the net cost of a particular load and resource scenario.

Here, we used this tool to measure the benefits of renewable technology diversity for serving 1 MW of Around-the-clock load under three resource scenarios:

- Solar PPA and Storage
- On-Shore Wind PPA and Storage
- Solar PPA + On-Shore Wind PPA and Storage

Under each scenario, the tool is used to determine the 10-year least-cost combination of generation, storage and spot market purchases, and track exposure to the spot market. 10 years was chosen because of the capital intensiveness of the batteries, and it is a reasonable lifetime before batteries would need to be replaced.

The following assumptions were made:

- Cost of New Solar Project - $106.00/MWh fixed price with no escalation. This is based on recent quotes received by VEC for new solar projects developed in its service territory if the projects can begin construction in time to qualify for investment tax credits in effect as of June 15, 2025.
- Cost of New On-shore Wind Project - $100/MWh fixed price with no escalation. This is based on recent quotes received by VEC for new projects developed in New England assuming the projects can begin construction in time to qualify for investment tax credits in effect as of June 15, 2025.
- Cost of Battery Storage - $500,000 per installed MWh.
- Batter Storage Round-Trip Efficiency – 90%
- Batteries are 100% charged at the beginning of the year analyzed
- All energy used to serve load will come from the solar or wind projects, by either serving load directly, or charging the battery for serving load a later time. Excess energy from the wind and solar projects can be sold to ISO-NE when the batteries are full. No energy from the grid will be used to serve load or to charge the batteries.
- Solar output shape is based on the 2024 hourly output of an individual 2.0 MW solar project that is part of the Vermont Standard offer program.
- Wind output shape is based on the 2024 hourly output of a 20-MW wind project located in Vermont.
- Hourly spot market prices are actual 2024 hourly Locational Marginal Prices for the Vermont Load Zone in the Real-Time Market administered by ISO-NE.
- 0% battery degradation
- 0% solar degradation
- Each year was assumed to be the same.

The assumptions of load and resource output being identical each year and 0% degradation for both the batteries (typically approximately 3.0% per year) and the solar panels (typically approximately 0.5% per year) are theoretically unrealistic. Those assumptions were made for the sake of simplicity given that the intent of the analysis is not to be precise, but instead to be thematically accurate.

To determine the optimum combination of resources, the model was run with different combinations of generation MW and Storage MWh until the least-cost combination was identified for each technology scenario.

The least expensive combinations are shown below:

Wind MW	Solar MW	Storage MWh	10-Year Net $	10-year Wind + Solar MWh	10-Year Load	10-Year MWh Removed from Battery to Serve Load	10-Year MWh Load Served by Wind and Solar When Generated	10-Year MWh Excess MWh Sold to ISO	Battery $
8	0	359	$194,026,138	149,796	87,600	33,785	53,815	58,442	$179,500,000
0	52	257	$177,629,501	600,760	87,600	50,469	37,131	513,160	$128,500,000
6	21	94	$77,266,556	354,962	87,600	20,342	67,258	265,101	$47,000,000

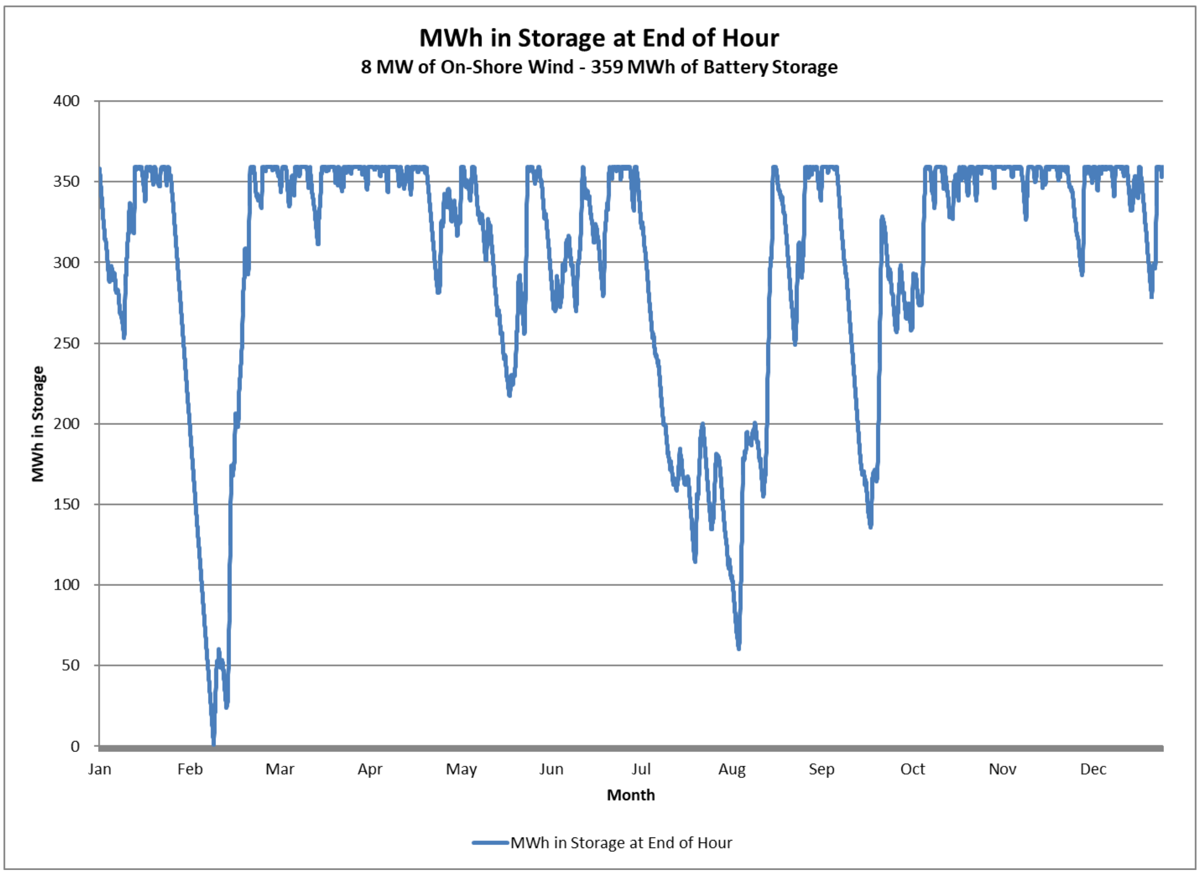
Wind/Storage

8 MW of Wind and 359 MWh of battery storage would be required to serve 1 MW of load around-the-clock for a year. It is the most expensive of the three scenarios under the assumptions, but has the least amount of excess MWh sold to the ISO thus subjects VEC to the least amount of risk to cost variance resulting from uncertainty of Real-Time Spot market prices.

Over a 10-year period, 1.7 times more generation (149,796 MWh) than load would be required. 35.9% of this generation would serve load at the time it is generated and 22.6% would be stored in the battery to serve load when the solar generation was not adequate to do so. 41.5% of the generation would be excess of the load plus the amount injected into storage each hour, and sold at Real-Time Spot market prices.

61.4% of load would be served by generation at the time it is generated while 38.6% of load would be served by energy that had been stored in the battery.

Below is a plot of the amount of energy in the battery in each hour of the year.



The battery is full at the beginning of the year, but gets depleted in early February as the generation does not keep up with the load across the month. With windy days in late February the generation exceeds load which allows more load to be served as the generation is produced, the batteries filled up and excess energy is sold on the spot market. The batteries contain sufficient energy to serve load through the rest of the year, but less windy periods can remove noticeable amounts of energy before windy spells recharge them. The major issue requiring so much battery storage is a lack of generation in mid-February, but this could happen at other times during wht year with different wind patterns. The batteries end the year fully charged, but different wind patterns in December could result in the batteries not being completely full. In a more realistic analysis than this simplified version this could create a problem in the following January or February if the batteries do not have a chance to get fully charged.

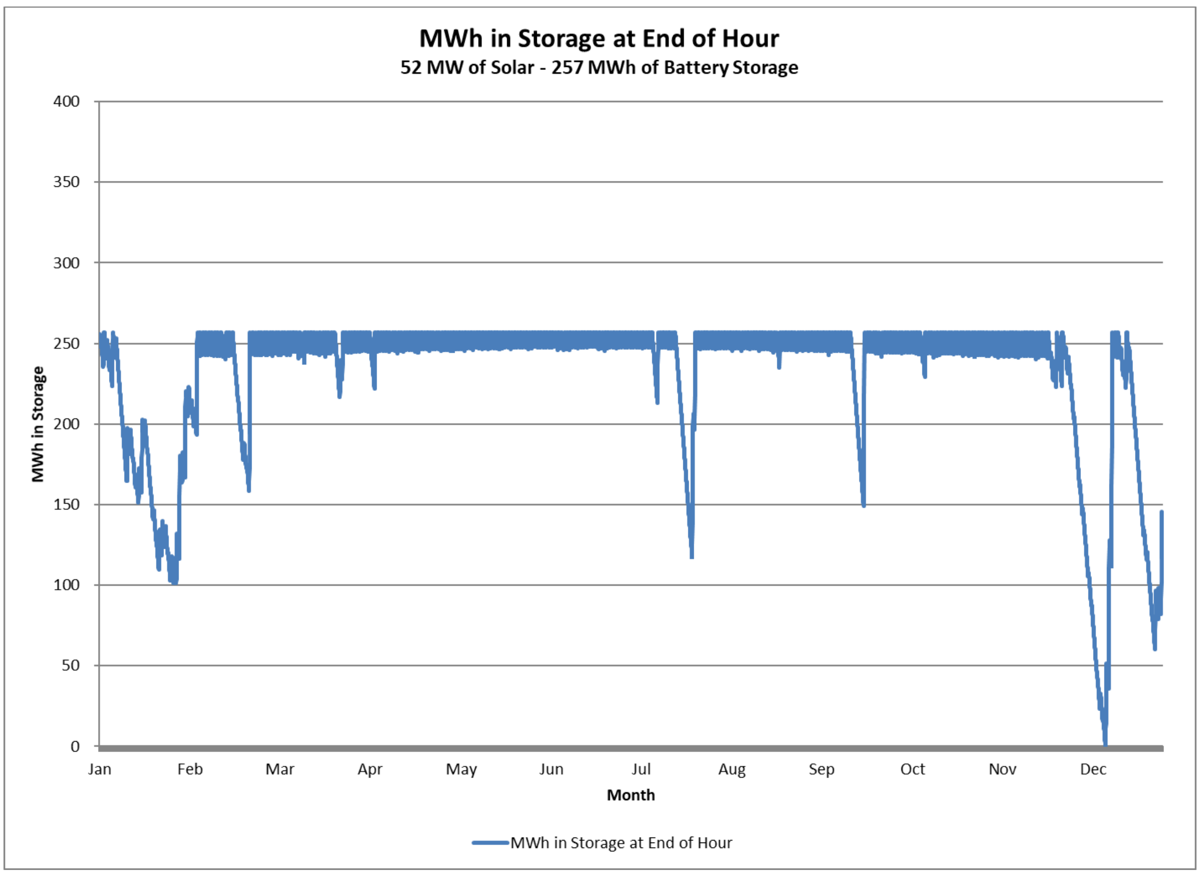
Solar/Storage

52 MW of Solar and 257 MWh of battery storage would be required to serve 1 MW of load around-the-clock for a year. The cost of this scenario is 8.5% less than the Wind/Storage scenario, but with over 8.2 times more excess energy, subjects VEC to much more risk to spot market price volatility.

Over a 10-year period, 6.9 times more generation (600,760 MWh) than load would be required. 6.2% of this generation would serve load at the time it is generated and 8.4% would be stored in the battery to serve load when the solar generation was not adequate to do so. 85.4% of the generation would be excess of the load plus the amount injected into storage each hour, and sold at Real-Time Spot market prices.

42.4% of the load would be served by generation at the time is was produced, while 57.6% of the load would be served by energy that had been put into storage.

Below is a plot of the amount of energy in the battery in each hour of the year.



The battery is full at the beginning of the year, but gets depleted in January as the generation does not keep up with the load across the month. With sunny days in February the generation exceeds load which allows more load to be served as the generation is produced, the batteries filled up and excess energy is sold on the spot market. The batteries are full for much of the summer as generation exceeds load in most daylight hours; some energy is used every night to serve load as the sun is down. The major issue requiring so much battery storage is a lack of generation in late November into early December which depletes the batteries. Lack of generation at the end of December results in only 150 MWh of energy in storage at the end of the year. In a more realistic analysis than this simplified version this could create a problem in the following January if output is similar to what is assumed here.

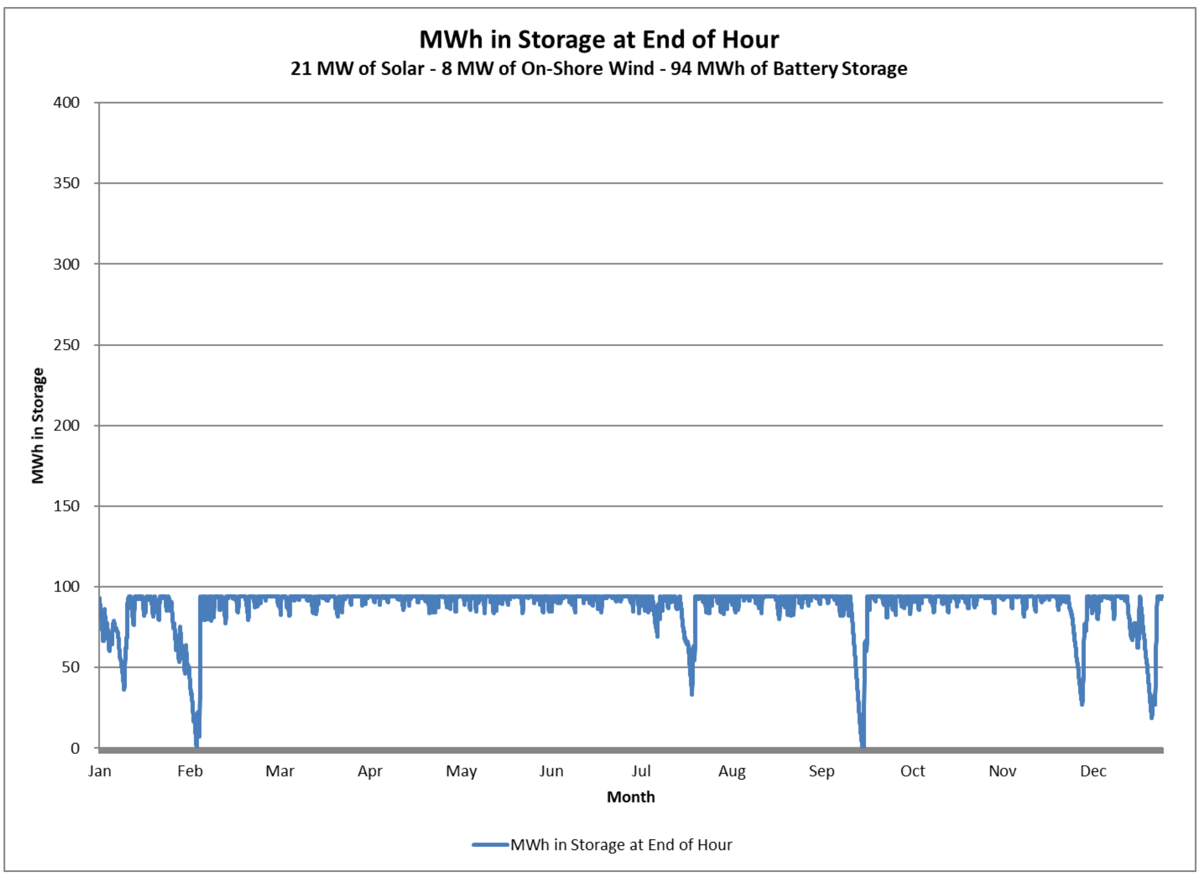
Solar/Wind/Storage

21 MW of Solar, 6 MW of Wind and 94 MWh of battery storage would be required to serve 1 MW of load around-the-clock for a year. This is, by far, the least expensive scenario, mainly because of the significant reduction in storage MWh required. <u>There is still a significant amount of risk as </u>75.3% of the total generation must be sold at spot market prices. Though this is noticeably less risk than in the Solar/Storage scenario, it is over 4-times more risk than in the Wind/Storage scenario.

Over a 10-year period, 4.1 times more generation (354,962 MWh) than load would be required. 18.9% of this generation would serve load at the time it is generated and 5.7% would be stored in the battery to serve load when the solar generation was not adequate to do so. 75.3% of the generation would be excess of the load plus the amount injected into storage each hour and sold at Real-Time Spot market prices.

76.8% of the load would be served by generation at the time is was produced, while 23.2% of the load would be served by energy that had been put into storage.

Below is a plot of the amount of energy in the battery in each hour of the year.



The storage profile exhibits similar characteristics to both the Solar/Storage and Wind/Storage scenarios, but to lesser degrees. The battery does get close to depleted in early February, as in the Wind/Storage scenario, but not for as long of a period as the 21 MW of solar makes up for the 2 MW reduction in wind. A risk in September is introduced that was not as prevalent in either of the Solar/Storage or Wind/Storage scenarios, but the risk in December in the Solar/Storage scenario is greatly reduced by replacing 31 MW of solar with 6 MW of Wind.

3.3.8 Takeaways from Renewable Technology Diversity Analyses

Because of the intermittency of some of the technologies, unknown future cost curves for each technology, the simplifying assumptions used and unresolved issues under each scenario, the analysis above is intended to provide directional level information regarding the output patterns of different resources types over the course of a year. It is not intended to provide information precise enough to prepare planning-level budgets.

What is clear though, is that reliance on solely on any one technology will be difficult, meaning technology diversification will be key if we are hoping to eliminate any reliance on fossil fuels for electricity generation.

The important takeaways, from VEC's perspective, are:

- Baseload renewable or fossil-free resources will be necessary to minimize costs;
- Relying on one technology source will lead to an over procurement of generating resources and introduce a high volume of risk on reselling excess generation when batteries are full;
- It will take a significant decrease in battery costs before Storage is a cost-effective strategy to turn intermittent resources into baseload resources;
- Until a significant decrease in Storage costs occurs, Storage can play a role around the edges.

3.4 Generation Impacts on Infrastructure

Distributed generation includes all generation that is connected to VEC's distribution system, generally located behind the meter, and owned by a member or a developer. Distributed generation is often grouped into a larger subset of resources called Distributed Energy Resources (DER) which also includes energy storage and other controllable resources.

VEC continues to see a dramatic rise in distributed generation on its electrical system, largely driven by technology availability and federal and state incentives. Distributed generation projects generally fall into one of three categories formats: net-metering projects, independent projects developed pursuant to Power Purchase Agreements (PPAs) with VEC, and Standard Offer projects. The chart below shows total nameplate (AC) generation of all active projects on VEC's system since 2014:

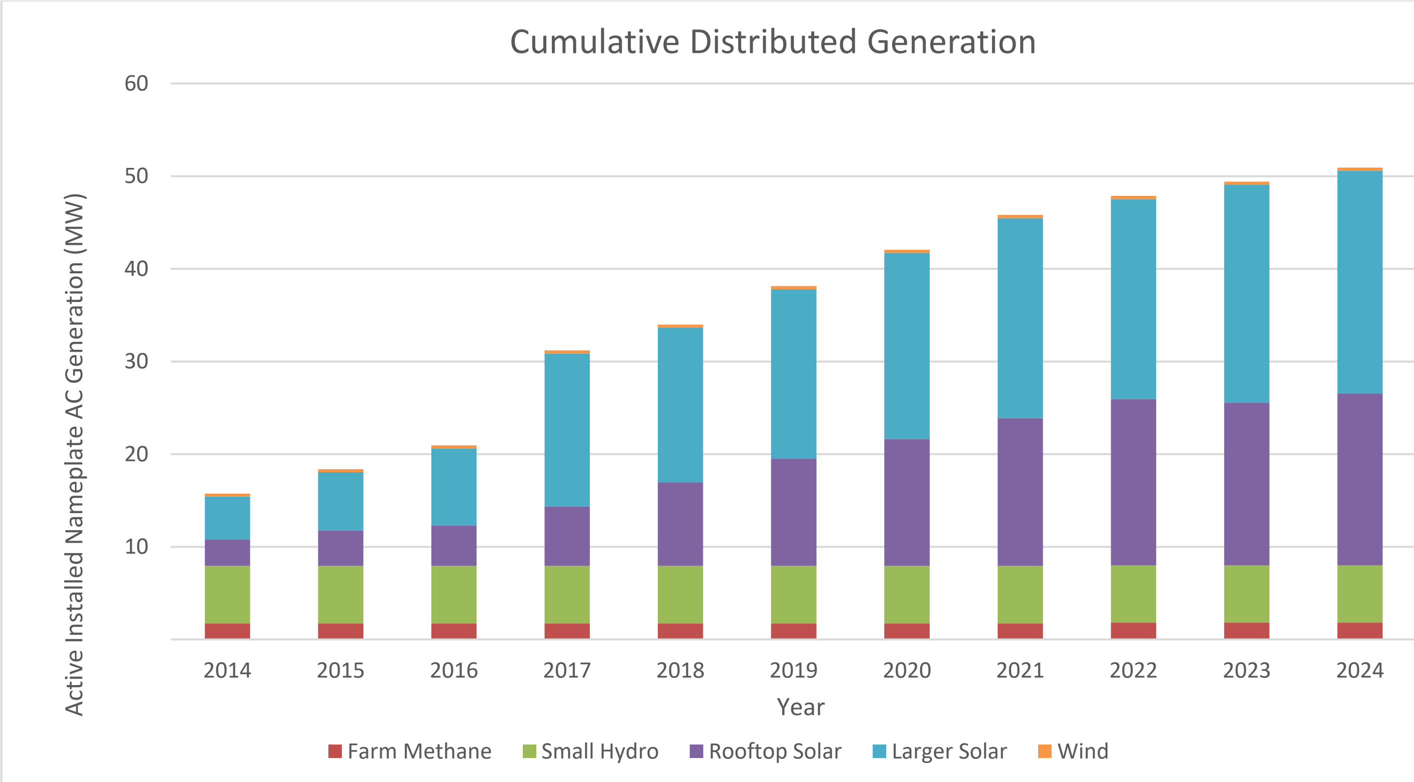


Figure 3.4.1.A Increase in installed distributed generation since 2011 (current as of 01/01/2022)

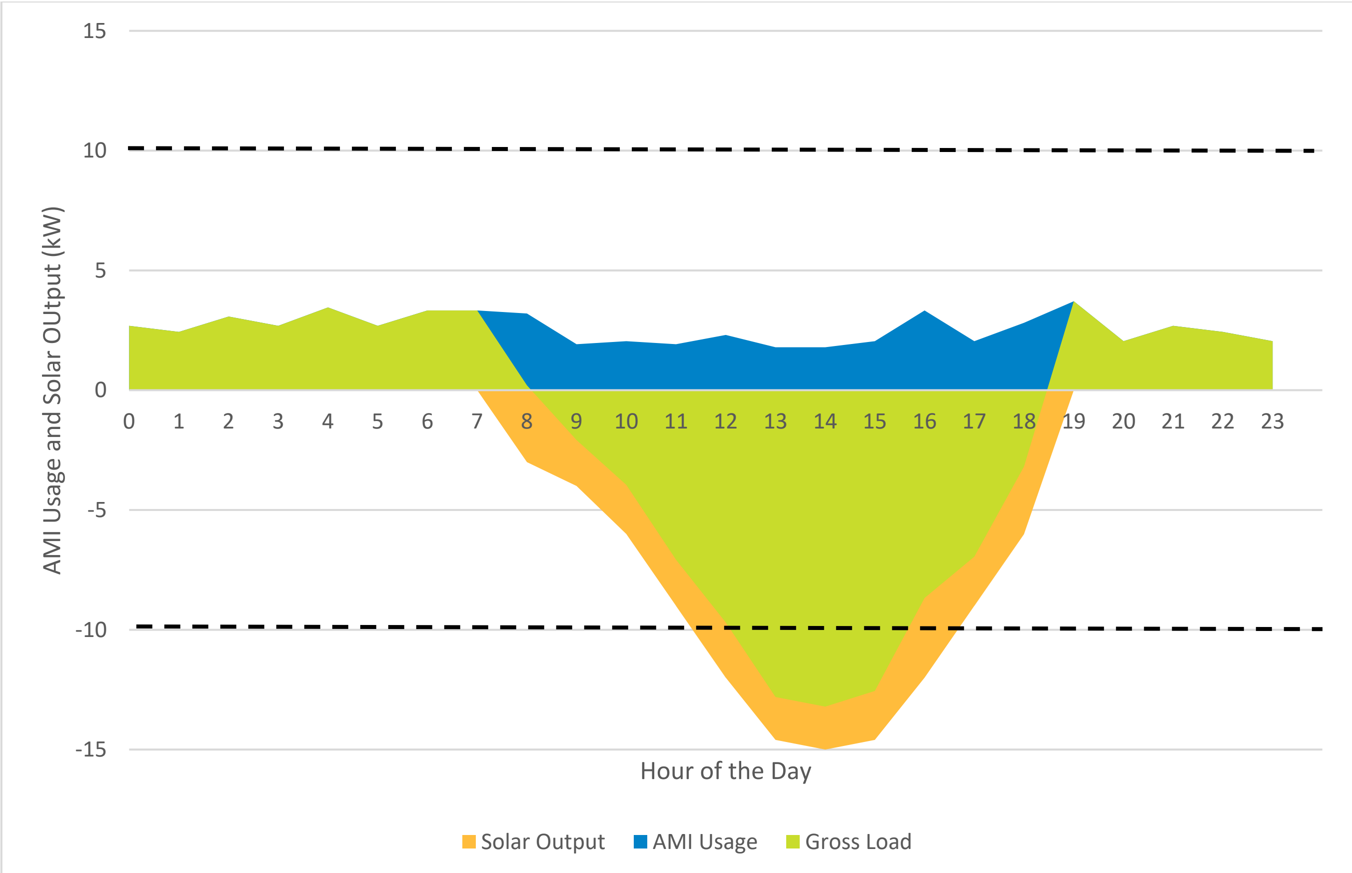
VEC currently has over 50 MW of distributed generation installed on its system (27.9 MW of which is net-metering solar). VEC maintains two internal databases to track net metering and Standard Offer/PPA projects. These databases include a queue for each project application, type of generator, technical application details including inverter type and system capacity, location, and member information. This database is fed into VEC's GIS system and then into its Milsoft WindMil Engineering model.

As a result of this rapid rise in generation VEC has experienced several key infrastructure challenges and has grouped the following conversation based on the assets affected

3.4.1 Local Service Transformer and Service Wire

Service Transformer Overloads

VEC's average residential solar (<15kW) solar application is typically around 8.5kW with several larger. VEC also averages around 1.2 meters per transformer and most transformers are 10kVA. The example below demonstrates the overloading that can occur when a 15kW solar site is added to a 10 KVA transformer.



Solution: Proactive Transformer Loading Analysis

VEC addresses this challenge by reviewing each application when it is received by VEC staff from the PUC. VEC's utility designers use the Camus transformer loading tool to look at the existing AMI load and determine whether a transformer upgrade is required. This analysis is performed prior to installation of the additional meter that is required for solar sites.

Service Wire Overloads

In some cases, especially with larger rooftop sites, the service wire feeding the house may be inadequately sized.

Solution: Proactive Analysis

VEC addresses this challenge by reviewing each application when it is received by VEC staff from the PUC. VEC's utility designers review the wire size listed in VEC's GIS system and if needed will request a service wire upgrade.

3.4.2 System Protection – Fuses and Reclosers

Fault Current Contributions:

Protection schemes on radial feeders are designed with the assumption that current flows in a single direction and into a fault through the upstream protective devices. Distributed generators can provide fault current from alternate directions resulting in the desensitizing of existing protection. Desensitizing means that less fault current may flow through the upstream protective device than would have otherwise existed if the downstream-distributed generators were not present.

Since faults are detected and sectionalized utilizing over-current protection schemes and an over-current relay's speed is inversely proportional to current magnitude (more current equals faster operation), the distributed generation contribution may slow the speed of operation. In some cases, it may keep the upstream protective device from reaching its pick-up current value until the distributed generators sense the fault and trip offline. In addition, given the low quantities of fault current on some parts of the system, distributed generation can further exacerbate protection margins.

> **Solution: Inverter Settings**
>
> IEEE 1547 requires all distribution generators to go offline during sustained fault conditions. Once the generation goes off-line, the upstream protective devices are no longer desensitized and should function normally. It should be noted that VEC does not foresee significant delays in its protective devices normal operation (through desensitizing) since most distribution generators contribute very little fault current to the system and go off-line very quickly during fault conditions as compared to traditional utility protection operation.

3.4.3 Substation Transformers and Primary Lines

Substation Transformer Capacity

As large group net-metering projects that far exceed the load they serve are built, the likelihood of substation capacity constraints also increases.

> **Solution: Investment or Flexible Interconnections**
>
> While VEC does not have any locations where this has occurred, it would be up to the next project in line (developer) to pay for any substation upgrades to allow their project to be constructed. VEC is also piloting flexible interconnections that would reduce infrastructure upgrades. This is discussed further below.

Impacts on Feeder Backup

If the feeder with a large generator is tied to and sourced from a feeder further from the source, the Voltage rise can exceed the top of the acceptable Voltage range.

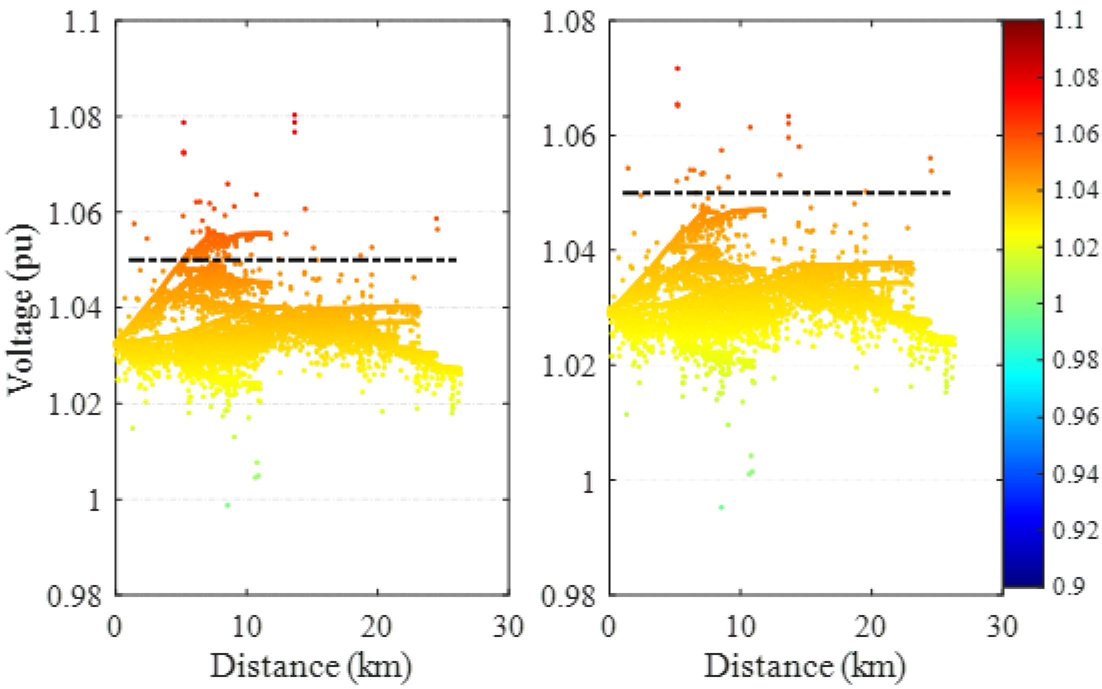
> **Solution: Planning and Disconnection**
>
> This issue is identified in VEC's Fast Track Screening of the project, and a typical solution is to install larger line conductors to reduce source impedance or to add strategically placed line Voltage regulators to buck (lower) the high Voltage. However, due to the cost implications of both of those solutions, VEC will typically request the generator go off-line while the feeders are tied.

Voltage

Most members on VEC's system are fed from long radial lines with small conductor; as such, distributed generation that exceeds load will typically result in a Voltage rise at the point of interconnection. As part of the System Impact Study process these issues are typically identified. However, for smaller residential sites this analysis is not performed. VEC's AMI system does not yet have the bandwidth to collect Voltage data, but the new system VEC is currently installing will have this capability.

Solution: Inverter Settings or T&D Infrastructure

Requirements for Volt/VAR compensation or system upgrades such as additional voltage regulation or reconductoring may be needed for mitigation of this situation. VEC is actively conducting research with PNNL and UVM to explore the value and impacts of voltage compensation. The charts below show the benefit of Volt/VAR compensation on two VEC substations.



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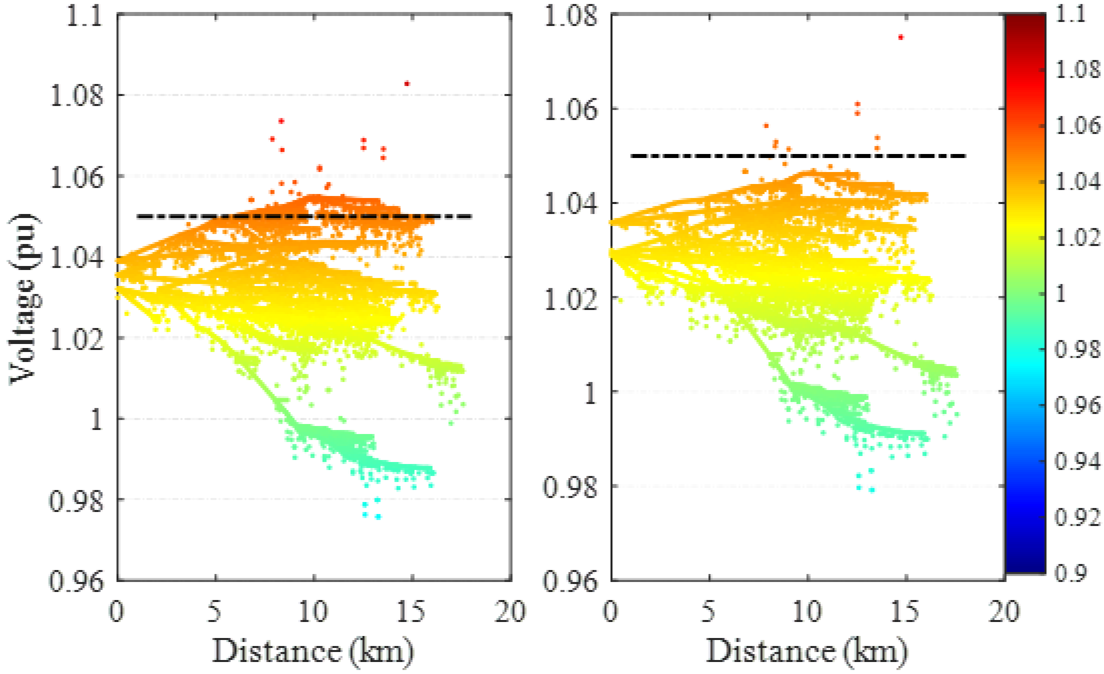

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While preliminary model results show some benefit, this approach has been challenging to implement. Model results are based on changing many existing generator inverter settings. VEC has had limited success in working with project owners (sites above 150kW) to change their settings. Potential impacts to energy production, and power factor management at the substation level could also be a challenge with this approach. To orchestrate continued growth of distributed renewable energy, VEC will ne

ed to change its approach to Voltage regulation and reduce the system Voltage to allow for Voltage rise from distributed generation. VEC will also need to upgrade conductors to larger size, add Voltage regulators to the distribution circuits where they do not already exist, and add phases where only one or two exist to allow for balancing load, generation, and voltage.

Solution: Voltage Regulator Voltage Drop Compensation

Voltage Drop compensation settings are one of the methods VEC can use to help mitigate the Voltage rise from distributed generation. Typically, VEC boosts the line Voltage above nominal to account for Voltage drop caused by load. Voltage Drop Compensation settings set the line Voltage to a Voltage closer to nominal and increase the line Voltage as the load increases. The lower line Voltage allows for the Voltage rise caused by distributed generation, helping prevent system Voltage from rising above acceptable limits. These settings are developed on a case-by-case basis and are based on the Voltage regulator location, circuit impedance, and load. This can therefore be challenging to implement if the circuit has large differences in impedance or load for different branches or taps beyond the Voltage regulator. Currently VEC is only implementing compensation settings in Voltage regulators that are on radial distribution circuits. VEC will need to consider changing from bus regulation to circuit regulation if these settings changes are to be applied at the substation. Circuit regulation utilizes sets of Voltage regulators for each substation circuit, whereas bus regulation utilizes only one set of regulators for all circuits. Differences in impedance and load between the circuits leaving a substation will require different regulator settings, and this cannot be achieved with all circuits being regulated by the same device as is the case with bus regulation.

3.4.4 Transmission

As distributed generation continues to increase so do the potential effects on the transmission grid.

Load Power Factor

ISO-NE is requesting that the transmission and distribution utilities regulate their power factor to unity.

> **Solution: Dynamic VAR compensation**
>
> VEC currently utilizes fixed capacitors for power factor correction. Capacitor sizes and locations are based on peak load conditions. Inevitably this approach results in excess reactive power being supplied by the distribution circuit capacitors back into the sub-transmission system during lower load times, or times when distributed generation is serving the load. To maintain a consistent power factor of unity, VEC will need to add switched and dynamic devices that change status or output based on system demands. Some fixed capacitors may be able to remain online, but many will need to be removed. Removing capacitors from parts of the distribution system may impact the amount of voltage drop on some circuits and require that voltage be increased through increasing conductor size, adding voltage regulators, or adding phases to help distribute load.

Voltage and Frequency Ride Through

Inverter Based Resources (IBR's), unlike synchronous generators, rely on power electronics and control algorithms that can behave unpredictably during grid disturbances. This has significant implications for transmission system stability and the ISO-NE region has seen several events where distributed generation on the distribution system has gone offline unexpectedly.

> **Solution: ISONE Source Requirements**
>
> VEC mitigates these instabilities by requiring inverters to ride through voltage and frequency irregularities per UL 1741-SA and ISO-NE Source Requirements document. These requirements are listed in PUC Rule 5.500. While this only applies to new installations, inverters typically are replaced on a 10-15-year basis and these replaced inverters will be required to have the new settings.

SHEI (Sheffield Highgate Export Interface) Transmission Constraint

The SHEI is an ISO-NE defined transmission region in northern Vermont. A VELCO-owned 115kV transmission line from Sheffield to Highgate to St. Albans and a GMP owned 34.5kV sub-transmission line from VELCO East Fairfax to Lowell make up the region. Around 21,500 VEC members are fed from these transmission lines via 16 substations, and the area has significantly less load than generation.

The average load in the region is around 35MW, and the total generating capacity is around 450 MW. This generating capacity includes imports from Hydro-Quebec on the Highgate Converter (225 MW), KCW (63 MW), Sheffield Wind (40 MW), Sheldon Springs Hydro (~26 MW), Coventry Landfill (8 MW), and several other net-metering and small generation projects (~80 MW).

Since the load in the region is often low (spring and fall) when generation from wind and hydro tends to be high, there is excess generation that needs to flow out on the transmission system. The capacity of this transmission system (originally designed to meet the load) limits its ability to export power to the rest of Vermont and New

England and as a result projects are curtailed (shut down or limited generation output). A map of the area is provided below along with a [more detailed version](#) which is available on our website.

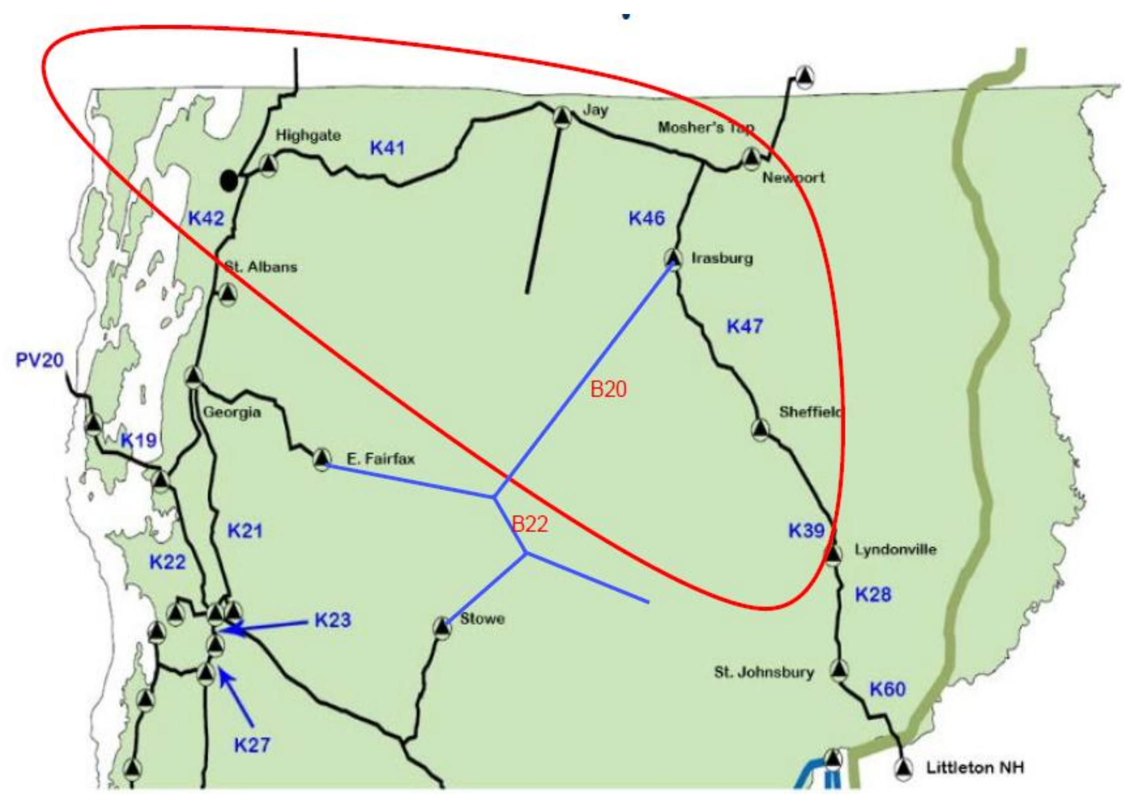

Figure 3.4.4.B Simplified visual of the SHEI

<u>Solutions to the SHEI Constraint</u>

- <u>Load Growth -</u> Load building within the SHEI may also provide relief to SHEI constraints, and VEC's Tier III Energy Transformation Program, discussed elsewhere in this Plan, may help with that, although we do not see enough load-building solutions that will allow us to "grow our way out" of the SHEI constraint.
- <u>Subtransmission Upgrades -</u> Upgrades to the Lowell Substation and some 18.1 miles of the B20 transmission line from Johnson to Lowell, as well as upgrades to 1.5 miles of the B22 line in the towns of Eden, Johnson, Lowell and Morrisville have been completed which have helped to reduce curtailments.
- <u>Transmission Upgrades – VELCO</u> The Highgate-St Albans-Georgia K42 115 kV line is a 1958 vintage line located in the Northwest corner of Vermont near the Canadian and New York Borders. The Highgate 225 MW HVDC converter, which connects Vermont to Hydro Québec, taps the K42 line near the Highgate ring substation. The K42 line is one of two 115 kV lines that cross the Sheffield Highgate export interface (SHEI), which is limited by Voltage and stability concerns. The K42 line is the primary path for power to flow out of the interface. VELCO's assessment of the K42 line's condition showed that 146 out of 212 structures need to be replaced. VELCO is in the early stages of completing a line rebuild project anticipated to address the asset condition concerns. It is expected that the project will increase the SHEI's output by 20MW. T. More information on the project can be found here:
- https://www.velco.com/projects/franklin-county-line-upgrade
- <u>Battery Storage -</u> VEC has completed construction of a joint utility scale battery storage with GMP located at its North Troy substation. The project is primarily driven by peak shaving benefits but is also looking at how

both utilities can use the battery to mitigate local generation constraints. The project was installed in 2024 and VEC and GMP are investigating how the battery can be used to reduce SHEI curtailments

Future challenges

While the SHEI is isolated to a specific location in Vermont, it is indicative of a greater issue that can arise when high penetrations of distributed generation occur in areas without adequate electric load. The VELCO Long Range Plan goes into greater detail with respect to how much more generation can fit in various zones of Vermont before creating the next export interface limitations. As we look ahead, we must continue to deploy in-state, distributed renewable generation while also working to locate these systems as optimally as possible to avoid, or at least defer, the need for bulk transmission upgrades like the work in the SHEI area. We will continue to work closely with VELCO to optimize the deployment of these resources.

Since the issue first began affecting VEC and other Vermont ratepayers VEC has intervened in any new generation over 150kW and encouraged developers to locate any larger generation outside of the SHEI. To resolve this constraint, several initiatives are underway at the distribution and transmission level (owned by GMP and VELCO).

3.4.5 Hosting Capacity

VEC provides developers and its members a map of generation constrained areas on its website https://vermontelectric.coop/electric-system/grid-data-and-mapping.

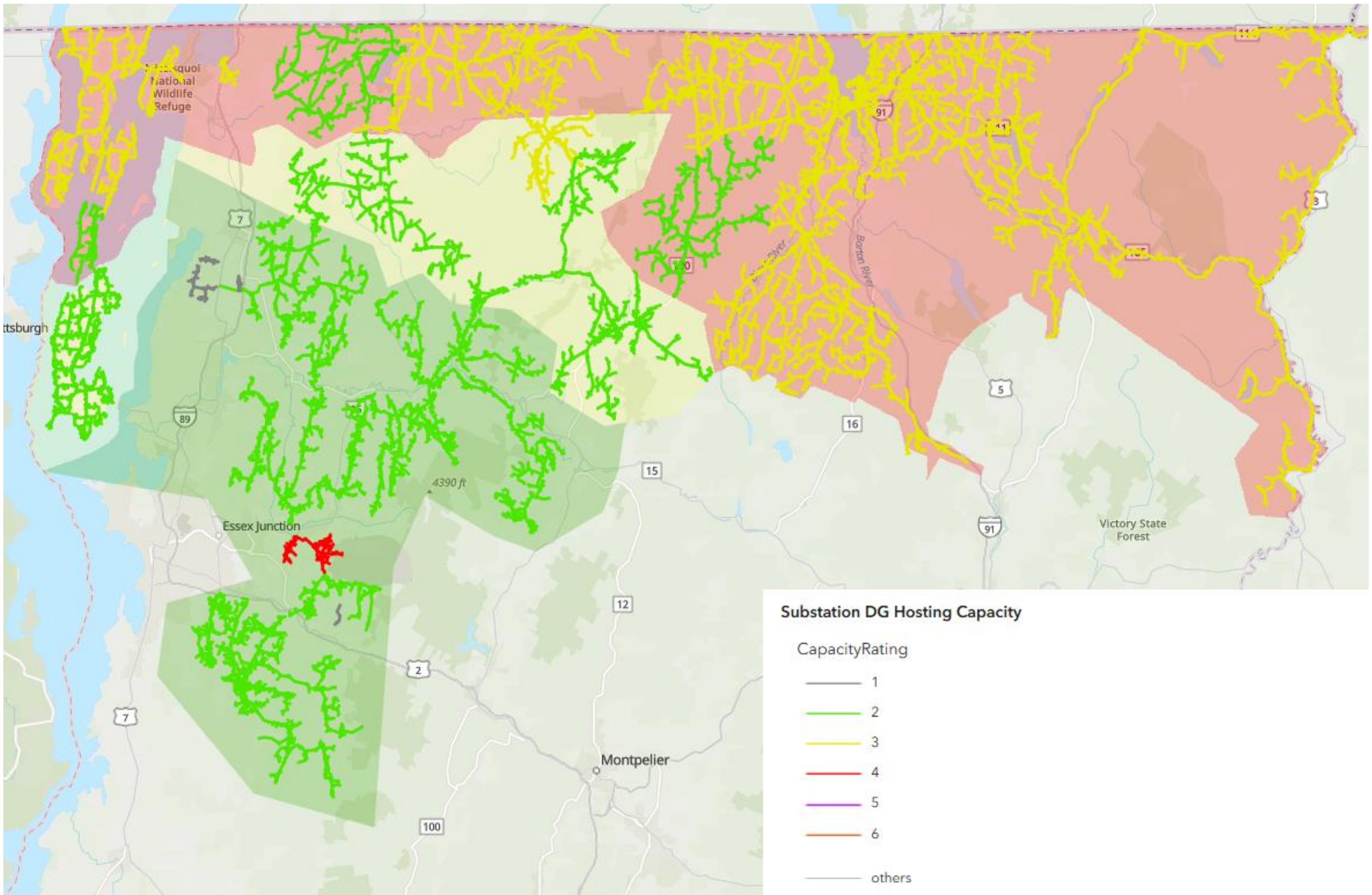

Figure 3.4.5.A VEC Generation Constraint Map

The Hosting Capacity map is updated every 6 months and shows capacity rating by substation. The rating is based on remaining transformer capacity.

- Unrated (grey) - rating = 1
- Substation Transformer with at least 20% capacity and no transmission constraint (green) - rating = 2
- Substation Transformer with at least 20% capacity and transmission constraint (yellow) - rating = 3
- Substation Transformer less than 20% capacity and no transmission constraint (red) - rating = 4
- Substation Transformer less than 20% capacity and transmission constraint (purple) - rating = 5
- Delayed interconnection and higher costs likely (orange) - rating = 6

VEC displays hosting capacity at the substation and circuit level for all locations on the distribution system. VEC does not determine hosting capacity by town. However, Regional Planning Commissions can use the solar map to determine how much hosting capacity is available on the distribution circuits that feed their towns.

VEC currently takes minimum load on a feeder and substation into account when performing feasibility studies for larger solar projects and when a substation's power transformer nameplate capacity is reached to allow additional DG to interconnect. As the system becomes more saturated with DG and reverse flow on transformers reaches nameplate values, VEC will be exploring time-of-day limited export agreements where projects limit export at peak solar production hours to avoid exceeding transformer ratings. This will move VEC more towards a seasonal and hourly hosting capacity for individual feeders which are export limited.