4 Energy Transformation and Energy Supply

4.1 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 2021, VEC's retail sales were approximately 455,000 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 489,000 MWh of electricity from various suppliers to meet its members' needs.

VEC's mission is to serve our Cooperative members with safe, reliable, 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 starting in 2023."
- "…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 significant 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:

- Compare the cost and rate impact of various Carbon Free and Renewable technologies assuming VEC's energy portfolio is 100% Carbon Free through 2029 and 100% Renewable for 2030-2042 measured on an annual basis;

- Estimate the incremental cost of serving VEC's 2030 load requirements with 100% Renewable Energy on an hourly basis with different individual renewable technologies combined with storage.

- Analyze the impact on VEC's hourly load shape of uncontrolled CCHP and EV projected to be installed in VEC's territory in 2025, 2030, 2035, and 2040 and identify potential risks associated with not controlling these resources.

- Estimate how many additional MW of battery storage can be installed state-wide before it becomes so difficult to identify the peak hour on a day-ahead-basis that VEC's current strategy of contracting with battery developers/owners solely for peak shaving services no longer is effective.

4.1.1 Section Overview

Energy Transformation Programs and Forecast
- VEC's Incentives
- Load Assumptions and Forecast
- Risks and Opportunities

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

100% Carbon Free and Renewable on an Annual Basis
- 100% Renewable – Energy and RECs from Existing Hydro
- 100% Renewable – Energy and RECs from Off Shore Wind
- 100% Renewable – New In-State Solar\

100% Renewable 24/7
- Capacity factor analysis
- Costs of implementing renewables plus storage
- Takeaways

ISONE and System Peaks
- ISONE and Transmission Costs
- Sustainability of VEC's Utility Scale Battery Storage
- VEC System Peaks

4.2 Energy Transformation Programs and Forecasts

As part of a larger goal to meet the climate needs of Vermont, VEC utilizes a portfolio of projects and programs to decarbonize the heating and transportation sectors. VEC offers bill credits for several Tier III measures such as CCHPs, heat pump water heaters (HPWHs), EVs, pellet stoves, electric forklifts and electric lawnmowers. VEC also offers discounts on line extensions and service upgrades for larger, custom projects that result in the elimination or reduction of fossil fuel usage. Additionally, VEC works with partners on non-electric efforts such as weatherization.

Tier III of the RES requires that Vermont retail electric providers achieve fossil-fuel savings from energy transformation projects at a level equivalent to 2% of the utility's annual retail sales (BTU equivalent) beginning in 2017, increasing by 0.667% each year until reaching 12% in 2032.

4.2.1 Programs and Incentives

VEC's Tier III programs and incentives come in several categories:

Heating and Cooling | Transportation | Home and Communitiy | Line Extensions and Increase in Service

Heating and Cooling

Heat Pumps, Heat Pump Water Heaters, and Pellet Stoves

VEC provides bill credits for the above device types.

On-bill Financing Pilot Project- Weatherization Repayment Assistance Program (WRAP)

VEC is working with Vermont Housing Finance Agency (VHFA) and a coalition of distribution and energy efficiency utilities on a "to-the-meter" tariff that would allow energy efficiency, electrification, and weatherization projects to be paid for through the electric bill. In addition to "on-bill financing," the program would include:

- a low-cost energy audit for income-qualified participants
- additional incentives that would help make the projects more affordable (up to $1 million, max of $20K each)
- the program will be accessible to renters in addition to homeowners

VHFA was allocated $9 million to support this effort over the next two years with 1,000 participants anticipated. Program launch is expected in summer 2022.

VEC Low- and Moderate-Income Heat Pump Incentives (Act 151 + VLITE grant)

The cost of these heat pump installations will be shared between VEC and Efficiency Vermont. VEC has been awarded $100,000 to help low- to moderate-income members pursue thermal fuel-switching, which will help them reduce fossil fuels and save money on heating. Program implementation will integrate with the weatherization and heat pump installation partnership with EVT through Act 151 funding.

- Eligible members are those who meet income eligibility and have homes that have been weatherized.
- At or below 80% of AMI (ow income): Free installation. Estimated 29 units in VEC's territory.
- Between 80% and 120% of AMI (Moderate income): $2000 per unit on top of existing incentives.
- Estimated 29 units in VEC's territory.

Transportation

EVs, Plug-In Hybrid Electric Vehicles (PHEVs) and Chargers

VEC provides bill credits for the above device types.

VEC Low Income Adders for Income Qualified Members

VEC provides low income adders to income qualified members who purchase EVs, and has offered incentives for previously owned vehicles (in addition to new vehicles) since the initial launch of our Energy Transformation program four years ago.

- Promote and administer state incentives (up to $4,000) for electric vehicles for income qualified. In addition to baseline VEC incentives, VEC offers $250 bonus for income-qualified members.
- VEC is also looking to continue to include pre-owned and leased electric vehicles in our electric vehicle incentive program.

Mileage Smart- Up to $5,000 towards purchase of used fuel-efficient vehicle (includes hybrids and EVs) is available through a Vermont state program which is promoted by VEC.

Vermont FY22 Transportation Incentive Programs

In the FY2022 transportation budget, the Legislature authorized three new vehicle incentive programs currently under development and expected to launch this year.

Home and Community

VEC ChargeItUp

VEC's ChargeItUp Program encourages people to purchase lower-cost electric items, such as yard equipment including like trimmers, leaf blowers, chainsaws, as well as other devices like e-bikes or motorcycles, by entering them in a monthly drawing for a $100 bill credit.

Rural Community Pilots (Newport/Richford)

VEC is working with EVT and other potential partners in Newport and Richford to identify efficiency and residential electrification opportunities. Some of the ideas and projects under development include:

- Newport multi-family residential EV charging grant applications (Rural Edge and private landlords)

- Newport multi-family thermal efficiency and fuel switching projects
- Capacity building in Richford with local leaders and Vermont Council on Rural Development
- Richford LED streetlights project and housing inventory

Collaboration with Partners.

VEC partners with Energy Smart Vermont which provides energy coaching through Community Action Agencies. In addition, we also work with EVT and Neighborworks to promote available programs and opportunities.

Line Extensions and Increase in Capacity

Clean Air Program

VEC's innovative Clean Air Program and tariff offers customized opportunities to members with off-grid or underserved homes or businesses to replace fossil fuel usage with electricity. These opportunities may include service upgrades or line extensions, the costs of which will be shared between the utility and the member through customized agreements. For example, someone in VEC's service territory who has a maple sugaring operation currently powered by a diesel or propane generator may be eligible to participate in the Clean Air Program and receive an incentive from VEC to assist with the cost of a line extension to retire the generator.

The benefits of the program include reduction in carbon emitting fuels, incentives (discounts) that are paid back to the membership through new margins from electric sales, and also timeliness of information to assist members make more informed decisions

Since VEC began offering the program in 2016 we have completed 27 projects saving over 176,000 gallons of propane, fuel oil, and diesel annually.

Energy Transformation Transformer Upgrades

VEC provides free transformer upgrades for members who install a level two EV charger or heat pump. In many cases the transformer serving their home cannot handle the additional load and to encourage carbon reduction we do not pass this cost on to the member. The additional kWH sales from either an EV or a heat pump provide a quick payback for the cost of upgrading the transformer.

4.2.2 Utility Incentive Comparison

The following table is a comparison of VEC's incentive offerings with other utilities in the state as of April of 2022.

Measure	VEC	VPPSA	GMP	WEC	Stowe	BED
Ductless HP*	350/450	350/450	350/450	350/450	600/700	2400-2950
HP thermal efficiency bonus	150	200	0		0	0
HP income-qualified adder	0	0	0	250	0	400
Pellet Stove	150	0	0	250	150	0
Pellet furnace/boiler	0	0	0	1000	0	0
HP water heater*	300-600	300-600	300-600	300-600	300-600	700-1000

Centrally Ducted HP*	1000 - 2000	1000 - 2000	1000 - 2000	1000 - 2000	1000 - 2000	1500/ton
A2W Heat Pump*	1000/ton	1000/ton	1000/ton	1000/ton	1000/ton	2000/ton
Ground source HP*	2100/ton	2100/ton	2100/ton	2100/ton	2100/ton	1500/ton
HP pool heater	600	0	0	0	0	
All electric vehicle**	200 - 500	500 - 1000	750-1500	1200	300-1000	2300
EV income-qualified**	450 - 750	900 - 1400	1750-2500	2200	550-1250	2900
Plug-in hybrid EV**	100 - 250	250 - 500	750-1000	950	300-750	2000
PHEV income-qualified**	350 - 500	650 - 1100	750=1000	1950	550-1000	2600
Level 2 home charger	250 - 300	0	Free charger	0	0	700-900
Public charging station	500	500	Free charger and installation	0	250-500	1500
Residential lawnmower	50	50	50-100	100	75	100-200
Commercial lawnmower	1000	1200	50-100	100	1250	500-3500
Electric forklifts	1000	2500	0	0	0	4000-6000
Home batteries	Monthly credit	0	Free, monthly fee	0	0	
Yard care	ChargeItUp raffle	25	25	0	25	50-150
Snowblower						15
E-Bike	0	100	200	200	200	200
Electric golf cart	0	100	0	0	0	0
Electric motorcycle	0	0	500	0	0	500
Induction cooktop	0	0	0	0	0	200

Table 4.2.2.A VEC's Incentives for Tier III programs as compared to other utilities in Vermont

*Joint incentive with Efficiency Vermont

**VEC offers a different incentive for leased vs owned and other DUs offer different incentive for used vs new.

4.2.3 How do we develop Tier III programs?

VEC developed an economic model for energy transformation to analyze and encourage our members' transition from carbon emitting fuels to VEC's renewable energy portfolio without creating subsidies from other VEC members. Our energy transformation model evaluates VEC's level of incentives while comparing the results to the expected gross contribution margins from new or incremental sales that could be realized by transforming our members' energy use to our clean energy portfolio. The overarching goal is to encourage our members to reduce their carbon footprints through fuel (energy) switching from carbon emitting energy fuels to VEC's renewable energy portfolio.

VEC's levels of incentives for fuel conversions are based on making sure the overall VEC membership also benefits in the longer-term period through new incremental margins rather than create incentive levels that only reward the actual members that fuel switch. VEC's sales revenue is only one input in the model's analysis. The model also considers costs of power supply and transmission for the sales and factors in other direct & indirect costs such as vegetative maintenance, overhead and underground line maintenance, and property taxes. While the model calculates payback for appliance purchases, it also can evaluate more sophisticated new applications such as line extensions or VEC system upgrades. Calculations included in the model for these more sophisticated analyses also include payback, NPV, IRR, penalty savings, and amount of VEC's annual target for Tier III.

4.2.4 Which members are using our incentives?

At the end of 2021, we had 493 (or 16%) self-reported Low-to-Moderate Income (LMI) member participants in VEC's energy transformation program out of 3,060 total participants. Additionally, around 17% of the total participants also participate in net metering.

4.2.5 Energy Transformation Forecasts

As shown in Figure 4.2.5.A below, VEC has exceeded its Tier III targets since the program started in 2017. We anticipate continuing to do so and the following section provides an overview of our assumptions and forecasts for energy transformation we expect to see in our service territory.

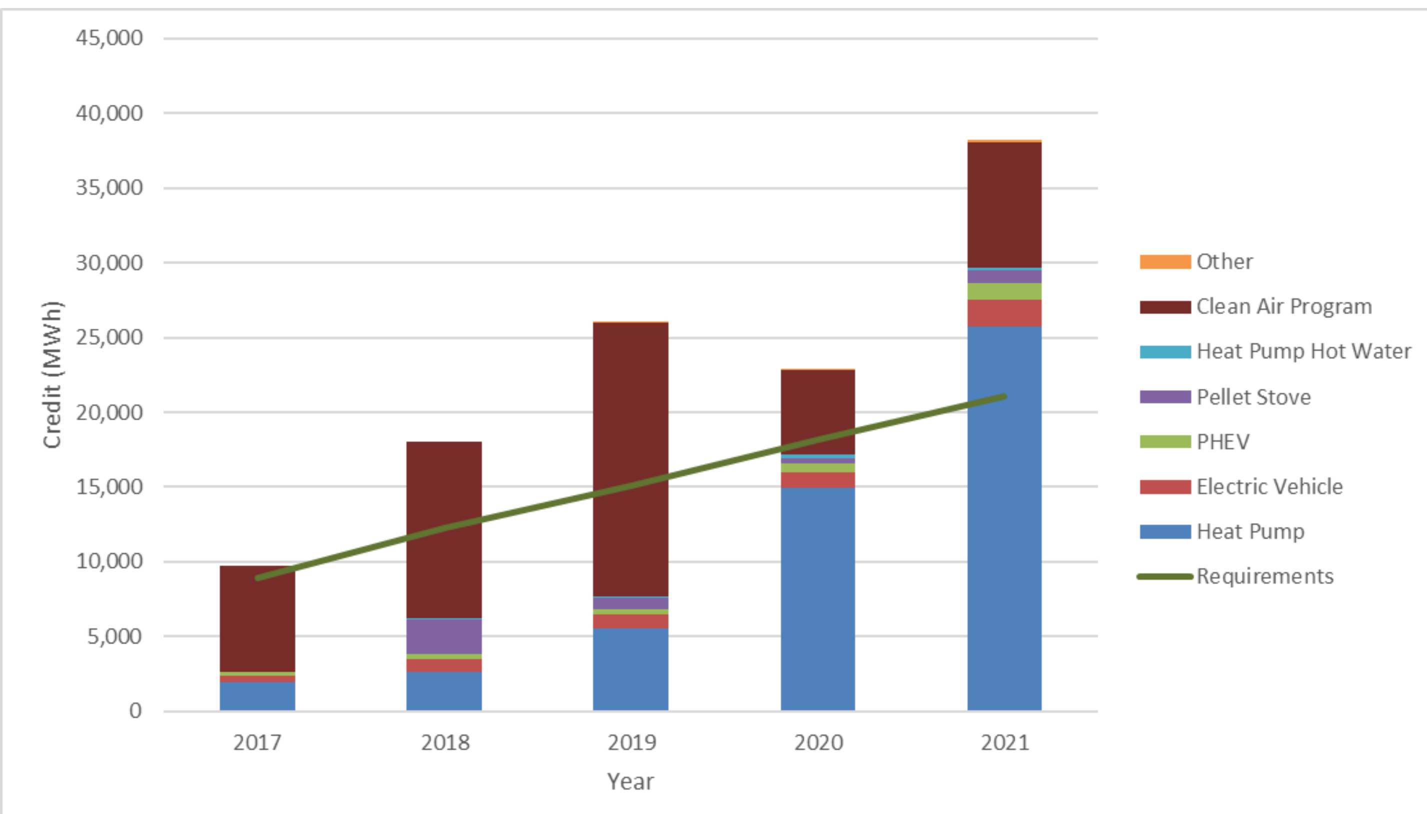

Figure 4.2.5.A VEC's Requirement for Tier III and type of Energy Transformation used to meet the goal

Cold Climate Heat Pumps

For CCHPs, VEC utilized two sources of information to develop forecasts. The first was the number of CCHPs needed to reach the goals of Vermont's Climate Action Plan and the second was a forecast provided by Efficiency Vermont (EVT). Additional details can be found in Section 4.3.3. Figure 4.2.5.B below shows VEC's Tier III Requirement vs Forecasted Tier III Credits from CCPHs using the Climate Action Plan forecast.

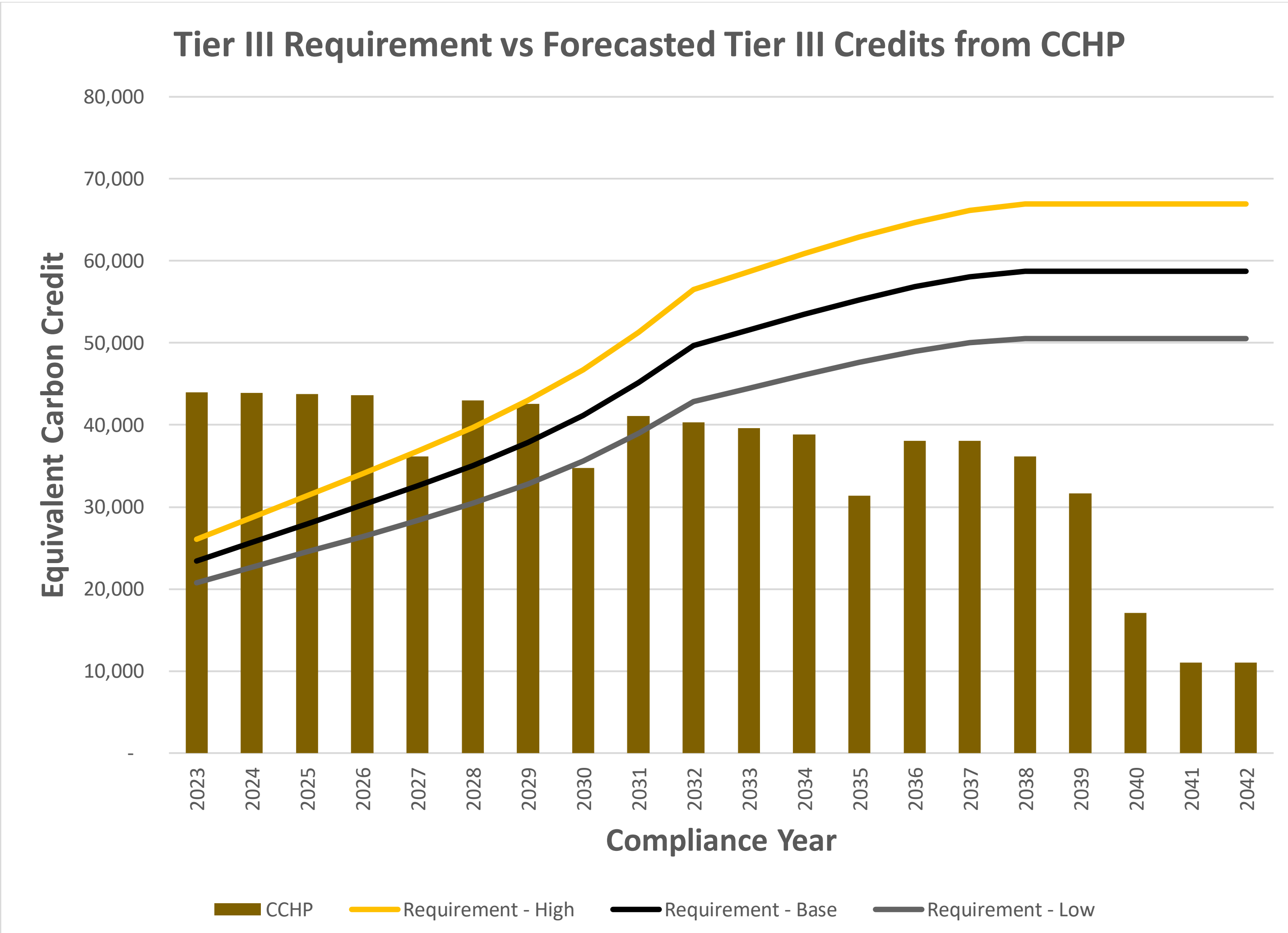

Figure 4.2.5.B Tier III Requirement vs Forecasted Tier III Credits from CCPHs

Electric Vehicles

For EVs, VEC utilized two sources of information to develop forecasts. The first was the number of EVs needed to reach the goals of Vermont's Climate Action Plan and the second was a forecast developed internally by VEC. Additional details can be found in Section 4.3.3. Figure 4.2.5.C below shows VEC's Tier III Requirement vs Forecasted Tier III Credits from EVs using the Climate Action Plan forecast.

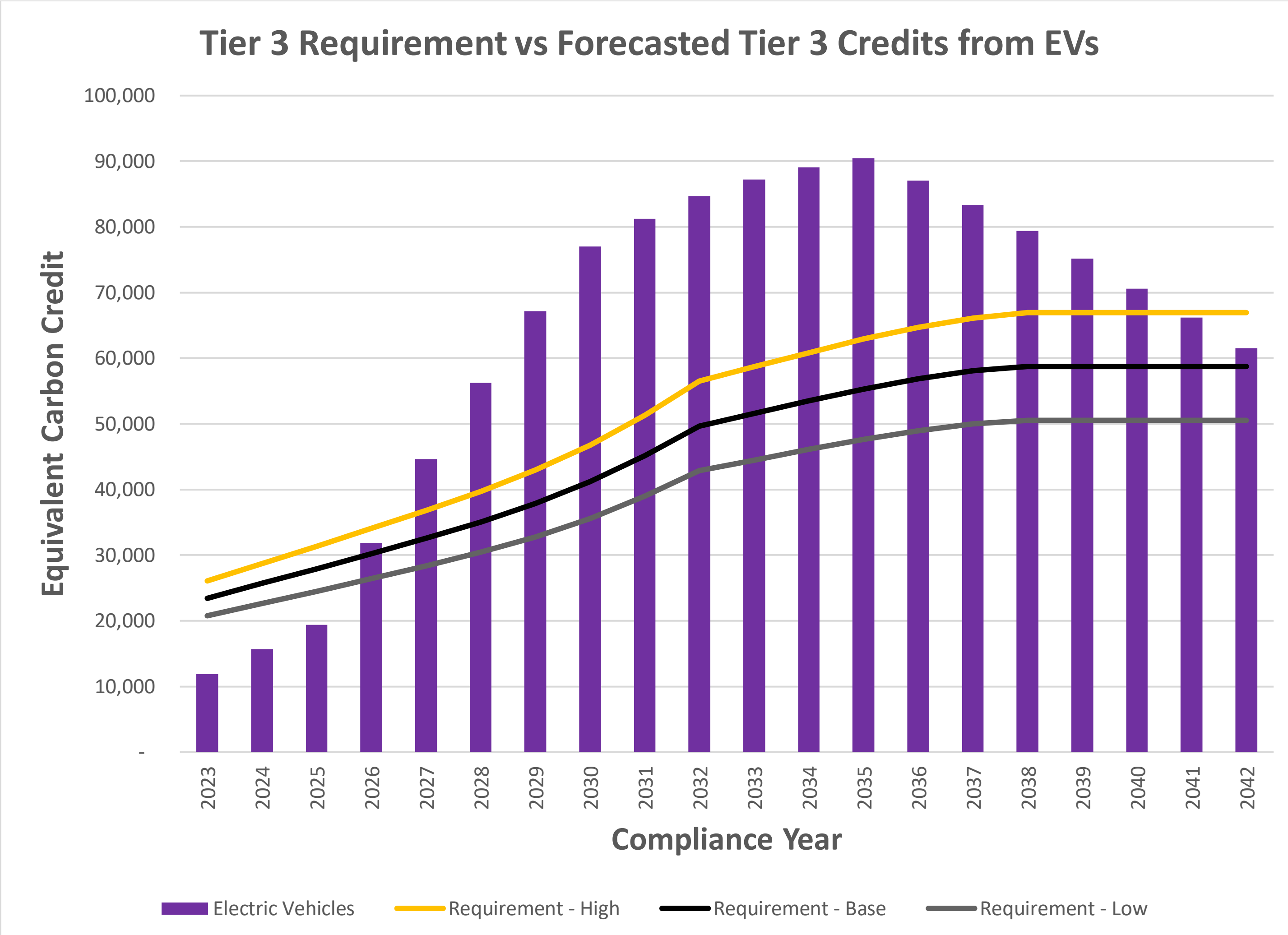

Figure 4.2.5.C Tier III Requirement vs Forecasted Tier III Credits from EVs

Pellet Stoves and Electric Forklifts

VEC now provides incentives for the purchase of pellet stoves and electric forklifts. In this plan, VEC forecasted new installs of pellet stoves and electric forklifts consistent with its 2019 Annual Tier III plan. For pellet stoves, that is 50 units in 2019, assumed to increase by 5 units each year throughout the 20-year forecast window. VEC distributed the annual energy usage for pellet stoves defined by TAG using historical percentages of Heating Degree Days for the assumed heating season of October through April. No electric usage by pellet stoves was assumed for May through September.

For electric forklifts, VEC assumed in its 2019 annual Tier III plan that 5 units come online in 2019. Since the need for electric forklifts is expected to be somewhat limited within VEC's membership, it is assumed that the number of new electric forklifts coming online each year remains at 5 units throughout the 20-year forecast window. Annual electric usage for electric forklifts, as defined by TAG, was assumed to be evenly distributed each month of the year.

Graphical representations, along with supporting tables, of the forecasted annual new pellet stoves and electric forklifts in VEC's service territory can be found in "Appendix O – Forecasted Adoption of Tier III Technologies."

4.2.6 Tier III Carbon Credits Forecast vs Tier III Requirement

Figure 4.2.6.A below shows VEC's forecasted annual Tier III requirement, in MWh, compared to its forecasted Tier III credit from each of the major Tier III technology categories. The chart below uses the Climate Action Plan forcast for both Electric Vehicles and Cold Climate Heat Pumps.

Figure 4.2.6.A Overall Tier III Requirement vs Forecasted Tier III Credits

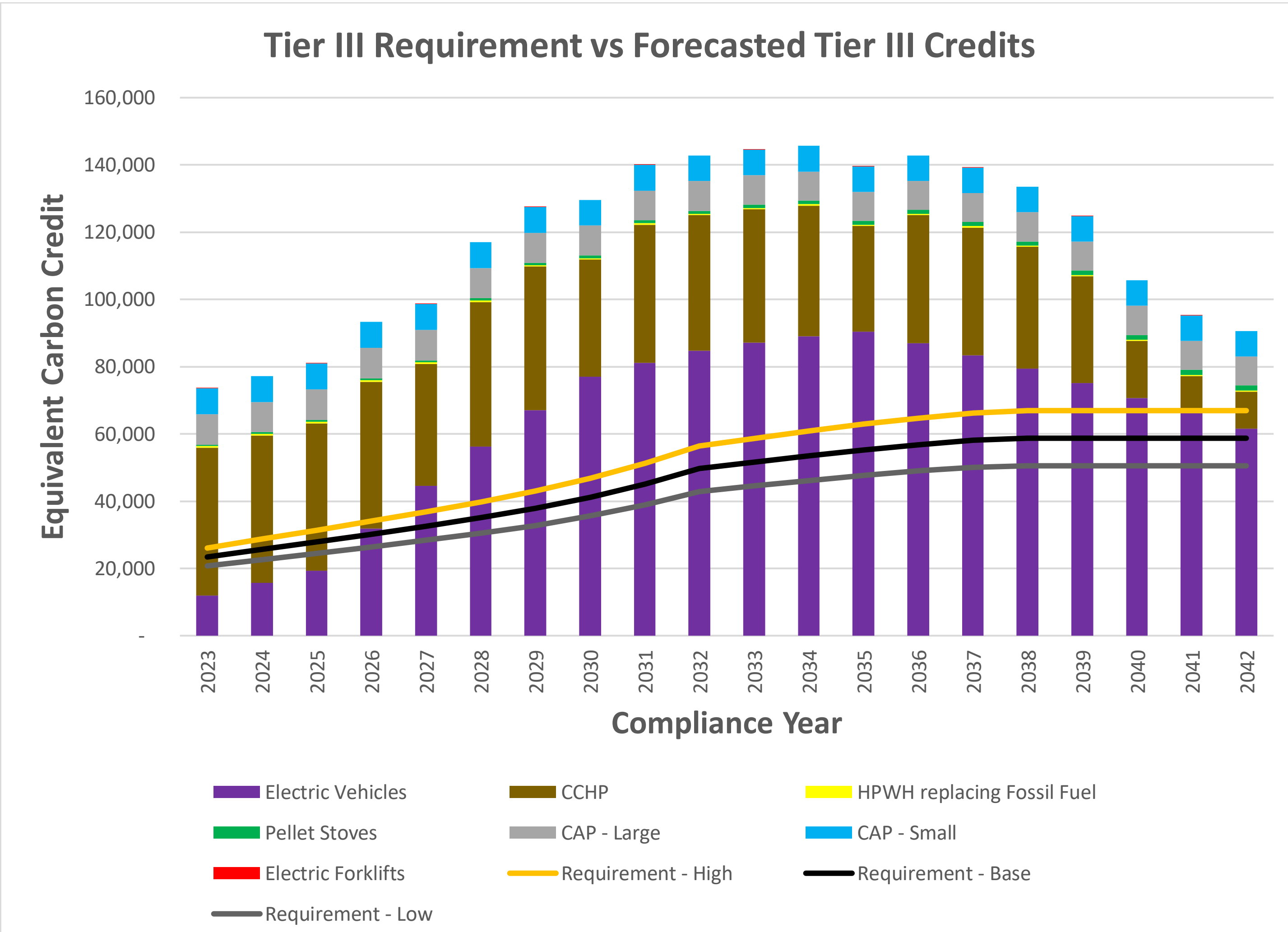

Figure 4.2.6.A – Overall Tier III Requirement vs Forecasted Tier III Credits

As the chart indicates, VEC's success in meeting its short-term Tier III requirements is dependent on the adoption of CCHPs and EVs. Longer term Tier III success will be heavily dependent on the pace of EV adoption in VEC's service territory, especially considering the possibility that Clean Air Program projects will be increasingly difficult to identify and complete as opportunities decline. VEC will need to consider a range of EV incentives to enable adoption including, but not limited to, EV specific rates, bill credits for purchase of EVs and/or charging equipment, investment in public EV charging infrastructure, and on-going bill credits for EV charging management.

4.2.7 Risks and Opportunities Present in Tier III Assumptions

There are a number of risks and opportunities associated with management of Tier III requirements. These include:

1. **<u>Sustainability of Clean Air Program projects –</u>** The quantity and sizing of custom Clean Air Program projects has been critical to VEC's early Tier III success. Efforts have been aided by the fact that VEC's service territory is home to many sugar makers, many of which currently or previously operated off-grid with fossil fuel generators. As more sugar makers transition to the electric grid, fewer opportunities remain. Those that do remain likely require more expensive line extensions and/or service upgrades meaning they will be more difficult to convert. VEC will need to aggressively pursue remaining Clean Air Program leads and work to identify additional Clean Air Program leads in other industries.

2. **<u>EV adoption –</u>** Particularly in later years, VEC's Tier III success will depend on the transformation of the transportation sector. Although largely driven by the price and convenience of models offered by automobile manufacturers, the overall pace of EV adoption can also be affected by VEC's efforts to enable its members to cost effectively switch to, and conveniently charge, electric vehicles. Regulatory changes may also impact adoption rates. VEC may need to develop innovative incentives for the purchase and desirable charging of electric vehicles such as cash incentives, charging station assistance or EV-specific rates. VEC may also need to consider how to encourage the development of more public charging infrastructure through partnerships with third parties, direct ownership, and/or charging station rates.

3. **<u>Fossil fuel prices –</u>** Fossil fuel prices have historically been very volatile compared to relatively stable electric retail rates. As society continues to work hard toward addressing climate change, it is possible that fossil fuel prices may increase over time at a more aggressive rate than electric retail rates will. If EV prices come down and fossil fuel prices remain elevated it may become more economical for members to switch if VEC can maintain its affordable rates or have them increase at a slower rate than fossil fuel prices. This would likely increase energy transformation participation across all VEC's Tier III programs.

4. **<u>Excess Tier II RECs used for Tier III –</u>** Vermont's Renewable Energy Standard allows for a utility to use excess Tier II RECs to meet its Tier III requirements. Thus far, it has been most cost effective for VEC to sell excess Tier II RECs on the open market. Moving forward, VEC will need to continually compare the benefits and challenges associated with selling excess Tier II RECs, banking them for future Tier II use, or using them to help meet Tier III requirements.

5. **<u>Tier III Credit Sharing -</u>** In 2019, EVT began offering an upstream incentive for pellet stoves that results in VEC claiming only 18% of the full pellet stove credit and the member able to take advantage of a larger overall incentive. This sharing breakdown is modeled to continue moving forward. VEC and EVT have also partnered on our most recent large Clean Air Program projects and have thus shared the carbon credit associated with such projects, with approximately 65% of the savings being claimed by VEC. VEC's Tier III carbon credit model assumes VEC continues to claim 65% of the Tier III carbon credits from large Clean Air Program projects due to expected continued partnerships with EVT.

4.3 Energy Requirements and Needs Assessment

4.3.1 Introduction

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, 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. Tier I Portfolio – (All Renewables excluding Distributed Renewable Generation)
3. Tier II Portfolio - (Distributed Renewable Generation)
4. Tier III – (Energy Transformation Projects)

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.

Table 4.3.1.A 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 2021:

Month	Load (MWh)	% of Annual Load	Peak (MW)	Peak Day of Week	Peak Day of Month	Peak Hour
Jan-21	46,557	9.5%	76.776	Wed	6	1800
Feb-21	41,466	8.5%	77.227	Wed	10	1900
Mar-21	43,266	8.9%	75.543	Tue	2	1900
Apr-21	36,566	7.5%	64.268	Mon	4	2000
May-21	35,083	7.2%	61.897	Wed	26	1900
Jun-21	40,127	8.2%	79.739	Mon	28	2100
Jul-21	41,576	8.5%	73.699	Thu	15	2100
Aug-21	44,988	9.2%	84.052	Thu	12	2100
Sep-21	36,481	7.5%	65.610	Thu	23	2000
Oct-21	37,161	7.6%	63.394	Mon	25	1900
Nov-21	39,430	8.1%	73.485	Sun	28	1800
Dec-21	45,855	9.4%	78.656	Mon	27	1800
Total	488,555	100.0%	84.052			

Table 4.3.1.A Purchased energy needs and peak hours

VEC's system peak load occurred in August; 2021 was the first year since at least 2005 that the system peak load occurred in the summer. Note also that, each month, the system peaked shortly before, or after, sunset, meaning there was little, if any, output from behind-the-meter solar facilities.

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 the following factors: 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 in their 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. Each REC allows VEC to claim 1 MWh of renewable generation. VEC can retain RECs to meet 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.

4.3.2 ISONE Energy Markets

Energy Market Prices

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.

To project energy market costs VEC hired Daymark Energy Advisors (DEA) to prepare a forecast of Vermont Load Zone LMPs for 2023-2042. 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. The DEA model takes each of these factors into account, each requiring their own projections, which interact to result in the LMP forecast. Recognizing uncertainty inherent in any forecast of future market conditions, DEA provided reference-, high- and low-price scenarios.

Figures 4.3.2.A - 4.3.2.C 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.

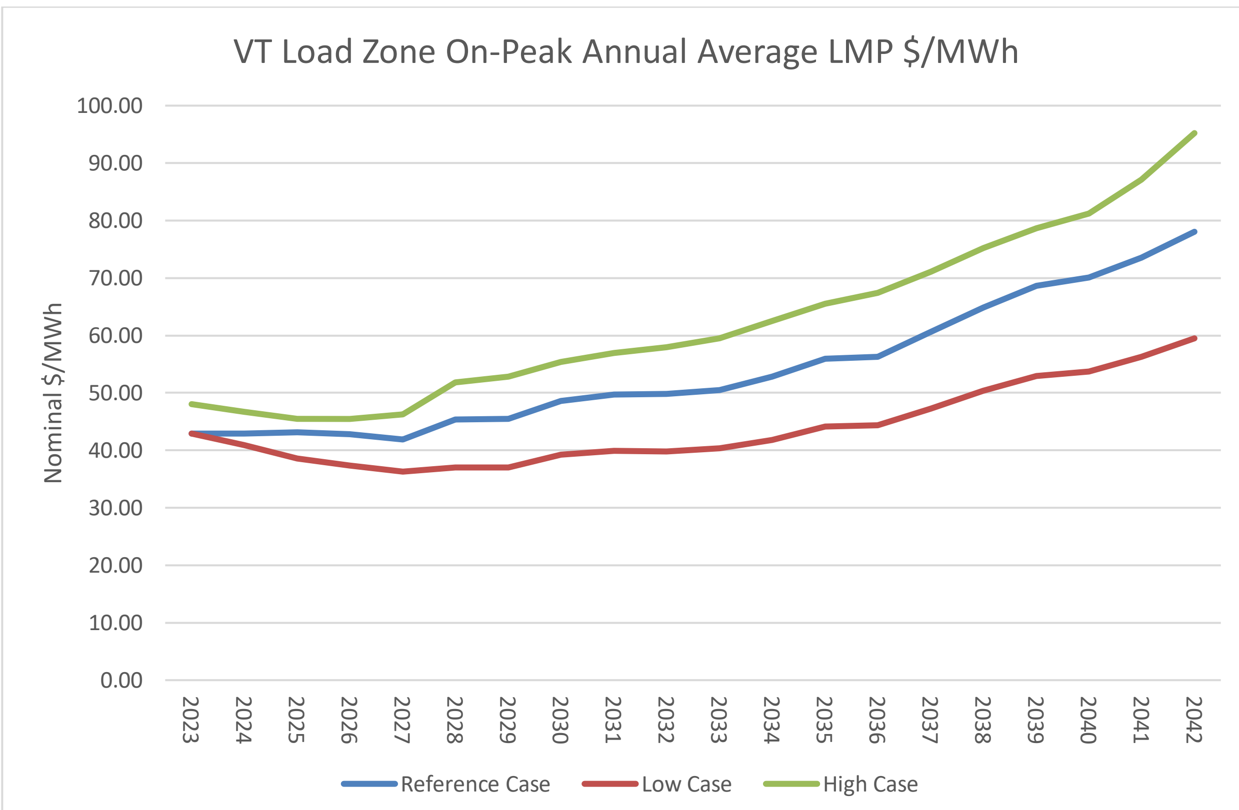

Figure 4.3.2.A – VT Load Zone On-Peak Annual Average LMP $/MWh

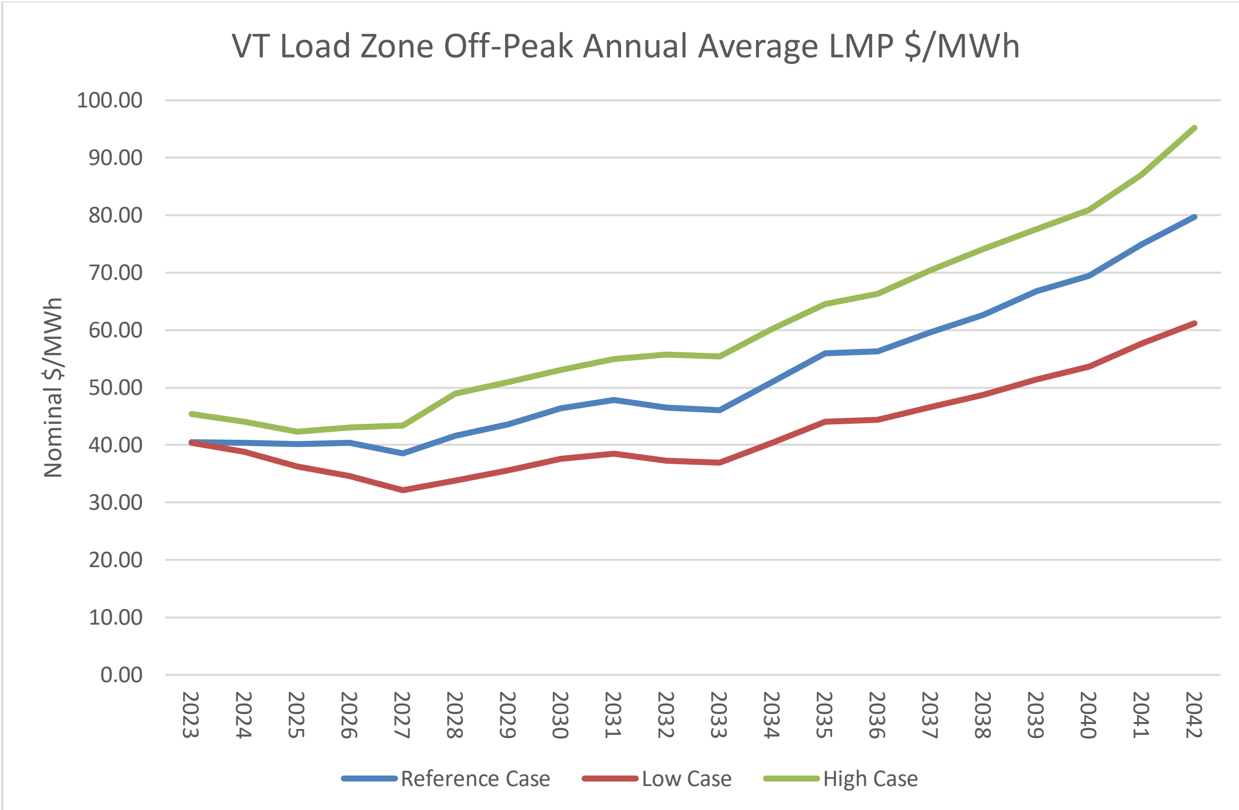

Figure 4.3.2.B – VT Load Zone Off-Peak Annual Averfage LMP $/MWh

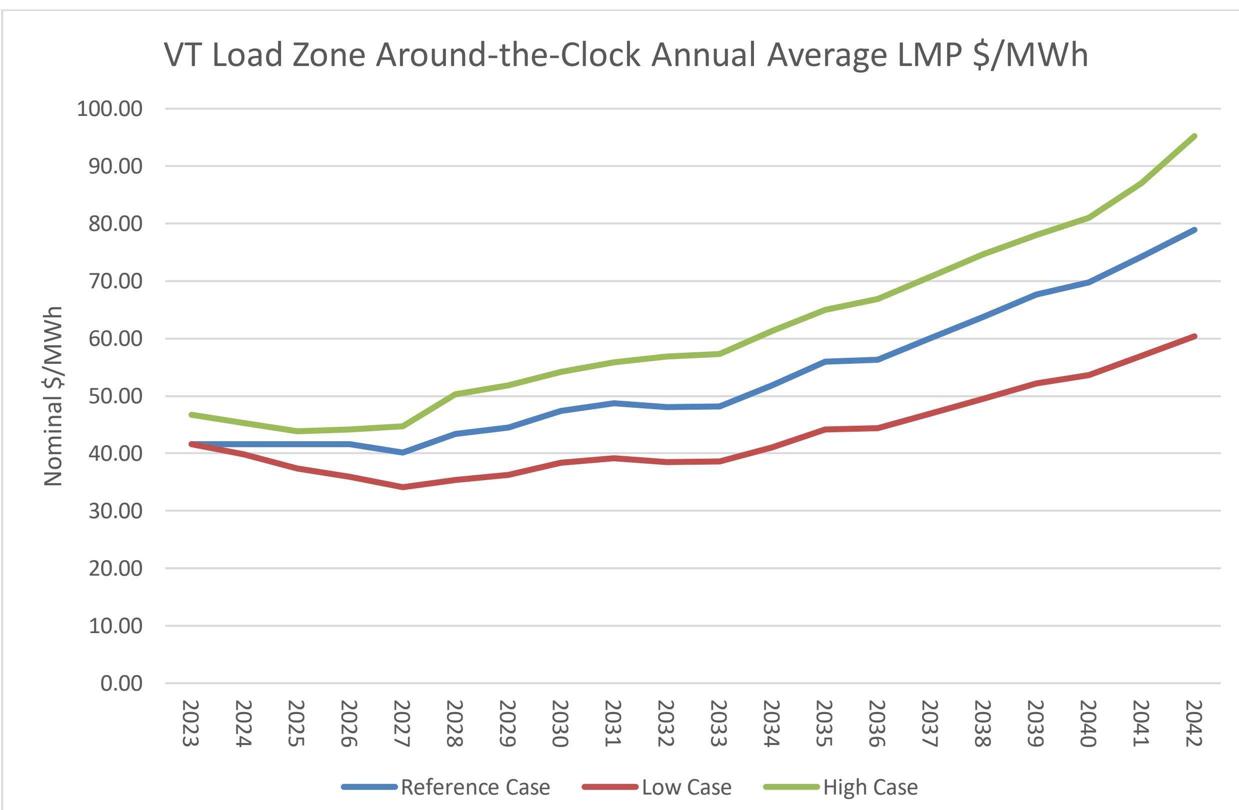

Figure 4.3.2.C – VT Load Zone Around-the-Clock Annual Average LMP $/MWh

More detailed information regarding the development of the energy price forecasts can be found in "Appendix P Vermont LMP Forecast for the 2022 IRP."

4.3.3 Member Energy Needs

Prior to the COVID-19 pandemic VEC's net load had been flat, except for cases of extreme weather. Although the number of members had grown, the increased load was offset by the impact of more efficient consumption and increased net metering saturation. This is expected to change with beneficial electrification anticipated by Vermont's RES, especially member adoption of CCHPs and EVs. During the pandemic VEC saw a significant increase in new construction and new service applications in its territory and a corresponding increase in load.

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. Those four individual forecasts are:

- Pre-New-Net-Metering-New-Efficiency-and-Tier-III-Program-Impact Load Forecast
- Load reduction resulting from Efficiency Vermont activity on the VEC system, not already embedded in the forecast above
- Load reduction from new net-metering to be installed on the VEC system
- Load increase from incremental Tier III activity on the VEC system.

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

- <u>CAP EV and CCHP Forecast</u> is based on: the Daymark Energy Advisors (DEA) Underlying Load Forecast, the Base Net Metering Forecast, the Efficiency Forecast, *the Climate Action Plan CCHP Forecast*, *the Climate Action Plan EVs Forecast* and the All Other Tier III Programs Forecast;
- <u>VEC EV and CAP CCHP</u>: the DEA Underlying load Forecast, the Base Net Metering Forecast, the Efficiency Forecast, *the Climate Action Plan CCHP Forecast, the VEC Electric Vehicles Forecast* and the All Other Tier III Programs Forecast; and
- <u>VEC EV and EVT CCHP</u>: the DEA Underlying Load Forecast, the Base Net Metering Forecast, the Efficiency Forecast, *the Efficiency Vermont (EVT) CCHP Forecast, the VEC Electric Vehicle Forecast* and the All Other Tier III Programs Forecast.

The forecasts using the projection of Climate Action Plan CCHPs show noticeable load growth in the first ten years compared to the forecast which uses the EVT projection for CCHPs. The forecasts using the VEC EV Forecast show significantly steeper load growth beginning in 2030 than the forecast that is based on the Climate Action Plan forecast for EVs.

Figure 4.3.3.A below shows the resulting annual load forecasts for the three forecasts for the first 10 years of the study period, while Figure 4.3.3.B shows the resulting forecasts for the entire 20-year study period.

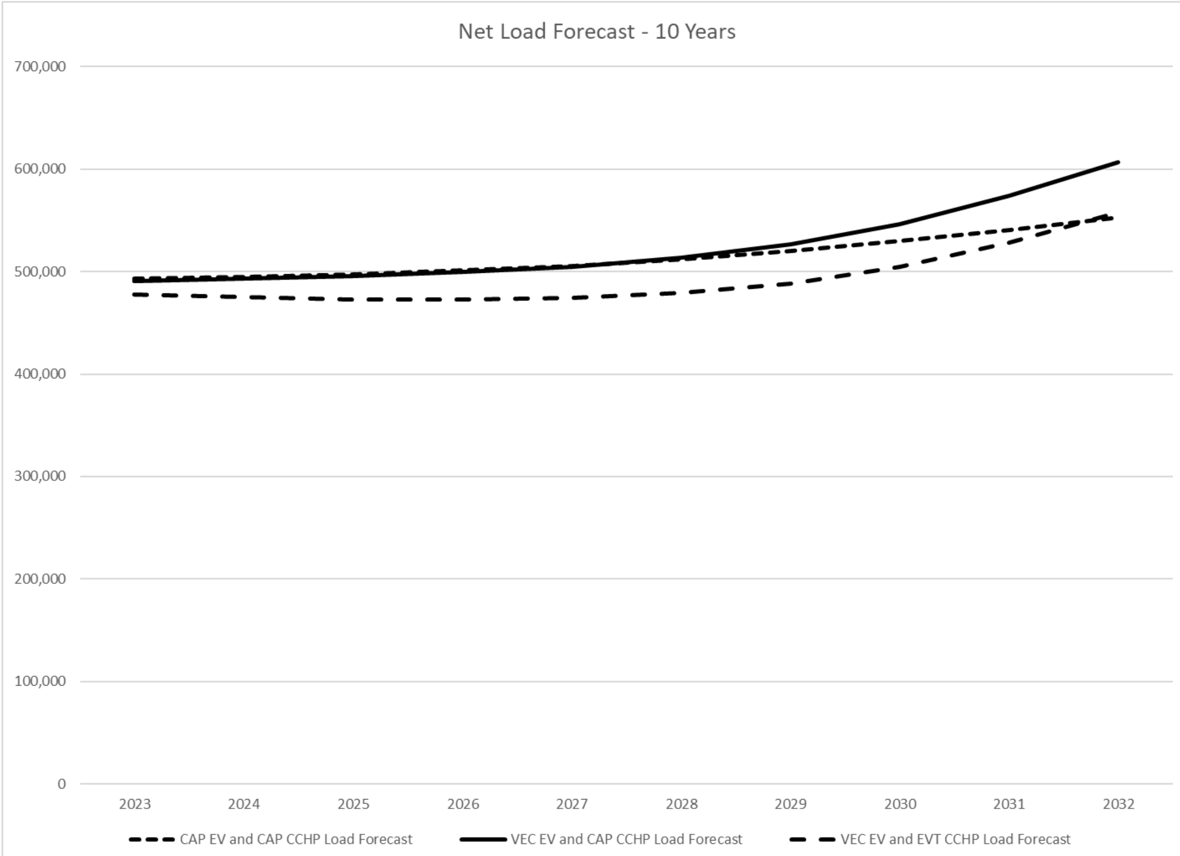

Figure 4.3.3.A - Net Load Forecast – 10 years

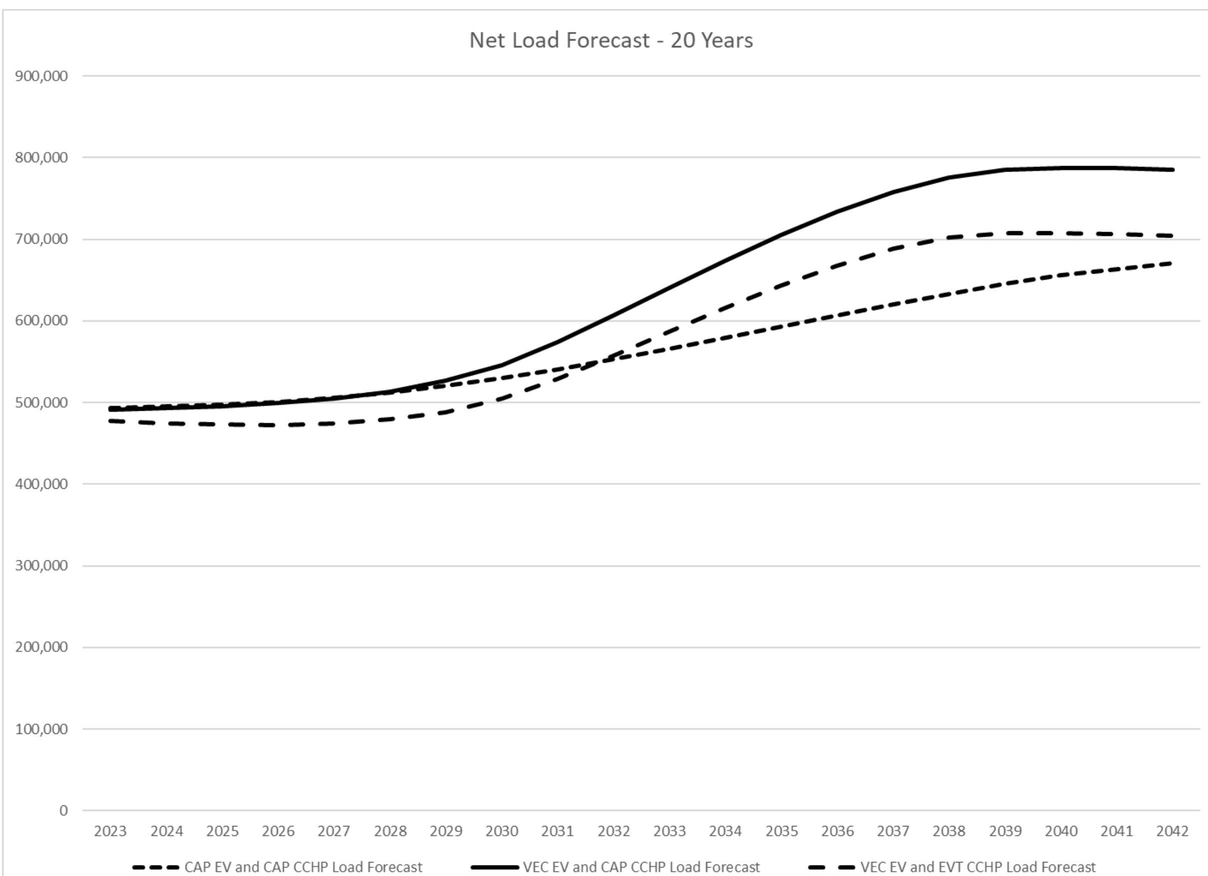

Figure 4.3.3.B - Net Load Forecast – 20 years

The data the plots are based on are shown in Table 4.3.3.C below.

Year	VEC EV and Climate Action Plan CCHP Load Forecast	Climate Action Plan EV and CCHP Load Forecast	VEC EV and EVT CCHP Load Forecast
2023	490,988	492,838	477,431
2024	492,852	494,907	474,819
2025	495,490	497,369	473,070
2026	499,474	500,922	472,756
2027	504,909	505,633	474,448
2028	513,171	511,901	479,123
2029	526,486	520,347	488,449
2030	545,953	529,933	504,423
2031	573,700	540,685	528,586
2032	606,834	552,822	557,471
2033	640,475	565,702	586,792
2034	673,850	579,245	615,811
2035	705,354	592,891	643,455
2036	733,861	606,493	668,168
2037	758,444	620,184	688,441
2038	776,318	633,314	702,145
2039	785,286	645,467	707,426
2040	787,636	655,612	707,508
2041	787,180	663,543	706,396
2042	785,355	670,367	704,405

Table 4.3.3.C Net Load Forecasts

Each of the components are explained below:

Pre-New Net Metering, New Efficiency and Tier III Program Impact Forecast

For VEC's 2019 IRP, Daymark Energy Advisors (DEA) prepared separate 3-year univariate (i.e. time series) and 20-year multivariate (i.e. econometric) forecasts of VEC system energy and peak demand based on historical data from January 2008 to December 2017. Monthly forecasts produced by the separate methods were analyzed individually and then blended into a single annual forecast, with accompanying upper and lower bounds. Using a bounding approach recognizes that no forecast will be 100% accurate and provides limits in which actual loads can reasonably be expected to fall between. Actual load can vary due to seasonal weather patterns, net immigration into VEC's service territory, regional economic conditions, electricity prices, and other factors.

A more detailed explanation of the forecast methodology can be found in "Appendix Q: Vermont Electric Cooperative 2019 Load Forecast."

The forecast for the 2019 IRP was based on pre-COVID-19 Pandemic data. 2021 actual member usage was between the Daymark's Base Load Forecast and Upper Bound forecast, for a year in which weather was below historical normal averages for Heating Degree Days and Cooling Degree Days. More precisely, actual 2021 annual loads were approximately = 0.73*High Load Forecast + 0.27*Base Load Forecast.

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, 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 is modeled as 50% * High Load Forecast + 50% * Base Load Forecast from Daymark's Pre-New Net Metering, Efficiency and Tier III Program Impact forecasts from the 2019 IRP.

The results are graphically in Figure 4.3.3.d and in tabular form in Table 4.3.3.E below.

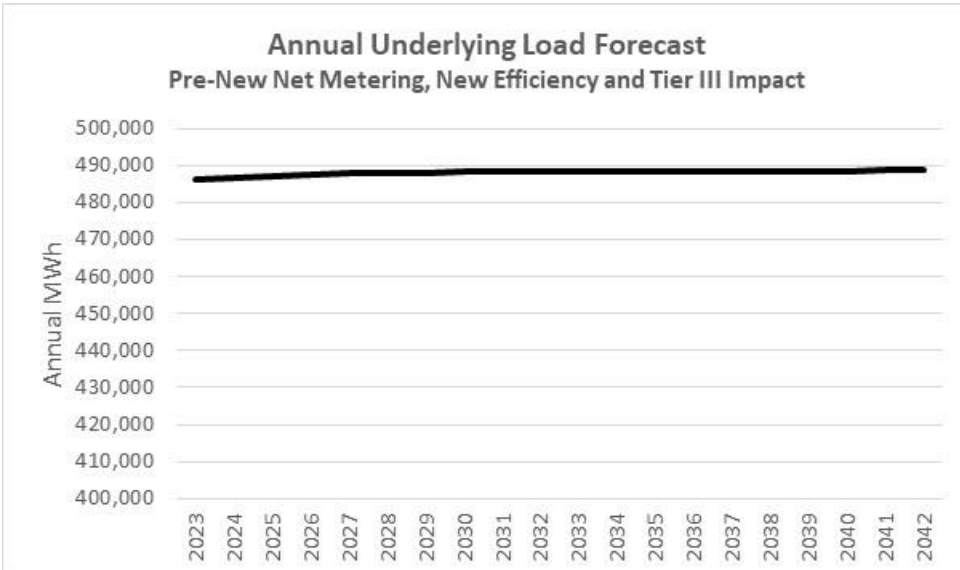

Figure 4.3.3. D – Annual Underlying Load Forecast: Pre-New Net Metering, New Efficiency and Tier III Impact

Year	Annual MWh
2023	486,003
2024	486,646
2025	487,121
2026	487,474
2027	487,737
2028	487,936
2029	488,085
2030	488,199
2031	488,285
2032	488,351
2033	488,401
2034	488,440
2035	488,470
2036	488,493
2037	488,511
2038	488,529
2039	488,548
2040	488,566
2041	488,584
2042	488,603

Figure 4.3.3.E - Annual Underlying Load Forecast: Pre-New Net Metering, New Efficiency and Tier III Impact

The underlying load forecast assumes a Compound Annual Growth Rate (CAGR) of 0.03%. This is very small, but not unexpected given that it is pre-Tier III. Much more important than the growth rate in the underlying load forecast is the impact of new Efficiency, new Net Metering, and the impact of Tier III programs, all of which are described in more detail below.

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

The DEA underlying load forecast was limited to the impact of EVT activity on the VEC system through December 2017. That underlying forecast must be adjusted by the incremental impact of EVT activity on the VEC system since that time. This adjustment is based on data provided to VEC by EVT.

EVT provided data for the annual MWh load reduction for both Commercial/Industrial and Residential efficiency measures installed on the VEC system through 2020 and projected to be installed in those parts of the state served by EVT each year from 2021-2040 (VEC then projected installs for 2041 and 2042 by using the 2039-2040 growth rate). These measures included lighting, motors, refrigeration, space heating, air conditioning, industrial processes, ventilation systems and consumer electronics. The historical share of actual measure installations on VEC's system relative to all installations in EVT service territory was used 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. EVT did not provide the impact of each individual measure, or the lifetime of each measure.

VEC converted the annual data to monthly cumulative data to arrive at the total projected load reduction each month for the 2023-2042 period. 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.

Figure 4.3.3.F below shows the annual **cumulative** load reduction of EVT activity in the VEC territory.

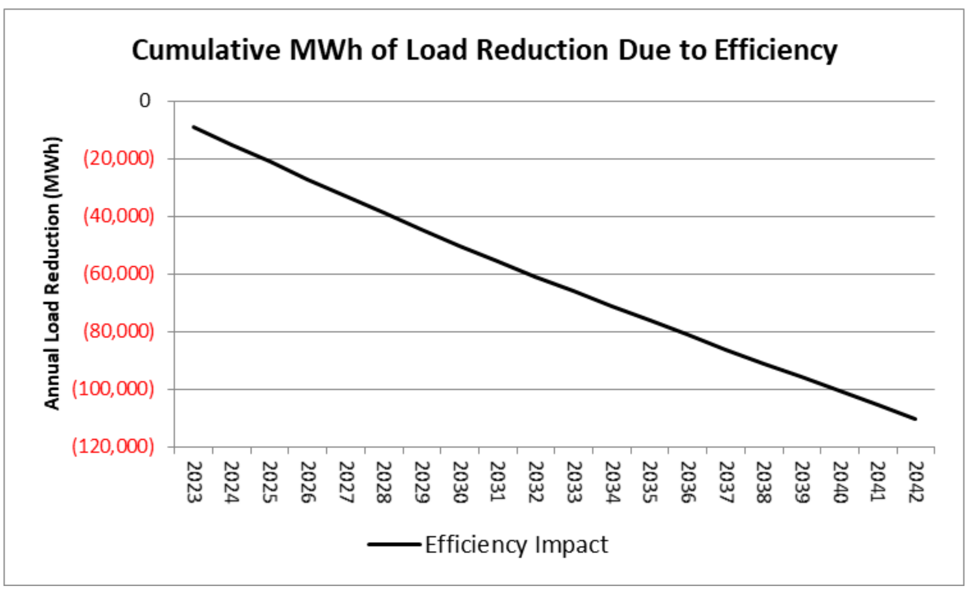

Figure 4.3.3.F – Cumulative MWh of Load Reduction Due to Efficiency

The chart is based on the data in Table 4.3.3.G below:

Year	Load Impact (MWh)
2023	(9,192)

2024	(15,162)
2025	(21,183)
2026	(27,148)
2027	(33,059)
2028	(38,922)
2029	(44,650)
2030	(50,236)
2031	(55,651)
2032	(60,893)
2033	(66,044)
2034	(71,121)
2035	(76,168)
2036	(81,209)
2037	(86,201)
2038	(91,092)
2039	(95,912)
2040	(100,708)
2041	(105,481)
2042	(110,233)

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

New Net Metering Forecast

The DEA underlying forecast is limited to the impact of net-metering projects installed on the VEC system through December 2017. Thus, the underlying forecast must be further adjusted by the Net Metering projects installed on the VEC system since that time. The adjustment is based on actual projects installed from 2018-2021 and a forecast of new net-metering penetration for 2022-2042. The 2022 forecast assumes the five 500 kW projects that were delayed due to the Derby Solar ruling come on line.

Net-metering rules in Vermont have evolved over time and we expect will continue to evolve as the industry further matures, 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 in Table 4.3.3.H below based on the possible scenarios we can envision today:

Scenario	Projects >150 kW inside the SHEI	Projects > 150 kW outside the SHEI	Projects <= 150 kW system wide
High	1.125 MW in 2023 with 85% each year thereafter.	375 kW coming online in 2022 and then 85% each year thereafter	2.5 MW new NM capacity online in 2022 for systems 150 kW or less, evenly distributed by month. Then 95% of previous year moving forward.
Base	750 kW in 2023 then 85% of previous year each year.	250 kW coming online in July of 2022 and then 85% of that each year thereafter.	2.5 MW new NM capacity online in 2022 for systems 150 kW or less, evenly distributed by month. Then 85% of previous year moving forward.
Low	No new projects over 150 kW (Legislative change).	No new projects over 150 kW (Legislative change).	2.5 MW new NM capacity online in 2022 for systems 150 kW or less, evenly distributed by month. Then 75% of previous year moving forward.

Table 4.3.3.H – Low, Base, and High Net Metering Forecast Scenarios

Figure 4.3.3.I below shows the annual output of new net-metering projects for each of the three scenarios.

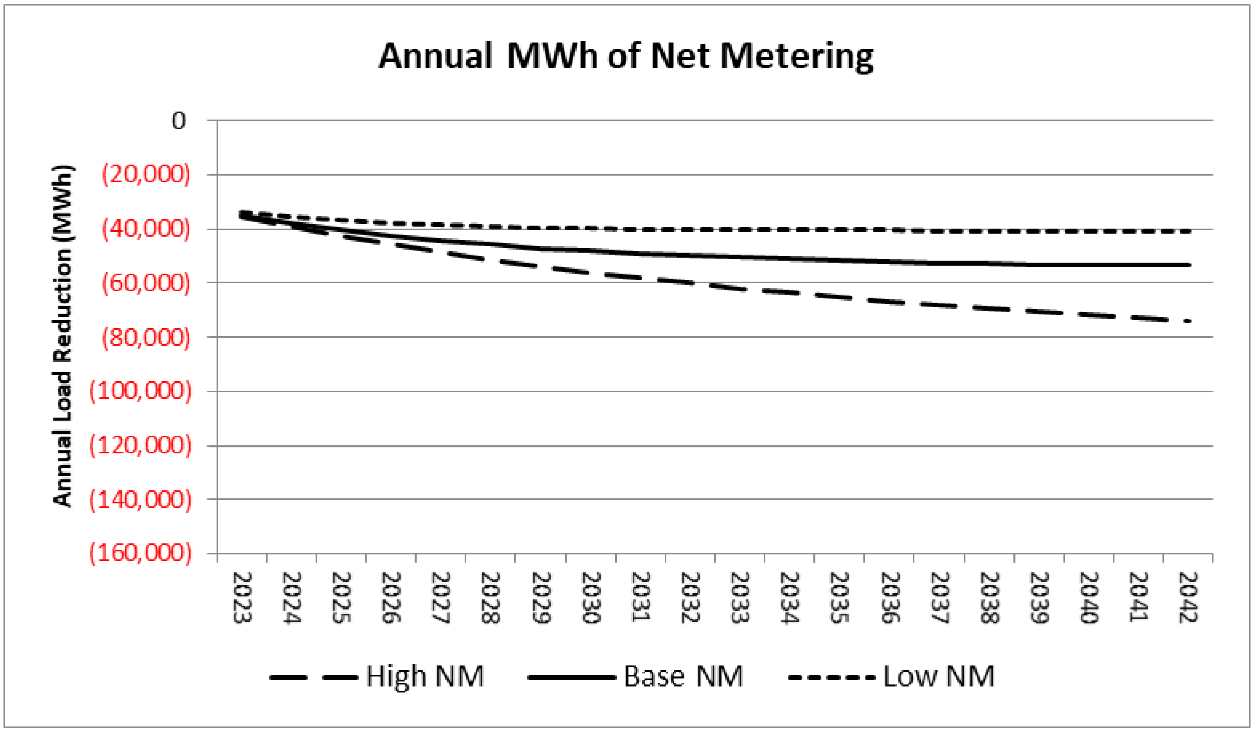

Figure 4.3.3.I – Annual MWh of New Net Metering

The data the plot is based on are shown in Table 4.3.3.J below.

Year	High NM MWh	Base NM MWh	Low NM MWh
2023	(35,288)	(34,778)	(33,895)
2024	(39,055)	(37,716)	(35,573)
2025	(42,496)	(40,214)	(36,831)
2026	(45,647)	(42,338)	(37,775)
2027	(48,541)	(44,143)	(38,483)
2028	(51,206)	(45,677)	(39,013)
2029	(53,665)	(46,981)	(39,411)
2030	(55,940)	(48,089)	(39,710)
2031	(58,049)	(49,031)	(39,934)
2032	(60,009)	(49,832)	(40,102)
2033	(61,832)	(50,513)	(40,228)
2034	(63,533)	(51,091)	(40,322)
2035	(65,122)	(51,583)	(40,393)
2036	(66,607)	(52,001)	(40,446)
2037	(67,999)	(52,356)	(40,486)
2038	(69,305)	(52,658)	(40,516)
2039	(70,531)	(52,915)	(40,539)
2040	(71,684)	(53,133)	(40,555)
2041	(72,769)	(53,319)	(40,568)
2042	(73,791)	(53,477)	(40,577)

Table 4.3.3.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.

Figure 4.3.3.K below shows the annual load reduction from new net-metering projects for each of the three scenarios.

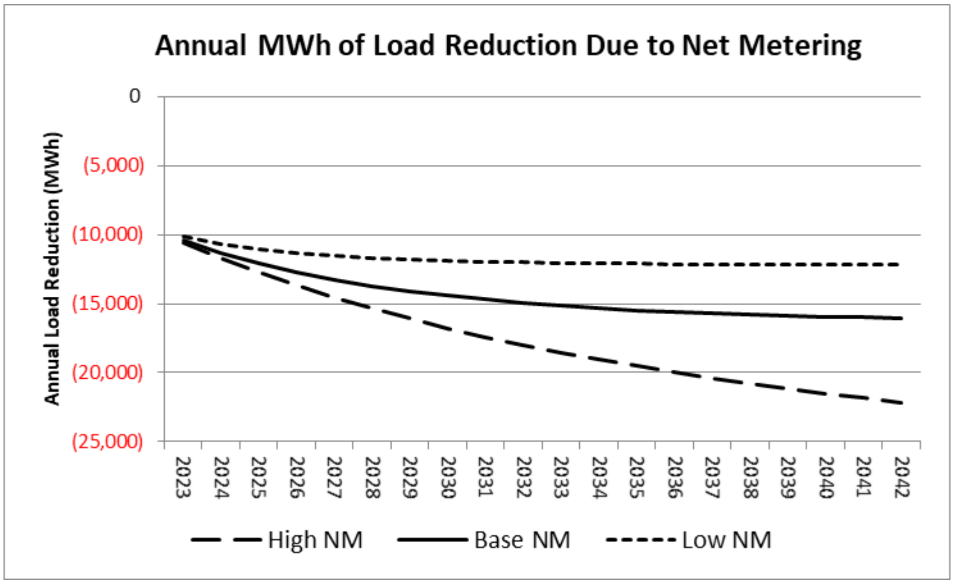

Figure 4.3.3.K – Annual MWh of Load Reduction Due to New Net Metering

The data the plots are based on are shown in Table 4.3.3.L below:

Year	Low NM MWh	Base NM MWh	High NM MWh
2023	(10,586)	(10,433)	(10,169)
2024	(11,716)	(11,315)	(10,672)
2025	(12,749)	(12,064)	(11,049)
2026	(13,694)	(12,701)	(11,332)
2027	(14,562)	(13,243)	(11,545)
2028	(15,362)	(13,703)	(11,704)
2029	(16,099)	(14,094)	(11,823)
2030	(16,782)	(14,427)	(11,913)
2031	(17,415)	(14,709)	(11,980)
2032	(18,003)	(14,950)	(12,031)
2033	(18,550)	(15,154)	(12,068)
2034	(19,060)	(15,327)	(12,097)
2035	(19,536)	(15,475)	(12,118)
2036	(19,982)	(15,600)	(12,134)
2037	(20,400)	(15,707)	(12,146)
2038	(20,792)	(15,798)	(12,155)
2039	(21,159)	(15,875)	(12,162)
2040	(21,505)	(15,940)	(12,167)
2041	(21,831)	(15,996)	(12,170)

2042	(22,137)	(16,043)	(12,173)

Table 4.3.3.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).

Tier III Program Impact Forecast

Tier III is a subset of the Vermont RES which sets requirements for Vermont distribution utility-led or utility-partnership projects that reduce fossil fuel usage, primarily by converting fossil fuel powered applications to be powered by the increasingly clean electric grid. Beginning in 2017, each utilities' requirement for Tier III credit is equal to 2% of the utility's annual sales for the year (BTU equivalency), with that percentage increasing 0.667% each year until reaching 12% in 2032. The 2021 requirement was 4.67%.

The volume of Tier III credits earned in a year is a function of the tons of carbon reduction achieved and the amount of non-fossil fuel generation in the utility's power supply mix. Projects that reduce more carbon earn more Tier III credits, as does a cleaner power supply mix for the utility. A utility can also use excess REC from Tier II-qualifying resources (in state distributed renewable generation) in place of Tier III credits in a given year.

VEC has developed projected load increases due to Tier III programs and other load growth due to electrification. VEC's portfolio of Tier III programs continues to evolve as new technologies come to market. However, several specific technologies and programs have provided the most significant load impacts to date and will likely continue to do so in the future. CCHPs, HPWHs, Pellet Stoves, Electric Forklifts, EVs, and VEC's Clean Air Program. The expected impact of EVs and CCHPs far exceed those of the other end uses.

Figure 4.3.3.M below shows the combined annual load increase due to the various electrification categories described above for each of the three load forecast scenarios.

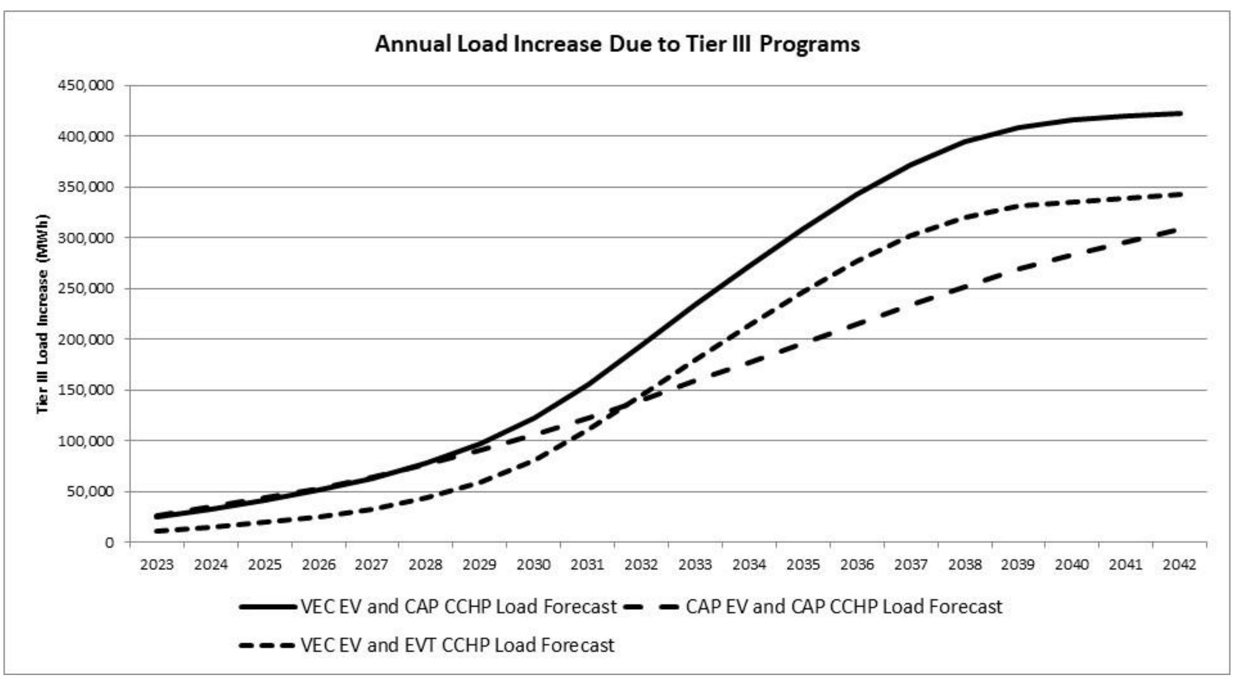

Figure 4.3.3.M – Annual Load Increase Due to Tier III Programs

The data the plot is based on are shown in Table 4.3.3.N below.

Year	VEC EV and Climate Action Plan CCHP Load Forecast	Climate Action Plan EV and CCHP Load Forecast	VEC EV and EVT CCHP Load Forecast
2023	24,611	26,460	11,053
2024	32,682	34,738	14,650
2025	41,617	43,495	19,197
2026	51,849	53,297	25,131
2027	63,473	64,197	33,012
2028	77,861	76,590	43,812
2029	97,144	91,006	59,108
2030	122,418	106,397	80,887
2031	155,775	122,760	110,661
2032	194,326	140,314	144,963
2033	233,272	158,498	179,589
2034	271,858	177,253	213,820
2035	308,528	196,064	246,629
2036	342,177	214,809	276,484
2037	371,840	233,580	301,837
2038	394,678	251,674	320,505
2039	408,525	268,706	330,665
2040	415,718	283,694	335,590
2041	420,073	296,436	339,289
2042	423,028	308,040	342,078

Table 4.3.3.N Annual Load Increase Due to Tier III Programs

4.3.4 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.

The Act defines existing renewables as those that came into service prior to July 1, 2015 and new renewables as those that came, or will come, into service after June 30, 2015. 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 June 30, 2015.

Each utility in Vermont is required to have total renewable energy (Tier I) equal to at least 55% of its annual retail sales beginning in 2017 escalating at 4% every 3rd year thereafter until reaching 75% in 2032. VEC's requirement in 2021 was 59%. 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 Rate 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 Alternative Compliance Rate began at $0.01/kWh in 2017 escalating at the Consumer Price Index.

As a subset of its total renewable energy requirement, each utility is required to have at least 1% of its annual retail sales from distributed renewable energy (Tier II) beginning in 2017, increasing by 0.6% each year until reaching 10% of annual retail sales by 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 Alternative Compliance Rate 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 Alternative Compliance Rate began at $0.06/kWh in 2017 escalating annually at the Consumer Price Index.

In addition to the Tier I and Tier II renewable energy requirements, each utility also has an annual energy transformation (Tier III) requirement equal to 2% of its annual retail sales in 2017 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 Alternative Compliance Rate 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 Alternative Compliance Rate began at $0.06/kWh in 2017 and escalates annually at the Consumer Price Index.

4.3.5 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. Figure 4.3.5.A 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."

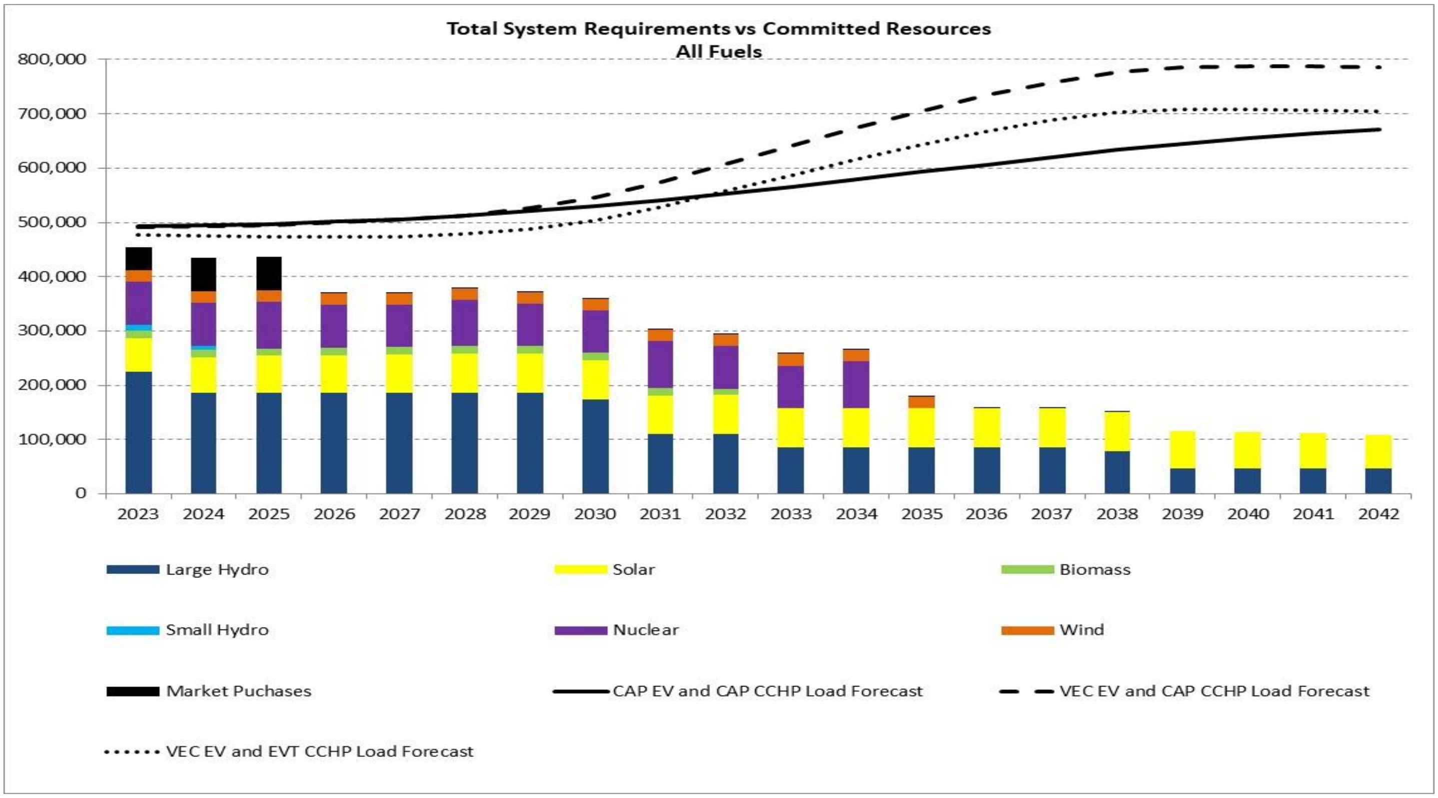

Figure 4.3.5.A – Total System Requirements vs Committed Resources

Table 4.3.5.B below with the Compound Annual Growth Rates (CAGR) for each of the three load forecast scenarios:

	VEC EV and Climate Action Plan CCHP Load Forecast	Climate Action Plan EV and CCHP Load Forecast	VEC EV and EVT CCHP Load Forecast
2023-2042 CAGR	2.5%	1.6%	2.1%
2023-2028 CAGR	0.9%	0.8%	0.1%
2028-2033 CAGR	4.5%	2.0%	4.1%
2033-2038 CAGR	3.9%	2.3%	3.7%
2038-2042 CAGR	0.3%	1.4%	0.1%
Total	12.10%	8.10%	10.10%

Table 4.3.5.B CAGR for three load forecast scenarios

The 2023-2042 CAGRs range from a low of 1.6% in the Climate Action Plan EV and CCHP scenario to a high of 2.5% in the VEC EV and Climate Action Plan CCHP scenario. However, the CAGR over a 20-year time horizon can be misleading. All three scenarios have significantly higher growth rates in the middle of the planning horizon than the rest of the horizon because of the projected rapid adoption of EVs beginning in the late 2020s.

Table 4.3.5.C below shows VEC's annual projected hedged position with currently committed resources for the three load scenarios:

Year	VEC EV and Climate Action Plan CCHP Load Forecast	Climate Action Plan EV and CCHP Load Forecast	VEC EV and EVT CCHP Load Forecast
2023	92%	92%	95%
2024	88%	88%	92%
2025	88%	88%	92%
2026	74%	74%	78%
2027	73%	73%	78%

2028	74%	74%	79%
2029	71%	72%	76%
2030	66%	68%	71%
2031	53%	56%	57%
2032	48%	53%	53%
2033	40%	46%	44%
2034	39%	46%	43%
2035	25%	30%	28%
2036	22%	26%	24%
2037	21%	25%	23%
2038	19%	24%	21%
2039	15%	18%	16%
2040	14%	17%	16%
2041	14%	17%	16%
2042	14%	16%	15%

Table 4.3.5.C Cost Exposure 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 approximately 2025 in all three load forecast scenarios, and exceeds it in the VEC EV and EVT CCHP Load forecast scenarios.

4.3.6 Tier I Analysis

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

As noted above, Act 56 requires that Vermont utilities retain RECs from resources that qualify to meet the total renewable energy requirement at a level that begins at 55% of total retail sales in 2017 increasing by 4% every 3 years. Distributed Renewable Generation, or Tier II resources, must make up 1% of the total retail sales in 2017 increasing by 0.6% every year for 15 years to reach a total of 10% of total retail sales in 2032. VEC refers to the difference between the Total Renewable Energy requirement and the Tier II requirement as the Tier I requirement.

Table 4.3.6.A below shows the percentages of the Total Renewable Energy, Tier I and Tier II requirements.

Year	Total Renewable Energy Requirement	Tier I Renewable Energy Requirement	Tier II Renewable Energy Requirement
2023	63.0%	58.4%	4.6%
2024	63.0%	57.8%	5.2%
2025	63.0%	57.2%	5.8%
2026	67.0%	60.6%	6.4%
2027	67.0%	60.0%	7.0%
2028	67.0%	59.4%	7.6%
2029	71.0%	62.8%	8.2%
2030	71.0%	62.2%	8.8%
2031	71.0%	61.6%	9.4%
2032 to	75.0%	65.0%	10.0%

2042			

Table 4.3.6.A Total Renewable Energy, Tier I and Tier II requirements

With Act 56, Vermont joined every other New England state in having some form of renewable energy standard. However, 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 July 1, 2015, and new renewable resources as those that come on line after June 30, 2015; 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 Kingdom Community Wind, Ryegate, Sheffield and Standard Offer projects on line before July 1, 2015) 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 Alternative Compliance Rate.

Figure 4.3.6.B below compares VEC's projected 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."

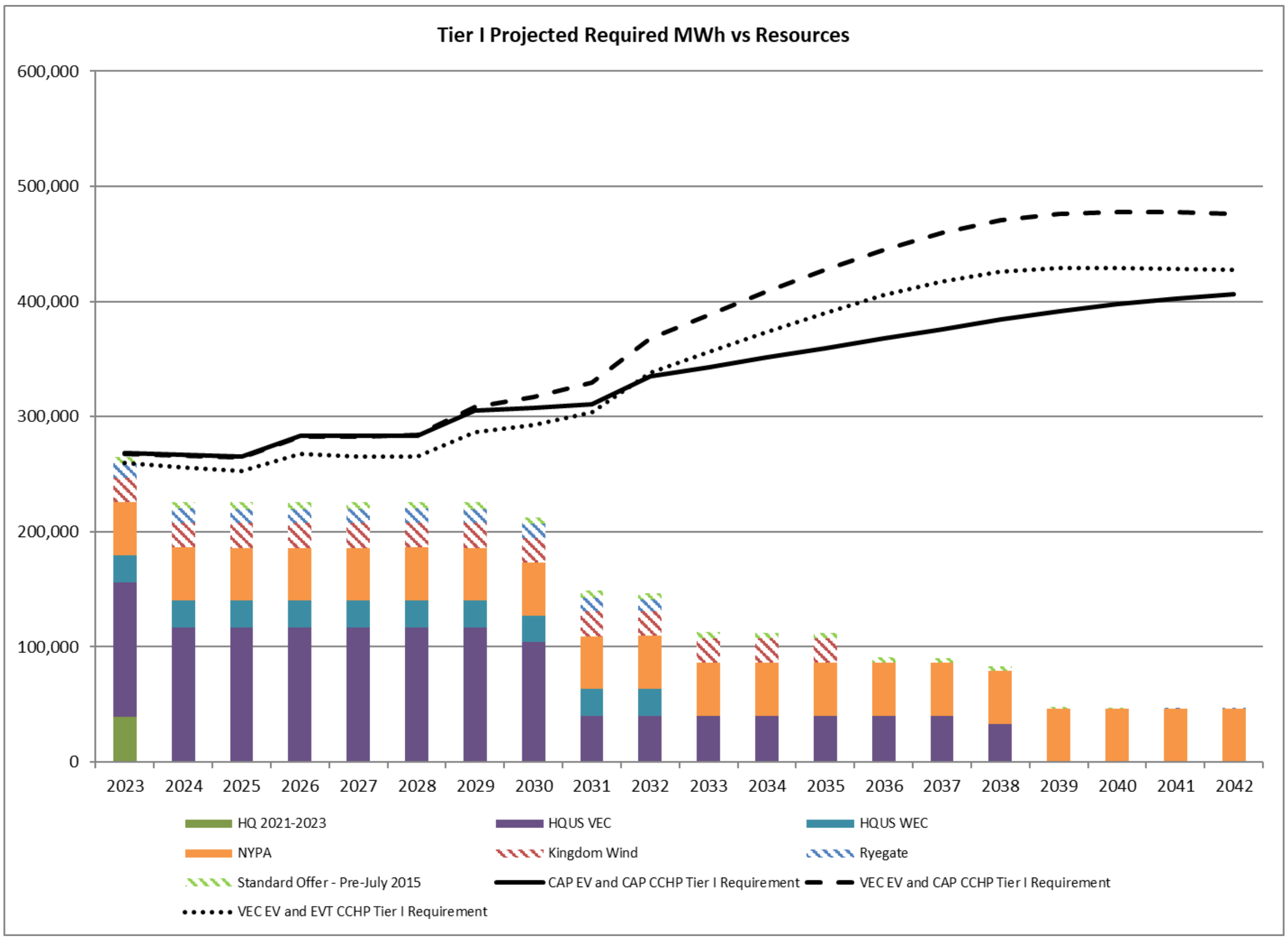

Figure 4.3.6.B – Tier I Pojrected Required MWh vs Resources Before Sale of High-Value REC

The graph shows that VEC projects to have enough resources to cover its Tier I energy requirement in 2023, but a shortfall beginning in 2024 in all three load scenarios. The shortfall increases through the study period as load grows and contracts with Ryegate and HQUS expire.

The graph assumes VEC retains the RECs from Kingdom Wind, Ryegate, and Standard Offer projects that came on line prior to July 1, 2015. As of the spring of 2022, VEC could sell 2023-2025 vintage RECs from these facilities as either CT Class I, MA Class I or NH Class III (in the case of Ryegate) for $30–$35/REC. In addition, 2023-2025-vintage Vermont Tier I RECs currently sell for approximately $10.00/REC.

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

Figure 4.3.6.C below compares VEC's projected Tier I requirement to its current Tier I committed and pending resources in each load scenario after the sale of high-value RECs. A table containing the data the graph is based on is included in "Appendix R: VEC Resource and Needs Projections."

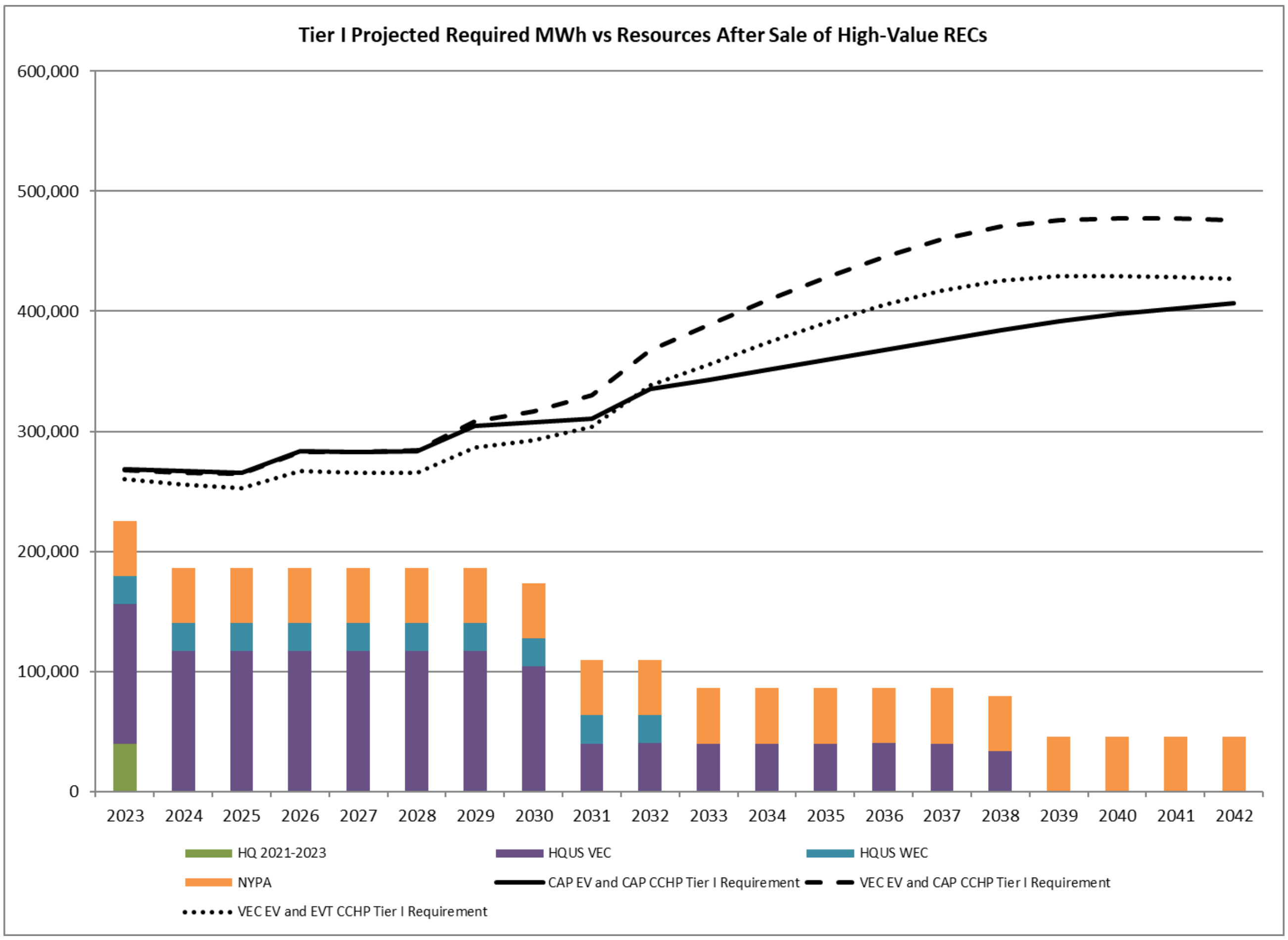

Figure 4.3.6.C – Tier I Projected Required MWh vs Resources After Sale of High-Value RECs

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. <u>Difference in Value of MA Class I, CT Class I and NH Class III RECs compared to VT Tier I RECs</u> – From 2023-2032 VEC expects to be able to have entitlement to approximately 39,300 RECs annually from Kingdom, Ryegate and the Standard Offer projects that came on line before July 1, 2015. This amount decreases slightly as the Ryegate contract is assumed to expire in 2032. If VEC could sell the RECs from these facilities

and replace them with less-expensive Tier I qualifying RECs at the current price differential of $25/REC, it could decrease net costs for its members by approximately $980,000 per year. This annual cost reduction changes by $39,300 for each $1.00/REC change in the price differential between the high-value RECs and the VT Tier I RECs.

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 acquire and 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 acquire and 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.

4.3.7 Tier II Analysis

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

Act 56 requires that each Vermont utility must acquire Distributed Renewable Generation resources at a level that begins at 1% of its annual retail sales beginning in 2017, increasing by 0.6% each year until reaching 10% by 2032.

Table 4.3.7.A below restates the percentages of Tier II requirements for each year of the study period.

Year	Tier II Renewable Energy Requirement
2023	4.6%
2024	5.2%
2025	5.8%
2026	6.4%
2027	7.0%
2028	7.6%
2029	8.2%
2030	8.8%
2031	9.4%
2032 to 2042	10.0%

Table 4.3.7.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 after June 30, 2015. 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.

At the same time, the cap on the amount of net-metering that could be installed in a utility's service territory was eliminated, which allowed for a rapid acceleration of deployment in the territory compared to what had been experienced in prior years.

Figure 4.3.7.B 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 before December 2021. A table containing the data the graph is based on is included in "Appendix R: VEC Resource and Needs Projections."

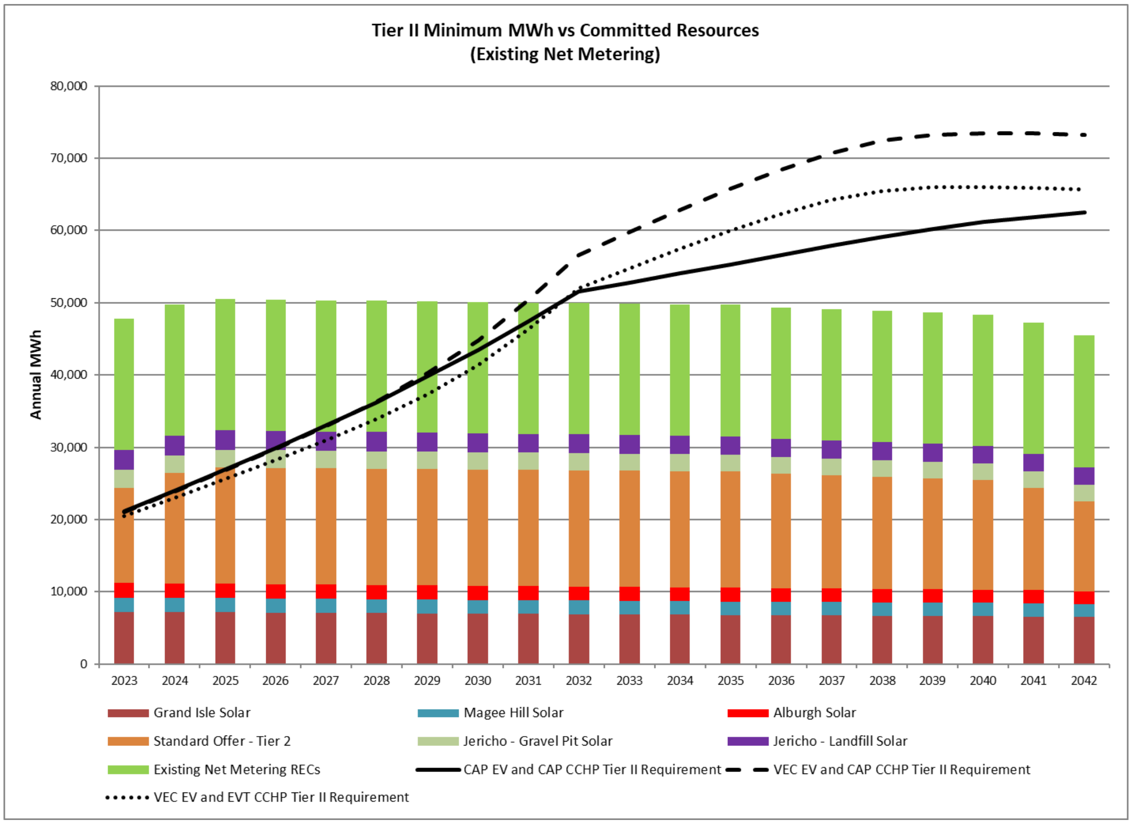

Figure 4.3.7.B VEC's projected Tier II requirement to its current Tier II committed and pending resources

VEC is projected to exceed its Tier II requirements through at least 2031 in all three load scenarios.

Figure 4.3.7.C below shows that even using VEC's Low projections for net-metering, it has resources in excess of its Tier II requirement through at least 2033 in all three load scenarios. Using Base net-metering projections VEC is projected to have resources in excess of its Tier II requirement through at least 2038 in all three load scenarios.

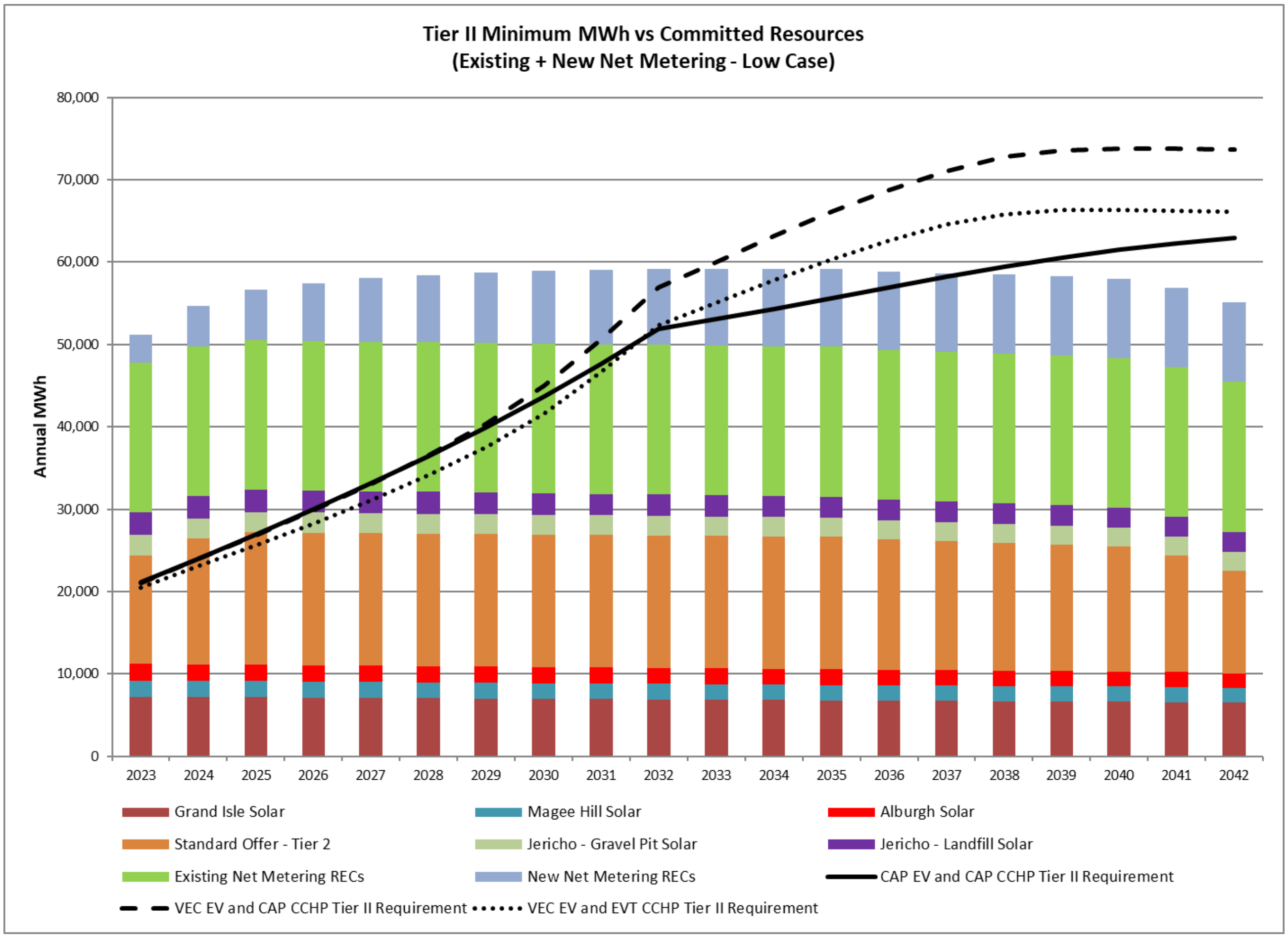

Figure 4.3.7.C VEC's Low projections for net-metering

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 acquire and 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 acquire and 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. 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 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.

Additional Risks and Opportunities in Current Portfolio

There are a number of risks and opportunities in the current portfolio including:

1. Noticeable shortfalls beginning in 2023.
2. Hourly spot market prices for energy which impact the costs of VEC's shortfalls.
3. Forward market prices for energy which can also impact the cost of VEC's shortfalls.
4. Load growth from EVs – which will impact VEC's load and the volume of RECs VEC will need to acquire and retain to meet Vermont's RES standards.
5. Net-metering adoption rate – which will impact VEC's sales and the volume of RECs that VEC will need to meet Vermont's RES standards.
6. Increasing VEC's share of VT peak, increased RNS rates, and/or increasing VEC's share of the New England peak if other VT DUs or load serving entities in New England pursue similar peak shaving strategies.

Value of Renewable Energy Certificates in other New England States

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 Alternative Compliance Rate 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 Alternative Compliance Rate, 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 could have a substantial impact on VEC's annual budget and long-range financial plans.

VEC currently receives approximately 58,000 RECs from facilities that qualify as both Vermont Tier I and Massachusetts and/or Connecticut Class I. This number increases to approximately 61,700 as new Standard Offer projects come on line over the next 10 years. For every $10.00/REC change in price VEC will realize a change in revenue of approximately $617,000, or approximately 0.75% in rates.

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.

Because of the many variables impacting each of the factors above, it is difficult to predict the future value of REC beyond any broker quotes. Because of this SEA provides REC forecasts under a number of scenarios which creates a range of possible price outcomes for each REC class by state.

Most SEA scenarios show REC prices remaining low relative to Alternative Compliance Prices and typically within a $10.00 - $37.00/REC range from 2023 – 2030, with Base Case costs in the low end of that range.

Tracking Emissions of VEC's Portfolio

To track the environmental impact of VEC's portfolio, the residual emissions rate of the NEPOOL mix as reported on the NEPOOL Generation Information System (NEPOOL GIS) from October 2020 – September 2021 was utilized.

The NEPOOL Residual Mix is used instead of the emissions of the NEPOOL Marginal unit, because the Residual Mix data should be based on attributes that have not been claimed, to avoid the possibility of double counting among load serving entities in New England.

The residual emissions rate is calculated using all energy in the NEPOOL GIS that has not been retired by a NEPOOL participant and claimed as a part of that participant's resource mix. October 2020 – September 2021 is the most recent period for which NEPOOL GIS data was available. The data was accessed from the NEPOOL GIS site using the file titled "NEPOOL_FuelTypeStatistics".[1]

The emissions in the NEPOOL Residual Mix are shown in Table 4.3.7.D below:

Carbon Dioxide Lb./MWh	Carbon Monoxide Lb./MWh	Mercury Lb./MWh	Nitrogen Oxides Lb./MWh	Particulates Lb./MWh	Particulates (<10 microns) Lb./MWh	Sulphur Dioxides Lb./MWh	Organic Compounds Lb./MWh
767.10193	1.27400	0.00001	0.68086	0.34031	0.26660	0.51787	0.04454

Table 4.3.7.D Emissions in the NEPOOL Residual Mix

Applying these emissions to the amount of energy in VEC's Climate Action Plan EV and CCHP Load Forecast scenario (including purchases at the spot market) that is supplied by emitting resources, prior to moving to a 100% fossil-free, or 100% renewable, portfolio results in the annual tons of emissions shown in Table 4.3.7.E below:

Year	Carbon Dioxide Short Tons	Carbon Monoxide Short Tons	Mercury Short Tons	Nitrogen Oxides Short Tons	Particulates short Tons	Particulates (<10 microns) Short Tons	Sulphur Dioxides Short Tons	Organic Compounds Short Tons
2023	39,874	66	0	35	18	14	27	2
2024	40,168	67	0	36	18	14	27	2
2025	37,824	63	0	34	17	13	26	2
2026	33,336	55	0	30	15	12	23	2
2027	34,022	57	0	30	15	12	23	2
2028	31,943	53	0	28	14	11	22	2
2029	27,812	46	0	25	12	10	19	2
2030	28,967	48	0	26	13	10	20	2
2031	27,381	45	0	24	12	10	18	2
2032	22,853	38	0	20	10	8	15	1
2033	24,267	40	0	22	11	8	16	1

[1] Although we believe the Residual Mix is the correct number to use, we could not verify the values reported by NEPOOL GIS for October 2020-Septmeber 2021 because there did not appear to be consistency among various reports on the NEPOOL GIS site that include statistics for Residual Mix.

2034	22,783	38	0	20	10	8	15	1
2035	56,851	94	0	50	25	20	38	3
2036	58,155	97	0	52	26	20	39	3
2037	59,468	99	0	53	26	21	40	3
2038	60,727	101	0	54	27	21	41	4
2039	61,892	103	0	55	27	22	42	4
2040	62,865	104	0	56	28	22	42	4
2041	63,626	106	0	56	28	22	43	4
2042	64,280	107	0	57	29	22	43	4

Table 4.3.7.E Annual tons of Emissions

Because the volume of emissions is a function of load, VEC also tracks emissions on a Lb./MWh basis. This allows for a more direct comparison to utilities of different sizes, without which a small utility with a dirty portfolio could appear to be cleaner than a larger utility with a cleaner portfolio simply because of the total volume of emissions.

Table 4.3.7.F below shows VEC's projected Lb./MWh of the various emissions through the study period for the Climate Action Plan EV and CCHP Load Forecast:

Year	**Total Load**	**Carbon Dioxide Lb./MWh**	**Carbon Monoxide Lb./MWh**	**Mercury Lb./MWh**	**Nitrogen Oxides Lb./MWh**	**Particulates Lb./MWh**	**Particulates (<10 microns) Lb./MWh**	**Sulphur Dioxides Lb./MWh**	**Organic Compounds Lb./MWh**
2023	492,838	161.8	0.3	0.0	0.1	0.1	0.1	0.1	0.0
2024	494,907	162.3	0.3	0.0	0.1	0.1	0.1	0.1	0.0
2025	497,369	152.1	0.3	0.0	0.1	0.1	0.1	0.1	0.0
2026	500,922	133.1	0.2	0.0	0.1	0.1	0.0	0.1	0.0
2027	505,633	134.6	0.2	0.0	0.1	0.1	0.0	0.1	0.0
2028	511,901	124.8	0.2	0.0	0.1	0.1	0.0	0.1	0.0
2029	520,347	106.9	0.2	0.0	0.1	0.0	0.0	0.1	0.0
2030	529,933	109.3	0.2	0.0	0.1	0.0	0.0	0.1	0.0
2031	540,685	101.3	0.2	0.0	0.1	0.0	0.0	0.1	0.0
2032	552,822	82.7	0.1	0.0	0.1	0.0	0.0	0.1	0.0
2033	565,702	85.8	0.1	0.0	0.1	0.0	0.0	0.1	0.0
2034	579,245	78.7	0.1	0.0	0.1	0.0	0.0	0.1	0.0
2035	592,891	191.8	0.3	0.0	0.2	0.1	0.1	0.1	0.0
2036	606,493	191.8	0.3	0.0	0.2	0.1	0.1	0.1	0.0
2037	620,184	191.8	0.3	0.0	0.2	0.1	0.1	0.1	0.0
2038	633,314	191.8	0.3	0.0	0.2	0.1	0.1	0.1	0.0
2039	645,467	191.8	0.3	0.0	0.2	0.1	0.1	0.1	0.0
2040	655,612	191.8	0.3	0.0	0.2	0.1	0.1	0.1	0.0
2041	663,543	191.8	0.3	0.0	0.2	0.1	0.1	0.1	0.0
2042	670,367	191.8	0.3	0.0	0.2	0.1	0.1	0.1	0.0

Table 4.3.7.F VEC's projected Lb./MWh of the various emissions through the study period

As the table shows, carbon dioxide is by far the greatest emission, by volume, of VEC's Reference Case resource mix. Even so, it is considerably less than the New England Residual Mix and System-Wide Mix. This is because of Vermont's relatively high Renewable Energy Standard and the amount of nuclear in VEC's reference portfolio.

VEC's percentage of non-emitting resources, after the sale of excess RECs decreases from slightly over 20% in 2023 to approximately 10% in 2034. Throughout the next 11 years the decrease in emissions is a function of increasing RES requirements. There is a steep increase in the % of MWh of emissions in 2035 after the expiration of the current contract with NextEra for 10 MW of Seabrook nuclear power and the associated environmental attributes. This trend is shown in Figure 4.3.7.G below.

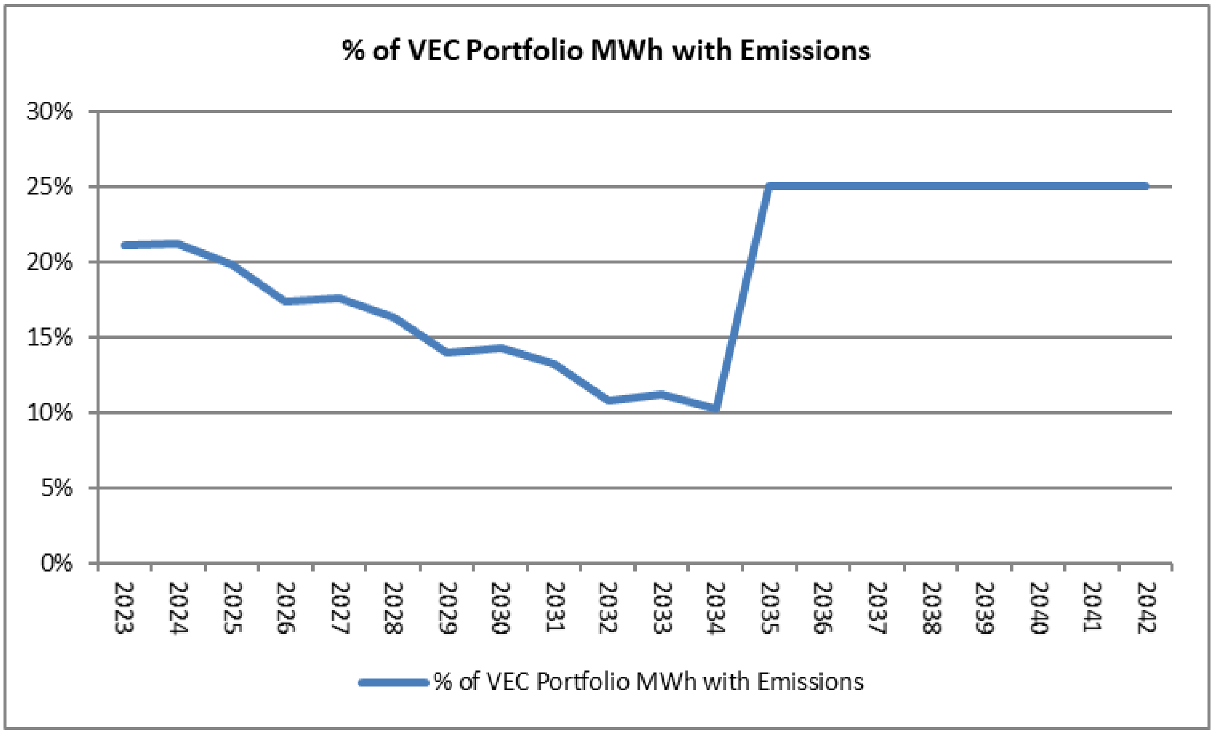

Figure 4.3.7.G - % of VEC Portfolio MWh with Emissions

There is no universally-defined value per ton of emissions. Carbon dioxide is by far the largest emission of VEC's portfolio and the one emission that appears to be the most popularly tracked by regulatory agencies or other groups due to its influence in global warming. Instead of assigning a specific societal cost to any emission, VEC is currently applying societal costs only to carbon dioxide. In addition, it is tracking the total societal cost (in nominal dollars) using a range of costs per ton of emission. In this case, VEC is using the term "societal cost" to mean the cost to society (and not VEC) for the mitigation of, and/or damage of, carbon dioxide impacts to the environment.

The analysis above allows for an easy calculation and comparison of the societal cost of the portfolio assuming different values for the cost/ton of emissions. Table 4.3.7.H below shows the societal costs of the Climate Action Plan EV and CCHP Load Forecast scenario assuming $5/Ton, $10/Ton, $50/ton and $100/ton in 2023 escalated at 2% per year and the 20-year net present value assuming VEC's discount rate of 6.0%:

Year	Emission $ assuming $5.00/ton in 2023	Emission $ assuming $10.00/ton in 2023	Emission $ assuming $50.00/ton in 2023	Emission $ assuming $100.00/ton in 2023
2023	$199,370	$398,739	$1,993,697	$3,987,394
2024	$204,855	$409,710	$2,048,549	$4,097,099

2025	$196,763	$393,525	$1,967,625	$3,935,250
2026	$176,882	$353,765	$1,768,825	$3,537,650
2027	$184,133	$368,266	$1,841,328	$3,682,656
2028	$176,340	$352,680	$1,763,402	$3,526,804
2029	$156,602	$313,203	$1,566,016	$3,132,032
2030	$166,373	$332,745	$1,663,727	$3,327,455
2031	$160,407	$320,814	$1,604,071	$3,208,142
2032	$136,555	$273,109	$1,365,545	$2,731,090
2033	$147,907	$295,814	$1,479,069	$2,958,139
2034	$141,641	$283,282	$1,416,412	$2,832,824
2035	$360,504	$721,008	$3,605,040	$7,210,080
2036	$376,150	$752,301	$3,761,503	$7,523,007
2037	$392,334	$784,668	$3,923,341	$7,846,681
2038	$408,653	$817,306	$4,086,531	$8,173,063
2039	$424,825	$849,650	$4,248,250	$8,496,499
2040	$440,132	$880,263	$4,401,317	$8,802,634
2041	$454,365	$908,731	$4,543,653	$9,087,306
2042	$468,219	$936,437	$4,682,187	$9,364,375
NPV	$3,037,681	$6,075,362	$30,376,812	$60,753,625

Table 4.3.7.H Societal costs of the Climate Action Plan EV and CCHP Load Forecast scenario

The annual increase in the societal cost/ton of carbon dioxide is as difficult to predict. An annual escalation rate that is higher than 2% per year would lead to higher annual societal costs of emissions in each cost scenario.

4.4 100% Carbon Free and 100% Renewable Analyses

As the Total System Energy Requirements analysis discussed earlier in this report shows, VEC has unhedged energy needs in each year beginning in 2023. In the Reference Case, this energy is assumed to be supplied with spot market purchases through ISONE.

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 the following Resolution:

- "…staff should enter contracts that 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 starting in 2023."
- "…staff should enter contracts that 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."

Prior to the Board's resolution, VEC's strategy was to meet its requirements under the Vermont Renewable Energy Standard as affordably as possible. In other words, VEC will meet its RES requirements but not go beyond them unless doing so would be economically beneficial to its members even without the standards.

With the Board's Resolution, VEC is interested in analyzing the magnitude of the change in costs it could reasonably expect if it were to meet the 100% carbon-free and/or 100% renewable targets under different strategies for acquiring environmental attributes.

To answer these questions VEC has modeled the change in costs and rates, under each of the three forecast scenarios, of the following portfolios:

a) 100% Carbon Free using:
    a. existing Carbon-Free resources
    b. new In-state Solar
b) 100% Renewable using:
    a. existing Renewable resources
    b. new Off-Shore Wind
    c. new In-state Solar

Analyses of the rate impact for various sources of energy and environmental attributes were performed across each of the three load forecast scenarios. However, for simplicity, only the results of analyses under the Climate Action Plan EV and Climate Action Plan CCHP Load Forecast Scenario are shown. Percentage increases differ very little between the 3 load forecasts because increases in loads between the 3 forecasts are associated with increased sales.

Each of these analyses and conclusions are explained below.

4.4.1 100% Carbon Free

Consistent with the Board's Resolution, for purposes of this analysis VEC defines 100% Carbon Free as having entitlement to environmental attributes equal to its annual load requirement. These environmental attributes can be associated with energy contracts VEC has entered to purchase energy from the same resources the environmental attributes are associated with, or through purchases of environmental attributes that are not necessarily associated with the same resources as VEC's energy supply.

Table 4.4.1.A below shows the additional volume of carbon-free environmental attributes to be purchased to reach a 100% Carbon-Free Energy Portfolio under each forecast scenario:

Year	Additional MWh Needed to be 100% Carbon Free VEC EV - Climate Action Plan CCHP	Additional MWh Needed to be 100% Carbon Free Climate Action Plan EV and CCHP	Additional MWh Needed to be 100% Carbon Free VEC EV - EVT CCHP
2023	124,000	124,763	118,412
2024	124,769	125,616	117,335
2025	118,836	119,610	109,594
2026	108,858	109,401	98,841
2027	111,129	111,401	99,710
2028	106,739	106,262	93,974
2029	99,336	97,264	86,496

Table 4.4.1.A Additional volume of environmental attributes needed to be 100% carbon-free

It should be noted that MWh shown in the table are the incremental MWh, above what is required by the RES, to reach a 100% Carbon-Free Energy Portfolio. As the RES required percentage increases each year until 2032, the incremental amount of MWh necessary to reach a 100% carbon-free portfolio decreases even though this assumes load growth.

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 the attributes are sourced, 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 in addition to the cost of the 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.

2023-2029 Rate Impact - Climate Action Plan EV and Climate Action Plan CCHP Load Forecast Scenario Purchase from an Existing Resource

Table 4.4.1.B below shows the 2023-2029 impact on rates of moving to 100% Carbon Free energy portfolio under the Climate Action Plan EV and CCHP Load Forecast scenario at various combinations of purchase price premiums above the projected market price at the delivery node and the environmental attribute price from an existing carbon-free resource. The rate impact is with respect to purchasing the equivalent amount of energy from a fossil fuel facility.

Premium Above Market	Environmental Attribute $2.00/MWh	Environmental Attribute $3.00/MWh	Environmental Attribute $4.00/MWh	Environmental Attribute $5.00/MWh	Environmental Attribute $6.00/MWh	Environmental Attribute $8.00/MWh	Environmental Attribute $10.00/MWh
0%	0.274%	0.411%	0.548%	0.685%	0.822%	1.096%	1.370%
2%	0.378%	0.515%	0.652%	0.789%	0.926%	1.200%	1.474%
4%	0.483%	0.620%	0.757%	0.894%	1.031%	1.305%	1.579%
6%	0.587%	0.724%	0.861%	0.998%	1.135%	1.409%	1.683%
8%	0.691%	0.828%	0.965%	1.102%	1.239%	1.513%	1.787%
10%	0.796%	0.933%	1.070%	1.207%	1.344%	1.618%	1.892%

Table 4.4.1.B Rate impact using Climate Action Plan EV and CCHP Load Forecast Scenario – Existing Resource

2023-2029 Rate Impact - Climate Action Plan EV and CCHP Load Forecast Scenario Purchase from New In-State Solar Resource

Table 4.4.1.C below shows the 2023-2029 impact on rates of moving to 100% Carbon Free energy portfolio under the Climate Action Plan EV and Climate Action Plan CCHP Load Forecast scenario at various combinations of PPA price from a new in-state solar facility assuming VEC retains the Environmental Attributes, which qualify as VT Tier II, as opposed to selling the attributes and purchasing back less expensive attributes. The rate impact is with respect to purchasing the equivalent amount of energy from a fossil fuel facility.

Daymark LMP Case	PPA Price $70/MWh	PPA Price $80/MWh	PPA Price $90/MWh	PPA Price $100/MWh	PPA Price $120/MWh	PPA Price $140/MWh
Low	1.192%	2.499%	3.806%	5.112%	7.726%	10.339%
Reference	0.638%	1.945%	3.251%	4.558%	7.171%	9.784%
High	0.081%	1.387%	2.694%	4.001%	6.614%	9.227%

Table 4.4.1.C Rate impact using Climate Action Plan EV and CCHP Load Forecast Scenario – New in state solar

The tables show that:

1. If the contract prices for existing resources are equal to the market value of the output at the node, VEC's rates would be higher than they otherwise would have been by 0.274% - 1.370% depending on the cost of the environmental attributes. The entire increase in costs is the result of the environmental attributes.

2. If the contract prices for existing resources were to end up being equal to 110% of the market value of the output at the node, VEC's rates would be higher than they otherwise would have been by 0.796% - 1.892% on an annual basis.

3. The cost impacts of New - Instate Solar increase noticeably as the PPA price increases. For example, at PPA prices of $90/MWh rate impacts range from approximately 2.694% - 3.806% depending on the LMP scenario, while at PPA prices of $140/MWh rate impacts range from approximately 9.227% - 10.339% depending on the LMP scenarios.

4. The rate impacts of New In-State Solar decrease as the LMPs (market prices for fossil-fuel based energy) increase because as the market for fossil-fuel based energy increase the amount a project is above market decreases.

It is important for the reader to be aware of several important points regarding this analysis and the resulting portfolio, including:

- A contract with an existing resource does not necessarily encourage the development of additional carbon-free generation.
- VEC would not be 100% carbon-free in every hour of the year. VEC would be excess carbon-free energy in some hours and short carbon-free energy in other hours (for example the middle of the night), with the excess in carbon-free energy being equal to, or greater than, the shortfall. For VEC to become carbon-free in every hour of the year would require a complete overhaul of its portfolio which we delve into with more detail in later sections. This annual net process for energy attribute claims is similar to accounting for renewable energy standards compliance and with methodologies used by other utilities claiming to be 100% carbon-free.
- Several studies have concluded that nuclear can act as a bridge to 100% renewables as the region wrestles with the intermittency of renewables and the best way to deal with that.
- Locking a long-term contract may require a Certificate of Public Good (CPG) if the project is out of state.
- The analyses have been performed based on acquiring REC equivalent to VEC's annual load, but not necessarily equal to each month's load. If VEC were to pursue a strategy to be 100% fossil-free in each month a more in-depth analysis would be required.
- Because these resources will likely be existing and outside Vermont, this case was assumed to not require any upgrades to the VELCO or VEC systems.

4.4.2 100% Renewable – Energy and RECs from Existing Hydro

For purposes of this analysis, 100% renewable is defined as meeting VEC's Tier I and Tier II requirements as defined by the RES, and all energy requirements above that being served by contracts to purchase energy and RECs (and retaining those RECs) from existing hydro facilities that qualify as Vermont Tier I resources. Recall that Tier I resources are those that are: a) out-of-state renewable resources; b) in-state renewable resources with a nameplate capacity greater than 5 MW AC; or c) in-state renewable resources with a nameplate capacity of 5 MW or less AC and came on-line prior to July 1, 2015.

Table 4.4.2.A below shows the additional volume of renewable energy above the RES requirements to be purchased to have renewable energy purchases equal load on an annual basis:

Year	Additional MWh Needed to be 100% Renewable VEC EV - Climate Action Plan CCHP	Additional MWh Needed to be 100% Renewable Climate Action Plan EV and CCHP	Additional MWh Needed to be 100% Renewable VEC EV - EVT CCHP
2023	202,390	203,153	196,802
2024	203,159	204,006	195,725
2025	204,246	205,020	195,004
2026	187,248	187,791	177,231
2027	189,285	189,557	177,866
2028	192,383	191,906	179,618
2029	177,726	175,654	164,886
2030	184,297	178,889	170,278
2031	193,664	182,519	178,435
2032	182,202	165,985	167,381
2033	192,303	169,852	176,184
2034	202,323	173,918	184,897
2035	211,783	178,016	193,197
2036	220,342	182,100	200,618
2037	227,723	186,210	206,704
2038	233,089	190,153	210,819
2039	235,782	193,802	212,405
2040	236,488	196,847	212,429
2041	236,351	199,229	212,095
2042	235,803	201,278	211,497

Table 4.4.2.A Renewable Energy above RES to be purchased

As in the 100% Carbon-Free analyses, VEC staff has not had any discussions with owners of any existing hydro facilities, because we do not want to engage potential suppliers in discussions unless VEC is interested in pursuing this strategy. Instead, the analysis calculates a matrix of rate impacts for 2030-2042 using a set of proxy purchase prices for energy and environmental attributes. This technique was chosen because discussions with suppliers for a theoretical analysis may not result in realistic proposals because suppliers could be reluctant to give away negotiating information, and discussions with no real intention of entering a contract could lead suppliers to not take VEC seriously the next time VEC conducts a legitimate solicitation.

The assumptions used in the analysis are shown in Table 4.4.2.B below:

Delivery Point	Vernon
Term	2030-2042
Purchase Price	0% - 10% premium over projected market prices at the node
Nodal Price	2022 = Avg of 3/2020-2/2022 escalated at Daymark Reference Case LMP
Environmental Attribute Price	$2.00 - $12.00/MWh
Annual MWH Volume Purchased	Load – Total RES Requirement

Table 4.4.2.B Assumptions for 100% Renewable

Tables 4.4.2.C below shows the 2030-2042 impact on rates with respect at various combinations of purchase price premium above the projected market price at the delivery node plus the environmental attribute prices under the Climate Action Plan EV and Climate Action Plan CCHP load forecast scenario.

The rate impact is with respect to purchasing the equivalent amount of energy from a fossil fuel facility.

2030-2042 Impact on Rates - Climate Action Plan EV and Climate Action Plan CCHP Load Forecast Scenario

Percentage Premium over LMP	REC $/MWh $2.00	REC $/MWh $4.00	REC $/MWh $6.00	REC $/MWh $8.00	REC $/MWh $10.00	REC $/MWh $12.00
0%	0.421%	0.843%	1.264%	1.686%	2.107%	2.529%
2%	0.606%	1.027%	1.449%	1.870%	2.292%	2.713%
4%	0.790%	1.212%	1.633%	2.055%	2.476%	2.898%
6%	0.975%	1.396%	1.818%	2.239%	2.661%	3.082%
8%	1.160%	1.581%	2.002%	2.424%	2.845%	3.267%
10%	1.344%	1.766%	2.187%	2.608%	3.030%	3.451%

Table 4.4.2.C Impact on Rates Climate Action Plan EV and CCHP Load Forecast Scenario

The table shows that:

1. If the contract price is equal to the market value, VEC's rates would be higher than they otherwise would have been by approximately 0.421% - 2.529%. The entire increase is due to the cost of the environmental attributes.
2. If the contract price were to end up being equal to 110% of the market value of the output at the node, VEC's rates would be higher than they otherwise would have been by approximately 1.344% - 3.451%.
3. For each $1.00 change in the price of RECs, the rate impact changes by 0.25% for the VEC EV and Climate Action Plan CCHP Load Forecast scenario, 0.21% for the Climate Action Plan EV and CCHP Load Forecast scenario and 0.22% for the VEC EV and EVT CCHP Load Forecast scenario.

It is important to for the reader to be aware of several important points regarding this analysis and the resulting portfolio, including:

- Because this is a contract with an existing resource this strategy would not necessarily encourage the development of additional renewable generation
- VEC would not be 100% renewable in every hour of the year. VEC would be excess renewable energy in some hours and short renewable energy in other hours (for example the middle of the night), with the excess in renewable energy being equal to, or greater than, the shortfall.
- Locking a long-term contract may require a CPG if the project is out of state.
- The analysis has been performed on annual assumptions. If VEC were to pursue this strategy, the analyses would likely be based on monthly assumptions.
- Because these resources already exist, this case would not require any upgrades to the VELCO or VEC systems.

4.4.3 100% Renewable – Energy and RECs from Off-Shore Wind

Similar to the 100% Renewable with Existing Hydro analysis, we have defined 100% renewable as meeting VEC's Tier I and Tier II requirements as defined by the RES, and all energy requirements above that being served by contracts to purchase energy and RECs (and retaining those RECs) from a new off-shore wind facility that qualifies as a Vermont

Tier I resource. (Although it is a new facility, the facility is not assumed to qualify as a VT Tier II resource because it is not in-state nor does it have a nameplate capacity of 5.0 MW or less.)

Table 4.4.3.A below shows the additional volume of renewable energy above the RES requirements to be purchased in order to have renewable energy purchases equal load on an annual basis:

Year	Additional MWh Needed to be 100% Renewable VEC EV - Climate Action Plan CCHP	Additional MWh Needed to be 100% Renewable Climate Action Plan EV CCHP	Additional MWh Needed to be 100% Renewable VEC EV - EVT CCHP
2023	202,390	203,153	196,802
2024	203,159	204,006	195,725
2025	204,246	205,020	195,004
2026	187,248	187,791	177,231
2027	189,285	189,557	177,866
2028	192,383	191,906	179,618
2029	177,726	175,654	164,886
2030	184,297	178,889	170,278
2031	193,664	182,519	178,435
2032	182,202	165,985	167,381
2033	192,303	169,852	176,184
2034	202,323	173,918	184,897
2035	211,783	178,016	193,197
2036	220,342	182,100	200,618
2037	227,723	186,210	206,704
2038	233,089	190,153	210,819
2039	235,782	193,802	212,405
2040	236,488	196,847	212,429
2041	236,351	199,229	212,095
2042	235,803	201,278	211,497

Table 4.4.3.A Additional Volume of Renewable Energy Above RES

Again, VEC staff has had preliminary discussions with two off-shore wind developers. Although no decision has been made regarding this strategy, we felt it was important to let developers know VEC may be interested because of the long lead-time for these projects and to be considered as potential off-takers. The assumed prices in this analysis are based on these discussions.

The assumptions used in the analysis are shown in Table 4.4.3.B below:

Delivery Point	for Sykes Rd FLRV Node
Term	2030-2042
Purchase Price	Ranging from $75/MWh to $100/MWh.
Nodal Price	2022 = Avg of 3/2020-2/2022 escalated at % in Daymark Forecasts
Environmental Attribute Price	Included in Purchase Price
Annual MWH Volume Purchased	Load – RES Requirement

Table 4.4.3.B Assumptions

Tables 4.4.3.C below shows the 2030-2042 rate impacts for 2030-2042 assuming the Climate Action Plan EV and Climate Action Plan CCHP load forecast scenario using a set of proxy PPA prices for energy and environmental attributes at the delivery node compared to the projected nodal prices based on the three Daymark LMP scenarios. The rate impact is with respect to purchasing the equivalent amount of energy from a fossil fuel facility.

2030-2042 Impact on Rates - Climate Action Plan EV and CCHP Load Forecast Scenario

Daymark LMP Case	Contract Price $60/MWh	Contract Price $65/MWh	Contract Price $70/MWh	Contract Price $75/MWh	Contract Price $80/MWh	Contract Price $85/MWh
Low	-1.832%	-1.033%	-0.234%	0.565%	1.364%	2.163%
Reference	-3.882%	-3.083%	-2.284%	-1.486%	-0.687%	0.112%
High	-5.504%	-4.705%	-3.906%	-3.107%	-2.308%	-1.509%

Table 4.4.3.C Impact on Rates Climate Action Plan EV and CCHP Load Forecast Scenario

The tables show that:

1. VEC's rates would range between 50504% lower and 2.163% higher be higher than they otherwise would have been. The lower rates suggest this would actually be a lower cost strategy than one assuming fossil-fuels, meaning VEC should pursue the strategy from both a financial standpoint as well as an environmental standpoint.
2. The impact is higher in the Low LMP scenario because the analysis assumes VEC would be paying a fixed price for the off-shore wind, whose cost is compared to lower alternative prices. This also makes sense from an ISONE settlement perspective because the fixed price contract will be less valuable to VEC in a Low LMP scenario than in the Reference of High LMP scenarios.
3. For each $5.00 change in the PPA price the rate impact changes by 0.93%for the VEC EV and Climate Action Plan CCHP Load Forecast scenario, 0.80% for the Climate Action Plan EV and CCHP Load Forecast scenario and 0.84% for the VEC EV and EVT CCHP Load Forecast scenario.

It is important to for the reader to be aware of several important points regarding this analysis and the resulting portfolio, including:

- Because this is a contract with a new resource it can be argued that the environment is better off by VEC pursuing this strategy if the revenues the project experiences from VEC's purchase are key to the project being built.
- VEC would not be 100% renewable in every hour of the year. VEC would be excess renewable energy in some hours and short renewable energy in other hours (for example the middle of the night), with the excess in renewable energy being equal to, or greater than, the shortfall.
- Locking up a long-term contract may require a CPG if the project is out of state.
- The analysis has been performed on annual assumptions. If VEC were to pursue this strategy, the analyses would likely be based on monthly assumptions.
- Because these resources will be outside Vermont, this case would not require any upgrades to the VELCO or VEC systems.

4.4.4 100% Renewable – New In-State Solar

Similar to the 100% Renewable with Existing Hydro analysis, for purposes of this analysis we have defined 100% renewable as meeting VEC's Tier I and Tier II requirements as defined by the RES, and all energy requirements above that being served by contracts to purchase energy and RECs (and retaining those RECs) from a new in-state solar facility that qualifies as a Vermont Tier II resource.

New in-state solar projects typically require a long-term commitment (net-metering or a Purchased Power Agreement) at set prices for the purchase of both energy and the Environmental Attributes. Depending on whether the energy and Environmental Attributes come from 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 to account for 1) the fact that prices have come down over time and 2) they may continue to do so.

Analyses of the rate impact for various sources of energy and environmental attributes were preformed across each of the three load forecast scenarios.

Table 4.4.4.A below shows the additional volume of renewable energy above the RES requirements to be purchased in order to have renewable energy purchases equal load on an annual basis:

Year	Additional MWh Needed to be 100% Renewable VEC EV - Climate Action Plan CCHP	Additional MWh Needed to be 100% Renewable Climate Action Plan EV and CCHP	Additional MWh Needed to be 100% Renewable VEC EV - EVT CCHP
2023	202,390	203,153	196,802
2024	203,159	204,006	195,725
2025	204,246	205,020	195,004
2026	187,248	187,791	177,231
2027	189,285	189,557	177,866
2028	192,383	191,906	179,618
2029	177,726	175,654	164,886
2030	184,297	178,889	170,278
2031	193,664	182,519	178,435
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2037	227,723	186,210	206,704
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2039	235,782	193,802	212,405
2040	236,488	196,847	212,429
2041	236,351	199,229	212,095
2042	235,803	201,278	211,497

Table 4.4.4.A

The analysis calculates a matrix of rate impacts for 2030-2042 using a set of proxy purchase prices for energy and environmental attributes. The purchase prices were assumed to be fixed prices, not percentage increases above the nodal LMP, with the prices ranging from slightly lower than the most recent Standard Offer Auction to prices similar to current Net Metering Rates.

The assumptions used in the analysis are shown in Table 4.4.4.B below:

Delivery Point	Vermont Load Zone
Term	2030-2042

Purchase Price	Ranging from $70/MWh to $140/MWh, escalating at 1.0% per year
Nodal Price	2022 = Avg of 3/2020-2/2022 escalated at % in Daymark Forecasts
Environmental Attribute Price	Included in Purchase Price
Annual MWH Volume Purchased	Load – RES Requirement

Table 4.4.4.B

Tables 4.4.4.C shows the 2030-2042 rate impacts for 2030-2042 assuming the Climate Action Plan EV and Climate Action Plan CCHP load forecast scenario using a set of proxy PPA prices for energy and environmental attributes at the delivery node including the environmental attribute price under the three Daymark LMP scenarios. The rate impact is with respect to purchasing the equivalent amount of energy from a fossil fuel facility.

2030-2042 Impact on Rates - Climate Action Plan EV and CCHP Load Forecast Scenario

Daymark LMP Case	Contract Price $70/MWh	Contract Price $80/MWh	Contract Price $90/MWh	Contract Price $100/MWh	Contract Price $120/MWh	Contract Price $140/MWh
Low	1.367%	3.165%	4.964%	6.763%	10.361%	13.958%
Reference	-0.631%	1.168%	2.967%	4.766%	8.363%	11.961%
High	-2.210%	-0.411%	1.388%	3.186%	6.784%	10.382%

Table 4.4.4.C Impact on Rates Climate Action Plan EV and CCHP Load Forecast Scenario

The tables show that:

1. The rate impacts range from a decrease of approximately 2.21% to an increase of approximately 13.958%. The lower rates suggest this would actually be a lower cost strategy than one assuming fossil-fuels, meaning VEC should pursue the strategy from both a financial standpoint as well as an environmental standpoint.
2. The impact is higher in the Low LMP scenario because the analysis assumes VEC would be paying a fixed price for the solar, whose cost is compared to lower alternative prices. This also makes sense from an ISONE settlement perspective because the fixed price contract will be less valuable to VEC in a Low LMP scenario than in the Reference or High LMP scenarios.
3. For each $10.00 change in the contract price the rate impact changes by 2.09% for the VEC EV and Climate Action Plan CCHP Load Forecast scenario, 1.80% for the Climate Action Plan EV and CCHP Load Forecast scenario and 1.90% for the VEC EV and EVT CCHP Load Forecast scenario.

Unless the contract price is specifically tied to the LMP at the node, it is impossible to model all scenarios. Thus, the tables do not show the full range of potential impacts. In fact, they only show cost increases.

As is the case with the other 100% renewable scenarios it is important to for the reader to be aware of several important points regarding this analysis and the resulting portfolio, including:

- Because this is a contract with a new resource it can be argued that the environment is better off by VEC pursuing this strategy if the revenues the project experiences from VEC's purchase a key to the project being built.
- No value for job retention or creation has been accounted for as that is not a criterion that VEC considers as part of power supply procurement decisions.
- VEC would not be 100% renewable in every hour of the year. VEC would be excess renewable energy in some hours and short renewable energy in other hours (for example the middle of the night), with the excess in renewable energy being equal to, or greater than, the shortfall.
- The analysis has been performed on annual assumptions. If VEC were to pursue this strategy, the analyses would likely be based on monthly assumptions.

- The analysis assumes no upgrades to the VELCO or VEC systems are necessary.

4.5 100% Renewable on An Hourly Basis

Vermont's current Renewable Energy Standard requires that load-serving entities (LSEs) have entitlement to RECs to meet a certain percentage of its load on an annual basis. There is no requirement for a minimum amount of renewable energy on an hourly or even monthly basis, which is a significantly different approach than the current annual requirements and attribute accounting.

4.5.1 Introduction

Currently renewable energy requirements in Vermont and New England are defined on an annual basis because there are no requirements for hourly or monthly emission-free portfolios. This allows LSEs to acquire more resources than they need to meet their customers' load requirements in some hours and purchase energy from emission-generating resources when renewable resources are not available, but still meet their renewable energy goals. This is also possible because baseload and dispatchable fossil fuel resources provide a balance to the intermittency of renewable resources, allowing the flow of energy and the renewable attributes to remain separate concerns and markets today.

As the region moves closer to 100% emission-free portfolios, the ability to meet requirements on an annual basis will become increasingly more difficult. On our current trajectory of incorporating renewables into our power supply there will need to be excess generation region-wide in some hours and enough storage capability to make up for hours when the renewable resources are not available. However, physics will not allow for excess emission-free energy in some hours to a degree large enough to make up for the lack of generation in other hours, without an extremely large quantity of storage capability. Instead, more baseload sources of emission-free energy may be necessary to achieve 100% emission-free goals in the relatively near future.

VEC believes that Vermont needs to begin a discussion and understanding of the implications as it moves to 100% renewable or emission-free portfolios and, if it hopes to be a leader in the region that others follow, how we envision the utility, state and regional goals be met on or close to an hourly basis as opposed to annual.

To illustrate this, Figures 4.5.1.A to 4.5.1.D show VEC's projected loads and currently-committed renewable resources on a typical weekday in January, May, July and October 2030 assuming the Climate Action Plan EV and CHHP load forecast with uncontrolled EV charging and its Base Net Metering forecast. For these charts, load has not been reduced by the Net Metering output, instead Net Metering is included as a resource.

Plots for 4 months have been shown instead of instead of all 12 months of the year to show the change by season, and to present the points efficiently. The plots for other months, as well as monthly plots for 2035 and 2042 are presented in Appendix S – Resources vs Load by Month.

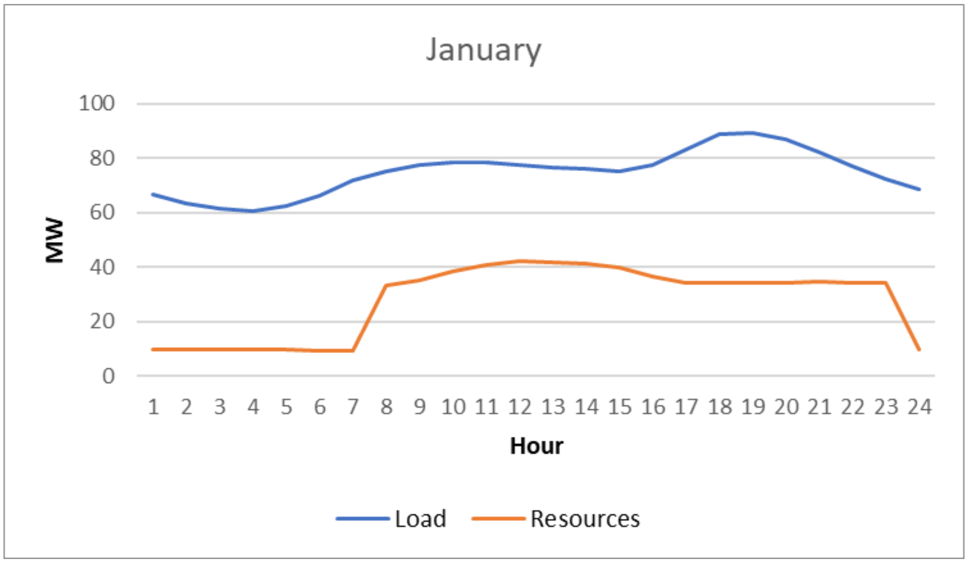

Figure 4.5.1.A January VEC load versus renewable resources purchased

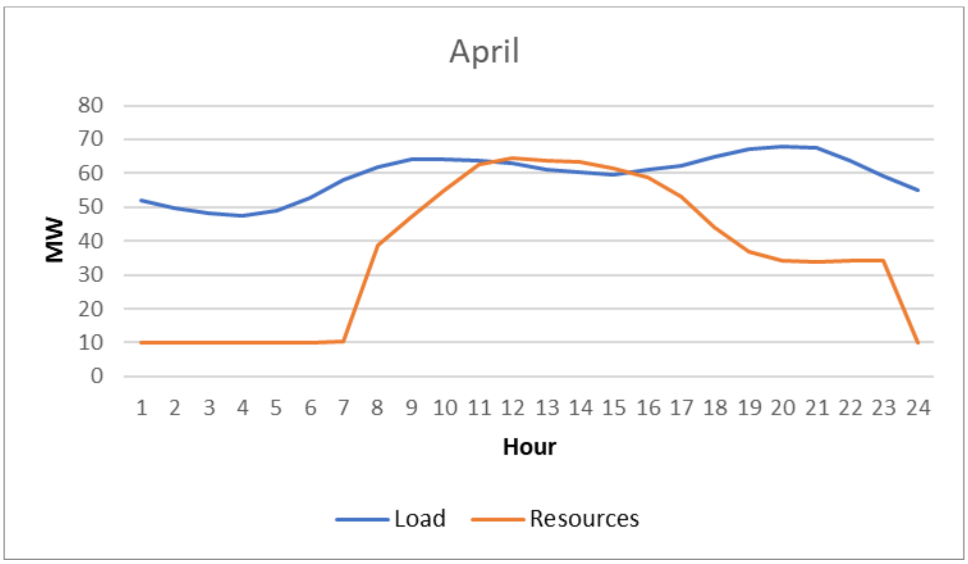

Figure 4.5.1.B April VEC load versus renewable resources purchased

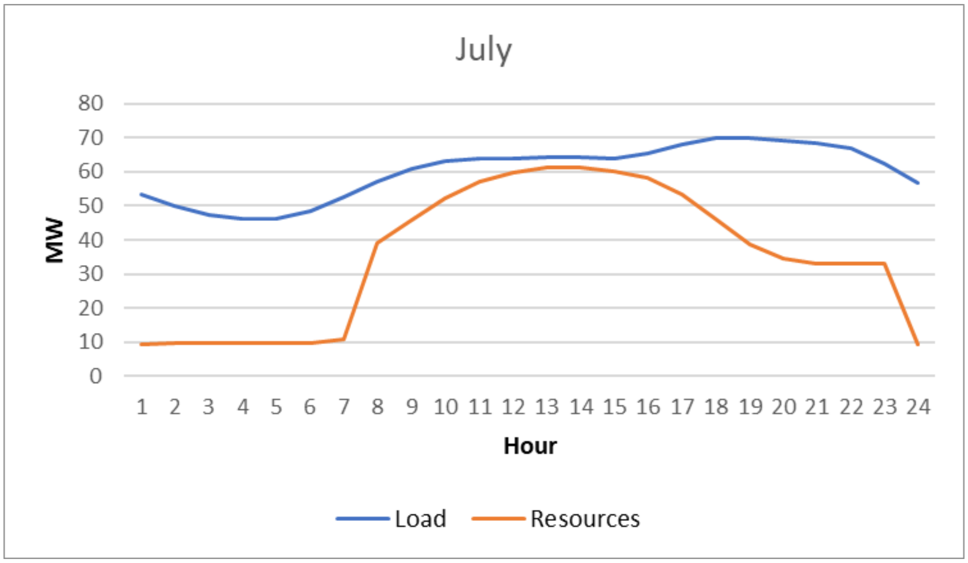

Figure 4.5.1.C July VEC load versus renewable resources purchased

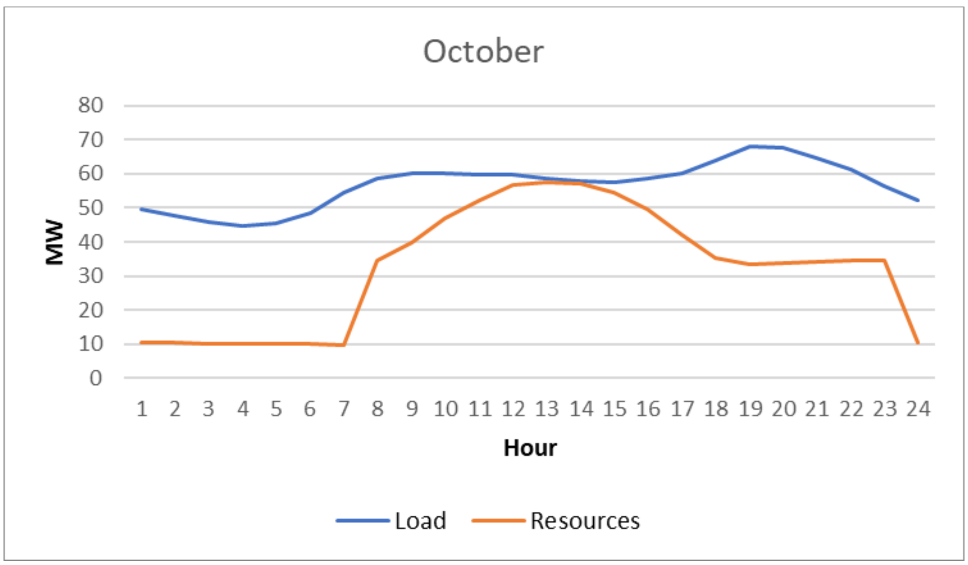

Figure 4.5.1.D October VEC load versus renewable resources purchased

The renewable resources VEC has in its mix in 2030 along with the hours of potential operation and capacity factor are shown in Table 4.5.1.E below:

Resource	Technology	Approx. MW	Hours of Potential Generation	Approx. Annual Capacity Factor
Kingdom Community Wind	Wind	8.0	1-24	28%
NYPA	Large Hydro	5.5	1-24	94%
Hydro Quebec	Large Hydro	24.0	8-23	67%
Alburgh	Solar	1.0	6-21	16%
Grand Isle	Solar	5.0	6-21	16%
Jericho Landfill	Solar	1.6	6-21	19%

Jericho Gravel Pit	Solar	1.5	6-21	19%
Magee Hill	Solar	1.0	6-21	14%
Ryegate	Biomass	1.8	1-24	88%
Net Metering	Solar	27.8	6-21	12%
Standard Offer - Biomass	Biomass	0.1	1-24	23%
Standard Offer - Farm Methane	Farm Methane	0.5	1-24	53%
Standard Offer - Food Waste	Food Waste	0.3	1-24	85%
Standard Offer - Hydro	Hydro	0.6	1-24	32%
Standard Offer – Landfill Methane	Methane	0.1	1-24	13%
Standard Offer - Solar	Solar	11.5	6-21	19%
Standard Offer - Wind	Wind	0.3	1-24	25%

Figure 4.5.1.E Renewable resources in 2030 mix

From the plots and the table, if VEC, and very likely most other utilities in Vermont and New England, are to move to 100% Renewable on an hourly basis, we will need a significant amount of resources in the middle of the night.

There are a handful of renewable resources that can provide energy in the middle of the night. They include:

- Solar paired with storage
- On-shore Wind paired with storage
- Off-shore Wind paired with storage
- Biomass paired with storage
- Hydro in New England
- Hydro-Quebec
- Farm Methane
- Food Waste
- Landfill Gas

VEC has developed a spreadsheet with hourly system-wide loads and output from the currently committed resources in its energy portfolio for 2030. The spreadsheet allows the user to input additional resources to see the effects of meeting VEC's load on an hourly basis with different combinations of technology types and volumes.

We have used this tool to determine the most financially efficient quantity of generation and storage required in VEC's portfolio if it were to fill the remaining energy not served by currently committed renewable resources with different technology types and storage, and assuming certain generation output shapes and cost metrics for both the energy and storage.

The technologies analyzed are:

- Solar paired with storage
- On-shore Wind paired with storage
- Off-shore Wind paired with storage
- Biomass paired with storage

Hydro in New England was not analyzed because we are not aware of any planned construction of new hydro facilities in New England. Also, new Farm Methane, Food Waste and Landfill Gas were not analyzed because, although they may need to be a part of the eventual resource mix in New England, we do not anticipate enough potential to be a large part of the solution. Although Hydro-Quebec may need to be part of the solution as well, it was not analyzed to show what would be required inside the New England control area.

It should be noted that the analysis below is simplified in that it does not consider:

- Round trip losses for battery
- Transmission or Distribution upgrades
- Curtailments if areas similar to the SHEI are created by the build out of renewable resources
- Battery or solar degradation over time
- Reserve Requirements
- Regulation Requirements
- Reliability Criteria for Control Area

Accounting for any of these issues with increase the quantity of generation and storage required.

The intent of this analysis is not to answer questions or argue for or against any strategy or resource, but instead to begin to highlight the opportunities and challenges of various renewable sources as well as begin to identify issues that will need to be addressed as we chart our path toward a fossil-free portfolio region-wide.

4.5.2 Solar and Storage

We analyzed the financially-optimum amount of Solar Wind and Storage needed to serve all VEC's projected 2030 hourly loads that are not covered by the projected output of its committed resources, with no energy shortfalls in any hour. This resulted in 1,570 MW of solar and 2,445 MWh of battery storage, with a 10-year cost of approximately $1.834 Billion, net of sales through the ISO New England Real-Time Energy market of excess generation when the batteries are full.

Three of the main drivers of a solar project's output shape are: latitude of the project's location, the direction on the compass the projects panels face, and the angle of tilt of the project's panels.

Since it would be impossible to know the location of all the solar required in VEC's territory required to meet load on an annual basis, the output shape of the required solar was based on the average of the actual 2021 hourly output of the Alburgh, Grand Isle and Jericho Gravel Pit solar projects (which VEC had PPAs with) for the entire calendar year.

We than attempted to identify the financially optimum combination of solar MW and storage MWh assuming:

- the average unitized output shape of the three projects;
- $80/MWh for Solar PPAs;
- $500,000/installed MWh of battery storage;
- 10-year financial analysis;
- No battery degradation;
- No load growth; and
- No load control of EVs or Cold-Climate Heat Pumps.

The hourly plot of the MWh of energy in storage is below:

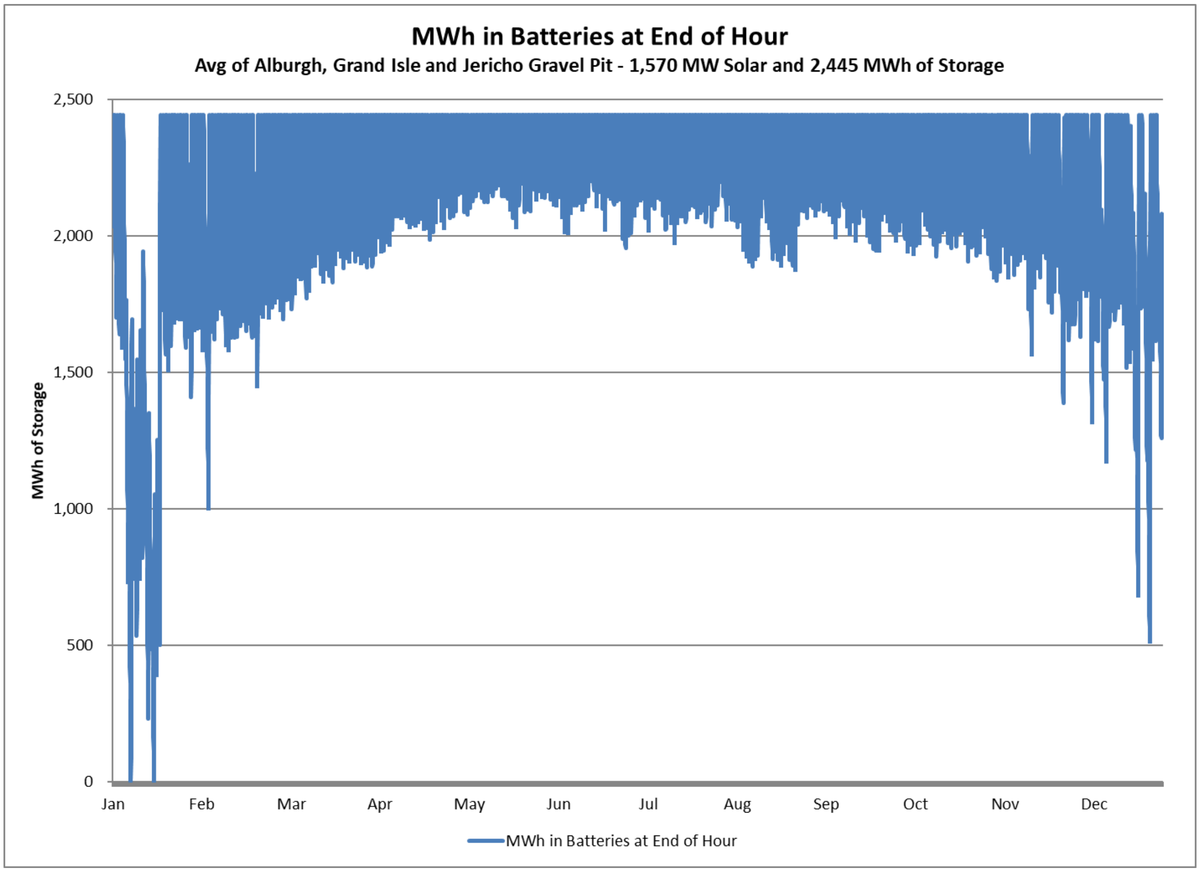

Figure 4.5.2.A - Solar and Storage – MWh in Batteries at End of Hour

Any hour in which there is 0 energy in the battery would represent an hour in which the next kWh of load on the system could not be served.

This scenario would likely result in the highest level of generation in the VEC system compared to the other scenarios modeled. The lack of solar output in January at all three locations dominates this scenario, with some potential concerns in February and December. The system is most vulnerable to battery depletion on cold days with very little solar output and very little wind from KCW, even at these quantities of new solar and storage. The analysis uses the simplifying assumption that the batteries are fully charged at the beginning of the year, however there are 1,781 MWh of energy in the battery at the end of the year, so the system is not quite as well prepared for several days with a lack of sun and wind at the beginning of year 2 as it was at the beginning of year 1.

The scenario shows that 2,251,487 MWh of new solar resources would be purchased in one year, of which 12.7% are either consumed when generated or put into storage to serve load, and 87.3% are sold through the ISONE Real-Time market as excess generation when the storage is at full capacity.

Potential issues to address or consider through this strategy include:

- Availability of enough land
- Availability of Solar Panels
- Availability of Battery Storage
- Alternative types of Storage
- Reliability criteria
- System upgrades on the distribution system

- Upgrades to the transmission system to prevent curtailment due to SHEI-like issues being exacerbated for exporting all excess energy out of the VEC system.

4.5.3 Off-Shore Wind and Storage

We analyzed the financially-optimum amount of Off-Shore Wind and Storage needed to serve all of VEC's projected 2030 hourly loads that is not covered by the projected output of its committed resources, with no energy shortfalls in any hour. With these assumptions, 299 MW of off-shore wind and 40 MWh of battery storage was the most financially efficient combination identified, with a 10-year cost of approximately $0.334 Billion, net of sales through the ISO New England Real-Time Energy market of excess generation when the batteries are full.

The hourly output shape of the proxy Off-Shore Wind project is the average of projected unitized shapes for several proposed off-shore wind sites. These unitized shapes are publicly available on the ISO New England Website.

Other assumptions were:

- A PPA price of $80/MWh, which is slightly above the PPA price of the Mayflower project between several utilities in Massachusetts and Mayflower Wind, LLC, the developer;
- $500,000/installed MWh of battery storage;
- 10-year financial analysis;
- No battery degradation;
- No load growth; and
- No load control of EVs or Cold-Climate Heat Pumps.

The high capacity factor of off-shore wind projects leads to the least expensive of the scenarios modeled. However, although this scenario is approximately $1.5 Billion less expensive than the solar option, it has an extremely low level of storage capacity which could lead to reliability concerns.

The hourly plot of the MWh of energy in storage is below:

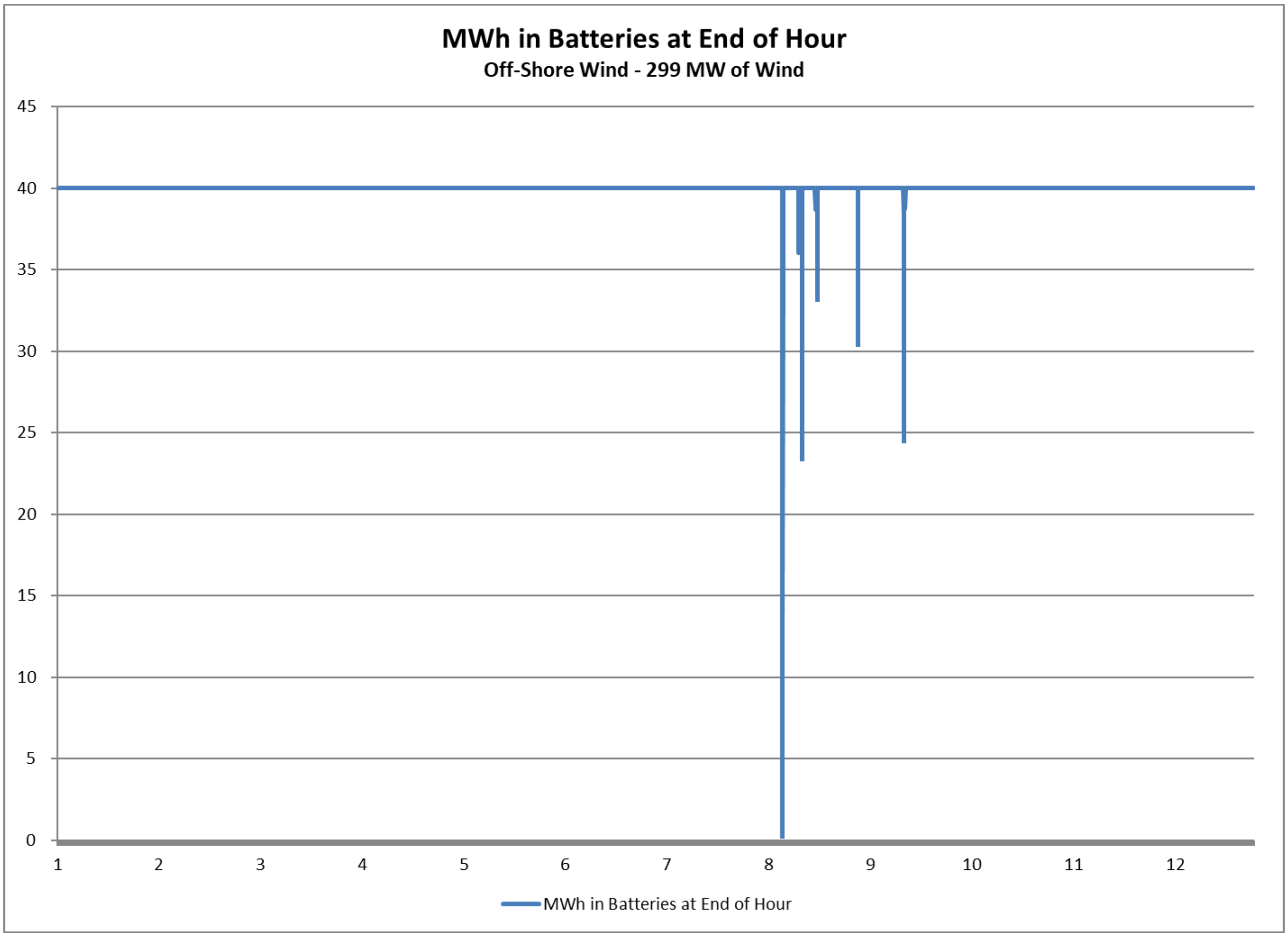

Figure 4.5.3.A – Off-Shore Wind and Storage – MWh in Batteries at End of Hour

The lack of wind output in August and September dominates this scenario. The 1,234,278 MWh of new off-shore wind resources are purchased in a year, of which 21.6% are either consumed when generated or put into storage to serve load, and 78.4% are sold through the ISONE Real-Time market as excess generation when the storage is at full capacity.

Potential issues to address or consider through this strategy include:

- This is an average shape. At some point the wind might stop, some hours the wind will be greater than projected here.
- Vermont does not have any borders that are ocean shoreline. To date, off-shore wind power purchase agreements in New England have been through solicitation conducted by states bordering the ocean. In addition, off-shore wind projects are considerably larger than VEC or Vermont would likely be able to support on our own. Vermont may need to consider working with other states to conduct joint solicitations/negotiations if it believes off-shore wind should play a part in the eventual portfolio.
- Reliability criteria
- Transmission costs associated with delivering energy from off-shore resources. The first several off-shore wind projects plan to interconnect at points very close to where retired generators interconnected, meaning there is sufficient transmission capacity to handle the generation. Thus, system upgrades will be minimal. As this existing capacity gets used up, upgrades may be necessary to be able to absorb the generation without curtailment. How these upgrades will be paid for, whether by all load-serving entities in New England

through Regional Network Service charges or by the developers and eventually the off-takers, has yet to be determined.

4.5.4 On-Shore Wind and Storage

We analyzed the financially-optimum amount of On-Shore Wind and Storage needed to serve all of VEC's projected 2030 hourly loads, that is not covered by the projected output of its committed resources, with no energy shortfalls in any hour. This resulted in an optimized combination of 8,280 MW of on-shore wind and 125 MWh of battery storage, with a 10-year cost of approximately $0.357 Billion, net of sales through the ISO New England Real-Time Energy market of excess generation when the batteries are full.

The hourly output shape of the proxy On-Shore Wind project is the 2021 average hourly output shape of all wind projects in New England for which ISONE has access to data. These unitized shapes are publicly available on the ISO New England Website.

Other assumptions were:

- A PPA price of $80/MWh, which is equal to the assumption for Off-Shore wind. This was done to show the difference in output between the On-Shore Wind and Off-Shore wind assumptions. In reality the contract will be based on market prices for the various markets in which On-shore wind qualifies;
- $500,000/installed MWh of battery storage;
- 10-year financial analysis;
- No battery degradation;
- No load growth; and
- No load control of EVs or Cold-Climate Heat Pumps.

The hourly plot of the MWh of energy in storage is below:

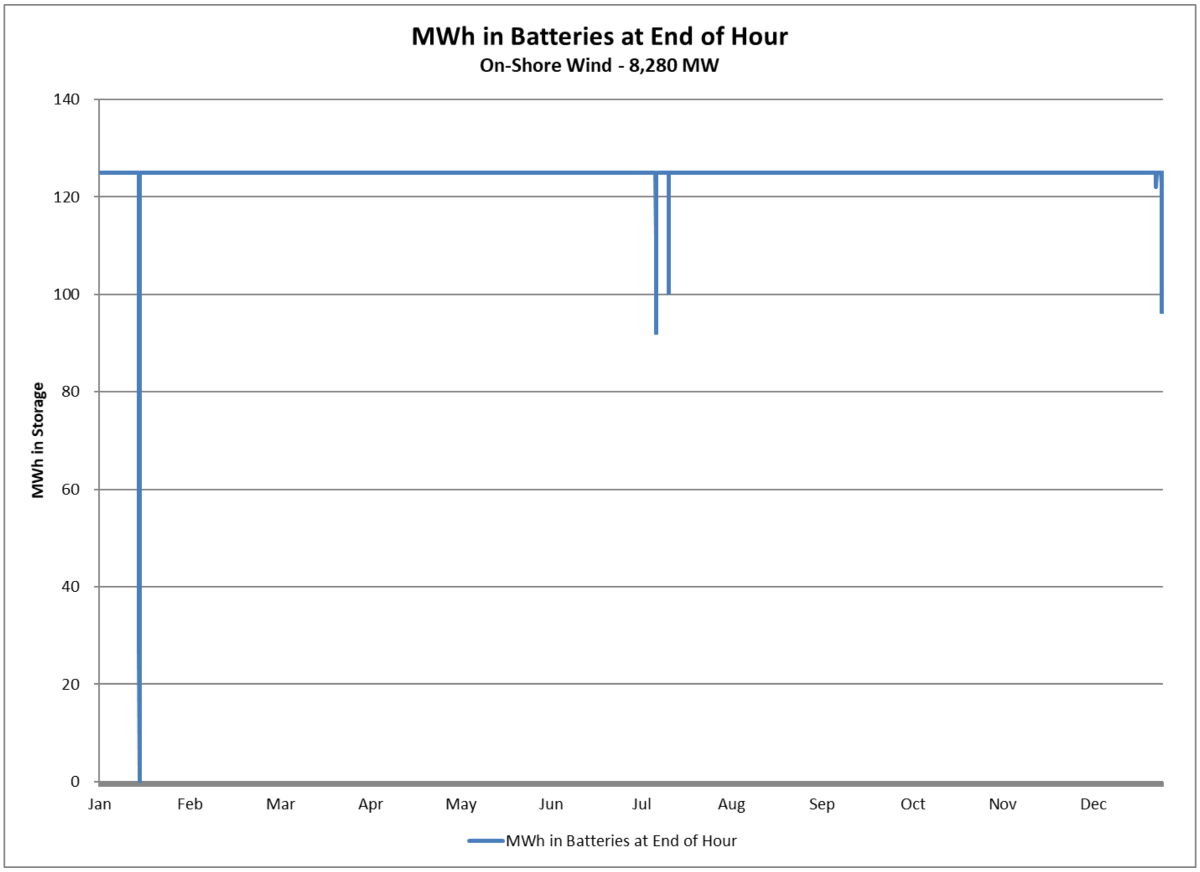

Figure 4.5.4.A – On-Shore Wind and Storage – MWh in Batteries at End of Hour

The lack of wind output in January dominates this scenario, with some concerns in July and December.

The capacity factor of on-shore wind is higher than that of solar, but lower than that for off-shore wind projects. This leads to the second-least expensive of the scenarios modeled. However, as in the off-shore wind scenario it also has an extremely low level of storage capacity which could lead to reliability concerns.

This scenario also results in an alarmingly high reliance on sales of excess generation through the ISONE Real-time energy market in hours when the storage facilities are already full. This is the result of the need to install enough MW of wind to overcome the light winds in January. We assumed that 24,144,071 MWh of new on-shore wind resources are purchased in a year, of which 1.1% are either consumed when generated or put into storage to serve load, and 98.9% are sold through the ISONE Real-Time market as excess generation when the storage is at full capacity.

Potential issues to address or consider through this strategy include:

- This is an average shape from resources throughout New England. At some point the wind might stop, some hours the wind will be greater than projected here.
- Siting this amount of wind in New England will be quite difficult, if not impossible.
- It is uncertain what Reliability criteria will be required given the intermittency of wind.
- Upgrades may be needed to the transmission system to prevent curtailment due to SHEI-like issues being created throughout New England.

4.5.5 Biomass and Storage

We analyzed the financially-optimum amount of Biomass and Storage needed to serve all of VEC's projected 2030 hourly loads, that is not covered by the projected output of its committed resources, with no energy shortfalls in any hour. This resulted in 85 MW of Biomass and 22 MWh of battery storage, with a 10-year cost of approximately $0.463 Billion, net of sales, through the ISO New England Real-Time Energy market, of excess generation when the batteries are full. At a PPA price of $80/MWh the optimum combination of MW of Biomass and MWh of storage remains the same, but the cost decreases to approximately $0.331 Billion, which would make it the least expensive scenario.

This analysis assumes 3 equal sized Biomass facilities to optimize output at times of scheduled and unscheduled outages. The hourly output shape was initially based on the hourly output of Ryegate, then adjusted to account for different outage schedules by allocating the full Ryegate outages over 3 facilities at different times, with one project having the same outage schedule as Ryegate, another having outage one week earlier and the third having outages one week later.

Other assumptions were:

- A PPA price of $100/MWh, which is a proxy for a new biomass facility;
- $500,000/installed MWh of battery storage;
- 10-year financial analysis;
- No battery degradation;
- No load growth; and
- No load control of EVs or Cold-Climate Heat Pumps.

The diversity of dividing the 85 MW across 3 equal-sized projects instead of one facility with the output shape that matches that of Ryegate in 2021 is significant. The optimum combination of one Biomass facility is 79 MW of Biomass and 4,567 MWh of storage, for a cost of $2.723 Billion over 10-years.

The hourly plot of the MWh of energy in storage for the 85 MW of Biomass and 22 MWh of Storage scenario is below:

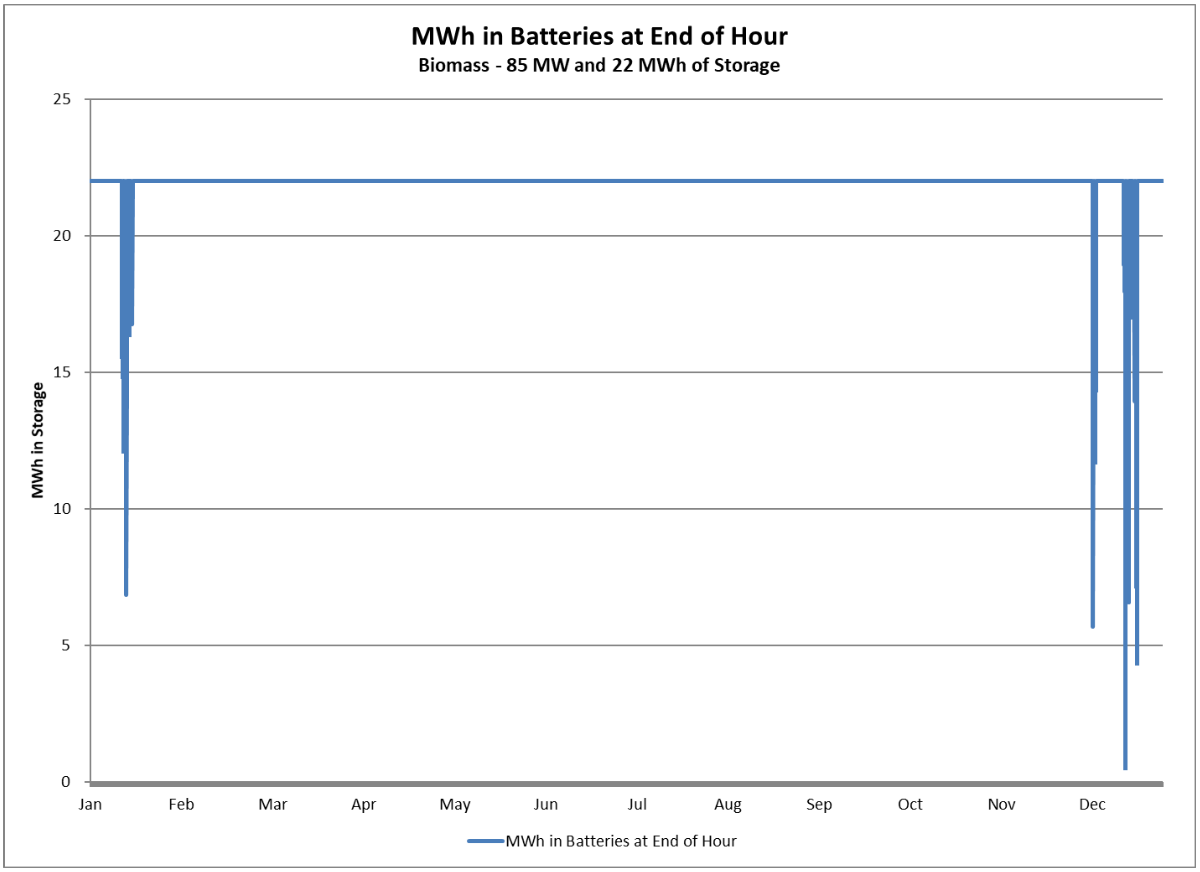

Figure 4.5.5.A - Biomass and Storage – MWh in Batteries at End of Hour

The capacity factor of Biomass is by far the highest of all of the technologies analyzed. This leads to the second-most expensive scenario, but much closer to the two lowest cost scenarios of off-shore wind and on-shore wind than to the most expensive scenario of solar. However, as in both wind scenarios it also has an extremely low level of storage capacity which could lead to reliability concerns.

This scenario is the least reliant on sales of excess generation through the ISONE Real-time energy market in hours when the storage facilities are already full. We assumed that 659,575 MWh of new Biomass ENERGY are purchased in a year, of which 40.4% are either consumed when generated or put into storage to serve load, and 59.6% are sold through the ISONE Real-Time market as excess generation when the storage is at full capacity.

Potential issues to address or consider through this strategy include:

- Is there enough sustainably harvested wood or another biomass supply in or around Vermont?
- Can the facilities by located to not require upgrades to the transmission system to prevent curtailment due to SHEI-like issues?

4.5.6 Metric Comparison Summary

Table 4.5.6.A below with key metrics for each of the four scenarios.

	Solar	On-Shore	Off-Shore	Biomass
Total Load	558,863	558,863	558,863	558,863
Total Resources	2,543,826	24,436,411	1,526,617	951,914
Hrs. Drawn from Storage to Serve Load	4,796	14	16	54

Hrs. Purchase from ISO to Serve Load	0	0	0	0
Hrs. Charge Battery w/Excess Resources	1,214	7	11	54
Hrs. Charge Battery w/Grid Power	0	0	0	0
MWh injected into Storage from Excess Resources	190,633	213	95	204
MWh injected into Storage From ISO	0	0	0	0
MWh Drawn from Battery to Serve Load	191,297	213	95	204
Days Drawn from Battery to Serve Load	0	0	0	0
Days Injected into Battery	0	0	0	0
MWh Sold to ISO from Excess Resources	1,964,446	23,877,524	967,744	393,028
MWh purchased from ISO to Serve Load	0	0	0	0
Hours at Maximum Storage	3,089	8,744	8,741	8,677
Hours at Minimum Storage	0	0	0	0
Revenue from Sales to ISO	($119,150,615)	($1,906,171,626)	($71,518,195)	($24,921,251)
Cost of Purchase additional MWh from ISO	$0	$0	$0	$0
% of Load Served by Purchases from ISO	0.0%	0.0%	0.0%	0.0%
MWH of New Resources Purchased	2,251,487	24,144,071	1,234,278	659,575
MW of New Resources	1570	8280	299	85
MWH of Battery	2445	125	40	22
Net Cost	$1,834,394,123	$357,488,435	$333,579,671	$463,168,653

Table 4.5.6.A – Metric Comparison between 100% Renewable on an Hourly Basis Scenarios

4.5.7 Complementary Nature of Various Renewable Options

The main lesson from the directional and intentionally limited analysis above is that, 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 resources that are complementary in nature with respect to when they generate electricity. To examine how complementary the resources are 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.

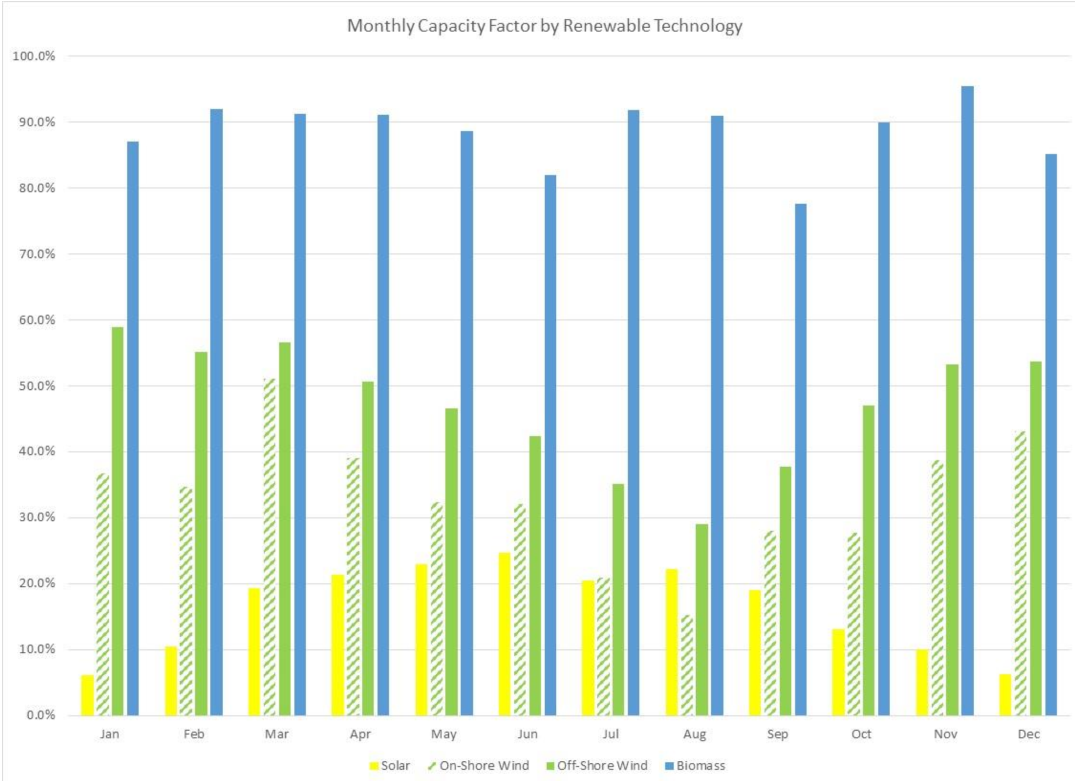

Figure 4.5.7.A – Monthly Capacity Factors by Renewable Technology

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.

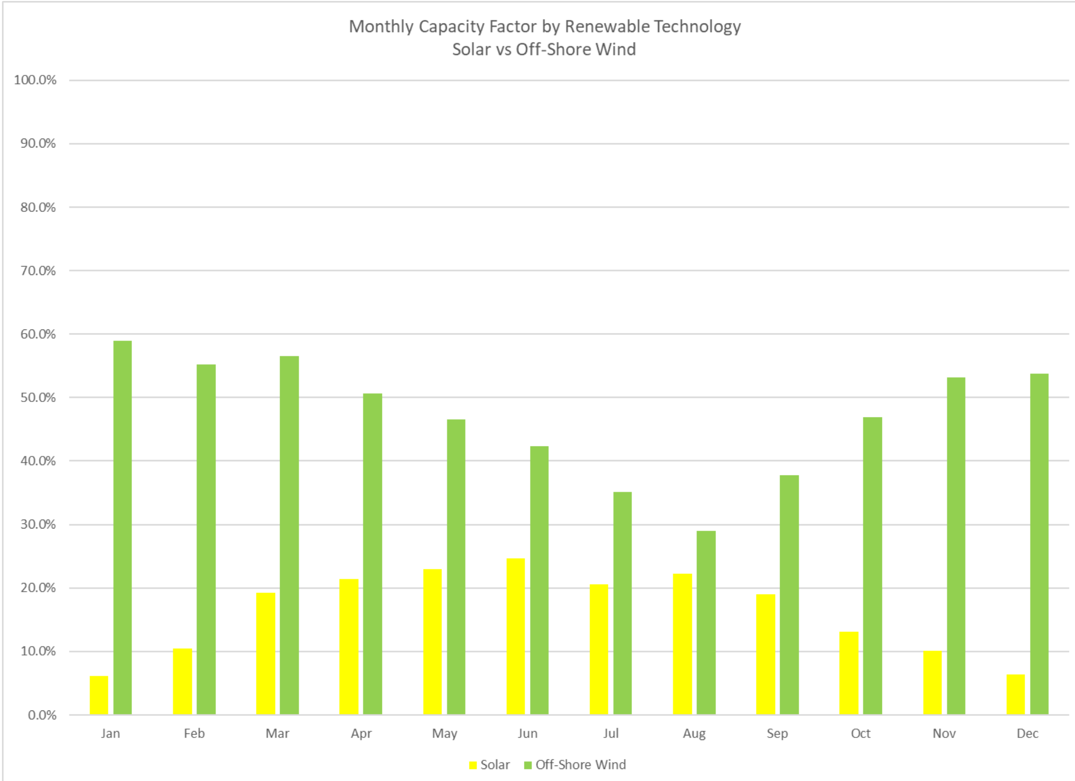

Figure 4.5.7.B – Solar and Off-Shore Wind Monthly Capacity Factor Comparison

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.

Figure 4.5.7.C_ below stacks the capacity factors on top of one another to provide an indication of the capacity factor of equal MW of resources.

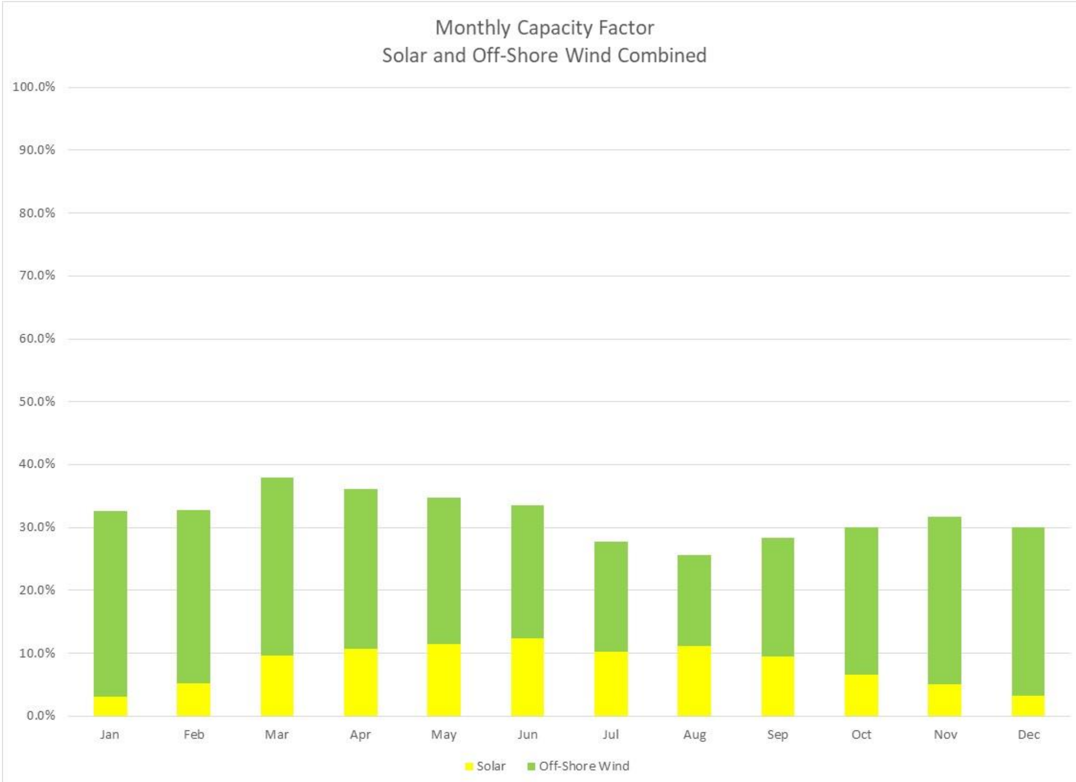

Figure 4.5.7.C – Solar and Off-Shore Wind Monthly Capacity Factor Stacked Comparison

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

Figure 4.5.7.D shows the monthly capacity factors for Solar and On-shore Wind.

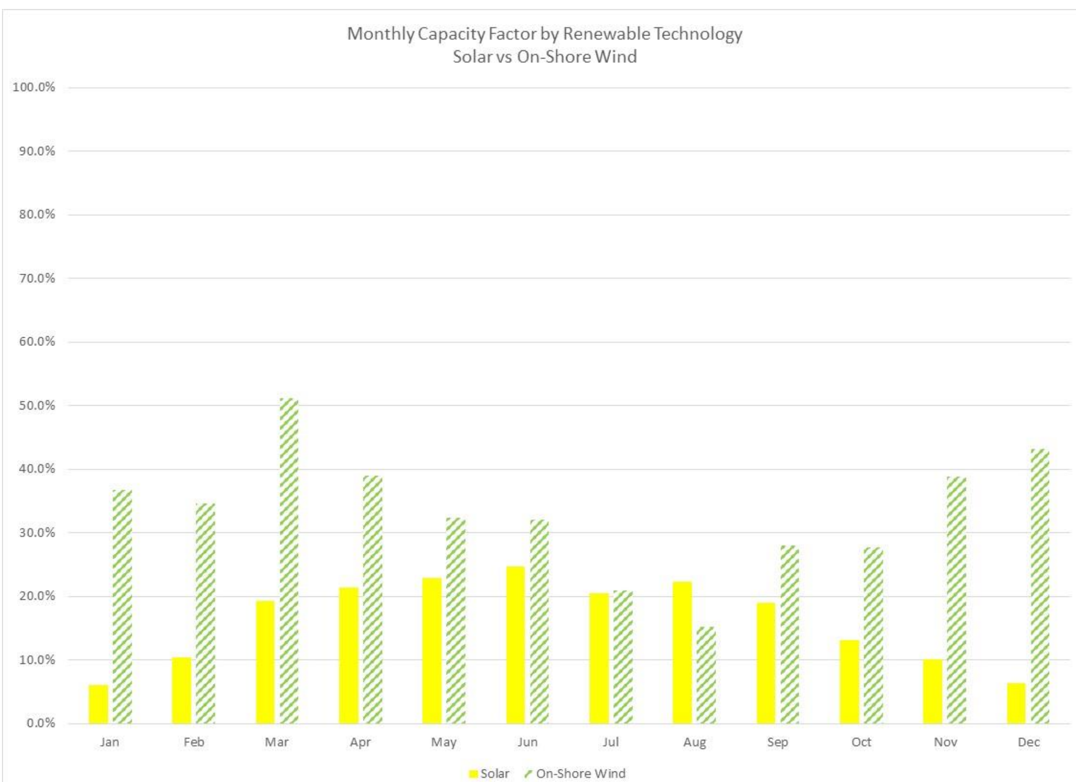

Figure 4.5.7.D – Solar and On-Shore Wind Monthly Capacity Factor Comparison

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.

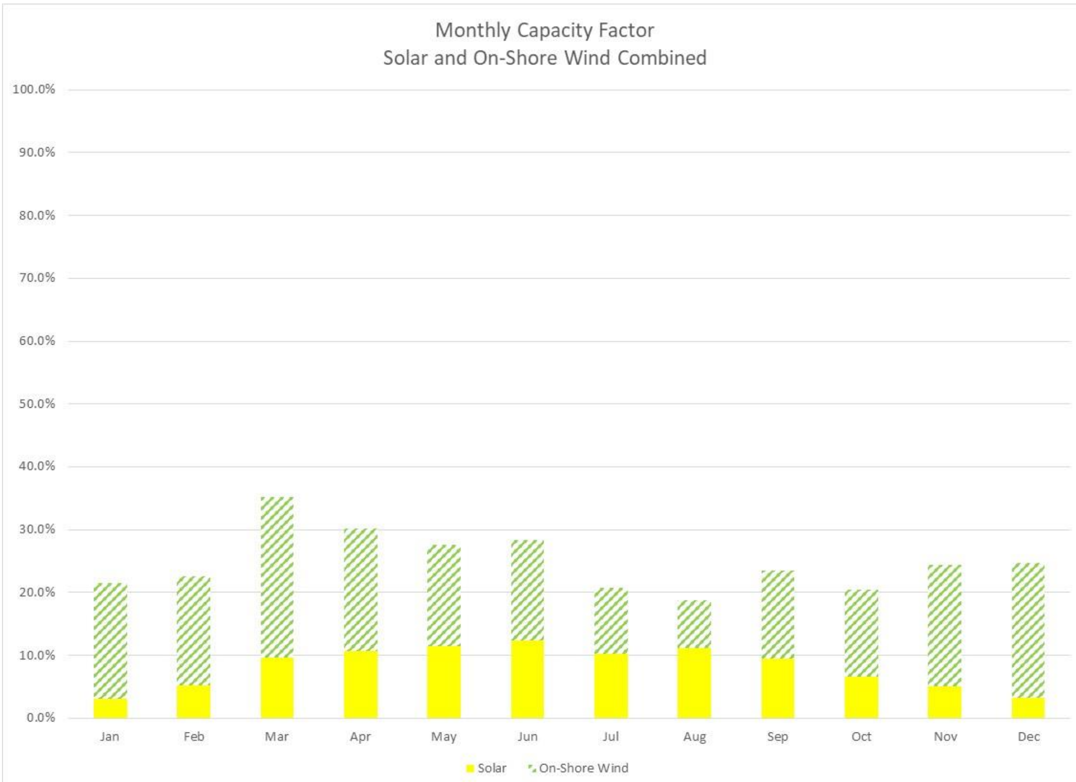

Figure 4.5.7.E - Solar and On-Shore Wind Monthly Capacity Factor Stacked Comparison

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.

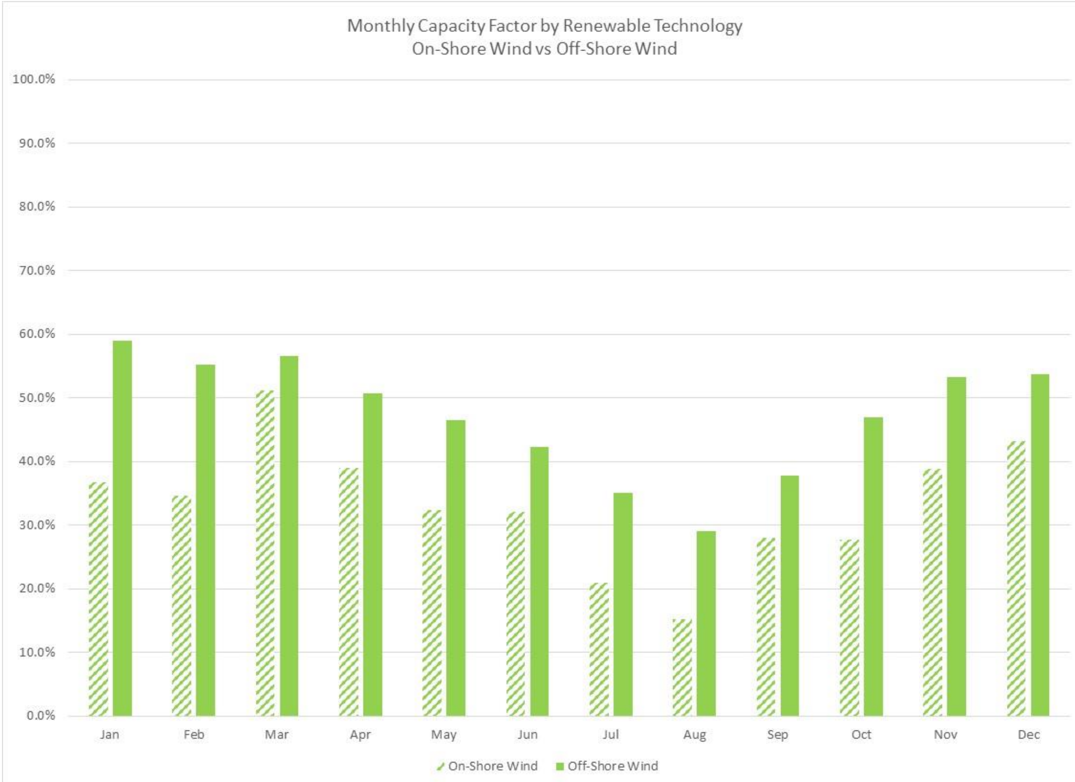

Figure 4.5.7.E – On-Shore and Off-Shore Wind Monthly Capacity Factor Comparison

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:

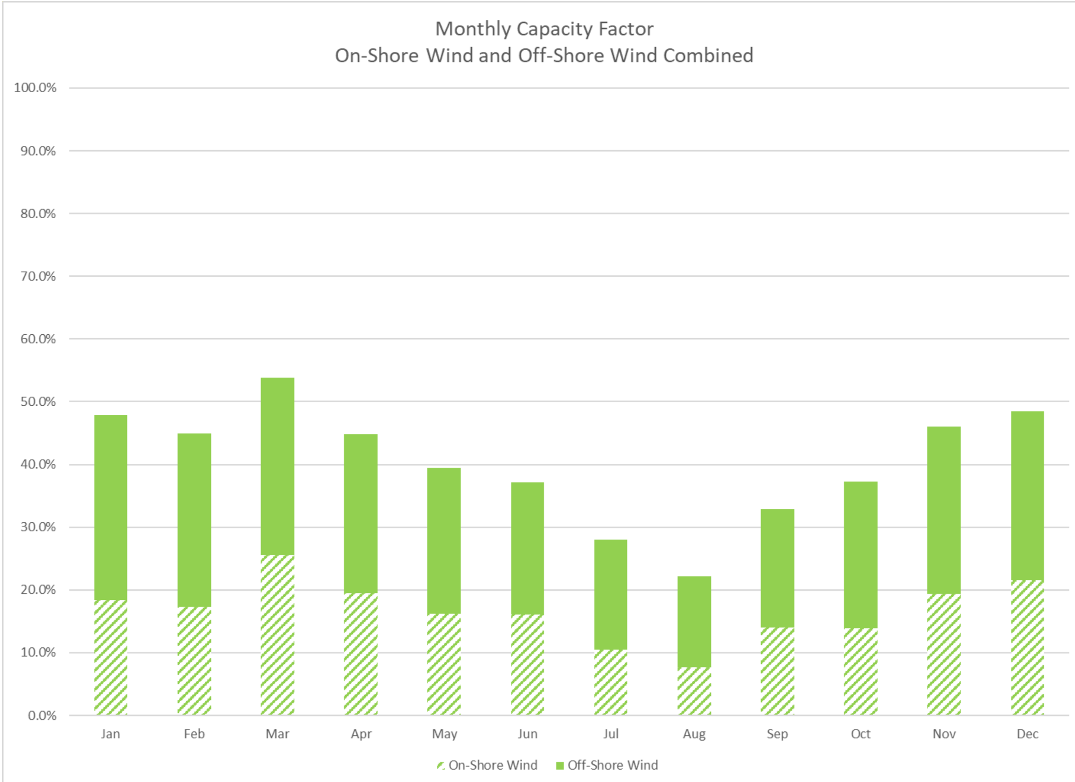

Figure 4.5.7.F - Figure 4.5.7.E – On-Shore and Off-Shore Wind Monthly Capacity Factor Stacked Comparison

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.

COMPLEMENTARY RESOURCES 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 T.

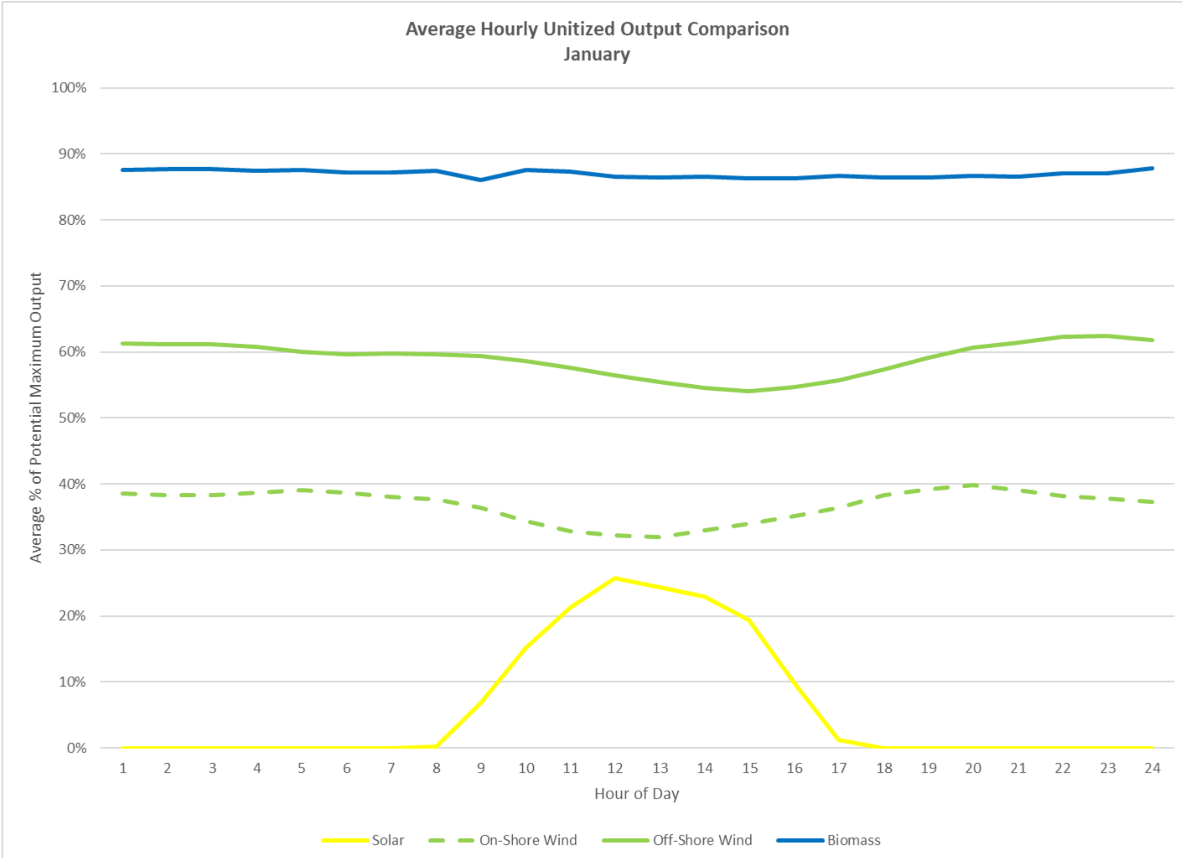

Figure 4.5.7.G – Average Hourly Unitized Output Comparison - January

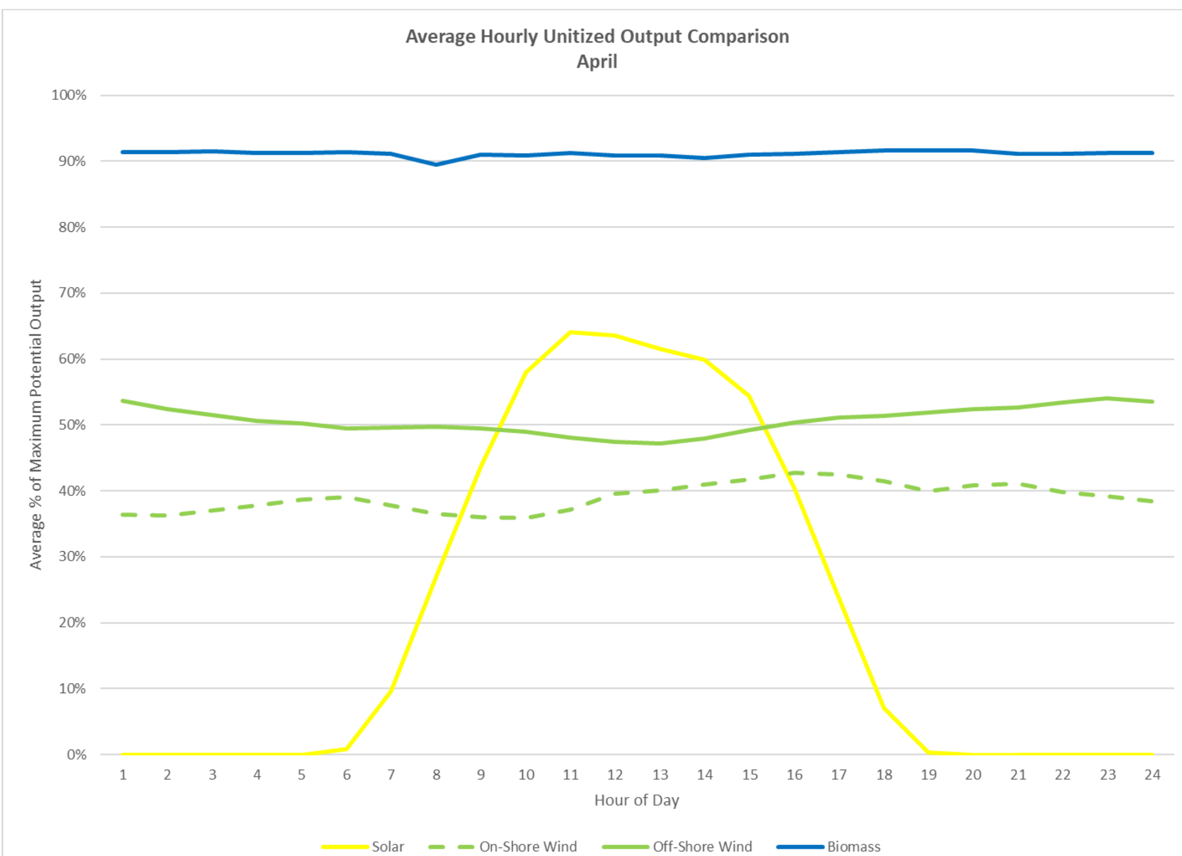

Figure 4.5.7.H – Average Hourly Unitized Output Comparison - April

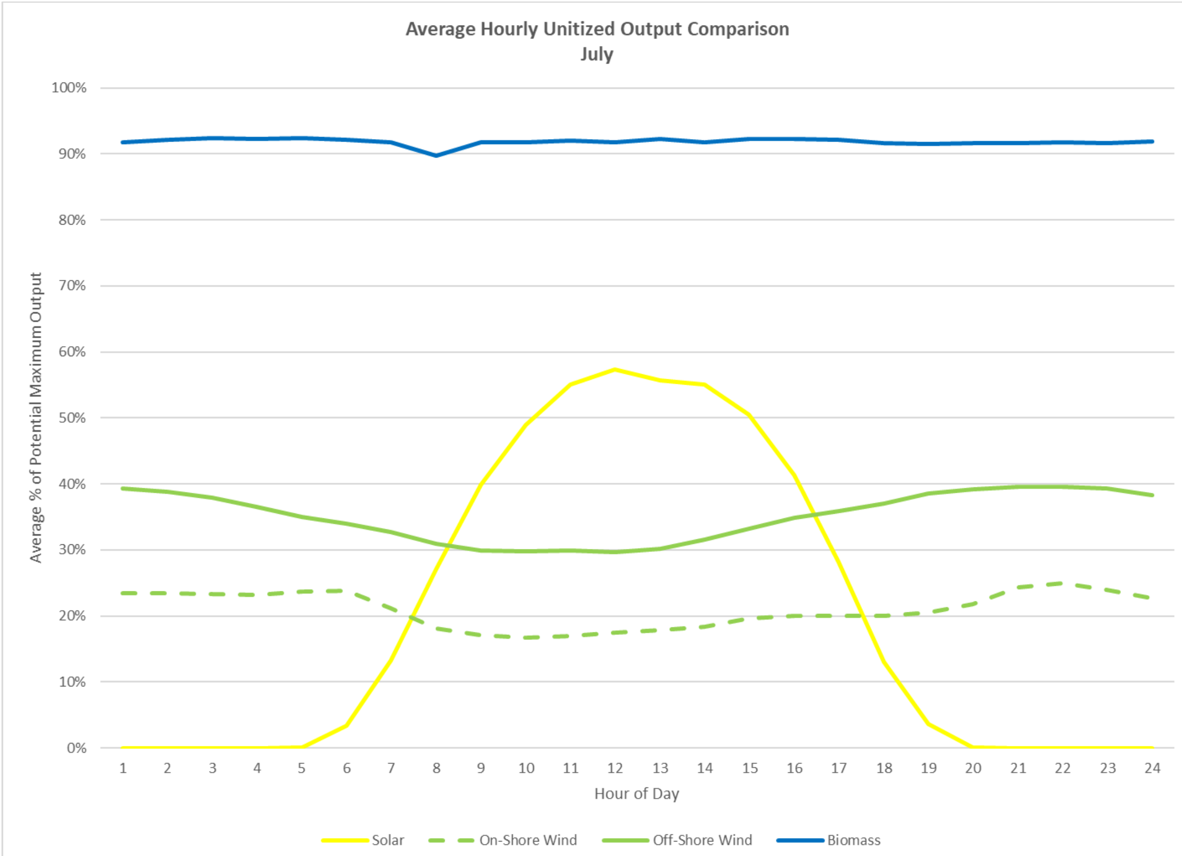

Figure 4.5.7.I – Average Hourly Unitized Output Comparison - July

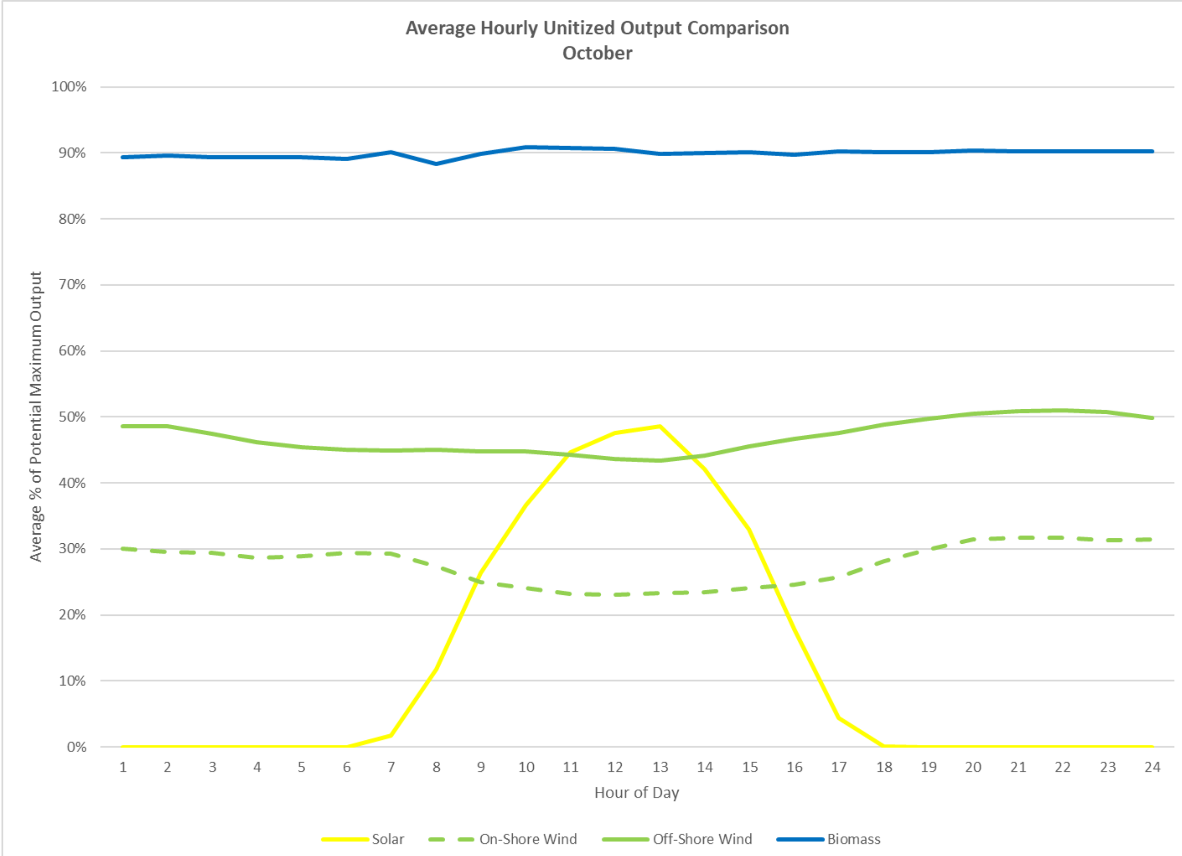

Figure 4.5.7.J– Average Hourly Unitized Output Comparison - October

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.

4.5.8 Takeaways from the 100% Renewable on an Hourly Basis 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 a 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.

4.5.9 California Analysis

This same challenge we have simply modeled is being looked at in other parts of the country as well, with some similar takeaways about the necessity of resource diversity. An example is the California analysis below.

A new technical study from GridLab and Telos Energy shows that California can build and manage an 85% clean electricity system by 2030. The study showed that California needs a mixture of resources to meet its energy needs and no one solution will meet all the requirements.

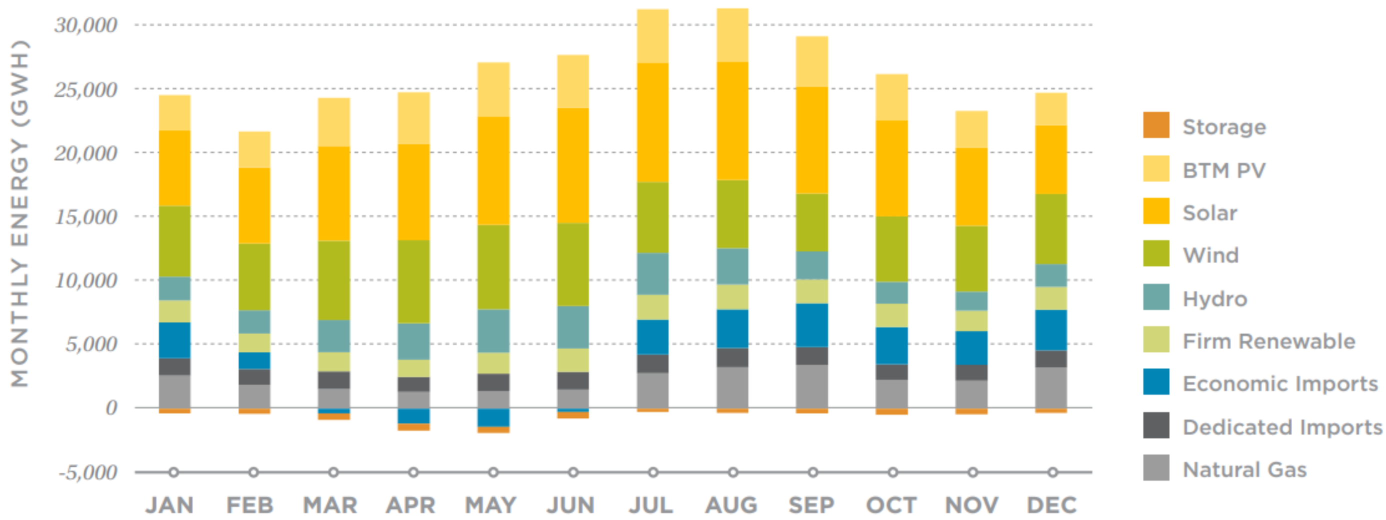

Figure 4.5.9.A California Monthly Net Generation by Resource Type for the Base Case portfolio

The report states "*Another observation is that the winter periods show potential for multi-day low wind and solar events. Historically, while summer months have been associated with increased resource adequacy risk, in the future, winter months may pose an increased reliability challenge as the power system becomes increasingly reliant on* *variable renewable energy and energy limited resources*

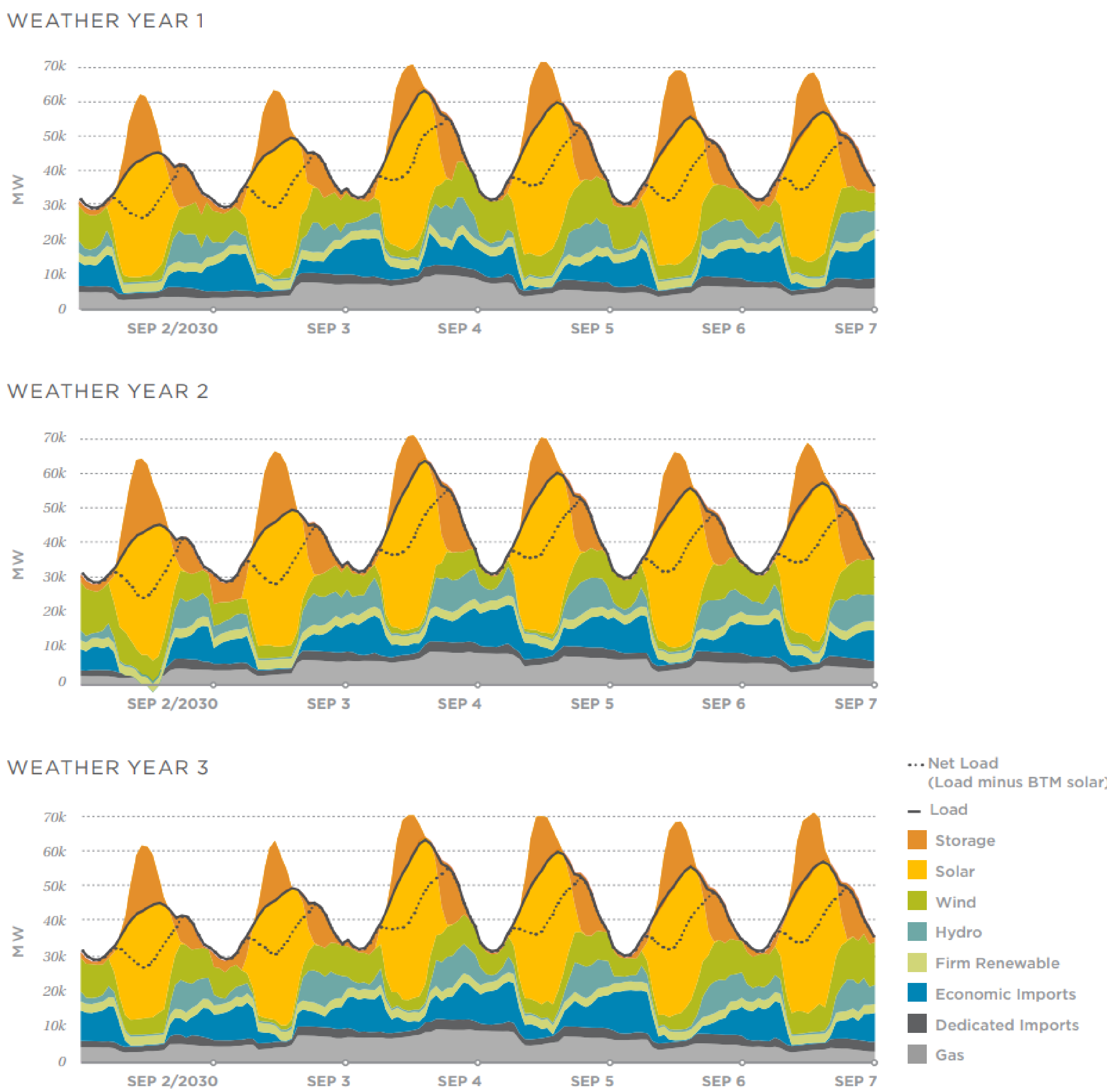

Figure 4.5.9.B Chronological Hourly Dispatch Across three Winter Peak Load Days and Three Weather Years

4.6 ISONE and System Peaks

4.6.1 ISO New England and New England Power Pool Regional Transmission Costs

As a member of the New England Power Pool (NEPOOL) and a participant in ISONE, VEC is responsible for paying for its share of the costs of the bulk transmission system in New England.

Through separate tariffs, portions of ISONE and NEPOOL costs are allocated to VEC and all other load serving entities in Vermont monthly based on their respective share of load on New England at the time of the Vermont peak for the month multiplied by a $/kw-month rate established by NEPOOL for each June – May period. For example, in January 2019, Vermont peaked on January 21st in hour ending 1800 (or hour beginning 5:00:01 PM and ending at 6:00:00 PM). VEC's load in that hour was 60.426 MW, while ISO OATT Schedule 1, NEPOOL OATT Schedule 1 and the NEPOOL OATT Schedule 9 rates were a combined $9.506516/kW-month for a resulting bill of $574,440 (60.426 MW x $9.506516/kW-month). In 2019 VEC has budgeted over $6.4 Million combined for ISONE Schedule 1 and NEPOOL OATT Schedule 9 expenses related to its load in the one-hour Vermont peaks each month.

To project monthly peak-related expenses VEC must project both its load on New England at the time of the VT peak each month and the ISO New England Schedule 1 and NEPOOL OATT Schedules 1 and 9 tariffs.

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

Daymark prepared Reference, Lower Limit and Upper Limit case forecasts of monthly peaks from January 2019 – December 2038 based on historic data. This historic data did not include the impact of new net metering or EVT installations in the territory after 2017, nor did it include the impact of peak shaving through energy storage to be installed and controlled by VEC on its system. The monthly load forecasts at the time of the Vermont monthly peak was developed through a process that included:

1. VEC's forecasted monthly peak loads from the Daymark load forecast;
2. Adjusting the monthly peak by a coincidence factor to consider that VEC's peak does not always occur in the same hour as the Vermont peak. The coincidence factor is 1.000 for all months but June – September; the coincidence factor for June – September is 0.95 through 2021, then 1.000 thereafter to acknowledge that behind-the-meter solar is pushing the Vermont peak later in the day, after the sun sets, which is when VEC now peaks in the summer;
3. This adjusted peak is then reduced by 1.000 MW to account for peak shaving due to VEC's Energy Storage Services Agreement with Viridity and then increased by a 4% loss factor to account for the load being on the low side of VEC's Hinesburg substation;
4. The peak is further reduced by EVT's projection of the impact on VEC's peak of energy efficiency installed on VEC's system from 2019 – 2038, also increased by a 6.7% loss factor to account for losses from the New England system to the members' meters.

As with the energy forecast, VEC developed its own peak load forecast based on the Daymark peak load forecast in the 2019 IRP. This was done by multiplying the ratio of monthly-peak-load-to-monthly-energy for the Reference Forecast and High Forecast cases in the IRP by the monthly energy forecast for each of the three energy load forecast scenarios in the 2022 IRP.

Figure 4.6.1.A 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:

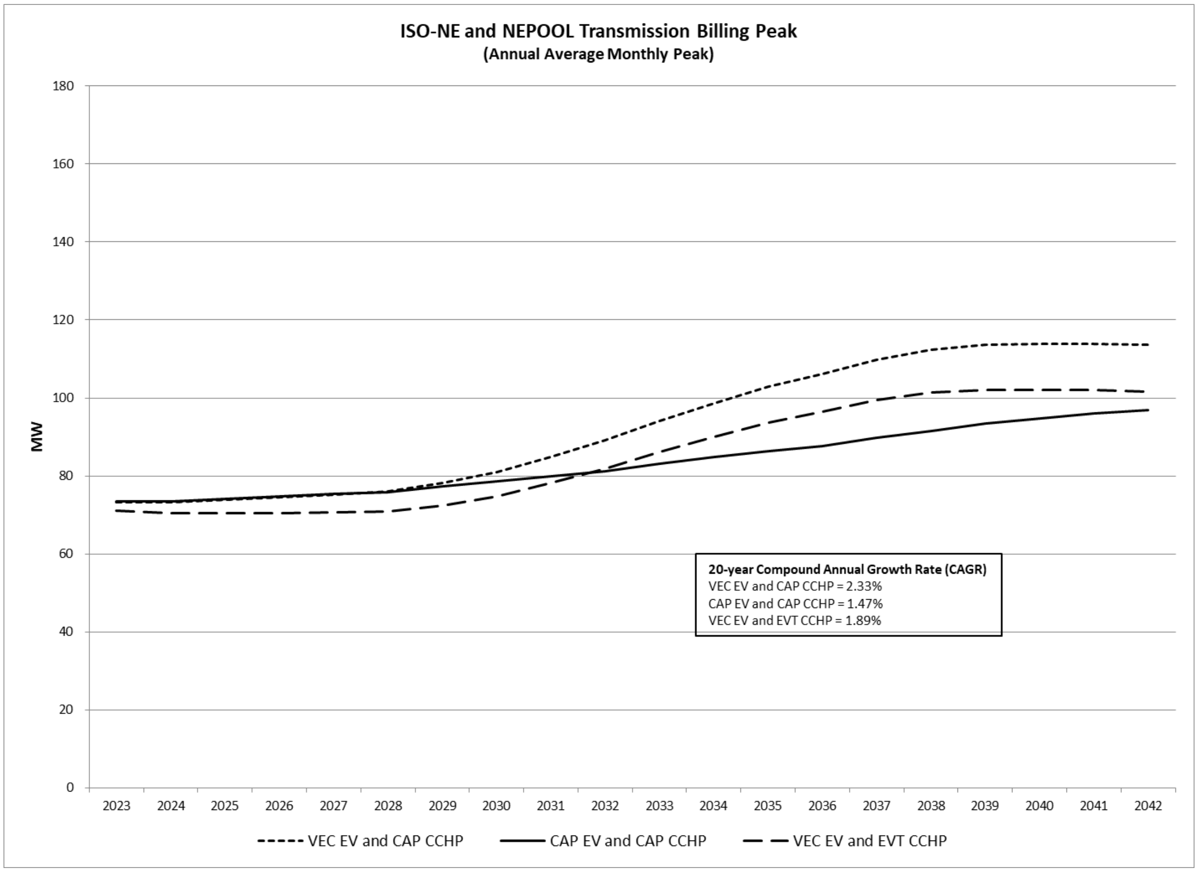

Figure 4.6.1.A – ISONE and NEPOOL Transmission Billing Peak

Under the CAP EV and CAP CCHP forecast, the average monthly peak demand for transmission billing purposes is projected to increase from approximately 73.5 MW in 2023, to approximately 97.0 MW by 2042, implying a CAGR of 1.47%. The CAGR for 2027-2038 of 1.80% is higher than that for 2023-2027 (0.60%) and 2038-2042 (1.43%) because the adoption rates for EVs and CCHPs are higher from 2027-2038 than the other periods.

Under the VEC EV and CAP CCHP forecast the average monthly peak demand for transmission billing purposes is projected to increase from approximately 73.3 MW in 2023 to 113.6 MW, with a CAGR of 1.42%. However, the CAGR is higher from 2027-2038 (3.343.71%) than from 2023-2027 (0.66%) and 2038-2024 (0.29%) due to the projected steep adoption of EVs in that time period.

The average monthly peak demand for transmission billing purposes is projected to grow from 71.2 MW to 101.7 MW in the VEC EV and EVT CCHP forecast. The 2023-2042 CAGR is 1.89%. As in the other two forecast scenarios, the CAGR for 2027-2038 of 3.34% is higher than the 2023-2027 CAGR of -0.21% and the 2038-2024 CAGR of 0.08% because of the projected adoption rate of EVs in that period. The relatively greater impact of efficiency installations than that of EV and CCHP adoption causes the CAGR in the beginning of the study period to be negative.

The plots are based on the following data:

Year	VEC EV and CAP CCHP	CAP EV and CAP CCHP	VEC EV and EVT CCHP

	(MW)	(MW)	(MW)
2023	73.253	73.530	71.182
2024	73.260	73.566	70.529
2025	73.906	74.186	70.499
2026	74.458	74.673	70.406
2027	75.197	75.303	70.591
2028	76.065	75.870	70.955
2029	78.236	77.310	72.504
2030	80.980	78.578	74.740
2031	84.889	79.964	78.125
2032	89.123	81.147	81.797
2033	94.134	83.111	86.140
2034	98.668	84.788	90.058
2035	102.869	86.448	93.725
2036	106.126	87.689	96.523
2037	109.733	89.731	99.464
2038	112.271	91.615	101.360
2039	113.558	93.379	102.108
2040	113.895	94.844	102.119
2041	113.829	95.990	101.960
2042	113.567	96.978	101.674
2023-2042 CAGR	2.33%	1.47%	1.89%
2023-2027 CAGR	0.66%	0.60%	-0.21%
2027-2038 CAGR	3.71%	1.80%	3.34%
2038-2042 CAGR	0.29%	1.43%	0.08%

Table 4.6.1.B – Projected Average Monthly Peak Demand 2023-2042

Forecasting ISONE Schedule 1 and NEPOOL OATT Schedules 1 and 9 Rates

Table 4.6.1.C shows the projected rates for the ISONE and NEPOOL rates that are applied to VEC's load at the one hour that Vermont peaks each month; these are the biggest drivers of VEC's transmission costs.

Year	ISO Tariff Schedule 1 ($/kW-month)	ISO Tariff Schedule 5 ($/kW-month)	NEPOOL OATT Schedule 1 ($/kW-month)	NEPOOL OATT Schedule 9 ($/kW-month)	Total ($/kW-month)
Jan-19	$0.172850	$0.007110	$0.132330	$9.202369	$9.51466
Jan-20	$0.176260	$0.008820	$0.132784	$9.328223	$9.64609
Jan-21	$0.193830	$0.006260	$0.145442	$10.771818	$11.11735
Jan-22	$0.191750	$0.007360	$0.155715	$11.898269	$12.25309
Jan-23	$0.198696	$0.007669	$0.164507	$12.981035	$13.35191
Jan-24	$0.205894	$0.007991	$0.173796	$14.162334	$14.55002
Jan-25	$0.213353	$0.008327	$0.183609	$15.451134	$15.85642
Jan-26	$0.221082	$0.008676	$0.193976	$16.857217	$17.28095
Jan-27	$0.227715	$0.008937	$0.199796	$17.362933	$17.79938
Jan-28	$0.234546	$0.009205	$0.205789	$17.883821	$18.33336
Jan-29	$0.241583	$0.009481	$0.211963	$18.420336	$18.88336
Jan-30	$0.248830	$0.009765	$0.218322	$18.972946	$19.44986

Jan-31	$0.256295	$0.010058	$0.224872	$19.542134	$20.03336
Jan-32	$0.263984	$0.010360	$0.231618	$20.128398	$20.63436
Jan-33	$0.271903	$0.010671	$0.238566	$20.732250	$21.25339
Jan-34	$0.280060	$0.010991	$0.245723	$21.354218	$21.89099
Jan-35	$0.288462	$0.011321	$0.253095	$21.994844	$22.54772
Jan-36	$0.297116	$0.011660	$0.260688	$22.654689	$23.22415
Jan-37	$0.306030	$0.012010	$0.268508	$23.334330	$23.92088
Jan-38	$0.315211	$0.012370	$0.276564	$24.034360	$24.63850
Jan-39	$0.324667	$0.012741	$0.284861	$24.755391	$25.37766
Jan-40	$0.334407	$0.013124	$0.293406	$25.498053	$26.13899
Jan-41	$0.344439	$0.013517	$0.302209	$26.262994	$26.92316
Jan-42	$0.354772	$0.013923	$0.311275	$27.050884	$27.73085

Table 4.6.1.C – Projected ISONE and NEPOOL OATT Tariff Rates

There is no market through which the tariff rates are set as in the Energy and Forward Capacity markets. The rates are set according to FERC approved rate making methodologies and are based on actual costs plus an approved rate of return.

Rates through January 2022 are actuals for all tariff rates.

Projected rates for January 2022 – December 2026 are based on January 2022 actual rates escalated at the average annual increase from January 2019 – January 202, which were approximately 3.62% or ISO Tariff Schedule 1, 4.20% for ISO Tariff Schedule 5, 5.65% for NEPOOL OATT Schedule 1, and 9.10% for NEPOOL OATT Schedule 9, for a total weighted average of 8.95%.

Rates for January 2027 – December 2042 are rates from the previous year escalated at 3% per year for all tariff schedules.

The rates and peak projections above result in the total cost projections in Figure 4.6.1.D below:

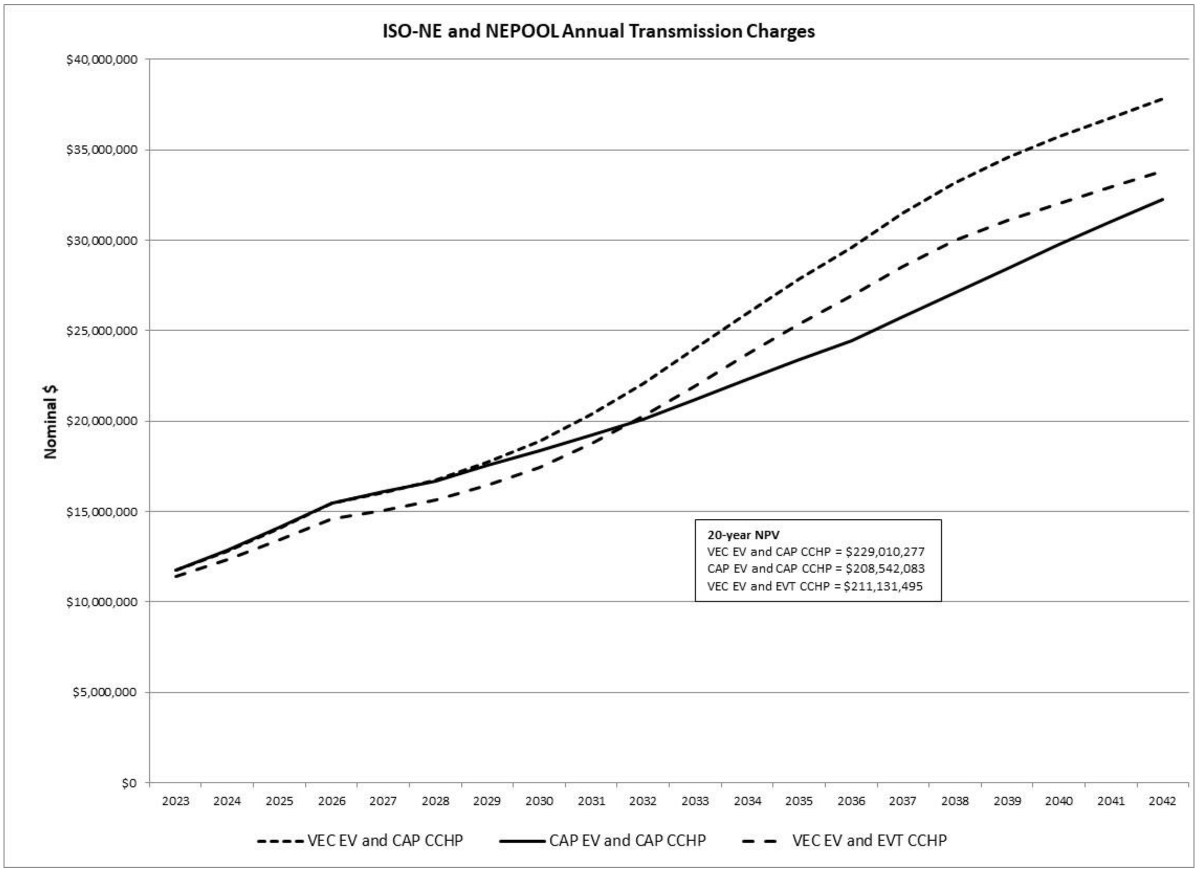

Figure 4.6.1.D – ISONE Schedule 1, NEPOOL OATT and VELCO Transmission Costs

Because there is no market for these tariffs, there is no way to hedge costs. However, costs can be managed by reducing load at the time of the Vermont peak. In addition, if VEC does not reduce its load at the time of the Vermont monthly peaks and if other utilities in Vermont reduce their load, there will be less load to cover expenses over, thus increasing the ISONE and NEPOOL OATT rates and increasing VEC's charges. The same is true if LSEs served by other transmission owners in New England (for example, Eversource or National Grid) reduce their load at the time of their respective transmission owner's monthly peak, because ISONE and NEPOOL will have fewer MW to allocate costs over, increasing the rate charged to all MW still on the system.

Add discussion about the analysis to determine how many MW of storage can be added before our current strategy for batteries is obsolete.

Forward Capacity Market

Through the Forward Capacity Market (FCM), ISONE purchases the right to call on capacity from various generation and demand resources for each month of a commitment period. A commitment period is a 12-month period beginning June 1 and extending through May 31 of the following year. The amount of capacity purchased by ISONE is based on predetermined reliability criteria.

The Installed Capability Requirement for each commitment period is set by ISO New England based on reliability criteria prior to the Forward Capacity Auction (which is held approximately 3 years and 4 months prior to the commitment period) then adjusted several times during annual and monthly reconfiguration auctions as more data regarding loads and unit performance become available. As a result, the monthly Installed Capability Requirement can change from month-to-month, but the change is relatively immaterial.

The total amount of money ISONE pays for capacity monthly is set primarily through a series of annual and monthly auctions in which capacity resources offer prices designating the lowest price they are willing to be paid to supply capacity.

ISONE pays the capacity resources at the end of each month. ISONE collects money to pay the capacity resources by charging load serving entities (LSE), such as VEC, their proportionate share of the monthly capacity costs it incurs. An LSE's capacity charge is a function of clearing prices in the various auctions, the amount of capacity purchased by ISONE and the LSE's load at the time of the annual peak in New England.

VEC's Capacity Load Obligation for a commitment period is a function of the Installed Capability Responsibility for New England and VEC's share of load in New England in the one-hour New England peaked in the previous calendar year. For example, VEC's monthly Capacity Load Obligation of 73.139 MW in the current commitment period (June 2022 – May 2023) is a function of the Installed Capability Requirement for New England (34,719 MW in June 2021), VEC's load on New England (53.830 MW) in hour ending 1700 on June 29, 2021 divided by the load in New England in that hour (25,279 MW).

An LSE can hedge its capacity charges by: a) having entitlement to resources that provide capacity to the ISO; or b) paying another market participant to take on a share of its Capacity Load Obligation.

Forward Capacity Market Prices and VEC's Capacity Load Obligation

Capacity is the second largest component of VEC's power supply costs. The ISONE Forward Capacity Market (FCM) is the benchmark for capacity prices in New England and establishes the price, which ISONE must pay to generators for having the installed capacity necessary to assure system reliability under peak conditions. ISONE then allocates the resulting costs to load serving entities to obtain revenues necessary to compensate generators for their installed capacity.

VEC's Capacity Load Obligation for a commitment period is a function of the Installed Capacity Requirement for New England and VEC's share of load in New England in the one-hour New England peaked in the previous calendar year. For example, VEC's monthly Capacity Load Obligation of 75.051 MW in the current commitment period (June 2019 – May 2020) is a function of the Installed Capacity Requirement for New England (35,396 MW in June 2019), VEC's load on New England (52.851 MW) in hour ending 1700 on August 29, 2018 divided by the load in New England in that hour (25,559 MW).

4.6.2 Sustainability Assessment of VEC's Current Utility-Scale Battery Storage Strategy

VEC's current utility-scale battery storage strategy has been to not own the battery, but instead to enter Battery Energy Storage Service (BESS) agreements through which VEC can use a battery for peak shaving purposes for a certain number of hours per year, and no more than 4 hours in a day. VEC provides notice to the developer of its intent to dispatch the battery by 10:00 AM the day before the requested dispatch. At VEC's expense, the developer charges the battery for VEC's use, with 50% of the battery charged in the 2 hours immediately preceding VEC's requested dispatch and 50% in the 2 hours immediately following the dispatch. In all other hours the developer can enter the battery in the ISO New England Regulation market to enhance its revenues.

Table 4.6.2.A below shows the percentage of days each month of 2021 the daily peak load for Vermont occurred in a given hour. For example, in January the daily peak for Vermont occurred in hour ending 1800 in 97%, or 30, days in the month and in hour ending 1900 in 3%, or 1, day of the month. The actual peak hour for the month is highlighted in yellow.

% of Days Peak Occurred in a Given Hour				Peak Hour for the Month							
Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	10%	7%	0%	0%	3%	0%	0%	3%	3%	0%
9	0%	0%	0%	0%	0%	3%	0%	0%	3%	0%	0%	0%
10	0%	0%	0%	3%	0%	0%	0%	0%	0%	0%	0%	3%
11	0%	4%	3%	0%	0%	0%	3%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	0%
13	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
14	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
15	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
16	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
17	0%	0%	0%	0%	3%	0%	3%	0%	0%	0%	0%	0%
18	97%	25%	0%	3%	0%	7%	3%	0%	0%	10%	73%	90%
19	3%	71%	48%	13%	3%	7%	10%	13%	17%	84%	20%	6%
20	0%	0%	39%	57%	10%	27%	29%	65%	80%	3%	0%	0%
21	0%	0%	0%	17%	74%	47%	48%	23%	0%	0%	0%	0%
22	0%	0%	0%	0%	10%	10%	0%	0%	0%	0%	0%	0%
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Figure 4.6.2.A – Percentage of Days Monthly Peak Occurred in a Given Hour

For January and February, dispatching peak shaving resources in a two-hour window starting at 5:00 PM and ending at 7:00 PM would have reduced a utility's load at the time of the Vermont peak each day. The window of hours in which the peak occurs begins to widen in March and through the spring and summer, when a three of four-hour dispatch window would have been required to hit the Vermont peak.

These monthly patterns have been consistent for several years. However, VEC is concerned that as more utilities install batteries and/or other load management devices, the Vermont peaks may become flatter, making calling dispatches a day before more difficult and increasing the risk of recharging batteries in peak hours, thus making VEC's current utility-scale battery strategy as described above more difficult to be cost effective.

One of the questions to be analyzed in this IRP is how many additional MW and MWh of load management devices can be added in Vermont before VEC needs to reassess its utility-scale battery strategy. To do this, VEC has developed a spreadsheet that allows the user to estimate the impact of various quantities of load management or peak shaving devices on the Vermont hourly load shape.

The analysis shows that, under a BESS agreement similar to that for the battery in Hinesburg, an additional 10 MW of load management would cause the peak to change to a day and/or hour of the Vermont system peak in 5 months, and reducing the average output of the battery at the time of the new Vermont peak to 7.57 MW instead of the 10 MW installed. This includes one month (April) where the Vermont load changed in a way to cause VEC's load at the time of the Vermont system peak to increase by approximately 5.7 MW. If 20 MW were added, Vermont load shape would change such that the average output at the time of the Vermont peak is reduced to approximately 6.06 MW, including two months (April and May) in which VEC's load at the time of the Vermont peak increased by approximately 16.8 MW and 10.4 MW respectively.

Table 4.6.2.B below shows the percentage of days each month of 2021 the daily peak load for Vermont occurred in a given hour with 20 MW/80 MWh of additional load management and/or battery storage.

% of Days Peak Occurred in a Given Hour					Peak Hour for the Month							
Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	10%	3%	0%	0%	3%	0%	0%	3%	7%	0%
9	3%	0%	0%	0%	0%	3%	0%	0%	3%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	6%
11	3%	7%	3%	0%	0%	0%	3%	0%	0%	3%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	0%
13	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
14	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
15	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
16	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
17	0%	0%	0%	0%	0%	0%	3%	0%	0%	3%	0%	3%
18	90%	18%	0%	3%	0%	7%	3%	16%	23%	6%	63%	81%
19	3%	68%	39%	3%	0%	13%	10%	13%	0%	65%	17%	6%
20	0%	0%	35%	47%	10%	23%	29%	52%	73%	3%	0%	0%
21	0%	7%	13%	43%	81%	43%	45%	19%	0%	16%	10%	0%
22	0%	0%	0%	0%	10%	10%	0%	0%	0%	0%	0%	3%
23	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Figure 4.6.2.B - Percentage of Days Monthly Peak Occurred in a Given Hour with 20MW/80MWh of Additional Batteries or Load Management

Comparing the two tables provides insight into how the daily peaks can move as more load management and/or peak shaving devices is installed in the state.

VEC will continue to use the analysis tool it developed in this IRP to provide insight into its load management/peak shaving strategies going forward.

Observations:

- VEC may want to reassess the charging and discharging terms of any future battery energy storage service agreements it enters with developers and providers of peak shaving services.
- VEC may want to consider owning utility-scale batteries in the future to provide more flexibility in charging and discharging.

4.6.3 VEC System Peaks

For VEC's 2019 IRP, Daymark Energy Advisors (DEA) prepared monthly peak forecasts which were a function of the historic relationship between monthly energy and peak loads.

As explained earlier, 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, 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, VEC developed its own peak load forecasts for each of the three load forecast scenarios based on the monthly energy forecasts and the ratio of monthly-peak-load-to-energy from the 2019 IRP forecast, adjusted for peak load reduction from the Hinesburg battery and energy efficiency installations in VEC's territory by Efficiency Vermont.

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 to identify 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 CAP EV and CAP CCHP forecast, system winter peak demand is projected to increase from about 89.0 MW in 2023, to about 139.8 MW by 2042, implying a CAGR of 2.41%. The CAGR for 2027-2038 of 2.87% is higher than that for 2023-2027 (1.94%) and 2038-2042 (1.62%) because the adoption rates for EVs and CCHPs are higher from 2027-2038 than the other periods.

Under the VEC EV and CAP CCHP forecast the winter peak is projected to increase from approximately 88.6 MW in 2023 to 160.6 MW, with a CAGR of 3.18%. However, the CAGR is much higher from 2027-2038 (4.63%) than from 2023-2027 (2.03%) and 2038-2024 (0.40%) due to the projected steep adoption of EVs in that period.

The winter peak is projected to grow from 82.4 MW to 130.0 MW in the VEC EV and EVT CCHP forecast. The 2023-2042 CAGR is 2.41%. As in the other forecast scenarios, the CAGR for 2027-2038 of 4.04% is higher than the 2023-2027 CAGR of 0.36% and the 2038-2024 CAGR of 0.14% because of the projected adoption rate of EVs in that period.

The System Winter peak forecasts are shown graphically in Figure 4.6.3.A below:

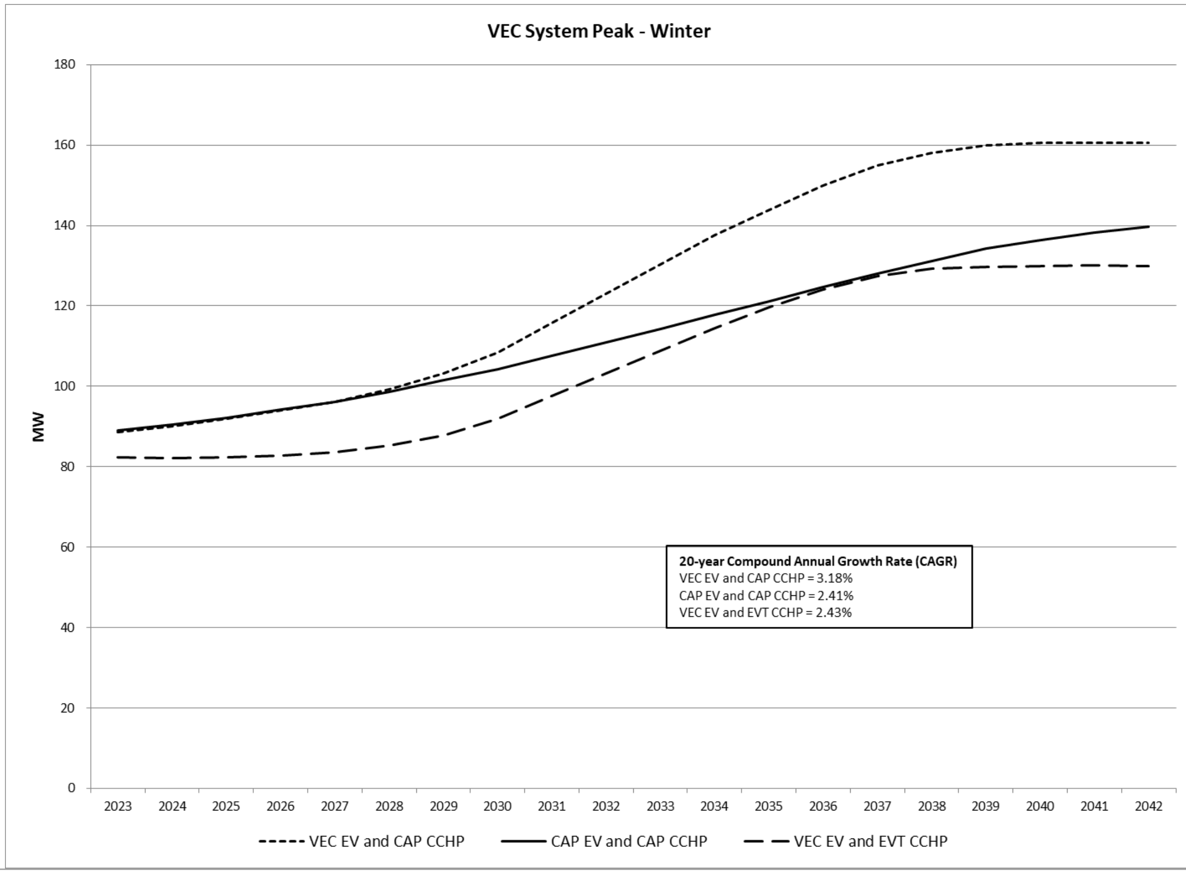

Figure 4.6.3.A – Projected System Winter Peak (MW)

The plots are based on the following data:

Year	VEC EV and CAP CCHP (MW)	CAP EV and CAP CCHP (MW)	VEC EV and EVT CCHP (MW)
2023	88.608	88.993	82.421
2024	90.158	90.564	82.257
2025	91.907	92.230	82.332
2026	93.955	94.195	82.743
2027	96.038	96.088	83.608
2028	99.179	98.675	85.199
2029	103.313	101.540	87.835
2030	108.508	104.294	91.893
2031	115.701	107.534	97.495
2032	123.066	110.873	103.258
2033	130.356	114.321	108.923
2034	137.520	117.851	114.481
2035	143.842	121.094	119.591
2036	149.862	124.623	124.028
2037	154.842	128.045	127.437
2038	158.067	131.114	129.240
2039	159.871	134.265	129.787
2040	160.497	136.457	129.999
2041	160.646	138.188	130.085
2042	160.595	139.796	129.972
2023-2042 CAGR	3.18%	2.41%	2.43%

2023-2027 CAGR	2.03%	1.94%	0.36%
2027-2038 CAGR	4.63%	2.87%	4.04%
2038-2042 CAGR	0.40%	1.62%	0.14%

Figure 4.6.3.B - Projected System Winter Peak (MW)

VEC Summer Peak

Under the CAP EV and CAP CCHP forecast, system summer peak demand is projected to increase from about 73.1 MW in 2023, to about 88.8 MW by 2042, implying a CAGR of 1.03%. The CAGR for 2027-2038 of 1.32% is higher than that for 2023-2027 (0.12%) and 2038-2042 (1.13%) because the adoption rates for EVs and CCHPs are higher from 2027-2038 than the other periods.

Under the VEC EV and CAP CCHP forecast the summer peak is projected to increase from approximately 72.8 MW in 2023 to 105.5 MW, with a CAGR of 1.95%. However, the CAGR is much higher from 2027-2038 (3.34) than from 2023-2027 (-0.18%) and 2038-2024 (-0.04%) due to the projected steep adoption of EVs in that period. The negative CAGRs for the beginning and the end of the study period are the result of the impact of efficiency installations being greater than that of EV and CCHP adoption.

The summer peak is projected to grow from 71.8 MW to 98.9 MW in the VEC EV and EVT CCHP forecast. The 2023-2042 CAGR is 1.70%. As in the other two forecast scenarios, the CAGR for 2027-2038 of 3.12% is higher than the 2023-2027 CAGR of -0.28% and the 2038-2024 CAGR of -0.17% because of the projected adoption rate of EVs in that period. The relatively greater impact of efficiency installations than that of EV and CCHP adoption causes the CAGRs in the beginning and the end of the study period to be negative.

The system summer peak forecasts are shown graphically in Figure 4.5.12.C below:

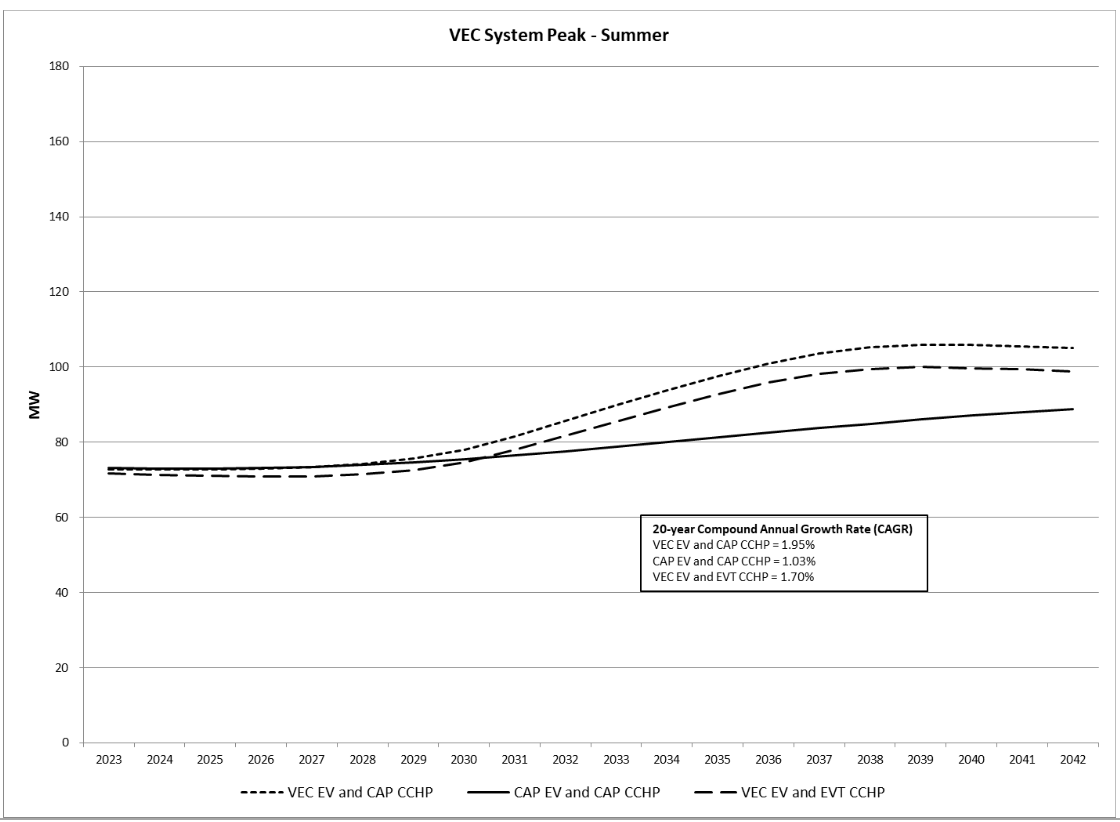

Figure 4.6.3.C – Projected System Summer Peak (MW)

The plots are based on the following data:

Year	VEC EV and CAP CCHP (MW)	CAP EV and CAP CCHP (MW)	VEC EV and EVT CCHP (MW)
2023	72.829	73.096	71.750
2024	72.750	73.046	71.323
2025	72.776	73.043	71.007
2026	72.955	73.161	70.850
2027	73.347	73.444	70.955
2028	74.171	73.965	71.489
2029	75.644	74.704	72.651
2030	77.996	75.576	74.738
2031	81.496	76.557	77.953
2032	85.616	77.648	81.749
2033	89.776	78.836	85.582
2034	93.854	80.092	89.333
2035	97.620	81.352	92.821
2036	100.969	82.629	95.882
2037	103.656	83.847	98.252
2038	105.224	84.875	99.526
2039	105.961	86.129	99.987
2040	105.893	87.177	99.763
2041	105.551	88.029	99.379
2042	105.052	88.763	98.867
2023-2042 CAGR	1.95%	1.03%	1.70%
2023-2027 CAGR	0.18%	0.12%	-0.28%
2027-2038 CAGR	3.34%	1.32%	3.12%
2038-2042 CAGR	-0.04%	1.13%	-0.17%

Figure 4.6.3.D – Projected System Summer Peak (MW)