3 Power Supply

3.1 Introduction

There are many factors that influence VEC's power supply management strategies, including the timing and volume of energy consumed by the membership, statewide renewable energy mandates, and the relative cost of various power supply products and services available in the region. VEC's power supply analysis begins with an assessment of its needs. For 2018, VEC's retail sales were approximately 460,000 MWh, as measured at the members' meters; this number includes the impact of reduced sales due to net-metering. Accounting for line losses, VEC had to purchase approximately 491,000 MWh of electricity from various suppliers to meet its members' needs.

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 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 2018:

Month	MWh	% of Annual Load	Monthly Peak Load (MW)	Peak Day of Week	Peak Day of Month	Peak Hour
Jan-18	47,963	9.8%	85.109	Tue	2	1800
Feb-18	40,512	8.2%	76.344	Mon	5	1900
Mar-18	42,939	8.7%	72.133	Tue	6	1900
Apr-18	39,566	8.1%	65.672	Tue	3	2000
May-18	34,425	7.0%	59.545	Thu	31	2100
Jun-18	36,634	7.5%	71.030	Sat	30	2100
Jul-18	44,760	9.1%	82.281	Mon	2	2000
Aug-18	43,964	8.9%	81.869	Mon	6	2000
Sep-18	37,612	7.7%	78.277	Wed	5	2000
Oct-18	37,703	7.7%	65.623	Thu	25	1900
Nov-18	40,234	8.2%	70.954	Thu	15	1900
Dec-18	45,101	9.2%	75.064	Tue	18	1900
Total	491,412	100.0%	85.109			

Table 3.2.1.A

Although actual monthly loads change 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 VEC members install new net metering systems or their own generation behind the VEC meter, reducing the load on VEC's system, as well as increased load due to member adoption of electrification measures on their own or through VEC's Tier III programs as required under the Vermont Renewable Energy Standard (RES).

As a utility in New England, VEC (and many of its suppliers) has its load and generation entitlements settled through the 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, VEC's effective participation in the regional REC and ISO New England 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.

The major factors are discussed in the following section.

3.2 Key External Factors

3.2.1 Member Energy and Capacity Needs

Over the past several years VEC's net load has been fairly flat, except for cases of extreme weather. Although the number of members has grown, the increased load is offset by the impact of more efficient consumption and increased net metering saturation. This may change with beneficial electrification anticipated by Vermont's RES.

One of the first challenges in managing a power supply portfolio is to develop a forecast of resource needs – which is not only necessary but also, by its nature, only an estimate of the future. VEC develops four individual forecasts which are then combined resulting in the final energy and capacity forecasts. Those four individual forecasts are:

- Pre-New-Net-Metering-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 Reference, Upper Limit and Lower Limit Net Load Forecasts. Where:

- Reference Forecast is based on: the Daymark Energy Advisors (DEA) Reference Forecast, the Base Net Metering Forecast, the Efficiency Forecast and the Base Tier III Forecast;

- Upper Limit Forecast is based on: the DEA Upper Limit Case Forecast, the Low Net Metering Forecast, the Efficiency Forecast and the High Tier III Forecast; and

- Lower Limit Forecast is based on: the DEA Lower Limit Forecast, the High Net Metering Forecast, the Efficiency Forecast and the Low Tier III Forecast.

All forecasts show net load reduction over the first 10 years, then growth in the following 10 years due to net metering saturation slowing new installations and the continued growth of beneficial electrification such as electric vehicles and heat pumps.

Figure 3.2.1.A and 3.2.1.B below show the resulting annual load forecasts for the Reference, Upper Limit and Lower Limit cases.

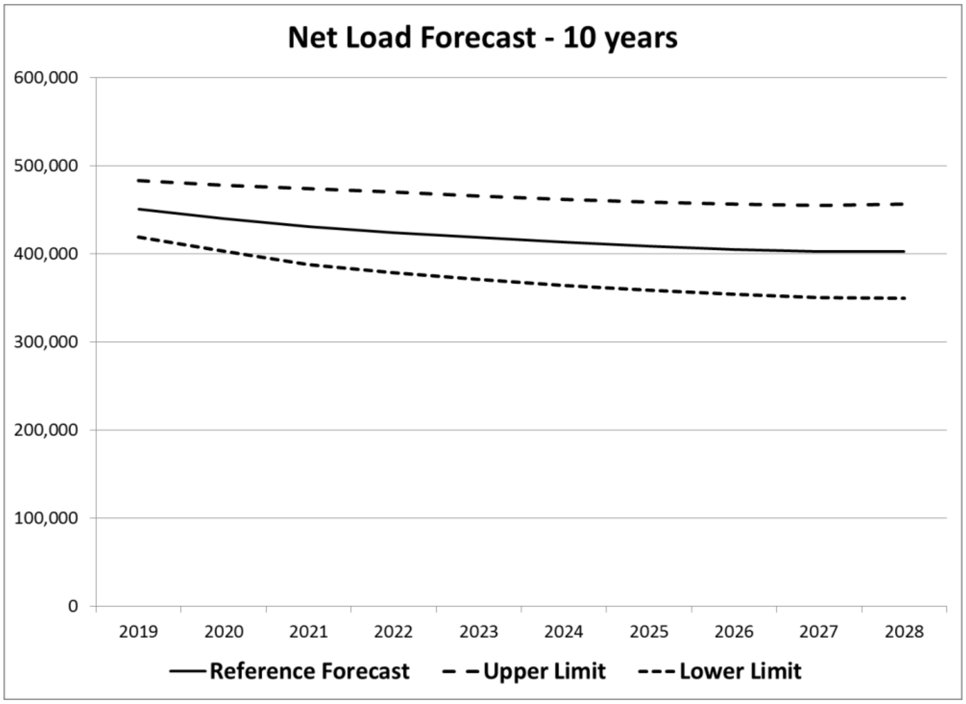

Figure 3.2.1.A - Net Load Forecast – 10 years

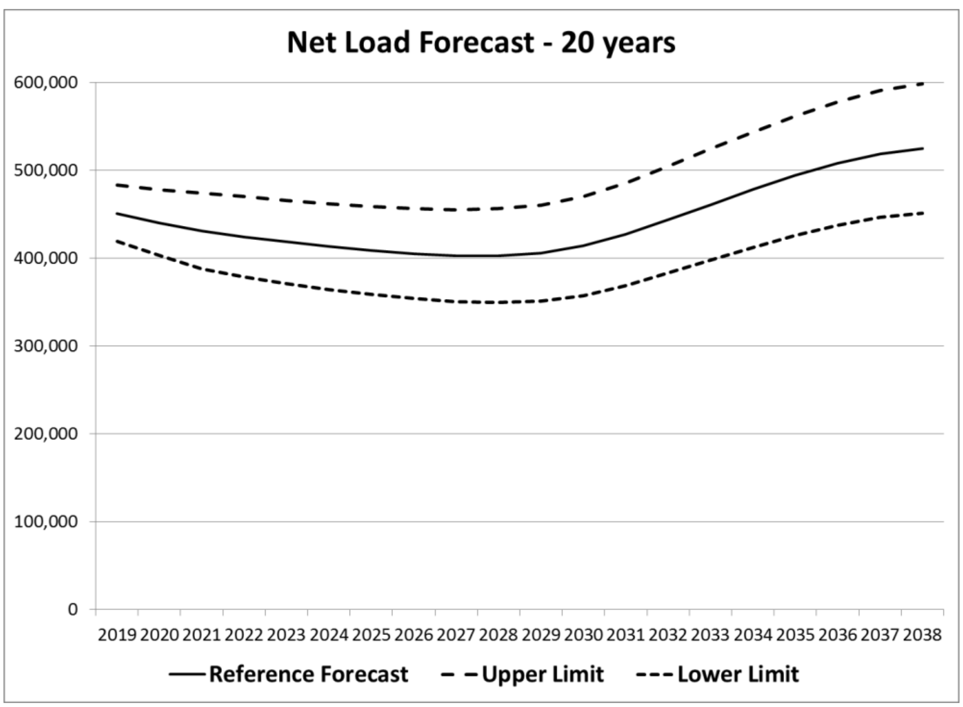

Figure 3.2.1.B - Net Load Forecast – 20 years

The data the plots are based on are shown in Table 3.2.1.A below.

Year	Low Load MWh	Base Load MWh	High Load MWh
2019	418,967	450,494	482,943
2020	402,508	440,090	478,021
2021	385,737	430,632	473,937
2022	375,371	424,084	469,845

2023	366,220	418,203	466,531
2024	358,095	413,007	463,429
2025	350,837	408,476	460,675
2026	344,650	404,922	458,705
2027	339,855	402,760	458,041
2028	337,079	402,722	459,532
2029	337,243	405,863	464,378
2030	341,578	413,575	474,145
2031	351,094	426,999	490,111
2032	363,593	443,705	509,622
2033	376,446	460,771	529,472
2034	389,189	477,685	549,106
2035	401,115	493,669	567,679
2036	411,274	507,667	584,034
2037	418,678	518,584	596,972
2038	421,617	524,566	604,499

Table 3.2.1.A

Each is explained below.

Pre-New Net Metering and Tier III Program Impact Forecast

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. The separate system energy and peak demand univariate and multivariate forecasts were prepared in order to:

- Provide a means of calibrating and blending the typically more accurate shorter-term univariate methods with the longer-term outlook offered by economic and weather data in econometric multivariate models;
- Recognize that no method is perfect and each method has its own strengths and weaknesses; and
- Use all available information to make projections. That is, information contained in both the monthly historical values of VEC sales and loads (univariate methodology), and information contained in aggregated annual VEC sales and load data in relation to exogenous economic and weather data (multivariate methodology).

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 A: Vermont Electric Cooperative 2019 Load Forecast."

The forecast was through 2037. For this IRP, VEC extrapolated 2038 loads by increasing 2037 monthly loads by the 2036-to-2037 growth rate for each month.

The results are discussed and presented graphically below.

VEC System Sales before adjustments for new Tier III and Net Metering Impacts

Prior to any impact from additional Tier III implementation or net metering installations, total sales are expected to decrease from about 444,000 MWh in 2017 to slightly less than 434,000 MWh by 2022, implying a compound annual growth rate (CAGR) of -0.005% in that time frame.

Long-term, VEC is projected to have total sales of slightly more than 434,000 MWh by 2038, implying a 20-year CAGR of -0.1% in the reference case. This long-term CAGR could vary from as low as -0.7% in the Lower Limit case, to 0.4% in the Upper Limit case. Effectively this points to flat sales over this time period. Figure 3.2.1.C is a graphical representation of the forecast for System Energy Sales.

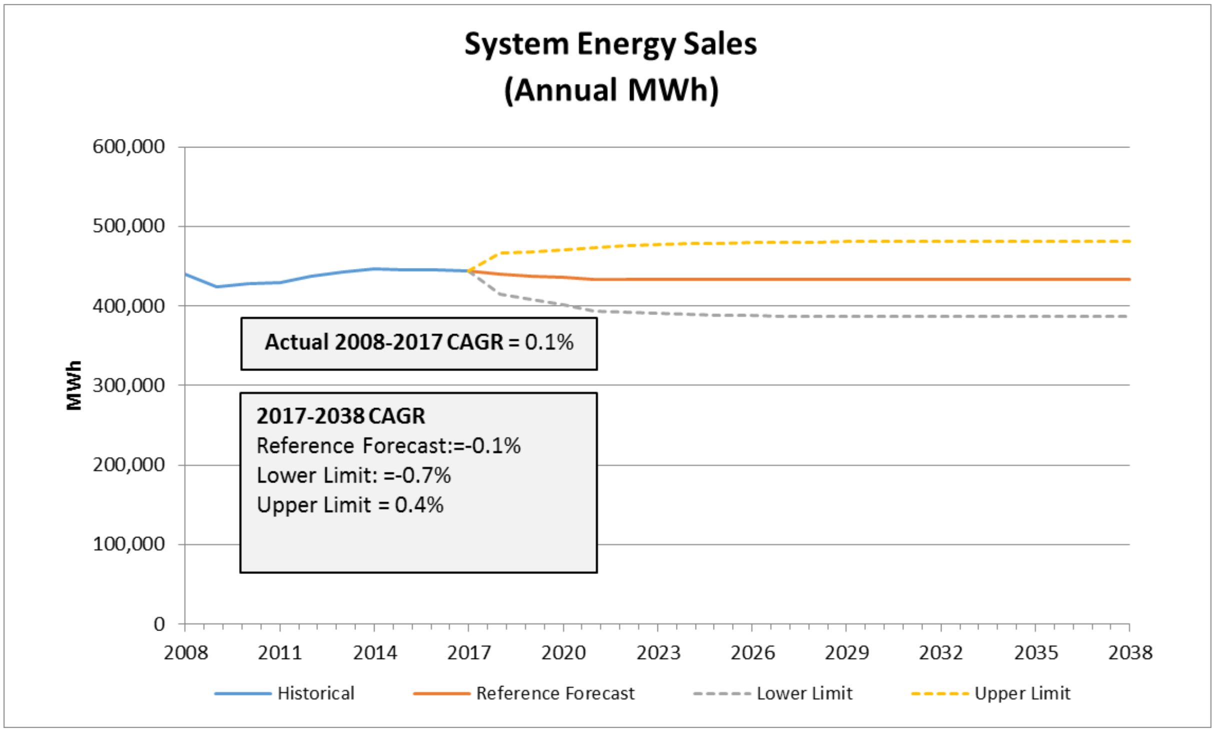

Figure 3.2.1.C - System Energy Sales (Annual MWh)

VEC Gross System Load

To arrive at gross system load, total system sales must be increased by a loss factor to account for line losses from NEPOOL Pool Transmission Facilities (PTF) where VEC's load for settlement in the ISO New England markets is measured to the members' meters. The loss factor assumed in this IRP is 7%, which is the average for difference between gross system load and customer sales from 2014 – 2017.

The resulting energy forecast shows system energy requirements decreasing from about 475,000 MWh in 2017, to slightly more than 464,000 MWh by 2022 then increasing to slightly less than 465,000 MWh by 2038. The CAGRs are the same as total customer sales CAGRs because the forecast is adjusted by a constant loss factor. Figure 3.2.1.D is a chart of annual Gross System Load for the study period.

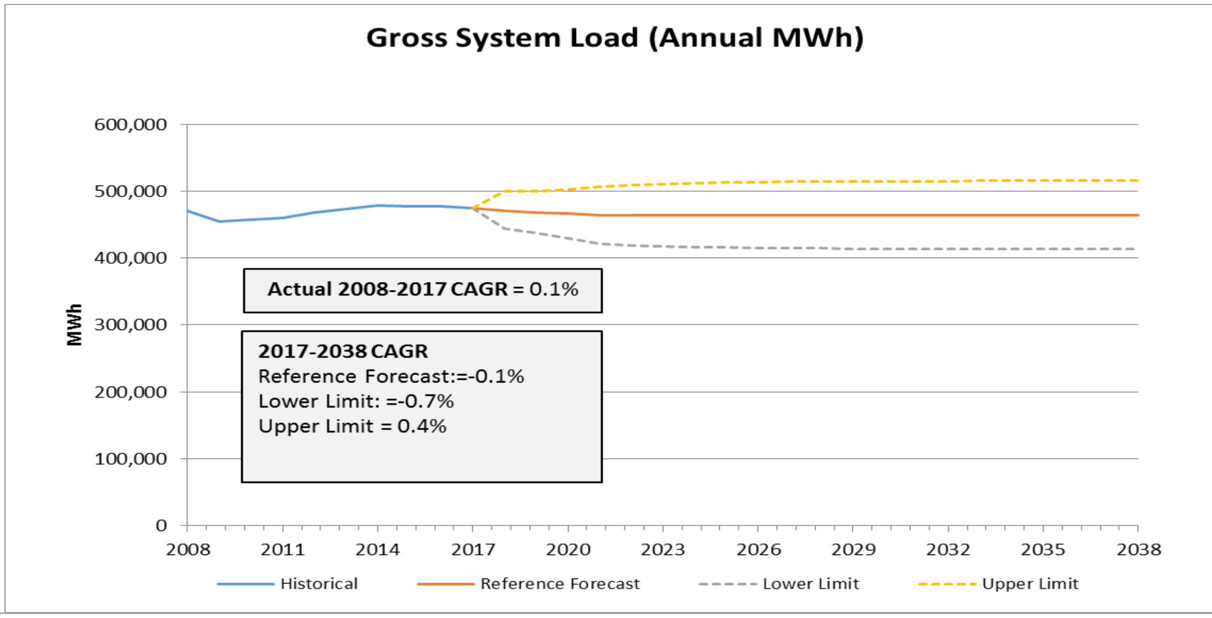

Figure 3.2.1.D – Gross System Load (Annual MWh)

VEC System (Winter) Peak

Monthly peaks were projected as a multiple of each month's forecast average hourly gross system load and the forecast monthly load factor. The low boundary was developed by using the gross system load Low Limit case (discussed above) with the 95% confidence interval upper limit load factor. Conversely, the high boundary was developed using the gross system load high case upper limit divided by the 95% confidence interval lower limit load factor.

System winter peak demand is expected to decrease from about 85.4 MW in 2017, to about 80.9 MW by 2022, implying a CAGR of -1.1% in that time frame. Long-term, VEC is projected to see winter peak demand continue to decrease at a CAGR of -0.3%, reaching 79.8 MW by 2038. The boundary cases show projected 20-year CAGRs ranging anywhere from -1.2% in the Lower Limit case to 0.6% in the Upper Limit case, with 2038 system peaks ranging from potentially as low as 65.7 MW to potentially as high as 96.5 MW. The System Winter peak is shown graphically in Figure 3.2.1.D

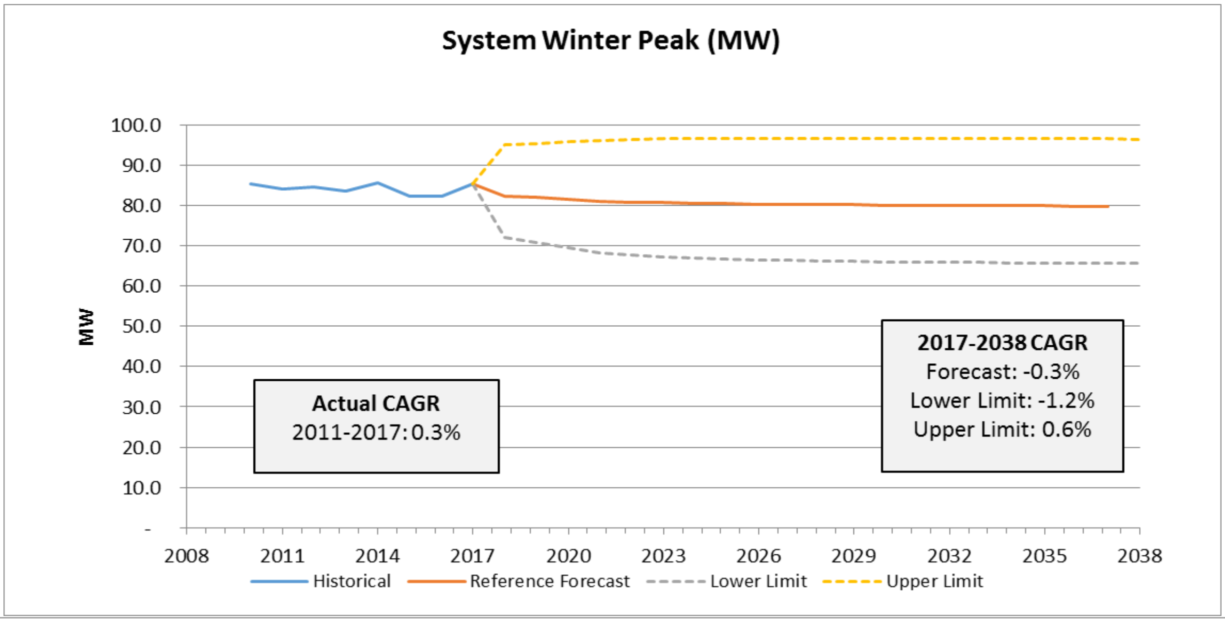

Figure 3.2.1.E – System Winter Peak (MW)

VEC Summer Peak

Summer monthly peaks were projected using the same approach as for the winter, described above.

The resulting summer peak load is expected to decrease from about 73.2 MW in 2017, to about 70.7 MW by 2022, implying a CAGR of -0.7% in that time frame. Long-term, VEC summer peak demand is expected to decrease at a rate of about -0.2% annually on average, reaching 70.8 MW by 2038. The boundary cases show projected 20-year CAGRs ranging anywhere from -1.1% in the Lower Limit case to 0.8%, with 2038 system peaks ranging from as low as 57.5 MW to as high as 86.8 MW. A plot of the System Summer Peak forecast is shown in Figure 3.2.1.F.

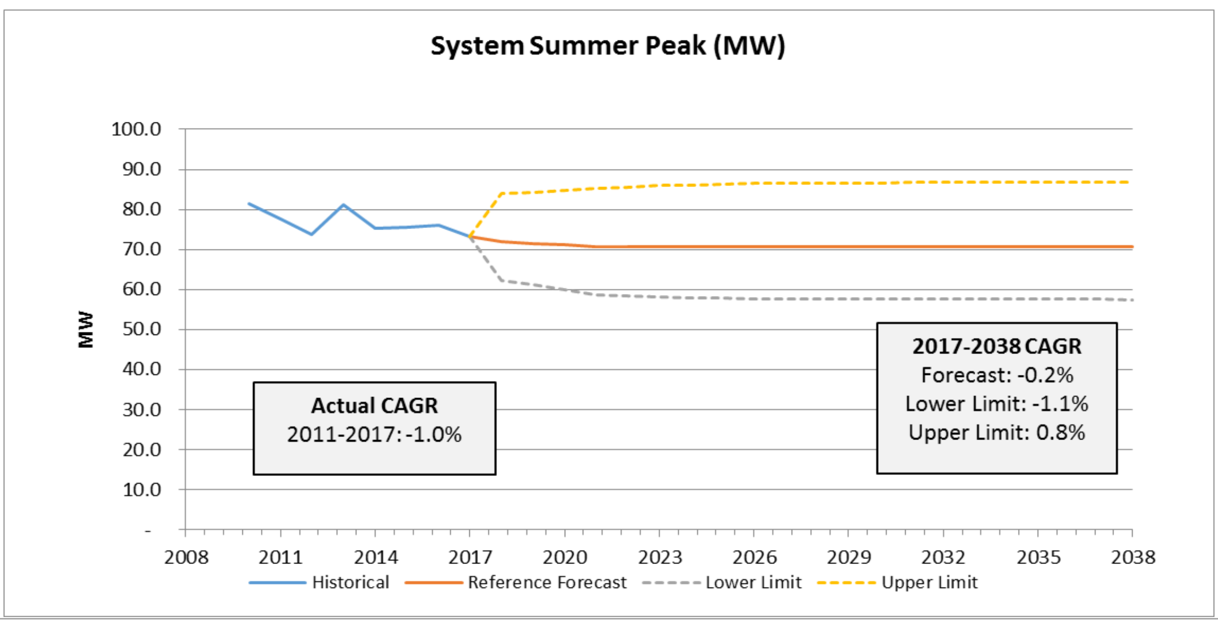

Figure 3.2.1.F – System Summer Peak (MW)

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

The incremental impact of EVT activity on the VEC system 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 projected to be installed in those parts of the state served by EVT each year from 2018-2037. 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. The data is provided in tabular form in "Appendix B: EVT DRP 2018-2037 Forecast."

VEC converted the annual data to monthly cumulative data to arrive at the total projected load reduction each month for the 2018-2037 period, and the 2038 impact was estimated by increasing the 2037 projections by the same percentage increase as is projected from 2016 to 2037 to extend the data through the time horizon of this IRP. 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 3.2.1.G below shows the annual <u>cumulative</u> load reduction of EVT activity in the VEC territory.

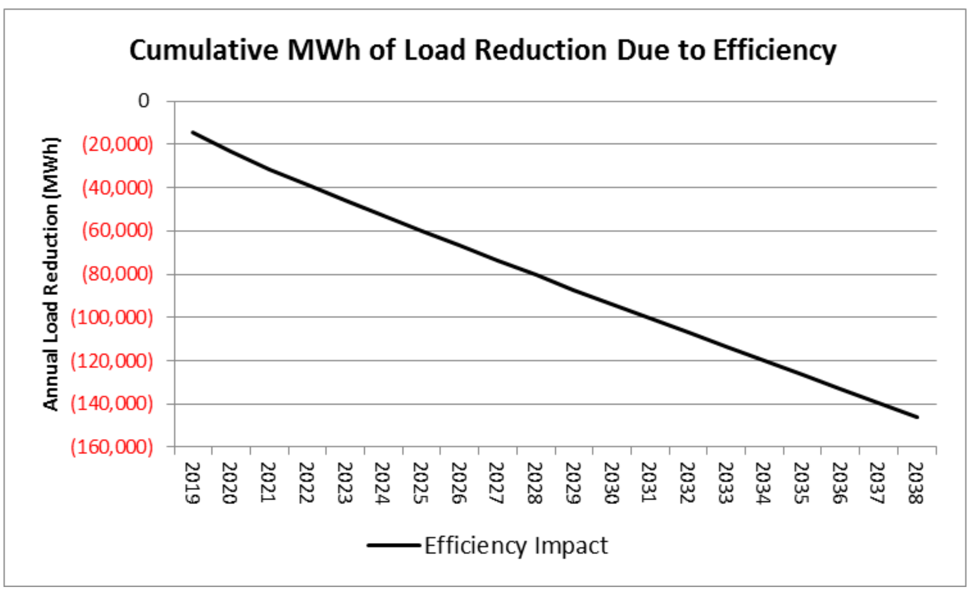

Figure 3.2.1.G – Cumulative MWH of Load Reduction Due to Efficiency

The data the plot is based on are shown in Table 3.2.1.B below.

Year	Efficiency Impact (MWh)
2019	(14,631)
2020	(23,393)
2021	(31,376)

2022	(38,855)
2023	(46,020)
2024	(52,988)
2025	(59,953)
2026	(66,885)
2027	(73,763)
2028	(80,518)
2029	(87,189)
2030	(93,825)
2031	(100,442)
2032	(107,069)
2033	(113,645)
2034	(120,156)
2035	(126,629)
2036	(133,045)
2037	(139,409)
2038	(146,078)

Table 3.2.1.B

EVT also provided projections for annual summer and winter peak reductions in VEC's territory resulting from both Residential and Commercial/Industrial end uses. Table 3.2.1.C below shows the annual summer and winter peak reductions after the EVT projections have been adjusted for line losses from the VEC members' meters to the bulk transmission:

Year	Efficiency Impact - Summer Peak (MW)	Efficiency Impact - Winter Peak (MW)
2019	(2.545)	(3.404)
2020	(3.825)	(4.934)
2021	(4.945)	(6.204)
2022	(6.024)	(7.407)
2023	(6.971)	(8.503)
2024	(7.925)	(9.605)
2025	(8.873)	(10.694)
2026	(9.838)	(11.772)
2027	(10.805)	(12.844)
2028	(11.758)	(13.888)
2029	(12.732)	(14.927)
2030	(13.723)	(15.950)
2031	(14.742)	(16.967)
2032	(15.763)	(17.981)
2033	(16.765)	(18.984)
2034	(17.763)	(19.979)
2035	(18.769)	(20.964)
2036	(19.750)	(21.938)
2037	(20.731)	(22.902)
2038	(21.761)	(23.908)

Table 3.2.1.C

EVT is projecting to install efficiency measures in VEC's territory that reduce VEC's 2019 winter and summer peaks by approximately 2.5 MW and 3.4 MW respectively. The impact of the annual installations will decrease gradually over time as efficiency gets harder and harder to achieve. In other words, the cumulative peak impact will continue to grow, but at a rate that is slowing through time. EVT installations are expected reduce the 2038 summer peak by over 21.7 MW and the winter peak by over 23.9 MW compared to what those peaks otherwise would have been.

The resulting winter peaks are shown for the Lower Limit, Reference and Upper Limit forecasts in Table 3.2.1.D and Figure 3.2.1.B below.

Year	Lower Limit MW	Reference MW	Upper Limit MW
2019	66.570	77.823	91.427
2020	63.818	75.810	90.034
2021	61.192	74.055	89.215
2022	59.446	72.668	88.252
2023	57.937	71.414	87.297
2024	56.516	70.174	86.272
2025	55.177	68.967	85.221
2026	53.901	67.787	84.153
2027	52.671	66.627	83.075
2028	51.500	65.507	82.014
2029	50.358	64.401	80.952
2030	49.252	63.322	79.904
2031	48.166	62.255	78.860
2032	47.095	61.198	77.820
2033	46.046	60.159	76.793
2034	45.012	59.132	75.774
2035	43.994	58.120	74.768
2036	42.993	57.122	73.774
2037	42.006	56.137	72.792
2038	40.977	55.111	71.769

Table 3.2.1.D

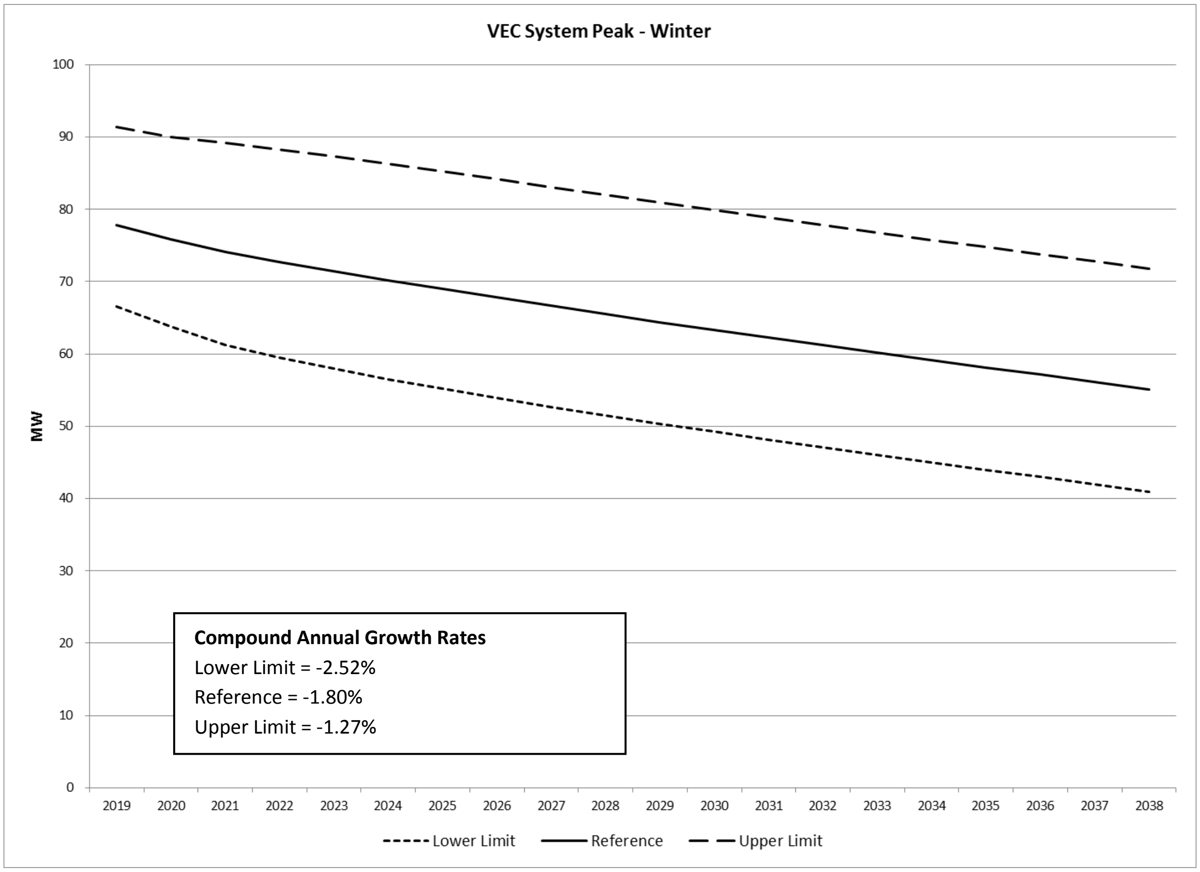

Figure 3.2.1.B – VEC System Peak - Winter

The resulting summer peaks are shown for the Lower Limit, Reference and Upper Limit forecasts are shown in Table 3.2.1.E and Figure 3.2.1.H below.

Year	Lower Limit MW	Reference MW	Upper Limit MW
2019	58.574	69.017	81.706
2020	55.337	66.546	80.076
2021	52.958	65.016	79.486
2022	51.543	63.945	78.826
2023	50.358	63.004	78.179
2024	49.232	62.055	77.443
2025	48.159	61.112	76.654
2026	47.103	60.150	75.807
2027	46.070	59.187	74.928
2028	45.067	58.236	74.040
2029	44.057	57.265	73.115
2030	43.040	56.276	72.160
2031	42.001	55.259	71.169
2032	40.966	54.240	70.169
2033	39.953	53.239	69.182
2034	38.948	52.242	68.196
2035	37.937	51.238	67.200
2036	36.951	50.257	66.225
2037	35.967	49.277	65.249

2038	34.934	48.248	64.224

Table 3.2.1.E

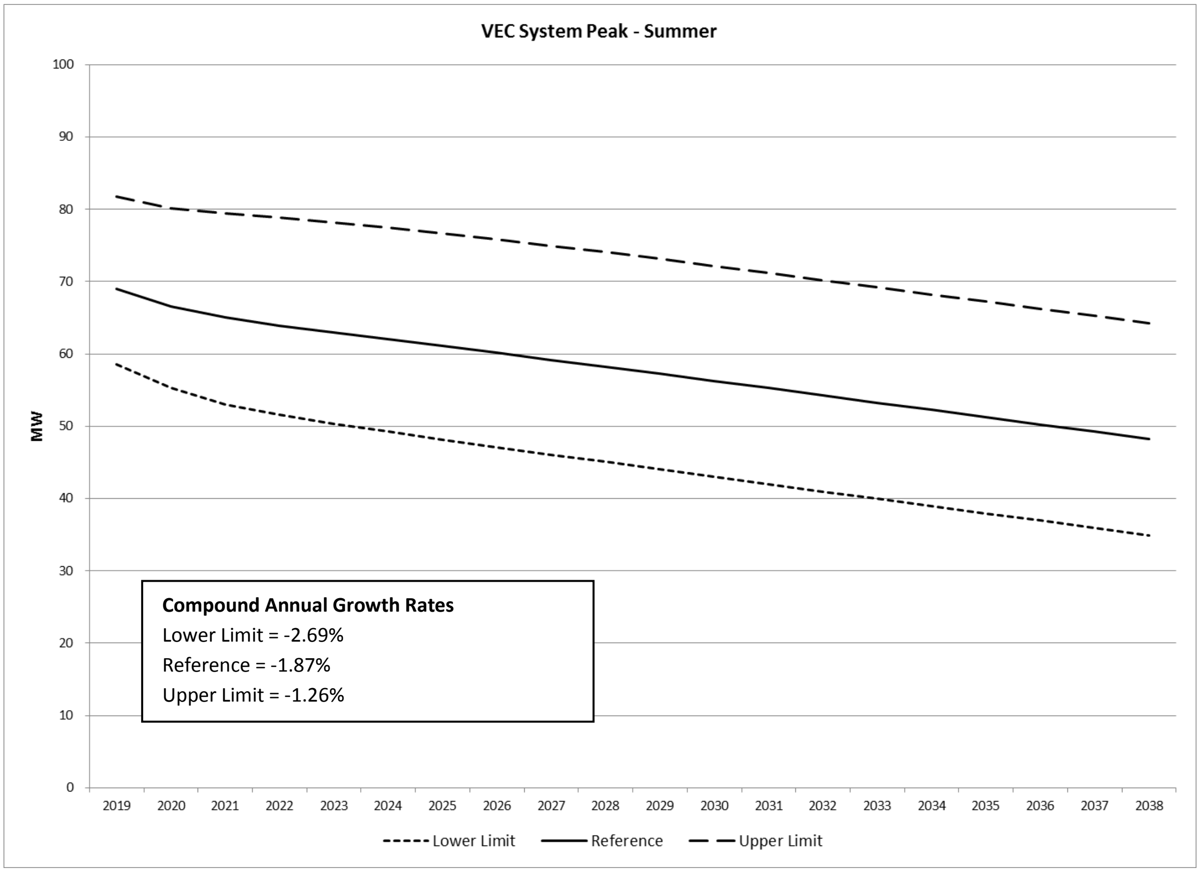

Figure 3.2.1.C – VEC System Peak - Summer

New Net Metering Forecast

The DEA forecasts were limited to the impact of net-metering projects installed on the VEC system through December 2017. Thus, a forecast of new net-metering must be modeled. Because net-metering is generation on the customer's side of the meter and its impact is a reduction in load requirements to be served by VEC, it will reduce the load forecast prepared by DEA.

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 3.2.1.F 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	Derby Solar Case results in all pending projects greater than 150 kW inside the SHEI coming online May-September of 2020 then 8 500 kW projects a year from May-September.	Pending projects greater than 150 kW but outside the SHEI come online in May-July of 2019. Then two 500 kW each July.	2.5 MW new NM capacity online in 2019 for systems 150 kW or less, evenly distributed by month. Then 95% of previous year moving forward.
Base	Derby Solar Case results in all pending projects greater than 150 kW inside the SHEI are	Assumes pending projects that are greater than 150 kW but outside the SHEI come online in May-July of 2019. Then one 500	2.5 MW new NM capacity online in 2019 for systems 150 kW or less, evenly distributed by month. Then 85% of previous year

	denied and all reapply as 150 kW projects coming online May-September 2020. Then 85% of previous year each year.	kW each July.	moving forward.
Low	Derby Solar Case results in all pending projects greater than 150 kW inside the SHEI do NOT come online. Then no new projects over 150 kW (Legislative change).	Projects greater than 150 kW but outside the SHEI come online in May-July of 2019. Then legislative changes result in no new projects greater than 150 kW.	2.5 MW new NM capacity online in 2019, evenly distributed by month. Then 75% of previous year moving forward.

Table 3.2.1.F

Figure 3.2.1.I below shows the annual output of new net-metering projects for each of the three scenarios.

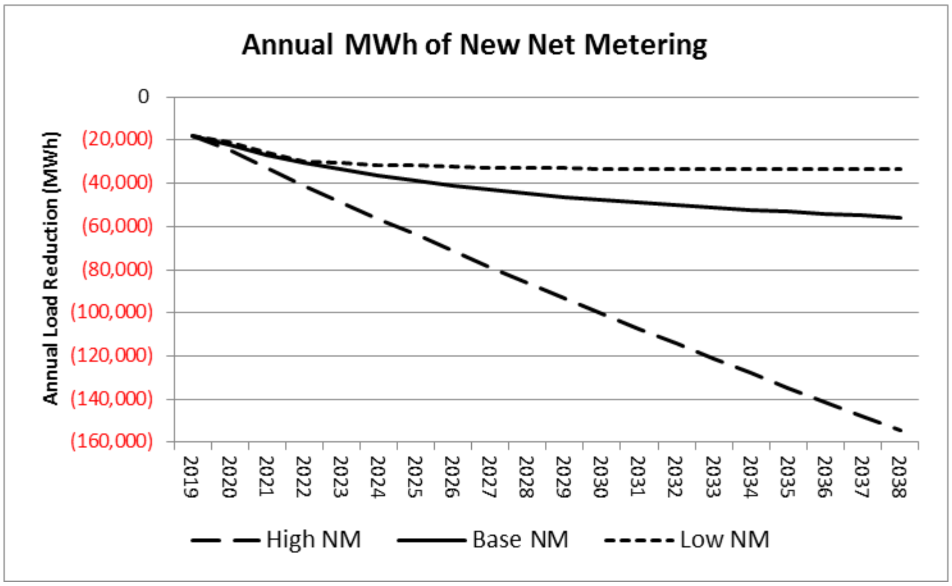

Figure 3.2.1.D – Annual MWh of New Net Metering

The data the plot is based on are shown in Table 3.2.1.G below.

Year	Low NM MWh	Base NM MWh	High NM MWh
2019	(18,137)	(18,137)	(18,137)
2020	(21,105)	(22,342)	(24,429)
2021	(25,534)	(26,603)	(32,974)
2022	(29,562)	(30,308)	(40,893)
2023	(30,575)	(33,541)	(48,691)
2024	(31,335)	(36,371)	(56,374)
2025	(31,905)	(38,860)	(63,946)
2026	(32,332)	(41,059)	(71,414)
2027	(32,653)	(43,011)	(78,783)
2028	(32,893)	(44,754)	(86,058)
2029	(33,073)	(46,318)	(93,244)
2030	(33,209)	(47,731)	(100,344)
2031	(33,310)	(49,015)	(107,364)
2032	(33,386)	(50,189)	(114,307)
2033	(33,443)	(51,271)	(121,177)

2034	(33,486)	(52,273)	(127,978)
2035	(33,518)	(53,208)	(134,713)
2036	(33,542)	(54,086)	(141,386)
2037	(33,560)	(54,915)	(147,999)
2038	(33,574)	(55,703)	(154,556)

Table 3.2.1.G

Historically, only 30% of the net-metering generation on VEC's system has reduced sales at member's 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 3.2.1.J below shows the annual output of new net-metering projects for each of the three scenarios.

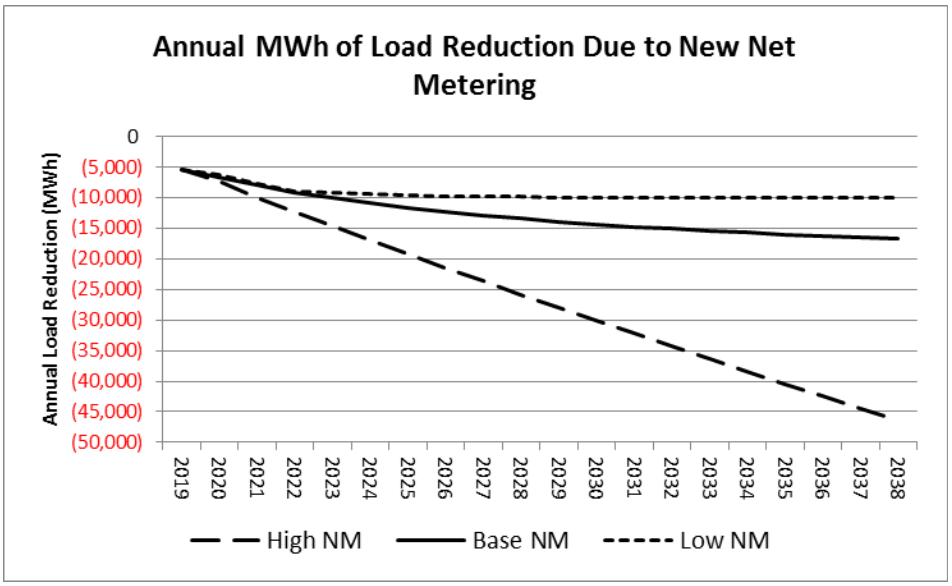

Figure 3.2.1.E – Annual MWh of Load Reduction Due to New Net Metering

The data the plots are based on are shown in Table 3.2.1.H below:

Year	Low NM MWh	Base NM MWh	High NM MWh
2019	(5,441)	(5,441)	(5,441)
2020	(6,332)	(6,703)	(7,329)
2021	(7,660)	(7,981)	(9,892)
2022	(8,869)	(9,092)	(12,268)
2023	(9,173)	(10,062)	(14,607)
2024	(9,401)	(10,911)	(16,912)
2025	(9,572)	(11,658)	(19,184)
2026	(9,700)	(12,318)	(21,424)
2027	(9,796)	(12,903)	(23,635)
2028	(9,868)	(13,426)	(25,817)
2029	(9,922)	(13,895)	(27,973)
2030	(9,963)	(14,319)	(30,103)
2031	(9,993)	(14,705)	(32,209)
2032	(10,016)	(15,057)	(34,292)

2033	(10,033)	(15,381)	(36,353)
2034	(10,046)	(15,682)	(38,393)
2035	(10,055)	(15,962)	(40,414)
2036	(10,063)	(16,226)	(42,416)
2037	(10,068)	(16,475)	(44,400)
2038	(10,072)	(16,711)	(46,367)

Table 3.2.1.H

Tier III Program Impact Forecast

Tier III is a subset of the Vermont Renewable Energy Standard 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 2019 requirement is 3.334%.

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. These categories are Cold Climate Heat Pumps, Heat Pump Water Heaters, Pellet Stoves, Electric Forklifts, Electric Vehicles, and VEC's Clean Air Program. Accordingly, VEC has developed adoption forecasts and corresponding load impact forecasts for these various categories, which are explained in Section 3.6.

Figure 3.2.1.K below shows the combined annual load increase due to the various electrification categories described above.

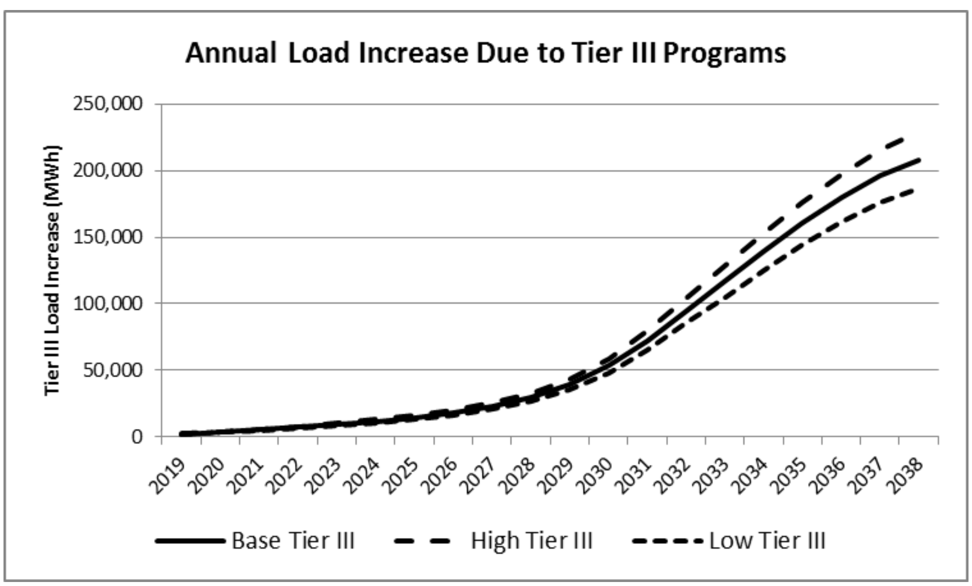

Figure 3.2.1.F – Annual Load Increase Due to Tier III Programs

The data the plot is based on are shown in Table 3.2.1.I below.

Year	Low Tier III MWh	Base Tier III MWh	High Tier III MWh
2019	2,125	2,361	2,597
2020	3,601	4,001	4,401
2021	5,221	5,801	6,382
2022	7,013	7,792	8,571
2023	9,003	10,003	11,004
2024	11,327	12,586	13,845
2025	14,160	15,734	17,307
2026	17,769	19,743	21,718
2027	22,519	25,022	27,524
2028	29,016	32,240	35,464
2029	38,253	42,503	46,753
2030	51,534	57,260	62,985
2031	69,905	77,673	85,440
2032	91,211	101,345	111,480
2033	112,772	125,302	137,832
2034	134,117	149,019	163,920
2035	154,574	171,749	188,923
2036	173,178	192,420	211,662
2037	188,950	209,944	230,939
2038	200,543	222,826	245,109

Table 3.2.1.I

3.2.2 Energy Market Prices

VEC operates in the wholesale power markets administered by the Independent System Operator of New England (ISO-NE). 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 ISO-NE 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 ISO-NE -- the Day-Ahead and the Real-Time market -- 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 ISO-NE market system for energy is 'multi-settlement', meaning there are separate settlements with ISO-NE for generators and dispatchable loads, on the one hand, and load-serving entities (including VEC), on the other. Specifically, ISO-NE 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 ISO-NE 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 DEA to prepare a forecast of Vermont Load Zone LMPs for 2019-2038. LMPs are a function of many factors including New England-wide load net of efficiency and behind-the-meter generation, natural gas prices, emissions pricing and the generation fleet in the region managed by ISO-NE. 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 3.2.2.A - 3.2.2.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.

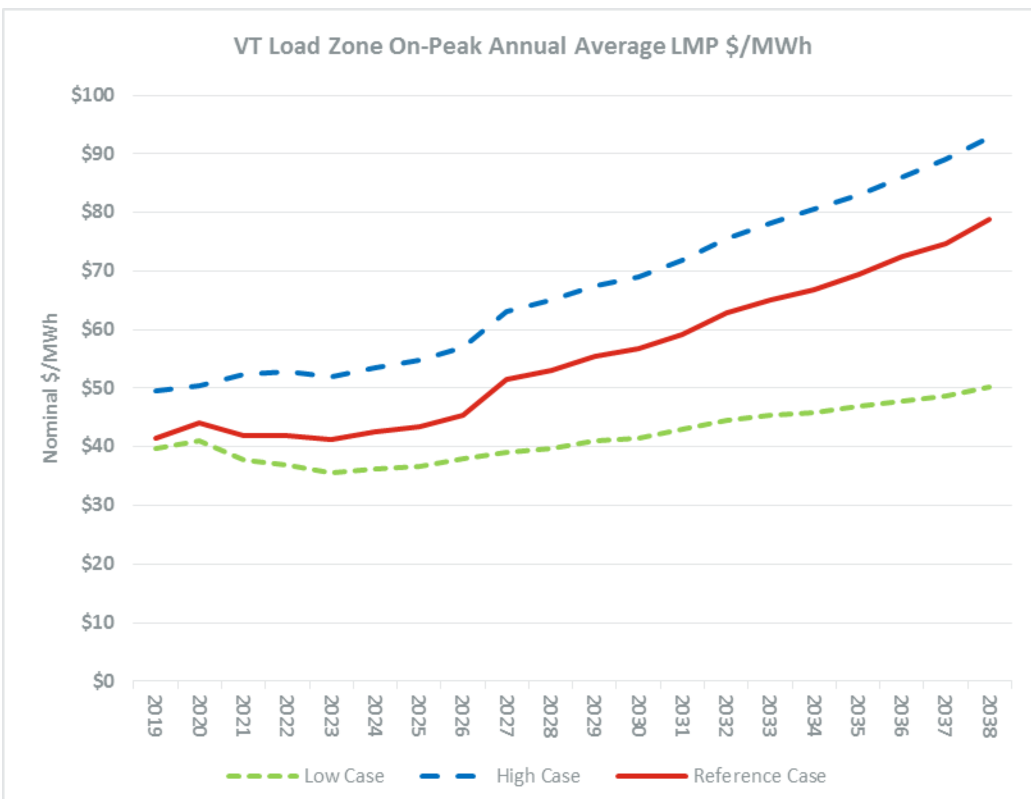

Figure 3.2.2.A – VT Load Zone On-Peak Annual Average LMP $/MWh

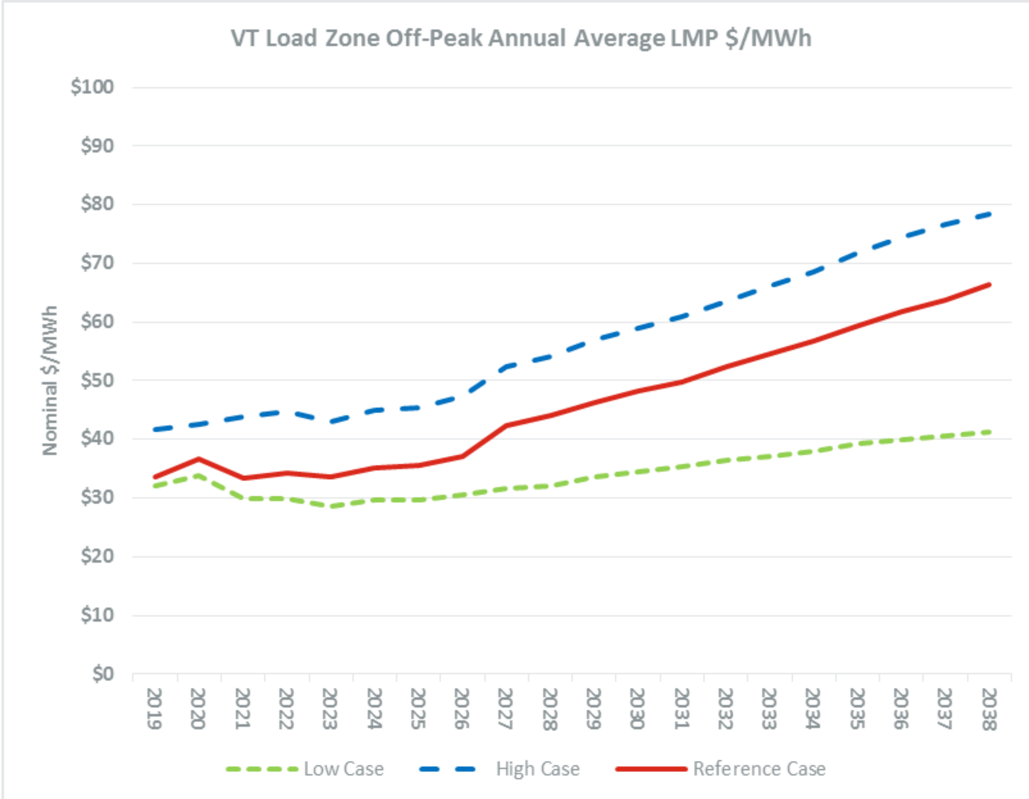

Figure 3.2.2.B – VT Load Zone Off-Peak Annual Averfage LMP $/MWh

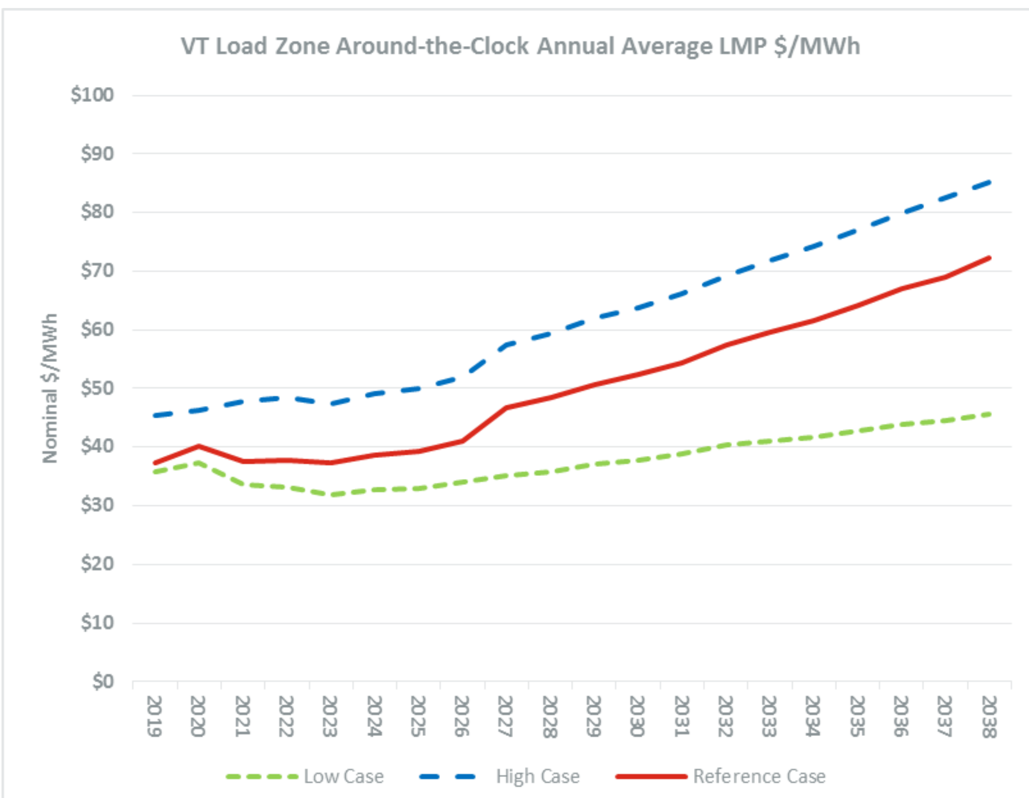

Figure 3.2.2.C – VT Load Zone Around-the-Clock Annual Average LMP $/MWh

More detailed information regarding the development of the energy price forecasts can be found in “Appendix C: Vermont LMP Forecast for 2019 IRP.”

3.2.3 Forward Capacity Market Prices and VEC’s Capacity Load Obligation

Capacity is the second largest component of VEC’s power supply costs. The ISO-NE Forward Capacity Market (FCM) is the benchmark for capacity prices in New England and establishes the price, which ISO-NE must pay to generators for having the installed capacity necessary to assure system reliability under peak conditions. ISO-NE 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 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 75.051 MW in the current commitment period (June 2019 – May 2020) is a function of the Installed Capability 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).

Further detail is provided in Section 3.7.

3.2.4 Value of Energy Storage

Battery storage is an emerging technology that, when cost-effective, has many practical uses, especially as the world shifts from fossil-fuel to renewable generation.

There are a number of potential benefits to battery storage including:

- NEPOOL Transmission Cost Reduction
- ISO-NE Capacity Market Cost Reduction
- Frequency Regulation/Spinning Reserve
- Energy Arbitrage
- T&D investment deferral/T&D support
- Customer Reliability

VEC’s NEPOOL Transmission costs are a function of its load in the one hour Vermont peaks each month. Current NEPOOL rates for transmission are approximately $10.00/kw-month. Thus, VEC can reduce its NEPOOL transmission $10,000 in each month it reduces its load by 1.0 MW in the one hour Vermont peaks for the month, or up to $120,000 in the year if it was able to reduce its load by 1 MW in each of Vermont’s 12 monthly peaks. For planning purposes VEC assumes 3% escalation in NEPOOL transmission rates through the planning period.

VEC’s costs for each June – May commitment period in the ISO-NE Capacity market are a function of its load in the one hour New England peaked in the previous calendar year. Because of the reserve requirement built into the amount of capacity ISO-NE procures through the Forward Capacity Market auctions, if VEC can reduce its load in the one hour New England peaks in a calendar year, it can reduce its capacity requirement by approximately 1.200 MW – 1.500 MW in each month of the subsequent commitment period. At VEC’s Base planning assumption of $5.000/kw-month, it can save approximately $80,000 per year. The actual cost-effectiveness will be a function of VEC’s ability to predict the one hour New England peaks each year, which will get more difficult over time as more market participants invest in storage for the same peak-shaving purposes.

When batteries are not being used for peak load reduction or energy arbitrage, they can be used in the ISO-NE Regulation market to produce more value. However, participation in this market is time consuming and requires an expertise VEC has not yet developed. VEC believes that, as more batteries are installed in New England, potential profits in the Regulation market will deteriorate, as occurred in the PJM Regulation market. Because of this, VEC does not assign any meaningful value to Regulation for batteries; therefore it is not a major factor in a decision of whether or not to invest in battery storage technology.

The ability to extract value from batteries through energy arbitrage is a function of the difference between the energy prices at the time of discharge (which results in revenue) and re-charge (which results in a cost) as well as the round-trip losses in the system. For example, if a battery has round-trip losses of 10%, the utility will need to incur a charge for 1.1 MW of energy to re-charge the battery for every 1.0 MW of energy it discharges in order to generate revenue. Although there is potentially some money to be gained there, VEC believes that, under current market conditions (and even more so as utility load shapes flatten out over time as expected) the amount of profit to be made is quite small compared to the potential cost reduction savings from peak load reduction. Because of this, VEC does not assign any meaningful value to energy arbitrage for batteries; therefore it is not a major factor in a decision of whether or not to invest in battery storage technology.

VEC currently has few, if any, locations on its system in need of significant upgrades that can be deferred or eliminated cost-effectively through the use of batteries, so this, by itself, is not a major factor in a decision of whether or not to invest in battery storage. However, there are points on the system that can make better use of batteries than others. Accordingly, although location on the system will not be a factor in a decision of whether or not to invest in battery storage technology, it may be a factor in deciding where on the system to place a battery.

Customer reliability is one major benefit of batteries. Batteries placed at substations or other VEC-owned property can also be used as backup power to improve reliability for a number of customers on connected circuits, while smaller batteries located behind an individual customer's meter can be used to supply that customer in the event of an outage on the circuit serving that customer. Although it can be difficult to assign a value to that improved reliability, aside from sales being higher than they may have otherwise been with the outage, VEC recognizes the value is there and is investigating the feasibility of Commercial/Industrial and Residential Class battery storage programs.

The cost of battery storage, especially Lithium Ion, has decreased significantly in the past several years and is expected to do so in the future.

VEC is a member of the National Rural Electric Cooperatives Association (NRECA) which is an association of electric cooperatives that provides research and other services its members. In July 2018 NRECA published a report titled "Battery Energy Storage Overview," which provides its view of the general price trends of battery storage technology through 2030.

Figure 3.2.4.A below is a chart from the NRECA study with cost ranges for 4 MW/16MWh Flow and Lithium-ion batteries for 2016 and 2030, in 2016 dollars.

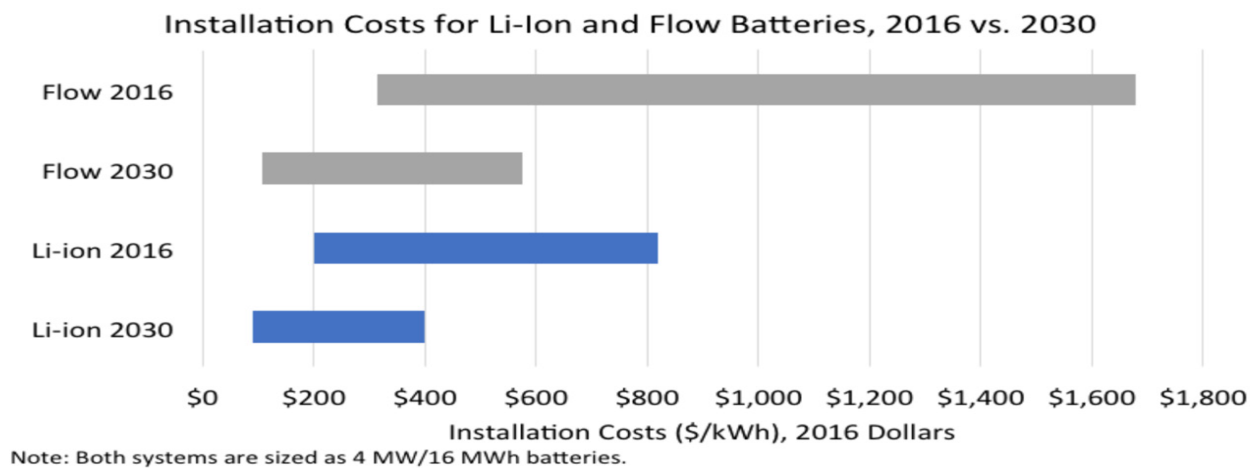

Figure 3.2.4.A – Installation Cost for Li-Ion and Flow Batteries, 2016 vs. 2030

(Note: the actual installed price of a specific battery is dependent upon several factors, including interconnection costs, location, and site preparation work.)

The chart suggests the cost of utility-scale Lithium ion batteries could decrease by approximately 50% in 2016 $ by 2030. Although the chart is for utility-scale batteries, VEC believes it is reasonable to assume that residential scale batteries will follow a similar price trend.

As the cost of battery storage comes down, batteries will become more prevalent at both the utility scale and residential scale.

VEC believes it can provide value to members by employing cost-effective utility scale storage throughout its system both to optimize the use of distributed generation on its system and to improve reliability.

In addition, with proper planning, VEC wants to be in a position to help members who want storage on their premises to plan and implement their own systems. By using these batteries for peak shaving purposes, VEC can provide the member added benefits they cannot get on their own and reduce costs for the entire VEC membership as well.

3.2.5 Cost of Solar Resources

The cost of solar generation continues to decrease, although not as dramatically as earlier in this decade. VEC is currently receiving quotes for 1.0 – 5.0 MW solar projects in the range of $0.105 – $0.110/kWh.

Research and development may further decrease the cost of solar. At the same time, tax credits for renewable generation are set to be reduced considerably by the end of 2020.

Whether the reduction in tax credits goes into effect and, if so, the impact on the cost of renewables to utilities and end-use customers remains to be seen. The end result could have a significant impact on VEC's power supply strategy and its overall power supply costs.

3.2.6 Vermont Renewable Energy Standard Rules

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

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 located 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 2019 is 55%. 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 begins 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 2019 requirement is 2.2%. 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 begins at $0.06/kWh in 2017 escalating annually at the Consumer Price Index.

In addition to the renewable energy requirement, 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 2019 requirement is 3.333%. 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 begins at $0.06/kWh in 2017 and escalates annually at the Consumer Price Index.

Although changes to the RES requirements can be made by the Vermont legislature, VEC is not aware of any meaningful changes proposed at this time. Instead of anticipating any number of potential rule changes, this IRP assumes the current rules stay in place for the entire study period.

3.2.7 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 REC from Tier I eligible resources as Class I REC 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 to. Some counterparties will go beyond 3 years, but there often is a noticeable drop in price due to the lack of liquidity and price uncertainty that far out.

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 - $30.00/REC range from 2019 – 2030, with Base Case costs in the low end of that range.

3.3 Energy Requirements and Needs Assessment

3.3.1 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 the energy transformation requirement each year as defined by Act 56. 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)

As discussed earlier, DEA prepared a load forecast, which VEC then adjusted for estimated energy efficiency impacts based on data provided by Efficiency Vermont, three scenarios of net-metering projections and the projected impacts of VEC's Tier III programs.

The Energy Requirements and needs assessment for each portfolio is discussed in the following sections.

3.3.2 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 ISO-New England 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 3.3.2.A below provides a graphical comparison of the two for VEC's Post-Tier III energy requirements. A table containing the data the graph is based on is included in "Appendix D: VEC Resource and Needs Projections."

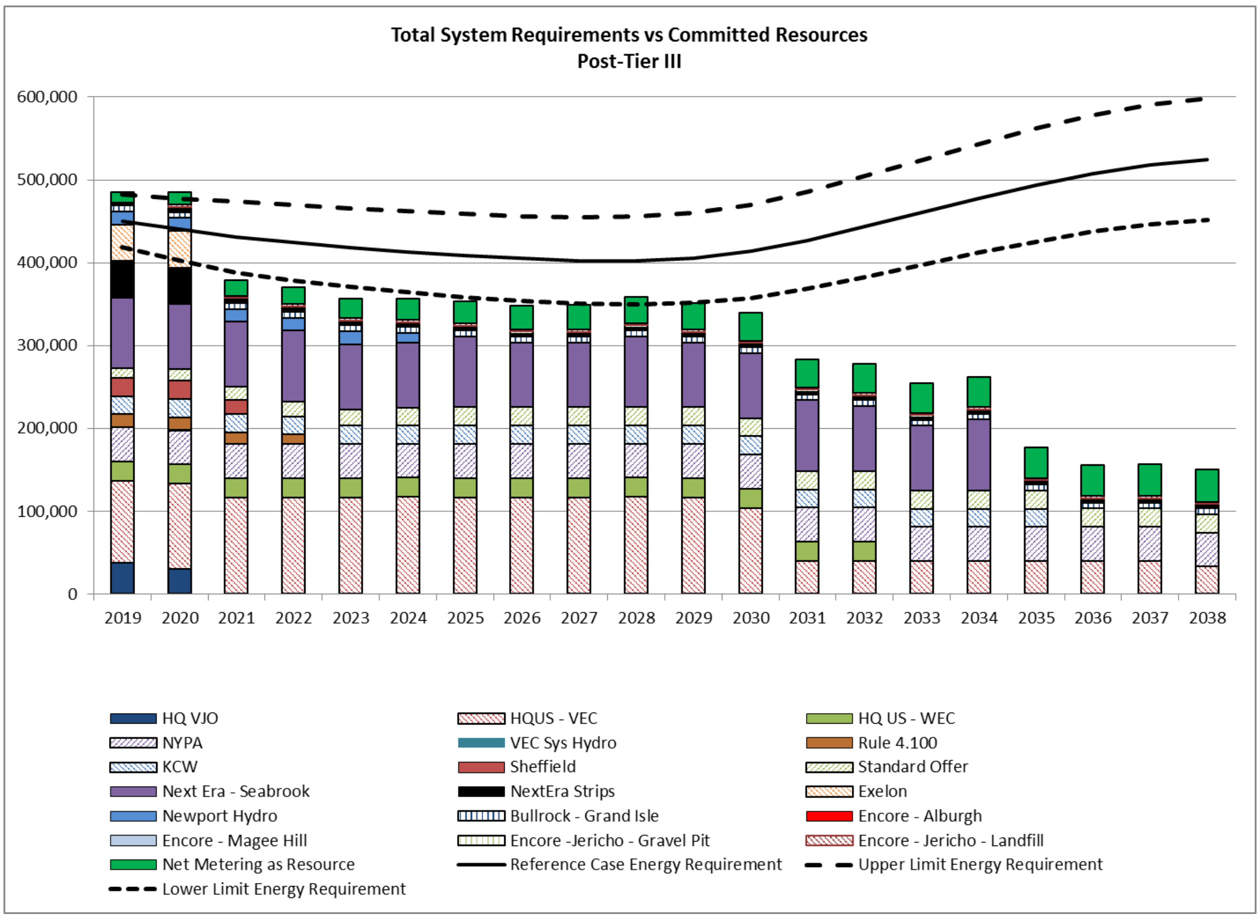

Figure 3.3.2.A – Total System Requirements vs Committed Resources – Post-Tier III

The 2019 – 2038 CAGR is 0.8% in the Reference Case forecast scenario, 1.1% in the Upper Limit forecast scenario and 0.4% in the Lower Limit forecast scenario. However, the 20-year CAGR can be misleading. In each forecast there is reduction in load through approximately 2028 as the impact of net metering installations as load reducers outpace the impact of Tier III. This trend is projected to reverse in approximately 2029 as Tier III programs that convert fossil fuel consumption to electricity (especially electric vehicles) begin to result in significant load increase while new net-metering installations slow because of the ever-increasing saturation level.

VEC is projected to be slightly excess in 2019 and 2020 for each of the three forecasts.

With respect to the Reference case Energy Requirement forecast VEC is projecting a shortfall ranging from 12% - 18% from 2021 – 2030. The shortfall then approaches 34% in 2031 as VEC's share of the HQUS contract decreases. The shortfall grows to approximately 64% in 2035 with the expiration of the Seabrook contract with NextEra.

With respect to the Upper Limit Energy Requirement forecast, VEC is projected to have a shortfall of approximately 20%-25% from 2021 – 2030. The shortfall then approaches 42% in 2031 and 68% in 2035 with the reduction in HQUS purchases and the expiration of the Seabrook contract.

As should be expected, the shortfalls are much smaller for the Lower Limit Energy Requirement forecast.

Table 3.3.2.A below shows VEC's annual projected hedged position for the Post-Tier III load scenarios:

Year	Post-Tier III Low Limit	Post-Tier III Reference	Post-Tier III Upper Limit
2019	116%	108%	100%
2020	120%	110%	102%
2021	98%	88%	80%
2022	98%	87%	79%
2023	96%	85%	77%
2024	98%	86%	77%
2025	99%	87%	77%
2026	98%	86%	76%
2027	100%	87%	77%
2028	102%	89%	79%
2029	100%	87%	76%
2030	95%	82%	72%
2031	77%	66%	58%
2032	73%	63%	55%
2033	64%	55%	49%
2034	64%	55%	48%
2035	42%	36%	32%
2036	36%	31%	27%
2037	35%	30%	27%
2038	33%	29%	25%

Table 3.3.2.A

The MWh shortfalls for the Post-Tier III scenarios are shown in Table 3.3.2.B:

Year	Post-Tier III Low Limit	Post-Tier III Reference	Post-Tier III Upper Limit
2019	(66,306)	(34,780)	(2,331)
2020	(82,464)	(45,508)	(7,948)
2021	8,780	51,764	94,748
2022	7,658	53,195	98,733
2023	14,311	61,749	109,187

2024	7,708	56,619	105,530
2025	4,677	54,790	104,902
2026	5,630	56,795	107,960
2027	1,405	53,579	105,753
2028	(8,724)	44,527	97,779
2029	(253)	54,288	108,830
2030	17,949	74,162	130,376
2031	85,096	143,496	201,897
2032	105,192	166,068	226,944
2033	143,102	206,455	269,808
2034	149,704	215,489	281,273
2035	248,200	316,303	384,406
2036	281,302	351,505	421,709
2037	290,044	362,025	434,006
2038	300,916	374,210	447,505

Table 3.3.2.B

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 levels we are not comfortable transacting at.

VEC is within its self-imposed minimum hedge criteria through approximately 2031 in its Post-Tier III Lower Limit Case, through 2029 in its Post-Tier III Reference Case and through 2021 in its Post-Tier III Upper Limit Case.

Table 3.3.2.C shows the 20-year NPV of costs of VEC's energy portfolio shortfall as various LMP scenarios:

	Lower Limit Load	Reference Load	Upper Limit Load
Lower Limit LMP	$27,447,790	$51,546,257	$74,438,501
Reference LMP	$41,335,298	$73,189,787	$103,268,696
Upper Limit LMP	$50,086,924	$89,061,393	$125,891,979

Table 3.3.2.C

Figure 3.3.2.B below shows the annual cost exposure for the three LMP scenarios in the Reference load case:

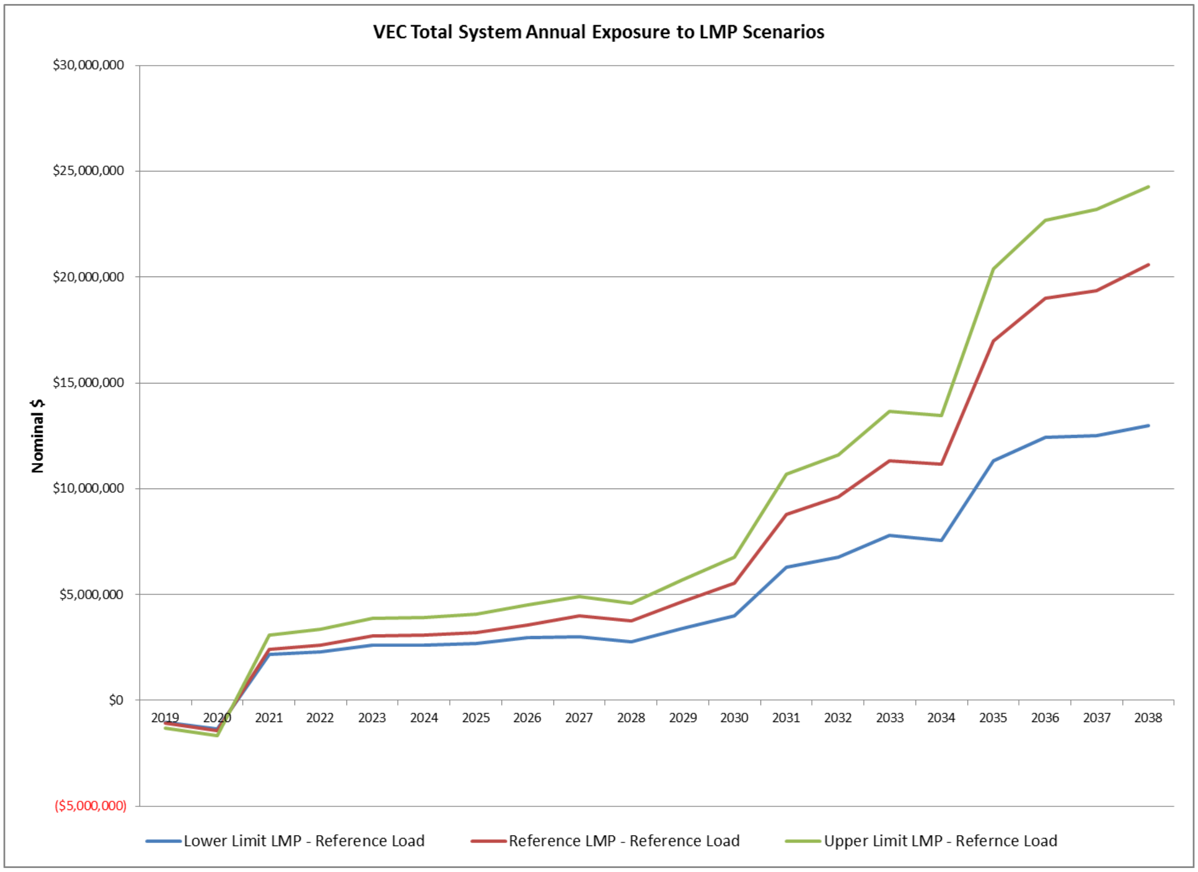

Figure 3.3.2.B – VEC Total System Annual Exposre to LMP Scenarios

Tracking Emissions of VEC's Portfolio

To track the environmental impact of VEC's portfolio, it now tracks the emissions of its resources based on the residual emissions rate of the NEPOOL mix as reported on the NEPOOL Generation Information System (NEPOOL GIS) from October 2017 – September 2018.

In addition to the NEPOOL GIS Residual Mix data, VEC looked at several other sources of information for measuring the environmental impact of its portfolio including New England power plant emission data available through both the Regional Greenhouse Gas Initiative and the Commission for Environmental Cooperation of North America, as well as the "Avoided Energy Supply Components in New England: 2018 Report" prepared by Synapse Energy Economics in October 2018. It was decided to use NEPOOL Residual Mix because that 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 could occur.

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 2017 – September 2018 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 3.3.2.D below:

[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 2017-Septmeber 2018 because there did not appear to be consistency among various reports on the NEPOOL GIS site that include statistics for Residual Mix.

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
821.37372	0.84222	0.00002	1.57757	2.57106	0.83416	3.49702	0.07816

Table 3.3.2.D

Applying these emissions to the amount of energy in VEC's Reference Case portfolio (including purchases at the spot market) that is supplied by non-emitting resource results in the annual tons of emissions shown in Table 3.3.2.E below:

	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
2019	48,179	49	0	93	151	49	205	5
2020	41,813	43	0	80	131	42	178	4
2021	40,413	41	0	78	127	41	172	4
2022	36,331	37	0	70	114	37	155	3
2023	31,354	32	0	60	98	32	133	3
2024	30,564	31	0	59	96	31	130	3
2025	26,993	28	0	52	84	27	115	3
2026	22,684	23	0	44	71	23	97	2
2027	22,487	23	0	43	70	23	96	2
2028	19,407	20	0	37	61	20	83	2
2029	16,144	17	0	31	51	16	69	2
2030	17,159	18	0	33	54	17	73	2
2031	15,779	16	0	30	49	16	67	2
2032	13,266	14	0	25	42	13	56	1
2033	15,211	16	0	29	48	15	65	1
2034	13,968	14	0	27	44	14	59	1
2035	50,686	52	0	97	159	51	216	5
2036	52,123	53	0	100	163	53	222	5
2037	53,244	55	0	102	167	54	227	5
2038	53,858	55	0	103	169	55	229	5

Table 3.3.2.E

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 3.3.2.F below shows VEC's projected Lb/MWh of the various emissions through the study period:

	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
2019	450,494	213.9	0.2	0.0	0.4	0.7	0.2	0.9	0.0
2020	440,090	190.0	0.2	0.0	0.4	0.6	0.2	0.8	0.0
2021	430,632	187.7	0.2	0.0	0.4	0.6	0.2	0.8	0.0
2022	424,083	171.3	0.2	0.0	0.3	0.5	0.2	0.7	0.0
2023	418,203	149.9	0.2	0.0	0.3	0.5	0.2	0.6	0.0

2024	413,007	148.0	0.2	0.0	0.3	0.5	0.2	0.6	0.0
2025	408,475	132.2	0.1	0.0	0.3	0.4	0.1	0.6	0.0
2026	404,922	112.0	0.1	0.0	0.2	0.4	0.1	0.5	0.0
2027	402,760	111.7	0.1	0.0	0.2	0.3	0.1	0.5	0.0
2028	402,722	96.4	0.1	0.0	0.2	0.3	0.1	0.4	0.0
2029	405,863	79.6	0.1	0.0	0.2	0.2	0.1	0.3	0.0
2030	413,575	83.0	0.1	0.0	0.2	0.3	0.1	0.4	0.0
2031	426,999	73.9	0.1	0.0	0.1	0.2	0.1	0.3	0.0
2032	443,705	59.8	0.1	0.0	0.1	0.2	0.1	0.3	0.0
2033	460,771	66.0	0.1	0.0	0.1	0.2	0.1	0.3	0.0
2034	477,685	58.5	0.1	0.0	0.1	0.2	0.1	0.2	0.0
2035	493,669	205.3	0.2	0.0	0.4	0.6	0.2	0.9	0.0
2036	507,667	205.3	0.2	0.0	0.4	0.6	0.2	0.9	0.0
2037	518,584	205.3	0.2	0.0	0.4	0.6	0.2	0.9	0.0
2038	524,566	205.3	0.2	0.0	0.4	0.6	0.2	0.9	0.0

Table 3.3.2.F

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 ranges from 7% in 2034 to 26% in 2019. Throughout the next 13 years the decrease in emissions is a function of both the decreasing load as result of net metering impacts out pacing Tier III load growth and 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 3.3.2.C below.

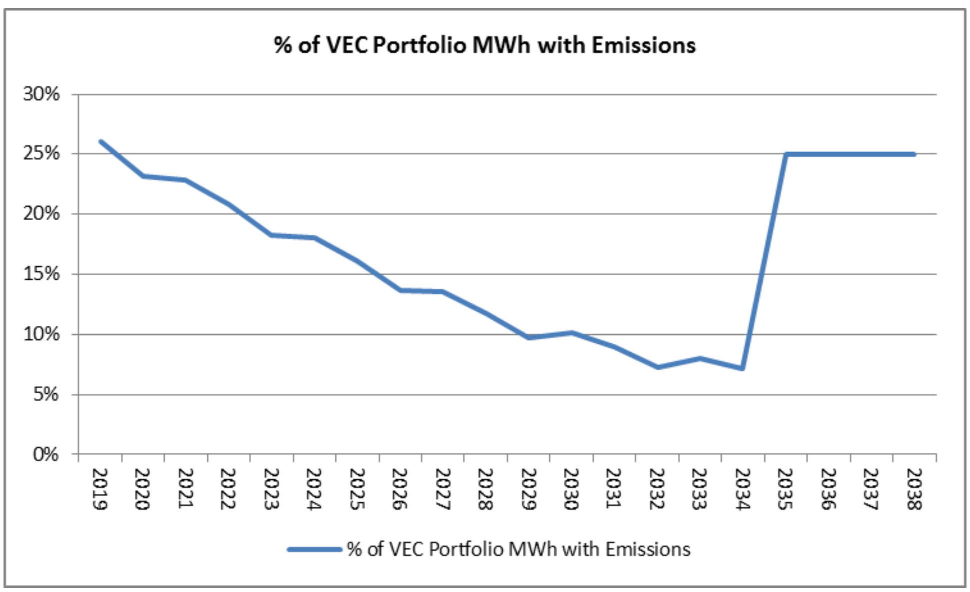

Figure 3.3.2.C - % of VEC Portfolio MWh with Emissions

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 3.3.2.G below shows the societal costs of the Reference Case assuming $5.00/Ton, $10.00/Ton, $50.00/ton and $100.00/ton in 2019 escalated at 2% per year and the 20-year net present value assuming VEC's discount rate of 4.96%:

	Emission $ assuming $5.00/ton in 2019	**Emission $ assuming $10.00/ton in 2019**	**Emission $ assuming $50.00/ton in 2019**	**Emission $ assuming $100.00/ton in 2019**
2019	$240,893	$481,786	$2,408,929	$4,817,857
2020	$213,247	$426,495	$2,132,474	$4,264,948
2021	$210,228	$420,456	$2,102,279	$4,204,558
2022	$192,774	$385,548	$1,927,742	$3,855,485
2023	$169,693	$339,386	$1,696,929	$3,393,858
2024	$168,728	$337,456	$1,687,278	$3,374,555
2025	$151,991	$303,982	$1,519,912	$3,039,824
2026	$130,284	$260,567	$1,302,836	$2,605,671
2027	$131,736	$263,472	$1,317,360	$2,634,719
2028	$115,964	$231,928	$1,159,640	$2,319,279
2029	$98,398	$196,797	$983,983	$1,967,967
2030	$106,674	$213,349	$1,066,744	$2,133,489
2031	$100,055	$200,110	$1,000,549	$2,001,098
2032	$85,805	$171,611	$858,054	$1,716,108
2033	$100,350	$200,700	$1,003,498	$2,006,997
2034	$93,995	$187,990	$939,952	$1,879,904
2035	$347,904	$695,808	$3,479,039	$6,958,078
2036	$364,925	$729,849	$3,649,245	$7,298,491
2037	$380,227	$760,455	$3,802,273	$7,604,545
2038	$392,306	$784,611	$3,923,056	$7,846,112
NPV	$2,288,776	$4,577,552	$22,887,758	$45,775,516

Table 3.3.2.G

The annual increase in the societal cost/ton of carbon dioxide is as difficult to predict as the actual 2019 value. An annual escalation rate that is higher than 2% per year would lead to higher annual societal costs of emissions.

3.3.3 100% Carbon Free and 100% Renewable Analyses

As the Total System Energy Requirements analysis discussed earlier in this report shows, VEC has unhedged energy in each year beginning in 2020. In the Reference Case, this energy is assumed to be supplied with spot market purchases through ISO-NE.

VEC's current strategy is 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 climate change concerns, VEC is interested in knowing the magnitude of the change in costs it could reasonably expect if it were to go 100% carbon-free and/or 100% renewable.

To answer these questions VEC has modeled the change in costs and rates, with respect to its Reference Case, of the following portfolios:

a) 100% Carbon Free
b) 100% Renewable using Existing Hydro
c) 100% Renewable using New Offshore Wind

Each of these analyses and conclusions are explained below. VEC is specifically conducting the 100% carbon-free analysis to show the cost of reducing our power supply's most significant emission source to zero. The 100% renewable analyses are conducted in recognition of the fact that although nuclear is currently an important source of carbon-free energy, VEC does not consider it renewable.

100% Carbon Free

For purposes of this analysis, 100% carbon-free is defined as having contracts to purchase energy and to cover 100% of its projected annual energy requirement and the associated environmental attributes, and retaining those attributes, either from resources that qualify as renewable resources as defined under the Vermont RES and/or from non-carbon emitting resources such as nuclear generation facilities. VEC chose this definition because it is reasonably consistent with 30 V.S.A. §8005a(k)(2)(B) which allows a utility to be exempt from Standard Offer if "…the amount of renewable energy supplied to the provider by generation owned by or under contract to the provider, regardless of whether the provider owned the energy's environmental attributes, was not less than the amount of energy sold by the provider to its retail customers." VEC's definition is stricter in that it requires VEC to retain the environmental attributes, which VEC believes is more consistent with the spirit of being 100% carbon-free.

For this scenario, VEC has assumed it meets its Tier I and Tier II requirements with its Reference Case portfolio, and the shortfall is made up with purchases of nuclear power and associated attributes.

Table 3.3.3.A below shows VEC projected annual load, sales, RES requirement and the additional volume of carbon-free energy to be purchased:

Year	Post-Tier III Load MWh	Post-Tier III Sales MWh	Post-Tier III RES Requirement MWh	Existing Nuclear Purchases MWh	Total Existing Carbon-Free Purchases MWh	Additional Carbon-Free Purchase MWh
2019	450,494	420,311	231,171	85,410	316,581	133,913
2020	440,090	410,604	242,256	78,624	320,880	119,210
2021	430,632	401,780	237,050	78,156	315,206	115,426
2022	424,083	395,670	233,445	85,410	318,855	105,228
2023	418,203	390,184	245,816	78,390	324,206	93,998
2024	413,007	385,336	242,761	78,390	321,151	91,856
2025	408,475	381,108	240,098	85,410	325,508	82,968
2026	404,922	377,792	253,121	78,390	331,511	73,411
2027	402,760	375,775	251,769	78,156	329,925	72,835
2028	402,722	375,740	251,746	85,644	337,390	65,332
2029	405,863	378,670	268,856	78,390	347,246	58,617
2030	413,575	385,866	273,965	78,156	352,121	61,455

2031	426,999	398,390	282,857	85,410	368,267	58,732
2032	443,705	413,976	310,482	78,624	389,106	54,598
2033	460,771	429,900	322,425	78,156	400,581	60,191
2034	477,685	445,680	334,260	85,410	419,670	58,015
2035	493,669	460,593	345,445	0	345,445	148,224
2036	507,667	473,654	355,240	0	355,240	152,427
2037	518,584	483,839	362,879	0	362,879	155,705
2038	524,566	489,420	367,065	0	367,065	157,501

Table 3.3.3.A

VEC staff has not had any discussions with owners of any nuclear plant in New England, 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 changes in the 2020-2038 net present value of costs and rates using a set of proxy purchase prices for energy and environmental attributes. This technique was chosen because a) discussions with suppliers for theoretical analysis may not result in realistic proposals because suppliers could be reluctant to give away negotiating information, and b) 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 3.3.3.B below:

Delivery Point	Seabrook
Term	2020-2038
Purchase Price	0% - 10% premium over Projected LMP at node
Nodal Price	2019 = Avg of 3/2017-2/2019 escalated at Daymark Reference Case LMP
Environmental Attribute Price	$0.10 - $0.50/MWh increasing at 2% per year
Annual MWH Volume Purchased	Load – Total RES Requirement– existing Seabrook contract deliveries
Discount Rate	4.96%

Table 3.3.3.B

Tables 3.3.3.C and 3.3.3.D below show the 2020-2038 change in net present value of total power costs and the average annual change in rates with respect to the Reference Case at various combinations of purchase price premiums above the projected LMP at the delivery node and the environmental attribute price, with Reference Case assumptions for all other variables.

2020-2038 Change in Net Present Value of Total Power Costs with Respect to the Reference Case

Percentage Premium over LMP	Environmental Attribute $/MWh $0.00	Environmental Attribute $/MWh $0.10	Environmental Attribute $/MWh $0.20	Environmental Attribute $/MWh $0.30	Environmental Attribute $/MWh $0.40	Environmental Attribute $/MWh $0.50
0%	$0	$140,580	$281,159	$421,739	$562,318	$702,898
2%	$1,183,552	$1,324,131	$1,464,711	$1,605,290	$1,745,870	$1,886,449
4%	$2,367,104	$2,507,683	$2,648,263	$2,788,842	$2,929,422	$3,070,001
6%	$3,550,656	$3,691,235	$3,831,815	$3,972,394	$4,112,974	$4,253,553
8%	$4,734,208	$4,874,787	$5,015,367	$5,155,946	$5,296,526	$5,437,105
10%	$5,917,759	$6,058,339	$6,198,918	$6,339,498	$6,480,077	$6,620,657

Table 3.3.3.C

2020-2038 Increase in Rates with Respect to the Reference Case

Percentage Premium over LMP	Environmental Attribute $/MWh $0.00	Environmental Attribute $/MWh $0.10	Environmental Attribute $/MWh $0.20	Environmental Attribute $/MWh $0.30	Environmental Attribute $/MWh $0.40	Environmental Attribute $/MWh $0.50
0%	0.000%	0.013%	0.027%	0.040%	0.054%	0.067%
2%	0.116%	0.129%	0.143%	0.156%	0.169%	0.183%
4%	0.231%	0.245%	0.258%	0.272%	0.285%	0.299%
6%	0.347%	0.360%	0.374%	0.387%	0.401%	0.414%
8%	0.463%	0.476%	0.490%	0.503%	0.516%	0.530%
10%	0.578%	0.592%	0.605%	0.619%	0.632%	0.646%

Table 3.3.3.D

The tables show, that:

1. If the contract price is equal to the LMP value of the output at the node, VEC's costs would increase in a range from $0 - $0.7 million on a 2020-2038 net present value basis, with rates higher than they otherwise would have been by an average of 0.000% - 0.067% on an annual basis. The entire increase in costs would be the result of the environmental attributes.

2. If the contract price were to end up being equal to 110% of the LMP value of the output at the node, VEC's costs would increase in a range from $5.9 million - $6.6 million on a 2020-2038 net present value basis, with rates higher than they otherwise would have been by an average of 0.5478% - 0.646% on an annual basis.

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. Because both parties in a transaction are hedging their costs, but from different perspectives, a fixed price contract, or a contract price based on pre-determined escalators could be negotiated, and the eventual contract price could be above or below the LMP value at the node.

It is important 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 carbon-free generation.
- VEC would not be 100% carbon-free in every hour of the year. Because of when much of its carbon-free energy is generated 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, adding costs that are unknown at this time. This is similar to accounting for renewable energy standards compliance (except for nuclear not being counted as renewable) and with methodologies used by other utilities claiming to be 100% carbon-free.
- A number of 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 contract up for over 5 years would require a Certificate of Public Good (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 likely be existing and outside Vermont, this case was assumed to not require any upgrades to the VELCO or VEC systems.

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 that came on-line prior to July 1, 2015.

Table 3.3.3.E below shows VEC projected annual load, sales, RES requirement and the additional volume of existing renewable energy to be purchased:

Year	Post-Tier III Load MWh	Post-Tier III Sales MWh	Post-Tier III RES Requirement MWh	Additional Renewable Energy Purchase MWh
2019	450,494	420,311	231,171	219,323
2020	440,090	410,604	242,256	197,834
2021	430,632	401,780	237,050	193,582
2022	424,083	395,670	233,445	190,638
2023	418,203	390,184	245,816	172,388
2024	413,007	385,336	242,761	170,246
2025	408,475	381,108	240,098	168,378
2026	404,922	377,792	253,121	151,801
2027	402,760	375,775	251,769	150,991
2028	402,722	375,740	251,746	150,976
2029	405,863	378,670	268,856	137,007
2030	413,575	385,866	273,965	139,611
2031	426,999	398,390	282,857	144,142
2032	443,705	413,976	310,482	133,222
2033	460,771	429,900	322,425	138,347
2034	477,685	445,680	334,260	143,425
2035	493,669	460,593	345,445	148,224
2036	507,667	473,654	355,240	152,427
2037	518,584	483,839	362,879	155,705
2038	524,566	489,420	367,065	157,501

Table 3.3.3.E

As in the other 100% carbon-free scenario, 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 changes in the 2020-2038 net present value of costs and rates using a set of proxy purchase prices for energy and environmental attributes. This technique was chosen because a) discussions with suppliers for theoretical analysis may not result in realistic proposals because suppliers could be reluctant to give away negotiating information, and b) 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 3.3.3.F below:

Delivery Point	Vernon
Term	2020-2038
Purchase Price	0% - 10% premium over Projected LMP at node
Nodal Price	2019 = Avg of 3/2017-2/2019 escalated at Daymark Reference Case LMP
Environmental Attribute Price	$0.00 - $5.00/MWh
Annual MWH Volume Purchased	Load – Total RES Requirement

Table 3.3.3.F

Tables 3.3.3.G and 3.3.3.H below show the 2020-2038 change in net present value of total power costs and the average annual change in rates with respect to the Reference Case at various combinations of purchase price premium above the projected LMP at the delivery node and the environmental attribute price, with Reference Case assumptions for all other variables.

2020-2038 Change in Net Present Value of Total Power Costs with Respect to the Reference Case

Percentage Premium over LMP	REC $/MWh $1.00	REC $/MWh $2.00	REC $/MWh $3.00	REC $/MWh $4.00	REC $/MWh $5.00	REC $/MWh $10.00
0%	$2,411,000	$4,822,001	$7,233,001	$9,644,001	$12,055,001	$24,110,003
2%	$4,469,152	$6,880,152	$9,291,152	$11,702,153	$14,113,153	$26,168,154
4%	$6,527,303	$8,938,304	$11,349,304	$13,760,304	$16,171,304	$28,226,306
6%	$8,585,455	$10,996,455	$13,407,455	$15,818,456	$18,229,456	$30,284,457
8%	$10,643,606	$13,054,607	$15,465,607	$17,876,607	$20,287,607	$32,342,609
10%	$12,701,758	$15,112,758	$17,523,758	$19,934,759	$22,345,759	$34,400,760

Table 3.3.3.G

2020-2038 Increase in Rates with Respect to the Reference Case

Percentage Premium over LMP	REC $/MWh $1.00	REC $/MWh $2.00	REC $/MWh $3.00	REC $/MWh $4.00	REC $/MWh $5.00	REC $/MWh $10.00
0%	0.225%	0.450%	0.676%	0.901%	1.126%	2.252%
2%	0.421%	0.646%	0.871%	1.096%	1.322%	2.448%
4%	0.617%	0.842%	1.067%	1.292%	1.517%	2.643%
6%	0.812%	1.038%	1.263%	1.488%	1.713%	2.839%
8%	1.008%	1.233%	1.458%	1.684%	1.909%	3.035%
10%	1.204%	1.429%	1.654%	1.879%	2.105%	3.231%

Table 3.3.3.H

The tables show, that:

1. If the contract price is equal to the LMP value of the output at the node, VEC's costs would increase in a range from $0 - $12.1 million on a 2020-2038 net present value basis, with rates being higher than they otherwise would have by an average of 0.000% - 1.126% on an annual basis. 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 LMP value of the output at the node, VEC's costs would increase in a range from $10.3 million - $22.3 million on a 2020-2038 net present value basis, with rates being higher than they otherwise would have by an average of 0.0.979% - 2.105% on an annual basis.

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. Because both parties in a transaction are hedging their costs, but from different perspectives, a fixed price contract, or a contract price based on pre-determined escalators could be negotiated, and the eventual contract price could be above or below the LMP value at the node.

As is the case with the 100% carbon-free scenario it is important to for the reader to be aware of several important points regarding this analysis and the resulting portfolio, including:

- RECs for existing renewables are currently selling in a range between $1.00 - $1.50/REC. In recent years the highest price VEC has witnessed is in the range of $2.00/REC. Other New England states may at some point increase or add existing renewable requirements. Should this happen the cost/value of existing renewables would likely increase since there is a fixed/limited supply of these resources. For that reason this analysis considers prices considerably higher than current market prices.
- 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. Because of when much of the renewable energy would be generated, 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. For VEC to become 100% renewable in every hour of the year would require a complete overhaul of its portfolio, adding costs that are unknown at this time. This is consistent with accounting for renewable energy standards and with methodologies used by other utilities claiming to be 100% renewable.
- Locking a contract up for over 5 years 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.

100% Renewable – Energy and RECs from Off Shore Wind

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 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 3.3.3.I below shows VEC's projected annual load, sales, RES requirement and the additional volume of existing renewable energy to be purchased:

Year	Post-Tier III Load MWh	Post-Tier III Sales MWh	Post-Tier III RES Requirement MWh	Additional Renewable Energy Purchase MWh
2019	450,494	420,311	231,171	219,323
2020	440,090	410,604	242,256	197,834
2021	430,632	401,780	237,050	193,582
2022	424,083	395,670	233,445	190,638
2023	418,203	390,184	245,816	172,388
2024	413,007	385,336	242,761	170,246

2025	408,475	381,108	240,098	168,378
2026	404,922	377,792	253,121	151,801
2027	402,760	375,775	251,769	150,991
2028	402,722	375,740	251,746	150,976
2029	405,863	378,670	268,856	137,007
2030	413,575	385,866	273,965	139,611
2031	426,999	398,390	282,857	144,142
2032	443,705	413,976	310,482	133,222
2033	460,771	429,900	322,425	138,347
2034	477,685	445,680	334,260	143,425
2035	493,669	460,593	345,445	148,224
2036	507,667	473,654	355,240	152,427
2037	518,584	483,839	362,879	155,705
2038	524,566	489,420	367,065	157,501

Table 3.3.3.I

Again, VEC staff has not had any discussions with developers of proposed off-shore wind projects. Instead, the analysis calculates a matrix of changes in the 2020-2038 net present value of costs and rates using a set of proxy purchase prices for energy including environmental attributes. The purchase prices were assumed to be fixed prices, not percentage increases above the nodal LMP, with the price range based on prices for off-shore wind projects discussed in publicly available data.

The assumptions used in the analysis are shown in Table 3.3.3.J below:

Delivery Point	70% Brayton Point/30% Kent County
Term	2025-2038
Purchase Price	Ranging from $75/MWh to $100/MWh.
Nodal Price	2019 = Avg of 3/2017-2/2019 escalated at Daymark Reference Case LMP
Environmental Attribute Price	Included in Purchase Price
Annual MWH Volume Purchased	Load – RES Requirement

Table 3.3.3.J

Tables 3.3.3.K and 3.3.3.L below show the 2020-2038 change in net present value of total power costs and the average annual change in rates with respect to the Reference Case at various combinations of purchase price at the delivery node including the environmental attribute price and various LMP scenarios, with Reference Case assumptions for all other variables.

2020-2038 Change in Net Present Value of Total Power Costs with Respect to the Reference Case

Daymark LMP Case	Contract Price $75/MWh	Contract Price $80/MWh	Contract Price $85/MWh	Contract Price $90/MWh	Contract Price $95/MWh	Contract Price $100/MWh
Low	$63,600,765	$71,421,323	$79,241,882	$87,062,440	$94,882,998	$102,703,557
Reference	$43,321,263	$51,141,821	$58,962,380	$66,782,938	$74,603,496	$82,424,055
High	$26,918,966	$34,739,525	$42,560,083	$50,380,641	$58,201,200	$66,021,758

Table 3.3.3.K

2020-2038 Average Annual Increase in Rates with Respect to the Reference Case

Daymark LMP Case	Contract Price $75/MWh	Contract Price $80/MWh	Contract Price $85/MWh	Contract Price $90/MWh	Contract Price $95/MWh	Contract Price $100/MWh
Low	6.671%	7.501%	8.331%	9.161%	9.991%	10.821%
Reference	4.397%	5.227%	6.057%	6.887%	7.717%	8.547%
High	2.638%	3.468%	4.298%	5.128%	5.958%	6.788%

Table 3.3.3.L

The tables show that:

1. VEC could expect rates to be in the range of 2.600% - 10.800% higher than the Reference Case, with the NPV of VEC's portfolio increasing in a range from $26.9 million in the High LMP scenario to $102.7 million in the Low Price scenario.
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 ISO-NE 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.

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. Because both parties in a transaction are hedging their costs, but from different perspectives, a fixed price contract, or a contract price based on pre-determined escalators could be negotiated, and the eventual contract price could be above or below the LMP value at the node.

As is the case with the 100% carbon-free 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 a key to the project being built.
- VEC would not be 100% renewable in every hour of the year. Because of when much of the renewable energy would be generated 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. For VEC to become 100% renewable in every hour of the year would require a complete overhaul of its portfolio, adding costs that are unknown at this time. This is consistent with accounting for renewable energy standards and with methodologies used by other utilities claiming to be 100% renewable.
- Locking a contract up for more than 5 years would 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.

3.3.4 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 2021

2. Hourly spot market prices for energy which impact the costs of VEC's shortfalls.
3. Forward market prices for energy with can also impact the cost of VEC's shortfalls.
4. Load growth from electric vehicles – which will impact VEC's load and the volume of RECs VEC will need to acquire and retain to meet Vermont's RES standards. VEC will need to acquire more energy and RECs than projected if EV implementation is faster than assumed in this analysis. Conversely, fewer energy and RECs will be required if EV implementation is slower than assumed.
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. VEC will need more 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.
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.

3.4 Tier I Analysis

3.4.1 Energy Requirements and Needs Assessment

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 3.4.1.A shows the percentages of the Total Renewable Energy, Tier I and Tier II requirements for each year of the study.

Year	Total Renewable Energy Requirement	Tier I Renewable Energy Requirement	Tier II Renewable Energy Requirement
2019	55.0%	52.8%	2.2%
2020	59.0%	56.2%	2.8%
2021	59.0%	55.6%	3.4%
2022	59.0%	55.0%	4.0%
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	75.0%	65.0%	10.0%
2033	75.0%	65.0%	10.0%
2034	75.0%	65.0%	10.0%

2035	75.0%	65.0%	10.0%
2036	75.0%	65.0%	10.0%
2037	75.0%	65.0%	10.0%
2038	75.0%	65.0%	10.0%

Table 3.4.1.A

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 3.4.1.A below compares VEC's projected Tier I requirement to its current Tier I committed and pending resources in Post-Tier III load scenarios. A table containing the data the graph is based on is included in "Appendix D: VEC Resource and Needs Projections."

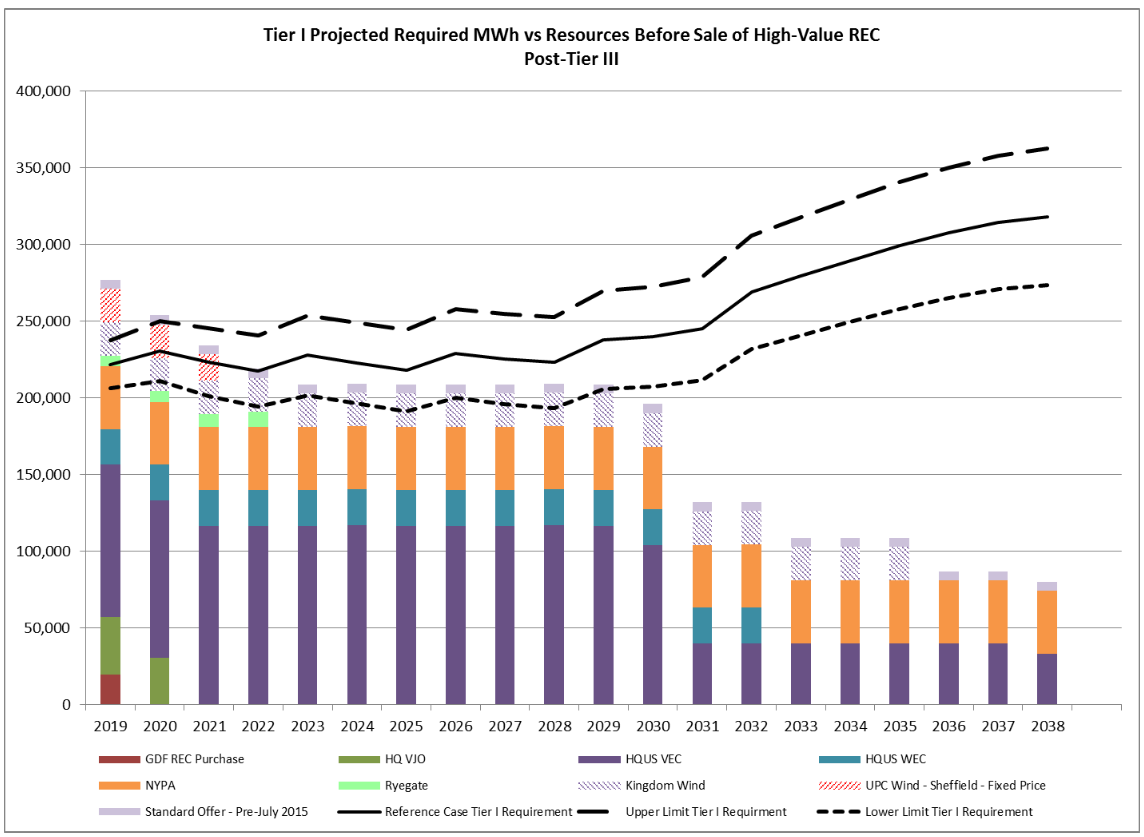

Figure 3.4.1.A – Tier I Pojrected Required MWh vs Resources Before Sale of High-Value REC – Post-Tier III

Table 3.4.1.B below shows the impact of Tier III on the Tier I Reference Case energy requirement on an annual basis.

Year	Post Tier-III MWh	% Increase Due to Tier III
2019	221,924	0.5%
2020	230,759	0.9%
2021	223,390	1.4%
2022	217,618	1.9%
2023	227,867	2.5%
2024	222,724	3.1%
2025	217,994	4.0%
2026	228,942	5.1%
2027	225,465	6.6%
2028	223,189	8.7%
2029	237,805	11.7%
2030	240,009	16.1%
2031	245,409	22.2%
2032	269,085	29.6%
2033	279,435	37.4%
2034	289,692	45.3%
2035	299,385	53.4%
2036	307,875	61.0%
2037	314,495	68.0%
2038	318,123	73.8%

Table 3.4.1.B

There is a noticeable step increase in the requirements every third year. This is a result of the total renewable energy requirement increasing by 4% every third year instead of increasing 1.33% every year.

The graph shows that VEC projects to have enough resources to cover its Tier I energy requirement through 2022. The first annual shortfall is projected for 2023. The shortfall increases through the study period as contracts with Ryegate and HQUS expire.

The graph assumes VEC retains the RECs from Kingdom Wind, Ryegate, Sheffield and Standard Offer projects that came on line prior to July 1, 2015. As of the fall of the spring of 2019, VEC could sell 2019-vintage RECs from these facilities for $8.00-$10.00/REC and its 2020-2022 RECs for $20.00 – $24.00/REC. In addition, 2019-2022-vintage Vermont Tier I RECs currently sell for less than $2.00/REC.

As long as the RECs from Kingdom Community Wind, Ryegate, Sheffield 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 3.4.1.B below compares VEC's projected Tier I requirement to its current Tier I committed and pending resources in the Post-Tier III load scenarios after the sale of high-value RECs. A table containing the data the graph is based on is included in "Appendix D: VEC Resource and Needs Projections."

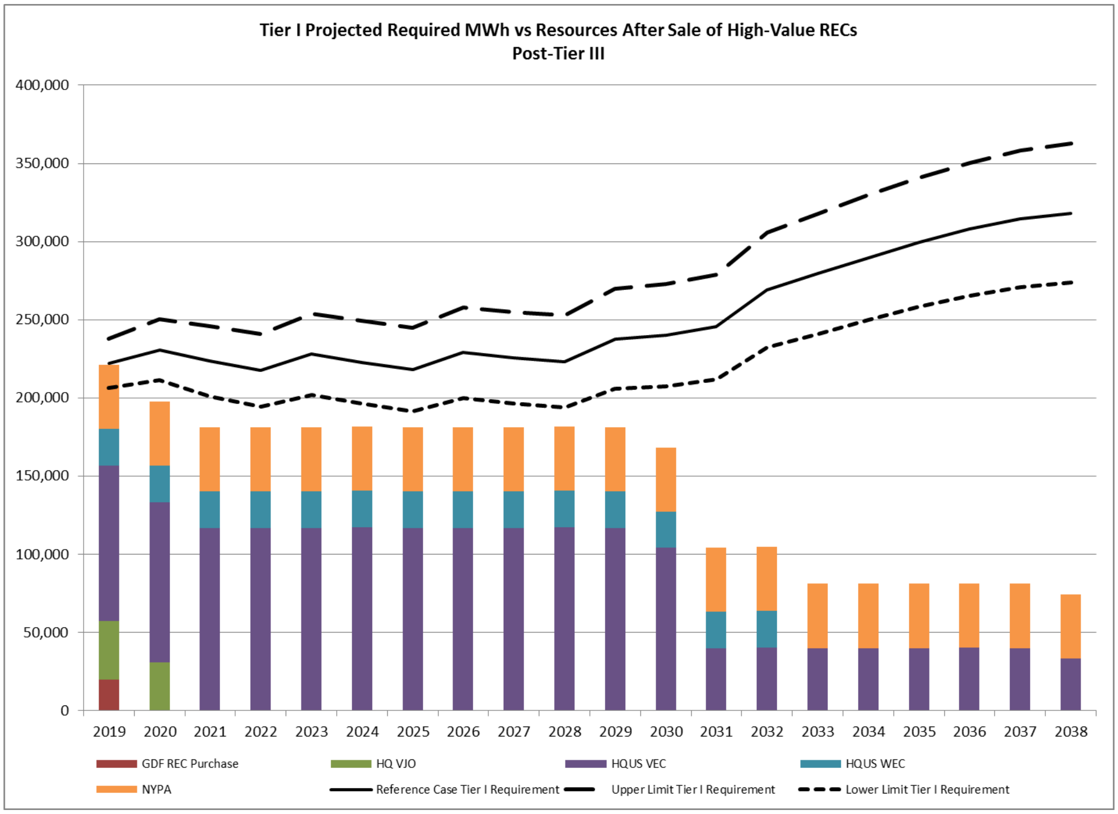

Figure 3.4.1.B – Tier I Projected Required MWh vs Resources After Sale of High-Value RECs – Post-Tier III

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. Sale price of high-priced RECs – In the Reference Case scenario, VEC's 20-year NPV of net costs will increase by approximately $449,923 for every $1/REC decrease in the value of higher-priced Tier I RECs in 2019, increasing by 2% per year. Conversely VEC's 20-year NPV of net costs will decrease by the same amount for every similar increase in the value of high-priced RECs.
2. Purchase price of Tier I RECs – In the Reference Case scenario, VEC's 20-year NPV of net costs will increase by approximately $44,992 for every $0.10/REC decrease in the value of lower-priced Tier I REC in 2019, increasing by 2% per year. Conversely VEC's 20-year NPV of net costs will decrease by the same amount for every similar increase in the value of low-priced RECs.
3. Load growth from 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.
4. 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.

3.5 Tier II Analysis

3.5.1 Tier II Minimum Energy Requirements and Needs Assessment

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

Year	Tier II Renewable Energy Requirement
2019	2.2%
2020	2.8%
2021	3.4%
2022	4.0%
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	10.0%
2033	10.0%
2034	10.0%
2035	10.0%
2036	10.0%
2037	10.0%
2038	10.0%

Table 3.5.1.A

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.

Figure 3.5.1.A below compares VEC's projected Tier II requirement to its current Tier II committed and pending resources in the Post-Tier III load scenarios. A table containing the data the graph is based on is included in "Appendix D: VEC Resource and Needs Projections."

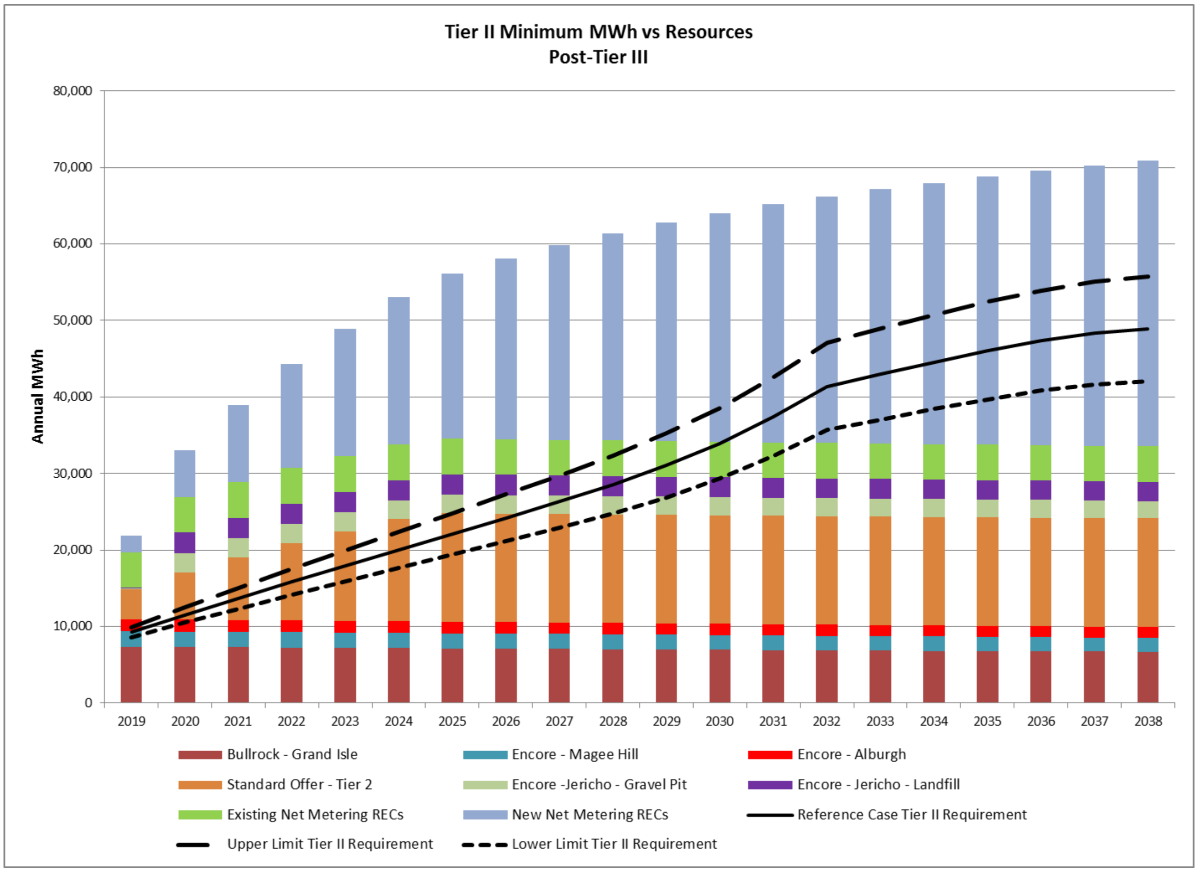

Figure 3.5.1.A

The post-Tier III graph below shows that VEC projects to have enough resources to cover its Tier II energy requirement beyond the end of the study period in all three load growth scenarios.

The scenarios in the graph use VEC's Base projections for net-metering.

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.

As a result, VEC is surpassing its projected Tier II requirements by a large margin assuming the Reference Case Post-Tier III load forecast and net-metering projections.

Figure 3.5.1.B below shows that even using VEC's Low projections for net-metering, it has resources in excess of its Tier II requirement through 2032 in the High Load Growth scenario, 2037 in the Base Load Growth scenario and beyond the end of the study period in the Low Load Growth scenario.

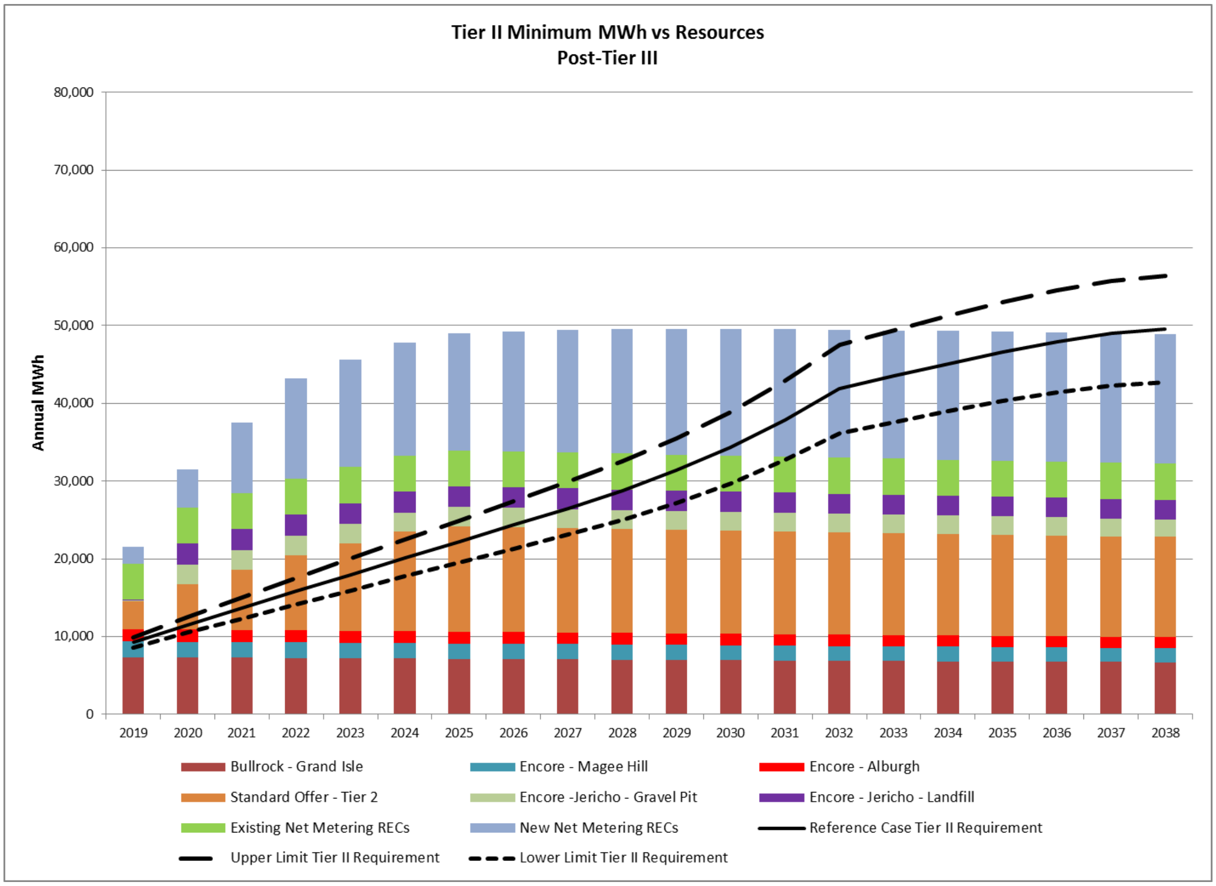

Figure 3.5.1.B

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 electric 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). For each $1.00/REC decrease in price, VEC's net costs will increase by $652,965 in 20-year NPV, using its Reference Case assumptions and $344,959 in 20-year NPV using its Upper Limit load growth assumptions. Conversely VEC's 20-year NPV of net costs will decrease by the same amount for every similar increase in the value of Tier II RECs.
4. Legislative changes to the Tier II requirements – VEC is not aware of any current discussions regarding changes to the Tier II requirements as defined by the RES. However, changes are always a possibility. 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.

3.6 Energy Transformation Tier III Analysis

Tier III of Act 56 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.

VEC utilizes a portfolio of various Tier III projects and programs to meet its annual Tier III requirements. VEC offers bill credits for several Tier III measures such as cold climate heat pumps, heat pump water heaters, electric vehicles, 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.

3.6.1 Cold Climate Heat Pumps and Heat Pump Water Heaters

For cold climate heat pumps (CCHPs) and heat pump water heaters (HPWHs), VEC based its assumptions as to penetration on a 20-year forecast provided by Efficiency Vermont (EVT). EVT provided annual forecasted new installations for CCHPs and HPWHs that replace fossil fuel water heaters across all of state that is served by EVT. VEC applied its historical share of actual installs from 2015-2018 to the EVT forecast in order to develop a forecast specific to VEC's service territory. The results of this approach are consistent with what VEC has observed to date and also with VEC's 2019 Annual Tier III plan. The timing of the annual installations are modeled to be evenly distributed across all months of the year, with the annual energy usage per device defined by Vermont's Technical Advisory Group (TAG). TAG currently assumes 2,345 annual kWh for CCHPs and 1,225 kWh for HPWHs. VEC assumed seasonality of the energy usage to be consistent with a 2018 study released by the Massachusetts Energy Efficiency Council (http://ma-eeac.org/studies/residential-program-studies/)[2]. For CCHPs, VEC made minor adjustments to the seasonality in order account for slightly cooler summers (less cooling load) and slightly colder winters (more heating load) in Vermont than in Massachusetts.

Graphical representations, along with supporting tables, of the forecasted annual new CCHPs and forecasted new HPWHs (that replace fossil fuel water heaters) in VEC's service territory can be found in "Appendix E – Forecasted Adoption of Tier III Technologies."

3.6.2 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

[2] "RES Baseline Load Shape Study" found by expanding the 2018 studies grouping. "Appendix C-4-1 HVAC Load Shape Results" and "Appendix C-4-2 Water Heating Load Shape Results" contain the specific data referenced.

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 E – Forecasted Adoption of Tier III Technologies."

3.6.3 Electric Vehicles

The adoption of electric vehicles (EVs) offers the largest potential impact to the electric grid, specifically in later years as adoption is expected to dramatically increase. VEC developed several basic assumptions in order to determine a forecast of expected EV adoption by members. To start, VEC assumed that on average each of our ~34,000 members owns 2 vehicles and vehicles are replaced every 8 years. This equated to ~8,500 new vehicle purchases by VEC members each year. VEC assumed that in 2019, 0.75% of the new vehicles purchased are EVs, increasing by 50% each year through 2030 and ultimately reaching 100% of new vehicle purchases in 2034. VEC also assumed that the EV purchases are split evenly (50%-50%) between All Electric Vehicles (AEVs) and Plug-in Hybrid Electric Vehicles (PHEVs) in 2019. This equates to 32 new AEVs and 32 new PHEVs for VEC in 2019, consistent with our 2019 Annual Tier III Plan. The split of AEVs and PHEVs is forecasted to shift toward AEVs by 5% each year, meaning that by 2029 100% of the new EVs purchased are AEVs. VEC distributed the annual electric usage for AEVs and PHEVs determined by TAG according to estimates from VEC employees that own, or have owned, EVs based on their experience of decreased efficiency in the winter months due to preheating needs and adverse road conditions in Vermont. VEC employees have experienced up to 30% greater electric consumption by their EVs in the winter months compared to summer months.

A graphical representation, along with a supporting table, of the forecasted annual new electric vehicles in VEC's service territory can be found in "Appendix E – Forecasted Adoption of Tier III Technologies."

3.6.4 Clean Air Program

VEC's innovative Clean Air Program (CAP) allows for discounts on line extensions and service upgrades that eliminate or avoid the use of existing fossil fuel generators. To date, CAP projects have provided the vast majority of VEC's Tier III credits with a focus on the maple sugaring, lumber processing, and paving material processing industries. VEC has forecasted the completion of three smaller CAP projects each year, as well as the completion of one larger CAP project each year. The load from the larger CAP project each year is assumed to be consistent in size and timing to that of our two most recent large CAP projects that have come online, which were a sawmill and a crushing/paving plant.

A graphical representation, along with a supporting table, of the forecasted annual new CAP Projects in VEC's service territory can be found in "Appendix E – Forecasted Adoption of Tier III Technologies."

3.6.5 Tier III Forecast vs Tier III Requirement

Figure 3.6.5.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 VEC has forecasted.

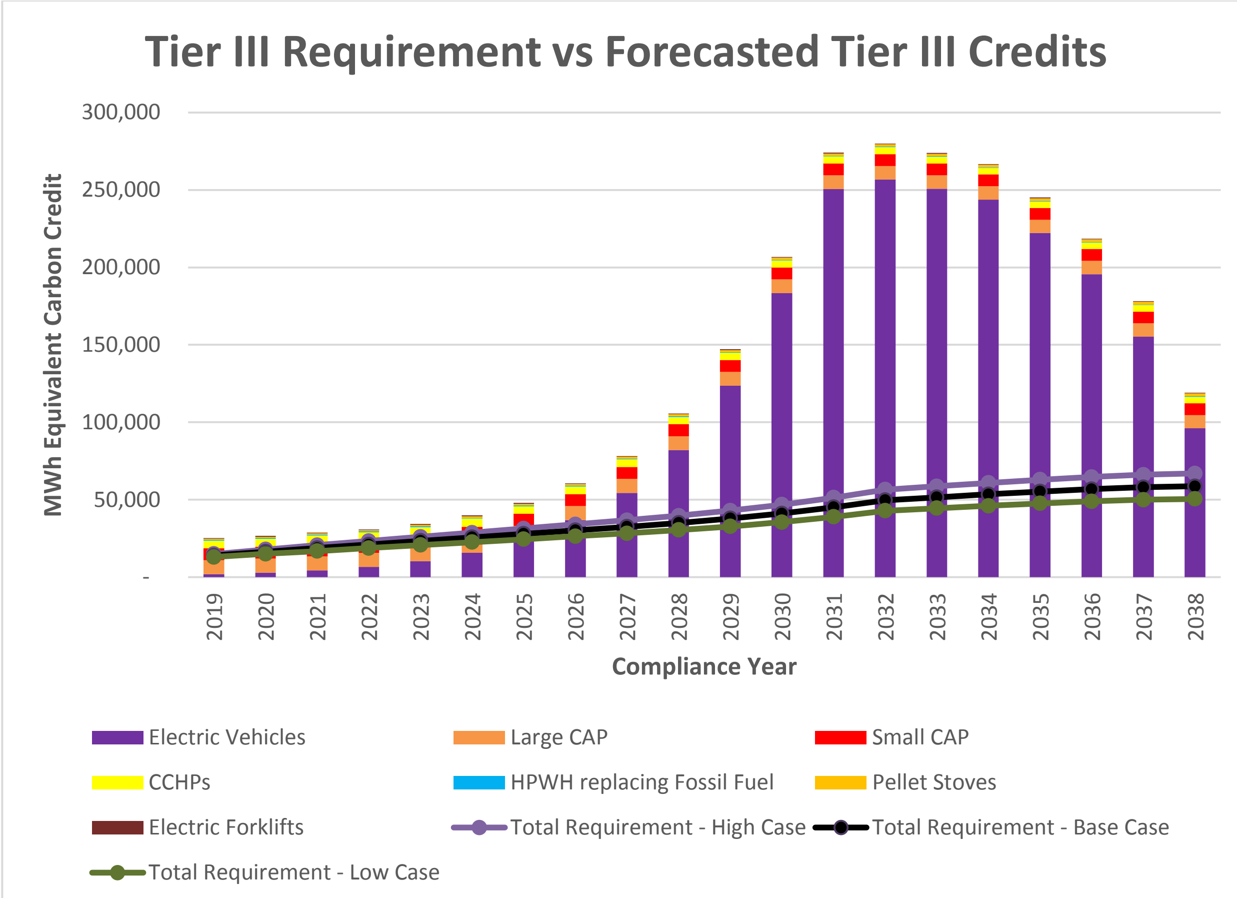

Figure 3.6.5.A – Tier III Requirement vs Foreasted Tier III Credits

As the chart indicates, VEC's success in meeting its short term Tier III requirements is heavily dependent on the completion of custom CAP projects. VEC will need to continue to aggressively pursue CAP project leads and look for new industries where CAP type projects might be a good fit. 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 CAP projects will be increasingly difficult to identify and complete as opportunities reduce. 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.

It is important to note that VEC will likely need to share Tier III carbon credits with other organizations such as EVT if and when VEC partners with such organizations on specific programs and/or projects. For example, in 2018 EVT provided an upstream incentive for CCHPs that resulted in VEC only claiming 23% of the full credit for each CCHP it incentivized.

EVT's CCHP upstream incentive ended in 2018 so VEC is currently able to claim 100% of the carbon credit for each CCHP. Additionally, for CCHPs, VEC has assumed that just 75% of the total installed units actually take advantage of VEC's bill credit incentive meaning VEC is able to claim credit for 75% of the total installed units.

In 2019, EVT began offering an upstream incentive for pellet stoves that results in VEC claiming only 18% of the full pellet stove credit. This sharing breakdown is modeled to continue moving forward. VEC and EVT have also partnered on our most recent large CAP 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 CAP projects due to expected continued partnerships with EVT.

3.6.6 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. Sustainability of CAP projects – The quantity and sizing of custom CAP projects is critical to VEC's short term Tier III success. VEC has been very successful to date in identifying and completing several CAP projects per year over the last several years. Efforts have been aided by the fact that VEC's service territory is home to a large number of 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 CAP leads and work to identify additional CAP leads in other industries.

2. EV adoption – 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 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, or charging station rates.

3. Fossil fuel prices – 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. Fossil fuel prices that are more expensive relative to electricity will result in transitioning off from fossil fuels being more economical to the individual member considering a switch. This would likely increase energy transformation participation across all of VEC's Tier III programs.

4. Excess Tier II RECs used for Tier III – Vermont's Renewable Energy Standard allows for a utility to use excess Tier II RECs in order to meet its Tier III requirements. This strategy helps a utility meet its Tier III requirements not just in the year that the excess RECs are used, but in future years as well. Since RES requirements are based on a percentage of a utilities retail sales and the vast majority of Tier III energy transformation projects result in increased electric sales, using excess Tier II RECs to meet Tier III requirements would keep future RES requirements lower than they would otherwise be if the Tier III requirement was met entirely by energy transformation projects. 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.

3.7 Forward Capacity Market

Through the Forward Capacity Market (FCM), ISO-NE 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 ISO-NE 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 ISO-NE pays for capacity on a monthly basis 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.

ISO-NE pays the capacity resources at the end of each month. ISO-NE 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 ISO-NE 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 75.051 MW in the current commitment period (June 2019 – May 2020) is a function of the Installed Capability 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).

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.

3.7.1 Requirements and Needs Assessment

The first step in projecting VEC's capacity requirement, or capacity load obligation, for each capacity commitment period is to develop a forecast of VEC's load on New England at the time of the New England peak for each year. This was done by using a five step process that included:

1. Starting with VEC's forecasted July peak load from the Daymark load forecast;
2. Adjusting the July peak for a coincidence factor to take into account that VEC's peak is not always in the same hour as the New England peak. The coincidence factor was 0.95 through 2021, then 1.000 thereafter to acknowledge that behind-the-meter solar is pushing the New England 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; and
5. Multiplying the result of steps 1-4 by a reserve margin that accounts for the fact that in the first auction for a commitment period ISO-NE procures an amount of capacity that is approximately 20% higher than the project median New England peak load for the commitment period. Because the amount of capacity procured is later allocated to LSE's based on the actual peak in the year prior to the commitment period, the effective reserve margin can deviate from that used in the auction. For this study VEC used a reserve margin of 42%.

As mentioned earlier in this section, an LSE can hedge it capacity charge from ISO-NE 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. Although VEC does not own any resources outright, it has developed a portfolio of capacity resources by entering fixed-price capacity contracts with a number of suppliers. The terms of these contracts range from 1-year, to up to 25 years.

Figure 3.7.1.A below compare VEC's capacity requirement (Reference Case, Lower Limit and Upper Limit) to the committed resources in its capacity portfolio for the planning period.

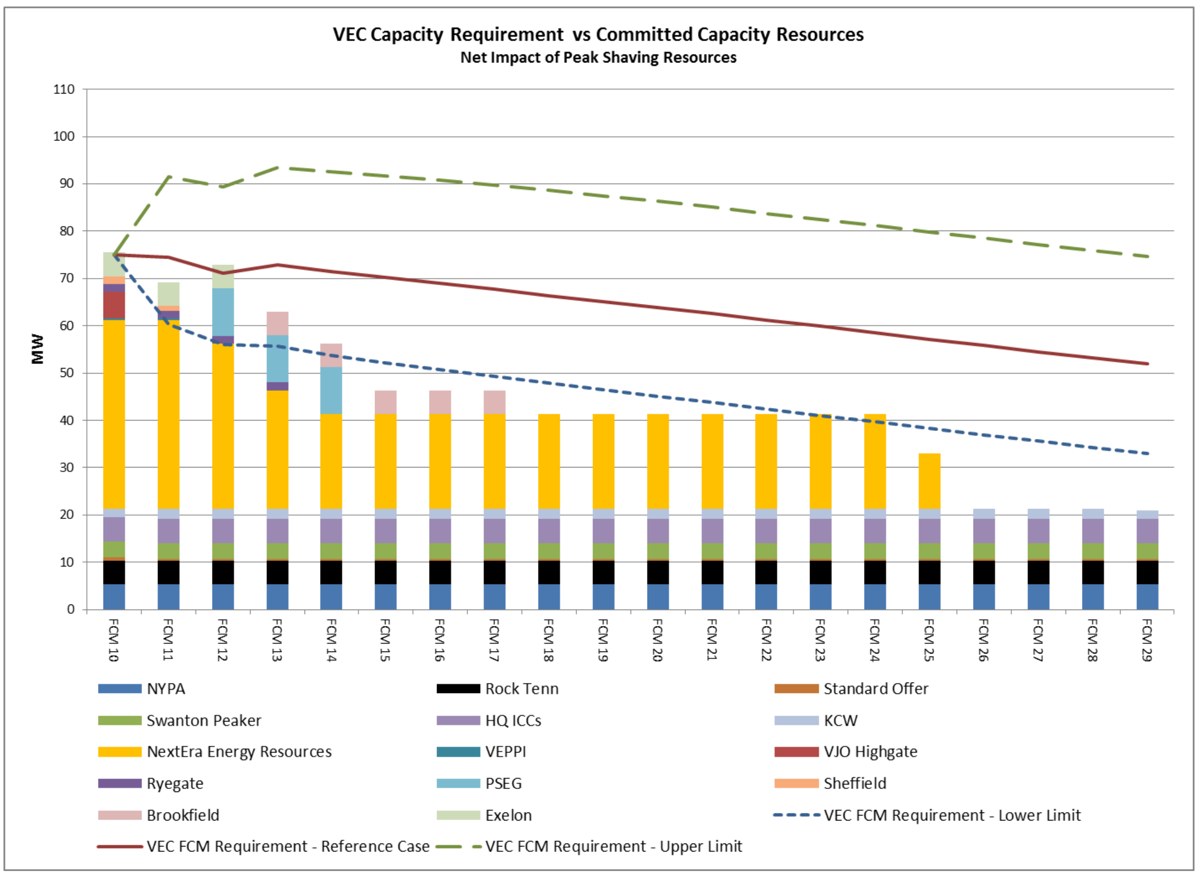

Figure 3.7.1.A – VEC Capacity Reuqirment vs Committed Capacity Resources

In its Reference Case, VEC is fairly well hedged through the June 2021 – May 2022 commitment period. Its open position beginning in June 2022 is currently approximately 9.9 MW, or 13.5% of its projected capacity requirement; this open position increases gradually as contract expire, ranging from 30%-40% from June 2024 through May 2034 before dropping off in June 2034 and again in June 2035.

The open positions in the Lower Limit and Upper Limit cases follow similar trends, but with different magnitudes because the resources are the same in all three cases, but capacity requirements change depending on which of the peak load forecasts, as explained in pages 5-10, is used.

As mentioned above, FCM clearing prices are established annually based on a series of auctions for each June – May commitment period in which various generators and demand response resources offer capacity into the auction at the minimum price they are willing to be paid to supply capacity. The auction clearing prices for each June – May commitment period are based on the highest offer price cleared in a reverse auction to procure enough capacity to meet ISO-NE projected peak demands plus reserves.

Each month, ISO-NE pays generators based on the results of the auctions and charges load serving entities (LSE), such as VEC, based on their percentage share of the load in the one hour ISO-NE peaked in the previous calendar year. For example, VEC's charges for the capacity commitment period covering June 2019 – May 2020 will be based on New England in hour ending 1700 (05:00 PM) on August 29, 2018.

An LSE, such as VEC, has little control over the clearing prices of the Forward Capacity Auctions. However, it can control the price it pays for capacity by entering contracts to purchase capacity at negotiated prices and can have some influence on its load at the time of the New England peak through demand response or some other peak-shaving programs.

Figure 3.7.1.B shows historic auction clearing prices and payment rates already conducted through the 2022-2023 commitment period and VEC's in-house-developed projections for Base, High and Low price cases in nominal dollars:

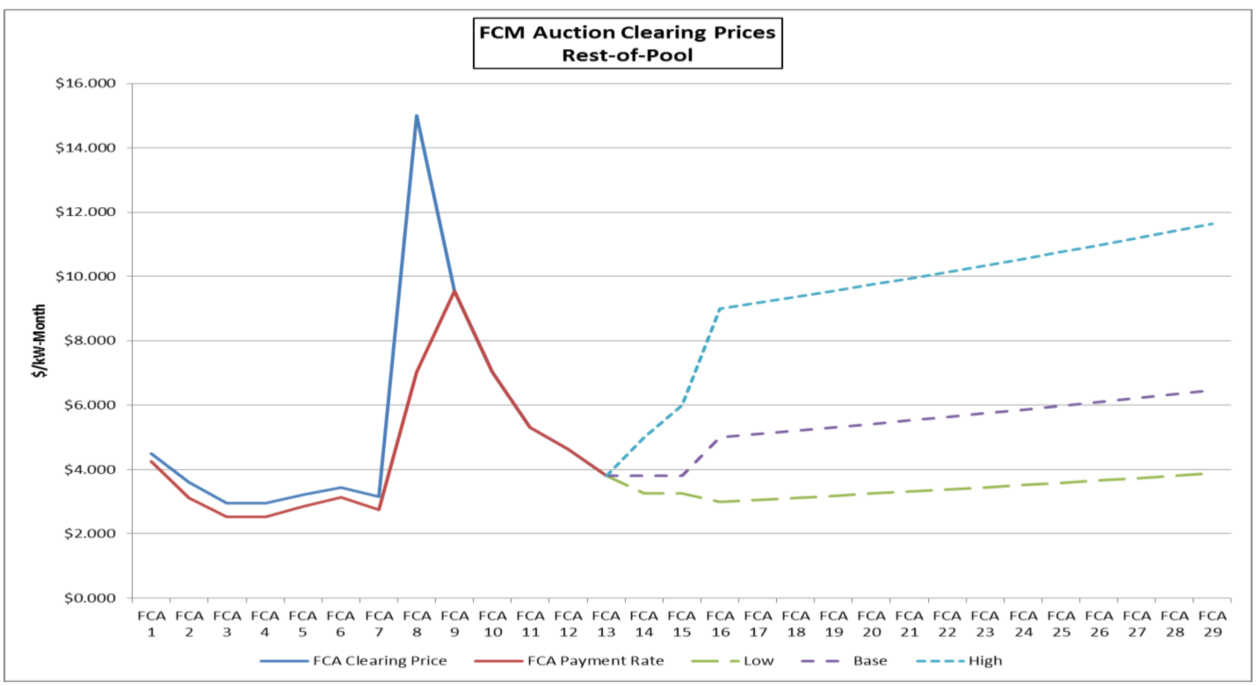

Figure 3.7.1.B – FCM Acutin Clearing Prices – Rest of Pool

New England is currently excess capacity by several thousand MW. This has been the case for the past several auctions. The market is also currently projected to be excess for the auction for the 2023-2024 commitment period to be conducted in February 2020.

The prices in the plot are shown in Table 3.7.1.A below:

Auction	Beginning Month	Low	Base	High	Type
FCA 1	Jun-10		$4.254		Actual
FCA 2	Jun-11		$3.119		Actual
FCA 3	Jun-12		$2.535		Actual
FCA 4	Jun-13		$2.516		Actual
FCA 5	Jun-14		$2.855		Actual
FCA 6	Jun-15		$3.129		Actual
FCA 7	Jun-16		$2.744		Actual
FCA 8	Jun-17		$7.025		Actual
FCA 9	Jun-18		$9.551		Actual
FCA 10	Jun-19		$7.030		Actual
FCA 11	Jun-20		$5.297		Actual
FCA 12	Jun-21		$4.631		Actual
FCA 13	Jun-22	$3.800	$3.800	$3.800	Actual
FCA 14	Jun-23	$3.250	$3.800	$5.000	Projected
FCA 15	Jun-24	$3.250	$3.800	$6.000	Projected
FCA 16	Jun-25	$3.000	$5.000	$9.000	Projected
FCA 17	Jun-26	$3.060	$5.100	$9.180	Projected
FCA 18	Jun-27	$3.121	$5.202	$9.364	Projected
FCA 19	Jun-28	$3.184	$5.306	$9.551	Projected
FCA 20	Jun-29	$3.247	$5.412	$9.742	Projected
FCA 21	Jun-30	$3.312	$5.520	$9.937	Projected
FCA 22	Jun-31	$3.378	$5.631	$10.135	Projected
FCA 23	Jun-32	$3.446	$5.743	$10.338	Projected
FCA 24	Jun-33	$3.515	$5.858	$10.545	Projected
FCA 25	Jun-34	$3.585	$5.975	$10.756	Projected
FCA 26	Jun-35	$3.657	$6.095	$10.971	Projected
FCA 27	Jun-36	$3.730	$6.217	$11.190	Projected
FCA 28	Jun-37	$3.805	$6.341	$11.414	Projected
FCA 29	Jun-38	$3.881	$6.468	$11.642	Projected

Table 3.7.1.A

As seen in Table 3.7.1.B below, the cost exposure to VEC of its open projected capacity position can range greatly depending on load and market prices.

	NPV Cost Exposure Low Price Case	NPV Cost Exposure Reference Price Case	NPV Cost Exposure High Price Case
Lower Limit Shortfall	$201,171	$1,371,172	$3,767,602
Reference Case Shortfall	$9,060,958	$14,153,405	$24,588,610
Upper Limit Shortfall	$19,710,051	$29,509,435	$49,591,168

Table 3.7.1.B

Using the Reference Case price forecast, the 20-year Net Present Value (NPV) of cost exposure ranges from approximately $1.4 million to $29.5 million depending on actual peak loads.

Using the Reference Case peak load forecast the 20-year NPV of cost exposure ranges from $9.0 million to $24.5 million dollars depending on market prices. The nominal annual cost exposure for the three market price projections assuming the Reference Case peak load and resulting shortfall are shown graphically in Figure 3.7.1.C below.

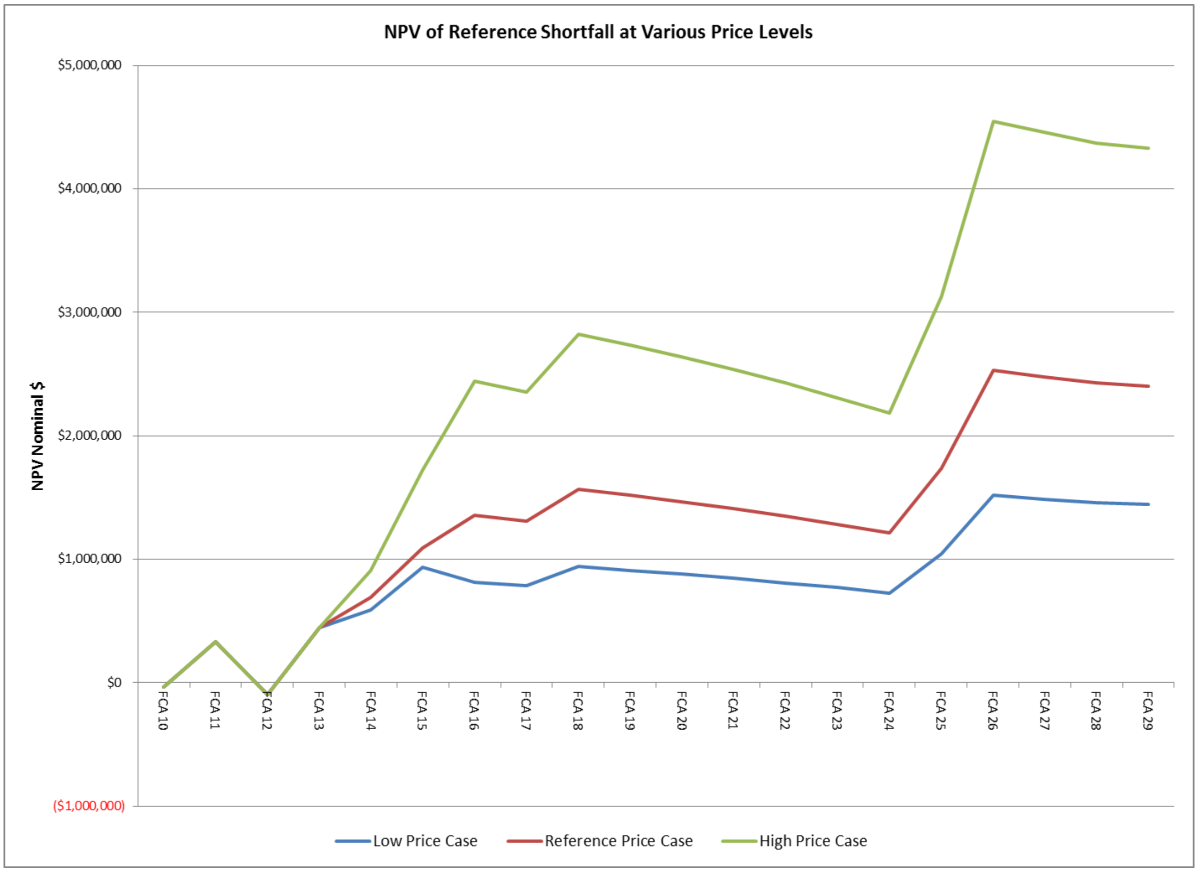

Figure 3.7.1.C – NPV of Reference Shortfall at Various Price Levels

3.7.2 Risks Associated with Management of Forward Capacity Market Portfolio

The range in costs depends on load at the time of the NE annual peak, market prices and the location of a utility's capacity resources compared to its load. This presents a degree of uncertainty for VEC. VEC's load at the time of the NE annual peak is based on many factors such as weather throughout New England, VEC member behavior, the behavior of customers of other utilities in NE, the output of behind-the-meter generation in VEC's territory and throughout New England, and new technologies, etc. that make it difficult to predict accurately. Because ISO-NE conducts the first auction for a commitment period slightly more than 3 years prior to the start of the period, market prices for the next three immediate years are fairly well established and easy to predict. However, because of the mechanics of the auctions and the fact that auction rules are changing each year, market prices for auctions that have not yet been conducted can be volatile, as historic prices show, and can be very difficult to predict. In addition, the changing nature of ISO-New England's defined capacity zones in the capacity market and the potential price separation between zones can result in a utility being compensated for its capacity resources at a different price from what its load is charged.

Fortunately, there are ways for VEC to gain some control over these variables. VEC can control its own loads at the time of the NE peak by developing peak shaving programs. This can be done either through rates designed to incentivize load reduction during peak hours or load shifting to other hours; developing battery programs incentivize using stored energy during peak periods; incentivizing members to use on-site generation during peak periods, or other demand response initiatives. However, peaks will become more difficult to predict as more storage and behind-the-meter solar is installed in Vermont and throughout New England. Storage will tend to flatten out the system peaks, making the exact hour more difficult to predict. Behind-the-meter solar will make the peaks as realized by ISO-NE more difficult to predict because the load as recognized by ISO-NE will change based on cloud coverage, meaning the one hour that New England peaks for the year could occur at 3:00 PM on a cloudy summer day or 7:00 or 8:00 pm on a sunny summer day.

Uncertainty in market prices can be reduced by developing our own capacity resources (whose costs can be largely known) or entering into contracts with suppliers of capacity resources at fixed prices, both of which will increase our capacity portfolio and lock in prices, thereby reducing VEC's exposure to spot market prices. In recognition of the volatility and uncertainty in the markets, it should be noted that although these resources can be used to provide a degree of cost certainty, that does not mean they will less expensive than eventual spot market prices.

Finally, capacity resources that are located in close proximity to Vermont can reduce the likelihood of price separation between VEC's resources and load, making it easier to predict total market costs.

3.8 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 ISO-NE, VEC is responsible for paying for its share of the costs of the bulk transmission system in New England.

Through separate tariffs, portions of ISO-NE and NEPOOL costs are allocated to VEC and all other load serving entities in Vermont on a monthly basis 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 ISO-NE 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.

3.8.1 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 take into account 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.

Figure 3.8.1.A below shows VEC's projected load at the annual average monthly load at the time of the Vermont monthly peak for each June – May period in for which transmission rates are set:

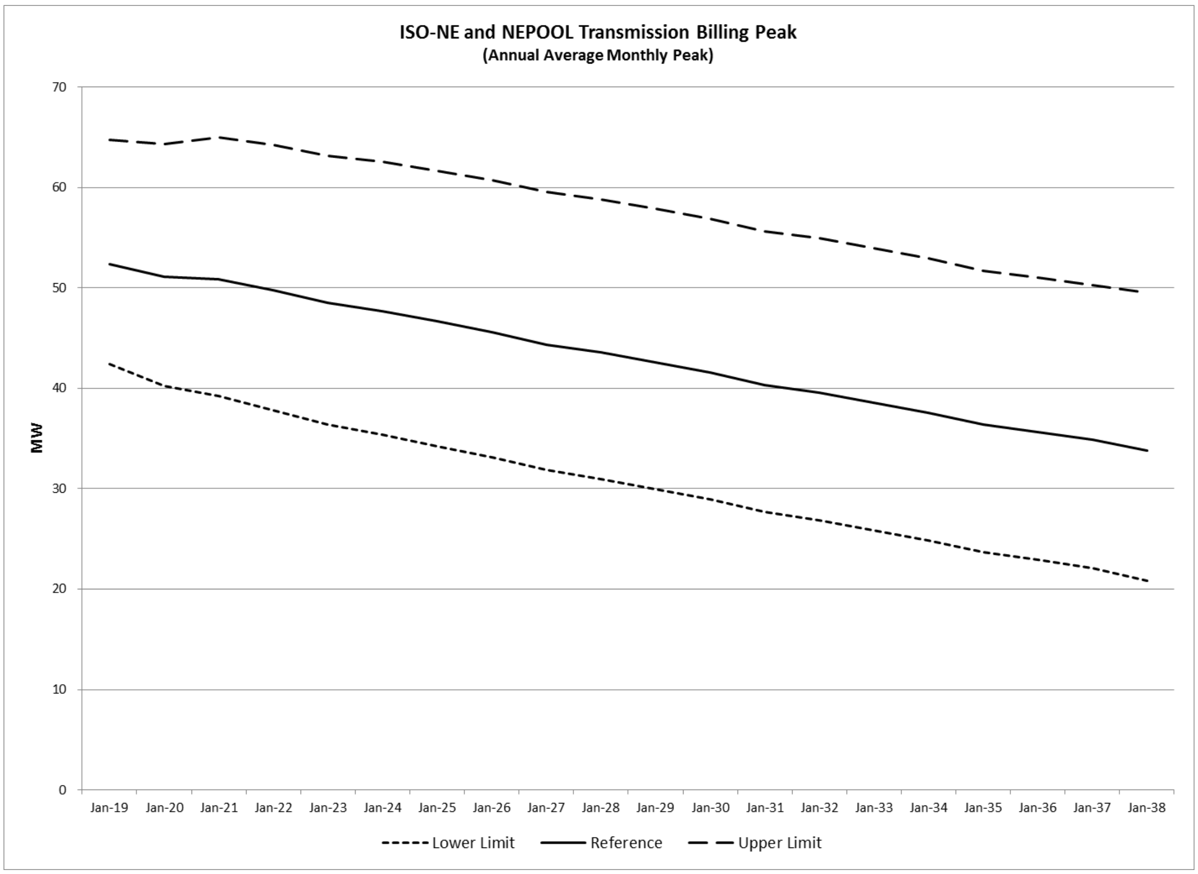

Figure 3.8.1.A – ISO-NE and NEPOOL Transmission Billing Peak

Recall from the forecast discussion earlier in this document, in all three cases, peak load growth prior to any adjustments for peak shaving or efficiency is fairly flat. The downward sloping trend is due to assumed success in dispatching storage peak shaving solutions such as the Hinesburg battery and ongoing energy efficiency installations in VEC's territory by EVT.

3.8.2 Forecasting ISO-NE Schedule 1 and NEPOOL OATT Schedules 1 and 9 Rates

Table 3.8.2.A shows the projected rates for the ISO-NE 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.

Beginning Month	ISO-NE Schedule 1 ($/kW-month)		Beginning Month	NEPOOL OATT Schedule 1 ($/kW-month)	NEPOOL OATT Schedule 9 ($/kW-month)	NEPOOL OATT Total ($/kW-month)
Jan-15	$0.155700		Jun-15	$0.134111	$8.225000	$8.514811
Jan-16	$0.192750		Jun-16	$0.149662	$8.675000	$9.017412
Jan-17	$0.190930		Jun-17	$0.150587	$9.329828	$9.671345
Jan-18	$0.178860		Jun-18	$0.131297	$9.202369	$9.512526
Jan-19	$0.172850		Jun-19	$0.132784	$9.328406	$9.634040
Jan-20	$0.178541		Jun-20	$0.133337	$9.928611	$10.240489
Jan-21	$0.184419		Jun-21	$0.133893	$10.567433	$10.885745
Jan-22	$0.190491		Jun-22	$0.134451	$11.247359	$11.572301
Jan-23	$0.196763		Jun-23	$0.135011	$11.971032	$12.302806
Jan-24	$0.203241		Jun-24	$0.135574	$12.330163	$12.668978
Jan-25	$0.209933		Jun-25	$0.136139	$12.700068	$13.046140
Jan-26	$0.216845		Jun-26	$0.136706	$13.081070	$13.434621
Jan-27	$0.223984		Jun-27	$0.137276	$13.473502	$13.834762
Jan-28	$0.231358		Jun-28	$0.137848	$13.877707	$14.246913
Jan-29	$0.238976		Jun-29	$0.138422	$14.294039	$14.671437
Jan-30	$0.246844		Jun-30	$0.138999	$14.722860	$15.108703
Jan-31	$0.254971		Jun-31	$0.139578	$15.164546	$15.559095
Jan-32	$0.263366		Jun-32	$0.140160	$15.619482	$16.023008
Jan-33	$0.272037		Jun-33	$0.140744	$16.088067	$16.500848
Jan-34	$0.280993		Jun-34	$0.141330	$16.570709	$16.993032
Jan-35	$0.290245		Jun-35	$0.141919	$17.067830	$17.499994
Jan-36	$0.299801		Jun-36	$0.142511	$17.579865	$18.022177
Jan-37	$0.309672		Jun-37	$0.143105	$18.107261	$18.560038
Jan-38	$0.319867		Jun-38	$0.143701	$18.650478	$19.114046

Table 3.8.2.A

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 May 2019 are actuals for all 3 tariff rates.

ISO Tariff 1 rates are actuals through January 2019. Projected rates for January 2020 – December 2038 are based on January 2019 actual rates escalated at the average annual increase from January 2015 – January 2019, which is approximately 3.294% per year.

NEPOOL OATT Schedule 1 rates are actuals through June 2019. Projected rates for June 2020 through June 2038 are based on June 2019 actual rates escalated at the average annual increase from June 2015 – June 2019, which is approximately 0.417% per year.

NEPOOL OATT Schedule 9 rates are actuals through June 2019. Projected rates for June 2020 through June 2023 are based on June 2019 actual rates escalated at the average annual increase from June 2011 – June 2019, which is approximately 6.430% per year. Rates for June 2024 – June 2038 are rates from the previous year escalated at 3% per year.

The rates and peak projections above result in the price projections in Figure 3.8.2.A below:

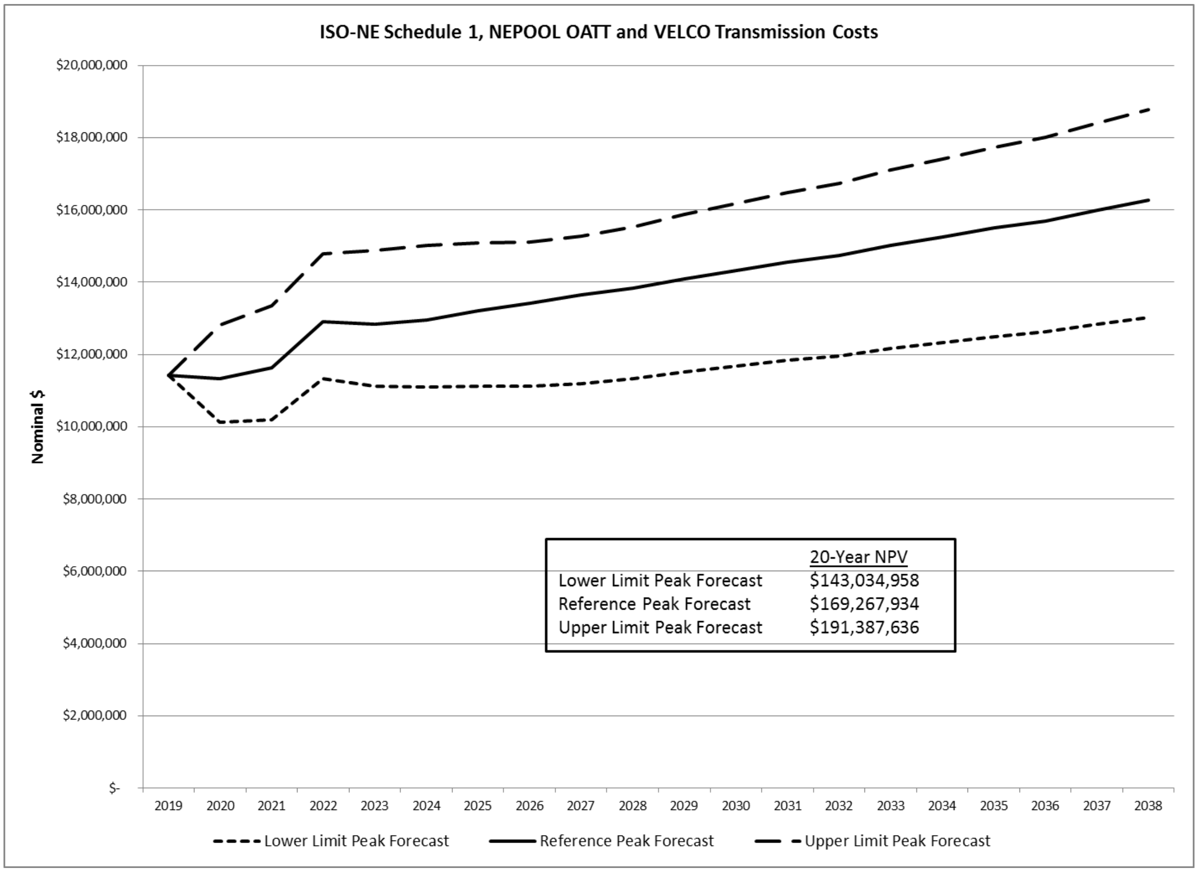

Figure 3.8.2.A – ISO-NE Schedule 1, NEPOOL OATT and VELCO Transmission Costs

It is interesting to note that although the peaks are decreasing, costs are increasing because rates are increasing faster.

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 ISO-NE 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 ISO-NE and NEPOOL will have fewer MW to allocate costs over, increasing the rate charged to all MW still on the system.

3.8.3 Current VEC Initiatives to Minimize Transmission Costs

VEC has been active in trying to minimize ISO-NE and NEPOOL transmission costs, primarily through battery storage at three different levels: utility scale, commercial/industrial sited and residential sited.

Utility Scale Storage

There is no industry specific definition of utility-scale storage. VEC uses the term to mean any storage that is not located at a specific customer site; we anticipate such projects to typically be 150 kW or larger.

VEC has entered an Energy Storage Services Agreement (ESSA) with Viridity Energy Solutions, through which VEC will have the right to call on a 1MW-4MWh battery for 400 hours per year (no more than 4 hours per day) for peak shaving purposes. VEC does not own the battery, but instead pays Viridity a fixed monthly fee for the right to use the battery. When VEC is not using battery, Viridity has the right to use the battery in other ISO-NE markets to enhance their revenue stream. The battery is located at VEC's Hinesburg Substation, and the expected commercial operation date is August 2019.

VEC is open to, and anticipates negotiations for, other utility scale batteries at other locations, some of which may provide benefits to grid operations as well as peak shaving.

Commercial/Industrial Scale

Again, there is no industry-standard definition for commercial/industrial size batteries. VEC uses the term to describe any battery at a specific commercial/industrial member's site for the purposes of providing back-up power or reducing demand charges.

Since September 2017, VEC has had a 2.5-5.0 kW/30 kWh battery located at a specific commercial member's site. The purpose of the project is to see if and how VEC can manage the battery to both reduce the member's demand charges as well as VEC's ISO-NE and NEPOOL transmission charges.

VEC recognizes the potential for third parties to provide storage services to members served through rates with demand charges for the purposes of reducing those demand charges. In this case, under current rate schedules, the member and/or third party could be focused only on reducing that member's peak loads, and not concerned with when the battery is recharged. If the battery is recharged at the time of Vermont's monthly peak or the New England annual peak, VEC's power costs could increase.

By managing the battery or through proper rate design, VEC could incentivize the battery to not be charged during Vermont and New England peak hours thus minimizing costs to VEC and its other members. In addition, if VEC can manage the battery, or incentivize the battery to be discharged in the right hours, VEC's costs could actually decrease.

Residential Scale

VEC has several projects under way on the residential level including:

Behind-the-Meter Device Management – Virtual Peaker

VEC recently entered 12-month agreement with Virtual Peaker (VP) to utilize VP's Software as a Service (SaaS) to manage a wide variety of behind the meter devices, including residential batteries, EV chargers, heat pumps and water heaters, as a Bring-Your-Own-Device (BYOD) offering for its members.

The concept is for members to receive an incentive (such as a fixed monthly bill credit or an upfront payment) in return for allowing VEC to manage the devices for peak shaving an estimated 4-6 times per month.

VEC is targeting a program launch in the third quarter of 2019. The program will likely be rolled out in phases, with an initial focus on batteries, EV charging equipment, and water heating. Cold Climate Heat Pumps may be included as well at a later date. Potential eligible battery systems include Sonnen, SolarEdge, Sunverge, Pika, Fortress Power, and Eguana Tech. Potential eligible EV charging manufacturers (Level II) include ChargePoint, Flo and JuiceNet/eMotorwerks, while potential eligible water heaters include Rheem and GE for Virtual Peaker.

Residential Water Heater Management – Packetized Energy

VEC has an active water-heater-control program with Packetized Energy utilizing their Mello smart controller hardware (retrofit installation) and their “Nimble” management platform. The Packetized Energy program provides participating members with a $25 gift card at signup and again after 1 year of participation. Currently there are approximately100 connected devices, dispatched daily for peak shaving/price arbitrage.

Packetized Energy’s software also works with Enphase 1.0 batteries (do not support back-up power for members).

Residential Battery Program

For the past 18 months VEC has been exploring options with Tesla in an attempt to offer a residential battery program through which VEC purchases Tesla Powerwalls and leases them to members at a fixed monthly fee. The member receives back-up power through the battery, but also agrees to allow VEC to control the battery for peak shaving purposes.

VEC and Tesla have not yet been able to reach favorable terms mainly due to VEC’s small scale. VEC has recently reached out to other Cooperatives to see if there is a way to offer a joint program and gain economies of scale.

Other

VEC also has several other projects that are designed to manage its load at times or state and/or regional peaks. These include:

Time of Use Rates

Time-of-Use rates are offered to all Tier III Energy Transformation program participants. The rate applies to their full account, not just the new technology.

Beat the Peak

“Beat-the-Peak” – VEC has had this program for several years in which is issues an alert 2-4 times per summer encouraging members to reduce electricity consumption for a specified window of hours with a reasonably high likelihood of being the ISO-NE annual peak hour. This is an optional program with no direct incentive to participating members. If we had a simple, reliable baselining tool, we could potentially offer a DR program that shares savings with participating members.

Peak Load Management

Peak Load Management (PLM) initiatives are led by VELCO. VEC is collaborating with VELCO and the other Vermont utilities evaluating software that can predict state and New England peaks based on weather forecasts and historic load data. The group had previously been working with collaboration with Utopus Insights, but Utopus has recently put PLM work on hold causing VELCO and the VT DU’s to pursue other options. Currently being considered are proposals from Itron and Arc that would entail load forecasting and peak prediction services for VT DU’s. Whether or not any fees for this service can be justified by more accurately predicting peaks than methods currently being used by the individual utilities is still uncertain at this point.