Barton Village, Inc.

2023 Integrated Resource Plan

As Filed with the Public Utility Commission

Vermont Public Power Supply Authority

EXECUTIVE SUMMARY

Barton Village, Inc. (BVI) has operated an electric utility system since 1894 in the northern part of Vermont, located close to the Canadian border, in Orleans County and part of Caledonia County in the Northeast Kingdom. BVI remains guided by the Vermont Public Utility Commission ("PUC") rules as well as by the American Public Power Association's ("APPA") safety manual. As a small municipal utility BVI is careful to balance maintaining reliability and reasonable cost levels with the need to deliver innovative programs to customers that provide practical value.

BVI's 95 square mile service territory encompasses the Village of Barton as well as portions of six of the surrounding towns: Barton Town, Charleston, Westmore, Brownington, and parts of Sutton and Irasburg. About 53% of BVI's customers are served within the village and town portions of Barton. In total, BVI serves approximately 2,100 customers.

BVI's distribution system serves a mix of residential and small commercial customers. Residential customers make up over 90% of the customer mix while accounting for three-quarters of BVI's retail kWh sales. One-hundred-and-eighty-three small commercial customers make up approximately 18% of retail usage with the remaining 7% of retail sales going to public authority customers, and public street and highway lighting.

Consistent with regulatory requirements, every 3 years BVI is required to prepare and implement a least cost integrated plan (also called an Integrated Resource Plan, or IRP) for provision of energy services to its Vermont customers. BVI's Integrated Resource Plan (IRP) is intended to meet the public's need for energy services, after safety concerns are addressed, at the lowest present value life cycle cost, including environmental and economic costs, through a strategy combining investments and expenditures on energy supply, transmission and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs.

ELECTRICITY DEMAND

BVI is facing a period of relatively flat demand influenced by several competing factors, all of which carry some uncertainty. Continued adoption of solar net metering reduces demand although the pace at which net metering will grow in BVI's territory is uncertain. As various incentives aimed at transitioning from fossil fuels to cleaner electricity are made available, increasing acceptance of cold climate heat pumps and similar appliances will likely increase demand, as will an expected increase in the use of electric vehicles. Forecast increases in the adoption of cold climate heat pumps, other appliances, and electric vehicles is expected to overtake demand reductions associated with solar net metering in the next 5 to 10 years, resulting in modest projected load growth in the longer term.

While no significant change in the demand associated with BVI's largest customers is currently anticipated, the potential does exist. BVI monitors the plans of these large customers in order to anticipate necessary changes to the existing system infrastructure. In the case of a significant expansion by one or more customers, detailed engineering studies may be needed to identify necessary system upgrades.

ELECTRICITY SUPPLY

BVI's current power supply portfolio includes entitlements in a mixture of baseload, firm and intermittent resources through ownership or contractual arrangements of varying duration, with most contracts carrying a fixed price feature. Designed to meet anticipated demand, as well as acting as a hedge against exposure to volatile ISO-New England spot market prices, the portfolio is heavily weighted toward hydro, solar, and other renewable resources.

When considering future electricity demand, BVI seeks to supplement its existing resources with market contracts as well as new demand-side and supply resources. BVI believes that in addition to working with financially stable counterparties, it is important for new resource decisions to balance four important characteristics: new resources should be low cost, locally located, renewable and reliable. Market contracts have the advantage of being both scalable and customizable in terms of delivery at specific times and locations. BVI anticipates regional availability of competitively priced renewable resources including solar, wind, (offshore wind as it becomes competitively priced), and hydro. In addition to being a factor in meeting future electricity requirements, these categories of resources contribute to meeting Renewal Energy Standard goals. Gas fired generation may have a role to play in the future portfolio for reliability purposes. As battery storage technology matures and proves economically feasible, BVI sees potential for storage to play an important load management role and to enhance the local impact of distributed generation.

RESOURCE PLANS

Looking ahead to evaluating major policy and resource acquisition decisions, BVI employs an integrated financial model that takes into account impacts on load and subsequent effects on revenue and power supply costs, as well effects on investment, financing and operating costs. Use of the integrated model allows for evaluation of uncertainty related to key variables, on the way to identifying anticipated rate impacts over time. While rate trajectory is the primary metric BVI relies on to evaluate resource decisions on an individual or portfolio basis there are other more subjective factors to consider, including resource diversity or exposure to major changes in market rules.

There are four major resource decisions that will affect BVI's resources over this IRP timeframe. Importantly, the first decision, occurs during 2028-2032 forecast period, when Brookfield Hydro expires at the end of 2027. Options being evaluated include extending the contract, which is a longer-term fixed-price contract for bundled hydro energy including Vermont Tier I RECs.

The second major resource decision faced by BVI involves whether to develop a solar array adjacent to the Heath Substation. The array under consideration will be sized to fulfill BVI's Vermont Tier II requirements, approximately 1 MW, and may be paired with battery storage.

The third major resource decision occurs when the Fitchburg Landfill PPA expires on 12/31/26. The PPA includes an option to extend by 5 years at a predetermined price. The election to extend the contract will need to be made by the middle of 2025.

The fourth major resource decision is to collaborate with a storage developer to develop a site adjacent to the Heath Substation in connection with the referenced solar array. If successful, this resource would be procured through a 25-year Energy Storage Service Agreement (ESSA).

RENEWABLE ENERGY STANDARD

BVI is subject to the Vermont Renewable Energy Standard (RES) which imposes an obligation for BVI to obtain a portion of its energy requirements from renewable resources. The RES obligation increases over time and is stratified into three categories, Tier I, Tier II, and Tier III. BVI' s obligations under Tier I can be satisfied by owning or purchasing RECs from qualifying regional resources. Tier II obligations must be satisfied by owning or purchasing RECs from renewable resources located within Vermont. Satisfaction of BVI's Tier III obligation involves energy transformation, or reduction of fossil fuel use within its territory. Tier III programs can consist of thermal efficiency measures, electrification of the transportation sector, and converting customers that rely on fossil fuel generation to electric service, among other things. By providing incentive programs to encourage conversion of traditional fossil fuel applications such as space heating, water heating, or internal combustion engine vehicles to electric power, BVI receives credits toward its Tier III obligation. More detail regarding BVI's plans to meet its Tier III obligation is available in Appendix A to this document.

ELECTRICITY TRANSMISSION AND DISTRIBUTION

BVI has a compact service territory as a result of being a small, municipal-owned electric utility and has consistently pursued upgrade initiatives in order to maintain a reliable and efficient system. BVI has over 200 miles of distribution lines in a radial feed configuration with two 13.2kV Y/7.6kV feeders from the Heath substation serving customers in the Village of Barton, Sutton, Westmore, Brownington, Town of Barton, Charleston, and Irasburg. Some older areas of the system step down further to 2.4kV delta.

BVI has undergone a variety of challenges and changes over the past few years. Barton Village Trustees pursued a sale of the utility beginning in 2019. On March 28, 2022, the Barton Village Trustees voted unanimously to recommend the sale of Barton Electric Department (BVI) to Vermont Electric Cooperative (VEC). The vote followed a three-year process of weighing options and developing a long-term plan for Barton Village and Barton Electric, including almost three years of contracting with VEC for services, following the departure of Barton's manager and line workers in April 2019. Informational meetings and public hearings regarding the proposed sale to VEC were held on April 16, 2022, and May 1, 2022. On May 10, 2022, Barton Village voters rejected Article 15 (100 to 48) in which they were asked "Shall the Village be authorized to sell substantially all of the assets of the Barton Electric Department, inclusive of any real estate assets, but exclusive of the Village's hydroelectric facility assets, to Vermont Electric Cooperative at a purchase price determined based on the net book value of such assets as of the closing date of sale."

As a result of the vote against the sale, VEC gave notice of its intent to terminate the operation agreement with it ultimately ending on August 12, 2022.

In June 2022, Barton Village Trustees hired consultants to provide professional services relative to the management and operation of Barton Electric Department (BVI) planning for next steps after the village vote.

As a result, an RFP was issued on July 8, 2022, which was sent to all Vermont distribution utilities. VPPSA responded to the RFP and Village Trustees selected their proposal on August 8, 2022. VPPSA began providing operation coverage and linework service on August 12, 2022, thereby replacing VEC with no gap in coverage to ratepayers.

Under the arrangement, VPPSA manages and provides Barton Electric with a contracted and dedicated line crew and the necessary tools and equipment to perform regular operations during business hours. VPPSA partnered with Orleans Electric and Lyndonville Electric Department to provide coverage around-the-clock and to restore any unplanned outages.

Village Trustees have indicated the desire to attempt to sell the utility again. At this point in time, trustees plan to solicit proposals from all Vermont distribution utilities and interested parties. In this second attempt to sell the utility, it will address issues and concerns brought forward by parties that were active in the original sale process. Barton, with the help of its consultants, will navigate this complex business situation and it plans to present an alternative sale to Village voters in the upcoming two years. Managing the utility through consultants and contractual arrangements will continue for the next several years until a sale is attempted. In the meantime, Barton Trustees will assure its ratepayers continued service and reliable operations through these agreements.

In addition to upgrading and routinely maintaining the system to ensure efficiency and reliability, BVI is looking at the need to update its system to support additional distributed generation and beneficial electrification on the system and to provide customers with targeted services including load management supported by more innovative programs and rate designs that reduce costs for both BVI and its customers. BVI is currently engaged, with VPPSA, in the final stages of a multi-phased process. Implementation of the AMI system is tentatively planned to begin in late 2024, dependent on the outcome of the ongoing evaluation for Barton to sell or retain the Electric Department. BVI sees potential value to customers by utilizing rate design, direct load control or other incentive programs as tools to manage both system and customer peak loads in unison. Implementation of an AMI system is expected to enhance BVI's ability to deliver these benefits and capture economic development/retention opportunities where possible.

BVI is also working with VPPSA on implementing a centralized GIS mapping system that will coordinate with the AMI system and benefit situational awareness of infrastructure, asset life cycles, preventive maintenance, and vegetation management. These new systems will also enhance BVI's ability to identify developing concentrations of load, distributed generation, and "hot spots" related to intensifying electrification.

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INTRODUCTION

Incorporated in 1894. Barton Village, Inc. (BVI)'s service territory is located in Orleans County and part of Caledonia County in the Northeast Kingdom of Vermont. Its approximately 95 square mile service territory can be seen on the Vermont Utility Service Territory map found below, and it encompasses the Village of Barton as well as portions of six of the surrounding towns: Barton Town, Charleston, Westmore, Brownington, and parts of Sutton and Irasburg. About 53% of BVI's customers are served within the village and town portions of Barton. BVI serves approximately 2,100 retail customers. Like most of Vermont's smaller municipal utilities, many of its utility functions, such as office staffing, are carried out by employees who also have responsibilities in other aspects of village municipal operations. BVI remains guided by the Vermont Public Utility Commission (PUC) rules as well as by the American Public Power Association's (APPA) safety manual. Well-established practices keep BVI operating safely, efficiently, and reliably.

BARTON VILLAGE, INC. SALE STATUS AND NEXT STEPS

Faced with several challenging issues related to running an electric utility, including increased industry complexity, cost of providing service, difficulty retaining line workers and challenges of securing experienced management, the Barton Village Trustees pursued a sale of the utility beginning in 2019. On March 28, 2022, the Barton Village Trustees voted unanimously to recommend the sale of Barton Electric Department (BVI) to Vermont Electric Cooperative (VEC). The vote followed a three-year process of weighing options and developing a long-term plan for Barton Village and Barton Electric, including almost three years of contracting with VEC for services, following the departure of Barton's manager and line workers in April 2019. Informational meetings and public hearings regarding the proposed sale to VEC were held on April 16 and May 1, 2022.

On May 10, 2022, Barton Village voters rejected Article 15 in which they were asked "Shall the Village be authorized to sell substantially all of the assets of the Barton Electric Department, inclusive of any real estate assets, but exclusive of the Village's hydroelectric facility assets, to

Vermont Electric Cooperative at a purchase price determined based on the net book value of such assets as of the closing date of sale." The vote was 100 to 48 against Article 15.

As a result of the vote against the sale, VEC gave notice of its intent to terminate an operation agreement that had been in effect since 2019. Through this agreement VEC provided linework, outage response and operation services via contract to roughly 2,200 Barton rate payers. VEC's contract for operation and line work services ended on August 12, 2022.

In the wake of these events, the Village Trustees requested assistance to devise a plan for the electric department including an assessment of its critical needs, outline of options to manage the utility, and identification of next steps after the village vote. Barton Village Trustees hired consultants to provide valuable professional services relative to the management and operation of Barton Electric Department (BVI); they were brought on in early June 2022. Their role was to help the Village Trustees implement a plan for next steps after the village vote.

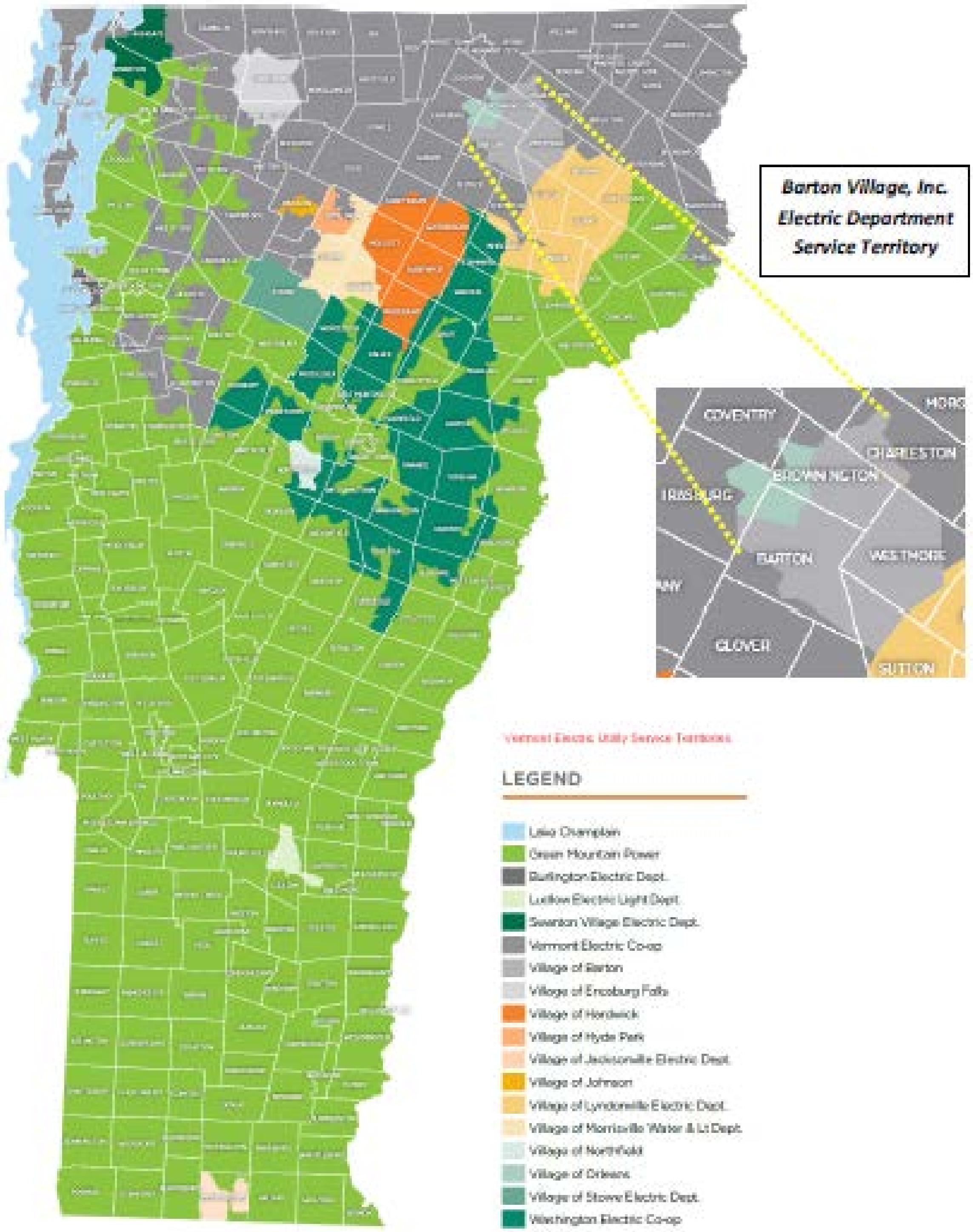
The first step was to devise a plan to provide replacement line work and operation services after VEC's contract ended. It was critically important to successfully replace VEC's operation service contract as electricity is vital to our daily lives. Simply put, power restoration must be addressed to assure reliable power to all of BVI's ratepayers. As a result, an RFP was issued on July 8, 2022, which was sent to all Vermont distribution utilities. VPPSA responded to the Barton RFP and its proposal was selected on August 8, 2022, by Village Trustees. VPPSA began providing operation coverage and linework service on August 12, 2022, thereby replacing VEC with no gap in coverage to ratepayers.

Under the arrangement, VPPSA manages and provides Barton Electric with a contracted and dedicated line crew and the necessary tools and equipment to perform regular operations during business hours. VPPSA partnered with Orleans Electric and Lyndonville Electric Department to provide coverage around-the-clock and restore any unplanned outages. As a result, Barton ratepayers have been provided seamless operation service with no gap in outage response.

Barton is working with VPPSA to identify operation challenges including safety and line maintenance needs, vegetation management improvements, and issues that can impact response time. System maintenance will be overseen and managed to assure reliable electric service to Barton consumers. A plan will be developed to address critical line and operational issues. Line related issues will be sorted into a rational timeline, weighing priorities and financial impacts. VPPSA will identify other issues that need to be addressed, and sort topics in terms of importance and costs.

With the operation and restoration work now being handled and managed by VPPSA, the Village Trustees can now develop an action plan for its next steps. Village Trustees have indicated the desire to attempt again to sell the utility noting the complexities of managing a utility continue and staffing challenges have been unresolved. At this point in time, trustees plan to solicit proposals from all Vermont distribution utilities and interested parties. In this second attempt to sell the utility, it will address issues and concerns brought forward by parties that were active in the original sale process. Barton and its consultants will navigate this complex business situation and plans to present an alternative sale to Village voters in the upcoming two years. Managing the utility through consultants and contractual arrangements will continue for the next several years until a sale is attempted. In the meantime, Barton Trustees will assure its ratepayers continued service and reliable operations through these agreements.

Figure 1: BVI's Distribution Territory



VERMONT PUBLIC POWER SUPPLY AUTHORITY

The Vermont Public Power Supply Authority (VPPSA) is a joint action agency established by the Vermont General Assembly in 1979 under Title 30 VSA, Chapter 84. It provides its members with a broad spectrum of services including power aggregation, financial support, IT support, rate planning support and legislative and regulatory representation. VPPSA is focused on helping local public power utilities remain competitive and thrive in a rapidly changing electric utility environment.

BVI is one of eleven member utilities of VPPSA, which is governed by a board of directors that consists of one appointed director from each member. This gives each municipality equal representation. VPPSA's membership includes:

- Barton Village Inc.,
- Village of Enosburg Falls Electric Light Department,
- Hardwick Electric Department,
- Village of Jacksonville Electric Company,
- Village of Johnson Electric Department,
- Ludlow Electric Light Department,
- Lyndonville Electric Department,
- Morrisville Water & Light Department,
- Northfield Electric Department,
- Orleans Electric Department, and
- Swanton Village Electric Department.

BVI and VPPSA are parties to a broad Master Supply Agreement (MSA). Under the MSA, VPPSA manages BVI's electricity loads and power supply resources, which are pooled with the loads and resources of other VPPSA members under VPPSA's Independent System Operator – New England (ISO-NE) identification number. This enables VPPSA to administer BVI's loads and power supply resources in the New England power markets.

SYSTEM OVERVIEW

In 2021 BVI's annual non-coincident peak demand in the winter months was 2,732 KW and 2,972 KW during the summer and shoulder months. Annual energy retail sales for 2021 were 14,231,551KWh and the annual load factor was 62%.

BVI is connected to the Vermont Electric Cooperative (VEC) transmission system.

Table 1: BVI's Retail Customer Counts

Data Element	2017	2018	2019	2020	2021
Residential (440)	1,949	1,945	1,957	1,969	1,978
Small C&I (442) 1000 kW or less	186	183	178	177	176
Large C&I (442) above 1,000 kW	0	0	0	0	0
Street Lighting (444)	3	3	3	3	3
Public Authorities (445)	14	15	15	15	15
Interdepartmental Sales (448)	14	15	18	20	19
Total	**2,166**	**2,162**	**2,172**	**2,185**	**2,191**

Table 2: BVI's Retail Sales (KWh)

Data Element	2017	2018	2019	2020	2021
Residential (440)	10,057,047	10,185,244	10,099,154	10,862,720	10,936,635
Small C&I (442) 1000 KW or less	2,619,983	2,513,736	2,493,312	2,335,433	2,397,667
Large C&I (442) above 1,000 KW	0	0	0	0	0
Street Lighting (444)	73,195	127,277	115,951	130,160	118,088
Public Authorities (445)	527,614	573,016	576,143	477,175	566,327
Interdepartmental Sales (448)	234,666	246,849	280,309	218,433	212,834
Total	**13,512,505**	**13,646,122**	**13,564,869**	**14,023,921**	**14,231,551**
YOY	-2%	1%	-1%	3%	1%

Table 3: BVI's Annual System ([1]NCP) Peak Demand ([2]TLEL)

Data Element	2017	2018	2019	2020	2021
Peak Demand KW	3,020	2,987	2,835	2,833	2,972
Peak Demand Date	12/28/17	01/01/18	01/21/19	08/11/20	08/13/21
Peak Demand Hour	18	19	18	20	19

BVI owns and operates the two-turbine 1,300 KW nameplate Barton Village Hydroelectric Project located in West Charleston.

[1] Noncoincident Peak (NCP)

[2] Total load excluding losses (TLEL)

STRUCTURE OF REPORT

This report is organized into six major sections plus an appendix and a glossary.

ELECTRICITY DEMAND

This chapter describes how BVI's electricity requirements were determined and discusses sources of uncertainty in the load forecast.

ELECTRICITY SUPPLY

This chapter describes BVI's electricity supply resources, and the options that are being considered to supply the electricity needs of BVI's customers.

RESOURCE PLANS

This chapter compares BVI's electricity demand to its supply and discusses how BVI will comply with the Renewable Energy Standard.

ELECTRICITY TRANSMISSION AND DISTRIBUTION

This chapter describes BVI's distribution system and discusses how it is being maintained to provide reliable service to its customers.

FINANCIAL ANALYSIS

This chapter presents a high-level forecast of BVI's power supply costs and cost of service.

ACTION PLAN

This chapter outlines specific actions the BVI expects to take as a result of this IRP.

APPENDIX

The appendix includes a series of supporting documents and reports.

GLOSSARY

ELECTRICITY DEMAND

I. ELECTRICITY DEMAND

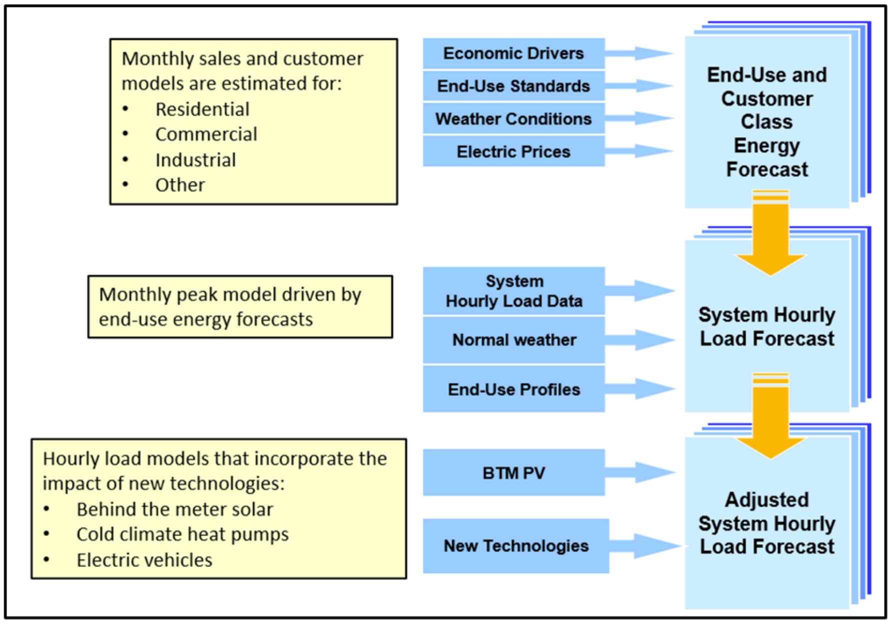
ENERGY FORECAST: STATISTICALLY ADJUSTED END USE METHODOLOGY

VPPSA retained Itron to forecast BVI's peak and energy requirements. Using the SAE (Statistically Adjusted End Use) methodology, the Itron team used the same electrification inputs and assumptions that were developed by the Vermont System Planning Committee in connection with development of VELCO's 2021 Long-Range Transmission Plan (LRTP). Specifically, the adoption rates for heat pumps and electric vehicles (also known as "electrification") are shared with the LRTP.

The 2022 long-term forecast includes energy and peaks underpinned by forecasts of customer class sales and adjusted for the impact of electrification technologies. The forecast is based on a bottom-up framework where long-term demand is driven by underlying customer class sales (residential, commercial, industrial, street lighting, and other use). The impact of new technologies is then layered on top of the baseline forecast as shown in Figure 2.[3]

[3] VPPSA 2022 Long-Term Load Forecast Report, Itron, 2022, page 2

Figure 2: Forecasting Process



ENERGY FORECAST RESULTS

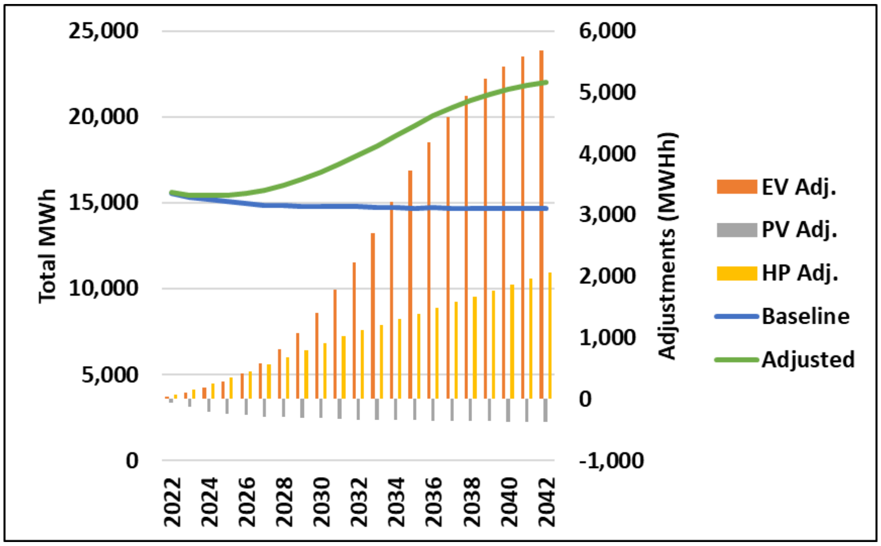
Table 4 shows the Baseline Forecast for energy, as well as the adjustments that are made to arrive at the Adjusted Forecast. The Compound Annual Growth Rates (CAGR) at the bottom of the table illustrate the trends in each of the columns. Notice that the Baseline Forecast itself is declining by 0.3% per year. After making adjustments for electric vehicles (EV), net metered solar (NM PV) and heat pumps (HP) the Adjusted Forecast increases by 1.6% per year.

Table 4: Adjusted Energy Forecast (MWh/Year)

Year	Yr #	Baseline Forecast (MWh)	EV Adj. (MWh)	NM PV Adj. (MWh)	HP Adj (MWh)	Adj. Forecast (MWh)
2022	1	15,577	45	-59	76	15,639
2027	5	14,874	590	-285	560	15,739
2032	10	14,782	2,227	-335	1,118	17,792
2037	15	14,701	4,605	-353	1,581	20,534
2042	20	14,656	5,680	-374	2,072	22,034
CAGR		-0.3%	25.9%	9.2%	17.0%	1.6%

The Adjusted Forecast is the result of high CAGRs for HPs (17%) and EVs (25.9%) and the impact of these trends can be seen in the green line in Figure 3.

Figure 3: Adjusted Energy Forecast (MWh/Year)



ENERGY FORECAST – HIGH & LOW CASES (IN PROGRESS)

To form a high case, we assumed that the penetration rate for EVs and HPs doubles from the base case in 2027 (Year 5) and 2032 (Year 10). We assume that net metering penetration continues as forecast in the base case. At these growth rates, the market penetration for CCHPs and EVs reaches approximately 160% and 94% each in 2042. This rough estimate assumes that most households and buildings will eventually have more than one CCHP and more than one car. Nevertheless, it gives a reasonable indication of the kind of growth in energy use that is possible: 3.1% per year. This growth rate results in a 90% increase over 2022 electricity use.

Table 5: Energy Forecast – High Case (MWH)

Year	Yr #	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	Adj. Forecast
2022	1	15,577	45	-59	76	15,639
2027	5	14,874	1,180	-285	1,119	16,889
2032	10	14,782	4,454	-335	2,236	21,137
2037	15	14,701	9,210	-353	3,163	26,721
2042	20	14,656	11,361	-374	4,143	29,786

CAGR	-0.3%	30.1%	9.2%	20.9%	3.1%

To form a low case, we assumed that the penetration for CCHPs and EVs is half of the base case, and we kept the net-metered PV penetration rate the same as the base case. This results in a forecast that increases by 0.7% per year.

Table 6: Energy Forecast - Low Case (MWH

Year	Yr #	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	Adj. Forecast
2022	1	15,577	45	-59	76	15,639
2027	5	14,874	295	-285	280	15,164
2032	10	14,782	1,114	-335	559	16,120
2037	15	14,701	2,302	-353	791	17,441
2042	20	14,656	2,840	-374	1,036	18,158
CAGR		-0.3%	21.8%	9.2%	13.2%	0.7%

PEAK FORECAST RESULTS

Table 7 and Table 8 show the results of the Baseline Forecast of peak loads, as well as the adjustments that are made to arrive at the Adjusted Forecast. The CAGR at the bottom of the table illustrate the trends in each of the columns. Notice that the Baseline Forecast itself is decreasing by 0.2% per year. After making adjustments for CCHPs, EVs, and net metering, the Adjusted Forecast increases by 2.0-3.2% per year. The timing of the peak hour is expected to be remain in the late afternoon and early evening hours.

Table 7: Summer Peak Forecast (MW)

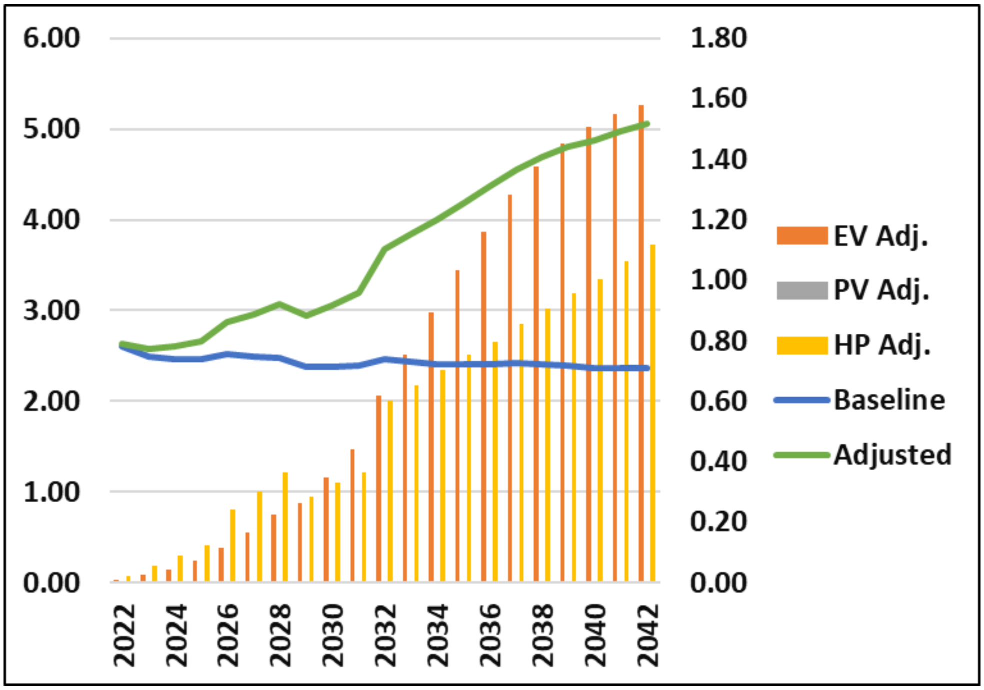
Year	Yr #	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	Adj. Forecast
2022	1	2.7	0.0	0.0	0.0	2.7
2027	5	2.6	0.1	0.0	0.1	2.8
2032	10	2.6	0.4	0.0	0.2	3.2
2037	15	2.7	0.9	0.0	0.2	3.8
2042	20	2.6	1.3	0.0	0.3	4.1
CAGR		-0.2%	27.4%		16.1%	2.0%

Table 8: Winter Peak Forecast (MW)

Year	Yr #	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	Adj. Forecast
2022	1	2.6	0.0	0.0	0.0	2.6
2027	5	2.5	0.2	0.0	0.3	3.0
2032	10	2.5	0.6	0.0	0.6	3.7
2037	15	2.4	1.3	0.0	0.9	4.6
2042	20	2.4	1.6	0.0	1.1	5.1
CAGR		-0.5%	26.7%		20.1%	3.2%

The size of the adjustments can be seen in Figure 4, which shows the winter peak forecast net of adjustments. The transformer at the Heath substation is rated up to 12.5 MVA, which is more than large enough to accommodate this peak load forecast, even when Orleans loads are included.

Figure 4: Adjusted Winter Peak Forecast (MW)



PEAK FORECAST – HIGH & LOW CASES

To form a high-case, we assume that neither load controls nor Time-of-Use (TOU) rates are implemented, and then we adopt the same assumptions from the high case as in the energy forecast. Under these assumptions, peak load growth starts to impact the system by 2027, and by 2042, the peak reaches 7.7 MW.

Table 9: Winter Peak Forecast – High Case (MW)

Year	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	Adj. Forecast
2022	2.6	0.0	0.0	0.0	2.6
2027	2.5	0.3	0.0	0.6	3.4
2032	2.5	1.2	0.0	1.2	4.9
2037	2.4	2.6	0.0	1.7	6.7
2042	2.4	3.2	0.0	2.2	7.7
CAGR	-0.5%	30.9%		24.1%	5.3%

A plausible low case for the peak forecast would involve applying TOU electric rates and load control devices on all of the major end uses, especially CCHPs and EVs. In theory, this strategy could completely offset any peak load growth resulting from CCHPs and EVs. As a result, it is not necessary to quantify a low case scenario. Peak loads would simply match the Baseline Forecast without any adjustments.

TIER III IMPACTS ON THE FORECAST

The provisions of the Tier III Best Practices and Minimum Standards state:

> "For a Retail Electricity Provider implementing Energy Transformation Projects that increase the use of electric energy, the Provider's Tier III annual plan shall include: (A) reference to the load forecast developed in the Provider's most recently Commission approved Integrated Resource Plan and any relevant updates to or major deviations from the assumptions used in that load forecast."[4]

Based on the following analysis, the load forecast adjustments for heat pumps and electric vehicles is greater than the electrification that is budgeted through Tier III programs. This difference represents a deviation between the load forecast and the Tier III Annual Plan.

Table 10 shows the budgeted measures from VPPSA's 2023 Tier III budget, and the increased electric loads that are anticipated. These loads are based on averages as published in the Tier III Planning Tool. Ninety-five percent of the new electric loads are expected to come from only two technologies: heat pumps and electric vehicles. Table 10 shows Barton's share of VPPSA's Tier III budget, and it indicates 32.9 MWH of new electric loads are likely in 2023.

This number is lower than the heat pump and electric vehicle adjustments from Itron. The work papers supporting Table 4 show that Itron forecasted a 265 MWH increase in electric loads for 2023 as a result of these technologies. The difference is about seven-to-one in terms of Tier III programs (265 MWH / 32.9 MWH), but is only 1.5% of the adjusted forecast in 2023. This is well within the forecast error[5] of the forecast itself.

[4] PUC Rule 4.415 (6)(A)

[5] The Mean Absolute Percentage Error (MAPE) in Itron's energy model was 3.83%.

Table 10: Program Year 2023 Tier III Measures & Their Expected Impact on Load

Measure	# Measures	Added MWH/Unit/Yr	Total New MWH/Yr
Electric Bicycle	1	0.03	0.03
Electric Vehicle – New	3	2.4	7.2
Heat Pump – Ductless	8	2.4	19
WBHP – Ducted	1	5.7	5.7
Heat Pump Water Heater	1	0.9	0.9
Total	14		32.9

TIER III LOAD CONTROL

Rule 4.417 requires "a discussion of the available options for controlling load and their effectiveness and costs, the options the Provider is implementing and why, and whether the projected volume of Energy Transformation Projects warrants demand management activities; strategies to be used for encouraging the installation of technologies in buildings that meet minimum energy performance standards, as applicable; and strategies to be used for Customer education, outreach, and marketing."

VPPSA continues to investigate options for load control and is piloting both GridFruit for controlling refrigeration loads and open-source Electric Vehicle Supply Equipment (EVSE). The EVSE pilot is particularly promising because it is attempting to gain cost-effective access to the data without having to pay for proprietary, subscription-based access.

From a technical perspective, there are many credible options for controlling load. However, they all must scale up to be economically competitive. Based on quotes from various vendors to date, the subscription cost of data acquisition and reporting can be prohibitive as shown in the following table.

Table 11: Cost and Size Ranges of Typical Pay-Per-Device Load Control Programs ($/kW-mo)

	kW Savings					
$/Yr/Device	**0.5**	**1.0**	**1.5**	**2.0**	**2.5**	**5.0**
$250	$41.67	$20.83	$13.89	$10.42	$8.33	$4.17
$200	$33.33	$16.67	$11.11	$8.33	$6.67	$3.33
$150	$25.00	$12.50	$8.33	$6.25	$5.00	$2.50
$100	$16.67	$8.33	$5.56	$4.17	$3.33	$1.67

Many vendors offer a pay-per-device subscription fee as shown in the first column of Table 11. For devices that are 1.5 kW and smaller, the fees are far too large to justify the cost. For example, a $250 per device charge for a one kW device would cost $20.83/kw-month. This compares to avoided capacity costs that are about $2.50/kW-month and transmission avoided costs that are about $12/kW-month. As a result, this business model does not work for small devices, at least not at low levels of participation. However, large devices can quickly become cost-effective as shown in the green shaded areas.

Innovative rates are a potentially cost-effective way to manage load. As a result, VPPSA is exploring innovative rates that may include Time-of-Use (TOU) based rates. This effort may inform rates applicable to both residential electric vehicle chargers and public charging stations, as well as providing rate research that can carry over into more generalized load management efforts.

VPPSA will continue to pilot promising load control technologies and work to gain cost-effective access to the devices and the data they can provide. From a load forecasting perspective, we will continue to use load shapes that reflect best practices, as determined by the Technical Advisory Group (TAG).

FORECAST UNCERTAINTIES & CONSIDERATIONS

BVI presently has forty-one residential scale (< 15 kW) net metered customers with a total installed capacity of about 310 kW. However, as solar net metering costs continue to decline, the cost of net metered solar could reach parity with the price of grid power. If state policy continues to be supportive of net metering in this event, it could lead to a step change in the adoption rate of net metering, and a quicker erosion of retail sales and revenues for the utility.

Given the small size of the customer base and the nascent trends involved, net-metering represents a key uncertainty for BVI to monitor, especially if larger net metered projects are proposed. For example, a 100 kW net metered solar project built in 2023 would add 33% to the base of installed, net metered capacity on the system. In this event, the impact would be captured in interconnection and annual power budgeting processes and managed accordingly.

ELECTRICITY SUPPLY

II. ELECTRICITY SUPPLY

BVI's power supply portfolio is made up of generation resources, long-term contracts, and short-term contracts. The portfolio acts as a diversified, financial hedge that buffers BVI and its customers from the cost and volatility of buying electricity from ISO New England on the spot market at the Vermont Zone. The following sections describe each of the power supply resources in BVI's portfolio.

EXISTING POWER SUPPLY RESOURCES

1. **Barton Hydro**

- Size: 1.4 MW
- Fuel: Hydro
- Location: Charleston, VT
- Entitlement: 100% (1.4 MW), Owned
- Products: Energy, capacity, renewable energy credits (VT Tier I & MA II)
- End Date: Life of Unit

2. **Brookfield Hydro 2023-2027**

- Size: 8-10 MW On-Peak, 7-8.5 MW Off-Peak
- Fuel: Hydro
- Location: MA HUB
- Entitlement: 6-7.5% On Peak, 7-8.6% Off Peak
- Products: Energy, VT Tier I RECs
- Term: 1/1/2023 - 12/31/2027

3. **Fitchburg Landfill**

- Size: 4.5 MW
- Fuel: Landfill Gas
- Location: Westminster, MA
- Entitlement: 5.553%, PPA
- Products: Energy, capacity, renewable energy credits (MA Class I)
- End Date: 12/31/26 with option to extend to 12/31/31

4. Kruger Hydro

- Size: 6.7 MW
- Fuel: Hydro
- Location: Maine and Rhode Island
- Entitlement: 5.7579%, 0.391 MW, PPA
- Products: Energy, capacity
- End Date: 12/31/37
- Notes: BVI has an agreement with VPPSA to purchase unit contingent energy and capacity from six hydroelectric generators. The contract does not include the environmental attributes and appears as system mix in the summary table.

5. Market Contracts

- Size: Varies
- Fuel: New England System Mix
- Location: New England
- Entitlement: Varies (PPA)
- Products: Energy, renewable energy credits
- End Date: Varies, less than 5 years.
- Notes: BVI purchases system power from various other entities under short-term (5 year or less) agreements.

6. New York Power Authority (NYPA)

- Size: 3.044 MW (Niagara), 0.195 MW (St. Lawrence)
- Fuel: Hydro
- Location: New York State
- Entitlement: 2.12%, 0.17 MW (Niagara PPA), 0.599%, 0.01 MW (St. Law. PPA)
- Products: Energy, capacity, renewable energy credits (NY System Mix)
- End Date: 9/1/25 (Niagara), 4/30/2032 (St. Lawrence)
- Notes: NYPA provides hydro power to BVI under two contracts, which will be extended at the end of their term.

7. Project 10

- Size: 40 MW
- Fuel: Oil
- Location: Swanton, VT
- Entitlement: 2.16% (0.864 MW), joint-owned through VPPSA
- Products: Energy, capacity, reserves
- End Date: Life of unit
- Notes: As the joint-owner, VPPSA has agreements with BVI to pay for and purchase 2.16% of the unit's output.

8. Ryegate

- Size: 20.5 MW
- Fuel: Wood
- Location: East Ryegate, VT
- Entitlement: 0.2658% (0.0545 MW), PPA
- Products: Energy, capacity, renewable energy credits (CT Class I)
- End Date: 10/31/2023

9. Standard Offer Program

- Size: Small renewables, primarily solar < 2.2 MW
- Fuel: Mostly solar, but also some wind, biogas and micro-hydro
- Location: Vermont
- Entitlement: 0.2694% (Statutory)
- Products: Energy, capacity, renewable energy credits
- End Date: Varies
- Notes: BVI is required to purchase power from small power producers through the Vermont Standard Offer Program in accordance with PUC Rule #4.300. The entitlement percentage fluctuates slightly each year with BVI's pro rata share of Vermont's retail energy sales.

10. Stetson Wind 2023-2027

- Size: 20-27 MW
- Fuel: Wind
- Location: Washington County, Maine
- Entitlement: 1.0% in 2023, 2.3% in 2024
- Products: Energy, VT Tier I RECs
- Term: 1/1/2023 - 12/31/2024

Table 12 summarizes the resources in the portfolio based on a series of important attributes. First the megawatt hours (MWH) and megawatts (MW) show the relative size of each resource. The delivery pattern indicates what time of the day and week the resource delivers energy, and the price pattern indicates how the resource is priced. Notice that most of the resources are fixed-price. This feature provides the hedge against spot market prices. If the resource produces Renewable Energy Credits (RECs), that is indicated in the seventh column, followed by the resource's expiration date and whether we assumed that it would be renewed until 2042.

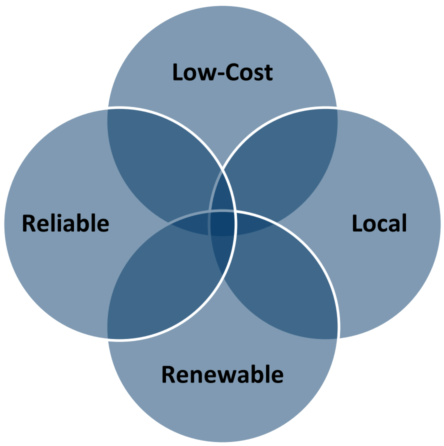
Table 12: Existing Power Supply Resources

RESOURCE	2023 MWH	% of MWH	2023 MW	Delivery Pattern	Price Pattern	REC	Expiration Date
Barton Hydro	4,416	27.1%	0	Run of river	O&M Only	✓	Life of unit
Brookfield Hydro	3,910	24.0%	0	Firm	Fixed + Annual %	✓	12/1/27
Fitchburg Landfill	2,021	12.4%	0.244	Baseload	Fixed	✓	12/31/27
Kruger Hydro	1,311	8.0%	0.213	Run of river	Fixed		12/1/2037
Market Contracts	1,310	8.0%	0	Firm	Fixed		Varies
NYPA Niagara	1,958	12.0%	0.303	Baseload	Fixed	✓	Life of unit
NYPA St. Lawrence	54	0.3%	0.008	Baseload	Fixed	✓	Life of unit
Project #10	10	0.1%	0.835	Peaking	Fuel Cost		Life of unit
Ryegate	436	2.7%	0.054	Baseload	Fixed	✓	2032
Standard Offer Program	411	2.5%	0	Intermittent	Fixed	✓	Varies
Stetson Wind	464	2.8%	0	Intermittent	Fixed + Annual %	✓	12/1/27
Total MWH	**16,301**	100.0%	1.657				

FUTURE RESOURCES

BVI will seek out future resources that meet as many of the following criteria as possible. Ideally, future resources will meet four criteria by being low-cost, local, renewable and reliable.

Figure 5: Resource Criteria



- ✓ **Low-Cost** resources reduce or stabilize electric rates.
- ✓ **Local** resources are located within BVI's Regional Planning Commission area or within Vermont.
- ✓ **Renewable** resources meet or exceed RES requirements.
- ✓ **Reliable** resources not only provide operational reliability, but are also owned and operated by financially strong and experienced companies.

These criteria enable BVI to focus on a subset of generation technologies, and to exclude coal, geothermal and solar thermal generation which do not meet them. Resources that BVI may consider fall into three categories: 1.) Existing resources in Table 12, 2.) demand-side resources, and 3.) new resources that meet the criteria in Figure 5.

CATEGORY 1: EXTENSIONS OF EXISTING RESOURCES

This plan assumes that two existing resources are extended past their current expiration date. These include Project 10 and NYPA. Depending on how contract negotiations align with the resource criteria, other existing resources may be extended including the Brookfield Hydro and Stetson Wind resources. Where resource needs remain, market contracts will be used to supply them.

1.1 MARKET CONTRACTS

Market contracts are expected to be the most readily available source of electric supply for energy, capacity, ancillary services and renewable attributes (RECs). By conducting competitive solicitations through VPPSA, BVI can not only get access to competitive prices (low-cost), but it also can structure the contracts to reduce volatility (stable rates) and potentially include contracts for RECs for RES compliance. Market contracts are also scalable and can be right-sized to match BVI's incremental electric demands by month, season and year. In many cases, the delivery point for market contracts can be set to the Vermont Zone reducing potential price differential risks between loads and resources. Finally, the financial strength of the suppliers in the solicitation can be predetermined. The combination of these attributes makes market contracts a good fit for procuring future resources.

CATEGORY 2: DEMAND-SIDE RESOURCES

The lowest cost, lowest environmental impact and most local source of energy is often energy that is conserved or never consumed. As a result, BVI will continue to welcome the work of the Efficiency Vermont (EVT). BVI will also continue to work with its customers, both large and small, to uncover demand response opportunities. This includes best practices for demand management as BVI continues to implement its energy transformation programs under RES.

VPPSA has several pilot projects that are in progress with Efficiency Vermont. This includes a Behavioral Demand Response program where VPPSA sends notices of potential transmission and capacity peaks to member utilities with recommendations to maximize generation and minimize electric demand during the forecast peak window. VPPSA also provides public notice of potential capacity peaks via social media, Front Porch Forum, and press releases. This includes recommendations to minimize electric demand during the forecast peak window.

VPPSA is also collaborating with Efficiency Vermont to install forty residential EV chargers. The chargers will be programmed to avoid charging during peak hours and customers will be provided with information about how this benefits the electric grid and the cost of electricity.

CATEGORY 3: NEW RESOURCES

VPPSA regularly meets with developers throughout New England, and through VPPSA staff, BVI will continue to monitor and evaluate new generation resources in the New England region.

3.1 BATTERY STORAGE

VPPSA conducted a Request for Information (RFI) process in 2020 to better understand the business case for storage. Nine companies responded, including four that were based in Vermont and two that are among the largest developers in the US. The pricing that was received was used to develop a net-present value positive business case for peak shaving that is congruent with other storage projects that have already been built in Vermont. Based on a peak shaving business case and the strength of the responses to the RFI, VPPSA conducted a Request for Proposals (RFP) process in 2021 and selected a development partner.

BVI is presently developing a storage project that is adjacent to the Heath substation. The size of the project is being studied, and if the results of that study are supportive, we expect that the 248 permitting process could begin in 2023.

3.2 HYDROELECTRIC GENERATION

Hydroelectric generation is widely available in the New England region, and can be purchased within the region or imported from New York and Quebec. Furthermore, it can be sourced from either small or large facilities, and can sometimes be purchased "firm", meaning that the seller is willing to guarantee delivery regardless of hydrological conditions. Like all existing resources, price negotiations begin at or near prevailing market prices. As a result, existing hydro generation could be both low-cost (or at least at market) and renewable.

3.3 SOLAR GENERATION

Solar is the primary technology that can meet BVI's Distributed Renewable Energy (TIER II) requirements under RES, and BVI is in the early stages of development with a utility scale solar project. As RES Tier II requirements increase, solar is likely to be a leading resource option. As a result, BVI will continue to investigate solar developments both within and outside its service territory.

3.3.1 NET METERING

BVI has 41 net-metered customers and an installed base of solar capacity of 310 kW. BVI will monitor the participation rate closely as solar costs approach grid parity. Should grid parity occur, not only would net metered solar penetration be expected to increase but the costs of the existing program would likely cause upward rate pressure. As a result, net metered solar is an inferior option when compared to lower-cost and utility scale solar projects.

3.4 WIND GENERATION (ON AND OFF-SHORE)

On-shore wind projects continue to be developed in New England, and entitlements to such projects can often be negotiated at competitive prices. RECs are often bundled into the PPA, making this resource a good fit for the low-cost and renewable criteria.

Off-shore wind projects are in development, and the costs are becoming competitive. As a result, BVI will consider both on and off-shore wind PPA's as those opportunities arise.

3.5 GAS OR OIL-FIRED GENERATION

Project 10 underwent a major overhaul in 2022, and the expected life of the unit spans the planning period. As a result, no new sources of gas or oil-fired generation are being planned for in this IRP.

3.6 NUCLEAR GENERATION

BVI's contract for nuclear energy expired in 2022, and is being replaced by renewables (hydro, solar and wind) to comply with the RES. However, BVI supports all forms of low-carbon energy, and will consider nuclear power in the future if it is feasible.

REGIONAL ENERGY PLANNING (ACT 174)

As part of the Northern Vermont Development Association (NVDA), BVI is part of a Regional Energy Plan[6] that was certified by the Department of Public Service on June 26, 2018. According to NVDA's Energy Plan, the aim is "to guide the region's energy development for the next eight years in support of Vermont's 2016 Comprehensive Energy Plan (CEP), which contains the following goals:

- Reduce total energy consumption per capita by 15% by 2025, and by more than one third by 2050.
- Meet 25% of the remaining energy need from renewable sources by 2025, 40% by 2035, and 90% by 2050.
- Achieve three renewable end-use sector goals for 2025: 10% transportation, 30% buildings, and 67% electric power."[7]

The full plan is included in the appendix, and all future resource decisions will be made with this plan in mind. Specifically, BVI will consult with the NVDA on resource decisions that involve potential siting of new resources in Vermont.

[6] The full plan can be found at http://www.nvda.net/regional-plan.php.

[7] NEK Regional Plan, Chapter 2: Energy, NVDA 2018, Page 2

RESOURCE PLAN

III. RESOURCE PLANS

ENERGY PROCUREMENT PROCESSES

MONTHLY PROCESS

VPPSA's Power Supply Authorities Policy requires that energy supplies be within +/-5% of the forecasted demand in each month of the year. The ratio of supply to demand is known as the hedge ratio. Any imbalances between supply and demand are hedged to these levels before the operating month begins. In practice, changes in weather, generator availability and other factors often combine to push the actual percentage outside of the +/-5% threshold.

VPPSA evaluates supply and demand every month and purchases or sells energy to refine the energy hedge ratio. The following three-step process is used to balance supply and demand.

1. Update Budget Forecast
    a. The budgeted volumes (MWH) are updated to reflect known changes to demand and supply (unit availability and hydro conditions).
2. Hydroelectric Adjustment
    a. Supply is sometimes reduced by one standard deviation from the long-term average in order to avoid making sales that could end up being unhedged by supply in the event of a drier-than-normal month.
3. Execute Purchases or Sales
    a. **Internal Transactions**: VPPSA seeks first to make internal transactions between its members to balance supply and demand. The transactions are designed to result in a hedge ratio that falls within the +/-5% range that is required by VPPSA's Power Supply Authorities Policy.
    b. **External Transactions**: In the event that internal transactions cannot bring BVI into the +/-5% range, external transactions are placed with power marketers, either directly or through a broker.
    c. **Price:** For Internal Transactions, the price of the transaction is set by an average of the bid-ask spread as reported by brokers on the date of the transaction. For External Transactions, the price is set through a negotiation with the counterparty.

ANNUAL PROCESS

Known within VPPSA as "planned purchases", these transactions are almost always purchases. They typically take place no more than once a year, usually carry a 1-5 year term, and if possible, are executed at a time when market prices are at or below budgeted levels.

These purchases are designed to fit the on and off-peak energy needs in each month of the year as precisely as possible. As a result, they minimize the need for monthly 7x24 hedging transactions under VPPSA's Power Supply Authorities Policy.

The solicitation method is an informal Request for Proposals (RFP), and follows a three-step process.

1. **Pre-Approval Term Sheet:** First, the proposed purchase volumes and anticipated prices are documented in a standardized term sheet. This document is distributed to each VPPSA member for their pre-approval, and it defines their share of the total purchase.
2. **Issue RFP:** Once all of the pre-approvals are received, the term sheet is distributed to three or more power marketers, who are asked to make their best offer by a deadline, typically within 5 business days.
3. **Evaluate & Execute:** When all of the bids are received, VPPSA evaluates them to determine the lowest cost bid, and executes the purchase with that counterparty. The purchase is allocated to each VPPSA member according to their pre-approved term sheet, and the data is entered into VPPSA's database for scheduling and invoice tracking.

LONG-TERM PROCESS

VPPSA evaluates long-term Purchased Power Agreements (PPAs) for bundled energy, capacity, renewable energy credits, and/or ancillary products on an ongoing basis. Because long-term contracts are subject to PUC approval, the acquisition strategy is simply to negotiate the best terms and to make the contract execution contingent on PUC approval.

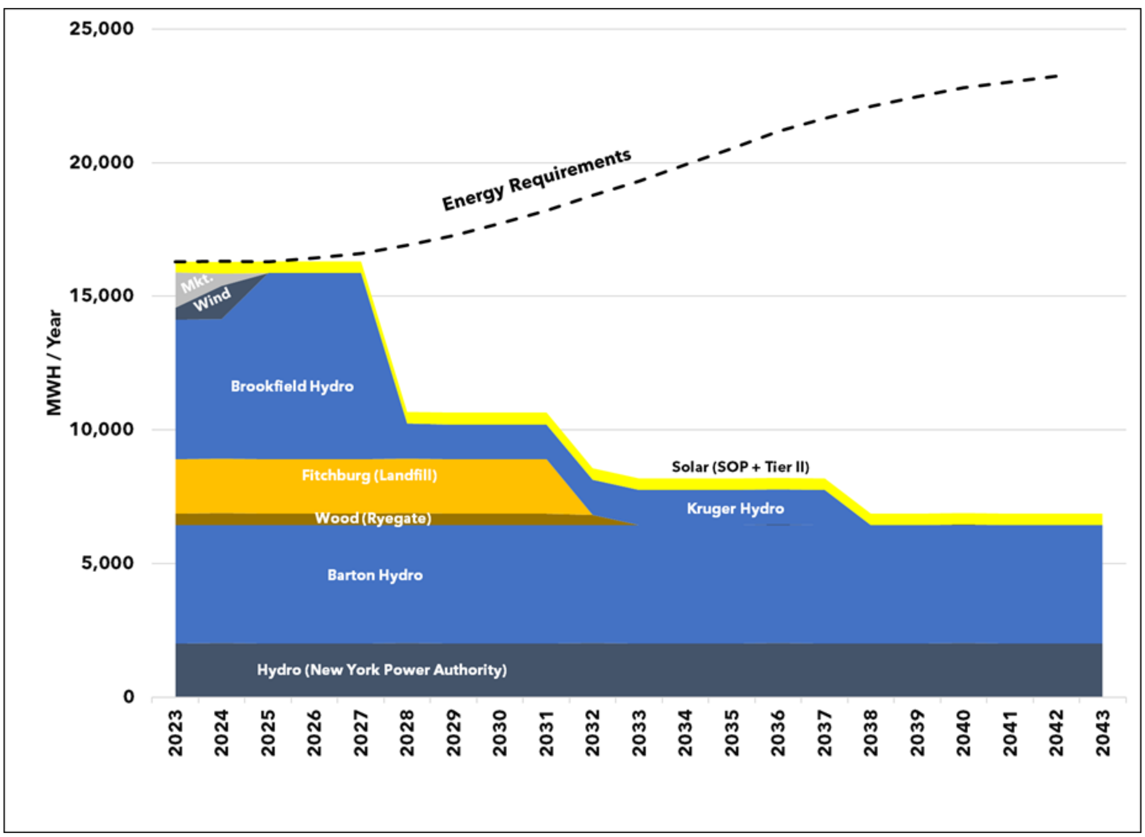
ENERGY RESOURCE PLAN

Figure 6 compares BVI's energy supply resources to its adjusted load. The supply resources closely match demand for the next five years, and consist primarily of hydro resources. Thereafter, new resources will be necessary.

DECISION 1: EXTEND EXISTING PPAS THROUGH 2032

The most straightforward option during this timeframe is to extend the term the Brookfield Hydro contract through 2032. This extension would be made at prevailing market prices, and since it includes RECs, it would help fulfill the RES requirements during that time period as well. The term of the contract could be extended to ten or twenty years depending on market pricing and renewable policy.

Figure 6: Energy Supply & Demand by Fuel Type



DECISION 2: SOLAR CONTRACT (PPA)

BVI is collaborating with a solar developer to develop an array adjacent to the Heath substation. The array will be sized to fulfill BVI's Tier II requirements (1 MW), and may be paired with battery storage, which will be modeled separately as part of Decision 3.

DECISION 3: EXTEND THE FITCHBURG LANDFILL CONTRACT

This PPA includes an option to extend the term by five years at a predetermined price. Notice must be given by the middle of 2025 for an extended term that would begin on 1/1/27. This resource plan assumes that the option will be used to extend the term through 2031. However, a final decision must be made in 2025 and the Financial Analysis includes the results of the Monte Carlo analysis that will be used to inform the decision.

DECISION 4: BATTERY STORAGE CONTRACT (ESSA)

Utility scale battery storage is an excellent way to manage transmission costs, and BVI is collaborating with a storage developer to develop a site adjacent to the Heath substation. If successful, this resource would be procured through a 25-year Energy Storage Service Agreement (ESSA). Table 13 summarizes the energy resources decisions BVI faces in the coming five to ten years.

Table 13: Energy Resource Decision Summary

Resource	Years Impacted	% of MWH	Rate Impact	RES Impact
Extend Hydro PPA	2028 - 2032	24%	Neutral	Tier I
Solar PPA	2025 - 2050	10-20%	Neutral	Tier II
Fitchburg Landfill PPA	2027 - 2031	12%	Neutral	None
Storage ESSA	2025 - 2050	80% of peak	Decrease	None

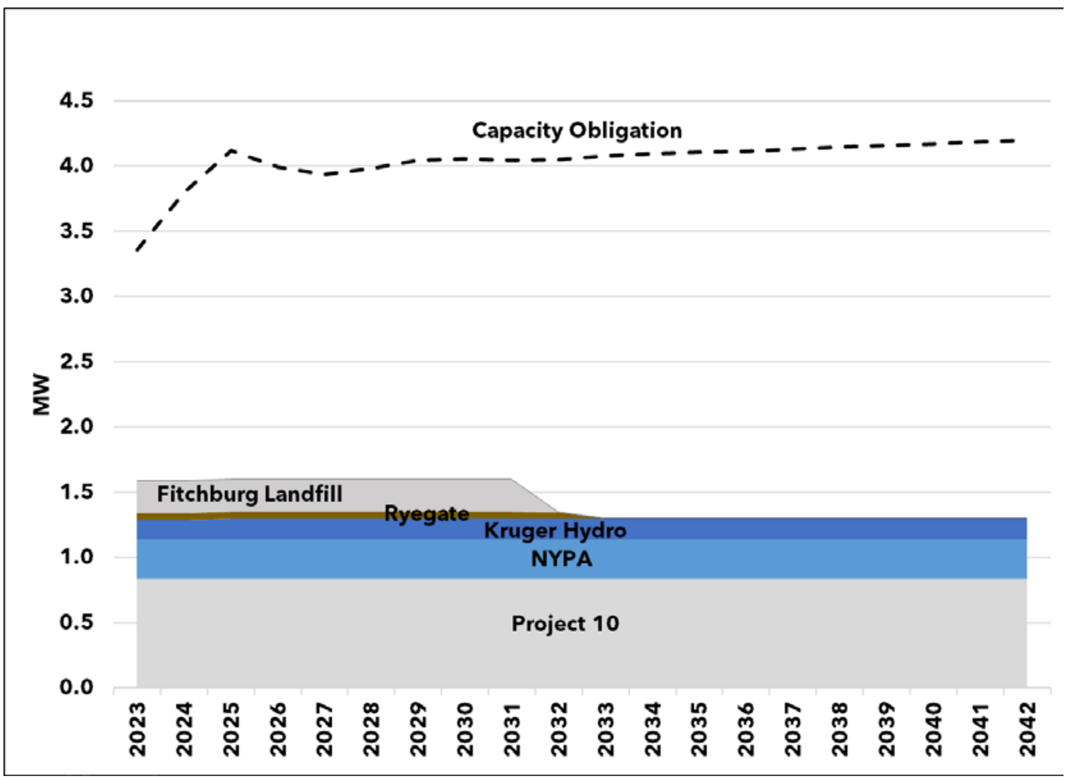
OTHER RESOURCE DECISIONS

Alternatives to these three decisions can be envisioned. For example, BVI could increase the size of the wind resource and rely on it to fulfill its energy needs. However, the pros and cons of this approach do not need to be quantified to be known. First, the wind power would be intermittent and more variable than the firm hydro power. However, the wind power would add diversity to compliment the primarily hydro-based portfolio. Finally, both wind and hydro power can be expected to have a similar price, because they are both located in New England.

CAPACITY RESOURCE PLAN

Figure 7 compares BVI's capacity supply to its capacity supply obligation (CSO). The CSO is equal to BVI's coincident peak demand with ISO New England plus a reserve margin. As a result, the CSO is higher than the Adjusted Peak Load Forecast. In any event, BVI has about 40% of its capacity obligation covered with existing resources.

Figure 7: Capacity Supply & Demand (Summer MW)



Project 10 represents about half of BVI's capacity supply, and as a result, the reliability of this resource will be the key to minimizing BVI's capacity costs, as explained in the next section.

ISO NEW ENGLAND'S PAY FOR PERFORMANCE PROGRAM

Because BVI is part of ISO New England, its capacity requirements are pooled with all of the other utilities in the region. As a result, if Project 10 is not available, BVI will be provided with (energy and) capacity by ISO New England. However, ISO New England's Pay for Performance[8] (PFP) program creates financial payments (and potential penalties) for generators to perform when the grid is experiencing a scarcity event.

The following table illustrates the range of performance payments that BVI's share of Project 10 creates in ISO New England's PFP Program. Depending on ISO-NE's load at the time of the scarcity event and Project 10's performance level, BVI could receive up to a $3,100 payment or pay up to a $3,500 penalty during a one-hour scarcity event. This represents a range of plus or minus 15% of BVI's 2022 monthly capacity budget. However, such events occur infrequently (only twice since 2018), and they typically last about one hour.

Table 14: Pay for Performance Ranges for One Hour of Project 10 Operation[9]

ISO-NE Load	Performance Payment Rate	0% Performance	50% Performance	100% Performance
10,000	$5,500/MWH	-$1,500	$800	$3,100
15,000	$5,500/MWH	-$2,200	$100	$2,400
20,000	$5,500/MWH	-$2,800	-$500	$1,800
25,000	$5,500/MWH	-$3,500	-$1,200	$1,100

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[8] For an overview of the PFP program, please visit https://www.iso-ne.com/participate/support/customer-readiness-outlook/fcm-pfp-project.

[9] Please refer to the following presentation from ISO-NE for the details of how the performance payments are calculated. https://www.iso-ne.com/static-assets/documents/2018/06/2018-06-14-egoc-a4.0-iso-ne-fcm-pay-for-performance.pdf

RENEWABLE ENERGY STANDARD (RES 1.0) REQUIREMENTS

BVI's obligations under the Vermont Renewable Energy Standard (RES) are shown in Table 15. Under RES, BVI must purchase increasing amounts of electricity from renewable sources. Specifically, its Total Renewable Energy (Tier I) requirements rise from 63% in 2023 to 75% in 2032, and the Distributed Renewable Energy (Tier II) requirement rises from 4.6% in 2023 to 10% in 2032. Note that this plan assumes that both the Tier I and Tier II requirements are maintained at their 2032 levels throughout the rest of the study period.

Under RES, the Tier II requirements are a subset of the Tier I requirements. As a result, we subtract the Tier II percentage from the Tier I percentage to get the Net Tier I requirement in the fourth column. Notice that the net Tier I requirement declines slightly every second and third year until the Tier I requirement increases. When these percentages are multiplied by the forecast of retail sales, the result is a small seesaw effect where the Net Tier I requirement declines every second and third year. This effect can be seen more clearly in Figure 8 in the next section.

Table 15: RES Requirements (% of Retail Sales)

Year	Tier I: Total Renewable Energy (A)	Tier II: Distributed Renewable Energy (B)	Net Tier I: Net Total Renewable Energy (A) - (B)	Tier III: Energy Transformation
2023	63%	4.60%	58.40%	4.67%
2024	63%	5.20%	57.80%	5.34%
2025	63%	5.80%	57.20%	6.00%
2026	67%	6.40%	60.60%	6.67%
2027	67%	7.00%	60.00%	7.34%
2028	67%	7.60%	59.40%	8.00%
2029	71%	8.20%	62.80%	8.67%
2030	71%	8.80%	62.20%	9.34%
2031	71%	9.40%	61.60%	10.00%
2032	75%	10.00%	65.00%	10.67%
2033-42	75%	10.00%	65.00%	10.67%

The final column shows the Energy Transformation (Tier III) requirement. Note that the Tier III requirement is held constant from the 2033 to 2042 period. This is due to the fact that the RES statute does not define an obligation during these years. Given the current push for electrification, we assume that the 10.67% requirement holds steady through these years.

Because it is designed to reduce fossil fuel use, the Tier III requirement is fundamentally different from Tier I and Tier II requirements. Unlike the Tier I and Tier II requirements…which count only electricity that is produced and consumed in an individual year[10]…Tier III programs account for the "lifetime" of the fossil fuel savings. For example, if a Tier III program installs a CCHP in 2023, the fossil fuel savings from that CCHP are counted such that the full thirteen-years of the CCHP's expected useful life accrue to the 2023 Tier III requirement.

Table 16: ACP Prices[11] ($/MWH)

Year	TIER I	TIER II & III
2023	$10.67	$64.05
2024	$10.91	$65.46
2025	$11.15	$66.90
2026	$11.39	$68.37
2027	$11.65	$69.87
2028	$11.90	$71.41
2029	$12.16	$72.98
2030	$12.43	$74.59
2031	$12.70	$76.23
2032	$12.98	$77.90

The RES statute provides a second way to comply with its requirements, the Alternative Compliance Payment (ACP). In the event that a utility has not achieved the requisite amount of Tier I, Tier II or Tier III credits in a particular year, then any deficit is multiplied by the ACP, and the funds are remitted to the Clean Energy Development Fund (CEDF).

However, utilities with a RES deficit may also petition the Public Utilities Commission (PUC) for relief from the ACP, or they may petition the PUC to roll the deficit into subsequent compliance years. As a result, there are multiple ways to comply with RES requirements.

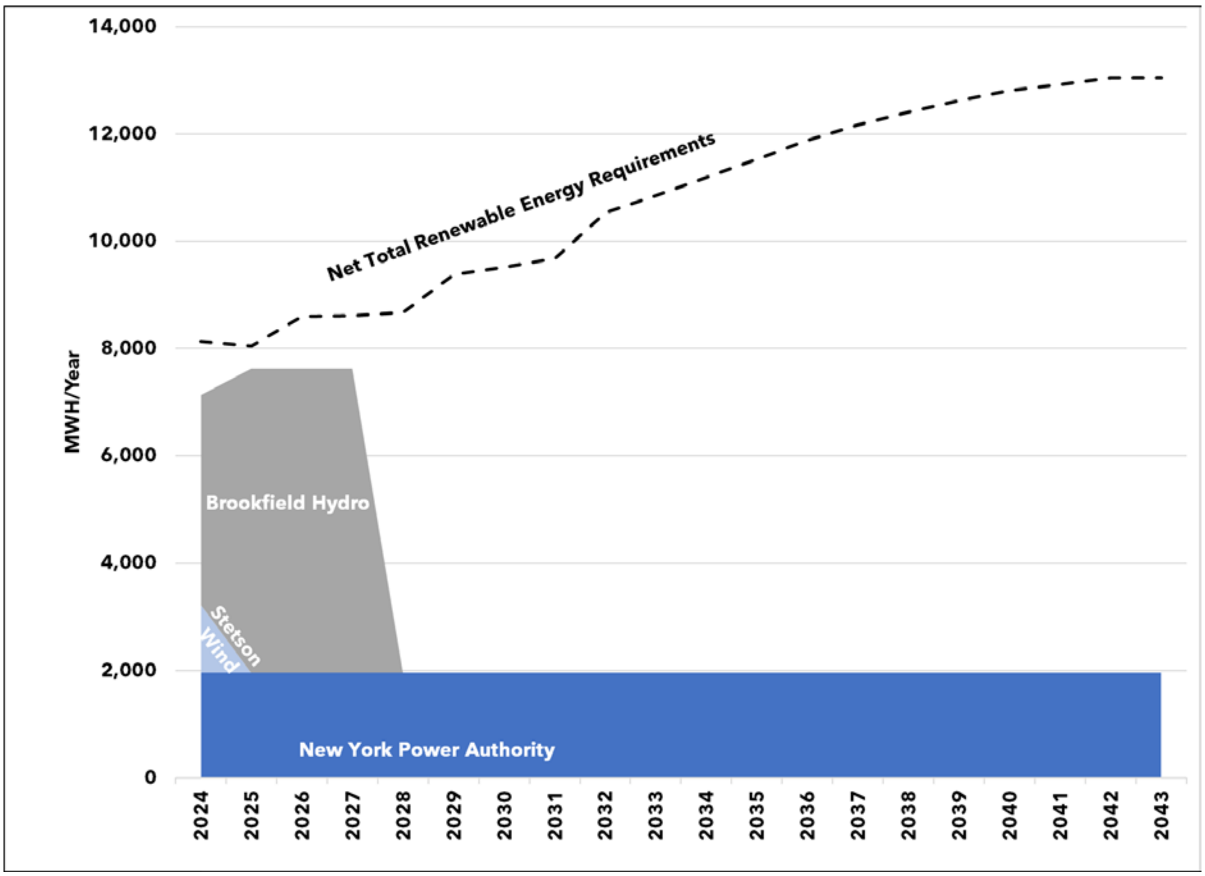
[10] For simplicity, we assume that no banking occurs in this example. In practice, banking excess TIER I and TIER II credits for use in future years is permitted under RES.

[11] Please note that these are estimates, and grow at inflation.

TIER I - TOTAL RENEWABLE ENERGY PLAN

Between 2023 and 2027, BVI's Net Tier I requirement is about 8,000 MWH per year. Two hydroelectric resources are the primary contributors to meeting the Net Tier I requirement; NYPA and the Brookfield Hydro PPA. These resources add up to about 5,868 MWH per year or 70% of BVI's Net Tier I requirement in 2023. In 2025, the Brookfield PPA entitlement increases, and BVI has a slight deficit of Tier I RECs through 2027. Thereafter, new resources will be required to meet the RES.

Figure 8: Tier I - Total Renewable Energy Supplies

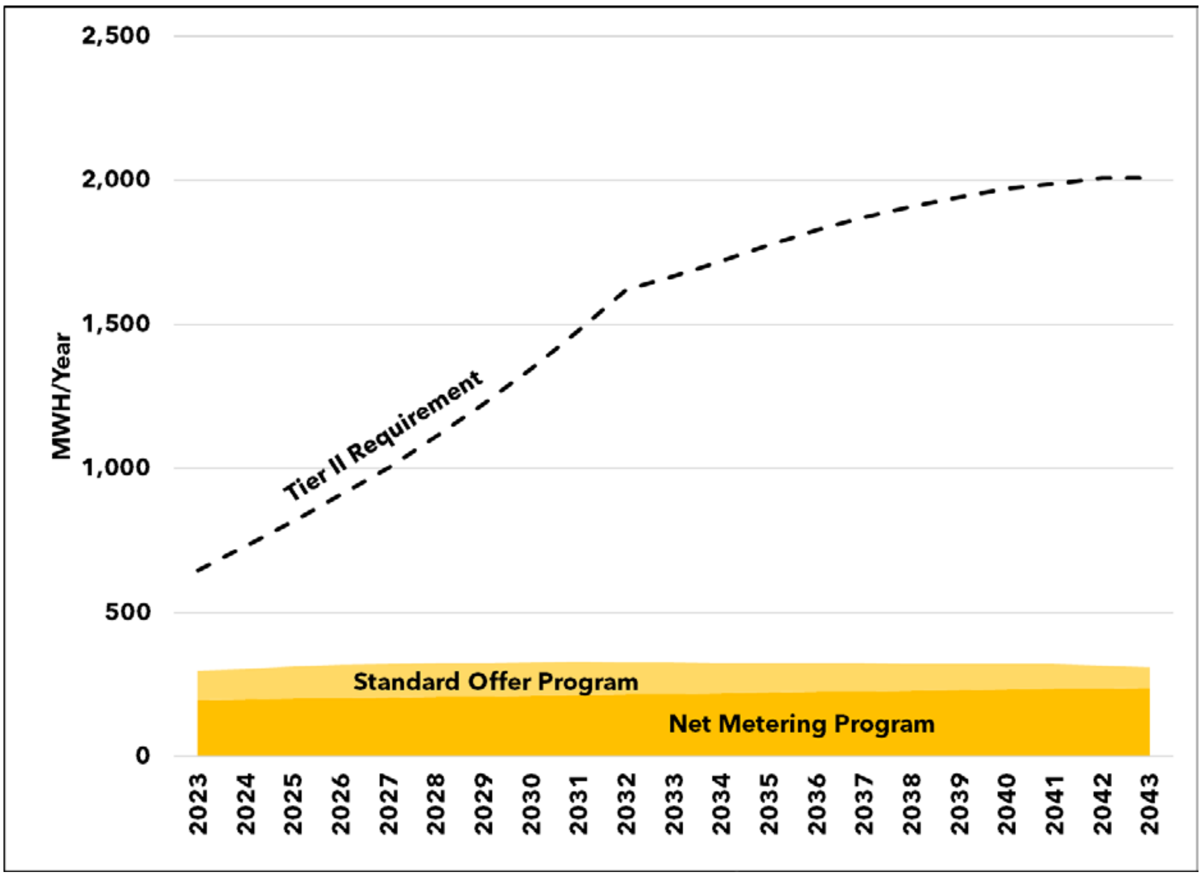


BVI is likely to meet its Net Tier I requirements by purchasing Maine Class II (ME II) Renewable Energy Credits (RECs) or extending the Brookfield PPA. In either case, the cost of Tier I RECs will be similar. Their price has ranged from a low of $1.00 to a high of $10.00 per MWH over the past five years. At the current price of $10/MWH, the cost of complying with Net Tier I between 2028 and 2032 with ME II RECs would be about $100,000 per year.

TIER II - DISTRIBUTED RENEWABLE ENERGY PLAN

The dashed line in Figure 9 shows BVI's Distributed Renewable Energy (Tier II) requirement, which rises steadily from 600 MWH in 2023 to over 1,600 MWH in 2032. BVI is presently developing a 1 MW AC (1,600 MWH/Yr) solar facility adjacent to the Heath substation to meet this need. The project is being developed in partnership with a solar developer, and it may be upsized to 2 MW in anticipation of higher RES requirements and to create a surplus that can be used toward its Energy Transformation requirement.

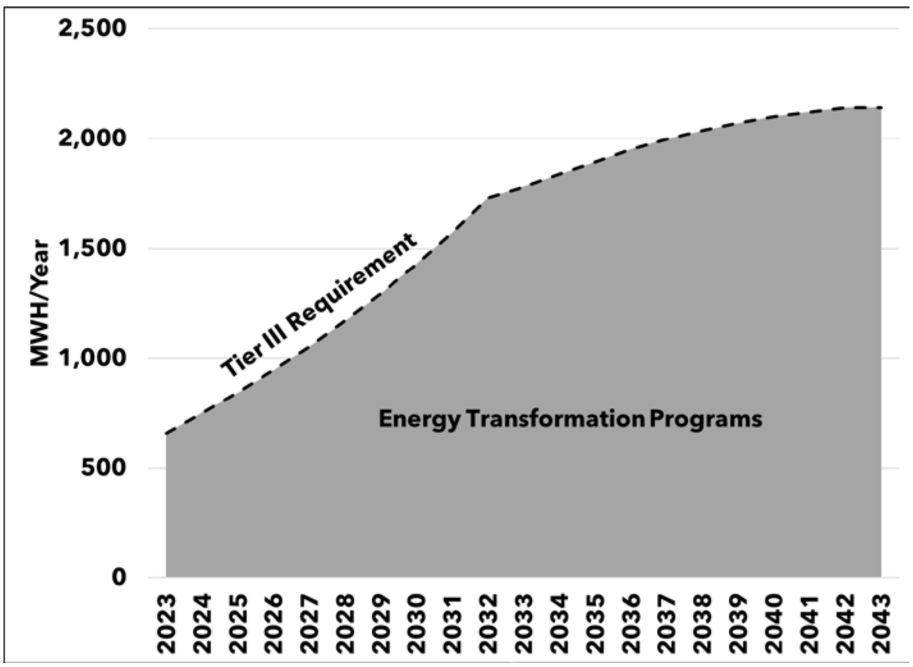
Figure 9: Tier II - Distributed Renewable Energy Supplies



TIER III - ENERGY TRANSFORMATION PLAN

The dashed line in Figure 10 shows BVI's Energy Transformation (Tier III) requirements, which rise from about 600 MWH in 2023 to 1,700 MWH in 2032. Prescriptive programs are presently budgeted to fulfill the entire requirement, and are shown in the gray-shaded area of Figure 10. These programs cover a range of qualifying technologies including EVs, CCHPs, and HPWHs. More detail on these programs can be found in Appendix A (VPPSA's 2023 Tier 3 Annual Plan) and in the following section.

Figure 10: Energy Transformation Supplies



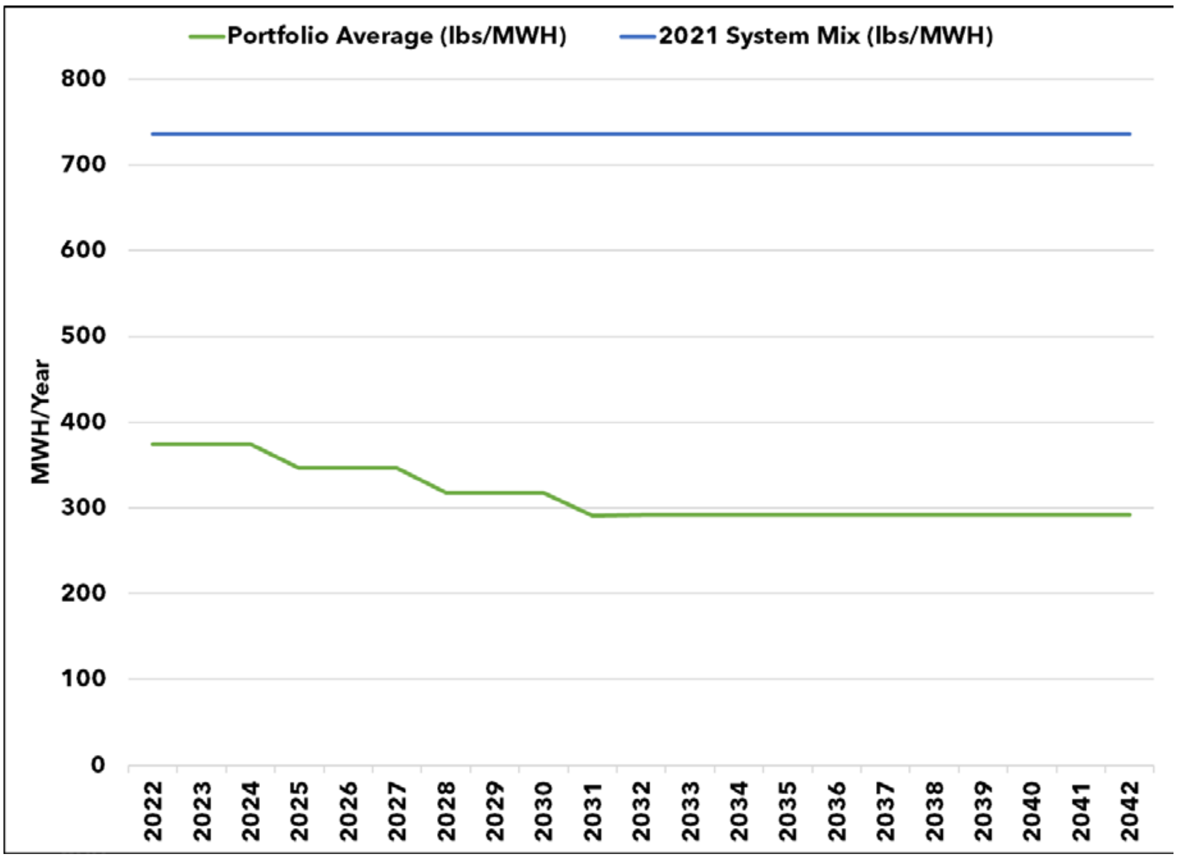
If prescriptive programs do not fulfill the entire requirement, custom Tier III projects may fill the gap as contemplated in the Tier 3 Annual Plan. BVI will follow a three-part strategy to fulfill its Tier III requirements.

1. Identify and deliver *prescriptive* Energy Transformation ("Base Program") programs, and/or
2. Identify and deliver *custom* Energy Transformation ("Custom Program") programs, and/or
3. Manage Tier II credits to maximize value across both Tier II and Tier III requirements.

CARBON EMISSIONS AND COSTS

Figure 11 shows an estimate of BVI's carbon emissions rate compared to the 2021 system average emissions rate in New England[12]. The emissions rate in 2023 is about 380 lbs/MWH because of the Brookfield Hydro contract, which includes Tier I RECs.

Figure 11: Portfolio Average Carbon Emissions Rate (lbs/MWH)



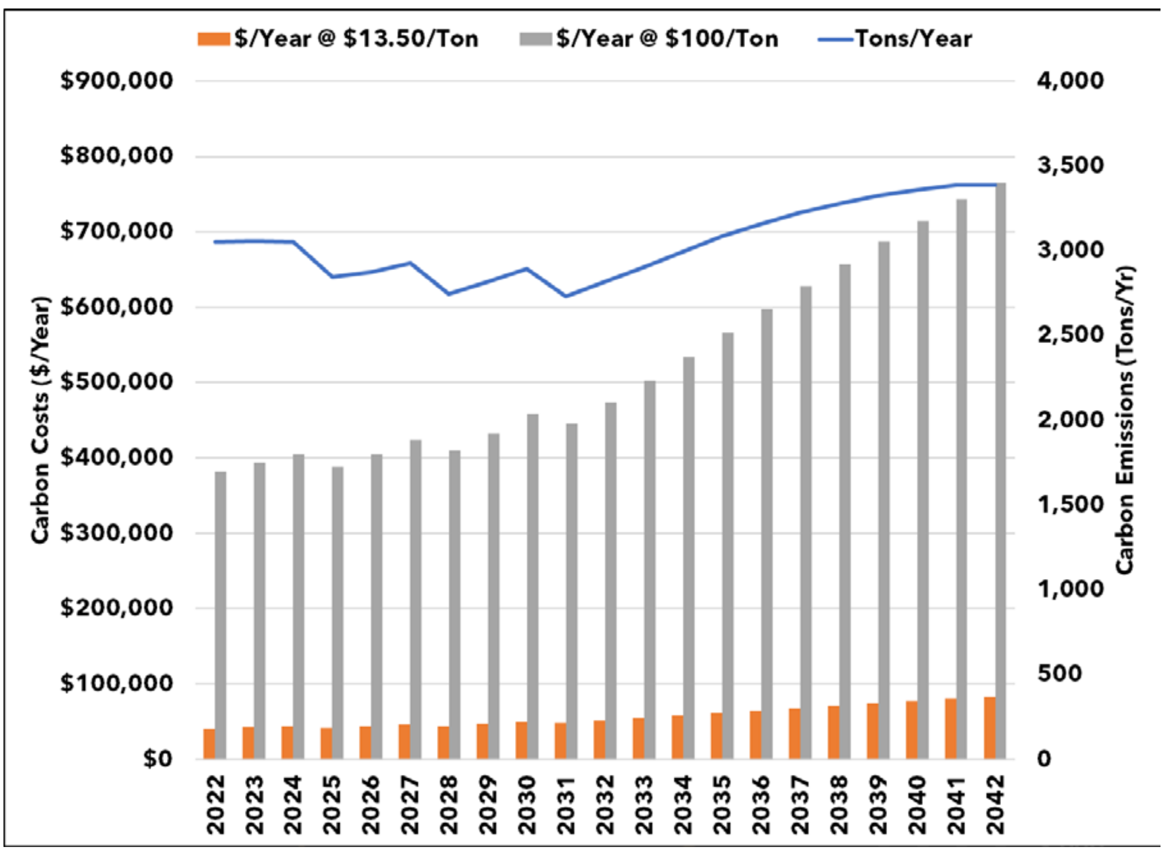
The emissions rate continues to decline in 2026 as a result of increasing RES requirements. This decline continues until 2032, when the RES requirements end. The emissions rate remains stable thereafter because this plan assumes that the RES requirements will be maintained.

[12] The source of this data is the NEPOOL GIS. https://www1.nepoolgis.com/

These emissions rates were multiplied by the load forecast from Section I. Electricity Demand to arrive at an estimate of carbon emissions in tons per year. The following figure shows that carbon emissions range from about 3,000 tons/year in 2023 down to 2,800 tons per year in 2032.

The costs of these emissions were calculated using two sources, the 2021 Regional Greenhouse Gas Initiative Auction (RGGI) results ($13.50 per ton) and the 2021 Avoided Cost of Energy Supply (AESC) study ($125 per ton). Using RGGI prices (plus inflation), the cost of carbon emissions is about $45,000 per year through 2032. Using AESC prices, the cost is about $420,000 per year.

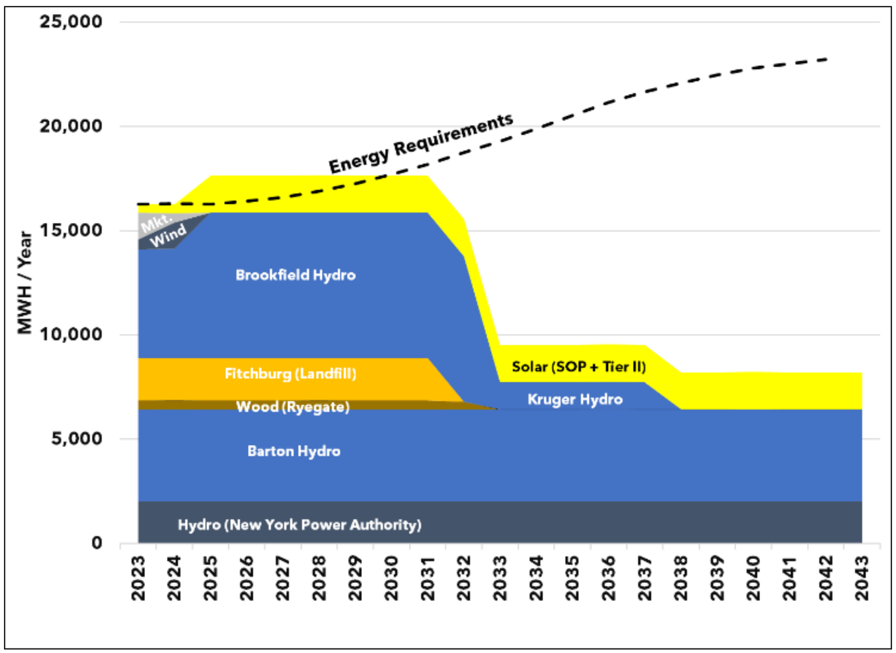
Figure 12: Carbon Emissions (Tons/Year) and Costs ($)

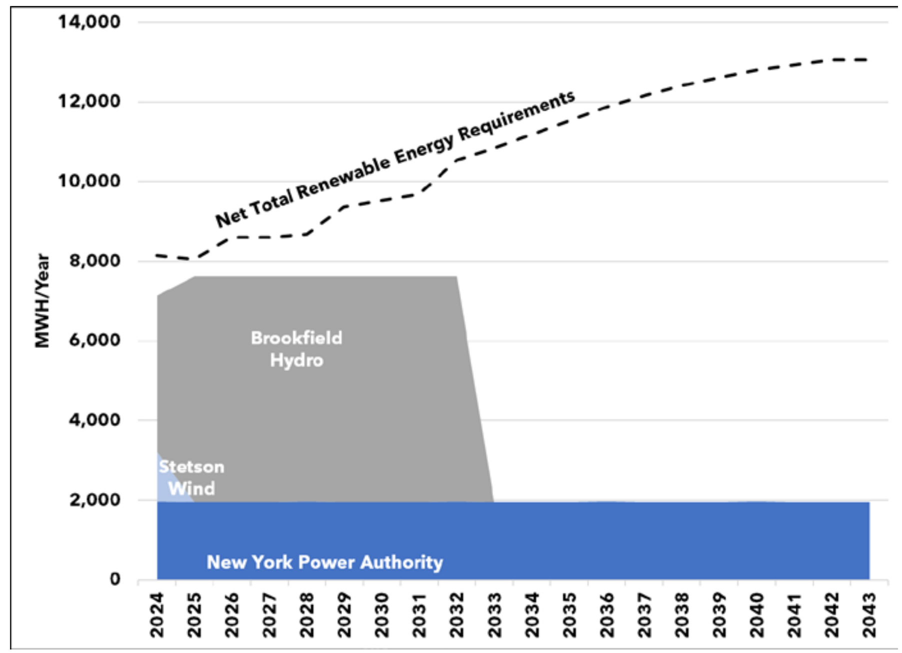


PROCUREMENT PLAN FOR RES 1.0

Under RES 1.0 requirements, BVI can simply extend the term on its existing hydro PPA. This approach would meet BVI's energy requirements until electrification starts to increase the load in the late 2020s and early 2030s. It would also fulfill most of the Tier I requirements of the RES. Notice that the solar PPA not only fulfills BVI's Tier II obligation, but it also hedges the anticipated load growth due to electrification. This PPA may cause some surplus generation, however, until electrification begins growing the load in the late 2020s and early 2030s.

Figure 13: RES 1.0 Option 1 – Hydro Energy & Tier I RECs Compared to Requirements





RESOURCE PLAN OBSERVATIONS

TIER I

BVI is meeting its Tier I requirements primarily with existing resources, and can continue to do so by simply extending the Brookfield Hydro PPA. In the event that its load starts growing faster and/or sooner than expected, it can either purchase additional Tier I RECs on the market or retire some of its RECs from Barton Hydro. Barton Hydro typically generates about 4,000 MWH per year, and could (in concept) fulfill BVI's remaining Tier I requirements throughout this next decade. As a result, BVI's Tier I compliance options are primarily economic decisions that will depend on REC market prices. The volumes of renewable energy in BVI's portfolio (before making REC sales) already exceed 80% of its load.

These observations hold up well even if RES requirements increase to 100% by 2032. The only resources in BVI's portfolio that don't include RECs are the Kruger Hydro and Market Contracts Resources, and they represent less than a fifth of BVI's supply. As a result, BVI is well positioned to meet a 100% renewability requirement with its existing resources. However, BVI would have to retire RECs that it currently sells from the Fitchburg Landfill and Ryegate. The cost of this approach are quantified in the Financial Analysis.

TIER II

BVI's Tier II obligations can be met with existing resources plus the 1 MW solar project that is in development. If Tier II requirements increase, additional development would be required if Barton Hydro did not qualify. As a result, additional development to meet an increased Tier II requirement is not anticipated.

TIER III

Tier III requirements continue to be met with prescriptive programs. In addition, BVI continues to investigate custom projects to supplement these programs.

TRANSMISSION & DISTRIBUTION

IV. ELECTRICITY TRANSMISSION & DISTRIBUTION

TRANSMISSION & DISTRIBUTION SYSTEM DESCRIPTION

BVI has entered a contract arrangement with VPPSA to provide field operations, system maintenance and 24-7 on-call service for emergency, restoration and safety related issues. This agreement allows BVI to temporarily operate with reduced staffing levels while it evaluates the most appropriate operational structure for maintaining infrastructure and providing quality customer service going forward. BVI continues to staff administrative, billing and customer service functions from its Barton offices, with support from Trustees, VPPSA, and consultants as needed.

BVI has part time services of an experienced line foreman who, among other things, actively oversees the vegetation management activity/budget and coordinates internal and contract trimming efforts. BVI is pleased with the efforts to date, having seen improvement in the amount of tree trimming accomplished due to better coordination, blending small outside contracts with internal trimming labor, and the use of mechanical trimming on cross country runs. Previously, BVI tried using linemen and hired a large contractor such as Asplundh. The experience was less than ideal as BVI found that BVI's crew was pulled in many directions, and BVI couldn't reliably retain these contractors, which resulted in major failures in maintenance. BVI started using a contractor with an excavator and mechanical mulch head and then BVI hired a small trimming company to come in and do small projects. These strategy shift has worked well in getting main feeders back to a reasonable clearance.

BVI is in the process of evaluating options ranging from selling its utility assets to keeping the department. Those discussions are active, ongoing, and subject to confidentiality requirements. Whichever path BVI chooses, long-term resource, capital maintenance, and action plans are likely to be affected. However, given the expected timeline for reaching a decision, and the lengthy approval process that may result following that decision, it is unlikely that this IRP cycle would be materially affected.

DISTRIBUTION SYSTEM DESCRIPTION

BVI has just over 200 miles of distribution lines in a radial feed configuration with two 13.2kV Y/7.6kV feeders from the Heath Substation serving customers in the Village of Barton, Sutton, Westmore, Brownington, Town of Barton, Charleston, and Irasburg. Some older areas of the system step down further to 2.4kV delta.

TRANSMISSION SYSTEM DESCRIPTION

BVI co-owns, with the Village of Orleans Electric Department (OED), approximately 5.5 miles of 46 KV transmission line that connects the Heath Substation to a side tap on a co-owned BVI/OED/VEC transmission line. This side tap is located approximately ¼ mile south of I-91 on Route 16 in Barton. The rebuild of this transmission line was completed in 2014.

BVI also co-owns, with OED and VEC, approximately 10 miles of 46 kV transmission line which extends from the VELCO Irasburg substation to the aforementioned side tap located on Route 16. BVI's pole ownership share for this line is approximately 12%; VEC has managed the pole replacement process during the past few years.

BVI-OWNED INTERNAL GENERATION

BVI owns and operates an internal hydro-electric generation resource.

Barton Village Hydroelectric Project:

The Barton Village Hydroelectric Project located in West Charleston operates on FERC License 7725-000–Vermont. The FERC license is in effect until 10/1/2043.

BVI created a new position in 2019 for a hydro-electric manager who also provides part-time operational control. The manager also utilizes other village staff and contractors as needed.

The facility can be monitored remotely, and the facility can automatically shut down if river levels do not meet minimum flow requirements.

Barton Village Hydroelectric Project is a two-turbine project. Turbine one was constructed and put into service in 1930 then rebuilt in 2008. This unit is a Francis vertical turbine manufactured by James Leffel & Co. coupled to a General Electric generator. It operates at 514 r.p.m 950 rated horsepower, 74 rated head, 2400 volts, frequency 60, 875 kva, with a 700-kW nameplate rating.

The second unit was put into service in 1948 then rebuilt in 2009. This unit is a Francis vertical turbine manufactured by S. Morgan Smith coupled to a General Electric generator. It operates at 360 r.p.m, 950 rated horsepower, 74 rated head, 2400 volts, frequency 60, 875 kva, with a 600-kW nameplate rating.

BVI replaced the majority of its penstock in 1991 and monitors the pipelines serving each turbine following the bifurcation structure for replacement. The penstock and the dam are monitored in part by following a Dam Safety Surveillance and Monitoring Plan (DSSMP) last updated in 2019.

BVI continues to invest in the hydro-electric facility. These investments include major hardware and software upgrades, a downstream fish passage added in 2015, and replacement of a low flow slide gate in 2018-2019. BVI understands that continued reinvestment in the project is necessary. BVI qualified for a Low Impact Hydropower Institute (LIHI) Certification in 2019. The certification allows BVI to sell REC credits to markets that are looking for high quality projects. This effort is expected to provide additional revenue for facility reinvestment. In 2022 BVI added a new roof to the powerhouse building. 2022 also included an independent inspection of the penstock including the remaining penstocks sections downhill of the bifurcation block as these segments were not replaced in 1991 with the upper penstock project and are original to the 1930's and 1940's era units. The report concluded that the penstock to unit #2 is in need of replacement. Finally, BVI expects to complete a financial analysis during the next couple of years to ensure that sufficient capital is reserved for operations, decommissioning funds, and capital replacement for the aging facility.

The most recent 10-year average annual production of the Barton Village Hydroelectric project is 4,154,090 kWh.

The following table summarizes the actual generation output of the hydroelectric plant for the past 10 years.

Table 17: Barton Village Hydroelectric Project Annual Generation (kWh)

Year	Total Annual Hydroelectric Generation (kWh)
2012	4,061,110
2013	3,411,541
2014	4,330,701
2015	4,091,374
2016	4,704,459
2017	3,371,743
2018	4,061,110
2019	4,264,134
2020	5,135,569
2021	4,109,156

Table 18: Barton Village Hydroelectric Project Nameplate Ratings

Unit Name	Hydroelectric Unit Nameplate Rating (KW)
West Charleston Hydro Unit 1	700
West Charleston Hydro Unit 2	600
Total	1,300

Barton Village Diesel Generation:

BVI has a non-functioning standby diesel generation system originally constructed in 1956. The building and equipment remain but fuel is no longer stored onsite. BVI continues to work on decommissioning the abandoned diesel generating facility which has included preparations of a Section 106 Analysis report in 2022, and an archaeological resource assessment in 2021, to remove the 50,000-gallon diesel fuel storage tank, generators, piping and electrical components. Non-historic structures have also recently been removed with concurrence of regulatory agencies. BVI hopes to have the fuel tank removed in 2023 and the switchgear for the diesel plant disconnected from inline operation with the hydro switchgear.

BVI SUBSTATIONS

BVI currently operates two substations. One is a jointly-owned substation and the other is a substation at the Barton Village Hydroelectric Project facility.

BVI also owns approximately 15 smaller step-downs that reduce voltage from 13.2kV/7.6kV Y to 2.4 kV. The substations are briefly described below.

Heath Substation:

BVI's entire load is served through the BVI-/OED co-owned Heath Substation located on Baird Road in Barton Town. The transformer has a high side voltage of 46.5kV, a low side of 13.2kv Y and a maximum transformer capacity of 10/12.5MVA. The Heath Substation has three feeders, two serving the entirety of BVI and one serving the entirety of OED. Feeder 1 for Barton serves south to the Barton Village area and feeder 2 services north to Brownington and the majority of Westmore.

Figure 14: BVI's Heath Substation

Barton Hydroelectric Substation:

BVI's hydroelectric plant is stepped up to 13.2kV Y/7.6kV from 2.4kV at the Barton Hydroelectric Substation. The transformer has a maximum transformer capacity of 2/2.3MVA. BVI has reinvested in the substation by replacing transformer oils.

Figure 15: Barton Hydroelectric Substation

CIRCUIT DESCRIPTION

There are two circuits in total, the West Charleston branch and the Barton branch. The voltage of the circuits is regulated at the substation bus with 333 kVa voltage regulators. These regulators were replaced in August of 2016.

T&D SYSTEM EVALUATION

System reliability is important to BVI for its customers. BVI currently relies on VPPSA contractors (Northline) and its subcontracting VPPSA-member utilities (Lyndonville Electric Department and Orleans Electric Department) for identification and evaluation of necessary safety and repair work and related reliability issues. VPPSA contractors and it's subcontracting utilities are reviewing structures and equipment and will continue to inspect the system to identify reliability issues.

Outage Statistics

BVI evaluates T&D circuits on an ongoing basis in order to identify the optimum economic and engineering configuration for each circuit. BVI reviews its Public Utility Commission Rule 4.900 Outage Report data in order to correct and/or prevent any reliability issues that may materialize.

BVI has committed to performance standards for reliability that measure the frequency and duration of outages affecting its customers. There are two measures for the frequency and duration of outages. The Public Utility Commission's Rule 4.900 defines them as:

System Average Interruption Frequency Index (SAIFI): Customers Out, divided by Customers Served. SAIFI is a measure of the average number of times that the average customer experienced an Outage.

Customer Average Interruption Duration Index (CAIDI): Customer Hours Out, divided by Customers Out. CAIDI is a measure of the average length of time, in hours, that was required to restore service to customers who experienced an Outage.

BVI has committed to achieve performance levels for its distribution system below an index of 1.8 for SAIFI and 2.5 for CAIDI. BVI maintains a record of and reports on all its system outages, including the root cause of an outage. While some outages cannot be prevented, there are a number of specific, cost-effective steps that can be taken to maintain or improve system reliability by working to eliminate the potential for some outages to occur and making changes that will promote reduced outage times when an unavoidable outage does occur.

Table 19: BVI Outage Statistics[13]

	Goals	2017	2018	2019	2020	2021[14]
SAIFI[15]	**1.8**	2.9	0.7	2.9	1.0	0.9
CAIDI[16]	**2.5**	5.1	2.6	4.0	2.3	2.2

RELIABILITY

BVI has a number of initiatives underway to improve reliability. Each of these initiatives is described below.

[13] Outage statistics shown are net of Major Storm outages.

[14] 2021 SAIFI & CAIDI shown are net of 8/31 H16 work outage.

[15] System Average Interruption Frequency Index

[16] Customer Average Interruption Duration Index

ANIMAL GUARDS

Animal guards are installed on all new services and on rebuilds. Additionally, whenever maintenance is done on existing services, animal guards are installed if they are not already in place.

FAULT INDICATORS

BVI uses flashing light fault indicators on its transmission lines. These devices improve field operation fault detection and improve outage restoration time.

POWER FACTOR MEASUREMENT AND CORRECTION

In recent years BVI has not applied high priority to expensive investments related to measuring power factor but will work with VPPSA to identify and evaluate adding more comprehensive metering to monitor power factor for key customers and sections of the system. Based on these measurement results, BVI will work with VPPSA to develop and implement measures to improve power factor as needed. On a total system basis, BVI's 2021 average power factor is 94.7%.

OTHER

BVI staff continue to evaluate vegetation management and prioritize high risk areas. In the short run, trimming in these high-risk areas may be limited to the most critical sections rather than undergoing complete vegetation removal. As a result, line sections containing these critical areas are expected to see a reduced trimming burden on the subsequent maintenance cycle.

DISTRIBUTION CIRCUIT CONFIGURATION

PHASE BALANCING / FEEDER BACK-UPS

BVI has no immediate plans for phase balancing as BVI's load is quite stable and is generally expected to remain so, although BVI is looking at phase balancing for a proposed line extension for agricultural projects in south Barton.

SYSTEM PROTECTION PRACTICES AND METHODOLOGIES

PROTECTION PHILOSOPHY

BVI's system protection includes transmission, substation and distribution protection. BVI has different settings because these reclosers can be used to protect a segment of the line or the entire line. Also, they can feed an adjacent circuit. Each protection practice is discussed briefly below.

Transmission Protection:

BVI's transmission system is protected by multiple devices. Primarily, OED/BVI/VEC co-own an H16 breaker at the VELCO Irasburg Substation. Also, a Supervisory Control and Data Acquisition (SCADA) controlled motorized switch is located where BVI and OED's co-owned 5.5 mile 46kV transmission line side taps off of the VEC/BVI/OED co-owned line on Route 16. Fuses are also located between switches that isolate the Heath Substation from the 5.5 mile 46kV line and the Heath main power transformer.

Substation Protection:

Equipment at the Heath Substation is protected by high side fuses just downstream of the Heath switches and upstream of the Heath main transformer. Additionally, reclosers are located on both West Charleston and BVI circuits.

Distribution Protection:

The distribution system protection involves a combination of distribution circuit reclosers and fuses. All side taps of the main line distribution feed are fused.

SMART GRID INITIATIVES

PLANNED AMI

Beginning in 2018, BVI began participating in a multi-phased, VPPSA joint-action project intended to assess individual member readiness for AMI, guide participating members through an RFP process culminating in vendor and equipment selection and implementation.

VPPSA contracted with Lemmerhirt Consulting to evaluate its member utilities readiness for an Automated Meter Infrastructure (AMI) in its territory. This effort was to provide a current assessment of business processes, systems, and equipment in place that would be impacted by AMI and evaluate the suitability, uses, challenges, and benefits for AMI at BVI. Since the Village of Barton provides both electric and water services, this evaluation covered an AMI implementation for both services. AMI is a major technical and business transition for any utility and provides a platform to improve operational efficiency, reliability, and customer service, including new functionality such as time-of-use or dynamic rate plans for customers, demand response programs, grid management improvements, and greater customer engagement.

Lemmerhirt Consulting visited and interviewed each member utility, gathering data from utility staff and driving the service territory to assess challenging geographic areas for AMI suitability. The Readiness Assessment addressed ten functional areas in some detail, rating the member system's readiness for each functional area according to the following criteria:

Table 20: AMI Readiness Assessment Criteria

Readiness	Definition
Good	The effort, cost, IT, business change, and training requirements are all low and achievable by the utility. The benefits to the utility of AMI surpass the challenges.
Fair	There is some effort, cost, business change, or training required; one or more areas may require significant change.
Difficult	The effort, cost, change to the business and IT, and training requirements are all significant for the utility. There are not many benefits of AMI to the utility.

The rating is an indication of the level of potential challenge associated with each functional area for an AMI implementation. An assessment of the level of effort needed, potential cost, and level of requirements to reap benefits can inform the utility in its business decision to pursue an AMI implementation, or not.

For a successful AMI project, the utility team and staff must be able to adopt new technology and implement new ways of doing business. BVI recognizes emerging requirements and value for AMI in offering more customer services such as time-of-use rates and self-service options; measuring and monitoring new technology - electric vehicles, distributed generation; distribution grid improvements by adopting programs like Conservation Voltage Reduction or Volt/Var Reduction. The Village of Barton provides water service, and as a result there may be benefits of adding water metering to the solution, ultimately strengthening an AMI business case. The Readiness Evaluation is summarized in the table below:

Table 21: AMI Readiness Evaluation

Overall AMI Readiness	Rating
Electric Meter Readiness	**Fair**
Water Meter Readiness	**Fair**
Meter Reading Readiness	**Fair**
Billing and IT Readiness	**Fair**
Customer Engagement Readiness	**Fair**
Electric Distribution Readiness	**Fair**
Outage Management Readiness	**Fair**
Water Distribution System Readiness	**Fair**
Telecommunications Readiness	**Fair**
Asset Data Readiness	**Fair**
Overall	**Fair**

Following the Readiness Assessment, an RFI was developed and issued to multiple vendors with an eye toward learning more about potential available solutions and identifying well qualified partners. The Respondents to the RFI were required to describe the general AMI solution(s) being proposed, the respondent's experience with AMI systems and whether their proposed solution(s) included functionality for water system operation and could be shared by all VPPSA members and centrally operated. Further detail regarding the respondent's experience, contract negotiation process, product roadmap and project management/professional services capability was also requested.

In broad terms the "must have" features for proposed solutions included the following features:

- Support both Electric & Water meter operations,
- Support multiple meter manufacturers,
- Multiple communication options to address hard to reach areas,
- Service level agreement,
- Hosted software solution for required Head End, Meter Data Management System (MDM) etc.,
- Multi-tenant software – segregate multiple members data in central database
- Support distribution automation/management capabilities

In support of these goals respondents were asked to respond to a series of detailed technical questions (See Appendix D – AMI RFI Technical Requirements) with respect to:

- Electric & Water Meters
- The AMI network/communication
- Head end software, MDM capabilities and other system tools
- Water system functionality and
- Project Plan & pricing

VPPSA received responses from 7 vendors which were evaluated by a team made up of a mix of about 20 VPPSA /Member management, staff, and consulting personnel. Members of the evaluation team reviewed the RFI responses to the detailed technical questions for completeness and "fit" and assigned a numerical ranking to each. Ultimately, the rankings were aggregated, and the three highest scoring vendors were selected to participate in the subsequent RFP.

Subsequent to evaluation of the responses to its RFI, VPPSA issued an RFP to three chosen vendors; Aclara Technologies (Aclara), Hometown Connections Inc, and Landis & Gyr. Respondents were asked to "…fully address the requirements of this solicitation related to performing all required work, including site assessment, drawings and document submittals, manufacturing, testing, delivery, and technical support during and after installation. This general statement of scope aligned with the RFP's stated selection criteria:

Proposals will be reviewed, evaluated, and ranked utilizing the following criteria:

- Price (20%)
- Experience Qualifications (15%)
- Technical and Non-Technical Requirements (30%)
- Project Delivery (15%)
- Ongoing Support (20%)

VPPSA reserved the right to award this contract to the Proposer providing the best overall match to the RFP requirements and which best serves the interest of VPPSA and its members.

Key requirements for the RFP were similar to those mentioned above for the prior RFI with emphasis on a hosted software solution that included functionality for both electric and water meters to be centrally purchased and share the same network with no collector device being a single point of failure, have one set of software licenses and have all data in a common, multi-tenant database with the ability to view individual member data and also access data as a group. In addition, the AMI solution was required to deliver data to each member's CIS. The detailed technical requirements are provided for reference in Appendix E (AMI – RFP Technical Requirements).

During the evaluation phase the three vendor responses were reviewed, discussed and scored by a group of about 20 staff and management personnel drawn from both VPPSA and individual VPPSA members. Early in that process the proposal From Landis & Gyr was eliminated from further consideration because it did not include the required MDM feature. Ultimately the Aclara proposal was selected for final contract negotiation; key factors in the Aclara proposal's favor included its fully integrated, single vendor aspect and its ability to meet several key requirements including:

- Single License (not separate licenses for individual VPPSA members)
- A hosted multi-tenant head end and MDM
- Inclusion of propagation study – confidence around cost estimates
- Licensed RF communication system; better penetration
- Reporting flexibility
- Customer support

The proposed Aclara system relies on a two-way, fixed base RF network that provides its meter-reading solutions through a secure, long-range wireless network using private licensed radio channels in the 450 - 470 MHz band. Built-in redundancy through multiple collection and processing paths without the use of repeaters prevents single-point failures from disrupting normal operation of the entire network. A failure of one DCU network device does not affect the entire network. The Aclara RF network uses conservative design, built-in redundancy, and continuous operation of multiple communication routes to prevent single-point failures from disrupting normal operation. The Aclara ONE headend and meter data management (MDM) system is hosted, multi-tenant software that will allow VPPSA members to see only their own data while providing VPPSA with an overview of the entire network and total distribution of electric and water across all members.

BVI expects to benefit from AMI implementation in a number of ways:

- Collection of interval data to support cost of service and innovative rate design
- Offer energy programs for customers to promote beneficial load management
- Increase customer engagement in their use of electricity and water resources
- Planning of future capital/T&D system investment strategies
- Comply with future regulatory and legislative requirements
- Reduction of overall meter reading impacts on staff and time
- Improve re-read needs and billing errors
- Reduce cost of non-pay disconnect/reconnect, move-in/out (off-cycle reads)
- Improve billing and customer care services
- Identify and reduce theft of service
- Improve accuracy of electric and water metering
- Optimize electric metering benefits such as transformer right-sizing
- Improved system planning capabilities and water resource management
- Improved water distribution system asset performance
- Reduced carbon footprint

In terms of business case, a cost benefit assessment, looking at about 20 areas of potential benefit, spanning field operations, metering and meter operations, billing, and customer and related rate programs was performed. This assessment indicates a positive NPV benefit of almost $300,000, with a positive cost-benefit ratio of 1.32 and an 8-year payback, providing Barton with reassurance that proceeding to the implementation phase is the correct decision. Note that the figures shown in this assessment are exclusive of any anticipated funding opportunity. Negotiation of a final contract with Aclara is ongoing at this time. Implementation of the AMI system is tentatively planned to begin in late 2024, dependent on the outcome of the ongoing evaluation for Barton to sell or retain the Electric Department.

GEOGRAPHIC INFORMATION SYSTEM

Recently, VPPSA has taken major steps forward in developing centralized geographic information system (GIS) utility mapping and data management programs. A new service offered in 2020, centralized GIS mapping maximizes efficiencies by standardizing data across member utilities and reducing the amount of time required to maintain map data. It additionally allows VPPSA to develop analytics, mapping deliverables, applications and field data collection tools. Through these assets each member utility empowers VPPSA to proactively manage their data and mapping capabilities. The VPPSA GIS program kicked off with hiring a GIS Administrator to join the Technology and Security Services Department. VPPSA's new administrator worked with each utility to identify strengths and short comings with their existing data and to plan for further data collection and/or updates where needed. Three categories of GIS maturity were identified across the membership, and a plan was developed to advance each group's status such that all VPPSA's members will have consistent capabilities and data standards. VPPSA GIS is in the process of implementing new and exciting GIS capabilities to allow affordable mapping solutions. Helped by a combination of partnerships with mPower innovations and the use of ESRI technologies, the final result culminates in a highly accurate, user friendly and affordable mapping solution for VPPSA's current and future members. These capabilities ensure that VPPSA members' GIS capable data solutions and mapping tools are connected to a variety of utility data such as AMI meter readings, spatially aware billing records, geospatially based load/voltage analysis, interconnection studies, and other insights into energy use trends. VPPSA members will also benefit from an enhanced situational awareness of infrastructure, asset life cycles, preventive maintenance, and vegetation management via real-time updates to data using VPPSA created mobile collection tools.

CYBER SECURITY

2020 was a cybersecurity turning point for many industries around the globe as nefarious digital attacks threatened to hold organizations hostage and utility regulators at the state and federal level increased focus on cybersecurity. BVI is mindful of the increasing importance of cybersecurity concerns, and the relationship of those concerns to technology selection and protection. While BVI is not presently required to undertake NERC or NPCC registration, VPPSA is a registered entity, and BVI's membership in VPPSA provides BVI with knowledge and insight regarding ongoing cybersecurity developments and risks. On a more local level, BVI endeavors to purchase and protect its IT systems (with assistance from VPPSA as needed), in a manner intended to minimize security risks to the system and its ratepayers.

VPPSA has initiated a cyber program that all members have access to and is working with each member individually to determine what the best approach is given individual member resources. VPPSA's Technology and Security Services team continues to work with its vendor consultants, developing cybersecurity hygiene and best practices to protect VPPSA and those of its members who choose to take advantage of it.

BVI and VPPSA remain mindful of the balance between the levels of cyber security risk protection and the associated costs to its ratepayers. VPPSA assists its members in pursuing and coordinating funding opportunities for various purposes, such as cyber security assistance and many other programs, to help its members reduce costs to their customers.

OTHER SYSTEM MAINTENANCE AND OPERATION:

RECONDUCTORING FOR RELIABILITY OR SYSTEM LOSS REDUCTION

Major system voltage upgrades from 2400 to 7620 were completed in the 1990s and early 2000s to reduce line loss. BVI continues to look for opportunities to upgrade lines from 2400 to 7620 to reduce line loss and 2400/7620 line duplications. BVI completed a voltage conversion to remove segments of 2.4kV delta in Brownington in 2019.

BVI considers several criteria when assessing conversion of a 2.4 kV line segment to 7.6 kV:

- Frequency & severity of reliability/voltage stability issues
- Value of expected loss reductions/reliability improvements
- Cost of the upgrade

• Resource availability

Line segments with identified reliability issues are upgraded as needed. Line segments considered less critical are upgraded subject to the above economic criteria. BVI plans to work with VPPSA to identify and prioritize system upgrades, including conversion of 2.4kV line segments, during this IRP cycle.

BVI has been gradually replacing small conductor over the last twenty years and plans to continue to replace small, aged conductors over the next ten years. Most conductors being used now are 1/0 aluminum AAAC. BVI has been replacing existing 2.4kV line sections constructed with #6 & #8 solid copper, with larger 1/0 aluminum AAAC and will continue to do so. BVI considers the above-mentioned criteria when assessing conversion of a lower voltage line segment.

TRANSFORMER ACQUISITION

BVI exclusively buys new and rebuilt transformers from major distributors such as WESCO. BVI will begin to look at transformer efficiencies with WESCO and other retailers to focus on life-cycle cost.

CONSERVATION VOLTAGE REGULATION

BVI's voltage setting is done with voltage regulators at the Heath Substation. These regulators were replaced with new units in August of 2016.

BVI does not have conservation voltage regulation.

DISTRIBUTION TRANSFORMER LOAD MANAGEMENT (DTLM)

BVI does not have a formal DTLM program. BVI consults experts which make recommendations on transformers used for different applications when there are questions.

SUBSTATIONS WITHIN THE 100- AND 500-YEAR FLOOD PLAINS

There are no current plans for relocation of step-downs out of flood plains however some units that are in flood plains were elevated around the year 2000. Step-downs will be re-evaluated in the future to assess the current risks associated with each step-down/transformer.

THE UTILITY UNDERGROUND DAMAGE PREVENTION PLAN (DPP)

Less than 1% of BVI's customers have primary lines underground. When damage occurs, BVI handles each incident on a case-by-case basis. BVI has collaborated with the Public Service Department (PSD) and VPPSA to develop a draft Damage Prevention Plan and filed it with the PSD in July 2019.

SELECTING TRANSMISSION AND DISTRIBUTION EQUIPMENT

BVI purchases standard certified transmission and distribution equipment from established trusted vendors. The majority of the equipment is purchased from WESCO. BVI prioritizes quality equipment and following utility standards over low purchase prices.

MAINTAINING OPTIMAL T&D EFFICIENCY

System Maintenance

BVI's system maintenance includes a number of components. Each is discussed briefly below.

Substation Maintenance

BVI inspects each major substation (Heath Substation and Barton Hydroelectric Substation) on a weekly basis. Oil tests on transformers are performed once a year. BVI uses infer-red technology to inspect the system annually, and any hot spots found are taken care of as soon as possible.

Pole Inspection

BVI inspects its poles on an annual cycle and regularly while conducting field work. Pole location and pole identification will be the foundation of a database which tracks pole condition, size, weight, class, age, pole preservative and other relevant information for equipment replacement planning. Other relevant information captured in this database will include factors such as the importance of the pole weighted by the number of customers impacted by failure. BVI recognizes a formal organized electronic method of monitoring pole condition is the only way to manage asset replacement and is fully committed to tracking and replacing poles in this way. BVI anticipates receiving shape files and GIS capable applications from the GIS system currently under development. As the GIS system matures over the next couple years the intent is to build pole management and tracking capabilities directly into the GIS system.

Equipment

BVI performs oil testing on its main transformers once a year. Additionally, thermal imaging tests are conducted on transformers in the system with heavy loads and cutouts. BVI continues to replace ceramic cutouts on an ongoing basis even if they seem to be in good condition. BVI also performs gas testing annually on the Heath Substation transformer.

Finally, under BVI's procurement & purchase policy, BVI solicits three different quotes before making a purchase above a certain dollar threshold.

System Losses

BVI is committed to providing efficient electric service to its customers. BVI's plan for improving system efficiency involves two actions. The first action involves monitoring actual system losses. The second action is to complete projects to reduce system losses. Each of these tasks is discussed briefly below.

Actual System Losses:

BVI and OED replaced their co-owned 5.5 mile major transmission line stretching from the VEC/BVI/OED co-owned split off to the Heath Substation. This activity involved replacing poles with taller ones, as well as changing wire, conductors and metering and switching components. This upgrade was completed in order to improve the overall efficiency of the transmission system.

It is expected that the replacement of the transmission line, described above, will reduce overall line losses. BVI will also continue to look for opportunities to upgrade conductor sizes where appropriate to further reduce system losses.

For 2021, BVI's actual distribution losses were 11.4%.

BVI does not currently have a specific quantitative loss reduction plan but is prepared to work with VPPSA to systematically evaluate and address opportunities to economically reduce losses. BVI is aware of remaining 2.4kV line sections and is aware there may be other unidentified opportunities throughout the system. At this time, BVI is focused on enhancing its vegetation management/tree trimming to improve reliability.

Efforts to Reduce Losses:

As mentioned previously BVI continues to look for opportunities to convert outlying lines from 2400 to 7620 in order to reduce losses as well as to have a unified 13,200/7620 grounded system. Voltage upgrades like this will have a significant impact on system efficiency.

Transmission Losses:

As mentioned previously, the main transmission line which feeds BVI was recently replaced. It is expected that the replacement of that line will have a positive impact on system level efficiency compared to historical levels.

Tracking Transfer of Utilities and Dual pole Removal (NJUNS)

BVI is using NJUNS and will continue to implement this practice into the future.

Relocating cross-country lines to road-side

BVI recognizes the significant cost associated with maintaining off-road assets. BVI has a policy in place where every attempt shall be made to make all new construction road-side. Additionally, when rebuilding off-road infrastructure BVI looks carefully at relocating assets to road-side when possible. On the transmission line, where some of the lines cannot be relocated to road-side, BVI works with landowners to improve its ability to access the line and improve restoration time.

DISTRIBUTED GENERATION IMPACT:

Currently, BVI has 41 solar net metering customers, with a combined total installed capacity of 310 kW.

Interconnection of Distributed Generation

BVI recognizes the unique challenges brought on by increasing penetration levels of distributed generation. BVI adheres to the procedures set forth in Rule 5.500 for the interconnection of new generation. Per rule 5.500, a fast-track screening process is utilized to expedite the installation of smaller generators which are less likely to result in issues that affect existing distribution customers. If a proposed installation fails the screening criteria, a Feasibility Study and/or System Impact Study is performed to fully identify and address any adverse effects that are a direct result of the proposed interconnection. These studies, performed by BVI or their representatives, typically include a review of the following issues that may arise as a result of a new generator interconnection:

- Steady state voltage (per ANSI C84.1)
- Flicker (per IEEE 1453)
- Temporary overvoltage due to load rejection and/or neutral shift
- Effective grounding (per IEEE 1547 & IEEE C62.91.1)
- Overcurrent coordination
- Equipment short circuit ratings
- Effect of distributed generation on reverse power and directional overcurrent relays
- Voltage regulator and load tap changer control settings (bi-directional operation)
- Unintentional Islanding
- Thermal loading of utility equipment
- Power factor and reactive compensation strategy
- Impact to underfrequency load shed
- Increased incident energy exposure (arc flash)

In addition, recognizing that the aggregate of many smaller installations which individually pass Rule 5.500 screening criteria can present problems that would otherwise go unnoticed, BVI will maintain detailed records of installed generation including location, type, and generating capacity. This information will allow BVI to periodically review how much generating capacity is installed on a particular feeder or substation transformer and identify any concerns as penetration increases over time.

For example, one issue of growing concern is the aggregate of smaller distributed generators being large enough to require voltage sensing on the primary side of substation power transformers for ground fault overvoltage protection. If a transmission (or sub-transmission) ground fault occurs and the remote terminals operate to clear the fault, an overvoltage due to neutral shift can occur when the ratio of generation to load in the islanded portion of the system is greater than 66% (presumes a standard delta primary, grounded-wye secondary substation power transformer). BVI continues to monitor trends for interconnection protection for abnormal conditions. Supplementing the process outlined in Rule 5.500 with detailed recordkeeping and periodic reviews of how much distributed generation is installed by feeder will help member utilities identify these types of issues before they occur.

As distributed generation penetration increases within BVI's service territory, BVI may consider performing a system-wide hosting capacity study and/or providing hosting capacity maps as a tool to steer development of future medium to large-scale distributed generation to the most suitable locations. This type of hosting study can result in significant up-front costs that must be borne by BVI. As a reasonable compromise, BVI may suggest that potential developers locate facilities within reasonable proximity to an existing substation and within portions of the system with low penetration levels of existing distributed generation, both of which should increase the likelihood that the facility will be able to successfully interconnect.

Inverter Requirements

Consistent with ISO New England requirements related to inverter "ride-through" settings, BVI now requires owners/developers of all new DER installations to self-certify installation of inverters compliant with the Inverter Source Requirement Document (SRD) of ISO New England, with settings consistent with IEEE 1547-2018 and UL 1741 SA. BVI recognizes the need to standardize efforts aimed at certifying inverter compliance with the ISO SRD and will work with VPPSA and the PSD to achieve use of common forms and process in this regard.

DISTRIBUTION-LEVEL IMPACT OF ELECTRIFICATION

BVI recognizes that developing and maintaining a distribution system capable of integrating both distributed generation and developing load concentrations resulting from beneficial electrification is a coming challenge. As electric vehicles, heat pumps, heat pump water heaters, electric mowers and other measures become more common, the need to upgrade or proactively manage portions of the distribution system is expected to increase. BVI is focused on the challenge of identifying and tracking "hot spots" on the system as they develop, with an eye toward formulating timely responses, whether those be load-management efforts, equipment upgrades, or addition of generation/storage at key locations.

The BVI distribution system currently has sufficient capacity for the immediate foreseeable future. As Table 22 indicates, BVI has just a few small solar projects and its 1,400-kW hydro on its system. Maximum loading on the Heath substation transformer is currently about 48% of its nameplate capacity and about 29% on average.

Table 22: BVI Distribution-Level Impact of Electrification

SUBSTATION	# of Transformers	Transformer Capacity	Peak % of Nameplate	Energy % of Nameplate (2)	CIRCUIT/ FEEDER	Circuit Voltage Kv	Solar/Hydro Dist. Generation # of Units	Solar/Hydro Dist. Generation kW	Storage kW	Large Load kW	Large Load kWh
Heath Substation (1)	1	6.25 MVA	48%	29%	West Charleston Branch	7.62 KV	23	1,556	-	-	-
					Barton Branch	7.62 KV	18	147	-	-	-

(1) BVI Jointly owns 50% of Heath Substation with OED
*(2) Annual kWh / (transformer capacity * 8760)*

We know from the Demand Chapter[17] that the transformers at BVI's Substations are not likely to become a constraint. Even when EV and HP penetration reaches high levels in the early 2040s, the peak load is forecast to be well below the transformer ratings. Furthermore, because conductor size is calculated based on the transformer rating, it is also unlikely that conductor size is going to be a constraint. One of the primary lessons learned from Washington Electric Cooperative's (WEC) ongoing PowerShift Electric Vehicle Charging Equipment (EVSE) pilot with Efficiency Vermont (EVT) was that addition of one or more uncontrolled EV charger(s), heat pump(s) or storage device(s) could stress transformers at the service drop level, necessitating an unanticipated upgrade. It was also a conclusion that was reached by GMP in their 2021 Integrated Resource Plan.

While the anticipated pressure point is at the service drop level, the upstream distribution system is adequate for the near future; electrification impacts have yet to become a critical issue at the substation level. In recognition of the potential stress on its system, BVI is exploring sources of data readily available in the short term, that will help identify locational trends, facilitate early identification of and inform proactive responses to, developing concentrations of electrification-driven load.

At the present time BVI tracks customer adoption of electrification measures based on data captured from past and current incentive programs. This incentive-program driven dataset provides a significant amount of information regarding the magnitude and approximate locational trends of electrification driven load. BVI is able to track installed electrification measures associated with incentive programs, by street address, within the BVI system. Use of this dataset in the short run assists the development and analysis of historic deployment patterns as well as anticipating penetration patterns. While this data currently shows a very limited level of penetration that is evenly scattered across the BVI system, the view of magnitude and locational trends this dataset will provide over time will inform policy and

[17] See 'Peak Forecast Results,' pages 28-29.

planning discussions related to BVI's responses to expected electrification impacts on its distribution system.

The current incentive program tracking effort is relatively simple and while it provides limited information, it serves a current need. BVI anticipates that implementation of integrated AMI and GIS systems, if it is decided that BVI will implement AMI, will provide the ability for implementation of more sophisticated, timely and location-targeted distribution system planning, rate driven load management responses, including load control programs where appropriate, and development of forward-looking distribution system improvements designed to take advantage of opportunities to encourage cost-efficient and balanced load growth. As the anticipated AMI and GIS implementations reach maturity, BVI will be in a position to systematically track and analyze transformer, circuit and substation loading on a locational basis and focus on exploiting the new systems abilities. The current incentive tracking effort will become less critical as BVI's ability to measure and analyze load, in something close to real time, from substation down to customer delivery points, comes into play. The improved data availability and analytical capability will facilitate BVI's planning for appropriate distribution system development by enhancing BVI's ability to:

- Monitor physical limits at substation, circuit and transformer levels.
- Identify areas of growing load concentration.
- Discern apparent penetration and deployment patterns of electrification measures based on actual metered load information at the customer level.
- Identify developing spatial patterns of load growth that highlight opportunities to target distribution system upgrades that are cost effective, shape efficient system load growth, and further resiliency efforts.
- Develop effective strategies to implement appropriate load management programs including amount of and optimal location of storage facilities, innovate rate designs, and active load control/management programs.

As data from the new AMI/GIS systems becomes available, and detailed patterns of loading on the distribution system become more readily available, the time will be right for BVI to commission a full T&D study. This will enable BVI to assess the current system conditions and identify/prioritize required improvement projects. Due to the continued efforts to sell the Electric Department, implementation of an AMI system will likely not occur in this cycle of the

IRP. If the Electric Department is retained by BVI, then it will revisit the decision to pursue an AMI system.

VEGETATION MANAGEMENT/TREE TRIMMING

BVI has made efforts to address long-term vegetation management strategies. BVI now has the majority of the system mapped with Google Earth for aerial evaluation of field cover/roadside and cross-country areas. BVI currently utilizes a manual tracking system that includes Google Earth maps and a spreadsheet that records sections trimmed. Going forward BVI intends to work with VPPSA and other contractors to improve trimming management. BVI has been able to evaluate that approximately 30 miles of the 50 miles of 7,620V distribution located within mowed or field areas that do not require active cycles for management. Approximately 20 miles, of the 7,620V line, are on a 10-year cycle. The majority of this high priority trimming is not on BVI's main feeders except for sections serving remote areas of Brownington and Westmore. The 7,620V areas are the arterial feeders to smaller fused step downs to BVI's 2,400V system. Therefore, outages are not expected to be system wide unless there are trouble trees that disrupt service during a wind or ice event.

Starting in 2019 BVI has for the first-time used contractors that employ mechanical trimmer attachments to tracked excavators. This method of clearing was successful and BVI expanded this use in 2020. The mechanical trimming method will be used at all non-roadside locations to the extent possible.

BVI will work during the next few years to evaluate the best approach to developing a trimming plan for the older segments of 2,400V areas. Approximately 70-80 miles of the 150 miles will need hand trimming, specifically roadside trees that continue to age that develop canopies with branches over lines. BVI will need to evaluate its ability to apply financial resources for this work.

Since BVI has struggled with attracting contractors to complete projects, staff has been instructed to triage the system by trimming the worst areas impacting the most customers. While this work may not be considered a thorough trim of the entire width of the right-of-way, it is intended to reduce the most immediate dangers until the routine trimming cycles have addressed the entire system.

BVI maintains a program to identify danger trees within its rights-of-way and targets these trees to either prune or full removal. The success of this program is measured by whether danger trees are a root cause of system outages. Danger trees are identified by utility personnel (and VPPSA contractors) while patrolling the lines, reading meters, or inspecting the system. Once a danger tree is identified, it is promptly removed if it is within BVI's right-of-way. For danger trees outside of the right-of-way, BVI contacts the property owner, explains the hazard, and with the owner's permission removes the tree. Where permission is not granted, BVI will periodically follow up with the property owner to attempt to obtain permission.

BVI has not used herbicides in the recent past and does not have any concrete plans to use them in the future.

The emerald ash borer has recently become an active issue in Orleans County. BVI is monitoring developments and coordinating efforts with VPPSA, danger tree contractors and VELCO and will make use of any guidance that becomes available. If and when the emerald ash borer does surface in BVI's territory, affected trees will be cut down, chipped and properly disposed of. BVI will also coordinate with municipal & local road officials to ensure proper handling of any ash trees that need to be disposed.

Table 23: BVI Vegetation Trimming Cycles

	Total Miles	Miles Needing Trimming	Trimming Cycle
Sub-Transmission	Approximately 5.5	3	7-year average cycle
Distribution 7600 V	Approximately 50	20	10-year average cycle
Distribution 2400 V	Approximately 150	75	10-year average cycle

Table 24: BVI Vegetation Management Costs

	2019	2020	2021	2023	2024	2025
Amount Budgeted	$40,000	$40,000	$40,000	$40,000	$40,000	$40,000
Amount Spent	$27,708	$54,058	$47,467	Deliberately left blank	Deliberately left blank	Deliberately left blank
Miles Trimmed	3 miles	5 miles	5 miles	9.5 miles to be trimmed	9.5 miles to be trimmed	9.5 miles to be trimmed

Table 25: BVI Tree-Related Outages

	2017	2018	2019	2020	2021
Tree Related Outages	22	18	12	29	37
Total Outages	54	50	55	95	91
Tree-related outages as % of total outages	41%	36%	22%	31%	41%

STORM/EMERGENCY PROCEDURES:

BVI's storm/emergency outages are all being handled under contract with VPPSA. BVI reports its outages on the www.vtoutages.com site during major storms especially if it experiences a large outage that is expected to have a long duration. BVI believes it is beneficial to inform the Public Service Department if it is experiencing these types of outages. BVI has a representative on the state emergency preparedness conference calls, which facilitate in-state coordination between utilities, state regulators and other interested parties.

PREVIOUS AND PLANNED T&D STUDIES:

BVI does not have any pending formal T&D studies. Distribution studies were last conducted in the 1990s and transmission studies were performed prior to the 5.5 mile 46kV upgrade. BVI will evaluate the appropriate timing and expenditure of the next study.

Fuse Coordination Study

There are no fuse coordination studies currently under way or planned for the short-term future. However, BVI continues to install fuses on side taps in order to isolate side taps to improve system robustness.

System Planning and Efficiency Studies

System Operation

BVI does not have any system operation studies currently underway, nor does it have any planned. BVI will be looking at the needs of the system and the timing of conducting such studies.

Distribution System Planning

BVI does not have any pending formal T&D studies. Distribution studies were last conducted in the 1990s and transmission studies were performed prior to the 5.5 mile 46kV upgrade. BVI will evaluate the appropriate timing and expenditure of the next study.

Transmission System Planning

As already mentioned in this document, BVI and OED have completed the upgrade to the 5.5 mile 46KV line. BVI continues to work closely with OED and VEC to plan for future load growth. Structure upgrades continue on the VEC/OED/BVI co-owned transmission lines.

CAPITAL SPENDING

HISTORICAL CONSTRUCTION COST 2019-2021

Table 26: BVI Historic Construction Costs 2019-2021

Barton Village, Inc.		**Historic Construction**		
Historic Construction		2019	2020	2021
Hydro	Prod	56,026		
Land and land rights	Dist			
Structures and improvements	Dist			
Station equipment	Dist			
Poles, towers, and fixtures	Dist		30,466	27,057
Overhead conductors & devices	Dist			9,356
Underground conduit	Dist			
Underground conductors & devices	Dist		2,270	
Line transformers	Dist		19,736	53,428
Services	Dist		7,611	11,757
Meters	Dist			
Street light & signal systems	Dist		511	5,005
Structures & improvements	Gen			
Offiice furniture & equipment	Gen			
Transportation equipment	Gen			
Tools, shop, & garage equipment	Gen			
Power operated equipment	Gen			
Land and land rights	Trans			
Station equipment	Trans			59,388
Towers & fixtures	Trans			
Poles & fixtures	Trans	24,920	51,830	47,836
Overhead conductors & devices	Trans	15,274	31,767	29,319
Construction WIP				
Total Construction		$ 96,220	$ 144,191	$ 243,145
Functional Summary:				
Prod		$ 56,026	$ -	$ -
General		$ -	$ -	$ -
Distribution		$ -	$ 60,594	$ 106,602
Transmission		$ 40,193	$ 83,597	$ 136,543
Total Construction		$ 96,220	$ 144,191	$ 243,145

PROJECTED CONSTRUCTION COSTS 2023-2025

Table 27: BVI Projected Construction Costs 2023-2025

Barton Village, Inc.		Projected Construction		
Projected Construction		2023	2024	2025
Hydro	Prod	65,000		
Office & computing Equipment	Gen'l	10,000		
Rebuild/Reconductor line	Dist	140,000		
Station Structures	Dist	25,000		
Transformers, Services & Meters	Dist	25,000		
Transmission	Trans	10,000		
Hydro	Prod		25,000	
Office & computing Equipment	Gen'l		15,000	
Rebuild/Reconductor line	Dist		150,000	
Station Structures	Dist		75,000	
Transformers, Services & Meters	Dist		25,000	
Transmission	Trans		10,000	
Hydro Misc	Prod			25,000
Penstock	Prod			100,000
Hydro transformer	Prod			250,000
Office & computing Equipment	Gen'l			15,000
Vehicle - Pickup	Gen'l			45,000
Rebuild/Reconductor line/3Ph upgrade	Dist			125,000
Station Structures	Dist			25,000
Transformers, Services & Meters	Dist			25,000
AMI	Dist			250,000
Transmission	Trans			10,000
Routine/Recurring/Misc plant & General	25%/75%	50,000	50,000	50,000
Total Construction		$ 325,000	$ 350,000	$ 920,000
Functional Summary:				
Production		65,000	25,000	375,000
General	25%	22,500	27,500	72,500
Distribution	75%	227,500	287,500	462,500
Transmission		10,000	10,000	10,000
Total Construction		325,000	350,000	920,000

V. FINANCIAL ANALYSIS

This section quantifies the costs of a Reference Case and a series of procurement scenarios that would fulfill the existing RES requirement. It also includes scenarios that anticipate increased RES requirements, 100% for Tier I and 20% for Tier II. Finally, it also includes an analysis of the Fitchburg Landfill PPA extension decision as well as a storage-only procurement to illustrate the cost saving potential of a MW-scale, peak-shaving battery. The characteristics of these scenarios are summarized in Table 28.

Table 28: Scenarios

#	Resource Scenario	Description	Size	Price
0	Reference Case	Monthly Market Energy & Annual REC-Only PPAs	N/A	Monthly DALMP
1	Existing RES Requirements	75% by 2032, 10% by 2032		
1.1	Extend Brookfield PPA	Fixed-price energy + Tier I RECs	0.7 MW	Fixed, Levelized
1.2	1 MW Solar PPA	Fixed-price energy + Tier II RECs	1 MW	Fixed, Levelized
1.3	Fitchburg Landfill Extension	Fixed-price energy + Class I RECs	0.3 MW	Fixed, Levelized
2	Increased RES Requirements	100% Tier I by 2032, 20% Tier II by 2032		
3	Storage	MW scale peak-shaving battery by Heath Substation	2 MW	Fixed, Levelized

The sizes and terms were chosen to align with RES requirements, and the pricing is levelized to enable easier comparisons between the scenarios. Levelized pricing is also a very common way to structure a PPA. The Brookfield PPA is priced using current energy market prices, plus an assumption that long-term Tier I RECs would cost $10/MWH. This reflects the current state of the REC market but could be on the high-side of the long-term range. The solar PPA is priced at $110/MWH levelized, which is in alignment with VPPSA's recent solar PPA's. Finally, storage is priced at $15/kW-month.

REFERENCE CASE

The results of the reference case reflect the underlying trends in the price and volume of serving load. The Net Resource and Load Charges and Credits are growing at a 5% annual rate, which reflects not only the underlying assumptions for energy and capacity prices but also the cost of retiring increasing amounts of RECs under the RES statute. Transmission charges are growing more quickly because this has been the trend over the past decade. Administrative costs grow more slowly, and the load itself grows at 2.0% per year after accounting for electrification trends. Finally, the coverage ratio drops as contracts expire.

Table 29: Reference Case Financial, Load and Coverage Ratio Outcomes ($ Million)

Cost Item	2022	2027	2032	2037	2042	CAGR
Net Resource and Load Charges & Credits	$0.69	$0.90	$1.26	$1.56	$1.84	5.0%
Transmission Charges	$0.40	$0.51	$0.72	$1.01	$1.44	6.6%
Administrative and Other Charges & Credits	$0.07	$0.07	$0.08	$0.09	$0.09	1.7%
Total Charges	$1.16	$1.49	$2.06	$2.66	$3.37	5.5%
Total Load - Including Losses (MWH)	15,632	16,606	18,772	21,665	23,247	2.0%
Coverage Ratio	104%	98%	46%	38%	30%	

There are two primary strategies available to reduce the trend in these costs. To stabilize net resource costs, long-term, fixed price contracts can be entered at or below the embedded cost of the existing (or expiring) resource. Accomplishing this outcome requires ongoing monitoring of both market prices and embedded costs, and then procuring resources during those times when it is cost-minimizing to do so.

To stabilize transmission costs, a fixed-price peak-shaving storage resource is being studied. The system is presently sized at 2 MW and 6 MWH, and the contract is structured to guarantee an 85% or greater peak shaving accuracy. At these levels of accuracy, there is an opportunity to stabilize transmission costs by managing peak loads with storage. The next section quantifies the relative cost of each procurement scenario.

PROCUREMENT SCENARIOS

Table 30 shows the present value of the 20-year revenue requirement (PVRR) for the Reference Case and for the RES 2.0 scenario. Notice that the PVRR increases by about $1.2 million dollars or 2% under the RES 2.0 requirements. This is due to the increased cost of procuring Tier I and Tier II RECs. It is also influenced by increasing Tier III requirements, which are assumed to rise to support the electrification trends that are built into the load forecast.

Table 30: Financial Outcomes of each Procurement Scenario ($ Million)

#	Procurement Scenario	PVRR	Unit	% Change
0	Reference Case	$60.1	PVRR	
1	Existing RES Requirement Scenarios			
1.1	Extend Brookfield PPA	($0.1)	Change from Ref. Case	-0.1%
1.2	1 MW Solar PPA	$1.1	Change from Ref. Case	1.8%
1.3	Extend Fitchburg Landfill PPA	$0.0	Change from Ref. Case	0.0%
2	RES 2.0 Requirement Scenario	$1.2	Change from Ref. Case	2.0%
3	Storage Scenario	($1.5)	Change from Ref. Case	-2.5%

The first scenario is modeled assuming the existing RES requirements and includes three closely related decisions. The Brookfield contract extension is priced at market prices, as a result its impact on the PVRR is negligible. However, building solar to meet Tier II requirements is expected to increase costs by 1.8% at today's market prices. This is because solar generation peaks during the spring, summer and early fall months when energy prices are lowest. Finally, the decision to extend the Fitchburg Landfill PPA appears to be cost neutral at today's prices. In this circumstance, it is likely that the contract will be extended because it provides a baseload, fixed-price resource that is an effective hedge against ISO-NE spot prices. Under this scenario the combined result of implementing all three decisions would be an increase in PVRR of $1.0M, or 1.7%.

The second scenario estimates the cost impacts of a 100% renewable requirement by 2032 combined with a doubling of the Tier II requirement to 20%. This scenario increases costs by about 2.0%, relative to the reference case, and is a direct result of the expected cost of purchasing and retiring Tier I and Tier II RECs.

Finally, the third scenario reflects the impact of the fourth decision; placing a 2 MW, 6 MWH battery at the Heath Substation. An estimated $1.5 million dollar savings is expected from storage, and this outcome is dependent on a continuation of transmission rate inflation and the cost of storage itself.

The effect of combining all three of the above scenarios would result in compliance with assumed increases in RES TIER I and TIER II obligations while increasing the PVRR compared to the reference case by $0.7 million or 1.2%.

STORAGE

Round 2 of VPPSA's storage RFP revealed indicative pricing for peak shaving batteries that ranged from about $8.00 to $12.00/kW-month, levelized over 20 years. This price range was applicable to batteries whose capacity was between 1-5 MW and whose energy output was between two and four hours in duration. At this scale, batteries have several advantages.

- They are size appropriate for the loads at BVI's substation.
- They are small enough to operate behind-the-meter with respect to ISO markets.
- They can be cycled 100 times per year to shave monthly and annual peaks.

Inflation and supply chain challenges have increased the cost of storage since the RFP was conducted, but the recently passed Inflation Reduction Act (IRA) is expected to counter this trend. If BVI were to sign a Battery Energy Storage Service Agreement (BESS) at the following prices, and share the savings 50/50 with the developer, the annualized cost savings to BVI would be between $98,000 and $146,000 per year.

Figure 16: Annual Cost of a 2 MW AC Battery ($/Year)

($/kW-mo)	2 MW AC
$8.00	$146,000
$10.00	$122,000
$12.00	$98,000

To determine the value of a peak shaving battery, VPPSA modeled the avoided cost of capacity and ISO transmission. We assumed an 85% success rate for shaving the monthly and annual peaks. Based on a Monte Carlo analysis of 1,000 different randomly generated results, the value of a peak shaving battery averaged $20/kW-month (levelized) between 2023 and 2042. As a result, any BESS agreement that is priced less than this should generate net present value and reduce costs over the life of the agreement. Specifically, a BESS agreement for $10/kW-month would be expected to reduce annual costs by $122,000 and PVRR by $1,500,000.

CONCLUSIONS

The financial analysis can be summarized by three primary points. First, existing Tier I RES requirement can be met with existing resources and by extending the Brookfield PPA. However, Tier II requirements must be met with a new renewable resource, namely solar, and that is expected to increase costs by $1.1 million or 1.8%. Second, RES 2.0 requirements may increase costs by an additional 2.0% as measured by the PVRR. Third and finally, peak shaving storage represents an opportunity to reduce costs nearly 2.5% by mitigating the increasing cost of transmission and capacity.

In any event, it is a best practice to procure new resources using a competitive process, as outlined in the Resource Plan chapter. The cost-minimizing resource(s) will be sensitive to energy, REC, and capacity market prices at the time of their procurement, and the size of each resource must align reasonably well with BVI's load to be an effective hedge against ISO-NE's day ahead and real time energy markets.

ACTION PLAN

VI. ACTION PLAN

Based on the foregoing analysis, we envision taking the following actions.

- Sale Evaluation of Utility
  - Village Trustees have indicated the desire to attempt to sell the utility again. At this point in time, trustees plan to solicit proposals from all Vermont distribution utilities and interested parties. In this second attempt to sell the utility, it will address issues and concerns brought forward by parties that were active in the original sale process. Barton, with the help of its consultants, will navigate this complex business situation and it plans to present an alternative sale to Village voters in the upcoming two years. Managing the utility through consultants and contractual arrangements will continue for the next several years until a sale is attempted. In the meantime, Barton Trustees will assure its ratepayers continued service and reliable operations through these agreements.

- Automated Metering Infrastructure (AMI)
  - Implementation of the AMI system is tentatively planned to begin in late 2024, dependent on the outcome of the ongoing evaluation for Barton to sell or retain the Electric Department.

- Energy Resource Actions
  - Manage year to year energy market requirements using fixed-price, market contracts that are less than five years in duration.
  - Using the Resource Acquisition Process, solicit and/or extend the existing hydro PPA bundled with Tier I RECs to fulfill RES requirements and hedge energy and REC price risk.

- Capacity Resource Actions
  - Manage and monitor the reliability of Project 10 to minimize Pay-for-Performance (PFP) risk and maximize PFP benefits.

- Tier I Actions

  - Solicit and/or extend both the existing hydro PPA bundled with Tier I RECs to fulfill RES requirements and hedge energy and REC price risk.
  - Make forward purchases, both short and long-term, of qualifying RECs on the regional market to manage REC price and ACP risk.

- Tier II Actions
  - Complete a 1 MW solar project.
  - Make forward purchases, both short and long-term, of qualifying RECs on the regional market to manage REC price and ACP risk.
  - Advocate for recognizing the value of in-state resources like Barton Hydro for meeting Tier II requirements.

- Tier III Actions
  - Identify and deliver prescriptive and/or custom Energy Transformation programs.

- Storage
  - Continue to develop storage near the Heath Substation.

- Active Load Control Pilot Program
  - Investigate options for engaging customers in active load control programs and tariffs, including end-uses such as electric thermal storage, CCHPs, and HPWHs.

- Innovative TOU Rates Program
  - Work with VPPSA to explore development and implementation of innovative, Time-of-Use (TOU) rates for residential electric vehicle chargers, public DC fast charging stations and more generalized (whole house) TOU and other innovative rate structures as a cost-effective way to supplement active load controls.

- Net Metering

- o Monitor the penetration rate and cost of solar net metering for future grid parity, and advocate for appropriate policies to mitigate potential upward rate pressure.

APPENDIX

APPENDIX A: 2023 TIER 3 ANNUAL PLAN

This appendix is provided separately in a file named:

Appendix A - VPPSA Tier 3 2023 Annual Plan.pdf

APPENDIX B: PRICING METHODOLOGY

This appendix is provided separately in a file named:

Appendix B – BVI Energy & Capacity Pricing Methodolgy.pdf

APPENDIX C: PUC RULE 4.900 OUTAGE REPORTS

This appendix is provided separately in a file named:

Appendix C – BVI 2017-2021 Rule 4.900 Electricity Outage Reports.pdf

APPENDIX D: AMI RFI TECHNICAL REQUIREMENTS

This appendix is provided separately in a file named:

Appendix D – AMI_RFI_Technical_Requirements.pdf

APPENDIX E: AMI RFP TECHNICAL REQUIREMENTS

This appendix is provided separately in a file named:

Appendix E – AMI_RFP_Technical_Requirements.pdf

APPENDIX F: ITRON'S LOAD FORECAST REPORT

This appendix is provided separately in a file named:

Appendix F – Barton IRP22 Demand Report.pdf

APPENDIX G: TIER III LIFE-CYCLE COST ANALYSIS

This appendix is provided separately in a file named:

Appendix G – Barton Tier III Life-Cycle Cost Analysis.pdf

APPENDIX H: NVDA REGIONAL ENERGY PLAN

Appendix H - https://www.nvda.net/regional-plan.php

GLOSSARY

ACP	Alternative Compliance Payment
ACSR	Aluminum conductor steel-reinforced
AEO	Annual Energy Outlook
AESC	Avoided Energy Supply Cost
AMI	Advanced Metering Infrastructure
APPA	American Public Power Association
BESS	Battery Energy Storage Service Agreement
BVI	Barton Village, Inc.
CAGR	Compound Annual Growth Rate
CAIDI	Customer Average Interruption Duration Index
CC	Combined Cycle (Power Plant)
CCHP	Cold Climate Heat Pump
CEDF	Clean Energy Development Fund
CEP	Comprehensive Energy Plan
CRC	Cooperative Response Center
CSO	Capacity Supply Obligation
CVRPC	Central Vermont Regional Planning Commission
DPP	Damage Prevention Plan
DTLM	Distribution Transformer Load Management
EIA	U.S. Energy Information Administration
ESSA	Energy Storage Service Agreement
ET	Energy Transformation (Tier III)
EV	Electric Vehicle
EVT	Efficiency Vermont
FERC	Federal Energy Regulatory Commission
GIS	Graphic Information Systems
GMP	Green Mountain Power
HED	Hardwick Electric Department
HP	Heat Pump
HPWH	Heat Pump Water Heater
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
ISO-NE	ISO New England (New England's Independent System Operator)

kV	Kilovolt
kVA	Kilovolt Amperes
kW	Kilowatt
kWh	Kilowatt-hour
LED	Lyndonville Electric Department
LIDAR	Light Detection and Ranging
LIHI	Low Impact Hydro Institute
LMP	Locational Marginal Price
LRTP	Long Range Transmission Plan
MAPE	Mean Absolute Percent Error
MSA	Master Supply Agreement
ME II	Maine Class II (RECs)
MEAV	Municipal Association of Vermont
MDMS	Meter Data Management System
MSA	Master Supply Agreement
MVA	Megavolt Ampere
MW	Megawatt
MWH	Megawatt-hour
NEPPA	Northeast Public Power Association
NESC	National Electrical Safety Code
NJUNS	National Joint Utilities Notification System
NVDA	Northeastern Vermont Development Association
NOAA	National Oceanic and Atmospheric Administration
NYPA	New York Power Authority
OED	Orleans Electric Department
PFP	Pay for Performance
PHEV	Plug-in Hybrid Electric Vehicle
PUC	Public Utility Commission
PPA	Power Purchase Agreement
PSD	Public Service Department or "Department"
PVRR	Present Value of Revenue Requirement
R^2	R-squared
REC	Renewable Energy Credit
RES	Renewable Energy Standard
ROW	Right-of-way

RTLO	Real-Time Load Obligation
SAE	Statistically Adjusted End Use
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SQRP	Service Quality & Reliability Performance, Monitoring & Reporting Plan
TAG	Technical Advisory Group
TIER I	Total Renewable Energy (Tier I)
TIER II	Distributed Renewable Energy (Tier II)
TIER III	Energy Transformation (Tier III)
TOU	Time-Of-Use (Rate)
VEC	Vermont Electric Cooperative
VELCO	Vermont Electric Power Company
VEPPI	Vermont Electric Power Producers, Inc.
VFD	Variable Frequency Drive
VPPSA	Vermont Public Power Supply Authority
VSPC	Vermont System Planning Committee
VT ANR	Vermont Agency of Natural Resources
VTrans	Vermont Agency of Transportation
WBHP	Whole Building Heat Pump
WQC	Water Quality Certificate

Vermont Public Power Supply Authority

2023
Renewable Energy Standard
Tier III Annual Plan

Filed via ePUC
November 1, 2022

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Table of Contents

Introduction

In accordance with the Public Utility Commission ("PUC") Rule 4.400, Vermont Public Power Supply Authority ("VPPSA") is filing its 2023 Renewable Energy Standard: Tier III Annual Plan describing the proposed strategy to meet its members' energy transformation program compliance.

Vermont's Renewable Energy Standard ("RES"), enacted through Act 56 in 2015, requires electric distribution utilities to either support fossil fuel savings by encouraging Energy Transformation ("Tier III") projects or purchase additional Renewable Energy Credits ("RECs") from new, small, distributed renewable generators ("Tier II").

As VPPSA's Tier III Program evolves, process improvements and responsiveness to customer trends, needs, and priorities are continuously monitored. Providing safe, reliable, and affordable electricity is a critical factor in supporting the State's renewable energy goals and expanded offerings must be evaluated to ensure cost-effectiveness.

VPPSA members continue to prioritize strategic electrification that minimizes cost-shifting or upward rate pressures; this is especially important in 2023 considering substantial increases in cost-of-living expenses, geopolitical conflicts straining the global economy, and mounting supply chain constraints because of inflation and shortages resulting from the COVID-19 pandemic. Responsiveness to needs of all customer classes remains a priority to ensure sustainable growth and community strength.

In consideration of all these factors, VPPSA submits its 2023 Tier III Annual Plan which aims to increase collaboration with the State's Energy Efficiency Utilities, strengthen opportunity for point-of-sale incentives, and streamline processes to encourage increased participation in energy transformation projects for residential, commercial, and industrial customers.

Respectfully,

Sarah E. Braese
Manager of Government and Member Relations
Vermont Public Power Supply Authority
(802) 882-8509

VPPSA Tier III Obligation Requirements

VPPSA Member Utilities'[1] Tier III obligation requirements are established by 30 V.S.A. § 8005(a)(3)(B), which states that "in the case of a provider that is a municipal electric utility serving not more than 6,000 customers, the required amount shall be two percent of the provider's annual retail sales beginning on January 1, 2019.[2]" Tier III requirements increase by two-thirds of a percent annually .

In 2023, VPPSA's aggregate requirement is estimated to be 16,531 MWh equivalent in savings, representing 4.67% of members' 2022 estimated Annual Retail Sales (kWh). The 11 VPPSA member utilities plan to meet their Tier III requirements in aggregate, as permitted under 30 V.S.A. § 8004 (e), which states "[i]n the case of members of the Vermont Public Power Supply Authority, the requirements of this chapter may be met in the aggregate."

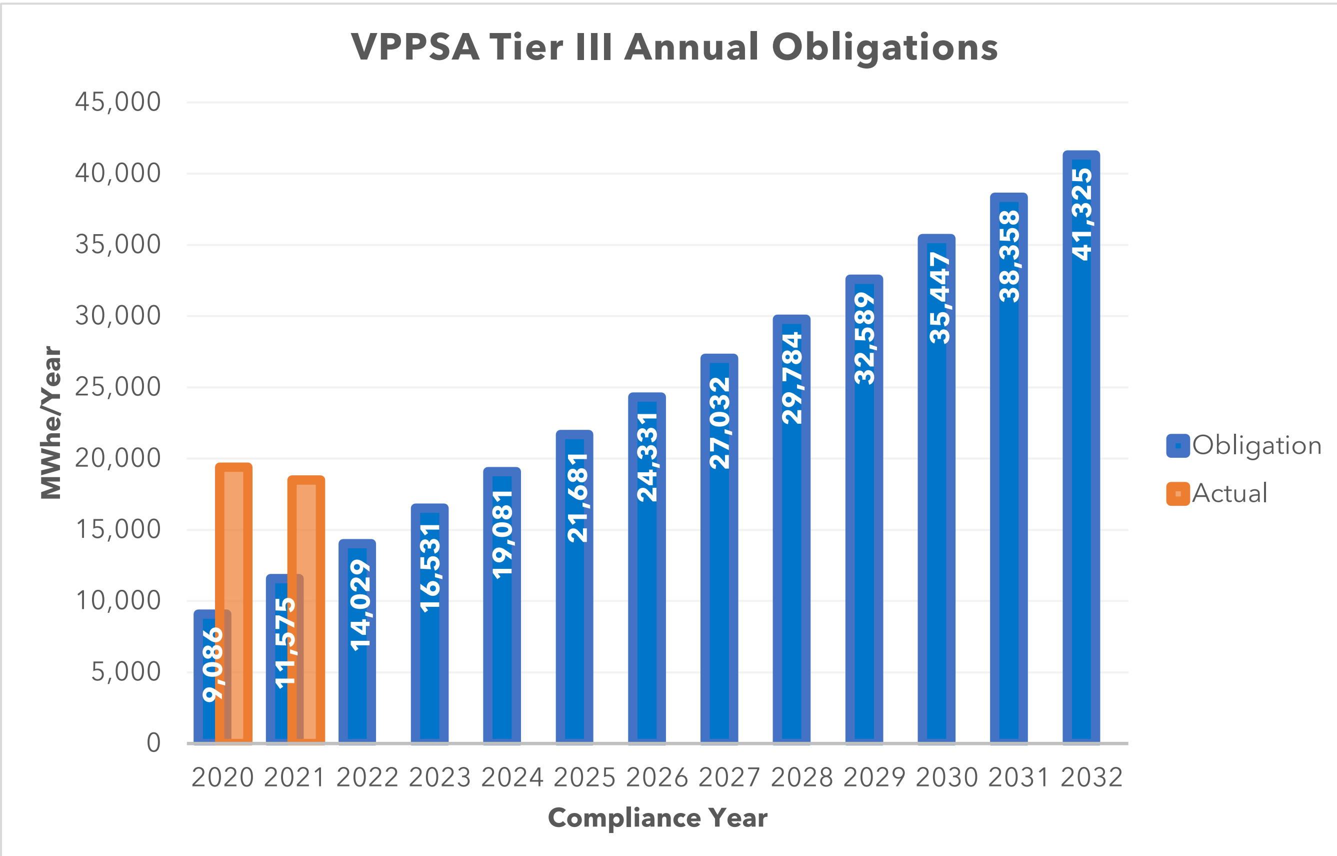
VPPSA's projected Tier III annual MWh equivalent (MWhe) savings obligations through 2032 and compliance performance are illustrated in Figure 1: VPPSA Tier III Annual Obligations (see Page 3)[3].

[1] VPPSA Members include Barton Village; Village of Enosburg Falls; Hardwick Electric Department; Village of Jacksonville; Village of Johnson; Ludlow Electric Light Department; Lyndonville Electric Department; Morrisville Water & Light; Northfield Electric Department; Village of Orleans; and Swanton Village.

[2] 30 V.S.A. § 8005(a)(3)(B)

[3] 2020 and 2021 Tier III "Actual" MWhe Savings as reported from VPPSA's Annual RES Compliance Filings in Case 21-1045-INV and Case 22-0604-INV, respectively.

Figure 1: VPPSA Tier III Annual Obligations



Summary of 2022 Projects

VPPSA is on track to meet its 2022 Tier III requirements of 14,029 MWhe through a portfolio of prescriptive and custom energy transformation measures.

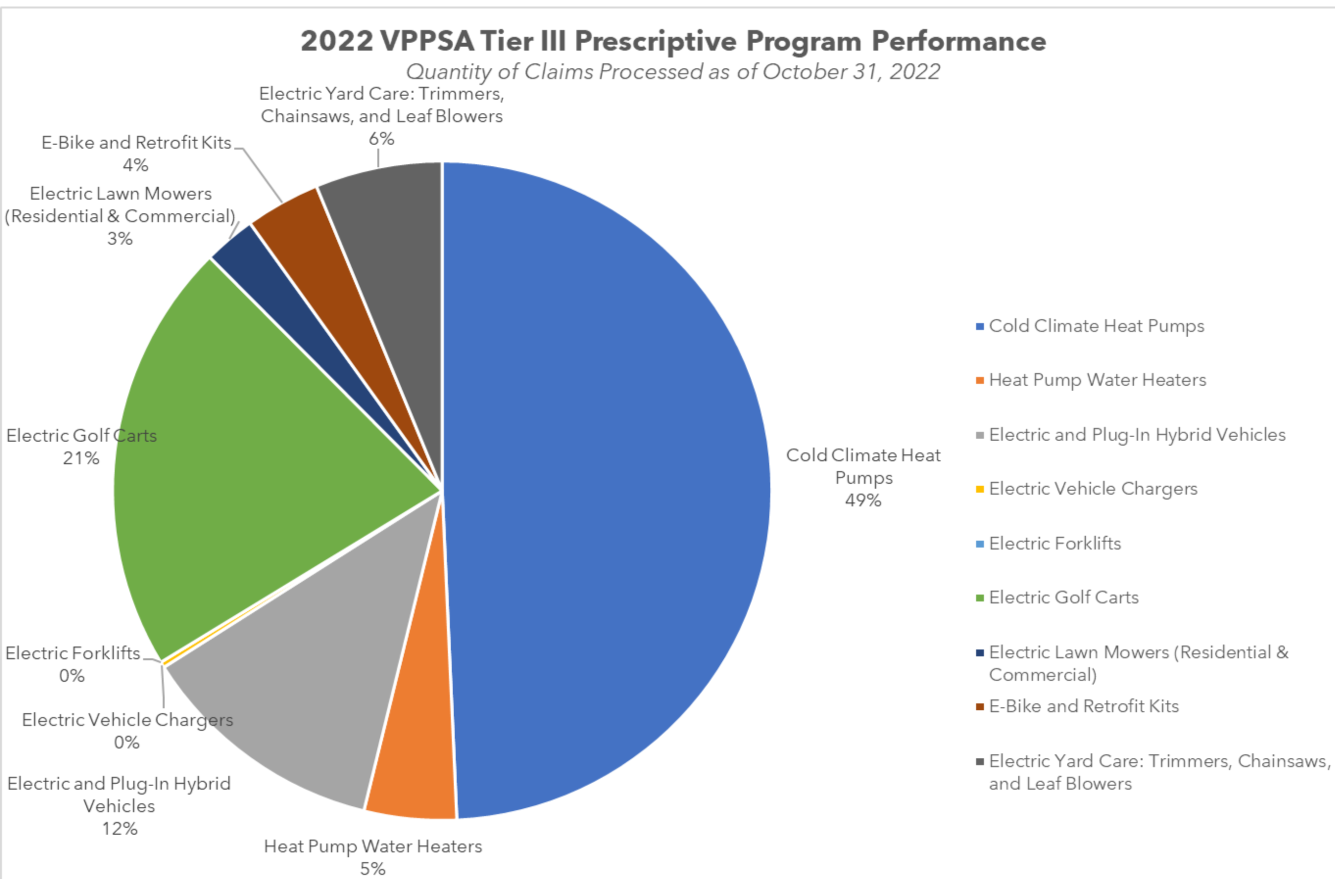
Prescriptive measures are administered using a combination of midstream and downstream incentives:

1. Cold Climate Heat Pumps
2. Heat Pump Water Heaters
3. Electric and Plug-In Hybrid Vehicles
4. Electric Vehicle Chargers
5. Electric Forklifts
6. Electric Golf Carts
7. Electric Lawn Mowers (Residential & Commercial)
8. E-Bike and Retrofit Kits
9. Electric Yard Care: Trimmers, Chainsaws, and Leaf Blowers

Of the prescriptive rebates offered, cold climate heat pumps represent a significant portion of the total number of measures processed to-date. VPPSA's strategy continues to focus on cost-effective prescriptive and custom Tier III measures which meet member and customer needs. This strategy includes monitoring consumer trends, potential grid infrastructure impacts, and external socio-economic factors that may affect supply chains and, ultimately, future compliance.

Figure 2: 2022 VPPSA Tier III Prescriptive Program Performance reflects processed claims as of October 31, 2022 and is intended for illustrative purposes only[4]. This data is not reflective of total nor expected claims for the entire 2022 Tier III Compliance year.

Figure 2: 2022 VPPSA Tier III Prescriptive Program Performance



[4] Figure 2 represents the quantity of completed prescriptive rebate claims processed to-date and is intended for illustrative purposes only. This data does not reflect the entirety of 2022 Tier III Compliance claims, nor does it represent expected compliance performance by year-end.

VPPSA recognizes that while custom measures have a longer ramp-up time and larger up-front incentives, their overall cost per MWh is, on average, substantially lower than both prescriptive incentives and Tier II RECs.

Custom projects, typically for commercial and industrial customers, include incentives for line extensions, service upgrades, or other energy transformation projects that reduce greenhouse gas emissions and reliance on fossil fuels. VPPSA continues to seek and support a robust pipeline of custom projects at various stages in their development. As it has been previously expressed, timelines for custom projects are often longer than the decision-making process for prescriptive rebates. For that reason, some custom projects may not be completed until 2023 or later.

2023 Tier III Program Overview

The focus of VPPSA's 2023 Tier III Program is to support Vermont's electrification transition while ensuring rates are affordable and maintaining reliability of service. It is important for distribution utilities to prioritize reliability as an assurance for customers during the decision-making process to adopt new electrification measures.

As in previous years, VPPSA plans to meet its 2023 Tier III requirements by further diversifying its portfolio of offerings at costs that mitigate pressure on electric rates. This portfolio includes a combination of prescriptive and custom measures and use of Tier II RECs, if needed.

VPPSA intends to maintain its current portfolio of prescriptive measure offerings with the addition of offering Smart Thermostats, and a renewed focus on improving the processes by which customers can obtain these financial incentives. In particular, VPPSA will be implementing a new rebate processing platform to better serve its members' customers by streamlining and expediting the application and claims approval process.

Prescriptive Measure Savings are calculated using the Net Lifetime MWh Saved measure characterizations created by the Tier III Technical Advisory Group ("TAG.").

To ensure a diversity of offerings that ensures equity in accessibility and customer participation, VPPSA has further defined its 2023 Tier III Program measures into four main categories, by type of electrification (aka energy transformation):

1. Transportation
2. Thermal
3. Commercial Equipment & Appliances
4. Residential Equipment & Appliances

Incentive offerings are explained in greater detail below.

Transportation

State and Federal funding and policy making decisions continue to support the expansion of the electric vehicle market and electric vehicle charging infrastructure. VPPSA plans to continue incentive offerings that encourage customer adoption, with a focus on equity and strategic monitoring of potential changes in load management.

Electric Vehicles (EV) and Plug-In Hybrids (PHEV)

VPPSA will continue to offer customer incentives for the purchase or lease of new and used EVs and PHEVs in 2023 as both point-of-sale or post-purchase rebates.

The customer incentives for EV and PHEVs are as follows:

Measure Type	Base Incentive	Additional Low-Income Incentive	Estimated Total MWhe Savings
Electric Vehicle (New)	$ 1,000	$ 400	1,007 MWhe
Electric Vehicle (Used)	$ 500	N/A	168 MWhe
Plug-in Hybrid Vehicle (New)	$ 500	$ 400	517 MWhe
Plug-in Hybrid Vehicle (Used)	$ 250	N/A	65 MWhe

In its second year of partnering with vehicle dealerships around the state to offer point-of-sale incentives, VPPSA is looking to expand its program to additional dealerships and increase awareness of incentive availability to member customers. Customers who purchase or lease a vehicle from a participating dealership will receive an instant, point-of-sale incentive discount. Dealerships then submit the required application and documentation to VPPSA for reimbursement.

Post-purchase rebate applications will continue to be accepted from eligible customers who provide all necessary documentation.

Electric Vehicle Charging

VPPSA will continue to offer a $500 rebate for customers installing electric vehicle chargers at a workplace and/or available for the public to use.

Using data analytics from the 2022 EVSE Powershift Pilot Program with Efficiency Vermont (EVT), VPPSA hopes to develop a more robust EV charging network within its member service territories to meet member and customer needs. The PowerShift Pilot Program provides residential customers with Open Charge Point Protocol ("OCPP") charging equipment, capable of integrated with multiple control platforms through open-source technology. As part of the Pilot, chargers are programmed to provide charging during off-peak hours and may facilitate direct control of EV charging in the future.

Thermal

As described above in relation to transportation, VPPSA recognizes that alleviating energy burden of its customers must also include supporting thermal, or heating and cooling electrification technologies such as cold climate heat pumps.

In collaboration with Efficiency Vermont (EVT) and other Vermont distribution utilities, beginning January 2021, EVT began administering state-wide utility heat pump incentive programs. This partnership and collaboration have greatly expanded the adoption and installation of these fuel-saving technologies, particularly in VPPSA member service territories which had been historically underrepresented in state-wide adoption metrics.

Cold Climate Heat Pumps

In 2023, VPPSA will continue to offer incentives on ductless and whole building heat pump technology through its partnership with EVT to administer midstream, point-of-sale and downstream heat pump incentives on VPPSA's behalf.

Efficiency Vermont will batch the incentives and invoice VPPSA monthly for reimbursement.

Ductless Heat Pumps:

In 2023, Efficiency Vermont will continue to administer the additional $250 utility incentive for ductless heat pumps as an instant, point-of-sale discount.

Utility incentives are applied when customers utilize participating contractors or distributors. Efficiency Vermont batches and reports incentives applied for VPPSA member customers and invoices VPPSA monthly for reimbursement. VPPSA expects a similar volume of ductless heat pump incentives to what was offered in 2022, however supply and labor constraints may impact the overall uptake and performance.

VPPSA is also partnering with Efficiency Vermont and other Vermont electric utilities to offer ductless heat pumps to income-qualifying households at no cost to the utility customer. These incentives would be offered to income-qualifying customers who have completed weatherization services provided through the Weatherization Assistance Program ("WAP"). The cost of the heat pumps will be shared between the distribution utilities and Efficiency Vermont, with Efficiency Vermont's portion coming through use of Act 151 funds. Consistent with the requirements of Act 151, the distribution utilities will claim the entire thermal savings for these CCHPs and EVT will claim the electric savings. VPPSA anticipates 11 ductless heat pumps will be installed in its member utility territories in 2023.

As part of its Tailored Efforts in partnership with Efficiency Vermont, VPPSA expects to offer a low-to moderate-income ducted and ductless heat pump adder for qualifying customers of 2023 Tailored Effort utilities. In 2022, VPPSA provided a $400 downstream heat pump incentive adder to income eligible customers of Hardwick Electric Department, Lyndonville Electric Department, and Morrisville Water & Light. VPPSA's adder was combined with the $200 statewide income adder from Efficiency Vermont, plus an additional $400 contribution from Efficiency Vermont. The total adder including both VPPSA and Efficiency Vermont's contributions came to $1,000 for low-to moderate-income customers. VPPSA and Efficiency Vermont are currently in conversations about offering a similar incentive in 2023 to customers of Tailored Effort utilities.

Whole Building Heat Pumps:

VPPSA will continue to offer incentives on centrally ducted heat pumps and air-to-water heat pumps. Efficiency Vermont administers all whole building heat pump incentives on behalf of VPPSA and several other Vermont utilities.

The centrally ducted heat pump incentive will continue to be offered as an instant discount at the point-of-sale. The incentive amount ranges from $750 – $1,500 depending on the size of the heat pump. VPPSA will offer the full incentive and claim 100% of the thermal savings. Efficiency Vermont may offer an additional incentive and claim electric efficiency savings.

Efficiency Vermont will continue to administer the incentive for air-to-water heat pumps. In most cases, VPPSA and Efficiency Vermont will each offer 50% of the $1,000/ton incentive and claim 50% of the thermal savings. When an air-to-water heat pump is installed in VGS territory, VPPSA will offer the full incentive and claim the full savings. This is equivalent to how the incentive was managed in 2022.

VPPSA and Efficiency Vermont are partnering on a low-to moderate-income ducted and ductless heat pump adder for qualifying customers of 2023 Tailored Effort utilities. See the "Ductless Heat Pumps" section for further information.

VPPSA will also continue to offer ground source heat pump ("GSHP") incentives on a prescribed custom basis.

Heat Pump + Weatherization:

VPPSA will continue to offer a $200 downstream incentive to customers who are installing heat pump technology in a weatherized building. The incentive applies to ductless, centrally ducted, and air-to-water heat pump technology.

If the customer wishes to receive the additional weatherization incentive, then they must fill out the Heat Pump + Weatherization rebate application form and submit it to VPPSA along with the necessary supporting documents. The additional incentive serves to highlight the importance of overall building performance. To be eligible for the higher incentive amount, customers will need to demonstrate that their homes were weatherized according to a list of standards developed and circulated by the Department during the CCHP measure characterization by the TAG.

VPPSA claims the incremental savings associated with a heat pump installed in a weatherized building. Currently there is a distinct measure characterization for ductless CCHP installed in a high performing (weatherized) building. VPPSA will advocate through the TAG to get distinct measure characterizations for WBHP (ducted, air to water, and GSHP) that are installed in weatherized buildings.

Heat Pump Water Heaters

VPPSA will continue to provide a $600 discount to customers that install heat pump water heaters ("HPWH") to replace fossil-fuel fired water heaters. This incentive is administered by Efficiency Vermont.

There are two pathways a customer can take to receive the incentive. The first scenario applies to customers working through a contractor. These customers may be eligible for an instant discount at the time of purchase. Efficiency Vermont provides a $650 discount at the distributor level. $600 is passed down through the contractor to the end use customer while $50 remains with the distributor as a stocking incentive. Efficiency Vermont batches incentives provided to distributors and end-use customers and bills VPPSA monthly.

In the second pathway the customer purchases a qualifying HPWH from a retail provider. The customer then completes and submits the appropriate Efficiency Vermont rebate form. VPPSA is billed monthly by EVT.

Approximately 75% percent of customers installing a new heat pump water heater are doing so to replace an electric water heater. In this instance, Efficiency Vermont pays the entire incentive and claims the electric efficiency savings. The remaining 25% of customers are replacing fossil fuel fired water heaters. VPPSA claims all the thermal savings associated with these energy transformation projects.

Commercial Equipment & Appliances

As key fixtures and economic drivers in member communities, VPPSA is pleased to continue offering specific prescriptive incentive measures to support the electrification of commercial equipment and appliances.

Forklifts

In support of the various business customers throughout VPPSA's member territories, VPPSA intends to continue offering a $2,500 rebate incentive for new electric forklifts. Increased marketing and outreach will be conducted to various businesses in an attempt to inform and encourage electrification of this equipment.

Golf Carts

In 2023, VPPSA continues to offer a $100 rebate incentive for customers that purchase new electric golf carts. As with forklifts, VPPSA intends to increase marketing and outreach to the various businesses which may benefit from the investment in new, electric golf carts.

Commercial Property Maintenance

Commercial Lawn Mowers

VPPSA will be offering a $1,200 incentive for purchase of an electric, commercial ride-on lawn mower. A $100 incentive will be offered for purchase of an electric, commercial push mower.

Commercial Leaf Blowers

VPPSA will continue to offer a rebate incentive of $25 for the purchase of a commercial electric leaf blower.

Commercial Trimmers

VPPSA will continue to offer a rebate incentive of $25 for the purchase of a commercial electric trimmer.

Commercial Chainsaws

VPPSA will continue to offer a rebate incentive of $25 for the purchase of a commercial electric chainsaw.

Residential Equipment & Appliances

VPPSA recognizes the enormous impact that local, state, and federal policies can have on the average residential customer and is pleased to offer the following suite of prescriptive incentives in 2023.

Electric Bikes (E-Bikes)

VPPSA will continue to offer a rebate incentive of $100 for the purchase of a new e-bike or e-bike conversion kit. Additionally, VPPSA intends to strengthen relationships with various e-bike retailers throughout the state to explore point-of-sale agreements, similar to those established with electric vehicle dealerships.

Residential Property Maintenance

In 2022, VPPSA saw increased customer claims for yard care rebates which will continue to be offered in 2023. Although these measures often have a high $/MWh cost, they are often a lower cost, entry level, electrification of equipment for the average customer.

Residential Lawn Mowers

VPPSA will continue to offer a $50 incentive for the purchase of either a residential push or ride-on electric lawn mower.

Residential Leaf Blowers

VPPSA will continue to offer a rebate incentive of $25 for the purchase of a residential electric leaf blower.

Residential Trimmers

VPPSA will continue to offer a rebate incentive of $25 for the purchase of a residential electric trimmer.

Residential Chainsaws

VPPSA will continue to offer a rebate incentive of $25 for the purchase of a residential electric chainsaw.

Smart Thermostats

As headlines warn of rising home heating costs, VPPSA intends to continue expanding partnerships with external entities to maximize efficiencies and weatherization of customers' homes. With that in mind, VPPSA is pleased to introduce a new $50 prescriptive incentive for smart thermostats in 2023. With more advanced controls and monitoring, this new measure is an affordable way to help customers better mitigate impacts of rising fuel costs and ideally, their overall energy burden.

Custom Measures

For commercial and industrial ("C&I") customers seeking more sophisticated energy transformation projects, VPPSA intends to continue offering Custom Measures, where appropriate. VPPSA maintains and tracks a pipeline of customers exploring potential Tier III customer projects, in collaboration with the work of Efficiency Vermont (EVT).

Due to various internal and external factors, identified custom projects with estimated completion in 2022 may indeed be postponed to 2023, including electric buses, commercial heat pump units for a new-construction multifamily unit, electric bucket trucks, and an industrial heat recapture project.

Due to the relatively lower cost of MWh savings from custom projects, VPPSA continues to focus on identifying opportunities and working with utility customers to engage in energy transformation. VPPSA's Key Accounts program is one tool to assist in the identification of custom projects with C&I customers. Additionally, VPPSA continues to partner with Efficiency Vermont to identify C&I customers that have potential Tier III and electric efficiency projects.

Incentives for custom measures are typically paid for by the host utility rather than through VPPSA, with the host utility retaining the associated Tier III credits. Upon approval of the VPPSA Board of Directors, VPPSA may fund custom projects through its Tier III budget and allocate savings among its members.

In 2022, VPPSA received an appropriation of $1 million from the Department of Energy through a federal earmark provided by Senator Sanders. VPPSA is using this funding to pilot an R&D project to determine if on-bill financing of custom commercial and industrial energy transformation projects could incentivize this customer class to reduce fossil fuel use. VPPSA is partnering with Efficiency Vermont and a yet-to-be-determined financial institution to explore and offer low-to-no interest financing options for projects that pass screening criteria. At this time of this report, the pilot project is still under negotiation with the Department of Energy for the final award announcement. We expect this Business Energy Repayment Assistance Program ("BERAP") will launch in 2023.

VPPSA will continue to work with the Department of Public Service on custom projects to ensure savings claims are verified and the Department is able to adequately budget for verification activities.

Tier II RECs

VPPSA manages its member Tier III compliance in a manner that meets statutory requirements while minimizing overall costs through a portfolio of prescriptive programs, custom projects, and Tier II RECs. Under this approach the Tier II REC price acts as a not-to-exceed per unit budgetary target when developing prescriptive and custom rebate offerings.

VPPSA may consider utilizing excess Tier II RECs from its growing solar project portfolio and/or purchase Tier II RECs when prices are low as a hedge against a deficit in savings from Tier III programs. To the extent that Tier II RECs are less expensive than implementing Tier III programs, VPPSA may exercise this strategy to benefit its members. For VPPSA members that own Tier II eligible generating resources, Tier II RECs may be the primary strategy for Tier III compliance.

Should Tier II REC prices increase, VPPSA will reevaluate its incentive levels and potentially increase the rebate value. In that situation, VPPSA would file a revised Tier III planning document.

Best Practices: Load Growth & Management

Over the long-term, energy transformation programs have the potential to increase loads for all Vermont utilities, however load impact potential is a complex scenario influenced by several factors. VPPSA members systems remain robust, and the expected growth in annual and local peak demand associated with proposed measures are supported and sustained through monitoring deployment.

In alignment with industry best practices, underlying assumptions used in VELCO's Long-Range Transmission Plan ("LRP") are used to develop members' Integrated Resource Plans (IRP). As a result, IRPs incorporate the State's latest outlook for Electric Vehicle (EV) and Cold Climate Heat Pump (CCHP) adoption. Additionally, State and Federal investments in electrification technologies for the thermal and transportation sectors are important factors that contribute to forecasting models in relation to consumer trends and adoption of electrification measures.

From a technical perspective, there are many credible options for controlling load which VPPSA continues to monitor, pilot, and deploy where shown to be economically competitive.

As part of VPPSA's long-term advanced metering infrastructure and GIS projects, member utilities will soon have the capacity to further refine analytics around load monitoring and forecasting correlating to energy transformation programs. This is particularly important as state policies continue to support electrification of transportation and thermal sectors. In the interim, VPPSA continues its partnership with Virtual Peaker, which supports internal utility behavioral demand-response programs that strategically maximizes load-reducing generation during high-cost time periods.

As previously stated in the Transportation Electrification section, VPPSA and Efficiency Vermont are partnering on a PowerShift Pilot that may mitigate the grid impacts of EV charging. Residential customers who purchase or lease an all-electric vehicle are eligible to receive a free level 2 charger and a $500 incentive for installation. These incentives are funded by Efficiency Vermont. Customers must provide proof of setting a daily charging schedule outside of peak hours to be eligible for the incentives. VPPSA anticipates installing 15-20 scheduled chargers in 2023. VPPSA expects to learn how incentives and rebates affect charging behavior through its PowerShift partnership with Efficiency Vermont. That said, alternative incentives like rate structures may similarly impact when utility customers choose to charge their electric vehicles. VPPSA applied for and received grant funding to study time-of-use rates as a means to shift utility customer demand to off-peak times. VPPSA also anticipates applying for funding through the Infrastructure Investment and Jobs Act. The Department of Public Service is receiving $3.2 million each year over a five-year period, which may be sub-awarded to utilities. VPPSA continues to work collaboratively with the Department and other distribution utilities to identify eligible projects that lead to investments in a smarter grid with greater flexibility.

VPPSA continues to pursue utility-scale storage as a cost-effective means of achieving demand reductions for its members. Current constraints on the supply chain have created complex challenges in equipment and material sourcing, however battery storage remains a key tool to meet demand reductions.

Lastly, as a method to encourage participation in buildings which meet established performance standards, thereby helping to manage load control, VPPSA also provides an additional $200 heat pump incentive for units installed in weatherized buildings.

Minimum Standards: Program Administration

As previously stated, VPPSA administers its Tier III Program in aggregate, on behalf of all members. As such there are a number of standards and processes which are employed to meet minimum standards and compliance.

In administering prescriptive measures, VPPSA maintains standard customer privacy and data security procedures to protect sensitive information. VPPSA also implements necessary internal controls to ensure the integrity of the Program. This requires a segregation of duties in the receipt, processing, and approval of incentive applications.

Equitable Opportunity

VPPSA strives to ensure that Tier III energy transformation programs are accessible and beneficial to all customers regardless of income level or rate class. The Tier III incentives described in this Plan are available to all VPPSA member utility customers. Commercial and Industrial customers have the ability to access VPPSA's prescriptive measures and are also served through custom incentives.

Consistent with Rule 4.413(c), each year VPPSA tracks and reports Tier III participation, spending, and benefits by Customer sector (residential, commercial and industrial, and low-income). For incentives administered directly by VPPSA, customers must answer a tracking question related to their household income. In the case of Efficiency Vermont administered incentives, VPPSA assumes 31% of statewide residential program uptake is from low-income households. This assumption was developed in partnership with Efficiency Vermont and the Department of Public Service.

Participation and spending are monitored and reviewed each year to inform program planning for future years. This data is included in VPPSA's Tier III savings filed in March and RES Compliance Filing in August. Each year, and over the life of the RES, VPPSA intends to provide equitable opportunities to its customer sectors in rough proportion to each customer sector's annual retail sales.

With some measures, such as electric vehicles, VPPSA is providing a significantly higher incentive to income-eligible customers to help offset cost barriers to purchasing these vehicles. VPPSA also provides incentives on used EVs and PHEVs which come with a lower upfront cost to the customer.

Additionally, VPPSA is engaging with Efficiency Vermont and other electric utilities to offer ductless cold climate heat pumps to income-qualifying households at no cost to the utility customer. Please refer to the Cold Climate Heat Pump section of this plan for more details on this low-income program offering.

Low-to moderate-income Vermonters face numerous hurdles when choosing to electrify. The state has an old building stock and is often only supplied with 100-amp electric service, which is inadequate to accommodate added electrification measures. Upgrades to 200-amp service can be costly and may prevent households with lower incomes from pursuing electrification despite robust incentives. In 2022, VPPSA applied for VLITE funding to reduce this barrier. In 2023, VPPSA expects to deploy funding for in-home service panel upgrades for income-qualifying customers who pursue heat pumps and all-electric vehicles.

Financing is another tool that can be used to make Tier III measures accessible to customers. In 2022, VPPSA encouraged member enrollment in the Weatherization Repayment Assistance Program (WRAP), financed through the Vermont Housing Finance Agency, to facilitate on-bill repayment and incentives for qualifying customers. Additionally, as mentioned above VPPSA is completing negotiations with the US Department of Energy to pilot a Business Energy Repayment Assistance Program (BERAP) which aims to provide a similar structure of on-bill financing for commercial and industrial energy transformation projects.

Finally, VPPSA's Tier III programs have a deliberate emphasis on electrification. The ability to bring financial benefits to all customers, rather than just participating customers, makes electrification an attractive Tier III option from an equity perspective. If additional kWh can be procured at costs at or below the costs embedded in a utility's rates, increasing the number of kWh delivered through the utility's system allows the fixed costs of operating the utility to be recovered over a larger number of units, driving the per kWh rate down for all customers. In this way both participants and non-participants stand to benefit from VPPSA's Tier III programs and cost-shifting among customers is minimized.

VPPSA's Utility Present Value Life Cycle Cost analysis shows that the incentive dollars paid to customers in rebates for electrification measures will typically be recovered through increased sales over the life of the measures, making these programs revenue neutral or beneficial for non-participating ratepayers.

Partnership & Collaboration

In 2023, VPPSA plans to continue actively working with both public and private partners to execute our Tier III plan in the most cost-effective way without sacrificing the customer experience.

The VPPSA/Efficiency Vermont MOU approved in 2019 has strengthened the partnership between the two organizations. In many cases, this partnership involves VPPSA providing incentives for electrification measures, which can provide benefits to all VPPSA utility customers, while Efficiency Vermont provides incentives for electric efficiency measures. With the exception of air-to-water heat pumps, there will be no prescriptive measures offered by VPPSA in 2022 for which costs and savings will be allocated between VPPSA and EVT. The allocation of savings and costs for joint custom commercial and industrial projects will be determined on a case-by-case basis. In general, savings allocated to each entity will be in proportion to the financial contribution to the specific project.

Under the MOU structure, VPPSA and Efficiency Vermont will implement tailored efforts in three VPPSA member communities each year of EVT's current performance period (2021-2023). In 2023, the Village of Enosburg Falls, Village of Johnson Electric, and Orleans Electric Department will be participants in the Tailored Efforts program. Additionally, as previously mentioned, VPPSA and Efficiency Vermont plan to partner on load management pilots.

Outside of VPPSA's partnership and collaboration with Efficiency Vermont, expansion of the point-of-sale incentive agreements with auto dealerships is expected in 2023. Not only will VPPSA plan to enter agreements with more dealerships across the state, but also seek to establish a similar agreement with businesses which sell electric bikes in Vermont.

Marketing & Communications

VPPSA continues to engage in utility customer interaction, marketing and communications. With the addition of Tier III projects, VPPSA will educate utility customers on the available incentives through use of the following:

- VPPSA member utility bill stuffers
- VPPSA member utility staff training
- VPPSA website and streamlined rebate processing platform
- VPPSA member utility websites
- Social media
- Front Porch Forum
- Collaborative events and workshops
- Car dealer and e-bike supplier outreach
- EVT contractor and distributor outreach
- Direct outreach to Key Account customers

Cost-Effectiveness & Equity

VPPSA's Tier III planning included consideration of the suite of measures in the 2023 Tier III Planning Tool developed by the TAG, including those measures that do not increase electric consumption. Specifically, VPPSA has initiated an overall analysis of the Tier III portfolio's diversity to ensure both cost-effectiveness and equity for customers at varying levels of spending ability while still meeting regulatory compliance.

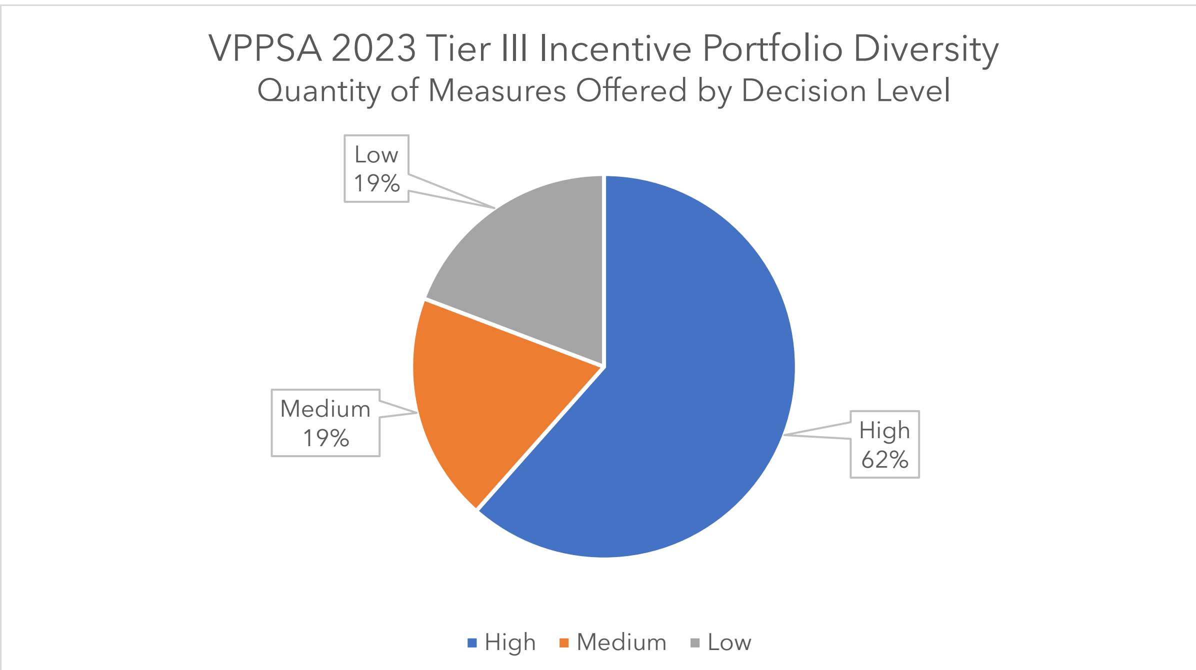
The analysis of VPPSA's 2023 Tier III Incentive Portfolio Diversity included a comparison of the quantity of measures offered in relation to:

1. Decision Level (i.e., impact of monetary investment)[5];
2. Energy Transformation Value Level (i.e., Savings/MWH)[6];
3. Type of Electrification[7]

Illustrations of this analysis are shown in Figure 3, Figure 4, and Figure 5, respectively.

The purpose of performing this analysis for the 2023 Tier III Incentive Program is to identify areas of potential cost-effective growth or expansion in offerings. VPPSA also envisions this analysis will help position our members to better respond to the various socio-economic and external factors which affect customer behaviors related to electrification now and in the future.

Figure 3: Tier III Portfolio Diversity by Decision Level



[5] Decision Level (High, Medium, Low) is calculated using the 2023 TAG Planning Tool's "Measure Cost" minus VPPSA's measure Incentive. High = Cost > $2,500; Medium = $501 < $2,499; Low = > $500.

[6] Energy Transformation Value Levels are determined based on the TAG Planning Tool's Savings/MWh: High = Savings > 50.1 MWh; Medium = Savings 10.1 MWh < 50 MWh; Low = Savings < 10 MWh

[7] Type of Electrification is classified into five broad categories, for the purposes of better aligning and analyzing the diversity of measures offered to customers: Thermal, Commercial Equipment & Appliances, Residential Equipment & Appliances, Transportation, and Custom Commercial & Industrial.

Figure 4: Tier III Portfolio Diversity by Energy Transformation Value

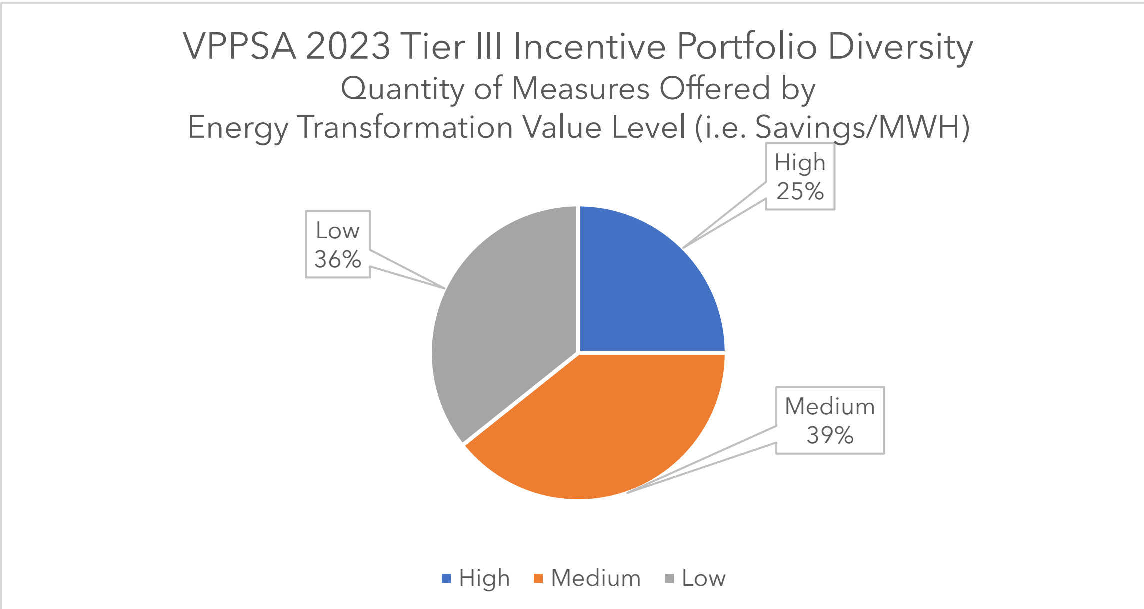
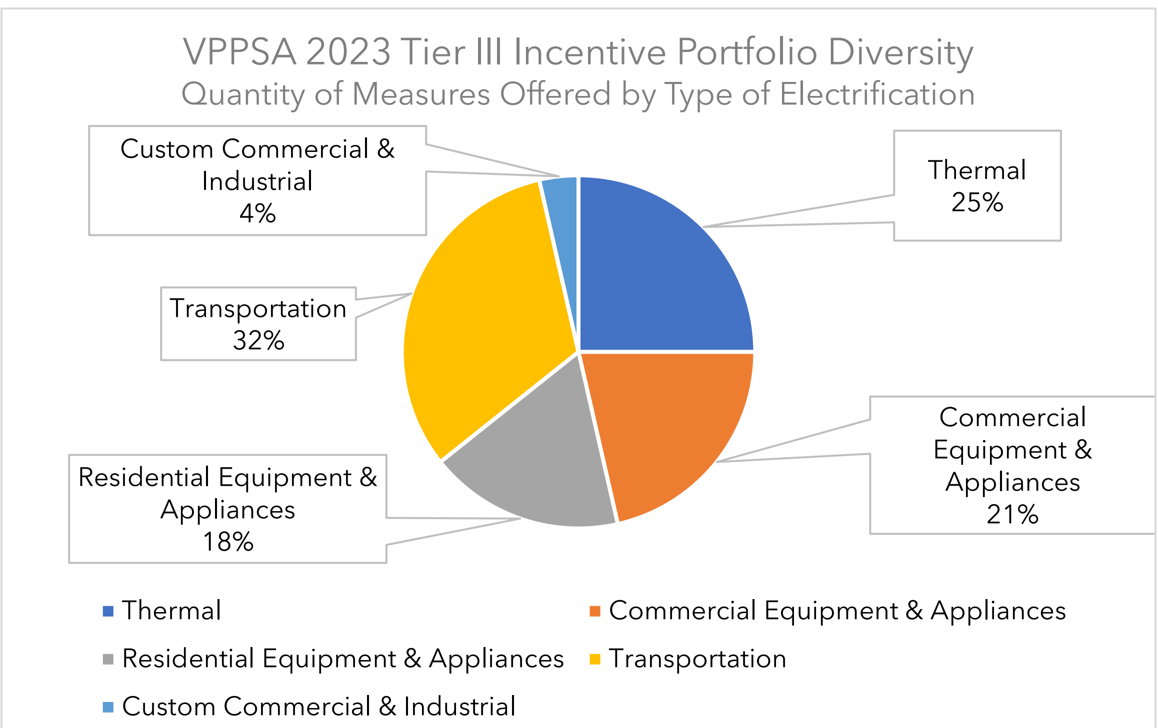


Figure 5: Tier III Portfolio Diversity by Type of Electrification



Utility Present Value Life Cycle Cost

VPPSA estimated the utility's net revenue for each of the 2023 Tier III measures. The analysis was conducted to provide a key input to the 2023 Tier III reporting template, specifically the 'Present Value Net Revenue' column. These estimates, when combined with other inputs to the template, ultimately calculate the 'Utility Present Value Life Cycle Cost Net' in $/MWhe.

The methodology followed a five-step process that netted utility costs from utility revenues.

First, the Tier III Planning Tool was used to gather several key inputs.

- Measure Life,
- Added kWh new system,
- Existing System MMBtu Displaced, and
- Assumed Fuel.

Second, seasonal load shapes were assumed for each measure. Specifically,

- Winter Peak MWH
- Winter Off-Peak MWH
- Summer Peak MWH
- Summer Off-Peak MWH
- Winter Peak MW
- Summer Peak MW

Third, current estimates of avoided costs were gathered. Energy, capacity, REC and transmission costs were sourced from VPPSA's budget models, and the cost of fossil fuels and non-embedded carbon were gathered from the AESC 2021 report.

Fourth, the volumes (MWH and MW) were multiplied by the appropriate avoided costs to arrive at an avoided cost estimate from the utility's perspective.

Fifth, the utility revenues were calculated using blended average retail rates as forecast during the 2019-2020 IRP cycle.

Finally, the 'Present Value Net Revenue' was calculated by subtracting the costs from the benefits and discounting the cash flows back to 2023 at a 5% discount rate.

The results of this analysis, as summarized in the Tier III reporting template, appear in Appendix B: 2023 Tier III Reporting Template & Life Cycle Cost Analysis.

Appendix A: Analysis of VPPSA's 2023 Tier III Incentive Portfolio Diversity

Prescriptive Measures	Energy Transformation Decision Level (Cost MINUS Incentive)	Energy Transformation Value Level	Type of Electrification	2023 TAG Measure Cost MINUS Incentive
Cold Climate Heat Pump (CCHP)	High	Medium	Thermal	$ 2,644.48
Cold Climate Heat Pump (CCHP) (weatherized)	Medium	Medium	Thermal	$ 2,444.48
Cold Climate Heat Pump (CCHP) Income Eligible Act 151	Medium	Medium	Thermal	$ 794.48
Heat Pump Water Heater	Medium	Medium	Thermal	$ 1,437.41
Whole Building Heat Pump (WBHP) - Air to Water - Residential	High	High	Thermal	$ 5,403.67
Whole Building Heat Pump (WBHP) - Ducted - Commercial	High	High	Thermal	$ 2,960.79
Whole Building Heat Pump (WBHP) - Ducted - Residential	High	High	Thermal	$ 2,960.79
Electric Forklift (New)	#VALUE!	High	Commercial Equipment & Appliances	#VALUE!
Electric Golf Cart (New)	#VALUE!	Low	Commercial Equipment & Appliances	#VALUE!
Lawnmower Commercial Electric Push	Low	Medium	Commercial Equipment & Appliances	$ 400.00
Lawnmower Commercial Ride-On	High	High	Commercial Equipment & Appliances	$ 20,173.00

Prescriptive Measures	Energy Transformation Decision Level (Cost MINUS Incentive)	Energy Transformation Value Level	Type of Electrification	2023 TAG Measure Cost MINUS Incentive
Yard Care Commercial Chainsaws	Medium	Low	Commercial Equipment & Appliances	$ 752.45
Yard Care Commercial Trimmers, Edgers, and Cultivators	Medium	Low	Commercial Equipment & Appliances	$ 569.94
Lawnmower Residential Electric Push	Low	Low	Residential Equipment & Appliances	$ 369.00
Lawnmower Residential Ride-On	High	Low	Residential Equipment & Appliances	$ 3,839.69
Smart Thermostat	Low	Low	Residential Equipment & Appliances	$ 125.00
Yard Care Residential Chainsaws	Low	Low	Residential Equipment & Appliances	$ 358.95
Yard Care Residential Trimmers, Edgers, and Cultivators	Low	Low	Residential Equipment & Appliances	$ 246.95
Electric Bike	High	Low	Transportation	$ 2,725.00
Electric Vehicle (New All Electric - Low Income)	High	Low	Transportation	$ 14,308.00
Electric Vehicle (New All Electric)	High	Medium	Transportation	$ 14,708.00
Electric Vehicle (New Plug-in Hybrid - Low Income)	High	Medium	Transportation	$ 6,401.00
Electric Vehicle (New Plug-in Hybrid)	High	Medium	Transportation	$ 6,801.00
Electric Vehicle (Used All Electric)	High	Medium	Transportation	$ 15,208.00
Electric Vehicle (Used Plug-in Hybrid)	High	Medium	Transportation	$ 7,051.00

Prescriptive Measures	Energy Transformation Decision Level (Cost MINUS Incentive)	Energy Transformation Value Level	Type of Electrification	2023 TAG Measure Cost MINUS Incentive
Electric Vehicle Charging Stations (Level 2 Public)	High	Medium	Transportation	$ 5,400.00
Electric Vehicle Charging Stations (Level 2 Workplace)	High	High	Transportation	$ 2,700.00

Appendix B: 2023 Tier III Reporting Template & Life Cycle Cost Analysis

2023 ANNUAL PLAN - TIER III REPORTING TEMPLATE					
			Discount Rate Applied (5%)		
Measure	**Total Gross Cost**	**Present Value Net Revenue**	**Utility Present Value Life Cycle Cost (Total Net Costs)**	**Gross $/MWhe**	**Utility Present Value Life Cycle Cost Net $/MWhe**
Cold Climate Heat Pump (CCHP)	$75,952	$13,039	$62,913	$12.33	$10.22
Cold Climate Heat Pump (CCHP) (weatherized)	$7,056	$144,605	($137,549)	$17.63	($343.70)
Cold Climate Heat Pump (CCHP) Income Eligible Act 151	$10,582	$106,046	($95,464)	$97.94	($883.52)
Heat Pump Water Heater	$23,275	$170	$23,105	$33.84	$33.60
Whole Building Heat Pump (WBHP) - Air to Water - Residential	$18,608	$96	$18,511	$23.38	$23.26
Whole Building Heat Pump (WBHP) - Ducted - Commercial	$15,421	$2,825	$12,596	$27.94	$22.82
Whole Building Heat Pump (WBHP) - Ducted - Residential	$15,606	$2,825	$12,781	$19.66	$16.11
Lawnmower Commercial Electric Push	$216	$2,825	($2,609)	$10.20	($123.06)
Lawnmower Commercial Ride-On	$6,263	$1,910	$4,352	$18.20	$12.65
Lawnmower Residential Electric Push	$254	$1,412	($1,158)	$45.41	($206.82)

2023 ANNUAL PLAN - TIER III REPORTING TEMPLATE					
			Discount Rate Applied (5%)		
Measure	**Total Gross Cost**	**Present Value Net Revenue**	**Utility Present Value Life Cycle Cost (Total Net Costs)**	**Gross $/MWhe**	**Utility Present Value Life Cycle Cost Net $/MWhe**
Lawnmower Residential Ride-On	$527	$1,412	($885)	$14.81	($24.87)
Smart Thermostat	$1,089	$1,412	($324)	$9.35	($2.78)
Yard Care Commercial Chainsaws	$137	$1,412	($1,276)	$8.91	($83.11)
Yard Care Commercial Trimmers, Edgers, and Cultivators	$137	$955	($818)	$8.78	($52.45)
Yard Care Residential Chainsaws	$519	$4,649	($4,130)	$20.60	($163.90)
Yard Care Residential Trimmers, Edgers, and Cultivators	$389	$4,649	($4,260)	$20.60	($225.40)
Electric Bike	$3,127	$4,649	($1,522)	$18.78	($9.14)
Electric Vehicle (New All Electric)	$30,769	$4,649	$26,119	$30.56	$25.94
Electric Vehicle (New All Electric - Low Income Adder)	$14,256	$4,649	$9,607	$42.48	$28.63
Electric Vehicle Charging Stations (Level 2 Public)	$424	$4,649	($4,225)	$13.41	($133.58)
Electric Vehicle Charging Stations (Level 2 Workplace)	$539	$1,327	($789)	$10.67	($15.63)
Electric Forklift (New)	$2,572	$1,327	$1,245	$27.20	$13.17
Electric Golf Cart (New)	$513	$1,327	($815)	$30.53	($48.48)

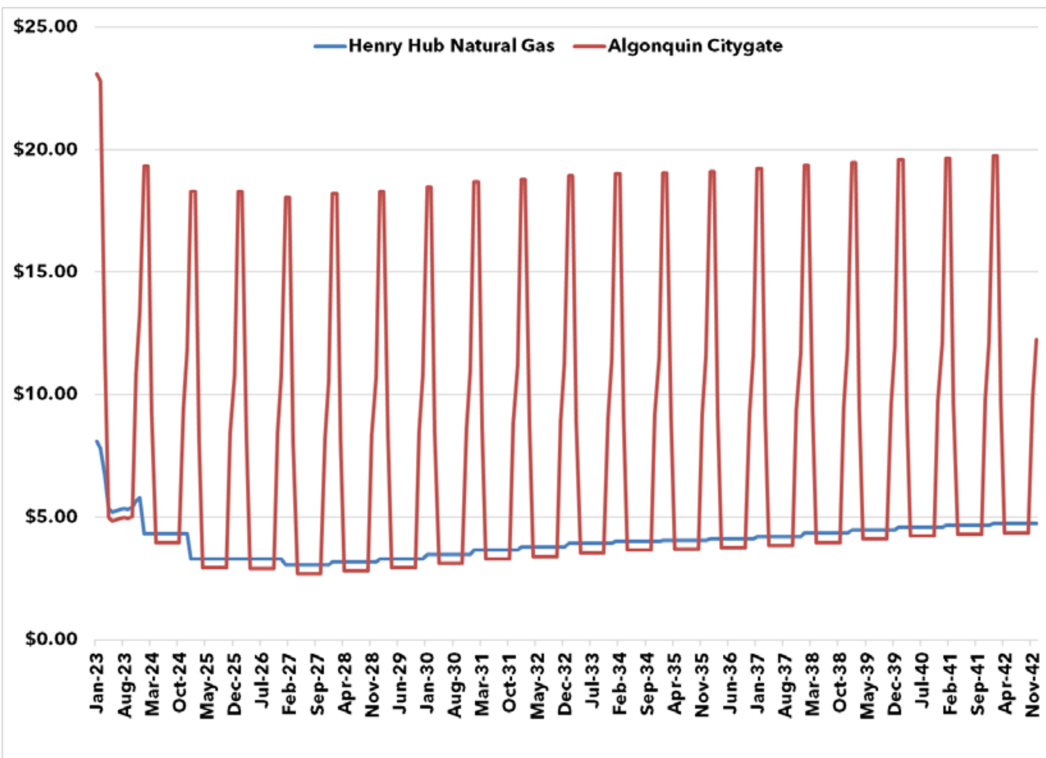
2023 ANNUAL PLAN - TIER III REPORTING TEMPLATE					
			Discount Rate Applied (5%)		
Measure	**Total Gross Cost**	**Present Value Net Revenue**	**Utility Present Value Life Cycle Cost (Total Net Costs)**	**Gross $/MWhe**	**Utility Present Value Life Cycle Cost Net $/MWhe**
Electric Vehicle (New Plug-in Hybrid)	$10,394	$1,327	$9,067	$20.12	$17.55
Electric Vehicle (New Plug-in Hybrid - Low Income Adder)	$7,358	$1,327	$6,030	$35.61	$29.18
Electric Vehicle (Used All Electric)	$5,128	$1,327	$3,801	$30.56	$22.65
Electric Vehicle (Used Plug-in Hybrid)	$1,299	$552	$747	$20.13	$11.57
Custom Projects	TBD		TBD	TBD	TBD
	$252,412	**$317,360**	**($64,948)**	**$25**	**($4)**

APPENDIX B: PRICING METHODOLOGY

ENERGY PRICING

Energy prices are forecast using a three-step method. First, a monthly natural gas price forecast is taken from broker quotes for the first two years of the forecast period. This includes both Henry Hub (HH) and Algonquin Citygate (AGT) prices, as well as NEPOOL electricity prices. Second, the AGT price is added to the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) HH forecast for the period 2025 to 2042. The forecast of HH and AGT prices can be seen in Figure 1.

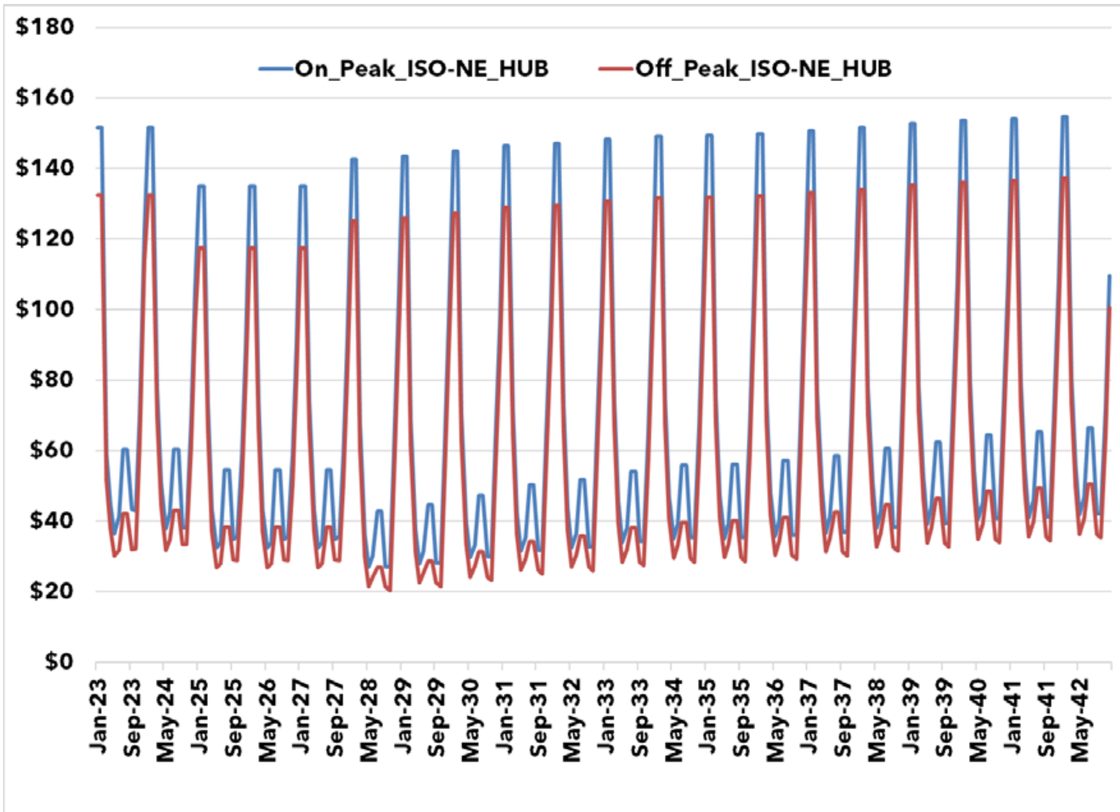
Figure 1: Henry Hub Natural Gas Price Forecast (Nominal $/MMBtu)



Notice that the Henry Hub price is stable and inflationary, while the Algonquin Citygate price is high and volatile. This is due to the fact that New England's marginal gas supply is imported Liquified Natural Gas (LNG) during the winter months. LNG's price is subject to international supply and demand balances, and is the cause for the very high winter-time price outlook.

Third, we multiply the natural gas price forecast by the implied heat rate in the broker quote to get the on-peak electricity price. From this value, we subtract the spread between the on and off-peak prices to get the off-peak price. The results can be seen in Figure 2.

Figure 2: Electricity Price Forecast (Nominal $/MWH)

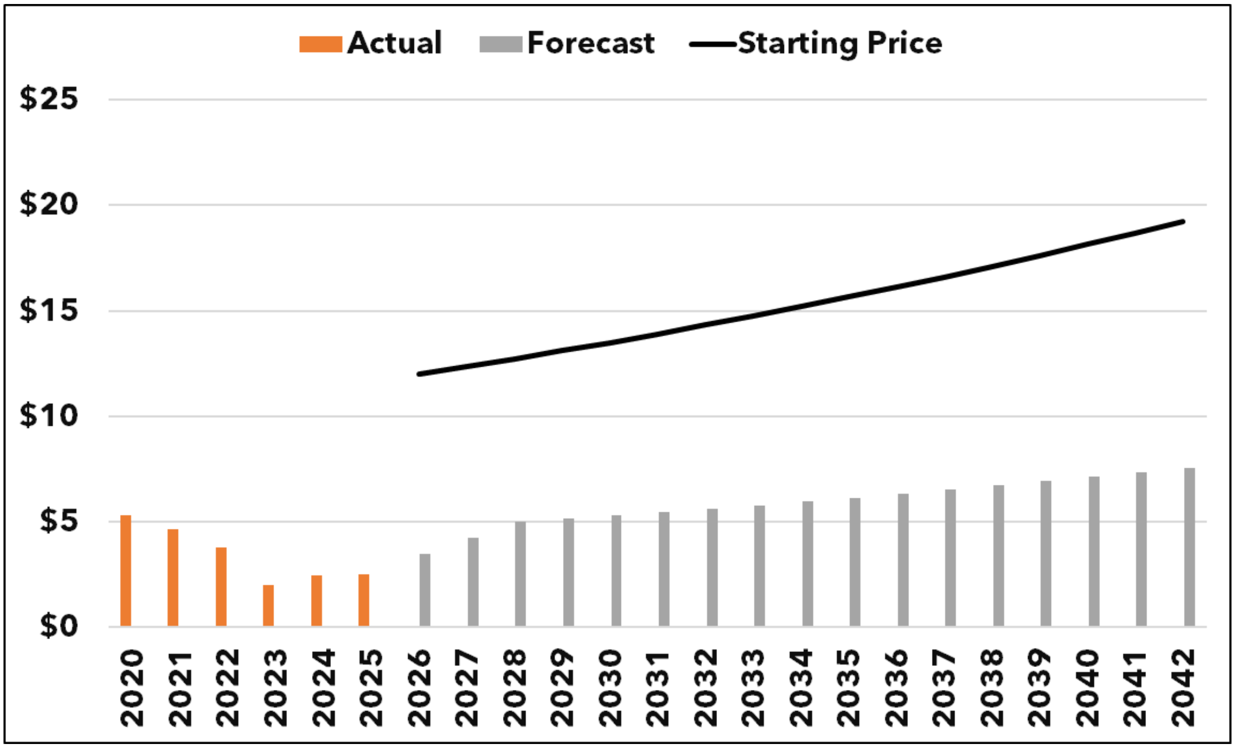


In keeping with the function of ISO-NE's Standard Market Design, we use a five-year average basis between Locational Marginal Price (LMP) nodes to adjust the price forecast at the MA Hub to the location of BVI's load and resources.

CAPACITY PRICING

The capacity price forecast starts at $3.50/kW-month, which is the average of the last six years of actual auction results for the Northern New England Zone. Inflation is added to this value, which grows the capacity price to about $7.50/kW-month in 2042. Significant upside price risk does exist, as shown by the Maximum line in Figure 3. This line represents the Forward Capacity Auction Starting Price plus inflation.

Figure 3: Capacity Price Forecast (Nominal $/kW-Month)



Barton Village, Inc.

This report is pursuant to PSB Rule 4.903B. It is to be submitted to the Public Service Board and the Department of Public Service no later than 30 days after the end of the calendar year.

Electricity Outage Report -- PSB Rule 4.900

Name of company	Barton Village, Inc.
Calendar year report covers	2017
Contact person	Evan Riordan
Phone number	802-525-4747
Number of customers	2,175

System average interruption frequency index (SAIFI) =	**2.9**
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	**5.1**
Customer Hours Out / Customers Out	

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	22	5,596
2	**Weather**	2	2,518
3	**Company initiated outage**	2	144
4	**Equipment failure**	20	2,551
5	**Operator error**	1	1
6	**Accidents**	1	0
7	**Animals**	2	11
8	**Power supplier**	1	20,662
9	**Non-utility power supplier**	0	0
10	**Other**	2	704
11	**Unknown**	1	6
	Total	54	32,194

Barton Village, Inc.

Original

This report is pursuant to PSB Rule 4.903B. It is to be submitted to the Public Service Board and the Department of Public Service no later than 30 days after the end of the calendar year.

Electricity Outage Report -- PSB Rule 4.900

Name of company	Barton Village, Inc.
Calendar year report covers	2018
Contact person	Evan Riordan
Phone number	802-525-4747
Number of customers	2,175

System average interruption frequency index (SAIFI) = 1.5
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 2.8
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	32	7,466
2	**Weather**	35	1,181
3	**Company initiated outage**	1	13
4	**Equipment failure**	10	435
5	**Operator error**	0	0
6	**Accidents**	1	1
7	**Animals**	3	14
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	3	48
	Total	85	9,157

Barton Village, Inc.

Revised Calculation - Removed Major Storm Outages of 10/15/18 & 11/27/18-11/29/18

This report is pursuant to PSB Rule 4.903B. It is to be submitted to the Public Service Board an
the Department of Public Service no later than 30 days after the end of the calendar year.

Electricity Outage Report -- PSB Rule 4.900

Name of company	Barton Village, Inc.
Calendar year report covers	2018
Contact person	Evan Riordan
Phone number	802-525-4747
Number of customers	2,175

System average interruption frequency index (SAIFI) =	**0.7**
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	**2.6**
Customer Hours Out / Customers Out	

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	18	3,398
2	**Weather**	16	113
3	**Company initiated outage**	1	13
4	**Equipment failure**	8	203
5	**Operator error**	0	0
6	**Accidents**	1	1
7	**Animals**	3	14
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	3	48
	Total	50	3,790

Barton Electric

2019
YTD

This report is pursuant to PSB Rule 4.903B. It is to be submitted to the Public Service Board and the Department of Public Service no later than 30 days after the end of the calendar year.

Electricity Outage Report -- PSB Rule 4.900

Name of company	Barton Electric
Calendar year report covers	2019
Contact person	Katelyn Kran
Phone number	802-525-4747
Number of customers	2,200

System average interruption frequency index (SAIFI) =	**2.9**
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	**4.0**
Customer Hours Out / Customers Out	
System Average Interruption Duration Index (SAIDI) =	**692.35**
Sum of All Customer Interruption Durations / Total Customers Served	

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	12	4,346
2	**Weather**	4	27
3	**Company initiated outage**	2	19,837
4	**Equipment failure**	19	1,040
5	**Operator error**	0	0
6	**Accidents**	6	66
7	**Animals**	11	65
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	1	6
	Total	55	25,386

Note: Per PSB Rule 4.903(B)(3), this report must be accompanied by an overall assessment of system reliability that addresses the areas where most outages occur and the causes underlying most outages. Based on this assessment, the utility should describe, for both the long and the short terms, appropriate and necessary activities, action plans, and implementation schedules for correcting any problems identified in the above assessment.

Major Storm 11/1/19 to 11/6/19 - Thirty Three outages and non outages during this time frame.

Barton Electric

2020
YTD

This report is pursuant to PSB Rule 4.903B. It is to be submitted to the Public Service Board and the Department of Public Service no later than 30 days after the end of the calendar year.

Electricity Outage Report -- PSB Rule 4.900

Name of company	Barton Electric
Calendar year report covers	2020
Contact person	Katelyn Kran
Phone number	802-525-4747
Number of customers	2,200

System average interruption frequency index (SAIFI) =	**1.04**
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	**2.27**
Customer Hours Out / Customers Out	
System Average Interruption Duration Index (SAIDI) =	**140.85**
Sum of All Customer Interruption Durations / Total Customers Served	

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	29	2,873
2	**Weather**	8	47
3	**Company initiated outage**	1	2
4	**Equipment failure**	28	1,724
5	**Operator error**	2	163
6	**Accidents**	2	4
7	**Animals**	6	48
8	**Power supplier**	0	0
9	**Non-utility power supplier**	1	4
10	**Other**	1	1
11	**Unknown**	17	299
	Total	95	5,164

Note: Per PSB Rule 4.903(B)(3), this report must be accompanied by an overall assessment of system reliability that addresses the areas where most outages occur and the causes underlying most outages. Based on this assessment, the utility should describe, for both the long and the short terms, appropriate and necessary activities, action plans, and implementation schedules for correcting any problems identified in the above assessment.

Barton Electric

2021
YTD

This report is pursuant to PSB Rule 4.903B. It is to be submitted to the Public Service Board and the Department of Public Service no later than 30 days after the end of the calendar year.

Electricity Outage Report -- PSB Rule 4.900

Name of company	Barton Electric
Calendar year report covers	2021
Contact person	Katelyn Kran
Phone number	802-525-4747
Number of customers	2,200

System average interruption frequency index (SAIFI) =	**2.0**
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	**3.9**
Customer Hours Out / Customers Out	
System Average Interruption Duration Index (SAIDI) =	**460.4**
Sum of All Customer Interruption Durations / Total Customers Served	

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	37	3,511
2	**Weather**	4	185
3	**Company initiated outage**	4	12,483
4	**Equipment failure**	25	177
5	**Operator error**	0	0
6	**Accidents**	5	293
7	**Animals**	5	19
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	11	212
	Total	91	16,881

Note: Per PSB Rule 4.903(B)(3), this report must be accompanied by an overall assessment of system reliability that addresses the areas where most outages occur and the causes underlying most outages. Based on this assessment, the utility should describe, for both the long and the short terms, appropriate and necessary activities, action plans, and implementation schedules for correcting any problems identified in the above assessment.

Barton Electric

2021
YTD

Net of 8/31 H16 Outage

This report is pursuant to PSB Rule 4.903B. It is to be submitted to the Public Service Board and the Department of Public Service no later than 30 days after the end of the calendar year.

Electricity Outage Report -- PSB Rule 4.900

Name of company	Barton Electric
Calendar year report covers	2021
Contact person	Katelyn Kran
Phone number	802-525-4747
Number of customers	2,200

System average interruption frequency index (SAIFI) = Customers Out / Customers Served	**0.9**
Customer average interruption duration index (CAIDI) = Customer Hours Out / Customers Out	**2.2**
System Average Interruption Duration Index (SAIDI) = Sum of All Customer Interruption Durations / Total Customers Served	**120.8**

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	37	3,511
2	**Weather**	4	185
3	**Company initiated outage**	4	33
4	**Equipment failure**	25	177
5	**Operator error**	0	0
6	**Accidents**	5	293
7	**Animals**	5	19
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	11	212
	Total	91	4,431

Note: Per PSB Rule 4.903(B)(3), this report must be accompanied by an overall assessment of system reliability that addresses the areas where most outages occur and the causes underlying most outages. Based on this assessment, the utility should describe, for both the long and the short terms, appropriate and necessary activities, action plans, and implementation schedules for correcting any problems identified in the above assessment.

1. TECHNICAL REQUIREMENTS

Please answer all questions and provide detail on any specific capabilities of your AMI technology in your response.

1.1 Electric Metering

The purpose of this section is to understand capabilities of the electric meters that work with the AMI solution.

1. Provide details of meters available with your AMI solution, e.g. meter type, manufacturer, etc.

2. List all the meters and manufacturers that your AMI solution will support.

3. Does your AMI solution support meters from more than one manufacturer in a single AMI implementation?

4. What compliance standards do your meters meet, e.g. ANSI, UL, IEC, etc.?

5. Meters will be installed in Vermont and be subject to a wide range of weather (ice, heat, snow, temperature) and environment considerations. Please provide details on the performance of meters given these details. This includes compliance with an outdoor installation. This includes UV resistance.

6. Describe the service life of the electric endpoint, including internal batteries, given weather/environment considerations.

7. Provide details regarding the failure rate of the electric meter and communications technology in a Pareto analysis format.

8. Provide details of the alerts, alarms, and configurations, i.e. tamper, temperature, reverse energy, voltage etc.

9. Describe the electric meter disconnect capability including support for remote disconnect, load limiting, disconnect security, etc.

10. Provide meter identification details including barcode, labeling and meter security keys. Describe how meter identification is handled if a single central AMI system is used across all Members.

11. Describe the measurement parameters available on all meter types, e.g. energy, demand, voltage, power factor, including interval data measurements.

12. Describe data storage capacity within the meter.

13. Provide details regarding the meter's ability to support Time-of-Use, Critical Peak Pricing and other rate designs.

14. Describe the meter display and any visual indicators, e.g. disconnect indicator.

15. Describe the meter's ability to support net energy metering installations.

16. Provide details regarding the meter data security, along with associated hardware considerations from field to back-office systems, including encryption/decryption.

17. Explain how security keys are managed. Include scenarios for a centralized implementation as well as individual Member deployment considerations.

18. Describe the processes available to access data from the meter (over-the-air, drive-by, manual, Wi-Fi, etc.).

19. Describe the process for meter firmware upgrades or configuration changes.

20. Describe any other functionality available in the meter.

1.2 Water Meters and Endpoints

The purpose of this section is to understand capabilities of a water AMI solution including water meter capabilities and/or the integration of an AMI water endpoint with existing water meters.

1. Describe features of the proposed system relating to water meters:

    a) Meter interface unit connection & mounting options. Address solutions for existing 6-digit touch read meters located in the basement with touchpad on the outside wall. There are a few meters in pits with a touchpad through the lid.

    b) Alarm and tamper alert features, e.g. reverse flow, tamper, battery life, etc.

    c) Read data and interval operations; describe the measurements available for each type of meter.

2. Provide a list of water meters and registers compatible with the AMI solution.

3. Explain power output and two-way communication functionality. Does the meter interface unit (MIU) have the ability to "hop" information to/from the electric meters or other water meters?

4. Explain the process of installation and commissioning of the meter and interface unit. Include any issues or concerns associated with communication devices. Address any issues of access to indoor meters. Most will be replacement of touchpad that is mounted on outside wall of the structure.

5. What industry compliance standards do your meter interface units meet, e.g. ANSI, UL, IEC, etc.?

6. What is the service life of the meter interface unit, including internal batteries, given weather/environment considerations?

7. Provide details regarding the failure rate of the water meter and meter interface unit in a Pareto analysis format.

8. Describe the capability of the system, meter interface unit and meter to support for remote disconnect, disconnect security, etc.

9. Provide details of meter identification including barcode, labeling, meter security keys. Describe implementation of meter identification/discretion if one central AMI system is used for several Member utilities.

10. Describe the meter data storage capacity within the meter interface unit.

11. Provide details regarding security of meter, interface unit and associated hardware considerations for back-office systems including encryption/decryption.

12. Explain how security keys are managed. Include scenarios for a centralized implementation as well as individual Member deployment considerations.

13. Describe the processes available to access data from the meter (over-the-air, drive-by, manual, Wi-Fi).

14. Describe the process for MIU firmware upgrades or configuration changes.

15. Describe any other functionality available in the meter.

16. Provide description of clock/calendar in the MIU including drift limits and synchronization intervals.

1.3 AMI Network

The purpose of this section is to understand the AMI network capabilities and operation as well as the equipment used for the network.

1. Describe the types of communications available with your AMI solution, e.g. RF, PLC. Include options for a mixed communication AMI solution.

2. Provide details regarding the metering communication network including types of equipment and backhaul options. Explain the alternative network backhaul options if cellular service is unavailable.

3. Explain the latency of your system for each communication and backhaul option used in your solution.

4. Explain the installation requirements for each type of network equipment, e.g. locations, mounting, height, power, protection from surges/lightning.

5. Describe the network architecture. Include the option of a shared AMI system for all Members. Does the configuration support common collection devices across Members, e.g. neighboring Members?

6. Describe the capacity of your AMI network, e.g. bandwidth, collector/repeater capacity (meters per network device), etc.

7. Describe the network security e.g. encryption, breach identification.

8. Provide an overview of how meters communicate with each type of collection device.

9. Describe how electric and water meters can be read concurrently through the network.

10. Describe how the network solution reaches hard-to-read meters (encumbered by terrain, foliage, etc.) or geographically dispersed meters.

11. Describe how the proposed system is managed over time, e.g. resource skill, training, remote management and maintenance, replacement process.

12. What service level agreement is supported by your solution and capabilities? Can the solution provide 99% of daily reads every day?

13. What is the success rate of last gasp messages for outages?

14. What is the success rate of on-demand meter interrogations or pings?

15. Provide a preliminary outline describing network solutions for VPPSA Members as a group and then also having each Member as an individual network.

16. Describe the procedure for AMI network component firmware upgrades.

17. Explain network disaster recovery processes specific to each proposed solution. Provide details regarding redundancy and failover of collection devices.

1.4 Software

In this section, provide a description of the AMI head end software, tools and software to operate the network and meter data management (MDM) capabilities. In addition, provide the options for implementation of the software and delivery of the solution.

1. Describe the software required to operate the AMI system. Provide product names of all software required for the solution. Include a MDM in your solution; third party solutions are acceptable.

2. Provide an architectural overview of the software solution provided with the AMI system.

3. Identify the software required to operate and troubleshoot the network.

4. Identify the software required to retrieve and manage all meter data.

5. What tools or software are available for field programming, data download and troubleshooting?

6. Does your company offer Meter Data Management (MDM) software?

7. Describe the following functionality and identify the software product performing the function:

    a) Meter Data Interrogation

    b) Meter Disconnect/Connect, Pinging

    c) Meter Data Validation, Estimation and Editing

    d) Reports

    e) Analytics

8. Describe how meter reads can be transferred to billing systems, include manual and automated processes.

9. Describe the options for software delivery including on-premise, hosted, managed services or others.

10. Can one central system serve all Members but have the data segregated and accessed by the Member owning the data, i.e. multi-tenant database

11. Can each VPPSA Member have their own separate system?

12. Describe the advantages and disadvantages of a single central system versus separate systems for each Member.

13. Has your system been integrated to the following systems and describe the type of integration, e.g. standard API, Multispeak, manual entry:

    a) SEDC

    b) NEMRC

    c) Harris Northstar

    d) Harris Spectrum

    e) Harris Select

    f) MUNIS

    g) Cogsdale

    h) Creative Technologies

    i) mPower

14. Does your company offer software for customer engagement such as a web portal? If not, what are your recommendations for a customer portal solution?

15. Does your company offer software for data analytics?

16. Does your software provide any mapping or GIS functionality? If so, describe any 3rd party products.

17. Provide al list of 3rd party products used in your AMI solution. Identify any product that requires a separate license.

1.5 Other Electric Capabilities

The purpose of this section is to understand the additional capabilities supported by the electric AMI solution beyond meter reading. If the solution has capabilities not captured in the questions below, please provide any additional material on those capabilities. Include any third-party solutions or partners that work with the AMI solution or network.

1. Describe your company's offerings for Demand Side Management (DSM).

2. Describe the AMI solution's capability to support Demand Response Programs.

3. Describe your AMI solution support for Home Area Networks (HAN).

4. What protocols are available to support DSM or HAN technologies, e.g. OpenADR, Zigbee, Multispeak?

5. What support does your AMI solution offer for outage management?

6. Describe the AMI solution's support for voltage reduction programs, e.g. CVR, VVR.

7. What support does your AMI solution offer for transformer sizing or transformer load management?

8. Describe the AMI solution's ability to support Distribution Automation.

9. Describe the AMI solution's support for net metering.

10. How does the AMI solution support new customer electric technologies, e.g. electric vehicles, power walls, etc.?

11. Describe methods of exporting data from your system.

12. Are there other functions available and supported by your AMI network e.g. streetlight control, security cameras, active shooter, propane tank monitoring?

13. Is there a customer pre-pay solution integrated with the AMI solution?

1.6 Water System Functionality and Leak Detection

The purpose of this section is to understand the additional capabilities of the water AMI solution beyond meter reading. If the solution has capabilities not captured in the questions below, please provide any additional material on those

capabilities. Include any third-party solutions or partners that work with the water AMI solution or network.

1. Describe leak detection features of the meter interface unit using existing meters

2. Describe distribution leak detection device, capabilities, and requirements.

3. Describe system capabilities for district (zone) metering

4. Describe other features available for use with the proposed AMI system such as:
   a) Pressure loggers
   b) Water quality monitoring
   c) Other water system monitoring features

Request for Proposal (RFP)

for an

Advanced Metering Infrastructure Solution

Deadline for Submission: March 4, 2020

Issued by Vermont Public Power Supply Authority
PO Box 126
5195 Waterbury-Stowe Road
Waterbury Center, VT 05677

Release Date: December 20, 2019

1. TECHNICAL REQUIREMENTS

1.1 Electric Meter Endpoints

This section defines the functional and technical requirements for new solid-state electric AMI revenue meters (AMI Meters) that shall be provided and deployed as part of this AMI project. VPPSA reserves the right to purchase one meter type or more than one meter type based on negotiations with the Vendor.

Please answer all questions with a Comply/No Comply/Alternative response. Provide an explanation if an Alternative is proposed.

Table 6

Question	**Response:** Comply, No Comply or Alternative
1. AMI Electric Meters shall be new, solid state with no moving parts except for the minimum number of required to support service disconnect switching, tamper detection, and/or "hard" demand reset.	
2. Functional features of the new meters shall be programmable. All programmable meter features shall be fully accessible to utility staff both locally and remotely. Initial programming is to be done at the factory according to utility specifications.	
3. AMI Electric Meters shall have a 20-year life.	
4. AMI Electric Meters shall be capable of recording total delivered and received energy measurement data in dedicated registers. Net energy is to be recorded in a dedicated register.	

5. AMI Electric Meters shall be capable of recording and storing interval data in interval lengths of 15, 30, or 60 minutes.	
6. AMI Electric Meters shall be capable of recording Time-of-Use (TOU) data.	
7. Demand quantity recorded in each register shall be configurable through programmable meter settings. Values stored in demand registers shall continuously increase until they are reset locally or via the AMI Network by an authorized AMI user.	
8. Meters registering peak demand shall support local resetting of the value (to zero) in any demand register.	
9. Meters shall feature security provisions that prevent local demand register resets by anyone other than authorized personnel.	
10. Programming of the AMI Electric Meters shall include an option to record either “rolling” or “block” interval demand values. Rolling demand subintervals shall include resolution of five (5) minutes, three (3) minutes, two (2) minutes or one (1) minute.	
11. AMI Electric Meters shall support KYZ data pulse (Form C) output.	
12. AMI Electric Meters must have the ability to provide “last gasp” notification of power outages within 30 seconds or less.	
13. All polyphase AMI meters shall auto-range when connected to services in the range of 120-277 Volts RMS, ± 20% with the exception that Form 12S must	

auto-range when connected to services in the range of 120-480 Volts RMS, ± 20%.	
14. The AMI Electric Meter shall be equipped with an industrial grade display capable of presenting at least five (5) reading digits, along with status enunciators and ID code numbers. The display shall include an easily interpreted graphic representing the magnitude and direction of energy quantities passing through the meter.	
15. Meters with an integrated service disconnect switch shall have an indicator that shows the status of the switch. The indicator shall be easily recognized, readily interpreted, and clearly visible to an observer viewing the meter.	
16. Meters equipped with a service switch shall perform reliably during continuous operation at the maximum load indicated on the meter's nameplate, while at minimum rated ambient temperature and humidity.	
17. Meters equipped with a service switch shall continuously monitor the service voltage on the customer side (load side) of the switch regardless of switch state. The meter shall generate an alert if voltage is present on a load terminal when the service switch is open.	
18. AMI Electric Meter display shall have an easily interpreted indicator showing the current status of the AMI Meter's AMI network connection. For example, the indicator may show the following states: • Network detected – connected • Network detected – not connected • No network detected • Transmitting	

• Receiving	
19. Meter displays may have an indicator that shows the TOU rate that is governing current TOU consumption registration in the meter.	
20. The meter nameplate shall include all applicable meter identification information. This information shall include a unique alphanumeric meter ID code (company number) specified by VPPSA, the manufacturer's name, the manufacturer's serial number, manufacturing date, bar coding, etc.	
21. Prior to delivery from the factory, the meter manufacturer shall test each meter to certify the accuracy and proper operation of the meter.	
22. A file with meter attribute information and test results shall be provided to VPPSA electronically prior to every shipment from the manufacturer.	
23. AMI Electric Meters provided shall not require any special equipment for shop or field-testing procedures. All testing should be capable of being conducted using standard, commercially available test equipment in both the field and the shop.	
24. All AMI Meters proposed shall feature a "test mode" that suspends normal meter operation so that consumption and demand measurements from tests are not recorded in the billing registers and/or interval data. All energy measurements and other measurements stored in the meter shall be unaffected by energy passing through the meter while in test mode.	

Provide detailed responses for the following questions:

1. Identify the specific make and model of AMI Electric Meters that support replacement of 100% of the meter population shown in Table 3. Note: actual number of meters to be ordered will be updated at the time of contract negotiations.
2. Provide a list of all alternate AMI Meters, by make and model, which currently work with the proposed AMI solution. Include a roadmap for future AMI Electric Meters that will be compatible with the AMI system.
3. Identify the electric quantities on all meter forms that the AMI meters are capable of measuring.
4. Provide a table that shows the relationship between number of channels, interval length, and days of storage in the proposed AMI Electric Meters. Describe the options to collect data in intervals shorter than 15-minutes.
5. Specify the number of TOU registers available.
6. Describe the process to perform a local demand reset in each proposed meter type.
7. Describe how the day/date/time of AMI Electric Meter is maintained in the network. Describe how time keeping is performed and if proposed meters contain clocks. Include the latency of getting AMI Electric Meters time synchronized after an outage.
8. Describe the abilities of the proposed AMI Electric Meters and the AMI system to provide time-stamped voltage data, maximum and minimum voltage data, sag and swell events or counts, loss of voltage, etc. Describe the method of measuring voltage, average or RMS. Include the frequency of data retrieval from the AMI Meter by the AMI system (real time, daily, scheduled, or on request).
9. Describe if any meter components (service switch, display, communication board) are serviceable and/or replaceable by VPPSA and/or the Vendor.
10. Vendors shall describe how the "last gasp" notifications occur, or if they may be impeded by the loss of power to a Meter Collection Point (MCP).
11. Vendors shall describe how the "test mode" feature is activated and suspended on each of the proposed models of AMI Electric Meters
12. Provide a list and description of all alerts, events and notifications provided by the AMI Electric Meter. This should include tamper, outage and deviations from nominal AC voltage, frequency, and waveform.
13. Describe if power quality functions are running all the time, or how the AMI Electric Meter can be remotely reconfigured to turn on power quality monitoring when needed.
14. Describe the following service disconnect and reconnect features:

a. Describe both remote and local operation of the service switch, including "arming" features, if any, available with the proposed solution.

b. Specify the number of disconnect/reconnect cycles that the switch is rated to perform at full meter load.

c. Identify if the AMI Meters and/or Head-End System has a duty cycle monitor for the service switch.

d. What features are in place in the AMI Meter to keep the switch from repeatedly cycling open and closed.

e. Describe whether a "demand limiting" capability can be enabled via the AMI Network. This means that control of the switch can be configured to disconnect the service if demand exceeds a threshold value. Service shall be re-connected after a predetermined time interval or when the demand drops below the threshold value. Specify if and how the proposed solution allows the threshold and time interval values to be securely set locally and/or remotely over the network using the AMI Head-End System.

f. Describe at what voltage level the service switch will not close, if the service has been disconnected. Vendor shall describe if this voltage level can be specified by the utility and how it is set.

15. Describe the local communication software and methods between the AMI meters and staff who locally read and/or service the meter. Local communications may be with a radio interface, WiFi or an optically isolated connection accessible on the outside of the meter cover.

16. Describe the AMI Meter's internal memory. Vendor shall describe how the proposed AMI performs in the event of a communication failure and the AMI meter's ability to store data until communication has been re-established.

17. Describe the meter's program security provisions including but not limited to the following information:

a. Method of multi-level authentication and authorization.

b. Explanation of how program access and change events are recorded by the meter.

c. Explanation of the provisions securing communication with the meter via the meter's local communications portal(s) (optical and/or RF.

18. Describe the use of batteries, if any, in proposed AMI Meters. Vendors shall describe the expected life of batteries, remote battery monitoring, recommended battery life management, and battery replacement procedures.

19. Provide details of all metering compliance (ANSI, UL, IEC, etc.) and certifications.

20. Provide details of the failure rate for the proposed AMI Meters.

1.2 Water Meter Endpoints & Water System Features

VPPSA intends to place priority on utilizing existing water meters that already have touch-type registers and converting them to the AMI system being proposed. Where meters do not have AMI-compatible registers, proposer may elect to either replace registers with AMI-ready registers or replace entire meter with new AMI Water Meters which meet the standards and specifications outlined in this section.

The functional and technical requirements for the new AMI endpoints, known hereon as Meter Interface Units (MIUs). These MIUs shall be used to convert existing compliant water meters to AMI Water Meters. And, where necessary, new water meters shall be provided by the Vendor as part of this AMI project, inclusive of compatible MIUs. VPPSA reserves the right to purchase one meter type or more than one meter type based upon project needs and negotiations with the Vendor.

VPPSA members having water metering as part of this project generally have mechanical meters currently in place. These include, but not limited to, positive displacement, turbine and compound meters. Meters proposed in response to this RFP should be similar in size and measurement technology. More modern technologies, such as magnetic resonance, ultrasonic, or others, may be proposed and will be considered by VPPSA Members for use in this project.

For those VPPSA Members that have water meters as part of this project, the meters are generally located inside basements, utility closets, etc. Few will be located outdoors in meter pits or vaults. Vendor shall provide propagation analysis and outline installation considerations for proper operation and to maximize radio performance between the AMI Water Meter MIU and AMI MCPs.

Please answer all questions with a Comply/No Comply/Alternative response. Provide an explanation if an Alternative is proposed.

Table 7

Question	Response: Comply, No Comply or Alternative

1. The AMI Water Meters provided as part of this solicitation shall be new meters meeting applicable AWWA and ANSI standards relative to type.	
2. Functional features of the new AMI Water Meters shall be programmable. All programmable meter features shall be fully accessible to utility staff both locally and remotely. Initial programming shall be done at the factory according to utility specifications.	
3. AMI Water Meters and MIUs provided by vendor as part of this project shall have a 20-year life.	
4. All AMI Water Meters and MIUs together shall record total water delivered, detect reverse flow, and provide notification of alert conditions to the Head End system.	
5. The AMI Meters shall have the capability to record and store interval data in interval lengths of 15, 30, or 60 minutes.	
6. The AMI Water MIUs shall feature security provisions to prevent local reading, configuration or programming by anyone other than authorized personnel.	
7. New AMI Water Meter supplied for this project shall be equipped with registers capable of presenting at least eight digits, either digital or mechanical, and provide electronic features for scale output resolution.	
8. The meter nameplate shall include all applicable meter identification information. This information shall include, at minimum, a unique 8-digit numeric meter/register ID, manufacturer’s name, FCC data, manufacturing date, bar coding, etc.	

9. Prior to shipment from the factory, the meter manufacturer shall test each meter and certify the accuracy and proper operation of the meter to AWWA/ANSI standards for the specific type of water meters.	
10. A file with meter attribute information and test results shall be electronically provided to VPPSA prior to every shipment from the manufacturer that includes the following information about the delivery: 1) Water meter type 2) Water meter size 3) Water meter serial numbers 4) Water meter test results 5) Meter register types 6) Meter register ID numbers	
11. The meter shall not require any special equipment for shop or field-testing procedures. All standard test equipment can be used for testing in both the field and the shop.	
12. AMI Water Meter MIU has ability to be retrofitted to existing water meters that have touch pads (external on wall for indoor/basement meters).	
13. AMI Water Meter register output to the MIU is ASCII-based, serial communication, no pulse-based registers will be allowed.	
14. Communication from the AMI Water Meter register shall include the meter register's unique ID and current meter reading, at minimum.	
15. The Vendor shall provide clear instructions for the wiring connection between the radio transmitter and encoder registers. All wiring connectors or splices	

shall be tamper resistance providing signs that the wire has been tampered with or disconnected.	
16. AMI Water Meter registers shall record usage in US Gallons or Cubic Feet as determined during negotiations.	
17. New AMI Water Meter encoder registers shall display a minimum of eight digits (high resolution). The register shall be shipped factory programmed encoding all digits, a minimum of eight digits.	
18. New AMI Water Meter encoder registers should be programmable so that Member personnel may alter the meter reading configuration. This includes, but is not limited to, the number of digits in the reading.	
19. New AMI Water Meter encoder registers shall be attached to the meter body by a method that will prevent or discourage customers from tampering with the meter and register. The register terminal screw cap shall allow for the sealing of the terminal screws.	
20. The register shall have permanently stamped on the dial face the manufacturer, meter size, meter type, register type and unit of measure.	
21. The register shall have a low flow indicator visible on the face of the meter for use by the customer in the detection of a leak within the property.	
22. For new AMI Water Meters and MIUs, the Vendor shall supply a wire connector that is certified as an IP 68 connection, tamper proof and can be connected and disconnected without having to cut the wire or destroy the connector itself. There shall be no manual connections (e.g. gel caps) and there must	

be consistency among connectors across all meter brands provided. Where the connector needs to be installed or potted to the water meter register, it is the Vendor’s responsibility to handle all communications, carrying costs and shipping costs imposed by the water meter register manufacturer(s).	

Provide detailed responses for the following questions:

Meter Interface Units (MIUs)

1. Identify the specific makes and models of MIUs that support conversion and/or replacement of 100% of the water meter population shown in Table 4. Note: actual number of MIUs and/or meters to be ordered will be updated at the time of contract negotiations.
2. Outline whether or not the proposed MIU has a multi-port option that will allow a multi-register AMI Water Meter to be read from a single MIU.
3. Provide a table that shows the relationship between datalogging interval and days of storage in the proposed AMI Water Meters. Describe the options to collect data in varying intervals, such as hourly, 30-minute, 15-minutes, etc.
4. Describe how the day/date/time of AMI Meters is maintained in the network. Describe how time keeping is performed and if proposed meters contain clocks. Include the latency of getting AMI Meters time synchronized after a network outage, firmware updates, demand reads and commands (remote shut off, etc.).
5. Provide a list and description of all alerts, events and notifications provided by the AMI Water Meter. This should include battery level, wire tamper, reverse flow, register removal, magnetic tamper, leak detection.
6. Describe the leak detection functionality of the water meter MIU and how it will work with 6-digit registers that are part of the existing meter inventory.
7. Describe the local communication software and methods between the AMI Water Meters, MIUs and staff who locally read and/or service the water meter. Local communications shall be done using a wireless interface.

8. Describe the use of batteries in proposed AMI Water Meter MIUs. Vendors shall describe the expected life of batteries, remote battery monitoring, recommended battery life management, and battery replacement procedures (if applicable). Describe how the low battery flag triggered, by a time-based calculation or by monitoring voltage?
9. Provide details regarding the typical and maximum expected failure rate for the proposed AMI Water Meters, registers and MIUs.
10. Describe the internal memory of the MIU. Vendor shall describe how the proposed AMI system performs in the event of a communication failure and the AMI Water Meter MIU's ability to store data until communication has been re-established.
11. Describe the MIU's programming security provisions including but not limited to the following information:
    a. Method of multi-level authentication and authorization.
    b. Explanation of how program access and change events are recorded by the MIU.
12. For indoor/basement water meter products, provide:
    a. Preferred mounting method of MIU (wall enclosure or flange).
    b. Two-wire and three-wire capability
    c. Describe how the MIU is to be connected to the AMI Water Meter register (e.g. splice, connector, etc.).
13. For pit-installed products, provide:
    a. Preferred mounting method.
    b. Minimum requirements of the meter pit lid (material construction, maximum thickness, depth of through the lid antenna recess necessary to make the antenna flush with the top of the lid and diameter of hole).
    c. Minimum clearance needed between the top of meter to bottom of pit lid.
    d. Describe how the radio is wired to the register (e.g. splice, connector).
14. Explain the provisions for securing communication with the meter via the meter's local communications portal(s) – optical and/or RF.
15. Provide MIU battery life warranty (in years). Describe the conditions of the warranty, such as if On-Demand Reads affect warranty terms, and if so to what extent.
16. Describe any other non-metering devices the AMI radio transmitter is compatible with.

<u>New AMI Water Meters & Registers</u>

17. Provide a table listing all AMI Water Meters being proposed by Vendor as part of this project. Include a listing of compatible AMI Water Meters indicating manufacturer, model and sizes, approved for use with the proposed AMI solution. Include any roadmap for future AMI Water Meters to be compatible with the proposed AMI system.
18. Provide details regarding the failure rate for the proposed AMI Water Meter registers.
19. Describe any provision for water service disconnect and reconnect options which may be incorporated in the water service:
    a. Describe both remote and local operation of the service disconnect functions.
    b. Specify the number of disconnect/reconnect cycles that the meter and MIU are capable of performing.
    c. Identify if the AMI Water Meter, MIU and/or Head-End System have a duty cycle monitor for the water service disconnect.
    d. What features are in place in the AMI Water Meter to keep the valve from repeatedly cycling open and closed or sticking.
    e. Describe whether a “flow-limiting” capability can be enabled via the AMI Network. This means that control of the service disconnect valve can be configured to provide limited water flow and be securely set locally and/or remotely over the network using the AMI Head-End System.
20. Describe the use of batteries in proposed AMI Water Meters. Vendors shall describe the expected life of batteries, remote battery monitoring, recommended battery life management practices and battery replacement procedures (if applicable).
21. Provide details of all meters regarding compliance with industry standards such as AWWA, ANSI, etc. Include any additional industry certifications.
22. Provide details regarding the failure rate for the proposed AMI Water Meters.
23. Describe the internal memory of the AMI Water Meter. Vendor shall describe how the proposed meter performs in the event of a communication failure between the meter register and MIU.
24. Provide water meter battery life warranty (in years) provided. Describe the conditions of this warranty. Explain if On-Demand Reads affect this warranty, and if so to what extent.
25. Describe the meter’s programming security provisions including but not limited to the following information:
    a. Method of multi-level authentication and authorization.

b. Explanation of how program access and change events are recorded by the meter.

26. Provide water meter battery life warranty (in years) provided. Describe the conditions of this warranty. Explain if On-Demand Reads affect this warranty, and if so to what extent.

Remote Disconnect Water Meters & Leak Detection

27. Provide AMI Water Meter battery life warranty (in years) provided. Describe the conditions of this warranty. Explain if On-Demand Reads affect this warranty, and if so to what extent.

1.3 AMI Network

Please answer all questions with a Comply/No Comply/Alternative response. Provide an explanation if an Alternative is proposed.

Table 8

Question	**Response:** Comply, No Comply or Alternative
1. AMI Solution shall use the same network for electric and water endpoints. The same MCPs will be used for both as well.	
2. AMI Network shall include two-way transport of data and commands between AMI endpoints and their respective AMI MCPs, which transfer the messages to/from the AMI Head-End System via the Vendor's proposed backhaul network.	
3. AMI System shall not rely on any collector device which may become a single point of failure for data retrieval of any specific endpoints.	

4. Authorized utility personnel shall be able to remotely access and modify all configurable AMI Meter programming/configuration parameters via the AMI Network.	
5. AMI System shall be IPv6 compliant.	
6. All elements of the proposed AMI Network shall support industry best practices for protection of data confidentiality, data integrity, and operational security.	
7. AMI Radio transmitters shall have multiple pathways to the Head End System with the intent of eliminating any single point of failure (redundancy).	

The following section includes the functional and technical requirements for interoperation of the AMI Head-End System, AMI Network, MCP's, and AMI MIU endpoints. If applicable, responses must include information for both AMI Electric Meters and AMI Water Meters. Please be sure that all responses cover both commodities (electric and water) where differentiation is necessary. VPPSA requires an AMI Network that will transport data and commands which support the proposed AMI functions at all AMI endpoints, in accordance with the functional and performance requirements specified throughout this RFP.

Provide detailed responses for the following questions:

1. Describe the proposed AMI Network and backhaul network provisions that will serve AMI endpoints. AMI endpoints will communicate with MCPs, and the MCPs will communicate directly with the Vendor's proposed backhaul network. Available fiber take-out points owned by VPPSA members are available, see Section 3 for background. Use of fiber for backhaul is preferred, wherever available.
2. Provide a network design showing the number and approximate location of MCP and/or Repeaters (if necessary) on a map of VPPSA member service territories. Use the GIS data provided in the files listed in Section 3.0. For purposes of sizing and configuring the network, assume the following baseline system activity:
    a. On-demand reading requests shall have an average response time of 30 seconds or less at least 90% of the time.

b. All polyphase AMI Meters will record, at least, four channels of 15-minute interval data, delivered to the AMI Head-End System three times within a 24 hour period.
c. All single-phase AMI Meters will record, at least, four channels of 15-minute interval data, delivered to the AMI Head-End System once every 24 hours.
d. The AMI Head-End System shall daily send 100 individual control message commands to AMI Meters with an integrated service switch to perform 50 connections or disconnections a day.
e. All AMI Meters will send outage notifications to the Head-End System as they occur.

3. Provide the percentage of total usable AMI network communication capacity Vendor expects to be used in the proposed AMI system under the baseline operating conditions described above. Additionally, Vendors shall predict the percent of network capacity utilized at the point in the AMI system with the least communication capacity and shall also recommend the maximum percentage loading that Vendor considers acceptable for VPPSA's intended uses of the AMI system.
4. Provide a proposed installation diagram that shows spacing requirements and where the MCP and associated equipment is to be placed on power poles, towers or other structures.
5. Provide the specification sheet for the MCP and associated equipment. Specifications must include how the MCPs will be powered and if there are any battery requirements or remote antennas needed. If multiple MCPs or external antenna versions are prescribed, then specification sheets will be included for each model variant.
6. All AMI firmware in the AMI Meters, Network devices, and customer premise devices, shall be remotely accessible for review, modification, and replacement over the AMI Network.
7. Describe how personnel will perform firmware upgrades (patches) using either the Head-End System or remote meter management software with the AMI Network. Clearly describe the AMI Meter's ability to sense, reverse, and report unauthorized or unsuccessful firmware replacements.
8. Describe how the AMI Radio transmitters will be read by more than one AMI data collector, providing MCP redundancy).

1.4 Head End System, Meter Data Management and Operations Software

VPPSA is seeking hosted software for both the Head-End System (HES) and Meter Data Management System (MDMD) functionality. The Proposer shall provide day to day support for the AMI solution. Seamless integration between HES and MDMS functions is expected.

Please answer all questions with a Comply/No Comply/Alternative response. Provide an explanation if an Alternative is proposed.

Table 9

Question	**Response:** Comply, No Comply or Alternative
1. The Head End and Meter Data Management systems shall be established, well-proven, commercially available products based on widely adopted technology standards.	
2. The Head End Software shall manage all meter interrogations and communications for the AMI Network.	
3. The HES shall: • Accept and schedule readings based on the billing system scheduled reads file • Perform scheduled demand meter resets based on the billing system scheduled reads file • Provide a meter reading file for the billing system of scheduled reads • Report unread meters in scheduled routes/cycles • Reschedule unread scheduled readings for following day reading file for the billing system • Report on exceptions.	
4. The HES shall gather the billing data from 99% of the meters successfully read each day without estimation.	

5. The AMI System shall not fail to retrieve billing data from any single meter more than 15 consecutive days in the absence of a permanent AMI communication failure.	
6. Data stored in the AMI Meters and/or in the AMI Network shall be stored for a minimum of five-years from the day the data is first stored.	
7. The Head End Software and Meter Data Management Software shall be located in a Tier 3 datacenter, at minimum.	
8. The MDMS shall be capable of Validation, Estimation and Editing (VEE) prior to delivering data to a member's billing system.	
9. The MDMS shall provide a dashboard and reports showing the status of data by Member and aggregated for all VPPSA members.	
10. A Service Level Agreement for the defined Tier 3 datacenter 99.982% datacenter uptime availability shall be provided.	
11. The HES and MDM shall have disaster recovery services.	
12. The MDMS shall calculate Time-Of-Use billing determinants by rate class or for individual customers.	
13. The MDMS shall support any billing calculations required by VPPSA members, e.g. Critical Peak Pricing, Dynamic Pricing, Aggregated Load, Net Billing for solar groups.	
14. Support for the AMI Network and Wide Area Services shall be included in the support services.	
15. Backup services of all software, data and configurations shall be performed at least daily.	

16. Backups shall be stored off site in a geographic region different from the hosting data center.	
17. The HES and MDM databases must be encrypted.	
18. The Head End Software supports a multi-tenant solution where each tenant has its own separate data and application set, independent of other tenants.	
19. The Head End Software shall support each tenant executing the same application set, but shared among the various tenets	
20. The HES shall provide software keys to separate individual member's data, in addition to security built into meters.	
21. The Meter Data Management System shall provide software keys to separate individual members data, in addition to security features that are built into the proposed meters.	
22. User access shall be limited to individual member system's database.	
23. VPPSA Administrator's user credentials shall be configured to allow access all Member's system data.	
24. Individual VPPSA Members shall be allowed access to only individual member's meter and system data.	
25. For VPPSA Administrators, reporting shall be set to report on combination of individual Members system data, i.e. VPPSA wide statistics.	
26. Policies, safeguards, parameters and monitoring shall be in place to prevent unacceptable interference (performance, high workload) problems among tenants.	

Provide detailed responses for the following questions:

1. Provide a description of the features and functionality of the HES and MDMS (maximum of 2-pages for each system).
2. Provide screen shots of the Head-End System dashboard and key screens or reports available from the proposed Head-End system.
3. Provide details of daily procedures to manage meters, collectors, and network.
4. Provide details of procedures when there is failure of meters, collectors, and network.
5. Describe the Validation, Editing and Estimation available in the MDMS.
6. Describe the types of billing determinant calculations available in the MDMS.
7. Provide screen shots of the Meter Data Management System dashboard and key screens or reports available from the proposed MDMS.
8. Describe the Data Center(s) hosting the HES and MDMS. Include ownership, location, physical facilities, tier and security.
9. Provide a copy of the Service Level Agreement with the hosting data center.
10. Describe the type of hosting services provided such as: Infrastructure as a Service (IaaS), Platform as a Service (PaaS), Software as a Service (SaaS)
11. Describe the disaster recovery services and process.
12. Describe separately the multi-tenant features of the HES and the MDM including login levels, data security and encryption capabilities of the proposed system.
13. Describe the data protection and operational security provisions in the HES and MDMS.

1.5 Other Capabilities with the AMI System

Please answer all questions with a Comply/No Comply/Alternative response. Provide an explanation if an Alternative is proposed.

Table 10

Question	Response: Comply, No Comply or Alternative
1. The AMI System shall support a customer pre-payment function.	

2. The AMI System shall support the measurement of load from electro-technologies such as electric vehicles.	
3. The AMI System solution shall provide load control capabilities integral to the AMI system and software.	

Provide detailed responses for the following questions:

1. Explain any additional system functionality available today which would add value to the project.

2022 Long-Term Forecast Report

BARTON VILLAGE, INC.

VERMONT PUBLIC POWER SUPPLY AUTHORITY

Prepared For:
VERMONT PUBLIC POWER SUPPLY AUTHORITY

Prepared By:
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2022 LONG-TERM DEMAND FORECAST SUMMARY – BARTON VILLAGE

The Barton Village Electric Department (Barton) is a rural distribution utility which surrounds Orleans County's summer recreation destinations of Lake Willoughby and Crystal Lake. Barton currently serves 2,000 electric customers in the greater Barton area including the Village of Barton as well as portions of six surrounding towns including Barton, Brownington, Irasburg, Sutton, Charleston, and Westmore. Barton serves a predominantly residential customer load, with approximately three quarters of annual retail sales coming from the residential class. Barton accounts for 0.5% of state residential sales and 0.2% of commercial sales.

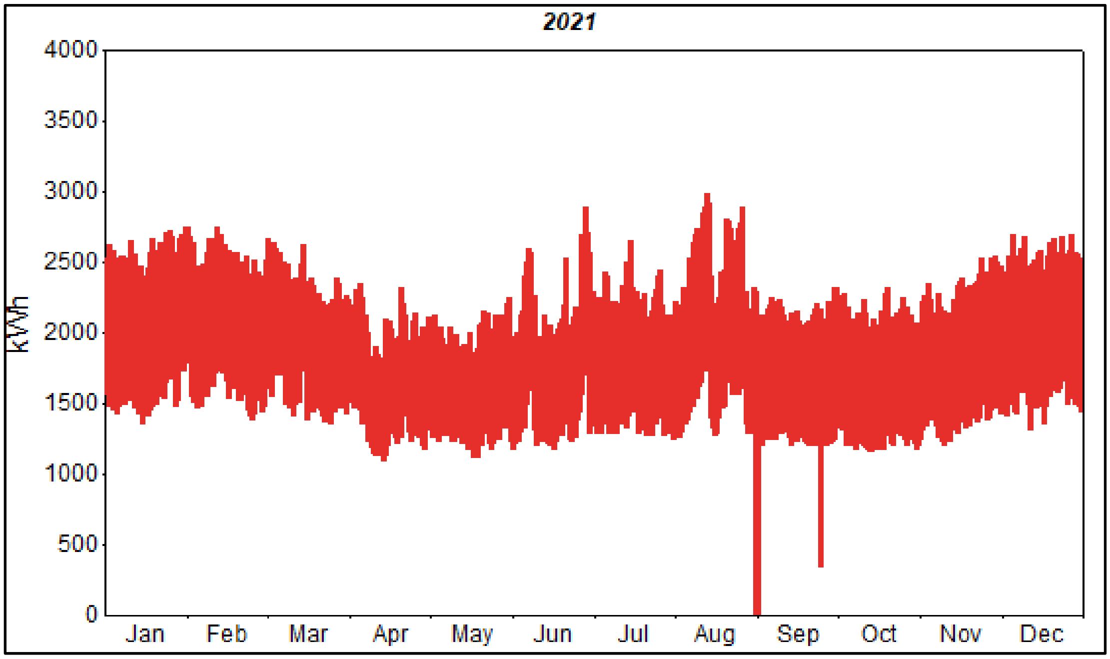
Over the last ten years excluding 2020, Barton electric loads have been averaging 0.6% annual decline. Residential sales have been largely flat and commercial sales have been declining. COVID-19 had a significant impact on sales, with commercial dropping 7.6% in 2020, against 7.8% increase in the residential sector. Table 1 shows historical residential customers and sales.

TABLE 1: BARTON HISTORICAL CALENDARIZED SALES AND CUSTOMERS

Year	Res Sales (MWh)	Chg	Res Custs	Chg	Res Avg Use (kWh)	Chg	Non-Res Sales (MWh)	Chg	Ttl Sales (MWh)	Chg
2011	10,536		1,678		6,281		3,758		14,294	
2012	10,558	0.2%	1,682	0.3%	6,277	-0.1%	3,695	-1.7%	14,253	-0.3%
2013	10,698	1.3%	1,683	0.1%	6,356	1.3%	3,625	-1.9%	14,324	0.5%
2014	10,734	0.3%	1,683	0.0%	6,376	0.3%	3,583	-1.2%	14,317	0.0%
2015	10,625	-1.0%	1,683	0.0%	6,312	-1.0%	3,542	-1.1%	14,168	-1.0%
2016	10,012	-5.8%	1,952	16.0%	5,129	-18.7%	3,603	1.7%	13,614	-3.9%
2017	10,075	0.6%	1,949	-0.2%	5,170	0.8%	3,563	-1.1%	13,638	0.2%
2018	10,102	0.3%	1,945	-0.2%	5,193	0.4%	3,585	0.6%	13,687	0.4%
2019	10,046	-0.6%	1,957	0.6%	5,132	-1.2%	3,525	-1.7%	13,571	-0.9%
2020	10,831	7.8%	1,969	0.6%	5,500	7.2%	3,257	-7.6%	14,088	3.8%
2021	10,772	-0.5%	1,978	0.4%	5,447	-1.0%	3,274	0.5%	14,046	-0.3%
11-21		**0.3%**		**0.2%**		**1.0%**		**-1.3%**		**-0.2%**

Barton generally peaks in the winter months. System peak is approximately 3 MW. Figure 1 shows the 2021 system hourly load; in 2021 Barton experienced a summer peak of 2.97 MW.

FIGURE 1: BARTON SYSTEM LOAD 2021



Forecast Approach

Like the approach used for the Vermont system, the Barton long-term forecast is based on a bottom-up modeling approach. The forecast starts at the revenue-class (e.g., residential, commercial, and industrial) and with heating, cooling, and base-use sales derived from the sales models used in driving baseline peak demand. The system energy forecast is based on the historical relationship between total monthly sales and monthly system delivered energy. A similar modeling approach has been used for all the VPPSA members. A detailed description of the modeling approach is included in the long-term forecast overview section.

Baseline Sales Forecast Models

Baseline sales models are estimated for each customer class. For Barton, this includes residential, total commercial, and other (other is primarily street lighting and is relatively small). Models are estimated using monthly linear regression models with historical billed sales and customer counts from January 2011 to December 2021. Model estimated coefficients, statistics and actual and predicted and results are included in Appendix A.

The baseline forecast captures expected load growth before adjustments for new PV adoptions, electric vehicle (EV), and cold climate heat pumps (CCHP). Baseline sales are driven by customer growth projections, state economic forecasts, end-use efficiency and saturation projections and temperature trends. Residential and commercial models are estimated using a Statistically Adjusted End-Use (SAE) model specifications. The SAE model is an approach where end-use saturation and efficiency trends that change slowly over time are combined with model variables that impact month-to-month sales variation and capture economic growth; this includes temperatures (HDD and CDD), economic conditions (household income, employment, and state output), and demographic trends (population, number of households, household size).

Economic Drivers

Historical and forecasted economic data is provided by Moody's Analytics. Forecasts are based on the January 2022 economic forecast. Model inputs include number of households, household income, gross state product, and employment. Economic data is provided in the forecast model overview section.

Efficiency and End-Use Saturations

End-use efficiency and saturations are derived from the 2020 Annual Energy Outlook (AEO) for the New England Census Division. Historical and projected residential saturations are adjusted to reflect Vermont where data is available. We assume commercial building energy intensities (measured in kWh per sq. ft.) for Vermont are like those of New England. The forecast is further adjusted for state energy efficiency program savings derived from the current state Demand Resource Plan (DRP).

Weather

Both actual and normal heating degree-days (HDD) and cooling degree-days (CDD) are derived from Burlington International Airport temperature data. Since 1970, average temperatures have been increasing 0.08 degrees per year (0.8 degrees per decade). This is reflected in the number of cooling degree-days (CDD) which are increasing 1.3% per year on a relatively low and decrease in heating degree-days (HDD) of 0.3% per year. We assume average temperature continues to increase at the current rate through the forecast period with decline in HDD contributing to lower heating requirements and increase in CDD to higher cooling requirements.

COVID-19

The "work at home" and closure of most retail businesses had a significant sales impact starting in late March 2020. The commercial sector saw a significant decline in sales while residential a large increase. Through 2021 sales began to normalize as more people went back to work. While there has been continued *sales normalization*, recent data from Burlington Electric and GMP has shown the trend through mid-July 2022 has slowed. We are seeing permanent structural change as many businesses transition to hybrid work environment (part-time at home and part-time at the office) and increasing number of workers that are and will continue to be working on a fully remote basis. COVID residential and nonresidential model variables are based on Vermont Google mobility data through the end of 2021. The mobility data measures the cellphone call volume variance from March 2020 (the month before COVID's load impact). In residential call volume increased and in the non-residential workplaces call volume decreased. For the forecast we trend the mobility variables back to base value in March 2020. By 2023 the COVID variables reaches 90% of pre-COVID level to capture what we believe will be some permanent shift in residential average use (up slightly from pre-COVID levels) and commercial sales (down slightly from pre-COVID levels).

A detailed description of the baseline model structure, and model inputs are included in 2022 LONG-TERM FORECAST MODEL OVERVIEW section.

Baseline Results

Slow state household and economic growth projections coupled with expected efficiency improvements and temperature trends results in declining baseline sales growth. Baseline sales are expected to fall to 12,865 MWh in 2032 compared with expected year-end sales (2022) of 13,639 MWh – a 5.7% decrease. Table 2 shows Barton baseline customer and sales forecast.

TABLE 2: BARTON BASELINE SALES FORECAST

Year	Res Sales (MWh)	Chg	Res Custs	Chg	Res Avg Use (kWh)	Chg	Non-Res Sales (MWh)	Chg	Ttl Sales (MWh)	Chg
2022	10,268		1,986		5,170		3,370		13,639	
2023	9,940	-3.2%	1,996	0.5%	4,979	-3.7%	3,427	1.7%	13,366	-2.0%
2024	9,854	-0.9%	2,003	0.3%	4,919	-1.2%	3,436	0.3%	13,290	-0.6%
2025	9,715	-1.4%	2,008	0.3%	4,837	-1.7%	3,419	-0.5%	13,134	-1.2%
2026	9,648	-0.7%	2,013	0.2%	4,793	-0.9%	3,400	-0.6%	13,048	-0.7%
2027	9,575	-0.8%	2,017	0.2%	4,748	-0.9%	3,379	-0.6%	12,954	-0.7%
2028	9,559	-0.2%	2,020	0.2%	4,733	-0.3%	3,368	-0.3%	12,927	-0.2%
2029	9,539	-0.2%	2,023	0.1%	4,716	-0.4%	3,347	-0.6%	12,886	-0.3%
2030	9,538	0.0%	2,025	0.1%	4,709	-0.1%	3,329	-0.5%	12,867	-0.1%
2031	9,540	0.0%	2,027	0.1%	4,706	-0.1%	3,309	-0.6%	12,849	-0.1%
2032	9,566	0.3%	2,029	0.1%	4,715	0.2%	3,299	-0.3%	12,865	0.1%
2033	9,537	-0.3%	2,030	0.0%	4,699	-0.3%	3,273	-0.8%	12,810	-0.4%
2034	9,534	0.0%	2,029	0.0%	4,699	0.0%	3,255	-0.5%	12,790	-0.2%
2035	9,546	0.1%	2,029	0.0%	4,706	0.1%	3,239	-0.5%	12,785	0.0%
2036	9,585	0.4%	2,028	0.0%	4,726	0.4%	3,235	-0.1%	12,820	0.3%
2037	9,573	-0.1%	2,027	-0.1%	4,724	-0.1%	3,213	-0.7%	12,786	-0.3%
2038	9,570	0.0%	2,024	-0.1%	4,727	0.1%	3,200	-0.4%	12,770	-0.1%
2039	9,569	0.0%	2,022	-0.1%	4,733	0.1%	3,186	-0.4%	12,755	-0.1%
2040	9,597	0.3%	2,019	-0.1%	4,753	0.4%	3,173	-0.4%	12,770	0.1%
2041	9,591	-0.1%	2,016	-0.2%	4,757	0.1%	3,146	-0.9%	12,737	-0.3%
2042	9,613	0.2%	2,013	-0.2%	4,776	0.4%	3,129	-0.6%	12,742	0.0%
22-32		**-0.7%**		**0.2%**		**-0.9%**		**-0.2%**		**-0.6%**
32-42		**0.0%**		**-0.1%**		**0.1%**		**-0.5%**		**-0.1%**

Adjusted Forecast

The baseline forecast is adjusted for new behind-the-meter (BTM) solar projections starting in 2022, electric vehicles, and cold climate heat pumps (CCHP). Future electricity sales and demand growth will largely be driven by these technologies that are being promoted as part of the state's electrification programs designed to reduce greenhouse gas emissions. Two of the primary targets are heating – converting fossil fuel heat to cold climate heat pumps (CCHP) and Electric Vehicles (EV). The state, through VEIC and state utilities are promoting the adoption of CCHP and EVs with rebates, low-interest loans, and building out electric vehicle infrastructure.

Long-term sales growth is largely driven by expected EV and CCHP market penetration with Projected behind the meter solar adoption (PV) mitigating some of this growth. The statewide forecast of these technologies (CCHP, EV, and PV) were developed through a collaborative process as part of the *Vermont Electric Power Company (VELCO) 2021 Long-Term Transmission Plan*. Forecast contributors include the Department of Public Service (DPS), the Vermont Energy Investment Company (VEIC), state utilities, and other state stakeholders. We are beginning work to update these assumptions as result of the recently passed *Vermont Climate Action Plan*.

CCHP, EV, and PV forecasts are derived by allocating the state forecast based on Barton' share of state residential customers. Table 3 shows the resulting forecast.

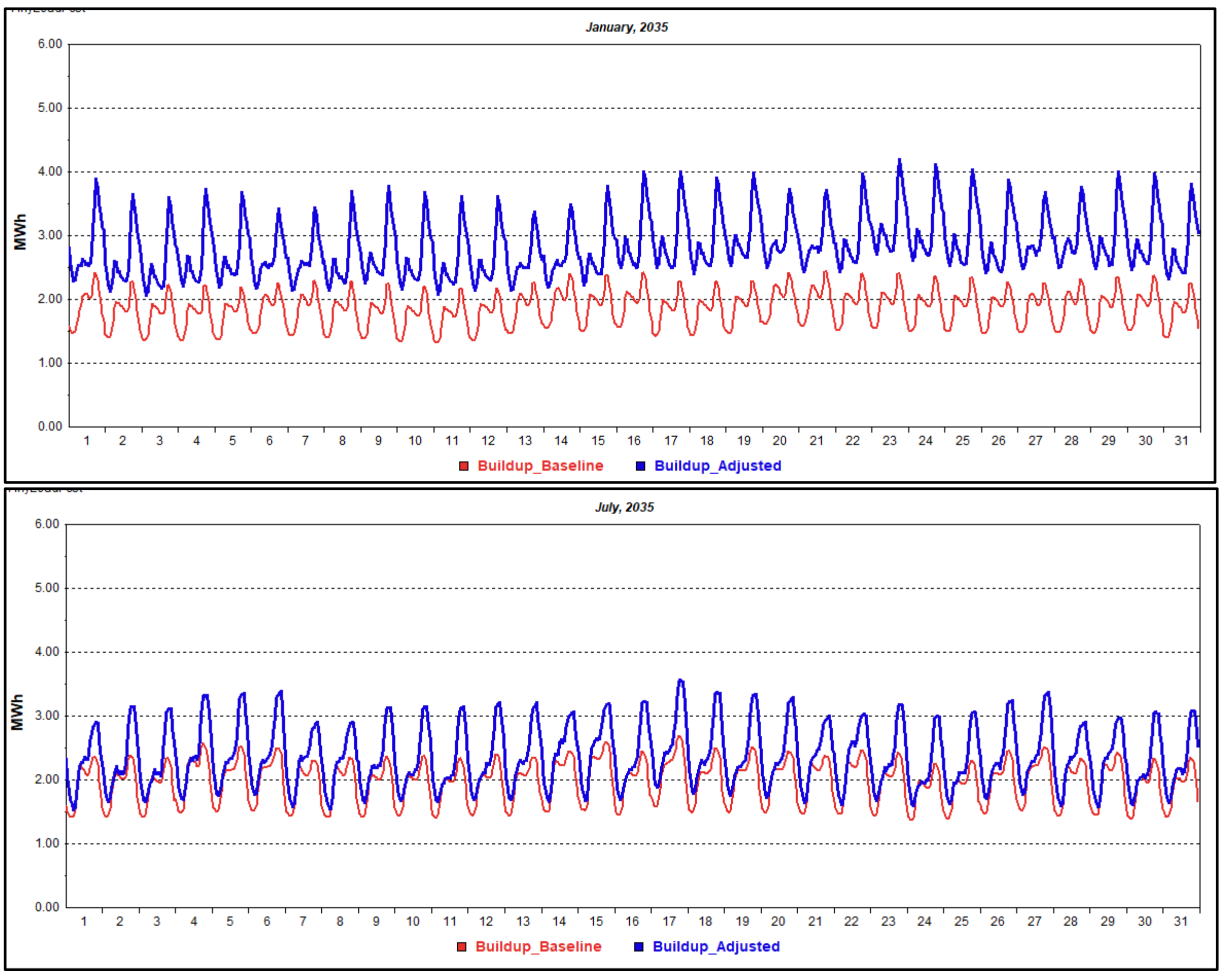
TABLE 3: EV, PV, AND CCHP FORECAST

Incremental New Tech Units			
Year	# Of Electric Vehicles	PV Installed Capacity (kW)	# Of HP Units
2022	13	42	35
2023	31	94	73
2024	55	145	115
2025	85	176	160
2026	124	191	208
2027	173	206	259
2028	236	214	313
2029	313	216	372
2030	407	223	427
2031	518	231	474
2032	645	241	520
2033	784	244	562
2034	928	248	605
2035	1,072	250	649
2036	1,206	253	693
2037	1,324	255	737
2038	1,422	258	782
2039	1,501	260	827
2040	1,559	263	871
2041	1,603	266	916
2042	1,634	268	962

Technology annual energy forecasts are estimated by combining technology characteristics such as average historical load profile, heating and cooling unit energy consumption, average miles driven, and technology efficiency trends with unit forecasts. Hourly (8,760) technology forecasts are then generated by combining technology annual energy forecast with technology hourly profiles that reflect seasonality, solar load patterns, and expected HDD and CDD.

The system adjusted hourly load forecast is calculated by subtracting PV hourly load forecast and adding EV and CCHP load forecasts to the baseline hourly load forecast. Figure 2 shows the baseline and adjusted hourly load forecast for January and July 2035.

FIGURE 2: BASELINE AND ADJUSTED HOURLY LOAD FORECAST



Expected baseline peak demand declines over the forecast period with winter baseline peak falling to 2.4 MW by 2035. EV and CCHP adoption add significant load. In the summer adjustments add 0.9 MW to baseline demand forecast and in the winter 1.8 MW pushing the winter peak over 4 MW. The winter load adjustments are much higher than summer adjustments as both EV charging and CCHP winter peak hour load impacts are higher. Adjusted energy is calculated by adding the hourly adjusted load forecasts and winter and summer peak demands are derived by finding the highest hourly load in each season and year. Table 4 shows the adjusted energy and demand forecasts.

TABLE 4: BARTON ENERGY FORECAST (MWH)

Energy and Peak										
Year	Energy (MWh)	Chg	Energy WN (MWh)	Chg	Summer Peak (MW)	Chg	Peak Time	Winter Peak (MW)	Chg	Peak Time
2011	16,551		16,583		2.75		8/18/11 8:00 PM	3.23		2/3/11 6:00 PM
2012	16,373	-1.1%	16,470	-0.7%	2.75	0.3%	8/5/12 8:00 PM	3.06	-5.4%	1/15/12 5:00 PM
2013	16,230	-0.9%	16,236	-1.4%	2.78	1.1%	7/5/13 5:00 PM	3.00	-1.9%	1/24/13 6:00 PM
2014	16,133	-0.6%	16,109	-0.8%	2.78	0.0%	7/2/14 5:00 PM	3.07	2.6%	1/2/14 6:00 PM
2015	16,002	-0.8%	15,898	-1.3%	2.84	1.8%	8/19/15 6:00 PM	2.94	-4.5%	1/8/15 5:00 PM
2016	15,817	-1.2%	15,816	-0.5%	2.71	-4.3%	8/11/16 8:00 PM	3.48	18.7%	2/14/16 6:00 PM
2017	15,501	-2.0%	15,594	-1.4%	2.47	-9.0%	8/19/17 6:00 PM	3.02	-13.3%	12/28/17 5:00 PM
2018	15,726	1.5%	15,603	0.1%	2.96	19.7%	7/5/18 6:00 PM	2.99	-1.1%	1/1/18 5:00 PM
2019	15,469	-1.6%	15,427	-1.1%	2.64	-10.6%	7/30/19 6:00 PM	2.84	-5.1%	1/21/19 5:00 PM
2020	15,940	3.0%	15,969	3.5%	2.83	7.1%	8/11/20 7:00 PM	2.83	-0.3%	12/16/20 5:00 PM
2021	16,070	0.8%	16,112	0.9%	2.97	4.9%	8/13/21 6:00 PM	2.73	-3.3%	1/30/21 6:00 PM
2022	15,639	-2.7%			2.72	-8.6%	7/19/22 6:00 PM	2.68	-2.1%	1/23/22 5:00 PM
2023	15,433	-1.3%			2.70	-0.4%	7/18/23 6:00 PM	2.67	-0.3%	1/24/23 6:00 PM
2024	15,451	0.1%			2.72	0.7%	7/16/24 6:00 PM	2.72	2.1%	1/23/24 6:00 PM
2025	15,447	0.0%			2.73	0.5%	7/15/25 6:00 PM	2.79	2.3%	1/21/25 6:00 PM
2026	15,575	0.8%			2.77	1.2%	7/21/26 6:00 PM	2.88	3.3%	1/20/26 6:00 PM
2027	15,739	1.1%			2.81	1.4%	7/20/27 6:00 PM	2.96	2.8%	1/19/27 6:00 PM
2028	16,032	1.9%			2.87	2.1%	7/18/28 6:00 PM	3.07	3.8%	1/18/28 6:00 PM
2029	16,380	2.2%			2.93	2.3%	7/17/29 6:00 PM	3.18	3.5%	1/23/29 6:00 PM
2030	16,795	2.5%			3.02	2.9%	7/16/30 7:00 PM	3.33	4.8%	1/22/30 6:00 PM
2031	17,252	2.7%			3.11	3.1%	7/15/31 7:00 PM	3.50	4.9%	1/21/31 6:00 PM
2032	17,792	3.1%			3.22	3.4%	7/20/32 7:00 PM	3.68	5.2%	1/20/32 6:00 PM
2033	18,308	2.9%			3.33	3.4%	7/19/33 7:00 PM	3.85	4.6%	1/18/33 6:00 PM
2034	18,879	3.1%			3.44	3.5%	7/18/34 7:00 PM	4.01	4.1%	1/24/34 6:00 PM
2035	19,467	3.1%			3.56	3.4%	7/17/35 7:00 PM	4.19	4.6%	1/23/35 6:00 PM
2036	20,060	3.0%			3.68	3.3%	7/15/36 7:00 PM	4.37	4.3%	1/22/36 6:00 PM
2037	20,534	2.4%			3.78	2.6%	7/21/37 7:00 PM	4.56	4.2%	1/20/37 6:00 PM
2038	20,951	2.0%			3.87	2.6%	7/20/38 9:00 PM	4.69	2.9%	1/19/38 6:00 PM
2039	21,303	1.7%			3.96	2.2%	7/19/39 9:00 PM	4.81	2.6%	1/18/39 6:00 PM
2040	21,614	1.5%			4.03	1.8%	7/17/40 9:00 PM	4.88	1.5%	1/24/40 6:00 PM
2041	21,825	1.0%			4.09	1.5%	7/16/41 9:00 PM	4.98	2.1%	1/22/41 6:00 PM
2042	22,034	1.0%			4.14	1.2%	7/15/42 9:00 PM	5.06	1.7%	1/21/42 6:00 PM
11-21		**-0.3%**		**-0.3%**		**1.1%**			**-1.4%**	
22-42		**1.7%**				**2.1%**			**3.3%**	

Projected EV, CCHP, and PVs have a significant impact on load; over the next twenty years, delivered energy is expected to average 1.7% annual growth. This compares with baseline annual sales decline of 0.1%. Winter adjusted peak averages 3.3% annual demand growth and summer 2.1% average annual growth. Strong peak growth is largely due to larger share of residential customers and consequent increases in EVs. Barton remains a winter peaking utility through the forecast horizon.

Table 5 and Table 6 summarizes the demand forecast by base load and technologies.

TABLE 5: BARTON SUMMER PEAK FORECAST (MW)

Summer Peaks (MW)							
Year	Baseline	Chg	EV	PV	HP	Adjusted	Chg
2022	2.70		0.01	0.00	0.01	2.72	
2023	2.67	-1.2%	0.02	0.00	0.02	2.70	-0.4%
2024	2.66	-0.1%	0.03	-0.01	0.04	2.72	0.7%
2025	2.65	-0.6%	0.05	-0.01	0.05	2.73	0.5%
2026	2.64	-0.2%	0.07	-0.01	0.06	2.77	1.2%
2027	2.63	-0.2%	0.11	-0.01	0.08	2.81	1.4%
2028	2.64	0.2%	0.14	-0.01	0.09	2.87	2.1%
2029	2.64	0.1%	0.19	-0.01	0.11	2.93	2.3%
2030	2.63	-0.5%	0.27	0.00	0.13	3.02	2.9%
2031	2.64	0.3%	0.34	0.00	0.14	3.11	3.1%
2032	2.65	0.4%	0.42	0.00	0.15	3.22	3.4%
2033	2.65	0.1%	0.51	0.00	0.16	3.33	3.4%
2034	2.66	0.3%	0.61	0.00	0.18	3.44	3.5%
2035	2.67	0.4%	0.70	0.00	0.19	3.56	3.4%
2036	2.69	0.7%	0.79	0.00	0.20	3.68	3.3%
2037	2.69	0.1%	0.87	0.00	0.21	3.78	2.6%
2038	2.54	-5.5%	1.13	0.00	0.20	3.87	2.6%
2039	2.55	0.4%	1.19	0.00	0.22	3.96	2.2%
2040	2.57	0.6%	1.23	0.00	0.23	4.03	1.8%
2041	2.58	0.4%	1.27	0.00	0.24	4.09	1.5%
2042	2.59	0.6%	1.29	0.00	0.25	4.14	1.2%
22-42		**-0.2%**					**2.1%**

Itron

TABLE 6: BARTON WINTER PEAK FORECAST (MW)

Winter Peaks (MW)							
Year	Baseline	Chg	EV	PV	HP	Adjusted	Chg
2022	2.63		0.01	0.00	0.03	2.68	
2023	2.55	-3.1%	0.03	0.00	0.09	2.67	-0.3%
2024	2.54	-0.5%	0.05	0.00	0.13	2.72	2.1%
2025	2.52	-0.7%	0.08	0.00	0.19	2.79	2.3%
2026	2.52	0.0%	0.12	0.00	0.24	2.88	3.3%
2027	2.49	-1.0%	0.16	0.00	0.30	2.96	2.8%
2028	2.49	-0.4%	0.22	0.00	0.36	3.07	3.8%
2029	2.45	-1.4%	0.30	0.00	0.43	3.18	3.5%
2030	2.45	-0.1%	0.39	0.00	0.50	3.33	4.8%
2031	2.45	0.0%	0.50	0.00	0.55	3.50	4.9%
2032	2.46	0.5%	0.62	0.00	0.60	3.68	5.2%
2033	2.44	-0.8%	0.75	0.00	0.65	3.85	4.6%
2034	2.41	-1.3%	0.90	0.00	0.70	4.01	4.1%
2035	2.40	-0.2%	1.04	0.00	0.75	4.19	4.6%
2036	2.41	0.3%	1.16	0.00	0.80	4.37	4.3%
2037	2.42	0.3%	1.28	0.00	0.85	4.56	4.2%
2038	2.41	-0.5%	1.38	0.00	0.91	4.69	2.9%
2039	2.40	-0.3%	1.45	0.00	0.96	4.81	2.6%
2040	2.37	-1.2%	1.51	0.00	1.00	4.88	1.5%
2041	2.36	-0.3%	1.55	0.00	1.06	4.98	2.1%
2042	2.37	0.1%	1.58	0.00	1.12	5.06	1.7%
22-42		**-0.5%**					**3.3%**

Baseline summer system peak averages 0.2% decline per year largely driven by projections of increasing equipment efficiency. Winter baseline demand declines as result of improving energy efficiency across all the non-weather sensitive end-uses excluding miscellaneous. PV has a limited to no impact on peak demand as the system peak has been moved out to later hours from past solar adoption. Most of the load growth is driven by EV charging and CCHP.

2022 LONG-TERM FORECAST MODEL OVERVIEW

INTRODUCTION

Vermont Public Power Supply Authority (VPPSA) serves 11 members located across Vermont. Combined VPPSA members serve 50 communities and over 30,000 customers.

The VPPSA members include:

- Barton
- Enosburg
- Hardwick
- Jacksonville
- Johnson
- Ludlow
- Lyndonville
- Morrisville
- Northfield
- Barton
- Swanton

Long-term sales, energy, and demand forecasts have been developed for each member.

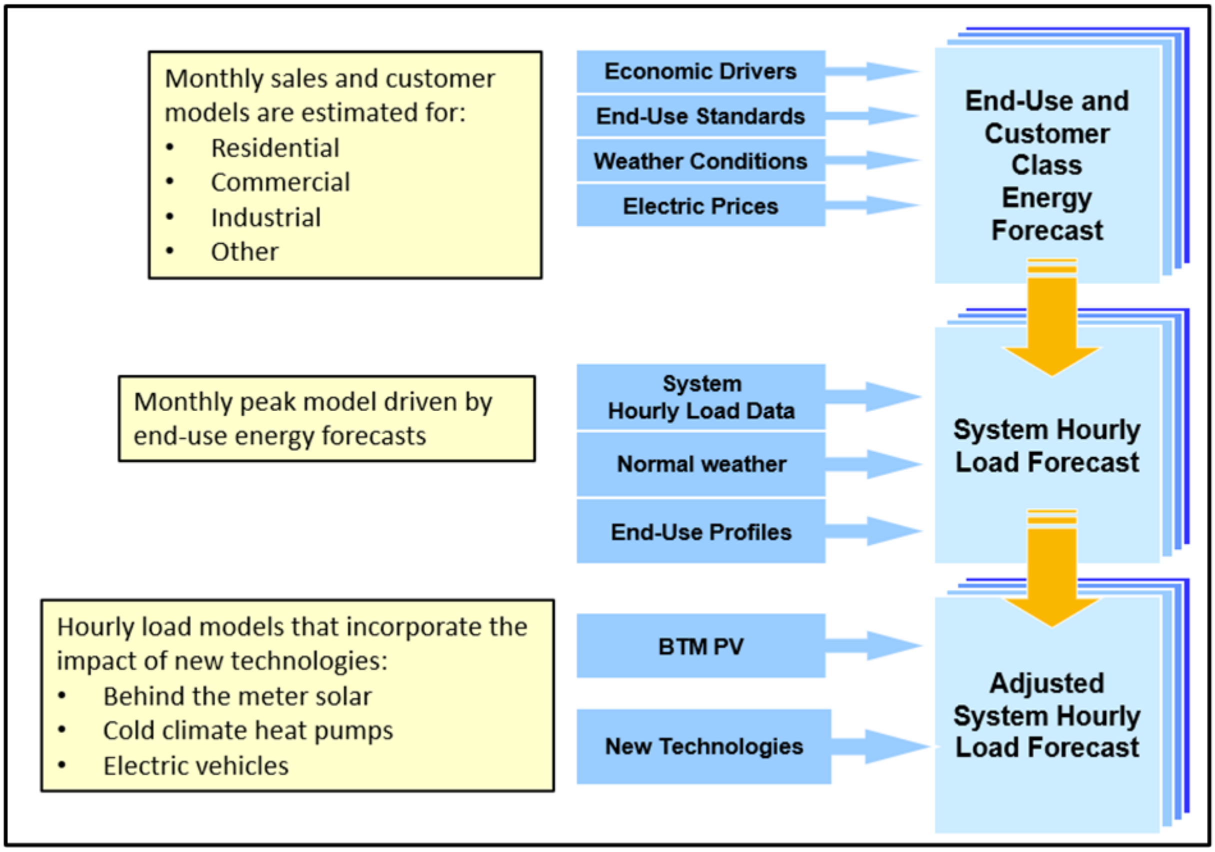
Forecast includes:

- Residential, commercial, industrial, and other classification sales and customers
- Baseline energy and peak demand
- Adjusted energy and peak demand. Adjusted for the impacts of new technologies including electric vehicles, photovoltaic solar, and cold-climate heat pumps.

FORECAST METHOD

The long-term forecasts are based on a bottom-up approach were baseline energy, demand, and hourly load is first developed from underlying customer class heating, cooling, and base-use energy requirements. The baseline hourly load forecast is then adjusted for the long-term load impacts of electric vehicles (EV’s), solar (PV’s), and cold-climate heat pumps (CCHP). Figure 3 shows the general forecasting approach.

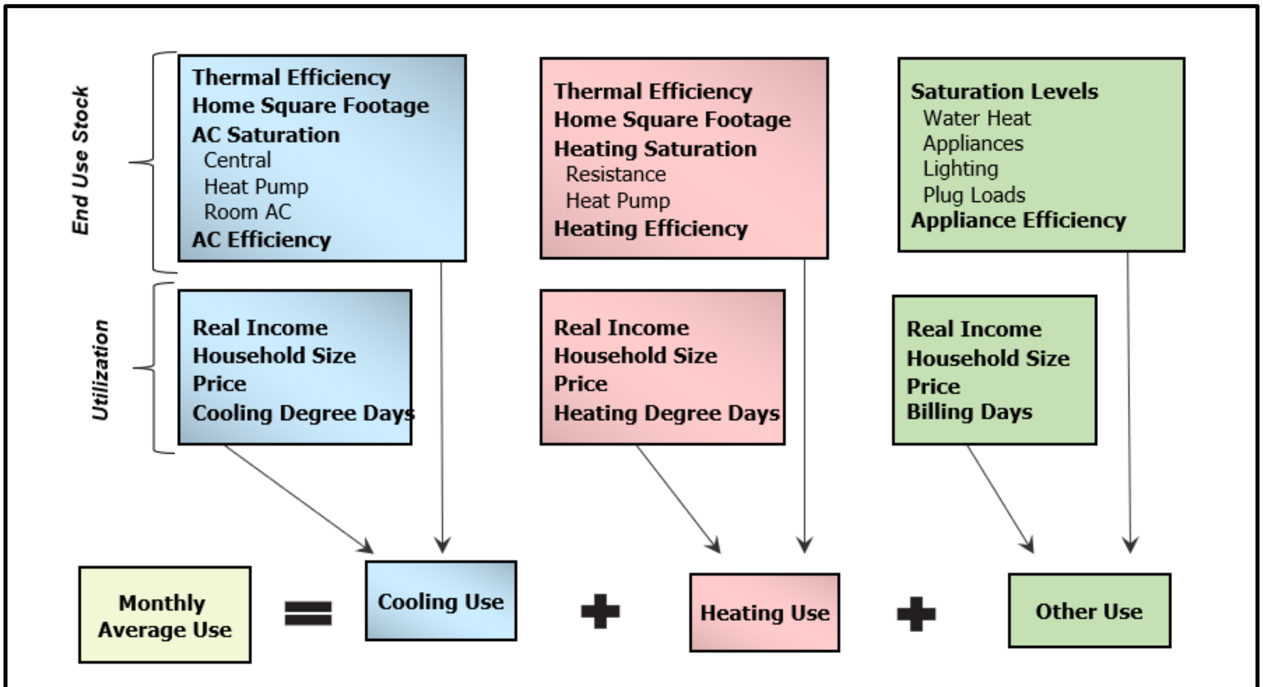
FIGURE 3: FORECASTING FRAMEWORK



Customer Class Sales Forecast

The forecast process starts with estimating sales models for residential, small commercial, large commercial, industrial, and other (mostly street lighting) classes. The residential forecast is derived as the product of the residential average use and customer forecast. Commercial, industrial, and other revenue classes are estimated as total sales models. Models are estimated with monthly billed sales data from January 2011 through December 2021 using linear regression. Models are used to forecast sales and customers based on projected demographic and economic growth, end-use intensity trends (reflecting both change in end-use ownership and efficiency improvement), and trended normal heating degree-days (HDD) and cooling degree-days (CDD). Where supported by the data, models are estimated using a modeling structure called a Statistically Adjusted End-Use (SAE) model. The SAE model specification integrates the forecast drivers into three primary model variables that include heating (XHeat), cooling (XCool), and other uses (XOther) variables. Figure 4 shows the SAE model specification.

FIGURE 4: RESIDENTIAL STATISTICALLY ADJUSTED END-USE (SAE) MODEL

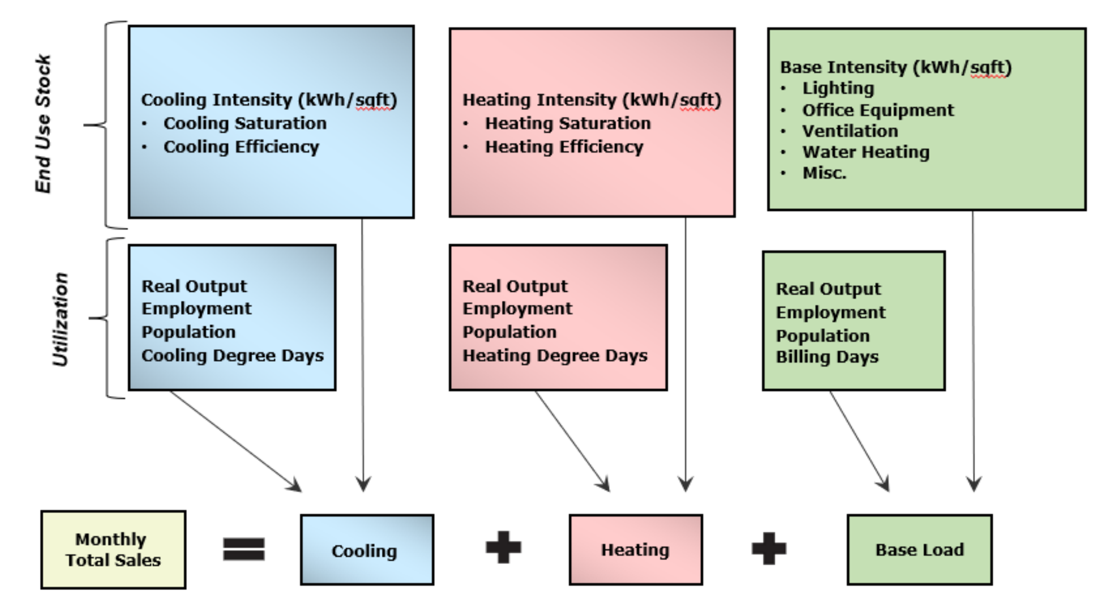


$$AvgUse_m = a + b_c \times XCool_m + b_h \times XHeat_m + b_o \times XOther_m + b_e \times EE_m$$

Residential forecast is the product of the customer forecast and average use forecast. Average use is defined as the sum of average monthly cooling (XCool), heating (XHeat), and other non-weather energy use (XOther). Historical EE estimates are also included in the model to account for any state efficiency savings that are not captured on the primary end-use variables. In most models the variable proved to be statistically insignificant largely as the number of customers and noise in the billing data proved to be too few to pick up much of an impact. A monthly average use regression model is used to estimate the coefficients a, b_c, b_h, and b_o,, and b_e which effectively *statistically adjust* the end-use model variables to actual customer usage. End-use sales estimates are then derived by combining the estimated model coefficients with the model variables (XCool, XHeat, and XOther) for normal weather conditions. The specification is theoretically strong and appropriately captures the impact and interaction of structural model variables (e.g., end-use saturation, efficiency, and thermal shell integrity) with monthly utilization variables – weather conditions, household size, and household income.

A similar SAE model specification is used for the commercial customer classes. Figure 5 shows the commercial model specification.

FIGURE 5: COMMERCIAL SAE MODEL



$$kWh_m = \quad a + b_c \times XCool_m + b_h \times XHeat_m + b_o \times XOther_m + b_d$$

In the commercial model end-use energy intensities are expressed on a kWh per square foot basis. Intensities for cooling, heating, and base-use are derived from EIA's Annual Energy Outlook for the New England Census Division. Annual end-use intensities are combined with monthly utilization variables that include monthly HDD and CDD, and constructed economic driver based that incorporates state economic output, employment, and population. Model variables are used in estimating monthly sales models. Commercial end-use energy requirements are derived as the product of the estimated model coefficient and initial end-use energy estimates (XCool, XHeat, and XOther).

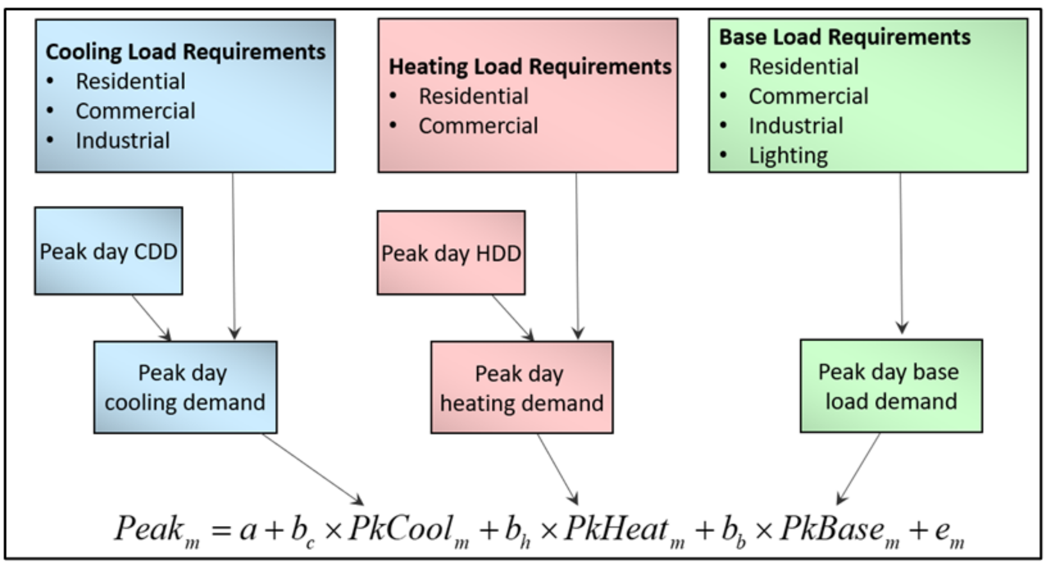
For many of the municipalities the larges C&I customer class is dominated by a few companies. The is often significant variation in month-to-month sales making it difficult to fit with an SAE model specification. For these classes, either a more generalized econometric or trend model is used. This is also true for the *other* customer class that is generally street lighting and municipal own use.

Baseline Energy, Peak, and Hourly Load Forecast

The baseline energy forecast is derived from the customer-class sales forecasts. For most members, the energy forecast is derived by aggregating the customer class sales forecasts and adjusting for line losses. In some case where billed sales data (used in estimating class sales) are too noisy due to the billing process, separate monthly energy regression models are estimated where the total sales forecast is the primary driver.

Monthly peak regression models are estimated based on underlying heating, cooling, and base-use loads derived from the customer class sales models. Heating and cooling load requirements are combined with peak-producing weather to generate peak-day heating and cooling variables; the impact of peak-day temperatures changes over time with changes in heating and cooling load requirements. In general baseline heating requirements are declining as traditional resistant heat saturation falls and cooling requirements are increasing with increasing air conditioning saturation. The expected growth due to CCHP program turns around the baseline decline in heating load and adds to cooling demand growth. Figure 6 shows the baseline peak demand model.

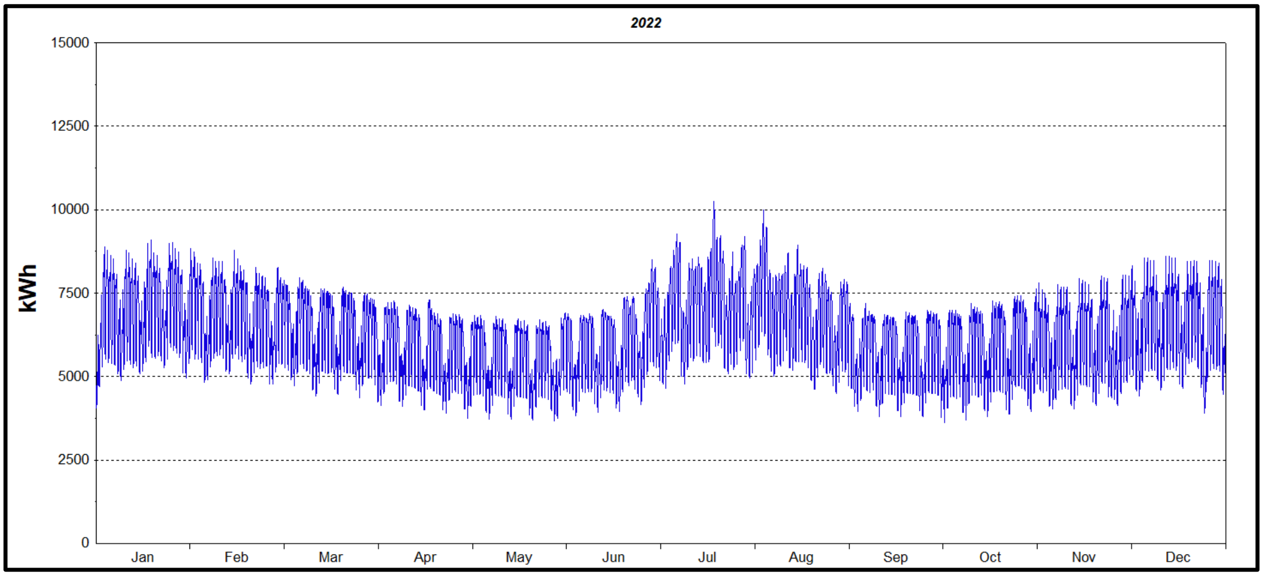
FIGURE 6: BASELINE PEAK MODEL



The peak model is estimated using linear regression that relates the monthly peak to peak-day CDD and HDD, combined with cooling, heating, and base load requirements at time of peak.

A baseline hourly load profile is derived from historical hourly system loads. Models are designed to capture expected hourly loads for typical weather conditions, day of the week, season, and holidays. Figure 7 shows the baseline profile for Swanton.

FIGURE 7: SWANTON HOURLY BASELINE PROFILE



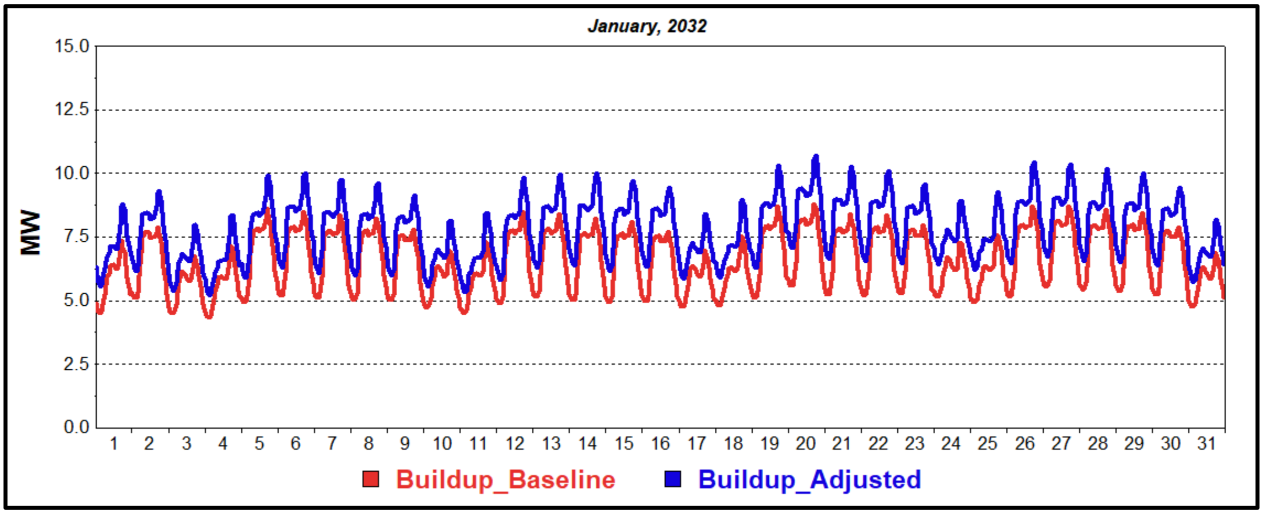
The baseline profile is constant over the estimation period. The baseline hourly load forecast is then derived by combining the baseline energy and peak forecast with the profile. Increase in energy requirements and peak demand lift the baseline profile over time. The baseline hourly load forecast reflects customer projections, economic impacts, weather conditions, and energy efficiency impacts.

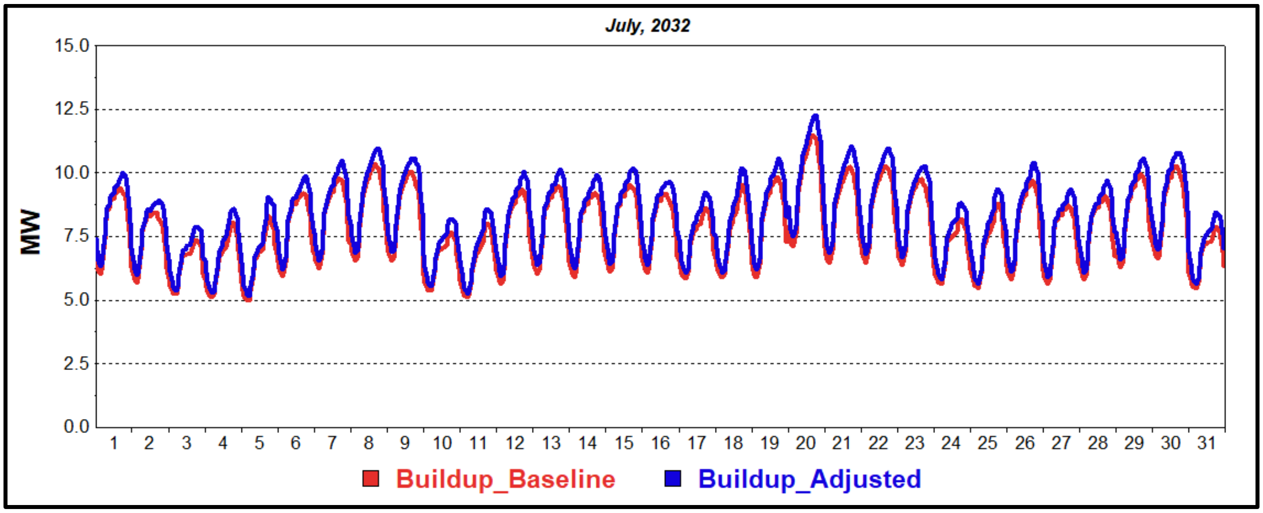
Adjusted Load Forecast

For the most part, baseline loads are either flat or declining as efficiency gains have outweighed customer and economic growth. The long-term peak demand drivers are expected market penetration of CCHP and EV purchases. Both incentivized CCHP and EVs are expected to play a significant role in achieving state greenhouse gas reduction. While PV market penetration is projected to continue to increase, capacity projections slow from current pace and have minimum impact on peak demand; PV capacity has already shifted peaks into the later summer hours and has no impact on winter peak demand.

The expected increase in PV adoption, CCHP, and EVs reshape system load over time and as a result the timing and level of peak demand. Incremental PV energy savings, and new heat pump and EV sales are combined with associated technology hourly load profiles and layered on the baseline hourly load forecast. Figure 8 compares the Swanton baseline and hourly load forecast for 2032.

FIGURE 8: SWANTON SYSTEM HOURLY LOAD COMPARISON (2032)





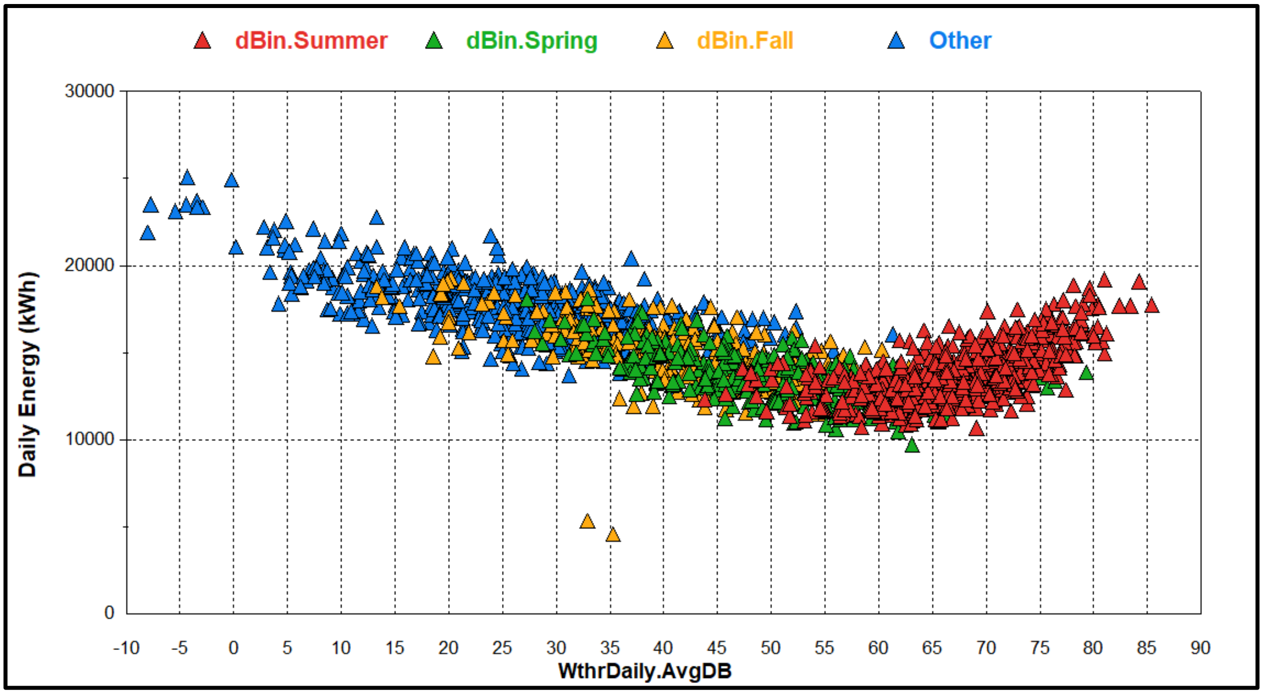
The initial baseline forecast is shown in red and the forecasted adjusted PV, EV, and heat pumps in blue. Solar adoption combined with EV charging shifts the summer peak into the evening hours while heat pumps and EV charging have a much larger impact on winter peaks than summer peaks.

FORECAST ASSUMPTIONS

Weather

Member forecasts use weather from either Burlington or Rutland depending on location. Burlington airport weather data is used for eight of VPPSA members that are clustered in north-central Vermont and Rutland weather data for the three large municipals in the central and southern regions of the state. The temperature/load relationship is evaluated at the system level. Figure 9 illustrates what this relationship looks like at the system level for Jacksonville.

FIGURE 9: LOAD-TEMPERATURE RELATIONSHIP (JACKSONVILLE)



Each point represents the daily average use (in kWh) and the average temperature for that day. The curve shows us a long heating curve with heating starting at 55 degrees, and a short cooling curve with cooling starting at around 60 degrees.

Historical temperature data is used to generate daily and monthly heating-degree days (HDD) and cooling degree-days (CDD). HDD are derived using a base temperature of 55 degrees; this is the temperature point where we begin to see heating load. HDD are positive when average daily temperature falls below 55 degrees and 0 when temperatures exceed 55 degrees. CDD are defined for a 60 degree-day. CDD are positive when temperatures are above 60 degrees and 0 when average daily temperature falls below 60 degrees.

Normal or expected degree-days are used to drive the forecast. The general approach is to calculate normal degree-days as an average of past temperature or degree-days over a historical time; most utilities will use a 30-year or 20-year period. The implied assumption is that future temperatures is best represented by the average of the past. Given climate change, however, this is probably not the best assumption.   Our analysis and that of others shows that average temperatures are increasing. An analysis of last 50 years of weather data for the Burlington airport shows average temperatures are increasing roughly .08 degrees per year or 0.8 degrees per decade. This is consistent with temperature trends we found in New York. Temperature trend studies have shown average temperatures increasing from 0.4 degrees to over 1.0 degrees per decade depending on geographic location. Temperature trends tend to be the lowest in cities near the ocean.

Increasing temperatures result in fewer HDD and increasing number of CDD. This is illustrated in Figure 10 and Figure 11 that show 20-year degree-day moving average against actual degree days.

FIGURE 10: HEATING TREND

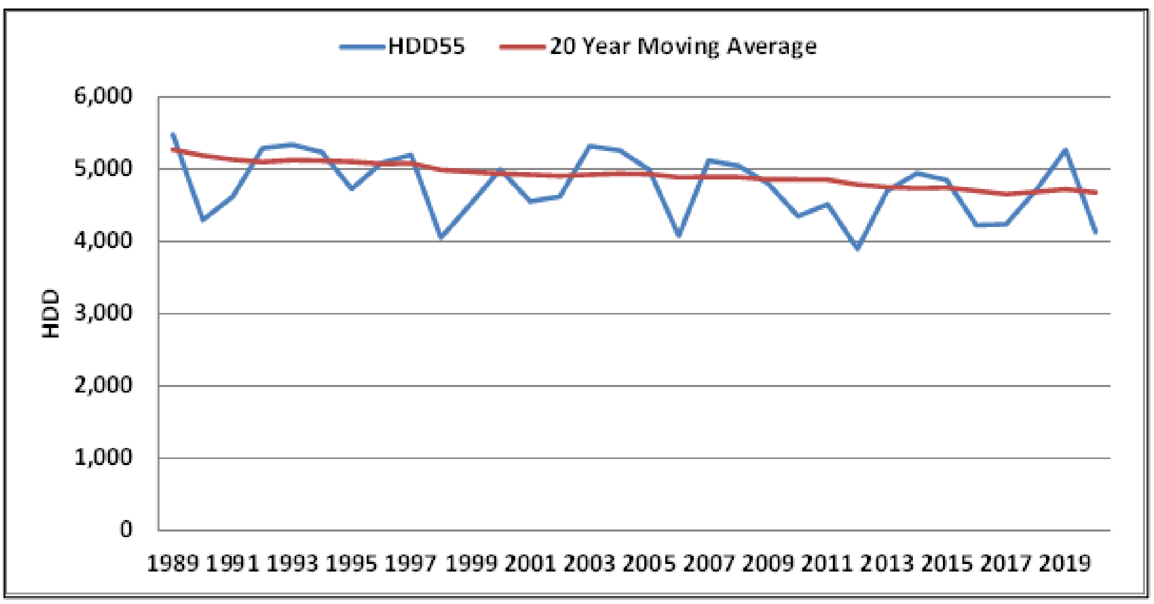
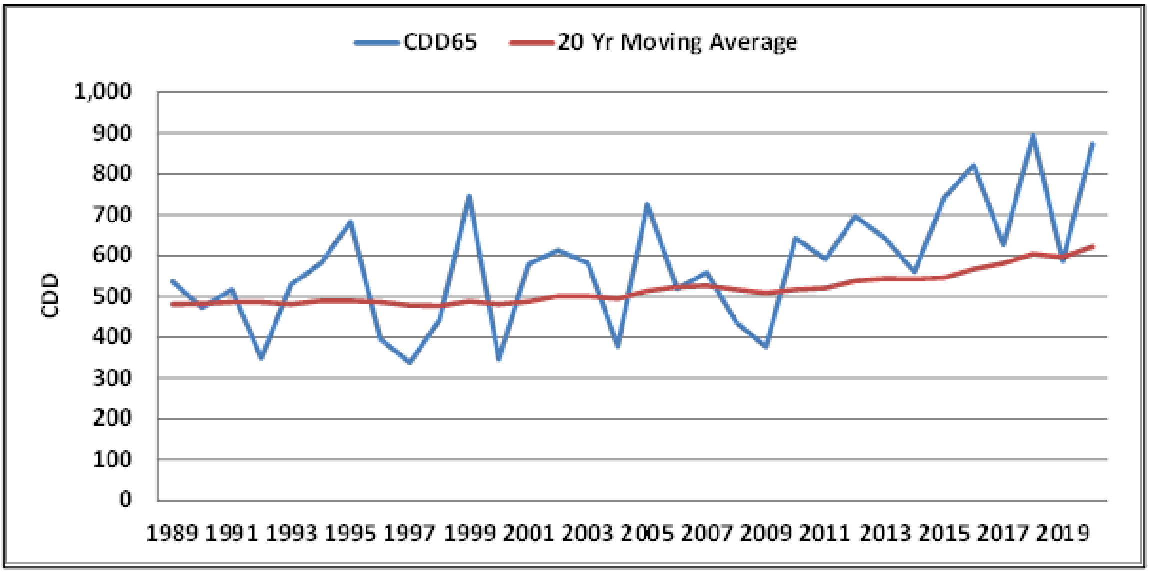


FIGURE 11: COOLING TREND



Recent climate studies show that we can expected temperatures to continue to increase. We assume HDD and CDD trends to persist through the forecast period.

Figure 12 and Figure 13 compare actual, 20-year normal, and trended HDD and CDD.

FIGURE 12: NORMAL AND TRENDED NORMAL HDD

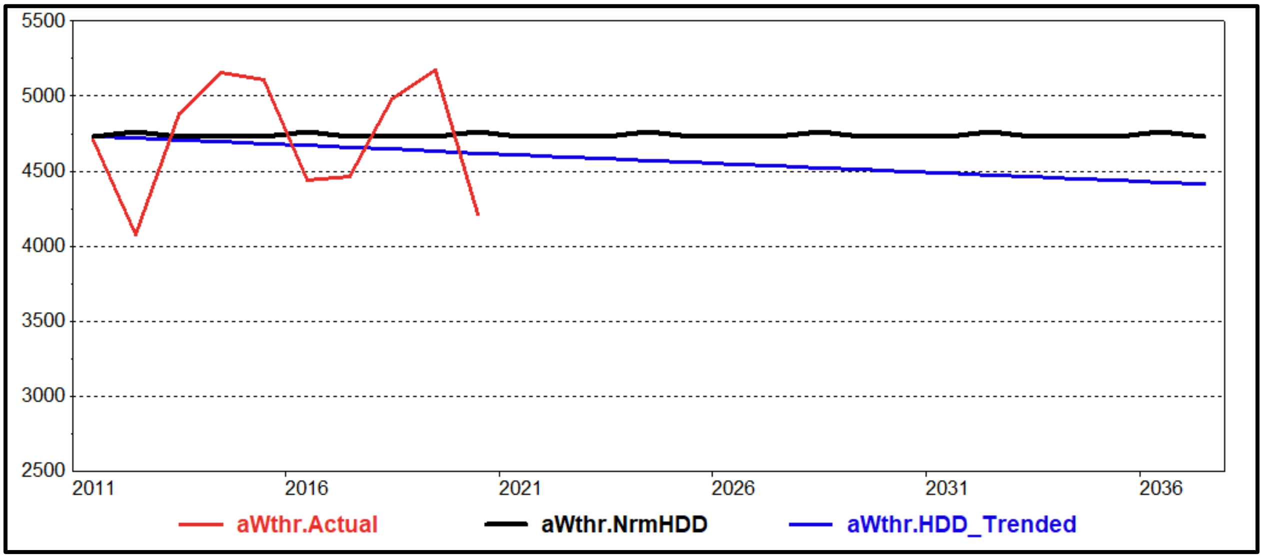
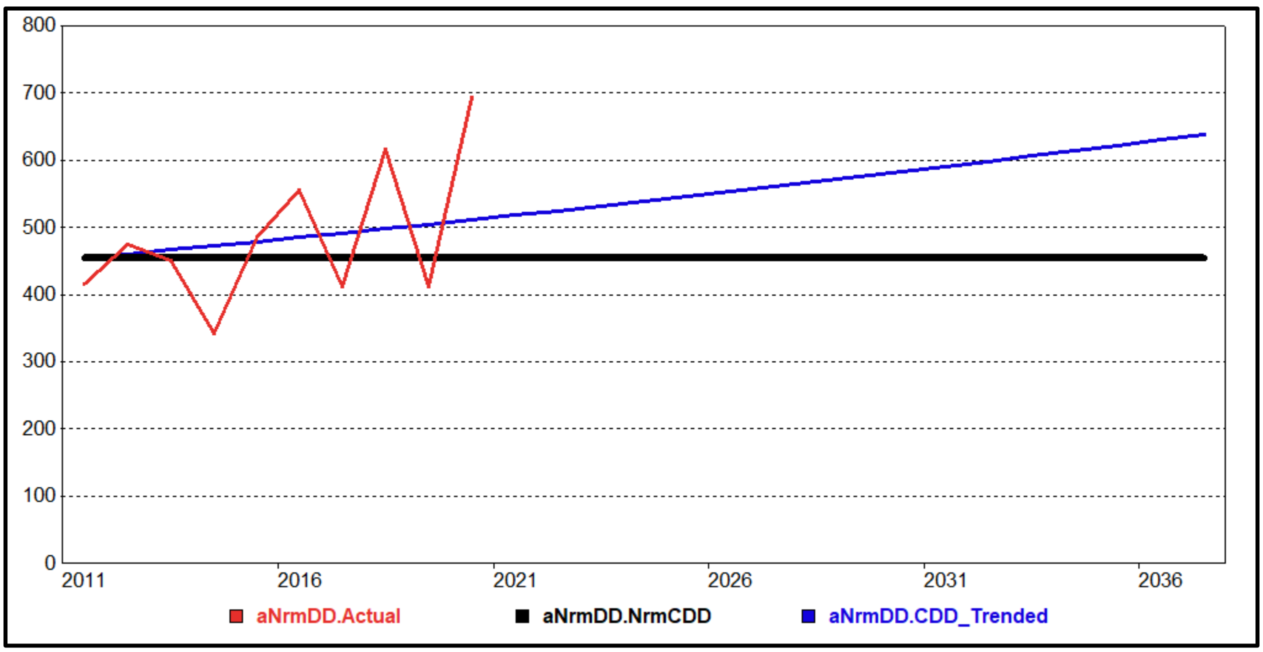


FIGURE 13: NORMAL AND TRENDED NORMAL CDD



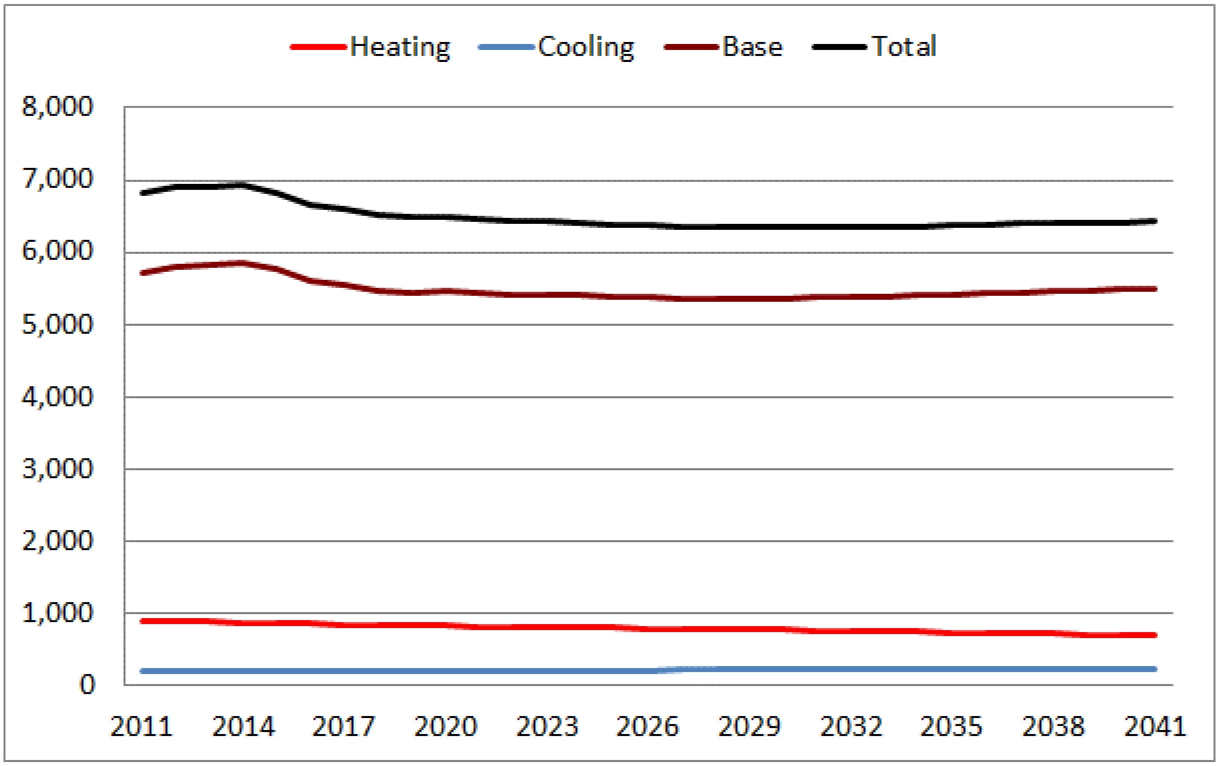
Based on historical data, CDD are expected to increase 1.3% per year and number of HDD decline 0.3% per year.

End-Use Intensities

Overall, sales have been flat to declining across the state. The decline is largely attributable to behind-the-meter solar adoption and end-use and efficiency gains resulting from new standards and state-incentivized energy efficiency programs. The impact of efficiency improvements is captured in the end-use intensities that reflect both changes in end-use ownership (saturation) and end-use efficiency. End-use intensities are derived for ten residential and nine C&I end-uses by combining saturation and efficiency projections. In the residential sector, intensities are measured on a kWh per household basis and in the commercial sector on a kWh per square-foot basis. End-use intensities are based on EIA 2020 Annual Energy Outlook for New England. Residential end-use saturations are calibrated to Vermont-specific end-use saturations where this data is available.

For most end-uses, increasing efficiency outweighs increase in saturation contributing to declining customer average use. The exception is miscellaneous use (e.g., plug loads, appliances, electric equipment) and residential cooling; in residential cooling saturation continues to trend positive at a rate faster than improvements in air conditioning stock efficiency. Increasing CDD and incentivized heat-pumps are also expected to contribute to additional cooling-related sales. Still, aggregate cooling consumption is relatively small given temperate summer weather conditions. Figure 14 shows residential end-use intensities aggregated into heating, cooling, base, and total intensity.

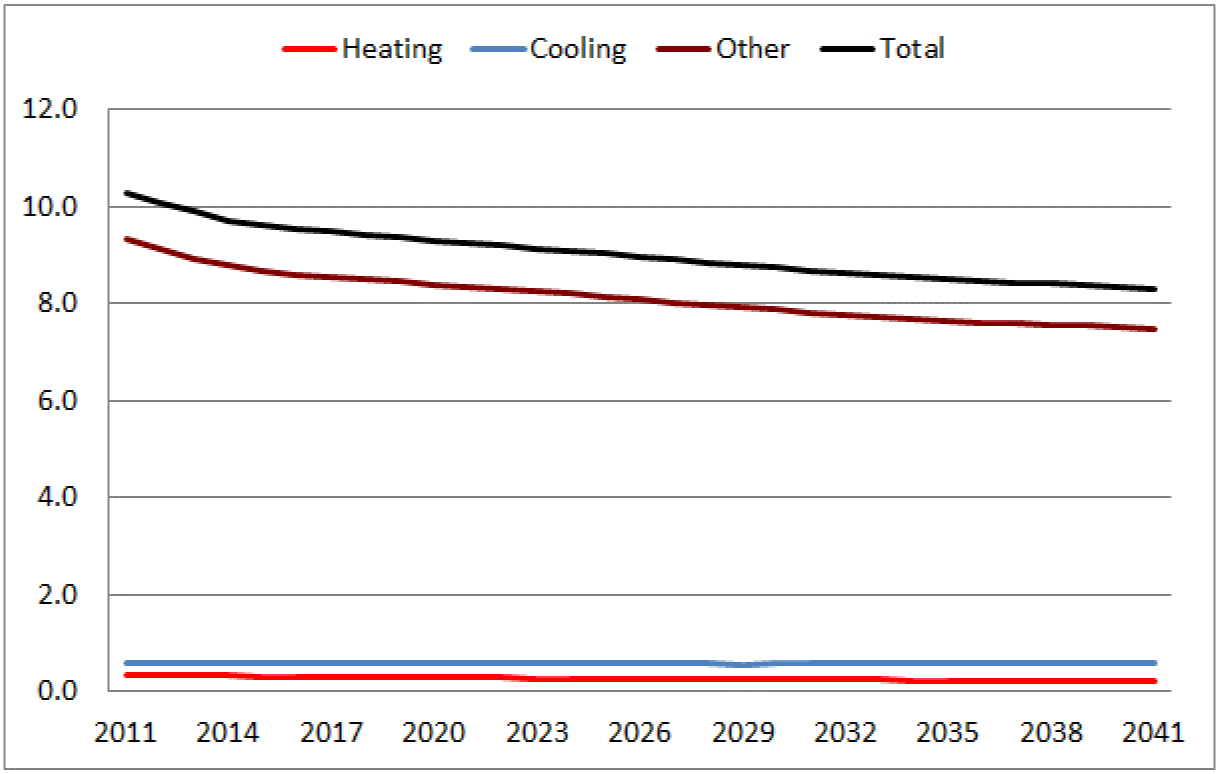
FIGURE 14: RESIDENTIAL SAE INDICES (KWH/HOUSEHOLD)



Since 2012, total residential intensity has declined 0.7% annually with the conversion from incandescent and florescent to LED being a major contributor. The energy intensity still declines but at a much slower rate over the next ten years (-0.2% per year) as the lighting savings have been realized and the impact of new appliance standards begins to slow.

Commercial energy intensities are measured on a kWh per Sq. ft. basis. Figure 15 shows commercial heating, cooling, and other use intensity trends. Heating and cooling are a relatively small part of commercial energy use. The non-weather sensitive use (Other) is composed of seven end-uses where the largest end-uses include ventilation, lighting, refrigeration, and miscellaneous use.

FIGURE 15: COMMERCIAL SAE INDICES (KWH/HOUSEHOLD)

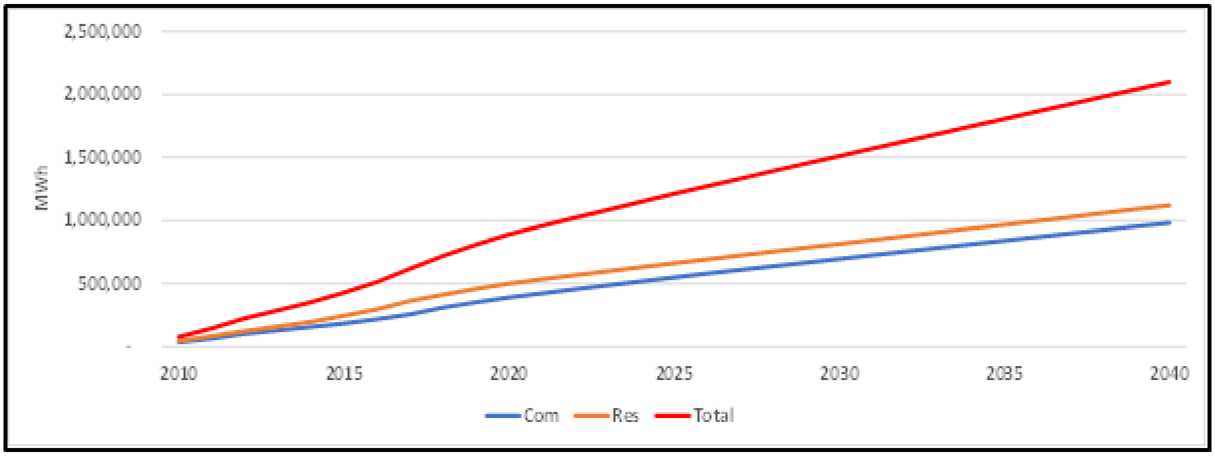


In general, there has been a long-term decline in commercial sales largely driven by efficiency gains. Commercial intensity has averaged 1.2% decline over the last ten years and is projected to decline another 0.7% over the next ten years.

EE Program Impacts

State efficiency programs have also had a significant impact on sales. At the state level, most of the impact is captured in the end-use intensities. EIA adjust end-use efficiencies to reflect New England EE program savings. Forecasts are further adjusted for Vermont-specific savings by incorporating VEIC measured and projected savings as an additional model variable. Where the variable is statistically insignificant, sales are adjusted based on allocated state EE savings projections. State savings projections are allocated to utilities based on customer class sales. Figure 16 shows the current state Demand Resource Plan (DRP) cumulative historical and projected savings.

FIGURE 16: VEIC HISTORICAL AND PROJECTED EE PROGRAM SAVINGS



Economic Outlook

The 2022 forecast is based on Moody's January 2022 state economic projections. The primary economic drivers include number of state households, population, real personal income, employment, and real economic output (GDP). Table 7 shows historical and projected economic outlook.

TABLE 7: ECONOMIC FORECAST

Year	Households (Thou)	Chg	RPI (Mil $)	Chg	GDP (Mil $)	Chg	Emp (Thou)	Chg
2011	258.9		28,119		28,981		300.9	
2012	260.2	0.5%	28,505	1.4%	29,281	1.0%	304.5	1.2%
2013	262.1	0.7%	28,624	0.4%	28,671	-2.1%	306.7	0.7%
2014	263.4	0.5%	29,295	2.3%	28,868	0.7%	309.6	0.9%
2015	264.1	0.3%	30,121	2.8%	29,163	1.0%	312.1	0.8%
2016	264.2	0.1%	30,316	0.6%	29,368	0.7%	313.3	0.4%
2017	264.5	0.1%	30,530	0.7%	29,506	0.5%	315.0	0.5%
2018	264.7	0.1%	30,895	1.2%	29,629	0.4%	316.1	0.3%
2019	265.0	0.1%	31,477	1.9%	29,775	0.5%	315.3	-0.3%
2020	263.9	-0.4%	33,348	5.9%	28,807	-3.2%	289.1	-8.3%
2021	265.1	0.5%	32,911	-1.3%	29,819	3.5%	293.5	1.5%
2022	266.6	0.6%	31,845	-3.2%	30,849	3.5%	301.9	2.9%
2023	268.3	0.6%	32,674	2.6%	31,788	3.0%	306.8	1.6%
2024	269.5	0.4%	33,550	2.7%	32,650	2.7%	309.1	0.7%
2025	270.3	0.3%	34,325	2.3%	33,439	2.4%	310.0	0.3%
2026	271.1	0.3%	35,042	2.1%	34,151	2.1%	310.2	0.1%
2027	271.7	0.2%	35,772	2.1%	34,760	1.8%	310.5	0.1%
2028	272.2	0.2%	36,583	2.3%	35,369	1.8%	310.9	0.1%
2029	272.7	0.2%	37,422	2.3%	35,986	1.7%	311.4	0.2%
2030	273.2	0.2%	38,226	2.1%	36,577	1.6%	311.8	0.1%
2031	273.5	0.1%	38,971	2.0%	37,168	1.6%	311.9	0.0%
2032	273.7	0.1%	39,711	1.9%	37,791	1.7%	311.9	0.0%
2033	273.9	0.0%	40,446	1.9%	38,443	1.7%	312.0	0.0%
2034	273.8	0.0%	41,147	1.7%	39,100	1.7%	312.1	0.0%
2035	273.7	0.0%	41,830	1.7%	39,757	1.7%	312.1	0.0%
2036	273.6	0.0%	42,494	1.6%	40,405	1.6%	311.9	-0.1%
2037	273.4	-0.1%	43,150	1.5%	41,042	1.6%	311.7	-0.1%
2038	273.0	-0.1%	43,783	1.5%	41,671	1.5%	311.5	-0.1%
2039	272.6	-0.2%	44,387	1.4%	42,302	1.5%	311.3	-0.1%
2040	272.2	-0.2%	44,973	1.3%	42,933	1.5%	311.1	-0.1%
2041	271.6	-0.2%	45,540	1.3%	43,570	1.5%	311.0	0.0%
2042	271.0	-0.2%	46,117	1.3%	44,215	1.5%	310.9	0.0%
11-21		0.2%		1.6%		0.3%		-0.2%
22-32		0.3%		2.2%		2.1%		0.3%
32-42		-0.1%		1.5%		1.6%		0.0%

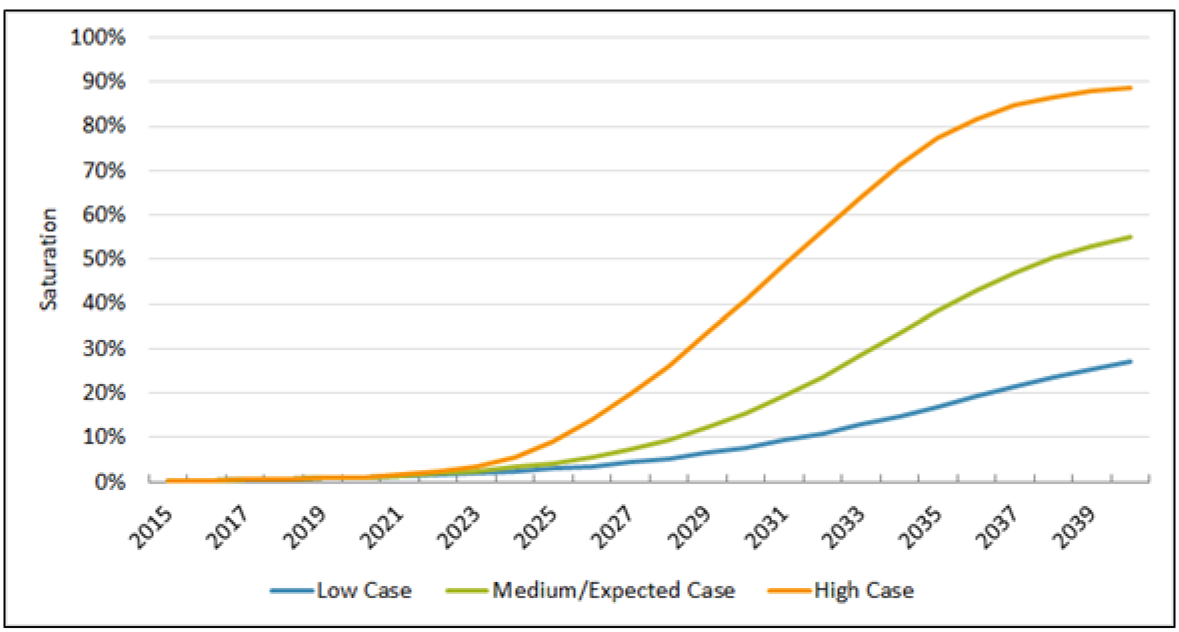
In 2020, state output (GDP) dropped 3.2% and employment declined 8.3% while personal income increased 5.9%. The large increase in real income is a result of government financial stimulus designed to counter the COVID employment impact. Moody's projects economic recovery to pre-pandemic levels by 2022 with strong economic growth coming out of the COVID-driven recession.

Over the long-term, number of households is expected to average 0.3% with employment increasing at roughly the same rate. GDP averages 2.1% per year largely driven by improvements in productivity and a jump in GDP coming out of the pandemic.

Electric Vehicles

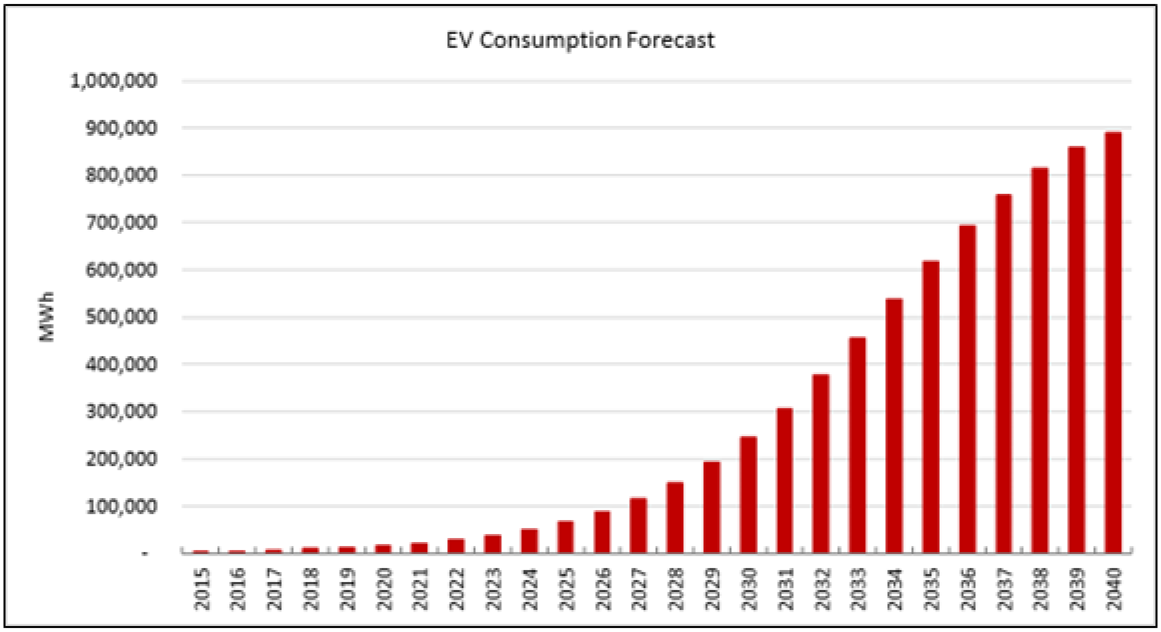
The electric vehicle (EV) forecast was developed by the VEIC as part of VELCO 2021 Long-Range Transmission Plan. VEIC provided three forecast scenarios; low, medium, and high, based on saturation targets for light-duty registered vehicles. The expected case (used in the VPPSA forecast) assumes that over 15% of all vehicles are electric by 2030 and by 2050, 60% of vehicles are electric. In the high case, 90% of all vehicles are electric by 2050 with a 50% market share by 2030. In the low case 35% of all vehicles are electric by 2050. Figure 17 shows the projected adoption paths.

FIGURE 17: ELECTRIC VEHICLE SATURATION PROJECTIONS



EV saturations are translated into number of vehicles and then total charging energy requirements based on estimated annual miles driven and kWh per mile driven. Figure 18 shows state EV electric consumption for the expected case.

FIGURE 18: EXPECTED CASE STATE EV ELECTRICITY FORECAST

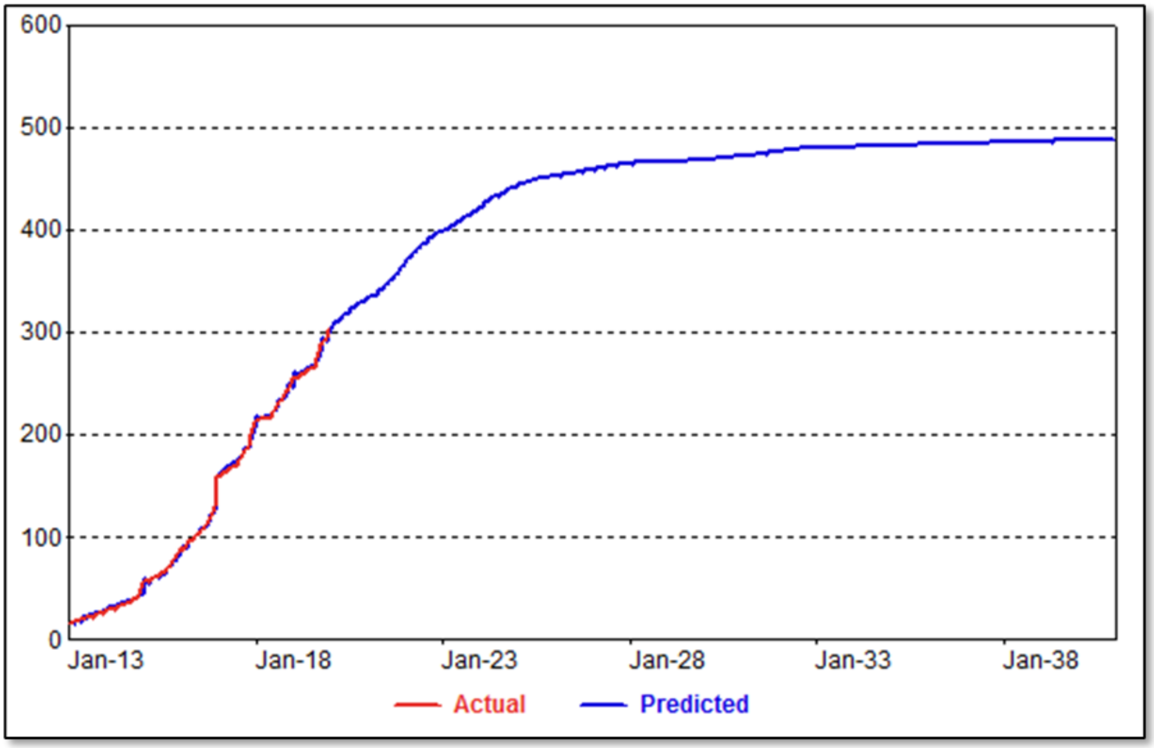


State EV sales are allocated to VPPSA member utilities based on each members' share of statewide number of residential customers.

Solar

The solar forecast is based on Itron's behind-the-meter (BTM) solar forecast developed also as part of the 2021 VELCO long-term forecast. BTM solar capacity is derived from an investment return-based model that relates installed capacity to average system payback (number of years before investment costs are recovered). Figure 19 shows state capacity forecast.

FIGURE 19: STATE SOLAR CAPACITY FORECAST (MW)

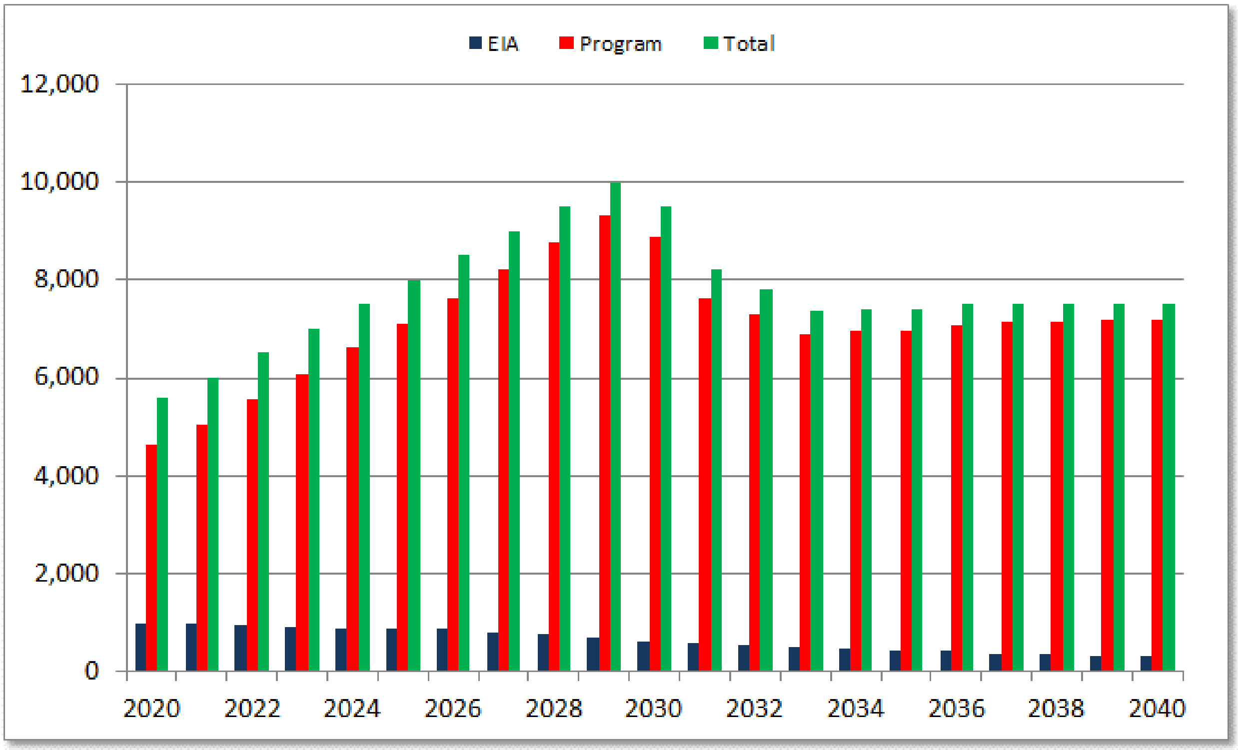


We expect the growth of BTM solar adoption to begin to slow by 2025 as system costs begin to flatten out. We project over 450 MW of installed solar capacity by 2032. This translates into nearly 650,000 MWh based on monthly load factors derived from Vermont solar generation profile data. Our default assumption is VPPSA member BTM solar is proportional to total state generation based on number of member customers.

Cold Climate Heat Pumps

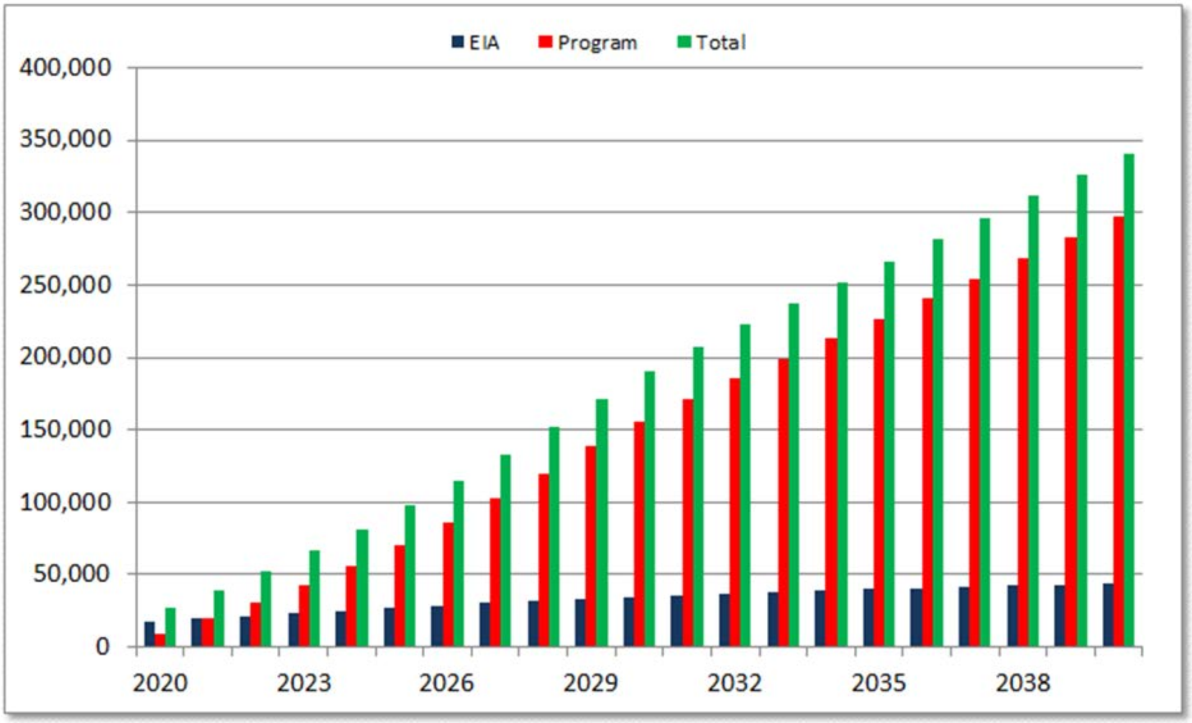
As part of state efforts to reduce CO_2 emissions, the state has launched a program to promote CCHP by offering financial incentives including rebates and 0 interest financing. The primary targets are homes that heat with oil, propane, and wood. VEIC along with input from the DPS developed a long-term forecast of CCHP units for low, medium, and high case. The reference case is based on the medium CCHP forecast with sales of around 6,000 units in the near-term, rising to 10,000 units by 2030. EIA projections are considerably more conservative with heat pumps primarily displacing electric resistant heat. Figure 20 shows state CCHP unit projections.

FIGURE 20: STATE CCHP FORECAST (UNITS PER YEAR)



VEIC further translated unit projections into electricity use based on recent CCHP measurement studies. Figure 21 shows projected state-level CCHP energy forecast.

FIGURE 21: STATE CCHP ENERGY PROJECTIONS (MWH)



CCHP sales are allocated to VPPSA members based the number of customers relative to state-level customer counts.

APPENDIX A

MODEL RESULTS

Residential Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructRes.LagXHeat	1480.841	141.775	10.445	0.00%
mStructRes.LagXCool	3108.112	327.453	9.492	0.00%
mStructRes.XOther	-1642.746	405.157	-4.055	0.01%
mStructRes.LagXOther	3182.506	396.18	8.033	0.00%
mCovid.ResIndex	82631.502	20792.13	3.974	0.01%
mBin.SepAft16	-490518.61	29462.25	-16.649	0.00%
mBin.Feb	-215834.759	40771.4	-5.294	0.00%
mBin.Apr	-177240.171	19130.14	-9.265	0.00%
mBin.Sep	204294.898	29273.41	6.979	0.00%
mBin.Dec	173209.535	24749.5	6.999	0.00%
MA(1)	0.245	0.097	2.535	1.25%
MA(2)	-0.33	0.094	-3.514	0.06%
MA(3)	0.74	0.098	7.52	0.00%

Model Statistics	
Iterations	99
Adjusted Observations	130
Deg. of Freedom for Error	117
R-Squared	0.787
Adjusted R-Squared	0.765
AIC	22.212
BIC	22.498
Log-Likelihood	-1,615.23
Model Sum of Squares	1,741,818,441,125.03
Sum of Squared Errors	471,544,625,348.39
Mean Squared Error	4,030,295,943.15
Std. Error of Regression	63,484.61
Mean Abs. Dev. (MAD)	48,064.25
Mean Abs. % Err. (MAPE)	5.58%
Durbin-Watson Statistic	1.818

Residential Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mEcon.HHs	6.005	0.014	420.528	0.00%
mBin.Feb	1084.185	9.816	110.454	0.00%
mBin.May	1091.116	9.816	111.158	0.00%
mBin.Aug	1094.028	9.816	111.451	0.00%
mBin.Nov	1074.769	9.817	109.485	0.00%
mBin.Aft20	23.071	5.667	4.071	0.01%

Model Statistics	
Iterations	1
Adjusted Observations	72
Deg. of Freedom for Error	66
R-Squared	0.998
Adjusted R-Squared	0.998
AIC	6.322
BIC	6.511
Log-Likelihood	-323.74
Model Sum of Squares	18,880,379.28
Sum of Squared Errors	33,917.33
Mean Squared Error	513.9
Std. Error of Regression	22.67
Mean Abs. Dev. (MAD)	18.72
Mean Abs. % Err. (MAPE)	0.98%
Durbin-Watson Statistic	2.517

Commercial Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructCom.XCool	113583.142	63013.77	1.803	7.39%
mStructCom.LagXCool	171049.876	62523.73	2.736	0.71%
mStructCom.LagXOther	32022.873	469.422	68.218	0.00%
mCovid.NResIndex	-16017.209	6227.492	-2.572	1.13%
mBin.Mar	16612.903	9569.167	1.736	8.50%
mBin.Oct	-26925.028	10227.35	-2.633	0.95%
mBin.Nov	-18579.155	9701.095	-1.915	5.78%

Model Statistics	
Iterations	1
Adjusted Observations	131
Deg. of Freedom for Error	124
R-Squared	0.454
Adjusted R-Squared	0.428
AIC	20.625
BIC	20.779
Log-Likelihood	-1,529.81
Model Sum of Squares	88,698,733,899.55
Sum of Squared Errors	106,689,795,575.62
Mean Squared Error	860,401,577.22
Std. Error of Regression	29,332.60
Mean Abs. Dev. (MAD)	21,444.01
Mean Abs. % Err. (MAPE)	7.38%
Durbin-Watson Statistic	2.292

Other Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	0.769	0.114	6.763	0
Seasonal	-0.09	0.292	-0.308	0.759

Model Statistics	
Iterations	18
Adjusted Observations	72
Deg. of Freedom for Error	70
R-Squared	0.727
Adjusted R-Squared	0.723
AIC	11.722
BIC	11.786
Log-Likelihood	-522.17
Model Sum of Squares	22,346,546
Sum of Squared Errors	8,397,709
Mean Squared Error	119,967.27
Std. Error of Regression	346.36
Mean Abs. Dev. (MAD)	198.57
Mean Abs. % Err. (MAPE)	1.98%
Durbin-Watson Statistic	2.035

Energy Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mFcst.TtlSales	1.027	0.011	89.916	0.00%
mBin.Jan	249563.096	24160.4	10.329	0.00%
mBin.Feb	174012.257	23587.83	7.377	0.00%
mBin.Mar	190726.821	23787.63	8.018	0.00%
mBin.Apr	213379.479	22849.42	9.339	0.00%
mBin.May	80127.274	23427.72	3.42	0.09%
mBin.Jul	146949.034	24248.46	6.06	0.00%
mBin.Aug	158940.775	24103.4	6.594	0.00%
mBin.Sep	142944.578	23108.51	6.186	0.00%
mBin.Oct	156701.989	23120.14	6.778	0.00%
mBin.Dec	54308.153	25191.36	2.156	3.31%

Model Statistics	
Iterations	1
Adjusted Observations	132
Deg. of Freedom for Error	121
R-Squared	0.666
Adjusted R-Squared	0.638
AIC	22.255
BIC	22.495
Log-Likelihood	-1,645.12
Model Sum of Squares	1,028,625,078,558.52
Sum of Squared Errors	516,871,358,468.04
Mean Squared Error	4,271,664,119.57
Std. Error of Regression	65,357.97
Mean Abs. Dev. (MAD)	50,142.45
Mean Abs. % Err. (MAPE)	3.83%
Durbin-Watson Statistic	1.994

Peak Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mWthr.HeatVar55	2.199	1.034	2.127	3.54%
mWthr.CoolVar60	20.278	1.96	10.346	0.00%
mCPkEndUses.BaseVar	2.056	0.03	69.164	0.00%
mBin.Mar	197.254	47.501	4.153	0.01%
mBin.May	-155.333	49.864	-3.115	0.23%
mBin.Jun	-178.294	50.455	-3.534	0.06%
mBin.Feb16	739.115	150.063	4.925	0.00%

Model Statistics	
Iterations	1
Adjusted Observations	132
Deg. of Freedom for Error	125
R-Squared	0.683
Adjusted R-Squared	0.668
AIC	10.024
BIC	10.177
Log-Likelihood	-841.91
Model Sum of Squares	5,779,176.12
Sum of Squared Errors	2,679,314.22
Mean Squared Error	21,434.51
Std. Error of Regression	146.41
Mean Abs. Dev. (MAD)	112.56
Mean Abs. % Err. (MAPE)	4.42%
Durbin-Watson Statistic	1.728

APPENDIX G: TIER III LIFE-CYCLE COST ANALYSIS

The Tier III Rule states that:

"4.410 (3) The Energy Transformation Project shall meet the need for its goods or services at the lowest present-value life-cycle cost, including environmental and economic costs. This evaluation shall include an analysis of alternatives that do not increase electric consumption. If a Retail Electricity Provider's Integrated Resource Plan includes an analysis of alternatives, the Provider's Tier III annual plan shall reference the analysis in the Integrated Resource Plan and shall include any significant changes. If a Provider's Integrated Resource Plan does not include an analysis of alternatives, the Provider's Tier III annual plan shall include the analysis."

Because ninety-five percent of the savings from BVI's Tier III programs are from four measures, we summarize the life cycle costs for electric vehicles and heat pumps in Table 1. In terms of avoided costs, these ratios are based on the forecast of electricity, capacity and transmission prices that support the financial analysis section. The measure savings (lifetime kWh) are consistent with the averages in the Tier III Planning Tool for Program Year 2022, and the value of avoided emissions is consistent with the 2021 Avoided Energy Supply Cost (AESC) study. Finally, the retail rates are based on a forecast of BVI's residential rate.

Table 1: Life-Cycle Cost-Benefit Ratios

Measure	Utility	Customer	Society
EV	0.8	0.4	0.5
PHEV	0.8	0.5	0.8
CCHP	1.0	1.1	1.3
WBHP	0.9	1.6	1.8

Heat pumps are the least-cost measure, and provide net benefits to both the customer and to society. They are break-even to the utility, however. Electric vehicles have much higher incremental costs as well as shorter measure lives. As a result, their cost-benefit ratios are less attractive.

The Tier III Planning Tool does include some measures that do not increase electric consumption. These measures include the use of biodiesel, the use of wood pellets, telecommuting, bicycle commuting, using public transportation and installing smart thermostats. BVI will include an evaluation of the cost-effectiveness of these measures in the next Tier III annual plan.