Village of Enosburg Falls Electric Light Department

2024 Integrated Resource Plan

As Filed with the Public Utility Commission

Vermont Public Power Supply Authority

EXECUTIVE SUMMARY

The Village of Enosburg Falls Electric Light Department (VOEF) has operated an electric utility system since 1896. Serving approximately 1,800 customers, VOEF's service territory is located in the northwestern part of Vermont, in an area where weather events–especially in recent years–have been both challenging and at times highly localized. Its service territory encompasses the Village of Enosburg Falls as well as portions of six surrounding towns: Bakersfield, Berkshire, Enosburgh, Fairfield, Franklin, and Sheldon. The service territory of VOEF is predominantly a dairy farming community, with 10 active farms and is home to the cheese manufacturer, Franklin Foods. Much of the remaining commercial activity in VOEF supports dairy farming. VOEF 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 VOEF is careful to balance maintaining reliability and reasonable cost levels with the need to deliver innovative programs to customers that provide practical value.

VOEF's distribution system serves a mix of residential, small commercial, and large commercial customers. Residential customers make up almost 90% of the customer mix while accounting for a little over half of VOEF's retail kWh sales. Twenty-one (about 1%) large commercial customers make up approximately 35% of retail usage with the remaining 11% of retail sales going to small commercial, public authority, and public street and highway lighting customers. Of these, Franklin Foods is the largest and represents 20% of retail sales.

Consistent with regulatory requirements, every three years VOEF is required to prepare and implement a least cost integrated plan (also called an Integrated Resource Plan or IRP) for the provision of energy services to its Vermont customers. VOEF'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

VOEF 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 has reduced demand. At this time, the pace at which net metering will grow in VOEF'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 VOEF's largest customers is currently anticipated the potential does exist. VOEF monitors the plans of large customers in order to anticipate necessary changes to the existing resource plan and 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

VOEF'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 prices, the portfolio is heavily weighted toward market contracts, hydro, and other renewable sources. VOEF owns and operates the Enosburg Falls Hydroelectric Facility, delivering a clean reliable source of power located on the Missisquoi River, within its service territory. The Enosburg Falls Hydroelectric Facility has been a dependable source of power for the evolving energy needs of northwestern Vermont.

VOEF is currently working with a developer to install a 2.13 MW AC utility-scale solar project, referred to as Reservoir Road Solar, in the VOEF's service territory. This project, anticipated to be commissioned in 2026, will provide energy for 25 years at a stable rate, and will provide VT Tier II RECs as well as capacity and transmission benefits.

When considering future electricity demand, VOEF seeks to supplement its existing resources with market contracts as well as new demand-side and supply resources. VOEF 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. VOEF anticipates regional availability of competitively priced renewable resources including solar, wind, and hydro. In addition to playing a role in meeting future electricity requirements, this category of resource contributes to meeting Renewable 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 VOEF 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, VOEF employs an integrated financial model that incorporates impacts on load and subsequent effects on revenue and power supply costs, as well as effects of 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 VOEF 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.

VOEF faces four major decisions over the 2028–2043 period covered by this Integrated Resource Plan (IRP). Options being evaluated include extending two PPA contracts, which are longer-term fixed-price contracts for bundled hydro energy including Vermont Tier I RECs; entering into a new contract; and developing a utility-scale storage project within its VOEF service territory.

The first two decisions will occur in 2027, when VOEF must decide how to replace the expiring Brookfield Hydro and Stetson Wind PPAs when they expire at the end of 2027. The most straightforward option during this timeframe is to extend the term of the Brookfield Hydro PPA. This extension would be made at prevailing market prices for both energy and RECs, and because it includes RECs it would help fulfill the RES requirements during that time period as well. An extension for the Stetson Wind PPA would also be made at market prices and would also help fulfill the RES requirements. The primary downside of this wind resource is its intermittency and price volatility. Both PPAs could be extended ten or twenty years.

The third decision to be made is whether to purchase a 2028-2032 market contract. This market contract would be system mix with no RECs attached, which would provide more price certainty, but it wouldn't help VOEF achieve RES obligations.

The main sources of uncertainty expected to impact these decisions are the price of natural gas; followed by the rate of load growth or decline; natural gas transportation via pipelines; peak coincidence factor; and the capacity market prices. Other important variables are the cost of regional transmission service and REC prices.

The fourth major resource decision is whether to collaborate with a storage developer to develop a site. An economic analysis including a variety of Energy Storage Solution Agreement (ESSA) options will be evaluated. Options include base payments with varying revenue share options.

VOEF's capacity supplies are forecast to be about 40% less than its current 2024 requirements. VOEF's capacity supply obligation (CSO) drops by about 1 MW from 2026 to 2027. This is because it is anticipated that the Reservoir Road Solar project will be installed by 2026. This project has the potential to reduce VOEF's coincident peak in the summer of 2026, which will reduce VOEF's CSO starting in June of 2027. It's assumed that with the increased penetration of solar that the effect of the Reservoir Road Solar project on the CSO will wane by year ten of the project, which explains the gradual increase in CSO between 2027 and 2036. As a result, a long-term capacity resource that is priced at or below today's market prices would be beneficial.

RENEWABLE ENERGY STANDARD

VOEF is subject to the Vermont Renewable Energy Standard (RES) that imposes an obligation for VOEF 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. VOEF' s obligations under Tier I can be satisfied by owning or purchasing RECs from qualifying regional resources. VOEF's obligation under Tier II must be satisfied by owning or purchasing RECs from renewable resources located within Vermont. VOEF's obligation under Tier III involves energy transformation or reduction of fossil fuel use within its territory. Valid Tier III programs can consist of thermal efficiency measures, electrification of the transportation sector, 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, VOEF receives credits toward its Tier III obligation. More detail regarding VOEF's plans to meet its Tier III obligation is available in Appendix A to this document. This IRP evaluates VOEF's plan to meet the current RES requirements (as can be seen in the Renewable Energy Standard ("RES 1.0") Requirements section) as well as the plan to meet the requirements of a potential "RES 3.0" (as can be seen in the Financial Analysis Chapter).

ELECTRICITY TRANSMISSION AND DISTRIBUTION

VOEF has consistently pursued upgrade initiatives each year to maintain a reliable and efficient system.

VOEF's distribution system presently serves approximately 1,800 customers in a 65 square mile service territory. The system is comprised of 103.746 miles of line at 12.47 kV and 3.53 miles of line at 2.4 kV for a total of 107.276 miles of distribution level line.

The system is a radial feed system. VOEF receives sub-transmission service from VEC. VOEF also taps the double-ended line between Highgate and Newport and a 46 kV line runs from the tap approximately 1 mile to the VOEF distribution substation.

In addition to upgrading and routinely maintaining the system to ensure efficiency and reliability, VOEF is examining the need to modernize to support beneficial electrification and additional distributed generation on the system and to provide more customer-oriented services, including load management programs that reduce costs for both VOEF and its customers. VOEF is currently engaged with VPPSA in a multi-phased process, designed to assess its readiness for Advanced Metering Infrastructure (AMI); guide it through an RFP process culminating in vendor and equipment selection; and ultimately resulting in implementation of an AMI system. The resulting cost estimates gained through the RFP process showed a positive NPV benefit with a positive cost-benefit ratio. VOEF also received state funding to help offset some of the project costs; therefore, VOEF is optimistic that it will begin implementation of a new AMI system in either late 2024 or early 2025, to be completed no later than the end of 2025.

VOEF sees potential value to customers from utilizing rate design and direct load management 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 VOEF's ability to deliver these benefits and capture economic development/retention opportunities where possible.

Although it has been some time since VOEF has conducted a full T&D system planning study, the interconnection study, recently performed for the planned Reservoir Road Solar project, highlighted areas that could benefit from improvements as well as some strong points within VOEF's distribution system. For example, the solar array will require reconductoring of Water Tower Road and the removal of a step-down from 7200 to 2400. Part of the project will also include bringing an estimated half mile of line roadside, which will improve resilience. With that said, VOEF anticipates that it will conduct a full T&D system study by the end of the IRP cycle. By then, VOEF will have more data on electrification load trends as well as more data available through its AMI and GIS systems. Therefore, it will have a more refined load forecast to use for the study. The fresher load forecast will be used to drive a more detailed system study and upgrade analysis.

TABLE OF CONTENTS

List of Tables

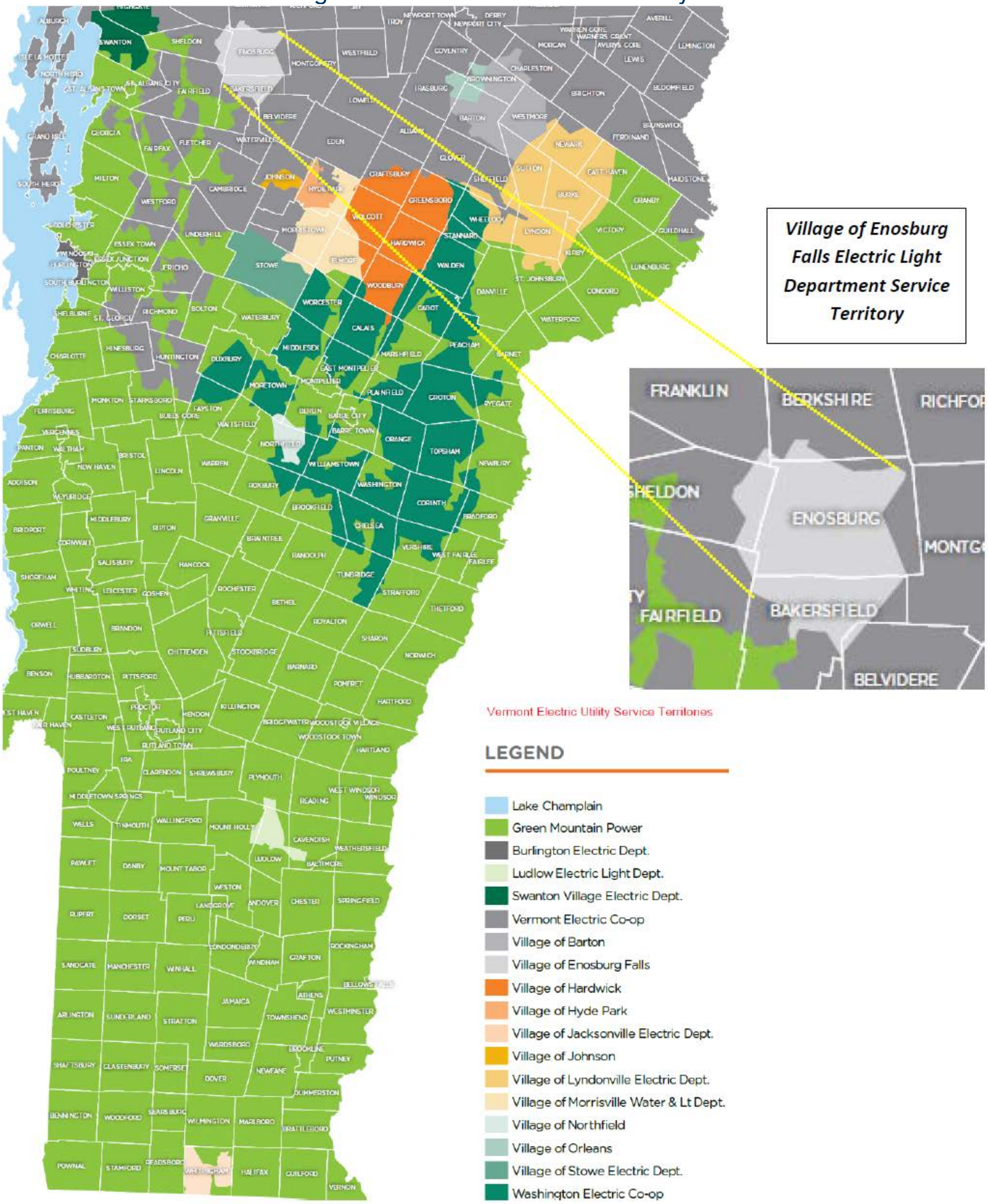
List of Figures

INTRODUCTION

The Village of Enosburg Falls Electric Light Department (VOEF) has operated an electric utility system since 1896. VOEF's service territory is located in the northwestern part of Vermont, in an area where weather events- especially in recent years- have been both challenging and at times highly localized. Its service territory can be seen on the Vermont Utility Service Territory map in Figure 11, below, and it encompasses the Village of Enosburg Falls as well as portions of six surrounding towns: Bakersfield, Berkshire, Enosburgh, Fairfield, Franklin, and Sheldon.

The Village sits on the Missisquoi River, is a part of the Missisquoi Valley Rail Trail, and is home to the cheese manufacturer, Franklin Foods. The service territory of VOEF is predominantly a dairy farming community, with 10 active farms. Much of the remaining commercial activity in Enosburg Falls supports dairy farming. VOEF's has added four to six new sugar maker customers in recent years. VOEF serves just over 1,800 retail customers.

Figure 1: VOEF'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.

VOEF 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:

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

VOEF and VPPSA are parties to a broad Master Supply Agreement (MSA). Under the MSA, VPPSA manages VOEF'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 VOEF's loads and power supply resources in the New England power markets.

SYSTEM OVERVIEW

In 2022 VOEF's peak demand in the winter months was 5,158 kW and 5,714 kW during the summer and shoulder months. Annual energy retail sales for 2022 were 26,811,756 kWh and the annual load factor for 2022 was 54%.

VOEF is connected to and receives sub-transmission service from the Vermont Electric Cooperative (VEC) system.

Table 1: VOEF's Retail Customer Counts

Data Element	2018	2019	2020	2021	2022
Residential (440)	576	578	581	581	580
Rural	952	966	978	989	1,001
Small C&I (442) 1000 kW or less	193	198	199	200	197
Large C&I (442) above 1,000 kW	21	20	21	20	21
Street Lighting (444)	0	0	0	0	0
Interdepartmental Sales (448)	0	0	0	0	0
Total	**1,742**	**1,762**	**1,779**	**1,790**	**1,800**

Table 2: VOEF's Retail Sales (KWh)

Data Element	2018	2019	2020	2021	2022
Residential (440)	3,939,122	3,608,747	3,787,555	3,779,846	3,885,350
Rural	10,557,933	10,045,527	10,518,166	10,585,812	10,862,498
Small C&I (442) 1000 kW or less	2,866,592	2,890,616	2,654,098	2,793,030	2,785,532
Large C&I (442) above 1,000 kW	9,331,848	9,590,321	9,349,145	9,379,180	9,214,112
Street Lighting (444)	152,603	126,686	83,813	64,259	64,264
Interdepartmental Sales (448)	0	0	0	0	0
Total	**26,848,098**	**26,261,897**	**26,392,777**	**26,602,128**	**26,811,756**
YOY	3%	-2%	0%	1%	1%

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

Data Element	2018	2019	2020	2021	2022
Peak Demand KW	4,889	4,723	4,858	4,918	5,714
Peak Demand Date	07/05/18	04/03/19	07/09/20	06/28/21	07/29/22
Peak Demand Hour	18	19	20	18	14

[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 VOEF's electricity requirements were determined and discusses sources of uncertainty in the load forecast.

ELECTRICITY SUPPLY

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

RESOURCE PLANS

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

ELECTRICITY TRANSMISSION AND DISTRIBUTION

This chapter describes VOEF'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 VOEF's power supply costs and cost of service.

ACTION PLAN

This chapter outlines specific actions the VOEF 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

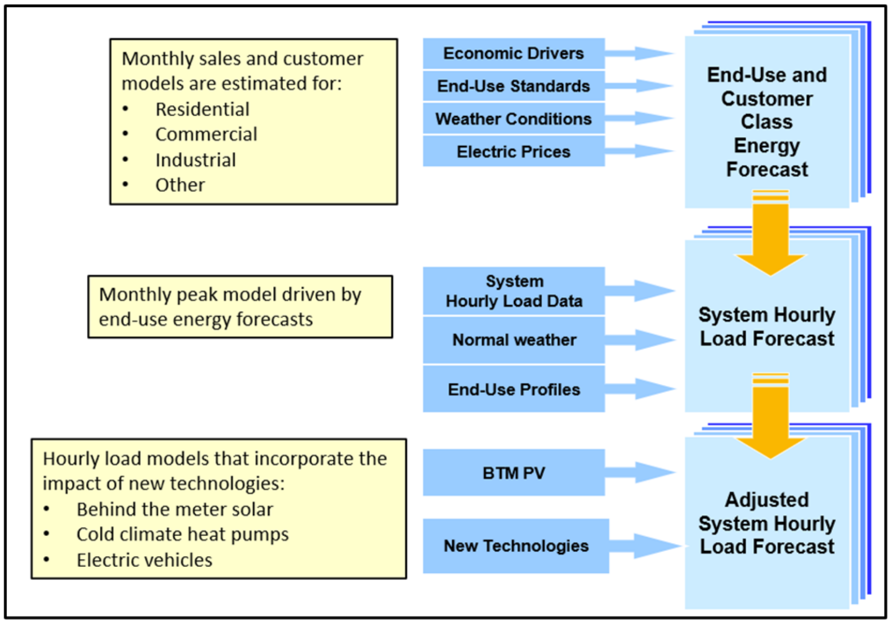
ENERGY FORECAST: STATISTICALLY ADJUSTED END USE METHODOLOGY

VPPSA retained Itron to forecast VOEF'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] Note that, the Itron forecast does not extend through the entirety of the IRP range. Therefore, the various values that comprise the Itron forecast were extrapolated to include 2043 for the purposes of this IRP.

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

Figure 2: Forecasting Process



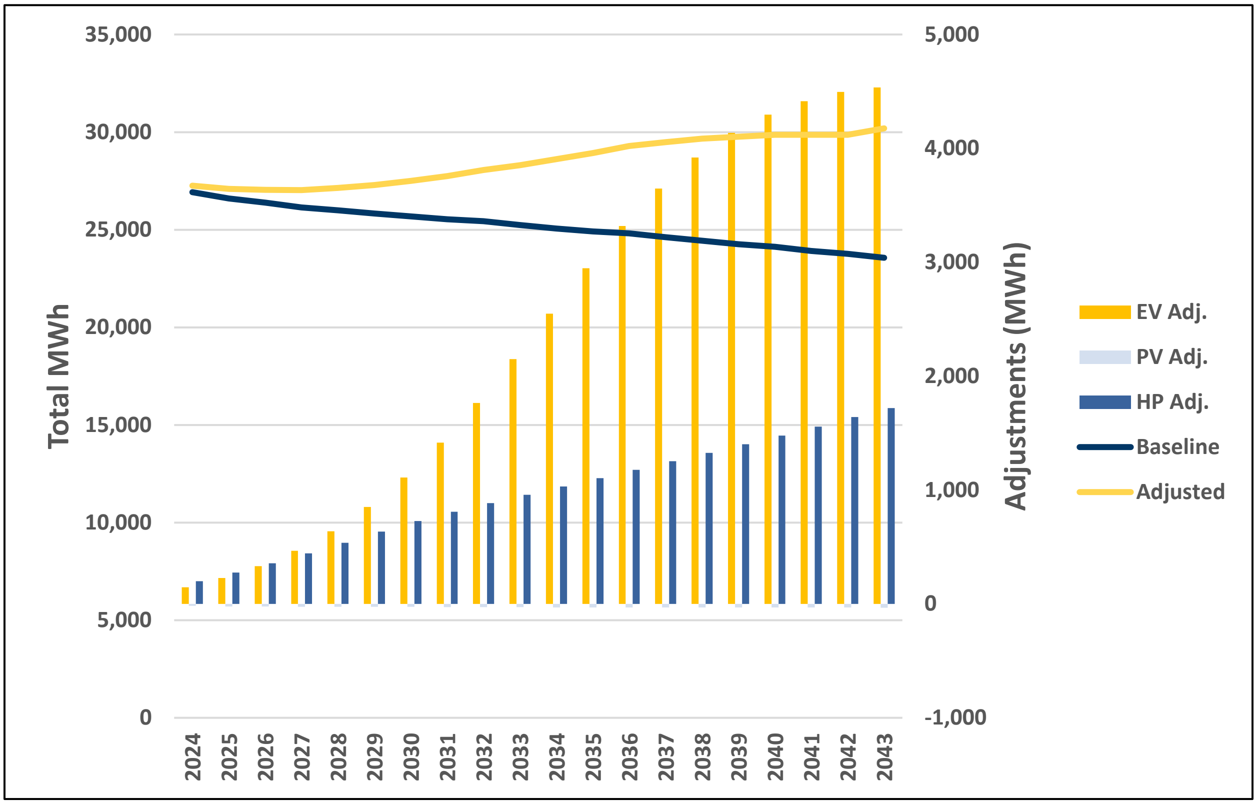
ENERGY FORECAST RESULTS

Table 4 shows the Baseline Forecast, as well as the adjustments that are made to arrive at the Adjusted Forecast. The effect of the electrification and net metering measures on the decreasing retail sales is an increasing adjusted forecast. The compound annual growth rate of the adjusted forecast is about 0.5%. This percentage is depicted in Figure 3.

Table 4: Adjusted Energy Forecast (MWh/Year)

Year	Yr #	Baseline Forecast	Cumulative EV Adj.	Cumulative NM PV Adj.	Cumulative HP Adj.	Adj. Forecast
2024	1	26,923	146	-17	198	27,249
2028	5	25,990	638	-25	536	27,139
2034	11	25,061	2,549	-30	1,031	28,612
2038	15	24,443	3,919	-31	1,327	29,658
2043	20	23,563	4,536	-32	1,721	30,193
CAGR		-0.7%				0.5%

Figure 3: Adjusted Energy Forecast (MWh/Year)



ENERGY FORECAST – HIGH & LOW CASES (IN PROGRESS)

To form a high case, we assumed that the increase in penetration per year for EVs and CCHPs doubles compared to the base case. We assume that net metering penetration continues as forecast in the base case. At these growth rates, the market penetration for EVs and CCHPs reaches approximately 140% and 80% each in 2043. This rough estimate assumes that most households will have one or more CCHP and more than one electric vehicle. This is a reasonable high case given the fact that most homes require more than one CCHP if the entire home is to be served by the CCHP and the average Vermont household currently has two vehicles. With these increases in electrification, the CAGR increases to 1.4%. This growth rate results in a 31% increase over 2024 electricity use.

Table 5: Energy Forecast – High Case (MWH)

Year	Yr #	Baseline Forecast	Cumulative EV Adj.	Cumulative NM PV Adj.	Cumulative HP Adj.	Adj. Forecast
2024	1	26,923	292	-17	396	27,593
2028	5	25,990	1,277	-25	1,072	28,313
2034	11	25,061	5,099	-30	2,062	32,193
2038	15	24,443	7,837	-31	2,654	34,904
2043	20	23,563	9,073	-32	3,442	36,045
CAGR		-0.7%				1.4%

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 decreases by 0.1% per year.

Table 6: Energy Forecast - Low Case (MWH

Year	Yr #	Baseline Forecast	Cumulative EV Adj.	Cumulative NM PV Adj.	Cumulative HP Adj.	Adj. Forecast
2024	1	26,923	73	-17	99	27,078
2028	5	25,990	319	-25	268	26,552
2034	11	25,061	1,275	-30	515	26,822
2038	15	24,443	1,959	-31	663	27,035
2043	20	23,563	2,268	-32	860	26,659
CAGR		-0.7%				-0.1%

PEAK FORECAST RESULTS

Table 7 and Table 8 show the results of the Baseline Forecast of peak loads for Summer and Winter periods, as well as the adjustments that are made to arrive at the Adjusted Forecast. The baseline forecast is decreasing by 0.3% per year for the Summer period. After adjustments for CCHPs, EVs, and net metering, the Adjusted Forecast increases by 0.9% per year. The Winter peak decreases by 0.4% per year. After making the same adjustments, the forecast increases by 1.6% per year. Note that these values do not include the proposed Reservoir Road solar project.

Table 7: Summer Peak Forecast (MW)

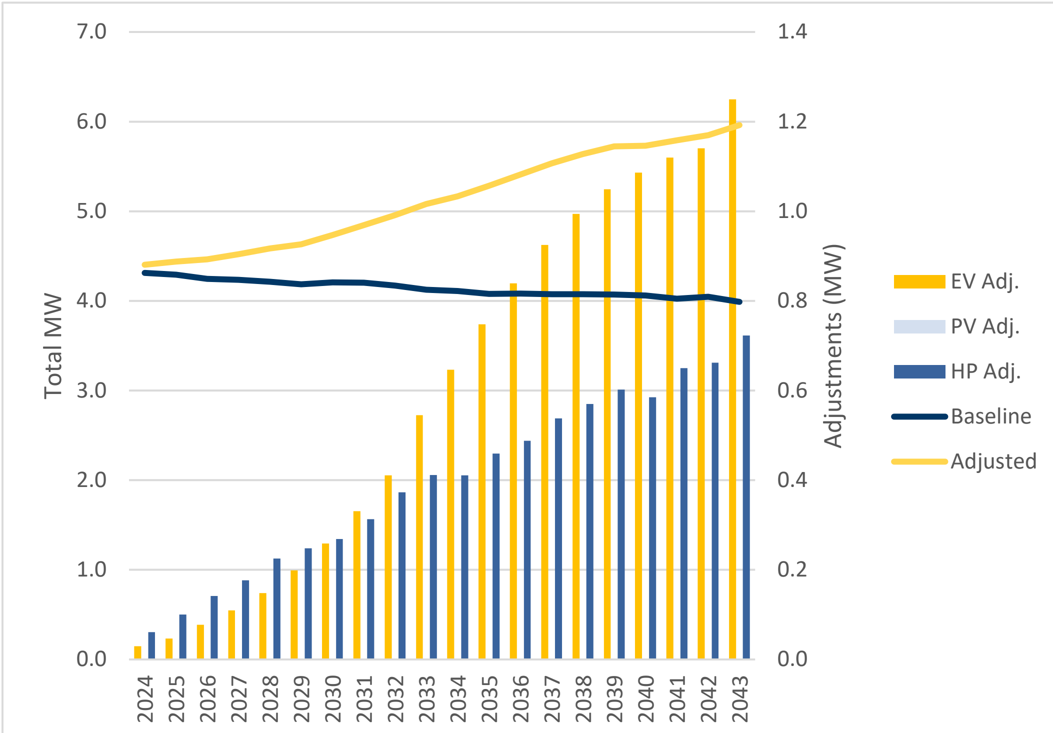
Year	Yr #	Baseline Forecast	Cumulative EV Adj.	Cumulative NM PV Adj.	Cumulative HP Adj.	Adj. Forecast
2024	1	4.5	0.0	0.0	0.0	4.6
2028	5	4.4	0.1	0.0	0.1	4.6
2034	11	4.4	0.5	0.0	0.1	5.0
2038	15	4.4	0.7	0.0	0.1	5.2
2043	20	4.3	0.9	0.0	0.1	5.4
CAGR		-0.3%				0.9%

Table 8: Winter Peak Forecast (MW)

Year	Yr #	Baseline Forecast	Cumulative EV Adj.	Cumulative NM PV Adj.	Cumulative HP Adj.	Adj. Forecast
2024	1	4.3	0.0	0.0	0.1	4.4
2028	5	4.2	0.1	0.0	0.2	4.6
2034	11	4.1	0.6	0.0	0.4	5.2
2038	15	4.1	1.0	0.0	0.6	5.6
2043	20	4.0	1.2	0.0	0.7	6.0
CAGR		-0.4%				1.6%

The size of the adjustments can be seen in Figure 4, which shows the winter peak forecast net of adjustments. The transformer at the substation is rated up to 9.4 MVA, which is more than large enough to accommodate this peak load forecast.

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 the peak reaches 7.9 MW by 2043.

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

Year	Yr #	Baseline Forecast	Cumulative EV Adj.	Cumulative NM PV Adj.	Cumulative HP Adj.	Adj. Forecast
2024	1	4.3	0.1	0.0	0.1	4.5
2028	5	4.2	0.3	0.0	0.5	5.0
2034	11	4.1	1.3	0.0	0.8	6.2
2038	15	4.1	2.0	0.0	1.1	7.2
2043	20	4.0	2.5	0.0	1.4	7.9
CAGR		-0.4%				3.0%

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 both heat pumps and electric vehicles are greater than the electrification that is budgeted through Tier III programs, which include numerous measures. 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. (Although this IRP covers years 2024 through 2043, the Tier III 2024 breakdown of measures has not been created at the time of writing. Therefore, this IRP will be reviewing 2023 data.) These loads are based on averages as published in the Tier III Planning Tool. Ninety-three percent (93%) of the new electric loads are expected to come from only two technologies: heat pumps and electric vehicles. Table 10 shows VOEF's share of VPPSA's Tier III budget, and it indicates 85.2 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 114 MWH increase in electric loads for 2023 because of these technologies. The forecasted increased load is about 0.4% 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	# of Measures	Added MWh/Unit/Yr	Total New MWh/Yr
Heat Pump	26	2.5	64.7
Electric Vehicle	7	2.1	14.9
Heat Pump Water Heater	3	0.8	2.4
Lawnmower/Yard Care	4	0.3	1.4
Various	2	1.0	1.9
TOTAL	42		85.2

TIER III LOAD MANAGEMENT

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 management control. From a technical perspective, there are many credible options for managing 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. However, large devices can become cost-effective as shown in the green shaded areas. Additionally, VOEF does not believe that the intensity of electrification is currently, or in the near future, at a point where active load management is reasonably necessary nor are there systems currently in place at this time to be able to perform active load management. VOEF also does not believe that active load management, which removes autonomy from the customer, is a principled method of load control.

Innovative rates are a potentially cost-effective way to manage load. In addition to helping with peak demand, this option allows customers to maintain their autonomy as opposed to imposing restrictions with active load management. As a result, VPPSA is exploring innovative software platforms to be used for implementing innovative rates that may include market based, Time-of-Use (TOU) 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.

VOEF is also exploring a 4MW battery storage option that will help reduce peak loads. Behind-the-meter generation of hydro and solar will also help offset increased load from electrification. This highlights the importance of allowing VOEF's hydro to operate as effectively as possible. VPPSA sends out capacity and transmission peak notifications to all members. With these notifications VOEF is able to increase hydro generation during the anticipated peak hours and post peak information on the VOEF Facebook page, which suggests customers reduce usage during the anticipated peak time. VPPSA also attends the Delta Climb program on behalf of its members. In more recent years, this program has focused heavily on load management, specifically in rural settings, such as those of the VPPSA member service territories. Lastly, AMI, once implemented, can be used to help identify when charging and discharging a battery will be most useful and it will help inform and implement Time-Of-Use rates. In short, the overarching approach to load management for VOEF involves dynamic rates with supplementation from battery storage, behind-the-meter generation, searching for and partnering with innovative technology and AMI.

FORECAST UNCERTAINTIES & CONSIDERATIONS

VOEF presently has fifty-five net metered projects with a total installed capacity of about 1,143 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. For example, a 125-kW net metered solar project built in 2023 would add 10% 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.

Electrification, particularly in the form of electric vehicles and cold climate heat pumps, has been accounted for in the load forecast. However, actual adoption of these measures will likely vary. While there is the potential for adoption rates to vary substantially from the current forecast, particularly given the statewide push toward electrification, this variation will likely be at a rate that would allow VOEF to adjust power supply resources so that the utility is not too short or too long on energy compared to load. Once AMI has been implemented, VOEF will have the ability to obtain much more granular, time-varying load and behind-the-meter generation data, which will then inform more granular load forecasting in the future.

ELECTRICITY SUPPLY

II. ELECTRICITY SUPPLY

VOEF'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 VOEF 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 VOEF's portfolio.

EXISTING POWER SUPPLY RESOURCES

1. **Brookfield 2023-2027**

- Size: 8-10 MW On-Peak, 7-8.5 MW Off-Peak
- Fuel: Hydro
- Location: MA HUB
- Entitlement: 8-10% On Peak, 7.06-8.57% Off Peak
- Products: Energy, Tier I RECs
- Term: 1/1/2023 – 12/31/2027

2. **Chester Solar**

- Size: 4.8 MW
- Fuel: Solar
- Location: Chester, MA
- Entitlement: 11.5% (0.552 MW), PPA
- Products: Energy, capacity
- End Date: 6/30/39

3. **Enosburg Falls Hydro**

- Size: 0.975 MW
- Fuel: Hydro
- Location: Enosburg, VT
- Entitlement: 100%, Owned
- Products: Energy, capacity, renewable energy credits (VT Tier I)
- End Date: Life of unit

4. **Fitchburg Landfill**

- Size: 4.5 MW
- Fuel: Landfill Gas
- Location: Westminster, MA
- Entitlement: 8.5% (0.383 MW), PPA
- Products: Energy, capacity, renewable energy credits (MA I)
- End Date: 12/31/31

5. Hydro Quebec US (HQUS)

- Size: 212 MW
- Fuel: Hydro
- Location: Quebec
- Entitlement: 0.1% (0.215) MW, PPA
- Products: Energy, renewable energy credits (Quebec system mix)
- End Date: 10/31/38

6. Kruger Hydro

- Size: 6.7 MW
- Fuel: Hydro
- Location: Maine and Rhode Island
- Entitlement: 11.2% (0.750) MW, PPA
- Products: Energy, capacity
- End Date: 12/31/37

7. 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.

8. McNeil

- Size: 54 MW
- Fuel: Wood
- Location: Burlington, Vermont
- Entitlement: 1.1% (0.6 MW), joint-owned through VPPSA
- Products: Energy, capacity, renewable energy credits (CT Class I)
- End Date: Life of Unit

9. New York Power Authority (NYPA)

- Size: 2,675 MW (Niagara), 1,957 MW (St. Lawrence)
- Fuel: Hydro
- Location: New York State
- Entitlement: 0.182 MW (Niagara PPA), 0.01 MW (St. Lawrence PPA)
- Products: Energy, capacity, renewable energy credits (NY System Mix)
- End Date: 4/30/32

10. Project 10

- Size: 40 MW
- Fuel: Oil
- Location: Swanton, VT
- Entitlement: 4.7% (1.9 MW) MW, joint-owned through VPPSA
- Products: Energy, capacity, reserves
- End Date: Life of unit

11. PUC Rule 4.300 (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: 0.54% (Statutory)
- Products: Energy, capacity, renewable energy credits
- End Date: Varies

12. Ryegate

- Size: 20.5 MW
- Fuel: Wood
- Location: East Ryegate, VT
- Entitlement: 0.5% (PPA)
- Products: Energy, capacity, renewable energy credits (CT Class I)
- End Date: 10/31/2032

13. Stetson Wind 2023-2027

- Size: 57 MW
- Fuel: Wind
- Location: UN.Stetson
- Entitlement: 3.5%-3.64%
- Products: Energy, Tier I RECs
- Term: 1/1/2023 – 12/31/2027

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 have a 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/or whether we assumed that it would be renewed until 2043.

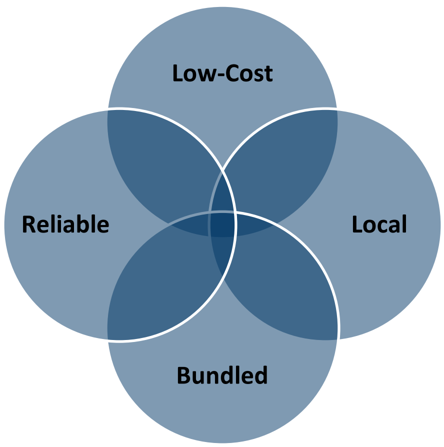
Table 12: Existing Power Supply Resources

Resource	2024 MWh	% of MWh	2024 MW	Delivery Pattern	Price Pattern	Rec	Expiration Date
Brookfield 2023-2027	6,090	21.4%	1.39	Firm	Fixed	Yes	12/31/2027
Chester Solar	780	2.7%	0.55	Intermittent	Fixed	No	6/30/2039
Enosburg Falls Hydro	3,654	12.8%	0.98	Run of River	O&M Only	Yes	Life of Unit
Fitchburg Landfill	3,026	10.6%	0.41	Intermittent	Fixed	Yes	12/31/2031
HQUS Contract	1,259	4.4%	0.22	Firm	Fixed	Yes	10/31/2038
Kruger Hydro	2,791	9.8%	0.76	Intermittent	Fixed	No	12/31/2037
Market Contracts	124	0.4%	0.11	Firm	Fixed	No	Varies
McNeil Facility	3,085	10.8%	0.58	Baseload	Fuel Cost	Yes	Life of Unit
NYPA	1,639	5.8%	0.22	Baseload	Fixed	Yes	Life of Unit
Project #10	28	0.1%	1.88	Peaking	Fuel Cost	No	Life of Unit
Ryegate Facility	813	2.9%	0.11	Baseload	Fixed	Yes	10/31/2032
Standard Offer Program	719	2.5%	0.00	Intermittent	Fixed	Yes	Varies
Stetson Wind 2023-2027	4,442	15.6%	2.03	Intermittent	Fixed	Yes	12/31/2027
Total	28,450	100.0%	9.22				

FUTURE RESOURCES

VOEF 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 ISO NE region.
- ✓ **Bundled** resources meet or exceed RES requirements with bundled energy and RECs.
- ✓ **Reliable** resources not only provide operational reliability, but are also owned and operated by financially strong and experienced companies.

Resources that VOEF 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 whenever possible.

CATEGORY 1: EXTENSIONS OF EXISTING RESOURCES

This plan assumes that two existing resources are extended past their current expiration date. These include Fitchburg 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, VOEF will not only have access to competitive prices (low-cost) but can structure the contracts to reduce volatility (stable rates and volumes) and potentially include contracts for RECs for RES compliance. Market contracts are also scalable and can be sized to match VOEF's incremental electric demands by on/off peak, month, season, and year. 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 and environmental impact source of energy is energy that is conserved or never consumed. VOEF participates in VPPSA's 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. VOEF uses these notifications to increase generation at the hydro plant when water levels permit and include a peak notification on the Village Facebook page to ask customers to reduce usage.

VPPSA is also collaborating with Efficiency Vermont to install up to 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 and maintains communications with developers throughout New England. Through VPPSA staff, VOEF 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.

VOEF is currently working with a storage developer on a potential storage project in their territory. The location of the project is currently being determined. An economic analysis including a variety of Energy Storage Solution Agreement (ESSA) options will be evaluated. Options include base payments with varying revenue share options. A commercial operation date is not yet known.

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 at least be at market value or lower and renewable.

3.3 SOLAR GENERATION

Solar is the primary technology that can meet VOEF's Distributed Renewable Energy (TIER II) requirements under RES, and VOEF is working with a developer to install a utility-scale solar project in its service territory. This project will provide energy for 25 years at a stable rate and will provide VT Tier II RECs, as well as capacity and transmission benefits.

As RES Tier II requirements increase, solar is likely to be a leading resource option. As a result, VOEF will continue to investigate solar developments both within and outside its service territory.

3.3.1 NET METERING

VOEF has 55 net-metered customers and an installed base of solar capacity of 1,143 kW. VOEF 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, utility scale solar projects.

3.4 WIND GENERATION (ON AND OFF-SHORE)

On-shore wind projects continue to be developed in New England. RECs are often bundled into the PPA, making this resource a potential fit for the low-cost and renewable criteria. VOEF already has Stetson Wind in its portfolio. This is a unit contingent resource that includes Tier I RECs. A downside to wind resources is the high level of intermittency that makes reliable energy prices more difficult to achieve. VOEF will review wind resources for future power contracts and will explore ways in which to make the power more reliable.

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

VOEF's contract for nuclear energy expired in 2022, and is being replaced by renewables (hydro, solar and wind) to comply with the RES. However, VOEF 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 Northwest Regional Planning Commissions (NRPC), VOEF is part of a Regional Energy Plan[6] that was created in 2017. The intent of the plan is "to complete in-depth energy planning at the regional level while achieving state and regional energy goals—most notably, the goal to have renewable energy sources meet 90% of the state's total energy needs by 2050 (90 x 50 goal)."[7]

The plan gives municipalities "substantial deference" before PUC for applications that seek a Certificate of Public Good (CPG)." The full plan is included in the appendix, and all future resource decisions will be made with this plan in mind.

---

[6] The full plan can be found at https://www.nrpcvt.com/energy-planning.

[7] Northwest Regional Energy Plan 2017, Page 5

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 either 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, such as unit availability and adjustments to load.
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**: If internal transactions cannot bring VOEF 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 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

VPPSA has already discussed with the resource owner the possibility of extending the Stetson Wind contract. An extension for Stetson Wind would also be made at market prices and would help fulfill the RES requirements. The primary downside of this resource is its intermittency. While renewability is something that VOEF is seeking in its resources and VPPSA purposefully sought out a wind resource to diversify a hydro-heavy portfolio and hedge against high winter prices, the highly variable nature of wind can cause some drastic variances from budget. VOEF values price certainty and variances in resource generation can cause large swings in energy charges and credits and leave the utility open to volatility in the Day-Ahead and seasonal pricing. Due to this concern, during conversations with the resource owner, VPPSA has discussed the desire to have a firm resource. One option discussed would be to firm up the wind resource with hydro generation, which would retain the renewability of the contract. The terms of this contract could also be extended ten or twenty years.

Figure 6 compares VOEF's energy supply resources to its adjusted load. The supply resources closely match demand through 2025. It is predicted that resources will exceed demand in 2026 and 2027 until the Stetson Wind and Brookfield contracts expire. This excess is caused by the Reservoir Road Solar project that is anticipated to be commissioned by 2026. After 2027 new resources will likely be necessary.

DECISION 1: EXTEND EXISTING BROOKFIELD HYDRO PPA THROUGH 2032

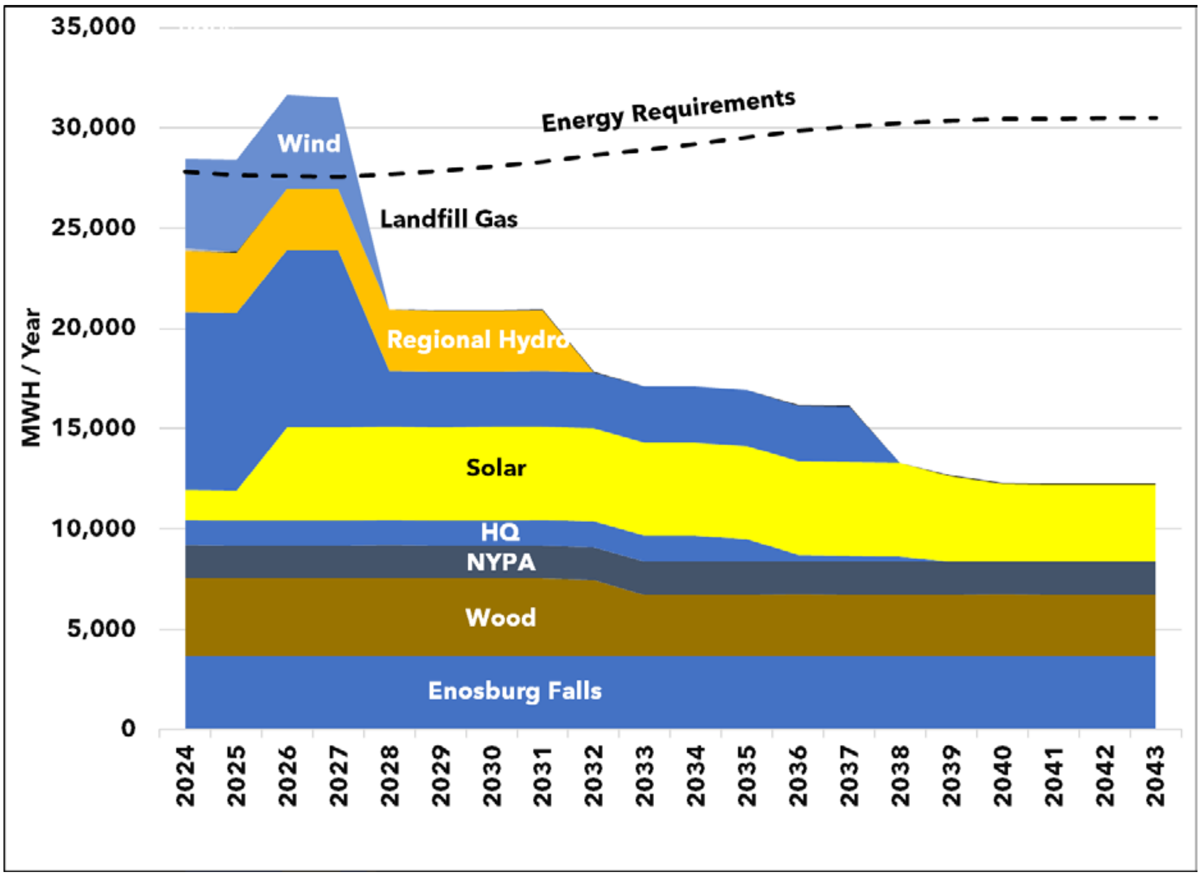
The most straightforward option during this timeframe is to extend the term of the Brookfield Hydro contract. This extension would be made at prevailing market prices for both energy and RECs, and because it includes RECs, it would help fulfill the RES requirements during that time period as well. This contract could also be extended ten or twenty years.

DECISION 2: EXTEND EXISTING STETSON WIND PPA THROUGH 2032

VPPSA has already discussed with the resource owner the possibility of extending the Stetson Wind contract. An extension for Stetson Wind would also be made at market prices and would help fulfill the RES requirements. The primary downside of this resource is its intermittency. While renewability is something that VOEF is seeking in its resources and VPPSA purposefully

sought out a wind resource to diversify a hydro-heavy portfolio and hedge against high winter prices, the highly variable nature of wind can cause some drastic variances from budget. VOEF values price certainty, and variances in resource generation can cause large swings in energy charges and credits leaving the utility open to volatility in the Day-Ahead and seasonal pricing. Due to this concern, VPPSA has discussed with the resource owner the desire to have a firm resource. One option discussed would be to firm up the wind resource with hydro generation, which would retain the renewability of the contract. The terms of this contract could also be extended ten or twenty years.

Figure 6: Energy Supply & Demand by Fuel Type



DECISION 3: MARKET ENERGY CONTRACT

VOEF could enter into a monthly shaped market contract. This would be system mix with no RECs attached. This would provide more price certainty as a result of few to no budget variances. However, this wouldn't help VOEF achieve RES obligations. While VPPSA members are moving away from this approach due to existing RES obligations as well as likely increases in RES obligations, it is still important to evaluate the overall effects on rates as a primary goal for VPPSA members is to provide the lowest rates possible for their customers.

DECISION 4: BATTERY STORAGE CONTRACT (ESSA)

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

Table 13: Energy Resource Decision Summary

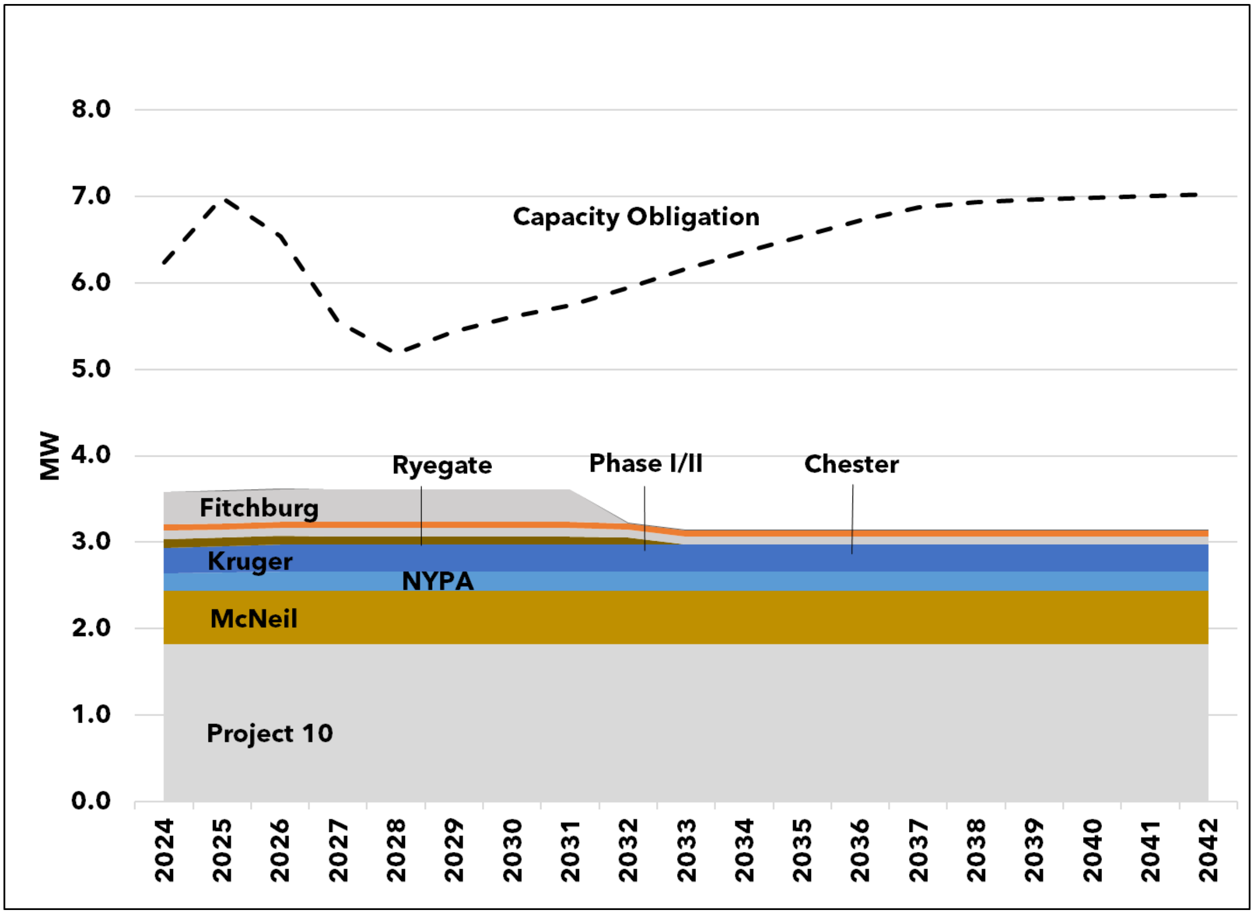
Resource	Years Impacted	% of MWH	Rate Impact	RES Impact
Extend Hydro PPA	2028 – 2032	23.2%	Neutral	Tier I
Extend Wind PPA	2028 – 2032	18.5%	Neutral	Tier I
Market Contract	2028 – 2032	25.4%	Neutral	None
Storage ESSA	2028 – 2048	70% of peak	Decrease	None

CAPACITY RESOURCE PLAN

Figure 7 compares VOEF's capacity supply to its capacity supply obligation (CSO). The CSO is equal to VOEF'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. VOEF's CSO drops by about 1 MW from 2026 to 2027. This is because it is anticipated that the Reservoir Road Solar project will be installed by 2026, which means it has the potential to reduce VOEF's coincident peak in the summer of 2026, which will reduce VOEF's CSO starting in June of 2027. It's assumed that with the increased penetration of solar, that the effect of the Reservoir Road Solar project on the CSO will wane by year ten of the project, which explains the gradual increase in CSO between 2027 and 2036. VOEF has about 60% of its capacity obligation covered with existing resources in 2024.

VPPSA is monitoring the current capacity prompt market discussions at ISO NE and will adjust the strategy as more becomes certain regarding the market.

Figure 7: Capacity Supply & Demand (Summer MW)



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

ISO NEW ENGLAND'S PAY FOR PERFORMANCE PROGRAM

Because VOEF 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, VOEF will be provided with 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 VOEF's share of Project 10 creates in ISO New England's PFP Program. Depending on ISO-New England's load at the time of the scarcity event and Project 10's performance level, VOEF could receive up to a $6,709 payment or pay up to a $7,565 penalty during a one-hour scarcity event. This represents a range of plus or minus 42% of VOEF's 2022 monthly capacity budget. However, such events occur infrequently and are short lived when they do occur.

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

ISO Load	Performance Payment Rate	0% Performance	50% Performance	100% Performance
10,000	$5,500/MWh	-$3,283	$1,713	$6,709
15,000	$5,500/MWh	-$4,710	$285	$5,281
20,000	$5,500/MWh	-$6,138	-$1,142	$3,854
25,000	$5,500/MWh	-$7,565	-$2,569	$2,427

[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

VOEF's obligations under the Vermont Renewable Energy Standard (RES) are shown in Table 15. Under RES, VOEF's Total Renewable Energy (Tier I) requirements rise from 63% in 2024 to 75% in 2032, and the Distributed Renewable Energy (Tier II) requirement rises from 5.2% in 2024 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
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%
2033-43	75%	10.00%	65.00%	10.67%

The final column shows the Energy Transformation (Tier III) requirement. Note that this plan assumes that Tier III requirements are maintained at their 2032 levels throughout the rest of the study period.

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 2024, 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 2024 Tier III requirement.

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).

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

Year	TIER I	TIER II & III
2024	$12.28	$73.70
2025	$12.53	$75.17
2026	$12.78	$76.68
2027	$13.03	$78.21
2028	$13.29	$79.78
2029	$13.56	$81.37
2030	$13.83	$83.00
2031	$14.11	$84.66
2032	$14.39	$86.35

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.

TIER I – TOTAL RENEWABLE ENERGY PLAN

Between 2024 and 2027, VOEF's Net Tier I requirement is between 15,600 and 16,300 MWH per year. The primary energy resource contributors to Tier I are the Brookfield and Stetson contracts as well as the owned Enosburg Hydro resource. Combined they add up to over 80% of the total RECs received annually and about 90% of the annual Tier I obligation within that timeframe. In addition to these bundled Tier I resources, VOEF is also part of larger, REC-only purchases, which occur in most years. VPPSA recently purchased a large volume of 2023

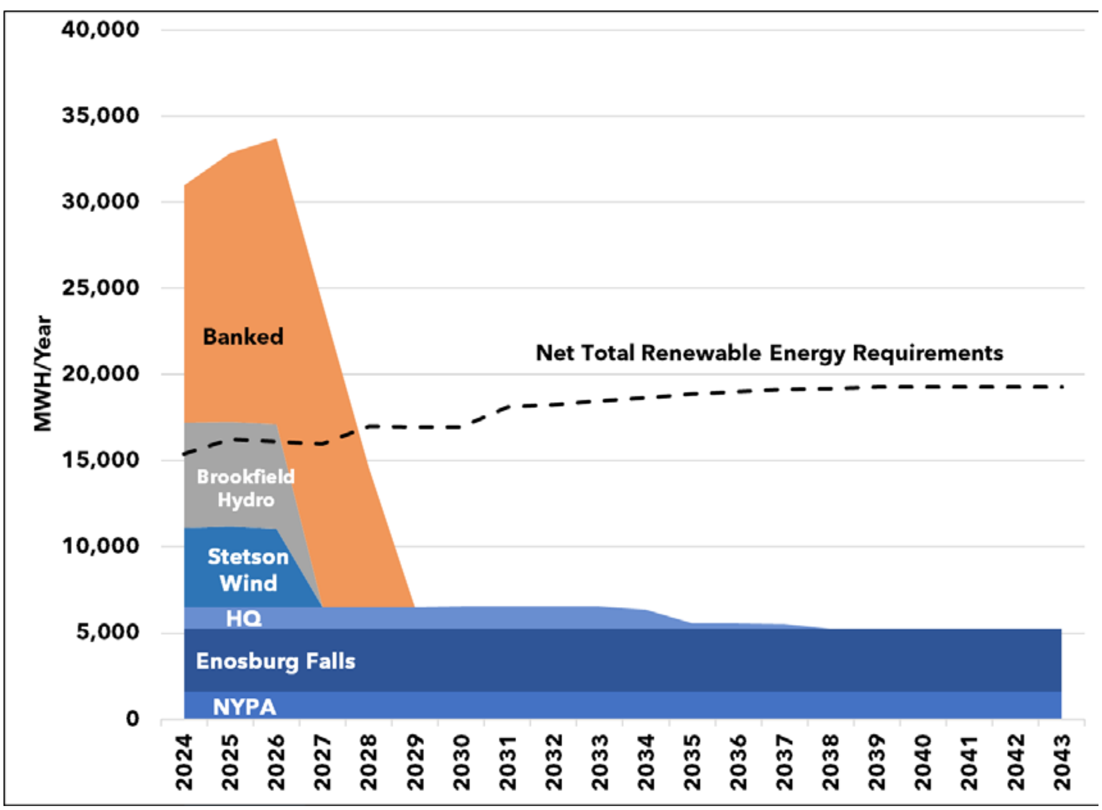
[10] For simplicity, we assume that no banking occurs in this example. In practice, banking excess TIER I and TIER II credits for use in future years is permitted under RES.

[11] Please note that 2024 is known but following years are estimates and grow at inflation.

vintage Tier I RECs for members due to low prices. While those RECs won't all be required for 2023 compliance, they will be banked for use in future years in anticipation of a RES obligation that won't be fully covered by bundled and owned resources.

VOEF will have an excess of Tier I RECs through 2028 due to the Brookfield and Stetson contracts as well as REC-only purchases. After that period, VOEF will have a deficit and will need to either purchase unbundled RECs, extend one or both of the Tier I bundled contracts, enter into a new bundled energy and Tier I REC contracts or some combination of multiple options. Regardless of how the utility obtains the RECs, the price of Tier I RECs has varied substantially from $0.25 to over $11 per REC in recent years. Current prices for 2024 vintage are between $2 and $3. At those prices, assuming gradual increases year on year, complying with net Tier I between 2028 and 2032 could be as much as $40,000 annually. If the cost increased again to the $11 range, the cost could be as high as $140,000 annually.

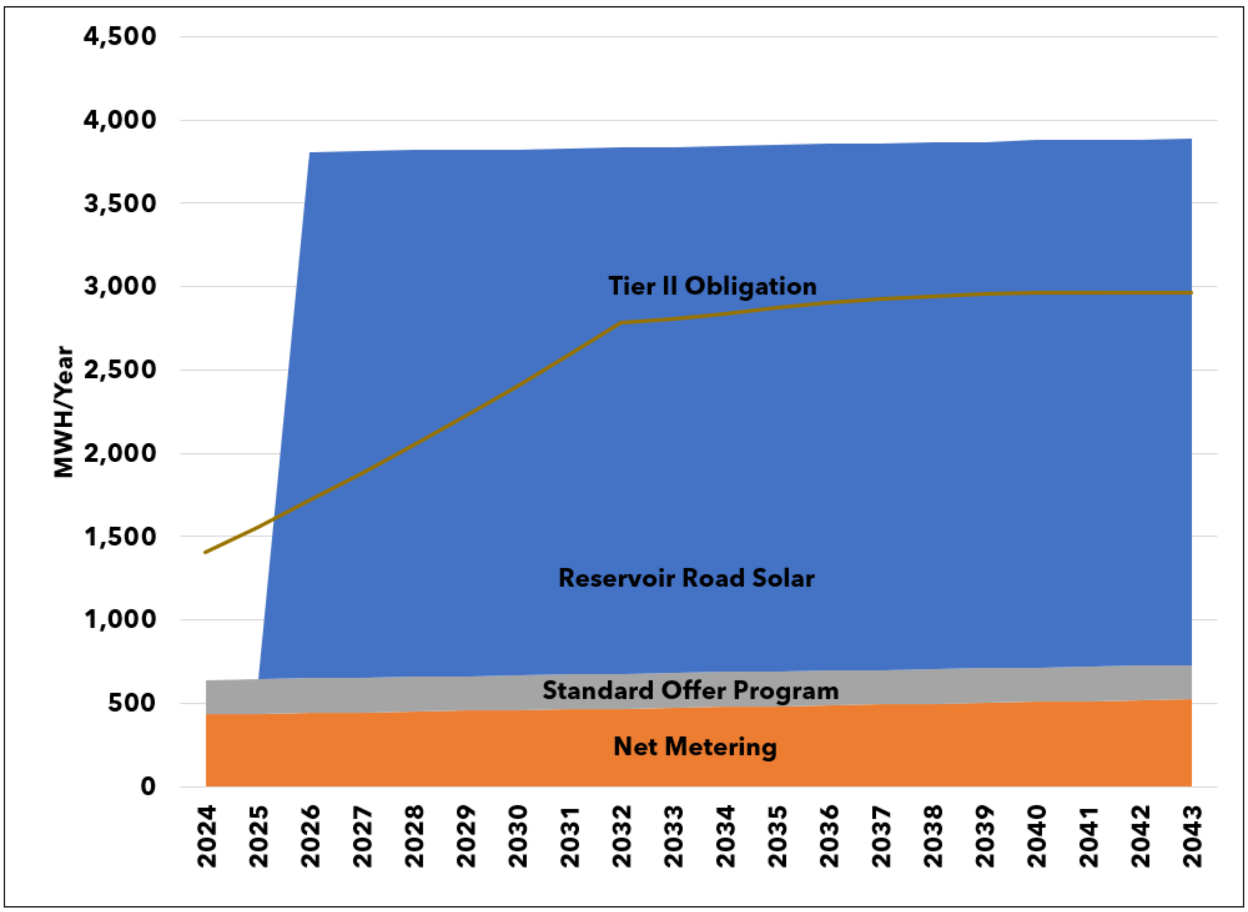
Figure 8: Tier I – Total Renewable Energy Supplies



TIER II – DISTRIBUTED RENEWABLE ENERGY PLAN

The line in Figure 9 shows VOEF's Distributed Renewable Energy (Tier II) requirement, which increases from 1,400 MWH in 2024 to almost 2,800 MWH in 2032. VOEF is presently developing a 2.13 MW AC (3,500 MWH/Yr) solar facility, which will exceed the current Tier II obligations. Excess RECs will either be banked, sold to other VPPSA members, or utilized to fulfill the Tier III obligation. It is unlikely that many excess Tier II RECs in the short term will be banked. It's more likely that they will be sold to other VPPSA members in need of Tier II RECs. Therefore, Figure 9 does not show any banking.

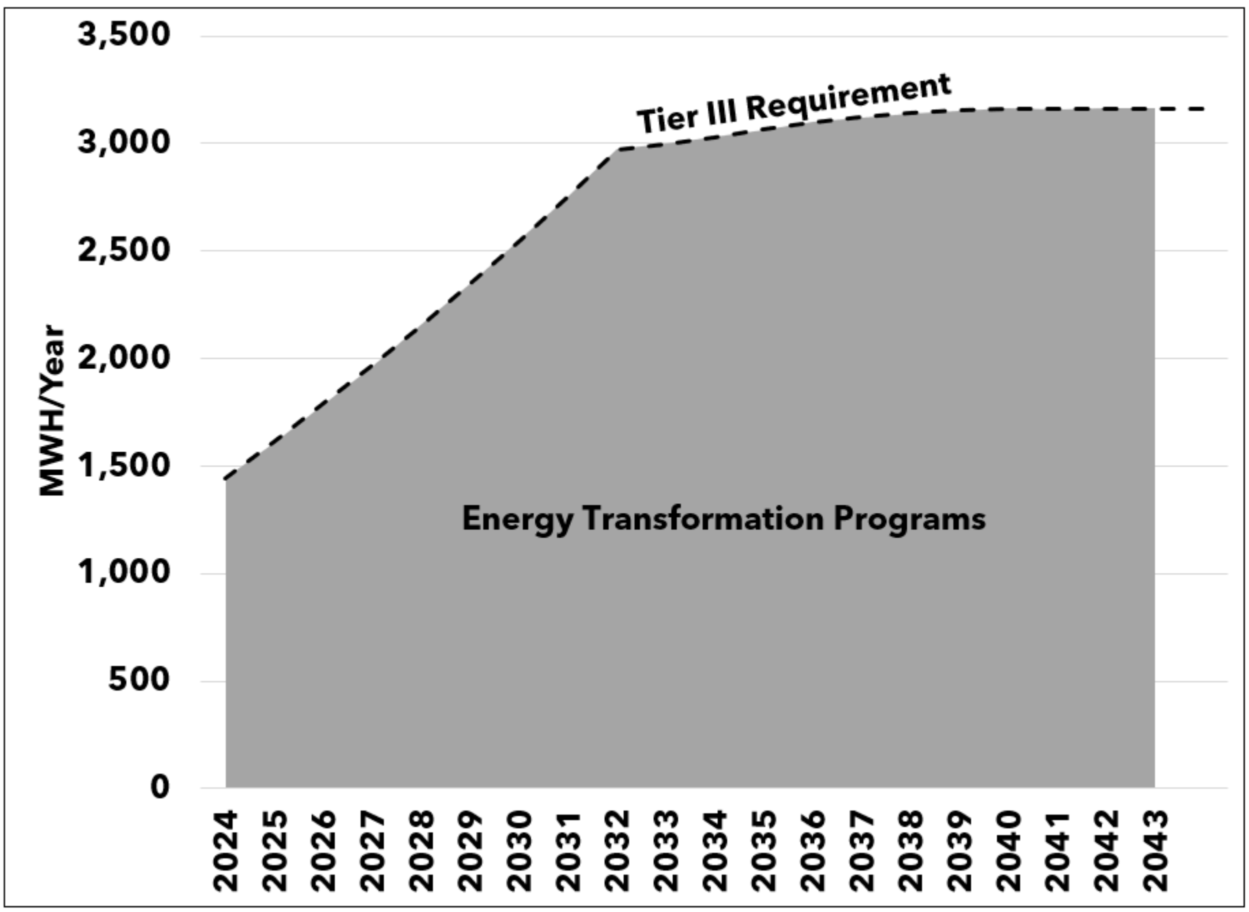
Figure 9: Tier II – Distributed Renewable Energy Supplies



TIER III – ENERGY TRANSFORMATION PLAN

The dashed line in Figure 10 shows VOEF's Energy Transformation (Tier III) requirements, which rise from about 1,500 MWH in 2024 to 3,000 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. The VPPSA 2024 Tier III Annual Plan was not completed at the time of filing this IRP. Note that VPPSA is monitoring the Clean Heat Standard proceeding, which could have an effect on VPPSA's Tier III approach moving forward.

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. VOEF will follow a three-part strategy to fulfill its Tier III requirements:

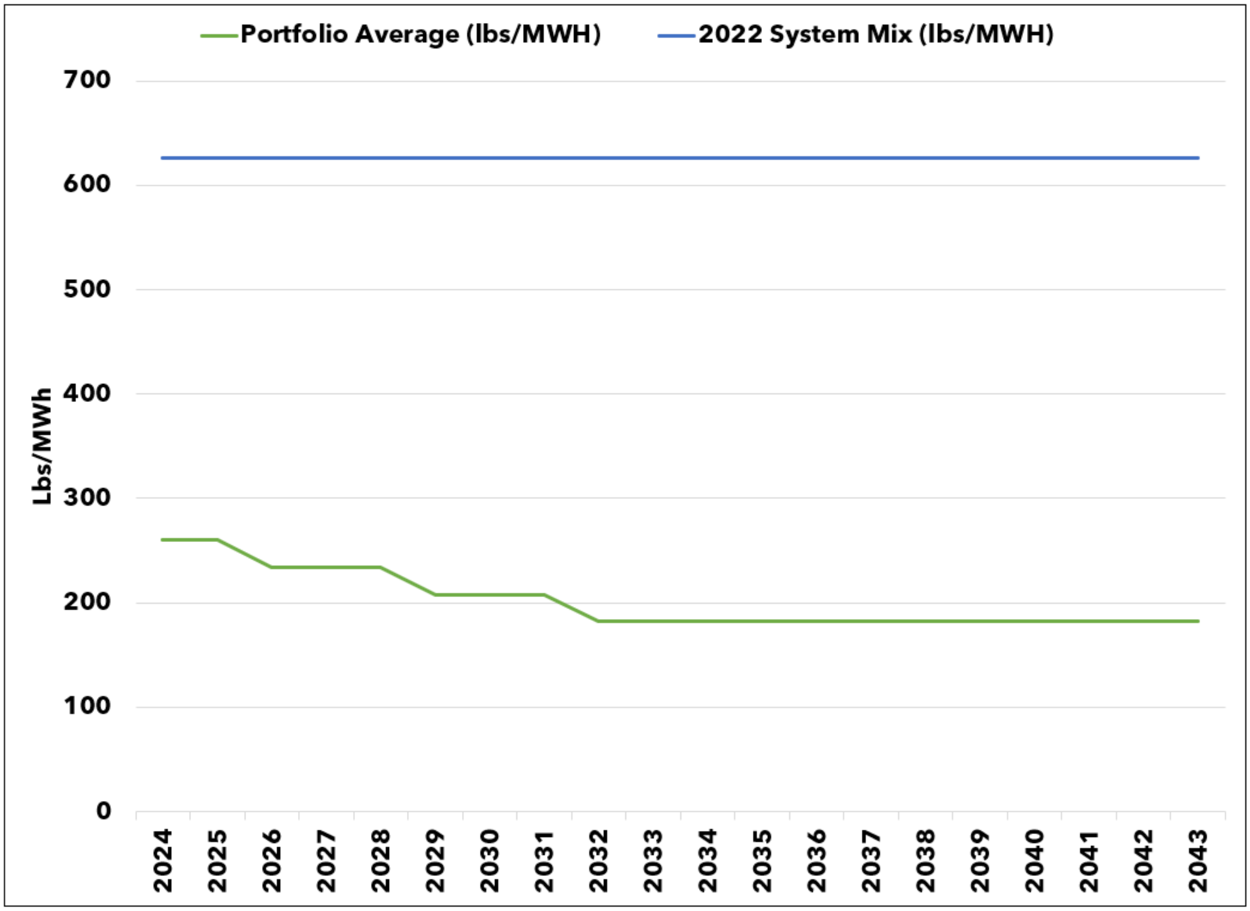
1. Identify and deliver *prescriptive* Energy Transformation ("Base Program") programs, and/or
2. Identify and deliver *custom* Energy Transformation ("Custom Program") programs, and/or
3. Manage Tier II credits to maximize value across both Tier II and Tier III requirements.

CARBON EMISSIONS AND COSTS

Figure 11 shows an estimate of VOEF's carbon emissions rate compared to the 2022 system average emissions rate from New England and imported resources.[12] The emissions rate in 2024 is about 260 lbs/MWH.

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

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

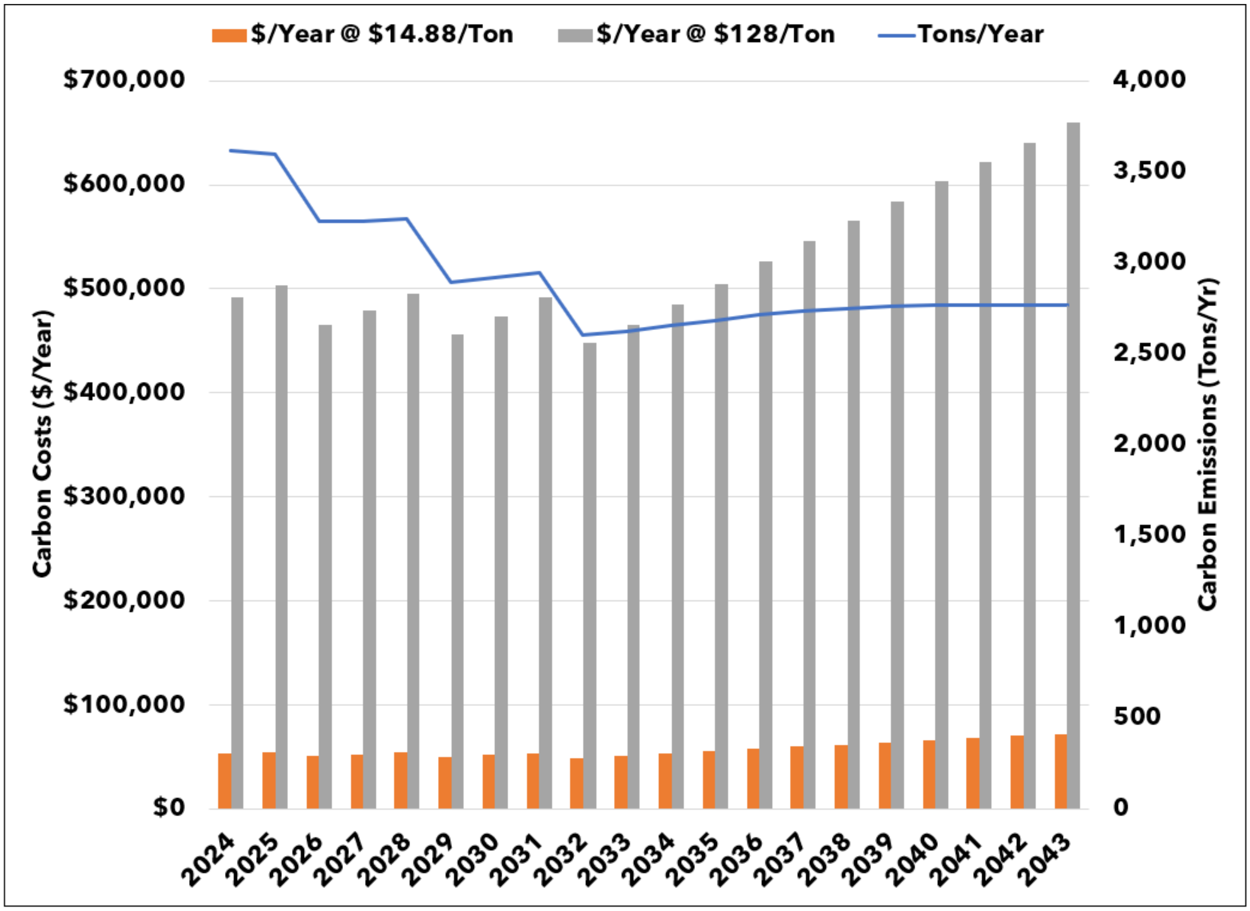


The emissions rate declines through 2032 because of increasing RES requirements. The emissions rate remains stable thereafter because this plan assumes that the RES requirements will be maintained.

These emissions rates were multiplied by the load forecast from Section I. Electricity Demand is going to arrive at an estimate of carbon emissions in tons per year. The following figure shows that carbon emissions range from about 3,600 tons/year in 2024 down to 2,600 tons per year in 2032.

The costs of these emissions were calculated using two sources, the Regional Greenhouse Gas Initiative Auction (RGGI) results for the most recent auction ($14.88 per ton) and the 2021 Avoided Cost of Energy Supply (AESC) study ($128 per ton in 2021). Using RGGI prices plus inflation, the cost of carbon emissions averages about $50,400 per year through 2032. Using AESC prices, plus inflation, the average cost through 2032 is about $460,000 per year.

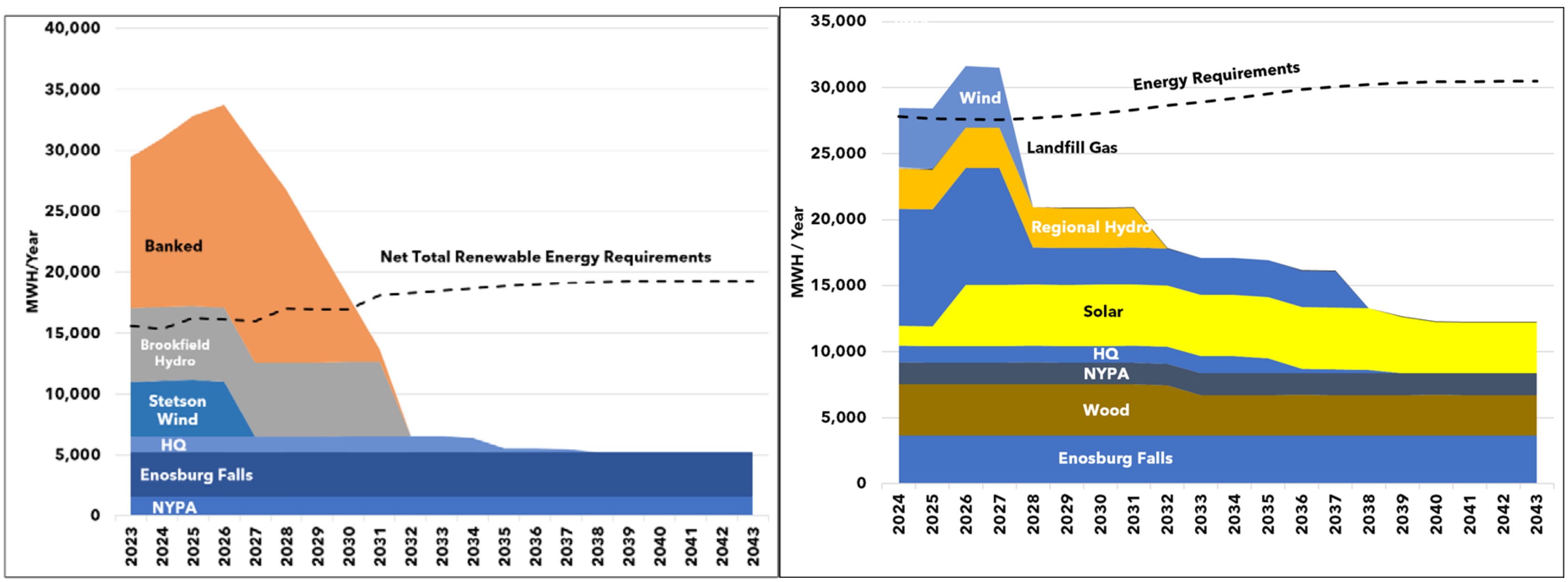
Figure 12: Carbon Emissions (Tons/Year) and Costs ($)



PROCUREMENT PLAN FOR RES 1.0

Under RES 1.0 requirements, VOEF can extend the term on its existing hydro PPA through 2032. This approach would keep VOEF above a 95% hedge ratio through 2030 after which the Fitchburg Landfill extension will expire. When the Fitchburg PPA expires, the coverage ratio drops down to about 80% in 2032 with this scenario. This option would also fulfill all of VOEF's Tier I requirements through 2031 if excess RECs in each year were banked. Another bundled energy and REC resource would need to be acquired for 2032 and years after to maintain an appropriate hedge ratio and Tier I REC volumes. This is required not only to fill the gap left by expiring resources, but also to account for increasing load starting 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

VOEF is meeting its Tier I requirements primarily with existing resources as well as annual REC-only purchases and can continue to do so by simply extending the Brookfield Hydro PPA. If load starts growing faster and/or sooner than expected, it can either purchase additional Tier I RECs on the market or increase the volume of a bundled energy and Tier I REC resource by extending an existing contract. The final decision in this regard would depend on REC and energy market prices.

It is assumed that if the RES requirements increase, they will increase to 100% by 2035, along with an increase in Tier II to 20% by 2035. Small, existing, municipally-owned hydro will then be eligible and there will be a creation of a New Renewable regional tier that requires 10% by 2035. This means an overall increase in Tier I obligation as well as a loss of the utility's major Tier I resources of Enosburg Hydro to the increased Tier II obligation. Given those potential changes to the RES, VOEF would require significantly more Tier I RECs even if the Brookfield Hydro resource was extended through 2032. VOEF could retain Fitchburg, McNeil, and Ryegate RECs to adhere to the increased Tier I obligation. However, those RECs are still valued higher in other state markets; therefore, it would be more likely those RECs would be used for arbitrage and sold at a higher price, and then used to purchase Tier I RECs. It is most likely that VOEF will continue to enter into bundled energy and Tier I REC contracts as well as REC-only purchases to obtain enough Tier I RECs to adhere to a new RES with higher obligations.

TIER II

Assuming the RES remains the same, VOEF can adhere to the obligations using primarily the RECs from the upcoming Reservoir Road solar project. Should the RES obligations increase as assumed above, VOEF's Tier II obligations can be met entirely using their solar and hydro resources. In either scenario, excess RECs will likely be sold to other VPPSA members that do not have any solar and/or hydro resources.

TIER III

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

TRANSMISSION & DISTRIBUTION

IV. ELECTRICITY TRANSMISSION & DISTRIBUTION

DISTRIBUTION SYSTEM DESCRIPTION

VOEF's distribution system presently serves approximately 1,800 customers in a 65 square mile service territory. The system is comprised of 103.746 miles of line at 12.47 kV and 3.53 miles of line at 2.4 kV for a total of 107.276 miles of distribution level line.

The system is a radial feed system. VOEF receives sub-transmission service from VEC. VOEF also taps the double-ended line between Highgate and Newport and a 46 kV line runs from the tap approximately 1 mile to the VOEF distribution substation.

VOEF-OWNED INTERNAL GENERATION

VOEF owns and operates the Enosburg Falls Hydroelectric Facility, which includes Village Plant No. 1 and Kendall Plant No. 2.

VOEF owns and operates two hydroelectric facilities, under the Federal Energy Regulatory Commission (FERC) project number P-2905. The facilities consist of Village Plant No. 1, containing a 600 kW Kaplan runner turbine, and Kendall Plant No. 2, containing a 375 kW Flygt pump-turbine. The project is currently licensed to generate 975 kW with a full reported hydraulic potential to meet future load demand of 3,000 (FERC, 1992). The facilities are located on the Missisquoi River in Enosburg Falls, Vermont. VOEF filed a new FERC application in April 2018. VOEF and Swanton Village Electric Department (SED) are on slightly different timelines but are working through the relicensing process together. VOEF received input from various stakeholders regarding the relicensing effort and has taken the comments into consideration. VOEF has done preliminary environmental studies and at this time, it is uncertain as to how long the process will last.

The first of the hydroelectric units, the Kendall Plant No. 2, was constructed and entered service in 1928. It was later refurbished in 1992. The second hydroelectric generator, the Village Plant No. 1, entered service in 1946. An "air bladder" was installed in 2013, which allows VOEF to have more control of water flow. In 2014, a few beneficial repairs and upgrades to the Kendall Plant No. 2 were completed. For several years this unit had to be shut down for most of the winter because the head gates would freeze up. New heaters and rollers were installed for winter operation to mitigate this problem. The head gates, to control water flow, were also rebuilt. The upgrades are expected to increase the number of months that the hydro facility can feasibly generate; therefore, revenue from generation is expected to increase as well. The most recent 5-year average generation from both plants combined, was 2,792,222 kWh annually. In 2022, the total annual generation from both plants was 3,559,221 kWh. In 2018, the total annual generation from both plants was significantly less than normal due to the plants being out of service for significant upgrades. An engineering study of the Enosburg Falls Hydroelectric Generation Facility was completed in January 2014. The study, conducted by The H.L. Turner Group, Inc. engineering firm, gave recommendations for improvements and upgrades to the facility with a cost/benefit analysis. VOEF has completed many of the improvements recommended by the engineering study. During the 2016-2018 timeframe, VOEF invested $2.3 million dollars in the Plant No. 1 hydro facility. In 2022, the Kendal Plant received all new controls, which has allowed for remote access and an upgraded monitoring system. Work was scheduled for December of 2023 to dredge the tail race and to flip and repair the racks that is anticipated to provide 10-15 years of life to the racks. Due to high waters and storms through the month of December, the project has been rescheduled until the spring of 2024 when runoff water levels subside. The Village, with the support of a MERP grant, is working on improving the efficiency of both hydro buildings. Providing better insulation for both buildings, which will lower the cost and the amount of fuel consumed.

Figure 14 summarizes the historical generation output of the hydroelectric facility for the past ten years.

Figure 14: Enosburg Hydroelectric Project Annual Generation (kWh)

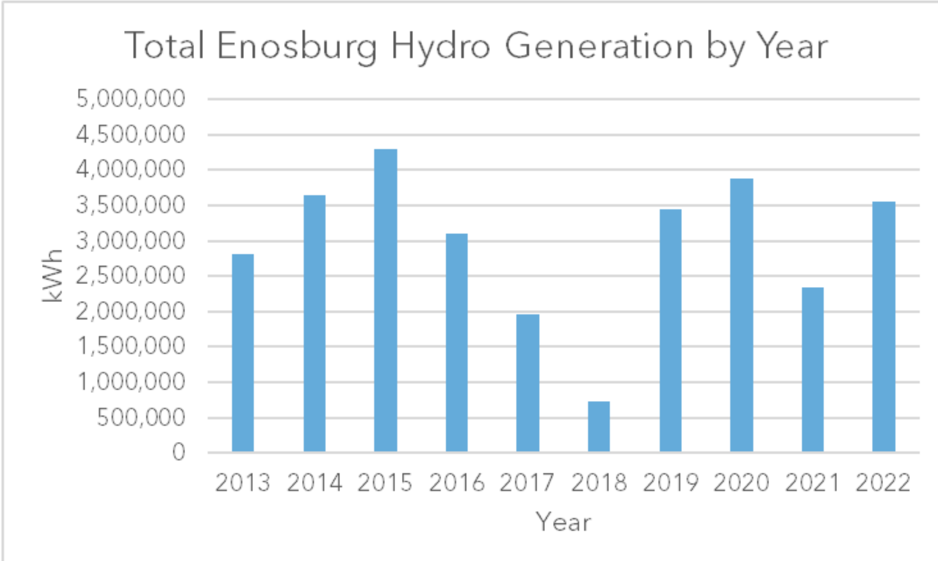


Table 17: Village of Enosburg Falls Hydroelectric Project Nameplate Ratings

Unit Name	Hydroelectric Unit Nameplate Rating (KW)
Village Plant Number 1	600
Kendall Plant Number 2	375
Total	975

VOEF SUBSTATIONS

The VOEF Substation was rebuilt in 2003. In conjunction with Vermont Electric Power Company (VELCO), VOEF has had fiber installed in the substation. The substation is in compliance with the National Electric Safety Code.

CIRCUIT DESCRIPTION

Table 18: VOEF Circuit Description

Circuit Name	Length (Miles)[13]	# of Customers by Circuit	Outages by Circuit 2022
Main Street	1.4	255	1
Cheese Plant	2.3	106	2
St. Albans Street	9.0113	492	5
West Enosburg	39.554	394	10
Sampsonville	55.004	569	32
Total	**107.27**	**1,816**	**50**

VOEF has a total of five circuits. The circuits vary in length and vary in the number of customers on each one.

The voltage of the circuits is regulated at the substation bus. VOEF operates its system to maintain 120 to 240 volts at the customer's outlets.

As shown in Table 18, in 2022, the Sampsonville circuit had the greatest number of outages. There were 32 outages on that circuit for that year. Over half of the outages were due to trees and weather. The other half were due to accidents, unknown reasons, equipment failure, and operator error. To prevent future outages and maintain reliability, VOEF continues to trim trees and add animal guards to equipment, paying particularly close attention to maintenance activity on the Sampsonville circuit.

[13] Estimated from circuit maps.

T&D SYSTEM EVALUATION

System reliability is important to VOEF and its customers. VOEF has several initiatives underway to improve reliability. Each of these initiatives is summarized below.

Outage Statistics

VOEF evaluates T&D circuits on an ongoing basis to identify the optimum economic and engineering configuration for each circuit. The evaluations include the review of the Public Utility Commission (PUC) Rule 4.900 Outage Reports. In addition, VOEF periodically completes long-term system planning studies to develop overall strategies for improving the performance of the T&D facilities. The cost of the improvements recommended in the study are developed into a 5-year budget and approved by the Trustees based upon the financial position of VOEF. The last study, completed in 2003-2004, recommended a new substation as well as new feeders out of the substation. The recommendations of the study have been implemented. At this time VOEF is pursuing, with the assistance of PLM engineering, a T&D Study to be completed before the end of this IRP cycle. VOEF is aware that it has been some time since the last study. However, VOEF is in the process of completing a 2.13 MW AC solar project that will also provide plant improvements as identified during the interconnection study for the project. The study showed the substation can handle the current and currently projected loads with the continued efforts of electrification. Improvements identified in the T&D study from 2003-04 will be improved upon with the interconnection. These include reconductoring of Water Tower Road and the removal of a step-down from 7200 to 2400.

VOEF's PUC 4.900 Electricity Outage Reports, reflecting the last five years (2018-2022) in their entirety, can be found in Appendix C, at the end of this document.

VOEF has committed to performance standards for reliability that measure the frequency and duration of outages affecting its customers. There are two primary measures for the frequency and duration of outages.

The PUC's Rule 4.900 defines these two measures 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.

VOEF has committed to achieve performance levels for its distribution system below an index of 2.5 for SAIFI and 1.0 for CAIDI. VOEF 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 some specific, cost-effective steps that can be taken to maintain or improve system reliability. These steps are completed 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.

The main cause for outages in VOEF's service territory is extreme weather events and the very rural nature of the service territory, which is the second most rural in the state. Ongoing solutions with respect to CAIDI might include larger right-of ways, continued relocation of lines closer to roadways, and more aggressive tree trimming, each of which comes at a cost.

Table 19 summarizes VOEF's SAIFI and CAIDI values for the years 2018 – 2022.

Table 19: VOEF Outage Statistics

	Goals	2018	2019	2020	2021	2022
SAIFI	**2.5**	2.9	1.8	2.0	2.0	0.6
CAIDI	**1.0**	1.8	2.6	2.9	1.1	1.9

VOEF will continue to evaluate all circuits on a basis that considers cost-efficiency, impact to rate payers, reliability, and safety measures. VOEF will also continue to look at ways to bring lines closer to roads while weighing the costs of doing so.

VOEF has several initiatives underway to improve reliability. Each of these initiatives is described below.

ANIMAL GUARDS

VOEF installs animal guards 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

VOEF does not use fault locators. VOEF has fuses, that indicate outages, at the beginning of each circuit.

AUTOMATIC RECLOSURES/FUSING

VOEF has automatic reclosers at its substation. There is one for each circuit.

FEEDER BACK-UP

VOEF substations do not currently have feeder backup capabilities. While VOEF understands the potential benefits, there is no immediate plan to add alternate feeders. VOEF will continue to explore cost effective opportunities to implement feeder back up capability to its substations.

POWER FACTOR MEASUREMENT AND CORRECTION

In 2022, VOEF had an approximate average power factor of 96.2%. In recent years VOEF 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, VOEF will work with VPPSA to develop and implement measures to improve power factor as needed.

OTHER

Vegetation management, tree trimming, and relocating country lines to roadside are also important initiatives that VOEF uses to meet reliability and safety criteria. These topics will be discussed in greater detail later in this document.

DISTRIBUTION CIRCUIT CONFIGURATION

VOLTAGE UPGRADES

VOEF considers several criteria when assessing conversion of a 2.4 kV line segment to higher voltage:

- Frequency & severity of reliability/voltage stability issues
- Value of expected loss reductions
- 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. VOEF plans to identify and prioritize system upgrades, including conversion of 2.4kV line segments during the remainder of this IRP cycle.

PHASE BALANCING

VOEF addresses circuit configuration, phase balancing, and fuse coordination on a continuous basis as the system changes.

SYSTEM PROTECTION PRACTICES AND METHODOLOGIES

PROTECTION PHILOSOPHY

VOEF's system protection includes substation and distribution protection. Each is discussed briefly below.

VOEF has replaced all porcelain cutouts with polysynthetic cutouts that are more resilient with respect to moisture and temperature changes and less likely to fail. VOEF has also replaced dead end insulators that are known to fail. Also, with every transformer that VOEF installs, a surge protector is installed and animal protectors in coated wire are installed, nearly eliminating that type of outage on the transformers.

Substation Protection:

The substation equipment is protected by a combination of high-side fuses and breakers.

Distribution Protection:

The distribution system protection involves a combination of distribution circuit reclosers for each feeder and fuses. All side taps of the main line distribution feed are fused. The last fuse coordination was completed in 2003; since that time VOEF has addressed fuse coordination on a continuous basis as the system changes.

VOEF had an arc flash analysis completed recently; that analysis included data on all relay and breaker settings.

SMART GRID INITIATIVES

PLANNED AMI

Beginning in 2018, VOEF began participating in a multi-phased, VPPSA joint-action project. This project is intended to assess individual member readiness for Automated Metering Infrastructure (AMI) and guide participating members through an RFP process culminating in vendor and equipment selection and implementation.

Vermont Public Power Supply Authority (VPPSA) contracted with Lemmerhirt Consulting to evaluate its member utilities readiness for 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 VOEF. Since VOEF 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, gathered data from utility staff and drove around 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. Awareness of the effort, potential cost, and requirements can inform the utility in its business decision to pursue an AMI implementation.

For a successful AMI project, the utility team and staff must be interested and receptive to adopting new technology and new ways of doing business. VOEF 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; and distribution grid improvements by adopting programs like Conservation Voltage Reduction or Volt/Var Reduction. Since VOEF provides water service, there is the benefit 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	Good
Meter Reading Readiness	Good
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	Difficult
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 served the interest of VPPSA and its members.

Key requirements for the RFP were similar to those mentioned above for the prior RFI. Emphasis was placed 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. The RFP also required the Proposer 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, and
- 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.

VOEF 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, and
- Reduced carbon footprint

In terms of business case, a cost benefit assessment considering field operations, metering and meter operations, billing, customer and other related rate programs was performed. This assessment indicates a positive NPV benefit of more than $980,000, with a positive cost-benefit ratio of 1.99 and a 5.6-year payback, providing VOEF with reassurance that proceeding to the implementation phase is the correct decision. Note that the figures shown in this assessment are exclusive of the state funding opportunity. The final contract with Aclara has been recently signed and VOEF is optimistic that it will begin implementation of a new AMI system in either late 2024 or early 2025, to be completed no later than the end of 2025.

GEOGRAPHIC INFORMATION SYSTEM

Recently, VPPSA has taken major steps forward in developing centralized geographic information system (GIS) utility mapping and data management programs. This new service was first offered in 2020 and includes centralized GIS mapping which maximizes efficiencies by standardizing data across member utilities and reducing the amount of time required to maintain map data. This program allows VPPSA to develop analytics and provide mapping deliverables, applications, and field data collection tools. Through these assets each member utility empowers VPPSA to proactively manage their data and mapping capabilities. VPPSA 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. As a result, utility regulators at the state and federal level increased their focus on cybersecurity. VOEF is mindful of the increasing importance of cybersecurity concerns and the relationship of those concerns to technology selection and protection. While VOEF is not presently required to undertake NERC or NPCC registration, VPPSA is a registered entity, and VOEF's membership in VPPSA provides VOEF with knowledge and insight regarding ongoing cybersecurity developments and risks. On a more local level, VOEF 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 to develop cybersecurity hygiene and best practices to protect VPPSA and those of its members who choose to take advantage of it.

VOEF 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. VOEF conducts ongoing vulnerability assessments and VOEF recently completed its most current assessment. VOEF now has a roadmap for necessary investments for implementation and budgeting for upcoming years and plans to, with support from VPPSA, budget improvements beginning in 2024. VOEF has already implemented many of the recommended changes identified in the assessment and is currently in the process of making more improvements. The Village is also working with federal agencies to implement a cyber security response plan.

OTHER SYSTEM MAINTENANCE AND OPERATION:

RECONDUCTORING FOR RELIABILITY OR SYSTEM LOSS REDUCTION

The replacement of high loss conductors with lower loss conductors is an ongoing process. VOEF is in the process of making cost-effective upgrades to conductors in outlying areas to decrease losses. VOEF considers the age, condition, safety, function, and overall economics when evaluating conductor replacement. VOEF is prepared to work with VPPSA to systematically evaluate and address opportunities to economically reduce losses.

In 2022, VOEF completed work on upgrades on the Chester Arthur Road and Boston Post Road, both located in the West Enosburg Circuit. These upgrades included setting new poles and reconductoring #8 and #6 wires to #2 aluminum wire.

As part of VOEF's short-term and long-term goals, VOEF continues to work on upgrades that will increase reliability. There is a section of line on the Boston Post Road in the Sampsonville circuit that VOEF plans to bring roadside to make the lines more accessible to utility workers. As part of VOEF's long-term goal, VOEF will continue to replace ceramic cut-outs with poly-cutouts and replace press-on connectors with bolt-on connectors.

In Q1 of 2024, VOEF will be applying for a CPG, with the assistance of Encore Renewable Energy, for the installation of a 2.13 MW AC solar array on the Village's property. This solar array will require the reconductoring of Water Tower Road and the removal of a step-down from 7200 to 2400. Part of the project will also include bringing an estimated half mile of line roadside, which will improve resilience.

TRANSFORMER ACQUISITION

Given cost considerations and the existence of a reasonable market in used transformers, VOEF generally purchases rebuilt transformers. The transformer supplier typically provides loss data for the transformers purchased. When evaluating the replacement of transformers, VOEF considers the cost of the transformer versus revenue from service. Transformer rebuilds have a three-year warranty whereas the new ones have only a one-year warranty. Due to electrification of homes and vehicles the VOEF has decided to purchase and install transformers at 15kva and above which will help manage loads without having to swap transformers in the future.

CONSERVATION VOLTAGE REGULATION

VOEF installed voltage regulators to keep voltage balanced. They are in the substation and there are a few out on the lines. VOEF's voltage settings at the substation for the various distribution circuits is 122 V.

DISTRIBUTION TRANSFORMER LOAD MANAGEMENT (DTLM)

VOEF does not currently have an official DTLM program. Every transformer that is worked on is thoroughly checked.

SUBSTATIONS WITHIN THE 100- AND 500-YEAR FLOOD PLAINS

VOEF has only one substation, and it has been in place for many decades. It has never flooded. There are no current plans to move the sub-station. VOEF will contact another utility for a temporary mobile substation if the substation floods. VOEF has checked the floodplain maps and has concluded that the substation is not within the 100-year floodplain. In 2023, the Village was above the 100-year floodplain level on three occasions and the substation was not at risk of flooding during any of these instances.

THE UTILITY UNDERGROUND DAMAGE PREVENTION PLAN (DPP)

VOEF follows the requirements of Dig Safe regarding utility underground damage protection. VOEF also digs at the proper depth, inserts marking tape, and takes all necessary precautions and steps. Any underground damage incidents are reported to the Department of Public Service and Public Utility Commission.

VOEF does the same thing for itself (internally) as it does for Dig Safe. VOEF does not have much underground. Most of the underground is privately owned by the customer.

As the quantity of VOEF's underground lines increase, VOEF will become increasingly more involved with the Damage Prevention Plan.

VOEF has collaborated with the Department of Public Service and VPPSA to develop a draft Damage Prevention Plan and filed it with the Department of Public Service in July 2019.

SELECTING TRANSMISSION AND DISTRIBUTION EQUIPMENT

VOEF has a procurement policy in which the Village Manager has discretion over purchases up to $5,000; purchases over that amount are required to either be put out to bid or a minimum of three quotes must be obtained and reviewed by the VOEF Board of Trustees.

The Village Manager makes recommendations to the Board, except in emergency situations. Creation of the budget by the Village Manager and the Board takes about four months. Through that process the Board determines priorities for the year and the staff complies with those mandates. For large purchases VOEF considers the upfront cost, prior experience with the specific type of equipment, and ensures that the piece of equipment addresses the anticipated demands on it.

VOEF's five experienced electric department employees, with assistance from the Village's administrative staff, develop plans and thoroughly research purchases before buying. VOEF also coordinates closely with VPPSA in ascertaining the prospective rate impacts and regulatory requirements around various purchase options.

MAINTAINING OPTIMAL T&D EFFICIENCY

System Maintenance

As VOEF is a small system. All line staff are routinely involved in inspections, vegetation management, fuse size location, and other various tasks. Information is shared verbally with each other. This method has been effective over the years and has not proved to be problematic. VOEF is working with VPPSA and has completed implementation of a GIS system and data collection has begun. This will lend structure to the system maintenance and tracking process.

Substation Maintenance

VOEF performs annual oil checks on transformers and monthly substation inspections. Meter readers and line crew report maintenance issues as they find them in the field. The voltage regulator oil is tested against manufacturer specs annually and replaced as needed.

Pole Inspection

VOEF has an informal pole inspection program to assure that poles in its service territory are in good, reliable condition. VOEF always inspects poles that are in the vicinity of normal field work. Due to the size of the system, VOEF personnel have a good understanding of the age and condition of its poles and proactively find problems before they start. VOEF expects that the GIS program will include information to facilitate pole inspection and tracking.

Equipment

Any time work is being performed on a pole, VOEF replaces any insulators and connectors that are no longer in working condition.

System Losses

VOEF is committed to providing efficient electric service to its customers. VOEF's plan for improving system efficiency involves two actions. The first action involves monitoring actual system losses. The second action involves completing projects to reduce system losses.

Actual System Losses:

Currently, VOEF's total (distribution and sub transmission) line losses are running around 1.8%.

Efforts to Reduce Losses:

The replacement of high loss conductors with lower loss conductors is an ongoing process. Subject to reasonable budget constraints, VOEF is prepared to work with VPPSA to systematically evaluate, prioritize, and address cost-effective opportunities to economically reduce losses.

Tracking Transfer of Utilities and Dual pole Removal (NJUNS)

VOEF does not use NJUNS.

Relocating cross-country lines to road-side

VOEF relocates cross-country lines to roadside when such relocation can be done consistent with cost consideration and customer concerns in terms of rights-of-way. Some customers do not want to see the lines in front of their houses. VOEF is working on two sections in the very near future. A half mile will be relocated as part of the solar interconnection. A one mile stretch on the Boston Post Road easements have been negotiated with the last resident to gain permission to move to roadside.

VOEF's goal is to continue to improve its system reliability as the demand for reliable electric service becomes more important to customers.

DISTRIBUTED GENERATION IMPACT:

VOEF presently has 56 distributed generation projects with a total installed capacity of 1,493 kW. Those projects consist of the following: 54 solar net-metering projects with an installed capacity of 1,137.4 kW, a net-metered wind project with an installed capacity of 5.6 kW, and a Standard Offer methane project with an installed capacity of 350 kW. Additionally, VOEF owns and operates two hydroelectric generation projects with a total installed capacity of 975 kW.

Interconnection of Distributed Generation

VOEF recognizes the unique challenges brought on by increasing penetration levels of distributed generation. VOEF 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 that 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 VOEF 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, and
- Increased incident energy exposure (arc flash)

In addition, recognizing that the aggregate of many smaller installations that individually pass Rule 5.500 screening criteria can present problems that would otherwise go unnoticed, VOEF will maintain detailed records of installed generation including location, type, and generating capacity. This information will allow VOEF 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). VOEF 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 VOEF's service territory, VOEF 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 VOEF. As a reasonable compromise, VOEF 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, VOEF 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. VOEF 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

VOEF 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. VOEF is focused on the challenge of identifying and tracking "hot spots" on the system as they develop. This includes keeping an eye toward formulating timely responses, whether those be load-management efforts, equipment upgrades, or the addition of generation/storage at key locations.

The VOEF distribution system currently has sufficient capacity for the foreseeable future. As Table 22 indicates, VOEF has mostly small solar projects on its system. Maximum loading on the substation transformer is currently about 55% of its nameplate capacity and about 34% on average.

Table 22: VOEF Distribution-Level Impact of Electrification

SUBSTATION	# of Transformers	Transformer Capacity	Peak % of Nameplate	Energy % of Nameplate (1)	CIRCUIT/ FEEDER	Circuit Voltage Kv	Solar/Hydro Dist. Generation # of Units	Solar/Hydro Dist. Generation kW (2)	Storage kW	Large Load kW	Large Load kWh
Enosburg Substation	1	9.375MVA	55%	34%	Main Street -1G5	7200	1	6	-	NA	NA
					Cheese Plant - 1G2	7200	1	8	-	950	5,147,040
					St. Albans Street - 1G1	2400/7200	4	89	-	NA	NA
					West Enosburg	7200	1	375	-	NA	NA
					Sampsonville - 1G3	7200	45	1,345	-	NA	NA
					Main Bus		1	600	-	NA	NA

*(1) Annual kWh / (transformer capacity * 8760)*
(2) DG shown up through end of 2022.

We know from the Demand Chapter[14] that the transformer at the Enosburg Substation is 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 rating. 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 the addition of one or more unmanaged 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 regulator level. In recognition of the potential stress on its system, VOEF 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, and develop concentrations of electrification-driven load.

Currently, VOEF 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

[14] See 'Peak Forecast Results.'

of electrification driven load. VOEF can track installed electrification measures associated with incentive programs, by street address, within the VOEF 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 VOEF system, the view of magnitude and locational trends this dataset will provide over time will inform policy and planning discussions related to VOEF'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. VOEF anticipates that implementation of integrated AMI and GIS systems over the next couple years will provide the ability for: implementation of more sophisticated, timely, and location-targeted distribution system planning' rate driven load management responses, including load management 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, VOEF will be able 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 VOEF'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 VOEF's planning for appropriate distribution system development by enhancing VOEF'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 for appropriate load management including innovative rate designs and optimal location of storage facilities.

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 VOEF to commission a full T&D study to take stock of current system conditions and identify/prioritize required improvement projects.

VEGETATION MANAGEMENT/TREE TRIMMING

VOEF has a line item for tree trimming in its annual budgets and carefully expends a certain amount per year. Most of the line maintenance is done in-house, although occasionally contractors are hired. The PUC Rule 4.900 Outage Report helps determine where tree trimming needs to be done. VOEF continues to budget aggressively for tree trimming efforts because of the 2013 ice storm. VOEF has a ten-year, vegetation management plan, and starts the cycle over again at the end of ten years.

VOEF deliberately observes the whole system each year while doing field work, and along with management, provides an annual assessment of system-wide trimming needs to its Board of Trustees. The VOEF's Board of Trustees is responsible for budgetary and policy decisions concerning the Village's departments, and is the authority ultimately responsible for setting goals, objectives, and priorities for the departments. The staff and Trustees for VOEF take this public responsibility seriously and make decisions with careful consideration for the overall goals and economic considerations the community must face.

The most recent calculations regarding tree trimming determined that VOEF has 43 miles of line requiring trimming. The other lines are in open areas with no vegetation that would affect the lines (i.e. located alongside roads/streets with no trees.); therefore, they do not require any trimming.

On an average basis, VOEF budgets approximately 4.3 distribution circuit miles of tree-trimming per year. These are not necessarily contiguous circuit miles. VOEF budgets $50,000 per year for tree-trimming. VOEF surveys at least 4.3 miles per year. In historical years, where the miles trimmed were fewer than 4.3 miles, at least 4.3 miles were surveyed but only those miles requiring trimming are shown in Table 24.

The schedule table, below, lists the annual miles of line trimmed over the past three years and the predicted annual miles of line to be trimmed over the next three years. Unlike some electric utilities in Vermont, VOEF does not hire-out all its tree trimming work. VOEF's own line crew does some of the tree trimming and VOEF hires out some of the tree trimming. Historically, VOEF has not tracked areas that its own crew has trimmed from year to year, nor has this been required in the past. Starting in September 2018, VOEF started to track and report on both the amounts trimmed by VOEF's own crew and amounts trimmed by outside contractors. The estimated annual miles of line to be trimmed in the future shown in Table 24 is a predicted assessment using a combination of contractors and VOEF's own line crew and is subject to the approval of the VOEF Board of Trustees. VOEF believes this is a realistic approach that can be maintained while keeping the utility on par to complete needed trimming services to those areas of our service territory that require this maintenance.

All lines are trimmed to the edge of the legal right-of-way, which is 50 feet. The trimming width on either side of the line is 25 feet.

In addition to its vegetation and brush management program, VOEF has a program to identify danger trees within its rights-of-way and to either prune or remove those trees. Again, 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 while patrolling the lines, reading meters, or inspecting the system. Patrols for danger trees are made simultaneously while accomplishing other field work in the same vicinity. The meter reader is also out twice a month (or more frequently) reading meters as well as making observations of danger trees. Additionally, customers notify VOEF about their observations of danger trees. Once a danger tree is identified, it is promptly removed if it is within VOEF's right-of-way. For danger trees outside of the right-of-way, VOEF contacts the property owner, explains the hazard, and with the owner's permission removes them. Where permission is not granted, VOEF will periodically follow up with the property owner to attempt to obtain permission.

The emerald ash borer has not yet become an active issue In VOEF's territory. VOEF is monitoring developments and coordinating efforts with VPPSA and VELCO and will make use of any guidance that becomes available as a result. If and when the emerald ash borer does surface in VOEF's territory, affected trees will be cut down, chipped, and properly disposed of.

Table 23: VOEF Vegetation Trimming Cycles

	Total Miles	Miles Needing Trimming	Trimming Cycle
Distribution	Approximately 106	43	10-year average cycle

Table 24: VOEF Vegetation Management Costs

	2020	2021	2022[15]	2024	2025	2026
Amount Budgeted	$44,000	$44,000	$44,000	$50,000	$50,000	$50,000
Amount Spent	$30,000 Contractor Labor + $26,761 Village Staff	$30,000 Contractor Labor + $33,792 Village Staff	$15,400 Contractor Labor + $13,230 Village Staff	Deliberately left blank	Deliberately left blank	Deliberately left blank
Miles Trimmed	3.79 Miles Contractor + 1.26 Miles Village Staff	3.19 Miles Contractor + 1.84 Miles Village Staff	0.93 Miles Contractor + 0.58 Miles Village Staff	4.3 miles to be trimmed	4.3 miles to be trimmed	4.3 miles to be trimmed

Table 25: VOEF Tree-Related Outages

	2018	2019	2020	2021	2022
Tree Related Outages	26	26	24	24	20
Total Outages	80	72	64	75	50
Tree-related outages as % of total outages	33%	36%	38%	32%	40%

[15] In 2022, not as much trimming was performed as was anticipated. This was due to a few reasons: two line technicians left employment with the village, they were not replaced until fall, and a key employee was out on leave for three months and returned with restrictions for two more months.

STORM/EMERGENCY PROCEDURES:

Like other Vermont municipal electric utilities, VOEF is an active participant in the Northeast Public Power Association (NEPPA) mutual aid system, which allows VOEF to coordinate not only with public power systems in Vermont, but with those throughout New England. The Village Manager is also on the state emergency preparedness conference calls, which facilitates in-state coordination between utilities, state regulators, and other interested parties. The Lead-Line Technician of VOEF is typically on the electric lines during emergency situations. VOEF has a paging system, utilizing Swanton Villages Electric dispatch to allow customers to call in during non-business hours and have access to 24-7 dispatch service. Swanton Village Electric and VOEF have joined forces and have developed a combined on-call rotation. This allows for more resources and quicker repair times. It also allows for proper coverage while allowing technicians relief from being on call. The VOEF has also implemented a "all hands-on deck" approach to storms. Once the Village Manager verifies storm information from the state emergency call, all employees in every department are informed and are prepared to respond to support if needed. The VOEF has also worked to improve its due diligence in updating the www.vtoutages.com site during major storms, especially if it experiences a large outage that is expected to have a long duration. VOEF believes it is beneficial to inform the Public Service Department if it is experiencing these types of outages. Along with reporting outages, multiple SOP's have been adopted and are to be used in the event of a storm. These SOP's identify processes to not only update social media, but to also support with food, accommodations for contractors, mechanics, tree trimmers, and a variety of logistical needs during a storm.

PREVIOUS AND PLANNED T&D STUDIES:

INTERCONNECTION STUDY

In partnership with VPPSA and Encore Renewable Energy, VOEF is installing a 2.13 MW AC solar array. Because of this project and the proximity to the substation, an interconnection study was performed. The study helped bring out the areas within the VOEF system that need attention as well as the strong points.

SYSTEM PLANNING AND EFFICIENCY STUDIES

Distribution System Planning

In 1996, PLM Electric Power Engineering of Hopkinton, MA conducted a System Planning Study of the VOEF system. In October of 1999, Lee Carroll, PE electrical consultants of Gorham, NH prepared a Work Plan for 1999-2002. More recent VOEF work plans and studies have focused primarily on the hydro facilities.

At this point, once the array is in place and operational, VOEF will begin to reassess and plan to perform a T&D planning study before the end of the IRP cycle. This will also give VOEF time to identify the changes in the rollout of electrification. Additionally, as data from the new AMI and GIS systems becomes available, and detailed patterns of loading on the distribution system become more readily available, the time will be right for VOEF to commission a full T&D study to take stock of the current system and future conditions and identify and prioritize required improvement projects.

VOEF is also interested in researching the possibility of developing a microgrid on its system; therefore, this concept will be considered in the next T&D system study.

CAPITAL SPENDING

HISTORICAL CONSTRUCTION COST 2020-2022

Table 26: VOEF Historic Construction Costs 2020-2022

Village of Enosburg Falls Electric Light Department		Historic Construction		
Historic Construction		**2020**	**2021**	**2022**
Structures and improvements (331)	Prod			
Reservoirs, dams and waterways (332)	Prod			
Poles, towers and fixtures (364)	Dist	$ 4,027	$ 10,258	$ 2,150
Line transformers (368)	Dist			
Services (369)	Dist			
Meters (370)	Dist	$ 2,779		$ 1,498
Structures and improvements (390)	Gen			
Office furniture and equipment (391)	Gen			
Transportation equipment (392)	Gen			
Stores equipment (393)	Gen			
Communication equipment (397)	Gen			
Miscellaneous equipment (398)	Gen			
Construction in Progress (FERC Relicense)		$ 101,156	$ 98,400	$ 94,681
Total Construction		**$ 107,961**	**$ 108,658**	**$ 98,329**
Functional Summary:				
Production		-	-	-
General		101,156	98,400	94,681
Distribution		6,806	10,258	3,648
Total Construction		**$ 107,961**	**$ 108,658**	**$ 98,329**

PROJECTED CONSTRUCTION COSTS 2024-2026

Table 27: VOEF Projected Construction Costs 2024-2026

Village of Enosburg Falls Electric Department		Projected Construction		
		2024	2025	2026
Hydro (generic)	Prod	$ 75,000	$ 75,000	$ 76,650
Water Filtration System	Prod		$ 40,000	
Kendall Building Maintenance	Prod		$ 200,000	
Village Hydro #1	Prod		$ 30,000	
Misc Hydro	Prod	$ 131,414		
Smaller Bucket Truck	General		$ 300,000	
Digger Truck	General	$ 280,000		
3/4 TON Pickup	General			$ 100,000
Office & computing Equipment	General	$ 10,909	$ 11,149	$ 11,395
	Trans			
Boston Post Road Line Upgrade	Dist	$ 135,000		
Reconducter section of Rt 108/Browns Pond	Dist	$ 6,500		
West Enosburg Road Line Upgrade	Dist			$ 125,000
Carpenter Road Line Upgrade	Dist			$ 25,000
AMI	Dist	$ 210,000	$ 210,000	
Misc distribution	Dist	$ 15,238		
Routine/Recurring/Misc plant & general		$ 40,880	$ 41,779	$ 42,699
Total Construction		**$ 904,942**	**$ 907,929**	**$ 380,743**
Functional Summary:				
Prod		$ 206,414	$ 345,000	$ 76,650
General	25%	$ 301,129	$ 321,594	$ 122,069
Distribution	75%	$ 397,398	$ 241,335	$ 182,024
Transmission		$ -	$ -	$ -
Total Construction		**$ 904,942**	**$ 907,929**	**$ 380,743**

V. FINANCIAL ANALYSIS

This section quantifies the costs of a Reference Case and a series of resource procurement scenarios that would fulfill the existing RES requirement. It also includes a scenario that anticipates increased RES requirements, 100% for Tier I and 20% for Tier II and 10% for New Renewables all based on total load, as well as small, municipally owned hydro qualifying for Tier II. Finally, it also includes an analysis of battery storage to illustrate the cost saving potential of a peak-shaving battery. The characteristics of these scenarios are summarized in Table 28.

Table 28: Scenarios

#	Resource Scenario	Description	Size	Price
0	Reference Case	RES 1.0 with Open Power Supply Position & Annual REC-Only Purchases	N/A	DA LMP, Annual REC Value
1	Existing RES Requirement Scenarios	Tier I 75% by 2032 Tier II 10% by 2032	N/A	
1.1	Extend Brookfield Hyro Contract	Fixed Price, Annually Fixed Volume and Tier I RECs	0.6MW Off Peak, 0.8MW On Peak	Fixed, Levelized
1.2	Extend Stetson Wind Contract	Fixed Price, Monthly Fixed Volume and Tier I RECs	Varies by month	Fixed, Levelized
1.3	Shaped Market Contract	Fixed Price, Monthly Fixed Volume	Varies by month	Fixed, Levelized
2	Increased RES Requirements	Tier I 100% by 2035 Tier II 20% by 2035 New Renewable 10% by 2035 Based on Total Load Owned Municipal Hydro Tier II qualified		
3	Storage Scenarios			
3.1	4MW Battery Storage	4MW Battery	4MW	Fixed Base Payment, 50% Revenue Share
3.2	4MW Battery Storage	4MW Battery	4MW	Fixed Base Payment 100% Revenue Retention

The sizes and terms were chosen to align with existing 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 Hydro PPA is priced using current energy market prices for energy and RECs. The Stetson Wind blend and extend is priced at $70, which includes REC pricing. The Shaped Market Contract is also priced at market prices.

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 0.7% annual rate, which reflects not only the underlying assumptions for energy and capacity prices but also a portion of the cost of procuring 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 0.5% per year after accounting for efficiency upgrades, electrification trends, and net metering. Finally, the coverage ratio drops as contracts expire.

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

Cost Item	2024	2028	2034	2038	2043	CAGR
Net Resource and Load Charges & Credits	$1.95	$2.29	$2.42	$2.09	$2.13	0.5%
Transmission Charges	$0.94	$1.19	$1.71	$2.20	$3.04	6.4%
Administrative and Other Charges & Credits	$0.07	$0.08	$0.10	$0.11	$0.13	3.1%
Total Charges	$2.96	$3.56	$4.23	$4.40	$5.30	3.1%
Total Load - Including Losses (MWH)	27,804	27,691	29,193	30,259	30,470	0.5%
Coverage Ratio	102%	76%	59%	44%	40%	

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. However, given market price trends this could be difficult to accomplish depending on the resource being replaced.

To reduce transmission costs, a peak-shaving storage resource is being studied. The system is presently sized at 4 MW with several contract options including a base payment rate with 50% revenue sharing and a higher base payment rate with VOEF retaining all revenues. With a high degree of accuracy of hitting the peaks, a battery would reduce transmission costs from present day costs due to lower coincident peaks. However, due to the year-on-year increase in transmission rates, the transmission costs likely wouldn't stabilize; instead, their cost would be reduced from what the cost would have been without a battery. 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 3.0 scenario. Notice that the PVRR increases by almost $870,000 or 1.13% under the RES 3.0 requirements. This is due to the increased volume of Tier I and New Renewable RECs to procure. With the commissioning of a Tier II qualified solar project, the costs of which are embedded in the Reference Case, and the assumption that RES 3.0 will allow Enosburg Falls Hydro to qualify for Tier II. VOEF is well situated to handle the assumed doubling in Tier II obligation at a relatively low cost compared to other utilities. It is also influenced by basing RES obligations on total load not just retail sales as total load is always a larger volume than retail sales due to line losses.

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

#	Procurement Scenario	PVRR	Unit	% Change
0	Reference Case	$77.10	PVRR	
1.1	Extend Brookfield Hyro Contract	$0.10	Change from Ref. Case	0.13%
1.2	Extend Stetson Wind Contract	$0.25	Change from Ref. Case	0.32%
1.3	Shaped Market Contract	-$0.05	Change from Ref. Case	-0.07%
2	Increased RES Requirements	$0.87	Change from Ref. Case	1.13%
3.1	Storage 50% Revenue Sharing	-$2.02	Change from Ref. Case	-2.62%
3.2	Storage 100% Revenue Retained	-$3.97	Change from Ref. Case	-5.15%

The first scenario is modeled assuming the existing RES requirements and includes three closely related decisions. The Brookfield Hydro contract extension is priced at a weighted average market prices for both energy and RECs. The price increases from the Reference Case by about $100,000. The Stetson Wind extension is a blend and extend, which reduces the near-term pricing of the contract due to lower market prices at the time of this evaluation than when the contract was initially brokered. However, the price of outer years of the contract are higher than market prices due to blending. This smooths out the cost for members. The Stetson Wind extension would increase the revenue requirement by about $250,000. Finally, a shaped market contract is essentially cost neutral. This contract assumed the volumes changed monthly but were constant year after year. These volumes formed the basis of the weighted average price that was used. The volumes were intended to get VOEF as close to 100% hedged through each month of the years of this contract as possible keeping annual volumes the same. The term for all contracts was 2028 through 2032.

The second scenario estimates the cost impacts of a 100% renewable requirement by 2035, doubling of the Tier II requirement to 20%, implementing a New Renewable requirement of 10%, allowing municipally owned small hydro to qualify as Tier II, and basing volumes on total load. This scenario increases costs by about $870,000, relative to the Reference Case, and is a direct result of the expected cost of purchasing and retiring Tier I and New Renewable RECs. The cost is limited to this amount because the cost of the solar project, which is currently being developed to hedge Tier II prices, is embedded in the Reference Case. Additionally, this scenario assumes Enosburg Falls Hydro qualifies for Tier II; therefore, there's no additional cost for a higher Tier II obligation.

Finally, the third scenario reflects the impact two-battery storage options. A 50% revenue share with a base payment rate and a 100% revenue retention with a higher base payment rate. Both options have substantial savings from the Reference Case, but the second option has more value to VOEF at a reduction of more than 5% of current revenue requirement.

CONCLUSIONS

The financial analysis can be summarized by three primary points. First, the existing Tier I RES requirement can be met through 2031 with existing resources and by extending the Brookfield Hydro PPA, and Tier II requirements will be met with the pending solar project. Second, RES 3.0 requirements will increase PVRR minimally thanks to the existing solar project that is already budgeted and embedded in power supply costs and that the owned hydro will qualify as Tier II. Third, battery storage represents an opportunity to reduce costs by over 5% by mitigating the increasing cost of transmission and capacity as well as some other ancillary revenues. 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 VOEF's load to be an effective hedge against ISO-New England's day ahead and real-time energy markets.

ACTION PLAN

VI. ACTION PLAN

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

- Advanced Metering Infrastructure
  - Implement an AMI system as reflected in the recent RFP within the 2024–2025-time frame.

- Energy Resource Actions
  - A preferred alternative is extending the Brookfield Hydro contract as it is a hedge against volatile Tier I REC prices. By keeping track of REC pricing and ensuring that the extension is entered into at a time when forward REC prices are reasonable, this extension is a good option to hedge against volatile energy and REC prices. Timing of the extension is important to ensure lowest REC and energy prices. Depending on the trajectory of forward REC prices reliance on a shaped market contract may be preferable, this is a decision that needs to be made before 2028.

- 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 the existing Brookfield 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. Follow broker price marks to ensure lowest price possible using REC banking when appropriate.

- Tier II Actions
  - Ensure the solar project is commissioned.
  - Continue to advocate for recognizing the value of in-state resources like Enosburg Falls Hydro for meeting Tier II requirements.

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

- Storage
    - Continue to work with battery storage developer to bring proposed battery storage to fruition to reduce rates and help with load management.

- Load Management
    - Work with VPPSA to develop innovative rates to achieve effective load management.
    - Continue operation of hydro.
    - Ensure solar project is commissioned.
    - Continue to pursue battery storage.
- Net Metering
    - Monitor the penetration rate and cost of 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 – VOEF Energy & Capacity Pricing Methodolgy.pdf

APPENDIX C: PUC RULE 4.900 OUTAGE REPORTS

This appendix is provided separately in a file named:

Appendix C – VOEF 2018-2022 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 – VOEF IRP22 Demand Report.pdf

APPENDIX G: TIER III LIFE-CYCLE COST ANALYSIS

This appendix is provided separately in a file named:

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

APPENDIX H: VOEF PROJECTED CAPITAL INVESTMENT

This appendix is provided separately in a file named:

Appendix H – VOEF Projected Capital Investment.pdf

APPENDIX I: VOEF PROJECTED FINANCIAL RESULTS

This appendix is provided separately in a file named:

Appendix I – VOEF Projected Financial Results.pdf

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
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
CSO	Capacity Supply Obligation
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DPP	Damage Prevention Plan
DPS	Department of Public Service or "Department"
DTLM	Distribution Transformer Load Management
EIA	Energy Information Administration
ET	Energy Transformation (Tier III)
EV	Electric Vehicle
EVT	Efficiency Vermont
FERC	Federal Energy Regulatory Commission
GIS	Geographic Information System
GMP	Green Mountain Power
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
LIHI	Low Impact Hydro Institute
LRTP	Long-Range Transmission Plan
MAPE	Mean Absolute Percent Error
MDMS	Meter Data Management System
ME II	Maine Class II (RECs)
MEAV	Municipal Association of Vermont
MSA	Master Supply Agreement
MVA	Megavolt Ampere
MW	Megawatt
MWH	Megawatt-hour
NEPPA	Northeast Public Power Association
NESC	National Electrical Safety Code
NOAA	National Oceanic and Atmospheric Administration
NRPC	Northwest Regional Planning Commission
NYPA	New York Power Authority
OMS	Outage Management System
PFP	Pay for Performance
PPA	Power Purchase Agreement
PSD	Public Service Department or "Department"
PUC	Public Utility Commission
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
SED	Swanton Village Electric Department
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
VOEF	Village of Enosburg Falls Electric Light Department
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
WEC	Washington Electric Cooperative
WQC	Water Quality Certificate

Vermont Public Power Supply Authority

2023
Renewable Energy Standard
Tier III Annual Plan

Filed via ePUC
November 1, 2022

Vermont Public Power Supply Authority
PO Box 126
5195 Waterbury-Stowe Road
Waterbury Center, VT 05677
www.vppsa.com

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."

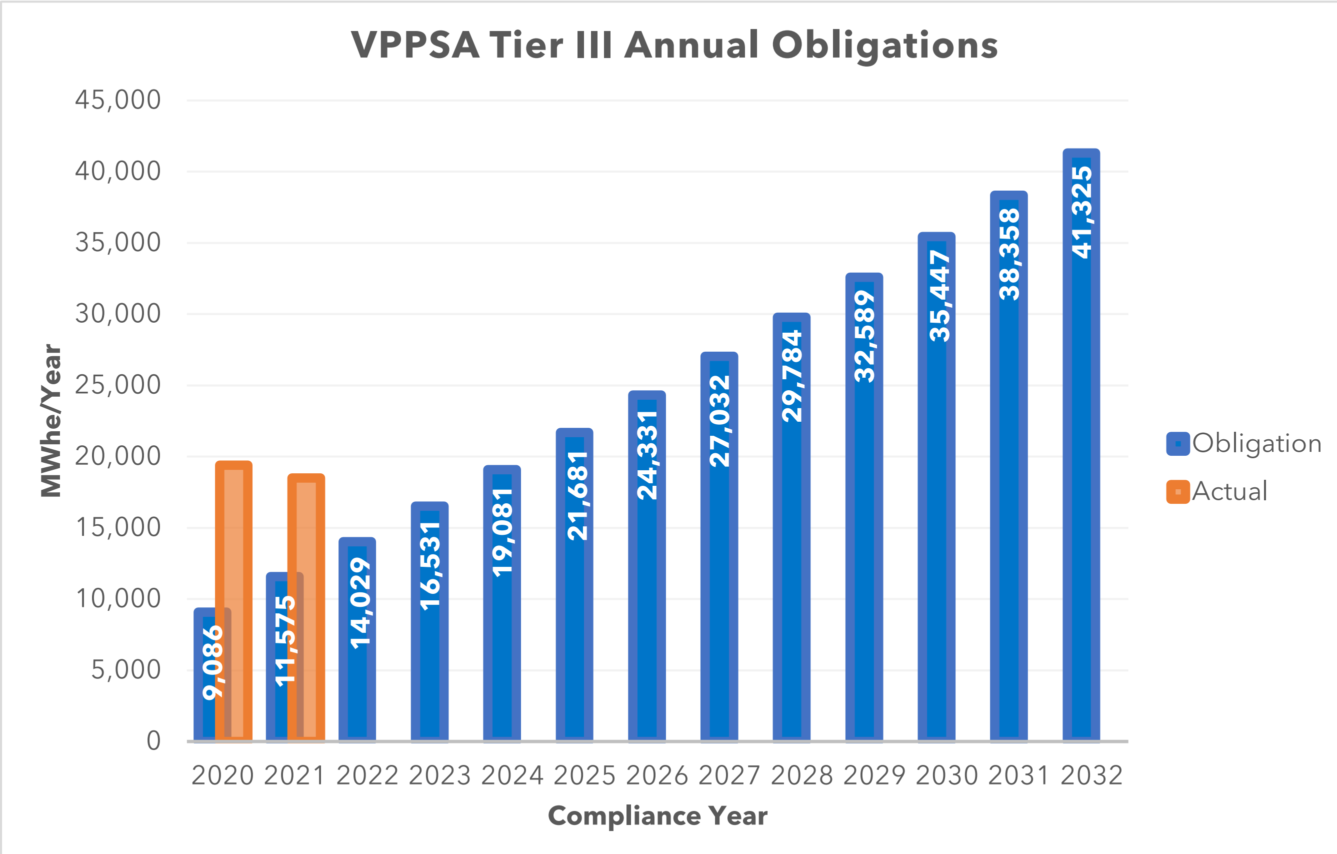
VPPSA's projected Tier III annual MWh equivalent (MWhe) savings obligations through 2032 and compliance performance are illustrated in Figure 1: VPPSA Tier III Annual Obligations (see Page 3)[3].

[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.

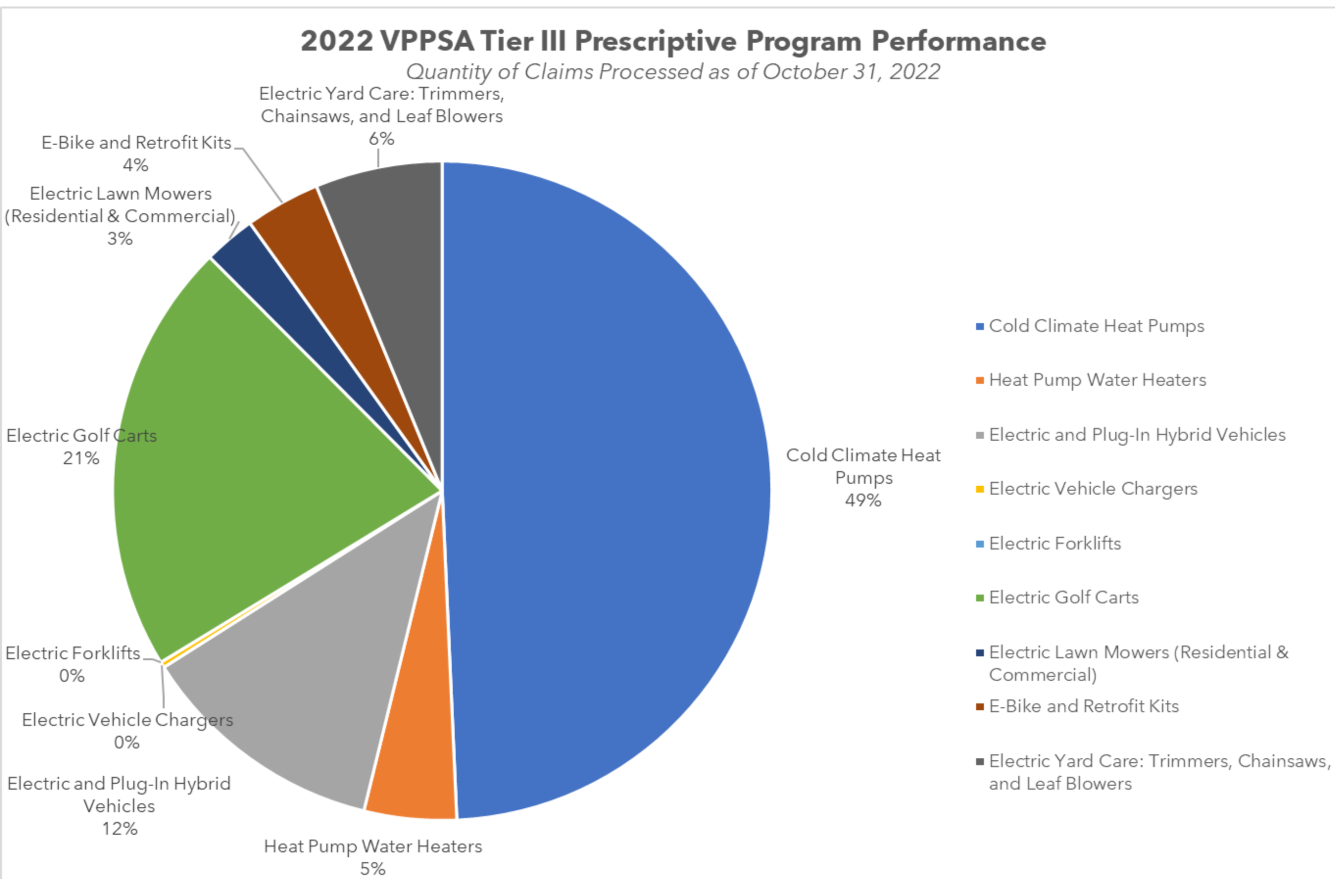
Prescriptive measures are administered using a combination of midstream and downstream incentives:

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.

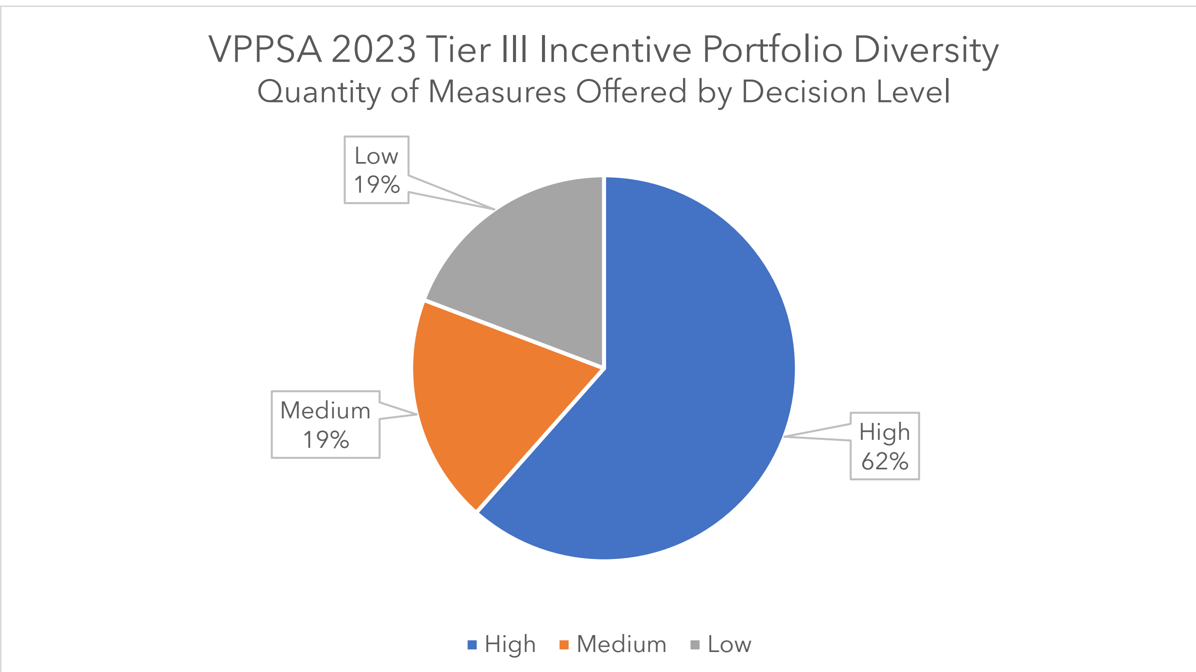
The analysis of VPPSA's 2023 Tier III Incentive Portfolio Diversity included a comparison of the quantity of measures offered in relation to:

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

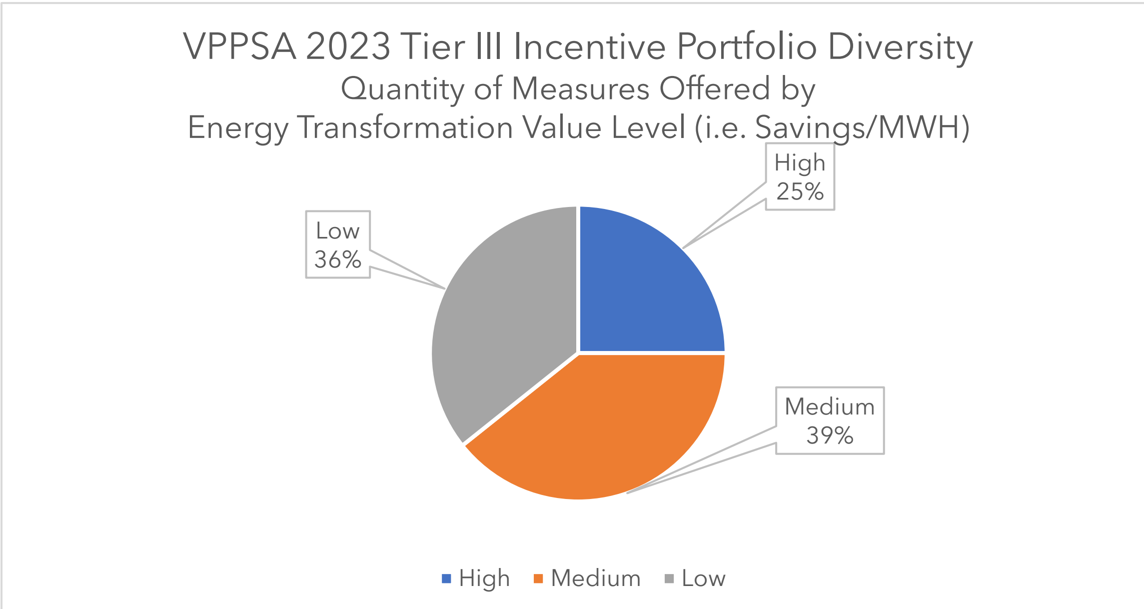
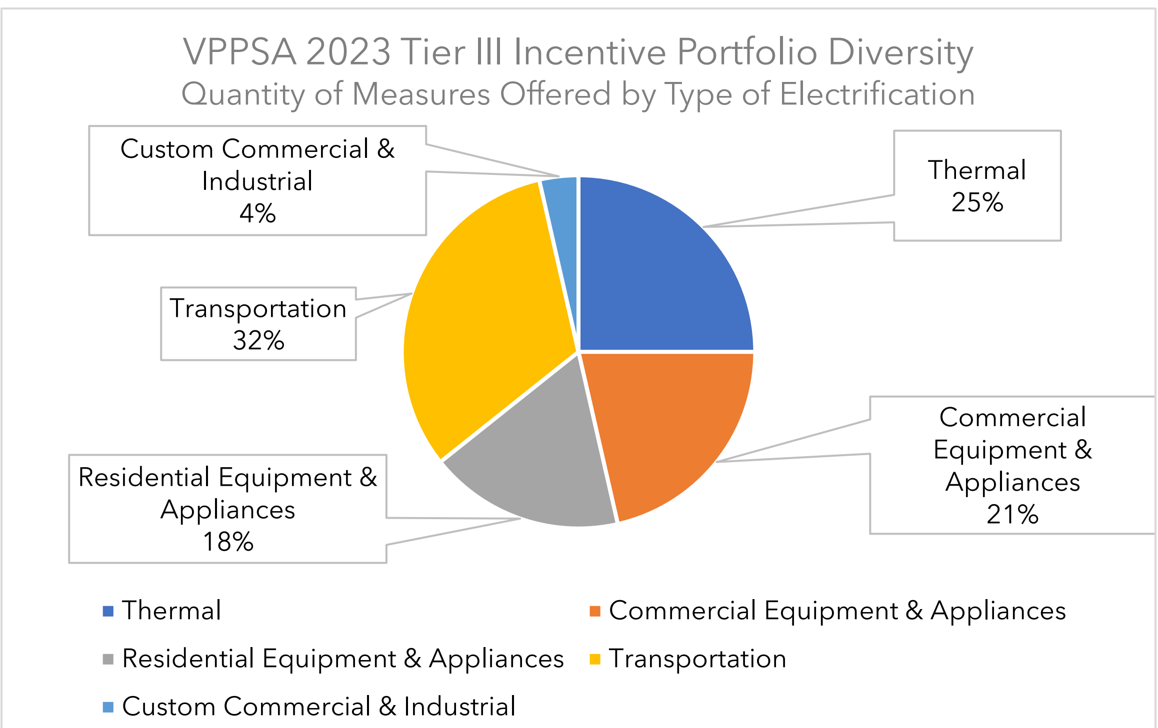


Figure 5: Tier III Portfolio Diversity by Type of Electrification



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)

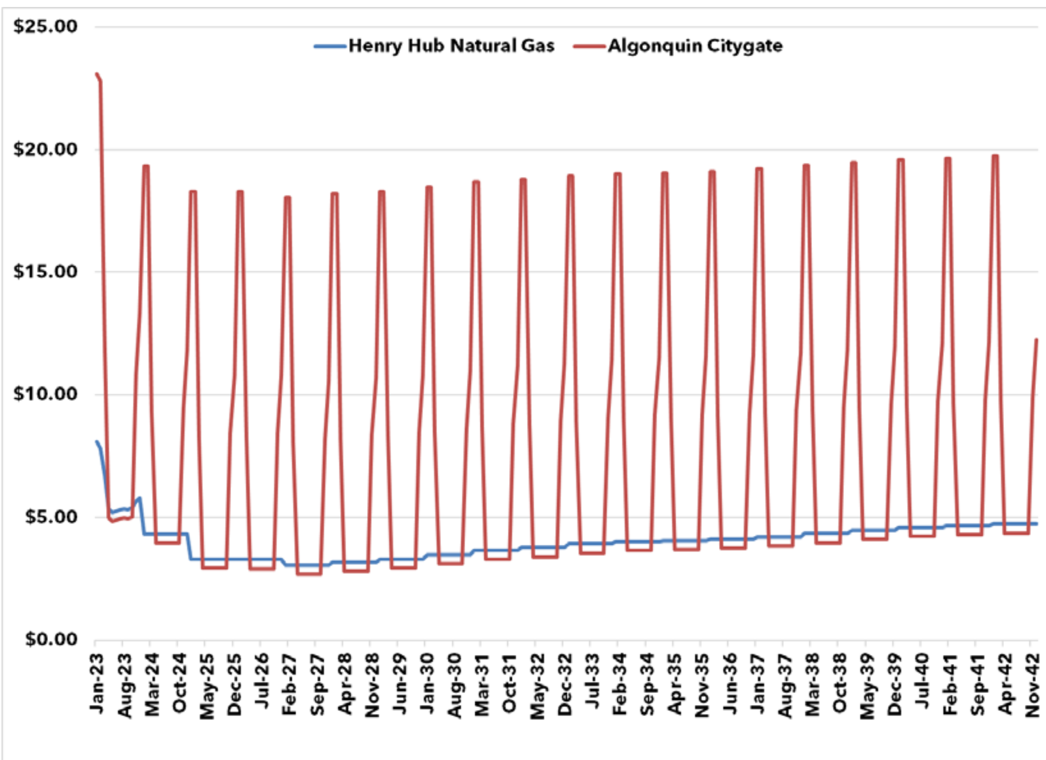
2023 ANNUAL PLAN - TIER III REPORTING TEMPLATE					
			Discount Rate Applied (5%)		
Measure	**Total Gross Cost**	**Present Value Net Revenue**	**Utility Present Value Life Cycle Cost (Total Net Costs)**	**Gross $/MWhe**	**Utility Present Value Life Cycle Cost Net $/MWhe**
Electric Vehicle (New Plug-in 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.

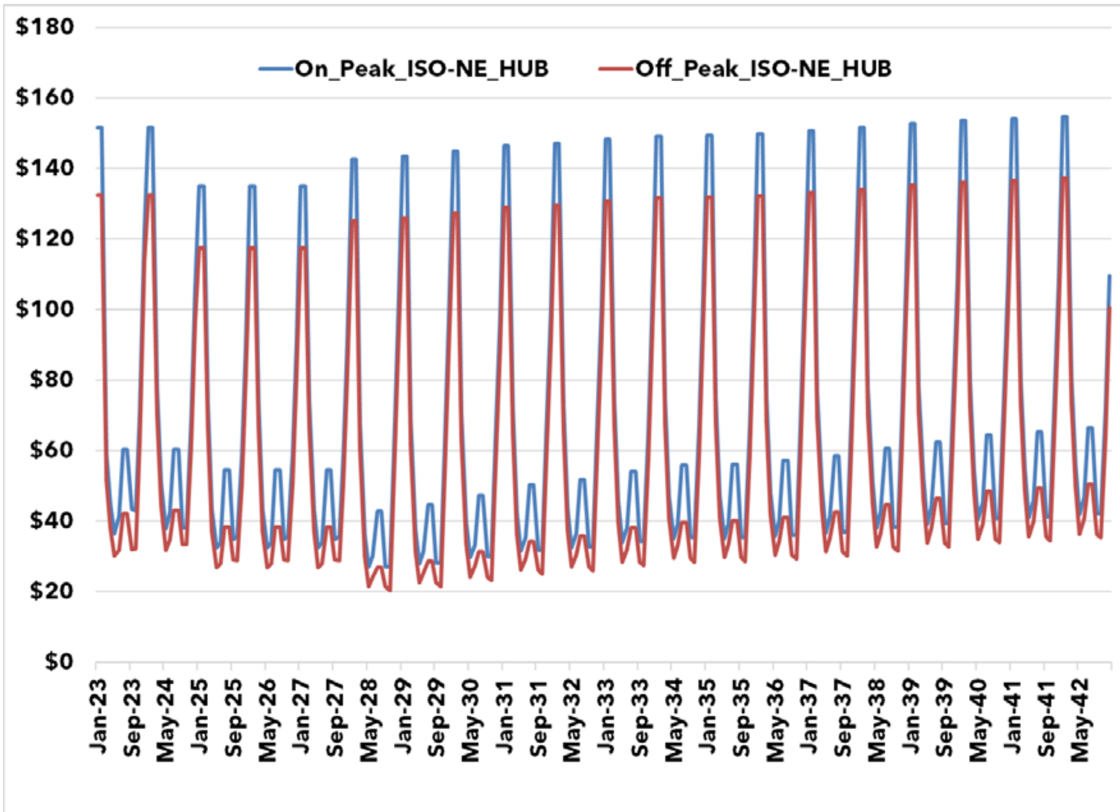
Figure 1: Henry Hub Natural Gas Price Forecast (Nominal $/MMBtu)



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)

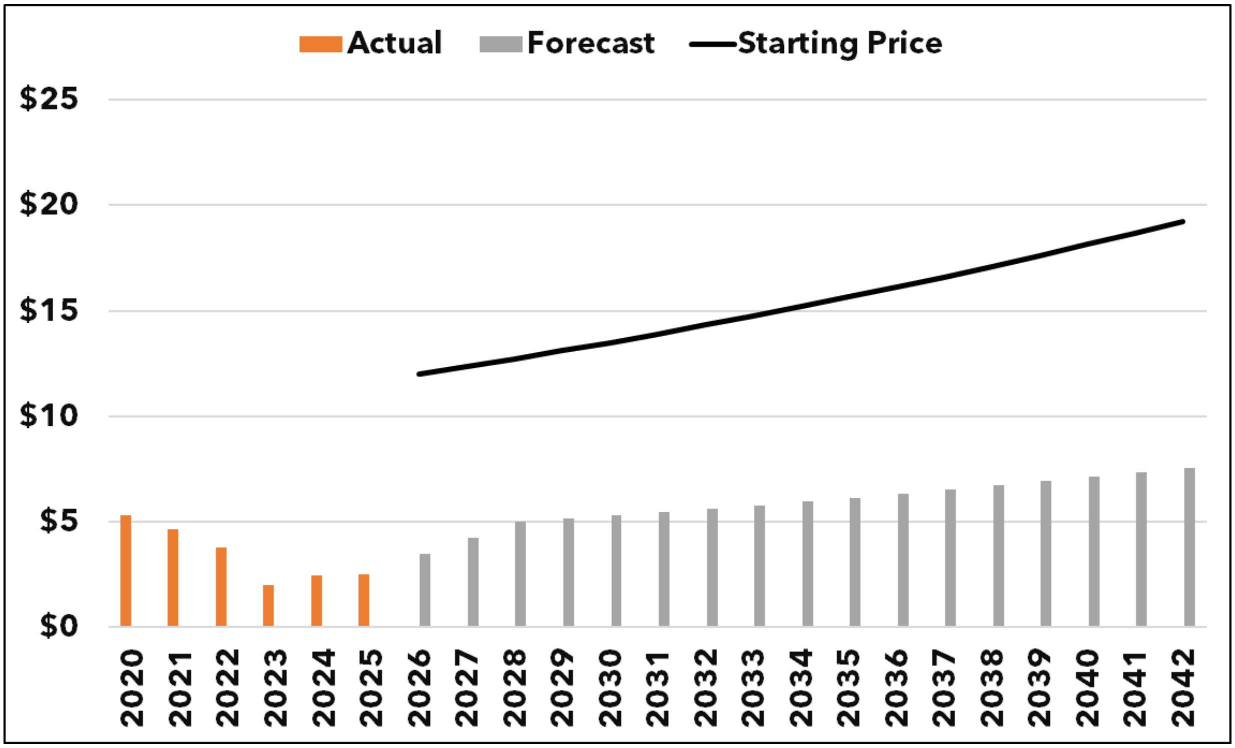


In keeping with the function of ISO-NE's Standard Market Design, we use a five-year average basis between Locational Marginal Price (LMP) nodes to adjust the price forecast at the MA Hub to the location of VOEF's load and resources.

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)



Enosburg Falls Electric Light Department 2018

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	Enosburg Falls Electric Light Department
Calendar year report covers	2018
Contact person	Laurie A. Stanley
Phone number	802-933-4443
Number of customers	1,742

System average interruption frequency index (SAIFI) = 2.9
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 1.8
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	26	2,208
2	**Weather**	11	548
3	**Company initiated outage**	4	1,543
4	**Equipment failure**	15	769
5	**Operator error**	0	0
6	**Accidents**	6	2,418
7	**Animals**	9	974
8	**Power supplier**	1	290
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	8	283
	Total	80	9,033

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.

Enosburg Falls Electric Light Department 2019

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	Enosburg Falls Electric Light Department
Calendar year report covers	2019
Contact person	Laurie A. Stanley
Phone number	802-933-4443
Number of customers	1,768

System average interruption frequency index (SAIFI) = Customers Out / Customers Served	**1.8**
Customer average interruption duration index (CAIDI) = Customer Hours Out / Customers Out	**2.6**

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	26	5,439
2	**Weather**	11	1,886
3	**Company initiated outage**	10	278
4	**Equipment failure**	9	44
5	**Operator error**	0	0
6	**Accidents**	3	322
7	**Animals**	6	127
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	7	167
	Total	72	8,263

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.

Enosburg Falls Electric Light Department 2020

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	Enosburg Falls Electric Light Department
Calendar year report covers	2020
Contact person	Laurie A. Stanley
Phone number	802-933-4443
Number of customers	1,781

System average interruption frequency index (SAIFI) =	**2.0**
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	**2.9**
Customer Hours Out / Customers Out	

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	24	1,179
2	**Weather**	7	84
3	**Company initiated outage**	9	1,140
4	**Equipment failure**	7	97
5	**Operator error**	0	0
6	**Accidents**	5	546
7	**Animals**	5	20
8	**Power supplier**	1	7,108
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	6	186
	Total	64	10,359

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.

Enosburg Falls Electric Light Department 2021

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	Enosburg Falls Electric Light Department
Calendar year report covers	2021
Contact person	Laurie A. Stanley
Phone number	802-933-4443
Number of customers	1,792

System average interruption frequency index (SAIFI) = 2.0
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 1.1
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	24	733
2	**Weather**	12	482
3	**Company initiated outage**	10	220
4	**Equipment failure**	9	261
5	**Operator error**	0	0
6	**Accidents**	4	163
7	**Animals**	7	81
8	**Power supplier**	1	1,430
9	**Non-utility power supplier**	0	0
10	**Other**	1	1
11	**Unknown**	7	410
	Total	75	3,781

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.

Enosburg Falls Electric Light Department 2022

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	Enosburg Falls Electric Light Department
Calendar year report covers	2022
Contact person	Laurie A. Stanley
Phone number	802-933-4443
Number of customers	1,816

System average interruption frequency index (SAIFI) =	**0.6**
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	**1.9**
Customer Hours Out / Customers Out	

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	20	635
2	**Weather**	13	415
3	**Company initiated outage**	1	33
4	**Equipment failure**	3	158
5	**Operator error**	1	7
6	**Accidents**	5	645
7	**Animals**	1	0
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	6	31
	Total	50	1,924

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

Vermont Public Power Supply Authority

Putting the Public in Power.

www.vppsa.com

P.O. Box 126 • 5195 Waterbury-Stowe Rd. • Waterbury Center, VT 05677 • 802.244.7678 • Fax: 802.244.6889

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:

<u>Meter Interface Units (MIUs)</u>

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.

Itron

2022 Long-Term Demand Forecast Summary

The Village of Enosburg Falls

Prepared For:
VERMONT PUBLIC POWER SUPPLY AUTHORITY

Prepared By:
ITRON, INC.

20 Park Plaza, 4th Floor, Boston, MA 02116 | (617) 423-7660 | www.itron.com/forecasting

TABLE OF CONTENTS

List of Figures

List of Tables

2022 LONG-TERM DEMAND FORECAST SUMMARY THE VILLAGE OF ENOSBURG FALLS

Itron, Inc. recently completed the long-term energy and demand forecast for The Village of Enosburg Falls (Enosburg). Enosburg serves approximately 1,600 residential customers and 200 commercial customers within the village and surrounding Towns of Enosburgh, Sheldon, Bakersfield, Berkshire, Fairfield, and Franklin. The utility has seen small but positive customer growth, adding on average 10 new residential customers per year – a 0.7% annual customer growth rate. Customer growth slows to a 0.2% annual rate over the next ten years as customer growth is tied to state population projections. Residential sales account for approximately 54% of sales and nonresidential sales 46%. Total 2021 sales are 26,393 MWh compared with sales of 25,443 MWh in 2011 representing a 3.7% increase over ten years. COVID-19 had a muted impact on sales as loss in commercial sales was largely mitigated by an increase in residential sales. Table 1 shows historical residential customers and class sales.

TABLE 1: ENOSBURG 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	13,070		1,467		8,911		12,373		25,443	
2012	13,260	1.5%	1,475	0.6%	8,988	0.9%	13,526	9.3%	26,786	5.3%
2013	13,520	2.0%	1,492	1.1%	9,061	0.8%	13,454	-0.5%	26,974	0.7%
2014	13,724	1.5%	1,502	0.7%	9,135	0.8%	13,091	-2.7%	26,815	-0.6%
2015	13,867	1.0%	1,521	1.3%	9,116	-0.2%	13,098	0.1%	26,965	0.6%
2016	13,523	-2.5%	1,522	0.1%	8,883	-2.6%	13,038	-0.5%	26,561	-1.5%
2017	13,446	-0.6%	1,522	0.0%	8,836	-0.5%	12,817	-1.7%	26,263	-1.1%
2018	13,754	2.3%	1,528	0.4%	9,003	1.9%	12,898	0.6%	26,652	1.5%
2019	13,704	-0.4%	1,544	1.1%	8,874	-1.4%	12,795	-0.8%	26,499	-0.6%
2020	14,311	4.4%	1,559	0.9%	9,180	3.5%	12,106	-5.4%	26,417	-0.3%
2021	14,246	-0.5%	1,570	0.7%	9,076	-1.1%	12,147	0.3%	26,393	-0.1%
11-21		**0.9%**		**0.7%**		**0.2%**		**-0.1%**		**0.4%**

Given the relatively large commercial sales base, Enosburg has been marginally summer peaking with a system peak of around 5 MW. While lower, winter peaks have been increasing at a faster rate than summer peak demand; winter peaks are largely driven by the residential sector. Table 2 shows historical system energy and peak demand.

TABLE 2: HISTORICAL SYSTEM ENERGY AND DEMAND

Year	MWh	chg	Sum Pk (MW)	chg	Wint Peak (MW)	chg
2011	27,968		4.88		4.39	
2012	28,644	2.4%	4.62	-5.2%	4.48	2.2%
2013	29,050	1.4%	5.01	8.5%	4.67	4.2%
2014	28,311	-2.5%	4.66	-7.1%	4.78	2.2%
2015	28,329	0.1%	4.56	-2.0%	4.56	-4.5%
2016	28,704	1.3%	4.65	2.0%	4.55	-0.3%
2017	27,805	-3.1%	4.48	-3.8%	4.70	3.4%
2018	27,515	-1.0%	4.91	9.8%	4.72	0.4%
2019	26,996	-1.9%	4.54	-7.7%	4.53	-4.0%
2020	27,008	0.0%	4.87	7.5%	4.74	4.5%
2021	27,343	1.2%	4.94	1.3%	4.69	-1.0%
Average		**-0.2%**		**0.3%**		**0.7%**

Forecast Approach

The Enosburg long-term forecast is based on a bottom-up modeling framework where the forecasts start with projected residential and commercial and industrial (C&I) heating, cooling, and base-use (nonweather-sensitive end-uses) energy requirements. that then drives system energy and peak demand. The baseline peak demand (which excludes adjustments for solar, cold-climate heat pumps, and electric vehicles) is based on a demand model that relates monthly peak demand to heating, cooling, and base-use energy requirements and peak-day weather conditions. The peak modeling approach is used for all VPPSA members, GMP, Burlington Electric, and VELCO. A detailed description of the modeling approach is included in the *2022 Long-Term Forecast Model Overview.*

Baseline Sales Forecast Models

Baseline sales models are estimated for each customer class. For Enosburg, this includes residential, small commercial, large commercial, industrial, and other (other is primarily street lighting and is relatively small). Forecasts are derived from linear regression models that are estimated using 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 sales forecast captures expected load growth before adjustments for new solar (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 (both due to standards and state EE program activity) and saturation projections, and temperature trends. Residential and commercial models are estimated using a Statistically Adjusted End-Use (SAE) model specifications. The SAE model integrates end-use saturation and efficiency trends that change slowly over time with variables that impact month-to-month sales variation and capture economic growth; this includes temperatures (HDD and CDD), economic activity (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 *2022 Long-Term 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). Enosburg accounts for 0.6% of state residential sales and 0.4% of commercial sales.

Weather

Both actual and normal heating degree-days (HDD) and cooling degree-days (CDD) are based on 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 base 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 impacted sales 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 state and GMP sales has shown the trend through 2023 has slowed. We are likely to see 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.

Baseline Results

With little to no customer growth and a declining baseline, average use baseline residential sales falls slowly over the forecast period. In the commercial sector, economic driven growth is countered by continuing end-use efficiency improvements and state energy efficiency program activity. Baseline sales are expected to reach 24,562 MWh in 2032 and 22,491 in 2042. This compares with 2021 baseline sales of 26,393 MWh. Table 3 shows Enosburg baseline customer and sales forecast.

TABLE 3: ENOSBURG 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	13,925		1,573		8,854		12,395		26,320	
2023	13,708	-1.6%	1,581	0.5%	8,669	-2.1%	12,464	0.6%	26,172	-0.6%
2024	13,585	-0.9%	1,587	0.4%	8,560	-1.3%	12,407	-0.5%	25,992	-0.7%
2025	13,376	-1.5%	1,591	0.3%	8,406	-1.8%	12,312	-0.8%	25,688	-1.2%
2026	13,260	-0.9%	1,595	0.2%	8,313	-1.1%	12,210	-0.8%	25,470	-0.8%
2027	13,128	-1.0%	1,598	0.2%	8,216	-1.2%	12,111	-0.8%	25,239	-0.9%
2028	13,069	-0.5%	1,600	0.2%	8,166	-0.6%	12,023	-0.7%	25,092	-0.6%
2029	13,002	-0.5%	1,603	0.2%	8,112	-0.7%	11,928	-0.8%	24,931	-0.6%
2030	12,961	-0.3%	1,605	0.1%	8,075	-0.5%	11,836	-0.8%	24,797	-0.5%
2031	12,920	-0.3%	1,607	0.1%	8,040	-0.4%	11,740	-0.8%	24,660	-0.6%
2032	12,907	-0.1%	1,608	0.1%	8,026	-0.2%	11,655	-0.7%	24,562	-0.4%
2033	12,807	-0.8%	1,609	0.0%	7,961	-0.8%	11,553	-0.9%	24,360	-0.8%
2034	12,735	-0.6%	1,608	0.0%	7,919	-0.5%	11,460	-0.8%	24,195	-0.7%
2035	12,682	-0.4%	1,608	0.0%	7,889	-0.4%	11,368	-0.8%	24,050	-0.6%
2036	12,665	-0.1%	1,607	0.0%	7,882	-0.1%	11,294	-0.7%	23,959	-0.4%
2037	12,569	-0.8%	1,605	-0.1%	7,830	-0.7%	11,201	-0.8%	23,770	-0.8%
2038	12,480	-0.7%	1,603	-0.1%	7,785	-0.6%	11,118	-0.7%	23,598	-0.7%
2039	12,390	-0.7%	1,601	-0.2%	7,740	-0.6%	11,035	-0.8%	23,425	-0.7%
2040	12,339	-0.4%	1,598	-0.2%	7,721	-0.2%	10,948	-0.8%	23,287	-0.6%
2041	12,250	-0.7%	1,595	-0.2%	7,680	-0.5%	10,842	-1.0%	23,092	-0.8%
2042	12,192	-0.5%	1,591	-0.2%	7,661	-0.3%	10,749	-0.9%	22,941	-0.7%
22-32		**-0.8%**		**0.2%**		**-1.0%**		**-0.6%**		**-0.7%**
32-42		**-0.6%**		**-0.1%**		**-0.5%**		**-0.8%**		**-0.7%**

Adjusted Forecast

Future load growth will come from CCHP and EVs with some of this growth mitigated by additional PV growth. The baseline forecast is adjusted for new PV capacity additions, EVs, and CCHP. Two of the primary electrification targets are heating – converting fossil fuel heat to

CCHP and EVs. The state, through VEIC and state utilities, is promoting the adoption of CCHP and EVs with rebates, low-interest loans, and construction of EV charging infrastructure. Expected increase in behind the meter PV mitigates some of the long-term energy 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 Enosburg's share of state residential customers. Table 4 shows the resulting forecast.

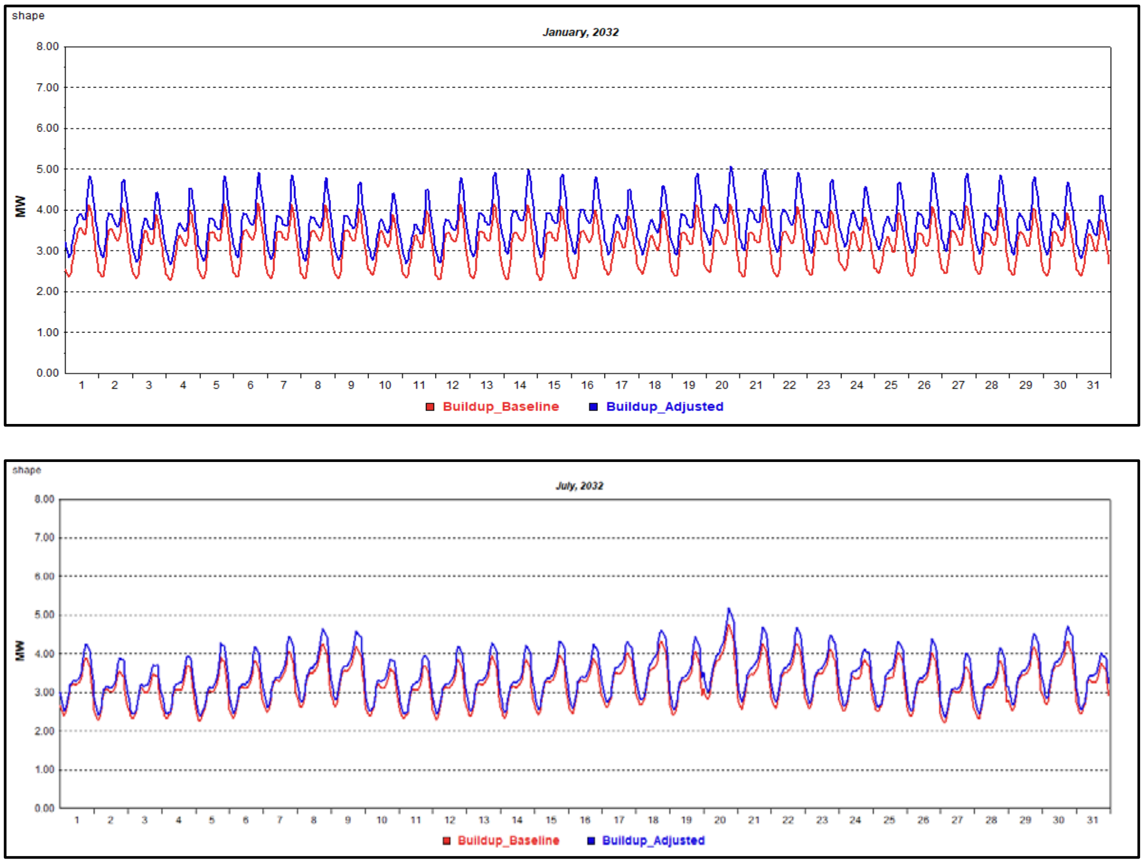
TABLE 4: EV, PV, AND CCHP FORECAST

Incremental New Tech Units			
Year	# Of Electric Vehicles	PV Installed Capacity (kW)	# Of HP Units
2022	11	4	28
2023	25	8	58
2024	43	12	91
2025	67	15	127
2026	98	16	164
2027	137	18	205
2028	187	18	248
2029	248	19	294
2030	323	19	338
2031	411	20	376
2032	511	21	412
2033	621	21	446
2034	736	21	480
2035	850	21	514
2036	956	22	549
2037	1,049	22	584
2038	1,126	22	619
2039	1,188	22	654
2040	1,234	23	690
2041	1,269	23	725
2042	1,293	23	761

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 1 shows the baseline and adjusted hourly load forecast for January and July 2032.

FIGURE 1: BASELINE AND ADJUSTED HOURLY LOAD FORECAST (2032)



All future load growth is driven by EV and CCHP adoption. By 2032, EVs and CCHP add significant load. Table 5 shows the adjusted energy and demand forecasts.

TABLE 5: ENOSBURG ENERGY FORECAST (MWH)

Energy and Peak								
Year	Energy (MWh)	Chg	Summer Peak (MW)	Chg	Peak Time	Winter Peak (MW)	Chg	Peak Time
2022	27,354		4.84		7/19/22 6:00 PM	4.50		3/1/22 6:00 PM
2023	27,308	-0.2%	4.86	0.4%	7/18/23 6:00 PM	4.52	0.4%	3/1/23 6:00 PM
2024	27,249	-0.2%	4.87	0.3%	7/16/24 6:00 PM	4.52	0.1%	3/5/24 6:00 PM
2025	27,089	-0.6%	4.87	0.0%	7/15/25 6:00 PM	4.55	0.6%	3/4/25 6:00 PM
2026	27,048	-0.1%	4.89	0.3%	7/21/26 6:00 PM	4.58	0.5%	3/3/26 6:00 PM
2027	27,029	-0.1%	4.91	0.4%	7/20/27 6:00 PM	4.63	1.1%	3/2/27 6:00 PM
2028	27,139	0.4%	4.95	0.7%	7/18/28 6:00 PM	4.67	0.8%	3/1/28 6:00 PM
2029	27,284	0.5%	4.99	0.9%	7/17/29 6:00 PM	4.72	1.1%	3/6/29 6:00 PM
2030	27,497	0.8%	5.05	1.2%	7/16/30 6:00 PM	4.81	2.0%	1/22/30 6:00 PM
2031	27,740	0.9%	5.11	1.2%	7/15/31 6:00 PM	4.94	2.7%	1/21/31 6:00 PM
2032	28,063	1.2%	5.19	1.5%	7/20/32 6:00 PM	5.06	2.5%	1/20/32 6:00 PM
2033	28,311	0.9%	5.25	1.3%	7/19/33 6:00 PM	5.21	2.9%	1/18/33 6:00 PM
2034	28,612	1.1%	5.33	1.4%	7/18/34 6:00 PM	5.32	2.1%	1/24/34 6:00 PM
2035	28,934	1.1%	5.40	1.4%	7/17/35 6:00 PM	5.47	2.8%	1/23/35 6:00 PM
2036	29,284	1.2%	5.48	1.5%	7/15/36 6:00 PM	5.61	2.6%	1/22/36 6:00 PM
2037	29,489	0.7%	5.54	1.1%	7/21/37 6:00 PM	5.73	2.1%	1/20/37 6:00 PM
2038	29,658	0.6%	5.60	1.0%	7/20/38 6:00 PM	5.85	2.0%	1/19/38 6:00 PM
2039	29,770	0.4%	5.64	0.8%	7/19/39 6:00 PM	5.95	1.7%	1/18/39 6:00 PM
2040	29,862	0.3%	5.67	0.6%	7/17/40 6:00 PM	5.99	0.6%	1/24/40 6:00 PM
2041	29,857	0.0%	5.70	0.4%	7/16/41 6:00 PM	6.07	1.4%	1/22/41 6:00 PM
2042	29,866	0.0%	5.72	0.4%	7/15/42 6:00 PM	6.14	1.1%	1/21/42 6:00 PM
22-32		**0.3%**		**0.7%**			**1.2%**	
32-42		**0.6%**		**1.0%**			**1.9%**	
22 - 42		**0.4%**		**0.8%**			**1.6%**	

Projected EV, CCHP, and have a significant impact on load with energy requirements averaging 0.4% annual growth. This compares with the baseline annual sales decline of 0.6%. Winter adjusted peak averages 1.6% annual demand growth and summer 0.8% average annual growth. Enosburg switches to winter peaking by 2035.

Table 6 and Table 7 summarizes the demand forecast by base load and technologies.

Itron

TABLE 6: ENOSBURG SUMMER PEAK FORECAST (MW)

Summer Peaks (MW)							
Year	Baseline	Chg	EV	PV	HP	Adjusted	Chg
2022	4.82		0.01	0.00	0.01	4.84	
2023	4.82	0.1%	0.02	0.00	0.02	4.86	0.4%
2024	4.82	-0.1%	0.03	0.00	0.03	4.87	0.3%
2025	4.79	-0.5%	0.04	0.00	0.04	4.87	0.0%
2026	4.78	-0.3%	0.06	0.00	0.05	4.89	0.3%
2027	4.77	-0.3%	0.08	0.00	0.06	4.91	0.4%
2028	4.76	-0.1%	0.11	0.00	0.08	4.95	0.7%
2029	4.75	-0.2%	0.15	0.00	0.09	4.99	0.9%
2030	4.75	0.0%	0.20	0.00	0.10	5.05	1.2%
2031	4.75	-0.1%	0.25	0.00	0.11	5.11	1.2%
2032	4.75	0.1%	0.31	0.00	0.12	5.19	1.5%
2033	4.74	-0.3%	0.38	0.00	0.13	5.25	1.3%
2034	4.73	-0.1%	0.45	0.00	0.14	5.33	1.4%
2035	4.73	-0.1%	0.52	0.00	0.15	5.40	1.4%
2036	4.73	0.1%	0.59	0.00	0.16	5.48	1.5%
2037	4.72	-0.2%	0.65	0.00	0.17	5.54	1.1%
2038	4.72	-0.1%	0.69	0.00	0.18	5.60	1.0%
2039	4.71	-0.1%	0.73	0.00	0.19	5.64	0.8%
2040	4.71	0.0%	0.76	0.00	0.20	5.67	0.6%
2041	4.70	-0.2%	0.78	0.00	0.22	5.70	0.4%
2042	4.70	-0.1%	0.80	0.00	0.23	5.72	0.4%
22-42		**-0.1%**					**0.8%**

TABLE 7: ENOSBURG WINTER PEAK FORECAST (MW)

Winter Peaks (MW)							
Year	Baseline	Chg	EV	PV	HP	Adjusted	Chg
2022	4.48		0.01	0.00	0.02	4.50	
2023	4.47	-0.2%	0.02	0.00	0.03	4.52	0.4%
2024	4.44	-0.7%	0.03	0.00	0.06	4.52	0.1%
2025	4.42	-0.2%	0.05	0.00	0.08	4.55	0.6%
2026	4.40	-0.5%	0.07	0.00	0.10	4.58	0.5%
2027	4.40	-0.1%	0.10	0.00	0.13	4.63	1.1%
2028	4.38	-0.4%	0.14	0.00	0.15	4.67	0.8%
2029	4.35	-0.7%	0.18	0.00	0.18	4.72	1.1%
2030	4.11	-5.6%	0.31	0.00	0.39	4.81	2.0%
2031	4.11	0.0%	0.39	0.00	0.44	4.94	2.7%
2032	4.10	-0.3%	0.49	0.00	0.48	5.06	2.5%
2033	4.10	-0.1%	0.60	0.00	0.52	5.21	2.9%
2034	4.06	-1.0%	0.71	0.00	0.56	5.32	2.1%
2035	4.05	0.0%	0.82	0.00	0.60	5.47	2.8%
2036	4.06	0.2%	0.92	0.00	0.63	5.61	2.6%
2037	4.04	-0.4%	1.01	0.00	0.68	5.73	2.1%
2038	4.04	0.0%	1.09	0.00	0.72	5.85	2.0%
2039	4.04	0.0%	1.15	0.00	0.76	5.95	1.7%
2040	4.00	-1.0%	1.19	0.00	0.79	5.99	0.6%
2041	4.00	0.0%	1.23	0.00	0.84	6.07	1.4%
2042	4.00	0.0%	1.25	0.00	0.89	6.14	1.1%
22-42		**-0.5%**					**1.6%**

Baseline summer system peak averages 0.2% growth per year largely driven by air conditioning saturation projections. Expected PV adoption negatively impacts energy growth but 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
- Lyndon
- Morrisville
- Northfield
- Orleans
- Swanton

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

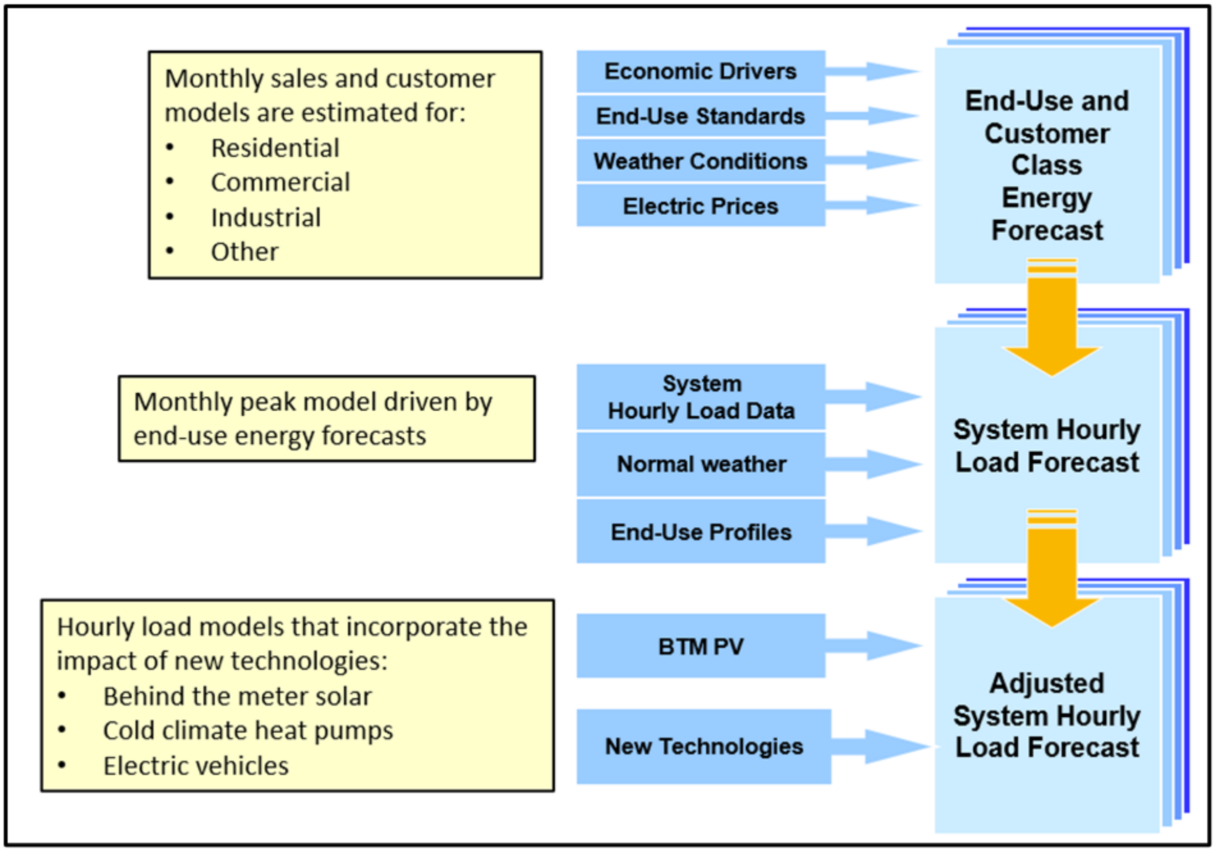
Forecast includes:

- 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 where 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 2 shows the general forecasting approach.

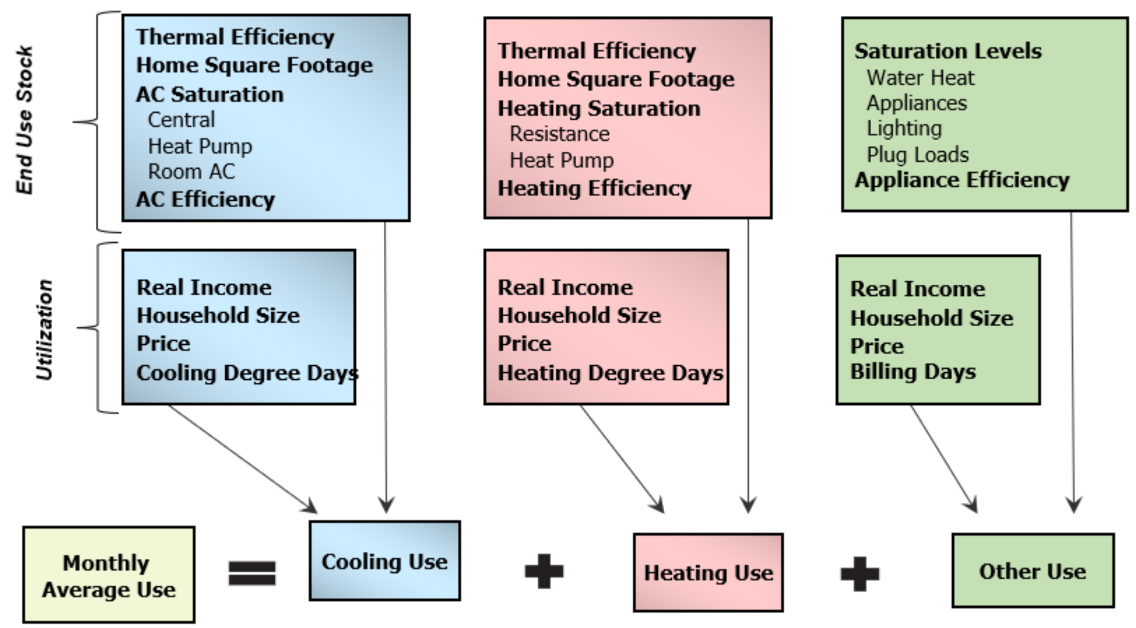
FIGURE 2: FORECASTING FRAMEWORK



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 household, employment and state output, end-use intensity trends (reflecting both change in end-use ownership and efficiency improvement), state energy efficiency activity, and trended normal heating degree-days (HDD) and cooling degree-days (CDD) that reflect measured temperature trends. 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 3 shows the SAE model specification.

FIGURE 3: RESIDENTIAL STATISTICALLY ADJUSTED END-USE (SAE) MODEL

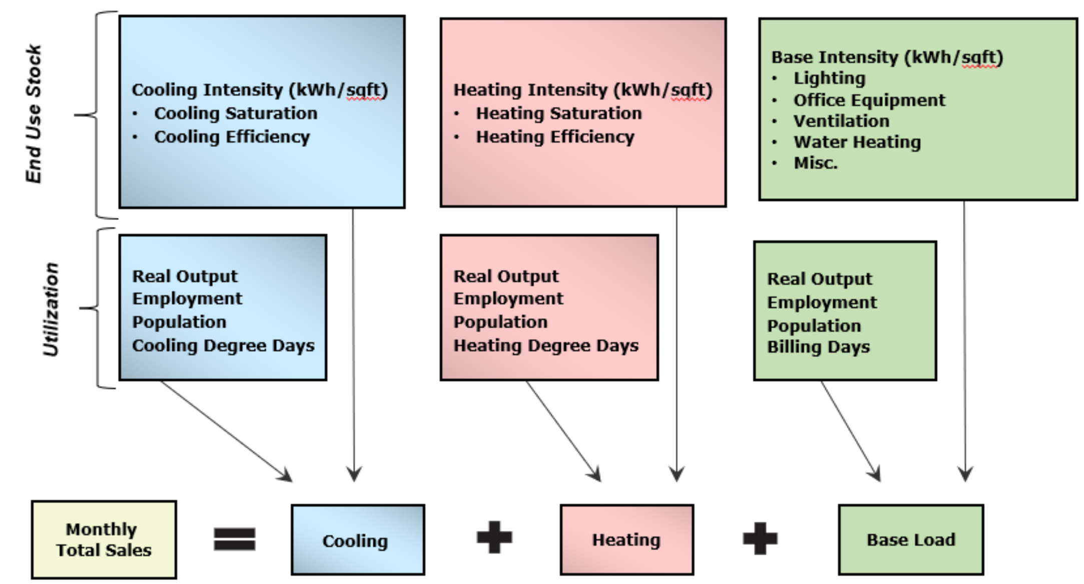


$$AvgUse_m = a + b_c \times XCool_m + b_h \times XHeat_m + b_o \times XOther_m + b_e \times EE_m$$

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 EE variable proved to be statistically insignificant largely because long-term efficiency trends are already captured in the constructed end-use variables. A monthly average use regression model is used to estimate the coefficients a, b_c, b_h, and b_o,, and b_e that effectively *statistically adjust* the initial estimates of monthly heating, cooling, and base-use to actual customer usage. 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. Historical and forecasted end-use energy requirements can be calculated by combining the estimated model coefficients with the cooling (XCool), heating (XHeat), and other use (XOther) where XCool and XHeat are constructed using normal weather.

A similar SAE model specification is used for the commercial customer classes. Figure 4 shows the commercial model specification.

FIGURE 4: 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 that incorporate state economic output, employment, and population. The end-use 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 the end-use model variables where XHeat and XCool incorporate normal weather.

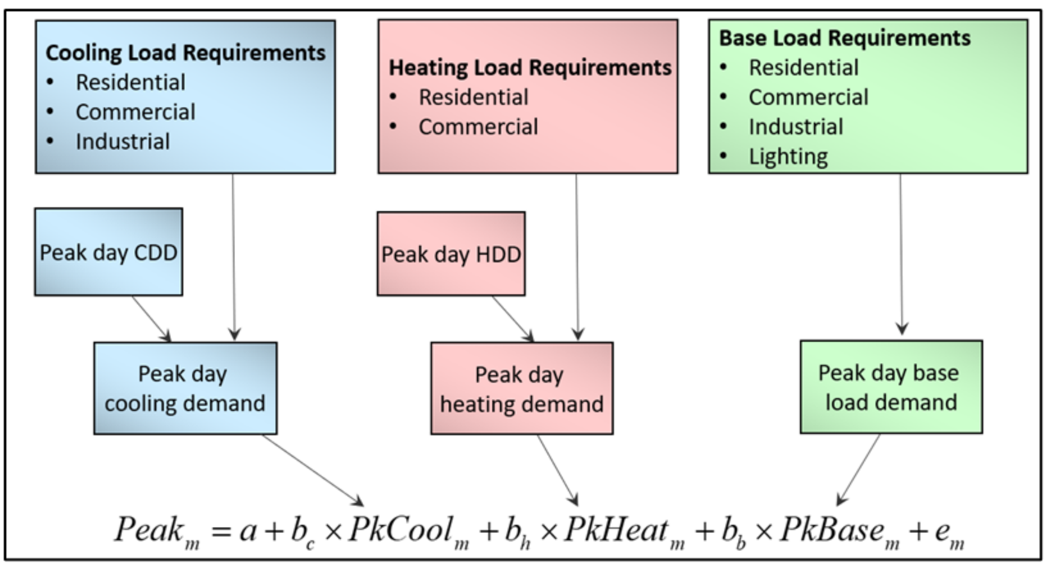
For many of the municipalities the large C&I customer class is dominated by a few companies; there is often significant variation in month-to-month sales data making it difficult to fit an SAE model specification. For these classes, either a more generalized econometric or trend model is used. This is 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 from the 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 the CCHP incentive program turns heat loads positive and also adds some cooling load (a significant share of heat pump cooling is displacing room air conditioning). The baseline peak model excludes CCHP, PV, and EV charging loads. Figure 5 shows the baseline peak demand model.

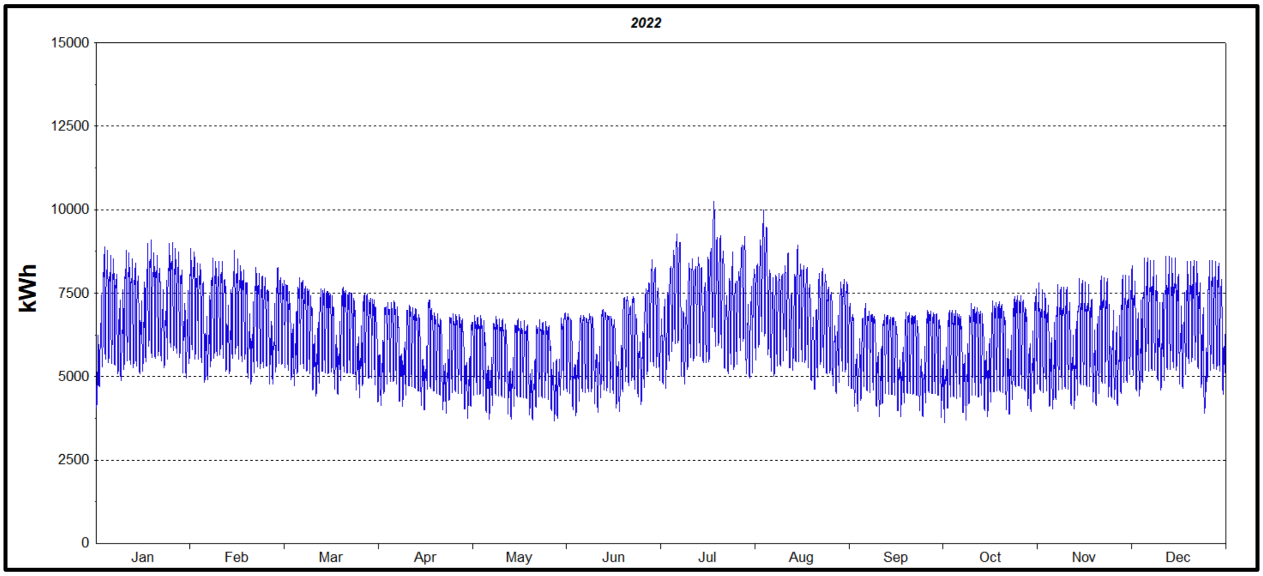
FIGURE 5: BASELINE PEAK MODEL



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. Hourly profile models are estimated at the gross level – that is, estimated hourly solar generation is added back to measured system hourly loads. The profile model captures expected hourly loads for typical weather conditions, day of the week, season, holidays, and hours of light. Figure 6 shows the baseline profile for Enosburg.

FIGURE 6: ENOSBURG LOAD PROFILE



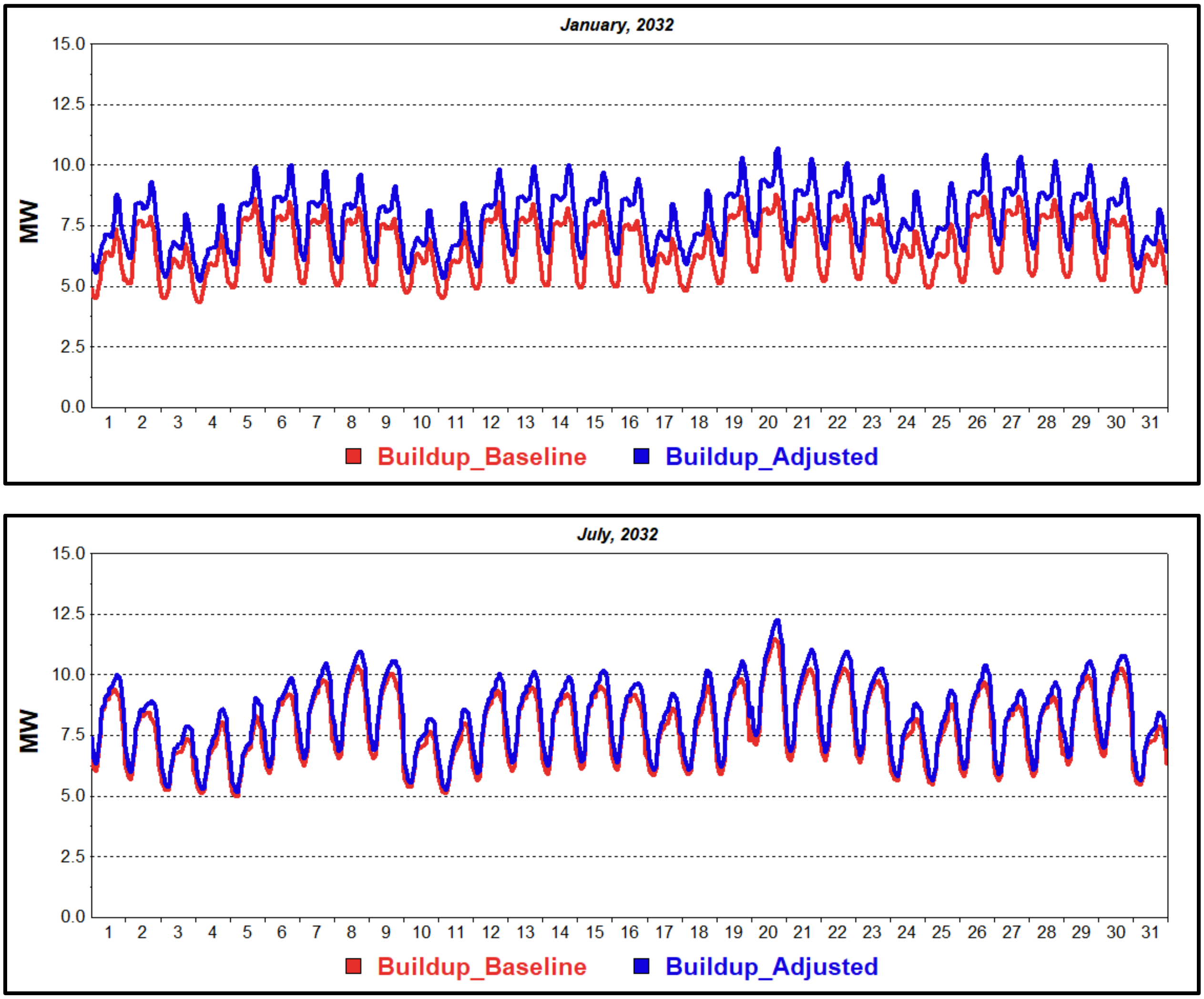
The baseline hourly load forecast is derived by combining the baseline energy and peak forecasts with the system hourly load profile. Increase in energy requirements and peak demand lifts the baseline profile over time. The baseline hourly load forecast reflects customer projections, economic impacts, weather conditions, and energy efficiency impacts.

Adjusted Load Forecast

For the most part, baseline loads are flat to declining as efficiency gains have outweighed customer and economic growth. What is driving forecast growth is the expected market penetration of CCHPs and EVs. Both incentivized CCHP and EVs are expected to play a significant role in achieving state greenhouse gas reduction. While PV generation continues to increase, capacity projections slow from the current pace. Further, PV has a minimum impact on peak demand as PV 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. PV generation, new heat pump and EV sales are combined with associated technology hourly load profiles and layered on the baseline hourly load forecast. Figure 7 compares the Enosburg baseline and hourly load forecast for 2032.

FIGURE 7: ENOSBURG SYSTEM HOURLY LOAD COMPARISON (2032)



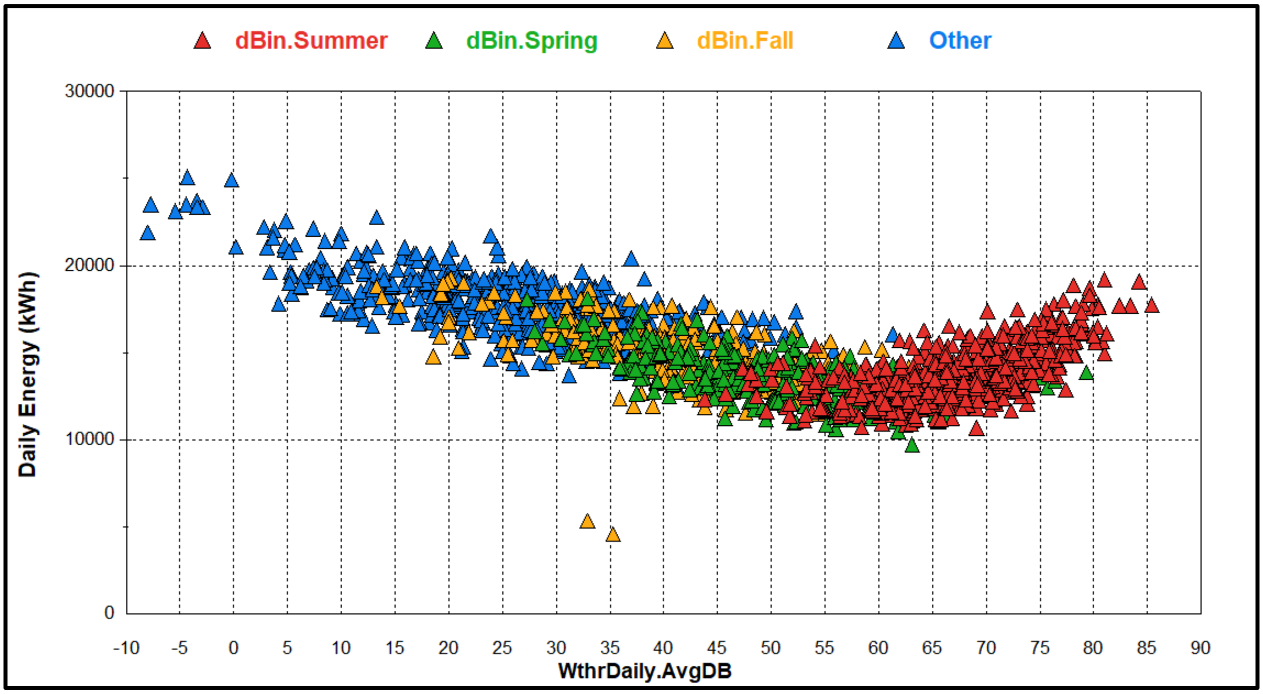
The initial baseline forecast is shown in red and the forecasted adjusted PV, EV, and heat pumps in blue. Solar adoption combined with EV charging shifts the summer peak into the evening hours while heat pumps and EV charging have a much larger impact on winter peaks than summer peaks.

FORECAST ASSUMPTIONS

Weather

Member forecasts use weather from either Burlington or Rutland depending on location. Burlington airport weather data is used for eight 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 8 illustrates what this relationship looks like at the system level for Enosburg.

FIGURE 8: LOAD-TEMPERATURE RELATIONSHIP (ENOSBURG)



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 the 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 9 and Figure 10 that show 20-year degree-day moving average against actual degree days.

FIGURE 9: HEATING TREND

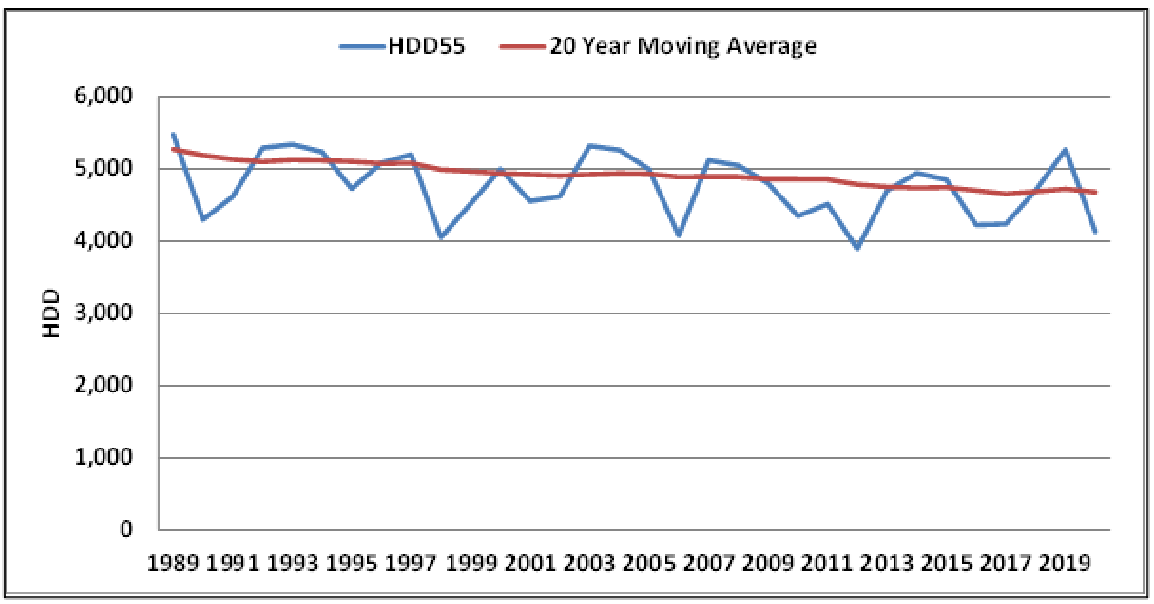
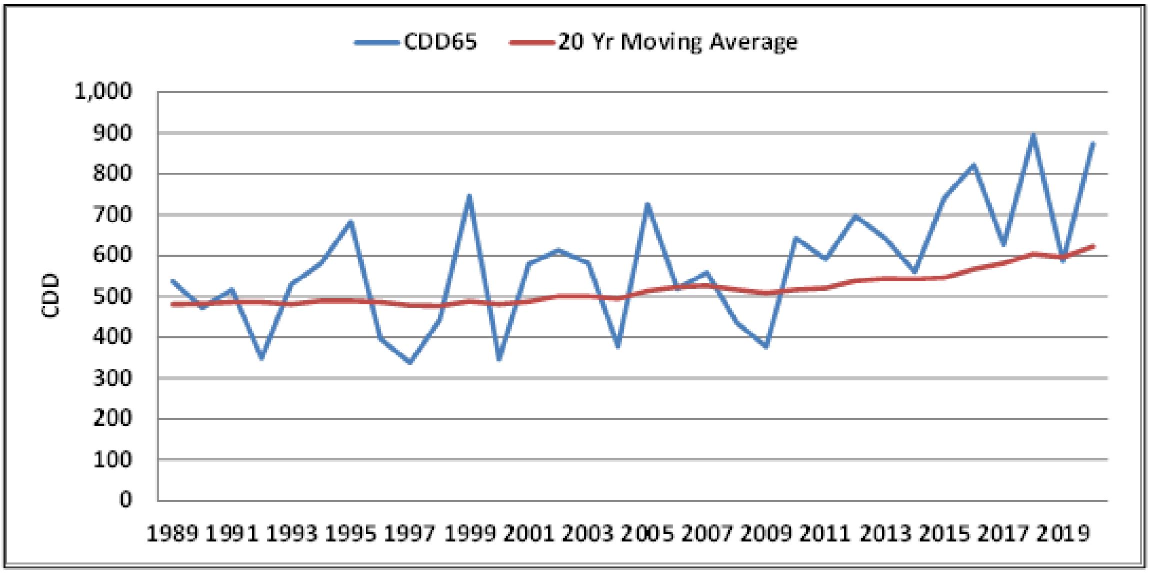


FIGURE 10: COOLING TREND



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

Figure 11 and Figure 12 compare actual, 20-year normal, and trended HDD and CDD.

FIGURE 11: NORMAL AND TRENDED NORMAL HDD

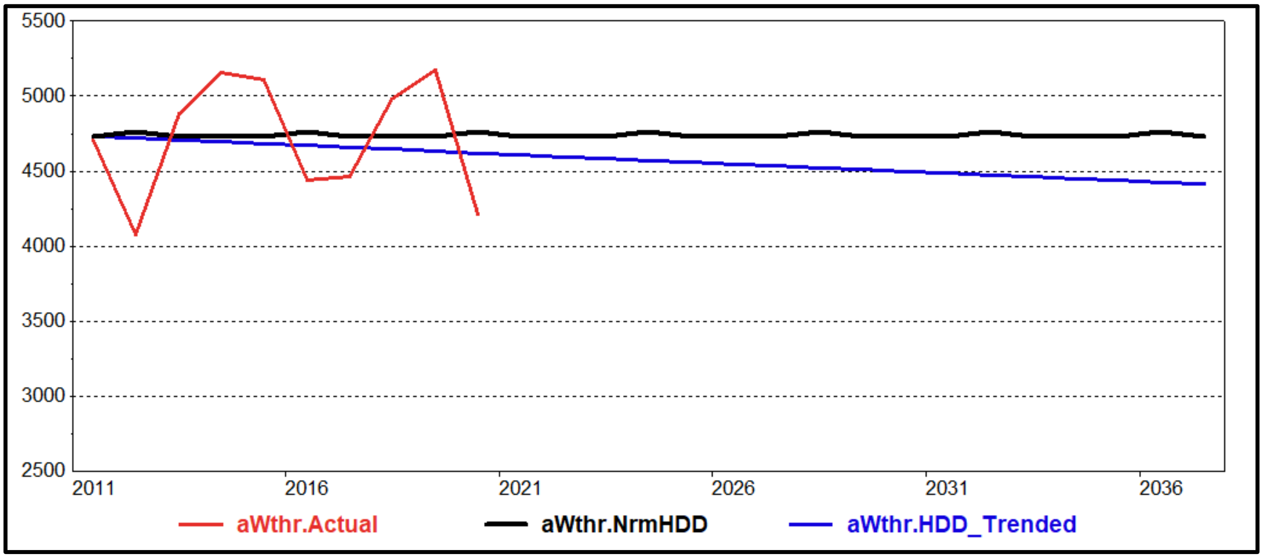
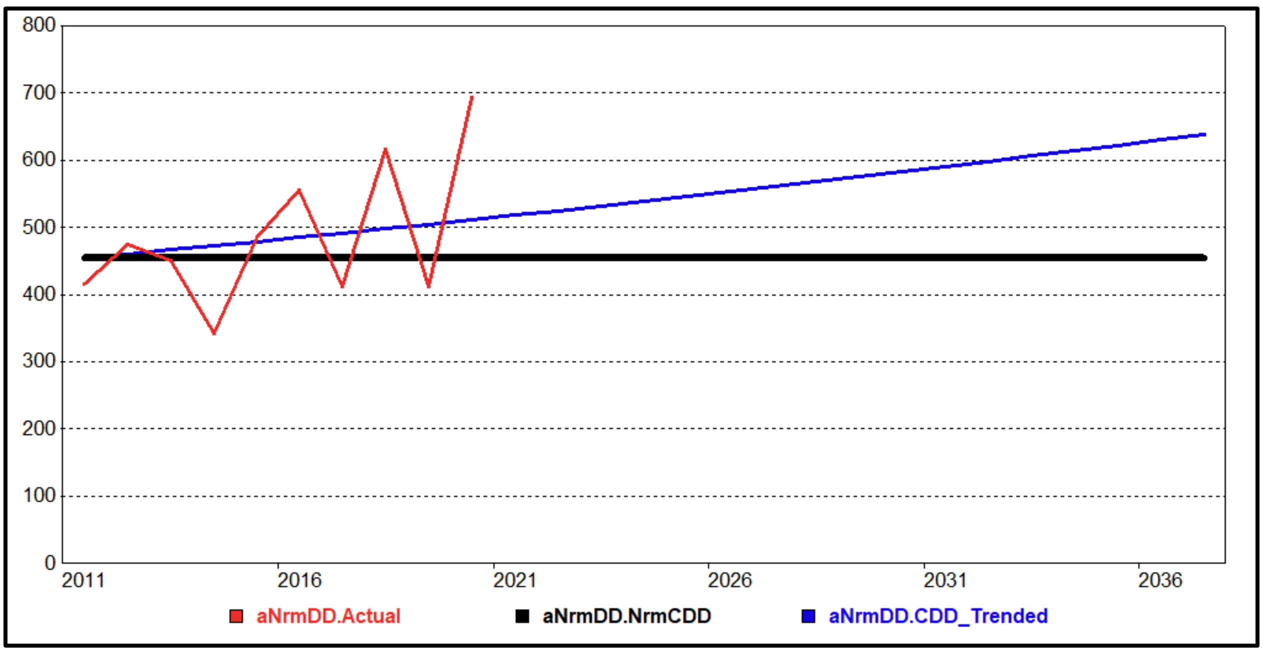


FIGURE 12: NORMAL AND TRENDED NORMAL CDD



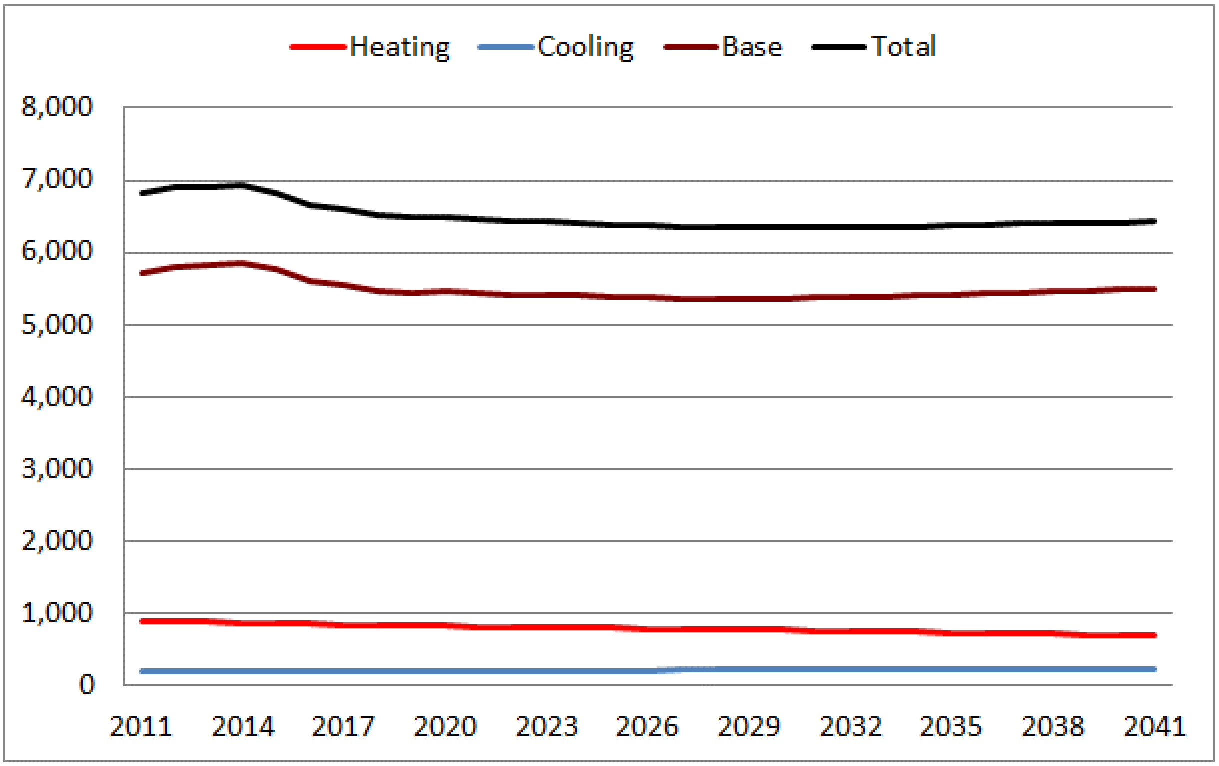
Based on historical data, CDD are expected to increase 1.3% per year and number of HDD decline 0.3% per year.

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 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 13 shows residential end-use intensities aggregated into heating, cooling, base, and total intensity.

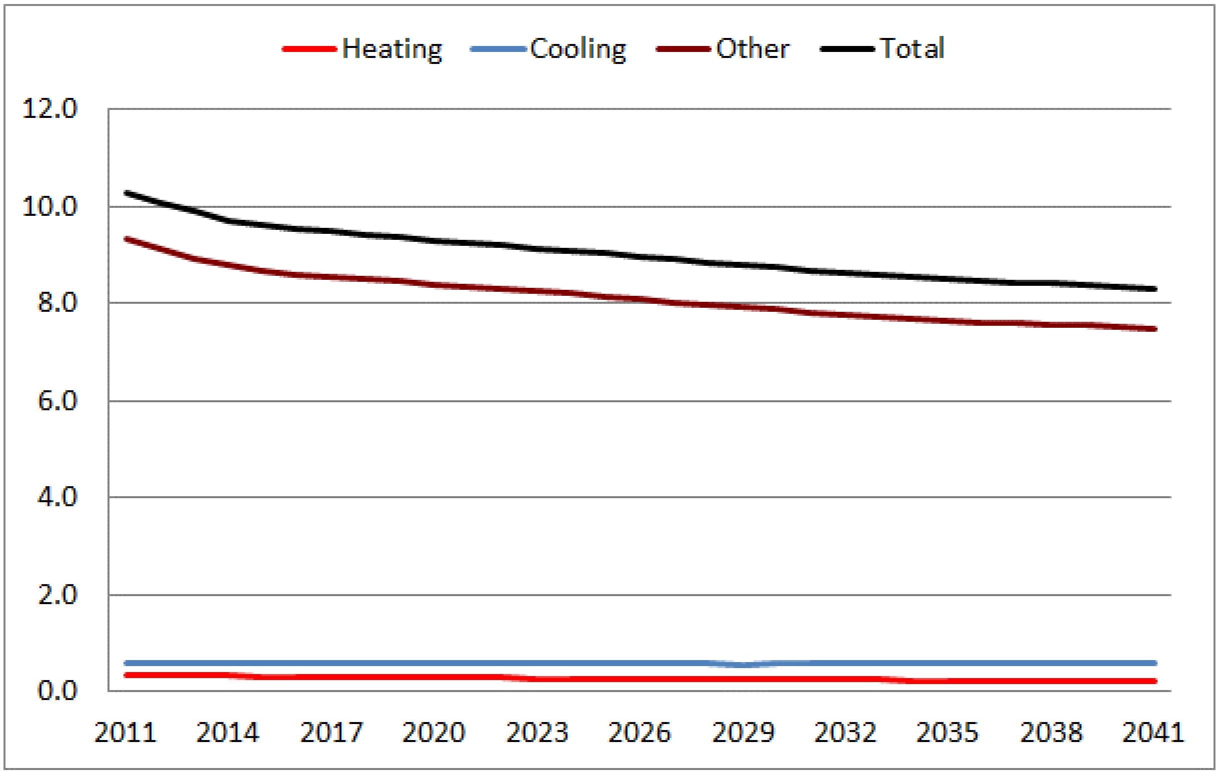
FIGURE 13: RESIDENTIAL SAE INDICES (KWH/HOUSEHOLD)



Since 2012, total residential intensity has declined 0.7% annually with the conversion from incandescent and fluorescent 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 14 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 14: COMMERCIAL SAE INDICES (KWH/HOUSEHOLD)

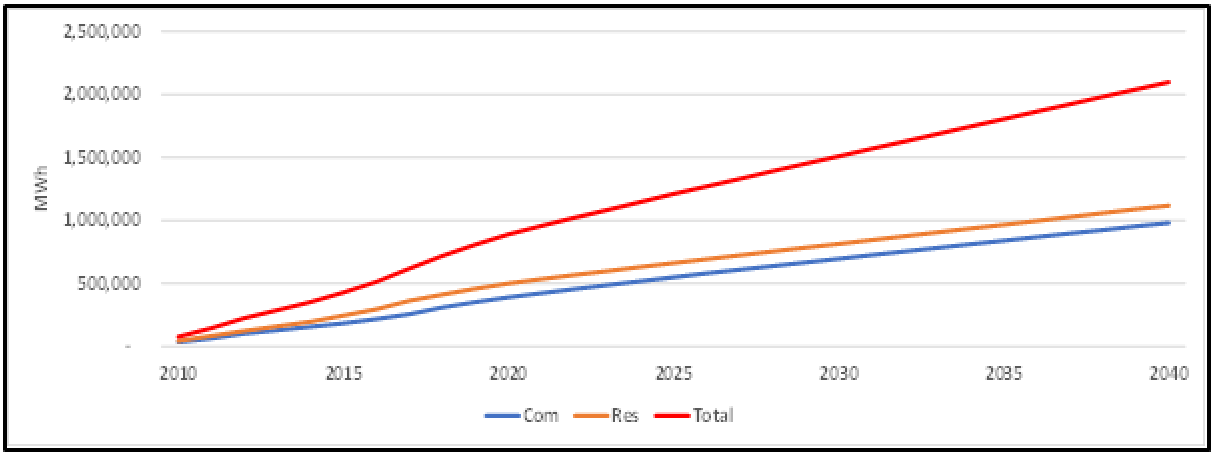


In general, there has been a long-term decline in commercial sales largely driven by efficiency gains. Commercial energy intensity has declined 1.2% annually over the last ten years; commercial intensity is projected to decline another 0.7% over the next ten years.

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 adjusts 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 15 shows the current state Demand Resource Plan (DRP) cumulative historical and projected savings.

FIGURE 15: 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 8 shows historical and projected economic outlook.

TABLE 8: 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%

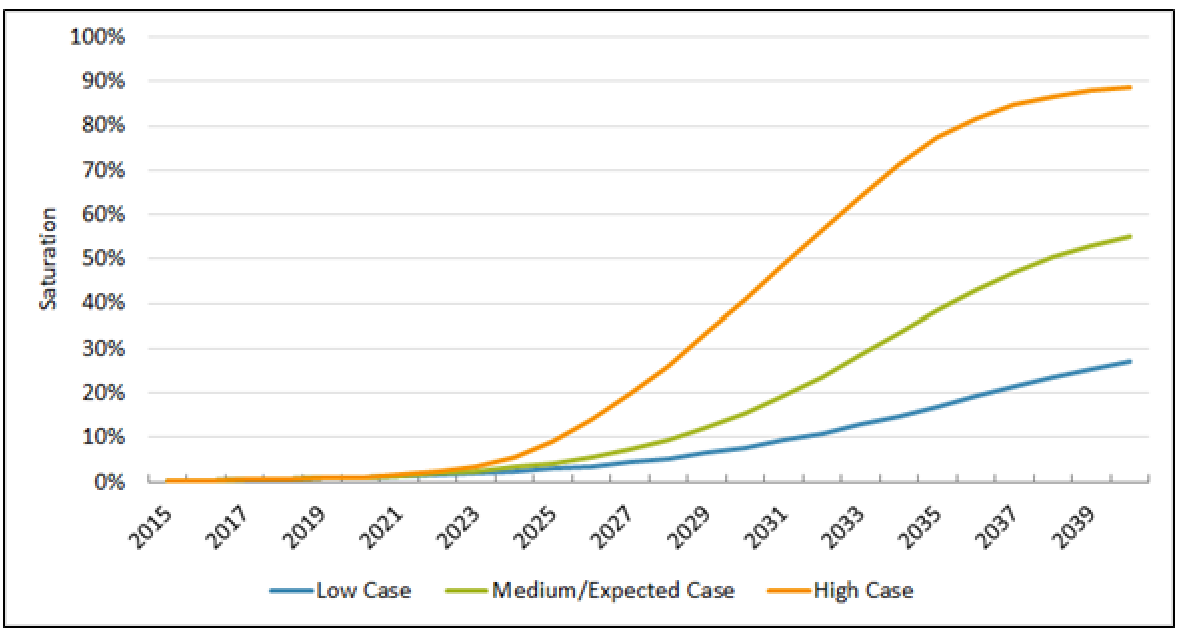
In 2020, state output (GDP) dropped 3.2% and employment declined 8.3% while personal income increased 5.9%. The large increase in real income is a result of government financial stimulus designed to counter the COVID employment impact. Moody's projects economic recovery to pre-pandemic levels by 2022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

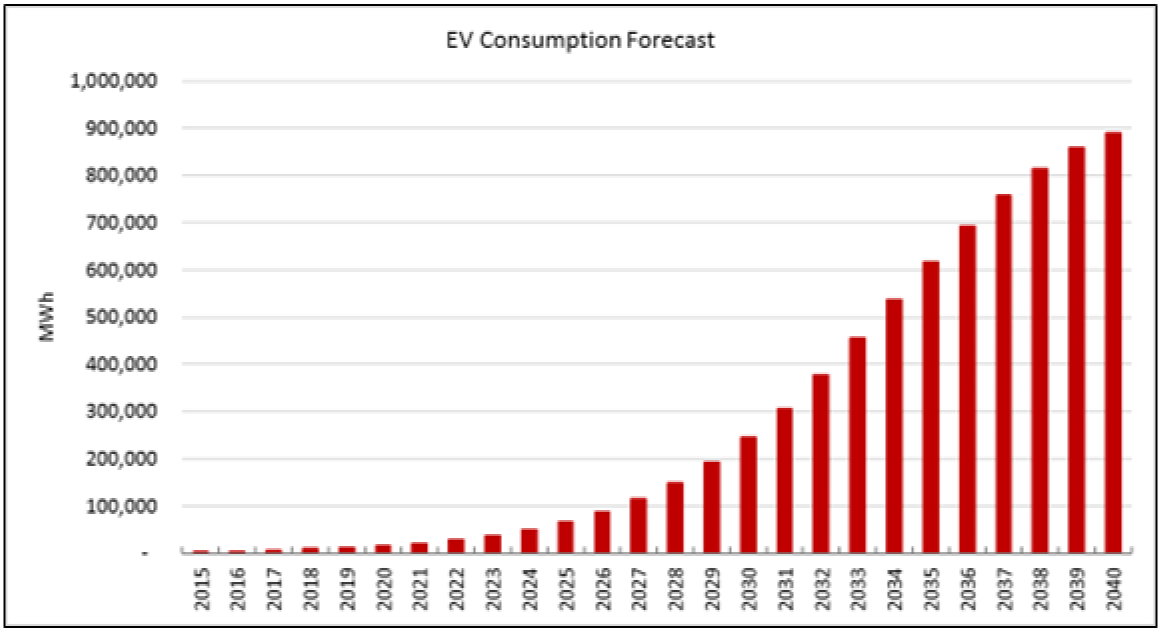
The electric vehicle (EV) forecast was developed by the VEIC as part of VELCO 2021 Long-Range Transmission Plan. VEIC provided three forecast scenarios; low, medium, and high, based on saturation targets for light-duty registered vehicles. The expected case (used in the VPPSA forecast) assumes that over 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 16 shows the projected adoption paths.

FIGURE 16: 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 17 shows state EV electric consumption for the expected case.

FIGURE 17: EXPECTED CASE STATE EV ELECTRICITY FORECAST

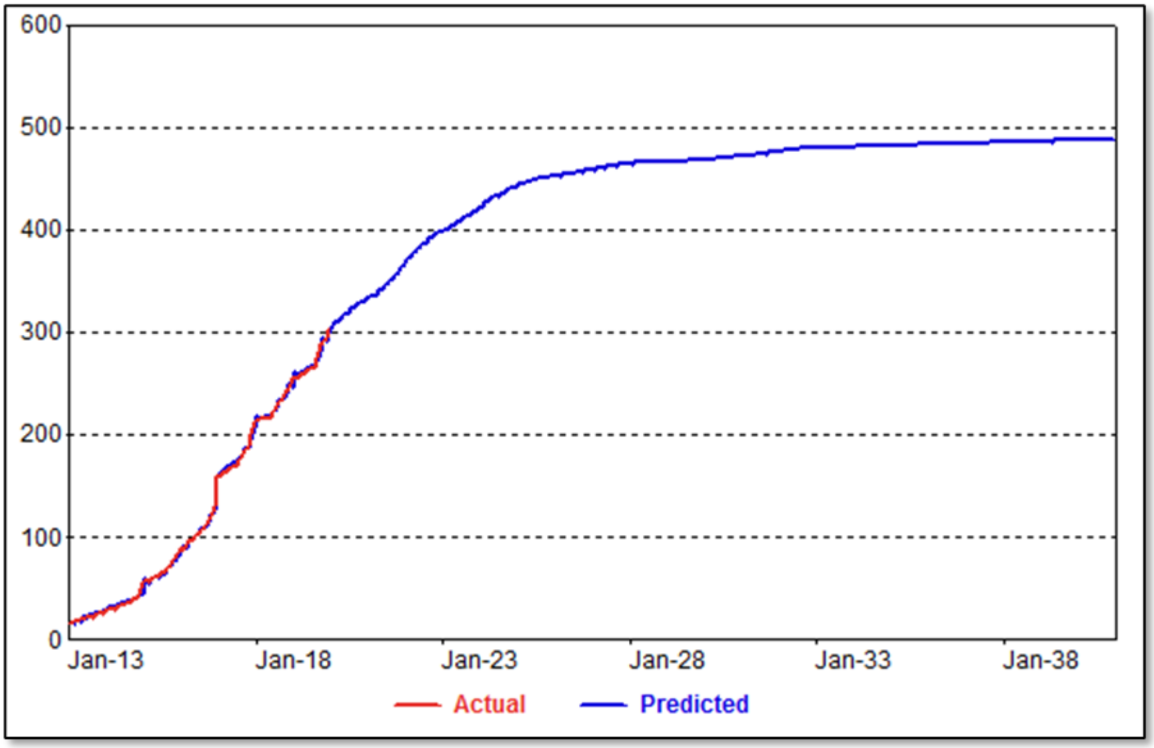


State EV sales are allocated to VPPSA member utilities based on each members' share of statewide number of residential customers.

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 18 shows state capacity forecast.

FIGURE 18: STATE SOLAR CAPACITY FORECAST (MW)

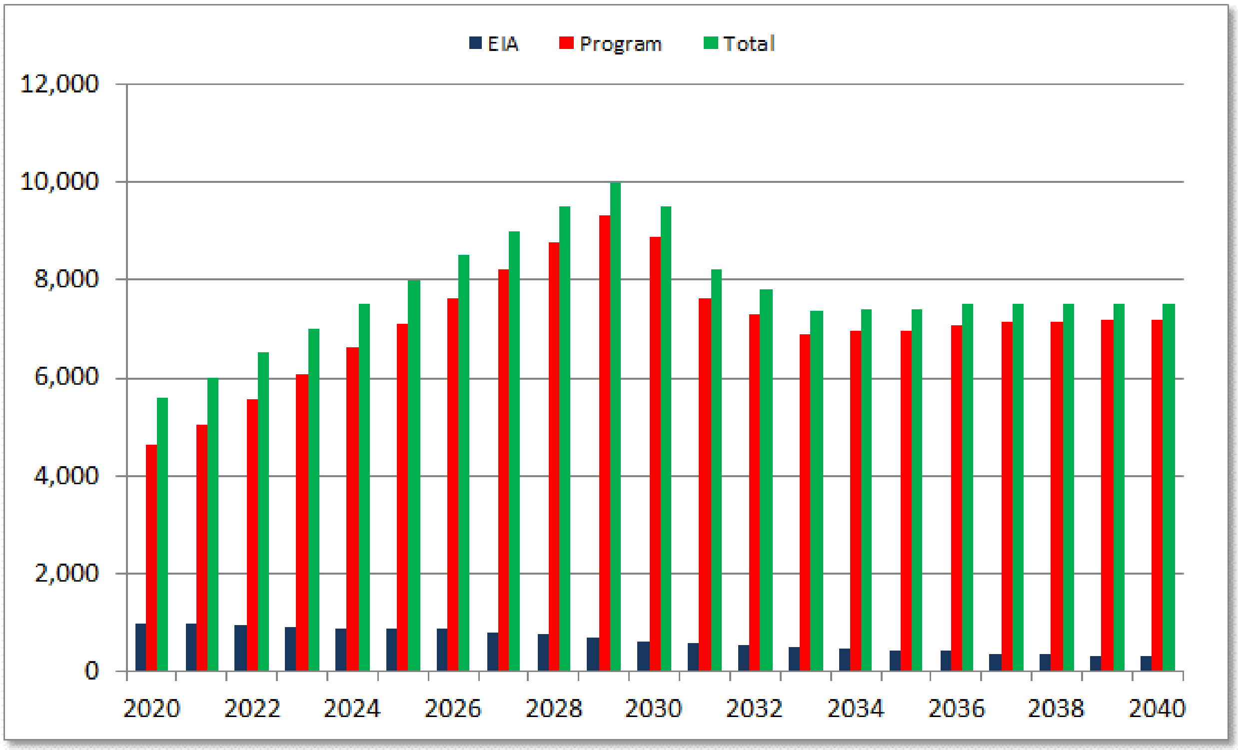


We expect BTM solar adoption to begin to slow by 2025 as system costs begin to flatten out and the number potential solar customers slows. We project over 450 MW of installed solar capacity by 2032. This translates into nearly 650,000 MWh based on monthly load factors derived from Vermont solar generation 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

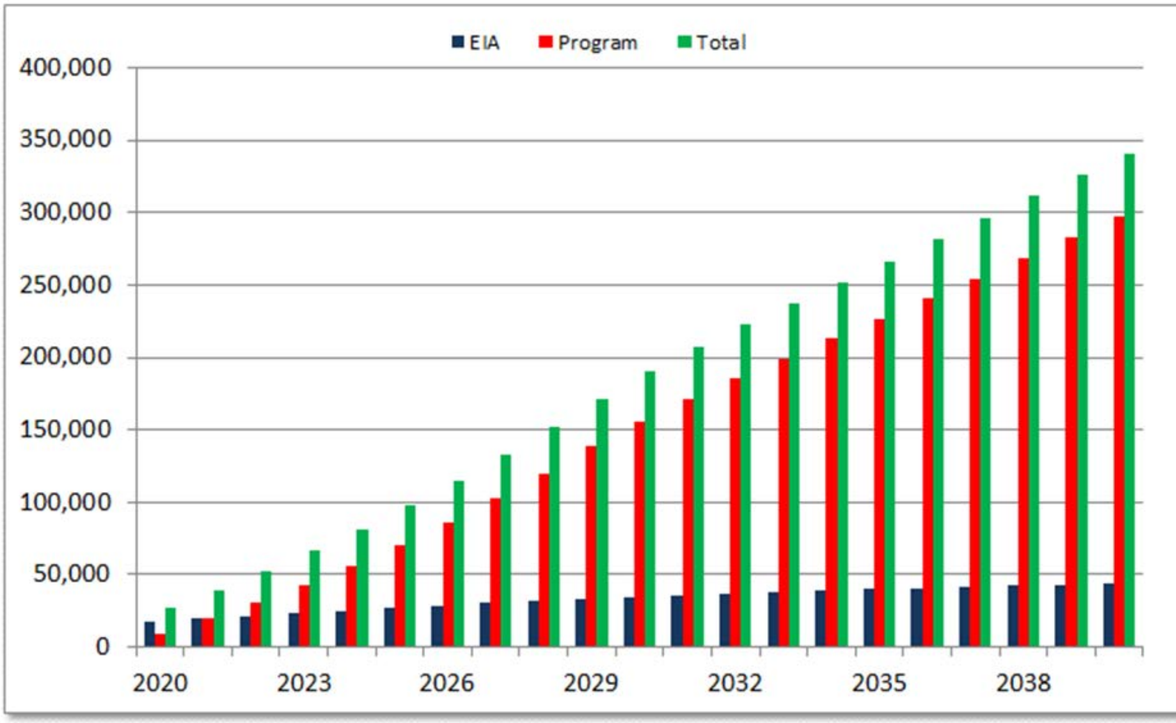
As part of state efforts to reduce CO_2 emissions, the state has launched a program to promote CCHP by offering financial incentives including rebates and 0 interest financing. The primary target are homes that heat with oil, propane, and wood. VEIC along with input from the DPS developed a long-term 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 19 shows state CCHP unit projections.

FIGURE 19: STATE CCHP FORECAST (UNITS PER YEAR)



VEIC further translated unit projections into electricity use based on recent CCHP measurement studies. Figure 20 shows projected state-level CCHP energy forecast.

FIGURE 20: 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 Average Use Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructRes.XHeat	0.583	0.137	4.248	0.00%
mStructRes.LagXHeat	0.515	0.156	3.291	0.13%
mStructRes.XCool	1.108	0.354	3.131	0.22%
mStructRes.LagXCool	1.923	0.3	6.411	0.00%
mStructRes.XOther	1.291	0.032	39.959	0.00%
mCovid.ResIndex	29.454	10.871	2.709	0.77%
mBin.Mar	41.335	17.326	2.386	1.86%
mBin.Apr	152.398	18.596	8.195	0.00%
mBin.Oct	-55.167	18.959	-2.91	0.43%
mBin.Nov	-30.257	18.152	-1.667	9.82%

Model Statistics	
Iterations	1
Adjusted Observations	130
Deg. of Freedom for Error	120
R-Squared	0.738
Adjusted R-Squared	0.719
AIC	7.73
BIC	7.951
Log-Likelihood	-676.94
Model Sum of Squares	715,945.05
Sum of Squared Errors	253,737.42
Mean Squared Error	2,114.48
Std. Error of Regression	45.98
Mean Abs. Dev. (MAD)	35.78
Mean Abs. % Err. (MAPE)	4.75%
Durbin-Watson Statistic	1.984

Residential Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mEcon.HHs	5.871	0.146	40.138	0.00%
AR(1)	0.984	0.018	54.112	0.00%
MA(1)	0.16	0.088	1.813	7.21%

Model Statistics	
Iterations	10
Adjusted Observations	131
Deg. of Freedom for Error	128
R-Squared	0.984
Adjusted R-Squared	0.984
AIC	2.751
BIC	2.817
Log-Likelihood	-363.06
Model Sum of Squares	123,374.51
Sum of Squared Errors	1,959.09
Mean Squared Error	15.31
Std. Error of Regression	3.91
Mean Abs. Dev. (MAD)	3
Mean Abs. % Err. (MAPE)	0.20%
Durbin-Watson Statistic	2.041

Itron

Small Commercial Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructCom.XHeat	398046.004	84544.41	4.708	0.00%
mStructCom.LagXHeat	395625.547	80900.62	4.89	0.00%
mStructCom.XCool	207968.048	27999.19	7.428	0.00%
mStructCom.LagXCool	73179.435	27897	2.623	0.98%
mStructCom.XOther	18056.526	375.292	48.113	0.00%
mBin.Bef14	-20197.102	2631.915	-7.674	0.00%

Model Statistics	
Iterations	1
Adjusted Observations	129
Deg. of Freedom for Error	123
R-Squared	0.578
Adjusted R-Squared	0.561
AIC	19
BIC	19.133
Log-Likelihood	-1,402.53
Model Sum of Squares	28,697,226,602.37
Sum of Squared Errors	20,975,828,148.02
Mean Squared Error	170,535,188.20
Std. Error of Regression	13,058.91
Mean Abs. Dev. (MAD)	10,432.64
Mean Abs. % Err. (MAPE)	5.62%
Durbin-Watson Statistic	2.184

Large Commercial Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructCom.XHeat	485038.093	106661.3	4.547	0.00%
mStructCom.XCool	179921.438	46256.15	3.89	0.02%
mStructCom.LagXCool	118639.326	43376.18	2.735	0.72%
mStructCom.XOther	27462.945	605.275	45.373	0.00%
mBin.Yr11	-37756.937	6917.625	-5.458	0.00%
mBin.Aft17	-11685.318	3919.033	-2.982	0.35%

Model Statistics	
Iterations	1
Adjusted Observations	129
Deg. of Freedom for Error	123
R-Squared	0.426
Adjusted R-Squared	0.403
AIC	20.007
BIC	20.14
Log-Likelihood	-1,467.50
Model Sum of Squares	42,595,154,479.94
Sum of Squared Errors	57,430,111,944.31
Mean Squared Error	466,911,479.22
Std. Error of Regression	21,608.13
Mean Abs. Dev. (MAD)	16,926.15
Mean Abs. % Err. (MAPE)	6.69%
Durbin-Watson Statistic	2.463

Industrial Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mBin.Yr11	-62775.371	19463.96	-3.225	0.17%
mBin.Bef14	45718.57	12593.28	3.63	0.04%
mBin.Jan	558807.022	17370.88	32.169	0.00%
mBin.Feb	513531.384	16509.63	31.105	0.00%
mBin.Mar	538595.761	17501.08	30.775	0.00%
mBin.Apr	568824.78	16842.88	33.772	0.00%
mBin.May	618738.346	17352.12	35.658	0.00%
mBin.Jun	649608.792	16536.51	39.283	0.00%
mBin.Jul	698666.17	16537.15	42.248	0.00%
mBin.Aug	681832.894	16504.45	41.312	0.00%
mBin.Sep	679756.801	16504.31	41.187	0.00%
mBin.Oct	657361.749	16469.66	39.913	0.00%
mBin.Nov	592576.524	17504.61	33.853	0.00%
mBin.Dec	667106.939	18550.3	35.962	0.00%
mCovid.NResIndex	-38058.465	11968.97	-3.18	0.19%

Model Statistics	
Iterations	1
Adjusted Observations	126
Deg. of Freedom for Error	111
R-Squared	0.639
Adjusted R-Squared	0.593
AIC	21.879
BIC	22.217
Log-Likelihood	-1,542.15
Model Sum of Squares	558,026,320,950.05
Sum of Squared Errors	315,380,461,751.67
Mean Squared Error	2,841,265,421.19
Std. Error of Regression	53,303.52
Mean Abs. Dev. (MAD)	39,771.21
Mean Abs. % Err. (MAPE)	6.32%
Durbin-Watson Statistic	2.151

Other Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	0.5	0	0	1
Seasonal	0	0	0	1

Model Statistics	
Iterations	0
Adjusted Observations	12
Deg. of Freedom for Error	10
R-Squared	1
Adjusted R-Squared	1
AIC	1.#QO
BIC	1.#QO
Log-Likelihood	1.#R
Model Sum of Squares	0
Sum of Squared Errors	0
Mean Squared Error	0
Std. Error of Regression	0
Mean Abs. Dev. (MAD)	0
Mean Abs. % Err. (MAPE)	0.00%
Durbin-Watson Statistic	0

Peak Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mWthr.CoolVar60	26.47	2.514	10.528	0.00%
mCPkEndUses.BaseVar	1.535	0.013	116.993	0.00%
mBin.Aft20	122.868	51.882	2.368	1.95%
mBin.Mar	665.005	65.584	10.14	0.00%
mBin.Apr	617.209	70.08	8.807	0.00%
mBin.May	-388.616	68.034	-5.712	0.00%
mBin.Jun	-202.374	66.961	-3.022	0.31%
mBin.Sep	-309.853	66.226	-4.679	0.00%
mBin.Oct	-284.234	67.379	-4.218	0.01%
mBin.Nov	-251.411	65.956	-3.812	0.02%
MA(1)	0.199	0.093	2.146	3.39%

Model Statistics	
Iterations	10
Adjusted Observations	131
Deg. of Freedom for Error	120
R-Squared	0.599
Adjusted R-Squared	0.566
AIC	10.625
BIC	10.866
Log-Likelihood	-870.79
Model Sum of Squares	6,806,235.79
Sum of Squared Errors	4,555,422.18
Mean Squared Error	37,961.85
Std. Error of Regression	194.84
Mean Abs. Dev. (MAD)	143.4
Mean Abs. % Err. (MAPE)	3.32%
Durbin-Watson Statistic	1.947

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 VOEF'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 VOEF'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. VOEF will include an evaluation of the cost-effectiveness of these measures in the next Tier III annual plan.

Village of Enosburg Falls Electric

2024 IRP Projected Capital Expenditures - Reference Case

Specific Projects		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Hydro Investment																					
Hydro (generic)	Prod	75,000	75,000	76,650	78,336	80,060	81,821	83,621	85,461	87,341	89,262	91,226	93,233	95,284	97,381	99,523	101,712	103,950	106,237	108,574	110,963
Hydro #1 bearing replacement	Prod																				
Hydro #1 Controls repair	Prod																				
Trash Rack Replacement	Prod																				
Pedestrian Bridge Replacement	Prod																				
Kendall Plant Control Upgrade	Prod																				
Water Filtration System	Prod		40,000																		
Kendall Building Maintenance	Prod		200,000																		
Village Hydro #1	Prod		30,000																		
FERC relicense Legal & Studies	Prod																				
misc hydro (deductible)	Prod																				
Misc Hydro	Prod	131,414																			
Smaller Bucket Truck	10 General		300,000										372,932								
Larger Bucket Truck	10 General					350,000										435,088					
Digger Truck	10 General	280,000										348,070									
Utility pickip Truck	7 General				45,000							52,405							61,027		
3/4 TON Pickup	7 General			100,000							116,454							135,617			
Office & computing Equipment	General	10,909	11,149	11,395	11,645	11,902	12,163	12,431	12,705	12,984	13,270	13,562	13,860	14,165	14,477	14,795	15,121	15,453	15,793	16,141	16,496
	non-recu Trans																				
	Trans																				
Boston Post Road Line Upgrade	Dist	135,000																			
Reconducter section of Rt 108/Browns Pond	Dist	6,500																			
West Enosburg Road Line Upgrade	Dist			125,000																	
Carpenter Road Line Upgrade	Dist			25,000																	
AMI	Dist	210,000	210,000																		
Line & Pole Upgrade Dufy Hill Rd.	Dist																				
Misc distribution	Dist	15,238																			
Subtotal Specific Projects		**$ 864,062**	**$ 866,149**	**$ 338,045**	**$ 134,982**	**$ 441,961**	**$ 93,984**	**$ 96,052**	**$ 98,165**	**$ 100,325**	**$ 218,987**	**$ 505,263**	**$ 480,026**	**$ 109,449**	**$ 111,857**	**$ 549,406**	**$ 116,833**	**$ 255,020**	**$ 183,058**	**$ 124,715**	**$ 127,458**
Routine/Recurring/Misc plant & general	**75% Dist / 25% Gen'l**	40,880	41,779	42,699	43,638	44,598	45,579	46,582	47,607	48,654	49,724	50,818	51,936	53,079	54,247	55,440	56,660	57,906	59,180	60,482	61,813
Total Construction		**$ 904,942**	**$ 907,929**	**$ 380,743**	**$ 178,620**	**$ 486,559**	**$ 139,564**	**$ 142,634**	**$ 145,772**	**$ 148,979**	**$ 268,711**	**$ 556,081**	**$ 531,962**	**$ 162,528**	**$ 166,104**	**$ 604,846**	**$ 173,493**	**$ 312,926**	**$ 242,238**	**$ 185,197**	**$ 189,271**

Functional Summary:		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Prod		206,414	345,000	76,650	78,336	80,060	81,821	83,621	85,461	87,341	89,262	91,226	93,233	95,284	97,381	99,523	101,712	103,950	106,237	108,574	110,963
General	25%	301,129	321,594	122,069	67,555	373,051	23,558	24,077	24,606	25,148	142,155	426,741	399,777	27,435	28,038	463,743	29,285	165,546	91,616	31,261	31,949
Distribution	75%	397,398	241,335	182,024	32,728	33,448	34,184	34,936	35,705	36,490	37,293	38,114	38,952	39,809	40,685	41,580	42,495	43,430	44,385	45,362	46,360
Transmission		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Construction		$ 904,942	$ 907,929	$ 380,743	$ 178,620	$ 486,559	$ 139,564	$ 142,634	$ 145,772	$ 148,979	$ 268,711	$ 556,081	$ 531,962	$ 162,528	$ 166,104	$ 604,846	$ 173,493	$ 312,926	$ 242,238	$ 185,197	$ 189,271

Village of Enosburg Falls Electric
IRP Reference Case Projected Financial Results 2024-2043

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Revenue Requirement Increase %	3.56%	6.79%	9.63%	3.84%	0.24%	1.41%	1.55%	0.38%	0.37%	2.48%
Retail Load MWH	26,988	26,828	26,788	26,769	26,877	27,021	27,231	27,472	27,792	28,037
Retail Load Growth	0.1%	-0.6%	-0.2%	-0.1%	0.4%	0.5%	0.8%	0.9%	1.2%	0.9%
Retail Revenue Requirements										
Production O&M	$ 156,384	$ 159,824	$ 163,340	$ 166,934	$ 170,606	$ 174,359	$ 178,195	$ 182,116	$ 186,122	$ 190,217
Purchased Power &TBO	2,959,280	3,099,466	3,499,319	3,614,589	3,720,775	3,815,718	3,942,105	4,005,739	3,898,803	4,072,478
TIER III projects	86,660	103,151	121,877	140,608	160,454	132,035	148,958	167,292	187,259	207,058
Other O&M	438,240	464,709	474,562	484,909	495,488	506,602	517,969	529,594	541,484	553,643
A&G	973,488	994,905	1,016,792	1,039,162	1,062,023	1,085,388	1,109,266	1,133,670	1,158,611	1,184,101
Depreciation	266,481	287,899	309,387	318,399	339,667	351,183	354,486	357,862	361,312	364,838
Taxes	211,346	222,610	230,263	244,625	252,462	255,372	259,098	263,137	266,618	271,415
Total Operating Expenses	$ 5,091,879	$ 5,332,563	$ 5,815,540	$ 6,009,225	$ 6,201,476	$ 6,320,658	$ 6,510,079	$ 6,639,410	$ 6,600,210	$ 6,843,750
Other Income & Expense										
Misc. Electric Revenue	16,197	16,553	16,917	17,289	17,670	18,058	18,456	18,862	19,277	19,701
Other Income	553,843	565,297	578,389	591,918	600,869	610,260	618,768	627,088	635,103	643,209
Interest Expense	132,263	165,139	170,760	185,531	192,814	180,465	167,989	155,401	142,716	130,513
Net Income	$ 132,236	$ 165,112	$ 170,732	$ 185,504	$ 192,786	$ 180,438	$ 167,962	$ 155,373	$ 142,689	$ 130,486
Total Revenue Requirement	$ 4,786,338	$ 5,080,964	$ 5,561,726	$ 5,771,053	$ 5,968,538	$ 6,053,243	$ 6,208,807	$ 6,304,234	$ 6,231,235	$ 6,441,839
Average Retail Rate $/MWH	$ 177.4	$ 189.4	$ 207.6	$ 215.6	$ 222.1	$ 224.0	$ 228.0	$ 229.5	$ 224.2	$ 229.8
YOY rate change	3.6%	6.8%	9.6%	3.8%	3.0%	0.9%	1.8%	0.6%	-2.3%	2.5%
Average Rates - CAGR										
Key Cash Related Items										
Cash provided by operations	$ 179,100	$ 230,300	$ 275,684	$ 304,900	$ 477,465	$ 489,382	$ 484,089	$ 483,049	$ 494,488	$ 485,136
Bonds Issued	$ 878,077	$ 886,251	$ 356,197	$ 36,352	$ 389,732	$ -	$ -	$ -	$ -	$ -
Construction expenditure	$ (904,942)	$ (907,929)	$ (380,743)	$ (178,620)	$ (486,559)	$ (139,564)	$ (142,634)	$ (145,772)	$ (148,979)	$ (268,711)
Long Term Debt Principal Payment	$ (162,608)	$ (202,886)	$ (215,696)	$ (253,513)	$ (272,561)	$ (271,947)	$ (271,947)	$ (271,947)	$ (266,947)	$ (247,225)
Operating reserve Balance	$ 243,357	$ 249,093	$ 284,535	$ 193,655	$ 301,731	$ 379,603	$ 449,111	$ 514,441	$ 593,003	$ 562,203
TIER (EBIT/INT) (excludes transco principal)	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**
Debt Service Coverage (EBITDA/(P&I))	**1.8**	**1.7**	**1.7**	**1.6**	**1.6**	**1.6**	**1.6**	**1.6**	**1.6**	**1.7**
Debt % of Capital Structure	**15%**	**17%**	**18%**	**17%**	**17%**	**16%**	**15%**	**14%**	**13%**	**12%**
Reserve % of 90 day O&M Target	**21%**	**21%**	**22%**	**14%**	**22%**	**27%**	**31%**	**35%**	**40%**	**36%**

	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Revenue Requirement Increase %	2.52%	-3.52%	2.39%	1.95%	2.40%	2.68%	2.40%	2.51%	2.65%	2.68%
Retail Load MWH	28,335	28,653	29,000	29,203	29,370	29,481	29,569	29,658	29,747	29,836
Retail Load Growth	1.1%	1.1%	1.2%	0.7%	0.6%	0.4%	0.3%	0.3%	0.3%	0.3%
Retail Revenue Requirements										
Production O&M	$ 194,402	$ 198,679	$ 203,049	$ 207,517	$ 212,082	$ 216,748	$ 221,516	$ 226,390	$ 231,370	$ 236,460
Purchased Power &TBO	4,230,230	3,981,946	4,185,761	4,337,551	4,483,290	4,642,911	4,818,624	4,990,924	5,181,458	5,382,128
TIER III projects	227,550	252,080	258,029	265,361	273,692	286,942	293,249	300,886	309,364	318,080
Other O&M	566,079	578,797	591,806	605,110	618,717	632,768	647,146	661,858	676,912	692,318
A&G	1,210,151	1,236,774	1,263,983	1,291,791	1,320,210	1,349,255	1,378,938	1,409,275	1,440,279	1,471,965
Depreciation	371,198	384,359	396,950	400,797	404,728	419,043	423,150	430,556	436,289	440,672
Taxes	280,082	288,772	290,100	295,485	304,422	309,649	316,328	322,184	327,678	333,417
Total Operating Expenses	$ 7,079,691	$ 6,921,407	$ 7,189,679	$ 7,403,610	$ 7,617,141	$ 7,857,315	$ 8,098,951	$ 8,342,072	$ 8,603,350	$ 8,875,041
Other Income & Expense										
Misc. Electric Revenue	20,134	20,577	21,030	21,492	21,965	22,448	22,942	23,447	23,963	24,490
Other Income	649,287	655,272	661,875	670,598	679,253	673,439	681,342	686,747	693,199	700,816
Interest Expense	132,005	132,945	120,446	107,946	109,259	96,033	78,948	66,573	54,198	41,823
Net Income	$ 131,977	$ 132,918	$ 120,418	$ 107,918	$ 109,231	$ 96,005	$ 78,920	$ 66,545	$ 54,170	$ 41,795
Total Revenue Requirement	$ 6,674,251	$ 6,511,421	$ 6,747,638	$ 6,927,384	$ 7,134,414	$ 7,353,466	$ 7,552,534	$ 7,764,996	$ 7,994,556	$ 8,233,352
Average Retail Rate $/MWH	$ 235.5	$ 227.2	$ 232.7	$ 237.2	$ 242.9	$ 249.4	$ 255.4	$ 261.8	$ 268.8	$ 276.0
YOY rate change	2.5%	-3.5%	2.4%	1.9%	2.4%	2.7%	2.4%	2.5%	2.6%	2.7%
Average Rates - CAGR										
Key Cash Related Items										
Cash provided by operations	$ 492,282	$ 505,629	$ 504,922	$ 495,399	$ 499,722	$ 511,338	$ 498,360	$ 493,391	$ 486,749	$ 478,757
Bonds Issued	$ 274,979	$ 273,118	$ -	$ -	$ 290,792	$ -	$ 21,006	$ -	$ -	$ -
Construction expenditure	$ (556,081)	$ (531,962)	$ (162,528)	$ (166,104)	$ (604,846)	$ (173,493)	$ (312,926)	$ (242,238)	$ (185,197)	$ (189,271)
Long Term Debt Principal Payment	$ (255,696)	$ (269,352)	$ (269,352)	$ (269,352)	$ (283,891)	$ (283,891)	$ (284,942)	$ (284,942)	$ (284,942)	$ (284,942)
Operating reserve Balance	$ 517,688	$ 495,122	$ 568,164	$ 628,108	$ 529,885	$ 583,839	$ 505,338	$ 471,549	$ 488,160	$ 492,704
TIER (EBIT/INT) (excludes transco principal)	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**
Debt Service Coverage (EBITDA/(P&I))	**1.6**	**1.6**	**1.6**	**1.6**	**1.6**	**1.6**	**1.6**	**1.6**	**1.6**	**1.6**
Debt % of Capital Structure	**12%**	**12%**	**11%**	**10%**	**10%**	**8%**	**7%**	**6%**	**5%**	**4%**
Reserve % of 90 day O&M Target	**32%**	**32%**	**35%**	**37%**	**31%**	**33%**	**27%**	**25%**	**25%**	**24%**