Village of Johnson Water & Light Department

2025 Integrated Resource Plan

As Filed with the Public Utility Commission

VPPSA
Vermont Public Power Supply Authority

Executive Summary

Incorporated in 1894, the Village of Johnson Water & Light Department (JW&L) serves approximately 990 retail customers in the Village of Johnson as well as part of the Town of Johnson. Its largest customer is Northern Vermont University (previously Johnson State College), which makes up about 30% of its retail sales. JW&L's small municipal system has a large residential customer base of elderly and below median income residents, including a high percentage of renters. JW&L 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 JW&L is careful to balance maintaining reliability and reasonable cost levels with the need to deliver innovative programs to customers that provide practical value.

JW&L's distribution system serves a mix of residential, small commercial, and large commercial customers. Residential customers make up over 82% of the customer mix while accounting for 44% of JW&L's retail kWh sales. Approximately 113 small commercial and large commercial customers (about 11%) make up a little over 50% of retail usage. Northern Vermont University (NVU) makes up approximately 30% of the 50%, with the remaining retail sales going to public street and highway lighting customers.

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

JW&L is facing a period of relatively flat demand influenced by several competing factors, all of which carry some uncertainty. Continued adoption of solar net metering reduces demand although the pace at which net metering will grow in JW&L'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 JW&L's largest customers is currently anticipated, the potential does exist. JW&L 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

JW&L'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 hydro, solar, and other renewable sources.

When considering future electricity demand, JW&L seeks to supplement its existing resources with market contracts as well as new demand-side and supply resources. JW&L 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 sited, renewable and reliable. Market contracts have the advantage of being both scalable and customizable in terms of delivery at specific times and locations. JW&L anticipates regional availability of competitively priced renewable resources including solar, wind, and hydro. In addition to being a factor 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 JW&L sees potential for storage to play an important system and load management role and to enhance the local impact of distributed generation.

RESOURCE PLANS

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

There are three major resource decisions facing JW&L over the next five to ten years, beginning with the option for a five-year extension of the Fitchburg Landfill Contract beginning in 2027 and running thru 2031. With the expiration of two significant hydro and wind contracts representing about 28% of JW&L's energy resources at the end of 2027, JW&L will need to evaluate options to replace the bundled energy and REC products associated with the Brookfield and Stetson contracts. The third evaluation facing JW&L is whether to commit to a utility scale storage contract in the near future; recent experience of other VPPSAa members indicates that evaluation of the economic viability of a utility scale storage project may have potential.

The main sources of uncertainty expected to impact these decisions include the potential loss of any large customer load, uncertainty in market energy prices that may be influenced by the price of natural gas and pipeline transportation prices, uncertainty regarding electrification related load growth, and the cost of regional transmission service. Because JW&L is largely hedged for the long run in the capacity market, capacity prices are not a large source of uncertainty.

RENEWABLE ENERGY STANDARD

JW&L is subject to the Vermont Renewable Energy Standard (RES) which imposes an obligation for JW&L to obtain a portion of its energy requirements from renewable resources. The RES obligation increases over time and is stratified into four categories, Tier I, TIER II, TIER III and TIER IV. JW&L' s obligations under TIER I can be satisfied by owning or purchasing RECs from qualifying regional resources. TIER II obligations must be satisfied by owning or purchasing RECs from renewable resources located within Vermont. Satisfaction of JW&L's TIER III obligation involves energy transformation, or reduction of fossil fuel use within its territory. TIER III programs can consist of thermal efficiency measures, electrification of the transportation sector, and converting customers that rely on diesel generation to electric service, among other things. TIER IV obligations may be met with RECs from new renewable resources. By providing incentive programs to encourage conversion of traditional fossil fuel applications JW&L receives credits toward its TIER III obligation.

ELECTRICITY TRANSMISSION AND DISTRIBUTION

JW&L has a compact service territory as a result of being a small, municipal-owned electric utility and has benefitted from several major system improvements over the past 15 years. JW&L's system is approximately 5 square miles of service territory, consisting of 28 miles of distribution line operating at 4160/2400 volts, one substation, and one back-up substation. JW&L purchased a 15% interest in Morrisville Water & Light's (MW&L) 34.5 kV transmission line that runs from the Green Mountain Power substation in Johnson, to MW&L's Substation #3 in Morrisville, to the Vermont Transco, LLC 115kV substation in Stowe.

In addition to upgrading and routinely maintaining the system to ensure efficiency and reliability, JW&L is examining the need to modernize in order to enhance distribution system management in the face of growing system complexities related to climate change, energy market changes, distributed generation and the effects of intensifying electrification. JW&L has implemented a new GIS system and is currently engaged with VPPSA to install AMI. In addition, JW&L is currently collaborating with VPPSA and its members to develop a Tech Roadmap that will guide and lead to implementation, over the next few years, of more sophisticated distribution system management capabilities. Potential additions to the GIS and AMI systems include SCADA and DERMS systems. JW&L sees potential value to customers from utilizing rate design along with other incentive or load control programs as tools to manage both system and customer peak loads in unison.

Table of Contents

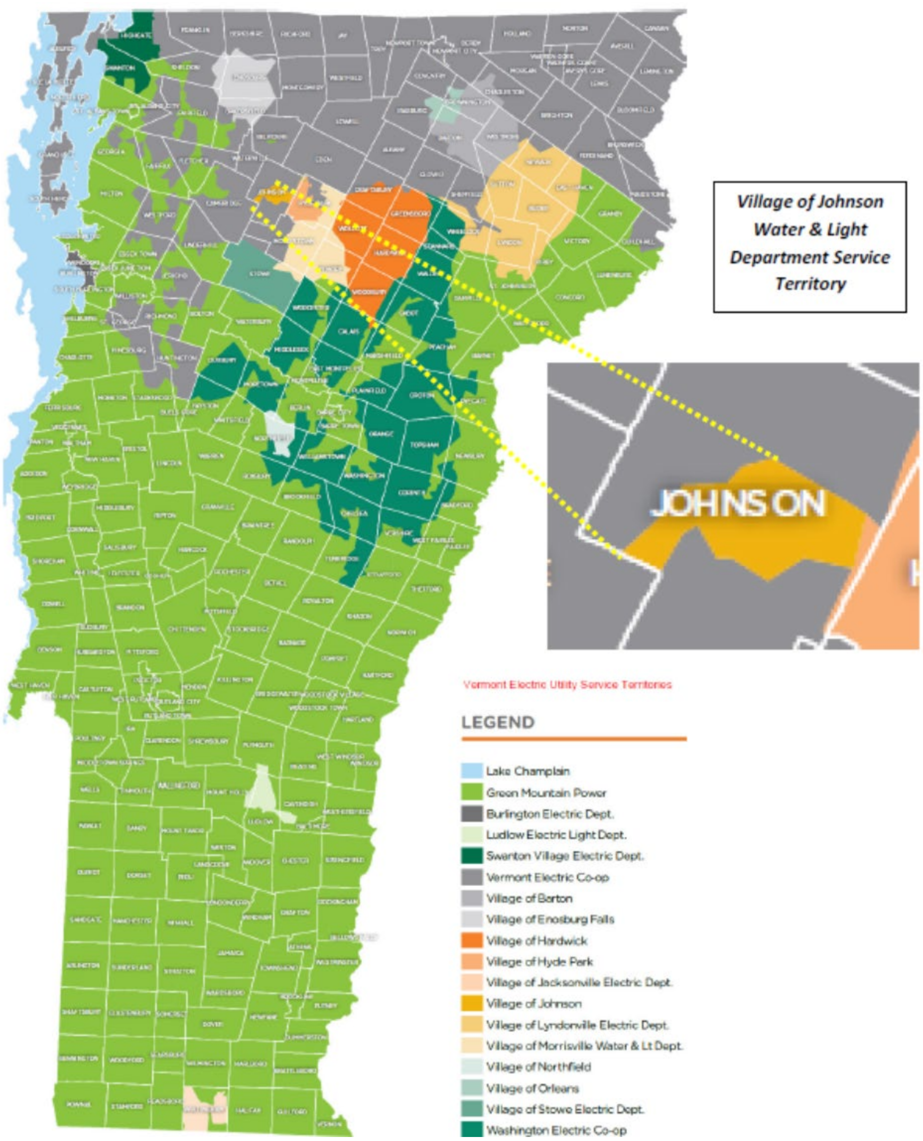
List of Tables

List of Figures

Introduction

JW&L's service territory is located in Lamoille County in north central Vermont. Its 5 square mile service territory can be seen on the Vermont Utility Service Territory map found below, and it encompasses the Village of Johnson as well as part of the Town of Johnson. JW&L serves approximately 970 retail customers, with its largest customer being Northern Vermont University (previously Johnson State College), which makes up about 30% of its retail sales. JW&L's small municipal system has a large residential customer base of elderly and below median income residents, including a high percentage of renters. JW&L remains guided by the Vermont Public Utility Commission (PUC) rules as well as by the American Public Power Association's (APPA) safety manual and the National Electric Safety Codef. Well-established practices keep JW&L operating safely, efficiently, and reliably.

Figure 1: JW&L'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.

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

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

System Overview

In 2023 JW&L's peak demand in the winter months was 2,652 kW. Annual energy retail sales for 2023 were 12,051,323 kWh and the annual load factor for 2023 was 51.9%.

For many years, JW&L was a sub-transmission customer of Green Mountain Power (GMP) and received service via a 34.5kV connection to the GMP Johnson substation. After obtaining regulatory approval, in 2014, JW&L became interconnected to the Morrisville Water & Light Department (MW&L) 34.5kV transmission line that enters the Johnson substation.

Table 1: JW&L's Retail Customer Counts

Data Element	2019	2020	2021	2022	2023
Residential (440)	805	810	821	819	810
Small C&I (442) 1000 kW or less	93	91	93	98	97
Large C&I (442) above 1,000 kW	15	16	17	15	15
Street Lighting (444)	33	33	34	34	35
Public Authorities (445)	30	30	30	31	32
Northern Vermont University	1	1	1	1	1
Total	**977**	**981**	**996**	**998**	**990**

Table 2: JW&L's Retail Sales

Data Element	2019	2020	2021	2022	2023
Residential (440)	5,134,304	5,474,159	5,396,836	5,508,108	5,310,828
Small C&I (442) 1000 kW or less	905,368	739,288	696,788	684,420	813,900
Large C&I (442) above 1,000 kW	1,908,151	1,874,600	1,938,762	1,781,498	1,781,163
Street Lighting (444)	63,661	63,776	63,993	62,449	62,905
Public Authorities (445)	708,837	604,417	606,113	584,100	602,992
Northern Vermont University	3,862,186	2,796,621	3,396,176	3,517,061	3,479,535
Total	**12,582,507**	**11,552,861**	**12,098,668**	**12,137,636**	**12,051,323**
YOY	1%	-8%	5%	0%	-1%

Table 3: JW&L's Annual System Peak Demand (kW)

Data Element	2019	2020	2021	2022	2023
Peak Demand kW	2,548	2,318	2,309	2,483	2,652
Peak Demand Date	01/21/19	02/09/20	01/31/21	01/15/22	02/03/23
Peak Demand Hour	19	19	19	18	18

Structure of Report

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

I. Electricity Demand
This chapter describes how JW&L's electricity requirements were determined and discusses sources of uncertainty in the load forecast.

II. Electricity Supply
This chapter describes JW&L's electricity supply resources, and the options that are being considered to supply the electricity needs of JW&L's customers.

III. Resource Plans
This chapter compares JW&L's electricity demand to its supply and discusses how JW&L will comply with the Renewable Energy Standard.

IV. Electricity Transmission and Distribution
This chapter describes JW&L's distribution system and discusses how it is being maintained to provide reliable service to its customers.

V. Financial Analysis
This chapter presents a high-level forecast of JW&L's power supply costs and cost of service.

VI. Action Plan
This chapter outlines specific actions JW&L expects to take as a result of this Integrated Resource Plan.

Appendix : Letters List
The appendix includes a series of supporting documents and reports, as listed in the Table of Contents.

Glossary

Electricity Demand

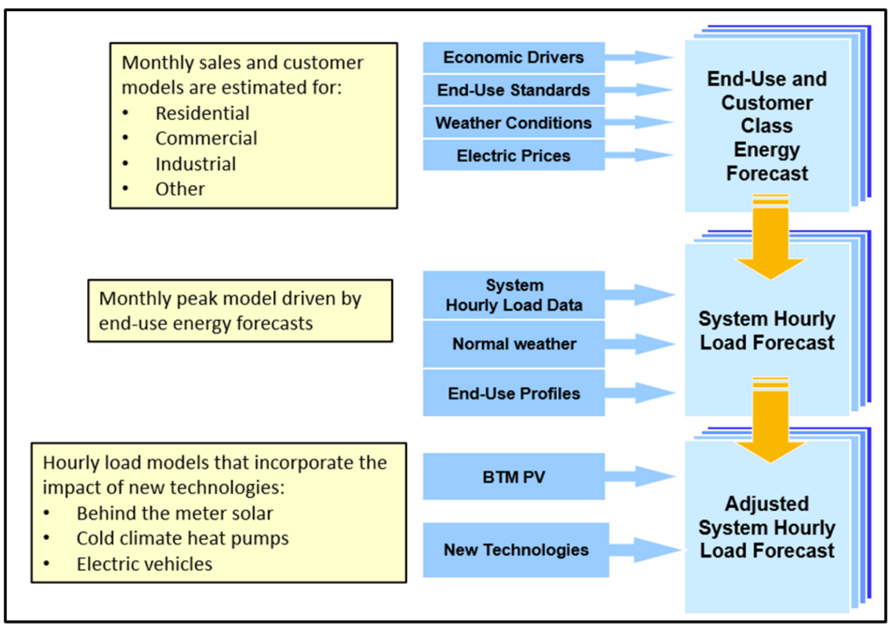
I. Electricity Demand

Energy Forecast Results:

VPPSA retained Itron to forecast JW&L'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 during VELCO's 2021 Long-Range Transmission Plan (LRTP) to create VPPSA's 2022 Long-Term Load Forecast Report. 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 uses). The impact of new technologies is then layered on top of the baseline forecast as shown in Figure 1.[1] 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 2044 for the purposes of this IRP.

Figure 2: Forecasting Process



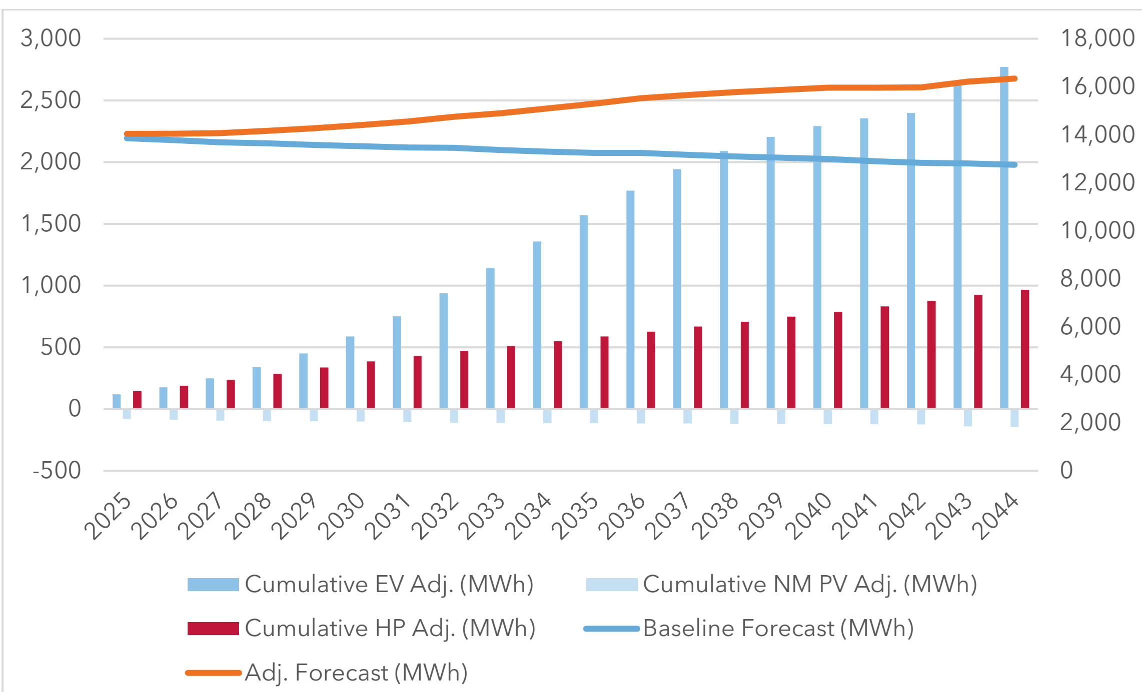
[1] VPPSA 2022 Long-Term Load Forecast Report, Itron, 2022, page 2

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 0.8%. This 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
2025	1	13,853	120	-80	145	14,038
2029	5	13,578	451	-99	336	14,266
2035	11	13,247	1,569	-115	588	15,289
2039	15	13,037	2,206	-119	748	15,871
2044	20	12,748	2,771	-145	967	16,341
CAGR		-0.4%				0.8%

Figure 3: Adjusted Energy Forecast (MWh/Year)



Energy Forecast – High & Low Cases

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 160% and 91%, respectively, in 2044. This rough estimate assumes that most households will have a 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 and the average Vermont household currently has two vehicles. With these increases in electrification the CAGR increases to 1.8%. This growth rate results in a 40% increase over 2025 electricity use.

Table 4: Energy Forecast – High Case (MWH)

Year	Yr #	Baseline Forecast	Cumulative EV Adj.	Cumulative NM PV Adj.	Cumulative HP Adj.	Adj. Forecast
2025	1	13,853	240	-80	290	14,302
2029	5	13,578	902	-99	673	15,053
2035	11	13,247	3,139	-115	1,176	17,447
2039	15	13,037	4,411	-119	1,496	18,825
2044	20	12,748	5,542	-145	1,934	20,079
CAGR		-0.4%				1.8%

To form a low case, we assumed that the penetration for CCHPs and EVs is half of the base case, and we kept the net-metered PV penetration rate the same as the base case. This results in a forecast that increases by 0.2% per year.

Table 5: Energy Forecast - Low Case (MWH)

Year	Yr #	Baseline Forecast	Cumulative EV Adj.	Cumulative NM PV Adj.	Cumulative HP Adj.	Adj. Forecast
2025	1	13,853	60	-80	72	13,905
2029	5	13,578	225	-99	168	13,873
2035	11	13,247	785	-115	294	14,211
2039	15	13,037	1,103	-119	374	14,395
2044	20	12,748	1,385	-145	484	14,472
CAGR		-0.4%				0.2%

Peak Forecast Results

Table 3 and Table 4 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 0.4% per year for the Summer period. After adjustments for CCHPs, EVs and net metering, the Adjusted Forecast increases by 1.0% per year. The Winter peak is decreasing by 0.6% per year. After making the same adjustments the forecast increases by 1.4% per year.

Table 6: Summer Peak Forecast (MW)

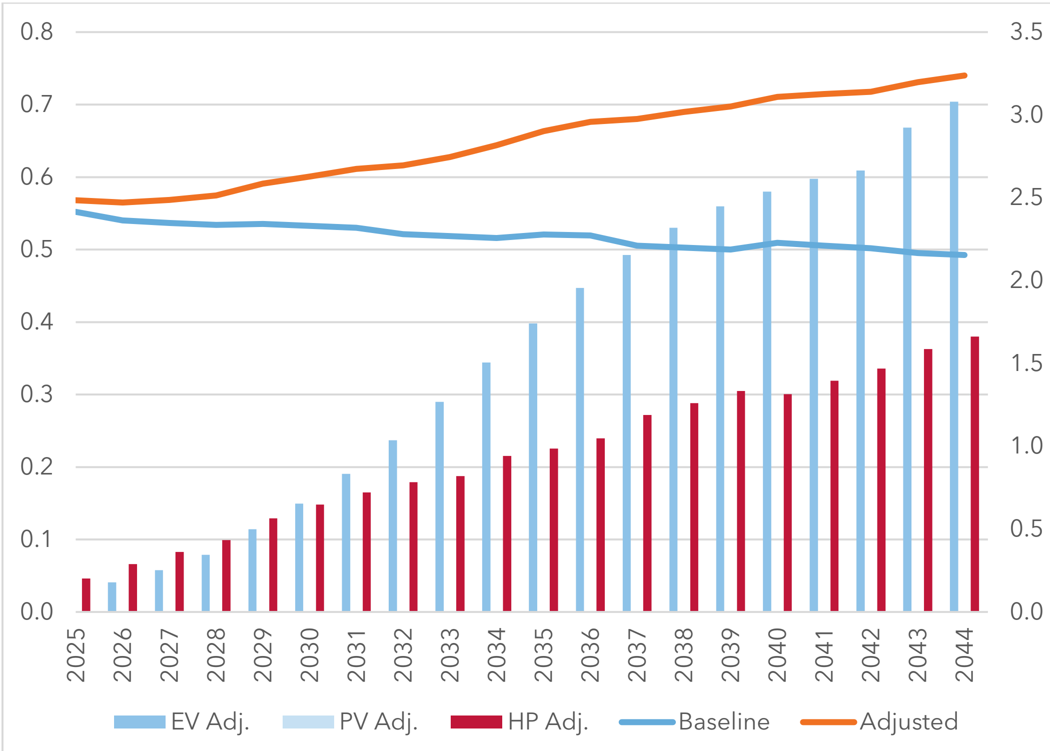
Year	Yr #	Baseline Forecast	Cumulative EV Adj.	Cumulative NM PV Adj.	Cumulative HP Adj.	Adj. Forecast
2025	1	2.0	0.0	0.0	0.0	2.0
2029	5	2.0	0.1	0.0	0.0	2.1
2035	11	1.9	0.3	0.0	0.0	2.3
2039	15	1.9	0.4	0.0	0.1	2.4
2044	20	1.8	0.5	0.0	0.1	2.4
CAGR		-0.4%				1.0%

Table 7: Winter Peak Forecast (MW)

Year	Yr #	Baseline Forecast	Cumulative EV Adj.	Cumulative NM PV Adj.	Cumulative HP Adj.	Adj. Forecast
2025	1	2.4	0.0	0.0	0.0	2.5
2029	5	2.3	0.1	0.0	0.1	2.6
2035	11	2.3	0.4	0.0	0.2	2.9
2039	15	2.2	0.6	0.0	0.3	3.1
2044	20	2.2	0.7	0.0	0.4	3.2
CAGR		-0.6%				1.4%

The size of the adjustments can be seen in Figure 3, which shows the winter peak forecast net of adjustments. The transformer at the substation is rated up to 5.0 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 4.3 MW by 2044.

Year	Yr #	Baseline Forecast	Cumulative EV Adj.	Cumulative NM PV Adj.	Cumulative HP Adj.	Adj. Forecast
2025	1	2.4	0.0	0.0	0.1	2.6
2029	5	2.3	0.2	0.0	0.3	2.8
2035	11	2.3	0.8	0.0	0.5	3.5
2039	15	2.2	1.1	0.0	0.6	3.9
2044	20	2.2	1.4	0.0	0.8	4.3
CAGR		-0.6%				2.8%

A plausible low case for the peak forecast would involve applying TOU electric rates and load control devices on all 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."[2]

Based on the following analysis, the load forecast adjustments for 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 5 shows the budgeted measures from VPPSA's 2025 Tier III plan, and the increased electric loads that are anticipated. These loads are based on averages as published in the Tier III Planning Tool. Eighty-six percent of the new electric loads are expected to come from only two technologies: heat pumps and electric vehicles. Table 5 shows Johnson's share of VPPSA's Tier III budget, and it indicates 30 MWH of new electric loads are likely in 2025.

This number is slightly lower than the heat pump and electric vehicle adjustments from Itron. The work papers supporting Table 5 show that Itron forecasted an 83.5 MWH increase in electric loads for 2025 as a result of these technologies. The forecasted increased load is about 0.6% of the adjusted forecast in 2025. This is well within the forecast error[3] of the forecast itself.

Table 8: Program Year 2025 Tier III Measures & Their Expected Impact on Load

Measure	# of Measures (rounded)	Added MWh/Unit/Yr	Total New MWh/Yr
Electric Vehicles	4	2.4	10
Heat Pumps	3	5.3	16
Heat Pump Water Heater	1	1	1
Other	3	1.1	3
TOTAL	11		30

Tier III Load Management

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

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

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 9: 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. 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 6. 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, JW&L does not believe that the intensity of electrification is currently, or in the near future, at a point where active load management is reasonable nor are there systems in place at this time to be able to perform active load management.

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.

VPPSA sends out capacity and transmission peak notifications to all members. With these notifications JW&L is able to adjust department use and notify customers. 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 control for JW&L is dynamic rates with supplementation from battery storage, behind-the-meter generation, searching for and partnering with innovative technology and AMI.

Forecast Uncertainties & Considerations

JW&L presently has thirteen residential scale (< 15 kW) net metered customers with a total installed capacity of about 95 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. In this event state policy continues to be supportive of net metering, 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.

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 JW&L 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, JW&L 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

JW&L'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 JW&L 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 JW&L portfolio.

Existing Power Supply Resources

1. Brookfield Hydro 2023-2027
   - Size: 10 MW On Peak, 8.5 MW Off Peak
   - Fuel: Hydro
   - Location: Varies
   - Entitlement: 0.6 MW On Peak, 0.3 MW Off Peak
   - Products: Energy, VT Tier I RECs
   - End Date: 12/31/27

2. Chester Solar
   - Size: 4.8 MW
   - Fuel: Solar
   - Location: Chester, MA
   - Entitlement: 6.6% (0.317 MW), PPA
   - Products: Energy, capacity
   - End Date: 6/30/39

3. Fitchburg Landfill
   - Size: 4.5 MW
   - Fuel: Landfill Gas
   - Location: Westminster, MA
   - Entitlement: 5.112%, 0.153MW, PPA
   - Products: Energy, capacity, renewable energy credits (MA I)
   - End Date: 12/31/31

4. Kruger Hydro
   - Size: 6.7 MW
   - Fuel: Hydro
   - Location: Maine and Rhode Island
   - Entitlement: 5.48%, PPA
   - Products: Energy, capacity
   - End Date: 12/31/37

5. New York Power Authority (NYPA)
   - Size: 2,675 MW (Niagara), 1,957 MW (St. Lawrence)

- Fuel: Hydro
- Location: New York State
- Entitlement: 0.094MW (Nia. PPA), 0.0061MW (St. Law PPA)
- Products: Energy, capacity, VT Tier I RECs
- End Date: 4/30/2032

6. Project 10

- Size: 40 MW
- Fuel: Oil
- Location: Swanton, VT
- Entitlement: 7.2%, joint-owned through VPPSA
- Products: Energy, capacity, reserves
- End Date: Life of unit

7. Ryegate

- Size: 20.5 MW
- Fuel: Wood
- Location: East Ryegate, VT
- Entitlement: 0.24% PPA
- Products: Energy, capacity, renewable energy credits (CT Class I)
- End Date: 10/31/2032

8. 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: 0.2467% (Statutory)
- Products: Energy, capacity, renewable energy credits
- End Date: Varies

9. Stetson Wind 2023-2027

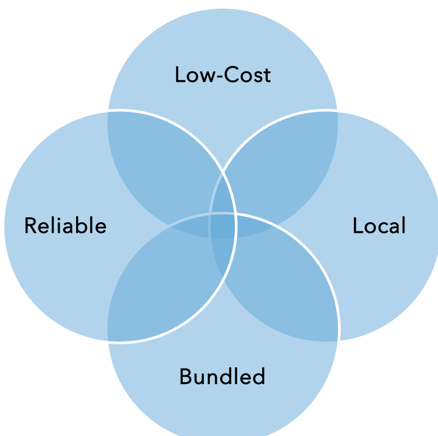
- Size: 57MW
- Fuel: Wind
- Location: Maine
- Entitlement: 3.65% (PPA)
- Products: Energy, VT Tier I RECs
- End Date: 12/31/27

Resource	2024 MWh	% of MWh	2024 MW	Delivery Pattern	Price Pattern	Rec	Expiration Date
Brookfield 2023-2027	3,853	29.7%	1.39	Firm	Fixed	Yes	12/31/2027
Chester Solar	441	3.4%	0.55	Intermittent	Fixed	No	6/30/2039
Fitchburg Landfill	1,783	13.8%	0.41	Intermittent	Fixed	Yes	12/31/2031
Kruger Hydro	1,378	10.6%	0.76	Intermittent	Fixed	No	12/31/2037
NYPA	842	6.5%	0.22	Baseload	Fixed	Yes	Life of Unit
Project #10	245	1.9%	1.88	Peaking	Fuel Cost	No	Life of Unit
Ryegate Facility	364	2.8%	0.11	Baseload	Fixed	Yes	10/31/2032
Standard Offer Program	312	2.4%	0.00	Intermittent	Fixed	Yes	Varies
Stetson Wind 2023-2027	3,736	28.8%	2.03	Intermittent	Fixed	Yes	12/31/2027
Total	12,955	100.0%	7.34				

Future Resources

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

Figure 5: Resource Criteria



- ✓ **Low-Cost** resources reduce or stabilize electric rates.
- ✓ **Local** resources are located within BVI's Regional Planning Commission area or within Vermont.
- ✓ **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 JW&L may consider fall into three categories: 1.) Existing resources 2.) demand-side resources, and 3.) new resources that meet the criteria in Figure 5.

Category 1: Extensions of Existing Resources

This plan assumes that NYPA Niagara and NYPA St. Lawrence are extended past their current expiration date. It is possible that existing resources, such as Brookfield and Stetson, could be extended. This IRP is exploring the possibility of entering into a contract for firm bundled energy and VT Tier I RECs, similar to the existing Brookfield contract.

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, JW&L will not only get access to competitive prices (low-cost), but it also can structure the contracts to reduce volatility (stable rates and volumes). Market contracts are also scalable and can be sized to match JW&L's incremental electric demands by 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 lowest environmental impact source of energy is energy that is conserved or never consumed. JW&L 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.

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

Category 3: New Resources

VPPSA regularly meets and maintains communications with developers throughout New England. Through VPPSA staff, JW&L 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. VPPSA continues to work directly with this partner but has also begun working with additional developers in several member territories. Currently no storage project has been proposed for JW&L territory, however, this is something VPPSA is actively pursuing for all members.

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. Hydro generators often create RECs that are qualified for VT Tier I so entering into bundled contracts is a possibility.

3.3 Solar Generation

While JW&L has an out of state solar resource in the portfolio, no solar projects within the state have been proposed for JW&L. Given the increased Tier II obligation for the Renewable Energy Standard it is possible that a solar project will be pursued in the future but a location suitable for a utility scale system in the JW&L territory has yet to be identified by developers. However, due to Johnson's small size, it may be difficult to achieve the economy of scale that helps these solar projects be economically viable.

3.3.1 Net Metering

JW&L has 18 net-metered customers and an installed base of solar capacity of 616 kW. JW&L will monitor the participation rate closely as solar costs approach grid parity. Should grid parity occur, not only would net metered solar penetration be expected to increase but the costs of the existing program would likely cause upward rate pressure. As a result, net metered solar is an inferior option when compared to lower-cost and utility scale solar projects.

3.4 Wind Generation (On and Off-Shore)

On-shore wind projects continue to be developed in New England. RECs are often bundled into the PPA, making this resource a potential fit for the renewable criteria. JW&L 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. VPPSA is currently working with Pecos Wind, a company that has developed a very small scale turbine. Given JW&L's small size, this could be an option to help procure VT Tier II RECs.

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

JW&L's contract for nuclear energy expired in 2022, and has been replaced by renewables (hydro, solar and wind) to comply with the RES. However, JW&L supports all forms of low-carbon energy, and will consider nuclear power in the future if it is feasible particularly given its high reliability compared to renewables.

Regional Energy Planning (Act 174)

As part of the Lamoille County Planning Commission (LCPC), JW&L is part of a Regional Energy Plan[4] that was created in 2024. The intent of the plan is to further "two broad state energy goals: reduce greenhouse gas emissions and meet energy needs using renewable sources." Future resource decisions will be made with this plan in mind.

[4] The full plan can be found at https://www.lcpcvt.org/regional-plan.

Resource Plan

III. Resource Plans

Energy Procurement Processes

Monthly Process

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

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

1. Update Budget Forecast
    a. The budgeted volumes (MWH) are updated to reflect known changes to demand and supply 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**: In the event that internal transactions cannot bring JW&L 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

Figure 6 compares JW&L's energy supply resources to its adjusted load. The supply resources closely match demand through 2027. After 2027 new resources will be necessary.

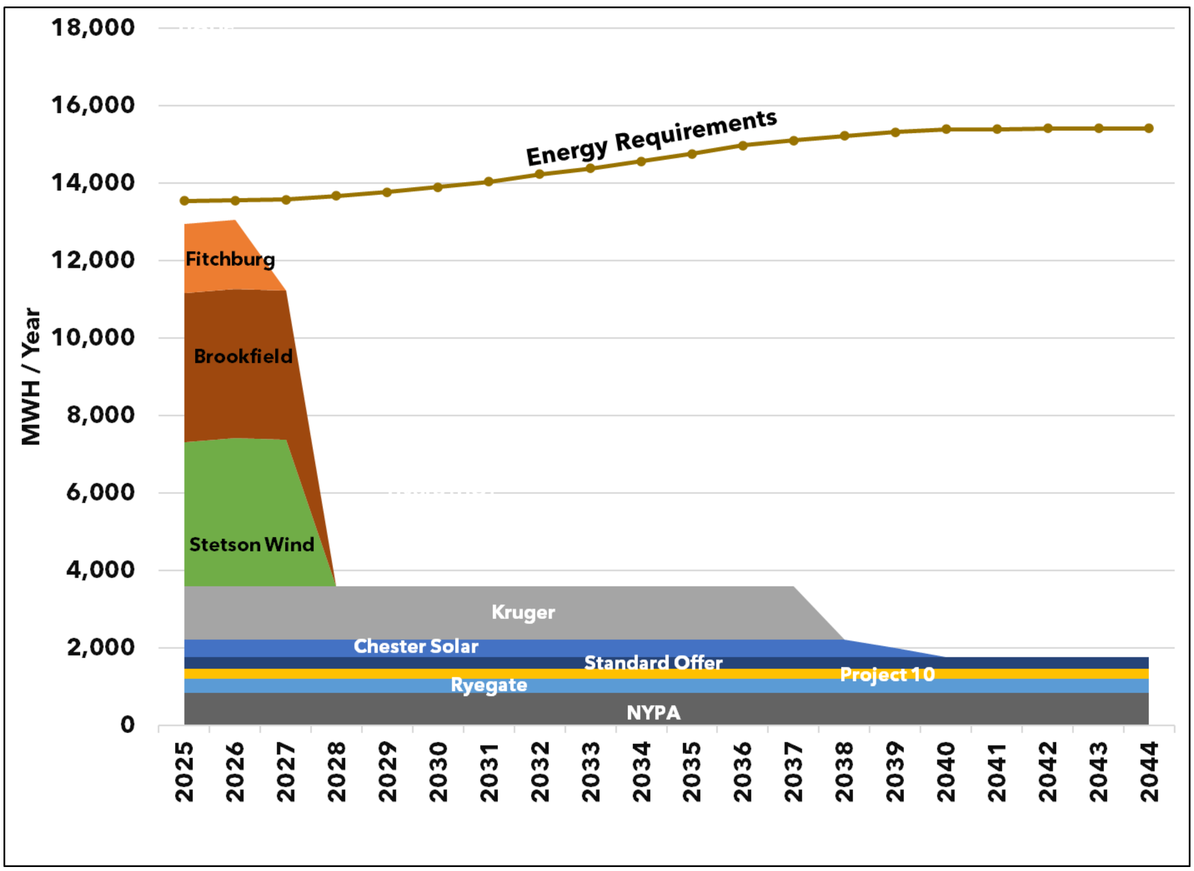
Decision 1: Extend Fitchburg Landfill Contract

This PPA includes an option to extend the term by five years at a predetermined price. Notice must be given by the middle of 2025 for an extended term that would begin on 1/1/27. The extension would be through 2031.

Decision 2: Energy Purchases 2028-2032

Both Brookfield and Stetson contracts expire at the end of 2027 leaving a large gap in coverage. This IRP will evaluate a bundled energy and REC purchase.

Figure 6: Energy Supply & Demand by Fuel Type



Decision 3: Battery Storage Contract (ESSA)

Utility scale battery storage is an excellent way to manage transmission costs and address load control. While JW&L is not currently working with a storage developer, an evaluation of the economic viability using an approximate Energy Storage Solution Agreement (ESSA) rate from other ESSA's VPPSA has worked with is an important first step in determining if this is an appropriate solution for JW&L.

Table 10 summarizes the energy resources decisions JW&L faces in the coming five to ten years.

Table 10: Energy Resource Decision Summary

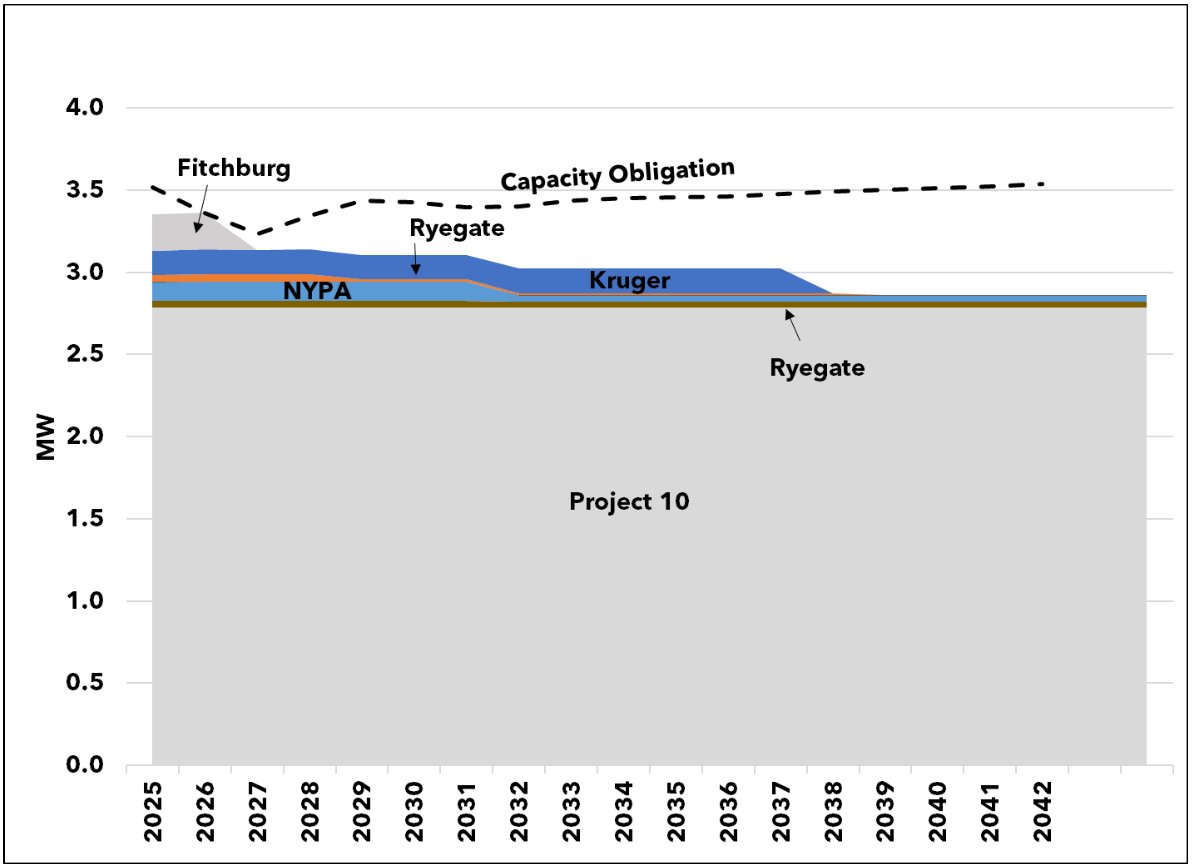
Resource	Years Impacted	% of MWH	Rate Impact
Bundled Energy & REC Contract	2028 - 2032	28%	Increase
Fitchburg Landfill PPA	2027 - 2031	13%	Increase
Storage ESSA	2027 – 2046	100% of Peak	Decrease

Capacity Resource Plan

The capacity supply obligation (CSO) is equal to JW&L'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. The vast majority of JW&L's CSO is covered by existing resources into 2027. Even after that point there is only a relatively small gap in coverage through the end of the IRP period.

Figure 7 compares JW&L's capacity supply to its capacity supply obligation (CSO). Project 10 represents about half of JW&L's capacity supply, and as a result, the reliability of this resource will be key to minimizing JW&L's capacity costs, as explained in the next section.

Figure 7: Capacity Supply & Demand (Summer MW)



ISO New England's Pay for Performance Program

Because JW&L 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, JW&L will be provided with capacity by ISO New England. However, ISO New England's Pay for Performance[5] (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 JW&L's share of Project 10 creates in ISO New England's PFP Program. Depending on ISO-NE's load at the time of the scarcity event and Project 10's performance level, JW&L could receive up to a $10,420 payment or pay up to a $11,750 penalty during a one-hour scarcity event. For context, the largest payments and penalties are more than JW&L's monthly capacity market budget for 2025. To date, Project 10 has performed well during capacity scarcity conditions and, therefore, has performed well as a hedge against such market conditions that would have otherwise cost JW&L more money.

Table 11: Pay for Performance Ranges for One Hour of Project 10 Operation[6]

ISO Load	0% Performance	50% Performance	100% Performance
10,000	-$5,099	$2,660	$10,420
15,000	-$7,316	$443	$8,203
20,000	-$9,533	-$1,774	$5,986
25,000	-$11,750	-$3,991	$3,769

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

[6] 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

Under RES, JW&L's Total Renewable Energy (Tier I) requirements rise from 63% in 2025 to 100% in 2030. The Distributed Renewable Energy (Tier II) requirement rises from 5.8% in 2025 to 20% in 2032. Energy transformation obligation increases from 6% in 2025 to 10.67% in 2032. The New Renewable Energy (Tier IV) requirements increase from 5% in 2030 to 10% in 2035. Note that this plan assumes that the maximum percent obligation of each tier as stated in act 179 is maintained at that level throughout 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, Tier III programs account for the "lifetime" of the fossil fuel savings. For example, if a Tier III program installs a CCHP in 2025, 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 2025 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).

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.

Table 12: ACP Prices[7] ($/MWH)

Year	TIER I	TIER II & III	TIER IV
2025	$12.72	$76.35	$40.00
2026	$13.06	$78.41	$41.08
2027	$13.42	$80.53	$42.19
2028	$13.78	$82.70	$43.33
2029	$14.15	$84.94	$44.50
2030	$14.53	$87.23	$45.70
2031	$14.92	$89.58	$46.93
2032	$15.33	$92.00	$48.20

Tier I - Total Renewable Energy Plan

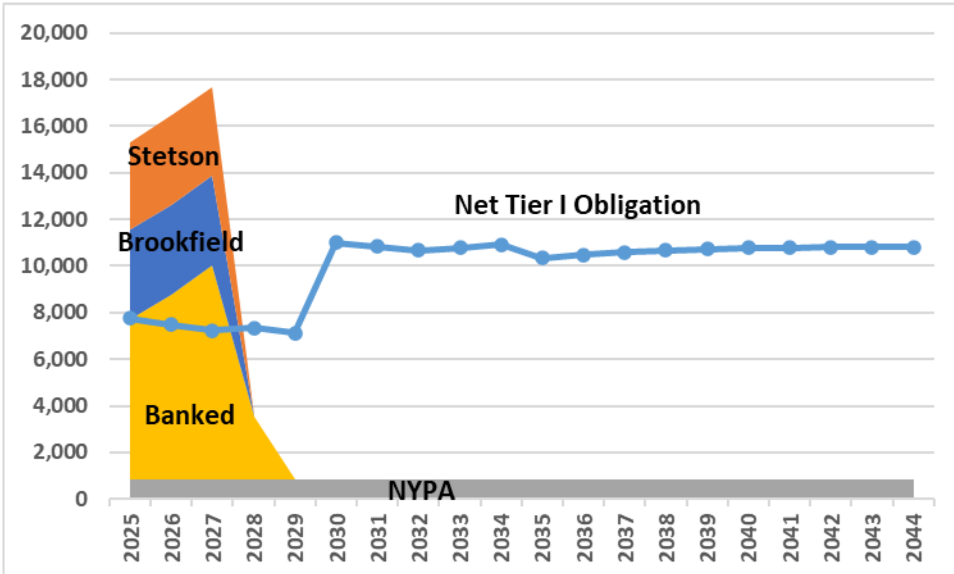
In 2025 JW&L's Net Tier I requirement is approximately 7,752 MWH. The primary energy resource contributors to Tier I are the Brookfield and Stetson Wind contracts. Combined they add up to almost 100% of the annual Tier I obligation within that timeframe.

JW&L will have an excess of Tier I RECs through 2028 due to the Brookfield and Stetson contracts as well as banked RECs from previous years. After that period, JW&L will have a deficit and will need to either purchase unbundled RECs, extend one or both of the Tier I bundled contracts, enter into 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. Current prices for 2025 vintage are about $4.50. At those prices, assuming gradual increases year on year, complying

[7] Please note that 2025 is known but following years are estimates and grow at inflation.

with net Tier I between 2029 and 2035 could be as much as $340,000. If the cost increased again to the $11 range, the cost could be as high as $837,000 annually.

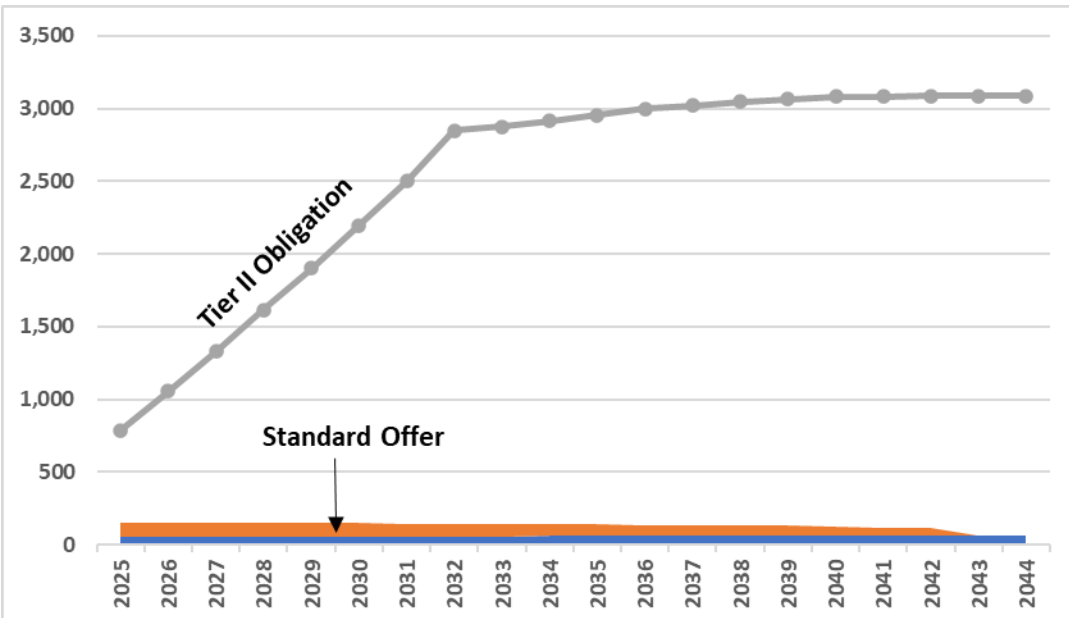
Figure 8: Tier I - Total Renewable Energy Supplies



Tier II - Distributed Renewable Energy Plan

The line in Figure 9 shows JW&L's Distributed Renewable Energy (Tier II) requirement, which increases from 786 MWH in 2025 to almost 2,197 MWH in 2030. JW&L's only Tier II RECs are from Standard Offer and Net Metering. Therefore, JW&L buys Tier II RECs from other VPPSA members that have more Tier II resources. The current cost of Tier II RECs is approximately $40 in 2025 with prices generally dropping to $36 through 2030. Using these assumptions, it will cost JW&L about $300,000 from 2025 to 2030 to comply with the Tier II portion of the RES.

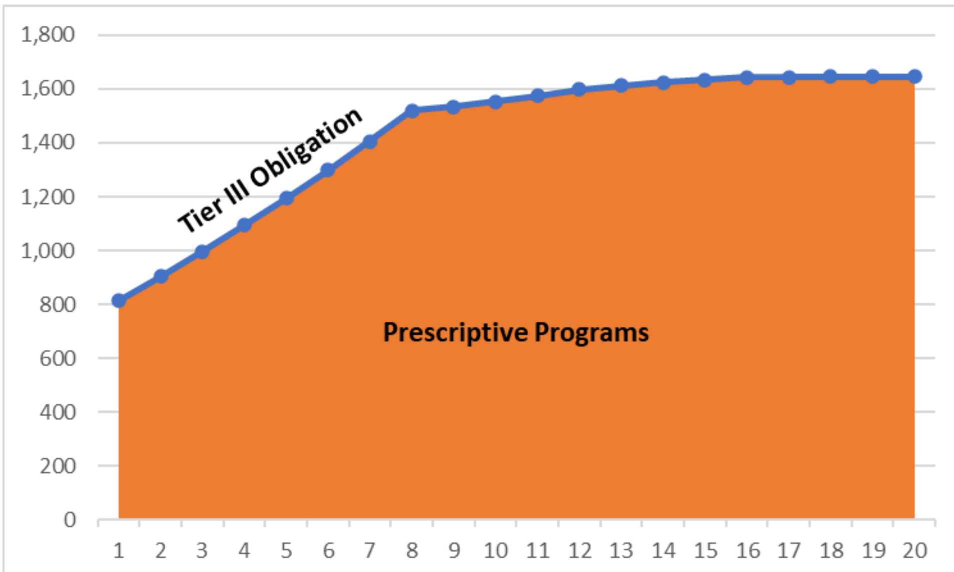
Figure 9: Tier II - Distributed Renewable Energy Supplies



Tier III - Energy Transformation Plan

The dashed line in Figure 10 shows JW&L's Energy Transformation (Tier III) requirements, which rise from about 810 MWH in 2025 to about 1,520 MWH in 2032. Prescriptive programs are presently budgeted to fulfill the entire requirement and are shown in the orange 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 2025 Tier 3 Annual Plan) and in the following section.

Figure 10: Energy Transformation Supplies



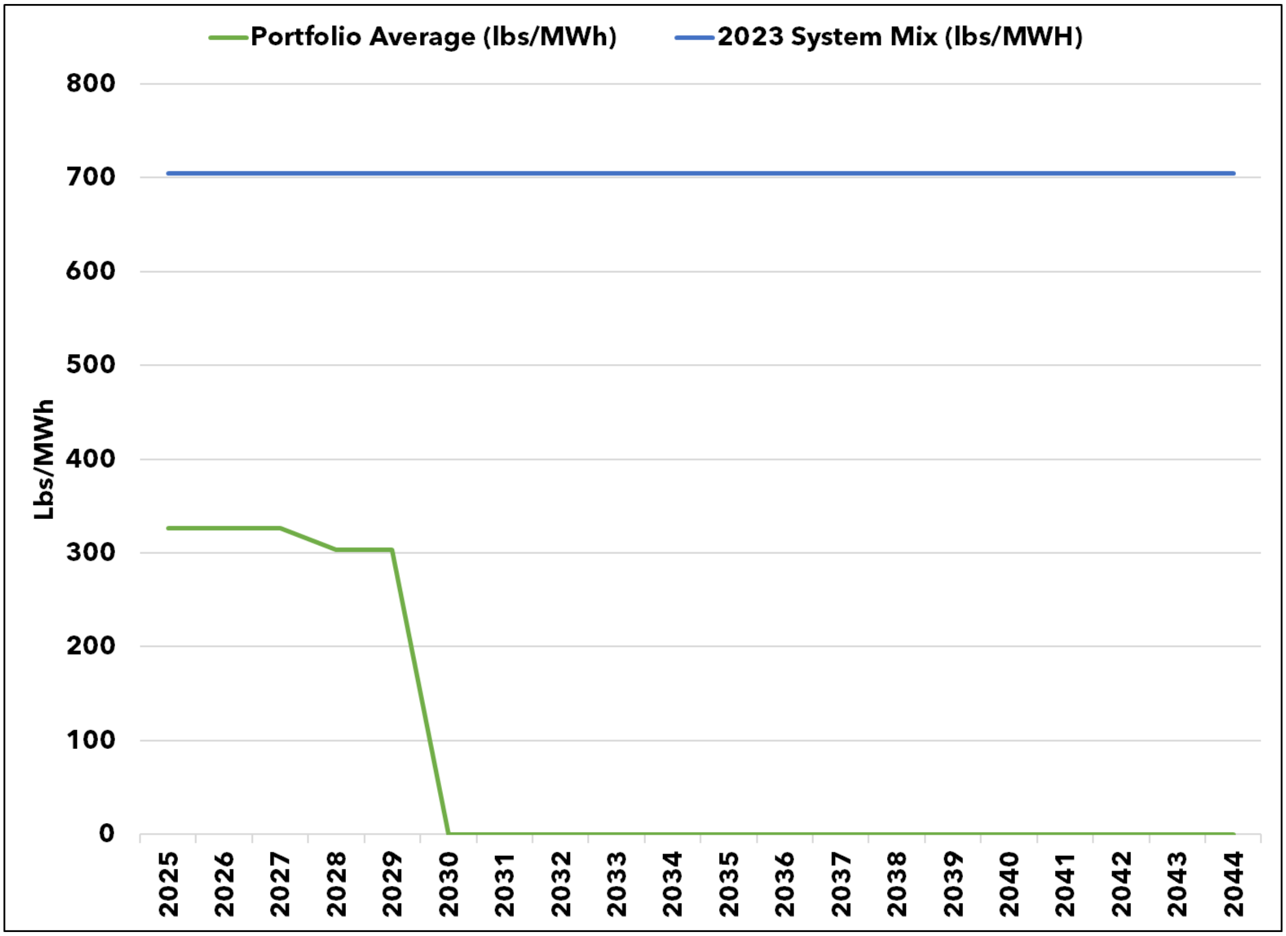
If prescriptive programs do not fulfill the entire requirement, custom Tier III projects may fill the gap as contemplated in the Tier 3 Annual Plan. JW&L will follow a three-part strategy to fulfill its Tier III requirements.

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 JW&L's carbon emissions rate compared to the 2023 system average emissions rate from New England and imported resources[8]. The emissions rate in 2025 is about 326 lbs/MWH.

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



The emissions rate declines through 2030 as a result of increasing RES requirements and eventually reaches zero at 2030 due to the RES obligation reaching 100% renewable.

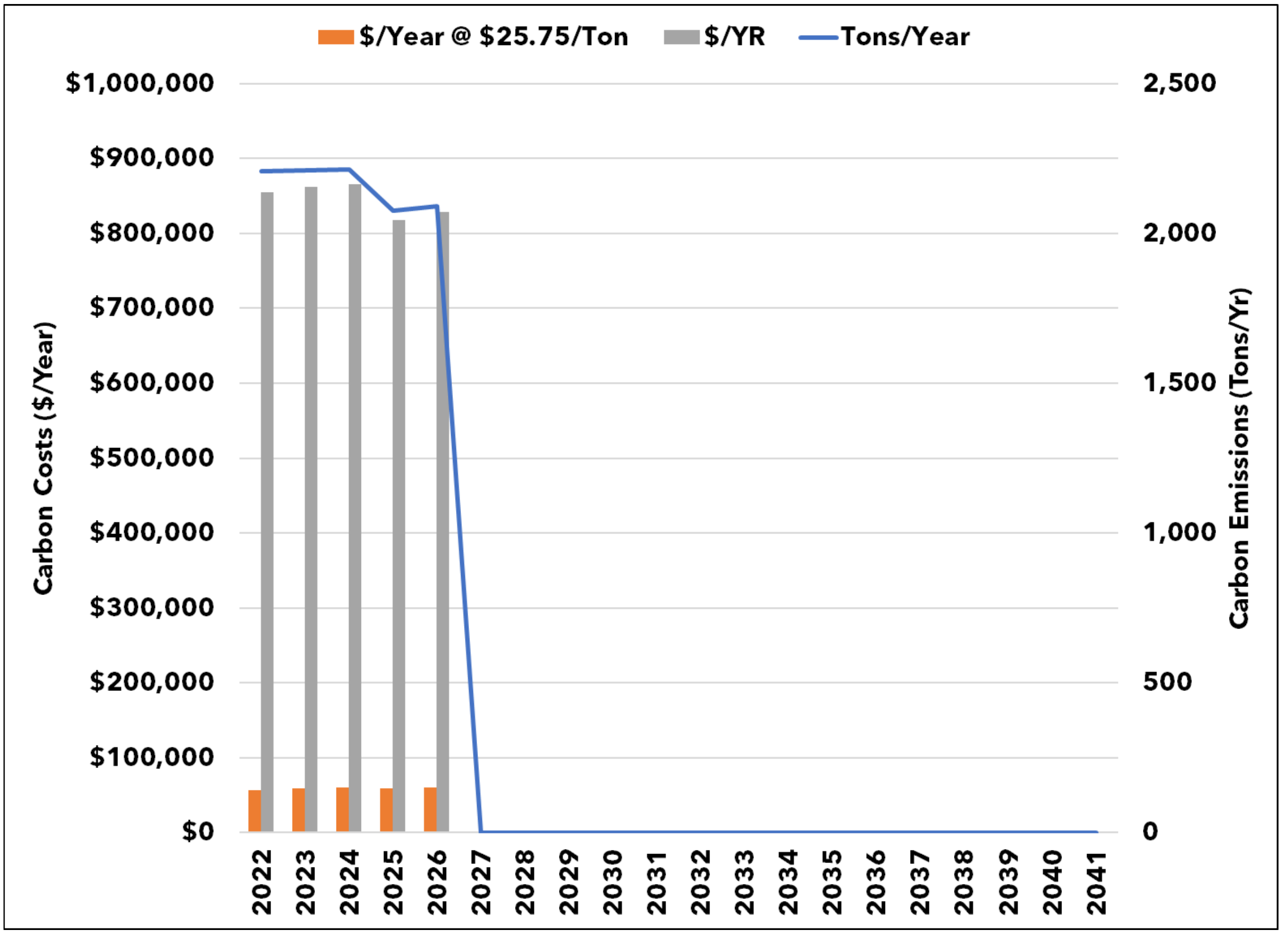
These emissions rates were multiplied by the load forecast from Section I. Electricity Demand to arrive at an estimate of carbon emissions in tons per year. The following figure shows that carbon emissions range from about 2,200 tons/year in 2025 down to 0 tons per year in 2030 and beyond.

The costs of these emissions were calculated using two sources, the Regional Greenhouse Gas Initiative Auction (RGGI) results for the most recent auction ($25.75 per ton) and the update to the 2021 Avoided Cost of Energy Supply (AESC) study ($387 per ton in 2025 and escalating). Using RGGI prices plus inflation, the cost of carbon emissions averages about

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

$59,000 per year through 2030. Using updated AESC prices, the average cost through 2030 is about $845,000 per year.

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



Procurement Plan for RES 1.0

JW&L does not need additional VT Tier I RECs until the Brookfield and Stetson contracts expire. After that point the utility will have a large gap. The two main options are to enter into another bundled energy and REC contract and/or buy RECs only. VPPSA will need to evaluate which option is more cost effective as the time gets closer. To obtain VT Tier II RECs JW&L will likely continue to purchase those from other VPPSA members. JW&L will also need to procure VT Tier II and IV RECs. VPPSA has an existing relationship with a company that has generators that are eligible for Tier IV qualification and will follow up with them to discuss REC purchases only or bundled energy and REC purchases to fulfill the Tier IV obligation.

Resource Plan Observations

Tier I

JW&L is meeting its Tier I requirements primarily with existing resources as well as annual REC only purchases. With the new RES law passed, the volumes of the existing bundled contracts will not be enough to meet Tier I obligations throughout the time period of this IRP. Therefore, it's likely that REC only purchases will need to be made and/or another bundled energy purchase procured. The final decision in this regard would depend on REC and energy market prices and how the indicative pricing from bundled contracts compares to market contracts.

Tier II

JW&L will continue to purchase Tier II RECs from other VPPSA members. It's possible that the utility would develop a solar project but the limited size of solar for this small of a utility would likely cause poor economics.

Tier III

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

Tier IV

Tier IV requirements will be met either by purchasing RECs only or by entering into a bundled contract. As stated previously, VPPSA has a relationship with an entity that has Tier IV eligible resources. VPPSA has already begun the conversation with that entity about the possibility of a REC only or bundled energy purchase.

Transmission & Distribution

IV. Electricity Transmission & Distribution

Transmission and Distribution System Planning

JW&L is in the early stages of developing a structured approach to integrate load management into its broader distribution system planning. Rather than viewing load management in isolation, JW&L believes it is most effective when integrated into the planning cycle, helping target strategies that enhance distribution efficiency.

The planning process begins with a load forecast that informs a distribution system study. This study identifies system weaknesses and the costs of necessary upgrades. At this stage, load management strategies are considered as alternatives to costly existing or future equipment upgrades. These strategies vary, targeting system peaks, specific devices, or sections of the distribution network. Their goals range from reducing wholesale costs to deferring or optimizing distribution investments and managing local constraints due to increased electrification and distributed generation.

Load management can take passive forms, such as rate design, or active forms like using storage assets or device-specific approaches. However, it must be balanced with expected load growth and future equipment needs. Since these upgrades and strategies unfold over time, planning must account for uncertainties, particularly as electrification accelerates. Recent cost benefit analysis included in the planning for JW&L's upcoming AMI implementation indicated that implementation of Time-of Use and peak penalty pricing rate design strategies could yield an NPV of about $200,000 in avoided costs.

As the planning cycle repeats, each iteration of the load forecast incorporates previous decisions, leading to ongoing refinements in both distribution investment and load management. With increasing distributed generation, the need for more granular system management will grow. JW&L, along with other VPPSA members, is working on a technology roadmap to improve distribution management and load measurement, with a report on new software systems expected in early 2025. Advanced technologies like SCADA, ADMS, and DERMS, along with existing AMI and GIS systems, are being considered.

As these systems come online, JW&L expects better data on localized load behavior, leading to more precise forecasts and the ability to evaluate alternatives. By modeling the effects of these alternatives, JW&L will be able to develop a structured analysis framework that tracks penetration of electrification and distributed generation impacts and compares the effect of applying alternate load management strategies over time. JW&L can make informed decisions on upgrades and load management strategies, considering factors like cost, rate impact, effectiveness, and flexibility. The utility is also open to collaboration with DPS and other utilities to share knowledge and insights.

Transmission and Distribution System Description:

Detail regarding JW&L transmission supply, sub-transmission and distribution facilities is provided below.

Transmission System Description:

JW&L purchased a 15% interest in MW&L's 34.5 kV transmission line that runs from the GMP substation in Johnson, to MW&L's Substation #3 in Morrisville, to the Vermont Transco, LLC 115kV substation in Stowe. As a result of obtaining a direct connection to Vermont Transco's high-voltage network at Stowe, JW&L is avoiding charges for sub transmission service that it had been paying to GMP. Once the initial purchase of the 15% interest in the MW&L 34.5 kV line is paid off, savings will accrue to JW&L and MW&L.

Distribution System Description:

The distribution system includes approximately 28 miles of line currently operating at 4160/2400 volts. There are currently three circuits out of the substation. Circuit R1 is the Johnson East circuit, circuit R2 is the NVU circuit (NVU owns its own underground system and its primary meter is on this circuit.), and circuit R4 is the Johnson West circuit.

An Electric System Study and Cost Benefit Analysis was performed for JW&L by GMP in 2009. The study provided good baseline data for undertaking capital improvements on its system. Study results include the following recommendations:

> Transformer Consolidation - While doing this work, new dual voltage transformers could be put out on the line to start preparing for conversion. JW&L aims to maintain a balanced load and installs new transformers on the lowest phase, when possible.

For the last five years any transformer replacement has been done with both the eventual voltage conversion and transformer consolidation in mind.

> Voltage Conversion – Benefits could include reduced line losses, and improved voltage quality. In addition, it would be easier on a normal and emergency basis to obtain transformers as the vast majority of Vermont, and the country, operate at 12.5 kV. This would eliminate the need to replace the overloaded step-down transformers on the R4 Feeder at the substation, as they would be removed. At present, only circuit #R4 is overloaded for short periods of time throughout the year. This overloading is not significant enough at this point to require replacement, but load growth should be watched to determine when these should be upgraded.

> Feeder Backup - Not mentioned in the System Study is the possibility of adding a fourth circuit (R3) and split some of the load from the present R4 Feeder in the future. Some of the necessary distribution work has been completed to accomplish this plan and the substation improvements were made with that in mind as well. However, JW&L is not actively pursuing this at this time.

A more recent evaluation has shown that current load levels indicate that adding a fourth circuit is not warranted at this time. JW&L's peak load is the same as, if not less than, the peak load in the previous IRP. NVU is a large portion of JW&L's peak, therefore JW&L's peak would be dramatically lower if NVU were to close.

> Capacitors - A complete power factor investigation needs to be completed. JW&L should be able to complete this after constructing a model using the data from the newly implemented GIS system.

JW&L Substations:

JW&L currently operates one substation with three circuits. A permanent back-up substation is present at the same location. The back-up substation has its own transformer, fence, ground grid, oil containment system, etc., offering full system functionality.

Johnson Substation:

The Johnson substation was originally built in 1965 as a cooperative effort between NVU and JW&L, when NVU was undertaking a major expansion. It is located on land owned by the University and leased to JW&L. The substation was completely rebuilt between 2007 and 2008. The project included re-building the substation superstructure, correction of applicable standards and codes issues, expansion of the fence line to provide for required clearances from live electrical equipment, replacement of the existing 5 MVA, 2,400/4,160 volt transformer with a 5MVA, 7,200/12,470 volt transformer, installation of step down transformers for exit circuits, installation of an oil containment system and ground grid, and related site work. The design employed a creative ring buss feature that allows great flexibility in switching and circuit maintenance and transfer of load from one circuit to another as well as one substation transformer to another. The failure of one of the recloser controls at the substation prompted JW&L to buy two new electronic controls. JW&L has budgeted for additional control in each of the next three years which would provide for complete replacement and standardization of the controls.

Figure 13: Main Substation

Figure 14: MW&L's Feed (on right)

Figure 15: Back-up Substation

Circuit Description:

Table 13: JW&L Circuit Description

Circuit Name	Description	Length [9](Miles)	# of Customers by Circuit	Outages by Circuit 2023
R1	Johnson East circuit	14.77	432	7
R2	Northern Vermont University) circuit (NVU owns its own underground system and its primary meter is on this circuit)	0 (NVU is primary metered and the circuit becomes NVU's about 50 feet outside the substation gate)	1	0
R4	Johnson West circuit	13.21	544	8

[9] Estimated from circuit maps

There are currently three circuits out of the substation. Circuit R1 is the Johnson East circuit, circuit R2 is the Northern Vermont University (NVU) circuit (NVU owns its own underground system and its primary meter is on this circuit) and circuit R4 is the Johnson West circuit. The voltage of the circuits is regulated at the substation bus. JW&L does not consider any of its circuits to be particularly long. JW&L operates its system to maintain 114 to 123 volts at the customer's outlets.

T&D System Evaluation:

System reliability is important to JW&L and its customers. JW&L has a number of initiatives underway to improve reliability. Each of these initiatives is summarized below.

Outage Statistics

JW&L evaluates T&D circuits on an ongoing basis in order to identify the optimum economic and engineering configuration for each circuit. The evaluations include the review of the PUC Rule 4.900 Outage Reports and data collected from voltage and amp readers. JW&L has also borrowed load loggers from other utilities to perform specific readings and analysis when needed. In addition, JW&L periodically completes long-term system planning studies to develop overall strategies for improving the performance of the T&D facilities. JW&L has not recently done a long-term system planning study, but it has done many smaller system impact studies as solar installations have been added.

The terms of JW&L's ownership share in the MW&L 34.5kV transmission line include JW&L's participation in line maintenance activities and planning. Specifically, the Joint Ownership Agreement indicates JW&L and MW&L will meet annually to discuss the operation of the facility and to plan and budget for line maintenance and upgrades. As part of the SHEI constraint solution, GMP lead a project to upgrade a section of the B-22 line. JW&L contributed towards the project.

JW&L's Public Utility Commission Rule 4.900 Electricity Outage Reports, reflecting the last five years (2019-2023) in their entirety, can be found in Appendix C, at the end of this document.

JW&L 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 Rule 4.900 defines them as:

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

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

JW&L has committed to achieve performance levels for its distribution system below an index of 1.0 for SAIFI and 2.7 for CAIDI. JW&L maintains a record of and reports on all its system outages, including the root cause of an outage. While some outages cannot be prevented, there are a number of specific, cost-effective steps that can be taken to maintain or improve system reliability by working to eliminate the potential for some outages to occur and making changes that will promote reduced outage times when an unavoidable outage does occur.

The following table summarizes JW&L's SAIFI and CAIDI values for the years 2018-2023.

Table 14: JW&L Outage Statistics

	Goals	2019[10]	2020	2021	2022	2023[11]
SAIFI[12]	1.0	0.3	1.1	0.3	0.1	3.1
CAIDI[13]	2.7	2.3	3.6	2.5	2.9	0.2

JW&L has a number of initiatives underway to improve reliability. Each of these initiatives is described below.

Animal Guards

JW&L has a policy to install animal guards on all new construction and line rebuilds. In addition, while changing out a number of porcelain cutouts, JW&L took the opportunity to install animal guards at the same time. JW&L believes that animal guards are a cost-effective means of reducing animal contacts and the associated service interruptions.

Fault Indicators

JW&L uses fault locators on 4KV Distribution Feeders to isolate faults and reduce outage time. There are three fault locators at the Johnson substation.

[10] SAIFI and CAIDI statistics shown are net of major storm outages

[11] SAIFI and CAIDI for 2023 were 3.7 and 1.9, respectively including major storms

[12] System Average Interruption Frequency Index

[13] Customer Average Interruption Duration Index

Automatic reclosers/Fusing

All three circuits in the substation have automatic reclosers, but elsewhere, the system is fuse coordinated. JW&L is in the process of upgrading the controls on these regulators.

Feeder back-up

JW&L has a method of temporarily back-feeding in the case of a circuit failure at the substation. The substation is set up in a radial feed allowing for feeder back-up. In JW&L's substation, there are switches located in a circular fashion that allow JW&L to easily switch a circuit that is out to another energized source. There is also a tie switch in the center of town that allows a significant section of each circuit to be switched to the other circuit for planned or emergency outages.

Power Factor Measurement and Correction

The most recently available power factor for JW&L is approximately 99%. This will be confirmed and used in a Power Factor and Capacitor Placement study.

Other

Vegetation management, tree trimming and relocating cross-country lines to roadside are also important initiatives that JW&L takes in order to meet reliability and safety criteria. Those topics will be discussed in further detail later in this document.

Distribution Circuit Configuration

Voltage Upgrades

JW&L has contemplated converting its 2,400/4,160 volt system to 7,200/12,470 volts. The substation improvements already completed would allow for this to be done if and when JW&L determines a conversion is in the best interest of the system. JW&L's decision to implement a voltage conversion will be based on several factors including load levels, capital costs, resulting reduced losses, reliability changes and preceded by completion of a system study. With the new GIS mapping system, JW&L will be able to download the information into a Distribution Circuit Analysis program. This will allow JW&L to allocate a value to loss reduction.

Phase balancing

While the 2009 System Study identified small phase balancing issues, JW&L has addressed many of these already. Therefore, currently, the phases are in balance to a large degree. The study also indicated that future corrective balancing can be accomplished by first adding new load to the unbalanced phases and then splitting load equally between phases, a practice JW&L has employed since 2009.

JW&L staff has begun to map customers to phases for improved outage response capabilities.

System Protection Practices and Methodologies;

Protection Philosophy

JW&L's system protection includes transmission, distribution, and substation protection. Each is discussed briefly below.

Transmission:

MW&L employs a networked system protection system in conjunction with the other utilities that MW&L interconnects with on the jointly owned 34.5 kV transmission line. JW&L has a direct feed from the 34.5 kV line and therefore does not have any transmission breakers on its side of the transmission feed.

Distribution:

JW&L uses distribution arrestors on equipment in the field.

Substation:

JW&L uses station class arrestors in its substation. The makeup of these devices is polymer not porcelain, due to safety concerns. All structures within the substation are metal for reduced fire risk. All equipment is also protected by fusing on the high side with a fuse saving philosophy in place due to the breaker protection programming.

Smart Grid Initiatives

Planned Smart Grid

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

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

Lemmerhirt Consulting visited and interviewed each member utility, gathering data from utility staff and driving 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 15: 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. JW&L recognizes emerging requirements and value for AMI in offering more customer services such as time-of-use rates and self-service options; measuring and monitoring new technology - electric vehicles, distributed generation; distribution grid improvements by adopting programs like Conservation Voltage Reduction or Volt/Var Reduction. Since JW&L 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 16: AMI Readiness Evaluation

Overall AMI Readiness	Rating
Electric Meter Readiness	**Good**
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	**Good**
Asset Data Readiness	**Fair**
Overall	**Fair**

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

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

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

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

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

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

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

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

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

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

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

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

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

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

JW&L expects to benefit from AMI implementation in a number of ways:

- Collection of interval data to support cost of service and innovative rate design
- Offer energy programs for customers to promote beneficial load management
- Increase customer engagement in their use of electricity and water resources
- Planning of future capital/T&D system investment strategies
- Comply with future regulatory and legislative requirements
- Reduction of overall meter reading impacts on staff and time
- Improve re-read needs and billing errors

- Reduce cost of non-pay disconnect/reconnect, move-in/out (off-cycle reads)
- Improve billing and customer care services
- Identify and reduce theft of service
- Improve accuracy of electric and water metering
- Optimize electric metering benefits such as transformer right-sizing
- Improved system planning capabilities and water resource management
- Improved water distribution system asset performance
- Reduced carbon footprint

In terms of business case, a cost benefit assessment, looking at about 20 areas of potential benefit, spanning field operations, metering and meter operations, billing, and customer and related rate programs was performed. This assessment indicates a positive NPV benefit of more than $500,000, with a positive cost-benefit ratio of 2.5 and a 4.2-year payback, providing JW&L with reassurance that proceeding to the implementation phase is the correct decision. Note that the figures shown in this assessment are inclusive of the Vermont state funding opportunity. The final contract with Aclara has been recently signed and JW&L is optimistic that it will begin implementation of a new AMI system in either late 2026 or early 2027.

Geographic Information System

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

Cyber Security

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

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

JW&L 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. JW&L conducts ongoing vulnerability assessments and JW&L recently completed its most current assessment.

Other System Maintenance and Operation:

Reconductoring for Loss Reduction

JW&L has been gradually replacing small and or aged conductors over the last twenty years and plans to continue to replace small, aged conductors over the next ten years. Most conductors being used now are 1/0 aluminum AAAC but sized according to present and future load requirements. When re-conductoring, JW&L is framing for compliance with 7,200/12,470 volt construction standards. Generally, in JW&L's system, "small conductor" means #8 copper wire and "aged conductor" means weak or stretched wire. JW&L's decisions to replace equipment are primarily based on functionality (consistent problems) and safety concerns. Of course, when functionality or safety concerns arise, JW&L aims to replace the equipment in the most economical method possible (considering upfront and life-cycle costs).

Transformer Acquisition

JW&L currently purchases new transformers that are dual-voltage transformers to allow for voltage conversion in the future. Life-cycle cost is considered when JW&L looks to purchase transformers. If possible, JW&L will purchase a new transformer that comes with a warranty. JW&L is willing to purchase a more expensive unit with greater reliability.

Conservation Voltage Regulation

JW&L does not have conservation voltage regulation. JW&L's voltage setting is done with an LTC[14] in the main substation only; voltage is set between 120 and 121.5 volts to provide proper voltage to the first and last customers. Conservation voltage reduction is achieved by using feedback to the LTC control, allowing the output voltage to be reduced during off-peak load periods. This reduces the core losses of every transformer on the system by the ratio of the nominal voltage to the actual voltage squared times the nominal losses. By reducing the voltage by 5% a loss reduction in transformer cores of 10% can be achieved.[15]
JW&L also participates in the spring and fall voltage reduction tests.

Distribution Transformer Load Management (DTLM)

JW&L does not have a formal DTLM program. The biggest concern is ensuring that transformers are not overloaded and operating too hot. JW&L checks transformers when there is a failure and considers current and anticipated load when ordering new transformers. When the new mapping system is completed, the customers will be tied to their transformer which would allow a simple transformer loading calculation.

[14] An LTC is a three-phase regulator that is integral to the substation transformer and adjusts the voltage output as necessary to keep the voltage between 115 and 125 volts.

[15] $Losses_{actual}=Loss_{nominal}\,(V_{actual}/V_{nominal})^2$

Substations within the 100- and 500-YEAR Flood Plains

JW&L's substation and back-up substation are located outside of the 500-year flood plain and were not affected by the floods of Tropical Storm Irene or the floods of July 2023 or July 2024.

The Utility Underground Damage Prevention Plan (DPP)

The majority of JW&L's lines are overhead lines. As the quantity of JW&L's underground lines increases, JW&L will become increasingly more involved with the Damage Prevention Plan. JW&L requires inspection of all underground lines prior to burial. This is performed by JW&L employees. JW&L participates in Dig Safe and responds with line personnel to mark all utility-owned underground lines. All primary underground is installed per JW&L's specifications. JW&L pulls all wire with its line crews. All underground is located on JW&L's Outage Management System/GIS and gets updated as needed. JW&L does the same thing for itself (internally) as it does for Dig Safe. JW&L follows and will continue to follow the Dig Safe rules.

JW&L has a Damage Prevention Plan (DPP) in place and filed it with the department in July 2018. JW&L's 2,400/4,160 volt system tends to be more resistant to damage and failure than 7,200/12,470 systems. Approximately 5% of JW&L's lines are underground.

Selecting Transmission and Distribution Equipment

When replacing transmission and distribution equipment, JW&L solicits three different quotes, when possible, before making a purchase. JW&L installs equipment that has proven to be effective and reliable based upon experience. These purchases are based on pricing and reliability. Equipment purchases are evaluated based upon actual experience of JW&L staff and the experience of other utilities.

Maintaining Optimal T&D Efficiency

System Maintenance

JW&L's system maintenance includes a very active annual vegetation effort as well as a plan for annual upgrades developed as part of the annual municipal budgeting process. JW&L is a small municipal system with one large customer and a large residential customer base of elderly and below median income residents, including a high percentage of renters. Resources can be limited at times and JW&L is cognizant of the impact rate increases have on its rate payers. Currently, JW&L's annual budgeting process is the primary method to identify system needs and prioritize projects for completion (construction or equipment upgrades/replacement). Staff meets to discuss the most important equipment and infrastructure needs in the system and works with the Trustees to determine a method to fund the improvement(s).

Substation Maintenance

JW&L uses infrared analyzers annually to identify hot connections and prioritize maintenance. Additionally, JW&L utilizes a contractor for oil analysis every year. JW&L crew performs regular weekly inspections of the substation utilizing an inspection checklist and performs additional inspections after high-wind events and other inclement weather.

Figure 16: JW&L's Substation Maintenance Checklist:

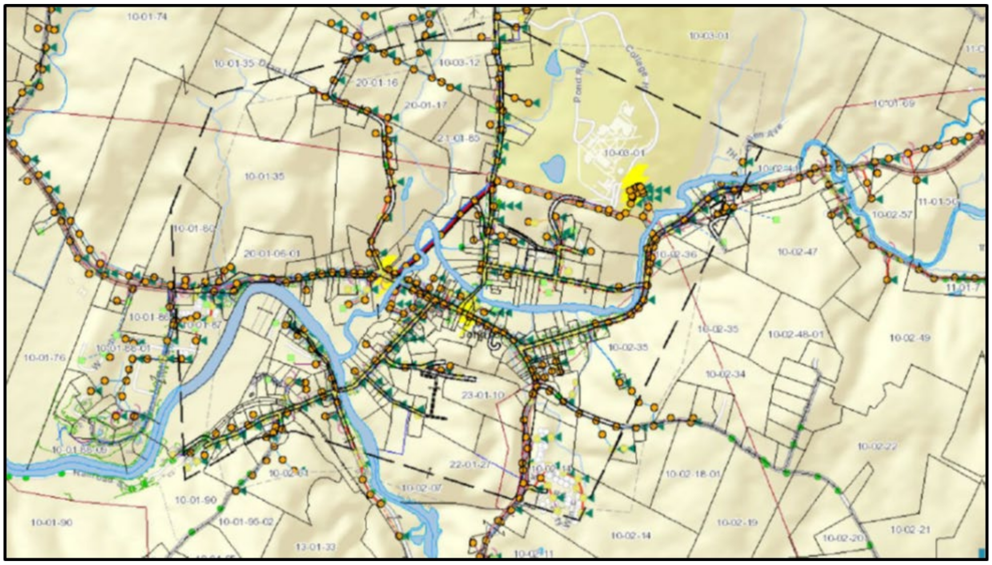
Substation Weekly Check Log Initial and Date under each Column....Comments.............		
Breaker R1 / Re-Boot / Battery Test		
Breaker R2 / Re-Boot / Battery Test		
Breaker R3 / Re-Boot / Battery Test		
Breaker R4 / Re-Boot / Battery Test		
Breaker R5 / Re-Boot / Battery Test		
LTC / Test Fans / Check Light / Re-Set Drag Hands		
B-22 Tie A.B.		
Main St. Tie A.B.		
Containment Main Sub		
Containment Back-Up Sub		
OIL LEAKS?		
FENCE ISSUES?		
GROUND GRID ISSUES?		
OTHER?		
OTHER?		

Pole Inspection

JW&L currently has an informal inspection and treatment program for its distribution poles. The system is quite small geographically and staff is able to complete an inspection of the system on a regular basis. Any poles that are observed to need replacement are dealt with as annual maintenance work or sooner if there are immediate safety issues that necessitate it. JW&L has an active and ongoing right-of-way tree trimming program, which provides an ongoing opportunity for staff to inspect many of the poles in the system.

JW&L has also completed and maintains a GIS based Electric System Map and associated database inventory, which provides detailed system information in map, database and report formats. Data collected includes pole location, heights, class, age, construction type and condition, all manner of pole attachments, conductor phasing, size and type, pole and pad mount transformer size, location, age and type, underground infrastructure, etc. This data is maintained on the town-wide mapping software system, which also includes parcel data, roads and bridges, sewer and water line infrastructure. Storm water systems, flood plains, wetlands, surfaces waters, E911 data, orthophotos, satellite images, etc. This makes for a very powerful planning and maintenance tool for all Village utilities. The following map demonstrates the information available from the system. VPPSA is currently working on a GIS database which will include a wide range of valuable system data, including pole inspection data, for JW&L and its other members.

Figure 17: JW&L GIS Map:



Equipment

JW&L currently performs regular inspections on all equipment and distribution lines. JW&L has established an annual gas testing program for all of its larger power transformers. JW&L performs oil sample testing regularly and also contracts with an outside entity to perform Doble testing approximately every five years.

System Losses

JW&L is committed to providing efficient electric service to its customers. JW&L's plan for improving system efficiency is to undertake a systematic capital improvement program that includes projects that will reduce losses.

Actual System Losses:

For 2023, actual distribution line losses were about 5.9%. Starting in 2014, sub transmission losses dropped due to JW&L's purchase of a share of MW&L's 34.5 kV transmission line.

Efforts to Reduce Losses:

JW&L has considered converting portions of its 2,400/4,160 volt system to 7,200/12,470 volts as potential method to improve system efficiency. Substation improvements already completed would allow for the conversion to take place in the future. However, future conversion projects will be targeted by evaluating the cost-effectiveness of such a conversion.

Tracking Transfer of Utilities and Dual pole Removal (NJUNS)

JW&L does not use NJUNS. JW&L has a direct relationship with Comcast, Consolidated Communications, and VTeL and it has not been problematic.

Relocating cross-country lines to road-side

JW&L recognizes the significant cost associated with maintaining off-road assets. JW&L has a policy in place where every attempt shall be made to make all new construction road-side. Additionally, when rebuilding off-road infrastructure JW&L looks carefully at relocating assets to road-side when possible.

Distributed Generation Impact:

JW&L presently has 13 residential scale (< 15 kW) net metered customers with a total installed capacity of about 95.0 kW. In addition, there are 5 customers who have arrays between 15 and 150 kW, and the total is 520.9 kW.

Interconnection of Distributed Generation

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

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

In addition, recognizing that the aggregate of many smaller installations which individually pass Rule 5.500 screening criteria can present problems that would otherwise go unnoticed, JW&L will maintain detailed records of installed generation including location, type, and generating capacity. This information will allow JW&L 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). JW&L 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 JW&L's service territory, JW&L 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 JW&L. As a reasonable compromise, JW&L 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, JW&L 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. This document is included as Appendix E at the end of this document. JW&L 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:

JW&L 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. JW&L is focused on identifying and developing technical systems that help with the challenge of identifying, tracking and managing "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 JW&L distribution system currently has sufficient capacity for the foreseeable future. As *Table 17* indicates, JW&L has mostly small solar projects on its system. Maximum loading on the substation transformer is currently about 53% of its nameplate capacity and about 29% on average.

Table 17: JW&L Distribution-Level Impact of Electrification

SUBSTATION	# of Transformers	Transformer Capacity (MVA)	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
Johnson Substation	**1 in service**	**5**	**53%**	**29%**	**R1 - Johnson East Circuit**	**4.16**	**11**	**383**	**-**	**NA**	**NA**
	1 Spare (energized)	**5**	**0%**	**0%**	**R2 - NVU Circuit**	**12.47**	**0**	**-**	**-**	**632**	**3,628,800**
					R4 - Johnson West Circuit	**4.16**	**6**	**222**	**-**	**NA**	**NA**

(1) Annual kWh / (transformer capacity * 8760)

(2) DG shown through end of 2022.

We know from the Demand Chapter[16] that the transformer at the Johnson 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. While substation transformer capacity appears adequate for the foreseeable future, JW&L recognizes that the addition of one or more EV charger(s), heat pump(s), or storage device(s) at some locations may stress transformers at the service drop level, necessitating unanticipated upgrades.

While the anticipated, immediate 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, JW&L 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, JW&L tracks customer adoption of electrification measures based on data captured from past and current incentive programs. This incentive program driven dataset provides a significant amount of information regarding the magnitude and approximate locational trends of electrification driven load. JW&L can track installed electrification measures associated with incentive programs, by street address, within the JW&L 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, the view of magnitude and locational trends this dataset will provide over time will inform policy and planning discussions related to JW&L's responses to expected electrification impacts on its distribution system.

As discussed earlier, JW&L anticipates through the tech roadmap project that phased implementation of AMI, GIS, SCADA and DERMS systems over the next few years will provide the ability for more sophisticated measurement, tracking and analysis frameworks that will support implementation of more sophisticated, and forward looking, load forecasting and distribution system planning. As the anticipated distribution system management implementations reach maturity, JW&L will be able to systematically track and analyze transformer, circuit, and substation loading on a locational basis and focus on exploiting the new system's abilities. The current incentive tracking effort will become less critical as JW&L'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 JW&L's planning for appropriate distribution system development by enhancing JW&L's ability to:

- Monitor physical limits at substation, circuit, and transformer levels.
- Identify areas of growing load concentration.

[16] See 'Peak Forecast Results.'

- 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 distribution system and load management.

Vegetation Management/Tree Trimming:

Annual vegetation management work is performed throughout the year. Line clearing is rotational and typically has a timeline of 4 to 5 years. Trimming has historically been performed with JW&L's personnel or use of part-time help, except for large trees, where JW&L hires professional tree services to remove them. JW&L tracks the areas trimmed in a spreadsheet. JW&L specifically performs preventive right-of-way cutting and performs annual ground clearing to prevent tree growth. In most areas, JW&L has a 30-foot right-of-way (15 feet on either side of the pole) and trims to the edge of the right-of-way. JW&L does not use herbicides in its trimming program and has no plans to change this policy in the near future.

Table 18 reflects tree inventory information and annual growth rates of tree species in JW&L's service territory.

Table 18: JW&L Tree Species & Growth Rates

Tree Species	% of Village Trees	Annual Height Growth
Sugar Maple	19.01%	1 foot
Eastern White Pine	14.33%	2 feet
Birch	8.26%	1 to 2 feet
Boxelder	5.79%	1 foot
Red Maple	5.23%	1 to 2 feet
Crabapple	4.68%	under 1 foot
Green Ash	4.41%	2 feet
Ash	3.58%	1 to 2 feet
Japanese Lilac	3.03%	1 to 2 feet
Maple	3.03%	1 to 2 feet
Eastern White Cedar	2.75%	under 1 foot
Northern Red Oak	2.75%	2 feet
Other	23.15%	NA

JW&L recognizes the correlation between tree trimming spending with strategic planning and delivery of service. As a result, JW&L has committed itself to an annual budget of approximately $50,000 for tree trimming. JW&L has an established policy regarding the removal of danger trees as well.

JW&L 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. Once a danger tree is identified, it is promptly removed if it is within JW&L's right-of-way. For danger trees outside of the right-of-way, JW&L contacts the property owner, explains the hazard, and with the owner's permission removes them. Where permission is not granted, JW&L 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 JW&L's territory. JW&L 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 JW&L's territory, affected trees will be cut down, chipped and properly disposed of.

Table 19: JW&L Vegetation Trimming Cycles

	Total Miles	Miles Needing Trimming	Trimming Cycle
Distribution	Approximately 28 miles	22	5-year average cycle

Table 20: JW&L Vegetation Management Costs

	2022	2023	2024	2025	2026	2027
Amount Budgeted	$50,000	$50,000	$48,000	$50,000	$50,000	$50,000
Amount Spent (FY)	$41,789	$9,534	$10,000	Deliberately left blank	Deliberately left blank	Deliberately left blank
Miles Trimmed	3.8 miles	1.0 miles	1.0 miles	4.5 miles to be trimmed	4.5 miles to be trimmed	4.5 miles to be trimmed

Table 21: JW&L Tree Related Outages

	2019	2020	2021	2022	2023
Tree Related Outages	0	0	1	0	2
Total Outages	21	15	16	5	15
Tree-related outages as % of total outages	**0%**	**0%**	**6%**	**0%**	**13%**

The tree-related outages are primarily due to danger/hazard trees outside the right-of-way (ROW) and are not associated with JW&L's ROW trimming schedule. While many of the danger trees are outside the JW&L ROW and are not directly addressed by JW&L's scheduled ROW trimming, JW&L does monitor their presence and strives to quickly address those that appear to be a threat. JW&L staff perform weekly ROW inspections of JW&L's system and when danger trees are identified outside the ROW, JW&L works closely with private property owners. In the fall of 2016, JW&L staff met with the Town Tree Warden to specifically discuss danger trees and to reach an understanding about how the removal of trees outside the JW&L ROW (but within the Town ROW) would be handled. JW&L's established Tree Removal Policy clearly defines the payment procedures for the removal of danger trees, which helps expedite the removal of danger trees.

Storm/Emergency Procedures:

Like other Vermont municipal electric utilities, JW&L is an active participant in the Northeast Public Power Association (NEPPA) mutual aid system, which allows JW&L to coordinate not only with public power systems in Vermont, but with those throughout New England. A JW&L representative is also on the state emergency preparedness conference calls, which facilitate in-state coordination between utilities, state regulators and other interested parties. JW&L uses the https://vtoutages.org/ site during major storms especially if it experiences a large outage that is expected to have a long duration. JW&L believes it is beneficial to inform the Public Service Department if it is experiencing these types of outages. JW&L partners with neighboring municipals and cooperative when extra crew power is required. JW&L does not typically use contract crews

Resilience Planning:

JW&L recognizes the need to actively address system resilience as electrification increases customers' dependence on the electric system at the same time as climate, cybersecurity, and other threats to that system are increasing. JW&L supports the development of a systematic approach to defining, valuing, and planning for resilience, including the use of metrics for measuring and tracking system quality beyond the standard reliability metrics of SAIDI, SAIFI, and CAIDI. Toward this end JW&L plans to follow the development of relevant metrics and planning frameworks being explored through resilience proceedings at the PUC and engage in resilience initiatives convened by the PUC or DPS and its partners.

Planned T&D Studies:

System Planning and Efficiency Studies

In conjunction with the ongoing tech roadmap effort discussed above, JW&L will evaluate the need for a comprehensive T&D study over the next several years. Completed at the right time in this process, the T&D study will provide baseline data relevant to planning distribution system upgrades along with responses to forecasted load growth and resilience needs driven by electrification and other forces.

Fuse Coordination Study

JW&L fuse coordination is currently functioning properly and will be addressed in conjunction with the next full T&D study.

Capital Spending:

Construction Cost (2021-2023):

Table 22: JW&L Historic Construction Costs

Village of Johnson Water & Light Department	Historic Construction		
	2021	2022	2023
Functional Summary:			
Production	$ -	$ -	$ -
General	$ 27,536	$ -	$ -
Distribution	$ 2,293	$ 6,911	$ 3,491
Transmission	$ -	$ -	$ 5,641
Total Construction	**$ 29,829**	**$ 6,911**	**$ 9,132**

Projected Construction Cost (2025-2027):

Table 23: JW&L Projected Construction Costs

Village of Johnson Water & Light Department	Projected Construction		
	2025	2026	2027
Functional Summary:			
Prod	-	-	-
General	14,362	14,678	58,301
Distribution	107,418	28,021	165,373
Transmission	-	-	-
Total Construction	**$ 121,779**	**$ 42,699**	**$ 223,674**

Financial Analysis

V. Financial Analysis

This section quantifies the costs of a Reference Case and a series of resource procurement scenarios as well as 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 24.

Table 24: Scenarios

#	Resource Scenario	Description
0	Reference Case	Open position starting 2028 and after. No Extension of Fitchburg
1	Extend Fitchburg	Extend Fitchburg contract from 2027 through 2031
2	Energy Purchase	Bundled Energy and REC purchase
3	Battery Storage	2MW Battery

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 compound annual growth rate of 0.7% 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 at 6.8%. This has been the trend over the past decade. Administrative costs grow at 2.8%. Loads grow at 0.7%. Finally, the coverage ratio drops as contracts expire.

Table 25: Reference Case Financial, Load and Coverage Ratio Outcomes ($ Million)

Cost Item	2025	2029	2035	2039	2044	CAGI
Net Resource/Load Charges & Credits	$1.11	$1.05	$1.00	$1.13	$1.26	0.7%
Transmission Charges	$0.47	$0.58	$0.87	$1.15	$1.64	6.8%
Administrative/Other Charges & Credits	$0.05	$0.05	$0.06	$0.07	$0.08	2.8%
Total Charges	$1.63	$1.68	$1.93	$2.34	$2.98	3.2%
Total Load - Including Losses (MWH)	13,553	13,773	14,761	15,322	15,425	0.7%
Coverage Ratio	96%	26%	24%	13%	11%	

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 evaluated is sized at 2 MW 100% revenue retention with an assumed commissioning year of

2027. 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 26 shows the present value of the 20-year revenue requirement (PVRR) for the Reference Case and the three scenarios evaluated.

Table 26: Financial Outcomes of each Procurement Scenario ($ Million)

#	Procurement Scenario	PVRR	Unit	% Change
0	Reference Case	$41.45	PVRR	
1	Extend Fitchburg	$0.05	Change from Ref. Case	0.11%
2	Energy Purchase	$0.05	Change from Ref. Case	0.11%
3	Battery Storage	-$1.55	Change from Ref. Case	-3.75%

The first scenario is modeled based on the possible extension of the Fitchburg contract as included in the PPA. The volume remains the same but the PPA rate increases to $95.

The second scenario of bundled energy purchase is based on market energy prices plus a slight premium, which is based on VPPSA's experience in obtaining indicative pricing from the counterparty that offers bundled contracts, and an assumption that REC values will mirror market values. The price increase from the reference case is about $45,500.

Finally, the third scenario reflects the impact of the battery storage option which is a 100% revenue retention with a high base payment rate. This reduces costs from the reference case by about $1.5 million.

Conclusions

The Fitchburg and bundled contracts as modeled increase costs slightly. However, the increase is very minimal so it is possible that JW&L would move forward with those options to maintain the renewability of the power supply. Fitchburg will need to be reevaluated as the deadline for the decision gets closer as market prices will have changed and it may be more economical at that time. A bundled contract would also need to be evaluated separately after getting indicative pricing. While it's unlikely a bundled contract would beat market prices, it's possible the difference would be small enough that JW&L would want to enter into a bundled contract to maintain the renewability of the resource mix. Regardless, VPPSA will need to track market prices to enter into a contract at the most advantageous time so as to keep costs as low as possible. Lastly, a battery at 100% revenue retention and the PPA rate that has been provided for other VPPSA member systems is very economically viable and will reduce rates. However, a location will need to be identified as well as a project specific PPA rate will need to be determined, and another economic analysis will need to occur prior to entering into a contract.

Action Plan

VI. Action Plan

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

- **Tech Roadmap**
  - Continue working to complete evaluation of Tech Roadmap and begin to pursue implementation of recommended systems, in the recommended sequence.
  - Complete implementation of a GIS system and of an AMI system as reflected in the recent RFP within the 2027–2028-time frame.
- **Energy Resource Actions**
  - A preferred alternative is to enter into a market contract for energy and a separate contract for RECs. This will reduce the upward pressure on rates. It will be important to track energy and REC prices to enter into contracts at times when prices are lower.
- **Capacity Resource Actions**
  - Continue to manage and monitor the reliability of Project 10 to minimize Pay-for-Performance (PFP) risk and maximize PFP benefits.
- **Tier I Actions**
  - While at this point it is preferrable to enter into separate contracts for energy and RECs, a bundled energy and REC contract is still a possibility and will be evaluated closer to the time when a purchase will need to be made.
  - 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**
  - Continue to purchase Tier II RECs from other VPPSA members that have excess.
- **Tier III Actions**
  - Identify and deliver prescriptive and/or custom Energy Transformation programs.
- **Tier IV Actions**
  - Maintain open lines of communication with the counterparty that has resources that will qualify for Tier IV to ensure those resources are qualified as quickly as possible and to enter into contracts when those resources are officially qualified.
- **Net Metering**
  - Monitor the penetration rate and cost of solar net metering for future grid parity, and advocate for appropriate policies to mitigate potential upward rate pressure.

- **Storage**
  - Begin discussions with a storage developer to site and develop a battery.

Appendix

Appendix A: 2025 Tier III Annual Plan

Appendix B: Pricing Methodology

Appendix C: JW&L PUC Rule 4.900 Outage Reports

Appendix D: AMI RFI Technical Requirements

Appendix E: AMI RFP Technical Requirements

Appendix F: Itron's Load Forecast Report

Appendix G: Tier III Life-Cycle Cost Analysis

Appendix H: JW&L Projected Capital Investment

Appendix I: JW&L Projected Financial Results

Glossary

Glossary

ACP	Alternative Compliance Payment
ACSR	Aluminum conductor steel-reinforced
APPA	American Public Power Association
CAGR	Compound Annual Growth Rate
CAIDI	Customer Average Interruption Duration Index
CC	Combined Cycle (Power Plant)
CCHP	Cold Climate Heat Pump
CEDF	Clean Energy Development Fund
CEP	Comprehensive Energy Plan
CRC	Cooperative Response Center
DPP	Damage Prevention Plan
DPS	Department of Public Service or "Department"
EIA	Energy Information Administration
ET	Energy Transformation (Tier III)
EV	Electric Vehicle
EVT	Efficiency Vermont
FERC	Federal Energy Regulatory Commission
GMP	Green Mountain Power
HPWH	Heat Pump Water Heater
IRP	Integrated Resource Plan
ISO-NE	ISO New England (New England's Independent System Operator)
JW&L	Village of Johnson Water & Light Department
JSC	Johnson State College
kV	Kilovolt
kVA	Kilovolt Amperes
kW	Kilowatt
kWh	Kilowatt-hour
LCPC	Lamoille County Planning Commission
LIHI	Low Impact Hydro Institute
MAPE	Mean Absolute Percent Error
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
NVU	Northern Vermont University (formerly Johnson State College)
NYPA	New York Power Authority
PFP	Pay for Performance
PUC	Public Utility Commission
PPA	Power Purchase Agreement
PVRR	Present Value of Revenue Requirement
R^2	R-squared
RES	Renewable Energy Standard
ROW	Right-of-way
RTLO	Real-Time Load Obligation

SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
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
VSPC	Vermont System Planning Committee
VT ANR	Vermont Agency of Natural Resources
VTel	Vermont Telephone Company, Inc.
WQC	Water Quality Certificate

Community is at the Heart of VPPSA.

Vermont Public Power Supply Authority

2025 Renewable Energy Standard: Tier III Annual Plan

Case No. 24-3273-INV 2025 RES Tier III Annual Plans

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Table of Contents

Introduction

In accordance with the Public Utility Commission ("PUC") Rule 4.400, Vermont Public Power Supply Authority ("VPPSA") is filing its 2025 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"). In 2024, the Vermont General Assembly passed H.289 (Act 179), *An act relating to the Renewable Energy Standard* which incorporates several revisions to the Renewable Energy Standard[1].

Act 179 created two new Tiers in the RES: Tier 4 (new regional renewable energy) and Tier 5 (load growth). It consolidates RES reporting requirements into the Comprehensive Energy Plan.

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. Further, the emerging and rapidly evolving landscape of systems to optimize grid modernization and energy transformation initiatives continues to expand opportunities for VPPSA and its members to design and develop innovative energy services programs.

VPPSA members continue to prioritize strategic electrification that minimizes cost-shifting or upward rate pressures. These issues remain top-of-mind as cost-of-living expenses continue to rise and geopolitical conflicts once again strain the global economy. Responsiveness to the needs of all customer classes remains a priority to ensure sustainable growth and promoting the values of local energy democracy.

In consideration of all these factors, VPPSA submits its 2025 Tier III Annual Plan which aims to support mutually beneficial statewide programs with Vermont's Energy Efficiency Utilities, while also strengthening opportunities to increase access to sustainable, clean, and cost-effective energy transformation solutions for residential, commercial, and industrial customers.

[1] See: https://legislature.vermont.gov/bill/status/2024/H.289

VPPSA Tier III Obligation Requirements

VPPSA Member Utilities'[2] 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.[3]" Tier III requirements increase by two-thirds of a percent annually.

The new RES policy requires that VPPAS obligation be based off of load which was interpreted as total load including losses. Total load including losses includes all energy purchased in additional to internal generation and losses incurred through transmission and distribution. The definition of load is pending and may change because there has not yet been a ruling by the PUC defining load.

Figure 1 illustrates that since 2019, VPPSA's member utilities have recorded modest load growth patterns, with a decrease observed between 2019 – 2020.

For 2025, VPPSA has estimated a 2.0% load growth that aligns with industry and statewide forecasts, while taking into consideration increased priority being placed on equitable access to electrification in more rural service territories. These assumptions are made with the acknowledgement that some member utilities may not trend precisely in alignment with these estimates.

Based on the proposed forecast of Total Load Including Losses (TLIL), VPPSA estimates its 2025 compliance requirement to be 22,455 MWh equivalent (MWhe) in savings, representing 5.34% of members' 2023 estimated Annual Retail Sales (kWh), per the statute.

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

[3] 30 V.S.A. § 8005(a)(3)(B)

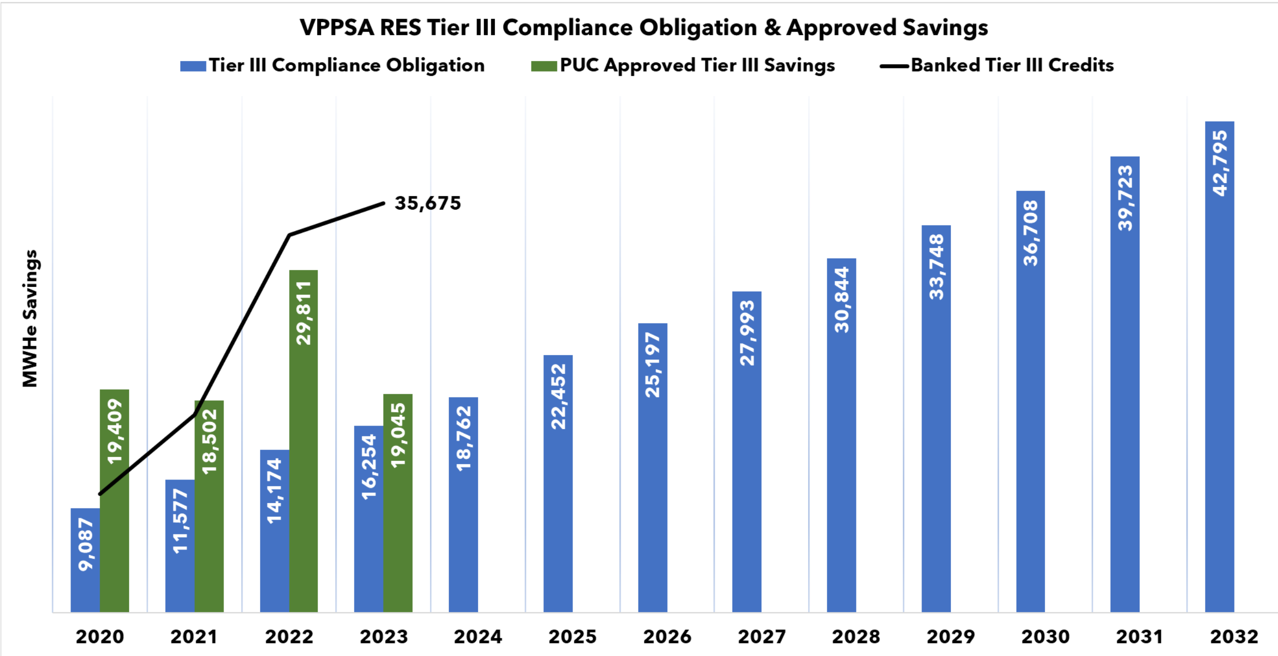
Figure 1: VPPSA Annual RES Compliance Obligation Calculations & Projects (2019 - 2025)

VPPSA Annual RES Compliance Obligation Calculations								*Estimates & Projections*	
% of Retail Sales	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	***2023***	***2024***	****2025***
Tier I	*55.00%*	*55.00%*	*55.00%*	*59.00%*	*59.00%*	*59.00%*	*63.00%*	*63.00%*	*63.00%*
Tier I - Tier II	*54.00%*	*53.40%*	*52.80%*	*56.20%*	*55.60%*	*55.00%*	*58.40%*	*57.80%*	*57.20%*
Tier II	*1.00%*	*1.60%*	*2.20%*	*2.80%*	*3.40%*	*4.00%*	*4.60%*	*5.20%*	*5.80%*
Tier III	*0.0%*	*0.0%*	*2.00%*	*2.67%*	*3.33%*	*4.00%*	*4.67%*	*5.33%*	*6.00%*
Retail Sales	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	***2023***	***2024***	***2025***
VPPSA Total (kWh)			344,106,701	340,727,482	347,253,486	354,352,447	348,300,088	351,783,089	
Retails Sales Growth				-1.0%	1.9%	2.0%	-1.7%	2.0%	
Total Load Including Losses (TLIL)									374,207,000
TLIL Growth									
kWh/Yr	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	***2023***	***2024***	***2025***
Tier I				201,029,214	204,879,557	209,067,944	219,429,055	221,623,346	235,750,410
Tier I - Tier II				191,488,845	193,072,938	194,893,846	203,407,251	203,330,625	214,046,404
Tier II				9,540,369	11,806,619	14,174,098	16,021,804	18,292,721	21,704,006
Tier III				9,087,202	11,577,431	14,174,098	16,254,004	18,767,628	22,454,915
MWh/Yr	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	***2023***	***2024***	***2025***
Tier I				201,029	204,880	209,068	219,429	221,623	235,750
Tier I - Tier II				191,489	193,073	194,894	203,407	203,331	214,046
Tier II				9,540	11,807	14,174	16,022	18,293	21,704
Tier III (MWhe)				9,087	11,577	14,174	16,254	18,768	22,455
PUC Approved Savings			8,553	19,409	18,502	29,811	19,045		
***2025 Obligations are based off percentages of Total Load Including Loses (TLIL)**									

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."

Figure 2: VPPSA Tier III Annual Obligation illustrates VPPSA's projected Tier III annual MWh equivalent (MWhe) savings obligations through 2032 and approved compliance performance.

Figure 2: VPPSA Tier III Annual Obligation



Summary of 2024 Projects

VPPSA is on track to meet its 2024 Tier III requirements of 18,862 MWhe through a portfolio of prescriptive and custom energy transformation measures.

The portfolio of eligible prescriptive measures diversified the 2024 program year and continue to be administered using a combination of mid- and downstream incentive models. VPPSA directly administers a broad portfolio of eligible measures including:

1) E-Bikes and Electric Scooters
2) Electric Golf Cart and Utility Vehicles
3) Electric Forklifts and Stock Chasers
4) Electric Motorcycles
5) Electric Snowmobiles
6) Electric Vehicles (All Electric, Plug-In Hybrid, Fleet Electrification)
7) Electric Vehicle Supply Equipment (EVSE) Charging
8) Electric Lawnmowers (Residential & Commercial)
9) Electric Yard Care: Trimmers, Chainsaws, and Leaf Blowers
10) Weatherization and Window Inserts

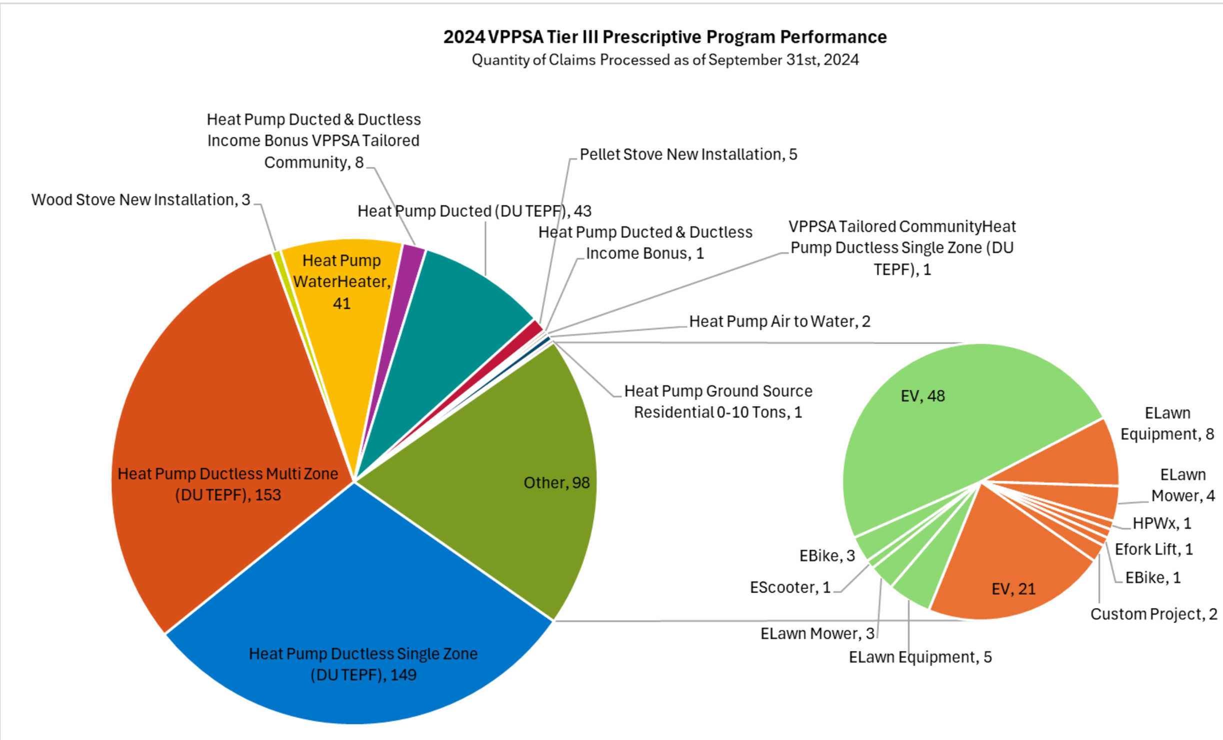
VPPSA members also help sustain the statewide midstream incentive programs administered through Efficiency Vermont (EVT). In 2024, VPPSA members' incentivized the following measures through the midstream program administered by Efficiency Vermont (EVT):

11) Cold Climate Heat Pumps
    a) Single Zone
    b) Multi-Zone
    c) Ducted
    d) Ductless (Additional Incentives offered for integrated controls)
12) Heat Pump Water Heater
13) Air-to-Water Heat Pumps
14) Ground Source Heat Pumps (aka Geothermal)
15) Advanced Wood Heating (Cord Wood/Pellet)

Figure 3: 2024 Tier III Prescriptive Program Performance reflects processed claims as of September 31, 2024 and is intended for illustrative purposes only[4].

This data is not reflective of the total or expected claims for the entire 2024 Tier III Compliance year.

Figure 3: 2024 Tier III Prescriptive Program Performance



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[4] Figure 3 represents the quantity of completed prescriptive rebate claims processed as of September 31, 2024 and is intended for illustrative purposes only. This data does not reflect the entirety of 2024 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 MWhe is, on average, lower than both prescriptive incentives and Tier II RECs.

Custom Energy Transformation 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. In2024 VPPSA finalized the program design and development of its Business Energy Repayment Assistance Program, a grant-funded initiative that provides an on-bill repayment structure for C&I customers of member utilities to implement eligible energy transformation projects.[5]

[5] See WCAX *Cabot Hosiery invests in efficiency upgrades at Northfield factory*, *October 23, 2024*

2025 Tier III Program Overview

The focus of VPPSA's 2025 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.

First and foremost, VPPSA's strategy for the 2025 Program Year continues to focus on cost-effective prescriptive and custom Tier III measures which meet member and customer needs. This strategy includes monitoring market saturation, external funding sources, potential grid infrastructure impacts, and external socio-economic factors that may affect supply chains and future compliance.

For the past several years, VPPSA has executed annual MOUs with EVT related to statewide programs and services. These MOUs have been beneficial in articulating clear roles and responsibilities to support increased collaboration and coordination with Vermont's Energy Efficiency Utilities, as required under the Renewable Energy Standard. For example, Efficiency Vermont's statewide EEN network of participating suppliers and distributors expands access to potential savings at the point of purchase.

Evaluation of the midstream program's shared savings model shows that VPPSA members' contributions for eligible measures accounts for, on average, 76% of the total incentive available to an end-use customer in the midstream program. Beginning in 2024, midstream incentive program partners are also subject to an additional 9.7% Cost-Recovery Fee[6] on every incentive administered through EVT on behalf of the distribution utility.

VPPSA continues to research innovative program opportunities for customers to participate in flexible load management programs for electric vehicles (EV) and electric vehicle station equipment (EVSE). VPPSA anticipates a new prices-to-devices program piloting in late 2024-early 2025 and ready for full implementation in early 2025.

Ongoing progress continues to be made to deploy Advanced Metering Infrastructure (AMI) for its eleven (11) member utilities, with installation occurring in tranches over a 3-year project period. As an enabling technology, AMI will support time-based energy

[6] 2024 Cost Recovery Fees = 9.7% (General Support-Indirect, 6.7% + Core IT, 3%.
2025 Cost Recovery Fees = 8.7% (General Support -Indirect, 6.7% + Core IT, 2%

usage monitoring, data analytics, and customer behaviors for sustainable distribution grid modernization and electrification.

In addition to traditional incentives, VPPSA plans to evolve the program to meet customer needs and increase accessibility, while simultaneously adjusting to market and compliance conditions. VPPSA continues to seek strategic partnerships that support economic development for grid modernization while continuing to align with the core values of local energy democracy, affordability, and reliable service.

As in previous years, VPPSA plans to meet its 2025 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 directly administered prescriptive measure offerings. 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 promotes equity in accessibility and customer participation, VPPSA's 2025 Tier III Program measures into four main categories, by type of electrification (aka energy transformation):

a) Transportation
b) Thermal
c) Commercial Equipment & Appliances
d) 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, ideally with the approval of our tariff rider program currently under development.

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 2025 as both point-of-sale or post-purchase rebates.

The incentive levels for the 2025 Tier III Transportation measures are shown in Figure 4: 2025 Electric Vehicle Incentive.

Electric Vehicle Fleets

VPPSA's 2025 program will continue to include incentives for electric vehicle fleets to support electrification of class 8 trucks, paratransit shuttles, school buses, garbage trucks, delivery trucks, mail trucks, and transit buses. These types of projects can be quite expensive, but the environmental benefits are quite high. VPPSA is offering a $5000 incentive for fleet conversion projects in 2025.

Electric Vehicle Charging

In 2024, VPPSA increased its rebate for customers installing Level 2 electric vehicle chargers at a workplace and/or available for the public to use to $950.

Using insights gained from the 2023 EVSE Powershift Pilot Program with Efficiency Vermont (EVT), VPPSA hopes to develop a more robust EV charging network and program through expanded access as part of its strategy to offer customers EV/EVSE rates in 2025. These programs will optimize EVSE charging to monitor grid impacts from this added load. EV Charging will be incentivized during off-peak hours and may facilitate direct control of EV charging in the future.

Figure 4: 2025 Electric Vehicle Incentive Levels

MEASURE TYPE	BASE INCENTIVE	INCOME QUALIFYING INCENTIVE ADDERS
ELECTRIC VEHICLE (NEW)	$ 1,250	**$ 400**
ELECTRIC VEHICLE (USED)	$ 500	**$ 400**
PLUG-IN HYBRID VEHICLE (NEW)	$ 500	**$ 400**
PLUG-IN HYBRID VEHICLE (USED)	$ 250	**$ 400**
ELECTRIC VEHICLE FLEETS	$ 5,000	N/A

In its fourth year of partnering with vehicle dealerships around the state to offer point-of-sale incentives, VPPSA again seeks 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. There are enhanced incentives for income-qualifying customers in our ongoing efforts for equity in energy transitions. These include a used all electric and used plug-in hybrid low-income adder that we have added this year.

e-Lite Transportation

New in 2024, we have added a new category of alternative, "e-Lite" electric transportation offerings. These include electric bikes, scooters, motorcycles, and snowmobiles (commercial and recreational)

MEASURE TYPE	BASE INCENTIVE
E-LITE BIKE	$ 100
E-LITE SCOOTER	$ 250
E-LITE MOTORCYCLE	$ 500
COMMERCIAL SNOWMOBILE	$ 500
RECREATIONAL SNOWMOBILE	$ 500

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. We have added pellet stoves, wood stoves, and window inserts into our offerings for 2025.

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 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 2025, VPPSA will continue to incent ducted cold-climate heat pumps through the midstream program administered through Efficiency Vermont, however, no longer incentivize purchases of ductless heat pumps.

Efficiency Vermont will batch midstream claims and invoice VPPSA monthly for reimbursement, inclusive of their cost-recovery fees.

Centrally Ducted Cold Climate Heat Pumps

VPPSA will continue to offer incentives on centrally ducted heat pumps, air-to-water heat pumps, and ground-source heat pumps. Efficiency Vermont administers these incentives through the statewide program.

Incentive levels vary by the units' size and range anywhere from $1,025 to $2,025.

Air-to-Water Heat Pumps

Efficiency Vermont will continue to administer midstream incentives 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. This is equivalent to how the incentive was managed in previous years.

Ground-Source Heat Pump

VPPSA also anticipates coordinating with Efficiency Vermont for ground source heat pump incentives which vary based on tonnage, but range anywhere from $2,100 - $1,000/ton.

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 including acceptable forms to prove weatherization. The additional incentive serves to highlight the importance of overall building performance.

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 continue to 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 $650 incentive to customers that install heat pump water heaters ("HPWH") to replace fossil-fuel fired water heaters. This incentive is administered by Efficiency Vermont and would also include the 10% administrative processing fee.

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.

Advanced Wood Heating (Pellet Stoves / Wood Stoves)

New in 2024, EVT and partner utilities have promoted a statewide midstream program for advanced wood heating (i.e. pellet and wood stoves). Both EVT and VPPSA contribute $200 to the offered incentive and MWhe savings are split based on the type of installation (new or replacement).

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.

Electric Forklifts & Stock Chasers

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 to inform and encourage the electrification of this equipment.

Electric Golf Carts & Utility Vehicles

VPPSA will continue 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 $1,500 incentive for the purchase of an electric, commercial ride-on lawn mower. A $100 incentive will be offered for the purchase of an electric, commercial push mower.

Commercial Leaf Blowers

The 2025 rebate incentive remains $50 for the purchase of a new commercial electric leaf blower.

Commercial Chainsaws, Trimmers, Edgers and Cultivators

The 2025 rebate incentive remains at 2024 levels, $50 for the purchase of a new commercial electric chainsaw, trimmer, edger, or cultivators.

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 2025.

Residential Property Maintenance

VPPSA continues to observe steady customer claims for yard care rebates which will continue to be offered in 2025. Although these measures often have a high $/MWh cost, they are often a lower cost, entry level, and electrification of equipment for the average customer.

Residential Lawn Mowers

VPPSA will continue to offer a $50 incentive for the purchase of a residential push and a $100 incentive for the purchase of a ride-on electric lawn mower.

Residential Leaf Blowers

VPPSA will continue to offer a $50 rebate incentive for the purchase of a new residential electric leaf blower in 2025.

Residential Chainsaws, Trimmers, Edgers, and Cultivators

VPPSA will continue to offer a $50 rebate incentive for the purchase of a residential electric chainsaw, trimmer, edgers or cultivators.

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 long lead times and complex project implementation schedules VPPSA continues support these projects where feasible and promote custom incentive opportunities, in addition to the grant-funded BERAP program previously referenced.

VPPSA members' strong community relationships for economic development inform project leads, in addition to coordination with Efficiency Vermont to identify qualifying Tier III energy transformation and electric efficiency projects.

Incentives for custom measures are typically paid for either by the host utility directly or by the approval of the VPPSA Board of Directors, customer incentives can be issued through its Tier III budget and allocate savings across its members.

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 & Minimum Standards

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 IT/OT plans, 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 is negotiating an agreement with a platform as a service provider while maintaining its existing partnership with Virtual Peaker. Virtual Peaker supports internal utility behavioral demand-response programs that strategically maximize load-reducing generation during high-cost time periods.

As previously stated in the Transportation Electrification section, VPPSA and Efficiency Vermont partnered on the PowerShift Pilot in 2023. VPPSA anticipates its proposed EVSE Tariff Rider program will optimize EVSE charging to monitor grid impacts from this added load. EV Charging will be incentivized during off-peak hour. VPPSA is also kicking of the project planning and implementation of its Energy Storage Access Program (ESAP) grant award for in-home and community-scale battery storage for municipal and income qualifying customers. Further, VPPSA continues to pursue utility-scale storage as a cost-effective means of achieving demand reductions for its members.

Lastly, as a method to encourage participation in buildings which meet established performance standards, thereby helping to manage load control, VPPSA also continues to provide additional incentives for measures 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 can 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.

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 for its customer sector 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 for the customer.

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 these measures, making these programs revenue neutral or beneficial for non-participating ratepayers.

Coordinated Delivery of Energy Transformation Projects

In 2025, 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, or cost-shifting to non-participating customers.

Under the revised MOU filed within case 22-2954-PET VPPSA and Efficiency Vermont anticipate continuing to collaborate on enhancing offerings to members' customers. In many cases, this partnership involves VPPSA providing incentives for energy transformation measures, which can provide benefits to all VPPSA utility customers, while Efficiency Vermont provides incentives for electric efficiency measures.

Through the MOU, VPPSA and Efficiency Vermont have developed a comprehensive program with enhanced benefits for its member utility customers[7]. These offers will be available in all eleven-member utility communities beginning for the duration of their DRP performance period (2024- 2026).

[7] See www.efficiencyvermont.com/vppsa

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 inserts
- 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
- Electric Vehicle/e-Lite product distributor and supplier outreach
- EVT contractor and distributor outreach
- Direct outreach to key community representatives and regional planning commissions

Cost-Effectiveness & Equity

VPPSA's Tier III planning included consideration of the suite of measures in the 2025 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.

Utility Present Value Life Cycle Cost

VPPSA estimated the utility's net revenue for each of the 2025 Tier III measures. The analysis was conducted to provide a key input to the 2025 Tier III reporting template, specifically the 'Present Value Net Revenue' column. These estimates, when combined with other inputs to the template, calculate the 'Utility Present Value Life Cycle Cost Net' in $/MWh.

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.

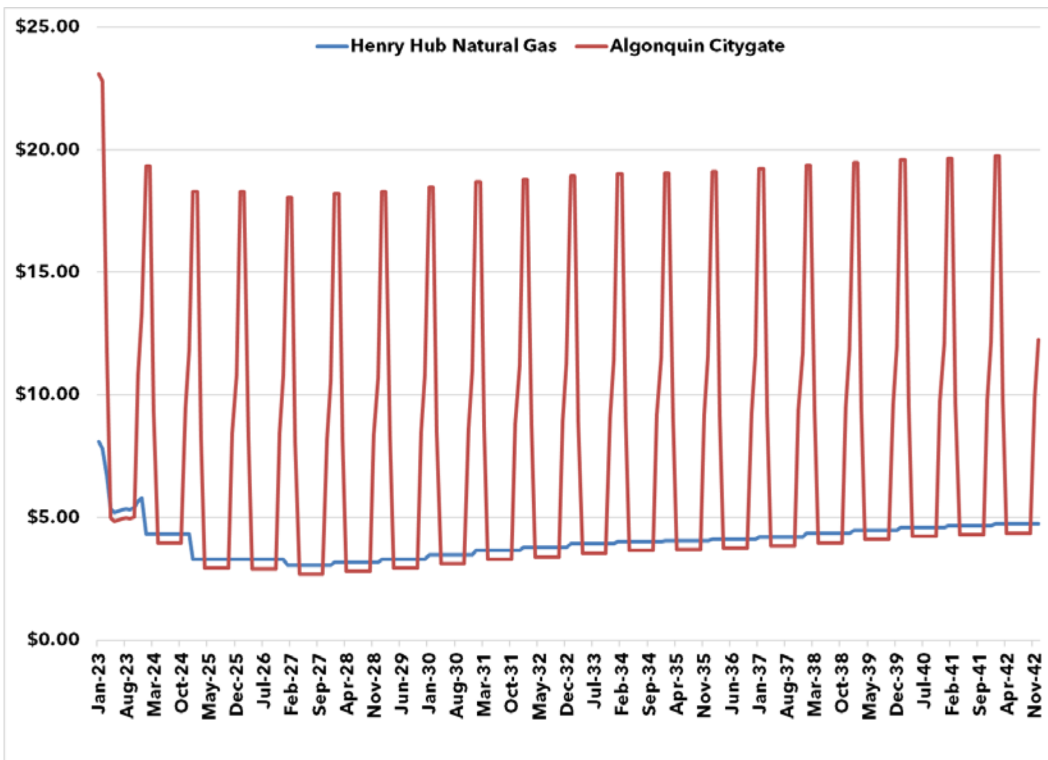
Finally, the 'Present Value Net Revenue' was calculated by subtracting the costs from the benefits and discounting the cash flows back to 2025 at a 5% discount rate.

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.

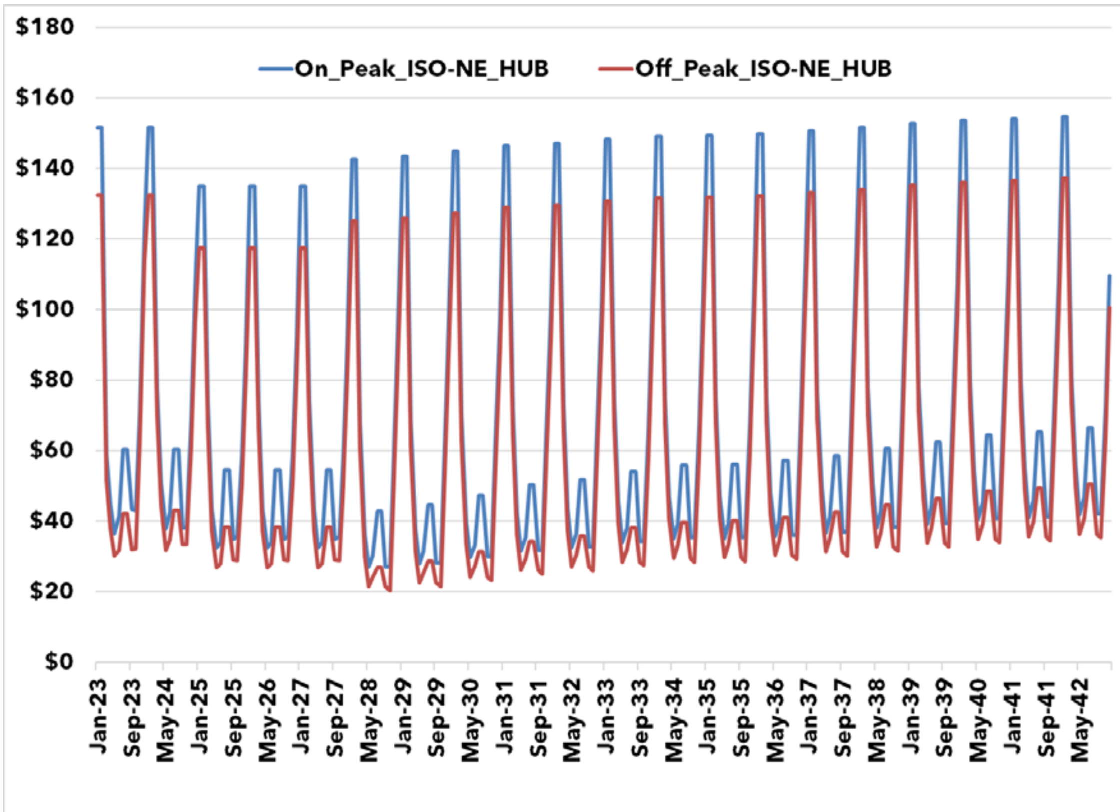
Figure 1: Henry Hub Natural Gas Price Forecast (Nominal $/MMBtu)



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)

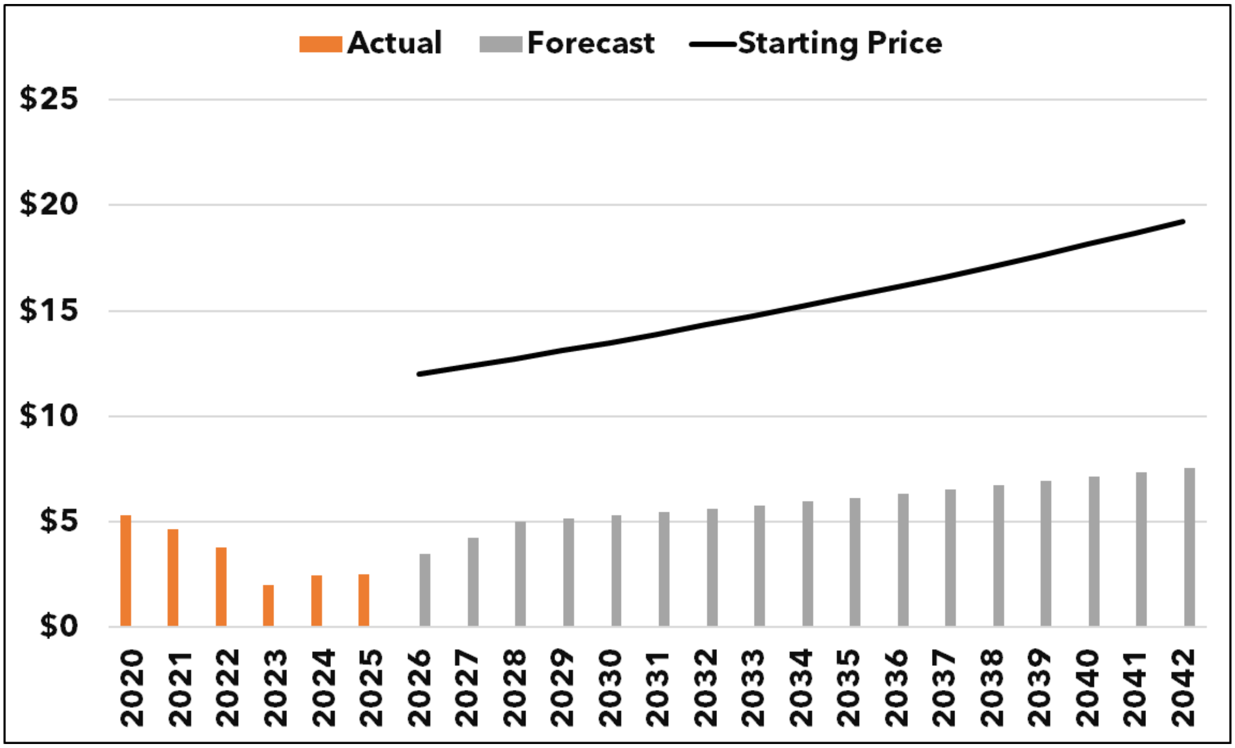


In keeping with the function of ISO-NE's Standard Market Design, we use a five-year average basis between Locational Marginal Price (LMP) nodes to adjust the price forecast at the MA Hub to the location of VOEF's load and resources.

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)



Village of Johnson

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	Village of Johnson
Calendar year report covers	2019
Contact person	Erik Bailey
Phone number	802-635-2611
Number of customers	976

System average interruption frequency index (SAIFI) =	**0.3**
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	**2.3**
Customer Hours Out / Customers Out	

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	0	0
2	**Weather**	12	148
3	**Company initiated outage**	5	107
4	**Equipment failure**	0	0
5	**Operator error**	0	0
6	**Accidents**	2	430
7	**Animals**	0	0
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	2	23
11	**Unknown**	0	0
	Total	21	708

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.

Village of Johnson

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	Village of Johnson
Calendar year report covers	2020
Contact person	Erik Bailey
Phone number	802-635-2611
Number of customers	970

System average interruption frequency index (SAIFI) = 1.1
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 3.6
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	0	0
2	**Weather**	10	1,736
3	**Company initiated outage**	2	1,916
4	**Equipment failure**	0	0
5	**Operator error**	0	0
6	**Accidents**	3	337
7	**Animals**	0	0
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	0	0
	Total	15	3,989

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.

Village of Johnson

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	Village of Johnson
Calendar year report covers	2021
Contact person	Erik Bailey
Phone number	802-635-2611
Number of customers	970

System average interruption frequency index (SAIFI) =	**0.3**
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	**2.5**
Customer Hours Out / Customers Out	

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	1	24
2	**Weather**	11	232
3	**Company initiated outage**	0	0
4	**Equipment failure**	0	0
5	**Operator error**	0	0
6	**Accidents**	4	370
7	**Animals**	0	0
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	0	0
	Total	16	626

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.

Village of Johnson

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	Village of Johnson
Calendar year report covers	2022
Contact person	Erik Bailey
Phone number	802-635-2611
Number of customers	1,001

System average interruption frequency index (SAIFI) = 0.1
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**	0	0
2	**Weather**	2	97
3	**Company initiated outage**	2	237
4	**Equipment failure**	1	2
5	**Operator error**	0	0
6	**Accidents**	0	0
7	**Animals**	0	0
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	0	0
	Total	5	336

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.

Village of Johnson

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	Village of Johnson
Calendar year report covers	2023
Contact person	Erik Bailey
Phone number	802-635-2611
Number of customers	1,009

System average interruption frequency index (SAIFI) = 3.7
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**	2	12
2	**Weather**	9	6,671
3	**Company initiated outage**	3	252
4	**Equipment failure**	0	0
5	**Operator error**	0	0
6	**Accidents**	1	8
7	**Animals**	0	0
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	0	0
	Total	15	6,943

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

1. TECHNICAL REQUIREMENTS

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

1.1 Electric Metering

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

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

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

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

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

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

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

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

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

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

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

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

12. Describe data storage capacity within the meter.

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

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

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

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

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

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

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

20. Describe any other functionality available in the meter.

1.2 Water Meters and Endpoints

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

15. Describe any other functionality available in the meter.

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

1.3 AMI Network

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

1.4 Software

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

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

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

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

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

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

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

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

   a) Meter Data Interrogation

   b) Meter Disconnect/Connect, Pinging

   c) Meter Data Validation, Estimation and Editing

   d) Reports

   e) Analytics

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

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

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

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

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

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

    a) SEDC

    b) NEMRC

    c) Harris Northstar

    d) Harris Spectrum

    e) Harris Select

    f) MUNIS

    g) Cogsdale

    h) Creative Technologies

    i) mPower

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

15. Does your company offer software for data analytics?

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

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

1.5 Other Electric Capabilities

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

1. Describe your company's offerings for Demand Side Management (DSM).
2. Describe the AMI solution's capability to support Demand Response Programs.
3. Describe your AMI solution support for Home Area Networks (HAN).
4. What protocols are available to support DSM or HAN technologies, e.g. OpenADR, Zigbee, Multispeak?
5. What support does your AMI solution offer for outage management?
6. Describe the AMI solution's support for voltage reduction programs, e.g. CVR, VVR.
7. What support does your AMI solution offer for transformer sizing or transformer load management?
8. Describe the AMI solution's ability to support Distribution Automation.
9. Describe the AMI solution's support for net metering.
10. How does the AMI solution support new customer electric technologies, e.g. electric vehicles, power walls, etc.?
11. Describe methods of exporting data from your system.
12. Are there other functions available and supported by your AMI network e.g. streetlight control, security cameras, active shooter, propane tank monitoring?
13. Is there a customer pre-pay solution integrated with the AMI solution?

1.6 Water System Functionality and Leak Detection

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

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

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

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

3. Describe system capabilities for district (zone) metering

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

Request for Proposal (RFP)

for an

Advanced Metering Infrastructure Solution

Deadline for Submission: March 4, 2020

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

Release Date: December 20, 2019

1. TECHNICAL REQUIREMENTS

1.1 Electric Meter Endpoints

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

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

Table 6

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

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

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

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

Provide detailed responses for the following questions:

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

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

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

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

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

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

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

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

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

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

    a. Method of multi-level authentication and authorization.

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

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

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

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

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

1.2 Water Meter Endpoints & Water System Features

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

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

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

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

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

Table 7

Question	Response: Comply, No Comply or Alternative

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

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

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

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

Provide detailed responses for the following questions:

Meter Interface Units (MIUs)

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

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

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

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

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

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

<u>Remote Disconnect Water Meters & Leak Detection</u>

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

1.3 AMI Network

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

Table 8

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

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

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

Provide detailed responses for the following questions:

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

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

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

1.4 Head End System, Meter Data Management and Operations Software

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

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

Table 9

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

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

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

Provide detailed responses for the following questions:

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

1.5 Other Capabilities with the AMI System

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

Table 10

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

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

Provide detailed responses for the following questions:

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

2022 LONG-TERM DEMAND FORECAST SUMMARY

Village of Johnson Water & Light

Prepared For:
Vermont Public Power Supply Authority

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TABLE OF CONTENTS

List of Figures

List of Tables

2022 LONG-TERM DEMAND FORECAST SUMMARY
THE VILLAGE OF JOHNSON

The Village of Johnson (Johnson) resides within the Town of Johnson in Lamoille County. Johnson serves approximately 820 residential customers and 150 commercial customers in the Village and part of the town; the largest customer is Northern Vermont University. Johnson has seen small but positive customer growth, adding on average 5 new residential customers per year; this represents a 0.7% annual customer growth rate. Residential sales account for approximately 45% of sales and nonresidential sales 55%. Total 2021 sales are 12,115 MWh compared with sales of 13,090 MWh in 2011 representing a 0.7% decrease over ten years. Residential average use has been flat with 2021 average use 6,590 kWh about the same as it was in 2013. In 2020, COVID-19 contributed to large decline in commercial sales; sales fell 15.0%. Sales have recovered somewhat since then with 2021 commercial sales up 6.2%. Table 1 shows historical residential customers and class sales.

TABLE 1: JOHNSON HISTORICAL CALENDARIZED SALES AND CUSTOMERS

Year	Res Sales (MWh)	Chg	Res Custs	Chg	Res Avg Use (kWh)	Chg	Non-Res Sales (MWh)	Chg	Total Sales (MWh)	Chg
2011	4,896		759		6,450		8,194		13,090	
2012	4,912	0.3%	764	0.7%	6,429	-0.3%	8,152	-0.5%	13,065	-0.2%
2013	5,028	2.3%	766	0.2%	6,564	2.1%	8,414	3.2%	13,441	2.9%
2014	5,106	1.6%	770	0.5%	6,632	1.0%	8,315	-1.2%	13,421	-0.2%
2015	5,095	-0.2%	772	0.2%	6,604	-0.4%	8,260	-0.7%	13,355	-0.5%
2016	4,941	-3.0%	776	0.5%	6,370	-3.5%	7,620	-7.7%	12,561	-5.9%
2017	4,997	1.1%	788	1.6%	6,340	-0.5%	7,553	-0.9%	12,550	-0.1%
2018	5,206	4.2%	802	1.7%	6,493	2.4%	7,512	-0.5%	12,718	1.3%
2019	5,218	0.2%	807	0.6%	6,470	-0.4%	7,459	-0.7%	12,677	-0.3%
2020	5,407	3.6%	811	0.5%	6,671	3.1%	6,337	-15.0%	11,744	-7.4%
2021	5,387	-0.4%	817	0.9%	6,590	-1.2%	6,728	6.2%	12,115	3.2%
11-21		1.0%		0.7%		0.2%		-1.8%		-0.7%

Given the relatively similar sizes in commercial sales and residential sales, Johnson has been marginally winter peaking with a system peak of around 2 MW. Winter peaks have been decreasing 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	Energy (MWh)	Chg	Sum Peak (MW)	Chg	Win Peak (MW)	Chg
2011	14,536		2.60		2.77	
2012	14,013	-3.6%	2.29	-12.2%	2.56	-7.4%
2013	14,193	1.3%	2.24	-2.0%	2.71	5.8%
2014	14,427	1.6%	2.45	9.5%	2.68	-1.1%
2015	14,050	-2.6%	2.33	-5.1%	2.56	-4.4%
2016	13,835	-1.5%	2.22	-4.8%	2.49	-3.0%
2017	13,173	-4.8%	2.15	-3.2%	2.34	-5.8%
2018	13,345	1.3%	2.26	5.4%	2.40	2.6%
2019	13,405	0.4%	2.16	-4.5%	2.55	6.1%
2020	12,432	-7.3%	2.10	-3.1%	2.32	-9.0%
2021	13,437	8.1%	2.28	8.8%	2.31	-0.4%
Average		**-0.7%**		**-1.1%**		**-1.7%**

Forecast Approach

The Johnson 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 Johnson, 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). Johnson accounts for 0.3% 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. Evaluating GMP's most recent sales trend indicates that residential are leveling out slightly higher than. We are likely seeing permanent structural change as many businesses transition to hybrid work environment (part-time at home and part-time at the office) and increasing number of workers that are working on a fully remote basis.

Baseline Results

The baseline sales incorporate the impact of economic and customer growth and end-use efficiency improvements. This is before adjusting for additional solar (PV), electric vehicles (EV), and cold climate heat pumps (CCHP). Over the next ten years baseline sales decline slightly (-0.3% per year) as improvements in efficiency outweigh the positive contribution for new customer and economic growth. Baseline sales are expected to reach 12,046 MWh in 2032 and 11,486 in 2042. This compares with 2021 baseline sales of 12,115 MWh. Table 3 shows Johnson baseline customer and sales forecast.

TABLE 3: JOHNSON BASELINE SALES FORECAST

Year	Res Sales (MWh)	Chg	Res Custs	Chg	Res Avg Use (kWh)	Chg	Non-Res Sales (MWh)	Chg	Total Sales (MWh)	Chg
2022	5,288		824		6,416		7,137		12,425	
2023	5,216	-1.4%	831	0.8%	6,280	-2.1%	7,296	2.2%	12,512	0.7%
2024	5,199	-0.3%	835	0.6%	6,225	-0.9%	7,303	0.1%	12,502	-0.1%
2025	5,150	-0.9%	839	0.4%	6,140	-1.4%	7,255	-0.7%	12,406	-0.8%
2026	5,133	-0.3%	842	0.4%	6,095	-0.7%	7,200	-0.8%	12,333	-0.6%
2027	5,109	-0.5%	845	0.3%	6,048	-0.8%	7,142	-0.8%	12,251	-0.7%
2028	5,112	0.0%	847	0.3%	6,034	-0.2%	7,105	-0.5%	12,217	-0.3%
2029	5,111	0.0%	849	0.3%	6,017	-0.3%	7,048	-0.8%	12,159	-0.5%
2030	5,118	0.1%	851	0.2%	6,011	-0.1%	6,996	-0.7%	12,114	-0.4%
2031	5,125	0.1%	853	0.2%	6,007	-0.1%	6,940	-0.8%	12,065	-0.4%
2032	5,142	0.3%	854	0.2%	6,017	0.2%	6,905	-0.5%	12,046	-0.2%
2033	5,128	-0.3%	855	0.1%	5,995	-0.4%	6,836	-1.0%	11,964	-0.7%
2034	5,124	-0.1%	856	0.0%	5,989	-0.1%	6,784	-0.7%	11,908	-0.5%
2035	5,126	0.0%	856	0.0%	5,990	0.0%	6,737	-0.7%	11,863	-0.4%
2036	5,141	0.3%	856	0.0%	6,007	0.3%	6,713	-0.4%	11,854	-0.1%
2037	5,128	-0.3%	855	0.0%	5,995	-0.2%	6,654	-0.9%	11,782	-0.6%
2038	5,118	-0.2%	855	-0.1%	5,988	-0.1%	6,611	-0.6%	11,729	-0.5%
2039	5,107	-0.2%	854	-0.1%	5,982	-0.1%	6,567	-0.7%	11,675	-0.5%
2040	5,110	0.1%	853	-0.1%	5,993	0.2%	6,526	-0.6%	11,637	-0.3%
2041	5,093	-0.3%	851	-0.2%	5,983	-0.2%	6,452	-1.1%	11,545	-0.8%
2042	5,088	-0.1%	850	-0.2%	5,988	0.1%	6,399	-0.8%	11,486	-0.5%
22-32		-0.3%		0.4%		-0.6%		-0.3%		-0.3%
32-42		-0.1%		-0.1%		0.0%		-0.8%		-0.5%

Adjusted Forecast

Future load growth will large 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 Johnson's share of state residential customers. Table 4 shows the resulting forecast.

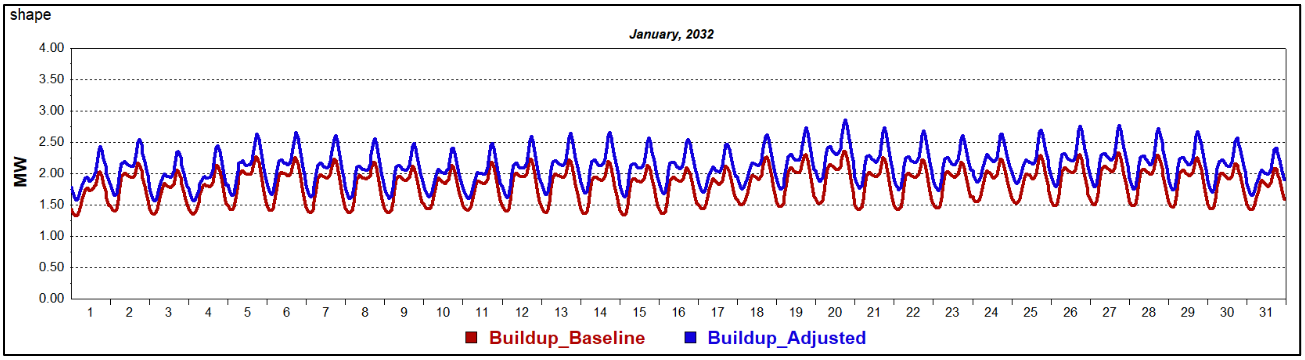
TABLE 4: EV, PV, AND CCHP FORECAST

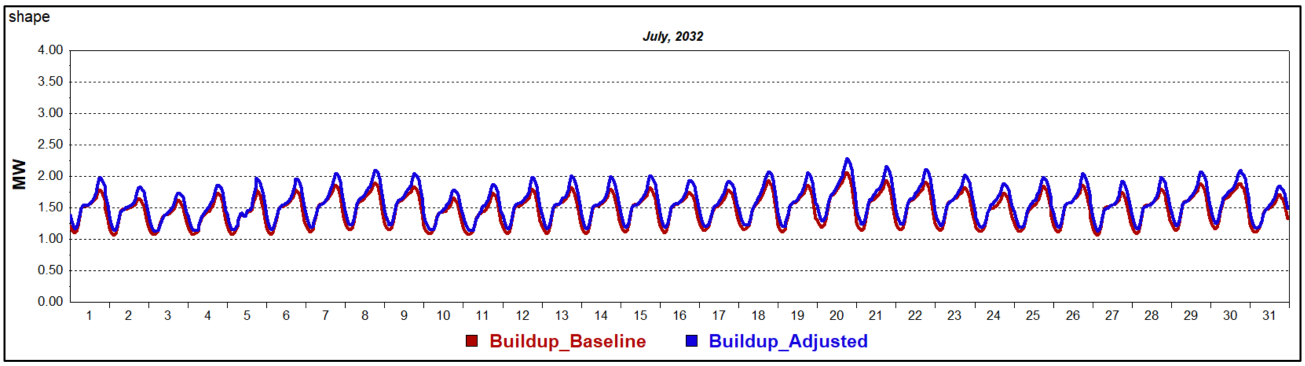
Incremental New Tech Units			
Year	# Of Electric Vehicles	PV Installed Capacity (kW)	# Of HP Units
2022	6	14	15
2023	13	31	31
2024	23	47	48
2025	35	58	67
2026	52	63	87
2027	73	68	108
2028	99	70	131
2029	132	71	156
2030	171	74	179
2031	218	76	200
2032	272	80	219
2033	330	81	237
2034	392	82	255
2035	452	83	274
2036	509	84	292
2037	559	85	311
2038	601	86	330
2039	634	86	349
2040	659	87	368
2041	677	88	387
2042	690	89	406

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: JOHNSON ENERGY FORECAST (MWH)

Energy and Peak								
Year	**Energy (MWh)**	**Chg**	**Summer Peak (MW)**	**Chg**	**Peak Time**	**Winter Peak (MW)**	**Chg**	**Peak Time**
2022	13,906		2.13		7/19/22 6:00 PM	2.47		2/1/22 6:00 PM
2023	14,040	1.0%	2.16	1.4%	7/18/23 6:00 PM	2.51	1.6%	2/13/23 6:00 PM
2024	14,076	0.3%	2.16	0.0%	7/16/24 6:00 PM	2.53	0.7%	2/12/24 6:00 PM
2025	14,038	-0.3%	2.15	-0.3%	7/15/25 6:00 PM	2.53	0.3%	2/10/25 6:00 PM
2026	14,049	0.1%	2.17	0.7%	7/21/26 6:00 PM	2.56	1.1%	1/20/26 6:00 PM
2027	14,069	0.1%	2.17	0.0%	7/20/27 6:00 PM	2.59	1.1%	1/19/27 6:00 PM
2028	14,166	0.7%	2.18	0.4%	7/18/28 6:00 PM	2.63	1.6%	1/18/28 6:00 PM
2029	14,266	0.7%	2.20	1.0%	7/17/29 6:00 PM	2.67	1.3%	1/23/29 6:00 PM
2030	14,400	0.9%	2.22	0.8%	7/16/30 6:00 PM	2.72	2.1%	1/22/30 6:00 PM
2031	14,548	1.0%	2.24	0.9%	7/15/31 6:00 PM	2.78	2.1%	1/21/31 6:00 PM
2032	14,749	1.4%	2.29	2.0%	7/20/32 6:00 PM	2.86	2.9%	1/20/32 6:00 PM
2033	14,899	1.0%	2.31	1.1%	7/19/33 6:00 PM	2.92	2.2%	1/18/33 6:00 PM
2034	15,090	1.3%	2.35	1.7%	7/18/34 6:00 PM	2.98	1.9%	1/24/34 6:00 PM
2035	15,289	1.3%	2.38	1.1%	7/17/35 6:00 PM	3.05	2.4%	1/23/35 6:00 PM
2036	15,517	1.5%	2.41	1.3%	7/15/36 6:00 PM	3.12	2.2%	1/22/36 6:00 PM
2037	15,649	0.9%	2.45	1.6%	7/21/37 6:00 PM	3.19	2.4%	1/20/37 6:00 PM
2038	15,777	0.8%	2.47	0.7%	7/20/38 6:00 PM	3.24	1.6%	1/19/38 6:00 PM
2039	15,871	0.6%	2.48	0.4%	7/19/39 6:00 PM	3.28	1.3%	1/18/39 6:00 PM
2040	15,955	0.5%	2.49	0.6%	7/17/40 6:00 PM	3.30	0.6%	1/24/40 6:00 PM
2041	15,957	0.0%	2.49	-0.1%	7/16/41 6:00 PM	3.33	0.8%	1/22/41 6:00 PM
2042	15,978	0.1%	2.49	0.0%	7/15/42 6:00 PM	3.35	0.7%	1/21/42 6:00 PM
22-32		**0.6%**		**0.7%**			**1.5%**	
32-42		**0.8%**		**0.9%**			**1.6%**	
22-42		**0.7%**		**0.8%**			**1.5%**	

Projected EV, CCHP, and have a significant impact on load with energy requirements averaging 0.7% annual growth. This compares with the baseline annual sales decline of 0.5%. Winter adjusted peak averages 1.5% annual demand growth and summer 0.8% average annual growth.

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

TABLE 6: JOHNSON SUMMER PEAK FORECAST (MW)

Summer Peaks (MW)							
Year	Baseline	Chg	EV	PV	HP	Adjusted	Chg
2022	2.13		0.00	0.00	0.00	2.13	
2023	2.15	0.9%	0.01	0.00	0.01	2.16	1.4%
2024	2.14	-0.5%	0.01	0.00	0.02	2.16	0.0%
2025	2.12	-0.9%	0.02	0.00	0.02	2.15	-0.3%
2026	2.12	0.0%	0.03	0.00	0.03	2.17	0.7%
2027	2.10	-0.9%	0.04	0.00	0.03	2.17	0.0%
2028	2.08	-0.6%	0.06	0.00	0.04	2.18	0.4%
2029	2.08	-0.2%	0.08	0.00	0.05	2.20	1.0%
2030	2.07	-0.7%	0.10	0.00	0.05	2.22	0.8%
2031	2.05	-0.6%	0.13	-0.01	0.06	2.24	0.9%
2032	2.06	0.3%	0.17	0.00	0.07	2.29	2.0%
2033	2.04	-0.8%	0.20	0.00	0.07	2.31	1.1%
2034	2.04	-0.3%	0.24	0.00	0.08	2.35	1.7%
2035	2.02	-0.7%	0.28	-0.01	0.08	2.38	1.1%
2036	2.01	-0.4%	0.31	-0.01	0.09	2.41	1.3%
2037	2.02	0.1%	0.34	0.00	0.09	2.45	1.6%
2038	2.00	-0.7%	0.37	0.00	0.10	2.47	0.7%
2039	1.99	-0.7%	0.39	-0.01	0.10	2.48	0.4%
2040	1.98	-0.3%	0.41	0.00	0.11	2.49	0.6%
2041	1.96	-1.0%	0.42	-0.01	0.12	2.49	-0.1%
2042	1.95	-0.8%	0.43	-0.01	0.12	2.49	0.0%
22-42		**-0.4%**					**0.8%**

TABLE 7: JOHNSON WINTER PEAK FORECAST (MW)

Winter Peaks (MW)							
Year	Baseline	Chg	EV	PV	HP	Adjusted	Chg
2022	2.46		0.01	0.00	0.01	2.47	
2023	2.47	0.7%	0.01	0.00	0.02	2.51	1.6%
2024	2.47	-0.2%	0.02	0.00	0.04	2.53	0.7%
2025	2.45	-0.7%	0.03	0.00	0.05	2.53	0.3%
2026	2.41	-1.7%	0.05	0.00	0.10	2.56	1.1%
2027	2.39	-0.7%	0.07	0.00	0.13	2.59	1.1%
2028	2.38	-0.4%	0.09	0.00	0.15	2.63	1.6%
2029	2.36	-1.1%	0.13	0.00	0.18	2.67	1.3%
2030	2.35	-0.5%	0.16	0.00	0.21	2.72	2.1%
2031	2.34	-0.5%	0.21	0.00	0.23	2.78	2.1%
2032	2.35	0.4%	0.26	0.00	0.25	2.86	2.9%
2033	2.33	-0.7%	0.32	0.00	0.28	2.92	2.2%
2034	2.30	-1.1%	0.38	0.00	0.30	2.98	1.9%
2035	2.29	-0.4%	0.44	0.00	0.32	3.05	2.4%
2036	2.29	-0.2%	0.49	0.00	0.34	3.12	2.2%
2037	2.29	0.1%	0.54	0.00	0.36	3.19	2.4%
2038	2.28	-0.6%	0.58	0.00	0.38	3.24	1.6%
2039	2.27	-0.5%	0.61	0.00	0.40	3.28	1.3%
2040	2.24	-1.0%	0.64	0.00	0.42	3.30	0.6%
2041	2.23	-0.8%	0.66	0.00	0.45	3.33	0.8%
2042	2.21	-0.6%	0.67	0.00	0.47	3.35	0.7%
22-42		**-0.5%**					**1.5%**

Adjusted summer system peak averages 0.8% growth per year. 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.

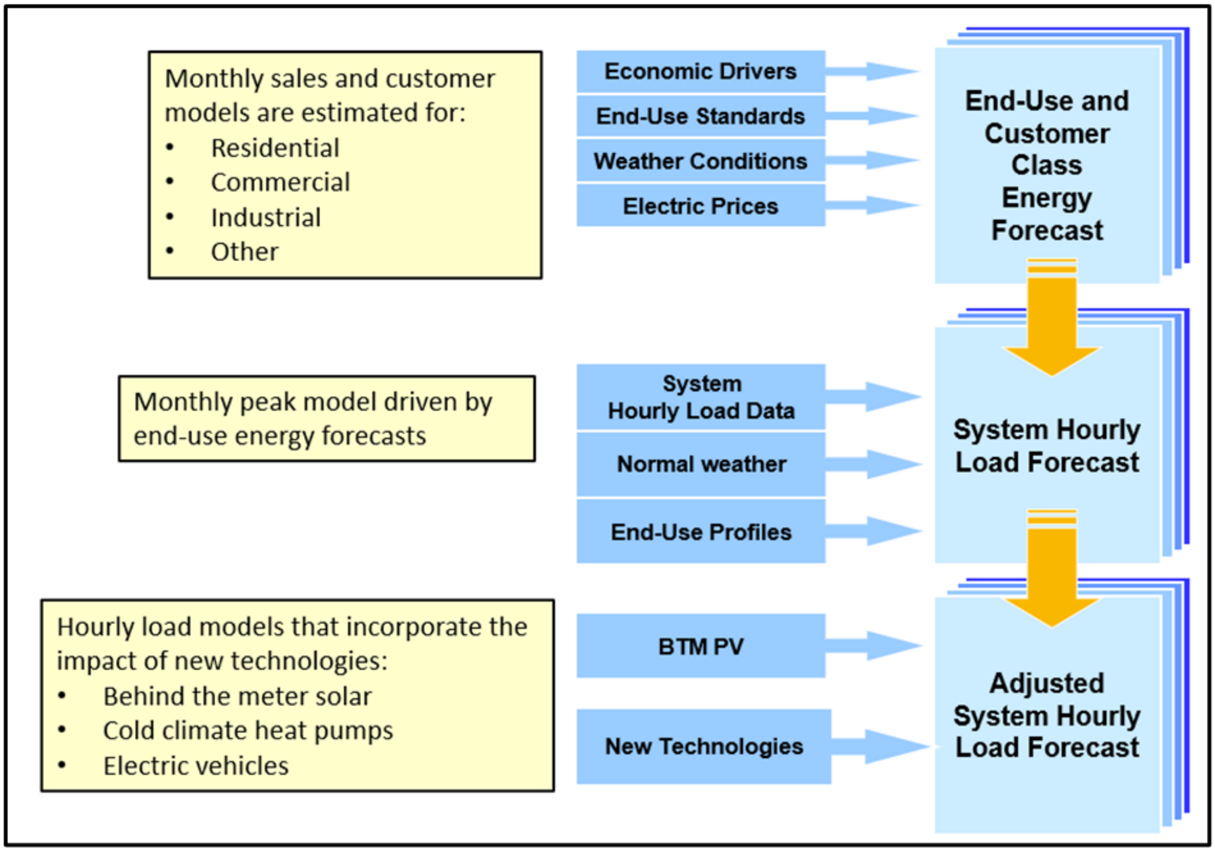
Forecast includes:

- 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.

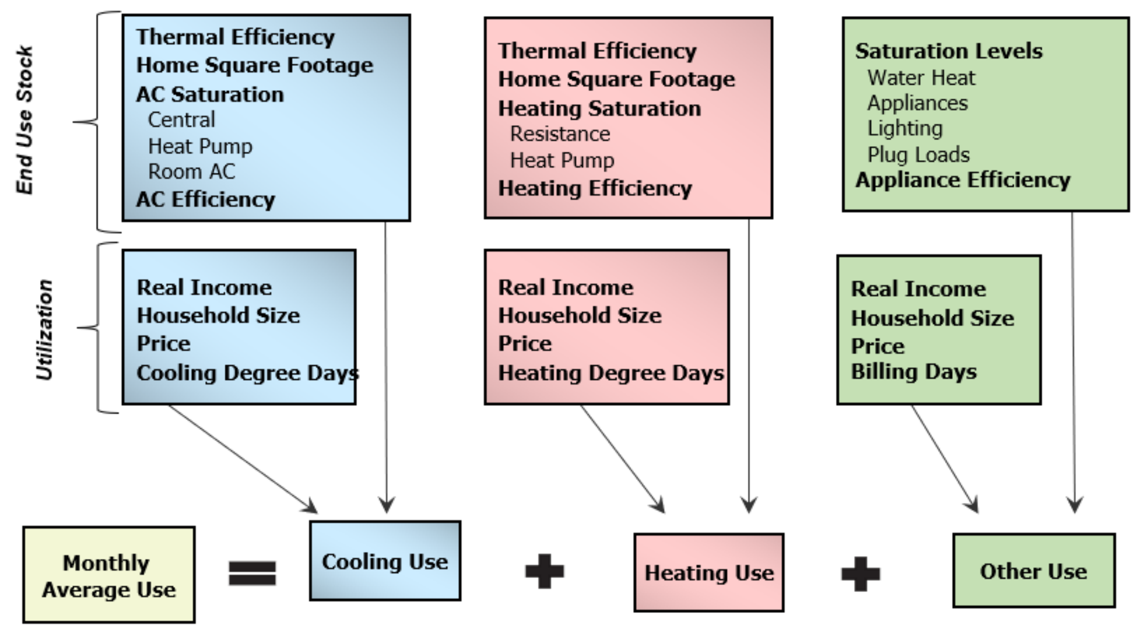
FIGURE 2: FORECASTING FRAMEWORK



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

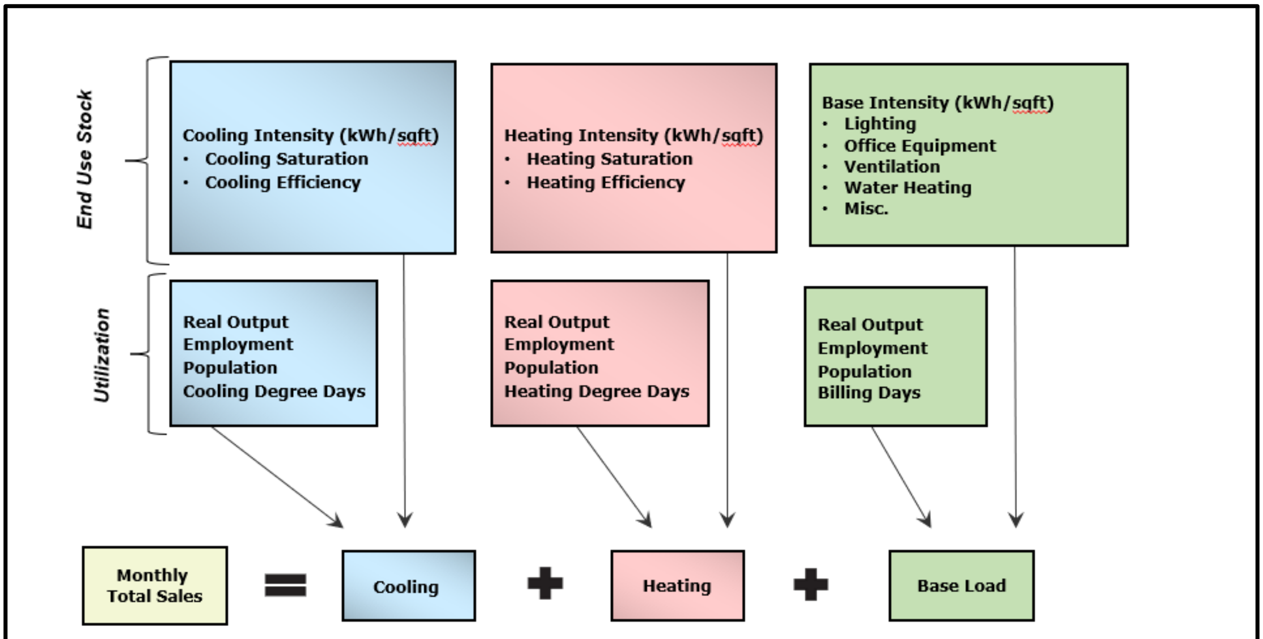


$$AvgUse_m = a + b_c \times XCool_m + b_h \times XHeat_m + b_o \times XOther_m + b_e \times EE_m$$

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.

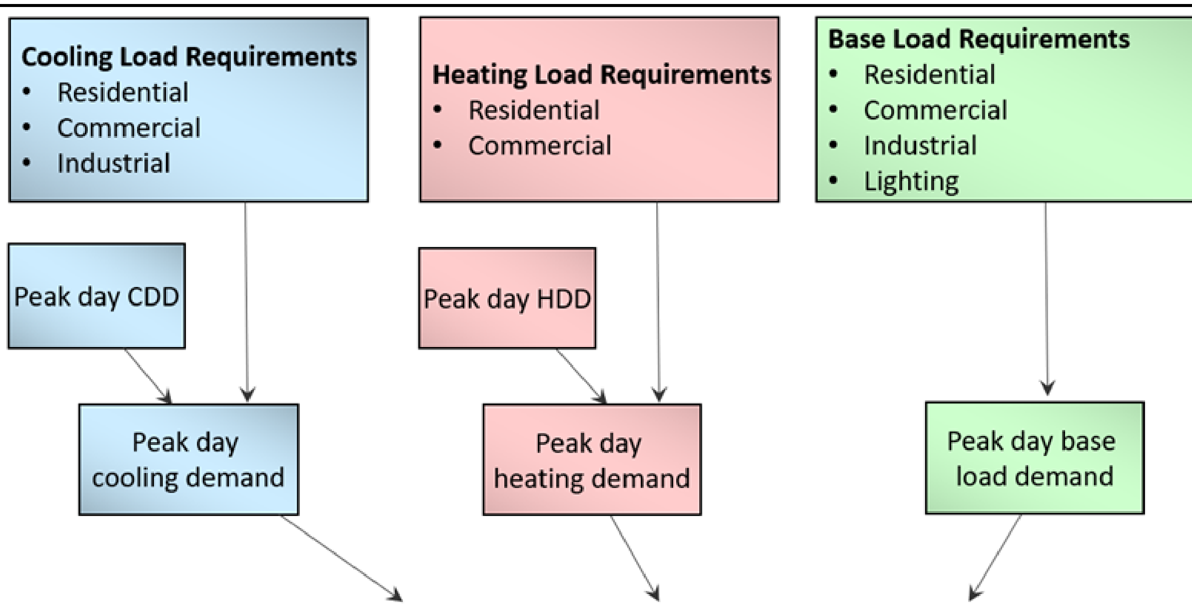
For many of the municipalities the large C&I customer class is dominated by a few companies; there is often significant variation in month-to-month sales data making it difficult to fit an SAE model specification. For these classes, either a more generalized econometric or trend model is used. This is 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

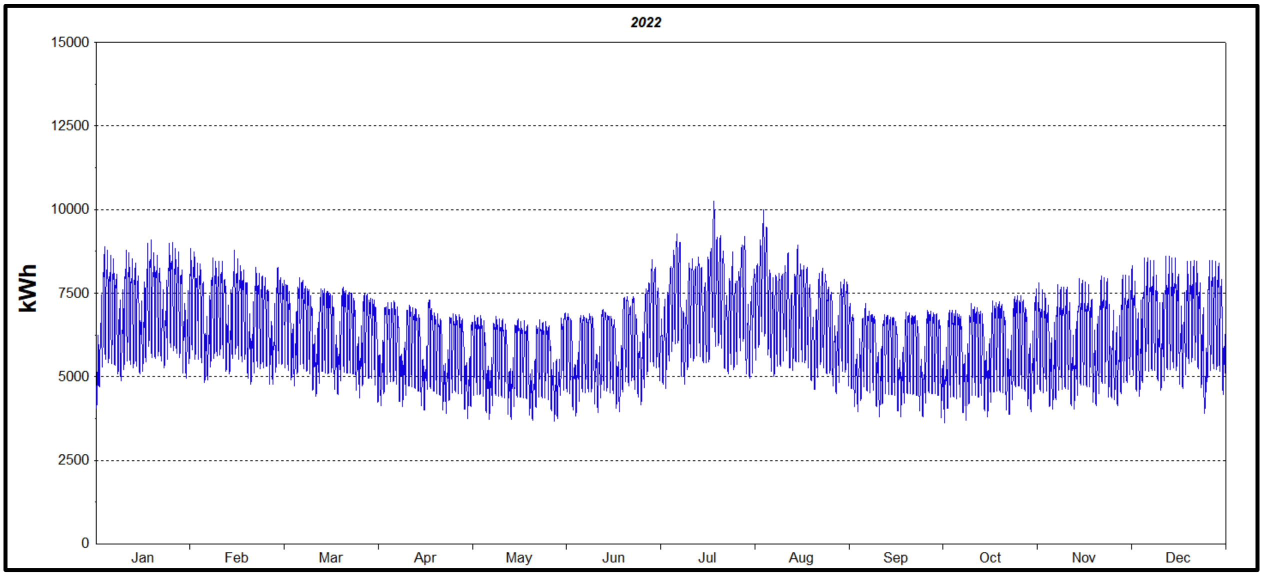


$$Peak_m = a + b_c \times PkCool_m + b_h \times PkHeat_m + b_b \times PkBase_m + e_m$$

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 Swanton.

FIGURE 6: SWANTON LOAD PROFILE



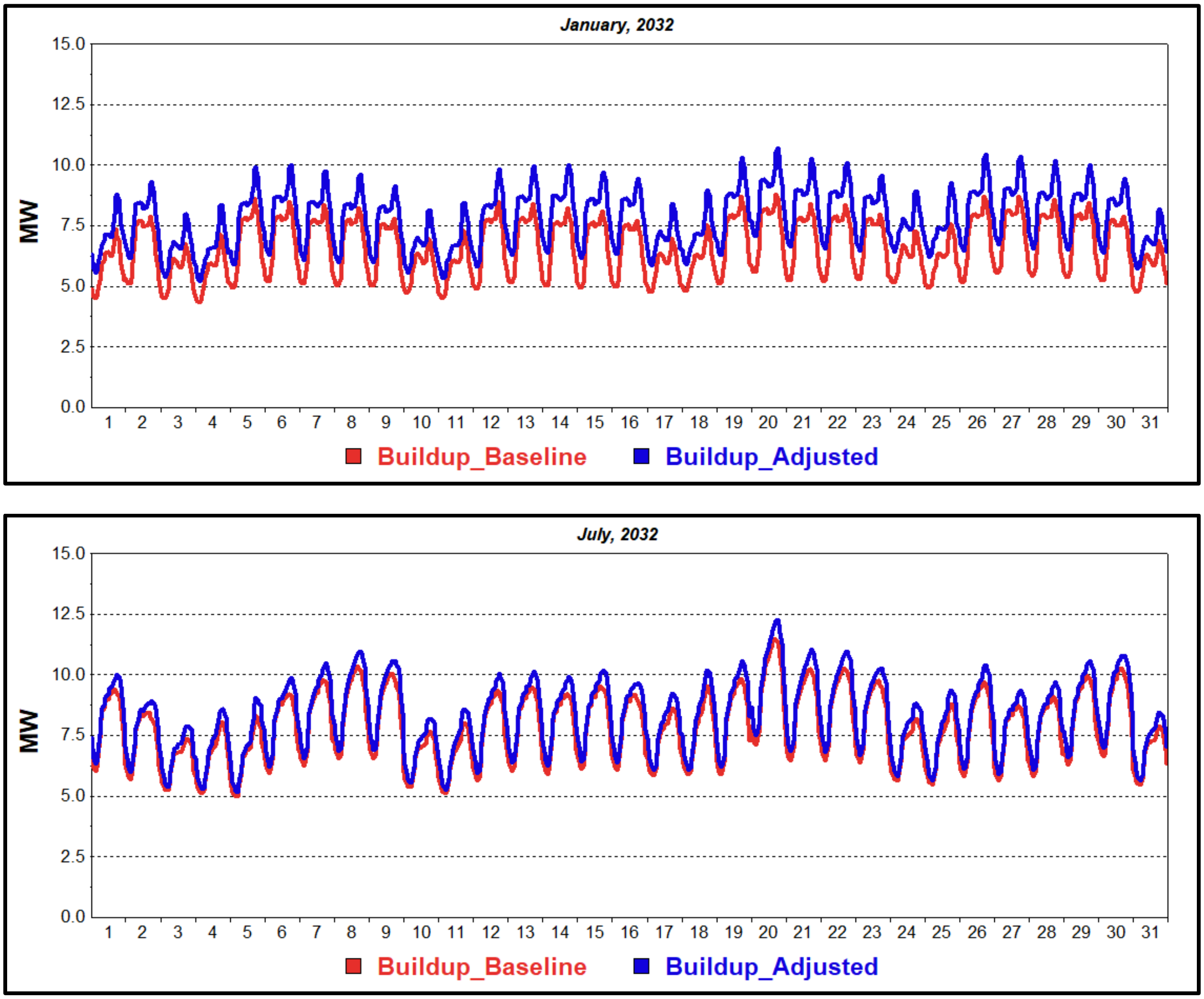
The baseline hourly load forecast is derived by combining the baseline energy and peak forecasts with the system hourly load profile. Increase in energy requirements and peak demand lifts the baseline profile over time. The baseline hourly load forecast reflects customer projections, economic impacts, 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 Swanton baseline and hourly load forecast for 2032.

FIGURE 7: SWANTON SYSTEM HOURLY LOAD COMPARISON (2032)



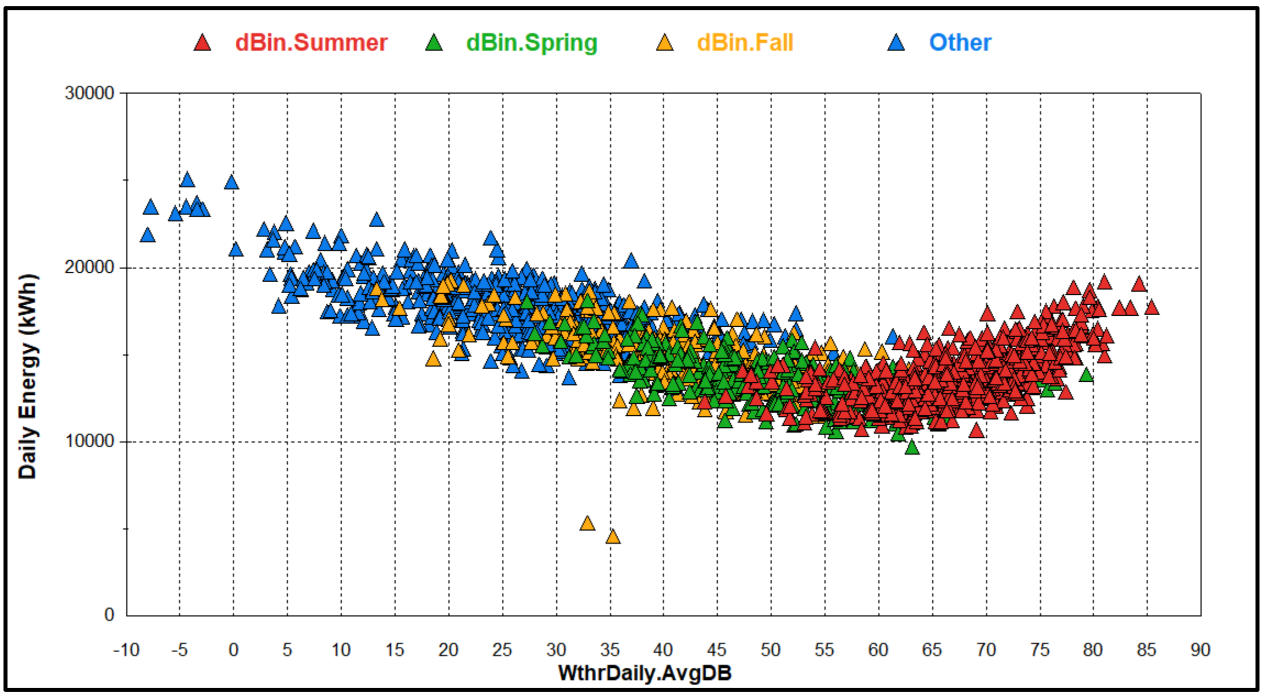
The initial baseline forecast is shown in red and the forecasted adjusted PV, EV, and heat pumps in blue. Solar adoption combined with EV charging shifts the summer peak into the evening hours while heat pumps and EV charging have a much larger impact on winter peaks than summer peaks.

FORECAST ASSUMPTIONS

Weather

Member forecasts use weather from either Burlington or Rutland depending on location. Burlington airport weather data is used for eight 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 Jacksonville.

FIGURE 8: LOAD-TEMPERATURE RELATIONSHIP (JACKSONVILLE)



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

Historical temperature data is used to generate daily and monthly heating-degree days (HDD) and cooling degree-days (CDD). HDD are derived using a base temperature of 55 degrees; this is the temperature point where we begin to see heating load. HDD are positive when 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 the 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

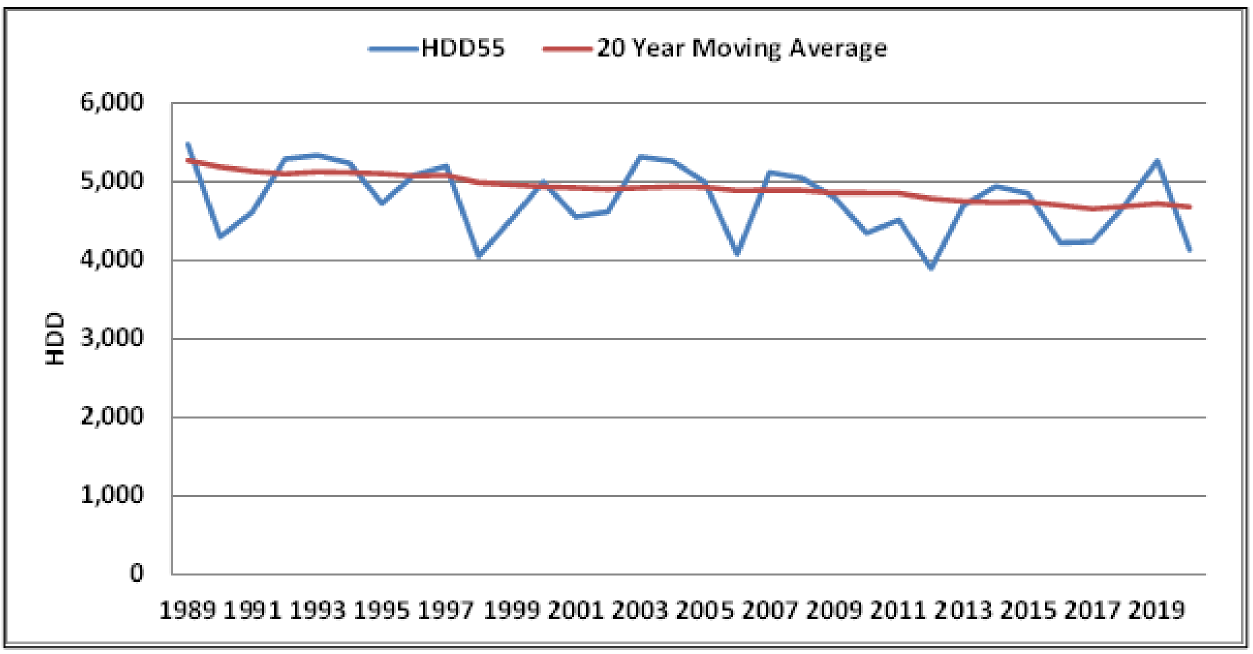
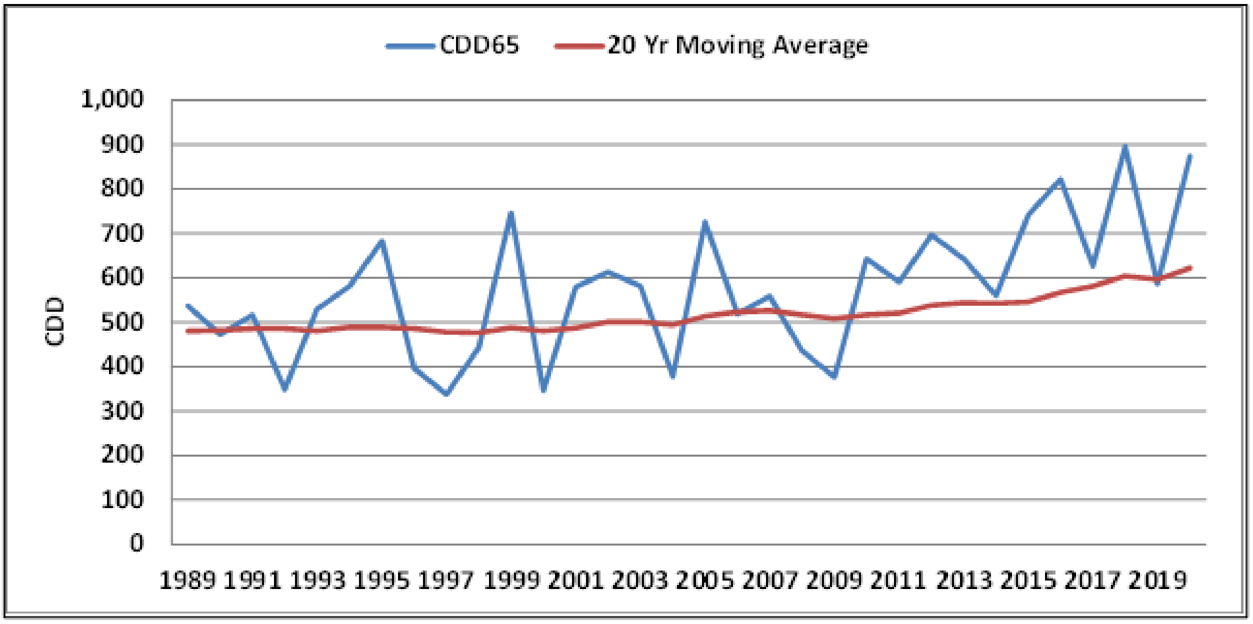


FIGURE 10: COOLING TREND



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

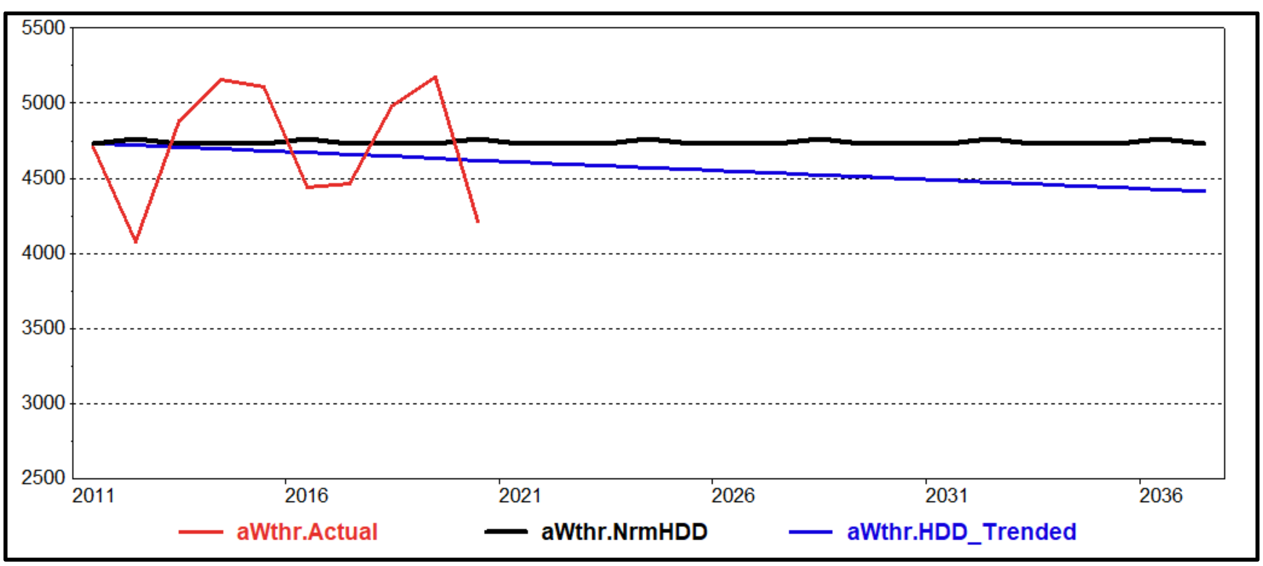
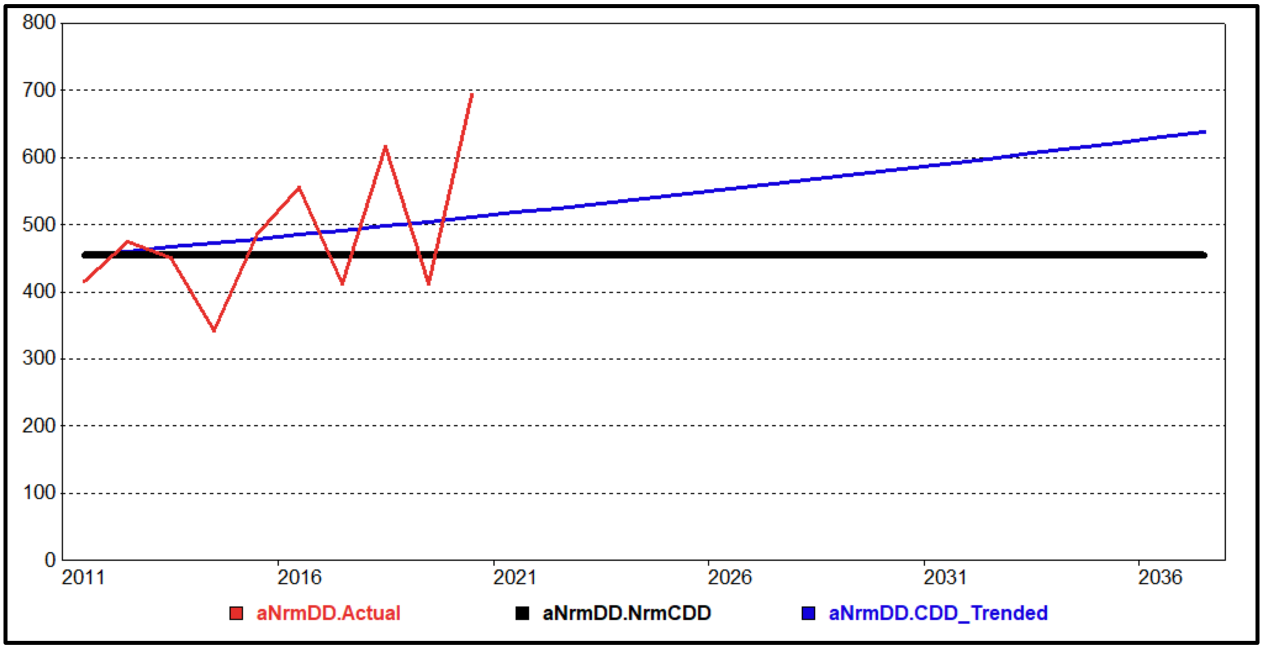


FIGURE 12: NORMAL AND TRENDED NORMAL CDD



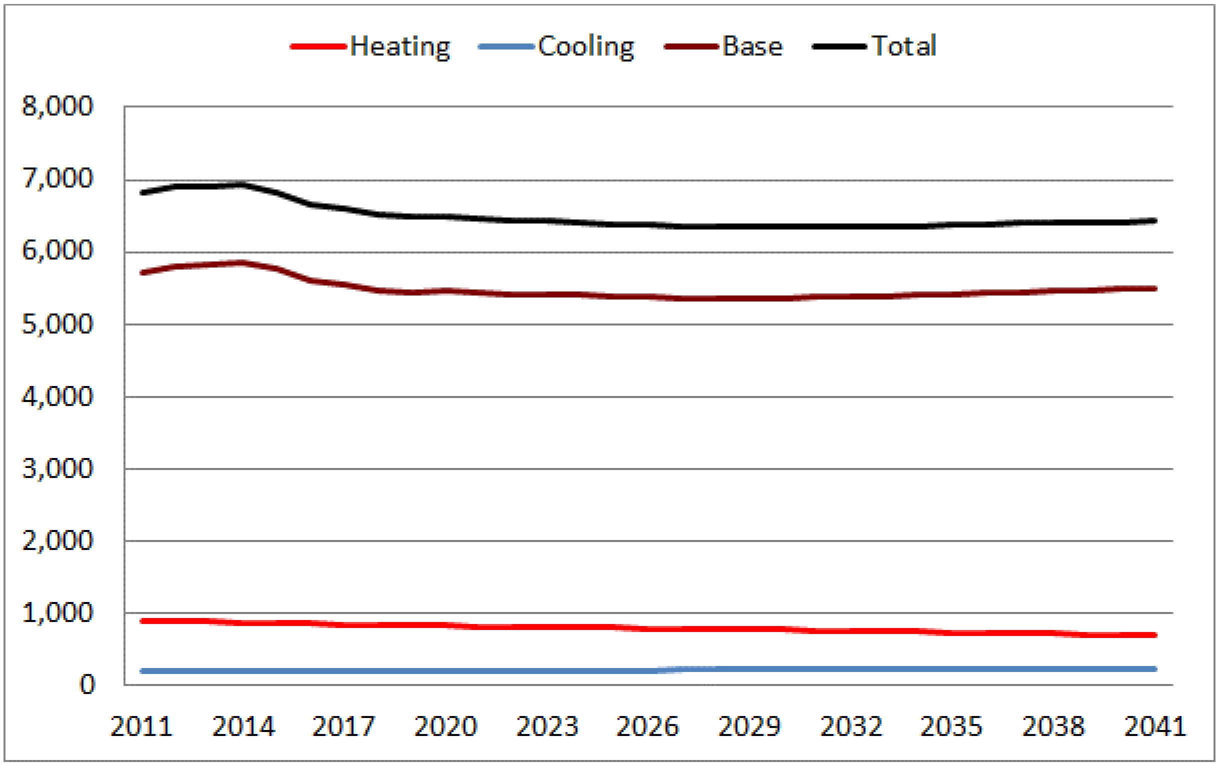
Based on historical data, CDD are expected to increase 1.3% per year and number of HDD decline 0.3% per year.

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.

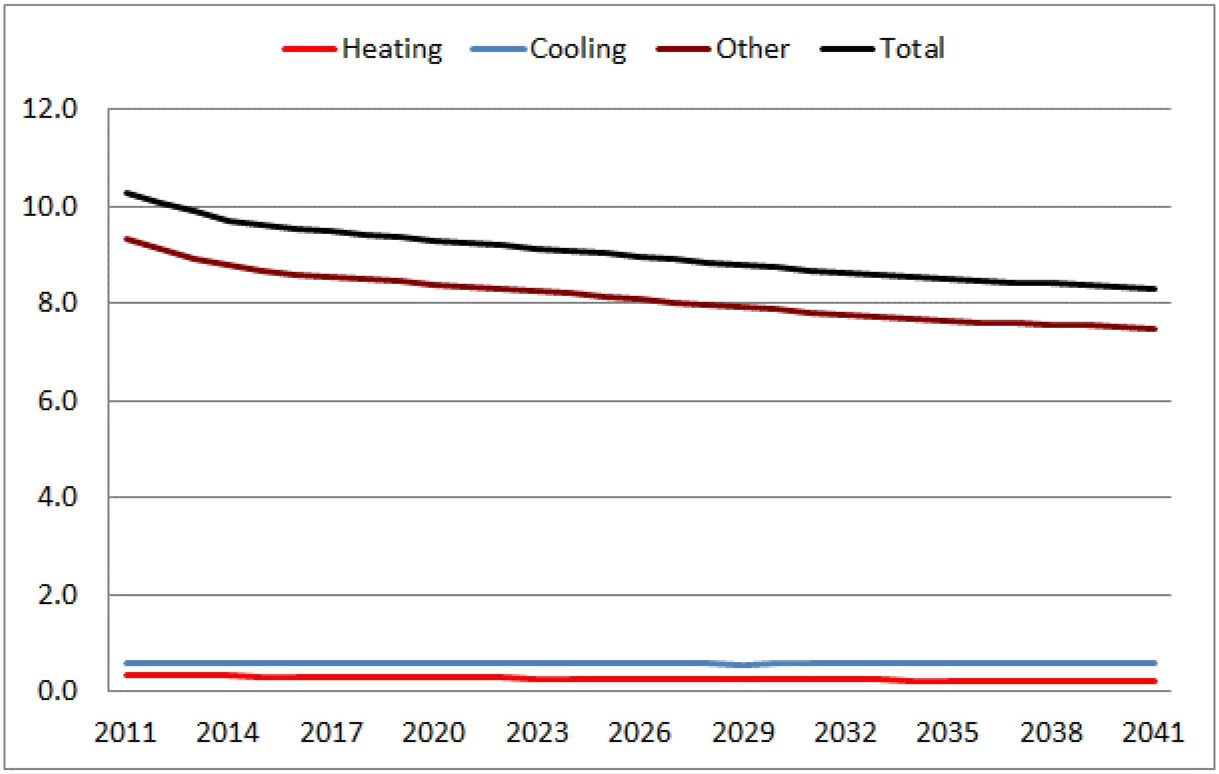
FIGURE 13: RESIDENTIAL SAE INDICES (KWH/HOUSEHOLD)



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)

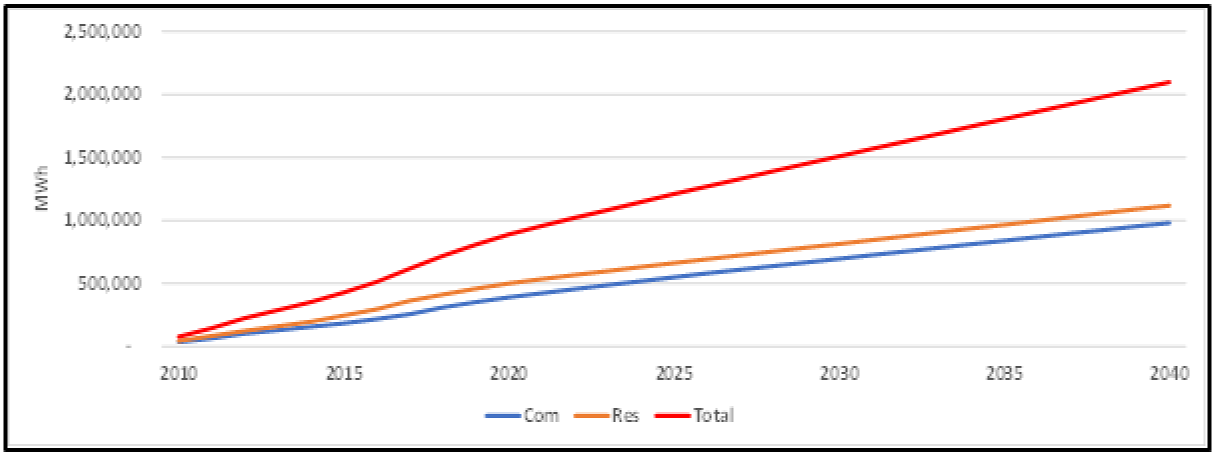


In general, there has been a long-term decline in commercial sales largely driven by efficiency gains. Commercial energy intensity has declined 1.2% annually over the last ten years; commercial intensity is projected to decline another 0.7% over the next ten years.

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%

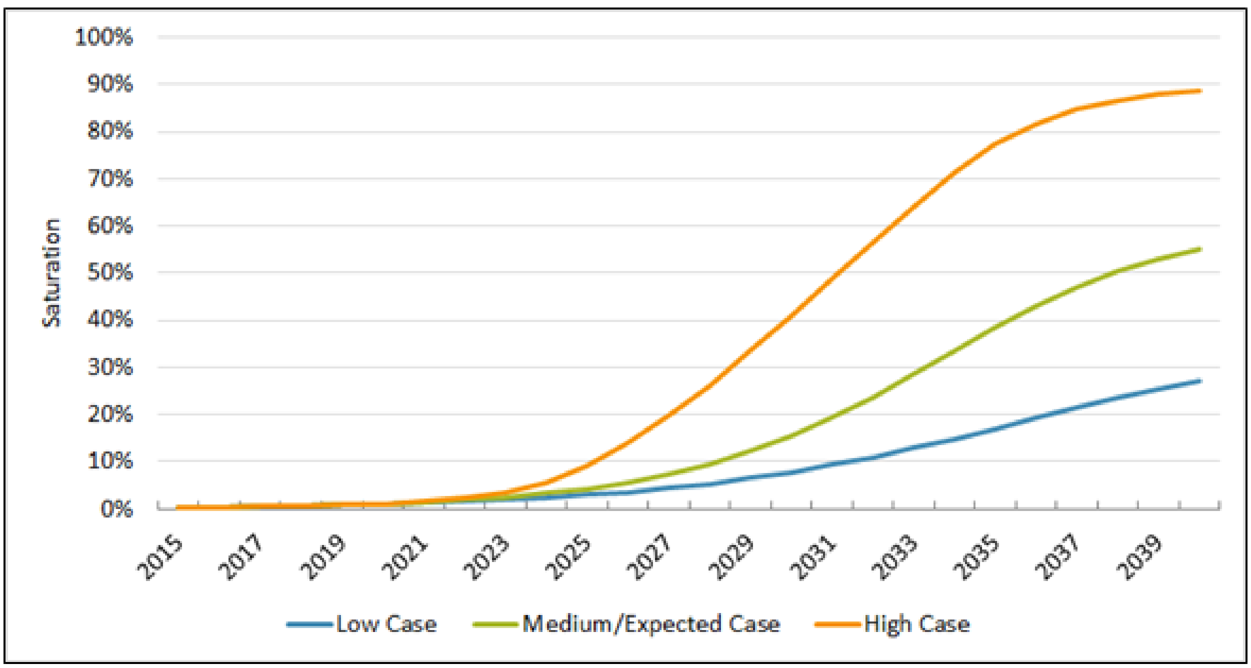
In 2020, state output (GDP) dropped 3.2% and employment declined 8.3% while personal income increased 5.9%. The large increase in real income is a result of government financial stimulus designed to counter the COVID employment impact. Moody's projects economic recovery to pre-pandemic levels by 2022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

Over the long term, the 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

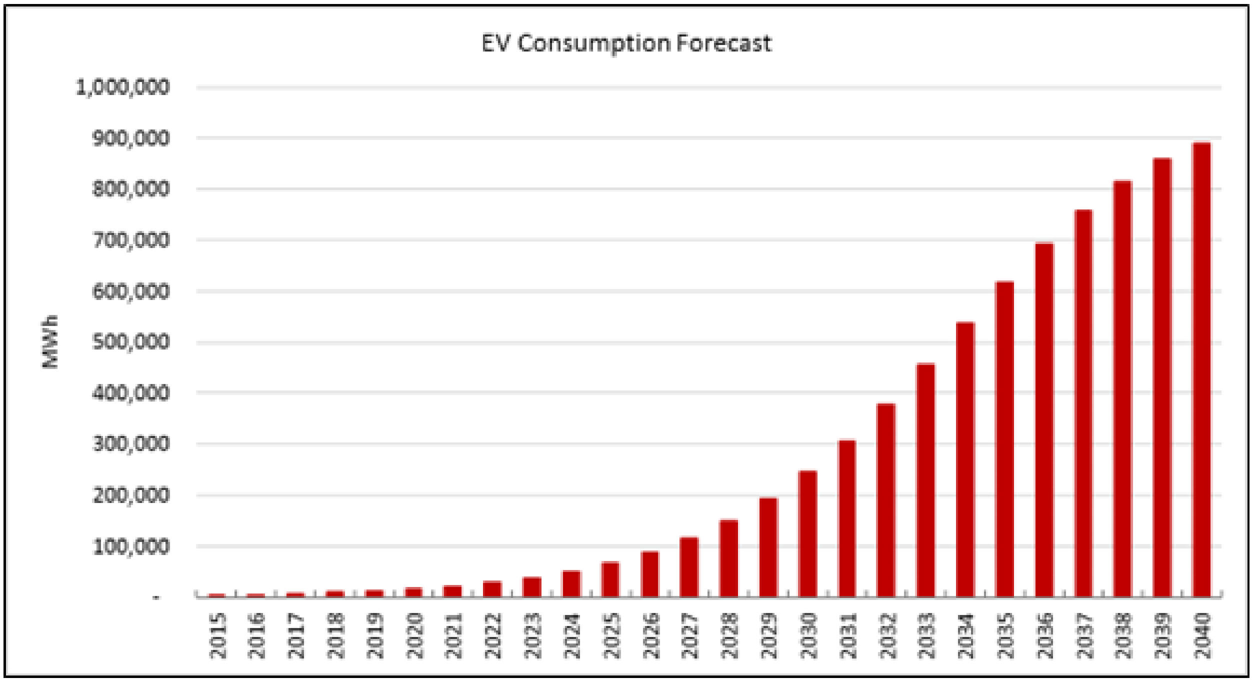
The electric vehicle (EV) forecast was developed by the VEIC as part of VELCO 2021 Long-Range Transmission Plan. VEIC provided three forecast scenarios; low, medium, and high, based on saturation targets for light-duty registered vehicles. The expected case (used in the VPPSA forecast) assumes that over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

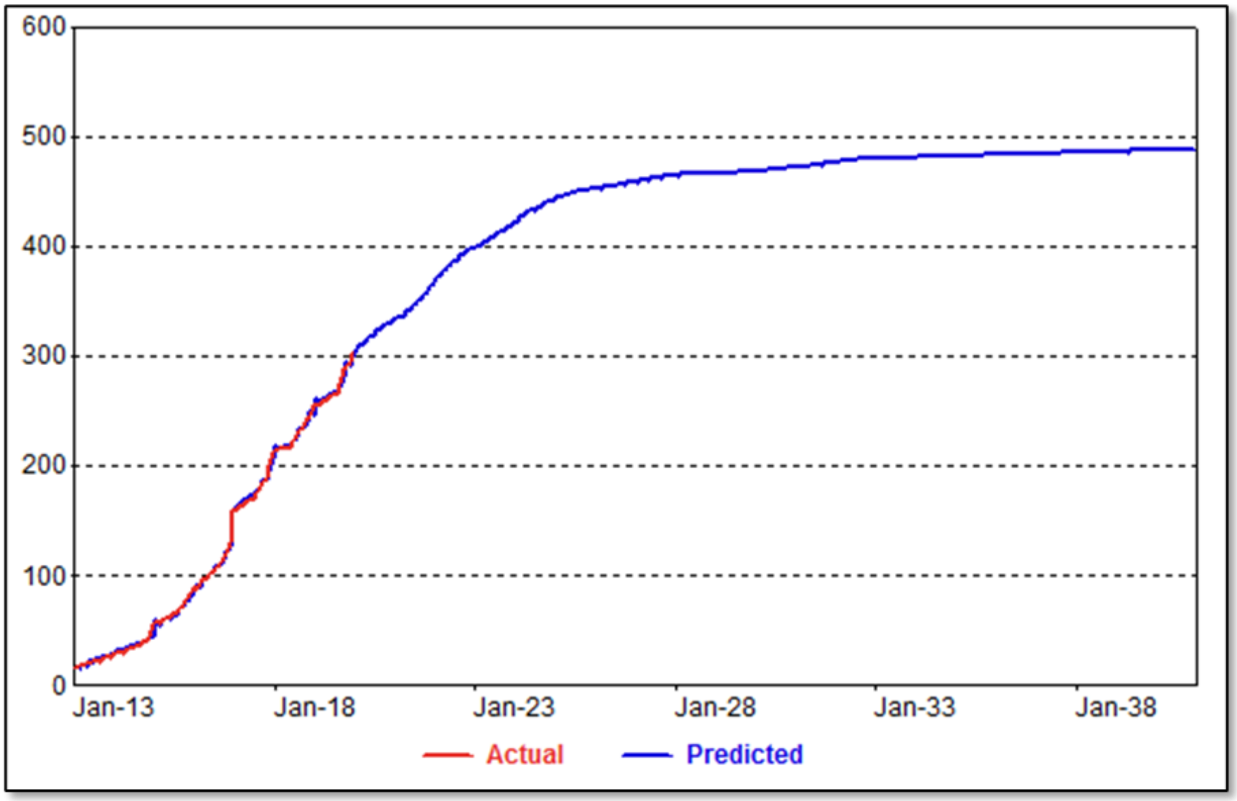


State EV sales are allocated to VPPSA member utilities based on each members' share of statewide number of residential customers.

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)

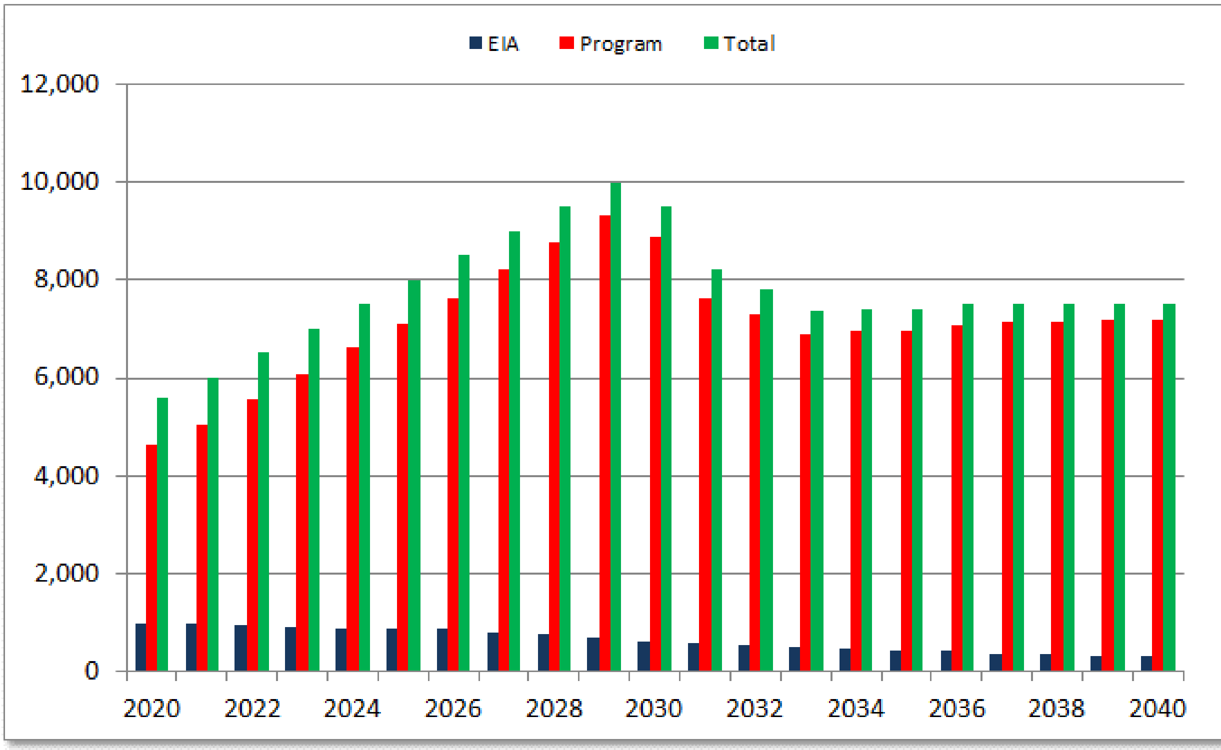


We expect BTM solar adoption to begin to slow by 2025 as system costs begin to flatten out and the number potential solar customers slows. We project over 450 MW of installed solar capacity by 2032. This translates into nearly 650,000 MWh based on monthly load factors derived from Vermont solar generation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

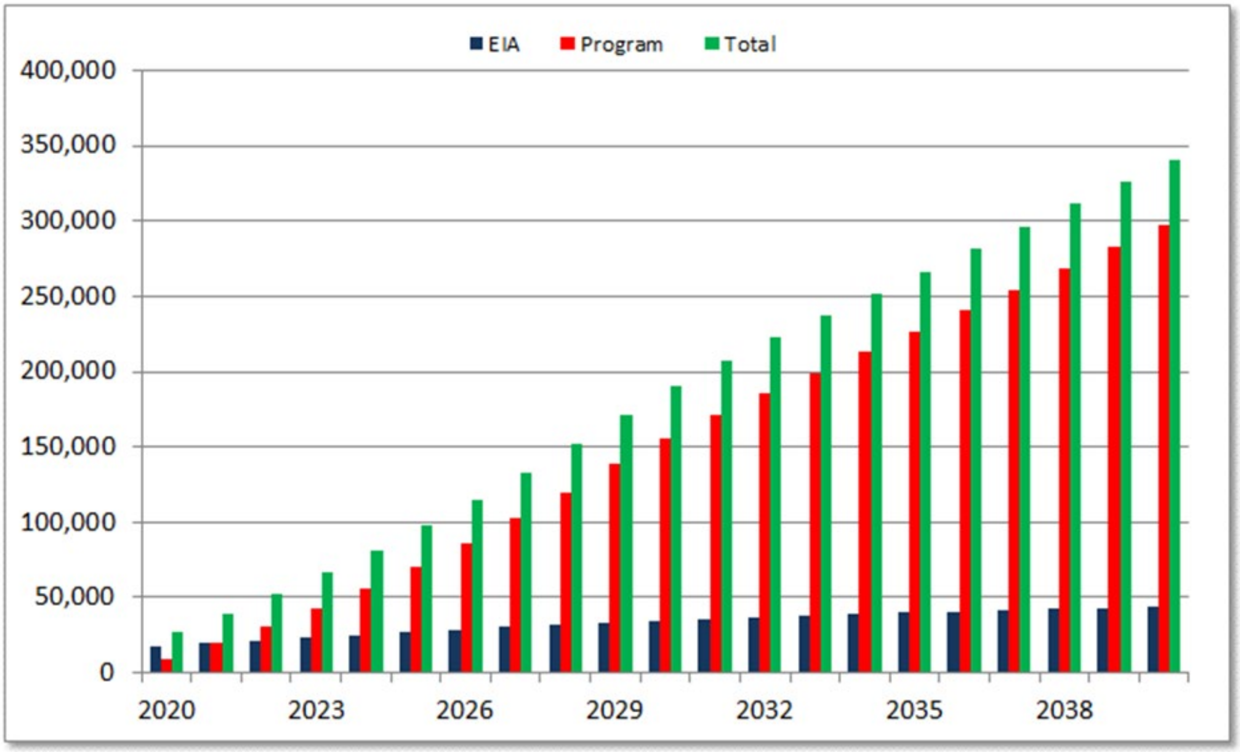
As part of state efforts to reduce CO_2 emissions, the state has launched a program to promote CCHP by offering financial incentives including rebates and 0 interest financing. The primary target are homes that heat with oil, propane, and wood. VEIC along with input from the DPS developed a long-term 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 on 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	0.974	0.071	13.815	0.00%
mStructRes.LagXHeat	0.358	0.071	5.051	0.00%
mStructRes.XCool	1.135	0.18	6.315	0.00%
mStructRes.LagXCool	0.756	0.18	4.194	0.01%
mStructRes.XOther	0.221	0.113	1.966	5.16%
mStructRes.LagXOther	0.658	0.114	5.75	0.00%
mCovid.ResIndex	31.522	6.842	4.607	0.00%

Model Statistics	
Iterations	1
Adjusted Observations	131
Deg. of Freedom for Error	124
R-Squared	0.865
Adjusted R-Squared	0.858
AIC	6.794
BIC	6.947
Log-Likelihood	-623.86
Model Sum of Squares	672,907.40
Sum of Squared Errors	105,013.96
Mean Squared Error	846.89
Std. Error of Regression	29.1
Mean Abs. Dev. (MAD)	22.39
Mean Abs. % Err. (MAPE)	4.10%
Durbin-Watson Statistic	1.814

Residential Customer Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mEcon.HHs	3.147	0.432	7.289	0.00%
AR(1)	0.994	0.015	64.496	0.00%

Model Statistics	
Iterations	19
Adjusted Observations	131
Deg. of Freedom for Error	129
R-Squared	0.981
Adjusted R-Squared	0.981
AIC	2.103
BIC	2.147
Log-Likelihood	-321.64
Model Sum of Squares	53,227.35
Sum of Squared Errors	1,040.88
Mean Squared Error	8.07
Std. Error of Regression	2.84
Mean Abs. Dev. (MAD)	2.15
Mean Abs. % Err. (MAPE)	0.27%
Durbin-Watson Statistic	2.108

Small Commercial Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructCom.XHeat	413068.563	82565.85	5.003	0.00%
mStructCom.LagXHeat	243682.524	83275.95	2.926	0.41%
mStructCom.LagXCool	38700.47	25918.98	1.493	13.80%
mStructCom.LagXOther	13445.925	618.603	21.736	0.00%
mCovid.NResIndex	-18866.91	4970.466	-3.796	0.02%
mBin.Yr11	-34848.461	5785.721	-6.023	0.00%
mBin.Yr12	-19296.534	5693.064	-3.389	0.10%
mBin.Bef18	14850.964	5017.306	2.96	0.37%
MA(1)	0.476	0.09	5.267	0.00%
MA(2)	0.275	0.089	3.104	0.24%

Model Statistics	
Iterations	10
Adjusted Observations	130
Deg. of Freedom for Error	120
R-Squared	0.814
Adjusted R-Squared	0.8
AIC	18.773
BIC	18.993
Log-Likelihood	-1,394.68
Model Sum of Squares	69,267,341,398.58
Sum of Squared Errors	15,846,502,567.74
Mean Squared Error	132,054,188.06
Std. Error of Regression	11,491.48
Mean Abs. Dev. (MAD)	9,293.16
Mean Abs. % Err. (MAPE)	6.97%
Durbin-Watson Statistic	1.84

Large Commercial Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructCom.XHeat	820156.429	219420.4	3.738	0.03%
mStructCom.LagXHeat	1213129.793	213578.3	5.68	0.00%
mStructCom.XCool	-144686.681	77591.7	-1.865	6.47%
mStructCom.LagXCool	247425.743	75581.71	3.274	0.14%
mStructCom.XOther	14986.15	7681.697	1.951	5.34%
mStructCom.LagXOther	39078.834	7761.919	5.035	0.00%
mCovid.NResIndex	-38106.419	10543.97	-3.614	0.04%
mBin.Aft16	-42850.579	6460.78	-6.632	0.00%
mBin.Aft21	26453.79	13508.28	1.958	5.25%

Model Statistics	
Iterations	1
Adjusted Observations	129
Deg. of Freedom for Error	120
R-Squared	0.768
Adjusted R-Squared	0.753
AIC	20.963
BIC	21.163
Log-Likelihood	-1,526.17
Model Sum of Squares	472,395,913,312.70
Sum of Squared Errors	142,618,184,135.13
Mean Squared Error	1,188,484,867.79
Std. Error of Regression	34,474.41
Mean Abs. Dev. (MAD)	26,154.49
Mean Abs. % Err. (MAPE)	5.28%
Durbin-Watson Statistic	1.913

Other Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	0.181	0.078	2.327	2.30%
Seasonal	-0.018	0.228	-0.078	93.80%

Model Statistics	
Iterations	27
Adjusted Observations	60
Deg. of Freedom for Error	58
R-Squared	0.91
Adjusted R-Squared	0.908
AIC	10.468
BIC	10.537
Log-Likelihood	-397.16
Model Sum of Squares	19,922,902
Sum of Squared Errors	1,973,380
Mean Squared Error	34,023.79
Std. Error of Regression	184.46
Mean Abs. Dev. (MAD)	139.68
Mean Abs. % Err. (MAPE)	2.17%
Durbin-Watson Statistic	1.707

Peak Model

mWthr.HeatVar55	3.356	1.014	3.311	0.12%
mWthr.CoolVar60	2.521	1.944	1.297	19.71%
mCPkEndUses.BaseVar	1.854	0.032	58.768	0.00%
mBin.Aft21	80.813	44.643	1.81	7.28%
mBin.Mar	131.713	33.248	3.962	0.01%
mBin.May	-317.368	39.603	-8.014	0.00%
mBin.Jun	-211.722	38.749	-5.464	0.00%
mBin.Sep	-103.703	38.75	-2.676	0.85%
mBin.Oct	-224.83	47.256	-4.758	0.00%
mBin.Nov	-107.568	36.967	-2.91	0.43%
MA(1)	0.374	0.085	4.381	0.00%

Model Statistics	
Iterations	14
Adjusted Observations	132
Deg. of Freedom for Error	121
R-Squared	0.746
Adjusted R-Squared	0.725
AIC	9.497
BIC	9.737
Log-Likelihood	-803.11
Model Sum of Squares	4,364,167.86
Sum of Squared Errors	1,488,427.65
Mean Squared Error	12,301.05
Std. Error of Regression	110.91
Mean Abs. Dev. (MAD)	83.56
Mean Abs. % Err. (MAPE)	3.82%
Durbin-Watson Statistic	1.818

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

Village of Johnson Electric Department

2025 IRP Projected Capital Expenditures - Reference Case

			2	3	4	5															
Specific Projects			**2025**	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Bucket Truck	10	General							124,310.83					-					154,531.82			
Digger Truck		General										124,310.83										154,531.82
Utility pickip Truck	6	General			43,300.11						49,339.45						56,221.15					
3/4 TON Pickup (foreman)	6	General				56,974						64,920						73,975				
Misc		General																				
Office & computing Equipment		General	5,222	5,337	5,455	5,575	5,697	5,823	5,951	6,082	6,216	6,352	6,492	6,635	6,781	6,930	7,082	7,238	7,398	7,560	7,727	7,897
	non-recu	Trans																				
		Trans																				
Line upgrades (rt 100c)		Dist	50,000																			
Substation upgrade		Dist	30,000																			
Misc distribution		Dist																				
		Dist																				
AMI		Dist			136,736	136,736																
		Dist																				
Misc distribution		Dist																				
Incremental Project assumption		Dist																				
Subtotal Specific Projects			**$ 85,222**	**$ 5,337**	**$ 185,490**	**$ 199,284**	**$ 5,697**	**$ 5,823**	**$ 130,262**	**$ 6,082**	**$ 55,555**	**$ 195,583**	**$ 6,492**	**$ 6,635**	**$ 6,781**	**$ 6,930**	**$ 63,304**	**$ 81,213**	**$ 161,929**	**$ 7,560**	**$ 7,727**	**$ 162,428**
Routine/Recurring/Misc plant & general	**75% Dist / 25% Gen'l**		36,557	37,361	38,183	39,023	39,882	40,759	41,656	42,572	43,509	44,466	45,444	46,444	47,466	48,510	49,577	50,668	51,783	52,922	54,086	55,276
Total Construction			**$ 121,779**	**$ 42,699**	**$ 223,674**	**$ 238,307**	**$ 45,579**	**$ 46,582**	**$ 171,917**	**$ 48,654**	**$ 99,064**	**$ 240,049**	**$ 51,936**	**$ 53,079**	**$ 54,247**	**$ 55,440**	**$ 112,881**	**$ 131,881**	**$ 213,712**	**$ 60,482**	**$ 61,813**	**$ 217,704**
Functional Summary:			2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Prod			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
General		25%	14,362	14,678	58,301	72,304	15,668	16,012	140,676	16,725	66,432	206,700	17,853	18,246	18,647	19,058	75,698	93,880	174,875	20,791	21,248	176,247
Distribution		75%	107,418	28,021	165,373	166,003	29,911	30,569	31,242	31,929	32,632	33,349	34,083	34,833	35,599	36,383	37,183	38,001	38,837	39,691	40,565	41,457
Transmission			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Construction			$ 121,779	$ 42,699	$ 223,674	$ 238,307	$ 45,579	$ 46,582	$ 171,917	$ 48,654	$ 99,064	$ 240,049	$ 51,936	$ 53,079	$ 54,247	$ 55,440	$ 112,881	$ 131,881	$ 213,712	$ 60,482	$ 61,813	$ 217,704