Village of Orleans Electric Department

2022 Integrated Resource Plan

Filed with the Public Utility Commission

EXECUTIVE SUMMARY

The Village of Orleans (OED) has operated an electric utility system since 1925 in the northern part of Vermont, located close to the Canadian border, and in the center of Vermont's Northeast Kingdom. OED's service territory, serving around 670 customers in total, encompasses the Village of Orleans, and adjacent portions of the towns of Barton, Brownington, Coventry, and Irasburg. As a small municipal utility OED is careful to balance maintaining reliability and reasonable cost levels with the need to deliver innovative programs to customers that provide practical value.

OED's distribution system serves a mix of residential, small commercial, and large commercial customers. Residential customers make up over 85% of the customer mix while accounting for close to a third of OED's retail kWh sales. One industrial customer makes up over 50% of retail usage with the remaining 16% of retail sales going to small commercial and public authority customers.

Consistent with regulatory requirements, every 3 years OED 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. OED'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

OED 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 OED'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 OED's largest customers is currently anticipated, the potential does exist. With over 50% of OED's energy requirements and about two-thirds of its peak concentrated on one single industrial customer, Ethan Allen manufacturing, OED monitors the plans of this large customer in order to anticipate necessary changes to the existing system infrastructure. In the case of a significant expansion by one or more customers, detailed engineering studies may be needed to identify necessary system upgrades.

ELECTRICITY SUPPLY

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

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

RESOURCE PLANS

Looking ahead to evaluating major policy and resource acquisition decisions, OED 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 OED 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 five major resource decisions that will affect OED's resources over this IRP timeframe. Importantly, the first decision occurs during 2028-2032 forecast period, and will affect over 80% of OEDs energy supply, when Brookfield Hydro and Howard Wind expire at the end of 2027. Options being evaluated include extending both of those contracts, which are longer-term fixed-price contracts for bundled hydro energy including Tier I RECs, and longer-term fixed-price contracts for bundled wind energy including MA class 1 RECs, respectively.

OED's contract for nuclear energy, almost 70% of OED's energy supply, expires in 2022, and is being replaced by renewables (hydro, solar and wind) to comply with the RES. However, OED supports all forms of low-carbon energy, and will consider nuclear power in the future if it is feasible.

The second major resource decision faced by OED occurs in 2025, which involves whether to develop a solar array adjacent to the Heath Substation. The array will be sized to fulfill OED's Tier II requirements.

The third major resource decision is to collaborate with a storage developer to develop a site adjacent to the Heath substation in connection with the referenced solar array.

The fourth major resource decision includes alternatives to these three resource decisions, which include increasing the size of the hydro resource to rely on it to fulfill OED's energy needs as well as increasing the size of the wind resource to fulfill OED's energy needs.

The fifth resource decision evaluates OED's choices for managing its power supply resources in a scenario where Ethan Allen Manufacturing closes, which could cause OED's hedge ratio (the ratio of supply to demand) to increase to about 200%.

About 75% of OED's capacity obligation is fulfilled by one resource. As a result, the reliability of this resource will be the key to minimizing OED's capacity costs.

RENEWABLE ENERGY STANDARD

OED is subject to the Vermont Renewable Energy Standard (RES) which imposes an obligation for OED to obtain a portion of its energy requirements from renewable resources. The RES obligation increases over time and is stratified into three categories, TIER I, TIER II, and TIER III. OED' 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 OED'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. By providing incentive programs to encourage conversion of traditional fossil fuel applications such as space heating, water heating, or internal combustion engine vehicles to electric power, OED receives credits toward its TIER III obligation. More detail regarding OED's plans to meet its TIER III obligation is available in Appendix A to this document.

ELECTRICITY TRANSMISSION AND DISTRIBUTION

OED has a compact service territory as a result of being a small, municipal-owned electric utility and has consistently pursued upgrade initiatives each year in order to maintain a reliable and efficient system. OED's distribution system consists of approximately 10 miles of distribution line operating at 13.2 kV, 30 miles operating at 2.4 kV, one jointly-owned substation, two wholly-owned substations, and is radially fed from a 5.5-mile 46kV transmission line jointly owned by OED, and Barton Village, Inc.

In addition to upgrading and routinely maintaining the system to ensure efficiency and reliability, OED is looking at the need to update its system to support additional distributed generation and beneficial electrification on the system and to provide customers with targeted services including load management supported by more innovative programs and rate designs that reduce costs for both OED and its customers. OED is currently engaged, with VPPSA, in the final stages of a multi-phased process that is expected to result in implementation of an AMI system beginning in late 2022. OED sees potential value to customers by utilizing rate design, direct load control or other incentive programs as tools to manage both system and customer peak loads in unison. Implementation of an AMI system is expected to enhance OED's ability to deliver these benefits and capture economic development/retention opportunities where possible.

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

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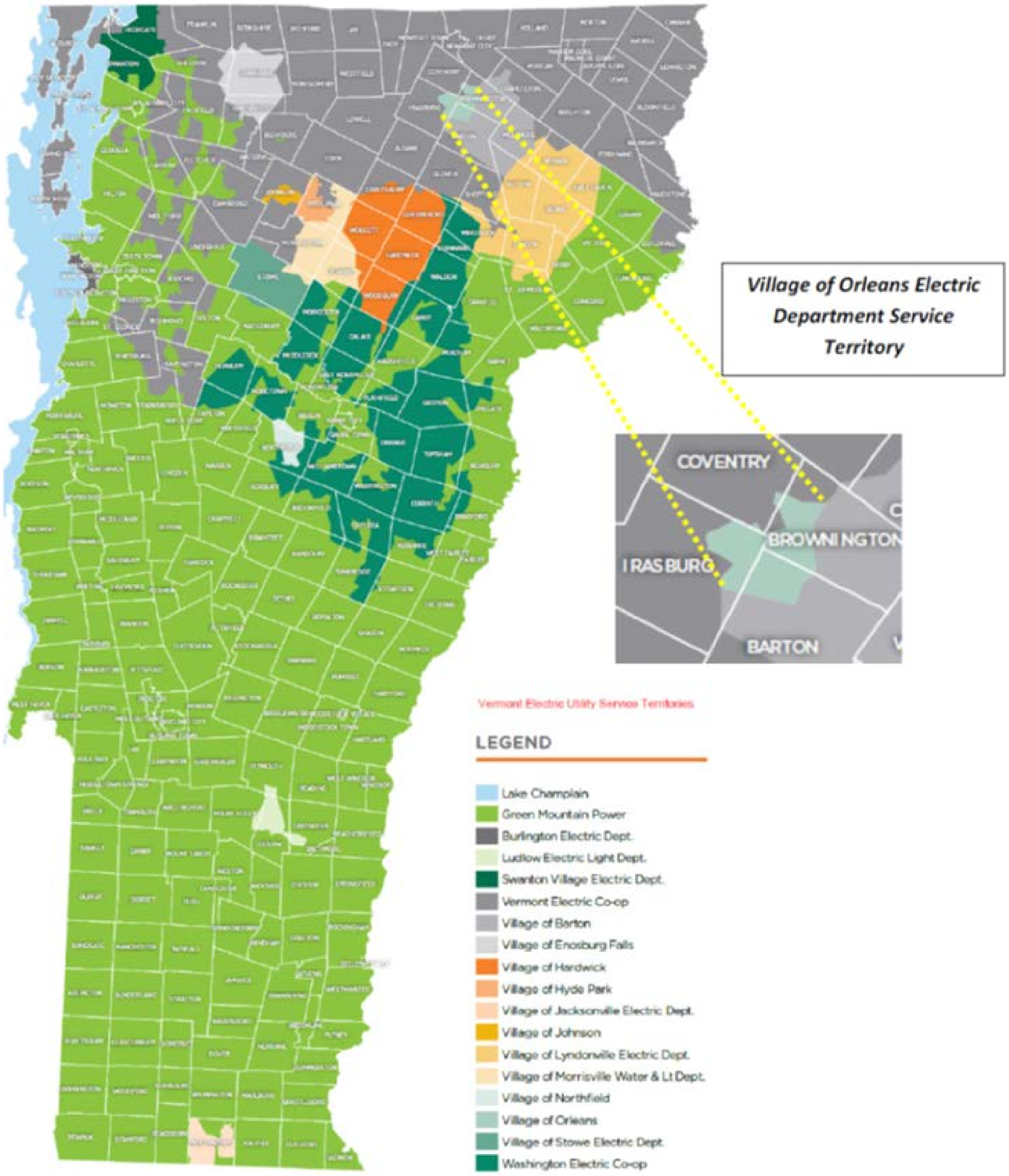
INTRODUCTION

Located in the Northeast Kingdom of Vermont, the Orleans Electric Department (OED) has operated an electric utility system since 1925. OED serves approximately 670 customers in the towns of Barton, Brownington, Coventry and Irasburg. The boundaries of OED's service territory can be seen on the map below. The service territory is small, covering 5 square miles, and walkable; the customer furthest out is a five-minute drive from the OED office. Like most of Vermont's smaller municipal utilities, many of its utility functions, such as office staffing, are carried out by employees who also have responsibilities in other aspects of village municipal operations. OED remains guided by the Vermont Public Utility Commission (PUC) rules as well as by the American Public Power Association's (APPA) safety manual. Well-established practices keep OED operating safely, efficiently, and reliably.

Figure 1: OED'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.

OED 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:

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

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

SYSTEM OVERVIEW

OED's distribution system serves about 670 customers in total consisting of a mix of residential and commercial customers, with over 85% of the customers being residential. The largest customer, and driver of load, is the Ethan Allen furniture manufacturing plant, spanning 85 acres and makes up approximately 50% of OED's total retail sales.

In 2021 OED's noncoincident system peak demand in the winter months was 3,175 kW and was 3,046 kW during the summer months, making OED a winter peaking utility. Annual retail energy sales for 2021 were 12,858,607 kWh and its annual load factor was 49%.

OED is connected to the Vermont Electric Power Company (VELCO) - Irasburg Substation and receives service at 46 kV. This line then runs to Barton where it feeds the distribution systems of both OED and Barton. The line that runs from the VELCO – Irasburg Substation to the Barton tap is jointly owned by the Barton Village Inc. (Barton), OED, and Vermont Electric Cooperative (VEC).

Table 1: OED's Retail Customer Counts

Data Element	2017	2018	2019	2020	2021
Residential (440)	578	580	575	577	580
Small C&I (442) 1000 kW or less	63	65	68	68	68
Large C&I (442) above 1,000 kW	1	1	1	1	1
Street Lighting (444)	3	3	2	2	3
Public Authorities (445)	20	20	19	19	20
Interdepartmental Sales (448)	0	0	0	0	0
Total	**665**	**669**	**665**	**667**	**672**
YOY	-1%	1%	-1%	0%	1%

Table 2: OED's Retail Sales (kWh)

Data Element	2017	2018	2019	2020	2021
Residential (440)	3,921,505	4,164,360	3,938,087	4,042,098	4,065,215
Small C&I (442) 1000 Kw or less	1,585,929	1,644,934	1,571,359	1,627,329	1,677,040
Large C&I (442) above 1,000 Kw	6,960,000	7,332,000	6,624,000	5,743,200	6,616,800
Street Lighting (444)	147,888	150,368	139,088	141,354	111,926
Public Authorities (445)	380,790	398,395	415,448	394,952	387,626
Interdepartmental Sales (448)	0	0	0	0	0
Total	**12,996,112**	**13,690,057**	**12,687,982**	**11,948,933**	**12,858,607**
YOY	0%	5%	-7%	-6%	8%

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

Data Element	2017	2018	2019	2020	2021
Peak Demand kW	3,337	3,305	3,370	3,240	3,175
Peak Demand Date	12/28/17	01/02/18	01/14/19	02/02/20	02/18/21
Peak Demand Hour	9	11	8	8	11

Finally, OED does not own or operate any generation plants. Instead, it supplies electricity to its customers with contractual entitlements to power plants and wholesale market contracts throughout the region.

[1] Noncoincident Peak (NCP)

[2] Total load excluding losses (TLEL)

STRUCTURE OF REPORT

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

ELECTRICITY DEMAND

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

ELECTRICITY SUPPLY

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

RESOURCE PLANS

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

ELECTRICITY TRANSMISSION AND DISTRIBUTION

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

FINANCIAL ANALYSIS

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

ACTION PLAN

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

APPENDIX

The appendix includes a series of supporting documents and reports.

GLOSSARY

ELECTRICITY DEMAND

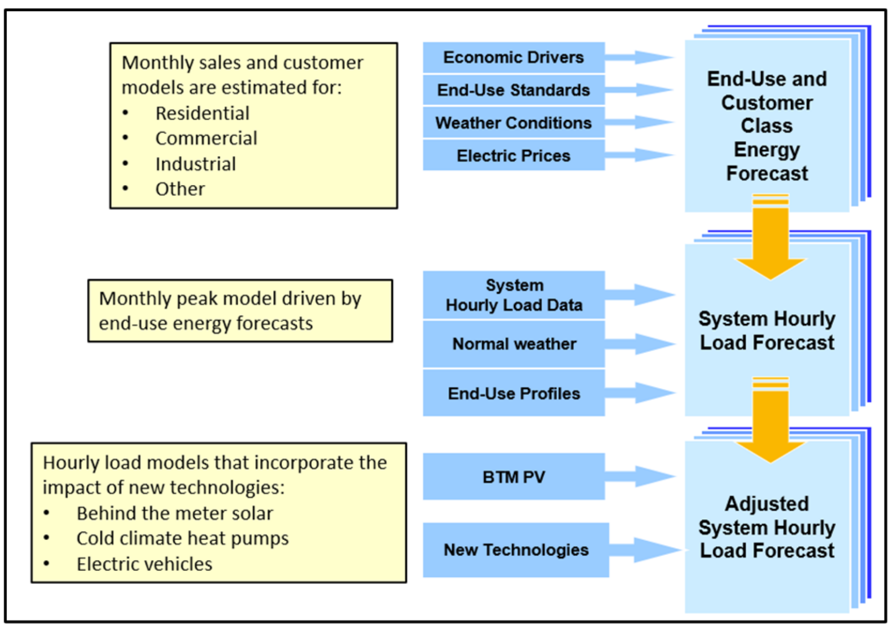
I. ELECTRICITY DEMAND

ENERGY FORECAST: STATISTICALLY ADJUSTED END USE METHODOLOGY

VPPSA retained Itron to forecast OED'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). Specifically, the adoption rates for heat pumps and electric vehicles (also known as "electrification") are shared with the LRTP.

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

Figure 2: Forecasting Process



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

ENERGY FORECAST RESULTS

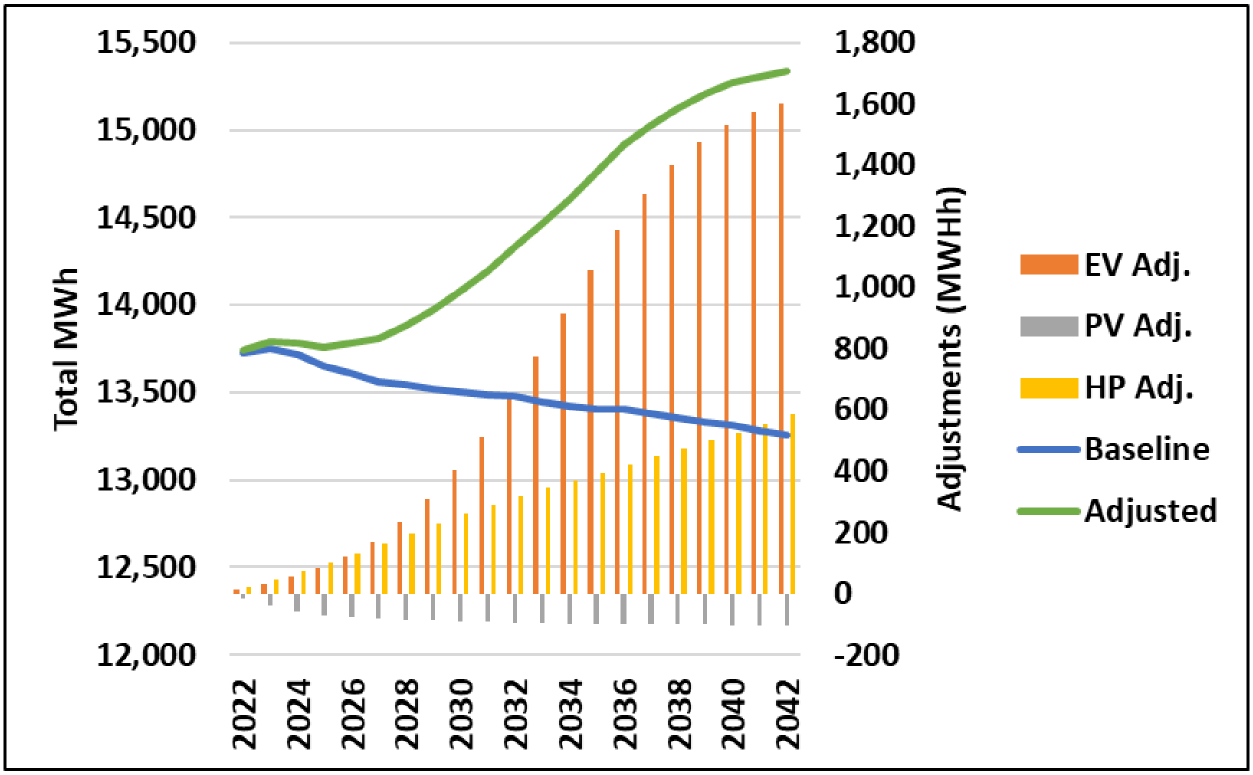
Table 3 shows the Baseline Forecast for energy, as well as the adjustments that are made to arrive at the Adjusted Forecast. The Compound Annual Growth Rates (CAGR) at the bottom of the table illustrate the trends in each of the columns. Notice that the Baseline Forecast itself is declining by 0.2% per year. After making adjustments for electric vehicles (EV), net metered solar (NM PV) and heat pumps (HP) the Adjusted Forecast increases by 0.6% per year.

Table 3: Adjusted Energy Forecast (MWh/Year)

Year	Yr #	Baseline Forecast (MWh)	EV Adj. (MWh)	NM PV Adj. (MWh)	HP Adj (MWh)	Adj. Forecast (MWh)
2022	1	13,721	13	-17	22	13,739
2027	5	13,561	170	-82	161	13,810
2032	10	13,478	636	-96	319	14,337
2037	15	13,376	1,304	-100	448	15,028
2042	20	13,256	1,601	-106	584	15,335
CAGR		-0.2%	27.1%	9.5%	17.7%	0.6%

The Adjusted Forecast is the result of high CAGRs for HPs (17.7%) and EVs (27.1%). During the first five years of the forecast, these two trends are offset somewhat by the net metering program, however. During the second five years of the forecast, the impact of CCHPs and EVs accelerates, and this can be seen in the green line in Figure 3.

Figure 3: Adjusted Energy Forecast (MWh/Year)



ENERGY FORECAST – HIGH & LOW CASES

To form a high case, we assumed that the penetration rate for EVs and HPs doubles from the base case in 2027 (Year 5) and 2032 (Year 10). We assume that net metering penetration continues as forecast in the base case.

At these growth rates, the market penetration for CCHPs and EVs reaches approximately 100% in 2042. This rough estimate assumes that most households and buildings will have more than one CCHP and more than one car. Nevertheless, it gives a reasonable indication of the kind of growth in energy use that is possible: 1.2% per year. This growth rate results in a 28% overall increase over 2022 electricity use.

Table 4: Energy Forecast – High Case (MWH)

Year	Yr #	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	Adj. Forecast
2022	1	13,721	26	-17	45	13,775
2027	5	13,561	340	-82	322	14,141
2032	10	13,478	1,271	-96	638	15,292
2037	15	13,376	2,608	-100	896	16,780
2042	20	13,256	3,202	-106	1,168	17,520
CAGR		-0.2%	27.1%	9.5%	17.7%	1.2%

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. Like the base case, this rate of change is well within the forecast error.

Table 5: Energy Forecast - Low Case (MWH

Year	Yr #	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	Adj. Forecast
2022	1	13,721	13	-17	22	13,739
2027	5	13,561	85	-82	81	13,644
2032	10	13,478	318	-96	160	13,860
2037	15	13,376	652	-100	224	14,152
2042	20	13,256	800	-106	292	14,242
CAGR		-0.2%	22.8%	9.5%	13.7%	0.2%

PEAK FORECAST RESULTS

Table 6 and Table 7 shows the results of the Baseline Forecast of peak loads, as well as the adjustments that are made to arrive at the Adjusted Forecast. The CAGR at the bottom of the table illustrate the trends in each of the columns. Notice that the Baseline Forecast itself is nearly flat. After making adjustments for CCHPs, EVs, and net metering, the Adjusted Forecast increases by 0.3-0.4% per year. Both the summer and winter peaks are forecast to remain steady, and the timing of the peak hour is expected to be remain in the morning hours between 7:00 AM and 11:00 AM.

Table 6: Summer Peak Forecast (MW)

Year	Yr #	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	Adj. Forecast
2022	1	2.7	0.0	0.0	0.0	2.7
2027	5	2.7	0.0	0.0	0.0	2.7
2032	10	2.8	0.0	0.0	0.0	2.8
2037	15	2.8	0.1	0.0	0.0	2.9
2042	20	2.8	0.1	0.0	0.0	2.9
CAGR		0.2%	23.0%	2.9%	6.2%	0.3%

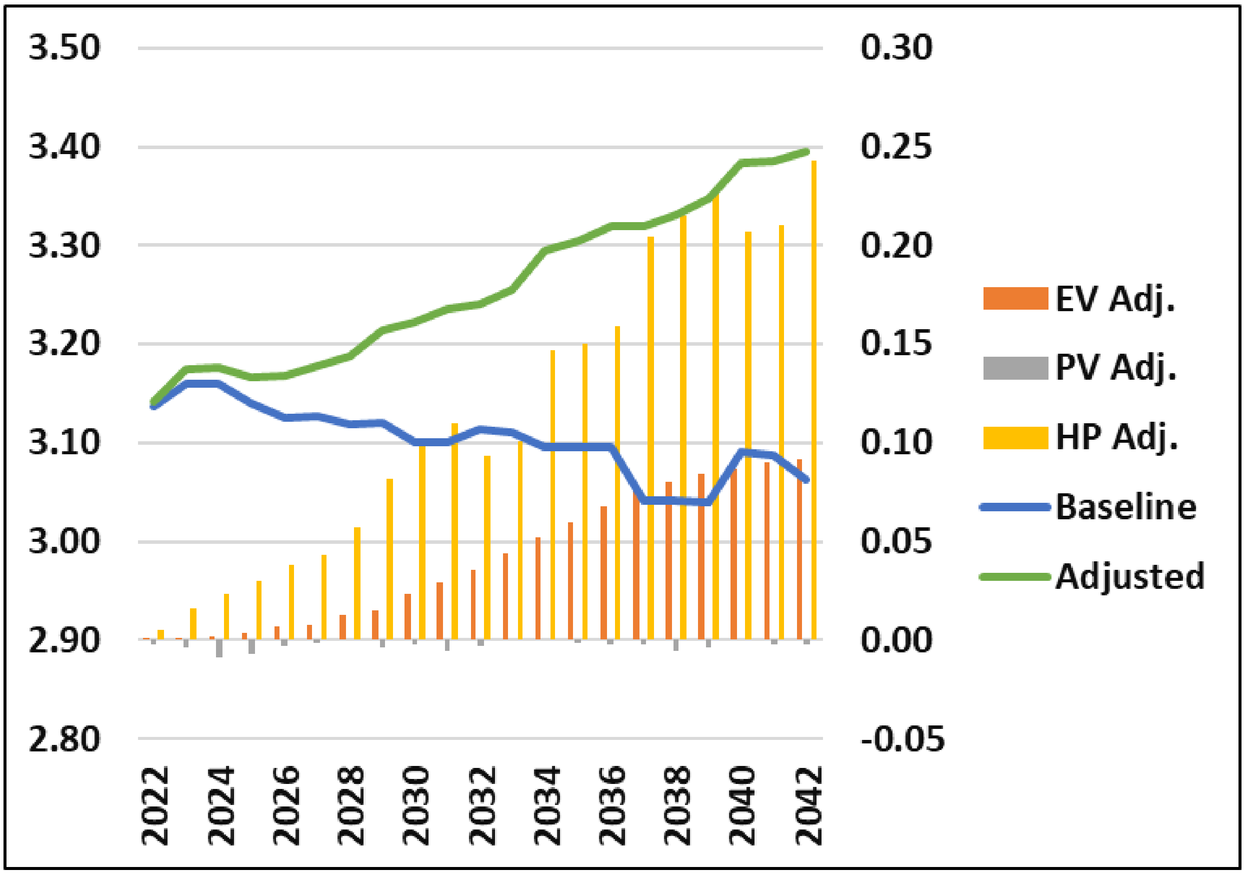
Table 7: Winter Peak Forecast (MW)

Year	Yr #	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	Adj. Forecast
2022	1	3.1	0.0	0.0	0.0	3.1
2027	5	3.1	0.0	0.0	0.0	3.2
2032	10	3.1	0.0	0.0	0.1	3.2
2037	15	3.0	0.1	0.0	0.2	3.3
2042	20	3.1	0.1	0.0	0.2	3.4
CAGR		-0.1%	25.4%	0.0%	21.4%	0.4%

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

The Adjusted Forecast exceeds the Baseline Forecast immediately as a result of high CAGRs for HPs and EVs.

Figure 4: Adjusted Winter Peak Forecast (MW)



PEAK FORECAST – HIGH & LOW CASES

To form a high-case, we assume that neither load controls nor Time-of-Use (TOU) rates are implemented, and then we adopt the same assumptions from the high case as in the energy forecast. Under these assumptions, peak load growth starts to impact the system after 2027, and by 2042, the peak reaches 3.7 MW.

Table 8: Winter Peak Forecast – High Case (MW)

Year	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	Adj. Forecast
2022	3.1	0.0	0.0	0.0	3.1
2027	3.1	0.0	0.0	0.1	3.2
2032	3.1	0.1	0.0	0.2	3.4
2037	3.0	0.2	0.0	0.4	3.6
2042	3.1	0.2	0.0	0.5	3.7
CAGR	-0.3%	25.4%	0.0%	21.4%	0.9%

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

TIER III IMPACTS ON THE FORECAST

The provisions of Tier 3 Best Practices and Minimum Standards state:

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

Based on the following analysis, the load forecast adjustments for heat pumps and electric vehicles are in alignment with the electrification that is budgeted through Tier III programs. As a result, we do not observe any major deviations from the assumptions used in the load forecast at this time.

Table 9 shows the budgeted measures from VPPSA's 2022 Tier III budget, and the increased electric loads that are anticipated. These loads are based on averages as published in the Tier III Planning Tool. Ninety-five percent of the new electric loads are expected to come from only two technologies: heat pumps and electric vehicles.

Table 9 shows Orleans' share of VPPSA's Tier III budget, and it indicates 46 MWH of new electric loads are likely in 2022. This number is in alignment with the heat pump and electric vehicle adjustments from Itron. As shown in Table 3, a 35 MWH increase in electric loads is expected in 2022 as a result of these technologies.

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

Table 9: Program Year 2022 Tier III Measures & Their Expected Impact on Load

Measure	# Measures	Added MWH/Unit/Yr	Total New MWH/Yr
Electric Bicycle	1	0.030	0
Electric Vehicle - New	1	2.8	3
Heat Pump - ductless	11	3.4	37
WBHP - Ducted	1	4.2	4
Heat Pump Water Heater	1	1.0	1
Golf Carts	1	0.8	1
Residential Lawn Mower	1	0.009	0
Total			46

TIER III LOAD CONTROL

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

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

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

Table 10: Cost and Size Ranges of Typical Pay-Per-Device Load Control Programs ($/kW-mo)

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

Many vendors offer a pay-per-device subscription fee as shown in the first column of Table 10. For devices that are 1.5 kW and smaller, the fees are far too large to justify the cost. For example, a $250 per device charge for a one kW device would cost $20.83/kw-month. This compares to avoided capacity costs that are about $2.50/kW-month and transmission avoided costs that are about $12/kW-month. As a result, this business model does not work for small devices, at least not at low levels of participation. However, large devices can quickly become cost-effective as shown in the green shaded areas.

Innovative rates are likely to be a cost-effective way to control load. As a result, VPPSA is exploring innovative rates that will be Time-of-Use (TOU) based. It would apply to both residential electric vehicle chargers and public DC fast charging stations and will provide rate research that can carry over into more generalized TOU rates for other end uses.

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

FORECAST UNCERTAINTIES & CONSIDERATIONS

OED presently has six residential scale (< 15 kW) net metered customers with a total installed capacity of about 35 kW. However, as solar net metering costs continue to decline, the cost of net metered solar could reach parity with the price of grid power. If state policy continues to be supportive of net metering in this event, it could lead to a step change in the adoption rate of net metering, and a quicker erosion of retail sales and revenues for the utility.

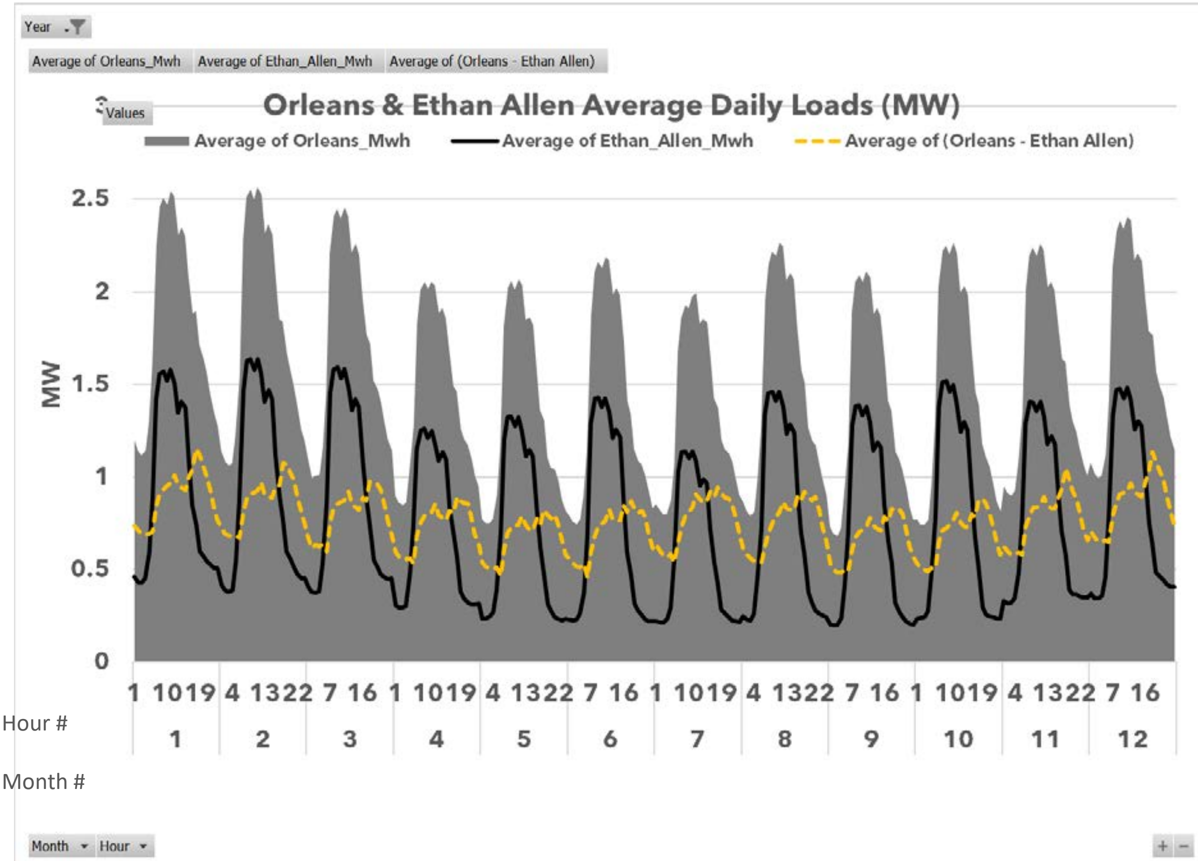
Given the small size of the customer base and the nascent trends involved, net-metering represents a key uncertainty for OED to monitor, especially if larger net metered projects are proposed. For example, a 100 kW net metered solar project built in 2023 would triple the base of installed, net metered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

ETHAN ALLEN

As OED's largest customer, Ethan Allen Furniture is responsible for about 50% of all of OED's load (MWH), and two-thirds of its peak. As a result, it represents a major uncertainty to the load forecast. This can be seen in

Figure 5. Ethan Allen's average weekday loads peak near 1.5 MW most of the year, while OED's load peaks between 2 and 2.5 MW. Without Ethan Allen (the yellow dotted line), OED's loads would only reach 1 MW during the winter months.

Figure 5: Average Wednesday Load With and Without Ethan Allen



Because Ethan Allen represents such a large load, the 2019 IRP explicitly estimated the rate impact of its departure in the Financial Analysis chapter. The results indicated that rates would likely increase by 50% in the first year after Ethan Allen left the system[5]. This result is unsurprising, and as a result, this analysis is not repeated in 2022. Instead, we have taken the conclusion from 2019, and applied it to the structure of the 2022 Resource Plan. Specifically, we have held the resource procurements leading up to the culmination of the RES to five-year terms. This choice would meet the RES requirements while also minimizing the rate impact of Ethan Allen should it leave the system.

[5] Orleans 2019 Integrated Resource Plan, Financial Analysis Chapter, page 65

ELECTRICITY SUPPLY

II. ELECTRICITY SUPPLY

OED'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 OED 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 OED's portfolio.

EXISTING POWER SUPPLY RESOURCES

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

2. **Howard Wind 2023-2027**
    - Size: 55 MW
    - Fuel: Wind
    - Location: Steuben County, NY
    - Entitlement: 3%, PPA
    - Products: Wind energy, MA Class I RECs
    - Term: 1/1/23 - 12/31/27
    - Notes: OED has signed a letter of intent to enter into a 5-year PPA for a portion of the output from Howard Wind. The PPA is expected to be executed in October 2022.

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

4. New York Power Authority (NYPA)
    - Size: 3.044 MW (Niagara), 0.195 MW (St. Lawrence)
    - Fuel: Hydro
    - Location: New York State
    - Entitlement: 0.643%, 0.052 MW (Nia. PPA), 0.299%, 0.005 MW (St. Law PPA)
    - Products: Energy, capacity, renewable energy credits (NY System Mix)
    - End Date: 9/1/25 (Niagara), 4/30/2032 (St. Lawrence)
    - Notes: NYPA provides hydro power to OED under two contracts, which will be extended at the end of their term.

5. Project 10
    - Size: 40 MW
    - Fuel: Oil
    - Location: Swanton, VT
    - Entitlement: 7.1% (2.84 MW), joint-owned through VPPSA
    - Products: Energy, capacity, reserves
    - End Date: Life of unit
    - Notes: As the joint-owner, VPPSA has agreements with OED to pay for and purchase 7.1% of the unit's output.

6. **Ryegate Facility**
   - Size: 20.5 MW
   - Fuel: Wood
   - Location: East Ryegate, VT
   - Entitlement: 0.264% (0.0541 MW), PPA
   - Products: Energy, capacity, renewable energy credits (CT Class I)
   - End Date: 10/31/2032

7. **Seabrook 2018-2022**
   - Size: 1,250 MW
   - Fuel: Nuclear
   - Location: Seabrook, NH
   - Entitlement: 1.4 MW On-Peak, 0.924 MW Off-Peak (PPA)
   - Products: Energy, capacity, environmental attributes (Carbon-free nuclear)
   - End Date: 12/31/2022

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: 0.268% (Statutory)
   - Products: Energy, capacity, renewable energy credits
   - End Date: Varies
   - Notes: OED is required to purchase power from small power producers through the Vermont Standard Offer Program in 2020, in accordance with PUC Rule #4.300. The entitlement percentage fluctuates slightly each year with OED's pro rata share of Vermont's retail energy sales.

Table 11 summarizes the resources in the portfolio based on a series of important attributes. First the megawatt hours (MWH) and megawatts (MW) show the relative size of each resource. The delivery pattern indicates what time of the day and week the resource delivers energy, and the price pattern indicates how the resource is priced. Notice that most of the resources are fixed-price. This feature provides the hedge against spot market prices. If the resource produces Renewable Energy Credits (RECs), that is indicated in the seventh column, followed by the resource's expiration date and whether we assumed that it would be renewed until 2042.

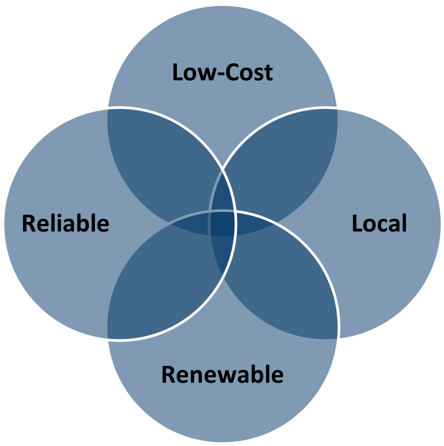
Table 11: Existing Power Supply Resources

RESOURCE	2021 MWH	% of MWH	2021 MW	Delivery Pattern	Price Pattern	REC	Expiration Date	Renewal to 2042
Brookfield Hydro 2023-2027	0	0%	0	Firm	Fixed	✓	12/31/27	No
Howard Wind 2023-2027	0	0%	0	Intermittent	Fixed	✓	12/31/27	No
Market Contracts	3,007	20.7%	0	Firm, Varies	Variable		6/30/24	No
NYPA Niagara Contract	735	5.0%	0.092	Baseload & Peaking	Fixed	✓	Perpetuity	Yes
NYPA St. Lawrence Contract	22	0.1%	0.004	Baseload & Peaking	Fixed	✓	Perpetuity	Yes
Project #10	28	0.2%	2.744	Dispatchable	Variable		Life of Unit	Yes
Ryegate Facility	400	2.8%	0.044	Baseload, Unit Contingent	Fixed	✓	10/31/32	No
Seabrook 2018-22 Purchase	10,089	69.3%	0	Baseload, Firm	Fixed		12/31/22	No
Standard Offer Program	277	1.9%	0	Intermittent	Fixed	✓	Varies	N/A
Total MWH	14,558	100.0%	2.9					

FUTURE RESOURCES

OED 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 6: Resource Criteria



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

These criteria enable OED to focus on a subset of generation technologies, and to exclude coal, geothermal and solar thermal generation which do not meet them. Resources that OED may consider fall into three categories: 1.) Existing resources in Table 11, 2.) demand-side resources, and 3.) new resources that meet the criteria in Figure 6.

CATEGORY 1: EXTENSIONS OF EXISTING RESOURCES

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

1.1 MARKET CONTRACTS

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

CATEGORY 2: DEMAND-SIDE RESOURCES

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

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

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

CATEGORY 3: NEW RESOURCES

VPPSA regularly meets with developers throughout New England, and through VPPSA staff, OED 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.

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

3.2 HYDROELECTRIC GENERATION

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

3.3 SOLAR GENERATION

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

3.3.1 NET METERING

OED has 6 net-metered customers and an installed base of solar capacity of 35 kW. OED will monitor the participation rate closely as solar costs approach grid parity. Should grid parity occur, not only would net metered solar penetration be expected to increase but the costs of the existing program would likely cause upward rate pressure. As a result, net metered solar is an inferior option when compared to lower-cost and utility scale solar projects.

3.4 WIND GENERATION (ON AND OFF-SHORE)

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

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

3.5 GAS OR OIL-FIRED GENERATION

Project 10 is undergoing 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

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

REGIONAL ENERGY PLANNING (ACT 174)

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

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

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

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

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

RESOURCE PLAN

III. RESOURCE PLANS

ENERGY PROCUREMENT PROCESSES

MONTHLY PROCESS

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

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

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

ANNUAL PROCESS

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

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

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

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

LONG-TERM PROCESS

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

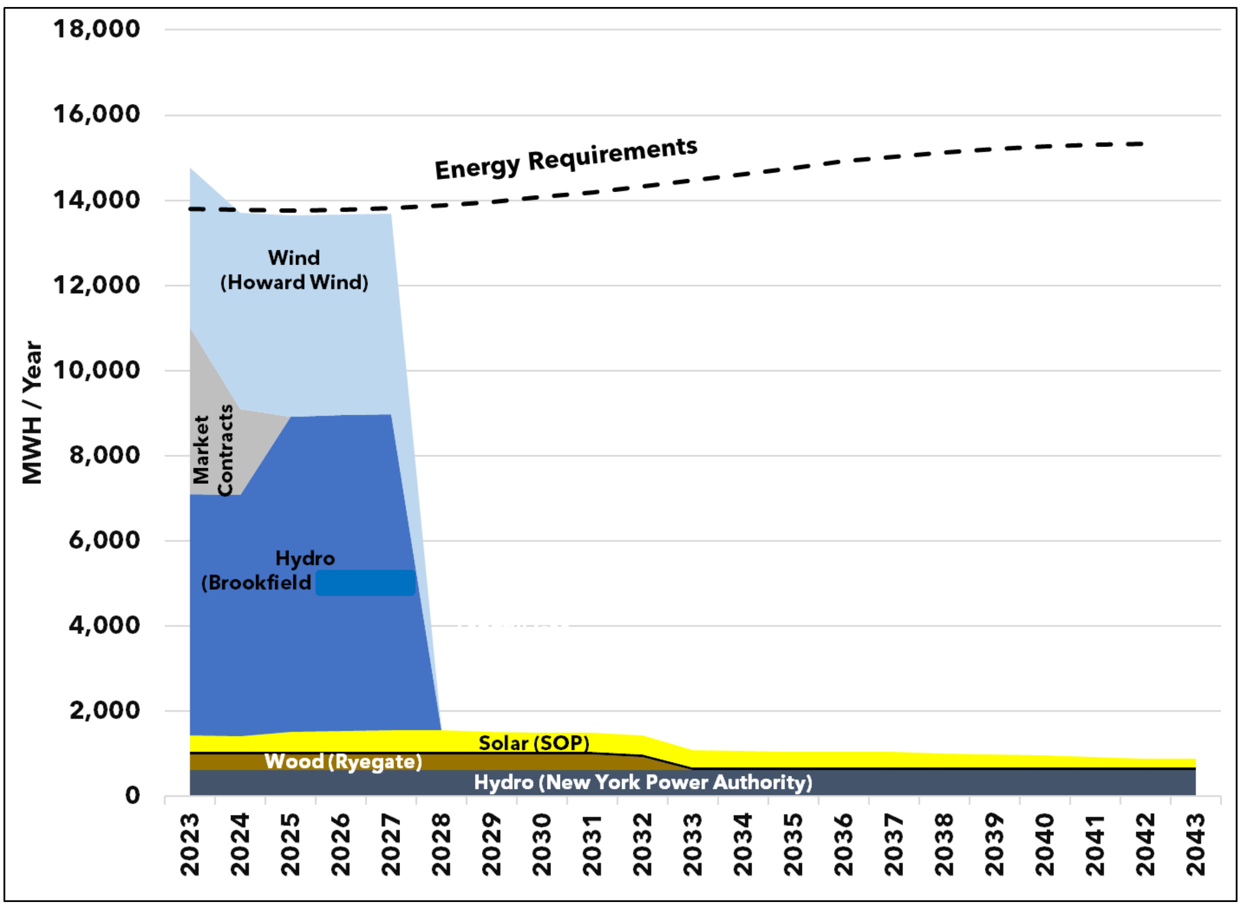
ENERGY RESOURCE PLAN

Figure 7 compares OED's energy supply resources to its adjusted load. The supply resources closely match demand for the next five years, and consist primarily of hydro and wind resources. Thereafter, new resources will be necessary.

DECISION 1: EXTEND EXISTING PPAS THROUGH 2032

The most straightforward option during this timeframe is to extend the term of both the Brookfield Hydro and the Howard Wind contracts through 2032. These extensions would be made at prevailing market prices, and since they both include RECs, they would help fulfill the RES requirements during that time period as well. The term of the contract extension is held to five years to minimize rate impacts and market price volatility in the event that Ethan Allen closes.

Figure 7: Energy Supply & Demand by Fuel Type



DECISION 2: SOLAR CONTRACT (PPA)

OED is collaborating with a solar developer to develop an array adjacent to the Heath substation. The array will be sized to fulfill OED's Tier II requirements (1-2 MW), and may be paired with battery storage, which will be modeled separately as part of Decision 3.

DECISION 3: BATTERY STORAGE CONTRACT (ESSA)

Utility scale battery storage is an excellent way to manage transmission costs, and OED is collaborating with a storage developer to develop a site adjacent to the Heath substation. If successful, this resource would be procured through a 25-year Energy Storage Service Agreement (ESSA). Table 12 summarizes the energy resources decisions OED faces in the coming five to ten years.

Table 12: Energy Resource Decision Summary

Resource	Years Impacted	% of MWH	Rate Impact	RES Impact
Extend Wind & Hydro PPAs	2028 - 2032	90%	Neutral	Tier I
Solar PPA	2025 - 2050	10-20%	Neutral	Tier II
Storage ESSA	2025 - 2050	100% of peak	Decrease	None

OTHER RESOURCE DECISIONS

Alternatives to these three decisions can be envisioned. For example, OED could increase the size of the hydroelectric resource and rely on it to fulfill its energy needs. However, the disadvantages of this approach do not need to be quantified to be known. First, the diversity of the supply portfolio would be reduced by this approach. Second, the cost of the supply portfolio would increase because the in-region hydro power would command a price premium as compared to the out-of-region wind power.

The disadvantages of increasing the size of the wind resource are also known. Diversity would also decrease, and while cost would be expected to decrease, the intermittency of the resource would greatly increase the price volatility that OED would absorb. The primary benefit of a diversified portfolio of supplies is to decrease volatility. As a result, increasing the amount of wind power at the expense of hydro power is not preferred.

DECISION MAKING IF ETHAN ALLEN CLOSES

If Ethan Allen were to close, OED's hedge ratio (the ratio of supply to demand) would increase to about 200%, and OED would face a choice about how to manage the excess supply. The default choice facing OED would be to let the excess supply settle against ISO-NE's day ahead and/or real time energy (spot) market. This is an undesirable outcome because of the inherent volatility of spot market prices. It would undermine the stability of OED's power supply costs.

Alternatively, OED could choose to sell the excess energy into the forward market at a fixed price. VPPSA's energy procurement processes would still apply, and OED could either sell the energy to another VPPSA member or to an external party. In both cases, the transaction would take place at prevailing market prices, and the financial outcome for OED would depend on market prices at the time of the sale.

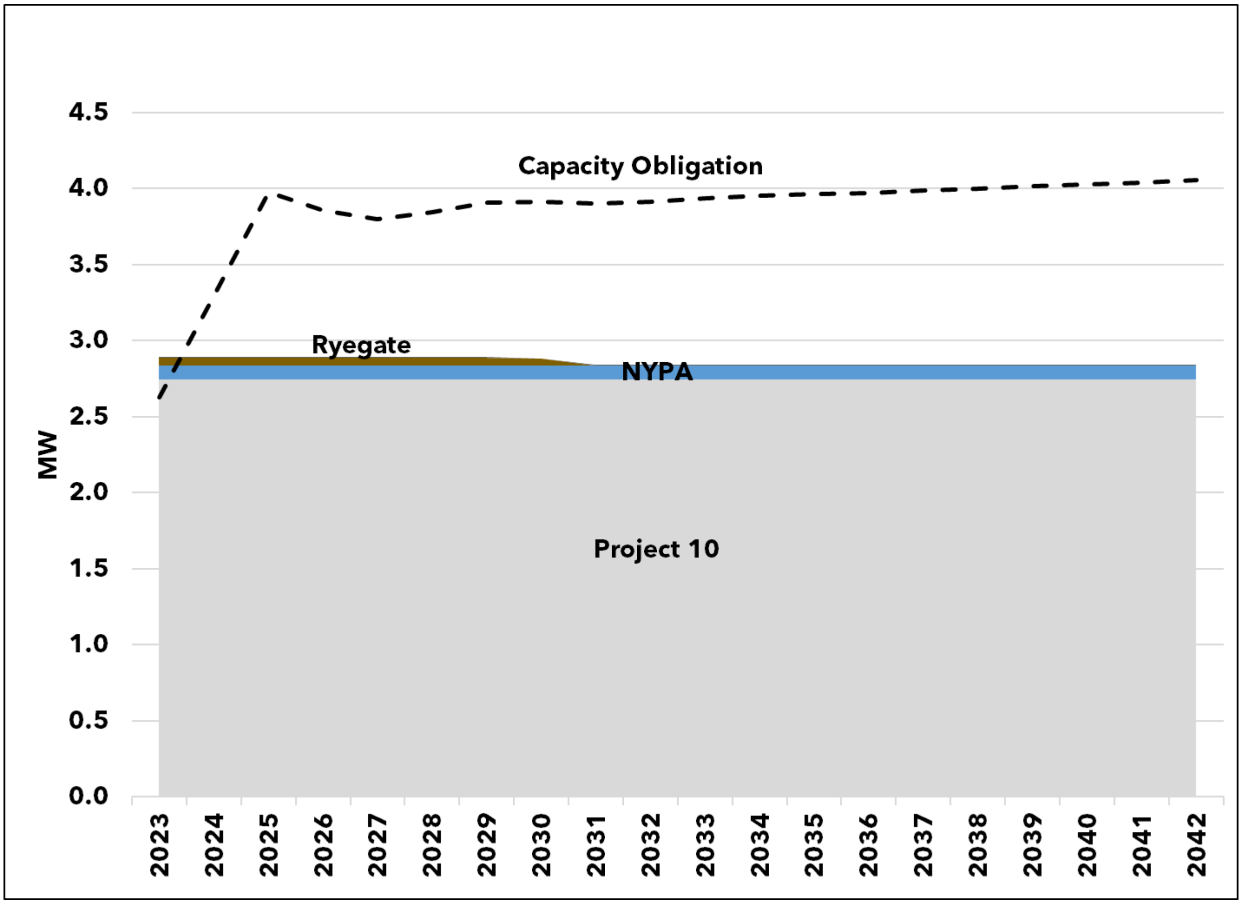
- If market prices are higher than the contract price at the time of the sale, OED will reap a financial benefit and its costs will be lower.
- If market prices are lower than the contract price at the time of the sale, OED will suffer a financial loss, and its costs will be higher.

Because the financial outcome of having excess supply cannot be known in advance, it is prudent to at least keep the duration of this uncertainty to a minimum. Signing long-term, fixed price contracts at a time when energy market prices are at historic highs (as is the case in 2022), risks locking in years of above-market energy supply costs. This is not in OED's nor its ratepayers' best interests. As a result, OED will continue to keep the duration of its power supply contracts relatively short.

CAPACITY RESOURCE PLAN

Figure 8 compares OED's capacity supply to its capacity supply obligation (CSO). The CSO is equal to OED's coincident peak demand with ISO New England plus a reserve margin. As a result, the CSO is higher than the Adjusted Peak Load Forecast. In any event, one resource provides about 75% of OED's capacity, Project 10.

Figure 8: Capacity Supply & Demand (Summer MW)



The supply of capacity is about equal to the demand in 2023, but this is due to an unusually low annual coincident peak. A more likely capacity obligation is nearer to four MW, and Project 10 fulfills about 75% of it. As a result, the reliability of this resource will be the key to minimizing OED's capacity costs, as explained in the next section.

ISO NEW ENGLAND'S PAY FOR PERFORMANCE PROGRAM

Because OED 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, OED will be provided with (energy and) capacity by ISO New England. However, ISO New England's Pay for Performance[8] (PFP) program creates financial payments (and potential penalties) for generators to perform when the grid is experiencing a scarcity event.

The following table illustrates the range of performance payments that OED's 7.1% 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, OED could receive up to a $10,000 payment or pay up to a $11,000 penalty during a one-hour scarcity event. This represents a range of plus or minus 40% of OED's 2022 monthly capacity budget. However, such events occur infrequently (only once since 2018), and they frequently last less than one hour.

Table 13: Pay for Performance Ranges for One Hour of Project 10 Operation[9]

ISO-NE Load	Performance Payment Rate	0% Performance	50% Performance	100% Performance
10,000	$5,500/MWH	-$5,000	$2,600	$10,100
15,000	$5,500/MWH	-$7,100	$400	$8,000
20,000	$5,500/MWH	-$9,300	-$1,700	$5,800
25,000	$5,500/MWH	-$11,400	-$3,900	$3,700

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

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

RENEWABLE ENERGY STANDARD (RES 1.0) REQUIREMENTS

OED's obligations under the Renewable Energy Standard (RES) are shown in Table 14. Under RES, OED must purchase increasing amounts of electricity from renewable sources. Specifically, its Total Renewable Energy (Tier I) requirements rise from 36% in 2023 to 75% in 2032, and the Distributed Renewable Energy (Tier II) requirement rises from 4.6% in 2023 to 9.4% in 2032. Note that this plan assumes that both the Tier I and Tier II requirements are maintained at their 2032 levels throughout the rest of the study period.

Under RES, the Tier II requirements are a subset of the Tier I requirements. As a result, we subtract the Tier II percentage from the Tier I percentage to get the Net Tier I requirement in the fourth column. Notice that the net Tier I requirement declines every second and third year until the Tier I requirement increases. When these percentages are multiplied by the forecast of retail sales, the result is a seesaw effect where the Net Tier I requirement declines every second and third year. This effect can be seen more clearly in Figure 9 in the next section.

Table 14: RES Requirements (% of Retail Sales)

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

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

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

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

Table 15: ACP Prices[11] ($/MWH)

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

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

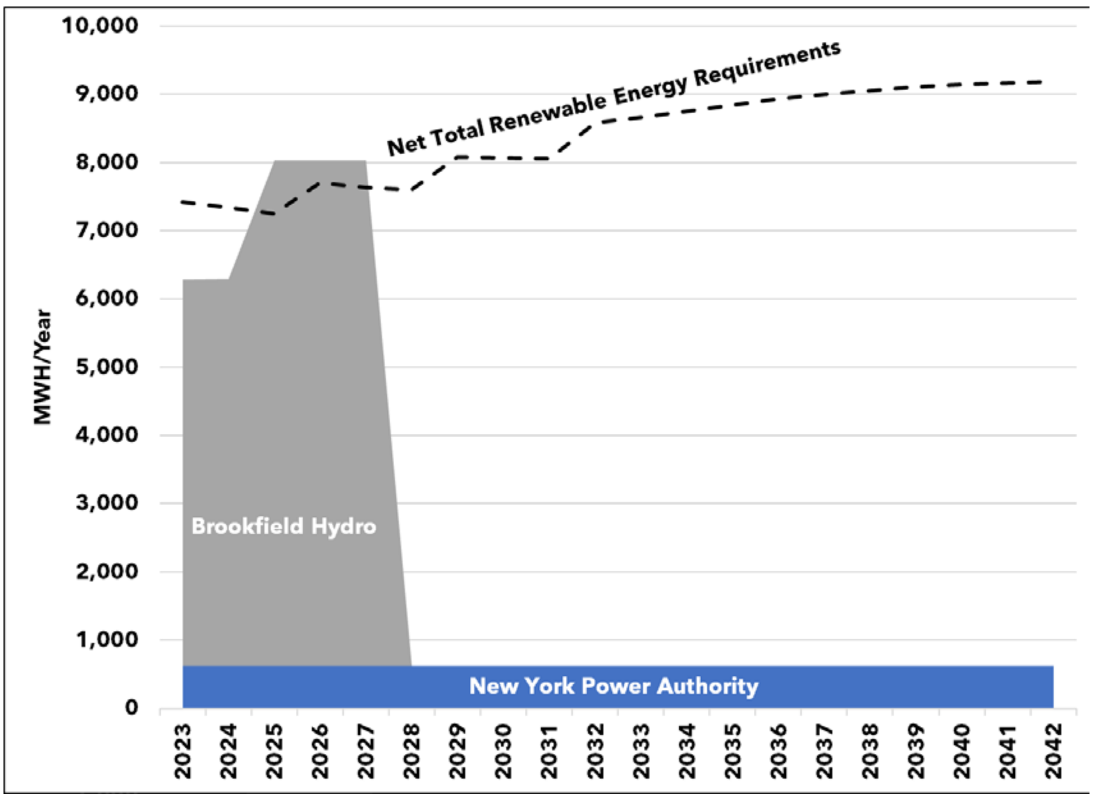
[10] For simplicity, we assume that no banking occurs in this example. In practice, banking excess TIER I and TIER II credits for use in future years is permitted under RES.

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

TIER I - TOTAL RENEWABLE ENERGY PLAN

Between 2023 and 2027, OED's Net Tier I requirement is about 7,500 MWH per year. There are two hydroelectric resources that contribute to meeting the Net Tier I requirement; NYPA, and the Brookfield Hydro PPA. These resources add up to about 6,300 MWH per year or 85% of OED's Net Tier I requirement in 2023. In 2025, the Brookfield PPA entitlement increases, and OED has a slight surplus of Tier I RECs through 2027. Thereafter, new resources will be required to meet the RES.

Figure 9: Tier I - Total Renewable Energy Supplies

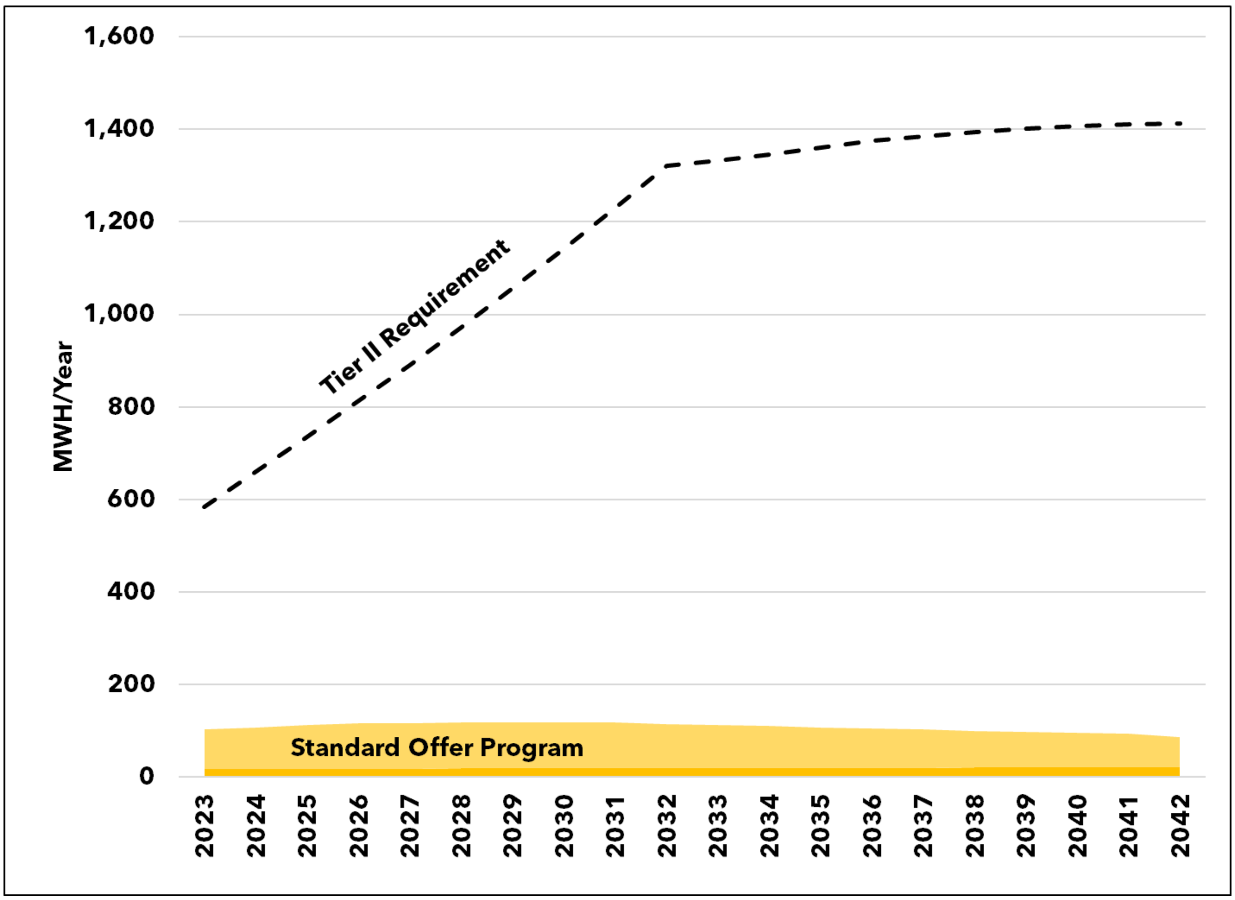


OED is likely to meet its Net Tier I requirements by purchasing Maine Class II (ME II) Renewable Energy Credits (RECs) or extending the Brookfield PPA. In either case, the cost of Tier I RECs will be similar. Their price has ranged from a low of $1.00 to a high of $10.00 per MWH over the past five years. At the current price of $10/MWH, the cost of complying with Net Tier I between 2028 and 2032 with ME II RECs would be about $86,000 per year.

TIER II - DISTRIBUTED RENEWABLE ENERGY PLAN

The dashed line in Figure 10 shows OED's Distributed Renewable Energy (Tier II) requirement, which rises steadily from 600 MWH in 2023 to over 1,300 MWH in 2032. OED is presently developing a 1 MW AC solar facility adjacent to the Heath substation to meet this need. The project is being developed in partnership with a solar developer, and it may be upsized to 2 MW in anticipation of higher RES requirements and to create a surplus that can be used toward its Energy Transformation requirement.

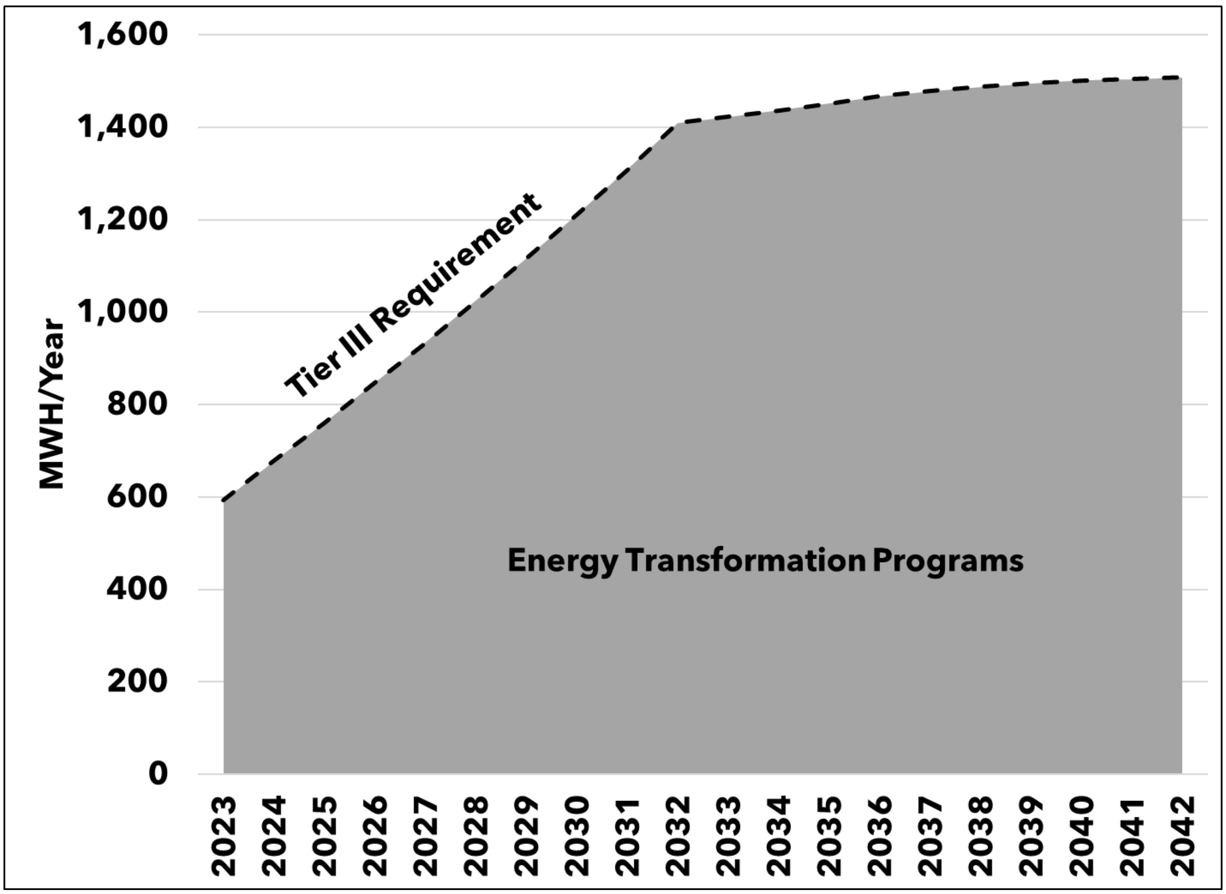
Figure 10: Tier II - Distributed Renewable Energy Supplies



TIER III - ENERGY TRANSFORMATION PLAN

The dashed line in Figure 11 shows OED's Energy Transformation (Tier III) requirements, which rise from about 600 MWH in 2023 to 1,400 MWH in 2032. Prescriptive programs are presently budgeted to fulfill the entire requirement, and are shown in the gray-shaded area of Figure 11. 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 2022 Tier 3 Annual Plan) and in the following section.

Figure 11: Energy Transformation Supplies



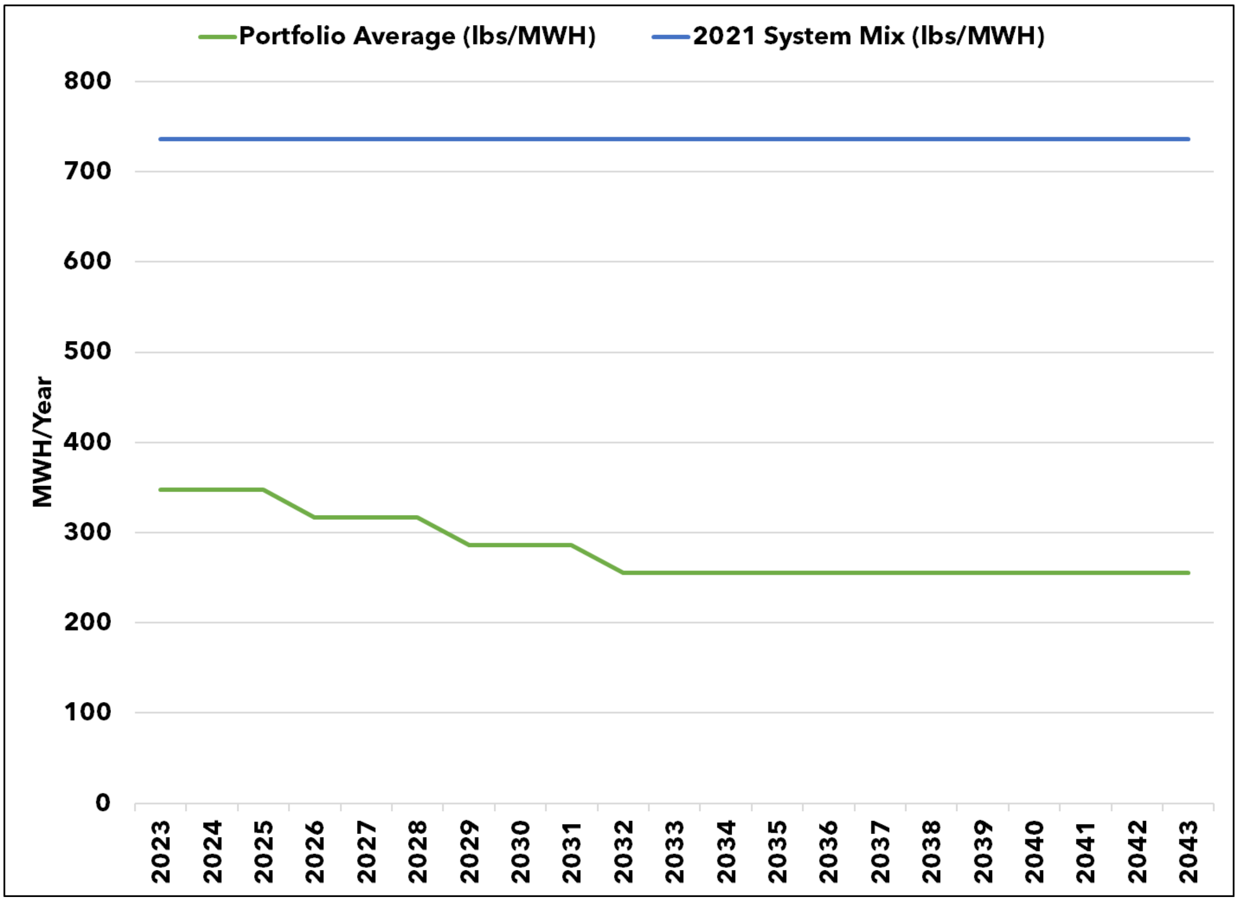
If prescriptive programs do not fulfill the entire requirement, custom Tier III projects may fill the gap as contemplated in the Tier 3 Annual Plan. OED will follow a three-part strategy to fulfill its Tier III requirements.

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 12 shows an estimate of OED's carbon emissions rate compared to the 2021 system average emissions rate in New England[12]. The emissions rate in 2023 is about 350 lbs/MWH because of the Brookfield Hydro contract, which includes Tier I RECs.

Figure 12: Portfolio Average Carbon Emissions Rate (lbs/MWH)



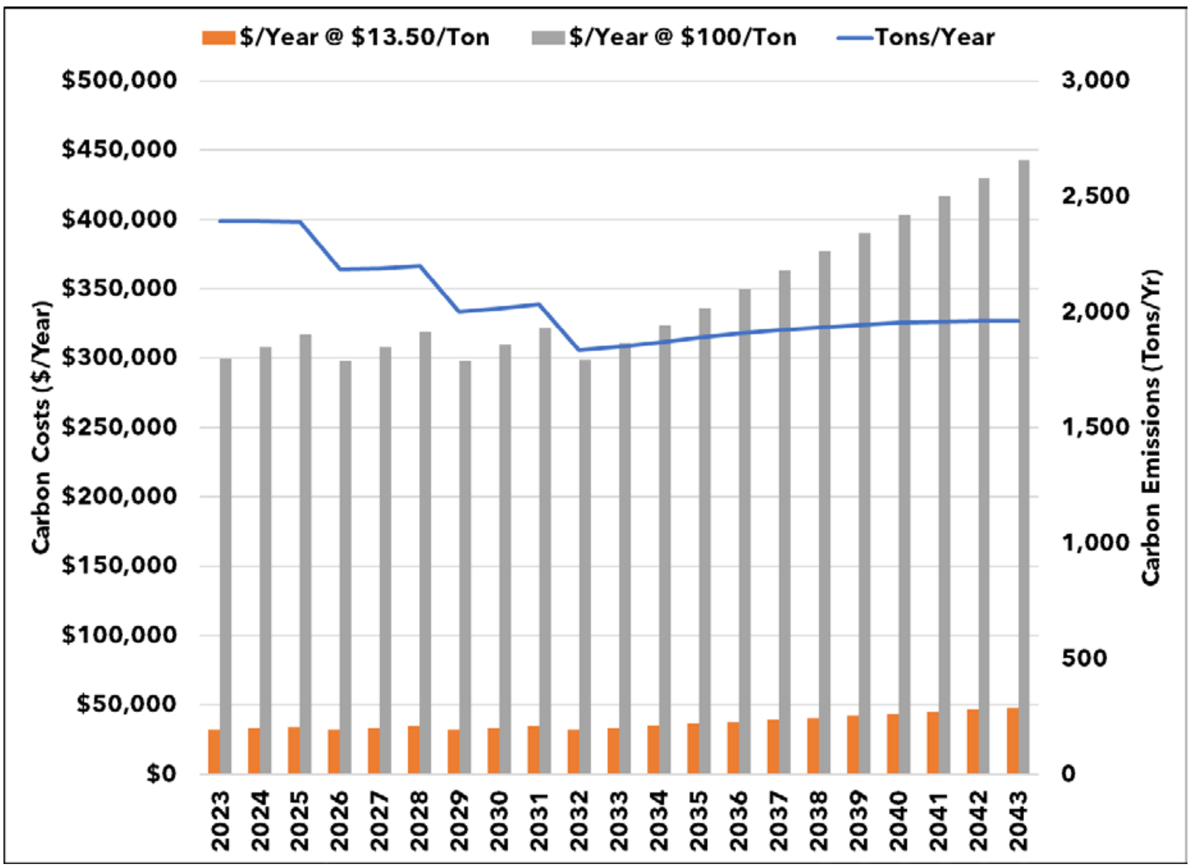
The emissions rate continues to decline in 2026 as a result of increasing RES requirements. This decline continues until 2032, when the RES requirements end. The emissions rate remains stable thereafter because this plan assumes that the RES requirements will be maintained.

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

These emissions rates were multiplied by the load forecast from Section I. Electricity Demand to arrive at an estimate of carbon emissions in tons per year. The following figure shows that carbon emissions range from about 2,400 tons/year in 2023 down to 1,800 tons per year in 2032.

The costs of these emissions were calculated using two sources, the 2021 Regional Greenhouse Gas Initiative Auction (RGGI) results ($13.50 per ton) and the 2021 Avoided Cost of Energy Supply (AESC) study ($125 per ton). Using RGGI prices (plus inflation), the cost of carbon emissions is about $32,000 per year through 2032. Using AESC prices, the cost is about $300,000 per year.

Figure 13: Carbon Emissions (Tons/Year) and Costs ($)



RES 2.0 REQUIREMENTS

Because there is discussion in the Vermont legislature to increase the RES requirements, we have analyzed the impact of a 100% by 2030 Tier I requirement and a doubling of the Tier II requirement. In addition, we assume that the Tier III requirements stays the same through 2032, and that they continue to increase by 0.67% per year through the forecast period. This would result in a Tier III requirement of 17.34% in 2042. Figure 14 shows the year by year trajectory of these changes to the RES.

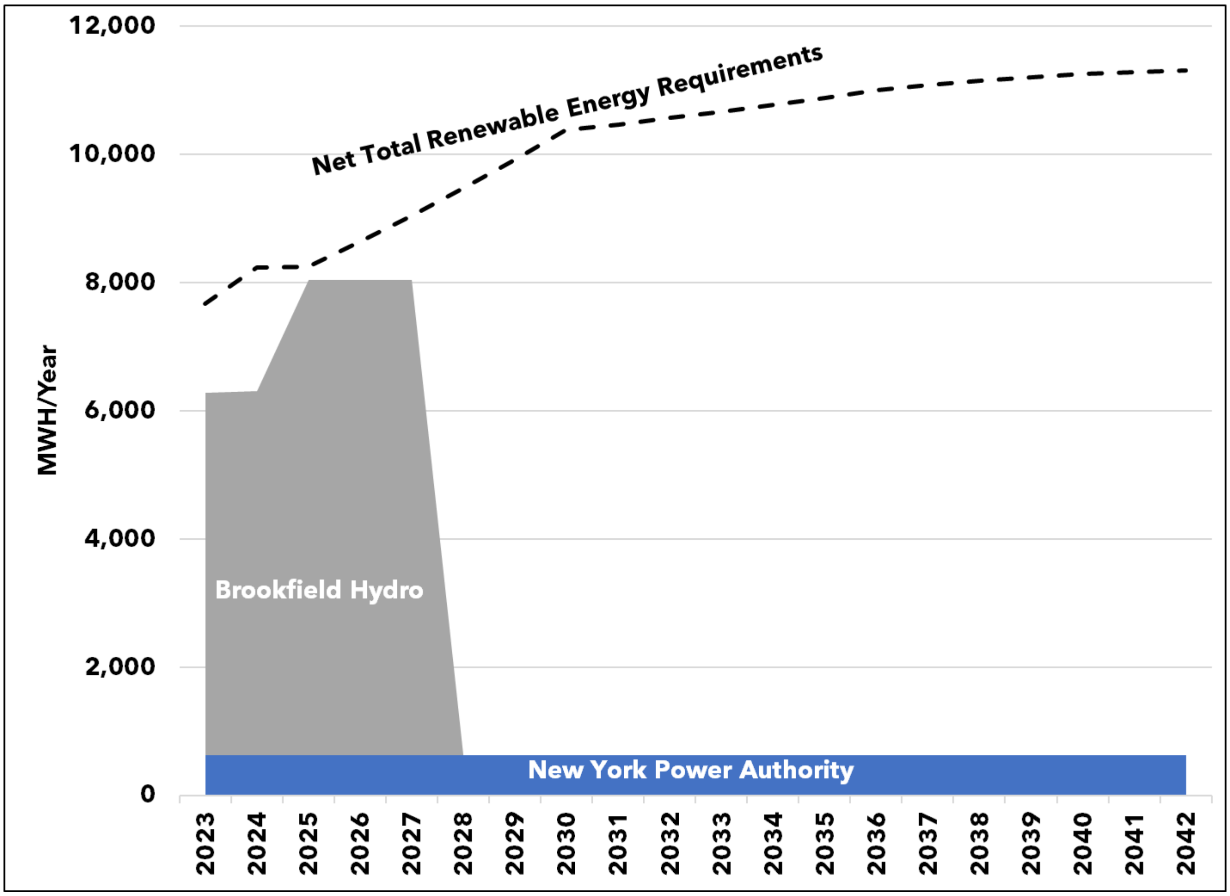
Figure 14: RES 2.0 Requirements

Year	Tier I: Total Renewable Energy (A)	Tier II: Distributed Renewable Energy (B)	Net Tier I: Net Total Renewable Energy (A) - (B)	Tier III: Energy Transformation
2022	59.0%	55.0%	4.0%	4.0%
2023	65.0%	60.4%	4.6%	4.7%
2024	70.0%	64.8%	5.2%	5.3%
2025	75.0%	65.0%	10.0%	6.0%
2026	80.0%	68.0%	12.0%	6.7%
2027	85.0%	71.0%	14.0%	7.3%
2028	90.0%	74.0%	16.0%	8.0%
2029	95.0%	77.0%	18.0%	8.7%
2030	100.0%	80.0%	20.0%	9.3%
2031	100.0%	80.0%	20.0%	10.0%
2032	100.0%	80.0%	20.0%	10.7%
2033	100.0%	80.0%	20.0%	11.3%
2034	100.0%	80.0%	20.0%	12.0%
2035	100.0%	80.0%	20.0%	12.7%
2036	100.0%	80.0%	20.0%	13.3%
2037	100.0%	80.0%	20.0%	14.0%
2038	100.0%	80.0%	20.0%	14.7%
2039	100.0%	80.0%	20.0%	15.3%
2040	100.0%	80.0%	20.0%	16.0%
2041	100.0%	80.0%	20.0%	16.7%
2042	100.0%	80.0%	20.0%	17.3%

TIER I - TOTAL RENEWABLE ENERGY PLAN

Under a 100% by 2030 Tier I requirement, OED would need 80% of its supply to come from Tier I resources. This may seem counterintuitive, but it is a basic feature of the RES. The Tier II requirement would be 20% by 2030, and Tier I's requirement is net of Tier II. In any case, OED's requirement would rise from 8,000 MWH per year in the mid 2020s to a little over 10,000 per year in 2030.

Figure 15: Tier I Requirements Under RES 2.0

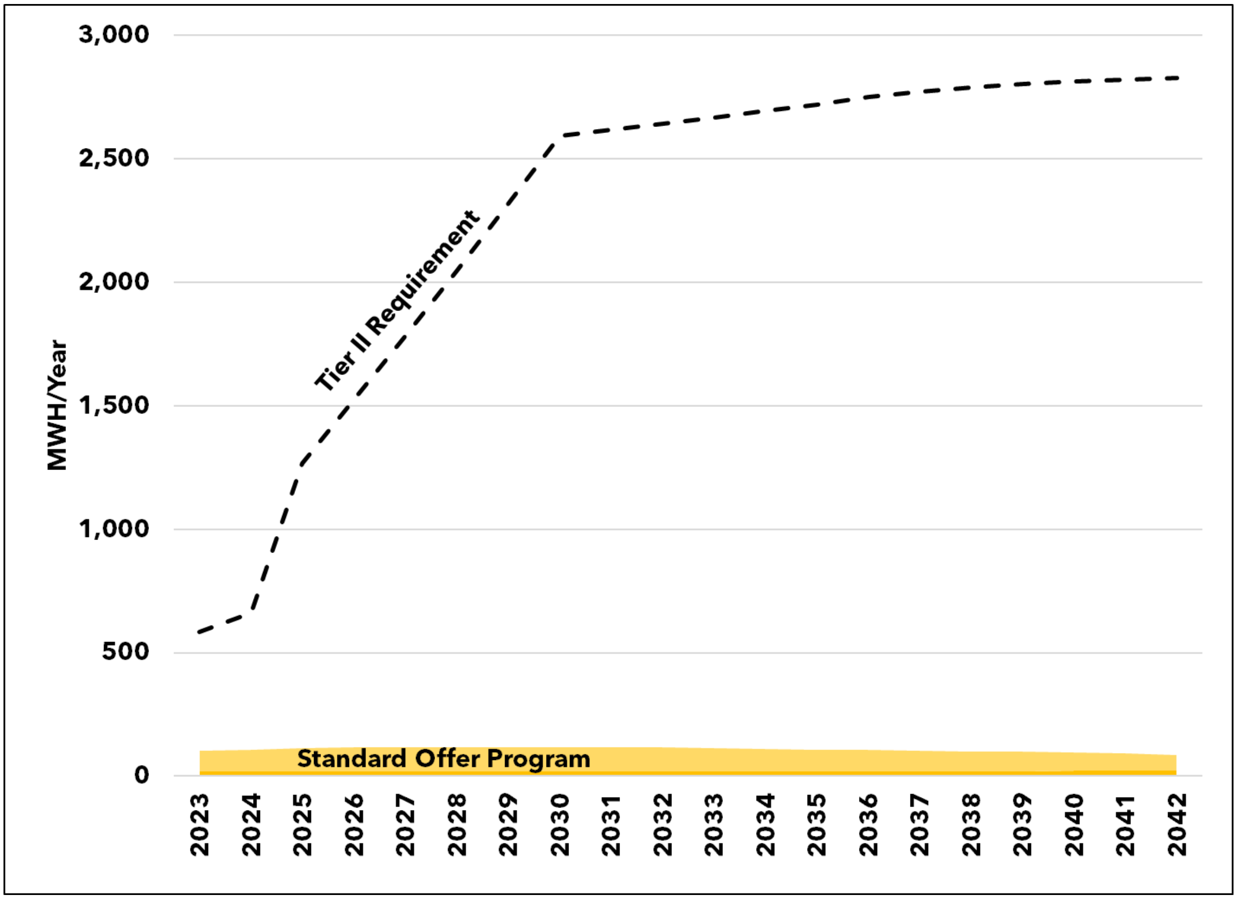


OED could meet this requirement by purchasing any number of hydro resources in New England, but it could also purchase a wind resource, whose Class I RECs could be resold and act as a hedge against the cost of Tier I RECs. The financial impact of this strategy will be measured in the Financial Analysis section.

TIER II - DISTRIBUTED RENEWABLE ENERGY PLAN

The impact of a 20% by 2030 Tier II requirement is shown in Figure 16. In 2030, the requirement rises to 2,600 MWH per year, and as a result, a new 1.6 MW resource would be needed to fulfill and maintain Tier II requirements through the 2030s. The cost of this resource will be measured in the Financial Analysis section.

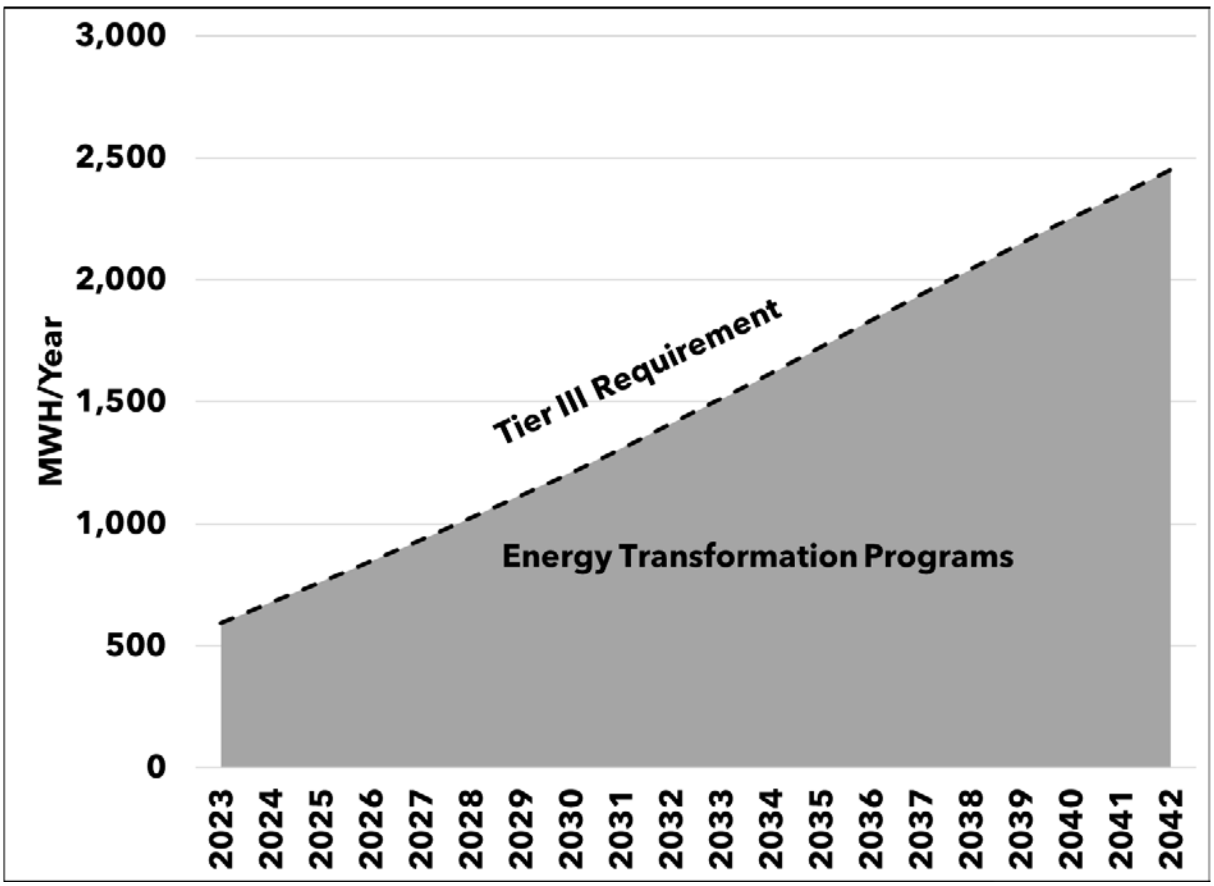
Figure 16: Tier II Requirements Under RES 2.0



TIER III - ENERGY TRANSFORMATION PLAN

The dashed line in Figure 17 shows OED's Energy Transformation (Tier III) requirements, which rise from about 600 MWH in 2023 to 2,500 MWH in 2042. A high level of market support may be necessary to support high penetrations of electrification technologies. In keeping with the current RES assumptions, prescriptive programs are assumed to fulfill the entire requirement, and are shown in the gray-shaded area. The cost of running these programs will be measured in the Financial Analysis section.

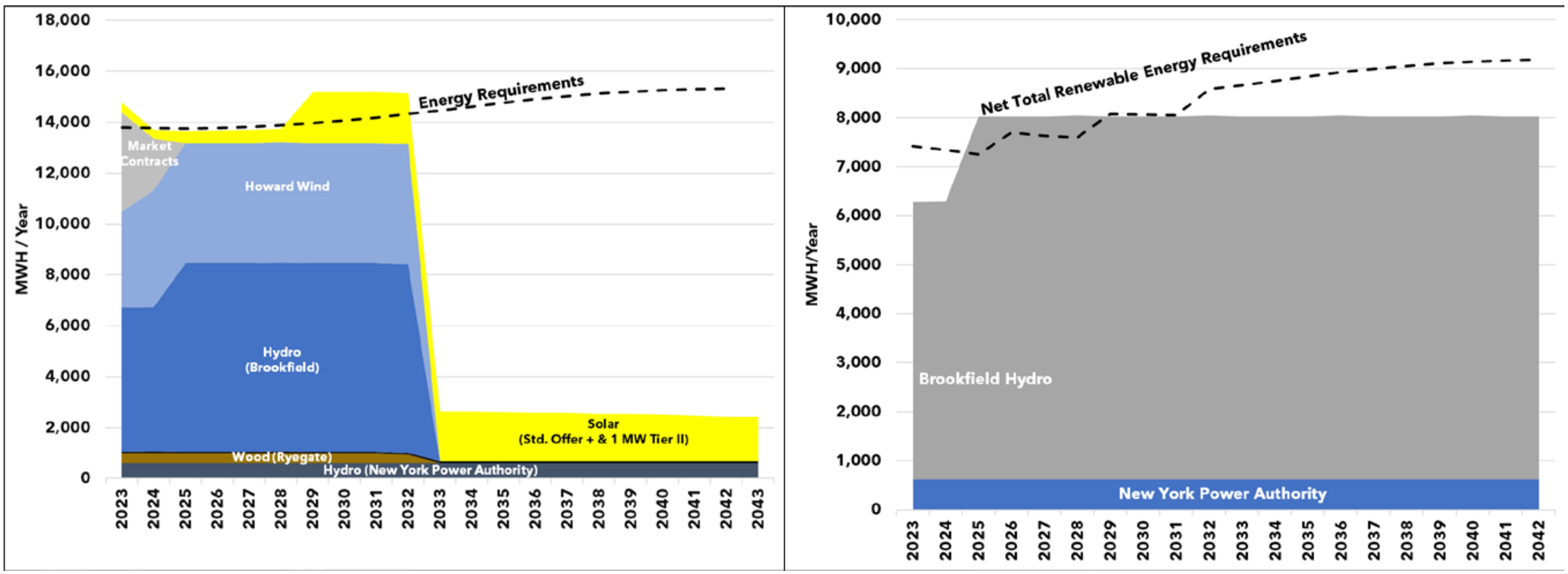
Figure 17: Tier III Requirements Under RES 2.0



PROCUREMENT PLAN FOR RES 1.0

Under RES 1.0 requirements, OED can simply extend the term on its existing hydro and wind PPAs. This approach would meet OED's energy requirements until electrification starts to increase the load in the 2030s. It would also fulfill most of the Tier I REC requirements until the final year (2032) of the RES, when a small Tier I REC purchase would be required. Note that the size and timing of the solar PPA as it coincides with the size and timing of electrification will determine how much surplus generation is present in the late 2020s and early 2030s.

Figure 18: RES 1.0 Option 1 – Hydro Energy & Tier I RECs Compared to Requirements



PROCUREMENT PLAN FOR RES 2.0

The procurement plan for meeting RES 2.0 involves a mix of three resources. First, the Brookfield Hydro PPA would be extended to 2032. This helps meet OED's energy requirements, but leaves OED in a deficit position on Tier I RECs. Second, the Howard Wind resource is extended to 2032, but at about half the volume. This reduction enables OED to build a 1.8 MW solar resource to fulfill Tier II requirements. Finally, the MA Class I RECs from Howard Wind can be sold to help fund the cost of buying the remaining Vermont Tier I.

Figure 19: RES 2.0 Energy Resources Compared to Requirements

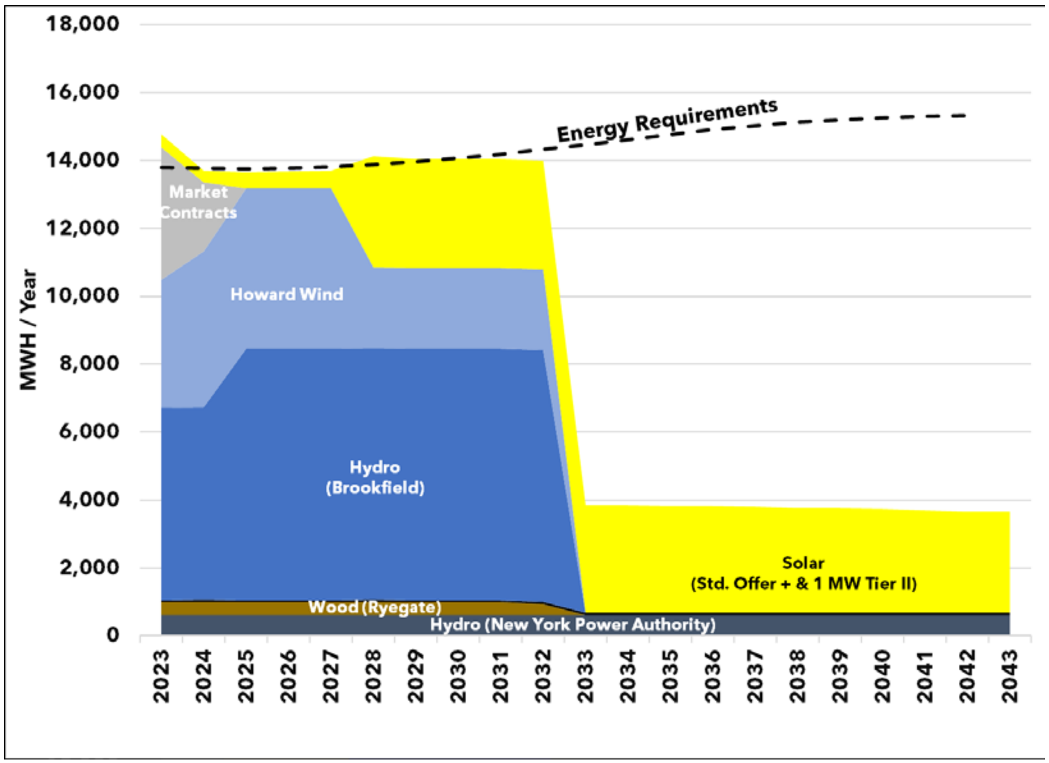
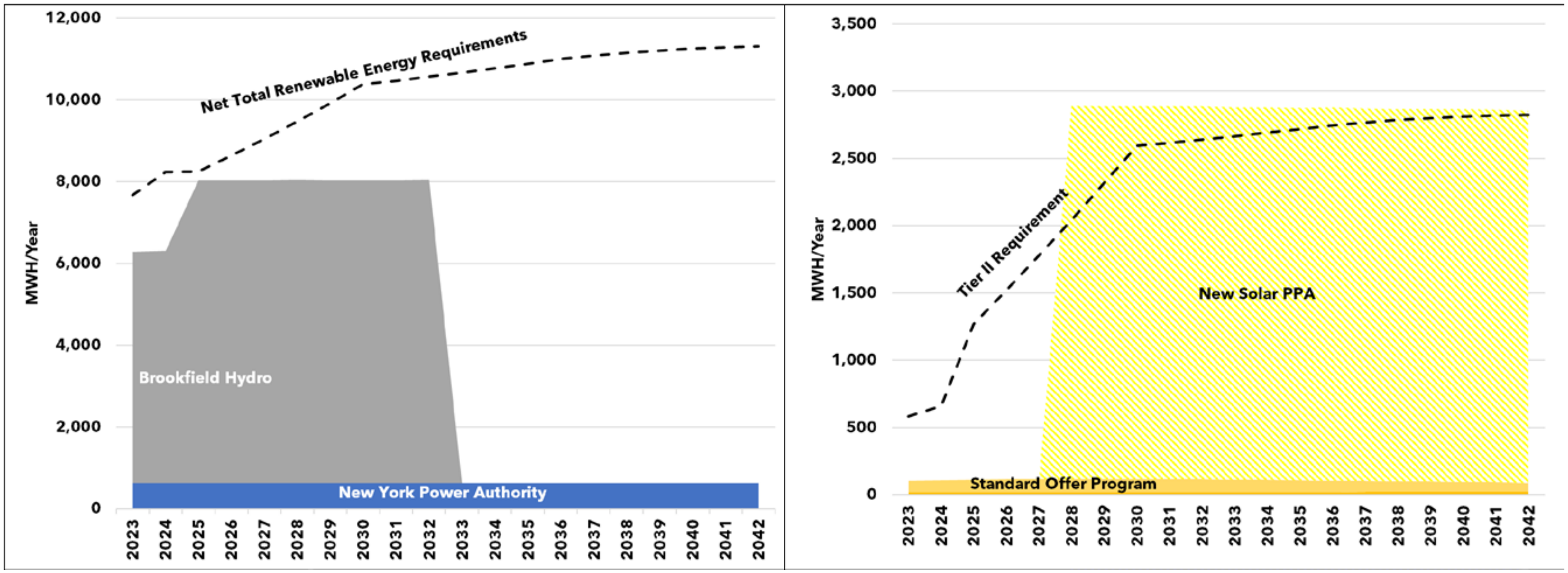


Figure 20: RES 2.0 Tier I and Tier II Resources Compared to Requirements



The following tables show how effective a Class I REC is at hedging Tier I REC prices.

Table 16 shows that there is always a positive spread between the price of Class I and Tier I RECs. Why? Historically, the lowest Class I REC price has been about 200% higher than the highest Tier I REC price. If this relationship holds going forward, Class I RECs will continue to be a good financial hedge against Tier I REC prices.

Table 16: Class I to Tier I Price Spread ($/MWH)

		Class I Price Range		
		$20.00	**$40.00**	**$60.00**
Tier I Price Range	**$1.00**	$19	$39	$59
	$5.00	$15	$35	$55
	$10.00	$10	$30	$50

Table 17 shows how this strategy would play out at today's energy and REC prices. First, energy prices are assumed to equal the forecast from the Energy Information Administration's (EIA) 2022 Annual Energy Outlook (AEO). Between 2028 and 2042, this value is $56/MWH levelized. Second, we assume that a bundled Tier I REC would cost an additional $10/MWH levelized for a total cost of $66/MWH.

Table 17: Bundled Hydro Vs. On-Shore Wind Costs (Levelized $/MWH, 2028-2032)

	Energy	Class I RECs	Tier I RECs	Total
Hydro + Tier I	$56.00		$10.00	$66.00
OffShore Wind	$95.00	-$40.00	$10.00	$65.00
Spread				$1.00

The On Shore Wind cost is assumed to be $95/MWH levelized, and the Class I RECs would be sold at their historical average of $40/MWH. After buying back the Tier I RECs with the Class I REC proceeds, the net cost is $65/MWH, a $1/MWH savings versus bundled hydro.

The conclusion to be drawn from this analysis is that new renewable resources can effectively hedge the cost of complying with Tier I requirements, despite the fact that new renewable resources are not required under RES 1.0 requirements. However, it is reasonable to expect that REC prices will converge over time, and that the price spread between Tier I and Class I RECs will narrow. As a result, OED will monitor this relationship and take it into account during procurement.

RESOURCE PLAN OBSERVATIONS

A number of observations can be drawn from these resource plans. First, although meeting additional Tier I and Tier II requirements by 2030 is feasible, there are some limits and some trade offs. For example, OED could meet a 100% Tier I requirement by 2030 using only the Brookfield Hydro resource. However, this approach would place a large majority of OED's supply with a single company and resource. A better approach might be to retain the Howard Wind resource and the diversity benefits (location, resource type) that come with it.

Second, there is a limit to the amount of Tier II resources that OED's can reasonably develop and use. OED's daytime load is about 1.5 MW higher than its nighttime load. As a result, any solar resource that is larger than 1.5 MW would have to be exported. This energy has financial value because there is a market (ISO New England) in which to liquidate it. However, it has limited value as a physical resource when there is insufficient load, and absent a large and cost-effective storage resource, it has no value during the night-time hours, when the major electrification technologies (EVs and heat pumps) are expected to be charging or operating.

The third conclusion is that there is trade off between procuring Tier I and Tier II resources. The more Tier II that is procured, the less load is available to be served by Tier I resources. The existing RES statute is structured to recognize and adjust for this simple fact. However, RES 2.0 would increase both requirements simultaneously, which results in a trade off. Procuring more Tier II resources would force OED to buy less Tier I resources, which would increase the amount of unbundled (without energy) Tier I REC resources it would require. This increases REC price risk.

TRANSMISSION & DISTRIBUTION

IV. ELECTRICITY TRANSMISSION & DISTRIBUTION

TRANSMISSION SYSTEM DESCRIPTION

Orleans Electric Department (OED), Barton, and VEC jointly-own the transmission line running from the VELCO– Irasburg Substation south to the Barton tap. This line is 336 ACSR and feeds a 5.5-mile line to the Heath Substation located in the Town of Barton on Baird Road. This 5.5-mile 46 kV line feeds both the OED and Barton utilities.

Both utilities, OED and Barton, have secured easements and reconstructed the 46 kV line from Route 16 to Baird Road. This upgrade included a new 46 kV SCADA controlled switch. This line is a radial feed and therefore is an important facility to both utilities. OED started investing in this project in 2008. The initial transmission line was put into service in 2014 and is now fully energized. There were only two outages during the whole construction process. The conductor sizing was done based on the recommendations of the previous T&D study. This was a massive investment for both municipalities and actual costs were significantly under budget.

All of OED's 46 kV system ownership has been rebuilt over the past several years and was finished being rebuilt in 2021.

DISTRIBUTION SYSTEM DESCRIPTION

The OED distribution system includes 10 miles of line operating at 13.2 kV and 30 miles operating at 2.4 kV. OED continues to work on upgrading the remaining 2.4 kV portions of the distribution system. In some sections the poles and wires have been set in preparation for completing the voltage upgrade. Finalized in 2006, OED completely upgraded its main feeder line from the Heath Substation to the Rainbow Substation.

OED monitors its load balances at a minimum of once a year and sometimes twice a year. This is heavily dependent on Ethan Allen Manufacturing. In recent years OED has upgraded all the infrastructure beyond the Ethan Allen Substation including a voltage upgrade from 2.4 kV to 13.2 kV.

OED-OWNED INTERNAL GENERATION

OED does not own or operate any generation plants within its service territory.

OED SUBSTATIONS

OED owns and operates three substation facilities. Each substation is briefly described below.

Heath Substation:

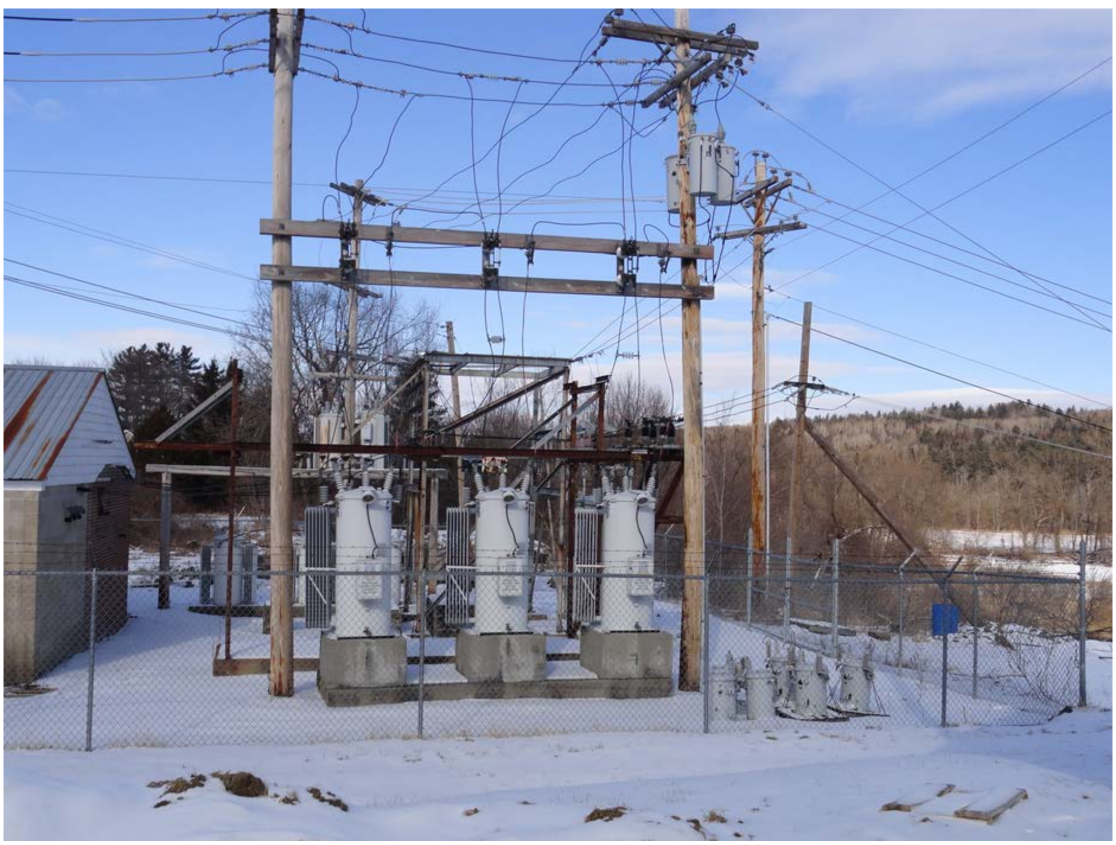
Heath Substation is jointly owned with the Barton Electric Department. It has a 12.5 MVA transformer with a primary voltage of 46 kV and a secondary voltage of 13.2 kV. OED has one feeder line leaving this substation going to OED. A brand-new transformer and grounding grid was recently installed in the substation. Recently Barton and OED added new regulators and replaced some beams. OED is planning to work with Barton to install oil containment in this substation.

Figure 21: OED's Heath Substation

Rainbow Substation:

Rainbow Substation is located in the OED territory behind the Rainbow Apartments on Church Street. This substation currently has three 333 kVA units feeding the village of Orleans at 2.4 kV. The second bank of transformers feeds the easterly side of the village of Orleans and Maple Street in Orleans. Much of the load has been taken off these transformers through upgrades. Also, in this substation is a bank of 432 kVA regulators on the Ethan Allen circuit. OED upgraded transformers by installing three brand-new 333 kVA units, as the older ones were gassing and therefore needed to be replaced. OED is upgrading voltage outside of the village limits for voltage stability reasons. Currently, there are no voltage stability issues in the village, therefore OED is keeping the 2,400-volt system at this time.

Figure 22: OED's Rainbow Substation



Ethan Allen Manufacturing Substation:

As the name suggests, the Ethan Allen Manufacturing Substation is the main substation for Ethan Allen Manufacturing. It consists of a 13.2 kV line feeding the substation with primary metering. One bank of 500 kVA transformers feeds the rough mill at 480 volts. A second set of 500 kVA transformers feeds the finish mill. A third set of 500 kVA transformers feeds the maintenance bus and 1,000-amp 480-volt bus next to the rough mill. This substation has had all the equipment replaced over the past thirteen years and recently OED has been replacing parts of the pole structure in this substation on an annual basis. The pole structure is now fully reconstructed and completed. During Ethan Allen's scheduled annual shutdown in July, OED uses this time to do any necessary, substantial work on this substation. Ethan Allen is the only customer impacted by the shutdown. OED also has a backup transformer in the substation should it ever need one. This substation is fed from the Rainbow Substation and the voltage is 13.2 kV with 336 MCM conductor. The distance between both subs is approximately ¼ mile.

Figure 23: OED's Ethan Allen Manufacturing Substation

CIRCUIT DESCRIPTION

Table 18: OED Circuit Description

Circuit Name	Description	Length (Miles)	# Customers by Circuit	Outages by Circuit 2021
Brownington	2/0 circuit protected by line fuses	19	305	1
West Orleans + Irasburg out of town	1/0 circuit protected by line fuses	12	234	2
East Orleans	1/0 circuit protected by line fuses	8	129	2
Ethan Allen	336 circuit with regulators and oil recloser	1	1	1

T&D SYSTEM EVALUATION

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

Outage Statistics

OED tracks all outage statistics as part of its Service Quality Reliability Plan (SQRP). These outage statistics allow us to examine number, cause, and length of outages by circuit and develop plans for the most cost-effective reliability improvements. The following table summarizes SAIFI and CAIDI results for the past five years. OED's Vermont Public Utility Commission Rule 4.900 Electricity Outage Reports, reflecting the last five years in their entirety, can be found at the end of this document.

When OED has a planned outage, it notifies its customers at least five days in advance by means of the local newspapers in its service territory: The Chronicle, The Newport Daily Express, and The Caledonia Record. Additionally, OED makes phone calls to businesses, farmers, the Rainbow Apartments, and residential customers on oxygen to inform them of the planned outage so that they can arrange for backup. Furthermore, OED notifies its customers through its Facebook page.

Table 19: OED Outage Statistics

	Goals	2017	2018	2019	2020	2021
SAIFI[13]	**1.0**	0.0	0.0	0.0	0.0	0.0
CAIDI[14]	**1.5**	2.4	1.6	2.1	2.4	2.7

[13] System Average Interruption Frequency Index

[14] Customer Average Interruption Duration Index

RELIABILITY

OED puts arrestors after the transformer cut-outs, instead of ahead of them. The method has proven to be more protective than the old practice of putting arrestors before the transformer cut-outs. The placement of the arrestors has contributed to OED's system reliability.

ANIMAL GUARDS

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

FAULT INDICATORS

OED uses fault locators on the 46 kV transmission line to isolate faults and reduce outage time. Fault indicators are not necessary on the distribution system, as these lines are too short.

POWER FACTOR MEASUREMENT AND CORRECTION

OED's power factor has historically been approximately 100%. This is due to a capacitor bank that monitors the system's power factor and switches in and out when necessary. It is located at the Ethan Allen Substation. The GE phase 3 meter monitors the power factor as well. The current power factor is near 100%.

DISTRIBUTION CIRCUIT CONFIGURATION

VOLTAGE UPGRADES

OED's plan for improving system efficiency is simple: completing voltage upgrades in order to reduce system losses. OED's long-term strategy is to improve system efficiency by converting the 2.4 kV portion of its system to 13.2 kV. The effort was initiated in 2004 and has continued to this day. The longest distribution lines have been targeted first with the distribution lines in the village being the last.

PHASE BALANCING / FEEDER BACK-UPS

Feeder/phase balancing is performed annually on the main line feeding the utility. The three distribution lines feeding Orleans, Maple Street and Brownington are evaluated and tested every two years.

SYSTEM PROTECTION PRACTICES AND METHODOLOGIES

PROTECTION PHILOSOPHY

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

OED uses station class arrestors in the substations and on the transmission line. It also uses distribution arrestors on equipment in the field. The makeup of these devices is now polymer, not porcelain, for safety concerns. All equipment is also protected with fusing on the high side. OED puts arrestors after the transformer cut-outs, instead of ahead of them. The method has proven to be more protective than the old practice of putting arrestors before the transformer cut-outs.

OED has reclosers at the Heath Substation watching the main line. There is also a recloser at the Ethan Allen Substation that monitors the load of Ethan Allen Manufacturing. There are sideline fuses on most lines unless there is a single customer located in a non-wooded area a short distance from the main line. If it's a one-pole spur line, OED does not fuse.

OED reviews fuse coordination and updates configuration on an ongoing, case-by-case basis, whenever and wherever a change is made to the system. This approach reduces the frequency of full system fuse coordination studies.

Inventory protection:

OED houses all of its wire and transformers at a secured facility.

Voltage Testing:

The existing electric distribution system is performing well. The system's voltage profile to its load center reflects a voltage of 120 volts on a base of 120 volts at peak under current conditions.

OED participates annually in the ISO-NE's voltage reduction tests.

SMART GRID INITIATIVES

EXISTING SMART GRID

OED has installed SCADA to its new 46 kV switch and fiber to its 46 kV metering package.

PLANNED AMI

Beginning in 2018, OED 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 OED. Since the Village of Orleans 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 20: AMI Readiness Assessment Criteria

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

The rating is an indication of the level of potential challenge associated with each functional area for an AMI implementation. Awareness of the effort, potential cost, and requirements can inform the utility in its business decision to pursue an AMI implementation.

For a successful AMI project, the utility team and staff must be interested and receptive to adopting new technology and new ways of doing business. OED 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 the Village of Orleans provides water service, there is the benefit of adding water metering to the solution, ultimately strengthening an AMI business case. The Readiness Evaluation is summarized in the table below:

Table 21: AMI Readiness Evaluation

Overall AMI Readiness	Rating
Electric Meter Readiness	Fair
Water Meter Readiness	Fair
Meter Reading Readiness	Difficult
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.

OED 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 $700,000, with a positive cost-benefit ratio of 2.85 and a 4.6-year payback, providing Orleans with reassurance that proceeding to the implementation phase is the correct decision. Note that the figures shown in this assessment are exclusive of any anticipated, but unconfirmed, state funding opportunity. While negotiation of a final contract with Aclara is ongoing at this time, Orleans is optimistic that it will begin implementation of a new AMI system during the 2022 to 2024 period.

GEOGRAPHIC INFORMATION SYSTEM

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

CYBER SECURITY

2020 was a cybersecurity turning point for many industries around the globe as nefarious digital attacks threatened to hold organizations hostage and utility regulators at the state and federal level increased focus on cybersecurity. OED is mindful of the increasing importance of cybersecurity concerns, and the relationship of those concerns to technology selection and protection. While OED is not presently required to undertake NERC or NPCC registration, VPPSA is a registered entity, and OED's membership in VPPSA provides OED with knowledge and insight regarding ongoing cybersecurity developments and risks. On a more local level, OED 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.

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

OTHER SYSTEM MAINTENANCE AND OPERATION:

RECONDUCTORING FOR LOSS REDUCTION

OED has been gradually replacing small conductor over the last twenty years and plans to continue to replace small, aged conductors. Most conductor being used now is 1/0 aluminum AAAC.

When evaluating when to replace conductor, OED takes into account the condition of the facilities, system reliability, and the economic cost-effectiveness for the upgrade for ratepayers. The age of the conductor is a proxy for condition and is only part of this analysis.

TRANSFORMER ACQUISITION

For transformers that are equal to or greater than 250 kVA, OED does the analysis that looks at high load losses, low load losses, twenty-five to thirty-year lifecycle in dollars. For transformers that are less than 250 kVA, OED buys second-hand at minimal cost. Many of the municipal utilities sell transformers to each other. This collaborative approach has worked well for OED. While not a formal written village bidding process, when OED goes out to bid, it places at least three bids with GE, ABB, Cooper, and ERMCO. OED uses the Department of Public Service's spreadsheet for determining life-cycle cost of transformers.

CONSERVATION VOLTAGE REGULATION

OED does not have conservation voltage regulation. OED's voltage setting is done with voltage regulators in substations only; voltage is set between 120 and 121.5 volts to provide proper voltage to the first and last customers. OED does not have voltage regulators outside the substations due to the short distance to last customers.

OED also participates in the spring and fall voltage reduction tests.

DISTRIBUTION TRANSFORMER LOAD MANAGEMENT (DTLM)

OED does not have a formal DTLM program. The biggest concern is that transformers are not overloaded and operating too hot.

SUBSTATIONS WITHIN THE 100- AND 500-YEAR FLOOD PLAINS

All three substations are located outside of the 500-year flood plain. None of the substations were affected by the floods of Tropical Storm Irene.

THE UTILITY UNDERGROUND DAMAGE PREVENTION PLAN (DPP)

As the quantity of OED's underground lines increase, OED will become increasingly more involved with the Damage Prevention Plan. OED only has approximately 1,500 feet of underground lines. OED has collaborated with the Department of Public Service and VPPSA to develop a draft Damage Prevention Plan and filed it with the Department of Public Service in April 2018.

SELECTING TRANSMISSION AND DISTRIBUTION EQUIPMENT

OED purchases standard certified transmission and distribution equipment from established, trusted vendors. The majority of the equipment is purchased from Twin State. OED prioritizes quality equipment and following utility standards over low purchase prices. Larger equipment, such as transformers, regulators, and trucks, is subject to a bid process.

MAINTAINING OPTIMAL T&D EFFICIENCY

Substation Maintenance

OED uses infrared analyzers annually to identify hot connections and prioritize maintenance. Additionally, OED utilizes a contractor for oil analysis every other year.

Pole Inspection

OED has first class linemen inspect its entire system once a year. Part of this examination is a pole inspection. This entails a visual inspection for general condition, cracks, shell rot, setting depth, hollow spots and even burnt spots. The age of the pole is also considered. After all of these things have been considered it is then determined which poles in the system need to be upgraded. The targeted pole upgrades typically take place in the nearest construction season. The pole inspection cycle is only one year in length therefore tracking the progress of inspections would be onerous to OED if it were done in a spreadsheet or database. OED inspects the poles on a line-by-line basis and keeps track by flagging the poles. OED also keeps track from an accounting perspective by looking at upgrades that have been put into service. By observing the birth mark, age, and the physical characteristics of the pole, OED determines if and when the pole needs to be replaced.

Equipment

OED annually scans all of its equipment and distribution lines with infrared. The infrared inspection has been enormously valuable to OED in forwarding its goal to provide safe reliable power. OED also performs gas testing regularly on all of its larger transformers and regulators. OED currently relies on an outside service (TCI) to handle all of its cleaning or replacing of PCB equipment.

Actual System Losses

OED has recently finished replacing its transmission system. Losses were reduced dramatically by eliminating the existing conductor #2A copper clad with new 336 ACSR. OED rebuilt the main line coming into OED and was able to reduce transmission losses through conductor sizing. PLM Engineering performed the loss analysis.

System Maintenance

OED's system maintenance includes a very active vegetation management plan as well as a scheduled annual system upgrade. OED is a small municipal with one very large industrial customer and resources can be limited at times. OED continues to invest in plant upgrades.

Tracking Transfer of Utilities and Dual pole Removal (NJUNS)

OED does not currently participate in the NJUNS database but will investigate and consider this resource in the future. OED can easily reach Comcast and Consolidated when necessary and vice versa. This system has not proved to be problematic.

Relocating cross-country lines to road-side

OED takes every opportunity during line rebuilds to relocate cross-country lines to roadside. This obviously reduces outages and maintenance costs. Should OED lose its main line it could receive service from a future connection on Route 5 where service territories of Barton and OED meet. The main line is well maintained, and a large amount of vegetation management is performed on it.

DISTRIBUTED GENERATION IMPACT:

Currently, OED has only 6 solar net metering customers, with a combined total installed capacity of about 35 kW.

Interconnection of Distributed Generation

OED recognizes the unique challenges brought on by increasing penetration levels of distributed generation. OED 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 OED 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, OED will maintain detailed records of installed generation including location, type, and generating capacity. This information will allow OED 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). OED 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 OED's service territory, OED 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 OED. As a reasonable compromise, OED 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, OED 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. OED 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

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

The OED distribution system currently has sufficient capacity for the immediate foreseeable future. As Table 22 indicates, OED has just a few small solar projects on its system. Maximum loading on the Heath substation transformer is currently about 51% of it's nameplate capacity and about 25% on average. There are two downstream substations fed from the Heath substation, the Ethan Allen and Rainbow substations. The Ethan Allen substation shows maximum usage just under 30% of nameplate capacity with average loading at about 10% of nameplate. The Rainbow substation, which feeds primarily residential load at 2.4kV, shows peak utilization of about 88% and average usage of just under 40%. As OED continues to convert 2.4kV circuits that are fed from the Rainbow Substation to 7.6kV over the next two years, capacity utilization on this substation's transformers will drop significantly.

Table 22: OED Distribution-Level Impact of Electrification

SUBSTATION	# of Transformers	Transformer Capacity	Peak % of Nameplate	Energy % of Nameplate (1)	CIRCUIT/ FEEDER	Circuit Voltage Kv	Solar/Hydro Dist. Generation # of Units	Solar/Hydro Dist. Generation kW	Storage kW	Large Load kW	Large Load kWh
Rainbow Substation	**6**	**2.0 MVA**	**88%**	**39%**	**Orleans/Irasburg**	**2.4 KV**	**2**	**27.6**	-		
Ethan Allen	**15**	**7.5 MVA**	**29%**	**10%**	**Ethan Allen**	**14.4 KV**			-	**2,177**	**6,879,747**
Heath Substation (2)	**1**	**6.25 MVA**	**51%**	**25%**	**Brownington**	**2.4 KV**	**4**	**15.2**	-		
Heath Substation					***Feeder to both Rainbow & Ethan***	***46 KV***					
*(1) Annual kWh / (transformer capacity * 8760)*											
(2) OED Jointly owns 50% of Heath Substation											

We know from the Demand Chapter[15] that the transformers at OED's Substations are not likely to become a constraint. Even when EV and HP penetration reaches high levels in the early 2040s, the peak load is forecast to be well below the transformer ratings. Furthermore, because conductor size is calculated based on the transformer rating, it is also unlikely that conductor size is going to be a constraint. One of the primary lessons learned from Washington Electric Cooperative's (WEC) ongoing PowerShift Electric Vehicle Charging Equipment (EVSE) pilot with Efficiency Vermont (EVT) was that addition of one or more uncontrolled EV charger(s), heat pump(s) or storage device(s) could stress transformers at the service drop level, necessitating an unanticipated upgrade. It was also a conclusion that was reached by GMP in their 2021 Integrated Resource Plan.

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

At the present time OED tracks customer adoption of electrification measures based on data captured from past and current incentive programs. This incentive-program driven dataset

[15] See 'Peak Forecast Results,' pages 13-14.

provides a significant amount of information regarding the magnitude and approximate locational trends of electrification driven load. OED is able to track installed electrification measures associated with incentive programs, by street address, within the OED system. Use of this dataset in the short run assists the development and analysis of historic deployment patterns as well as anticipating penetration patterns. While this data currently shows a very limited level of penetration that is evenly scattered across the OED system, the view of magnitude and locational trends this dataset will provide over time will inform policy and planning discussions related to OED's responses to expected electrification impacts on its distribution system.

The current incentive program tracking effort is relatively simple and while it provides limited information, it serves a current need. OED anticipates that implementation of integrated AMI and GIS systems over the next couple years will provide the ability for implementation of more sophisticated, timely and location-targeted distribution system planning, rate driven load management responses, including load control programs where appropriate, and development of forward-looking distribution system improvements designed to take advantage of opportunities to encourage cost-efficient and balanced load growth. As the anticipated AMI and GIS implementations reach maturity, OED will be in a position to systematically track and analyze transformer, circuit and substation loading on a locational basis and focus on exploiting the new systems abilities. The current incentive tracking effort will become less critical as OED'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 OED's planning for appropriate distribution system development by enhancing OED's ability to:

- Monitor physical limits at substation, circuit and transformer levels,
- Identify areas of growing load concentration,
- Discern apparent penetration and deployment patterns of electrification measures based on actual metered load information at the customer level
- Identify developing spatial patterns of load growth that highlight opportunities to target distribution system upgrades that are cost effective, shape efficient system load growth, and further resiliency efforts.

- Develop effective strategies to implement appropriate load management programs including amount of and optimal location of storage facilities, innovate rate designs, and active load control/management programs.

As data from the new AMI/GIS systems becomes available, and detailed patterns of loading on the distribution system become more readily available, the time will be right for OED to commission a full T&D study to take stock of current system conditions and identify/prioritize required improvement projects.

VEGETATION MANAGEMENT/TREE TRIMMING

OED has a very active tree trimming program. It is performed in the springtime as well as in the fall. Line clearing is rotational and typically has a timeline of four to five years. Due to the short length of miles to trim and diligent trimming, the growth never gets ahead of OED. OED performs all of the trimming labor itself. OED trains in-house labor and provides safety measures and equipment to workers. OED does not use herbicides in its trimming program and does not plan to change this policy in the near future. About forty percent of OED's lines need to be trimmed and that number is declining as lines are being moved out to roadside and brush hogs are replacing chainsaws and brush cutters in certain areas. The annual cost of vegetation management is in the range of approximately $15,000 - $40,000. OED spent more than budgeted in recent years due to the high number of danger trees needing to be removed and the large amount of cross-country trimming needing to be done. All lines are trimmed to the edge of the legal right-of-way. The trimming width on either side of the line is twenty-five feet.

In addition to its vegetation and brush management program, OED has a program to identify danger trees. Danger trees are identified by all of our utility personnel while patrolling the lines or inspecting the system. Once a danger tree is identified, it is promptly removed if it is within OED's right-of-way. For danger trees outside of the right-of-way, OED contacts the property owner, explains the hazard, and with the owner's permission removes them. Where permission is not granted, OED will periodically follow up with the property owner to attempt to obtain permission.

The majority of tree species in OED's service territory are conifers, ash, white birch and maple. The emerald ash borer has very recently become an active issue in Orleans County. OED 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 OED's territory, affected trees will be cut down, chipped and properly disposed of.

Table 23: OED Vegetation Trimming Cycles

	Total Miles	Miles Needing Trimming	Trimming Cycle
Sub-Transmission	Approximately 20 miles	1	7-year average cycle
Distribution	Approximately 37-40 miles	15	5-year average cycle

Table 24: OED Vegetation Management Costs

	2019	2020	2021	2023	2024	2025
Amount Budgeted	$25,000	$40,000	$40,000	$30,000	$25,000	$25,000
Amount Spent	$35,000	$36,000	$25,000	Deliberately left blank	Deliberately left blank	Deliberately left blank
Miles Trimmed	3 miles	3 miles	3 miles	3 miles to be trimmed	3 miles to be trimmed	3 miles to be trimmed

Table 25: OED Tree-Related Outages

	2017	2018	2019	2020	2021
Tree Related Outages	0	1	1	1	1
Total Outages	7	8	7	8	7
Tree-related outages as % of total outages	0%	13%	14%	13%	14%

STORM/EMERGENCY PROCEDURES:

OED believes it is beneficial to inform the Department of Public Service if it is experiencing these types of outages. OED participates in www.vtoutages.com. Having compact utility territories has encouraged a strong collaborative mutual aid system between OED, Barton, and VEC. OED has access to local contractors, such as Bemis Line Construction, Energized Line Construction, and Charles Curtis to rely on if a big storm is forecast to hit OED's service territory.

PREVIOUS AND PLANNED T&D STUDIES:

Fuse Coordination Study

OED is so small that a fuse coordination study is not warranted and certainly would not demonstrate least-cost planning.

System Planning and Efficiency Studies

OED has implemented many of the goals and recommendations in the transmission and distribution evaluation. The last T&D study was done in 2001 by Robert Arnold, P.E.

There are no more studies planned at this time.

CAPITAL SPENDING

HISTORICAL CONSTRUCTION COST 2019-2021

Table 26 Orleans Historic Construction Costs 2019-2021

Village of Orleans Electric Department		Historic Construction		
Historic Construction		2019	2020	2021
General 150 Pick-up	Gen	32,757		
Station Equipment	Dist	61,447		
Line Upgrade -South Street	Dist	807		
Line Upgrade-Water and South Street	Dist	1,384		
Line Upgrade -South Street	Dist	195		
Line Upgrades-South Street	Dist	5,967		
Line upgrade- rt 5	Dist	2,070		
Line Upgrade-East Street	Dist	2,259		
Line upgrade - Ingalls Road	Dist	996		
Line Upgrade- Ingalls Drive	Dist	1,949		
upgrade Sub Station Rainbow	Dist	3,831		
Upgrade Line Trasformers Maple Fields	Dist	5,229		
46 kV Transmission Line Upgrade-Rt 14-Rt 58 in Irasburg	Trans	40,193		
Line Upgrade- Himan Settler Road	Dist		1,820	
Line Upgrades-Baxter Lane	Dist		1,588	
Line Upgrade-Water Street	Dist		3,166	
Line Upgrades Water Street	Dist		3,212	
Station Equipment Ethan Allen	Dist		4,179	
Line Upgrades Main Street	Dist		1,507	
Line Upgrade-Church Street	Dist		1,400	
Line Upgrade-Church Street to Rainbow Apt	Dist		917	
Line Upgrade-overhead conductors & Devices	Dist		606	
Station Equipment Rainbow Sub Station	Dist		1,167	
Line Upgrade-River Road	Dist		1,097	
Line Upgrade- River Road Hamel	Dist		991	
Line Upgrade- Main Street General Store	Dist		2,805	
46 kV Transmission Line Upgrade-VELCO Irasburg Sub to Rt14	Trans		-	
General F-250	Gen			35,579
Upgrade-Transformer 72 Main Street	Dist			6,653
Line Upgrades-Old Stone House	Dist			623
Line Upgrade- Hinman Settler Road	Dist			3,751
Line Upgrade- Ethan Allen	Dist			7,176
Line Upgrade- Church Street	Dist			4,013
Line Upgrade- Church Street	Dist			2,039
Line Upgrade- Irasburg Street	Dist			2,547
Line Upgrade- Irasburg Street	Dist			1,099
Line Upgrade- Irasburg Street	Dist			4,389
Line Upgrade- West end Footbridge	Dist			3,277
Line Upgrade- Hinman Settler Road	Dist			2,902
Line Upgrade-overhead conductors & Devices South Street	Dist			3,299
46 kV Transmission Line Upgrade-Burton Hill in Irasburg Complete	Trans			165,550
Total Construction		$ 159,086	$ 24,455	$ 242,898
Functional Summary:				
Prod		$ -	$ -	$ -
General		$ 32,757	$ -	$ 35,579
Distribution		$ 86,135	$ 24,455	$ 41,769
Transmission		$ 40,193	$ -	$ 165,550
Total Construction		$ 159,086	$ 24,455	$ 242,898

Projected Construction Costs 2023-2025

Table 27 Orleans Projected Construction Costs 2023-2025

Village of Orleans Electric Department		Projected Construction		
Projected Construction		2023	2024	2025
AMI	Gen	100,000		
Upgrade Part of Browington	Dist	25,000		
EA Rough Mill Service	Dist	5,000		
East Street rebuild	Dist		30,000	
EA Finish Mill Service	Dist		10,000	
Upgrade more line in Brownington	Dist		25,000	
Oil Containment Healt Sub	Trans		15,000	
Orleans East Voltage Conversion	Dist			120,000
Total Construction		$ 130,000	$ 80,000	$ 120,000
Functional Summary:				
Prod		-	-	-
General		100,000	30,000	-
Distribution		30,000	35,000	120,000
Transmission		-	15,000	-
Total Construction		130,000	80,000	120,000

V. FINANCIAL ANALYSIS

This section quantifies the costs of a Reference Case and a series of procurement scenarios that would fulfill RES 1.0 and RES 2.0 requirements as discussed in the Resource Plans chapter. It also includes a storage-only procurement to illustrate the cost saving potential of a MW-scale, peak-shaving battery. The characteristics of these scenarios are summarized in Table 28.

Table 28: Scenarios

#	Resource Scenario	Description	Size	Price
0	Reference Case	Monthly Market Energy & Annual REC-Only PPAs	N/A	Monthly DALMP
1.1	RES 1.0 - Extend Brookfield to 2032	Firm ATC Hydro Energy + Tier I REC PPA (2023-2042)	1 MW ATC	$95/MWH Levelized
1.2	RES 1.0 – Extend Howard Wind to 2032	NYISO Wind	2 MW	$98.50/MWH Levelized
1.3	RES 1.0 - Solar PPA in 2028	Solar	1 MW	$90/MWH Levelized
1.4	Hydro + Wind + Solar to 2032	All In		
2	RES 2.0 Requirements	Monthly Market Energy & Annual REC-Only PPAs		Monthly DALMP
2.1	RES 2.0 - Extend Brookfield to 2032	Firm ATC Hydro Energy + Tier I REC PPA (2023-2042)	1 MW ATC	$95/MWH Levelized
2.2	RES 2.0 – Extend Howard Wind to 2032	NYISO Wind	1 MW	$98.50/MWH Levelized
2.3	RES 2.0 - Solar PPA in 2028	Solar	1.8 MW	$90/MWH Levelized
2.4	Hydro + Wind + Solar to 2032	All In		
3	Storage		2 MW, 6 MWH	$15/kW-Month Levelized

The sizes and terms were chosen to align with RES requirements, and the pricing is levelized to enable easier comparisons between the scenarios. Levelized pricing is also a very common way to structure a PPA.

The hydro PPAs are priced using current energy market prices, plus an assumption that long-term Tier I RECs would cost $10/MWH. This reflects the current state of the REC market but could be on the high-side of the long-term range.

Howard Wind pricing is based on inflation and simply escalates the current contract price. The solar PPA is priced at $90/MWH levelized, which is in alignment with VPPSA's recent solar PPA's. Finally, storage is priced at $15/kW-month, which is a lower than recent values due to the passage of the Inflation Reduction Act (IRA).

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 slightly-higher-than-inflationary rate, which reflects not only the underlying assumptions for energy and capacity prices but also the cost of retiring increasing amounts of RECs under the RES statute. Transmission charges are growing more quickly because this has been the trend over the past decade. Administrative costs grow more slowly, and the load itself grows at 0.6% per year after accounting for electrification trends. Finally, the coverage ratio drops as contracts expire.

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

Cost Item	2022	2027	2032	2037	2042	CAGR
Net Resource and Load Charges & Credits	$0.89	$1.12	$1.74	$1.97	$2.16	4.5%
Transmission Charges	$0.33	$0.44	$0.62	$0.88	$1.24	6.8%
Administrative and Other Charges & Credits	$0.04	$0.04	$0.05	$0.05	$0.06	2.0%
Total Charges	$1.26	$1.60	$2.40	$2.89	$3.46	5.2%
Total Load - Including Losses (MWH)	13,612	13,810	14,337	15,028	15,335	0.6%
Coverage Ratio	114%	99%	10%	7%	6%	

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

To stabilize transmission costs, a fixed-price peak-shaving storage resource is being studied. The system is presently sized at 2 MW and 6 MWH, and the contract is structured to guarantee a 90% or greater peak shaving accuracy. At these levels of accuracy, there is an opportunity to stabilize transmission costs by managing peak loads with storage. The next section quantifies the relative cost of each procurement scenario.

PROCUREMENT SCENARIOS

Table 30 shows the present value of the 20-year revenue requirement (PVRR) for the Reference Case and for the RES 2.0 scenario. Notice that the PVRR increases by about $0.8 million dollars or 2% under the RES 2.0 requirements. This is due to the increased cost of procuring Tier I and Tier II RECs. It is also influenced by increasing Tier III requirements, which are assumed to rise to support the electrification trends that are built into the load forecast.

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

#	Procurement Scenario	PVRR	Unit	% Change
0	Reference Case	$40.4	PVRR	
1	RES 1.0 - Extend Brookfield to 2032	($0.0)	Chg. from Ref. Case	-0.1%
1.1	RES 1.0 – Extend Howard Wind to 2032	($0.8)	Chg. from Ref. Case	-2.1%
1.2	RES 1.0 - Tier II with Solar in 2028	($0.1)	Chg. from Ref. Case	-0.3%
1.3	Hydro + Wind + Solar to 2032	($1.0)	Chg. from Ref. Case	-2.5%
2	RES 2.0 Requirements	$41.2	PVRR	2.1%
2.1	RES 2.0 – Brookfield Hydro	($0.0)	Chg. from RES 2.0 Req.	-0.1%
2.2	RES 2.0 – Howard Wind	($0.0)	Chg. from RES 2.0 Req.	-0.1%
2.3	RES 2.0 - Tier II Solar PPA	($0.4)	Chg. from RES 2.0 Req.	-0.9%
2.4	RES 2.0 – Hydro + Wind + Solar	($0.5)	Chg. from RES 2.0 Req.	-1.2%
3	Storage	($2.0)	Chg. from Ref. Case	-5.0%

Because the Brookfield contract extension is priced at market prices, its impact on the PVRR is negligible. However, there are cost savings that can be attributed to extending the Howard Wind contract because its price is linked to NYISO prices, which are lower than ISO-NE prices. Finally, solar energy is economic given today's market prices, and it can be expected to create cost savings for OED as well. Combining these three resources sums up the savings from each resource. The largest cost savings is expected from storage, and is dependent on a continuation of transmission rate inflation and the cost of storage itself.

STORAGE

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

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

Inflation and supply chain challenges have undoubtedly increased the cost of storage since the RFP was conducted, but the recently passed Inflation Reduction Act (IRA) is expected to counter this trend. If OED were to sign a Battery Energy Storage Service Agreement (BESS) at the following prices, the cost to OED would be between $288,000 and $432,000 per year.

Figure 24: Annual Cost of a 2 MW AC Battery ($/Year)

($/kW-mo)	2 MW AC
$12.00	$288,000
$15.00	$360,000
$18.00	$432,000

To determine the value of a peak shaving battery, VPPSA modeled the avoided cost of capacity and ISO transmission. Because our storage partner is offering a performance guarantee that ensures 90% accuracy of operating the battery during peak hours, we assumed a 90% success rate for shaving the monthly and annual peaks. Based on a Monte Carlo analysis of 1,000 different randomly generated results, the value of a peak shaving battery averaged $24.50/kW-month (levelized) between 2023 and 2042. As a result, any BESS agreement that is priced less than this should generate net present value and reduce costs over the life of the agreement. Specifically, a BESS agreement for $18/kW-month would be expected to reduce annual costs by $150,000 and PVRR by $2,000,000.

CONCLUSIONS

The financial analysis can be summarized by three primary points. First, costs can be minimized by importing wind from NYISO. However, the more intermittent wind that is added, the wider the range of power supply costs will be. As a result, it makes sense to use firm hydro resources to compliment (and stabilize) the costs of the portfolio.

Second, RES 2.0 requirements will increase costs by about 2.1% as measured by the PVRR. Third, peak shaving storage represents an opportunity to reduce costs by mitigating the increasing cost of transmission.

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

ACTION PLAN

VI. ACTION PLAN

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

- Automated Metering Infrastructure (AMI)
  - Pursue implementation of an AMI system as reflected in the recent RFP within the 2022-2024 time frame.

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

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

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

- Tier II Actions
  - Complete a 1-1.8 MW solar project.
  - Make forward purchases, both short and long-term, of qualifying RECs on the regional market to manage REC price and ACP risk.
  - If Tier II requirements increase, develop another in-state solar project and size the procurement of energy and Tier I resources to accommodate it.

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

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

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

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

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

APPENDIX

APPENDIX A: 2022 TIER 3 ANNUAL PLAN

This appendix is provided separately in a file named:

Appendix A - VPPSA Tier 3 2022 Annual Plan.pdf

APPENDIX B: PRICING METHODOLOGY

This appendix is provided separately in a file named:

Appendix B – OED Energy & Capacity Pricing Methodolgy.pdf

APPENDIX C: PUC RULE 4.900 OUTAGE REPORTS

This appendix is provided separately in a file named:

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

APPENDIX D: AMI RFI TECHNICAL REQUIREMENTS

This appendix is provided separately in a file named:

Appendix D – AMI_RFI_Technical_Requirements.pdf

APPENDIX E: AMI RFP TECHNICAL REQUIREMENTS

This appendix is provided separately in a file named:

Appendix E – AMI_RFP_Technical_Requirements.pdf

APPENDIX F: ITRON'S LOAD FORECAST REPORT

This appendix is provided separately in a file named:

Appendix F – Orleans IRP22 Demand Report.pdf

APPENDIX G: TIER III LIFE-CYCLE COST ANALYSIS

This appendix is provided separately in a file named:

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

APPENDIX H: NVDA REGIONAL ENERGY PLAN

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

GLOSSARY

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

kVA	Kilovolt Amperes
kW	Kilowatt
kWh	Kilowatt-hour
LIDAR	Light Detection and Ranging
LIHI	Low Impact Hydro Institute
LMP	Locational Marginal Price
LRTP	Long Range Transmission Plan
MAPE	Mean Absolute Percent Error
MSA	Master Supply Agreement
ME II	Maine Class II (RECs)
MEAV	Municipal Association of Vermont
MDMS	Meter Data Management System
MSA	Master Supply Agreement
MVA	Megavolt Ampere
MW	Megawatt
MWH	Megawatt-hour
NEPPA	Northeast Public Power Association
NESC	National Electrical Safety Code
NJUNS	National Joint Utilities Notification System
NOAA	National Oceanic and Atmospheric Administration
NU	Norwich University
NYPA	New York Power Authority
NVDA	Northeastern Vermont Development Association
OED	Orleans Electric Department
PFP	Pay for Performance
PUC	Public Utility Commission
PPA	Power Purchase Agreement
PVRR	Present Value of Revenue Requirement
R^2	R-squared
REC	Renewable Energy Credit
RES	Renewable Energy Standard
ROW	Right-of-way
RTLO	Real-Time Load Obligation
SAE	Statistically Adjusted End Use
SAIFI	System Average Interruption Frequency Index

SCADA	Supervisory Control and Data Acquisition
SQRP	Service Quality & Reliability Performance, Monitoring & Reporting Plan
TAG	Technical Advisory Group
TIER I	Total Renewable Energy (Tier I)
TIER II	Distributed Renewable Energy (Tier II)
TIER III	Energy Transformation (Tier III)
TOU	Time-Of-Use (Rate)
VEC	Vermont Electric Cooperative
VELCO	Vermont Electric Power Company
VEPPI	Vermont Electric Power Producers, Inc.
VFD	Variable Frequency Drive
VSPC	Vermont System Planning Committee
VT ANR	Vermont Agency of Natural Resources
VTrans	Vermont Agency of Transportation
WQC	Water Quality Certificate

Vermont Public Power Supply Authority

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Vermont Public Power Supply Authority
2022 Tier 3 Annual Plan

In accordance with the Public Utility Commission ("PUC") Rule 4.400, Vermont Public Power Supply Authority ("VPPSA") is filing this Annual Plan describing its proposed 2022 Energy Transformation programs. 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 3") projects or purchase additional Renewable Energy Credits ("RECs") from new, small, distributed renewable generators ("Tier 2").

VPPSA's Requirement

Utilities' Tier 3 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.[1]" Tier 3 requirements increase by .67% annually.

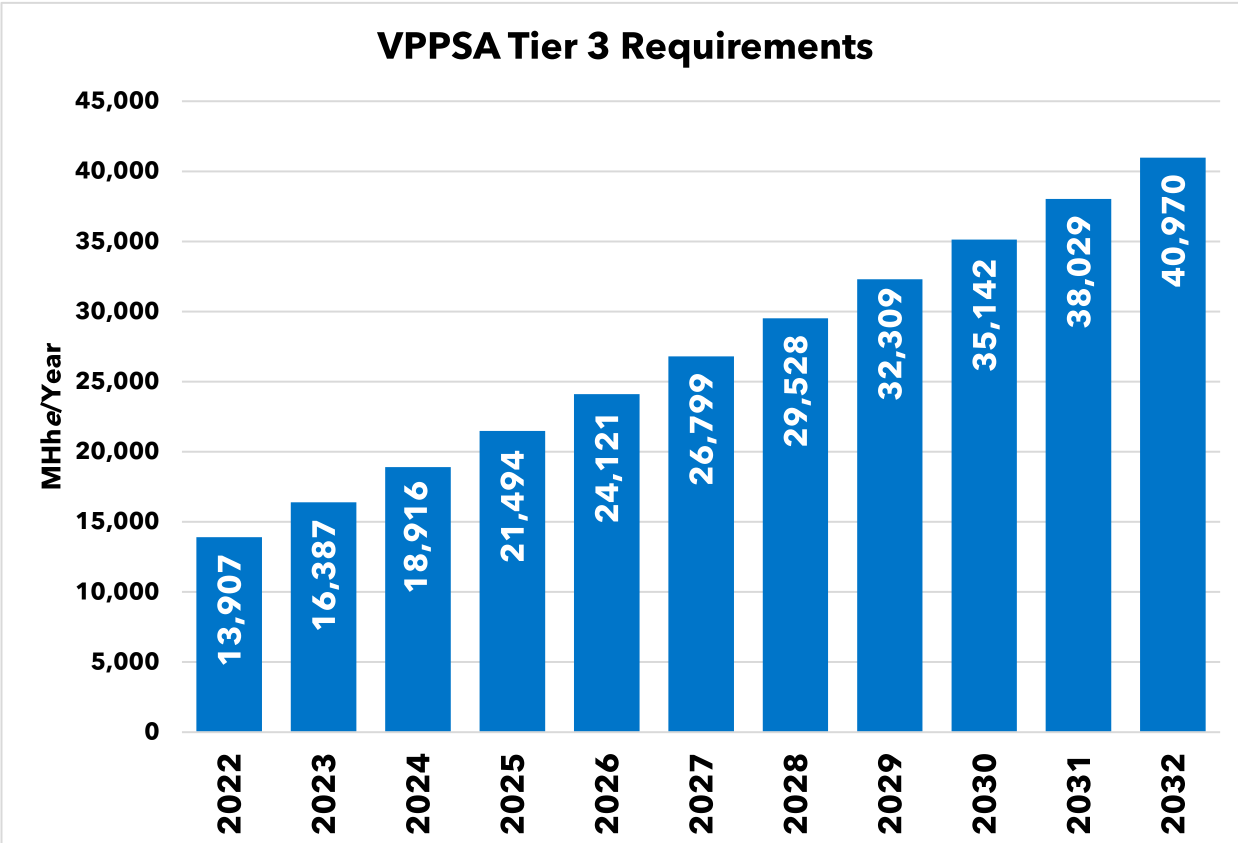
In 2022, VPPSA's aggregate requirement is estimated to be 13,907 MWh equivalent in savings, representing 4% of annual retail sales. The 11 VPPSA member utilities plan to meet their Tier 3 requirements in aggregate, as permitted under 30 V.S.A. § 8004 (e), which states "[i]n the case of members of the Vermont Public Power Supply Authority, the requirements of this chapter may be met in the aggregate."

VPPSA Members:

- **Barton Village**
- **The Village of Enosburg Falls**
- **Hardwick Electric Department**
- **Village of Jacksonville**
- **Village of Johnson**
- **Ludlow Electric Light Department**
- **Lyndonville Electric Department**
- **Morrisville Water & Light**
- **Northfield Electric Department**
- **Village of Orleans**
- **Swanton Village**

[1] 30 V.S.A. § 8005(a)(3)(B)

The below chart represents VPPSA's projected annual MWh equivalent in savings through 2032.



Summary of 2021 Projects

VPPSA expects to meet its 2021 Tier 3 requirements of approximately 11,605 MWh through a combination of prescriptive and custom measures. Prescriptive measures included post-purchase rebates or instant discounts for:

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

Of the prescriptive rebates offered, cold climate heat pumps have had the greatest uptake. VPPSA's strategy continues to focus on cost-effective prescriptive and custom Tier 3 measures. VPPSA continues to observe that while custom measures have a longer ramp-up time and larger up-front incentives, their overall cost per MWh is lower than both prescriptive incentives and Tier 2 RECs. Custom projects include incentives for line extensions and service upgrades that removed the need for diesel generators. Several custom projects were identified in 2021 but likely will not be completed until 2022 or later.

2022 Program Overview

VPPSA proposes meeting 2022 Tier 3 requirements in a manner that mitigates costs that could put upward pressure on electric rates. This includes a combination of prescriptive and custom measures and use of Tier 2 RECs if needed. The focus of VPPSA's offerings is on electrification measures that will benefit all ratepayers by bringing in additional revenue to the host utilities.

Prescriptive Measures

VPPSA intends to maintain its current portfolio of prescriptive measure offerings with a few additions. Savings are calculated using measure characterizations created by the Tier 3 Technical Advisory Group ("TAG.")

Electric Vehicles and Plug-In Hybrids

VPPSA will continue to offer customer incentives for the purchase or lease of EVs and PHEVs in 2022. The customer incentive for purchasing or leasing a new electric vehicle will be $1000 and the customer incentive for purchasing or leasing a new plug-in hybrid electric vehicle will be $500. Low-income customers[2] will receive an additional $400 towards the purchase or lease of an EV or PHEV.

VPPSA plans to continue incentives for purchasing used EVs and PHEVs. The customer incentive will be $500 for the purchase of a used EV and $250 for the purchase of a used PHEV.

Upfront cost has been identified as a major barrier to purchasing an electric vehicle. Beginning July 1, 2021, VPPSA piloted a point-of-sale incentive with two auto dealerships: Burlington Cars and Lamoille Valley Chevrolet. These dealerships were chosen due to their willingness to participate in a pilot and their proximity to VPPSA members.

VPPSA has chosen to expand this approach in 2022. VPPSA is currently engaging with vehicle dealerships around the state to offer a point-of-sale incentive. Customers who

[2] According to Rule 4.413, "A low-income customer shall be defined as a customer whose household income is at or below 80% of Vermont statewide median income."

purchase or lease a vehicle from a participating dealership will receive their incentive as an instant discount. The dealership will then submit to VPPSA for reimbursement.

Should an eligible customer purchase or lease a vehicle from a non-participating dealership, the option will still be available to receive a post-purchase rebate.

Electric Vehicle Charging

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

VPPSA is planning an EV Charging pilot for 2022 in conjunction with Efficiency Vermont ("EVT"). The pilot will provide free Level 2 charging equipment to some residential utility customers who purchase electric vehicles. The chargers that are provided will be equipped with Open Charge Point Protocol ("OCPP") meaning that they can be integrated with multiple control platforms through open-source technology. These EV chargers will initially be programmed to provide charging during off-peak hours and will facilitate direct control of EV charging in the future. This pilot will be offered in a subset of the VPPSA members' service territories in which VPPSA and EVT are conducting tailored programs in 2022.

Cold Climate Heat Pumps

VPPSA will continue to offer incentives on ductless and whole building heat pump technology. Efficiency Vermont will continue to administer point-of-sale heat pump incentives on VPPSA's behalf.

Ductless Heat Pumps:

VPPSA began offering downstream, post-purchase incentives for ductless heat pumps in 2019. Upon installation the customer would complete the rebate form, submit the application and supporting documents to VPPSA, and receive a check in the mail upon approval.

VPPSA collaborated with Efficiency Vermont and other Vermont distribution utilities to change the administration of the heat pump incentive beginning January 2021. In 2022, Efficiency Vermont will continue to administer the ductless heat pump incentive as an instant discount at the point-of-sale. The $250 utility incentive will be applied when a customer works through a participating contractor or distributor. Efficiency Vermont will batch the incentives applied in VPPSA member territories and invoice VPPSA monthly for reimbursement. VPPSA expects a similar volume of ductless heat pump incentives to what was offered in 2021.

VPPSA is also engaged in discussions with Efficiency Vermont and other Vermont electric utilities around the potential to offer ductless heat pumps to income-qualifying households at no cost to the utility customer. These incentives would be offered in tandem with weatherization services provided through the Weatherization Assistance Program ("WAP") to income eligible customers. The cost of the heat pumps will be split 50-50 between the distribution utilities and Efficiency Vermont through use of Act 151 funds. Consistent with the requirements of Act 151, the distribution utilities will claim the entire thermal savings for these CCHPs and EVT will claim the electric savings. This pilot envisions providing ductless CCHP to 150 Vermont households and VPPSA anticipates 11 of these will be installed in its member utility territories in 2022. Conversations with Efficiency Vermont and the WAPs are ongoing.

VPPSA will also be participating in an Efficiency Vermont pilot to promote integrated controls that are installed to ensure customers' ductless CCHPs are working efficiently with the buildings' central heating systems and thermostats. This is a downstream rebate offering up to $600 for integrated controls. VPPSA will fund $400 of this incentive and claim the thermal savings resulting from more efficient operations of the CCHP and central system. Efficiency Vermont has developed a custom savings tool to evaluate the electric and thermal savings values attributable to integrated controls and this tool will be shared with the Department of Public Service ("Department") in order to verify Tier 3 savings.

Whole Building Heat Pumps:
VPPSA will continue to offer incentives on centrally ducted heat pumps and air-to-water heat pumps. Beginning January 1, 2022, VPPSA will offer prescribed custom incentives for ground source heat pumps. Efficiency Vermont administers all whole building heat pump incentives on behalf of VPPSA and several other Vermont utilities.

The centrally ducted heat pump incentive will continue to be offered as an instant discount at the point-of-sale. The incentive amount ranges from $750 – $1,500 depending on the size of the heat pump.

Efficiency Vermont will continue to administer the post-purchase rebate available for air-to-water heat pumps. In most cases, VPPSA and Efficiency Vermont will each offer 50% of the $1,000/ton incentive and claim 50% of the thermal savings. When an air-to-water heat pump is installed in VGS territory, VPPSA will offer the full incentive and claim the full savings. This is equivalent to how the incentive was managed in 2021.

VPPSA will offer the statewide ground source heat pump ("GSHP") incentive beginning in 2022. The incentive offered will be $2,100/ton. Because ground source heat pumps are not characterized by the TAG, VPPSA is approaching these incentives on a prescribed custom basis. The incentive offering will remain constant at $2,100/ton while savings will be calculated using a tool developed by Efficiency Vermont that has been shared with the Department through the TAG.

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

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

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

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

Heat Pump Water Heaters

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

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

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

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

Forklifts

VPPSA continues to offer a $2,500 rebate incentive for customers that purchase a new electric forklift.

Golf Carts

VPPSA continues to offer a $100 rebate incentive for customers that purchase new electric golf carts.

Lawn Mowers

VPPSA will continue to offer both commercial and residential lawn mower incentives. The rebate for a residential lawn mower will continue to be $50. VPPSA will continue to offer a $1,000 incentive for commercial lawn mowers in 2022.

E-Bikes

VPPSA will continue to offer a rebate incentive of $100 for the purchase of a new e-bike or e-bike conversion kit.

Residential Yard Care

VPPSA introduced several new incentives in July 2021 through an amendment to the 2021 Annual Plan. The following rebates were added in 2021 and will be continued in 2022.

Leaf Blowers:

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

Trimmers:

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

Chainsaws:

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

Custom Measures

Commercial and industrial ("C&I") customers will continue to be served on an individual, custom basis in 2022. VPPSA continues to explore cost-effective Tier 3 custom projects. Identified custom projects with estimated completion in 2022 include electric buses, commercial heat pump units for a new-construction multifamily unit, electric bucket trucks, and an industrial heat recapture project.

Due to the relatively lower cost of MWh savings from custom projects, VPPSA continues to focus on identifying opportunities and working with utility customers to engage in energy transformation. VPPSA has launched a Key Accounts program that will better enable identification of custom projects with C&I customers. Additionally, VPPSA continues to partner with Efficiency Vermont to identify C&I customers that have potential Tier 3 and electric efficiency projects. Incentives for custom measures are typically paid for by the host utility rather than through VPPSA, with the host utility retaining the associated Tier 3 credits. Upon approval of the VPPSA Board of Directors, VPPSA may fund custom projects through its Tier 3 budget and allocate the Tier 3 savings among its members.

VPPSA is currently partnering with WexEnergy to pilot their new product, WindowSkins. WexEnergy was a participant in the 2020 DeltaClime business accelerator program, which VPPSA sponsors. VPPSA staff mentored DeltaClime participants throughout the accelerator program as they pitched their innovative products designed to minimize heat loss through windows. The pilot program involves testing the WindowSkin product in municipal buildings and one industrial customer through the 2021/2022 heating season. The WindowSkins should assist the municipalities and industrial customer in lowering the amount of fossil fuel used to heat their buildings and meet internal energy goals.

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

Tier 2 RECs

To the extent that there is a shortfall in savings from the prescriptive and custom measures, VPPSA may utilize excess Tier 2 RECs from its growing solar project portfolio and/or purchase Tier 2 RECs when prices are low as a hedge against a deficit in savings from Tier 3 programs. To the extent that Tier 2 RECs are less expensive than implementing Tier 3 programs, VPPSA may exercise this strategy to benefit its members. For VPPSA members that own Tier 2 eligible generating resources, Tier 2 RECs may be the primary strategy for Tier 3 compliance.

VPPSA is managing member Tier 3 compliance in a manner that meets statutory requirements while minimizing overall costs through a portfolio of prescriptive programs, custom projects, and Tier 2 RECs. Under this approach the Tier 2 REC price acts as a not-to-exceed per unit budgetary target when developing prescriptive and custom rebate offerings. Should Tier 2 REC prices increase, VPPSA will reevaluate its incentive levels and potentially increase the rebate value. In that situation, VPPSA would file a revised Tier 3 planning document.

Best Practices and Minimum Standards

Over the long-term, Tier 3 programs have the potential to significantly increase loads for Vermont utilities. VPPSA members have identified that their systems remain robust, and the expected growth in annual and local peak demand associated with proposed measures can generally be sustained if monitored and deployed carefully.

VPPSA's most recent, Commission-approved IRP used the same underlying assumptions as VELCO's Long-Range Transmission Plan ("LRP"). As a result, they incorporate the State's latest outlook for EVs and CCHPs. These technology trends are still nascent and are significant inputs to the load forecast. However, according to the IRP load forecast analysis, they are not likely to cause any major deviations to the IRP, either this year or in the next three years.

VPPSA continues to monitor COVID-related load impacts, as well as the potential impacts of large, custom Tier 3 projects. To date, VPPSA has not identified any major deviations from its IRP load forecasts, especially in light of the high and low forecast cases that were analyzed in the IRPs.

VPPSA has established a partnership with Virtual Peaker, allowing us to assist our members in demand-response programming. In 2022, VPPSA will continue to use the platform for an internal utility behavioral demand-response program to strategically maximize load-reducing generation during high-cost time periods.

VPPSA's memorandum of understanding ("MOU") with Efficiency Vermont, which the PUC approved under Case 19-3272, continues through 2023. The VPPSA/Efficiency Vermont MOU includes the potential for an active demand response pilot. The utility economics of active load control remain a challenge, and involvement from Efficiency Vermont could help lower utility costs. VPPSA and Efficiency Vermont are in the early stages of discussing a load management program that would enable VPPSA member utilities to control multiple technologies through one integrated platform in order to overcome the cost barriers of utilizing distinct, proprietary platforms to manage each technology (e.g. EV chargers, CCHP, smart thermostats.) The OCPP pilot discussed above is a component of this demand management strategy and will mitigate the grid impacts of EV charging.

As discussed in the CCHP section of this plan, VPPSA is partnering with EVT on a pilot to promote integrated controls for CCHP. This pilot is expected to increase the fossil fuel savings from CCHP installations through more efficient integration with the buildings' central heating systems. This technology will also lay the groundwork for future load management of CCHP electric demand.

In addition, VPPSA is pursuing utility-scale storage as a cost-effective means of achieving demand reductions for its members. A Request for Proposals to install storage facilities sized between 100 kW and 4.9 MW within the VPPSA member utilities' service territories was issued in October 2020 and VPPSA has narrowed the selection down to a final vendor.

Finally, as noted in the discussion on prescriptive rebates, VPPSA provides an additional $200 heat pump incentive for units that are installed in weatherized buildings as a mechanism to encourage the installation of heat pumps in buildings that meet established performance standards.

Equitable Opportunity

VPPSA strives to ensure that Tier 3 programs are accessible and beneficial to all customers regardless of income level or rate class. The Tier 3 incentives described in the Plan will be available to all VPPSA member utility customers. Commercial and Industrial customers have the ability to access VPPSA's prescriptive measures and are also served through custom incentives.

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

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

Financing is another tool that can be used to make Tier 3 measures accessible to customers. VPPSA is co-chairing an Energy Action Network subgroup to develop an on-bill tariff efficiency program through which customers could pay for their efficiency and Tier 3 measures on their electric bill. This program, which is being financed by Vermont Housing Finance Agency, will include robust incentives to low-income customers. The program is being structured such that participating customers' total monthly energy costs, including the on-bill tariff payment, will be the same or lower after making the efficiency upgrades than they were previously. This "revenue neutrality" is seen as a critical element for reaching lower income households.

In compliance with Rule 4.413 VPPSA tracks and reports Tier 3 participation, spending, and benefits by Customer sector (residential, commercial and industrial, and low-income) each year. Participation and spending are monitored and reviewed each year to inform program planning for future years.

Finally, VPPSA's Tier 3 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 3 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 3 programs and cost-shifting among customers is minimized.

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

Consistent with Commission Rule 4.413 (c), VPPSA tracks and reports Tier 3 participation, spending, and benefits by Customer sector (residential, commercial and industrial, and low-income) each year. This data is included in VPPSA's Tier 3 savings filed in March and RES Compliance Filing in August. Over the life of the RES, VPPSA intends to provide equitable opportunities to its customer sectors in rough proportion to each customer sector's annual retail sales.

Partnership, Collaboration, and Marketing

VPPSA plans to continue actively working with both public and private partners to execute our Tier 3 plan in the most cost-effective way.

VPPSA continues to administer the VTrans income-qualifying electric vehicle incentive. The VTrans incentive is offered on the sale of any electric vehicle registered in Vermont. The value of the VTrans incentive is dependent upon the owner's household income level. Participating car dealers sell vehicles at a price reduced by the statewide incentive for eligible customers. Each dealer then submits the customer's information and vehicle details to VPPSA. VPPSA batches the incentives each month and sends the information to VTrans with a summary report and invoice. VTrans will pay VPPSA for the state incentive, which VPPSA will then remit to the dealer. In 2021 there was an increase in uptake of the income-qualifying VPPSA electric vehicle incentive.

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

Under the MOU structure, VPPSA and Efficiency Vermont will implement tailored efforts in three VPPSA member communities each year of EVT's current performance period (2021-2023.) Morrisville Water & Light, Lyndonville Electric Department, and Hardwick Electric Department have been identified for 2022 Tailored Efforts. Additionally, as previously mentioned, VPPSA and Efficiency Vermont plan to partner on load management pilots.

VPPSA continues to take on a greater role in utility customer interaction. Historically, the individual VPPSA member utilities were responsible for customer outreach. With the addition of Tier 3 projects, VPPSA will educate utility customers on the available incentives through use of the following:

- VPPSA member utility bill stuffers
- VPPSA member utility staff training
- VPPSA website
- VPPSA member utility websites
- Social media
- Front Porch Forum
- Collaborative events and workshops

- Car dealer outreach
- EVT contractor and distributor outreach
- Direct outreach to Key Account customers

Cost-Effectiveness

VPPSA's Tier 3 planning included consideration of the suite of measures in the 2022 Tier 3 Planning Tool developed by the TAG, including those measures that do not increase electric consumption. Specifically, VPPSA analyzed the inclusion of wood pellet stoves for 2022. This measure would have been delivered in conjunction with Efficiency Vermont and necessitated a 50/50 split of the thermal savings. The incentive and Tier 3 savings values for pellet stoves are included in the table below. Ultimately VPPSA decided not to include pellet stoves as a measure in 2022 because projections of electrification measures show that VPPSA's entire Tier 3 requirement is likely to be met through existing prescriptive programs. As described in the Equitable Opportunity section above, VPPSA's Tier 3 strategy prioritizes electrification measures that have the potential to bring financial benefits to all customers. VPPSA will re-visit the inclusion of pellet stoves in future Tier 3 planning cycles.

Measure	Incentive	MWh	Cost/MWh
Residential Pellet Stoves, Existing Home	$225.00	90.05	$2.50
Residential Pellet Stoves, New Construction	$225.00	40.46	$5.56

VPPSA has completed lifecycle cost analysis for its Tier 3 measures. Cost-effectiveness was evaluated based on both the Utility Cost Test ("UTC") and Societal Cost Test ("SCT"). Lifetime utility net costs are presented in the Summary Table of the Tier 3 Reporting template that accompanies this plan. Results of the SCT analysis are presented below. In future years, lifecycle analysis of VPPSA's Tier 3 programs will be included in the VPPSA members' Integrated Resource Plans.

Measure	Budgeted Incentive	Incremental Cost	Life (Years)
EV	$1,022	$15,708	8
PHEV	$650	$7,301	8
CCHP	$381	$3,293	15
WBHP	$1,535	$10,159	18

Utility Cost Test	Societal Cost Test
0.9	0.5
0.9	0.8
1.1	1.6
1.0	1.1

- EV
  - Both the UCT and the SCT are less than one.

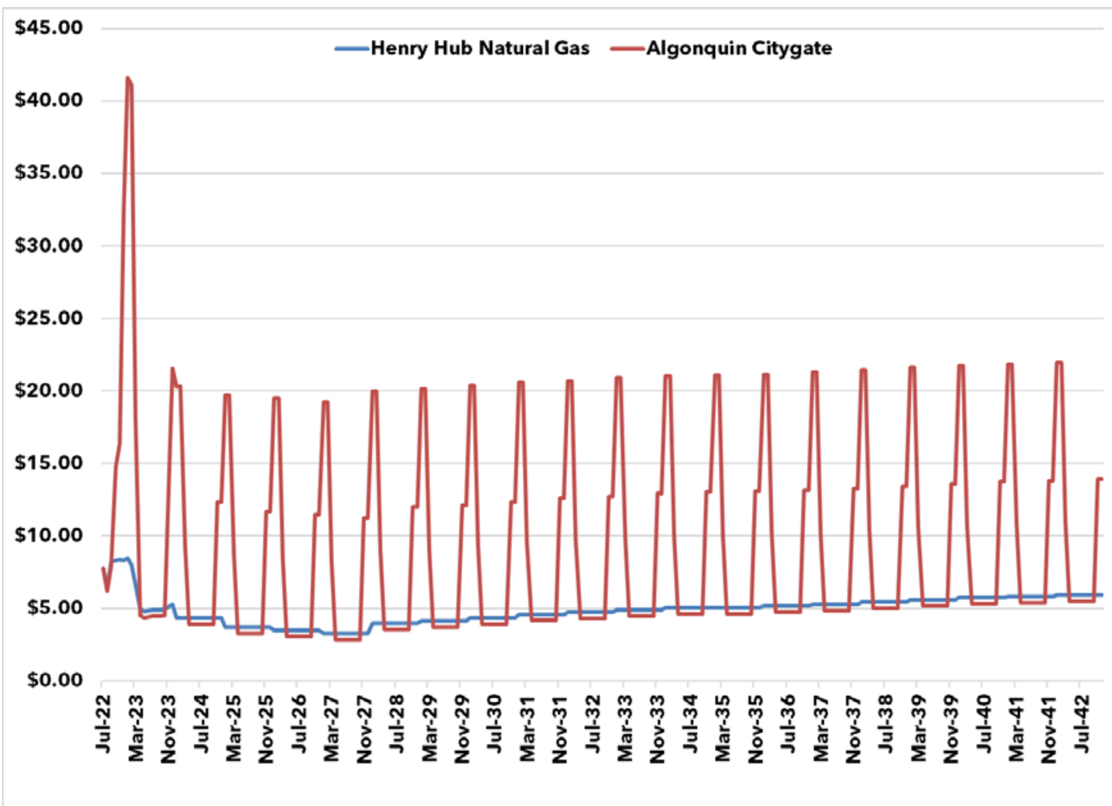
    - This is due to a combination of a relatively high incremental cost and a relatively short measure life.
- PHEV
    - Both the UCT and the SCT are less than one.
    - This is due to a combination of a relatively high incremental cost and a relatively short measure life.
- CCHP
    - Both the UCT and the SCT are greater than one.
    - This is due to a combination of a relatively low incremental costs and a relatively long measure life.
- WBHP
    - Both the UCT and the SCT are greater than one.
    - Incremental costs are relatively high for this measure, but the long measure life offsets it.
- Assumptions
    - Incentive levels match the VPPSA Tier III Budget.
    - Incremental costs and measure lives match the Tier III Planning Tool for 2022.
    - Seasonal on and off-peak load shapes (MWH and MW) are based on a combination of Itron, Cadmus and TAG working documents. Total MWH match the Tier III Planning Tool.
    - Avoided Costs for wholesale energy, capacity, transmission and RECs align with VPPSA's 2022 power budgeting assumptions.
    - Avoided fuels and carbon costs are from the AESC 2021 report.
    - The methods for calculating the UCT and SCT are from the EPA's National Action Plan for Energy Efficiency, 2009.

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.

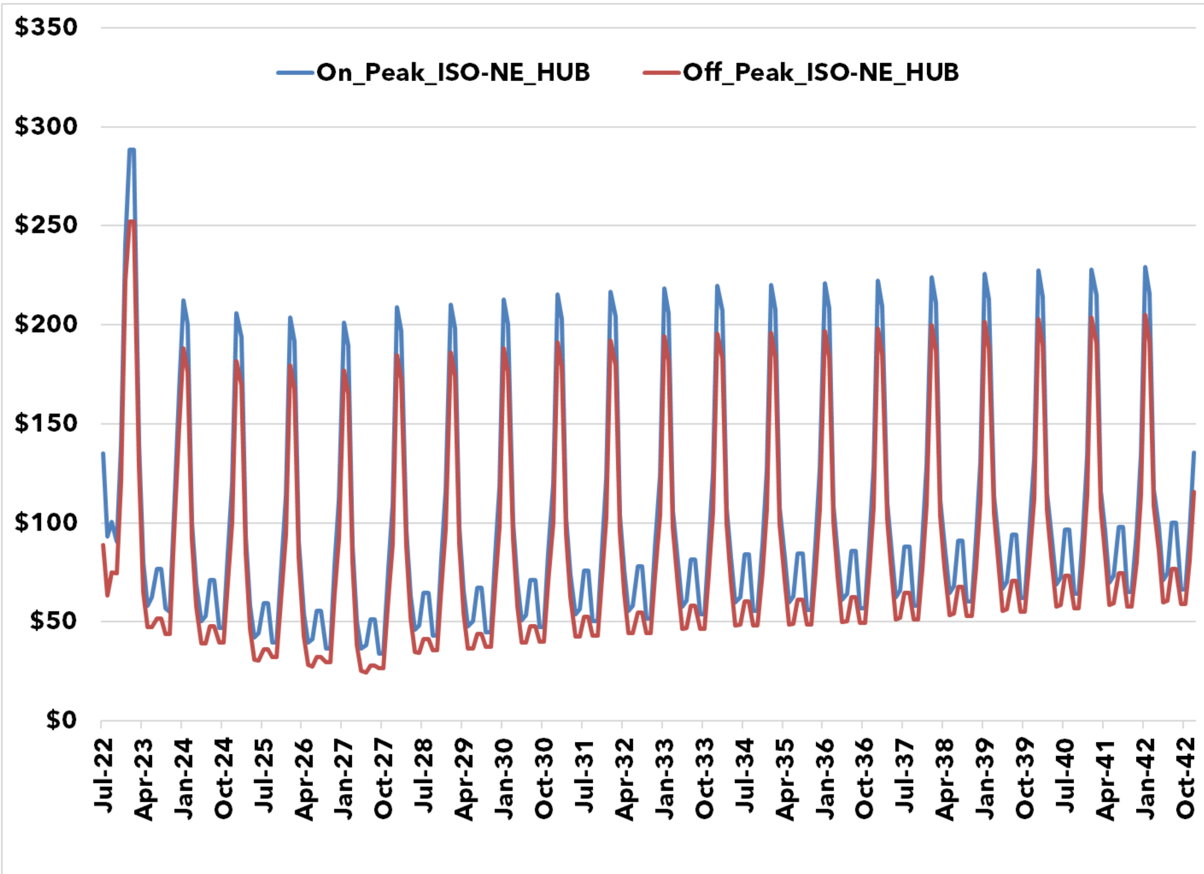
Figure 1: Henry Hub Natural Gas Price Forecast (Nominal $/MMBtu)



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)

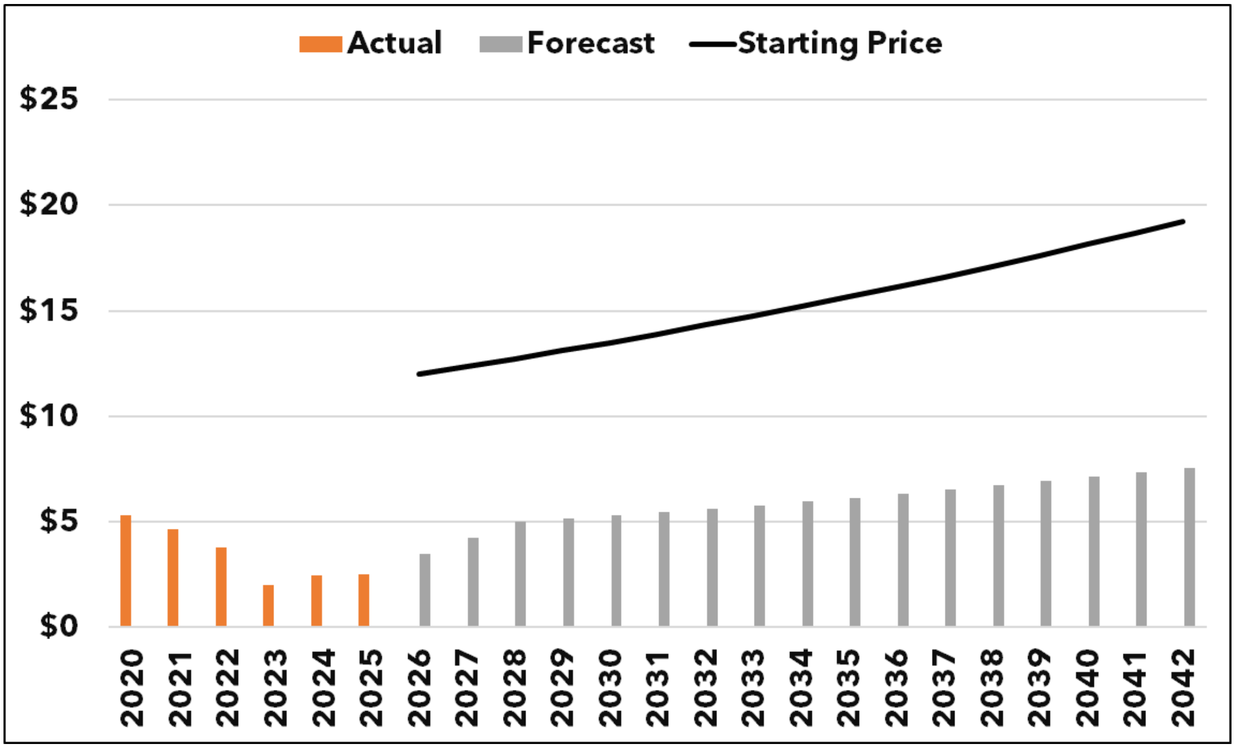


In keeping with the function of ISO-NE's Standard Market Design, we use a five-year average basis between Locational Marginal Price (LMP) nodes to adjust the price forecast at the MA Hub to the location of OED's load and resources.

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)



Orleans Electric Department

2017

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	Orleans Electric Department
Calendar year report covers	2017
Contact person	John Morley III
Phone number	802-754-8584
Number of customers	662

System average interruption frequency index (SAIFI) = Customers Out / Customers Served	**0.0**
Customer average interruption duration index (CAIDI) = Customer Hours Out / Customers Out	**2.4**

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	0	0
2	**Weather**	0	0
3	**Company initiated outage**	4	31
4	**Equipment failure**	2	10
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**	1	0
	Total	7	42

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.

Orleans Electric Department 2018

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

Electricity Outage Report -- PSB Rule 4.900

Name of company	Orleans Electric Department
Calendar year report covers	2018
Contact person	John Morley III
Phone number	802-754-8584
Number of customers	667

System average interruption frequency index (SAIFI) =	**0.0**
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	**1.6**
Customer Hours Out / Customers Out	

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	1	1
2	**Weather**	2	4
3	**Company initiated outage**	2	15
4	**Equipment failure**	2	6
5	**Operator error**	0	0
6	**Accidents**	0	0
7	**Animals**	1	2
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	0	0
	Total	8	28

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.

Orleans Electric Department 2019

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

Electricity Outage Report -- PSB Rule 4.900

Name of company	Orleans Electric Department
Calendar year report covers	2019
Contact person	John Morley III
Phone number	802-754-8584
Number of customers	665

System average interruption frequency index (SAIFI) =	**0.0**
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	**2.0**
Customer Hours Out / Customers Out	

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	1	2
2	**Weather**	0	0
3	**Company initiated outage**	2	20
4	**Equipment failure**	2	11
5	**Operator error**	0	0
6	**Accidents**	0	0
7	**Animals**	1	3
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	1	6
	Total	7	42

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.

Orleans Electric Department 2020

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

Electricity Outage Report -- PSB Rule 4.900

Name of company	Orleans Electric Department
Calendar year report covers	2020
Contact person	John Morley III
Phone number	802-754-8584
Number of customers	670

System average interruption frequency index (SAIFI) = 0.0
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 2.4
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	1	12
2	**Weather**	0	0
3	**Company initiated outage**	4	21
4	**Equipment failure**	2	31
5	**Operator error**	0	0
6	**Accidents**	0	0
7	**Animals**	1	4
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	0	0
	Total	8	68

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.

Orleans Electric Department 2021

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

Electricity Outage Report -- PSB Rule 4.900

Name of company	Orleans Electric Department
Calendar year report covers	2021
Contact person	John Morley III
Phone number	802-754-8584
Number of customers	670

System average interruption frequency index (SAIFI) = 0.0
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 2.7
Customer Hours Out / Customers Out

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

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

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Putting the Public in Power.
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P.O. Box 126 • 5195 Waterbury-Stowe Rd. • Waterbury Center, VT 05677 • 802.244.7678 • Fax: 802.244.6889

Request for Proposal (RFP)

for an

Advanced Metering Infrastructure Solution

Deadline for Submission: March 4, 2020

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

Release Date: December 20, 2019

1. TECHNICAL REQUIREMENTS

1.1 Electric Meter Endpoints

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

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

Table 6

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

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

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

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

Provide detailed responses for the following questions:

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

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

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

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

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

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

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

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

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

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

a. Method of multi-level authentication and authorization.

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

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

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

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

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

1.2 Water Meter Endpoints & Water System Features

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

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

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

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

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

Table 7

Question	Response: Comply, No Comply or Alternative

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

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

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

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

Provide detailed responses for the following questions:

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

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

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

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

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

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

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

Remote Disconnect Water Meters & Leak Detection

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

1.3 AMI Network

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

Table 8

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

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

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

Provide detailed responses for the following questions:

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

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

3. Provide the percentage of total usable AMI network communication capacity Vendor expects to be used in the proposed AMI system under the baseline operating conditions described above. Additionally, Vendors shall predict the percent of network capacity utilized at the point in the AMI system with the least communication capacity and shall also recommend the maximum percentage loading that Vendor considers acceptable for VPPSA's intended uses of the AMI system.

4. Provide a proposed installation diagram that shows spacing requirements and where the MCP and associated equipment is to be placed on power poles, towers or other structures.

5. Provide the specification sheet for the MCP and associated equipment. Specifications must include how the MCPs will be powered and if there are any battery requirements or remote antennas needed. If multiple MCPs or external antenna versions are prescribed, then specification sheets will be included for each model variant.

6. All AMI firmware in the AMI Meters, Network devices, and customer premise devices, shall be remotely accessible for review, modification, and replacement over the AMI Network.

7. Describe how personnel will perform firmware upgrades (patches) using either the Head-End System or remote meter management software with the AMI Network. Clearly describe the AMI Meter's ability to sense, reverse, and report unauthorized or unsuccessful firmware replacements.

8. Describe how the AMI Radio transmitters will be read by more than one AMI data collector, providing MCP redundancy).

1.4 Head End System, Meter Data Management and Operations Software

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

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

Table 9

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

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

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

Provide detailed responses for the following questions:

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

1.5 Other Capabilities with the AMI System

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

Table 10

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

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

Provide detailed responses for the following questions:

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

2022 Long-Term Forecast Report

INCORPORATED VILLAGE OF ORLEANS

VERMONT PUBLIC POWER SUPPLY AUTHORITY

Prepared For:
VERMONT PUBLIC POWER SUPPLY AUTHORITY

Prepared By:
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2022 LONG-TERM DEMAND FORECAST SUMMARY – INCORPORATED VILLAGE OF ORLEANS

The Incorporated Village of Orleans (Orleans) serves just under 600 customers in the Village of Orleans and adjacent portions of the Towns of Barton, Brownington, Coventry, and Irasburg. Residential customers account for approximately 30% of sales and small and medium commercial for the remainder.

Over the last ten years, Orleans electric loads have been averaging 0.3% annual decline. Residential sales have been slightly decreasing with a flat customer base and slightly declining average use. Commercial sales have been declining 0.3% per year. COVID-19 had a greater impact on commercial sales which went down 4.0% in 2020, against 1.5% increase in the residential sector. Table 1 shows historical customer and sales.

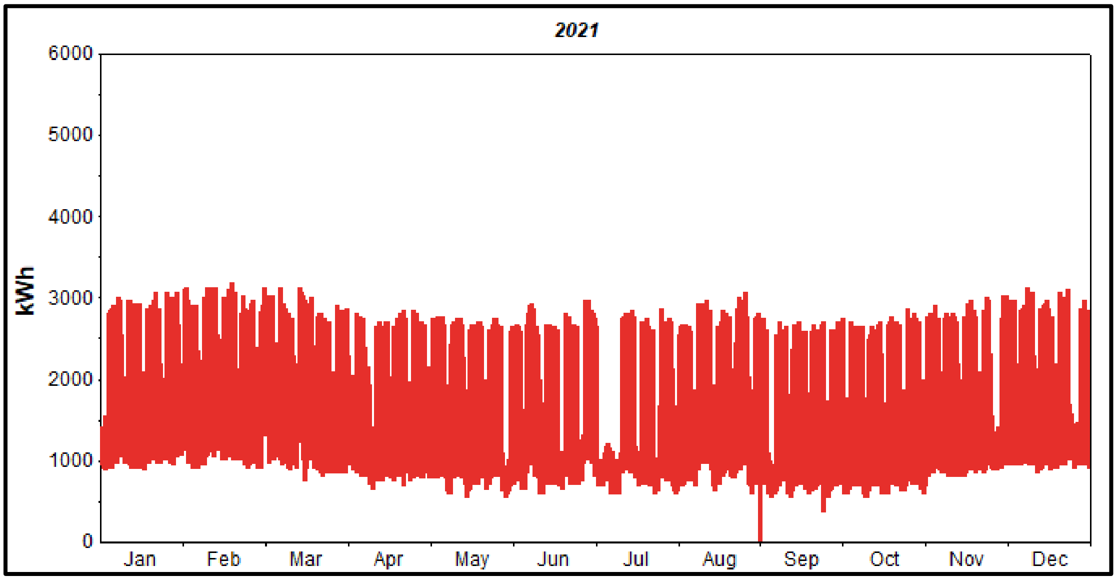
TABLE 1: ORLEANS HISTORICAL CALENDARIZED SALES AND CUSTOMERS

Year	Res Sales (MWh)	Chg	Res Custs	Chg	Res Avg Use (kWh)	Chg	Non-Res Sales (MWh)	Chg	Ttl Sales (MWh)	Chg
2011	4,144		581		7,129		9,066		13,210	
2012	4,156	0.3%	584	0.5%	7,114	-0.2%	9,056	-0.1%	13,211	0.0%
2013	4,242	2.1%	585	0.1%	7,256	2.0%	9,041	-0.2%	13,283	0.5%
2014	4,154	-2.1%	585	0.0%	7,107	-2.1%	9,035	-0.1%	13,189	-0.7%
2015	4,121	-0.8%	585	0.1%	7,044	-0.9%	8,934	-1.1%	13,054	-1.0%
2016	3,964	-3.8%	583	-0.3%	6,800	-3.5%	9,125	2.1%	13,089	0.3%
2017	3,933	-0.8%	578	-0.8%	6,799	0.0%	9,086	-0.4%	13,019	-0.5%
2018	4,001	1.8%	580	0.2%	6,905	1.6%	9,129	0.5%	13,130	0.9%
2019	4,008	0.2%	579	0.0%	6,919	0.2%	9,105	-0.3%	13,113	-0.1%
2020	4,067	1.5%	577	-0.4%	7,047	1.9%	8,741	-4.0%	12,808	-2.3%
2021	4,039	-0.7%	580	0.4%	6,968	-1.1%	8,747	0.1%	12,786	-0.2%
11-21		**-0.2%**		**0.0%**		**-0.2%**		**-0.3%**		**-0.3%**

Orleans peaks in the winter months. System peak is approximately 3 MW.

Figure 1 shows the 2021 system hourly load.

FIGURE 1: ORLEANS SYSTEM LOAD 2021



Forecast Approach

The Orleans long-term forecast is constructed using a bottom-up modeling approach where the forecast starts at the revenue-class (e.g., residential, commercial, and industrial) and with heating, cooling, and base-use sales derived from the sales models used in constructing and forecasting peak demand. System energy is based on the historical relationship between total monthly sales and monthly system delivered energy. A similar modeling approach has been used for all the VPPSA members, GMP, Burlington Electric, and VELCO. A detailed description of the modeling approach is included in the 2022 LONG-TERM FORECAST MODEL OVERVIEW section.

Baseline Sales Forecast Models

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

The baseline forecast captures expected load growth before adjustments for new PV adoptions, electric vehicle (EV), and cold climate heat pumps (CCHP). Baseline sales are driven by customer growth projections, state economic forecasts, end-use efficiency and saturation projections and temperature trends. Residential and commercial models are estimated using a Statistically Adjusted End-Use (SAE) model specifications. The SAE model 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 conditions (household income, employment, and state output), and demographic trends (population, number of households, household size).

Economic Drivers

Historical and forecasted economic data is provided by Moody's Analytics. Forecasts are based on the January 2022 economic forecast. Model inputs include number of households, household income, gross state product, and employment. Economic data is provided in 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). Orleans accounts for 0.2% of state residential sales and 0.1% 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 (there are not many CDD in Vermont) and decrease in heating degree-days (HDD) of 0.3% per year. We assume average temperature continues to increase at the current rate through the forecast period with decline in HDD contributing to lower heating requirements and increase in CDD to higher cooling requirements.

COVID-19

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

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

Baseline Results

Slow state household and economic growth projections coupled with expected efficiency improvements (both due to appliance purchases and state EE programs) and temperature trends results in flat baseline sales growth. Baseline sales are expected to reach 12,686 MWh in 2032 compared with expected year-end sales (2022) of 12,914 MWh – a 1.8% decrease. Table 2 shows Orleans baseline customer and sales forecast.

TABLE 2: ORLEANS BASELINE SALES FORECAST

Year	Res Sales (MWh)	Chg	Res Custs	Chg	Res Avg Use (kWh)	Chg	Non-Res Sales (MWh)	Chg	Ttl Sales (MWh)	Chg
2022	3,957		580		6,816		8,957		12,914	
2023	3,885	-1.8%	581	0.2%	6,681	-2.0%	9,056	1.1%	12,941	0.2%
2024	3,851	-0.9%	582	0.0%	6,619	-0.9%	9,059	0.0%	12,910	-0.2%
2025	3,795	-1.5%	582	0.0%	6,523	-1.5%	9,051	-0.1%	12,845	-0.5%
2026	3,765	-0.8%	582	0.0%	6,474	-0.8%	9,041	-0.1%	12,806	-0.3%
2027	3,732	-0.9%	581	0.0%	6,420	-0.8%	9,031	-0.1%	12,763	-0.3%
2028	3,721	-0.3%	581	0.0%	6,403	-0.3%	9,025	-0.1%	12,745	-0.1%
2029	3,707	-0.4%	581	-0.1%	6,383	-0.3%	9,014	-0.1%	12,721	-0.2%
2030	3,700	-0.2%	580	-0.1%	6,376	-0.1%	9,006	-0.1%	12,706	-0.1%
2031	3,694	-0.2%	580	-0.1%	6,371	-0.1%	8,995	-0.1%	12,690	-0.1%
2032	3,696	0.0%	579	-0.1%	6,381	0.2%	8,990	-0.1%	12,686	0.0%
2033	3,676	-0.5%	578	-0.1%	6,355	-0.4%	8,977	-0.1%	12,653	-0.3%
2034	3,665	-0.3%	577	-0.2%	6,346	-0.1%	8,968	-0.1%	12,633	-0.2%
2035	3,658	-0.2%	576	-0.2%	6,347	0.0%	8,960	-0.1%	12,618	-0.1%
2036	3,661	0.1%	575	-0.2%	6,365	0.3%	8,957	0.0%	12,617	0.0%
2037	3,643	-0.5%	574	-0.2%	6,349	-0.2%	8,946	-0.1%	12,589	-0.2%
2038	3,628	-0.4%	572	-0.3%	6,340	-0.1%	8,940	-0.1%	12,568	-0.2%
2039	3,613	-0.4%	571	-0.3%	6,332	-0.1%	8,932	-0.1%	12,545	-0.2%
2040	3,608	-0.1%	569	-0.3%	6,343	0.2%	8,925	-0.1%	12,533	-0.1%
2041	3,586	-0.6%	567	-0.3%	6,326	-0.3%	8,912	-0.1%	12,498	-0.3%
2042	3,573	-0.4%	565	-0.4%	6,326	0.0%	8,903	-0.1%	12,476	-0.2%
22-32		**-0.7%**		**0.0%**		**-0.7%**		**0.0%**		**-0.2%**
32-42		**-0.3%**		**-0.3%**		**-0.1%**		**-0.1%**		**-0.2%**

Adjusted Forecast

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

Expected increase in behind the meter solar adoption (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 Orleans' share of state residential and commercial customers. Table 3 shows the resulting forecast.

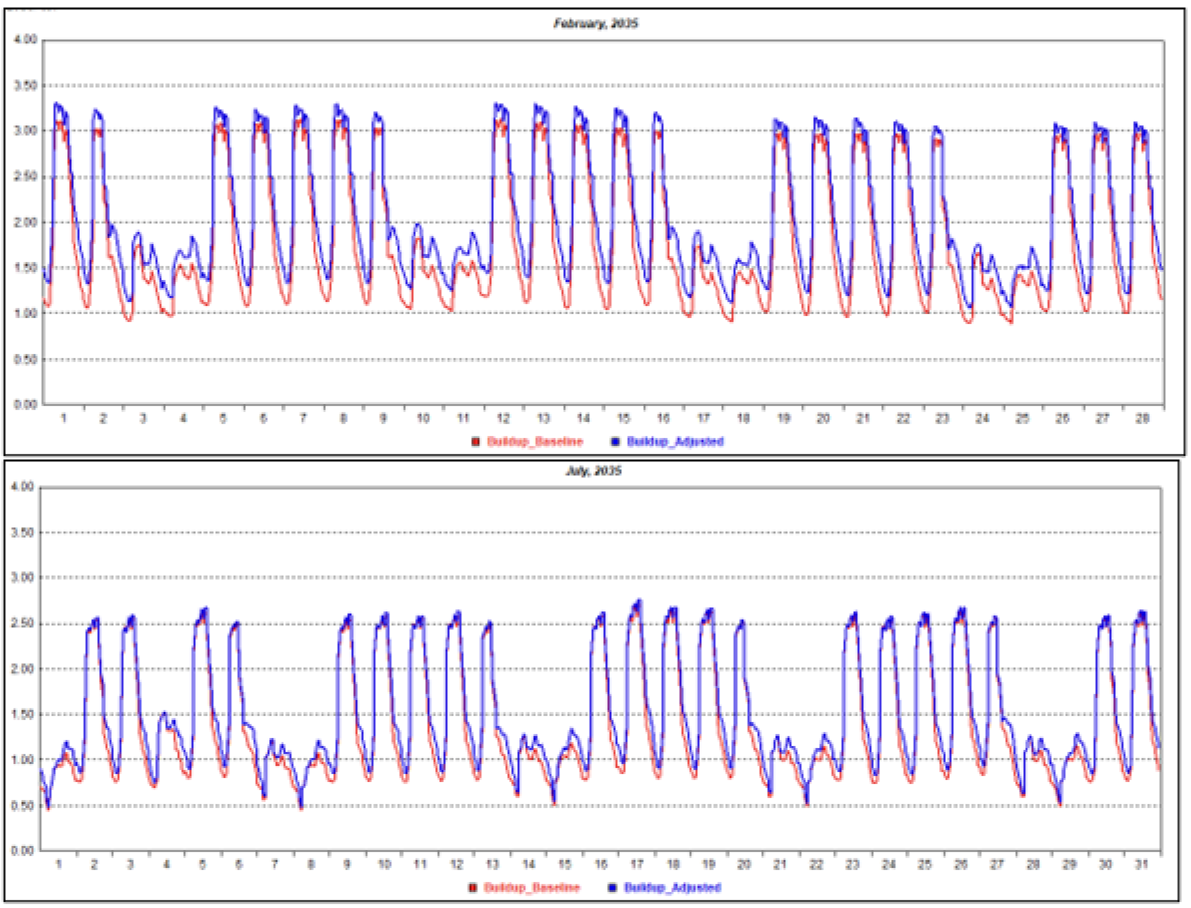
TABLE 3: EV, PV, AND CCHP FORECAST

Incremental New Tech Units			
Year	# Of Electric Vehicles	PV Installed Capacity (kW)	# Of HP Units
2022	4	12	10
2023	9	27	21
2024	16	42	33
2025	25	51	46
2026	36	55	60
2027	50	59	75
2028	68	62	90
2029	90	62	107
2030	117	64	122
2031	148	66	136
2032	184	69	148
2033	223	70	160
2034	264	71	172
2035	304	71	184
2036	342	72	196
2037	375	73	209
2038	402	73	221
2039	424	74	233
2040	439	74	246
2041	452	75	258
2042	460	76	271

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

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

FIGURE 2: BASELINE AND ADJUSTED HOURLY LOAD FORECAST



By 2035, EVs and CCHP add significant load. In the summer adjustments add 1.3 MW to baseline demand forecast and in the winter 2.2 MW. The winter load adjustments are much higher than summer adjustments as both EV charging and CCHP winter peak hour load impacts are higher. Adjusted energy is calculated by adding the hourly adjusted load forecasts and winter and summer peak demands are derived by finding the highest hourly load in each season and year. Table 4 shows the adjusted energy and demand forecasts.

TABLE 4: ORLEANS ENERGY FORECAST (MWH)

Energy and Peak										
Year	Energy (MWh)	Chg	Energy WN (MWh)	Chg	Summer Peak (MW)	Chg	Peak Time	Winter Peak (MW)	Chg	Peak Time
2011	14,370		14,390		3.08		7/21/11 11:00 AM	3.76		12/22/11 7:00 AM
2012	14,336	-0.2%	14,386	0.0%	3.11	1.0%	6/21/12 2:00 PM	3.88	2.9%	1/19/12 7:00 AM
2013	13,996	-2.4%	14,003	-2.7%	3.14	1.1%	7/18/13 2:00 PM	3.50	-9.7%	1/24/13 8:00 AM
2014	13,937	-0.4%	13,931	-0.5%	3.11	-1.0%	7/2/14 11:00 AM	3.47	-0.9%	1/23/14 8:00 AM
2015	13,838	-0.7%	13,765	-1.2%	3.18	2.1%	8/19/15 2:00 PM	3.40	-1.9%	2/24/15 10:00 AM
2016	13,897	0.4%	13,883	0.9%	3.05	-4.1%	8/11/16 10:00 AM	3.31	-2.9%	12/16/16 7:00 AM
2017	13,755	-1.0%	13,816	-0.5%	2.88	-5.3%	8/2/17 11:00 AM	3.34	1.0%	12/28/17 8:00 AM
2018	14,285	3.9%	14,193	2.7%	2.98	3.4%	8/15/18 1:00 PM	3.31	-1.0%	1/2/18 8:00 AM
2019	13,498	-5.5%	13,491	-4.9%	2.98	0.0%	7/17/19 1:00 PM	3.37	2.0%	1/14/19 7:00 AM
2020	12,693	-6.0%	12,701	-5.9%	3.01	1.1%	6/23/20 11:00 AM	3.14	-6.7%	1/21/20 7:00 AM
2021	13,699	7.9%	13,719	8.0%	3.05	1.1%	8/26/21 11:00 AM	3.18	1.0%	2/18/21 10:00 AM
2022	13,739	0.3%			2.68	-12.0%	7/19/22 2:00 PM	3.14	-1.1%	2/1/22 10:00 AM
2023	13,789	0.4%			2.71	1.0%	7/18/23 2:00 PM	3.17	1.1%	2/1/23 10:00 AM
2024	13,784	0.0%			2.79	3.0%	8/1/24 11:00 AM	3.18	0.1%	2/12/24 10:00 AM
2025	13,761	-0.2%			2.72	-2.5%	8/13/25 10:00 AM	3.17	-0.3%	2/5/25 8:00 AM
2026	13,781	0.1%			2.76	1.4%	8/6/26 11:00 AM	3.17	0.0%	2/3/26 7:00 AM
2027	13,810	0.2%			2.71	-1.9%	8/5/27 1:00 PM	3.18	0.3%	2/2/27 8:00 AM
2028	13,883	0.5%			2.75	1.5%	7/18/28 2:00 PM	3.19	0.3%	2/1/28 7:00 AM
2029	13,969	0.6%			2.69	-2.1%	8/2/29 11:00 AM	3.21	0.8%	2/12/29 8:00 AM
2030	14,076	0.8%			2.73	1.8%	8/1/30 11:00 AM	3.22	0.2%	2/11/30 7:00 AM
2031	14,194	0.8%			2.75	0.5%	8/13/31 10:00 AM	3.24	0.4%	2/10/31 7:00 AM
2032	14,337	1.0%			2.80	1.9%	8/5/32 11:00 AM	3.24	0.2%	2/3/32 7:00 AM
2033	14,463	0.9%			2.77	-1.2%	7/19/33 2:00 PM	3.26	0.5%	2/1/33 7:00 AM
2034	14,609	1.0%			2.81	1.5%	7/18/34 2:00 PM	3.30	1.2%	2/1/34 7:00 AM
2035	14,759	1.0%			2.77	-1.4%	7/17/35 2:00 PM	3.30	0.3%	2/12/35 7:00 AM
2036	14,915	1.1%			2.87	3.7%	8/11/36 1:00 PM	3.32	0.5%	2/11/36 7:00 AM
2037	15,028	0.8%			2.88	0.3%	8/6/37 11:00 AM	3.32	0.0%	2/11/37 7:00 AM
2038	15,124	0.6%			2.85	-1.0%	8/5/38 1:00 PM	3.33	0.4%	2/10/38 7:00 AM
2039	15,202	0.5%			2.87	0.5%	7/19/39 2:00 PM	3.35	0.5%	2/9/39 7:00 AM
2040	15,269	0.4%			2.93	2.3%	8/2/40 1:00 PM	3.38	1.1%	2/1/40 7:00 AM
2041	15,300	0.2%			2.87	-1.9%	8/1/41 2:00 PM	3.39	0.0%	2/11/41 7:00 AM
2042	15,335	0.2%			2.86	-0.6%	8/13/42 10:00 AM	3.40	0.3%	2/11/42 7:00 AM
11-21		**-0.4%**		**-0.4%**		**-0.1%**			**-1.6%**	
22-42		**0.6%**				**0.3%**			**0.4%**	

Projected EV, CCHP, and PVs have a significant impact on load; over the next twenty years, delivered energy is expected to average 0.6% annual growth. This compares with baseline annual sales decline of 0.2%. Winter adjusted peak averages 0.4% annual demand growth and summer 0.3% average annual growth. Orleans remains a winter peaking utility through the forecast horizon.

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

TABLE 5: ORLEANS SUMMER PEAK FORECAST (MW)

Summer Peaks (MW)							
Year	Baseline	Chg	EV	PV	HP	Adjusted	Chg
2022	2.69		0.00	-0.01	0.00	2.68	
2023	2.72	1.0%	0.00	-0.02	0.01	2.71	1.0%
2024	2.81	3.6%	0.00	-0.03	0.01	2.79	3.0%
2025	2.72	-3.2%	0.00	-0.01	0.00	2.72	-2.5%
2026	2.76	1.2%	0.01	-0.02	0.01	2.76	1.4%
2027	2.69	-2.3%	0.01	-0.01	0.02	2.71	-1.9%
2028	2.75	2.0%	0.01	-0.04	0.03	2.75	1.5%
2029	2.70	-1.6%	0.01	-0.05	0.02	2.69	-2.1%
2030	2.75	1.6%	0.02	-0.05	0.02	2.73	1.8%
2031	2.74	-0.3%	0.02	-0.01	0.01	2.75	0.5%
2032	2.77	1.1%	0.03	-0.02	0.03	2.80	1.9%
2033	2.72	-1.7%	0.04	-0.05	0.05	2.77	-1.2%
2034	2.74	0.8%	0.05	-0.04	0.05	2.81	1.5%
2035	2.70	-1.7%	0.06	-0.05	0.06	2.77	-1.4%
2036	2.81	4.3%	0.06	-0.02	0.02	2.87	3.7%
2037	2.81	-0.2%	0.06	-0.02	0.04	2.88	0.3%
2038	2.75	-2.1%	0.07	-0.02	0.05	2.85	-1.0%
2039	2.76	0.5%	0.08	-0.05	0.07	2.87	0.5%
2040	2.82	2.2%	0.08	-0.02	0.06	2.93	2.3%
2041	2.78	-1.5%	0.09	-0.05	0.06	2.87	-1.9%
2042	2.80	0.8%	0.06	-0.02	0.01	2.86	-0.6%
22-42		**0.2%**					**0.3%**

TABLE 6: ORLEANS WINTER PEAK FORECAST (MW)

Winter Peaks (MW)							
Year	Baseline	Chg	EV	PV	HP	Adjusted	Chg
2022	3.14		0.00	0.00	0.01	3.14	
2023	3.16	0.7%	0.00	0.00	0.02	3.17	1.1%
2024	3.16	0.0%	0.00	-0.01	0.02	3.18	0.1%
2025	3.14	-0.6%	0.00	-0.01	0.03	3.17	-0.3%
2026	3.13	-0.4%	0.01	0.00	0.04	3.17	0.0%
2027	3.13	0.0%	0.01	0.00	0.04	3.18	0.3%
2028	3.12	-0.3%	0.01	0.00	0.06	3.19	0.3%
2029	3.12	0.1%	0.02	0.00	0.08	3.21	0.8%
2030	3.10	-0.7%	0.02	0.00	0.10	3.22	0.2%
2031	3.10	0.0%	0.03	-0.01	0.11	3.24	0.4%
2032	3.11	0.5%	0.04	0.00	0.09	3.24	0.2%
2033	3.11	-0.1%	0.04	0.00	0.10	3.26	0.5%
2034	3.10	-0.5%	0.05	0.00	0.15	3.30	1.2%
2035	3.10	0.0%	0.06	0.00	0.15	3.30	0.3%
2036	3.10	0.0%	0.07	0.00	0.16	3.32	0.5%
2037	3.04	-1.7%	0.08	0.00	0.20	3.32	0.0%
2038	3.04	0.0%	0.08	-0.01	0.22	3.33	0.4%
2039	3.04	0.0%	0.08	0.00	0.23	3.35	0.5%
2040	3.09	1.6%	0.09	0.00	0.21	3.38	1.1%
2041	3.09	-0.1%	0.09	0.00	0.21	3.39	0.0%
2042	3.06	-0.8%	0.09	0.00	0.24	3.40	0.3%
22-42		**-0.1%**					**0.4%**

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

2022 LONG-TERM FORECAST MODEL OVERVIEW

INTRODUCTION

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

The VPPSA members include:

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

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

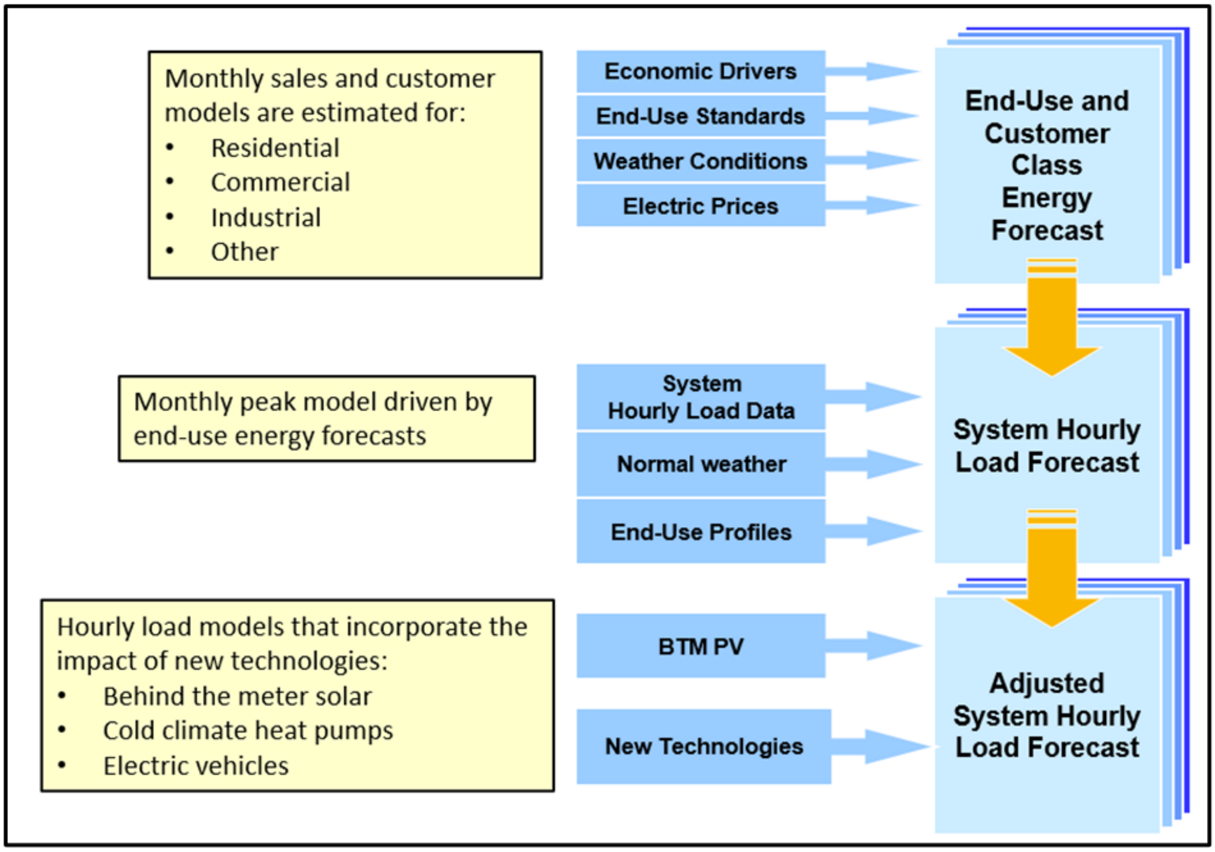
Forecast includes:

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

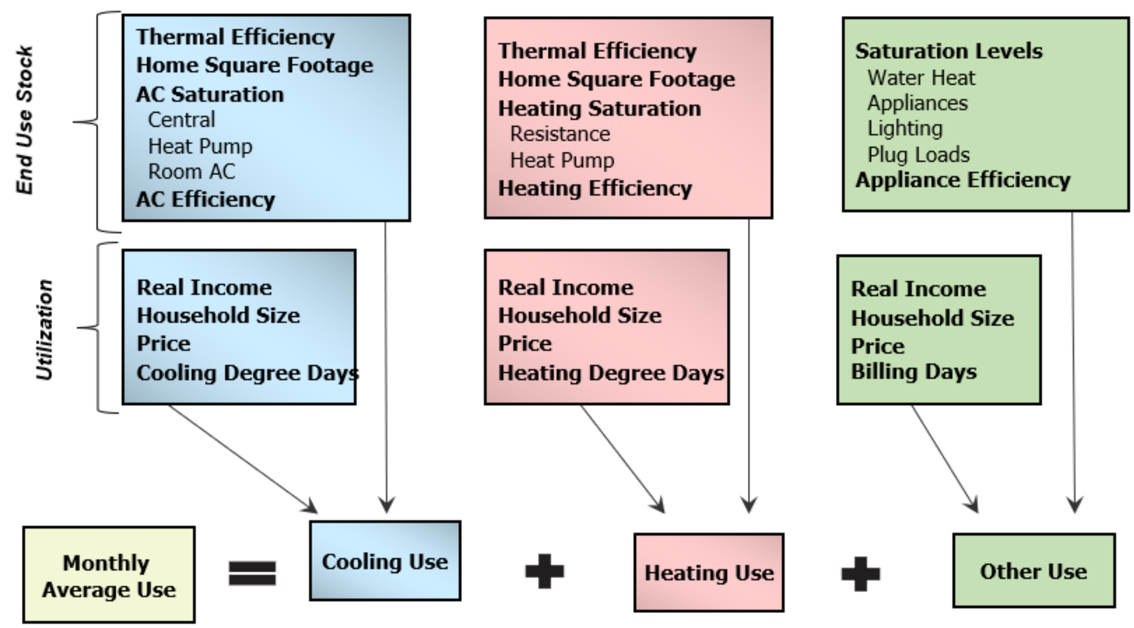
FIGURE 3: FORECASTING FRAMEWORK



Customer Class Sales Forecast

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

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

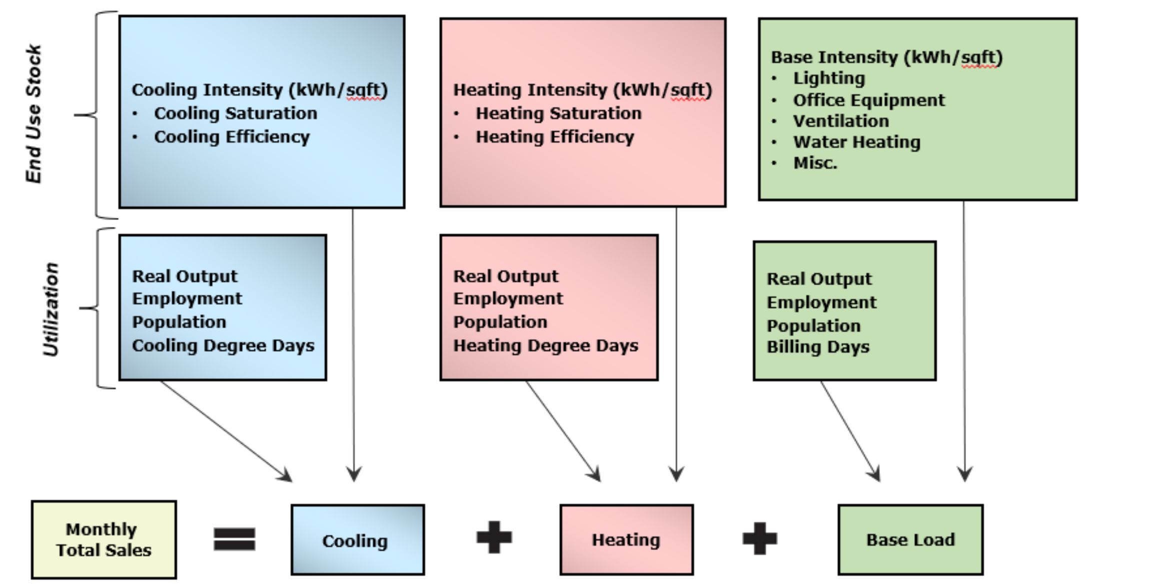


$$AvgUse_m = a + b_c \times XCool_m + b_h \times XHeat_m + b_o \times XOther_m + b_e \times EE_m$$

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

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

FIGURE 5: COMMERCIAL SAE MODEL



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

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

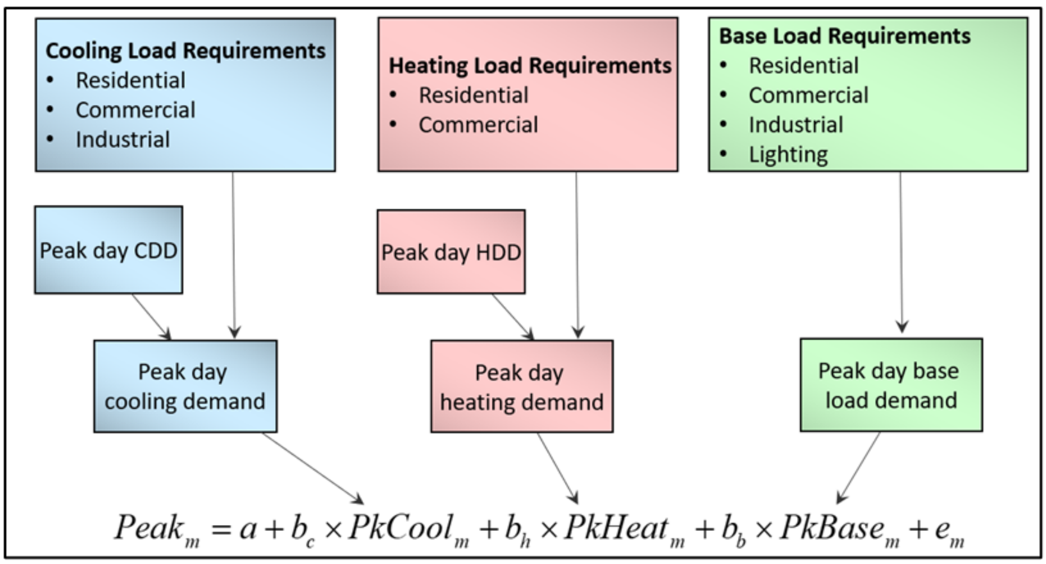
For many of the municipalities the larges C&I customer class is dominated by a few companies. The is often significant variation in month-to-month sales making it difficult to fit with an SAE model specification. For these classes, either a more generalized econometric or trend model is used. This is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

Baseline Energy, Peak, and Hourly Load Forecast

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

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

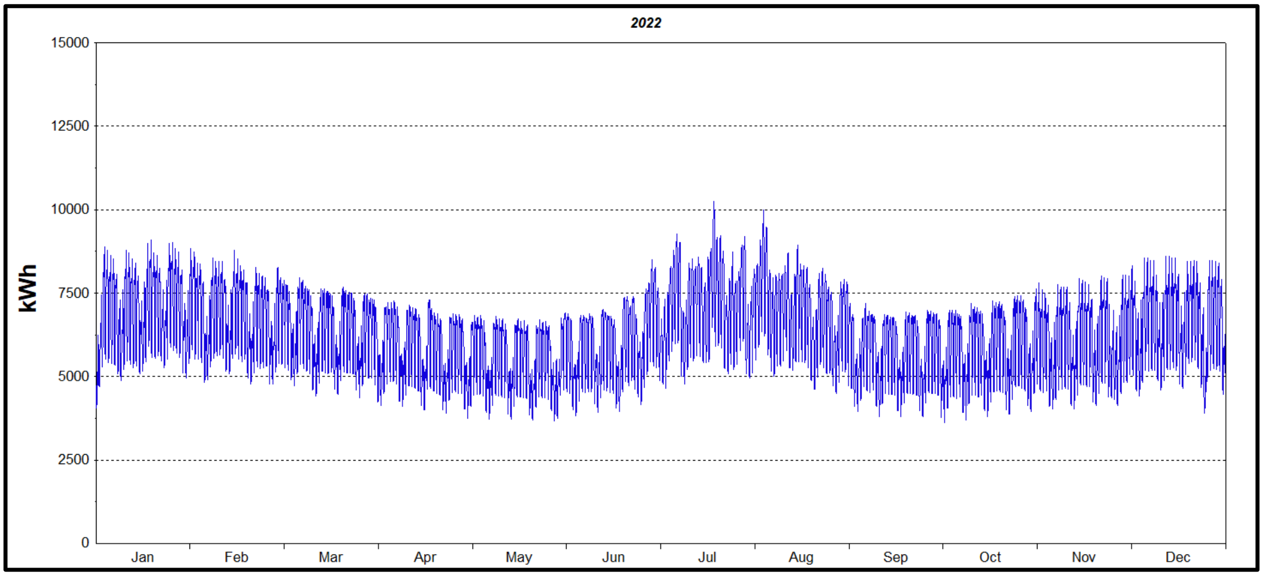
FIGURE 6: BASELINE PEAK MODEL



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

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

FIGURE 7: SWANTON HOURLY BASELINE PROFILE



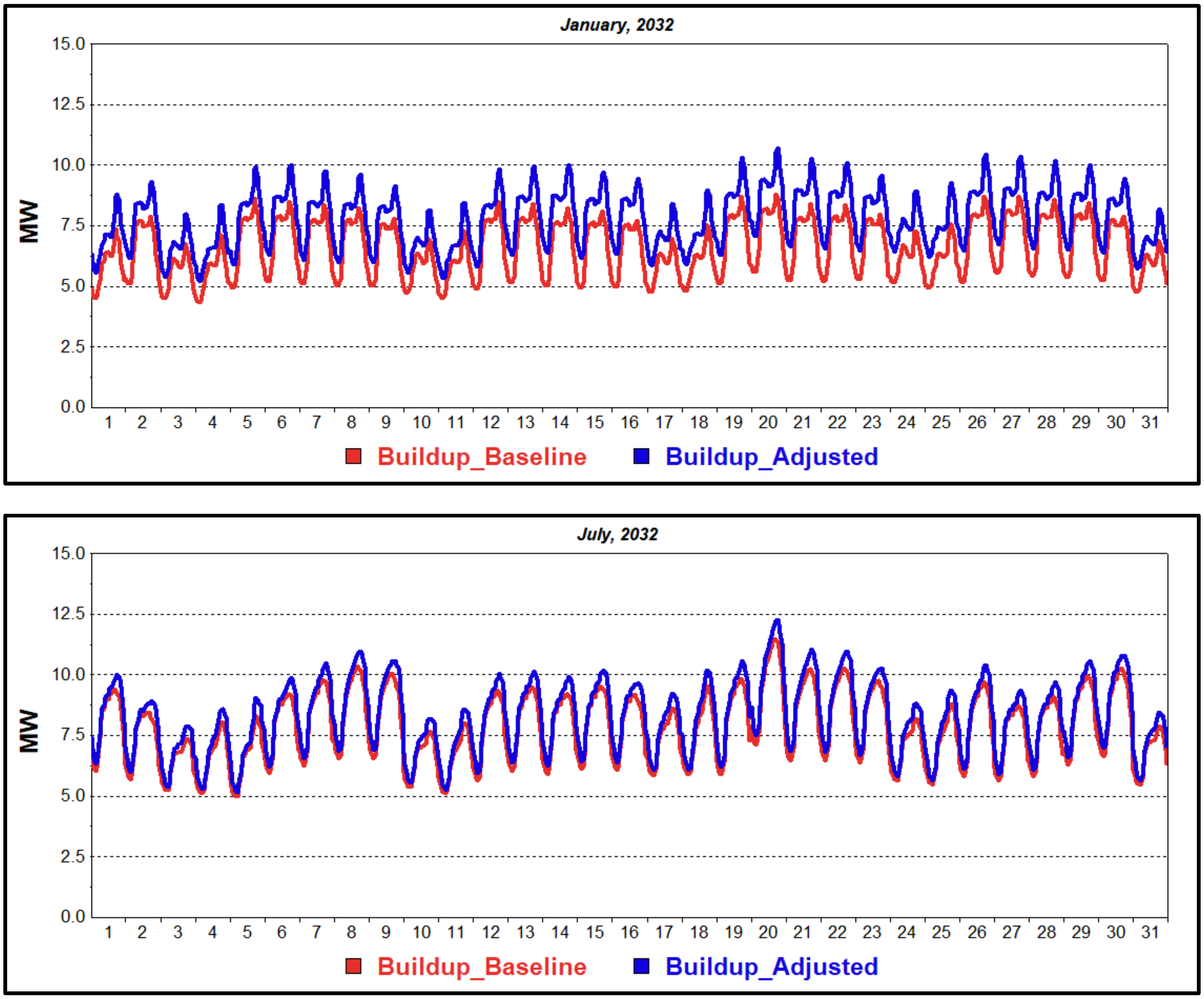
The baseline profile is constant over the estimation period. The baseline hourly load forecast is then derived by combining the baseline energy and peak forecast with the profile. Increase in energy requirements and peak demand lift the baseline profile over time. The baseline hourly load forecast reflects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

Adjusted Load Forecast

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

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

FIGURE 8: SWANTON SYSTEM HOURLY LOAD COMPARISON (2032)



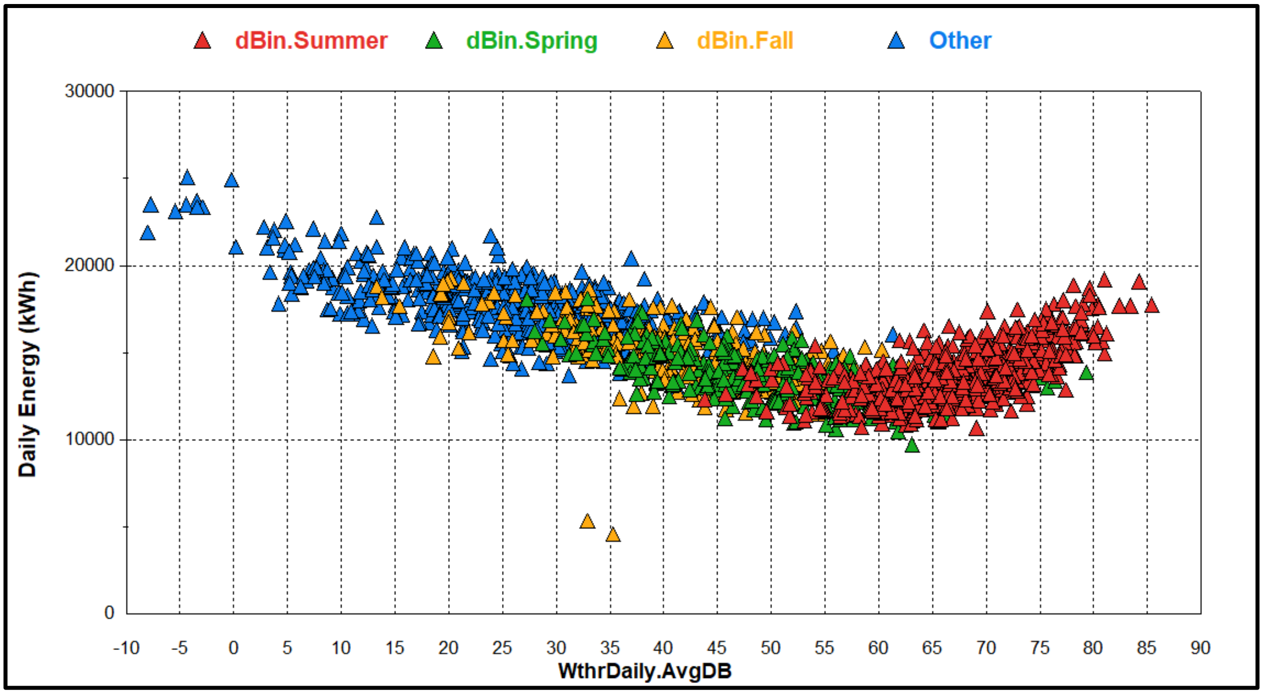
The initial baseline forecast is shown in red and the forecasted adjusted PV, EV, and heat pumps in blue. Solar adoption combined with EV charging shifts the summer peak into the evening hours while heat pumps and EV charging have a much larger impact on winter peaks than summer peaks.

FORECAST ASSUMPTIONS

Weather

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

FIGURE 9: LOAD-TEMPERATURE RELATIONSHIP (JACKSONVILLE)



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

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

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

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

FIGURE 10: HEATING TREND

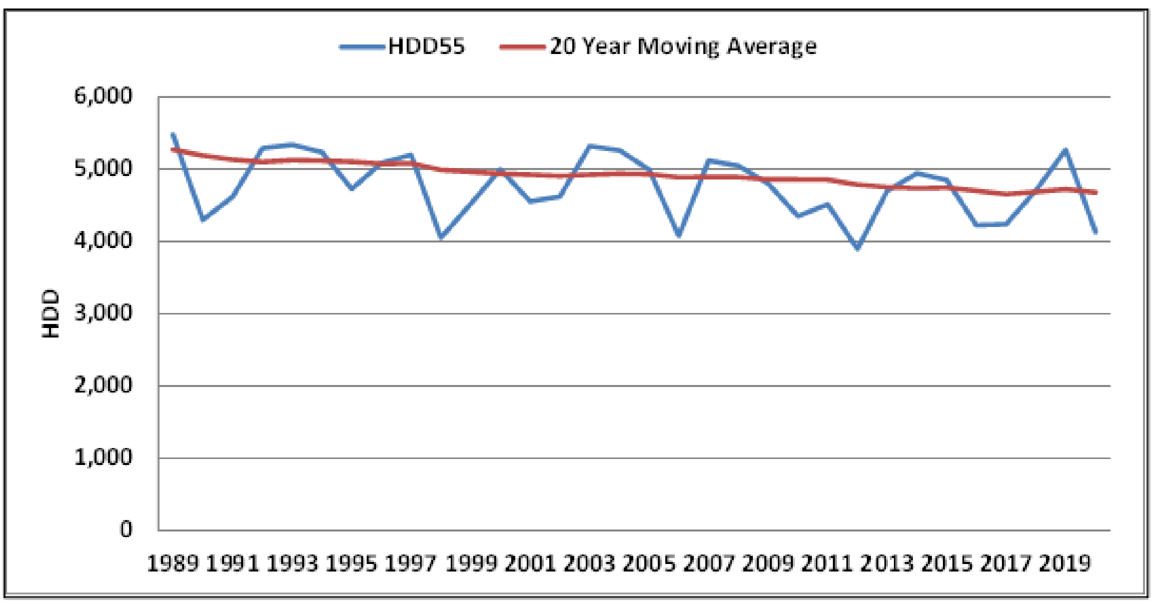
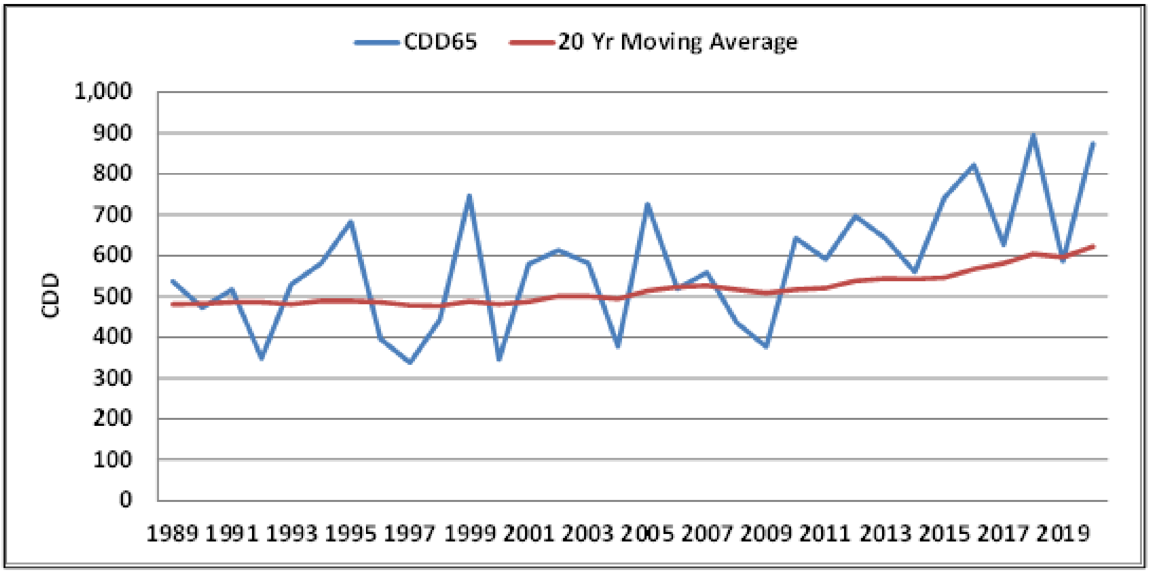


FIGURE 11: COOLING TREND



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

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

FIGURE 12: NORMAL AND TRENDED NORMAL HDD

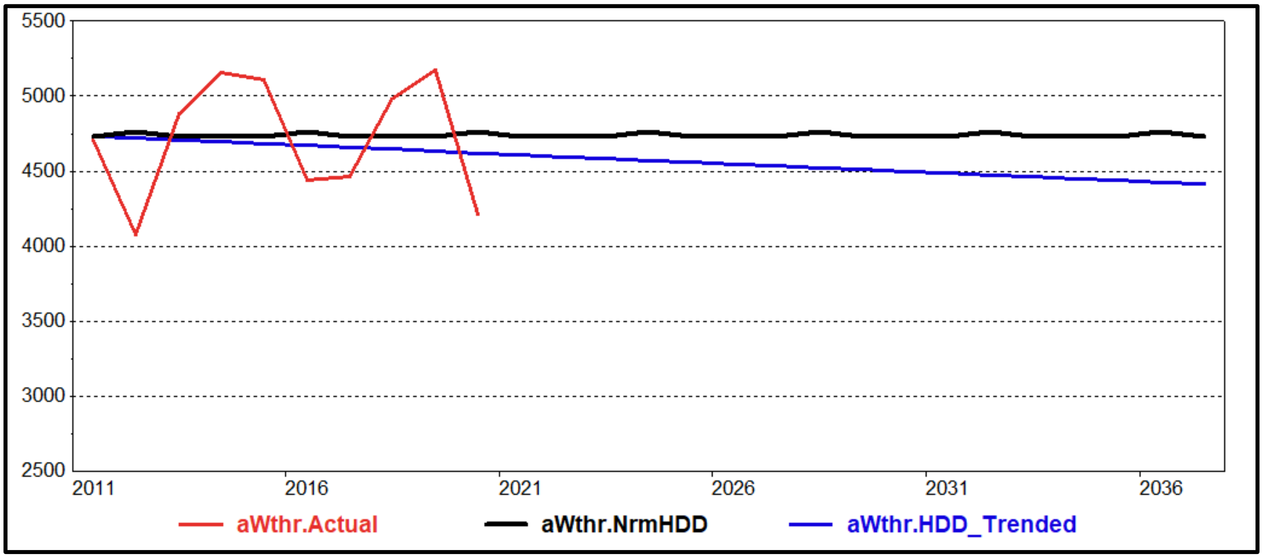
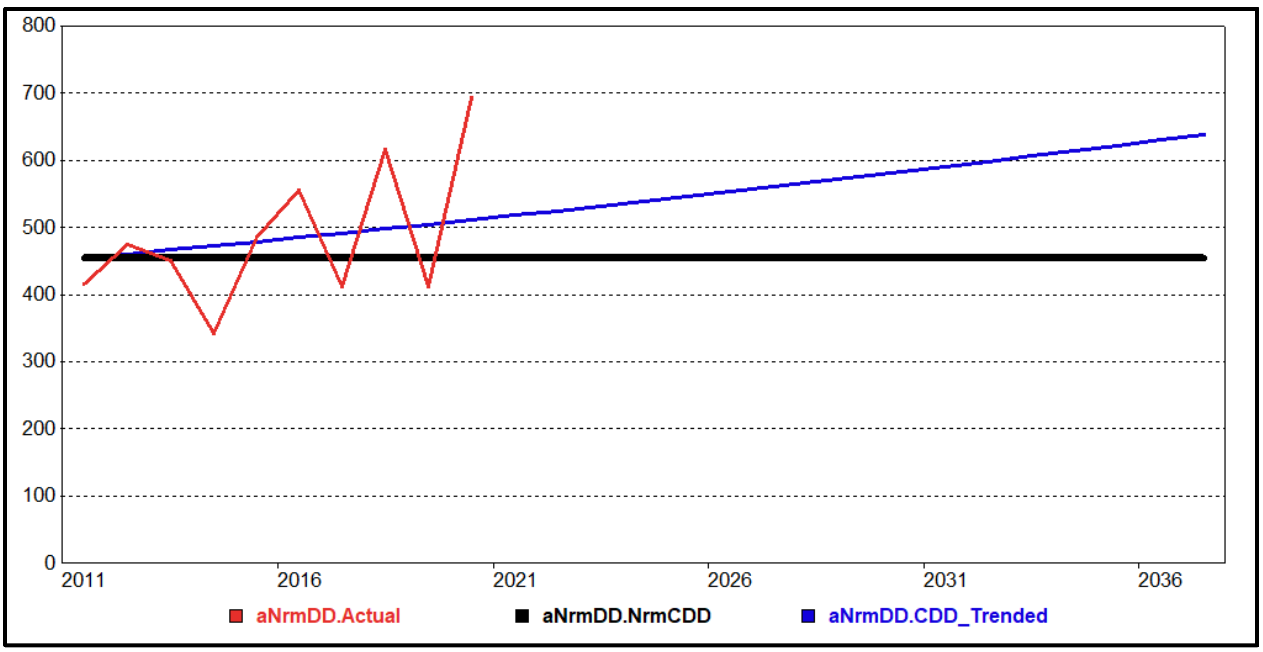


FIGURE 13: NORMAL AND TRENDED NORMAL CDD



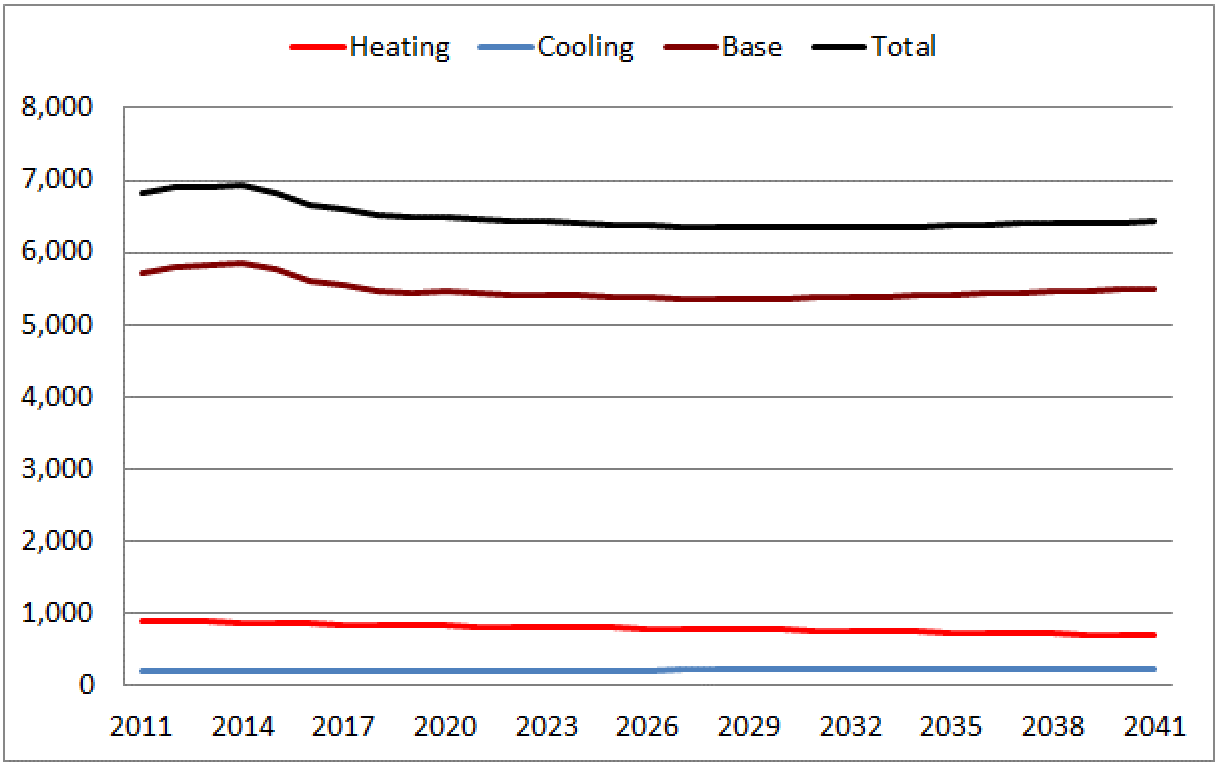
Based on historical data, CDD are expected to increase 1.3% per year and number of HDD decline 0.3% per year.

End-Use Intensities

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

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

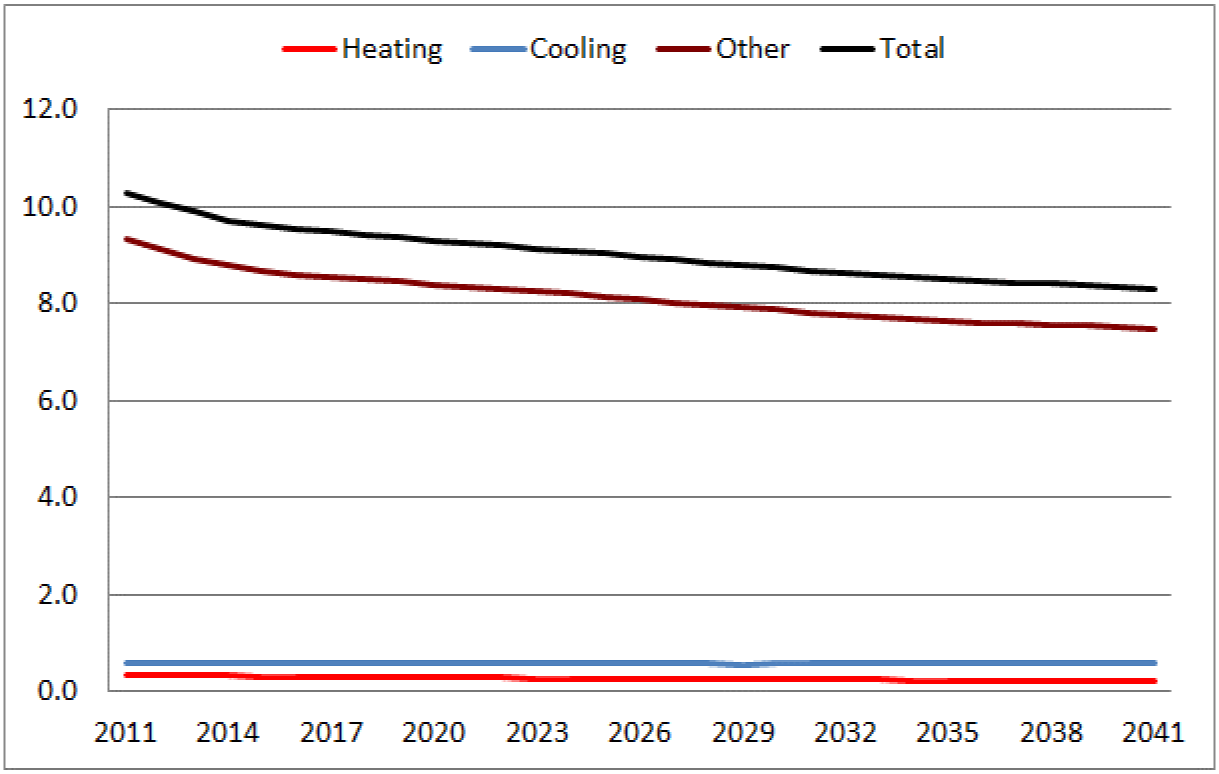
FIGURE 14: RESIDENTIAL SAE INDICES (KWH/HOUSEHOLD)



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

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

FIGURE 15: COMMERCIAL SAE INDICES (KWH/HOUSEHOLD)

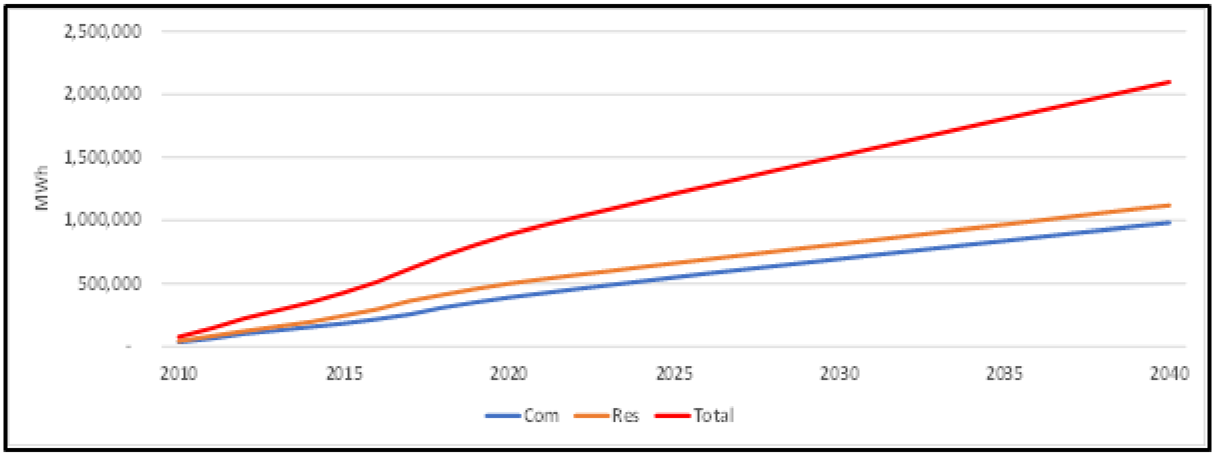


In general, there has been a long-term decline in commercial sales largely driven by efficiency gains. Commercial intensity has averaged 1.2% decline over the last ten years and is projected to decline another 0.7% over the next ten years.

EE Program Impacts

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

FIGURE 16: VEIC HISTORICAL AND PROJECTED EE PROGRAM SAVINGS



Economic Outlook

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

TABLE 7: ECONOMIC FORECAST

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

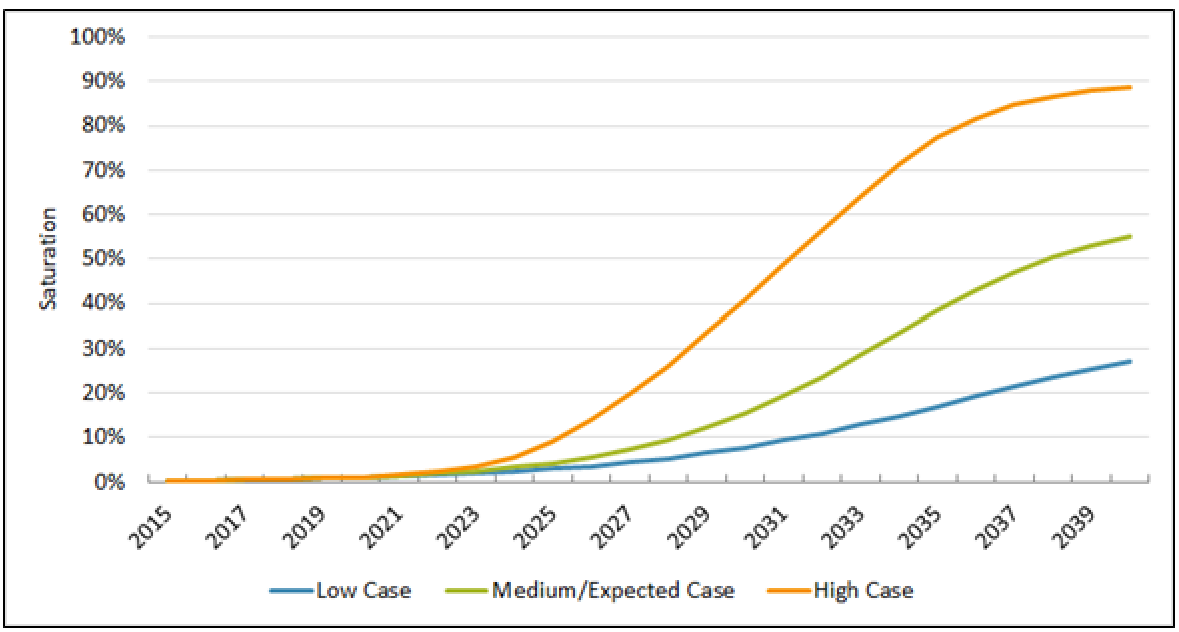
In 2020, state output (GDP) dropped 3.2% and employment declined 8.3% while personal income increased 5.9%. The large increase in real income is a result of government financial stimulus designed to counter the COVID employment impact. Moody's projects economic recovery to pre-pandemic levels by 2022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

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

Electric Vehicles

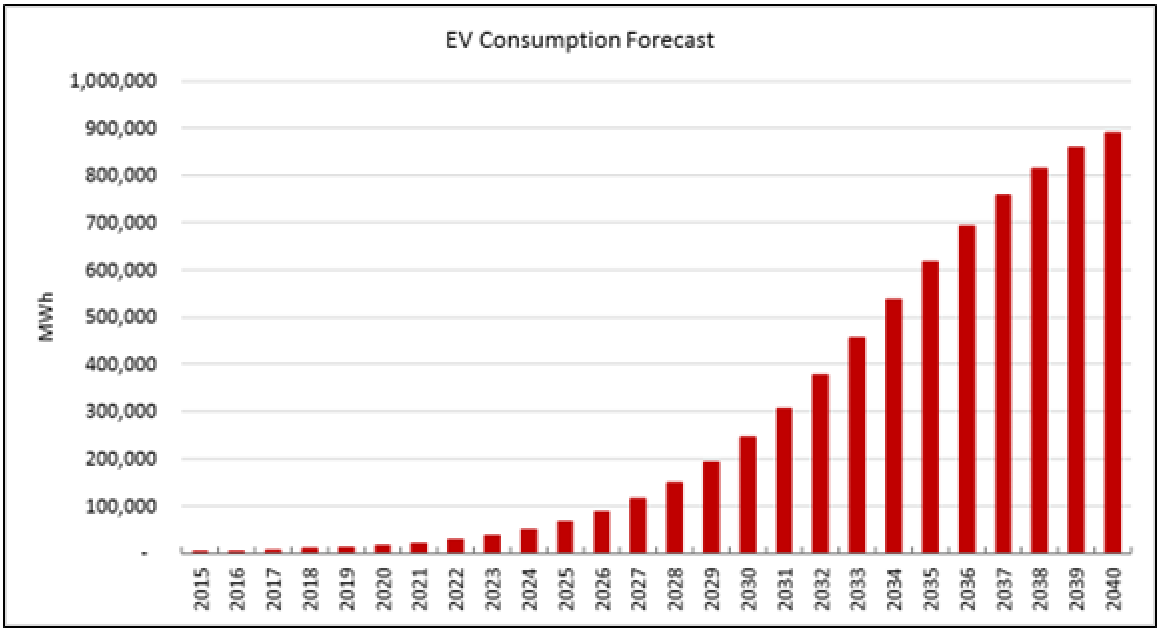
The electric vehicle (EV) forecast was developed by the VEIC as part of VELCO 2021 Long-Range Transmission Plan. VEIC provided three forecast scenarios; low, medium, and high, based on saturation targets for light-duty registered vehicles. The expected case (used in the VPPSA forecast) assumes that over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

FIGURE 17: ELECTRIC VEHICLE SATURATION PROJECTIONS



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

FIGURE 18: EXPECTED CASE STATE EV ELECTRICITY FORECAST

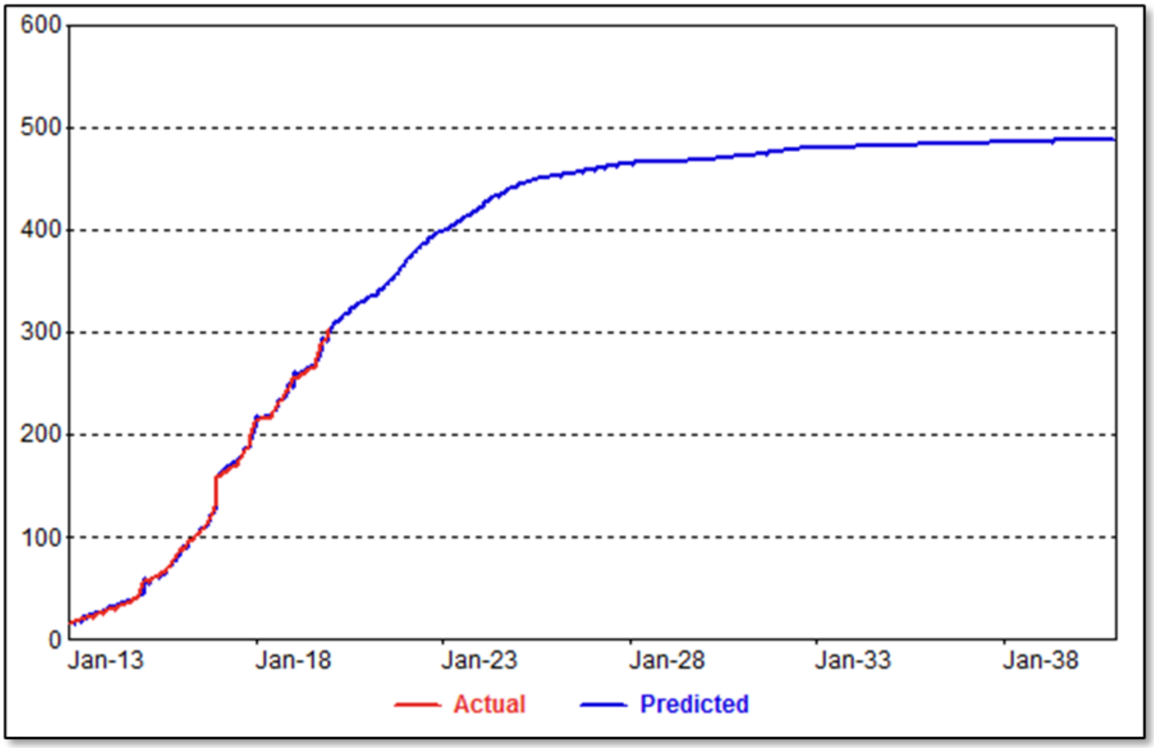


State EV sales are allocated to VPPSA member utilities based on each members' share of statewide number of residential customers.

Solar

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

FIGURE 19: STATE SOLAR CAPACITY FORECAST (MW)

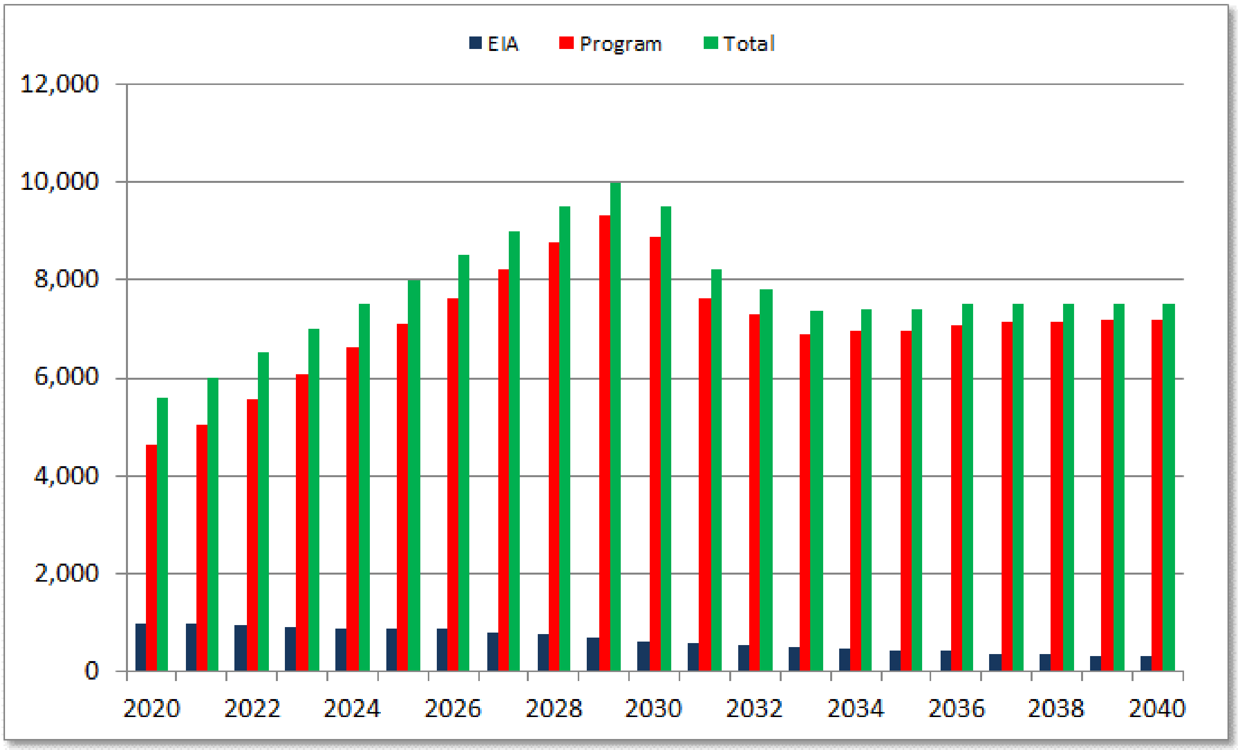


We expect the growth of BTM solar adoption to begin to slow by 2025 as system costs begin to flatten out. We project over 450 MW of installed solar capacity by 2032. This translates into nearly 650,000 MWh based on monthly load factors derived from Vermont solar generation profile data. Our default assumption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

Cold Climate Heat Pumps

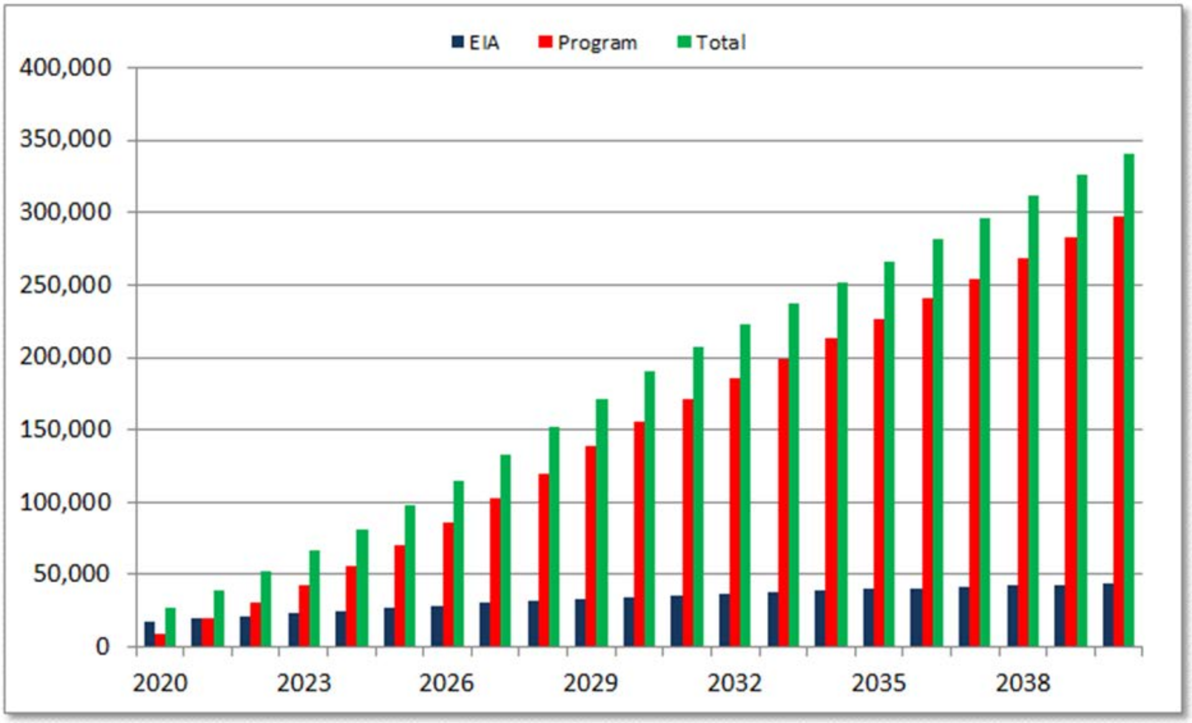
As part of state efforts to reduce CO_2 emissions, the state has launched a program to promote CCHP by offering financial incentives including rebates and 0 interest financing. The primary targets are homes that heat with oil, propane, and wood. VEIC along with input from the DPS developed a long-term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

FIGURE 20: STATE CCHP FORECAST (UNITS PER YEAR)



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

FIGURE 21: STATE CCHP ENERGY PROJECTIONS (MWH)



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

APPENDIX A

MODEL RESULTS

Residential Average Use Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructRes.XHeat	0.901	0.081	11.124	0.00%
mStructRes.LagXHeat	0.359	0.075	4.795	0.00%
mStructRes.XCool	1.078	0.184	5.846	0.00%
mStructRes.LagXOther	0.995	0.017	59.021	0.00%
mCovid.ResIndex	26.776	8.262	3.241	0.15%
mBin.Bef14	19.01	6.912	2.75	0.68%

Model Statistics	
Iterations	1
Adjusted Observations	132
Deg. of Freedom for Error	126
R-Squared	0.846
Adjusted R-Squared	0.84
AIC	7.102
BIC	7.233
Log-Likelihood	-650.01
Model Sum of Squares	805,801.68
Sum of Squared Errors	146,320.47
Mean Squared Error	1,161.27
Std. Error of Regression	34.08
Mean Abs. Dev. (MAD)	25.63
Mean Abs. % Err. (MAPE)	4.33%
Durbin-Watson Statistic	2.122

Residential Customer Model

Variable	Coefficier	StdErr	T-Stat	P-Value
mEcon.Pop	0.931	0.001	1002.115	0.00%
AR(1)	0.577	0.071	8.131	0.00%

Model Statistics	
Iterations	7
Adjusted Observations	131
Deg. of Freedom for Error	129
R-Squared	0.444
Adjusted R-Squared	0.44
AIC	2.091
BIC	2.135
Log-Likelihood	-320.83
Model Sum of Squares	822.54
Sum of Squared Errors	1,028.19
Mean Squared Error	7.97
Std. Error of Regression	2.82
Mean Abs. Dev. (MAD)	2.17
Mean Abs. % Err. (MAPE)	0.37%
Durbin-Watson Statistic	2.245

Small Commercial Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mStructCom.XHeat	99431.298	41336.9	2.405	1.76%
mStructCom.LagXHeat	121538.487	39849.73	3.05	0.28%
mStructCom.XCool	116360.764	13789.58	8.438	0.00%
mStructCom.LagXCool	63145.312	13882.31	4.549	0.00%
mStructCom.LagXOther	13923.029	196.325	70.918	0.00%
mBin.Bef15	7509.034	1281.37	5.86	0.00%
mBin.Aft20	9802.352	1566.78	6.256	0.00%

Model Statistics	
Iterations	1
Adjusted Observations	130
Deg. of Freedom for Error	123
R-Squared	0.717
Adjusted R-Squared	0.704
AIC	17.599
BIC	17.753
Log-Likelihood	-1,321.38
Model Sum of Squares	13,021,463,423.16
Sum of Squared Errors	5,130,952,013.31
Mean Squared Error	41,715,057.02
Std. Error of Regression	6,458.72
Mean Abs. Dev. (MAD)	5,179.86
Mean Abs. % Err. (MAPE)	3.70%
Durbin-Watson Statistic	2.136

Industrial Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mBin.Jan	658633.917	10418.79	63.216	0.00%
mBin.Feb	625292.902	10419.19	60.014	0.00%
mBin.Mar	638147.825	10426.46	61.205	0.00%
mBin.Apr	598316.423	10807.01	55.364	0.00%
mBin.May	516987.581	10813.97	47.807	0.00%
mBin.Jun	521747.496	10418.53	50.079	0.00%
mBin.Jul	409832.419	10418.53	39.337	0.00%
mBin.Aug	556459.613	10419.51	53.406	0.00%
mBin.Sep	512602.169	10419.52	49.196	0.00%
mBin.Oct	550902.936	10423.65	52.851	0.00%
mBin.Nov	581800.908	11461.79	50.76	0.00%
mBin.Dec	596244.991	10991.46	54.246	0.00%
mCovid.NResIndex	-35666.756	8644.895	-4.126	0.01%
mBin.Aft16	16052.006	6319.779	2.54	1.24%

Model Statistics	
Iterations	1
Adjusted Observations	127
Deg. of Freedom for Error	113
R-Squared	0.825
Adjusted R-Squared	0.804
AIC	20.905
BIC	21.219
Log-Likelihood	-1,493.69
Model Sum of Squares	574,320,849,391.84
Sum of Squared Errors	122,201,844,151.46
Mean Squared Error	1,081,432,249.13
Std. Error of Regression	32,885.14
Mean Abs. Dev. (MAD)	25,202.51
Mean Abs. % Err. (MAPE)	4.45%
Durbin-Watson Statistic	1.43

Other Sales Model

Variable	Coefficient	StdErr	T-Stat	P-Value
Simple	0.133	0.048	2.773	0.006
Seasonal	0.086	0.067	1.276	0.204

Model Statistics	
Iterations	16
Adjusted Observations	132
Deg. of Freedom for Error	130
R-Squared	0.829
Adjusted R-Squared	0.827
AIC	15.967
BIC	16.011
Log-Likelihood	-1,239.13
Model Sum of Squares	5,328,618,830
Sum of Squared Errors	1,101,194,056
Mean Squared Error	8,470,723.51
Std. Error of Regression	2,910.45
Mean Abs. Dev. (MAD)	2,169.87
Mean Abs. % Err. (MAPE)	4.75%
Durbin-Watson Statistic	2.065

Peak Model

Variable	Coefficient	StdErr	T-Stat	P-Value
mWthr.HeatVar55	-4.254	0.672	-6.332	0.00%
mWthr.CoolVar60	11.171	1.397	7.995	0.00%
mCPkEndUses.BaseVar	1.707	0.012	144.067	0.00%
mBin.Aft16	-133.347	17.559	-7.594	0.00%
mBin.Mar	171.662	34.161	5.025	0.00%
mBin.Jun	102.536	33.765	3.037	0.29%

Model Statistics	
Iterations	1
Adjusted Observations	129
Deg. of Freedom for Errc	123
R-Squared	0.776
Adjusted R-Squared	0.767
AIC	9.234
BIC	9.367
Log-Likelihood	-772.65
Model Sum of Squares	4,165,848.33
Sum of Squared Errors	1,203,900.69
Mean Squared Error	9,787.81
Std. Error of Regression	98.93
Mean Abs. Dev. (MAD)	76.02
Mean Abs. % Err. (MAPE	2.44%
Durbin-Watson Statistic	1.631

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