Village of Enosburg Falls Electric Light Department

2019 Integrated Resource Plan

Vermont Public Power Supply Authority

Executive Summary:

The Village of Enosburg Falls Electric Light Department (VOEF) has operated an electric utility system since 1896. Serving approximately 1,740 customers, VOEF's service territory is located in the northwestern part of Vermont, in an area where weather events- especially in recent years- have been both challenging and at times highly localized. Its service territory encompasses the Village of Enosburg Falls as well as portions of six surrounding towns; Bakersfield, Berkshire, Enosburgh, Fairfield, Franklin, and Sheldon. The service territory of VOEF is predominantly a dairy farming community, with 10 active farms and is home to the cheese manufacturer, Franklin Foods. Much of the remaining commercial activity in VOEF supports dairy farming. VOEF remains guided by the Vermont Public Utility Commission (PUC) rules as well as by the American Public Power Association's (APPA) safety manual. As a small municipal utility VOEF is careful to balance maintaining reliability and reasonable cost levels with the need to deliver innovative programs to customers that provide practical value.

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

Consistent with regulatory requirements, every 3 years VOEF 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. VOEF's Integrated Resource Plan (IRP) is intended to meet the public's need for energy services, after safety concerns are addressed, at the lowest present value life cycle cost, including environmental and economic costs, through a strategy combining investments and expenditures on energy supply, transmission and distribution capacity, transmission and distribution efficiency, and comprehensive energy efficiency programs.

ELECTRICITY DEMAND

VOEF is facing a period of relatively flat demand influenced by several competing factors, all of which carry some uncertainty. Continued adoption of solar net metering reduces demand although the pace at which net metering will grow in VOEF's territory is uncertain. As various incentives aimed at transitioning from fossil fuels to cleaner electricity are made available, increasing acceptance of cold climate heat pumps and similar appliances will likely increase demand, as will an expected increase in the use of electric vehicles.

While no significant change in the demand associated with VOEF's largest customers is currently anticipated, the potential does exist. VOEF monitors the plans of large customers in order to anticipate necessary changes to the existing resource plan and system infrastructure.

In the case of a significant expansion by one or more customers, detailed engineering studies may be needed to identify necessary system upgrades.

ELECTRICITY SUPPLY

VOEF's current power supply portfolio includes entitlements in a mixture of baseload, firm and intermittent resources through ownership or contractual arrangements of varying duration, with most contracts carrying a fixed price feature. Designed to meet anticipated demand, as well as acting as a hedge against exposure to volatile ISO-New England spot prices, the portfolio is heavily weighted toward market contracts, hydro, and other renewable sources. VOEF owns and operates the Enosburg Falls Hydroelectric Facility, delivering a clean reliable source of power located on the Missisquoi River, within its service territory. The Enosburg Falls Hydroelectric Facility has been a dependable source of power for the evolving energy needs of northwestern Vermont.

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

RESOURCE PLANS

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

VOEF faces four major decisions over the 2020 – 2039 period covered by this Integrated Resource Plan (IRP).

The two major resource decisions faced by VOEF occur in 2020 and 2024, respectively, which in total, will affect about one third of VOEF's energy supply between 2020 and 2024. The first is the expiration of a contract near the end of 2020, which represents about 5% of VOEF's energy supply. The second is the expiration of a contract at the end of 2022, which represents about 26% of VOEF's energy supply.

Options being evaluated by VOEF to replace these three contracts include renegotiating the contract expiring in 2022 and extending its term, signing a PPA for an existing hydro plant to provide capacity, energy, and Tier I RECs, signing a PPA for a solar plant to provide energy and Tier II RECs, or signing a PPA for market energy supplies.

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

VOEF's capacity supplies are forecast to be about 1 MW less than its requirements. As a result, a long-term capacity resource that is prices at or below today's market prices would be beneficial.

Analysis of these major resource decisions also addresses two load-related questions: what is the rate impact of 1% compound annual load growth and what is the rate impact if loads dropped by 20%, which approximates the impact of Franklin Foods leaving the system. Additionally ,the analysis quantifies the costs and benefits of gaining LIHI certification for the Enosburg Falls Hydroelectric Facility by the beginning of 2025.

RENEWABLE ENERGY STANDARD

VOEF is subject to the Vermont Renewable Energy Standard (RES) which imposes an obligation for VOEF to obtain a portion of its energy requirements from renewable resources. The RES obligation increases over time and is stratified into three categories, TIER I, TIER II and TIER III. VOEF's obligations under TIER I can be satisfied by owning or purchasing RECs from qualifying regional resources. TIER II obligations must be satisfied by owning or purchasing RECs from renewable resources located within Vermont. Satisfaction of VOEF'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 and space heating sectors, 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 VOEF receives credits toward its TIER III obligation. More information regarding VOEF's approach to meeting its TIER III obligation is available in Appendix B to this document.

ELECTRICITY TRANSMISSION AND DISTRIBUTION

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

VOEF's distribution system presently serves approximately 1,740 customers in a 65 square mile service territory. The system is comprised of 102.1 miles of line at 12.47 kV and 3.53 miles of line at 2.4 kV for a total of 105.63 miles of distribution level line.

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

In addition to upgrading and routinely maintaining the system to ensure efficiency and reliability, VOEF is examining the need to modernize in order to support beneficial electrification and additional distributed generation on the system and to provide more customer oriented services, including load management programs that reduce costs for both VOEF and its customers. VOEF is currently engaged with VPPSA in a multi-phased process designed to assess its readiness for AMI, guide it through an RFP process culminating in vendor and equipment selection and ultimately resulting in implementation of an AMI system, provided the resulting cost estimates gained through the RFP process are not prohibitive.

VOEF sees potential value to customers from 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 VOEF's ability to deliver these benefits and capture economic development/retention opportunities where possible.

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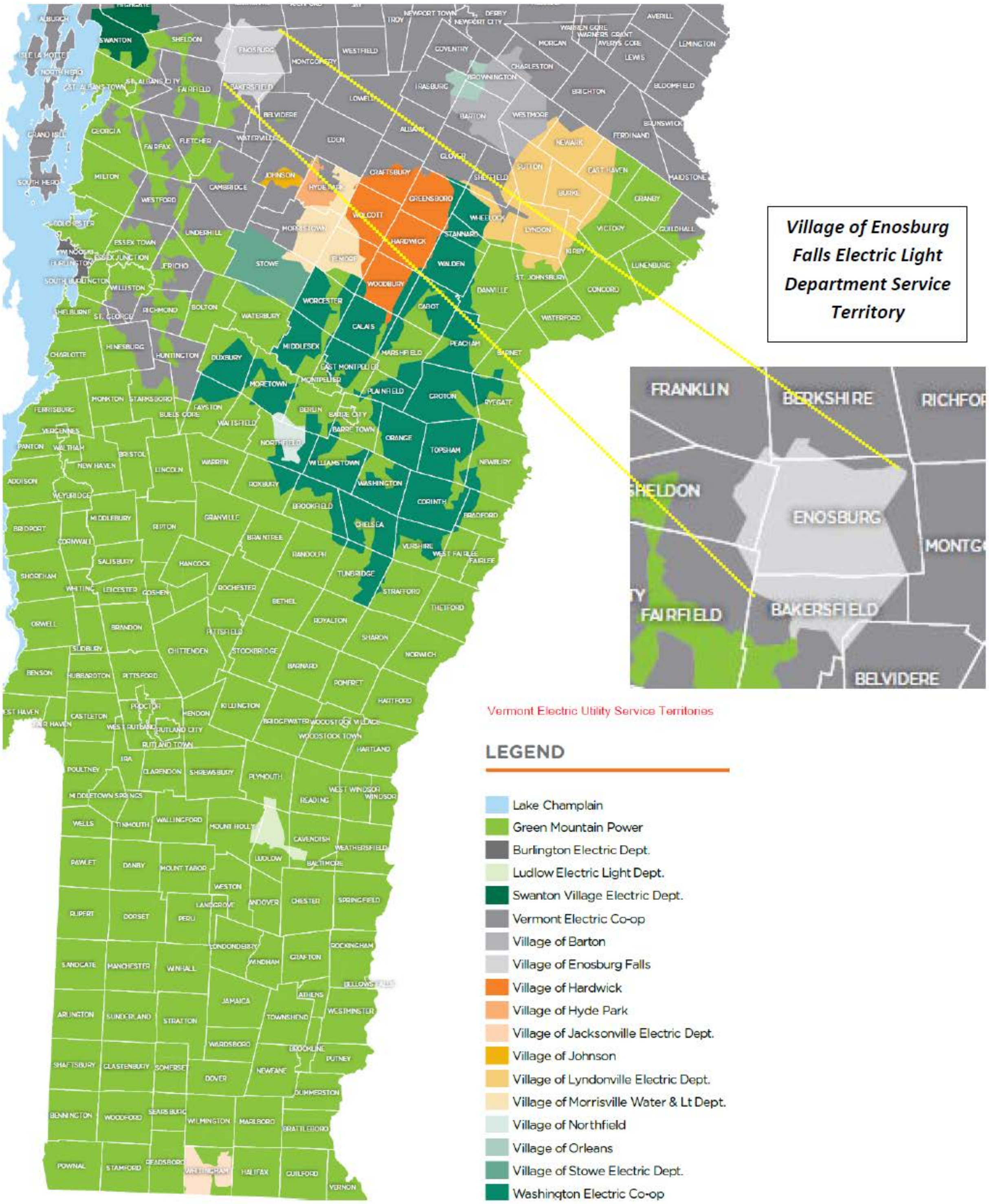
Introduction:

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

The Village sits on the Mississquoi River, is a part of the Mississquoi Valley Rail Trail, and is home to the cheese manufacturer, Franklin Foods. The service territory of VOEF is predominantly a dairy farming community, with 10 active farms. Much of the remaining commercial activity in Enosburg Falls supports dairy farming. VOEF's has added four to six new sugar maker customers in recent years. VOEF serves just over 1,740 retail customers.

Figure 1: VOEF's Distribution Territory



Vermont Public Power Supply Authority:

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

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

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

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

System Overview

In 2018 VOEF's peak demand in the winter months was 4,678 kW and 4,889 kW during the summer and shoulder months. Annual energy retail sales for 2018 were 26,848,098 kWh and the annual load factor for 2018 was 63.1%.

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

Table 1: VOEF's Retail Customer Counts

Data Element	2014	2015	2016	2017	2018
Residential (440)	579	585	581	576	576
Rural	923	936	942	946	952
Small C&I (442) 1000 kW or less	136	138	140	145	149
Large C&I (442) above 1,000 kW	23	23	22	22	21
Street Lighting (444)					
Public Authorities (445)	44	45	45	45	44
Interdepartmental Sales (448)	0	0	0	0	0
Total	**1,706**	**1,727**	**1,729**	**1,734**	**1,742**

Table 2: VOEF's Retail Sales

Data Element	2014	2015	2016	2017	2018
Residential (440)	3,715,077	3,711,538	3,537,458	3,487,677	3,939,122
Rural	9,674,097	9,945,511	9,929,727	10,074,531	10,557,933
Small C&I (442) 1000 kW or less	1,752,644	1,817,374	1,820,079	1,754,283	1,826,067
Large C&I (442) above 1,000 kW	9,756,321	10,198,626	10,269,601	9,615,156	9,331,848
Street Lighting (444)	169,739	167,640	166,254	158,053	152,603
Public Authorities (445)	1,045,066	1,091,236	1,081,877	1,082,702	1,040,525
Interdepartmental Sales (448)	0	0	0	0	0
Total	**26,112,944**	**26,931,926**	**26,804,996**	**26,172,402**	**26,848,098**
YOY	-6%	3%	0%	-2%	3%

Table 3: VOEF's Annual System Peak Demand (kW)

Data Element	2014	2015	2016	2017	2018
Peak Demand kW	4,775	4,669	4,654	4,700	4,889
Peak Demand Date	01/02/14	04/08/15	08/11/16	02/28/17	07/05/18
Peak Demand Hour	18	20	19	19	18

Structure of Report

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

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

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

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

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

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

VI. Action Plan
This chapter outlines specific actions the VOEF expects to take as a result of this Integrated Resource Plan.

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

B. Glossary

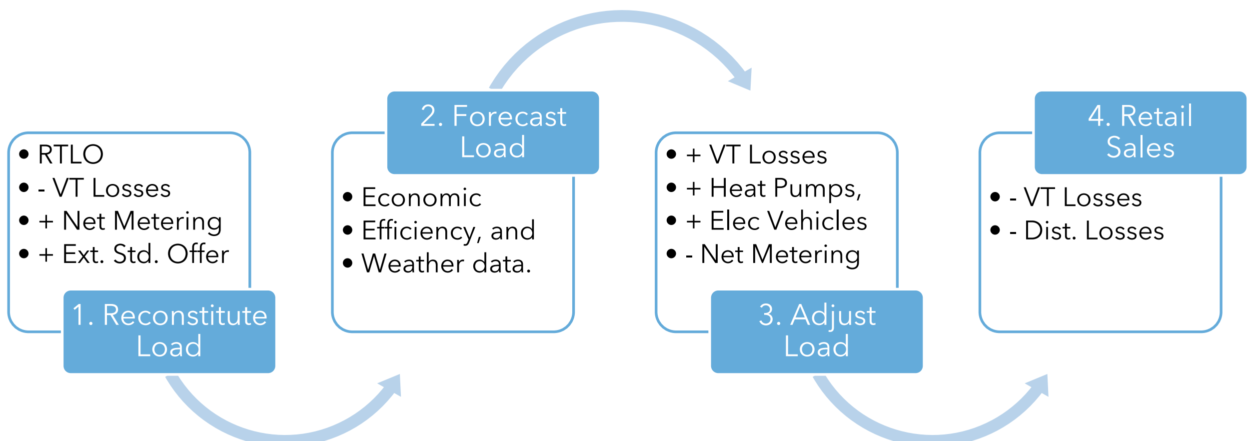
Electricity Demand

I. Electricity Demand

Energy Forecast Methodology: Regression with Adjustments

VPPSA uses Itron's Metrix ND software package and a pair of multiple regression equations to forecast VOEF's peak and energy requirements. Importantly, the peak and energy forecasts are based on the same underlying data sets and the same methodologies that are used to set VOEF's annual power budget. As a result, the forecasts are updated annually, and variances are evaluated monthly as actual loads become available. The forecast methodology follows a four-step process.

Figure 2: Forecasting Process



1. Reconstitute Load

In the past, metered load at the distribution system's tie points (boundaries) was used as the 'dependent' variable in the regression equations. However, the growing impact of the net metering and Standard Offer Programs has effectively obscured the historical trends in this data, and this would cause the accuracy of the regression equations to decrease. To preserve the accuracy of the regression forecast, VPPSA "reconstitutes" the Real-Time Load Obligation (RTLO) data by 1.) adding back generation from the net metering and Standard Offer Programs, and 2.) subtracting Vermont's transmission losses. This results in a data set that can be accurately modeled using multiple regression and creates consistency with the historical data.

The resulting, reconstituted load is used as the dependent variable in the regression equations and forms a historical time series data that the regression equations use to predict future loads. The following table summarizes the data that is used to reconstitute the load.

Table 4: Data Sources for Reconstituting RTLO

Data Element	Source
RTLO	ISO-NE
– Vermont Transmission Losses	VELCO[1]
+ Net Metering Program Generation	VPPSA
+ Standard Offer Program Generation	VELCO
= Reconstituted Load	

2. Forecast Load

The regression equations use a series of independent or "explanatory" variables to explain the trends in the reconstituted load data. The equations themselves consist of the explanatory variables that are listed in Table 5.

Table 5: Load Forecast Explanatory Variables

Data Category	Explanatory Variable	Source
Dummy Variables	These variables consist of zeros and ones that capture seasonal, holiday-related, and large, one-time changes in demand.	Not applicable. Determined by the forecast analyst.
Economic Indicators	Unemployment Rate (%)	Vermont Department of Labor
	Eating and Drinking Sales ($)	Woods and Poole
Energy Efficiency	Cumulative EE Savings Claims (kWh)	Efficiency Vermont Reports and Demand Resource Plan
Weather Variables	Temperature – 10-year average heating & cooling degree days.	National Oceanic and Atmospheric Administration (NOAA)

The forecast accuracy of the regression model is good. Based on monthly data, it has an adjusted R-squared of 89.2%, and a Mean Absolute Percent Error (MAPE) of 1.48%.

[1] Vermont Electric Power Company

3. Adjust Load

Once the regression models are complete and the forecast accuracy is maximized, the load forecast is adjusted to account for the impact (both historical and forward-looking) of cold climate heat pumps (CCHP), electric vehicles (EV), and net metering. As new electricity-using devices, CCHPs and EVs increase the load. However, by its nature, net metering decreases it[2].

Because the historical trends for these three items are still nascent, they cannot be effectively captured in the regression equations. In the case of net metering, VPPSA used the most recent three-year average to determine the rate of net metering growth in VOEF. For CCHPs and EVs, we used the same data (provided by Itron) that the Vermont System Planning Committee (VSPC) used in VELCO's 2018 Long Range Transmission Plan.

Notice that the adjusted load does not account for the presence of the Standard Offer Program. This is a deliberate choice that enables the resource planning model to treat the Standard Offer Program as a supply-side resource instead of a load-reducer.

4. Retail Sales

A forecast of retail sales is required to estimate compliance with the Renewable Energy Standard (RES) and is calculated by subtracting Vermont transmission and local distribution losses from the Adjusted Forecast.

[2] For more information on net-metering, please refer to https://vppsa.com/energy/net-metering/.

Energy Forecast Results

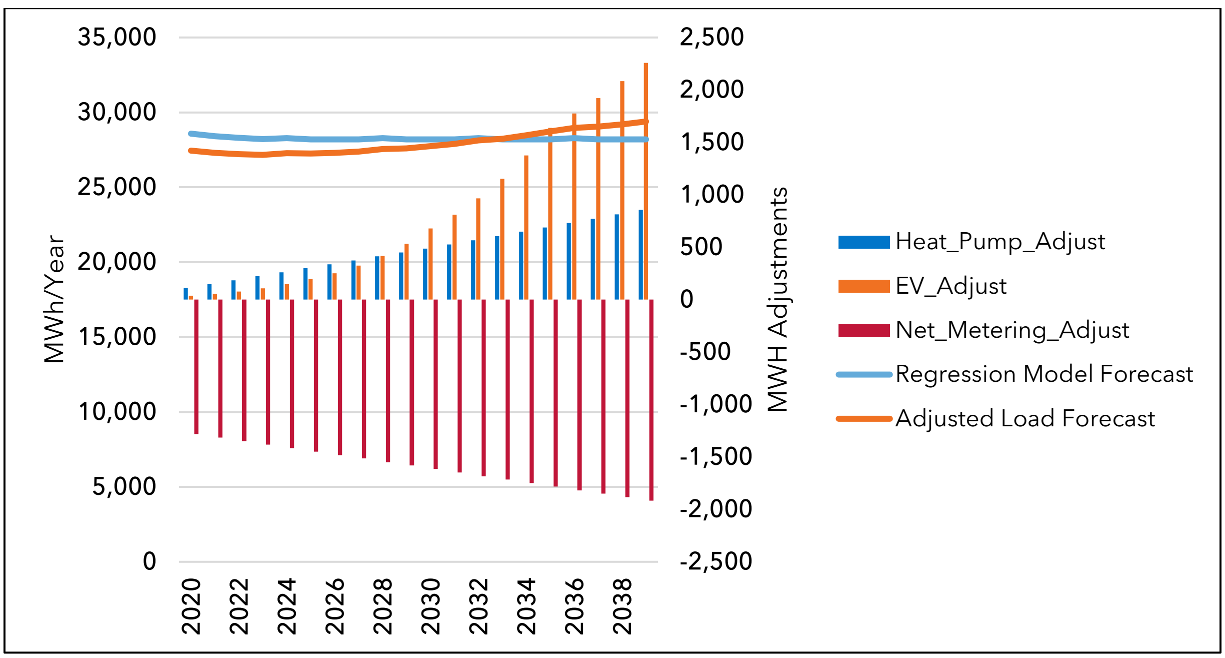
Table 6 shows the results of the Regression Forecast for energy, as well as the adjustments that are made to arrive at the Adjusted Forecast. The Compound Annual Growth Rates (CAGR) at the bottom of the table illustrate the trends in each of the columns. Notice that the Regression Forecast itself is flat. However, after making adjustments for CCHPs, EVs, and net metering, the Adjusted Forecast increases by 0.3% per year.

Table 6: Adjusted Energy Forecast (MWh/Year)

Year	Year #	Regression Fcst. (MWh)	CCHP Adjustment (MWh)	EV Adjustment (MWh)	Net Metering Adjustment (MWh)	Adjusted Fcst. (MWh)
2020	**1**	28,580	111	39	-1,283	27,447
2025	**6**	28,198	299	196	-1,448	27,245
2030	**11**	28,198	488	679	-1,616	27,750
2035	**16**	28,198	689	1,637	-1,783	28,740
2039	**20**	28,198	856	2,257	-1,918	29,393
CAGR		**-0.1%**	**10.7%**	**22.5%**	**2.0%**	**0.3%**

The Adjusted Forecast is the result of high CAGRs for CCHPs (10.7%) and EVs (22.5%). During the first eight years of the forecast, these two trends are more than offset by the net metering program, which grows by the historical three-year average of 2.0% per year. By 2033, the impact of CCHPs and EVs is on part with the impact of net metering, and the load growth accelerates from that year forward.

Figure 3: Adjusted Energy Forecast (MWh/Year)



Energy Forecast – High & Low Cases

To form a high case, we assumed that the CAGR for CCHPs and EV's about doubles to 25% and 40% respectively. Simultaneously, we assume that net metering penetration stops at today's levels. At these growth rates, 2039 energy demand rises by over 200% compared to 2020 electricity use, a result that is driven by the 40% CAGR for EVs. Because of the nature of compound growth, the increase in energy demand does not start to accelerate until 2030. As a result, there is ample opportunity to monitor these trends during the annual budget and the triennial IRP cycles.

Table 7: Energy Forecast – High Case

Year	Year #	Regression Fcst. (MWh)	CCHP Adjustment (MWh)	EV Adjustment (MWh)	Net Metering Adjustment (MWh)	Adjusted Fcst. (MWh)
2020	1	28,580	111	39	-1,283	27,447
2025	6	28,198	339	208	-1,283	27,463
2030	11	28,198	1,035	1,121	-1,283	29,071
2035	16	28,198	3,158	6,030	-1,283	36,103
2039	20	28,198	7,710	23,164	-1,283	57,789
CAGR		-0.1%	23.6%	37.7%	0.0%	3.8%

To form a low case, we assumed that the CAGRs for CCHPs and EVs decreases by more than 50% from the base case. In addition, we assumed that the CAGR for net metering triples. This combination of trends is a plausible worst-case scenario, and results in a forecast that *decreases* by 0.5% per year.

Table 8: Energy Forecast - Low Case

Year	Year #	Regression Fcst. (MWh)	CCHP Adjustment (MWh)	EV Adjustment (MWh)	Net Metering Adjustment (MWh)	Adjusted Fcst. (MWh)
2020	1	28,580	111	39	-1283	27,447
2025	6	28,198	142	62	-1724	26,678
2030	11	28,198	181	101	-2317	26,163
2035	16	28,198	231	162	-3113	25,478
2039	20	28,198	281	237	-3944	24,772
CAGR		**-0.1%**	**4.7%**	**9.5%**	**5.8%**	**-0.5%**

Peak Forecast Methodology: The Peak & Average Method

The peak forecast regression model forecasts the load during the peak hour each day. Because utility loads are strongly influenced by temperature, this peak usually occurs during an hour of relatively extreme temperatures. In winter, this is during a very cold hour, and in summer it is during a very hot hour.

Unlike the energy forecast model, using average weather in the peak forecast model is not appropriate. Why? By definition, the coldest day and hour is always colder than average, and the hottest day and hour is always hotter than average. As a result, using average weather in the peak forecast model would result in a forecast that is biased and too low. In this context, the key question is, "How can historical weather data be used to develop an accurate representation of future weather, while still maintaining the extremes?"

The answer is the rank-and-average method, which is widely accepted[3] and effectively represents the random, real-life extremes in average historical weather. This method assigns a temperature to each day of the year that is representative of the average of the coldest (or hottest) days. It is important to highlight that the rank and average method produces a "50/50" forecast. While one may expect this to be a method for forecasting extreme weather conditions, in reality extreme weather *is* normal.

Finally, the accuracy of the peak forecast regression model is good. Based on daily data, it has an R-squared of 73%, and a MAPE of 2.32%.

[3] For a more in-depth discussion of the method, please refer to Itron's white paper on the topic. https://www1.itron.com/PublishedContent/Defining%20Normal%20Weather%20for%20Energy%20and%20Peak%20Normalization.pdf

Peak Forecast Results

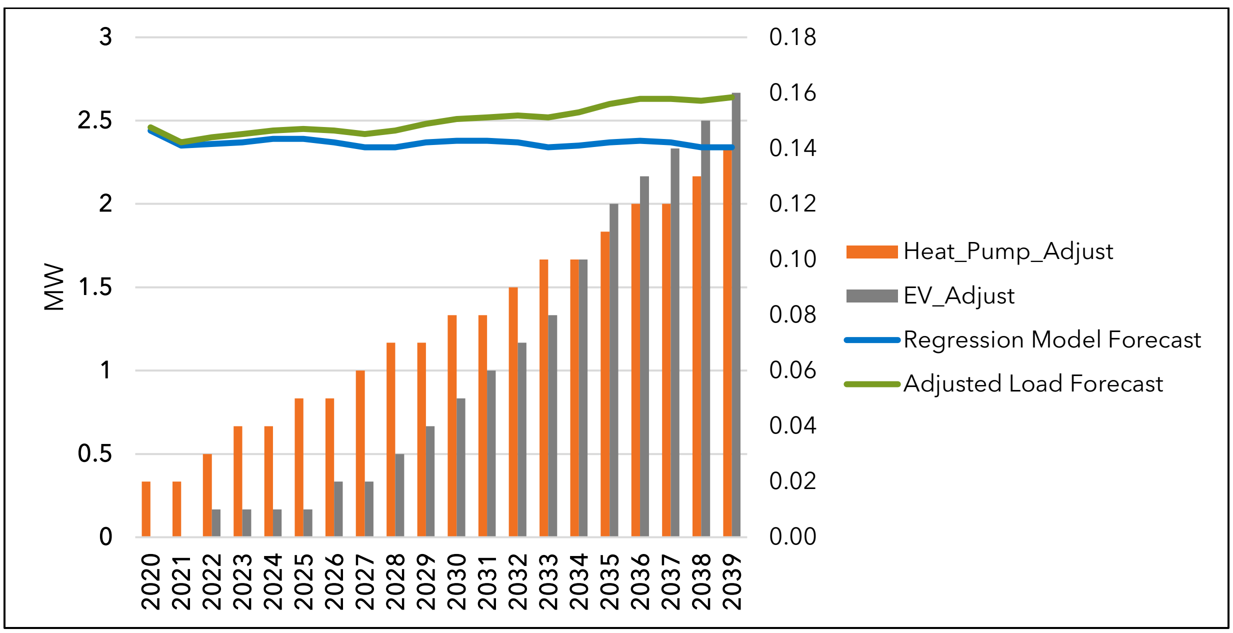
Table 9 shows the results of the Regression Forecast of peak loads, as well as the adjustments that are made to arrive at the Adjusted Forecast. The CAGR at the bottom of the table illustrate the trends in each of the columns. Notice that the Regression Forecast itself is decreasing by 0.1% per year. After making adjustments for CCHPs, EVs, and net metering, the Adjusted Forecast actually increases by 0.3% per year. Finally, the table shows that the timing of VOEF's peak load is forecast to stay in March at 1900 (7:00 PM).

Table 9: Peak Forecast (MW)

MMM-YY	Peak Hour	Regression Forecast	EV Adjustment	CCHP Adjustment	Net Metering Adjustment	Adjusted Forecast
Mar-20	1900	4.98	0.01	0.02	0.00	5.01
Mar-25	1900	4.94	0.03	0.05	0.00	5.02
Mar-30	1900	4.91	0.09	0.08	0.00	5.08
Mar-35	1900	4.91	0.23	0.11	0.00	5.25
Mar-39	1900	4.91	0.32	0.14	0.00	5.37
CAGR		**-0.1%**	**17.1%**	**10.2%**	**0.0%**	**0.3%**

The peak load forecast starts at 5.01 MW and ends at 5.37 MW. The Adjusted Forecast exceeds the Regression Forecast immediately in 2020 due to high CAGRs for CCHPs (10%). By 2034, EV's are forecast to be responsible for as much peak load growth as CCHP's, and can be seen in Figure 4.

Figure 4: Adjusted Peak Forecast (MW)



Peak Forecast – High & Low Cases

To form a high-case, we assumed that neither load controls nor Time-of-Use (TOU) rates are implemented, and then we adopt the same CAGR assumptions from the high case as in the energy forecast. Even under these assumptions, peak load growth does not start to materially impact the system until after 2030. Absent a step change in consumer adoption of CCHPs and EVs, electrification is not likely to produce any appreciable peak load growth for the next ten years. However, we will continue to monitor these trends annually.

Table 10: Peak Forecast – High Case

MMM-YY	Peak Hour	Regression Forecast	CCHP Adjustment (MW)	EV Adjustment (MW)	Net Metering Adj. (MW)	Adjusted Fcst. (MW)
Mar-20	1900	4.98	0.01	0.02	0.00	5.01
Mar-25	1900	4.94	0.03	0.06	0.00	5.03
Mar-30	1900	4.91	0.16	0.19	0.00	5.25
Mar-35	1900	4.91	0.87	0.57	0.00	6.34
Mar-39	1900	4.91	3.33	1.39	0.00	9.63
CAGR		**-0.1%**	**36.9%**	**23.6%**	**0.0%**	**3.3%**

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

Forecast Uncertainties & Considerations

The uncertainties facing VOEF stem from the growth rate of net-metering, CCHPs and EVs all of which are nascent trends that will almost certainly progress at different rates than forecast.

Franklin Foods

As VOEF's largest customer, Franklin Foods represents about 20% of VOEF's peak load and annual energy requirements. As the supply chapter will show, about 20% of VOEF's energy supplies reach the end of their term by 6/30/2024, and as long as this is the case, there is little risk of having a long-term surplus of energy in the event that Franklin Foods leaves the system. However, the loss of their retail revenue could cause some rate pressure, and this circumstance will be modeled explicitly in the Financial Analysis.

Net Metering

VOEF presently has 41 residential scale (< 15 kW) net metered customers with a total installed capacity of about 293 kW. In addition, there are four customers who have arrays between 15 and 500 kW, and they total 860 kW. In all, VOEF has about 1.2 MW of net metered capacity on its system which is 24% of the 2020 peak (5 MW).

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, it could lead to a step change in the adoption rate of net metering, and a quicker erosion of retail revenues for the utility.

Given the small size of the customer base and the nascent trends involved, net-metering represents a key uncertainty for VOEF to monitor, especially if more large net metered projects are proposed. For example, a 500 kW net metered solar project built in 2020 would represent a 41% increase in the base of installed, net metered capacity on the system. In this event, the impact would be captured in interconnection and annual power budgeting processes and managed accordingly.

Electricity Supply

II. Electricity Supply

VOEF's power supply is made up of owned generation, long-term contracts, and short-term contracts. The resources in VOEF's portfolio represent a range of fuel types and technologies. In addition, they are located throughout Vermont and New England, and many of their expiration dates have been chosen not to overlap. As a result, they act as a diversified portfolio that effectively hedges VOEF's power supply costs against the cost of serving load in ISO New England's energy, capacity and ancillary markets. The following sections describe each of VOEF's power supply resources, both in bulleted and in table formats.

1. Chester Solar

- Size: 4.8 MW
- Fuel: Solar
- Location: Chester, MA
- Entitlement: 11.5% (0.552 MW), PPA
- Products: Energy, capacity
- End Date: 6/30/39
- Notes: The contract does not include the environmental attributes.

2. Enosburg Falls Hydro

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

3. Fitchburg Landfill

- Size: 4.5 MW
- Fuel: Landfill Gas
- Location: Westminster, MA
- Entitlement: 8.5% (0.225 MW), PPA
- Products: Energy, capacity, renewable energy credits (MA I)
- End Date: 12/31/31

4. Hydro Quebec US (HQUS)

- Size: 212 MW
- Fuel: Hydro
- Location: Quebec
- Entitlement: 0.5% (0.214) MW, PPA
- Products: Energy, renewable energy credits (Quebec system mix)
- End Date: 10/31/38

5. Hydro Quebec / Vermont Joint Owners (VJO)

- Size: 6 MW

- Fuel: Hydro
- Location: Quebec
- Entitlement: 5.5% (0.25) MW, PPA
- Products: Energy, capacity, renewable energy credits (Quebec system mix)
- End Date: 10/31/20
- Notes: The Electric Department receives hydro power from a state-wide contract with the Hydro Quebec/Vermont Joint Owners.

6. Kruger Hydro

- Size: 6.7 MW
- Fuel: Hydro
- Location: Maine and Rhode Island
- Entitlement: 11.2% (0.760) MW, PPA
- Products: Energy, capacity
- End Date: 12/31/37
- Notes: The Electric Department has an agreement with VPPSA to purchase unit contingent energy and capacity from six hydroelectric generators. The contract does not include the environmental attributes.

7. Market Contracts

- Size: Varies
- Fuel: New England System Mix
- Location: New England
- Entitlement: Varies (PPA)
- Products: Energy, renewable energy credits
- End Date: Varies, less than 5 years.
- Notes: In addition to the above resources, the Electric Department purchases system power from various other entities under short-term (5 year or less) agreements. These contracts are described as Planned and Market Purchases in the tables below.

8. McNeil

- Size: 54 MW
- Fuel: Wood
- Location: Burlington, Vermont
- Entitlement: 1.2% (0.6 MW), joint-owned through VPPSA
- Products: Energy, capacity, renewable energy credits (CT Class I)
- End Date: Life of Unit
- Notes: As the joint-owner, VPPSA has agreements with the Electric Department to pay for and purchase 1.2% of the unit's output.

9. New York Power Authority (NYPA)

- Size: 2,675 MW (Niagara), 1,957 MW (St. Lawrence)
- Fuel: Hydro
- Location: New York State
- Entitlement: 0.220 MW (Niagara PPA), 0.005 MW (St. Lawrence PPA)
- Products: Energy, capacity, renewable energy credits (NY System Mix)
- End Date: 9/1/25 (Niagara), 4/30/32 (St. Lawrence)
- Notes: NYPA provides hydro power to the Electric Department under two contracts, which will be extended at the end of their term.

10. NextEra 2018-22

- Size: 1,250 MW
- Fuel: Nuclear
- Location: East Ryegate, VT
- Entitlement: 0.867 MW On-Peak, 0.720 MW Off-Peak (PPA)
- Products: Energy, capacity, environmental attributes (Carbon-free nuclear)
- End Date: 12/31/2022

11. Project 10

- Size: 40 MW
- Fuel: Oil
- Location: Swanton, VT
- Entitlement: 4.7% (1.9 MW) MW, joint-owned through VPPSA
- Products: Energy, capacity, reserves
- End Date: Life of unit
- Notes: As the joint-owner, VPPSA has agreements with the Electric Department pay for and purchase 4.7% of the unit's output.

12. PUC Rule 4.100 (VEPPI Program)

- Size: Small hydro < 80 MW
- Fuel: Hydro
- Location: Vermont
- Entitlement: 0.5% (Statutory)
- Products: Energy, capacity
- End Date: 10/31/2020
- Notes: The Electric Department is required to purchase hydro power from small power producers through Vermont Electric Power Producers, Inc. ("VEPPI"), in accordance with PUC Rule #4.100. The entitlement percentage fluctuates slightly each year with the Electric Department's pro rata share of Vermont's retail energy sales, and does not include the renewable energy credits.

13. PUC Rule 4.300 (Standard Offer Program)

- Size: Small renewables, primarily solar < 2.2 MW
- Fuel: Mostly solar, but also some wind, biogas and micro-hydro
- Location: Vermont
- Entitlement: 0.52% (Statutory)
- Products: Energy, capacity, renewable energy credits
- End Date: Varies
- Notes: The Electric Department is required to purchase power from small power producers through the Vermont Standard Offer Program, in accordance with PUC Rule #4.300. The entitlement percentage fluctuates slightly each year with the Electric Department's pro rata share of Vermont's retail energy sales.

14. Ryegate

- Size: 20.5 MW
- Fuel: Wood
- Location: East Ryegate, VT
- Entitlement: 0.5% (PPA)
- Products: Energy, capacity, renewable energy credits (CT Class I)
- End Date: 10/31/2021

Enosburg Falls Hydro

The federal license to operate Enosburg Falls Hydro expires on April 23, 2023. The relicensing process has been ongoing since the fall of 2018, when VOEF held a public meeting[4] and site visit for all interested agencies and the public.

VOEF expects to file final application by February of 2021, several months in advance of the deadline. After the final application is made, it is uncertain how long it will take to complete the relicensing process. For the purpose of this IRP, we assume that the generator is relicensed by April 2023 and continues to generate electricity near its recent historical average.

[4] The public meeting was held on November 8, 2018.

Existing Power Supply Resources

Table 11 summarizes VOEF's resources 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[5] (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 2039.

Table 11: Existing Power Supply Resources

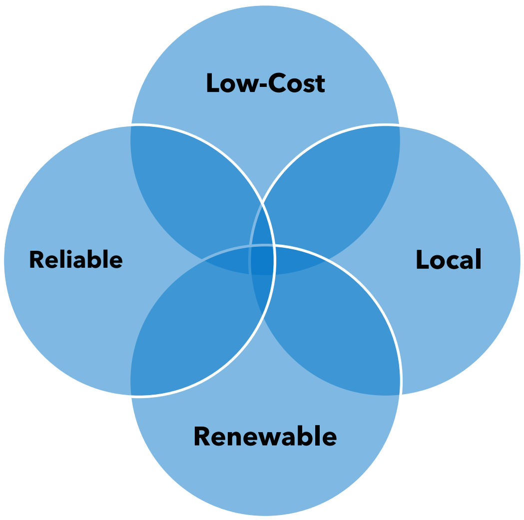
Resource	2020 MWH	% of MWH	2020 MW	Delivery Pattern	Price Pattern	REC	Expiration Date	Renewal to 2039
1. Chester Solar	768	2.9%	0.219	Intermittent	Fixed		6/30/2039	No
2. Enosburg Falls Hydro	3,441	13.0%	0.000	Intermittent	Fixed	✓	Life of unit.	Yes
3. Fitchburg Landfill	2,871	10.9%	0.285	Firm	Fixed	✓	12/31/2031	No
4. HQ US	1,255	4.8%	0.000	Firm	Indexed	✓	10/31/2038	No
5. HQ VJO	1,486	5.6%	0.329	Firm	Indexed	✓	10/31/2020	No
6. Kruger Hydro	2,831	10.7%	0.176	Intermittent	Fixed		12/31/2037	No
7. Market Contracts	377	1.4%	0.000	Firm, Shaped	Fixed		6/30/2024	No
8. McNeil	3,193	12.1%	0.600	Dispatchable	Variable	✓	Life of unit	Yes
9. New York Power Authority	1,596	6.0%	0.226	Baseload	Fixed	✓	9/25, 4/32	Yes
10. NextEra 2018-22	6,929	26.2%	0.000	Firm, Shaped	Fixed	✓	12/31/2022	No
11. Project 10	28	0.1%	1.817	Dispatchable	Variable		Life of unit.	Yes
12. PUC Rule 4.100	138	0.5%	0.017	Intermittent	Fixed		2020	No
13. PUC Rule 4.300	661	2.5%	0.006	Intermittent	Fixed	✓	Varies	No
14. Ryegate	844	3.2%	0.098	Baseload	Fixed	✓	10/31/2021	Yes
Total MWH	26,418	100.0%	3.776					

[5] Note that RECs are defined broadly in this table, and the "emissions attributes" from non-renewable (but also non-carbon emitting) resources such as nuclear are included in this table.

Future Resources

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

Figure 5: Resource Criteria



- ✓ **Low-Cost** resources reduce and stabilize electric rates.
- ✓ **Local** resources are located within the Northwest 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 VOEF to focus on a subset of generation technologies, and to exclude coal, geothermal and solar thermal generation which do not meet them. Resources that VOEF may consider fall into three categories: 1.) Existing resources in Table 11, 2.) Demand-side resources, and 3.) New resources.

Category 1: Extensions of Existing Resources

This plan assumes that three existing resources are extended past their current expiration date. These include NYPA, Project 10, and Ryegate. The most crucial of these is Project 10, which supplies over 95% of VOEF's capacity. Where resource needs remain, market contracts will be used to supply them.

1.1 Market Contracts

Market contracts are expected to be the most readily available source of electric supply for energy, capacity, ancillary services and renewable attributes (RECs). By conducting competitive solicitations through VPPSA, VOEF 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 VOEF'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, VOEF will continue to welcome the work of the Efficiency Vermont (EVT) in its service territory. VOEF 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 VOEF continues to implement its energy transformation programs under RES.

Category 3: New Resources

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

3.1 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, but the costs remain substantially higher than for on-shore wind. As a result, VOEF would approach such projects with more reserve.

3.2 Gas-Fired Generation

As Project 10 approaches an investment in a major overhaul and the requirements for reserves, voltage support and other ancillary services shift, VOEF will investigate simple and combined cycle (CC) generation. This includes entitlements to new or existing plants in New England, and to traditional peaking generation which continues to provide reliable peak-day service to the New England region. It should be noted that as a participant in ISO New England's markets, the marginal cost of supply is set by these same resources, and that the benefit of owning an entitlement in one is primarily to reduce heat rate risk.

3.3 Solar Generation

Solar development is increasingly common and cost-effective, particularly at utility scales. Plus, it can be deployed locally. Furthermore, solar is expected to be the primary technology that is employed to meet its Distributed Renewable Energy (Tier II) requirements under RES. For these reasons, solar is likely to be a leading resource option, and VOEF will continue to investigate solar developments both within its service territory and outside of it.

3.31 Net Metering

While net metering participation rates are presently modest and are forecast to grow modestly, VOEF will monitor the participation rate closely as solar costs approach grid parity. Should grid parity occur, not only would net metered solar penetration be expected to take off but the costs of the existing program would likely cause upward rate pressure[6]. As a result, net metered solar is an inferior option when compared to lower-cost and utility scale solar projects.

3.4 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. 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.

3.5 Battery Storage

Any discussion of future resources would be remis without including battery storage. While still in its initial phase of commercialization, there are six use cases where storage is being installed. According to a recent analysis by Lazard[7], use cases fall into two categories:

1. **In-Front-of-the-Meter**
    a. Wholesale (Used as a replacement for peaking generation.)
    b. Transmission and Distribution (Used to defer or replace traditional T&D investments.)
    c. Utility-Scale (Solar + Storage)

2. **Behind-the-Meter**
    a. Commercial & Industrial (Used as a standalone way to reduce demand charges.)
    b. Commercial & Industrial (Solar + Storage)
    c. Residential (Solar + Storage)

All of the In-Front-of-the-Meter use cases are large-scale, and small public power utilities like VOEF may be best served by participating in such projects as a joint owner or entitlement holder, not the lead participant. However, where local T&D constraints are present or when utility-scale solar plus storage sites are being developed, VOEF will work through VPPSA to quantify the business case. Similarly, the business case for Behind-the-Meter applications will be quantified as those opportunities are identified.

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[6] An excellent discussion of net metering and rate-design policy issues by Dr. Ahmad Faruqui can be found in the October 2018 issue of Public Utilities Fortnightly. https://www.fortnightly.com/fortnightly/2018/10/net metering-faq

[7] For a current analysis and list of use cases, please refer to the "Levelized Cost of Storage Analysis – Version 4.0", Lazard, November 2018. https://www.lazard.com/perspective/levelized-cost-of-energy-and-levelized-cost-of-storage-2018/

Regional Energy Planning (Act 174)

As part of the Northwest Regional Planning Commissions (NRPC), VOEF is part of a Regional Energy Plan[8] that was created in 2017. The intent of the plan is "to complete in-depth energy planning at the regional level while achieving state and regional energy goals—most notably, the goal to have renewable energy sources meet 90% of the state's total energy needs by 2050 (90 x 50 goal)."[9]

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

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

[9] Northwest Regional Energy Plan 2017, Page 5

Resource Plan

III. Resource Plans

Resource Acquisition Strategy

VOEF evaluates resource acquisitions on three different time scales.

Short-Term (< 1 year)

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

At least seasonally (four times a year), VPPSA uses a 7x24 energy product to refine the energy hedge ratio for VOEF. The following three-step process is used to balance supply and demand on a monthly basis within the current budget (calendar) year.

1. Update Budget Forecast
    a. The budgeted volumes (MWH) are updated to reflect known changes to demand and supply including unit availability, fuel supply, and hydrological conditions.
2. Hydroelectric Adjustment
    a. Supply is 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 dryer-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 VOEF into the +/-5% range, external transactions are placed with power marketers, either directly or through a broker.
    c. Price: For Internal Transactions, the price of the transaction is set by an average of the bid-ask spread as reported by brokers on the date of the transaction. For External Transactions, the price is set through a negotiation with the counterparty.

Medium Term (1-5 years)

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. Then 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, delivery and invoice tracking.

Long Term (> 5 years)

VOEF evaluates long-term Purchased Power Agreements (PPAs) for bundled energy, capacity, renewable energy credits, and/or ancillary products on an ongoing basis. Recently, VOEF has evaluated a solar PPA in partnership with VPPSA and Encore Renewables, and in 2020, VOEF anticipates that it may evaluate two other resource acquisitions.

1. A contract extension with NextEra as the current PPA expires at the end of 2022, and/or

2. A hydro PPA that includes energy, capacity, and Tier I RECs.

Because long-term PPAs are subject to PUC approval, the acquisition strategy is to identify the optimal size and shape of the desired products (energy, capacity, RECs, ancillary services), and then negotiate the best possible terms with creditworthy counterparties. Once the rate impact of these terms is determined and the requirements of Act 248 are met, then VOEF would file for PUC approval. In all circumstances, the resource acquisition would be made contingent on PUC approval.

Major Decisions

As the following sections will explain, VOEF faces a series of potential risks and accompanying resource decisions that can prudently fulfill its energy, capacity and RES obligations in the coming years. These include:

1. Energy and RECs

    a. Contract Expirations: There are three contract expirations that VOEF faces in the coming three years. First, the HQ VJO Contract expires on 10/31/20, and it represents about 5% of VOEF's energy supply. Second, the NextEra contract expires on 12/31/2022, and it represents about 26% of VOEF's energy supply. Finally, VOEF has some small market contracts that expire on 6/30/24 that represents about 2% of its energy supply. In total, these resources account for about a third of VOEF's energy supply and replacing them represents the first major decision point in the IRP.

    b. Contract Extension: One way to manage the contract expirations is to extend the existing contract with NextEra and continue to hedge the remaining energy market exposure with market contracts. This approach is modeled in the financial analysis.

    c. Large Hydro Resource & LIHI Certification for Enosburg Falls Hydro: Because large hydro resources are dispatchable, they could hedge VOEF's energy requirements as effectively as a market contract. A large hydro resource could also supply Tier I RECs, which would be particularly attractive if Enosburg Falls Hydro becomes LIHI certified and starts selling RECs to reduce rates. As a result, this approach is modeled in the financial analysis.

    d. Solar Resource: An in-state solar PPA that includes Tier II RECs is an ideal way to comply with and manage the cost of RES compliance. As a result, the following analysis will illustrate how a 1 MW PV PPA with Tier II eligible RECs can cost-effectively reduce the cost and risk of complying with Tiers II and III of the RES.

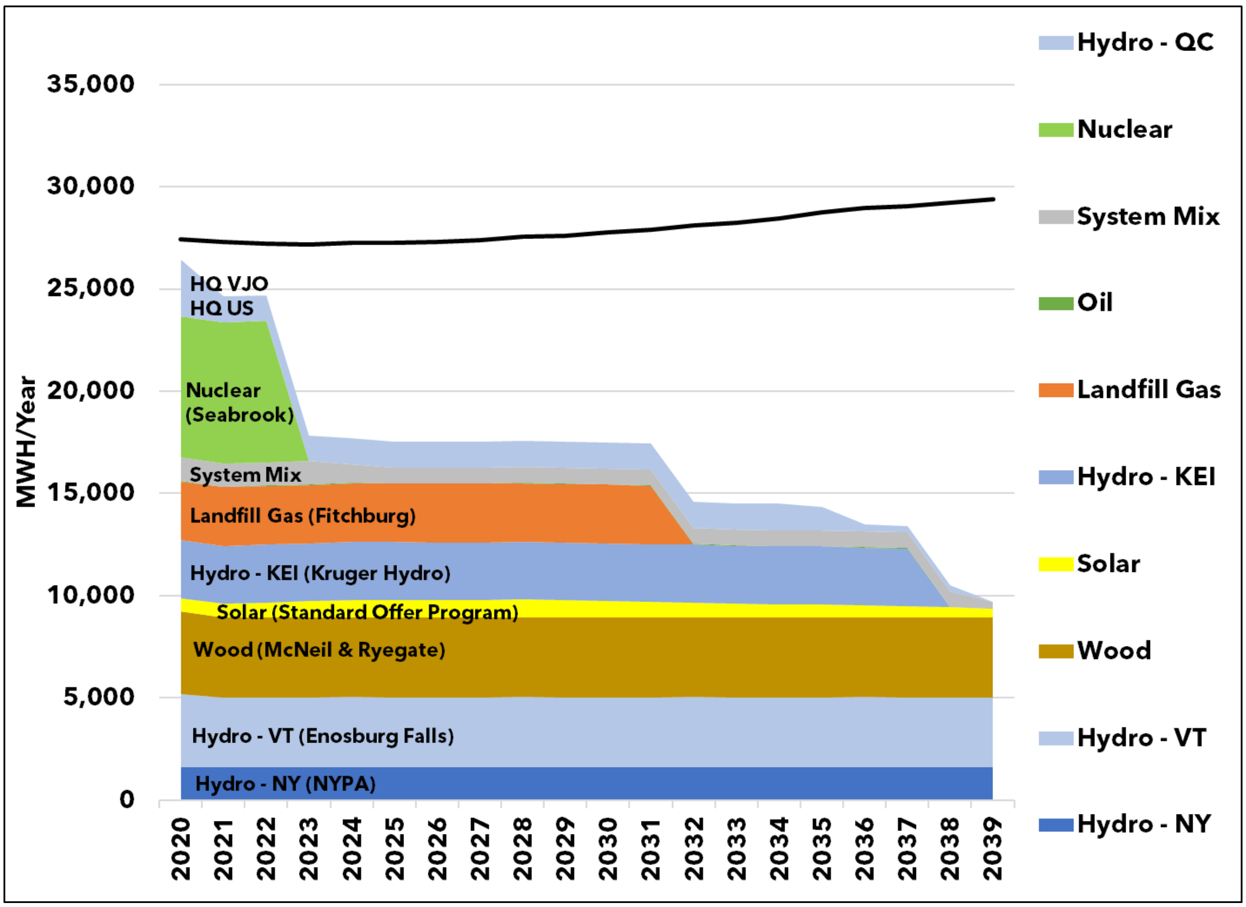
Energy Resource Plan

Figure 6 compares VOEF's energy supply resources to its adjusted load. There are two major resource decisions that, in total, will affect almost one third of VOEF's energy supply between 2020 and 2024. The first is the expiration of the Hydro Quebec – Vermont Joint Owners (QH VJO) contract on 10/31/2020, which represents about 5% of VOEF's energy supply. The second is the expiration of the NextEra contract on 12/31/2022, which represents about 26% of VOEF's energy supply.

Leading options to replace these contracts include:

- Market Contracts: Sign a PPA for market energy supplies.
- NextEra: Renegotiate the NextEra contract and extend its term,
- Large Hydro: Sign a PPA for an existing, dispatchable hydro plant to provide energy and Tier I RECs, and

Figure 6: Energy Supply & Demand by Fuel Type



The impact of these two resource expirations on the portfolio is summarized in Table 12. Because the price of the NextEra contract is presently above the market price forecast, its expiration could potentially reduce rate pressure. It will have no impact on RES compliance, but because it includes emissions free nuclear attributes, it will increase VOEF's emissions rate if it is not replaced with another emissions free resource. The impact of the market contracts' expiration is not expected to impact rates because they are priced very close to today's market price forecast.

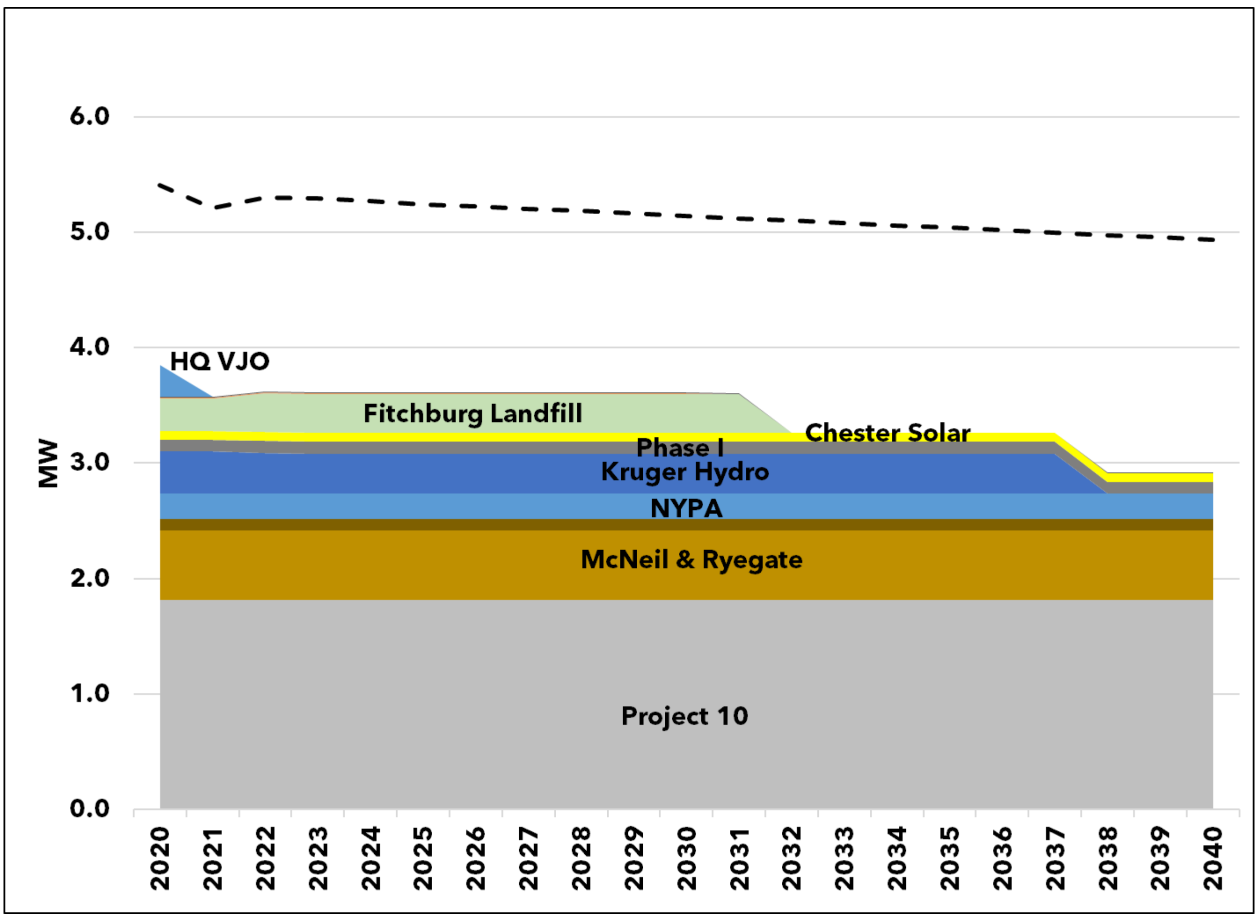
Table 12: Energy Resource Decision Summary

Resource	Years Impacted	% of MWH	Rate Impact	RES Impact
1. HQ VJO	2021+	5%	Beneficial	Detrimental
2. NextEra 2018-2022	2023+	26%	Beneficial	None

Capacity Resource Plan

Figure 7 compares VOEF's capacity supply to its demand. Project 10 provides about half of VOEF's capacity, and eight other resources contribute to the other half. In total, these resources meet 67-75% of VOEF's capacity requirement. In the early 2020s.

Figure 7: Capacity Supply & Demand (Summer MW)



The gap between supply and demand is 1.8 MW or a 33% deficit. This deficit is contingent on VOEF's annual coincident peak with ISO-NE, which has varied by as much as +/-15% in a single year. In addition, Enosburg Falls Hydro could contribute up to 1 MW (as a load reducer) during wet summers. As a result, this deficit is not out of scale with VOEF's peak loads, and in any case, any imbalances will be settled through the Forward Capacity Market.

As the largest part of the capacity supply, the reliability of Project 10 is the primary concern for VOEF. As a result, maintaining the reliability of Project 10 will be the key to minimizing VOEF's capacity costs, as explained in the next section.

ISO New England's Pay for Performance Program

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

The following table illustrates the range of performance payments that VOEF's 4.7% (1.8 MW) 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, VOEF could receive up to a $2,400 payment or pay up to a $2,800 penalty during a one-hour scarcity event. This represents a range of plus or minus 8% of VOEF's monthly capacity budget. However, such events are not expected to occur more than a few times a year (if at all) and can last less than one hour.

Table 13: Pay for Performance Ranges for One Hour of Project 10 Operation[11]

ISO-NE Load	Performance Payment Rate	0% Performance	50% Performance	100% Performance
10,000	$2,000/MWH	-$1,200	$600	$2,400
15,000	$2,000/MWH	-$1,700	$100	$1,900
20,000	$2,000/MWH	-$2,200	-$400	$1,400
25,000	$2,000/MWH	-$2,800	-$900	$900

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

[11] 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 Requirements

VOEF's obligations under the Renewable Energy Standard[12] (RES) are shown in Table 14. Under RES, VOEF must purchase increasing amounts of electricity from renewable sources. Specifically, its Total Renewable Energy (Tier I) requirements rise from 59% in 2020 to 75% in 2032, and the Distributed Renewable Energy[13] (Tier II) requirement rises from 2.8% in 2020 to 10% in 2032. Note that this IRP assumes that these requirements are maintained at their 2032 levels throughout the rest of the study period.

Table 14: RES Requirements (% of Retail Sales)

Year	Tier I (A)	Tier II (B)	Net Tier I (A) - (B)	Tier III
2020	59%	2.80%	56.20%	2.67%
2021	59%	3.40%	55.60%	3.33%
2022	59%	4.00%	55.00%	4.00%
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%
2033-2039	75%	10.00%	65.00%	10.67%

Under RES, Tier II is a subset of Tier I. 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 2nd and 3rd 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 2nd and 3rd year. This can be seen more clearly in Figure 8 in the next section.

The final column shows the Energy Transformation (Tier III) requirement. Because it is designed to reduce fossil fuel use, the Tier III requirement is fundamentally different from Tier I and Tier II requirements. And unlike the Tier I & II requirements…which count only electricity that is produced and consumed in an individual year[14]…Tier III programs account for the "lifetime" the fossil fuel savings. For example, if a Tier III program installs a CCHP in 2020, the fossil fuel savings from that CCHP are counted such that the full ten-years of the CCHP's expected useful life accrue to the 2020 Tier III requirement.

[12] For more information on the RES program, please visit https://vppsa.com/energy/renewable-energy-standard/.

[13] Distributed Renewable Energy must come from projects that are located in Vermont, are less than five MW in size, and are built after June 30th, 2015.

[14] 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.

Table 15: Alternative Compliance Payment[15] ($/MWH)

Year	Tier I	Tier II & III
2020	$10.00	$60.00
2021	$10.22	$61.32
2022	$10.44	$62.67
2023	$10.67	$64.05
2024	$10.91	$65.46
2025	$11.15	$66.90
2026	$11.39	$68.37
2027	$11.65	$69.87
2028	$11.90	$71.41
2029	$12.16	$72.98
2030	$12.43	$74.59
2031	$12.70	$76.23
2032	$12.98	$77.90

The RES statute provides a second way to comply with its requirements, the Alternative Compliance Payment (ACP). In the event that a utility has not achieved the requisite amount of Tier I, II or 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).

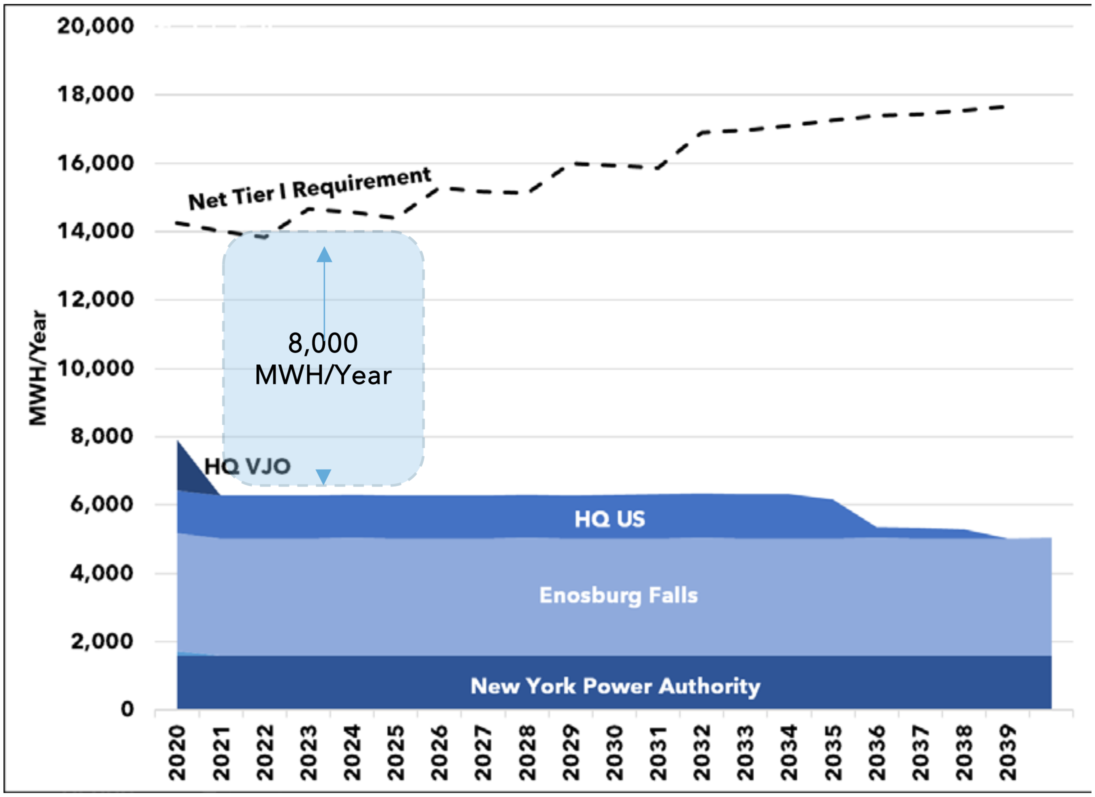
Finally, utilities with a RES deficit may also petition the Public Utilities Commission (PUC) for relief from the ACP. Alternatively, utilities may petition PUC to roll the deficit into subsequent compliance years. As a result, there are multiple ways to comply with RES requirements.

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

Tier I - Total Renewable Energy Plan

Between 2020 and 2024, VOEF's Net Tier I requirement is about 14,000 MWH per year. Three resources (NYPA, Enosburg Falls Hydro and HQ US/VJO) contribute to meeting it and provide almost 8,000 MWH in 2020 as shown in Figure 8. However, the HQ VJO contract expires in October, leaving just over 6,000 MWH/year of supply. This results in a deficit of about 8,000 MWH per year or 45% of VOEF's Net Tier I requirement.

Figure 8: Tier I - Demand & Supply (MWH)



In the early years of the 2020s, VOEF is likely to meet its Net Tier I requirements by purchasing Maine Class II (ME II) Renewable Energy Credits (RECs). These are presently the lowest cost source of Tier I compliant RECs in the region, and their price has ranged from a low of $0.25 to a high of $2.50 per MWH over the past four years. At the current price of $1.5/MWH, the cost of complying with Net Tier I in the 2020 to 2024 period would be about $13,000 per year.

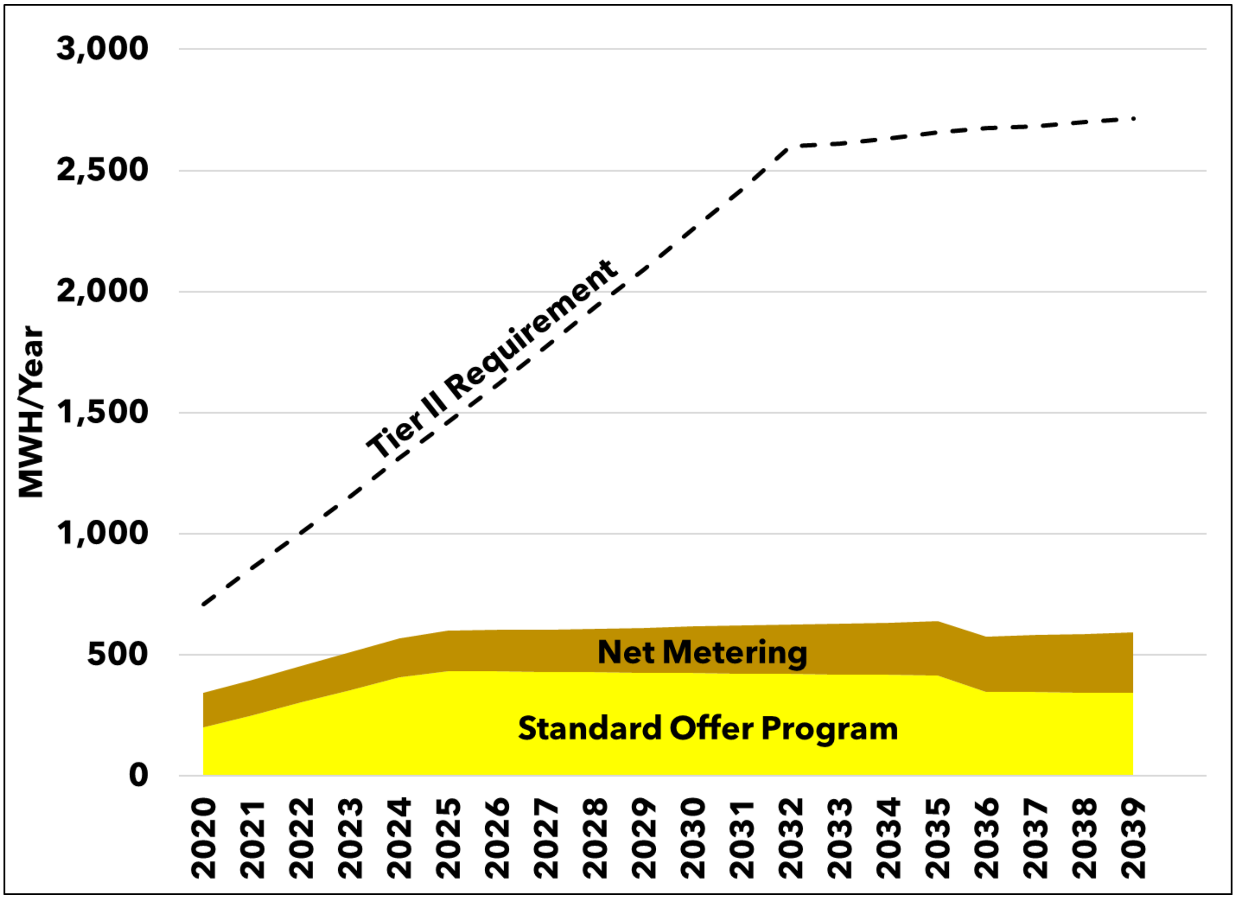
As mentioned in the Energy Resource Plan, the expiration of the NextEra 2018-2022 and Market PPAs creates an opportunity to purchase a resource that provides both energy and RECs. The 8,000 MWH per year deficit is equivalent to a 2.3 MW hydro facility[16], and if the output from a hydro resource of this size and capacity factor was purchased (including RECs), the Net Tier I deficit between 2020 and 2024 would be erased. This resource choice is one of the major resource decisions that is analyzed in this IRP.

[16] We have assumed a 40% capacity factor, which results in roughly 8,000 MWH per year.

Tier II - Distributed Renewable Energy Plan

The dashed line in Figure 9 shows VOEF's Distributed Renewable Energy[17] (Tier II) requirement, which rises steadily from 710 MWH in 2020 to 2,600 MWH in 2032. VOEF's demand exceeds the supply despite the net metering program and the standard offer (PUC Rule 4.300) program. In the short-term, market REC purchases will likely be used to fulfill the Tier II requirement. In the long-term, a 250-1,000 kW solar project could meet the requirement.

Figure 9: Tier II – Demand & Supply (MWH)

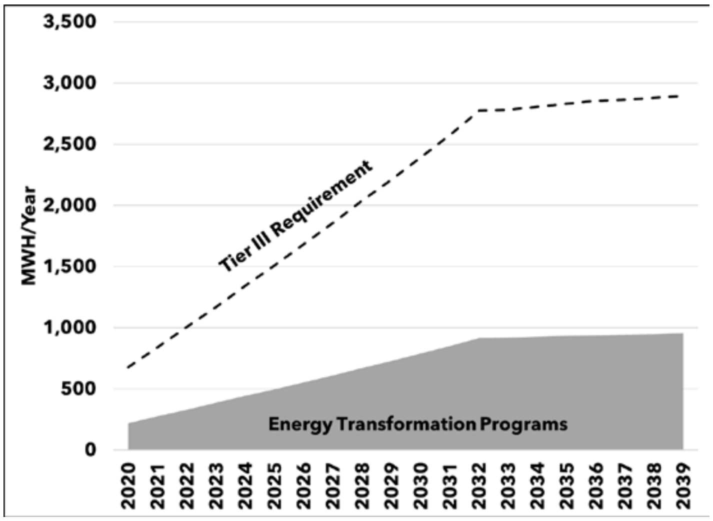


[17] The TIER II requirement is also known as "Tier 2".

Tier III - Energy Transformation Plan

The dashed line in Figure 10 shows VOEF's Tier III requirements, which rise from about 700 MWH in 2020 to about 2,800 MWH in 2032. Energy Transformation programs are presently budgeted to fulfill about a third of the requirement in the early 2020s,and are shown in the gray-shaded area of Figure 10. These programs[18] cover a range of qualifying technologies including EVs, CCHPs, and HPWHs. For perspective, the Tier III requirement is equivalent to installing 30-60 CCHP[19] per year between 2020 and 2025.

Figure 10: Energy Transformation Supplies



In the early and mid 2020s, VOEF is expected to have a substantial deficit which is illustrated in Figure 10. This deficit is likely to be fulfilled with market purchase of Tier II RECs. However, whatever the deficit or surplus position, VOEF will follow a four-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. Develop and complete the Lawrence Brook Solar or a comparable, Vermont-based solar project, and/or

4. Purchase a surplus of Tier II qualifying renewable energy credits.

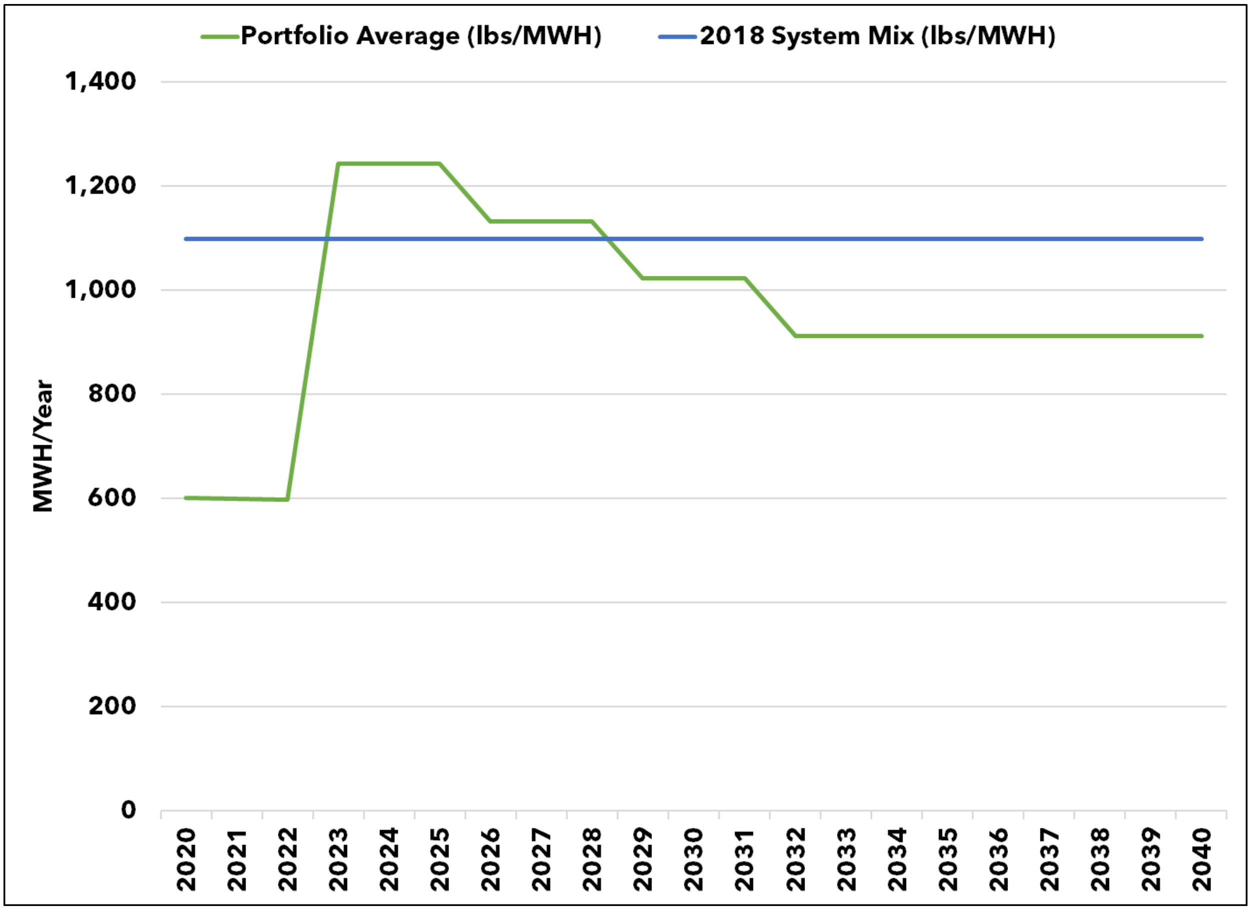
[18] More detail on these programs can be found in Appendix B (VPPSA's 2019 Tier 3 Annual Plan) and on VPPSA's website.

[19] This estimate is based on 15 MWH/CCHP of net lifetime savings, which is an average of all listed single-zone CCHP measures in the 'Act 56 Tier III Planning Tool FINAL PY2019.xls' spreadsheet.

Carbon Emissions and Costs

Figure 11 shows an estimate of VOEF's carbon emissions rate compared to the 2018 system average emissions rate in the New England region[20]. The emissions rate between 2020 and 2022 is about 600 lbs/MWH. However, the emissions level rises to over 1,200 lbs/MWH in 2023, which is a level that is slightly above the 2018 system mix. This is due to the expiration of the HQ VJO and the NextEra 2018-2022 contract, whose MWHs are being replaced by fossil fuels[21]. Thereafter, the carbon emissions rate declines until 2032 as the RES requirements increase.

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



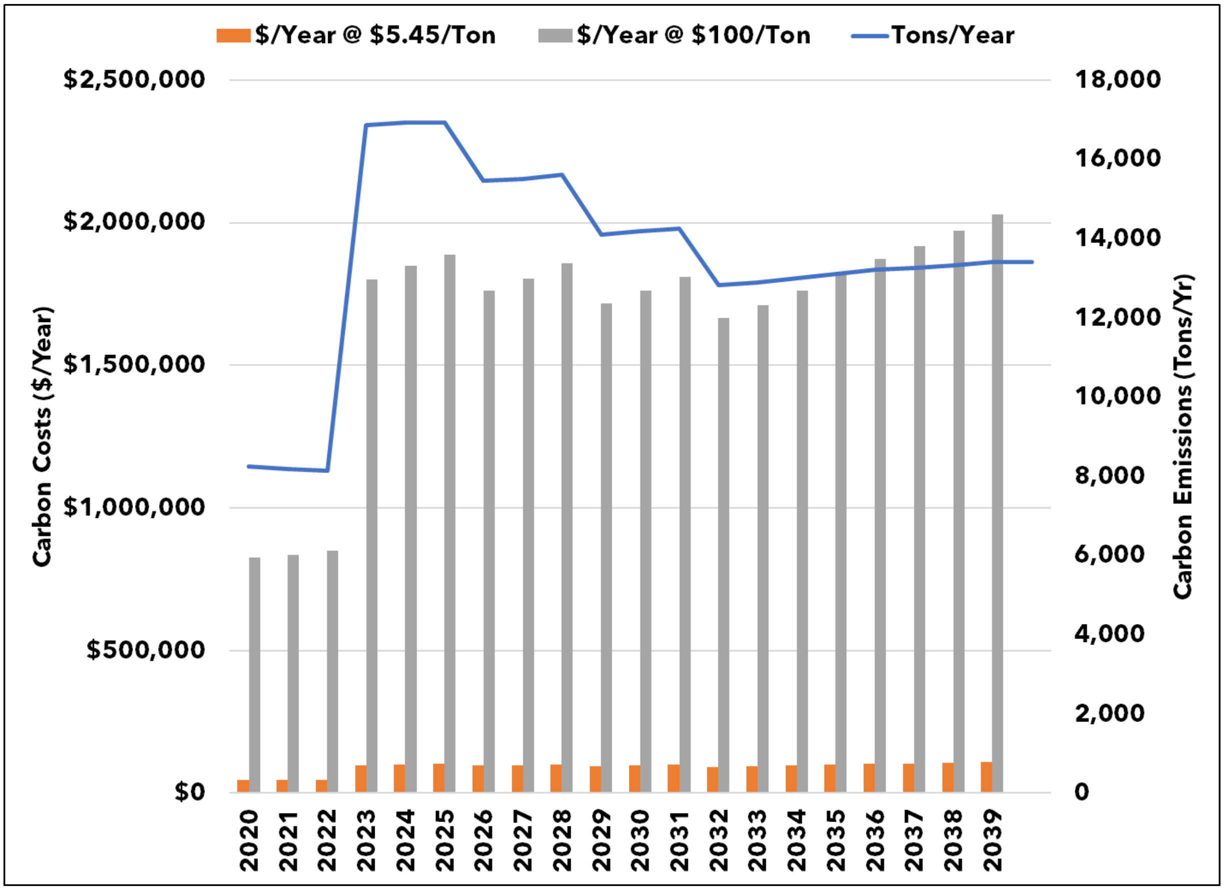
[20] The source of this data is the NEPOOL GIS. https://www1.nepoolgis.com/

[21] We assume that the carbon emissions rate of these MWH will be equal to the 2018 NEPOOL Residual Mix, which is a proxy for the fossil fuel emissions rate in the region. For the current value of the NEPOOL Residual Mix, please visit https://www.nepoolgis.com/public-reports/.

These emissions rates were multiplied by the Adjusted 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 8,000 tons/year in 2020 up to 16000 tons/year in 2023, and then decline as the RES requirement increase through 2032.

The costs of these emissions were calculated using two sources, the 2019 Regional Greenhouse Initiative Auction[22] (RGGI) results ($5.45/ton) and the 2018 Avoided Cost of Energy Supply[23] (AESC) study ($100/ton). Using RGGI prices (plus inflation), the cost of carbon emissions in 2020 is $45,000/year and about $90,000/year in 2032. Using AESC prices, the range is $850,000 in 2023 and almost $1.7 million 2032.

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



[22] https://www.rggi.org/auctions/auction-results/prices-volumes

[23] https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080.pdf

Conclusions

There are four decisions facing VOEF that the financial analysis will quantify.

1. LIHI for Enosburg Falls Hydro
   Q1: What are the costs and benefits of gaining LIHI certification by 1/1/25?

2. Extension of the NextEra PPA
   Q2: What are the costs and benefits of extending NextEra volumes through 2039?

3. New Long-Term Hydro PPA
   Q3: What are the costs and benefits of a dispatchable, Tier I qualifying hydro PPA that would supplant the extension of the NextEra PPA starting on 1/1/23?

4. New Solar PPA
   Q4: What are the costs and benefits of a 500 kW solar PPA that includes both energy and Tier II RECs starting on 1/1/22?

In addition, we quantify two load-related questions.

5. 1% CAGR
   Q5: What is the rate impact of 1% compound annual load growth?

6. Franklin Foods
   Q6: What is the rate impact if loads dropped by 20%, which approximates the impact of Franklin Foods leaving the system?

Transmission & Distribution

IV. Electricity Transmission & Distribution

Distribution System Description:

VOEF's distribution system presently serves approximately 1,740 customers in a 65 square mile service territory. The system is comprised of 102.1 miles of line at 12.47 kV and 3.53 miles of line at 2.4 kV for a total of 105.63 miles of distribution level line.

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

VOEF-Owned Internal Generation:

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

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

The first of the hydroelectric units, the Kendall Plant No. 2, was constructed and entered service in 1928; it was refurbished in 1992. The second hydroelectric generator, the Village Plant No. 1, entered service in 1946. An "air bladder" was installed in 2013, which allows VOEF to have more control of water flow. In 2014, a few beneficial repairs and upgrades to the Kendall Plant No. 2 were completed. For several years this unit had to be shut down for most of the winter because the head gates would freeze up. New heaters and rollers were installed for winter operation in order to mitigate this problem. The head gates, to control water flow, were also rebuilt. The upgrades are expected to increase the number of months that the hydro facility is able to generate; therefore, revenue from generation is expected to increase as well. The most recent 5-year average generation from both plants combined, was 2,744,356 kWh annually. In 2018, the total annual generation from both plants was 725,322 kWh, significantly less than normal due to the plants being out of service for significant upgrades. An engineering study of the Enosburg Falls Hydroelectric Generation Facility was completed in January 2014. The study, conducted by The H.L. Turner Group, Inc. engineering firm, gave recommendations for improvements and upgrades to the facility with a cost/benefit analysis. VOEF has completed many of the improvements recommended by the engineering study. During the 2016-2018 timeframe VOEF invested $2.3 million dollars in the Plant No. 1 hydro facility.

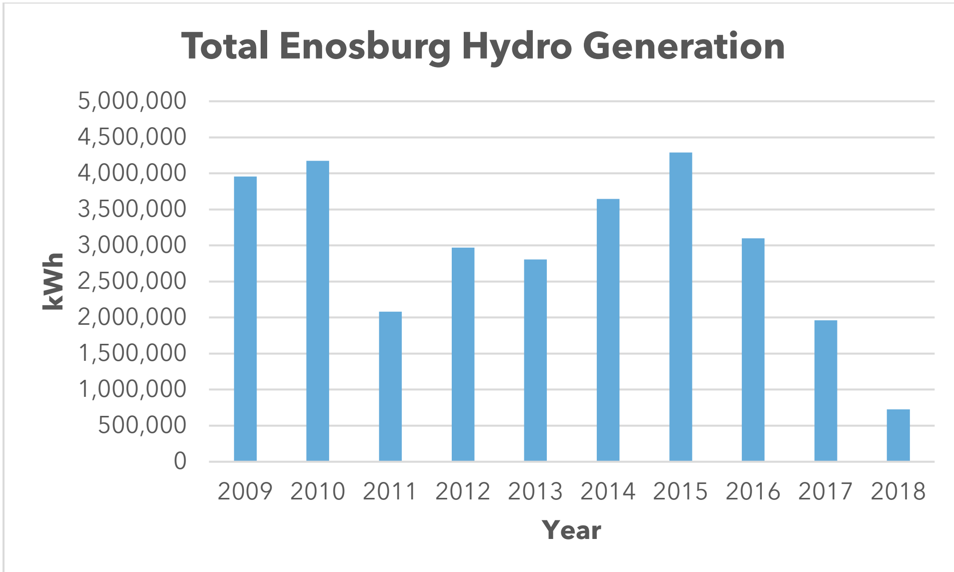
.

The following table summarizes the historical generation output of the hydroelectric facility for the past 10 years.

Table 16: VOEF's Historical Hydro Generation

Year	Total Annual Hydroelectric Generation (kWh)
2009	3,955,792
2010	4,172,102
2011	2,083,795
2012	2,969,512
2013	2,806,053
2014	3,643,623
2015	4,289,192
2016	3,100,834
2017	1,962,811
2018	725,322

Figure 13: VOEF Historical Hydro Generation



VOEF Substations:

VOEF Substation:

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

Circuit Description:

Table 17: VOEF Circuit Description

Circuit Name	Length [24](Miles)	# of Customers by Circuit	Outages by Circuit 2018
Main Street	1.4	706	2
Cheese Plant	2.3	45	1
St. Albans Street	9	102	8
West Enosburg	38.75	385	20
Sampsonville	54.18	470	49
Total	**105.63**	**1,708**	**80**

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

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

As shown in the tables (above and below), in 2018, the Sampsonville circuits had the greatest number of outages. There were 49 outages in total on the Sampsonville circuit for that year. To prevent future outages and maintain reliability, VOEF continues to trim trees and add animal guards to equipment.

T&D System Evaluation:

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

[24] Estimated from circuit maps

Outage Statistics

VOEF evaluates T&D circuits on an ongoing basis in order to identify the optimum economic and engineering configuration for each circuit. The evaluations include the review of the Public Utility Commission (PUC) Rule 4.900 Outage Reports. In addition, VOEF periodically completes long-term system planning studies to develop overall strategies for improving the performance of the T&D facilities. The cost of the improvements recommended in the study are developed into a 5-year budget and approved by the Trustees based upon the financial position of VOEF. The last study, completed in 2003-2004, recommended a new substation as well as new feeders out of the substation. The recommendations of the study have been implemented. It is unknown at this time when the next study will be completed.

VOEF's PUC 4.900 Electricity Outage Reports, reflecting the last five years (2014-2018) in their entirety, can be found in Appendix D, at the end of this document.

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

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

VOEF has committed to achieve performance levels for its distribution system below an index of 2.5 for SAIFI and 1.0 for CAIDI. VOEF maintains a record of and reports on all its system outages, including the root cause of an outage. While some outages cannot be prevented, there are a number of specific, cost-effective steps that can be taken to maintain or improve system reliability by working to eliminate the potential for some outages to occur and making changes that will promote reduced outage times when an unavoidable outage does occur.

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

The following table summarizes VOEF's SAIFI and CAIDI values for the years 2014 – 2018.

Table 18: VOEF Outage Statistics

	Goals	2014[25]	2015	2016	2017	2018
SAIFI[26]	2.5	0.4	0.8	0.7	0.7	2.9
CAIDI[27]	1.0	1.6	1.8	1.9	1.5	1.8

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

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

Animal Guards

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

Fault Indicators

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

Automatic reclosers/Fusing

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

Feeder back-up

[25] SAIFI and CAIDI statistics shown are net of major storm outages. Storms impacted SAIFI and CAIDI during 2014.

[26] System Average Interruption Frequency Index

[27] Customer Average Interruption Duration Index

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

Power Factor Measurement and Correction

VOEF had an approximate 2019 average power factor of 95.3%. In recent years VOEF has not applied high priority to expensive investments related to measuring power factor but will work with VPPSA to identify and evaluate adding more comprehensive metering to monitor power factor for key customers and sections of the system. Based on these measurement results, VOEF will work with VPPSA to develop and implement measures to improve power factor as needed.

Other

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

Distribution Circuit Configuration

Voltage Upgrades

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

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

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

Phase balancing

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

System Protection Practices and Methodologies;

Protection Philosophy

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

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

Substation Protection:

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

Distribution Protection:

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

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

Smart Grid Initiatives

Planned Smart Grid

Beginning in 2018, VOEF began participating in a multi-phased, VPPSA joint-action project intended to (1) assess individual member readiness for AMI, (2) guide participating members through an RFP process culminating in vendor and equipment selection and (3) guide members through the implementation phase. At the end of the initial assessment phase individual members will make the choice to go forward with the RFP process, or not. Upon completion of the RFP phase of the project, individual members will have the information needed to examine the business case and make a decision to commit to implementation of an AMI system, or not.

At this time VOEF is participating in the initial readiness assessment phase of the project, gaining information pertaining to its initial readiness, potential required changes to staffing and operating processes, as well as potential benefits to municipal electric, water and wastewater systems. As the assessment phase wraps up later in 2020, VOEF will decide whether to proceed to the RFP phase of the process.

VOEF is mindful of the many facets of the evolving grid and their impact on the value of implementing AMI. Advanced metering may play a key role in taking advantage of more sophisticated rate design and load management/retention opportunities as we see continued expansion of net metering, heat pump installations, and adoption of electric vehicles.

VOEF recognizes the potential value of utilizing rate design, direct load control or other incentive programs as tools to manage both system and customer peak loads in unison to create value for both the utility and the customer. In the absence of an AMI system, or pending development and implementation of an AMI system, VOEF will explore the use of pilot programs or tariffs that may be implemented using currently available technology. Initial efforts in this area will focus on larger customers with the greatest opportunity to manage loads in a way that will reduce both system and customer costs, capture economic development/retention opportunities and reduce carbon footprint where possible.

Working with VPPSA, Efficiency Vermont, and other stakeholders, VOEF stays abreast of these developments and the strategies needed to maintain a safe, reliable, and economically viable distribution system.

VOEF is also mindful of the increasing importance of cybersecurity concerns, and the relationship of those concerns to technology selection and protection. While VOEF is not presently required to undertake NERC or NPCC registration, VPPSA is a registered entity, and VOEF's membership in VPPSA provides VOEF with knowledge and insight regarding ongoing cybersecurity developments and risks. On a more local level, VOEF endeavors to purchase and protect its IT systems (with assistance from VPPSA as needed), in a manner intended to minimize security risks to the system and its ratepayers. VOEF remains mindful of the balance between the levels of cyber security risk protection and the associated costs to its ratepayers.

Other System Maintenance and Operation:

Reconductoring for Loss Reduction

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

As part of its long-term goals VOEF continues to work on upgrades that will increase reliability. In 2016 VOEF completed three projects of reconductoring 4,525 feet of #8 and #6 wires to #2 aluminum enhancing reliability and capacity. During one of those projects VOEF also brought 2,400 feet of cross-country lines to the roadside on Witchcat Road. In 2017 VOEF completed a reconductoring project on Tyler Branch Road, which is in the West Enosburg circuit. In 2017 VOEF started upgrades on Boston Post Road, located on the Sampsonville circuit. These upgrades included new poles and larger conductors. VOEF's long-term goal is to work on upgrading 2400 Delta Volts to 7200/12470 Volts Y in our St. Albans Street circuit.

Transformer Acquisition

Given cost considerations and the existence of a reasonable market in used transformers, VOEF generally purchases rebuilt transformers. The transformer supplier typically provides loss data for the transformers purchased. When evaluating the replacement of transformers, VOEF considers the cost of the transformer versus revenue from service. Transformer rebuilds have a three-year warranty whereas the new ones have only a one-year warranty.

Conservation Voltage Regulation

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

Distribution Transformer Load Management (DTLM)

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

Substations within the 100- and 500-YEAR Flood Plains

VOEF has only one substation, and it has been in place for many decades. It has never flooded. There are no current plans to move the sub-station. VOEF will contact another utility for a temporary mobile substation if its substation floods. VOEF has checked the floodplain maps and has concluded that the substation is not within the 100-year floodplain.

The Utility Underground Damage Prevention Plan (DPP)

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

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

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

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

Selecting Transmission and Distribution Equipment

VOEF has a procurement policy in which the Village Manager has discretion over purchases up to $5,000.00; purchases over that amount are required to either be put out to bid or a minimum of three quotes must be obtained and reviewed by the VOEF Board of Trustees.

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

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

Maintaining Optimal T&D Efficiency

System Maintenance

As VOEF is a small system, all line staff are routinely involved in inspections, vegetation management, fuse size location, etc., and information is shared verbally with each other. This method has been effective over the years and has not proved to be problematic. Going forward, VOEF is open to working with VPPSA to explore the potential for developing a GIS system that would lend structure to the system maintenance process.

Substation Maintenance

VOEF performs annual oil checks on transformers, and monthly substation inspections. Meter readers and line crew report maintenance issues as they find them in the field.

Pole Inspection

VOEF has an informal pole inspection program to assure that poles in its service territory are in good, reliable condition. VOEF always inspects poles that are in the vicinity of normal field work. Due to the size of the system, VOEF personnel have a good understanding of the age and condition of its poles and proactively find problems before they start. VOEF is open to working with VPPSA to develop a more formal, size appropriate electronic pole management system over the remainder of the 2019-22 IRP cycle.

Equipment

Any time work is being performed on a pole, any insulators and connectors that need to be replaced are replaced.

System Losses

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

Actual System Losses:

Currently, VOEF's total line losses are running around 2.4%.

Efforts to Reduce Losses:

The replacement of high loss conductors with lower loss conductors is an ongoing process. Subject to reasonable budget constraints, VOEF is prepared to work with

VPPSA to systematically evaluate, prioritize, and address cost effective opportunities to economically reduce losses.

Tracking Transfer of Utilities and Dual pole Removal (NJUNS)

VOEF does not use NJUNS.

Relocating cross-country lines to road-side

VOEF relocates cross-country lines to road-side when such relocation can be done consistent with cost consideration and customer concerns in terms of rights-of-way. Some customers do not want to see the lines in front of their houses. This hasn't been too problematic so far. There have been a few issues with easements.

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

Distributed Generation Impact:

VOEF presently has 41 residential scale (< 15 kW) net metered customers with a total installed capacity of about 293 kW. In addition, there are 3 customers who have arrays between 15 and 500 kW totaling 860 kW; the combined total is about 1,153 kW.

Interconnection of Distributed Generation

VOEF recognizes the unique challenges brought on by increasing penetration levels of distributed generation. VOEF adheres to the procedures set forth in Rule 5.500 for the interconnection of new generation. Per rule 5.500, a fast track screening process is utilized to expedite the installation of smaller generators 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 VOEF or their representatives, typically include a review of the following issues that may arise as a result of a new generator interconnection:

- Steady state voltage (per ANSI C84.1)
- Flicker (per IEEE 1453)
- Temporary overvoltage due to load rejection and/or neutral shift
- Effective grounding (per IEEE 1547 & IEEE C62.91.1)

- Overcurrent coordination
- Equipment short circuit ratings
- Effect of distributed generation on reverse power and directional overcurrent relays
- Voltage regulator and load tap changer control settings (bi-directional operation)
- Unintentional Islanding
- Thermal loading of utility equipment
- Power factor and reactive compensation strategy
- Impact to underfrequency load shed
- 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, VOEF will maintain detailed records of installed generation including location, type, and generating capacity. This information will allow VOEF to periodically review how much generating capacity is installed on a particular feeder or substation transformer and identify any concerns as penetration increases over time.

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

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

Inverter requirements

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

Vegetation Management/Tree Trimming:

VOEF has a line item for tree trimming in its annual budgets, and carefully expends a certain amount per year. Most of the line maintenance is done in-house, although occasionally contractors are hired. The PUC Rule 4.900 Outage Report helps determine where tree trimming needs to be done. VOEF continues to budget aggressively for tree trimming efforts as a result of the 2013 ice storm. VOEF has a ten-year, vegetation management plan, and starts the cycle over again at the end of ten years. A windstorm in 2010 knocked down a large quantity of trees that thus didn't need trimming. More trees came down in the ice storm in December 2013.

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

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

On an average basis, VOEF budgets approximately 4.3 distribution circuit miles of tree-trimming per year. These are not necessarily contiguous circuit miles. VOEF budgets $44,000 per year for tree-trimming. VOEF surveys at least 4.3 miles per year. In historical years, where the miles trimmed were fewer than 4.3 miles, at least 4.3 miles were surveyed but only those miles actually requiring trimming are shown in the table.

The schedule table, below, lists the annual miles of line trimmed over the past three years and the predicted annual miles of line to be trimmed over the next three years. Unlike some electric utilities in Vermont, VOEF does not hire-out all its tree trimming work. VOEF's own line crew does some of the tree trimming and VOEF hires out some of the tree trimming.

Historically, VOEF has not tracked areas that its own crew has trimmed from year to year, nor has this been required in the past. Starting in September 2018, VOEF started to track and report on both the amounts trimmed by VOEF's own crew and amounts trimmed by outside contractors. The estimated annual miles of line to be trimmed in the future (*Table 20*) is a predicted assessment using a combination of contractors and VOEF's own line crew and is subject to the approval of the VOEF Board of Trustees. VOEF believes this is a realistic approach, however, and can be maintained while keeping the utility on par to complete needed trimming services to those areas of our service territory that require this maintenance.

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

In addition to its vegetative and brush management program, VOEF has a program to identify danger trees within its rights-of-way and to either prune or remove those trees. Again, the success of this program is measured by whether danger trees are a root cause of system outages. Danger trees are identified by utility personnel while patrolling the lines, reading meters, or inspecting the system. Patrols for danger trees are made simultaneously while accomplishing other field work in the same vicinity. The meter reader is also out twice a month (or more frequently) reading meters as well as making observations of danger trees. Additionally, customers notify VOEF about their observations of danger trees.

Once a danger tree is identified, it is promptly removed if it is within VOEF's right-of-way. For danger trees outside of the right-of-way, VOEF contacts the property owner, explains the hazard, and with the owner's permission removes them. Where permission is not granted, VOEF will periodically follow up with the property owner to attempt to obtain permission.

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

Table 19: VOEF Vegetation Trimming Cycles

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

Table 20: VOEF Vegetation Management Costs [28]

	2016	2017	2018[29]	2019	2020	2021	2022
Amount Budgeted	$27,000	$27,553	$26,310	$40,776	$44,000	$44,000	$44,000
Amount Spent (FY)	$23,497	$20,324	$14,885 Contractor Labor + $7,447 Village staff (vill. Staff partial yr)	$24,840 Contractor Labor + $13,590 Village Staff	Deliberately left blank	Deliberately left blank	Deliberately left blank
Miles Trimmed	2 miles	0.43 miles	1.75 Miles Contractor + .18 Village Staff	1.37 Miles Contractor + 1.19 Village Staff	4.3 miles to be trimmed	4.3 miles to be trimmed	4.3 miles to be trimmed

Table 21: VOEF Tree Related Outages [30]

	2014	2015	2016	2017	2018
Tree Related Outages	25	15	20	14	26
Total Outages	57	49	52	43	80
Tree-related outages as % of total outages	44%	31%	38%	33%	33%

[28] 2016-2017 miles, shown in table, only reflect those amounts trimmed by outside contractors, whereas, the future projected years include the combined amounts expected to be trimmed by outside contractors and by the VOEF's own line crew

[29] Starting in September 2018, VOEF started tracking and reporting on both the historical amounts trimmed by VOEF's own crew and historical amounts trimmed by outside contractors, therefore the figures shown for trimming done by VOEF's own line crew for 2018 only reflect a very small fraction of what was done for that year.

Storm/Emergency Procedures:

Like other Vermont municipal electric utilities, VOEF is an active participant in the Northeast Public Power Association (NEPPA) mutual aid system, which allows VOEF to coordinate not only with public power systems in Vermont, but with those throughout New England. The Village Manager is also on the state emergency preparedness conference calls, which facilitates in-state coordination between utilities, state regulators and other interested parties. The Lead-Line Technician of VOEF is typically on the electric lines during emergency situations. VOEF has a paging system, "Contact," to allow customers to call in during non-business hours and have access to 24-7 dispatch service. VOEF has also worked to improve its diligence in updating the www.vtoutages.com site during major storms especially if it experiences a large outage that is expected to have a long duration. VOEF believes it is beneficial to inform the Public Service Department if it is experiencing these types of outages.

As a result of the ice storm of December 2013, VOEF has improved its emergency response plan and will continue to find better ways to serve its customers.

Previous and Planned T&D Studies:

Fuse Coordination Study

A fuse coordination study was done in 2003, at the time before the substation was upgraded. Larger fuses are situated closer to the substation, and smaller ones further away. VOEF 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.

System Planning and Efficiency Studies

Distribution System Planning

In 1996, PLM Electric Power Engineering of Hopkinton, MA conducted a System Planning Study of the VOEF system. In October of 1999, Lee Carroll, PE electrical consultants of Gorham, NH prepared a Work Plan for 1999-2002. More recent VOEF work plans and studies have focused primarily on the hydro facilities. No T&D study is currently contemplated.

Capital Spending:

Construction Cost (2016-2018):

Table 22: VOEF Historic Construction Costs

Village of Enosburg Falls Electric Light Department		Historic Construction		
Historic Construction		**2016**	**2017**	**2018**
Structures and improvements (331)	Prod	$ 382,644	$ 912,510	$ 1,421,096
Reservoirs, dams and waterways (332)	Prod			
Poles, towers and fixtures (364)	Dist	$ 12,623	$ 16,046	
Line transformers (368)	Dist	$ 8,172	$ 5,825	$ 14,001
Services (369)	Dist			
Meters (370)	Dist		$ 633	$ 2,517
Structures and improvements (390)	Gen	$ 42,238	$ 215,445	
Office furniture and equipment (391)	Gen	$ 2,321	$ 3,334	
Transportation equipment (392)	Gen	$ 142,097	$ 103,478	
Stores equipment (393)	Gen			$ 409,674
Communication equipment (397)	Gen			
Miscellaneous equipment (398)	Gen		$ 1,443	
Construction in Progress (FERC Relicense)			$ 6,960	$ 11,019
Total Construction		**$ 590,095**	**$ 1,265,674**	**$ 1,858,307**
Functional Summary:				
Production		382,644	912,510	1,421,096
General		186,656	330,660	420,693
Distribution		20,795	22,505	16,518
Total Construction		**$ 590,095**	**$ 1,265,674**	**$ 1,858,307**

Projected Construction Cost (2020-2022):

Table 23: VOEF Projected Construction Costs

Village of Enosburg Falls Electric Light Department		Projected Construction		
Projected Construction		**2020**	**2021**	**2022**
Hydro #1 Bearing Replacement	Prod	$ 15,000		
Hydro #1 Controls Repair	Prod	$ 10,000		
Trash Rack Replacement	Prod		$ 165,000	
Pedestrian Bridge Replacment	Prod	$ 10,000		
Kendall Plant Control Upgrade	Prod	$ 30,000		
FERC Relicencing - Legal & Studies	Prod	$ 165,000	$ 105,000	$ 160,000
N. Main Line-Power Conversion to 7200 Volts	Dist		$ 45,000	
Line and Pole Upgrade Duffy Hill Road	Dist			$ 45,000
Village Plant Window Replacement	Gen	$ 9,000		
Replace 3/4 Ton Pickup	Gen		$ 45,000	
Replace 2.5 Ton Dodge Bucket Truck	Gen			$ 150,000
Total Construction		**$ 239,000**	**$ 360,000**	**$ 355,000**
Functional Summary:				
Production		230,000	270,000	160,000
General		9,000	45,000	150,000
Distribution		-	45,000	45,000
Total Construction		**$ 239,000**	**$ 360,000**	**$ 355,000**

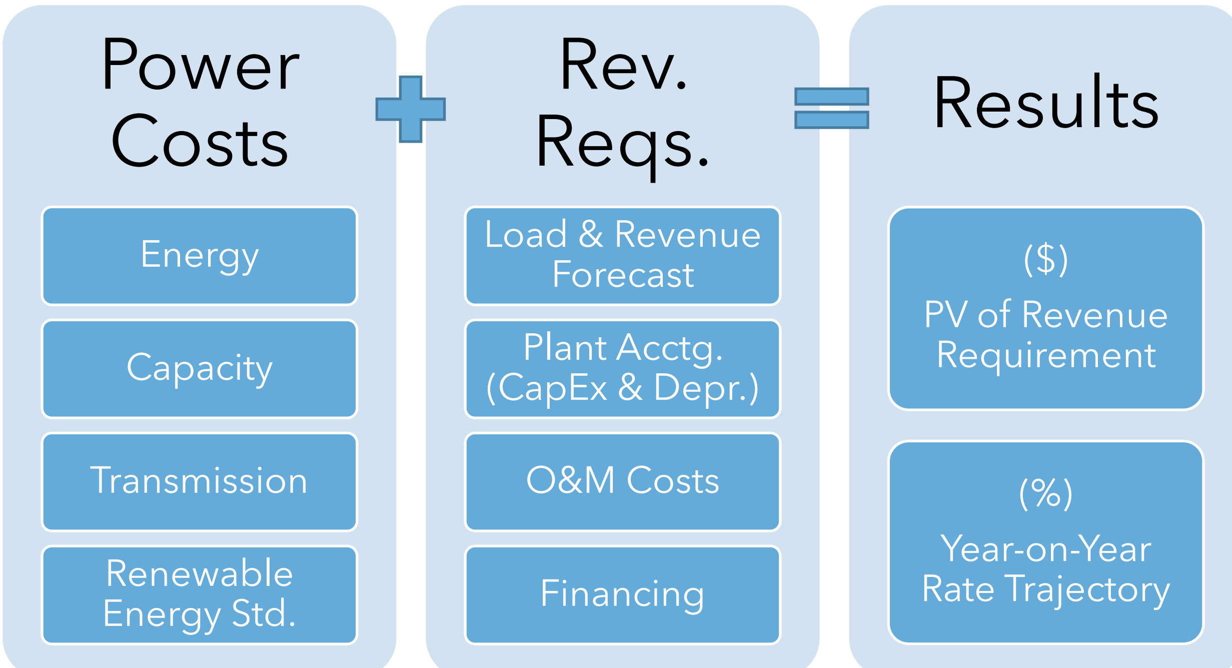
Financial Analysis

V. Financial Analysis

Components

The financial analysis represents an integrated analysis of VOEF's power supply costs and its revenue requirements. The results include the present value of VOEF's revenue requirements (a proxy for least cost) and the annual change in retail rates. The following figure illustrates the primary components of the analysis.

Figure 14: Primary Components of the Financial Analysis



The power supply cost models consist of four primary spreadsheets that estimate the cost of energy, capacity, transmission, and the costs of complying with the Renewable Energy Standard. The power supply models are monthly and roll up to annual numbers for integration with the revenue requirements model. The revenue requirements model contains annual estimates of VOEF's load, revenue, plant accounting activity (including capital expenditures and depreciation), O&M costs, and ultimately, a profit and loss statement. Its outputs are annual revenue requirements, average rates, and the annual change in rates.

Importantly, the power cost spreadsheets are the same models that are used to create VOEF's annual power cost budget and are formatted to be consistent with the spreadsheets that are used for monthly budget to actual analysis. As a result, they are operational as well as planning tools.

Methodology

The financial analysis estimates the costs and benefits of three major decisions that were identified in Section III. Resource Plans, and one load-related uncertainty. These include:

Decisions

There are four decisions facing VOEF that the financial analysis will quantify.

1. LIHI for Enosburg Falls Hydro
   Q1: What are the costs and benefits of gaining LIHI certification by 1/1/25?

2. Extension of the NextEra PPA
   Q2: What are the costs and benefits of extending NextEra volumes through 2039?

3. New Long-Term Hydro PPA
   Q3: What are the costs and benefits of a dispatchable, Tier I qualifying hydro PPA that would supplant the extension of the NextEra PPA starting on 1/1/23?

4. New Solar PPA
   Q4: What are the costs and benefits of a 500 kW solar PPA that includes both energy and Tier II RECs starting on 1/1/22?

In addition, we quantify two load-related questions.

5. 1% CAGR
   Q5: What is the rate impact of 1% compound annual load growth?

6. Franklin Foods
   Q6: What is the rate impact if loads dropped by 20%, which approximates the impact of Franklin Foods leaving the system?

There are twelve relevant combinations of the four decisions, as shown in Table 24.

- Path 1 is the reference case.
- Path 2 shows the impact of losing Franklin Foods.
- Path 3 shows the impact of having loads grow by 1% per year.
- Path 4 shows the cost and benefits of seeking LIHI certification for Enosburg Falls Hydro.
- Path 5 shows the costs and benefits of extending the NextEra PPA only.
- Path 6 shows the costs and benefits of the large hydro PPA only.
- Path 7 shows the costs and benefits of the solar PPA only.
- Path 8 combines the hydro with the solar PPA.
- Path 9 combines LIHI with a large hydro PPA.
- Path 10 combines LIHI with the large hydro PPA and the solar PPA.
- Path 11 combines LIHI with an extension of the NextEra PPA.
- Path 12 combines LIHI with an extension of the NextEra PPA and a solar PPA.

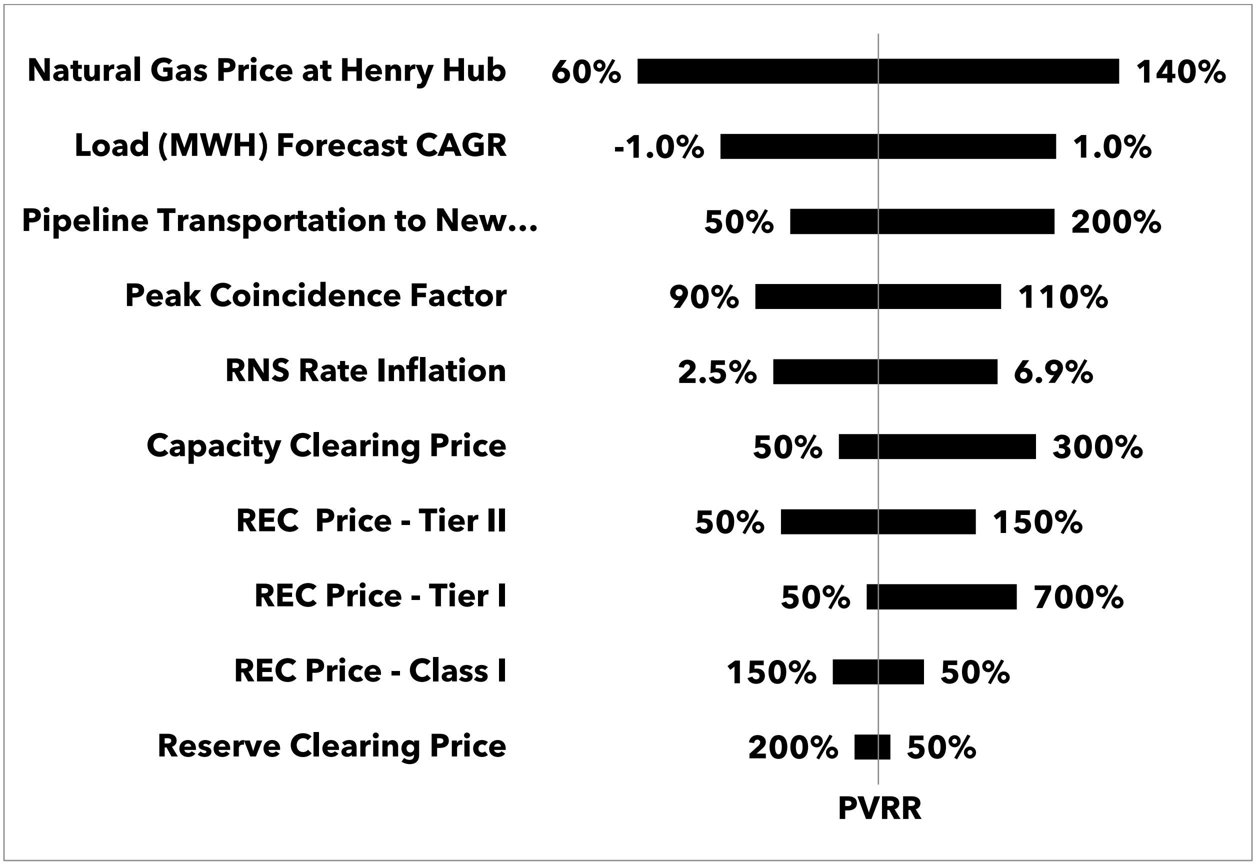
Table 24: Event / Decision Pathways

Path	Name	LIHI Certification	Extend NextEra PPA	Large Hydro PPA	Solar PPA (1 MW)
1	Reference Case				
2	Loss of Franklin Foods				
3	1% CAGR				
4	LIHI for Enosburg Falls Hydro	X			
5	Extend NextEra PPA		X		
6	Hydro PPA			X	
7	Solar PPA				X
8	Hydro PPA + Solar PPA			X	X
9	LIHI + Hydro PPA	X		X	
10	LIHI + Hydro PPA + Solar PPA	X		X	X
11	LIHI + Extend NextEra PPA	X	X		
12	LIHI + Extend NextEra PPA + Solar PPA	X	X		X

Not all combinations of each scenario are of interest. For example, making the decision to both extend the NextEra PPA and sign a new long-term hydro PPA would make VOEF significantly and chronically long on energy. VPPSA's energy hedging policy explicitly seeks to hedge energy to within +/-5% of 100%, and such a combination of decisions would be contrary to that policy.

The financial analysis estimates the cost of each of these pathways, and then runs sensitivity analysis on ten different variables that are known to have a material impact on VOEF's revenue requirements. Low, base and high ranges were set up using historical data for each of these variables, as shown in Figure 15

Figure 15: Sensitivity Analysis of Key Variables – Pathway 1 (Reference Case)



Note that changes in load (not load growth) are not included in the sensitivity analysis. This is due to the fact it was always at the top of the tornado chart, regardless of the decision being analyzed. Furthermore, it effectively masked the impacts of the other ten variables on Figure 16, the scatter plot of financial outcomes.

The conclusion is that +/-20% changes in load is the biggest variable impacting VOEF's cost of service, as measured by the Present Value of its Revenue Requirement (PVRR). Because VOEF has one large customer of this size, this risk is a possibility. With this conclusion established, we decided to omit large changes in load from the sensitivity analysis in order to draw out the impacts of the remaining ten variables.

With this in mind, the number one and three risks facing VOEF is the price of natural gas and natural gas transportation. These outcomes are intuitive because price of natural gas is known to change quickly and competing alternatives (supplies) are limited in the short-term.

The number two risk is the rate of load growth or decline, followed by the peak coincidence factor. The peak coincidence with monthly and annual load in New England determines transmission and capacity costs and is subject to a high degree of uncertainty. As load reducers, the hydroelectric generation from Enosburg Falls Hydro has a direct impact on VOEF's peak coincidence, and if it is generating at the coincident peak hour, it can and does reduce transmission and capacity costs.

Number six on the list is the price of capacity. Because VOEF's capacity supply is forecast to be about 1 MW less than its requirements, increases in capacity prices can increase its costs.

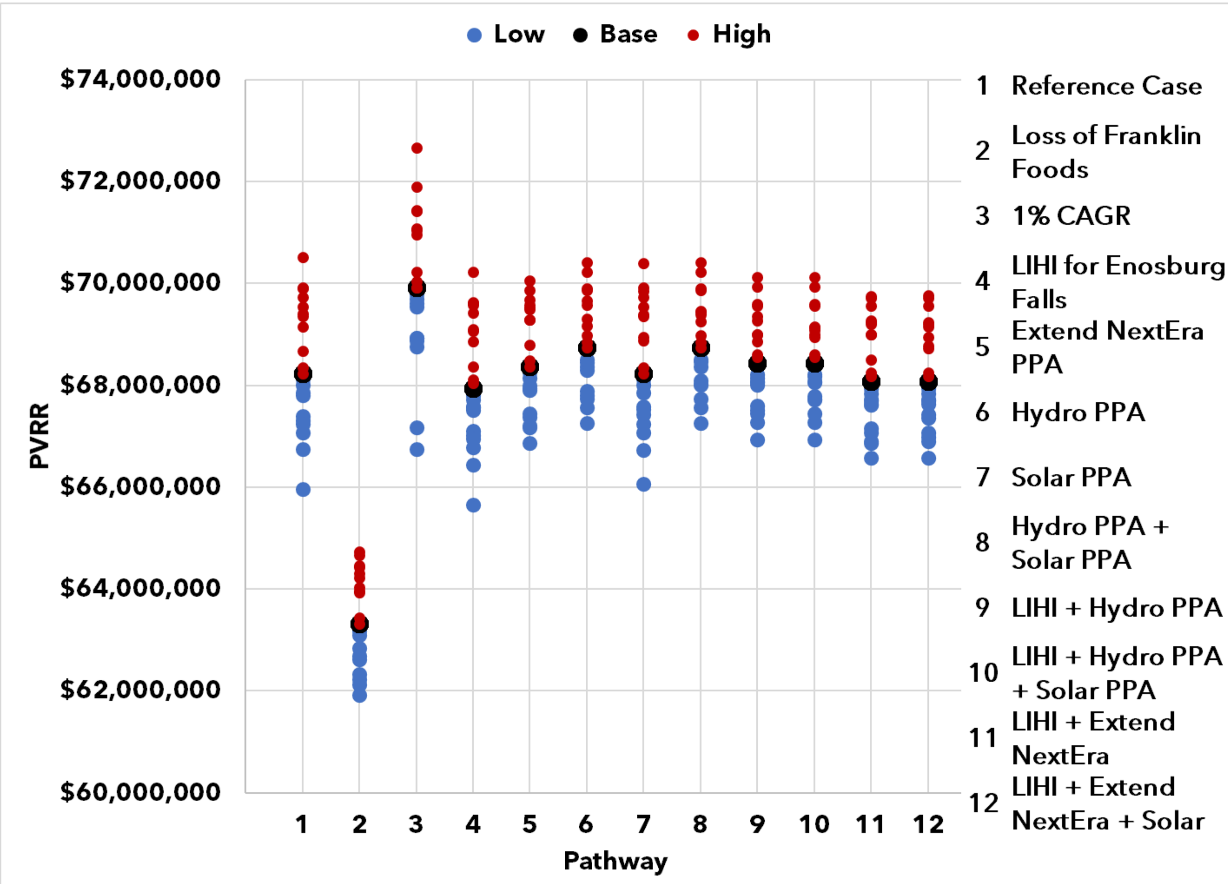
However, in today's market environment, capacity prices have been falling, which has reduced VOEFs costs. This level of market price risk is not a concern, but there is an opportunity to use demand response and/or new capacity supplies to manage these costs.

The last variables of note are the costs of RECs. Although the risk in any single REC market is relatively low, the combined risk of all three REC markets can be considered substantial. As a result, minimizing REC market exposure with long term contracts is a topic of interest in this analysis.

Revenue Requirement Results

The high-level results of the financial analysis appear in Figure 16 and Figure 17.

Figure 16: Scatter Plot of Financial Analysis Results (PV of Revenue Requirement)

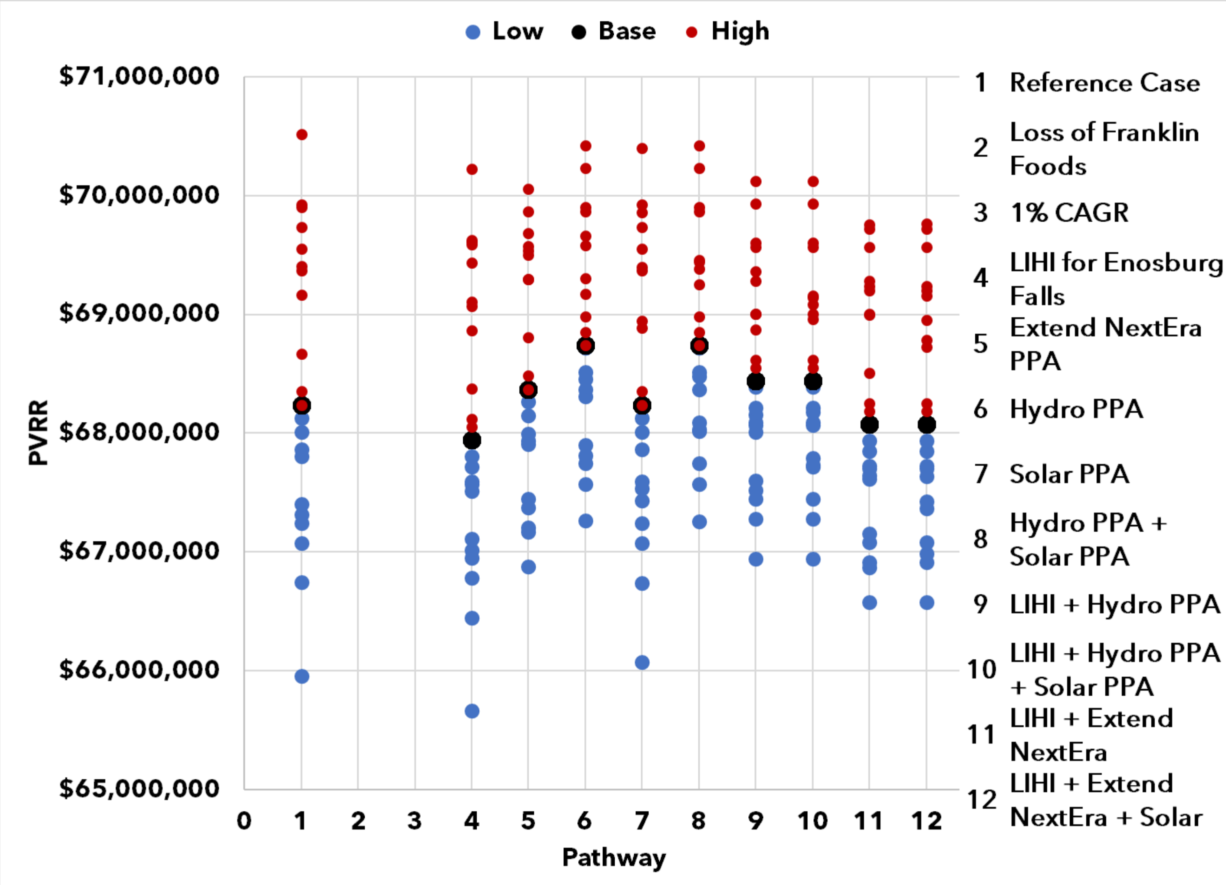


The lowest cost outcome occurs when load drops by 20% (Pathway #2). While this is an appealing outcome on the surface, it also comes with a matching degree of rate pressure due to the loss of retail revenue. As a result, it is only indicative of what might happen if Franklin Foods were to leave the system. It is not considered a least cost outcome.

The highest cost outcome occurs when load increases by 1% per year. This is a goal that would increase power supply costs but should also put downward pressure on rates.

Figure 17 is the same as Figure 16, but is excludes pathways 2 and 3. It features a narrower y-axis scale to show the differences between the remaining pathways.

Figure 17: Scatter Plot of Financial Analysis Results (PV of Revenue Requirement)

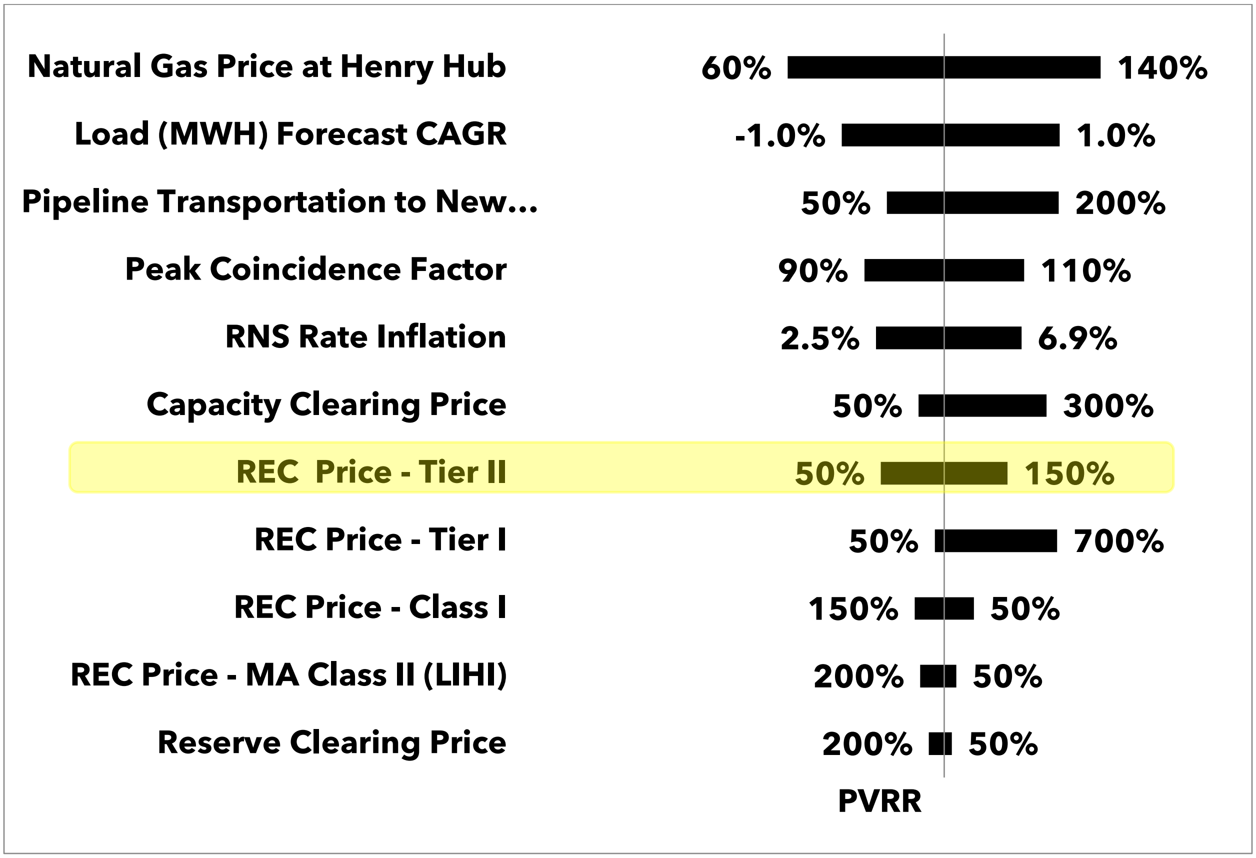


- Conclusion 1: The lowest cost outcomes in this depiction occur when VOEF seeks LIHI certification for Enosburg Falls Hydro. As a result, LIHI certification can measurably lower VOEF's costs.

- Conclusion 2: The other major conclusion is that the range of financial outcomes narrows when the cost of energy is hedged with some precision, as is the case with the hydro PPA and the extension of the NextEra PPA.

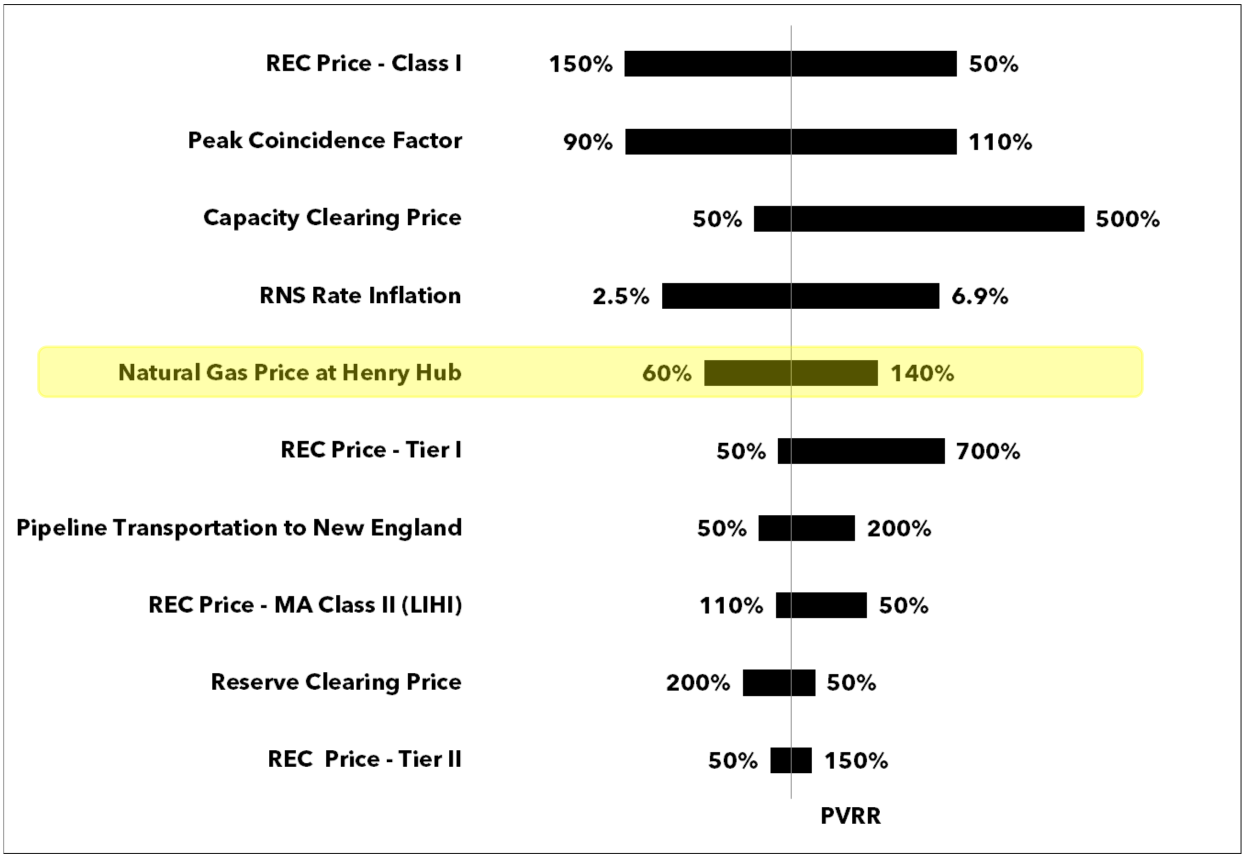
Figure 18 shows how the decision to seek LIHI certification changes the financial risks that VOEF faces. The primary change is highlighted in yellow. Pathway 4 shows that MA Class II REC prices become a minor financial risk, when before it was not present. In return for this risk, VOEF gets a significant, $300,000 (0.4%) decrease in its cost of service. As a result, this is one of the preferred pathways in the analysis.

Figure 18: Sensitivity Analysis of Key Variables – Pathway 4 (LIHI Certification)



Pathway 6 (LIHI + Hydro PPA) is shown in Figure 19 and its risk profile is distinct from the other pathways. Class I REC prices rise into the top spot on the chart. However, this is not because REC price risk increases, but because natural gas price risk is so well hedged by the hydro PPA that it drops down into the middle of the chart.

Figure 19: Sensitivity Analysis of Key Variables – Pathway 6 (LIHI Certification + Hydro PPA)



- **Conclusion 2.1:** This is a key conclusion of the analysis, and it is closely related to Conclusion 2. The hydro PPA was modeled using monthly on and off-peak volumes that precisely matched up to the load forecast. As a result, it is a measurably superior hedge to the NextEra PPA, whose volumes were simply extended at their current levels. The conclusion is that any effort to more precisely forecast the load and shape the supply to match it is well spent. Precise matching of supply and demand reduces risks considerably compared to either the status quo.

Preferred Pathways

The preferred pathways are those with a combination of low cost and low risk. While Figure 30 is scaled to emphasize the differences between the pathways, the cost difference between the reference cases in Pathways 4-12 is less than 1%. Considering the uncertainties inherent in a 20-year analysis, these cost differences are very small. In this context, the choice of the preferred pathways relies on an assessment of risk and some judgement about what macrotrends the industry is experiencing.

- Risk: For example, pathways that hedge a greater percentage of energy, capacity and REC volumes (Pathways 8-12) are inherently less risky than pathways that do not (Pathways 1-7). This can be seen in a narrower range of dots in Figure 30.

- Macrotrends: In addition, pathways that include more renewable and less nuclear power are congruent with the ongoing macrotrends affecting the industry. Specifically, renewable energy has been growing in proportion to other sources of energy, while two nuclear power plants have been retired in New England in recent years.

With these two assessments in mind, **the preferred pathways are 10 and 12**. Both include LIHI certification for Enosburg Falls Hydro, which lowers cost, as well as a Solar PPA which lowers Tier II REC price risk. The primary difference between the two pathways is that the Hydro PPA includes Tier I RECs, which fixes Tier I price risk, while the NextEra PPA does not. Instead, the NextEra PPA pathway relies on spot market REC purchases, which are modeled to be less expensive than buying them through a bundled Hydro PPA.

Which pathway is ultimately least cost will depend on the price offers from suitable counterparties, and the actual market prices for energy and RECs that are realized over the term of the PPAs.

Impact of Supply – Demand Imbalances

The impacts of supply-demand imbalances are summarized in Figure 20. Any time the supply of energy is less than the demand, lower market prices also lower VOEF's cost of service. Conversely, any time the supply is greater than the demand, higher market prices lower VOEF's cost of service. As a result, the financial impact of supply-demand imbalances are indeterminant, and depend on the market price of energy. Said differently, we cannot say with certainty that an imbalance (surplus or deficit of energy) is cost minimizing.

However, as we just learned in the previous section, the *size* of the imbalance has a direct impact on the price risk that VOEF faces. As a result, minimizing supply-demand imbalances is definitely *risk* minimizing.

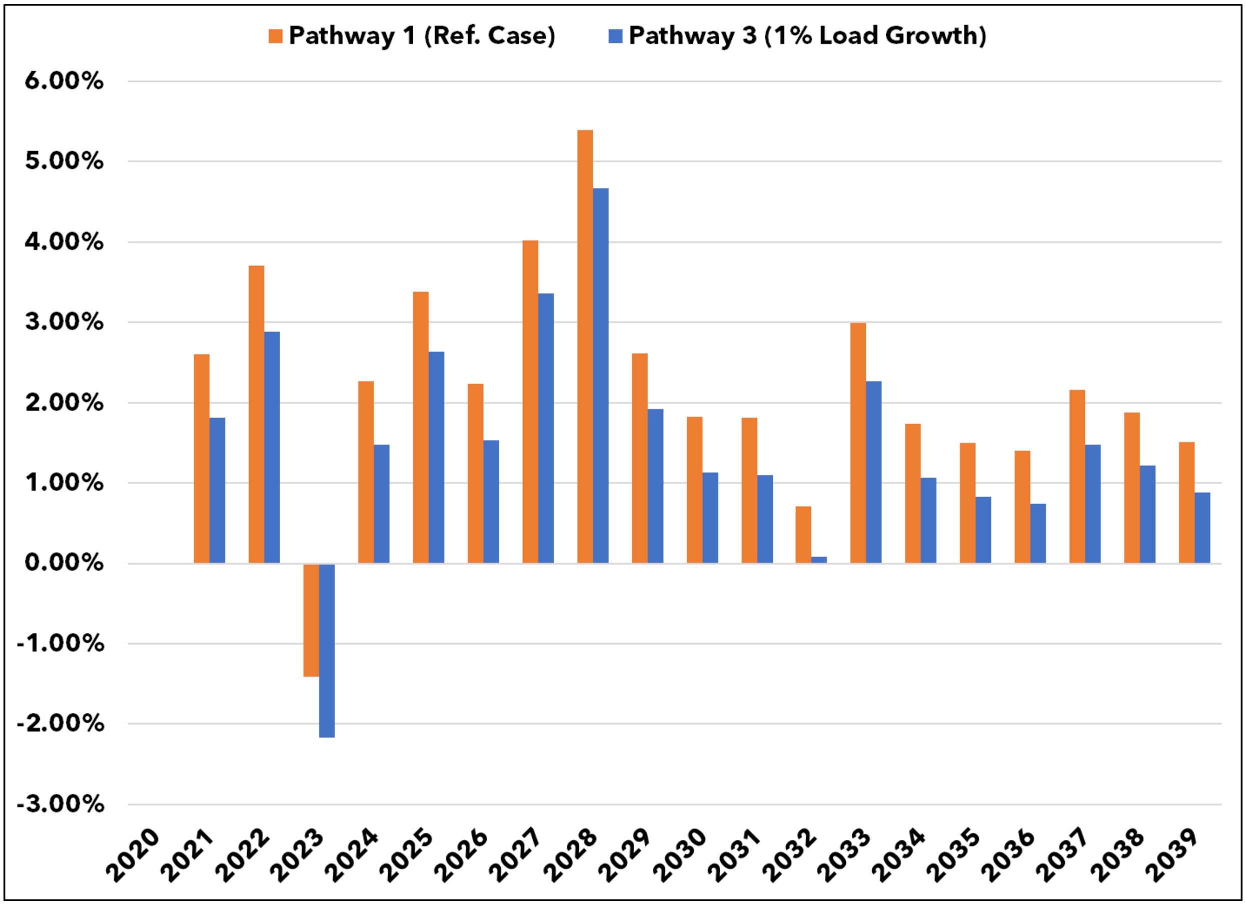
Figure 20: Quadrant Analysis of Market Price & Energy Length Outcomes

	Long MWH	**Short MWH**
Market Energy Prices HIGHER than Contract Price	**Cost of Service DECREASES**	**Cost of Service INCREASES**
Market Energy Prices LOWER than Contract Price	**Cost of Service INCREASES**	**Cost of Service DECREASES**

Impact of 1% Compound Annual Load Growth (CAGR)

Promoting energy-efficient load growth is an implied goal of the RES's Energy Transformation (Tier III) requirements. This section quantifies the impact that a 1% increase in annual load growth would have on retail rates. As Figure 21 shows, the impact is uniformly to lower rates. This is intuitive but is an important outcome to quantify. If this level of load growth were to occur between 2020 and 2032, for example, the 1% compound annual load growth could reduce rates by about 8% in 2032 as compared to the reference case.

Figure 21: Rate Impact of 1% CAGR Load Growth



Summary and Conclusions

The answers to the questions that were posed at the beginning of this chapter are now evident.

Decisions

1. LIHI for Enosburg Falls Hydro
   Q1: What are the costs and benefits of gaining LIHI certification by 1/1/25?
   A1: LIHI certification is a decision that can reduce costs more than any other. This analysis suggests that Enosburg Falls Hydro should pursue LIHI certification after the relicensing process is complete.

2. Extension of the NextEra PPA
   Q2: What are the costs and benefits of extending NextEra volumes through 2039?
   A2: Extending the NextEra PPA simply continues the status quo in terms of the cost and risk that VOEF faces. However, the risk mitigating benefits could be increased by renegotiating the volumes to more precisely match the electricity demand.

3. New Long-Term Hydro PPA
   Q3: What are the costs and benefits of a firm, Tier I qualifying hydro PPA that would supplant the extension of the NextEra PPA starting on 1/1/23?
   A3: This decision represents an excellent hedge against the energy market, especially as compared to a small-hydro PPA whose volumes are seasonal. If Tier I RECs can be bundled into the PPA at an attractive price, this decision would also fulfill a large part of VOEF's Tier I requirements and reduce Tier I price risk.

4. New Solar PPA
   Q4: What are the costs and benefits of a 500 kW solar PPA that includes both energy and Tier II RECs starting on 1/1/22?
   Q4: At today's prices, the solar PPA can be added to the portfolio at almost no cost, and it would measurably reduce the risk associated with purchasing Tier II (and perhaps Tier III) RECs.

In addition, we quantify two load-related questions.

5. 1% CAGR
   Q5: What is the rate impact of 1% compound annual load growth?
   A5: 1% compound annual growth in load could reduce rates in 2032 by 8% compared to the reference case.

6. Franklin Foods
   Q6: What is the rate impact if loads dropped by 20%, which approximates the impact of Franklin Foods leaving the system?
   A7: The loss of Franklin Foods would create upward rate pressure of about 20% in the first year.

These and other conclusions are carried into the Action Plan in the following section.

Action Plan

VI. Action Plan

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

1. Automated Metering Infrastructure (AMI)

- VOEF will participate in an evaluation of AMI readiness which, if results are positive, will lead to preparation of an RFP leading to vendor and equipment selection and ultimately to implementation of an AMI system. Upon completion of the RFP phase of the project, VOEF will have the information needed to examine the business case and make a decision to commit to implementation of an AMI system, or not. VOEF recognizes that cost reduction, while desirable, is but one of many factors that must be weighed in making the decision to go forward with AMI VOEF sees the potential for a number of future benefits that, while difficult to quantify in cost/benefit terms, will clearly be desirable to various stakeholders. These benefits include (but may not be limited to) improved system control/optimization, ability to deliver/administer more creative customer and load management initiatives, and ability to accommodate emerging initiatives such as EV charging. VOEF also notes that unanticipated initiatives may emerge over time that positively impact the perceived value of having an AMI system in place. VOEF is considering the potential benefit of a staged implementation that would initially focus on limited areas of high load or customer concentration.

2. Pursue LIHI certification for Enosburg Falls Hydroelectric

- Pursue LIHI certification by 1/1/2025.

3. Energy Resource Actions

- Manage year to year energy market requirements using fixed-price, market contracts until outlook for the load-related variables becomes better known.
- Canvass the market for firm hydro PPA pricing that includes bundled energy and Tier I renewable energy credits. This can reduce both energy and Tier I costs and risks.
- At the same time, get indicative prices from NextEra using more precise MWH volumes that match up to VOEF's load forecast.
- Negotiate a final PPA with the supplier that combines the lowest possible cost with the lowest possible risk from energy and REC market prices.

4. Capacity Resource Actions

- Manage and monitor the reliability of Project 10 to minimize Pay-for-Performance (PFP) risk and maximize capacity, reserves, and PFP benefits.

5. Tier I Requirements

- Canvass the market for long-term Tier I RECs and compare this to the bundled Hydro PPA option from the Energy Resource Actions.
- Make forward purchases of qualifying RECs on the regional market to manage REC price and ACP risk.

6. Tier II Requirements

- Seek a 500+kW solar PPA to hedge Tier II and Tier III requirements.

- Make forward purchases of qualifying RECs on the Vermont market to manage REC price and ACP risk.
- Investigate adding storage to upcoming solar projects to increase their value and decrease overall project costs.

7. Tier III Requirements

- Identify and deliver prescriptive and/or custom Energy Transformation programs, and/or
- Seek a 500+kW solar PPA to hedge Tier III requirements.
- Purchase a surplus of Tier II qualifying renewable energy credits.

8. 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.

9. Peak Load Management Pilot Program

- Explore ways to align reductions in customer demand charges with utility coincident peak costs through use of a pilot tariff.

10. 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.

11. Storage

- Monitor cost trends and potential use cases, and
- Identify Behind-the-Meter use cases and sites, and
- Develop project-specific cost-benefit analysis.

Appendix

Appendix A: Northwest Regional Planning Commission Energy Plan

This appendix is provided separately in a file named:

Appendix A – NRPC Regional Energy Plan.pdf

Appendix B: 2020 Tier 3 Annual Plan

This appendix is provided separately in a file named:

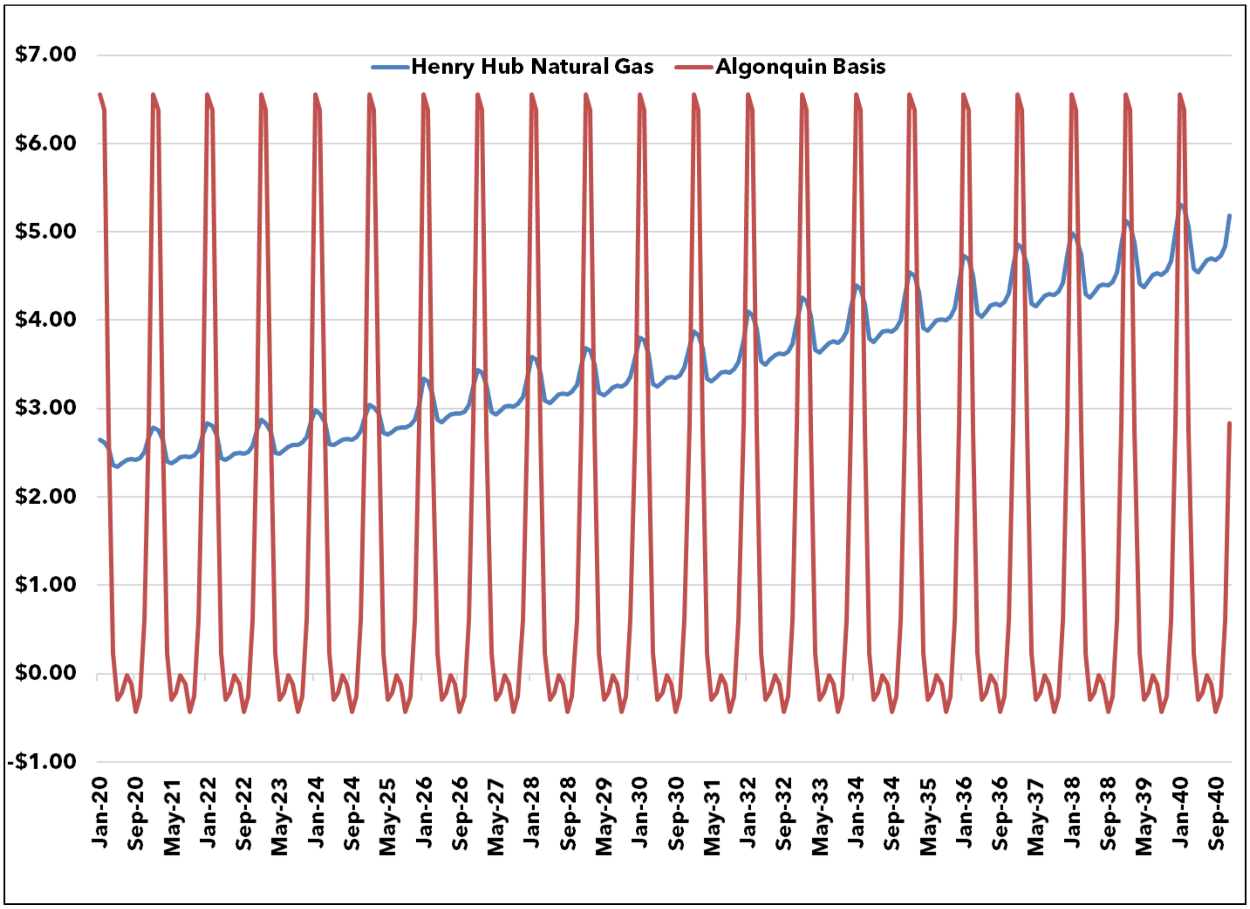
Appendix B - VPPSA Tier 3 2020 Annual Plan.pdf

Appendix C: Pricing Methodology

Energy Pricing

Energy prices are forecast using a three-step method. First, a natural gas price forecast is formed by combining a 3-month average of NYMEX Henry Hub futures prices for the period 2020 to 2021 with the Energy Information Administration (EIA) Annual Energy Outlook (AEO) Henry Hub forecast for the period 2022 to 2039. The forecast of Henry Hub Natural Gas prices can be seen in Figure 22.

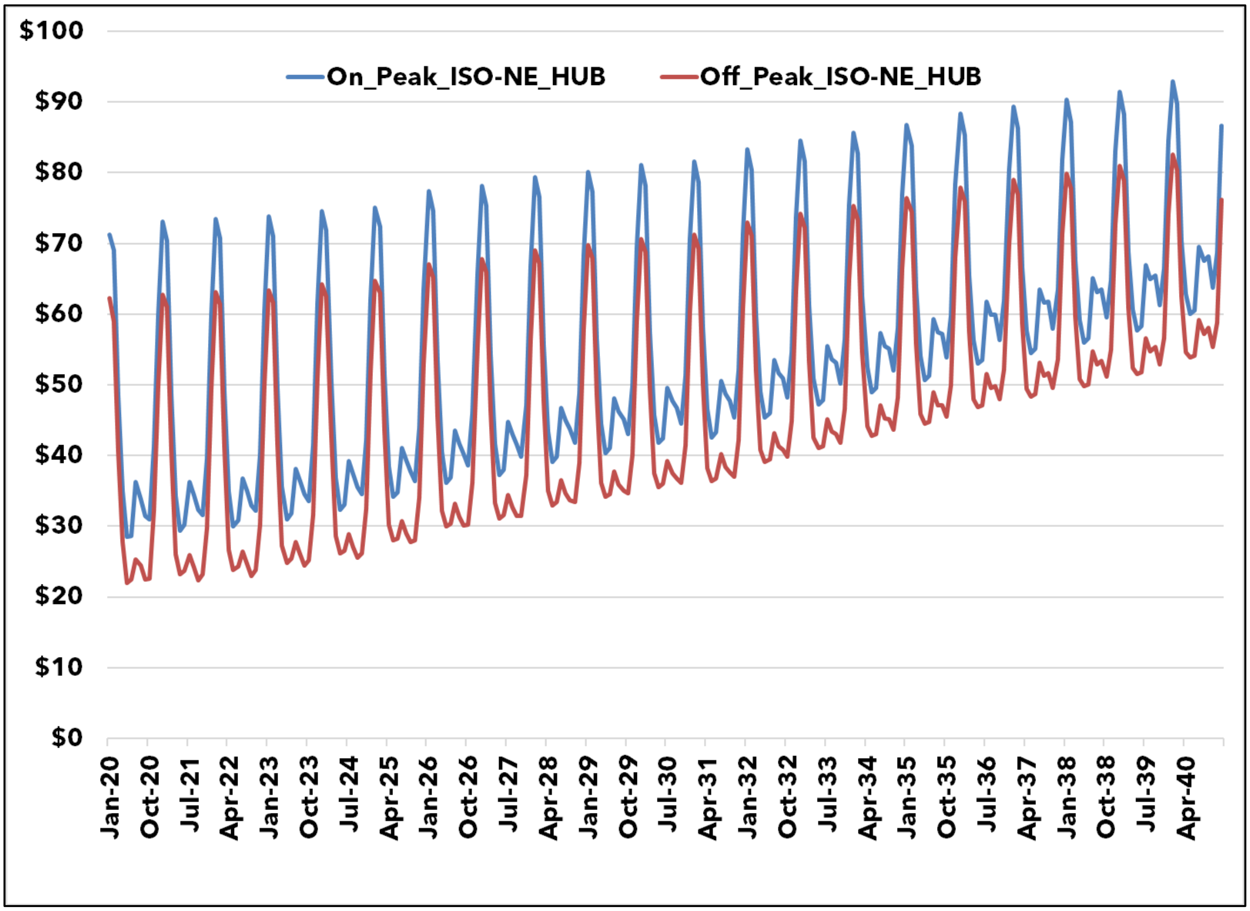
Figure 22: Henry Hub Natural Gas Price Forecast (Nominal $/MMBtu)



Second, we use NYMEX futures prices (between 2020-2021) to find 1.) the cost of transportation (basis) to the Algonquin Hub and 2.) the cost of on and off-peak energy at the Massachusetts Hub (MA Hub). These prices are used to calculate an implied heat rate (MMBtu/MWH) and a spread between on and off-peak electricity prices. These values (sometimes called shapes) are used for the remainder of the forecast period.

Third and finally, we multiply the natural gas price forecast by the implied heat rate 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 23.

Figure 23: Electricity Price Forecast (Nominal $/MWH)

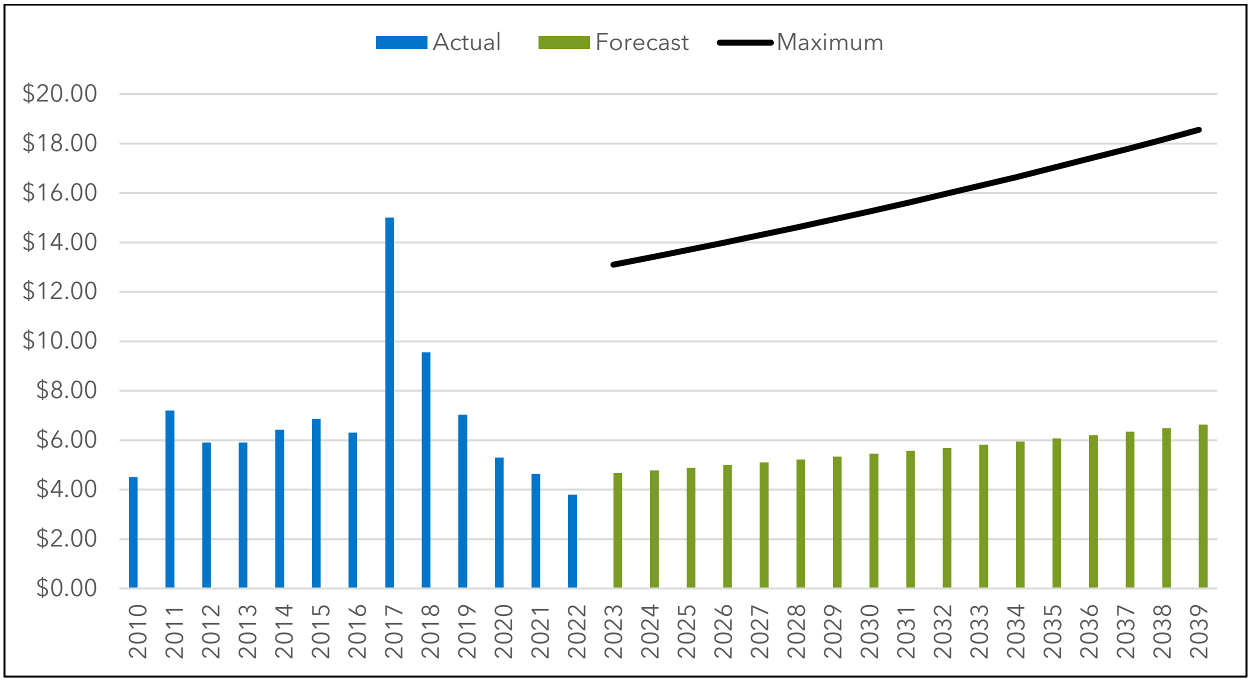


Finally, and in keeping with the function of ISO-NE's Standard Market Design, we use a five-year average basis between LMP nodes to adjust the price forecast at the MA Hub to the location of VOEF's load and resources.

Capacity Pricing

The capacity price forecast is an average of the last three years of actual auction results plus inflation, and it grows from $4.68 per kW-month in 2023 to $6.77 per kW-month in 2039. Significant upside price risk does exist, as shown by the Maximum line in Figure 24. This line represents the Forward Capacity Auction Starting Price plus inflation.

Figure 24: Capacity Price Forecast (Nominal $/kW-Month)



Appendix D: PUC Rule 4.900 Outage Reports

Enosburg Falls Electric Light Department 2014

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

Electricity Outage Report -- PSB Rule 4.900

Name of company	Enosburg Falls Electric Light Department
Calendar year report covers	2014
Contact person	Laurie A. Stanley
Phone number	802-933-4443
Number of customers	1,707

System average interruption frequency index (SAIFI) = 0.4
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**	15	556
2	**Weather**	4	140
3	**Company initiated outage**	3	84
4	**Equipment failure**	8	116
5	**Operator error**	0	0
6	**Accidents**	5	136
7	**Animals**	3	99
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	1	55
	Total	39	1,185

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

Enosburg Falls Electric Light Department 2015

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

Electricity Outage Report -- PSB Rule 4.900

Name of company	Enosburg Falls Electric Light Department
Calendar year report covers	2015
Contact person	Laurie A. Stanley
Phone number	802-933-4443
Number of customers	1,723

System average interruption frequency index (SAIFI) =	**0.8**
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	**1.8**
Customer Hours Out / Customers Out	

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	15	728
2	**Weather**	9	342
3	**Company initiated outage**	3	207
4	**Equipment failure**	11	521
5	**Operator error**	0	0
6	**Accidents**	1	50
7	**Animals**	7	102
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	1	8
11	**Unknown**	2	650
	Total	49	2,608

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

Enosburg Falls Electric Light Department 2016

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

Electricity Outage Report -- PSB Rule 4.900

Name of company	Enosburg Falls Electric Light Department
Calendar year report covers	2016
Contact person	Laurie A. Stanley
Phone number	802-933-4443
Number of customers	1,729

System average interruption frequency index (SAIFI) =	**0.7**
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	**1.9**
Customer Hours Out / Customers Out	

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	20	916
2	**Weather**	3	246
3	**Company initiated outage**	6	325
4	**Equipment failure**	7	72
5	**Operator error**	0	0
6	**Accidents**	5	120
7	**Animals**	6	173
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	5	407
	Total	52	2,260

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

Enosburg Falls Electric Light Department 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	Enosburg Falls Electric Light Department
Calendar year report covers	2017
Contact person	Laurie A. Stanley
Phone number	802-933-4443
Number of customers	1,733

System average interruption frequency index (SAIFI) = 0.7
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 1.5
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	14	591
2	**Weather**	4	198
3	**Company initiated outage**	2	12
4	**Equipment failure**	8	311
5	**Operator error**	0	0
6	**Accidents**	0	0
7	**Animals**	4	33
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	11	677
	Total	43	1,822

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

Enosburg Falls Electric Light Department 2018

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

Electricity Outage Report -- PSB Rule 4.900

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

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

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

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

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.

Appendix E: Inverter Source Requirements

Inverter Source Requirement Document of ISO New England (ISO-NE)

This Source Requirement Document applies to inverters associated with specific types of generation for projects that have applied for interconnection after specific dates. These details will be described in separate document(s). This document was developed with the help of the Massachusetts Technical Standards Review Group and is consistent with the pending revision of the IEEE 1547 Standard for Interconnection and Interoperability of Distributed Resources with Associated Electrical Power Systems Interfaces. All applicable inverter-based applications shall:

- be certified per the requirements of UL 1741 SA as a grid support utility interactive inverter
- have the voltage and frequency trip settings
- have the abnormal performance capabilities (ride-through)
- comply with other grid support utility interactive inverter functions statuses

These specifications are detailed below and are consistent with the amended IEEE Std 1547a-2014.

1. **Certification per UL 1741 SA as grid support utility interactive inverters**

   In the interim period while IEEE P1547.1 is not yet revised and published, certification of all inverter- based applications:

   a. shall be compliant with only those parts of Clause 6 (Response to Area EPS abnormal conditions) of IEEE Std 1547-2018 (2nd ed.)1 that can be certified per the type test requirements of
   UL 1741 SA (September 2016). IEEE Std 1547-2018 (2nd ed.) in combination with this document

   replaces other Source Requirements Documents (SRDs), as applicable;

   b. may be sufficiently achieved by certifying inverters as grid support utility interactive inverters per the requirements of UL 1741 SA (September 2016) with either CA Rule 21 or Hawai'ian Rule 14H as the SRD. Such inverters are deemed capable of meeting the requirements of this document.

2. **Voltage and frequency trip settings for inverter based applications**

   Applications shall have the voltage and frequency trip points specified in Tables I and II below.

3. **Abnormal performance capability (ride-through) requirements for inverter based applications**

The inverters shall have the ride-through capability per abnormal performance category II of IEEE Std 1547-2018 (2nd ed.) as quoted in Tables III and IV.

The following additional performance requirements shall apply for all inverters:

a. In the Permissive Operation region above 0.5 p.u., inverters shall ride-through in Mandatory Operation mode, and
b. In the Permissive Operation region below 0.5 p.u., inverters shall ride-through in Momentary Cessation mode.

1

7.3 as a proxy, subject to minor

editorial changes.

Consistent with IEEE Std 1547-2018 (2nd ed.) the following shall apply:

a. DER tripping requirements specified in this SRD shall take precedence over the abnormal performance capability (ride-through) requirements in this section, subject to the following:
    1. Where the prescribed trip duration settings for the respective voltage or frequency magnitude are set at least 160 ms or 1% of the prescribed tripping time, whichever is greater, beyond the prescribed ride-through duration, the DER shall comply with the ride-through requirements specified in this section prior to tripping.
    2. In all other cases, the ride-through requirements shall apply until 160 ms or 1% of the prescribed tripping time, whichever is greater, prior to the prescribed tripping time.
b. DER ride-through requirements specified in this section shall take precedence over all other requirements within this SRD with the exception of tripping requirements listed in item a. above. Ride-through may be terminated by the detection of an unintentional island. However, false detection of an unintentional island that does not actually exist shall not justify non- compliance with ride-through requirements. Conversely, ride-through requirements specified in this section shall not inhibit the islanding detection performance where a valid unintentional islanding condition exists.

4. **Other grid support utility interactive inverter functions statuses**

Other functions required by UL 1741 SA shall comply with the requirements specified in Table V. For functions not activated by default, the inverter is compliant if tested to the manufacturers stated capability.

5. Definitions

The following definitions which are consistent with IEEE Std 1547-2018 (2nd ed.) and UL 1741 SA shall apply:

cease to energize: Cessation of active power delivery under steady state and transient conditions and limitation of reactive power exchange. This may lead to momentary cessation or trip.

clearing time: The time between the start of an abnormal condition and the DER ceasing to energize the utility's distribution circuit(s) to which it is connected. It is the sum of the detection time, any adjustable time delay, the operating time plus arcing time for any interposing devices (if used), and the operating time plus arcing time for the interrupting device (used to interconnect the DER with the utility's distribution circuit).

continuous operation: Exchange of current between the DER and an EPS within prescribed behavior while connected to the utility's distribution system and while the applicable voltage and the system frequency is within specified parameters.

mandatory operation: Required continuance of active current and reactive current exchange of DER with utility's distribution system as prescribed, notwithstanding disturbances of the utility's distribution system voltage or frequency having magnitude and duration severity within defined limits.

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momentary cessation: Temporarily cease to energize the utility's distribution system while connected to the utility's distribution system, in response to a disturbance of the applicable voltages or the system frequency, with the capability of immediate restore output of operation when the applicable voltages and the system frequency return to within defined ranges.

permissive operation: operating mode where the DER performs ride-through either in mandatory operation or in momentary cessation, in response to a disturbance of the applicable voltages or the system frequency.

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ISO-NE PUBLIC **Table I: Inverters' Voltage Trip Settings**

Shall Trip – IEEE Std 1547-2018 (2nd ed.) Category II					
Shall Trip Function	Required Settings		Comparison to IEEE Std 1547-2018 (2nd ed.) default settings and ranges of allowable settings for Category II		
	Voltage (p.u. of nominal voltage)	Clearing Time(s)	Voltage	Clearing Time(s)	Within ranges of allowable settings?
OV2	1.20	0.16	Identical	Identical	Yes
OV1	1.10	2.0	Identical	Identical	Yes
UV1	0.88	2.0	Higher (default is 0.70 p.u.)	Much shorter (default is 10 s)	Yes
UV2	0.50	1.1	Slightly higher (default is 0.45 p.u.)	Much longer (default is 0.16 s)	Yes

Table II: Inverters' Frequency Trip Settings

Shall Trip Function	Required Settings		Comparison to IEEE Std 1547-2018 (2nd ed.) default settings and ranges of allowable		
	Frequency (Hz)	Clearing Time(s)	Frequency	Clearing Time(s)	Within ranges of allowable settings?
OF2	62.0	0.16	Identical	Identical	Yes
OF1	61.2	300.0	Identical	Identical	Yes
UF1	58.5	300.0	Identical	Identical	Yes
UF2	56.5	0.16	Identical	Identical	Yes

Table III: Inverters' Voltage Ride-through Capability and Operational Requirements

Voltage Range (p.u.)	Operating Mode/ Response	Minimum Ride-through Time(s) (design criteria)	Maximum Response Time(s) (design criteria)	Comparison to IEEE Std 1547-2018
V > 1.20	Cease to Energize	N/A	0.16	Identical
1.175 < V ≤ 1.20	Permissive Operation	0.2	N/A	Identical
1.15 < V ≤ 1.175	Permissive Operation	0.5	N/A	Identical
1.10 < V ≤ 1.15	Permissive Operation	1	N/A	Identical
0.88 ≤ V ≤ 1.10	Continuous Operation	infinite	N/A	Identical
0.65 ≤ V < 0.88	Mandatory Operation	Linear slope of 8.7 s/1 p.u. voltage starting at 3 s @ 0.65 p.u.: T = 3 s + 8.7 s (V − 0.65 p.u.)	N/A	Identical
0.45 ≤ V < 0.65	Permissive Operation [a,b]	0.32	N/A	See footnotes a & b
0.30 ≤ V < 0.45	Permissive Operation [b]	0.16	N/A	See footnote b
V < 0.30	Cease to Energize	N/A	0.16	Identical

The following additional operational requirements shall apply for all inverters:

a. In the Permissive Operation region above 0.5 p.u., inverters shall ride-through in Mandatory Operation mode, and
b. In the Permissive Operation region below 0.5 p.u., inverters shall ride-through in Momentary Cessation mode with a maximum response time of 0.083 seconds.

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Table IV: Inverters' Frequency Ride-through Capability

Frequency Range (Hz)	Operating Mode	Minimum Time(s) (design criteria)	Comparison to IEEE Std 1547-2018 (2nd ed.)
f > 62.0	No ride-through requirements apply to this range		Identical
61.2 < f ≤ 61.8	Mandatory Operation	299	Identical
58.8 ≤ f ≤ 61.2	Continuous Operation	Infinite	Identical
57.0 ≤ f < 58.8	Mandatory Operation	299	Identical
f < 57.0	No ride-through requirements apply to this range		Identical

Table V: Grid Support Utility Interactive Inverter Functions Status

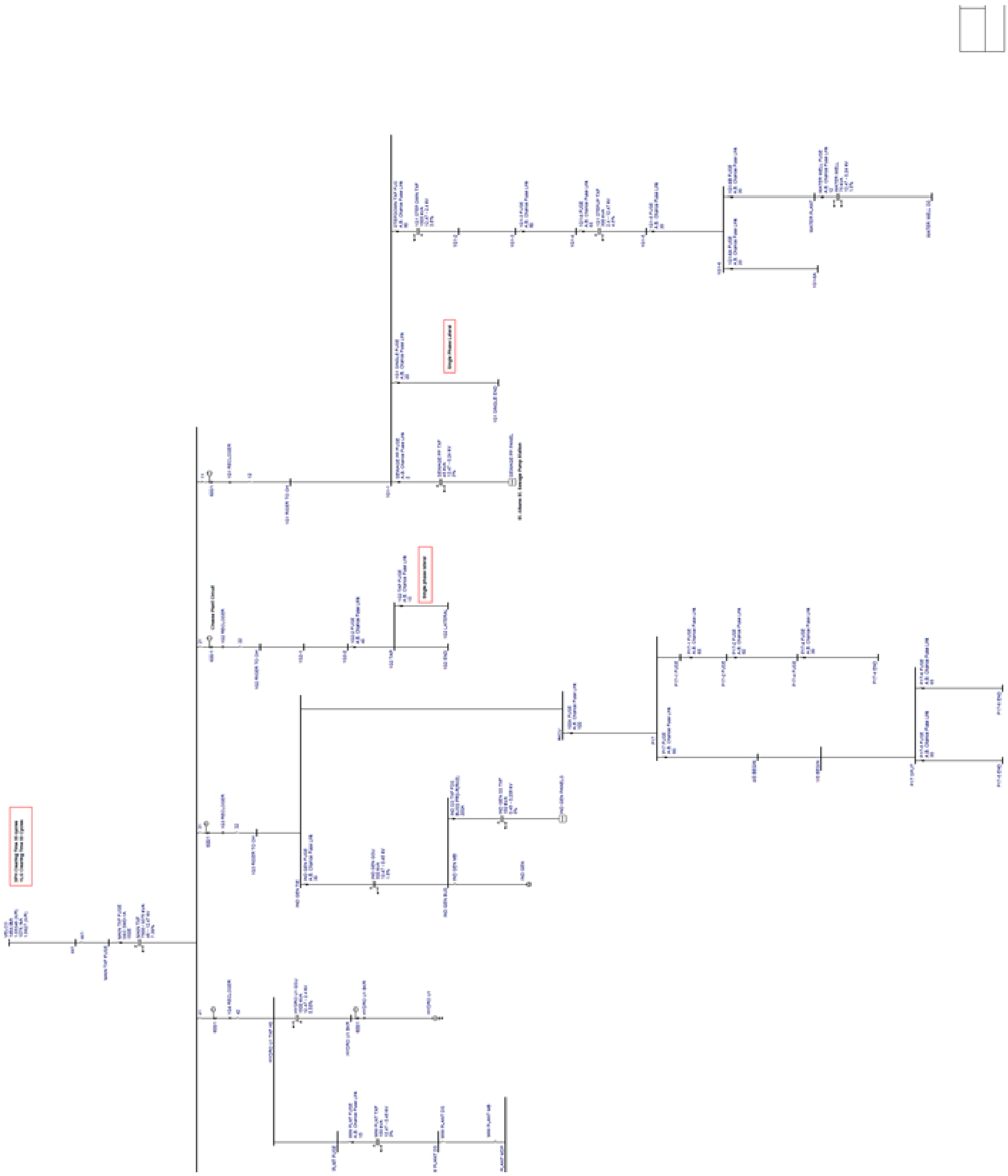
Function	Default Activation State
SPF, Specified Power Factor	**OFF[2]**
Q(V), Volt-Var Function with Watt	**OFF**
SS, Soft-Start Ramp Rate	**ON** **Default value: 2% of maximum current**
FW, Freq-Watt Function OFF	**OFF**

2

with unity PF.

Appendix F: One-Line Diagrams

Figure 25: VOEF One-Line Diagram



Glossary

Glossary

ACP	Alternative Compliance Payment
ACSR	Aluminum conductor steel-reinforced
APPA	American Public Power Association
CAGR	Compound Annual Growth Rate
CAIDI	Customer Average Interruption Duration Index
CC	Combined Cycle (Power Plant)
CCHP	Cold Climate Heat Pump
CEDF	Clean Energy Development Fund
CEP	Comprehensive Energy Plan
DPS	Department of Public Service or "Department"
EIA	Energy Information Administration
ET	Energy Transformation (Tier III)
EV	Electric Vehicle
EVT	Efficiency Vermont
FERC	Federal Energy Regulatory Commission
GMP	Green Mountain Power
HPWH	Heat Pump Water Heater
IRP	Integrated Resource Plan
ISO-NE	ISO New England (New England's Independent System Operator)
kV	Kilovolt
kVA	Kilovolt Amperes
kW	Kilowatt
kWh	Kilowatt-hour
LIHI	Low Impact Hydro Institute
MAPE	Mean Absolute Percent Error
ME II	Maine Class II (RECs)
MEAV	Municipal Association of Vermont
MSA	Master Supply Agreement
MVA	Megavolt Ampere
MW	Megawatt
MWH	Megawatt-hour
NEPPA	Northeast Public Power Association
NRPC	Northwest Regional Planning Commission
NYPA	New York Power Authority
PFP	Pay for Performance
PUC	Public Utility Commission
PPA	Power Purchase Agreement
R^2	R-squared
RES	Renewable Energy Standard
RTLO	Real-Time Load Obligation
SAIFI	System Average Interruption Frequency Index
SED	Swanton Village Electric Department
SCADA	Supervisory Control and Data Acquisition
TIER I	Total Renewable Energy (Tier I)
TIER II	Distributed Renewable Energy (Tier II)
TIER III	Energy Transformation (Tier III)
TOU	Time-Of-Use (Rate)
VEC	Vermont Electric Cooperative

VELCO	Vermont Electric Power Company
VEPPI	Vermont Electric Power Producers, Inc.
VOEF	Village of Enosburg Falls Electric Light Department
VFD	Variable Frequency Drive
VSPC	Vermont System Planning Committee
VT ANR	Vermont Agency of Natural Resources
WQC	Water Quality Certificate