Village of Enosburg Falls Electric Light Department

2019 Integrated Resource Plan

Filed with the Public Utility Commission

Vermont Public Power Supply Authority

Executive Summary:

The Village of Enosburg Falls Electric Light Department (VOEF) has operated an electric utility system since 1896. Serving approximately 1,740 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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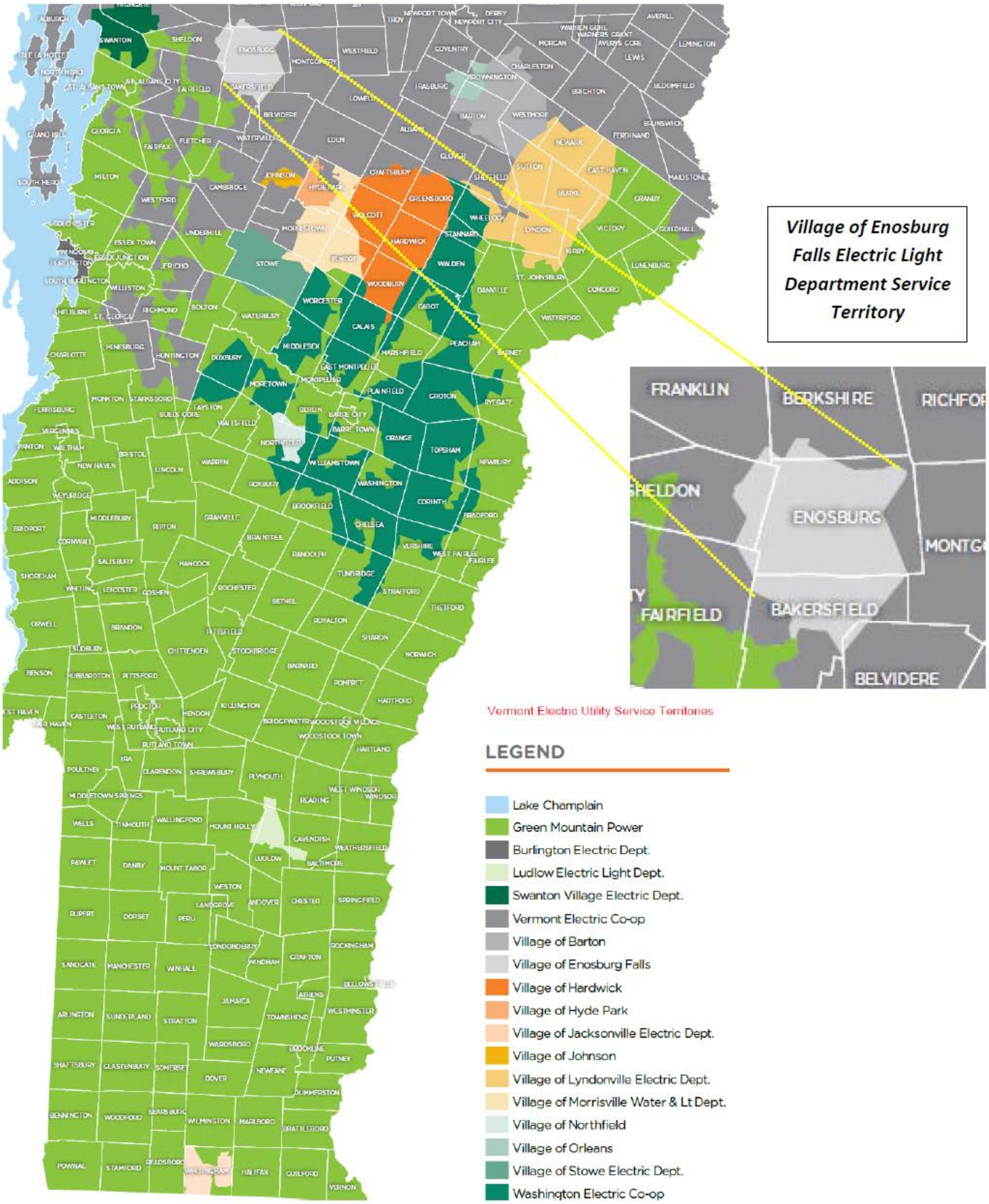
Introduction:

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

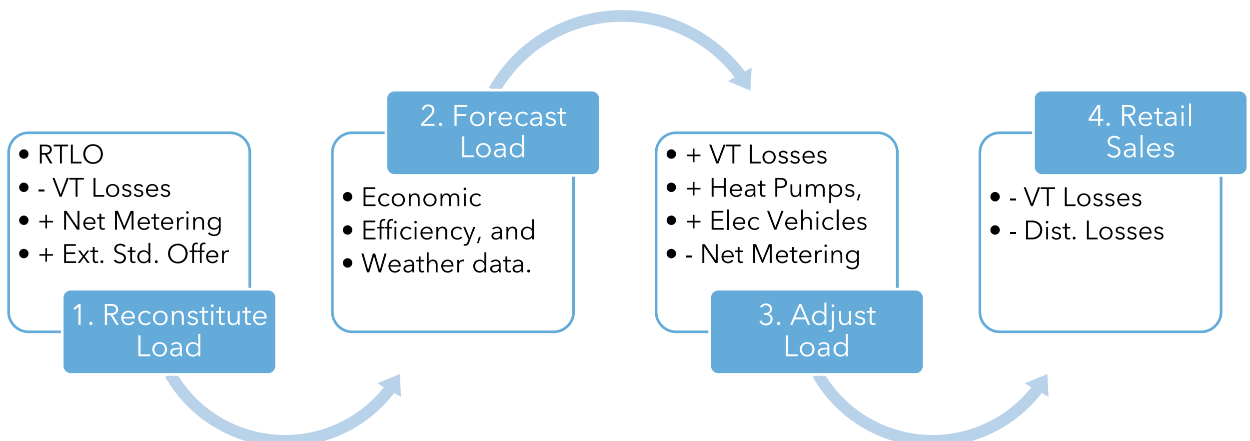
Electricity Demand

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

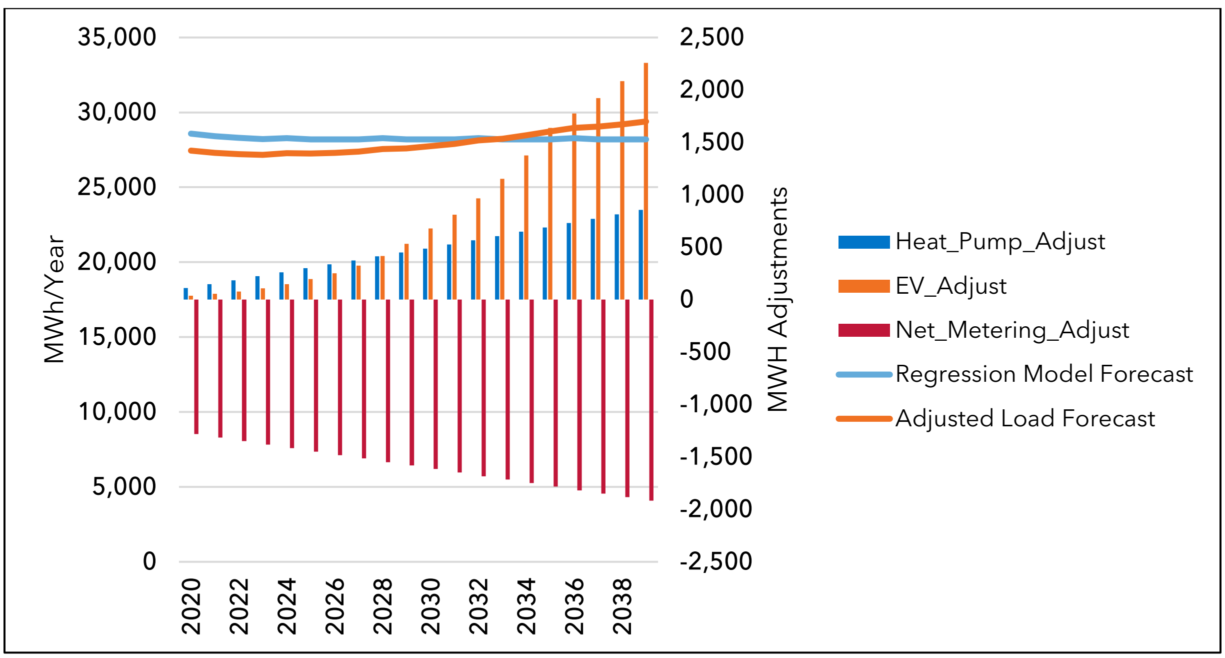
Table 6 shows the results of the Regression Forecast for energy, as well as the adjustments that are made to arrive at the Adjusted Forecast. The Compound Annual Growth Rates (CAGR) at the bottom of the table illustrate the trends in each of the columns. Notice that the Regression Forecast itself is 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

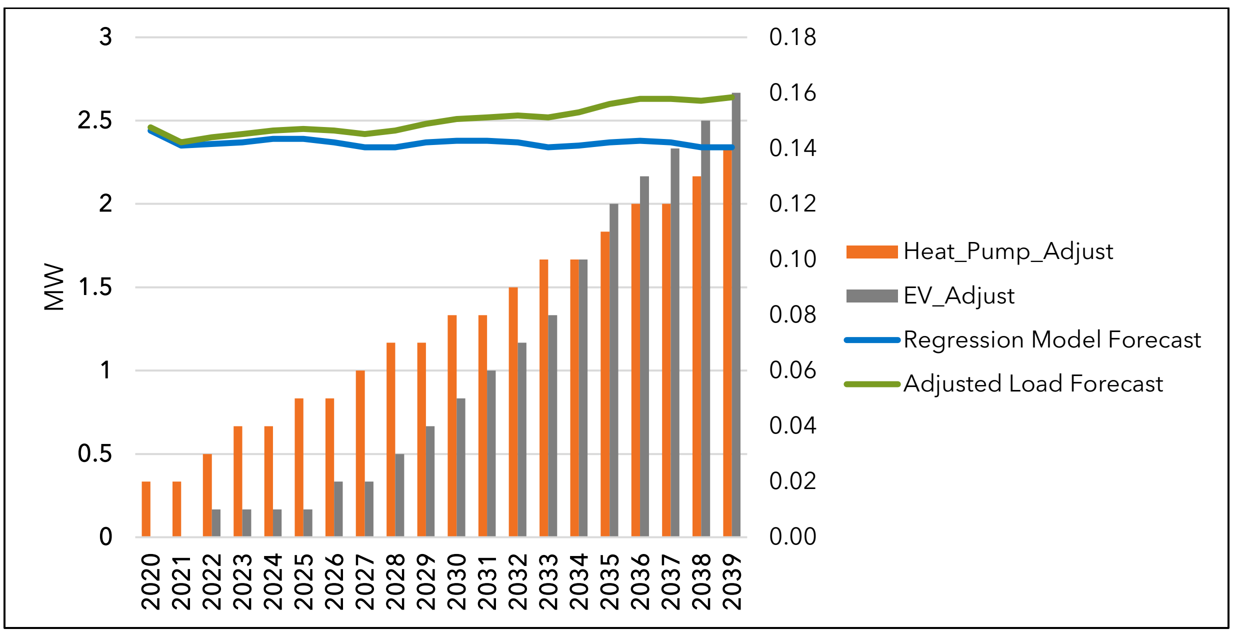
Table 9 shows the results of the Regression Forecast of peak loads, as well as the adjustments that are made to arrive at the Adjusted Forecast. The CAGR at the bottom of the table illustrate the trends in each of the columns. Notice that the Regression Forecast itself is decreasing by 0.1% per year. 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

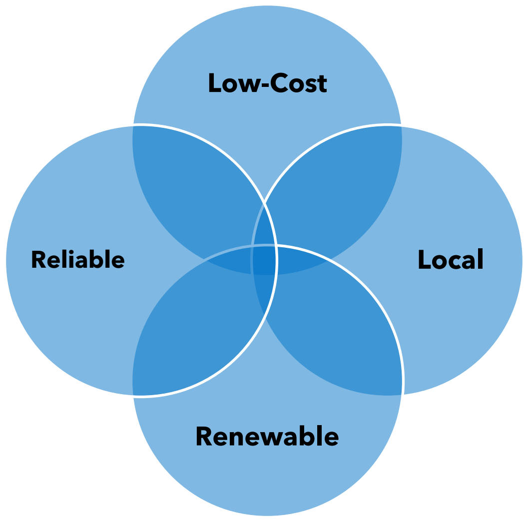
Resource	2020 MWH	% of MWH	2020 MW	Delivery Pattern	Price Pattern	REC	Expiration Date	Renewal to 2039
1. Chester Solar	768	2.9%	0.219	Intermittent	Fixed		6/30/2039	No
2. Enosburg Falls Hydro	3,441	13.0%	0.000	Intermittent	Fixed	✓	Life of unit.	Yes
3. Fitchburg Landfill	2,871	10.9%	0.285	Firm	Fixed	✓	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.

[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.

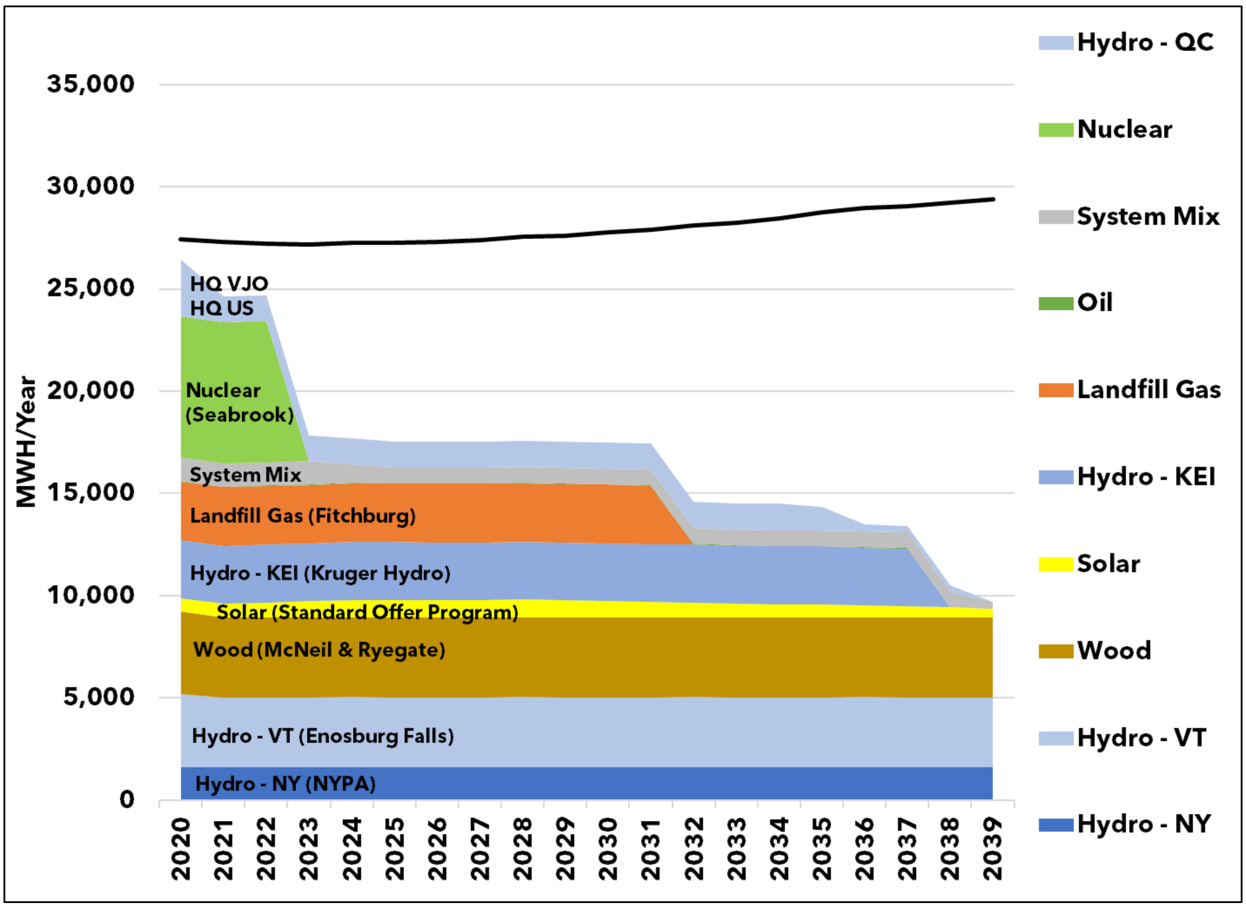
Energy Resource Plan

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.

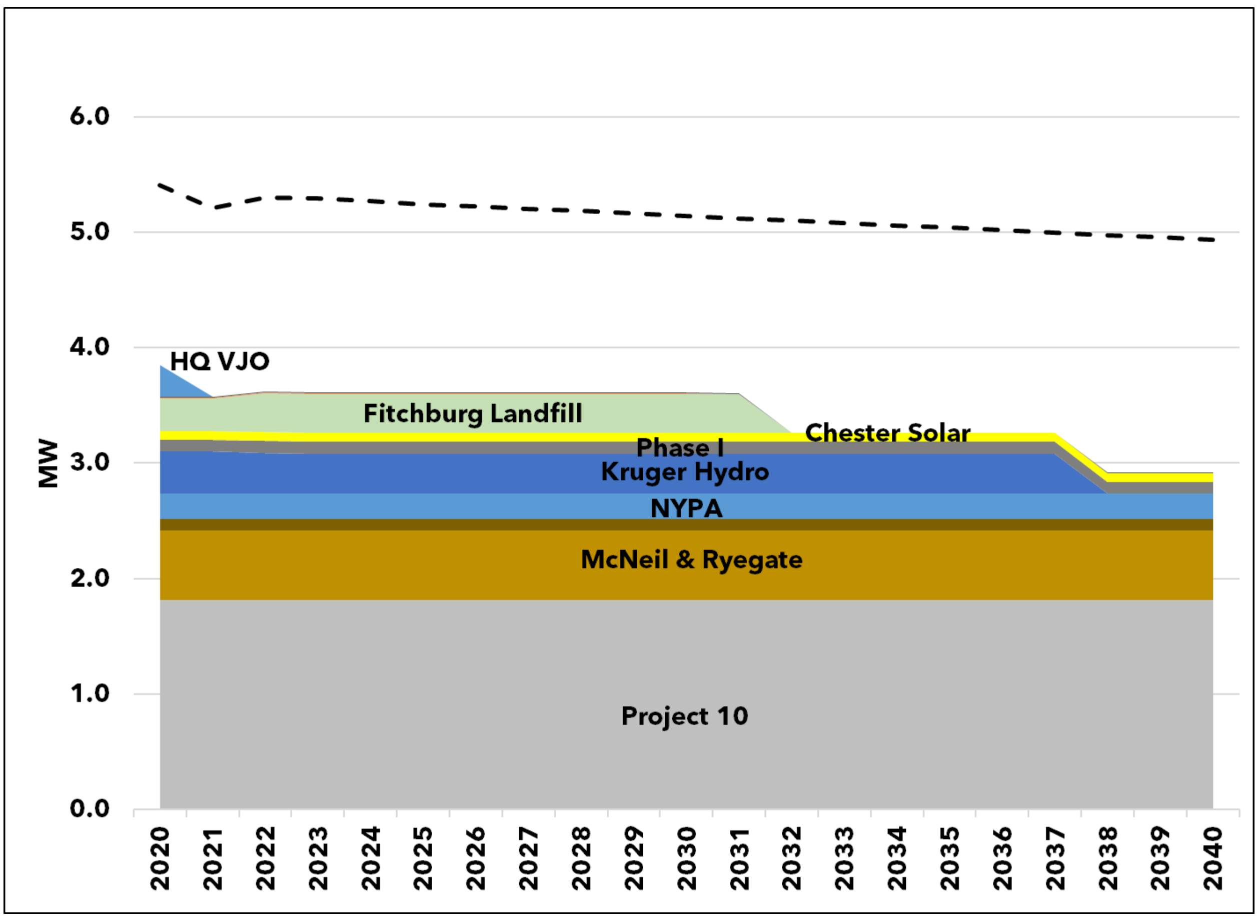
Table 12: Energy Resource Decision Summary

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).

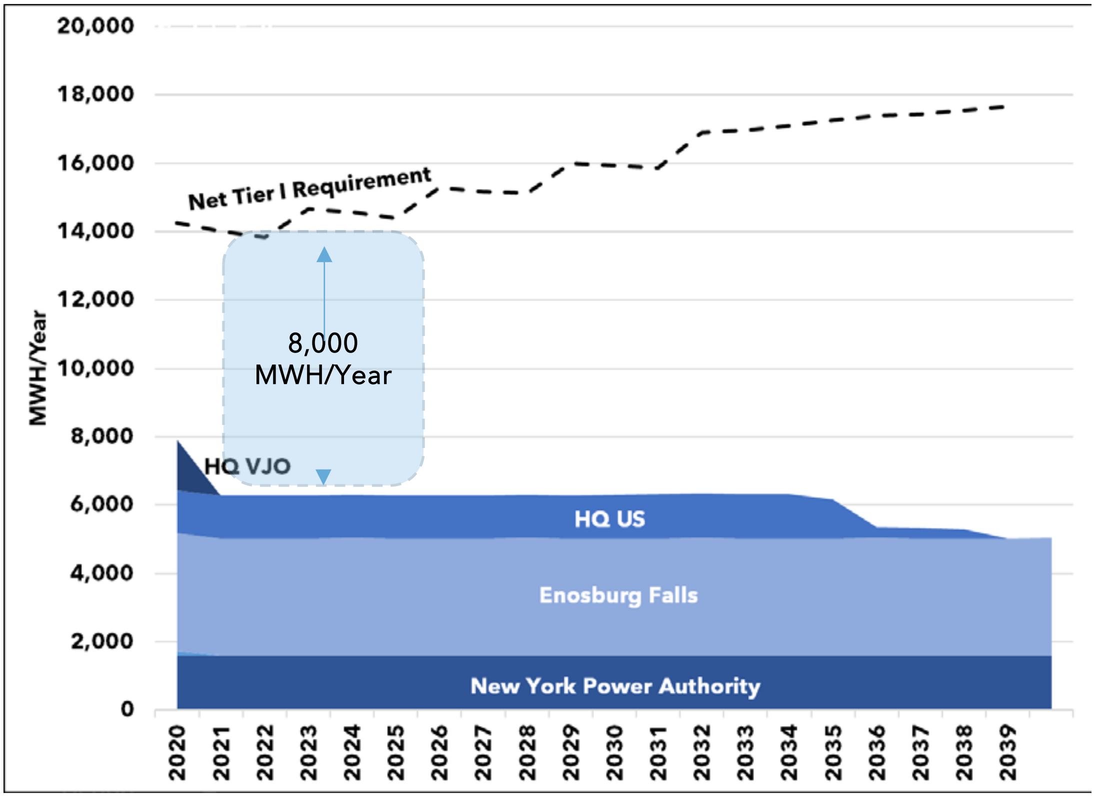
Finally, utilities with a RES deficit may also petition the Public Utilities Commission (PUC) for relief from the ACP. Alternatively, utilities may petition PUC to roll the deficit into subsequent compliance years. As a result, there are multiple ways to comply with RES requirements.

[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.

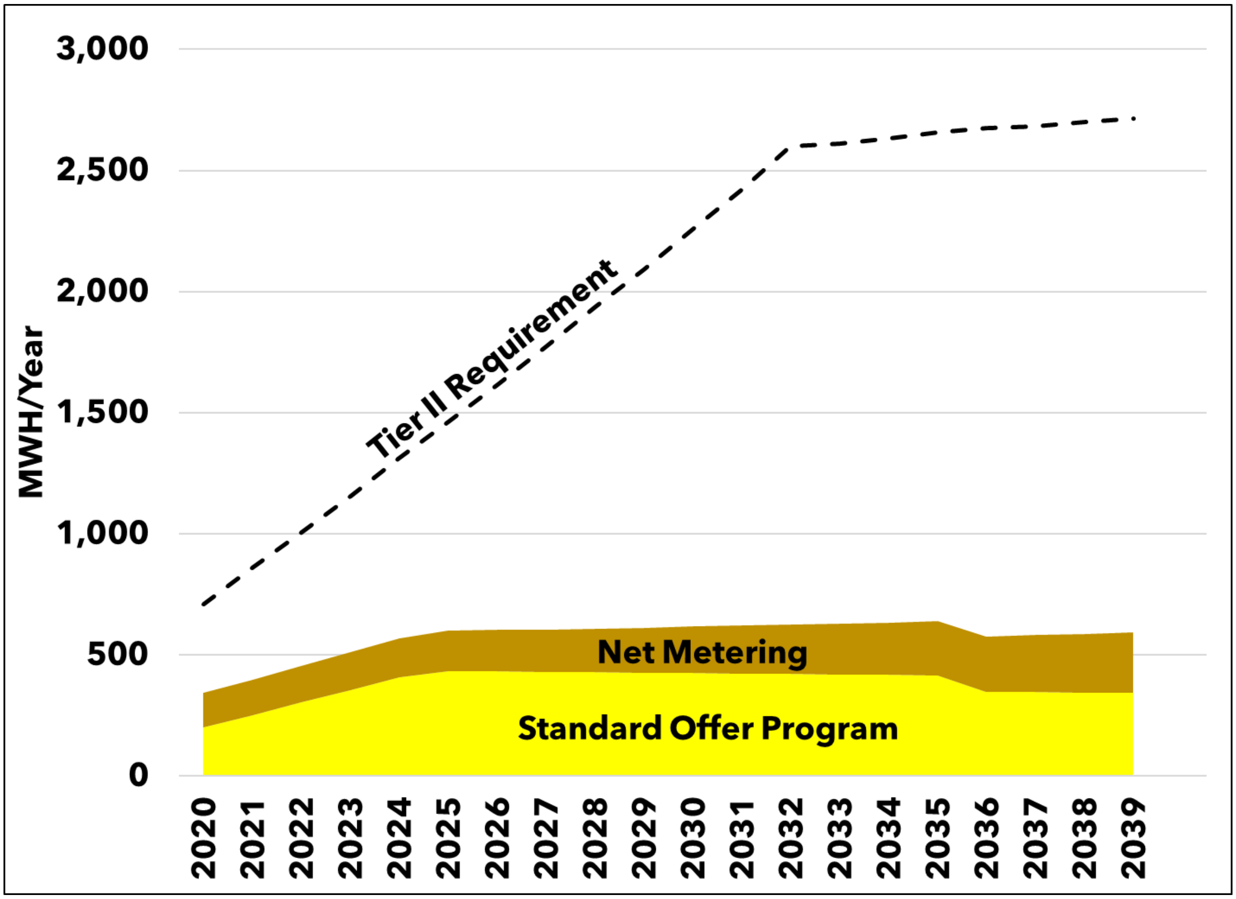
As mentioned in the Energy Resource Plan, the expiration of the NextEra 2018-2022 and Market PPAs creates an opportunity to purchase a resource that provides both energy and RECs. The 8,000 MWH per year deficit is equivalent to a 2.3 MW hydro facility[16], and if the output from a hydro resource of this 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)

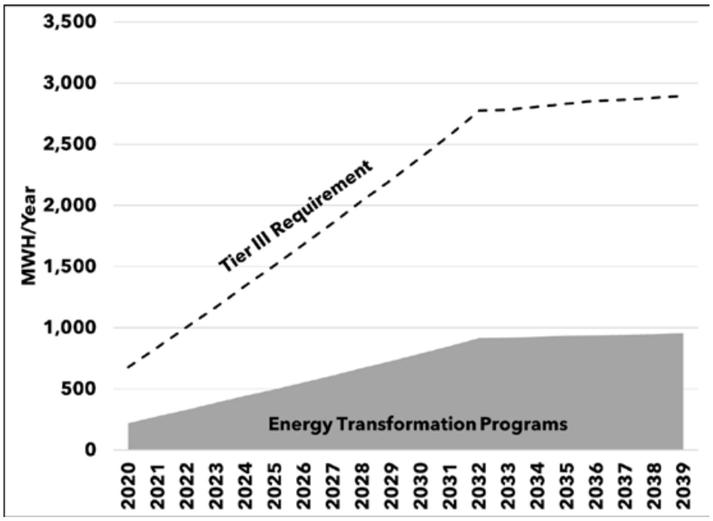


[17] The TIER II requirement is also known as "Tier 2".

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.

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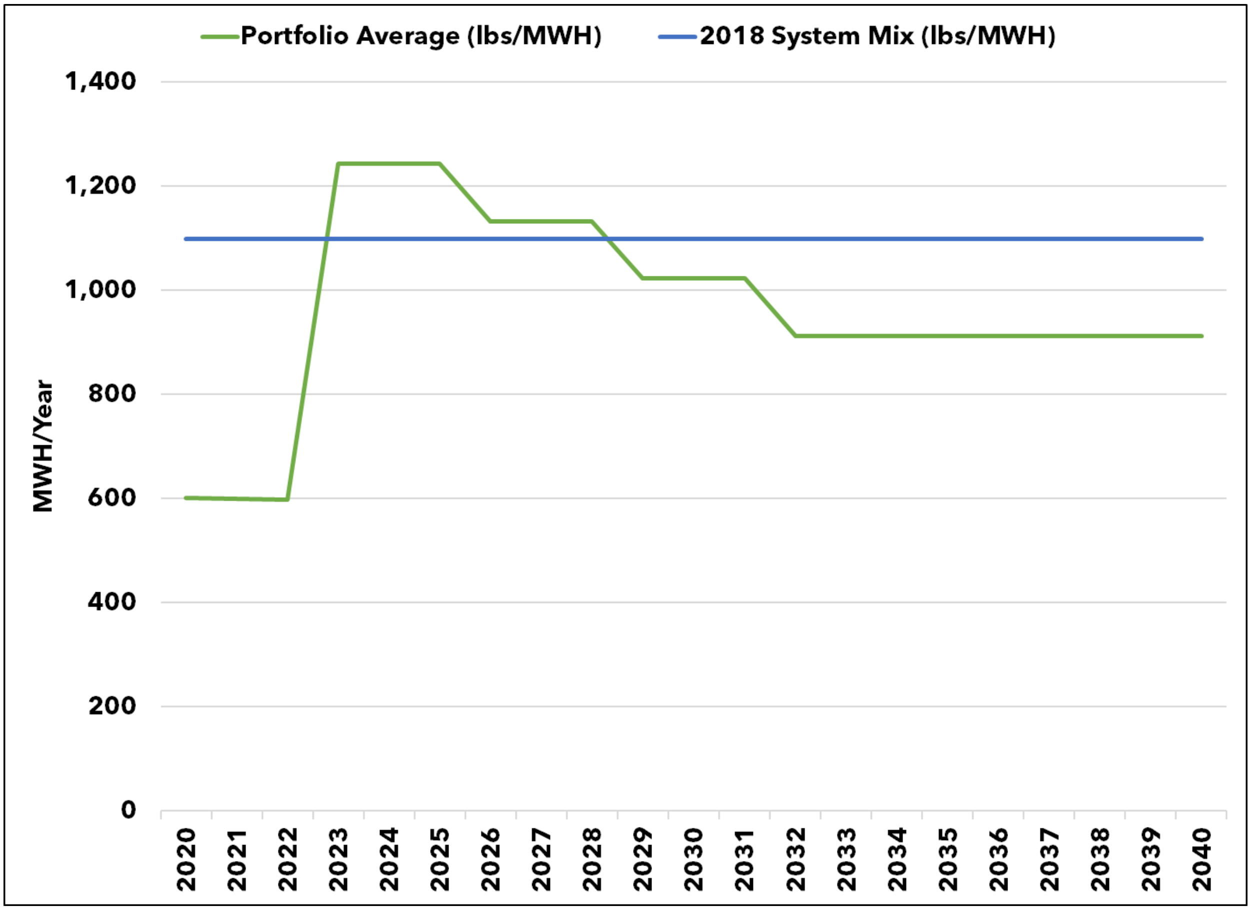
[18] More detail on these programs can be found in Appendix B (VPPSA's 2019 Tier 3 Annual Plan) and on VPPSA's website.

[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)



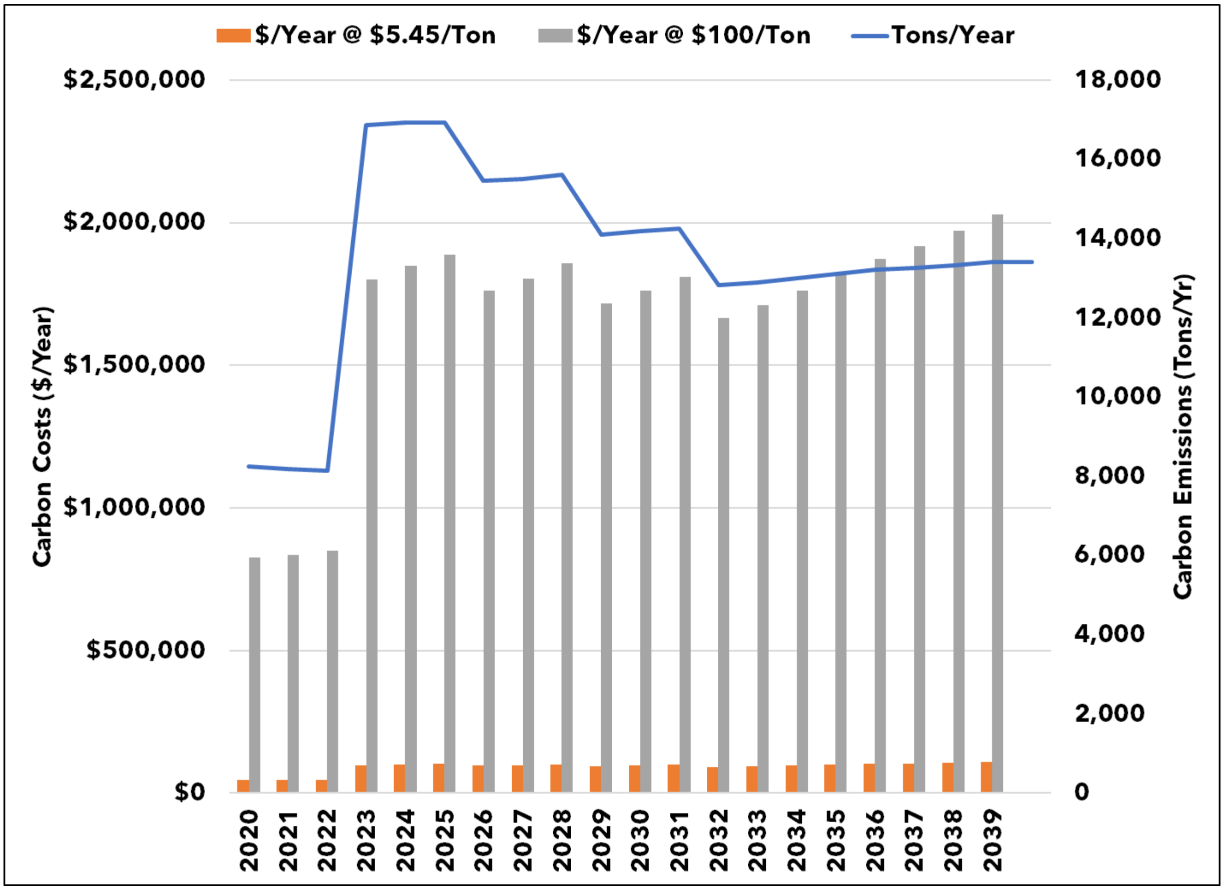
[20] The source of this data is the NEPOOL GIS. https://www1.nepoolgis.com/

[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.

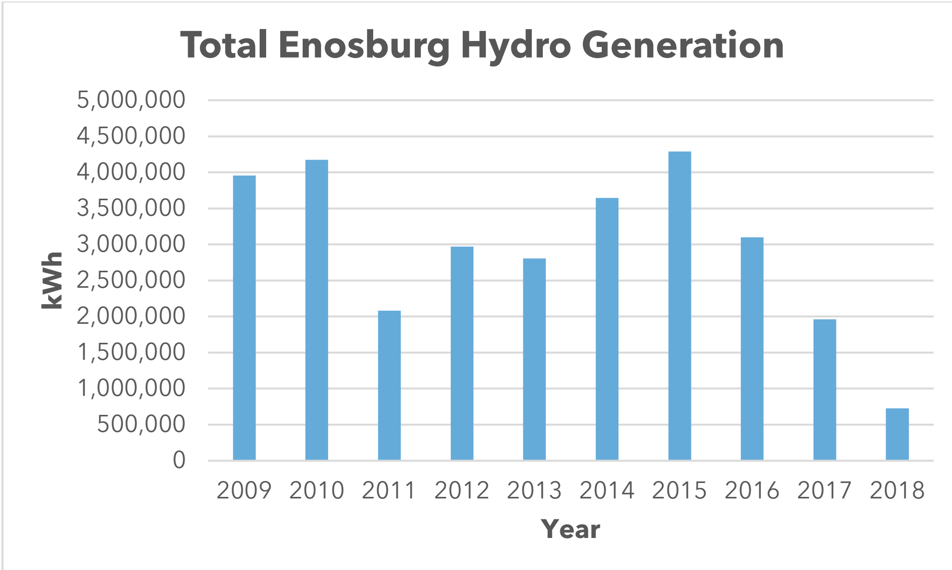
.

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**

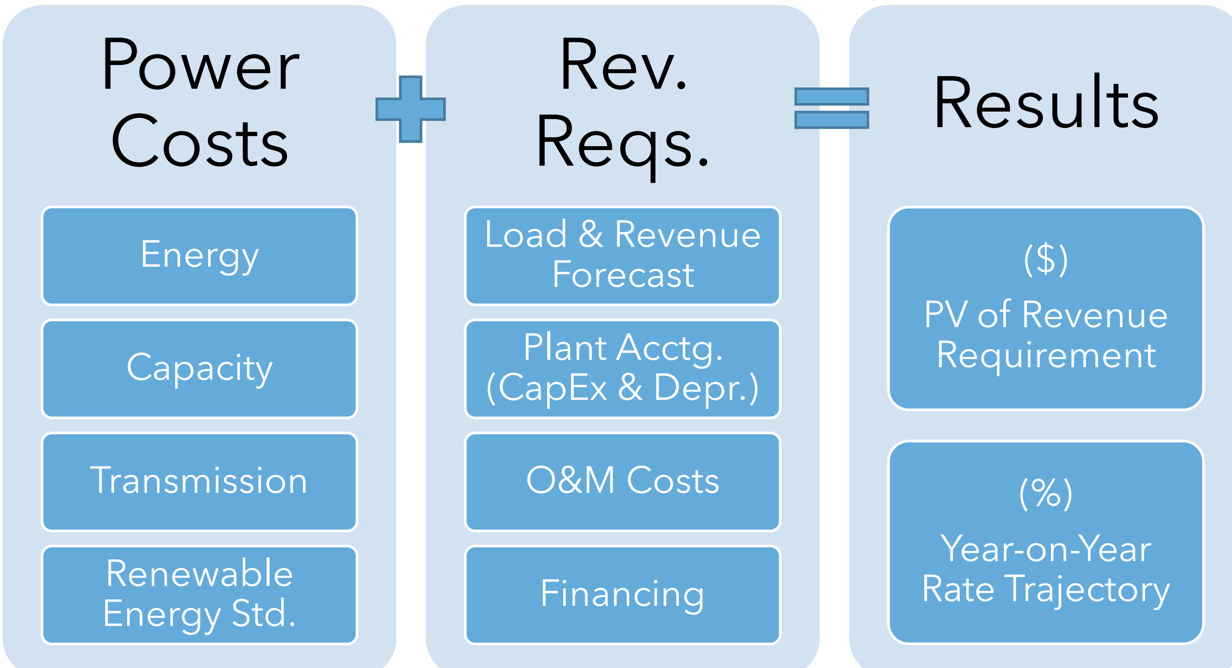
Financial Analysis

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.

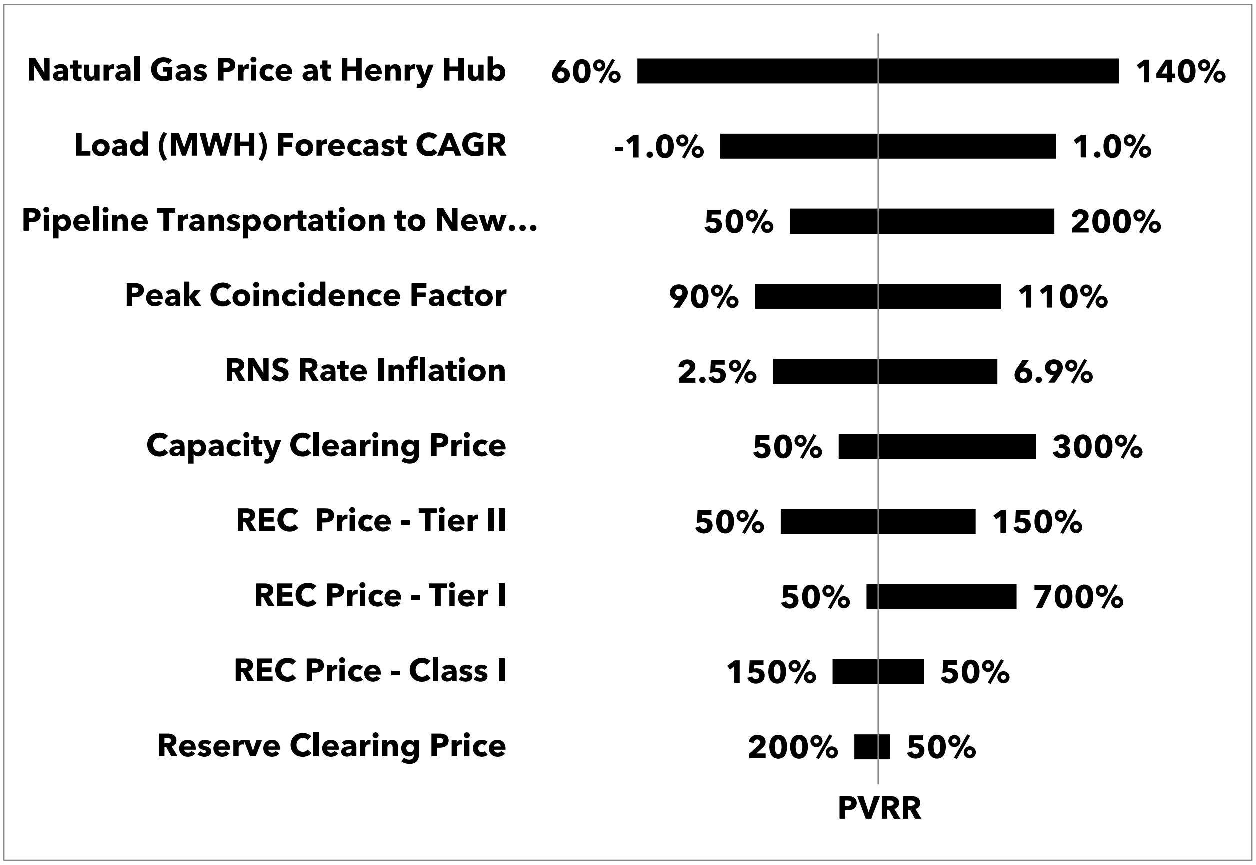
Table 24: Event / Decision Pathways

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.

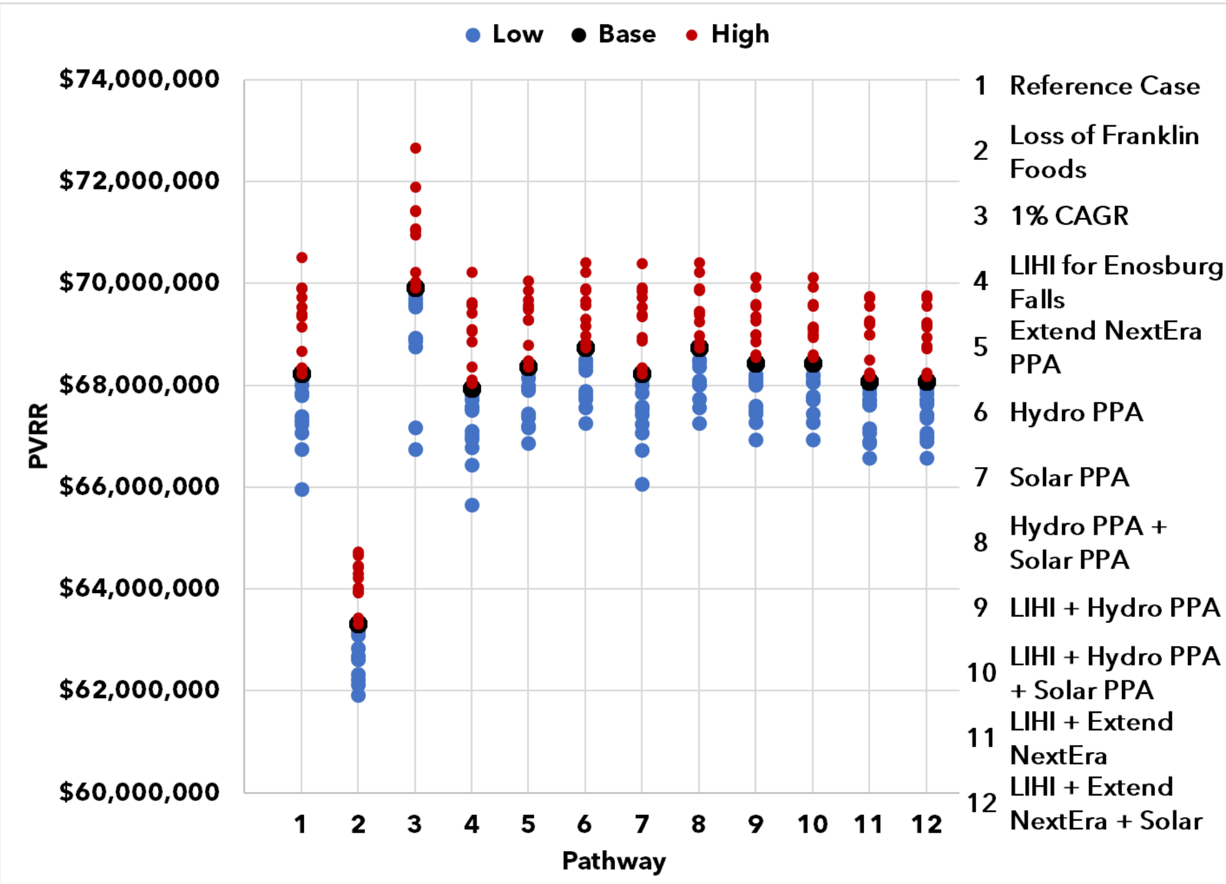
However, in today's market environment, capacity prices have been falling, which has reduced VOEFs costs. This level of market price risk is not a concern, but there is an opportunity to use demand response and/or new capacity supplies to manage these costs.

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)

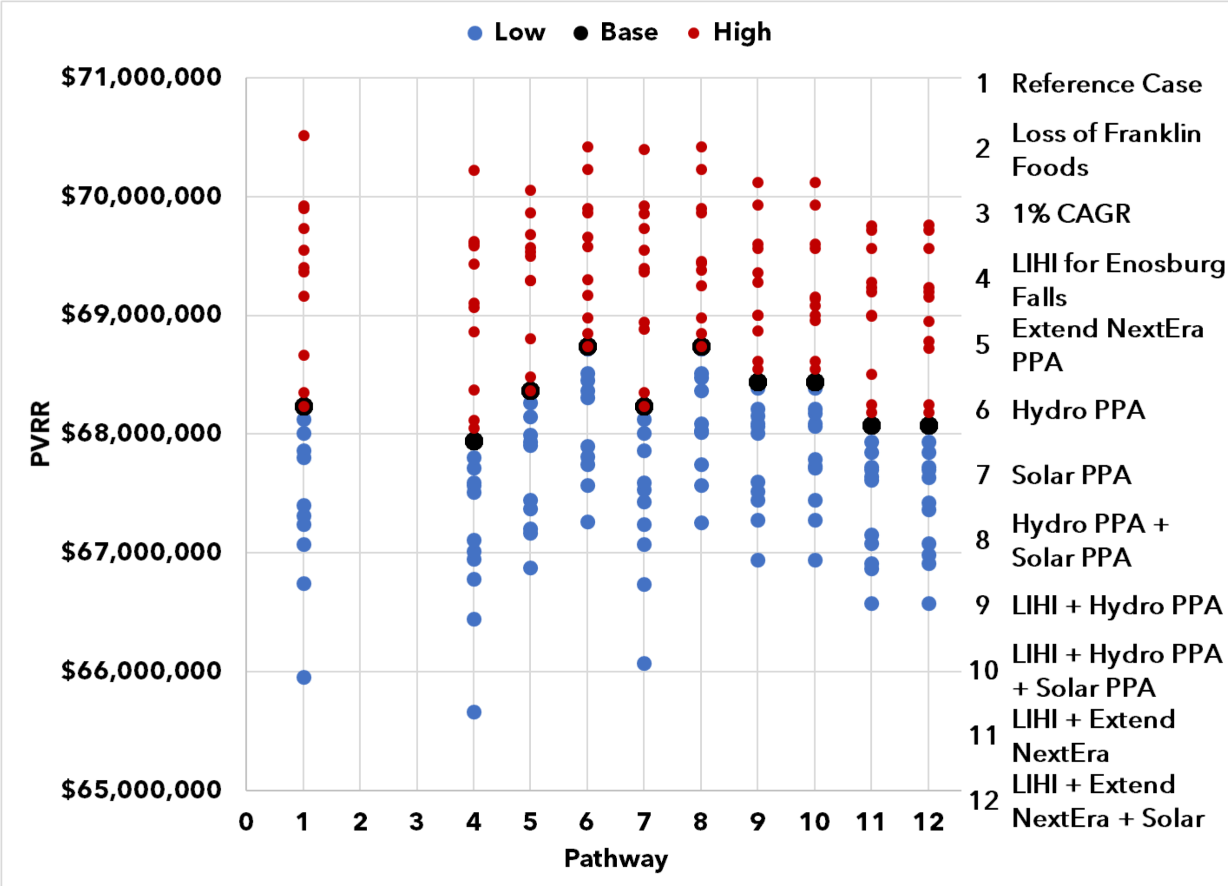


The lowest cost outcome occurs when load drops by 20% (Pathway #2). While this is an appealing outcome on the surface, it also comes with a matching degree of rate pressure due to the loss of retail revenue. As a result, it is only indicative of what might happen if Franklin Foods were to leave the system. 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)

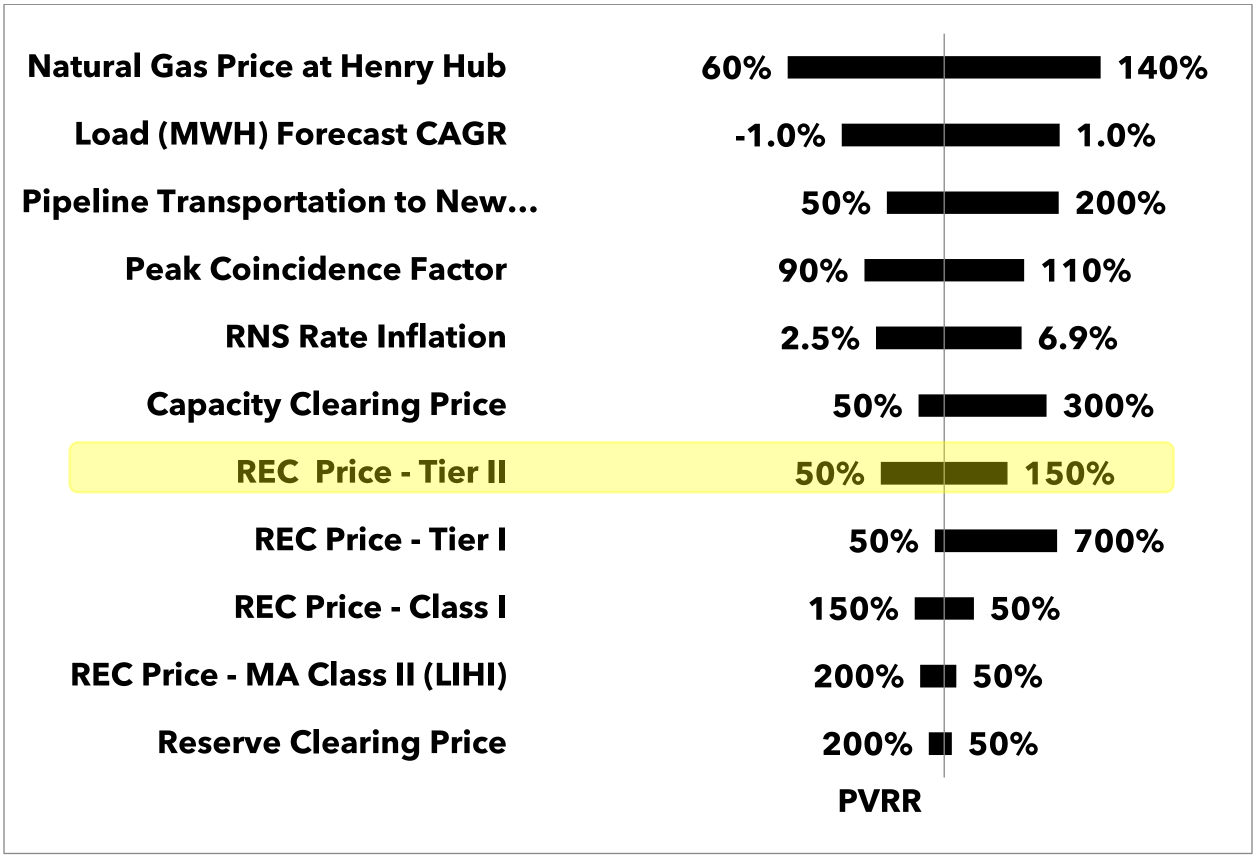


- Conclusion 1: The lowest cost outcomes in this depiction occur when VOEF seeks LIHI certification for Enosburg Falls Hydro. As a result, LIHI certification can measurably lower VOEF's costs.

- 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.

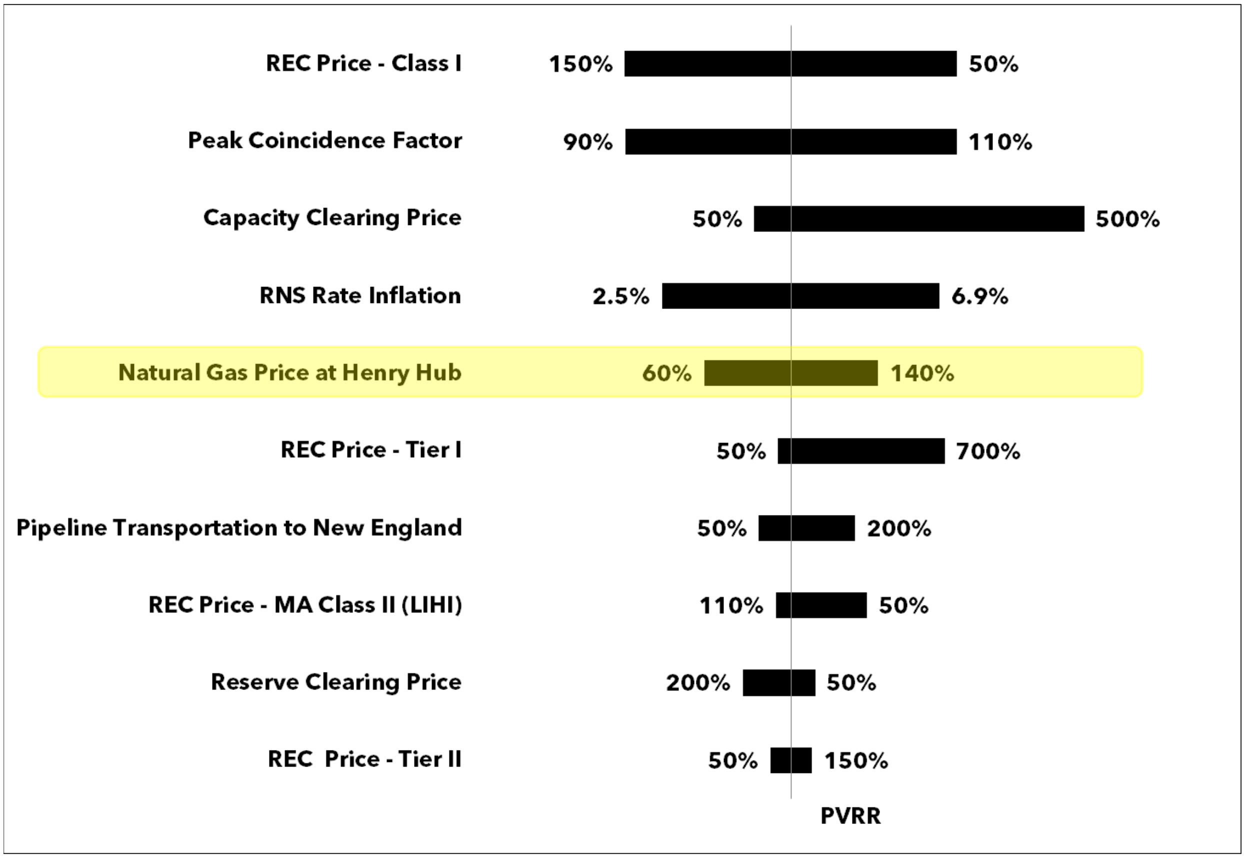
Figure 18 shows how the decision to seek LIHI certification changes the financial risks that VOEF faces. The primary change is highlighted in yellow. Pathway 4 shows that MA Class II REC prices become a minor financial risk, when before it was not present. In return for this risk, VOEF gets a significant, $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.

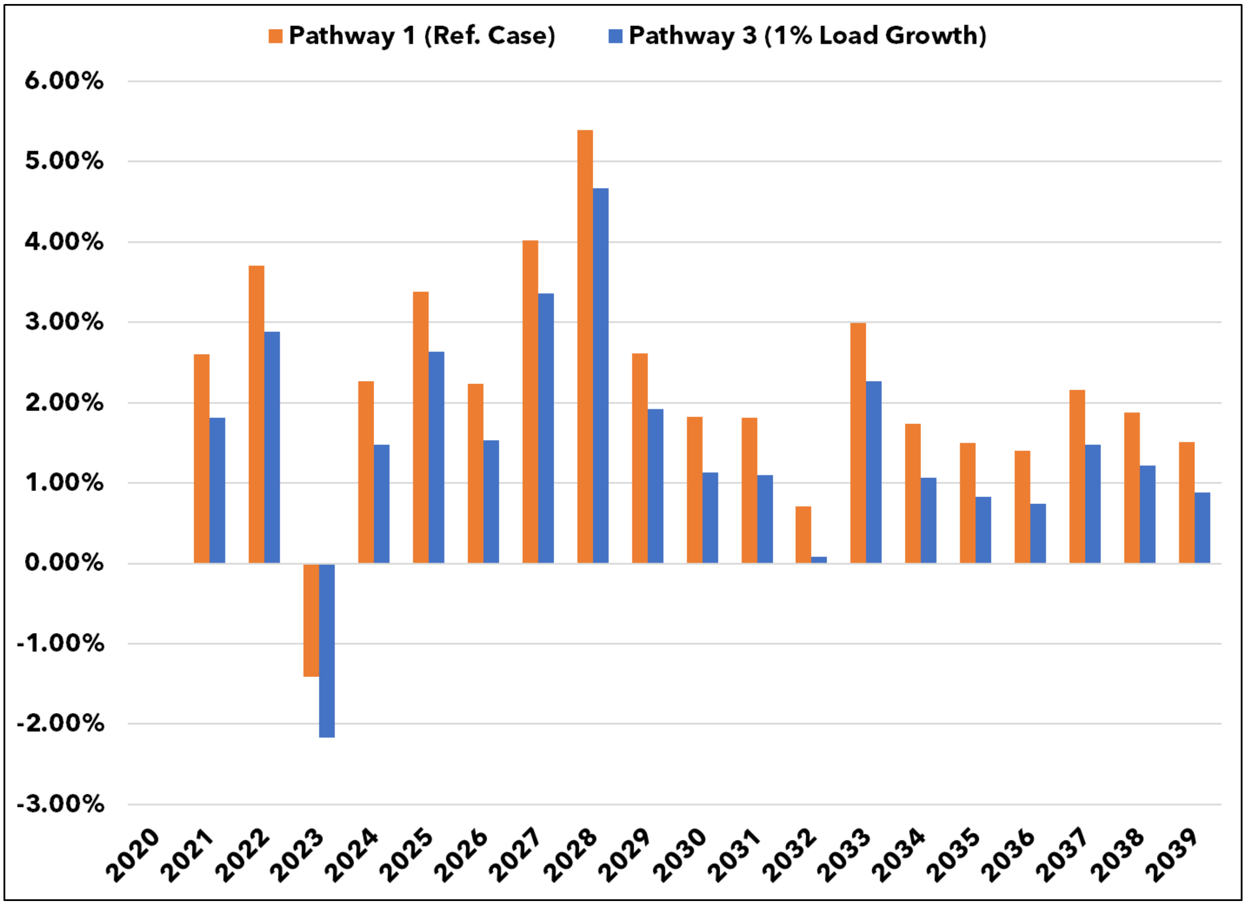
Figure 20: Quadrant Analysis of Market Price & Energy Length Outcomes

	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:

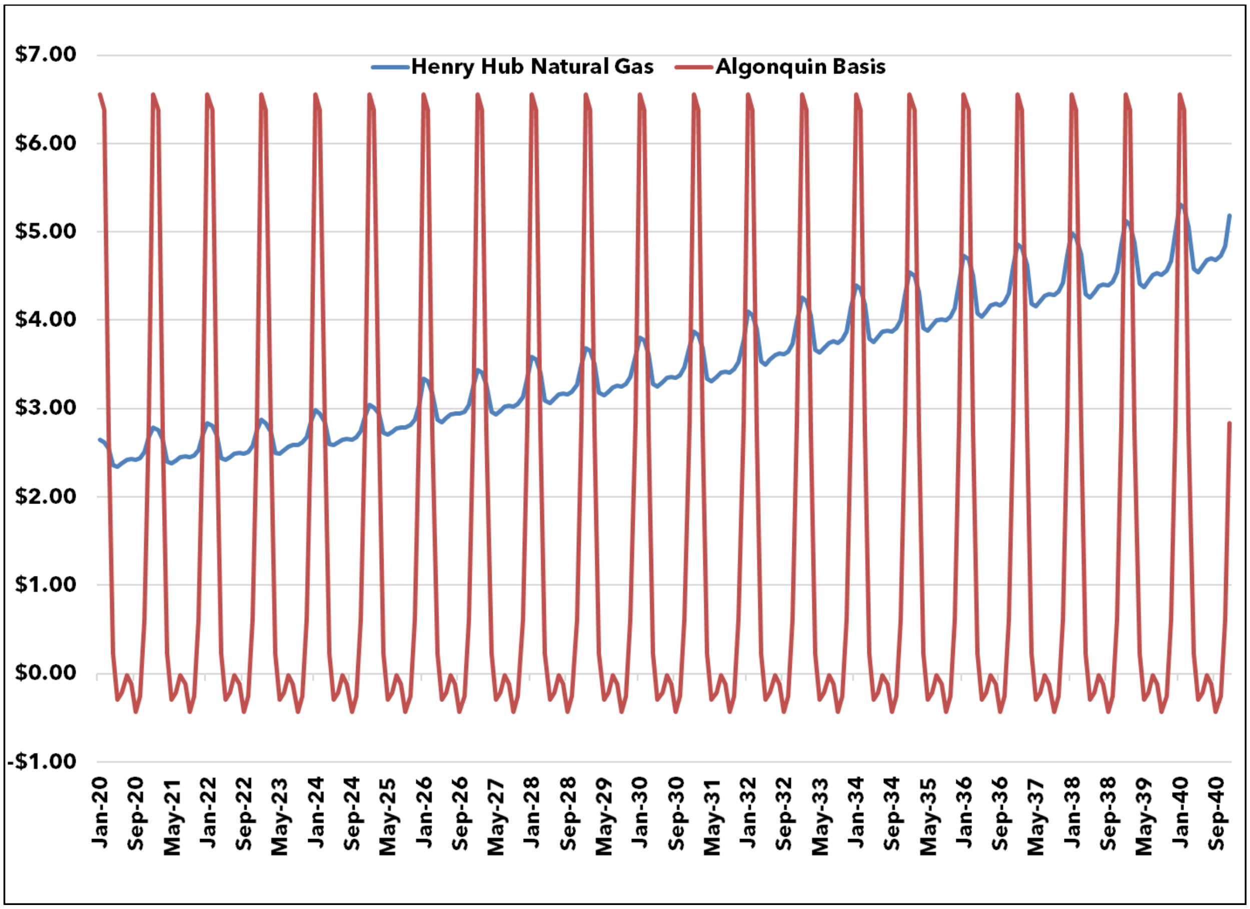
Appendix B - VPPSA Tier 3 2020 Annual Plan.pdf

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.

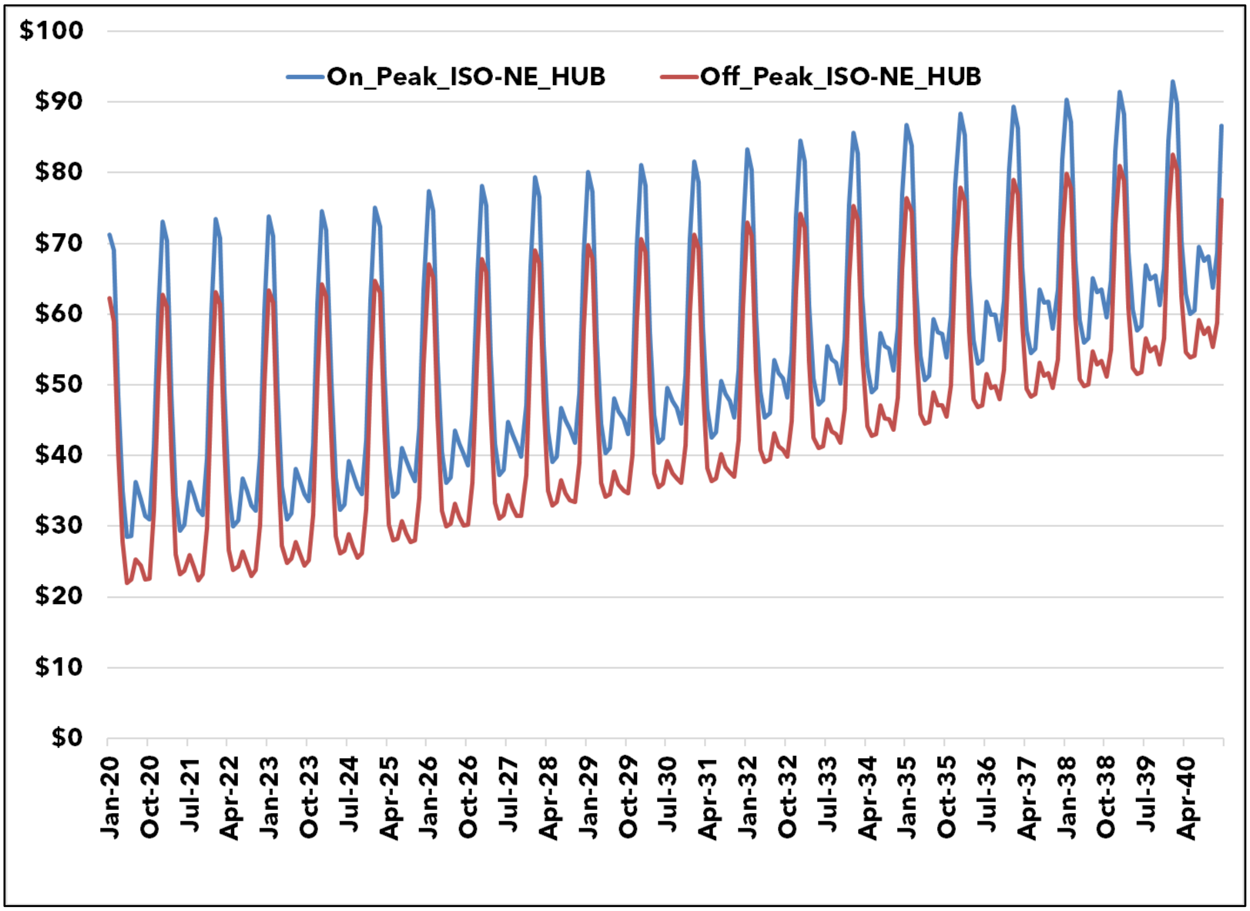
Figure 22: Henry Hub Natural Gas Price Forecast (Nominal $/MMBtu)



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)

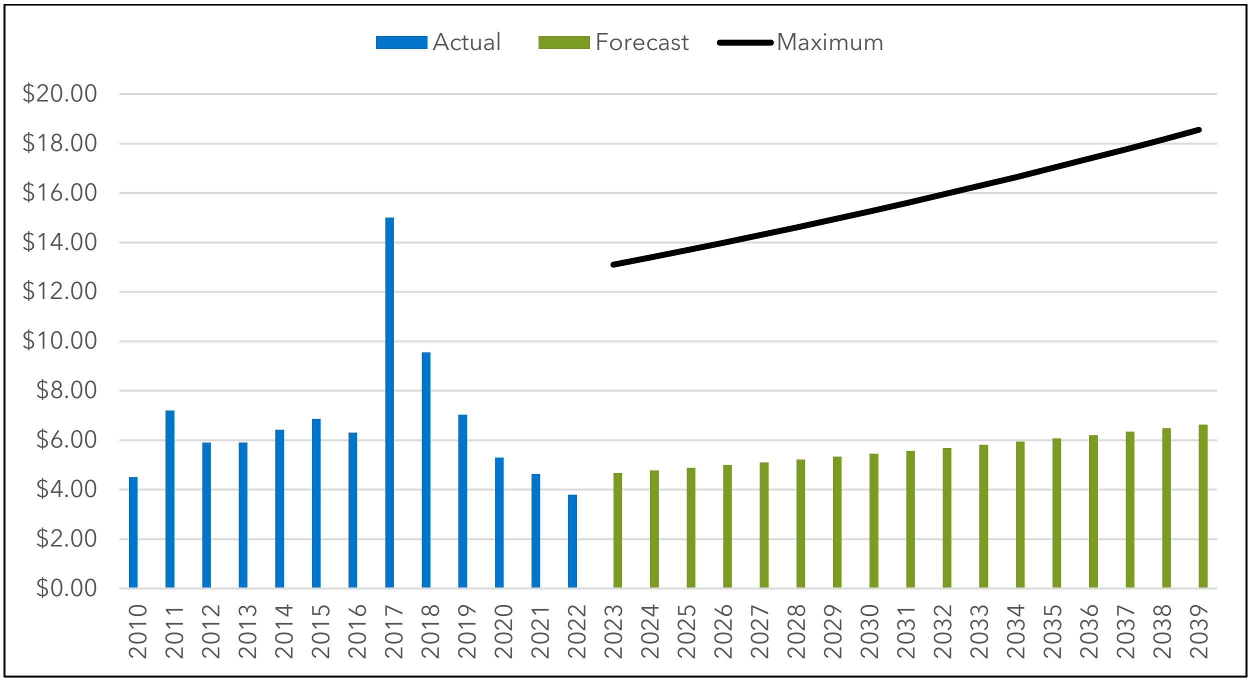


Finally, and in keeping with the function of ISO-NE's Standard Market Design, we use a five-year average basis between LMP nodes to adjust the price forecast at the MA Hub to the location of VOEF's load and resources.

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.

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

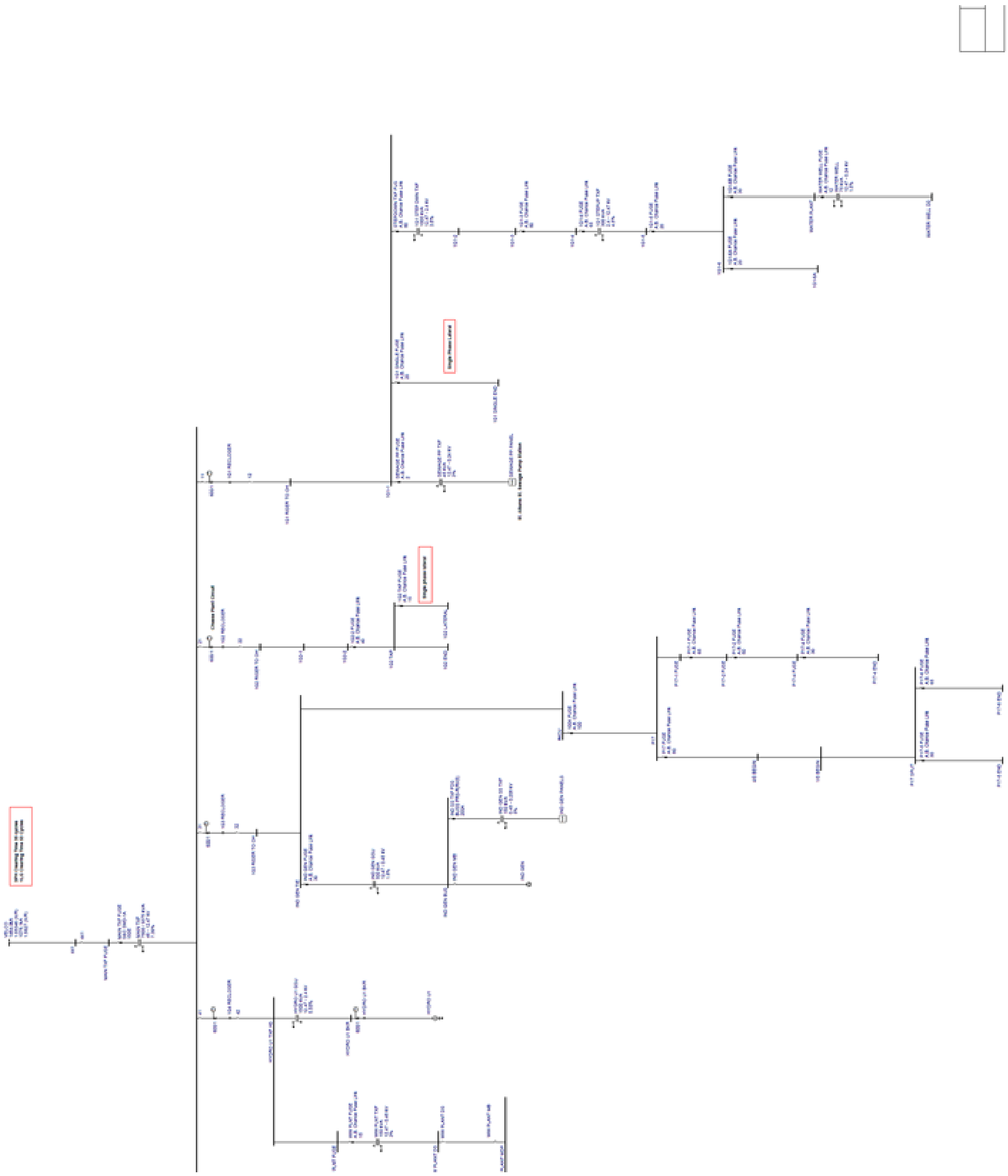
Function	Default Activation State
SPF, Specified Power Factor	**OFF[2]**
Q(V), Volt-Var Function with Watt	**OFF**
SS, Soft-Start Ramp Rate	**ON** **Default value: 2% of maximum current**
FW, Freq-Watt Function OFF	**OFF**

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

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Vermont Public Power Supply Authority
2020 Tier 3 Annual Plan

In accordance with the Public Utility Commission's ("PUC") *Final Order in Docket 8550*, Vermont Public Power Supply Authority ("VPPSA") is filing this Annual Plan describing its proposed 2020 Energy Transformation programs. Vermont's Renewable Energy Standard ("RES"), enacted through Act 56 in 2015, requires electric distribution utilities to either generate fossil fuel savings by encouraging Energy Transformation ("Tier 3") projects or purchase additional Renewable Energy Credits ("RECs") from small, distributed renewable generators ("Tier 2").

VPPSA's Requirement

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

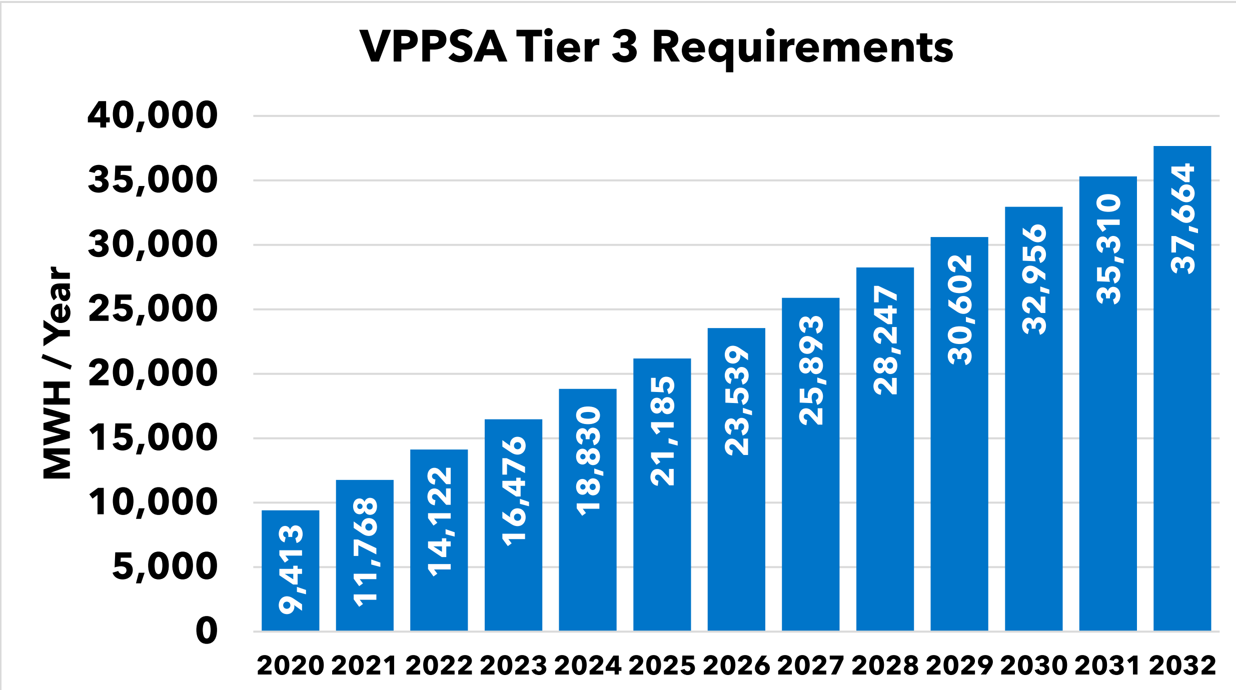
Under 30 V.S.A. § 8004 (e) "[i]n the case of members of the Vermont Public Power Supply Authority, the requirements of this chapter may be met in the aggregate." The 11 VPPSA member utilities plan to meet Tier 3 requirements in aggregate. In 2020, VPPSA's aggregate requirement is estimated to be 9,413 MWh equivalent in savings, representing 2.67% of annual retail sales.

VPPSA Members:

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

[1] 30 V.S.A. § 8005(a)(3)(B)

Tier 3 requirements increase by .67% annually. The below chart represents VPPSA's projected annual MWh equivalent in savings through 2032.



Summary of 2019 Projects

VPPSA expects to meet its 2019 Tier 3 requirements of 7,059 MWh through a combination of prescriptive and custom measures and through employing excess Tier 2 RECs as needed.

Prescriptive measures included post-purchase rebates for:

1. Cold Climate Heat Pumps
2. Heat Pump Water Heaters
3. Electric and Plug-In Hybrid Vehicles

Of the three prescriptive measures, we found cold climate heat pumps to be the most successful. We additionally found that custom measures, while providing a greater return in MWh savings at a lower cost, tend to have a longer ramp-up time. We identified and began working on multiple custom measures in 2019, but completion will likely not take place until a later date. Because the pricing of Tier 2 RECs was lower than the cost of implementing Tier 3 programs, purchasing excess Tier 2 was an effective strategy for keeping the Tier 3 compliance cost low. However, to accommodate the changing REC market prices, we have preemptively employed a Tier 3 marketing strategy to raise customer awareness around Energy Transformation Projects and increase uptake in the coming years.

2020 Program Overview

VPPSA proposes employing a similar strategy to meet the 2020 Tier 3 requirements while mitigating costs that could put upward pressure on rates. This includes a combination of prescriptive and custom measures and use of excess Tier 2 RECs.

Prescriptive Measures

VPPSA intends to expand its prescriptive measures offerings. Savings are estimated using measure characterizations created by the Tier 3 TAG. VPPSA's budget and estimated savings for prescriptive Tier 3 Programs is summarized below.

Cold Climate Heat Pumps

VPPSA will continue to offer customer rebates for the purchase of cold climate heat pumps ("CCHP".) In 2020 the rebate amount will be increased to $400. For customers that can demonstrate a defined level of building performance, the CCHP rebate will be increased to $500. The additional incentive serves to highlight the importance of overall building performance. In order to be eligible for the higher incentive amount, customers will need to demonstrate that their homes were weatherized according to a list of standards developed and circulated by the Department of Public Service ("DPS") during the CCHP measure characterization by the TAG.

Heat Pump Water Heaters

VPPSA will provide rebates to customers that install heat pump water heaters ("HPWH") to replace fossil-fuel fired water heaters. In 2019, VPPSA's post-purchase incentives were provided in conjunction with Efficiency Vermont's ("EVT") upstream rebates, which are paid to the equipment distributor. Because EVT and VPPSA were both claiming fossil fuel savings in 2019 for HPWH that replaced fossil-fuel water heaters, it was necessary to split savings and costs between the two entities. VPPSA continues to urge EVT to avoid using Thermal Energy and Process Fuels ("TEPF") funds for incentives on electrification measures. For 2020, VPPSA and EVT have agreed that VPPSA will fund 100% of the upstream rebate for HPWH that replace fossil fuel systems and thus will claim 100% of the fossil fuel savings in the form of Tier 3 credits. Efficiency Vermont will fund the upstream rebate and claim the associated savings for HPWH that are installed to replace *electric* water heaters.

Electric Vehicles and Plug-In Hybrids

Despite lower operating and maintenance costs associated with electric vehicles ("EVs") and plug-in hybrid electric vehicles ("PHEVs"), the upfront cost continues to be a major barrier to greater EV penetration in the state. EVs and PHEVs remain a relatively low percentage of overall vehicle sales in the state. According to Drive Electric Vermont, the number of plug-in vehicles (EVs and PHEVs) in the state increased by 676 vehicles, or 26%, over the past year. These vehicles comprised 4.1% of new passenger vehicle registrations over the past quarter. Nonetheless, there were only 3,288 plug-in vehicles registered in Vermont as of July 2019.

VPPSA is working to raise awareness of the benefits of plug-in vehicles and help alleviate the financial barriers to EV and PHEV adoption. VPPSA will continue to offer customer rebates for the purchase or lease of EVs and PHEVs and raise the rebate levels in 2020. The customer incentive for purchasing or leasing a new electric vehicle will be $1000 and the customer incentive for purchasing or leasing a new plug-in hybrid electric vehicle will be $500. Low-income customers[2] will receive an additional $400 towards the purchase or lease of an EV or PHEV.

To further expand on this program, VPPSA is adding incentives for purchasing used EVs and PHEVs. The customer incentive will be $500 for the purchase of a used EV and $250 for the purchase of a used PHEV. We are also adding a $500 incentive for the purchase of a Level 2 Charger.

Forklifts

Several industrial customers in VPPSA Members' territories utilize forklifts in their operations. Because the potential fossil fuel savings from converting diesel forklifts to those powered by electricity is significant VPPSA will actively work with these customers to determine whether a conversion is feasible. We are adding a rebate incentive of $3000.

Golf Carts

VPPSA has identified opportunities to switch golf carts from fossil fuel to battery powered. We are adding a rebate incentive of $50.

Lawn Mowers

VPPSA will be adding both commercial and residential lawn mower incentives. A rebate of $25 for a residential lawn mower and $1,000 for a commercial lawn mower will be available in 2020.

E-Bikes

Utility customers have expressed interest in e-bikes, which has led VPPSA to add a rebate incentive of $100 for the purchase of a new e-bike or e-bike conversion kit.

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[2] According to the PUC's *Order Implementing the Renewable Energy Standard* dated 6/28/2016, "A low-income customer shall be defined as a customer whose household income is at or below 80% of Vermont statewide median income.

Measure	Savings/Unit (MWh)	Incentive Amount	Admin Cost	Total Cost	Volume	Cost/MWh	Credit (MWh)	Budget
EV	31.88	$1,000	$403	$1,403	16	$44.00	510	$22,443
PHEV	24.55	$500	$310	$810	18	$33.00	442	$14,582
EV (Low Income)	31.88	$1,400	$403	$1,803	5	$56.55	159	$9,013
PHEV (Low Income)	24.55	$900	$310	$1,210	5	$49.29	123	$6,050
EV (Used)	15.94	$500	$201	$701	4	$44.00	64	$2,805
PHEV (Used)	12.27	$250	$155	$405	4	$33.01	49	$1,620
CCHP	21.74	$400	$275	$675	42	$ 31.03	913	$28,333
CCHP (Weatherized)	26.84	$500	$339	$ 839	8	$31.26	215	$6,712
HPWH	14.23	$650	$180	$830	10	$58.31	142	$8,297
Level 2 Charger	16.75	$500	$212	$ 712	4	$42.48	67	$2,805
Forklift	89.64	$3,000	$1,132	$4,132	3	$46.10	269	$12,397
Golf Cart	3.24	$50	$41	$91	25	$28.06	81	$2,273
Lawn Mower (Residential)	1.51	$25	$19	$44	20	$29.19	30	$881
Lawn Mower (Commercial)	52.35	$1,000	$814	$1,814	2	$28.15	129	$3,628
E-Bike	5.3	$100	$67	$167	10	$31.57	53	$1,667
TOTAL					**176**	**$38.06**	**3,246**	**$123,549**

Custom Measures

Commercial and industrial ("C&I") customers will be served on an individual, custom basis in 2020. VPPSA continues to explore cost-effective Tier 3 custom projects, including converting utility customers from diesel generators to electric service. In addition, C&I customers that have potential Tier 3 projects are being identified by Efficiency Vermont through a joint arrangement with VPPSA to ensure that these customers receive comprehensive efficiency services. To date, opportunities have been identified at ski resorts, a furniture maker, a quarry, and a candy manufacturer. Due to the long ramp-up time expected for these projects, completion will likely take place after 2020. The Tier 3 savings would be claimed in the year the project is completed. VPPSA will continue to work with the DPS on custom projects to ensure savings claims are valid and able to be evaluated.

Tier 2 RECs

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

Should REC prices increase, VPPSA will reevaluate its incentive levels and potentially increase the rebate value. In that situation, VPPSA would re-file its annual Tier 3 planning document.

Demand Management

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

VPPSA has established a partnership with Virtual Peaker, allowing us to assist our members in demand-response programming. In 2020, VPPSA will be piloting the following demand-response programs to keep peak load and the cost of electricity at a minimum:

1. Internal utility behavioral demand-response program to strategically maximize load-reducing generation
2. Active demand-response programs to control electric devices including CCHPs, HPWHs, and Level 2 chargers

VPPSA is also exploring partnerships outside of Virtual Peaker to best deploy demand-response programming.

Equitable Opportunity

The Tier 3 incentives described above will be available to all VPPSA member utility customers. The ability to bring financial benefits to all customers, rather than just participating customers, makes electrification an attractive Tier 3 option from an equity perspective. If additional kWh can be procured at costs at or below the costs embedded in a utility's rates, increasing the number of kWh delivered through the utility's system allows the fixed costs of operating the utility to be recovered over a larger number of units, driving the per kWh rate down.

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

Partnership, Collaboration, and Marketing

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

VPPSA is participating in administering the VTrans electric vehicle incentive. The VTrans incentive is offered on the sale of any vehicle registered in Vermont. The value of the VTrans incentive is dependent upon the owner's household income level. Participating car dealers will sell the vehicle at a price reduced by the statewide incentive. The dealer will then submit the customer's information and vehicle details to VPPSA. VPPSA will batch the incentives on a monthly basis and send the information to VTrans with a summary report and invoice. VTrans will pay VPPSA for the state incentive, which VPPSA will then remit to the dealer. We anticipate that stacked incentives and collaboration with car dealers will help to increase participation in VPPSA's electric vehicle rebate program.

VPPSA and EVT are working together to define how the two entities can provide holistic efficiency services to residential, commercial, and industrial customers. In many cases, this partnership involves VPPSA providing incentives for electrification measures, which can provide benefits to all VPPSA utility customers, while EVT provides incentives for thermal and electric efficiency measures.

VPPSA and EVT are also working closely on the Energy Savings Account pilot, which involves Ethan Allen and the Village of Orleans. This pilot allows Ethan Allen to engage in electrical efficiency measures and helps to identify opportunities for strategic energy transformation projects.

Two VPPSA member utility areas have been selected for EVT's 2020 Targeted Communities. The Village of Johnson and the Village of Orleans will both receive enhanced services from EVT for efficiency. This is yet another opportunity to explore strategic electrification for customers while reducing overall energy burden. The 2020 Targeted Communities effort is designed to have the greatest impact on low-income households.

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

- VPPSA website
- VPPSA member utility websites
- Social media
- Front Porch Forum
- Collaborative events and workshops
- Car dealer outreach
- EVT contractor and distributor outreach

NORTHWEST REGIONAL PLANNING COMMISSION

REGIONAL ENERGY PLAN

Adopted June 28, 2017

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SECTION I

I. EXECUTIVE SUMMARY

I. EXECUTIVE SUMMARY

The Northwest Regional Energy Plan is a pilot project funded by the Vermont Department of Public Service. The intent of the project 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). In-depth regional energy planning is needed to address three key issues: energy security, environmental protection, and economic needs and opportunities. The Northwest Regional Energy Plan consists of the plan and all plan appendices.

Specific goals to be achieved by this plan include the following:

- Collaboration with Vermont Energy Investment Corporation (VEIC) to create a regional energy model that identifies targets for energy conservation and renewable energy generation
- Creation of specific strategies to help the region achieve state energy goals
- Creation of regional maps prioritizing locations for the development of future renewable generation facilities in the region

The region's energy supply and consumption are analyzed in Section III to establish baseline energy use. The use of space heating energy, transportation energy, and electricity in the region is specifically examined. Based on the NRPC's estimates, the region currently uses approximately 2.243 trillion BTUs to space heat residential units each year and about 2.7 trillion BTUs to space heat commercial, industrial, and institutional structures. Regional electricity use totals approximately 1.647 trillion BTUs per year based on 2013 data available from Efficiency Vermont. Regional transportation energy use is greater than 3.1 trillion BTUs per year based on approximate passenger vehicle fuel use in the region. Actual regional transportation energy use is likely greater due to the use of commercial vehicles in the region.

As of January 2017, the Northwest region had the capacity to generate 58.4 MW of electricity through hydro, wind, solar, and biomass technologies, and it had 98.4 MW of total generation capacity from all sources, according to data available from the Community Energy Dashboard.3 The 58.4MW of renewable generation in the region is a "raw" number that does not take "capacity factors, renewable energy credits sold, or ownership of the systems" into consideration. The NRPC has estimated renewable generation in the region to be about 182,190.79 MWh per year when factoring capacity factors for solar, wind, and hydro.

Regional electricity generation is also investigated and catalogued in Section III. Currently, the region has the capacity to generate approximately 98.4 MW of electricity. About 58.4 MW of this electricity comes from hydro, wind, solar, and biomass sources. Approximately 75.211 MW of additional renewable generation has been proposed to be sited in the region.

The NRPC cooperated with VEIC to create targets for energy conservation and renewable energy generation. The energy saved via conservation and improved efficiency is targeted to equal approximately 3.5 trillion BTUs by 2050. Conservation and improved efficiency are planned through a variety of means including increased use of efficient materials during construction and weatherization of existing structures. Most prominently, improved efficiency is targeted through the use of electric vehicles for transportation and electric heat pumps for space heating. The resulting increase in regional electricity demand means that electricity generation in the region will also need to increase. Specific targets for new in-region electricity generation by 2050 include the following: 208.5 MW (711.4 billion BTU/hour) of solar generation, 19 MW (64.8 billion BTU/hour) of wind generation, and 10 MW (34.1 billion BTU/hour) of hydro generation.

Goals, strategies, and implementation steps are established in Section V to guide the Northwest region to achieve the energy conservation and renewable energy generation targets created in Section IV. Goals, strategies, and implementation steps have been specifically identified for the following categories: electricity conservation, thermal efficiency, and transportation. Electricity conservation, thermal efficiency and transportation are the types of energy conservation that the Northwest Region focuses upon in this section. Achievement of the goals set by NRPC will require the cooperation of multiple regional partners and the efforts of individual citizens.

A substantial part of the Northwest Region's effort to set renewable electricity generations goals involves the creation of regional energy generation maps in Section IV. The regional energy generation maps are meant to guide the development of new solar, wind, hydro, and biomass energy generation facilities in the Northwest region. The NRPC Regional Energy Committee was actively involved in this effort. The maps inform and help guide the siting of new renewable energy generation facilities in the region. The maps provide a macro-scale look at different factors that impact the siting of renewable generation facilities including generation potential. The objective of the NRPC Regional Energy Committee was to allow for sufficient renewable electricity generation in the region while avoiding undue adverse impacts upon known and possible constraints (these resources are specifically identified in Appendix B).

Section VI assesses the feasibility of meeting regional goals and outlines challenges to plan implementation. Regional energy generation goals are attainable while still allowing for the protection of known and possible constraints. The identified conservation goals and strategies may be more difficult for the NRPC to implement given that implementation is heavily reliant on the choices of individual consumers in the region. The thermal efficiency goals and strategies are similar. The NRPC can aid the efforts of other organizations to increase conservation and thermal efficiency in the region, and it cannot accomplish the goals and implement the strategies in the plan alone.

Achieving transportation-related energy goals is more straightforward. One of the NRPC's core functions is coordinating transportation planning for the region. The NRPC is well suited to achieving goals and implementing strategies for transportation. Progress on transportation-related implementation actions will be prioritized.

There are several challenges to successful plan implementation. Some of these challenges pertain to how the electric grid operates. This includes the need to balance "baseload" and "intermittent" electricity generation to ensure grid reliability and challenges related to the infrastructural capacity of the regional grid. Other challenges exist due to geography. Inclement weather is common in the region and can threaten electricity service. The Northwest Region's proximity to Chittenden County may create challenges related to the equity of renewable generation siting. Other challenges include:

- Environmental issues when developing new hydro generation
- Lack of sufficient biofuel or ethanol technologies and research
- Potential reliance on cord wood
- Lack of site specific guidelines for solar and wind generation facilities
- Lack of residential building energy standard (RBES) and commercial building energy standards (CBES) outreach and enforcement
- The limits of regional planning commissions' jurisdiction

Overcoming the challenges to implementation will likely mean bearing both economic and environmental costs. The equity issues related to who will bear those costs is of continuing concern to NRPC.

Appendix A contains the full results of NRPC's cooperation with VEIC to set regional targets for energy conservation and renewable generation. Appendix B contains a list of the known and possible constraints identified by the NRPC Regional Energy Committee that were used to create the regional energy generation maps. Appendix C contains the regional generation maps to be used in regulatory proceedings (Section 248). Appendix D summarizes the planning approach and process used to create this plan. Appendix E contains a list of acronyms and phrases used throughout the plan. Appendix F is a summary of existing renewable generation facilities in the Northwest Region (by municipality). Appendix G includes a summary of municipal energy analysis and targets.

SECTION II

II. INTRODUCTION

A. BACKGROUND AND VERMONT STATE ENERGY GOALS

B. PURPOSE OF THE PLAN

C. KEY ISSUES

ENERGY SECURITY
ENVIRONMENTAL PROTECTION
ECONOMIC NEEDS AND OPPORTUNITIES

II. INTRODUCTION

A. BACKGROUND AND VERMONT STATE ENERGY GOALS

The Northwest Regional Energy Plan is a pilot project funded via the Vermont Department of Public Service. The Northwest Regional Planning Commission (NRPC) is joined by the Bennington County Regional Commission (BCRC) and the Two Rivers-Ottauquechee Regional Commission (TRORC) as members of this pilot project. The intent of the project is to complete in-depth energy planning at the regional level. Subsection B outlines how this goal will be accomplished. The impetus for this project was a recommendation made in the 2013 Vermont Energy Generation Siting Policy Commission's report, which suggested more robust energy planning at the regional level. The Northwest Regional Energy Plan consists of the plan and all plan appendices.

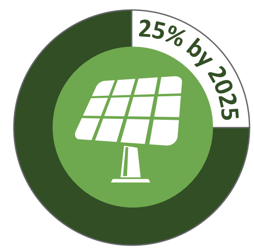
The State of Vermont has adopted several ambitious energy goals. The Vermont Comprehensive Energy Plan, developed by the Department of Public Service, calls for the state to meet 90% of its total energy needs through renewable energy sources by 2050 (90 x 50 scenario). State statute also contains several goals pertaining to greenhouse gas emissions, energy generation, and energy efficiency (Figure 2.1):

FIGURE 2.1 STATE ENERGY AND GREENHOUSE GAS EMISSION GOALS

Goals for Reducing Greenhouse Gases *10 V.S.A. § 578(a)*

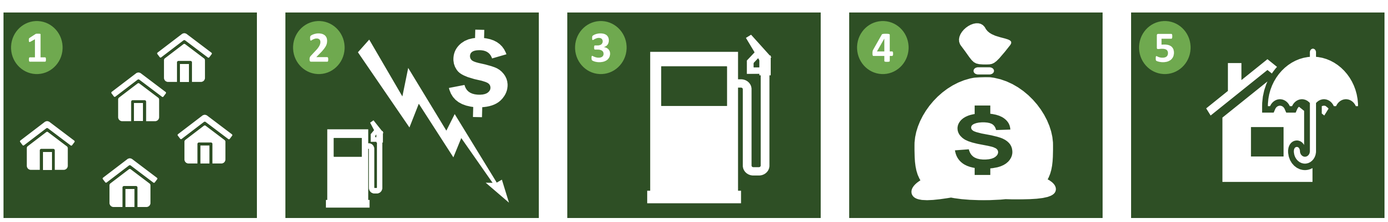
All percentages are based on 1990 levels

Increasing Renewable Energy
10 V.S.A. § 580(a)



Produce 25% of energy consumed within the state through renewable energy by 2025

Additional Goals Regarding Renewable Energy *10 V.S.A. § 581(a)*



1. To improve substantially the energy fitness of at least 20% of the state's housing stock by 2017 (more than 60,000 housing units) and 25% of the state's housing stock by 2020 (approximately 80,000 housing units)
2. To reduce annual fuel needs and fuel bills by an average of 25% in the housing units served
3. To reduce total fossil fuel consumption across all buildings by an additional 0.5% each year, leading to a total reduction of 6% annually by 2017 and 10% annually by 2025
4. To save Vermont families and businesses a total of $1.5 billion on their fuel bills over the lifetimes of the improvements and measures installed between 2008 and 2017
5. To increase weatherization services to low-income Vermonters by expanding the number of units weatherized, or the scope of services provided, or both, as revenue becomes available in the home weatherization assistance trust fund

Additional energy goals have also been set for Vermont's public utilities for renewable energy generation, distributed generation, and fossil fuel use through Act 56 (the Vermont Renewable Energy Standard).[1] It is important that these goals be kept in mind while reading and using this document. The goals and strategies in this plan will provide a path to achieving regional and state energy goals.

B. PURPOSE OF THE PLAN

The NRPC has identified regional goals and strategies for energy conservation and renewable energy generation that will support the attainment of Vermont's energy goals. The NRPC has also identified specific implementable strategies appropriate to the region to accomplish these goals.

The NRPC collaborated with Vermont Energy Investment Corporation (VEIC) to create a regional energy model to identify targets for energy conservation and renewable energy generation. VEIC used the Long-range Energy Alternatives Planning (LEAP) modeling system to create a statewide model as well as regional models for the regional planning commissions (RPCs) participating in the pilot project. The models provide one possible scenario of accomplishing the state's goal of meeting 90% of total energy demand through renewable energy resources by 2050 and analyze the potential energy demand within the region. They also look at regional energy generation needs. Specific information about the models and their results can be found in Section IV.

The modeling work completed by VEIC provided a framework for two other tasks completed by the NRPC:

- Creation of specific strategies to help the region achieve state energy goals
- Creation of regional maps prioritizing locations for the development of future renewable generation facilities in the region

Regional strategies are outlined in Section V. The regional energy maps as well as information regarding the process by which the maps were developed are located in Section V, Appendix B, and Appendix C.

While reading this document, it is also important to keep in mind what the Regional Energy Plan will not do. Much like the Vermont Comprehensive Energy Plan, the Regional Energy Plan does not intend to directly address every specific energy-related issue within the region, and it does not discuss or provide recommendations regarding specific renewable energy generation projects that have been proposed in the region. Although it provides a prospective vision of the mix of renewables that may be developed in the region to attain state goals, the Regional Energy Plan does not specify the mix of renewable energy generation facilities that will actually be built or contracted by utilities serving the Northwest region. In addition, the plan does not provide direct information about the costs of implementing the plan or the costs of failing to implement the plan.

The energy landscape in Vermont has rapidly changed over the past 10 years. This has been driven by climate change, policy changes, materials cost reductions, and quickly evolving technologies. The NRPC anticipates that methods of generating, distributing, and conserving energy will continue to evolve over the next 30 to 40 years. This plan should be revisited and revised—perhaps more frequently than other regional plans adopted by the NRPC—to account for changes in federal and state policy as well as regulatory framework, and for changes in environmental conditions due to climate change.

The NRPC will work to incorporate the strategies identified in this plan into the Northwest Regional Plan during 2017.

C. KEY ISSUES

While it is important to understand the energy goals established by the legislature, it is more important to understand the reasons why the goals were established. The "why" behind this plan can be explained by looking at three different motivations that are important both regionally and statewide: energy security, environmental protection, and economic needs and opportunities.

[1]Act 56: Vermont Renewable Energy Standard (http://legislature.vermont.gov/bill/status/2016/h.40)

ENERGY SECURITY

Vermont and the Northwest region are reliant upon other states and countries for a large portion of their energy needs. To address this issue, a state statute (10 V.S.A. 580(a)) has set a goal that by 2025, 25% of the energy consumed within the state will also be produced in the state by renewable generation.

Transportation energy is a clear example of the threats to both state and regional energy security. Vermont imports all of the gasoline and diesel fuels that are required to operate passenger and heavy vehicles in the state. And while there are varying opinions about "peak oil," there is no debate that fossil fuels are a finite resource. The continuing reliance on a finite resource combined with the volatility of the fossil fuel market will result in higher transportation costs with potentially far-reaching implications.

Transportation energy isn't the only example of a threat to energy security. The source of electrical energy is also a concern. Vermont currently obtains much of its electricity from hydroelectric facilities located out of state, primarily Quebec. Although these sources of electricity currently provide the region with low-cost, renewable generation, the prospective construction of high-capacity transmission lines from Quebec to southern New England may create increased competition for electricity between Vermont and other, faster-growing states that are seeking electricity from renewable sources. With increased competition, costs typically increase. Maintaining or decreasing reliance on electricity from sources located outside Vermont will certainly make both the state and the region more energy secure, especially in a future where electricity demand is anticipated to almost double by 2050 (see Section IV).

It is possible to have a state and a region that are less reliant on others for their energy needs. By utilizing the resources that exist inside both the state and the region, long-term security concerns about energy supply and energy costs can be alleviated.

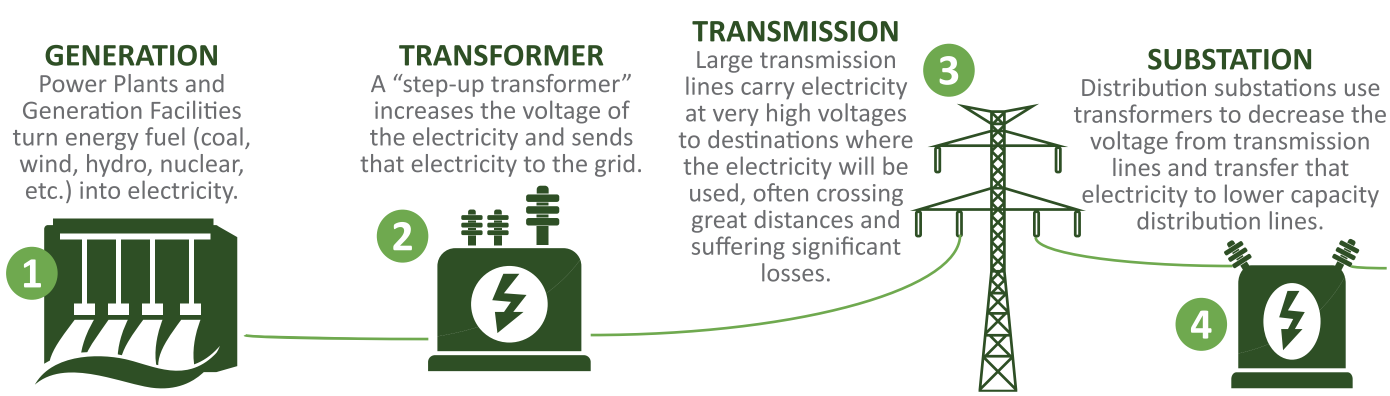
ENVIRONMENTAL PROTECTION

Human energy needs over the past few centuries have had confirmed negative impacts upon environmental quality worldwide—primarily due to fossil fuel use. And while these effects have often seemed intangible in the past, Vermonters are becoming well acquainted with the influence of climate change.

The changing composition of the state and region's forest may have a real impact on the future of the sugaring industry. This is an issue of immense importance in the Northwest region, the highest-producing maple

FIGURE 2.2 UNDERSTANDING THE GRID

The major components in the US electrical generation and distribution grid are enumerated and described in the diagram below (continued on the following page)



syrup region in the state. Pollution from coal-burning power plants in the Midwest continues to cause acid rain, which also threatens forests. In addition, higher temperatures threaten the future of the ski industry in Vermont as well as the industries that support skiing and tourism. More frequent and substantial precipitation threatens public infrastructure—bridges, culverts, etc.—and financially burdens local governments' ability to pay for repair or replacement. Climate change alone has provided more than an adequate basis for seeking alternative, renewable fuel sources and striving to achieve the 90 x 50 goal.

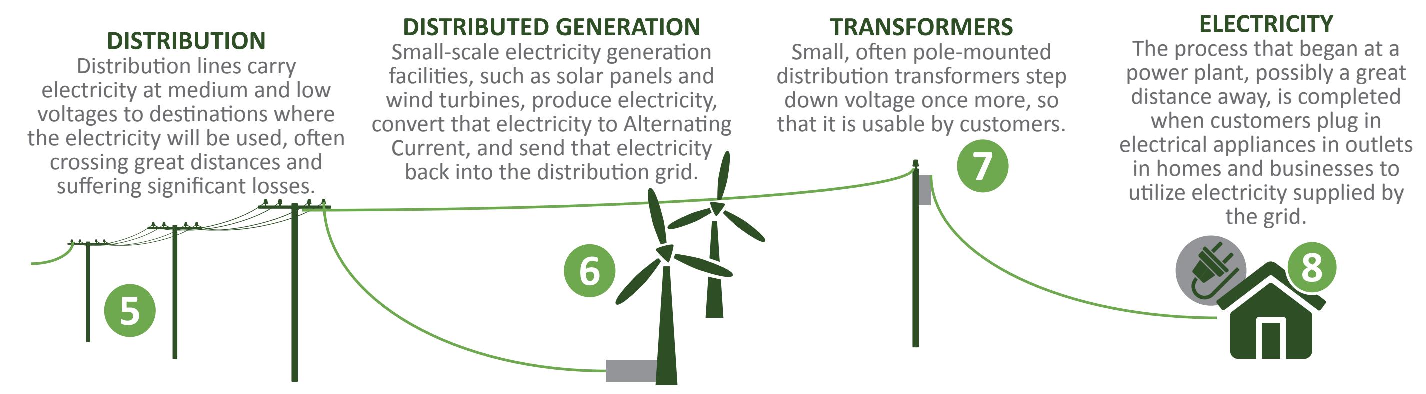
ECONOMIC NEEDS AND OPPORTUNITIES

Energy costs have historically increased in both the state and the region. As fossil fuels have become more difficult to obtain, the costs to extract and bring fuels to market have also risen. These additional costs have been passed on to the consumer. In the long term, this trend could potentially have devastating consequences on Vermont and the region. In April 2017, NRPC estimated that regional residents spend approximately $60 million a year on gasoline for transportation (not including local businesses' expenses). While some of this money may be retained by local distributors, much of the money spent on gasoline leaves the state, the region, and sometimes the country. A similar scenario exists for other fossil fuel–dependent activities. The ability to retain even a fraction of the money spent each year on fossil fuel–related expenses in the region would mean a tremendous financial gain for regional residents and businesses.

Prices of other energy sources have also historically risen, including electricity. However, programs like net metering have provided Vermonters with the ability to produce their own electricity and "zero-out" their own costs, eventually delivering cost savings to those individuals.

It should also be noted that the industries that support small-scale solar and other "clean energy" technologies—installers, distribution, sales, etc.—have created jobs in the state. There are now 2,519 "clean energy"–related business establishments employing 16,231 in-state workers, according to the Public Service Department's Vermont Clean Energy – 2015 Industry Report.

The NRPC understands that achieving the goals established by the state legislature and the Comprehensive Energy Plan will require significant change in the Northwest region. These changes will affect local governments, institutions, and individuals. Some of the changes may have economic costs, especially in the short term. The NRPC aspires to have the economic impacts from energy-related decisions in the region—both pro and con—spread as equally as possible across the region. The commission also hopes to ensure the continued viability of the public utilities serving the region, including municipal utilities. This plan broadly addresses the potential economic impacts of energy transformation on the region over the next 35 years, but it does not delve into the specific accounting costs of enacting this plan (or the costs of inaction). This plan remains focused on accomplishing goals that will positively affect the long-term environmental and economic sustainability of the Northwest region.



SECTION III

III. REGIONAL ENERGY SUPPLY AND CONSUMPTION

A. SPACE HEATING

RESIDENTIAL HEATING SOURCES AND COSTS
COMMERCIAL, INDUSTRIAL, AND INSTITUTIONAL HEATING SOURCES AND COSTS
COST OF FOSSIL FUEL SPACE HEATING
WEATHERIZATION

B. TRANSPORTATION

AUTOMOBILE RELIANCE
LAND USE PATTERNS
FUEL USE AND COSTS
PUBLIC TRANSIT

C. ELECTRICITY

ELECTRICITY USE
REGIONAL ELECTRICITY GENERATION
PUBLIC UTILITY ENERGY SOURCES AND IMPORTED ELECTRICITY

III. REGIONAL ENERGY SUPPLY AND CONSUMPTION

To adequately understand what strategies the region needs to implement to achieve state energy goals, it is important to understand more about the region's current energy supply and energy consumption. Using federal, state, and regional data, the NRPC has estimated regional energy consumption for space heating, transportation, and electric uses. The regional energy supply for heating and transportation has also been estimated. Regional information regarding electricity supply has been compiled using data available from public utilities servicing the Northwest region.

Where possible, space heating, transportation, and electric uses have been broken down into subsectors (residential, commercial, industrial, institutional) to provide a more refined understanding of the data. All energy data in this section is expressed in British thermal units (BTUs) (Figure 3.1). The data in this section provides some context for the changes that will need to occur in the future to achieve state and regional energy goals.

A. SPACE HEATING

RESIDENTIAL HEATING SOURCES AND COSTS

Estimates for residential space heating fuel use by household are available from the American Community Survey (ACS). The primary heating sources in the region are fuel oil (including kerosene), electricity, liquid propane (LP), utility gas (such as natural gas), and wood. Utility gas is available in the region, but only in western Franklin County and in the vicinity of Enosburg Falls (see Appendix C for map of service area). Wood includes both cord wood and wood pellets. Fuel oil is the most common residential heating source in the region (43%), followed by utility gas (20%) and wood (19%).

The use of electrical heat pumps and geothermal heating system s in the state and region has been increasing in recent years, but overall use remains low.

Based on the NRPC's estimates, the region currently uses approximately 2.243 trillion BTUs to heat residential units each year. Work completed by the Vermont Energy Investment Corporation (VEIC) for this project, which is discussed in Section IV, does not provide a direct comparison to this calculation, but instead estimates the number of BTUs required to heat single-family homes in the region. To provide some context, the NRPC compared

FIGURE 3.1 BRITISH THERMAL UNITS (BTUs)

British thermal units (BTUs) are the standard of measurement used in this plan. Using BTUs allows for comparisons between different types of energy inputs (e.g., electricity vs. cord wood). Here are some example conversions:

Common Measurement	BTU
1 gallon of gasoline	120,404
1 gallon of diesel fuel	137,571
1 gallon of heating oil	137,571
1 gallon of liquid propane	84,738
1 cord of wood	20,000,000
1 kWh of electricity	3,412

FIGURE 3.2 AMERICAN COMMUNITY SURVEY (ACS)

Much of the information used in this section is derived from the American Community Survey (ACS), which is conducted by the U.S. Census Bureau. This is because the U.S. Census no longer collects a considerable amount of data that it previously compiled.

The main difference between the ACS and the U.S. Census is that the ACS is based on surveys of random households within a community during a five-year period (e.g., 2009–2013). It is not a "count" like the census. The ACS is collected via mail.

According to the U.S. Census Bureau, approximately 295,000 surveys are mailed per month to randomly selected addresses in the United States. Follow-up phone calls or personal visits by U.S. Census workers are made to households that do not respond to the mailed survey.

Since the Northwest region has a relatively small population, and since the ACS is a survey and not a census, regional data from the ACS has a margin of error. This should be kept in mind while reading this report. Regardless, the ACS is the best available source for a variety of data points used in this plan.

More information about the ACS can be found at www.census.gov/acs/www/.

this estimate to baseline estimates used by VEIC in the LEAP model. VEIC estimated that approximately 1.828 trillion BTUs are needed to space heat single-family homes in the region each year (this number excludes all other residential units like duplexes and multi-family units in the region).

Figure 3.3 shows estimated residential heating costs.[2] Regional households spend the highest amount on fuel oil. Although only 14% of households use LP gas, the fuel source accounts for 26% of regional residential heating costs.

Wood is estimated to account for 13% of regional residential heating costs, yet this may be a high estimate because many residents in the region use cord wood harvested on their property and may not actually pay for wood. Cost information may vary considerably year to year based on global and regional fuel market prices.

There are approximately 21,650 households in the region. Roughly 75% of regional households are owner-occupied households, and 25% are renter-occupied households. According to the ACS, renter-occupied households are more likely to be heated using utility gas than owner-occupied households (32% versus 17%). This many not be directly related to being renter-occupied, but could instead be due to the fact that households with access to utility gas use it because it is more affordable and many renter-occupied units are in areas with access to utility gas. LP gas and fuel oil heating use is comparable for each type of household, yet 22% of owner-occupied households are heated using wood versus only 7% of renter-occupied households.

It is important to note that renter-occupied households often have little to no control over the heating source used in their housing unit because renters cannot lawfully change their heating source. In addition, landlords often have little incentive to upgrade to more efficient heating sources when the tenant is paying for heat.

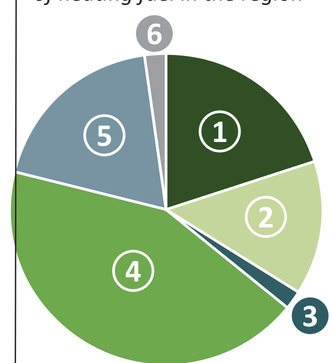
FIGURE 3.3 HOME HEATING ESTIMATES

Heating fuel use by household in the Northwest region, showing current prominence of fossil fuels that exist throughout the region.

Data from 2009-2013 U.S. Census Bureau American Community Survey estimates

	Fuel Type: Space Heating	# of Households	Average Use *(Annual)*	% of Use *(All HHs)*	% of Cost *(All HHs)*
1	Utility Gas	4,414	4,175,237 Gallons	20%	16%
2	Bottled/Tank/LP Gas	3,051	3,786,720 Gallons	14%	26%
3	Electricity	470	11,923,470 kWh	2%	5%
4	Fuel Oil/Kerosene	9,328	6,481,465 Gallons	43%	39%
5	Wood	4,008	22,062 Cords	19%	14%
6	Coal/Solar Energy/ Other or No Fuel	379	84 lbs.	2%	0%

ALL HOUSEHOLDS
Estimated percent of all households using each type of heating fuel in the region



[2]Unit costs were calculated as follows: Estimated fuel costs generally come from the U.S. Energy Information Administration and are Vermont specific where possible. Electricity costs were based on Green Mountain Power (GMP) rates. Wood costs are based on prices provided by various dealers.

Several state programs provide assistance to individuals who have difficulty affording heating fuel for their homes. The Vermont Agency of Human Services operates the Fuel Assistance program and the Crisis Fuel Assistance program. The Fuel Assistance program is available to households with a gross household income that is equal to or less than 185% of the federal poverty level (based on household size) to help pay for heating fuel. The Crisis Fuel Assistance program is available to households that have an income up to 200% of the federal poverty level and can provide proof that the household is experiencing a crisis (either the household is out of fuel or very close to running out).

FIGURE 3.4 VERMONT FUEL PROGRAMS

Year	Vermont Households Using Fuel Assistance	Vermont Household Using Crisis Fuel Assistance
2010-2011	26,546	14,977
2011-2012	27,400	11,824
2012-2013	27,776	10,560
2013-2014	26,625	7,801
2014-2015	25,147	6,860

Source: *VT Agency of Human Services*

County-level data for each program is not available for the state fuel assistance programs. However, statewide data is available for each program. Figure 3.4 shows the total number of households in Vermont that have used the state fuel programs over the past five years. Approximately 10% of total households statewide used the Fuel Assistance program in 2014–2015 (if estimated regionally, this would equal about 2,164 households). This percentage has held relatively steady over the past five years and illustrates the continuing stress that households face when paying to heat their homes. About 2.6% of households used the Crisis Fuel Assistance program during the same time period, a reduction of more than 50% from 2010–2011. Some of this drop may be related to the drop in home heating oil prices over this time period and cutbacks in state funding of these programs.

COMMERCIAL, INDUSTRIAL, AND INSTITUTIONAL HEATING SOURCES AND COSTS

Estimating space heating sources and costs for non-residential structures is more difficult than for residential structures given the lack of available information about structure square footage. There isn't enough existing data to provide an accurate estimate regarding heating sources and costs for non-residential uses in the state and the region.

However, a rough estimate of total energy use can be calculated. This is done by calculating the percentage of commercial and industrial establishments in the region versus the state and then multiplying this percentage by the amount of BTUs used by commercial and industrial sectors statewide (which is available from the U.S. Energy Information Agency [EIA]). The region accounts for about 5.7% of all commercial and industrial establishments in the state, which can be estimated to account for approximately 2.4 trillion BTUs. This is approximately the same as the NRPC's estimate for residential heating energy use (2.388 trillion BTUs) and highlights the equal importance of ensuring the efficiency of space heating for all types of structures to achieve the 90 x 50 goal.

There are approximately 6,000 commercial and industrial natural gas customers in Franklin County and Chittenden County according to the 2015 per Vermont Gas Systems annual report. Despite the lack of precise information about the number of commercial, industrial, and institutional organizations that use natural gas in Franklin County alone, it should be noted that the transmission system is located between Highgate and Georgia and between Swanton and Enosburg Falls (see Appendix C). Industrial parks in these communities are serviced by natural gas.

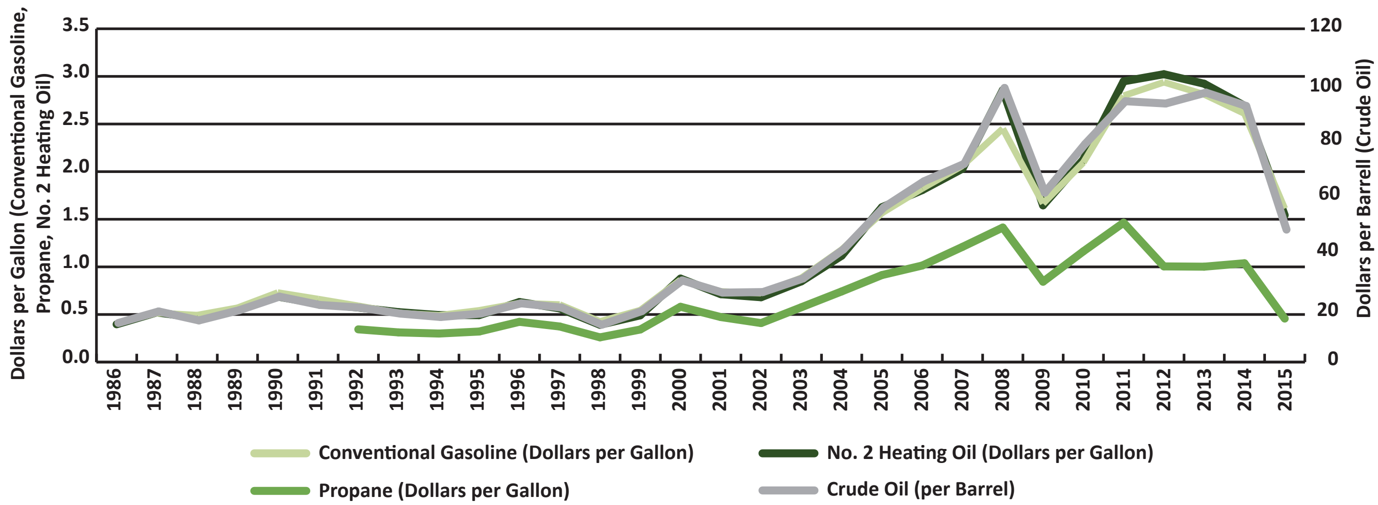
Some institutions in the region, such as schools, utilize biomass heating systems (usually wood pellet systems). The Biomass Energy Resource Center (BERC) database contains records that indicate five schools in the region use biomass systems. According to the state wood utilization forester, Paul Frederick, some of the schools that utilize wood pellet systems currently have difficulty obtaining a supplier from within the region and the state. Some schools are supplied by companies located as far away as Maine. BERC records also indicate that several multi-family apartments and government buildings (Vermont State Police barracks and Northwest State Correctional Facility) use biomass heating systems, but data from the organization is not comprehensive.

According to the Vermont Wood Fuel Supply Study: 2010 Update completed by BERC, Franklin County has approximately 39,369 green tons (gt) of net available low-grade (NALG) wood growth, a measure of wood that would be appropriate for use as biomass fuel above and beyond current levels of harvesting. Grand Isle County has approximately 750 gt of NALG wood growth. This leaves these two counties in the Northwest region in the bottom four counties statewide in terms of NALG wood growth. This may limit the region's ability to use locally sourced biomass for heat and electricity production.

COST OF FOSSIL FUEL SPACE HEATING

When analyzing current space heating fuels, it is important to note the current price of fossil fuels, including fuel oil, liquefied petroleum (LP gas, propane) and utility gas (natural gas). Prices for these products are currently low when compared to historical prices, especially when compared to prices in the mid-2000s. Figure 3.5 shows the wholesale prices of each type of fuel as reported by the U.S. EIA. The drop in fossil fuel prices has likely influenced how regional residents currently heat their homes.

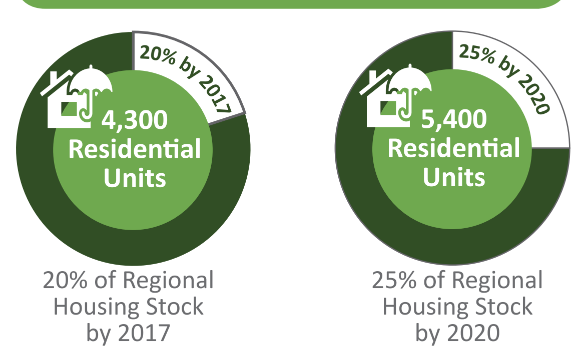
FIGURE 3.5 FOSSIL FUEL PRICES OVER TIME



WEATHERIZATION

Weatherization of existing structures is an increasingly important part of the conversation about space heating and thermal efficiency. A state statute includes a goal of improving the energy fitness of at least 20% of the state's housing stock by 2017 (more than 60,000 housing units) and 25% of the state's housing stock by 2020 (approximately 80,000 housing units (24 V.S.A. 578(a)). Regionally, this will require weatherization of approximately 4,300 residential units by 2017 and 5,400 residential units by 2020. By analyzing data from public organizations such as Efficiency Vermont (EVT) and Vermont Gas, we can see that the region is making progress toward these goals.

FIGURE 3.6 REGIONAL WEATHERIZATION GOALS



Weatherization of existing structures in the region may be completed by various parties: individual homeowners, businesspersons, or institutions. Several public and private organizations in the region can help residential, commercial, and industrial customers weatherize their structures.

Data from public organizations regarding their weatherization efforts in the region is available. The Champlain Valley Office of Economic Opportunity (CVOEO), Efficiency Vermont, and Vermont Gas are three prominent organizations operating within the region that provide weatherization-related services to individuals and business. Many private businesses also specialize in helping individuals and businesses weatherize. The NRPC has chosen to highlight these three organizations because they are public utilities and/or provide services that are publicly funded.

Weatherization Challenges

The age of structures in the region is a major challenge to weatherization efforts. About a quarter of the regional housing stock predates World War II according to the ACS (27.5%), and many commercial structures, especially in the Northwest region's village centers, are equally historical. Many of these structures have not been updated to include modern materials that increase the thermal efficiency of structures and decrease fuel costs. Some of the same structures, and even structures constructed through the 1970s, contain building materials like asbestos and vermiculite that make weatherization difficult and expensive for property owners.

The variety of entities completing weatherization work in the region complicates the process of collecting accurate information regarding weatherization. The passage of Act 89 in 2013 by the state legislature aimed to help address this issue. The act requires that building owners meet the state residential and commercial energy standards, which have existed since 1998, when completing most renovations and construction projects. Compliance requires that structure owners complete a residential or commercial building energy certificate after finishing the project to certify that the project meets state standards. Owners are also required to record the certificate in the local town clerk's office. However, the lack of widespread information about the requirements, uncertainty about when certificates are required, and a lack of enforcement make it unclear how many Vermonters and regional residents are meeting these standards. Stricter enforcement and increased education about state energy standards are needed to ensure that Vermont and the region can meet the 90 x 50 goal.

As mentioned before, rental housing poses unique energy-related challenges especially with regard to space heating and weatherization efforts. Tenants are legally unable to make weatherization improvements to their housing units (even if they are financially able to do so). Landlords do not have a financial incentive to weatherize their structures if tenants are required to pay for heating. In addition, most weatherization programs are aimed at homeowners, not landlords. These challenges have the potential to stifle weatherization of the state and regional rental housing stock, which negatively impacts the finances of renters and makes achieving the 90 x 50 goal more difficult. The NRPC, State of Vermont, and public utilities serving the region must look to identify strategies to overcome these challenges with the cooperation of regional partners.

According to the Vermont Comprehensive Energy Plan, energy-efficiency programs, such as the Champlain Valley Office of Economic Opportunity, Vermont Gas, and Efficiency Vermont in the Northwest region, have "facilitated the installation of efficiency improvements in just under 18,300 Vermont housing units" since 2008. Although this progress is admirable, the current rate of weatherization efforts is insufficient to meet the legislature's goal of 80,000 weatherized homes by 2020. Additional efforts will need to be made across the state and the region to hasten weatherization and ensure that the 2020 state weatherization goal and, more prominently, the 90 x 50 goal are met.

Champlain Valley Office of Economic Opportunity

The Champlain Valley Office of Economic Opportunity (CVOEO) is the state-appointed community action agency serving the Northwest region. The organization administers a variety of programs focused on combating poverty and enabling individuals to reach self-sufficiency. One program operated by CVOEO is the low-income weatherization program in the region. This program is available to homeowners and renters that have a median income that is less than 80% of the state median income (about $43,500). According to CVOEO, the organization typically serves those that are at the lowest end of the economic spectrum. Many of the program's grantees are also eligible for other state programs focused on making heating more affordable, including the Fuel Assistance program.

CVOEO partners with Efficiency Vermont to have an "efficiency coach" work with homeowners in the program to complete minor work within their housing unit to increase efficiency. The housing unit is then audited and a scope of work created based on audit findings. Weatherization is then completed by CVOEO and inspected by the organization's quality control team. CVOEO receives reimbursement for the work from the State of Vermont after each project has been completed.

The low-income weatherization program currently accounts for retrofits in approximately 1,500 units in CVOEO's territory each year (Addison, Chittenden, Franklin, and Grand Isle Counties). Through the program, approximately 769 retrofits were completed in the Northwest region between March 2010 and February 2015. Retrofits include both major projects, such as reinsulating walls and attics or replacing furnaces, and minor projects, such as upgrading lighting. According to CVOEO, an average retrofit costs approximately $8,500.

However, CVOEO's efforts may be reduced moving forward. The low-income weatherization program lost approximately 30% of its funding in 2015 with the expiration of funding available through the American Recovery and Reinvestment Act (ARRA).

Vermont Gas

Vermont Gas is the natural gas utility serving the region. The organization offers several weatherization programs to its customers. Specific programs for residential customers, both renters and homeowners, include the Retrofit Program and the New Construction Program. Each program allows the customer to install significant building improvements to increase thermal efficiency. The Retrofit Program includes a free energy audit and low-interest financing options. Vermont Gas also provides comparable programs to its commercial customers. The most popular program for both residential and commercial customers provides rebates or other financial incentives to install high-efficiency equipment such as furnaces and water heaters. Figure 3.7 shows the number of customers in the region that have benefited from each program.

Efficiency Vermont

Efficiency Vermont is the statewide Energy Efficiency Utility (EEU) appointed by the Public Service Board. It manages a broad array of programs that are focused on conservation efforts through providing education, services, and incentives to Vermont homeowners and businesses. This includes providing financing and technical support to homeowners and businesses seeking to complete energy-saving improvements and administering rebate programs for a variety of appliances and equipment.

Efficiency Vermont reports that it managed contractors that completed 276 residential energy audits in the region between January 2011 and December 2015 through its Home Performance program. This resulted in 129 completed weatherization projects in the region during the same time period, with a high of 31 projects completed in the region during 2014. Efficiency Vermont also operates a comparable Business Energy Assessments program. Data from this program is not readily available.

CVOEO and Efficiency Vermont have recognized that occasionally their efforts may duplicate, especially with regard to weatherizing multi-family housing because property owners may be eligible for programs through each organization. There may also be some overlap with Vermont Gas programs. However, this circumstance is the exception, not the rule. The above cited data from Efficiency Vermont excludes projects completed that overlap Vermont Gas or CVOEO programs.

FIGURE 3.7 VERMONT GAS WEATHERIZATION PROGRAMS

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016 to date	Total
Residential Programs											
Residential Home Performance/EVT			1	3	3	3	1	3	4		18
Residential Equipment Replacement	51	65	111	92	82	93	119	185	151	7	956
Residential Retrofit	8	5	16	8	8	7	8	9	9	1	79
Residential Low Income	10	15	14	17	5	13	21	29	8	1	133
Residential New Construction		1	12	11	6	7	8	9	11	1	66
										Total	1,252
Commercial Programs											
Commercial Equipment Replacement	6	4	5	6	11	4	9	11	9	0	65
Commercial New Construction	1	4	1	2	1	4	2	2	2	0	19
Commercial Retrofit	1	6	3	2	6	1	1	5	1	0	26
										Total	110

Source: *Vermont Gas. The Vermont Gas service area includes the following municipalities in Franklin County: Georgia, Highgate, Sheldon, St Albans, Swanton, Enosburgh.*

B. TRANSPORTATION

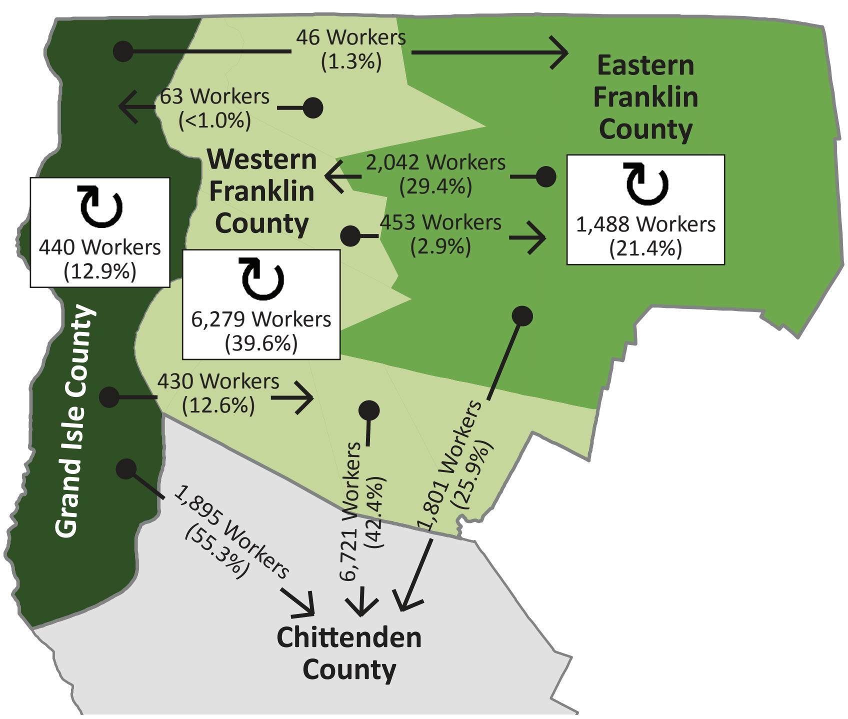
Transportation contributes a considerable amount to the region's total energy use. This is due to several factors: reliance upon the automobile for transportation, land use patterns, and fuel costs.

AUTOMOBILE RELIANCE

Data regarding vehicle use and vehicle miles traveled is available from both state and federal sources, and it provides a clear picture of auto reliance in the state and the region:

- Passenger vehicles in the region: 42,471 (2011–2015 ACS)
- Realized MPG in VT (Vermont Agency of Transportation [VTrans]): 18.6 MPG
- Approximate passenger fuel use in the region per year: 3.1 trillion BTUs or 25.9 million gallons
- Vermont per-capita vehicle miles

FIGURE 3.8 NORTHWEST REGION WORKERS



traveled (VMT) in 2014: 11,356 miles—tenth highest in the country (VTrans)
- Mean commute time in the region: 25 minutes in Franklin County and 34 minutes in Grand Isle County (2011–2015 ACS)
- Commuters driving alone: 78% (2011–2015 ACS)
- Commuters using public transportation: 0.5% (2011–2015 ACS)

This much is clear: Vermonters drive a great deal, and they often drive alone. But there is one promising trend: Per-capita VMT have actually decreased in Vermont from a high of 11,402 miles per capita in 2011.

FIGURE 3.9 REGIONAL COMMUTING PATTERNS

- Almost 50% of workers who reside in western Franklin County commute to Chittenden County for work. About 46% of workers commute within western Franklin County.
- More than 75% of eastern Franklin County residents commute to western Franklin County and Chittenden County for work.
- Approximately 75% of Grand Isle County workers commute to jobs outside the county, including a total of 54% of all workers who commute to Chittenden County.

Source: *US Census – Longitudinal Employer-Household Dynamics On The Map tool (2014)*

LAND USE PATTERNS

The transportation choices made by regional residents are influenced significantly by regional land use patterns. Land use in the region has historically been characterized as compact development (downtowns and villages) surrounded by working landscape (agriculture and forestry). This model of development is still supported by the Northwest Regional Plan because it promotes concentrated economic development, walkability, and viability of public transportation, and it limits threats to the region's working landscape. It also decreases transportation costs.

With the development of the Interstate Highway System, land use patterns in the region began to change. Access to less expensive rural land and cheap fuel as well as the region's proximity to Chittenden County, the economic center of Vermont, have altered the way the region has developed over the past 60 years. The result is the loss of working landscape in the region (notably agricultural lands), increased commute times, and increased VMT. The highway system has also contributed negatively to environmental quality and greenhouse gas emissions and has led to changed commuting patterns (Figure 3.9).

FUEL USE AND COSTS

Current land use and commuting patterns have led to heightened transportation costs for individuals and a comprehensive reliance on increasingly expensive fossil fuels. Transportation fuel use and costs for individuals in the region can be estimated using data from the ACS and VTrans. Using the average fuel cost in April 2017, individuals in the region spend approximately $67 million per year in transportation fuel costs (Figure 3.10). This figure is even higher when vehicles owned by regional businesses are considered. In addition, much of this money leaves the local economy.

FIGURE 3.10 ESTIMATED REGIONAL FUEL COSTS

	Regional Estimates
Total # of vehicles in region (ACS)	42,471.00
Average gallons used per vehicle per year (VTrans)	18.6
Total gallons used per year in region	25,930,143.87
Average cost per gallon of gas	$2.31
Total Fuel Costs	**$59,898,632.34**

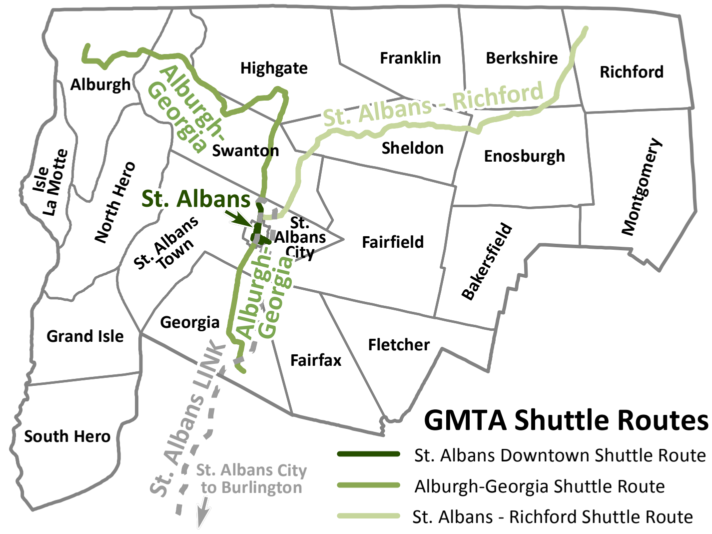
Hybrid and electric vehicles can decrease residents' reliance on fossil fuels. Regionally, hybrid vehicles are becoming more common. As of January 2016, there were 41 electric vehicles registered in the region. This trend is encouraging, but the region still lags behind other parts of the state in converting to alternatively fueled vehicles. This may be due to a variety of reasons, such as electric vehicle cost, electric vehicle range, and the lack of public charging stations. There are currently a few public charging stations in the region, but they are concentrated in three municipalities: St. Albans City, St. Albans Town and Swanton.

PUBLIC TRANSIT

As previously noted, fewer than 1% of regional residents use public transportation during their commute to work. However, public transit will be a key component to reducing transportation costs and meeting state and regional energy goals.

Green Mountain Transit (GMT) provides public transportation to the Northwest region and operates four routes in the region: the Alburgh–Georgia Shuttle, the St. Albans–Richford Shuttle, the St. Albans Downtown Shuttle, and the St. Albans LINK which provides access to Burlington (Figure 3.11). The former two routes terminate in two of the region's industrial parks. However, most of Grand Isle County and eastern Franklin County is without public transportation services. GMT also provides special transportation services to the elderly and disabled in the region. In addition, GMT serves as the fiscal agent for its partner agency, Champlain Islanders Developing Essential Resources (C.I.D.E.R.), which provides transportation to elderly and disabled residents of Grand Isle County. All buses in the region currently run on gasoline.

FIGURE 3.11 GMT SHUTTLE ROUTES



Source: NRPC

There are seven park and ride lots in the region, which are all concentrated in western Franklin County. Southern Grand Isle County and eastern Franklin County do not have park and ride lots and are considered underserved. A park and ride lot location has been identified in South Hero, and NRPC is currently working with VTrans to determine potential locations for additional park and ride lots in the county.

Amtrak serves St. Albans City via the Vermonter Line. According to Amtrak, in 2014 there were approximately 4,400 arrivals and departures at the St. Albans stop. There is no commuter rail service in the region.

The financial costs and environmental impact of moving goods in the region are substantial. Currently, trucks move approximately 83% of goods by weight and 88% of goods by value statewide, according to the 2015 Vermont Freight Plan. St. Albans is home to a private railyard owned by New England Central Railroad. Information about freight capacity and current traffic through the railyard is private and unavailable.

FIGURE 3.12 MEGAWATT TO GIGAWATT CONVERSION

1 MW = .001 GW
1 MWh = .001 GWh

C. ELECTRICITY

ELECTRICITY USE

The 2016 Vermont Comprehensive Energy Plan states that approximately 5.5 GWh of electricity are used statewide each year. This use has remained fairly consistent since 2009 and is down from peak electricity use of approximately 5.9 GWh in 2005.

FIGURE 3.13 REGIONAL ELECTRICITY USE IN REGION - 2013

Sector	Regional Electricity Use	Regional Electricity in Trillions BTUs
Residential (kWh)	194,619,255	0.664
Commercial and Industrial (kWh)	288,131,747	0.983
Total (kWh)	482,751,002	1.647

Source: *Efficiency Vermont*

Electricity use data available from the U.S. Energy Information Administration does not provide details on a regional level. The LEAP model estimates 2010 regional electricity demand to be 1.832 trillion BTUs per year. This is equivalent to 536.9 MWh per year, which totals approximately 9.6% of the state's electricity use. The LEAP model estimate is relatively close to data available from Efficiency Vermont in 2013. EVT shows regional electricity use accounting for approximately 1.647 trillion BTUs.

As discussed in the next section, electricity use must continue to grow through 2050 in order to meet the 90 x 50 goal.

REGIONAL ELECTRICITY GENERATION

As of January 2017, the Northwest region had the capacity to generate 58.4 MW of electricity through hydro, wind, solar, and biomass technologies, and it had 98.4 MW of total generation capacity from all sources, according to data available from the Community Energy Dashboard.[3] The 58.4 MW of renewable generation in the region is a "raw" number that does not take "capacity factors, renewable energy credits sold, or ownership of the systems" into consideration. The NRPC has estimated renewable generation in the region to be about 182,190.79 MWh per year when factoring capacity factors for solar, wind, and hydro.

The region has four dams with a total generation capacity of approximately 41.4 MW of electricity. Three of the dams are located on the lower portions of the Missisquoi River. A privately owned dam in Sheldon Springs has a generation capacity of approximately 26 MW of electricity. It is the largest dam both on the Missisquoi and in the region. The two other dams on the Missisquoi are located in Highgate and Enosburgh, and they are owned by public electric utilities in Swanton Village and Enosburg Falls, respectively. The dam at Enosburg Falls will undergo extensive repairs within the next five years to remain operating at its current capacity. The fourth dam in the region is located on the Lamoille River in Fairfax and is owned by Green Mountain Power.

Georgia Mountain Community Wind is the only existing, large-scale wind project in the region. Two of the project's four turbines are located in Franklin County (Georgia), and the other two turbines are located in neighboring Chittenden County. The project generates approximately 10 MW in total (5 MW is estimated to be generated within the region). As of January 2017, the Community Energy Dashboard indicated that there were 25 other small-scale wind facilities in the region that have received a Certificate of Public Good from the Public Service Board. Total wind-generation capacity in the region, including half of Georgia Mountain Community Wind, equals 5.26 MW.

Another large-scale wind project, Swanton Wind, has currently entered the regulatory process with the filing of an application with the Public Service Board in August 2016. As proposed, the project would generate 20 MW of electricity.

In January 2017, the Community Energy Dashboard reported that it had approved 9.5 MW of solar generation in the region. This includes several facilities that were "large" when they were permitted: a 2.2 MW project in Sheldon Springs and three 500 kW projects, including one located at the correctional facility in St. Albans Town. In addition, several larger solar facilities, ranging in size from 5 MW to 20 MW, are currently proposed in the region.

Biomass electric generation is also occurring in the region. According to the Community Energy Dashboard, approximately 2.3 MW of electricity was generated from biomass sources in the region as of January 2017. All of this electric generation took place in Franklin County through the use of anaerobic digestion on dairy farms (some woody biomass in the region is used for heating systems, not electric generation).

Green Mountain Power has applied for an anaerobic digester in cooperation with three dairy farms in St. Albans Town. The digester would use manure and food scrap from solid waste districts in the northwest part of the state. The potential capacity of the facility is approximately 800 kW.

[3] http://www.vtenergydashboard.org/

There is one non-renewable energy generator in the region: Project 10. This facility, which is located in Swanton, is owned by the Vermont Public Power Supply Authority (VPPSA) and runs on fuel oil and/or biodiesel. The facility is a "peaking" plant that operates only during peak electric loads, which, according to the project's Certificate of Public Good, equals approximately 600 hours per year. The facility can be converted to use natural gas as a fuel and is located near a natural gas line.

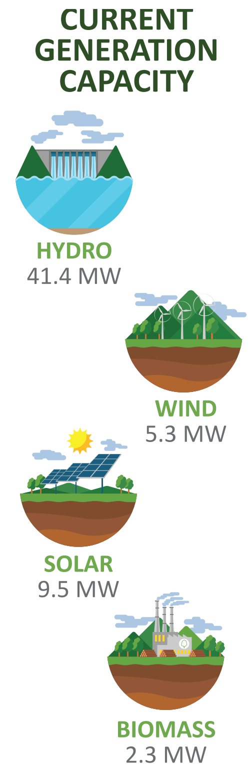
The amount of currently proposed generation in the region equals 75.211 MW (excluding withdrawn applications), and this total would increase regional generation by 75% (Figure 3.14). All of the proposed projects use renewable energy sources. And although not all of the currently proposed projects will necessarily be built, the amount of generation development has substantially increased since the early 2010s. In addition, this increase is not expected to subside in the near term given the extension of federal tax credits for solar facilities until 2021 and the renewable generation standards set for public utilities in the state Renewable Energy Standard. A full summary of regional renewable generation facilities is located in Appendix E.

FIGURE 3.14 REGIONAL GENERATION CAPACITY

Type of Generation	Generation Capacity (in MW) January 2017	Generation Capacity Currenty Proposed (in MW)
Hydro	41.4	0
Wind	5.3	20
Solar	9.5	54.411
Biomass	2.3	0.8
Fuel Oil/Biodiesel	40	0
Other	0	0
Total	**98.4**	**75.211**

1. Current Fuel Oil/Biodiesel Generation is only a peaking plant. It is only permitted for use a maximum of 600 hours per year.
2. Some proposed generation may have been constructed.

Source: *Community Energy Dashboard, Public Service Department, and NRPC*



PUBLIC UTILITY ENERGY SOURCES AND IMPORTED ELECTRICITY

Four public utility companies in the Northwest region supply electricity (see Appendix C). Two of these utilities are operated by municipalities: Swanton Village and Enosburg Falls. Both of these utilities are part of VPPSA, an organization that represents 12 municipal electric utilities in Vermont. The other electric utilities servicing the region are Green Mountain Power and Vermont Electric Cooperative (VEC).

Green Mountain Power

Green Mountain Power generally services the southern and western parts of Franklin County. Figure 3.15 shows sources of electricity distributed by GMP in 2015 (before the sale of renewable energy credits (RECs)). The electricity comes from primarily outside the region with the exception of distributed solar generation and the GMP-owned dam at Fairfax Falls. GMP owns several generation facilities. It also enters into power purchasing agreements with individual power suppliers and purchases power on the open market ("System" power) (Figure 3.15).

Vermont Electric Cooperative

VEC's territory includes all of Grand Isle County and most of the northern and eastern parts of Franklin County. VEC does not own any electric-generating facilities; it instead has power purchasing agreements with individual electric suppliers and purchases power on the open market. Figure 3.16 shows VEC's energy sources by type of resource and energy sources by provider. Generally, electricity distributed by VEC comes from primarily outside the region with the exception of distributed solar generation and electricity generated from methane on regional farms.

FIGURE 3.15 GREEN MOUNTAIN POWER ELECTRICITY SOURCES

Ownership	Subtype	Generator Description
Owned Generation	Joint Owned	McNeil Generating Plant (31%), Millstone 3 (Nuclear), Stony Brook (gas/oil fired facility), Wyman #4 (oil fired)
	Wholly Owned	GMP Hydroelectric (32 facilities), oil-fired (6 facilities), solar and wind generators (2 large facilities)
Power Purchase Agreements	Long-Term Units	NextEra Seabrook (nuclear), Granite Reliable Wind (wind), Moretown Landfill (landfill methane), Ryegate (biomass), Stony Brook (oil), New York Power Authority (hydro)
	Long-Term System	HydroQuebec Vermont Joint Owners Agreement, (HQUS PPA)
	Short-Term Unit	Amersand Gilman, North Harland, other small independent producers
	Short-Term System	J.P. Morgan, Shell, Citigroup, exGen, and NextEra energy contracts ("do not convey generation attributes from particular sources")
	Standard Offer (SPEED)	Biomass, farm or landfill methane, hydro, solar
	VEPPI	Vermont's Quality Facilities under PURPA (hydro)

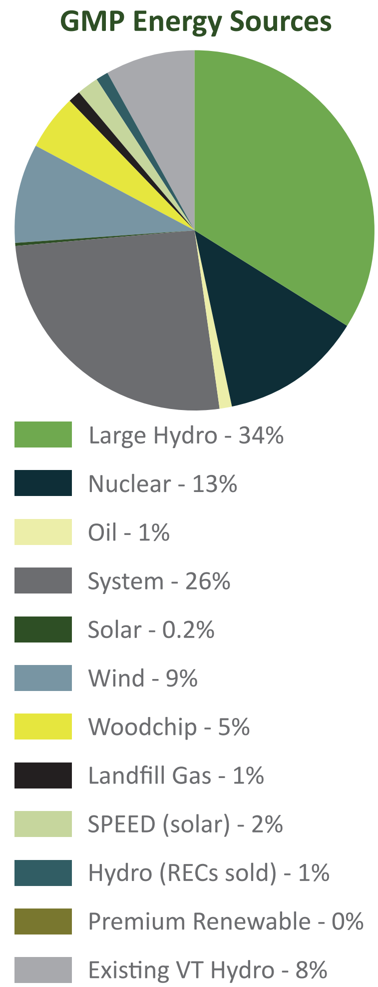
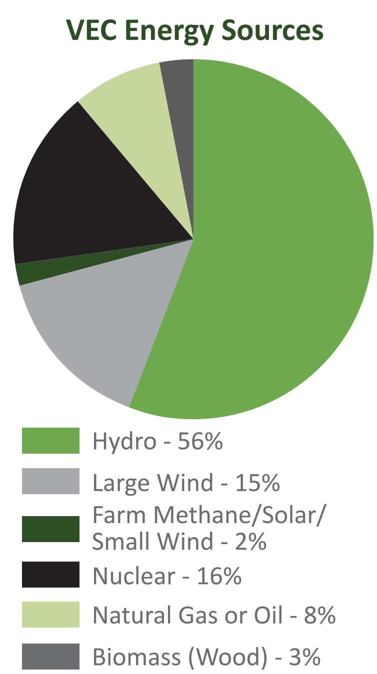


FIGURE 3.16 VERMONT ELECTRIC CO-OP ELECTRICITY SOURCES

Type of Power	Generator
Large Hydro	Hydro-Quebec, NY Power Authority (St. Lawrence and Niagra)
Small Hydro	VEPPI and two Warner's hydro generators
Large Wind	First Wind, LLC (Sheffield, VT) and Kingdom Community Wind (Lowell, VT)
Farm Methane/Solar/ Small Wind	Standard Offer
Nuclear	NextEra Seabrook
Natural Gas or Oil	System Power (source of supply not identified)
Biomass	Ryegate Woodchip Facility (Ryegate, VT)



Enosburg Falls Village and Swanton Village Electric Departments

Despite their small service territories, both the Enosburg Falls Electric Department and Swanton Village Electric Department distribute electricity that is generated from a variety of facilities. Both utilities have dams located in the region (Enosburgh and Highgate, respectively). Both also rely, to some extent, on importing electricity from outside the region. Information about electricity used by Enosburg Falls and Swanton was provided by VPPSA.

Enosburg Falls' dam supplied approximately 12.82% of the power distributed by the Enosburg Falls Electric Department in 2014. About 27.6% of the electricity distributed in 2014 came from Hydro-Québec, and about 28.2% came from the utility purchasing electricity on the open market (Figure 3.17).

The Swanton Dam supplied 74.3% of the electricity distributed by Swanton Village Electric Department in 2014. The McNeil Generating Station in Burlington contributed an additional 17.7% of the electricity distributed. Notably absent from the list is Hydro-Québec, which did not provide any electricity to Swanton Village Electric Department.

FIGURE 3.17 VILLAGE OF ENOSBURG FALLS ELECTRICITY SOURCES

Type of Power	Generator
Hydro	Enosburgh Dam, NY Power Authority, Hydro Quebec, VEPPI
Farm Methane/ Solar/Small Wind	Chester Solar (Chester, MA), Standard Offer
Landfill Gas	Fitchburg Landfill (Fitchburg, MA)
Fuel Oil or Biodiesel	Project 10 (Swanton, VT)
Natural Gas or Oil	System Power (source of supply not identified)
Biomass	McNeil (Burlington, VT), Ryegate (Ryegate, VT), VEPPI

FIGURE 3.18 SWANTON VILLAGE ELECTRIC DEPT. SOURCES

Type of Power	Generator
Hydro	Highgate Dam, NY Power Authority, VEPPI
Farm Methane/Solar/ Small Wind	Standard Offer
Landfill Gas	Fitchburg Landfill (Fitchburg, MA)
Fuel Oil or Biodiesel	Project 10 (Swanton, VT)
Natural Gas or Oil	System Power (source of supply not identified), Stonybrook (MA)
Biomass	McNeil (Burlington, VT), Ryegate (Ryegate, VT), VEPPI

What is particularly striking about Swanton Village Electric Department is that approximately 98.7% of the electricity generated on its system in 2014 came from what are generally considered renewable sources: hydro and biomass. This is a considerably larger use of renewable sources compared to the other three public utilities servicing the region.

It is also worth noting that about 74.2% of the electricity distributed by Swanton Electric in 2014 was produced within the region at the utility's dam in Highgate (Figure 3.18).

Several existing dams in the region do not currently produce electricity, yet they could potentially be used in the future. According to the Vermont Renewable Energy Atlas, the future generation capacity of these dams could be in excess of 1 MW (Appendix C). The possible future use of these dams is a point of controversy given the related environmental impacts. This topic is discussed in greater detail in Section V (see Figure 5.9).

Appendix C contains maps that shows areas in the region with solar and wind generation potential.

SECTION IV

IV. TARGETS FOR ENERGY CONSERVATION, ENERGY USE, AND ELECTRICITY GENERATION

IV. TARGETS FOR ENERGY CONSERVATION, ENERGY USE, AND ELECTRICITY GENERATION

While Section III focuses on cataloguing the Northwest region's current energy demand and generation capacity, Section IV creates targets for regional energy conservation, use, and generation. The targets will guide the region toward achieving the state's and region's energy goals.

Achieving these energy goals will be challenging. Intensive conservation methods will need to be employed throughout the region in all sectors. Increased electrification of transportation and space heating will also be needed (combined with the subsequent decrease in fossil fuel use). But perhaps most importantly, total energy demand in the region will need to decrease despite population growth. The specifics of regional conservation and generation targets are covered in detail in Subsection B. Subsection A provides context for how regional targets were developed. Appendix H contains a comprehensive list of regional energy targets.

A. LEAP MODEL AND METHODOLOGY

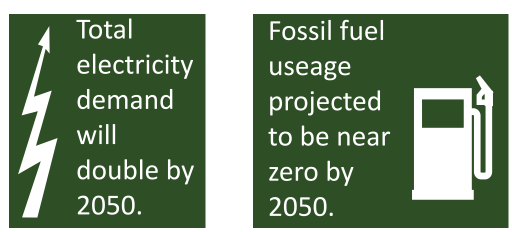
To create targets for conservation and use, the NRPC teamed with VEIC. The VEIC staff used LEAP (Long-range Energy Alternatives Planning) software to create a model of the demand for and supply of total energy usage in Vermont and the region. LEAP software allows users to create complex models of systems with editable inputs from the large scale (such as population or vehicle miles traveled) to the small scale (the electrical demand of individual appliances). Because of the model's complexity, it is difficult to explain comprehensively. The following scenarios provide some background on the methodology and the inputs used to create both statewide and regional models in LEAP. Appendix A presents the full model results for the region and the state as well as a more thorough explanation of the model assumptions and methodology.

Targets for generation were developed by the Department of Public Service in partnership with the state regional planning commissions. Generation targets were based on estimates in the Vermont Comprehensive Energy Plan and the LEAP model. The Department of Public Service and regional planning commissions then took into considerations variables such as generation potential, population, and existing generation to develop targets for renewable generation.

ONE MODEL – TWO SCENARIOS

The model created in LEAP actually contains two scenarios. The first scenario—the reference scenario—contains inputs that reflect current energy use and generation trends. The second scenario is designed to achieve the goal of meeting 90% of Vermont's total energy demand with renewable sources. This scenario, called the 90 x 50 VEIC scenario, is adapted from the Vermont Total Energy Study (TES) Total Renewable Energy and Efficiency Standard (TREES) Local scenarios.[4] This scenario is a hybrid of the high and low biofuel cost scenarios used in the TES. More information regarding the TES can be found on the Department of Public Service website.[5] Both scenarios are based on projected energy demand.

FIGURE 4.1 PROJECTED ENERGY DEMAND AND FOSSIL FUEL USEAGE



The model results show that, despite a growing population and economy, energy use will decline in the 90 x 50 VEIC scenario because of increased efficiency and conservation. Electricity use will increase with the intensified use of heat pumps as primary heating sources and the use of electric vehicles. Because those choices are powered by electricity, and electricity is three to four times more efficient compared to fossil fuels, overall energy use will decrease both regionally and statewide.

[4] Required by Act 170 of 2012 and by Act 89 of 2013, the intent of the TES according to the VT Public Service Dept. was "to identify the most promising policy and technology pathways to employ in order to reach Vermont's energy and greenhouse gas goals."

[5] Vermont Total Energy Study: http://publicservice.vermont.gov/publications-resources/publications/total_energy_study

The difference in total energy demand between the reference scenario and the 90 x 50 VEIC scenario is a key point. This difference, or "avoidance," estimates the amount of total energy demand that will need to be eliminated through conservation efforts to ensure that the state's and region's energy goals are met by 2050. The many challenges that will inhibit regional efforts to reach conservation and generation targets are covered in detail in Section VI.

LEAP INPUTS AND ASSUMPTIONS

Data used to construct the model was primarily drawn from the Public Service Department's Utility Facts 2013 and information available from the U.S. EIA, a federal entity associated with the U.S. Department of Energy that maintains official, federal energy statistics. Projections used in the model came from the Vermont TES, information from Vermont public utilities about their committed electricity supply, and stakeholder input.

In the model, VEIC projects that the population of the state and the region will grow by 0.87% per year. This number was chosen based on population projections completed by the Vermont Agency of Commerce and Community Development. In the model, the number of persons per household was assumed to decrease from 2.4 in 2010 to 2.17 in 2050. This assumption was based on historical trends. The projected number of households is an important piece of the model; it is the basic unit in the model on which residential energy consumption is projected.

The commercial energy demand driver in the model is the square footage of commercial buildings. Data and projections about commercial building area were extracted from inputs for the TES. Industrial energy use was entered into the model using actual totals without a driver specified. Commercial and industrial demand calculated at the state level was then allocated to the regions by service-providing and goods-producing North American Industry Classification System (NAICS) codes, respectively.

Transportation energy use in the model is based on projections of vehicle miles traveled, which are available from VTrans for county-based totals. Although VMT have risen throughout most of American history, it peaked in Vermont in 2006 and has since slightly declined. Given this trend and Vermont's efforts to concentrate development and to support alternatives to single-occupant vehicles, the model assumes that VMT in the state and county will remain flat despite growth in population and economic activity.

The 90 x 50 VEIC scenario assumes that diesel used in heavy-duty vehicles is replaced with biodiesel. It also assumes that electricity will replace gasoline in passenger (i.e., light duty) vehicles and that electricity will provide an increasing amount of energy used for space heating, primarily through the use of cold climate heat pumps. The challenges associated with meeting these assumptions, including challenges related to infrastructure required to transition to biodiesel fuel sources, are outlined in Appendix A.

The supply side of the model was first calculated on a statewide basis. The reasons for this, according to VEIC, is that "no region is going to host a small share" of electricity generated by a larger source like the Seabrook Station Nuclear Power Plant in New Hampshire or Hydro-Québec. Instead, the electricity generation capacity of these large electricity suppliers is allocated according to the region's 2050 modeled electricity consumption. The resulting supply side focuses on "each region's 'share' of new (installed after 2015) in-state generation by 2050." The "share" data is meant to aid the Northwest region in attaining the 90 x 50 goal. However, it should be kept in mind that this "share" represents only one of the many paths the Northwest region may take to attain the 90 x 50 goal and does not necessarily set a mandatory target for the region to achieve.

B. REGIONAL LEAP MODEL

Because different fuels are measured in different units (e.g., gallons, cords, pounds, cubic feet), the results of the LEAP model can be difficult to compare. To help make comparisons between fuel types easier, the NRPC has decided to report the scenario results in a standard unit: BTUs. To provide some additional context, see Figure 3.1.

Results from the LEAP model show similar trends for both the state and the region. The following results focus on the region. When a significant difference exists between the state and regional model results, the difference will be addressed.

SPACE HEATING

Per the LEAP model results, the amount of energy used for single-family home space heating demand is expected to fall regionally between the present and 2050 (again, due to heat pumps). It is also due to increasing energy savings gained through weatherization retrofits of existing single-family structures and through the construction of new single-family homes that are compliant with the state's residential building energy standards (RBES).

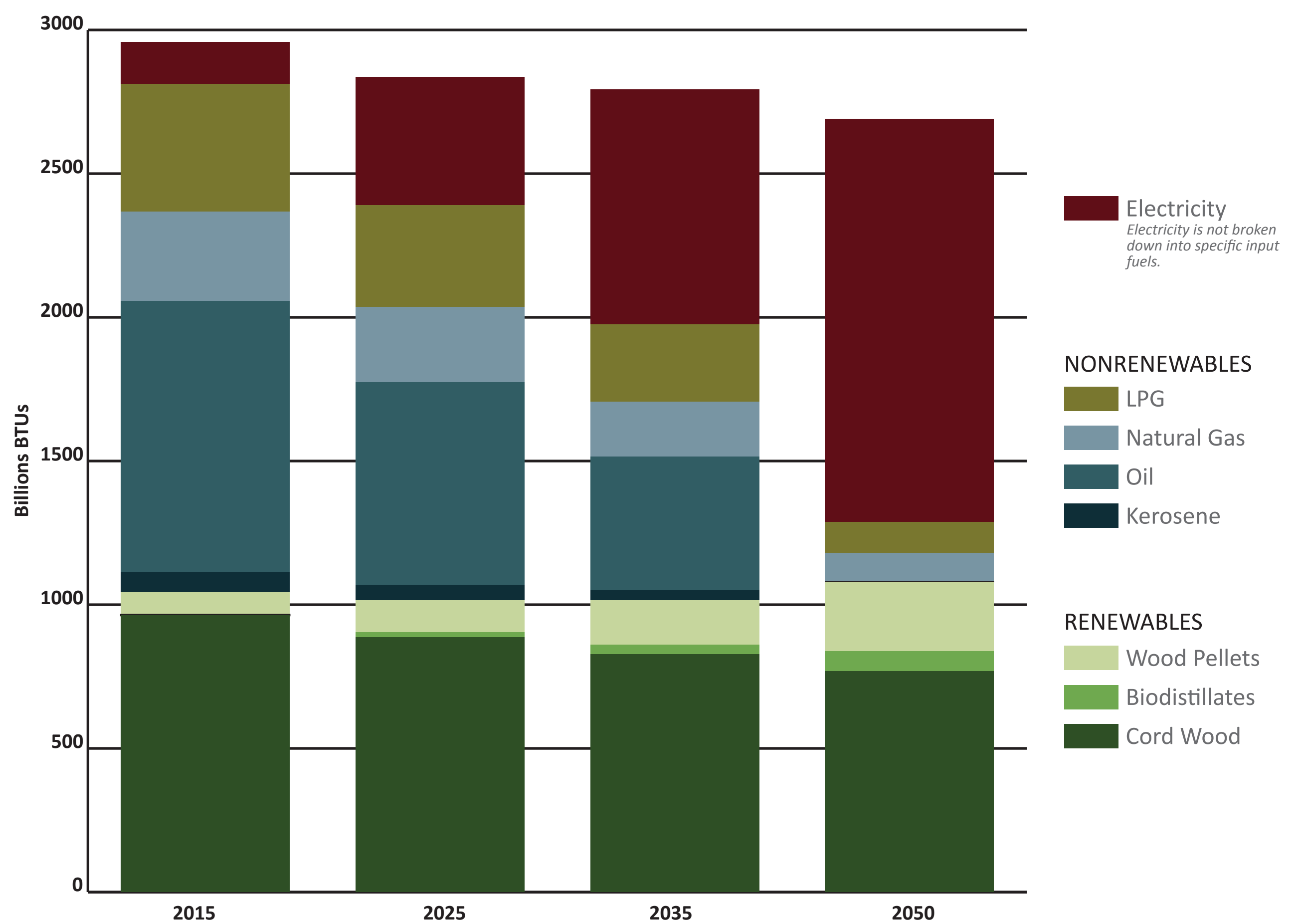
FIGURE 4.2 PROJECTED HEATING

Oil, Propane, and Kerosene are projected to be eliminated as single family home heating sources by 2050.

Total BTUs from wood heating projected to decrease by 3% between 2015 and 2050.

The model results also show a significant reduction in the use of fossil fuels (or in the case of some fossil fuels, complete elimination) as a single-family home heating source. The regional model shows the elimination of kerosene and fuel oil as heating sources by 2050. Liquid propane and even natural gas use are projected to drop during the model time frame.

FIGURE 4.3 LEAP PROJECTED REGIONAL SPACE HEATING ENERGY DEMAND



The model shows cord wood as continuing to provide a significant amount of BTUs for single-family home space heating in both 2015 and 2050 in the model. In 2050, the model shows cord wood providing about 29% of single-family home heating BTUs in the region. Wood pellet use grows considerably during the model time period from approximately 78 thousand million BTUs in 2015 to 241 thousand million BTUs in 2050. Despite this gain, pellets still only account for 9% of the total BTUs needed to meet model targets in 2050, a much smaller percentage than cord wood.

In total, wood sources account for approximately 37% of single-family home heating BTUs in 2050 according to the model. This represents a small increase from 2015 when wood sources were estimated to account for 35% of single-family home heating BTUs according to LEAP. Comparatively, electric heating sources account for a significant increase in terms of percentage of single-family home heating BTUS moving from about 5% of the single-family home heating BTUs in 2015 to 52% of the single-family home heating BTUs in 2050.

The NRPC has some concerns about continuing reliance on cord wood for space heating. These concerns—namely, sustainable harvesting and impacts on greenhouse gas emissions—are covered in Section VI.

Industrial and commercial space heating demand is not provided separately from total industrial and commercial energy demand in the LEAP model results. Heating is just one element of the total energy demand, so it is a little difficult to accurately provide data that reflects energy used for space heating instead of energy used for lighting, manufacturing processes, and other uses. However, a closer look at the data reveals that the energy, or BTUs, used by the commercial and industrial sectors is used primarily for space heating (natural gas, for instance, is used for space heating in the region, not generating electricity) and not for other types of uses (e.g., the electricity used for operating a machine).

In the model, the total demand for industrial and commercial energy includes reductions in natural gas use. Commercial demand also includes reductions in propane, oil, and residual fuel oil demand, with the latter two sources essentially eliminated from the fuel mix in 2050. Industrial demand for propane and residual fuel oil remains relatively constant throughout the model time frame. Demand for cord wood, another heating source, increases in terms of BTUs as well as overall percentage for both industrial and commercial sectors by 2050. This result was a surprise to the NRPC, as it is the opposite of the trend seen for single-family homes.

FIGURE 4.4 THERMAL FUEL SWITCHING TARGETS (Residential and Commercial)

	2025	2035	2050
New Efficient Wood Heat Systems (in units)	46	89	720
New Heat Pumps (in units)	3203	6407	11603

To meet the targets for wood and electricity thermal generation for single family home and commercial heating, there will need to be approximately 720 new high-efficiency wood systems installed and 11,603 new electric heat pumps systems installed in the region by 2050. Targets for 2025 and 2035, targets based on the LEAP model, are shown in Figure 4.4.

Weatherization is also a key element regional conservation of space heating energy. By utilizing LEAP data, and a model developed by the Vermont Department of Public Service, the NRPC establishes the following targets for weatherization within the region, shown in Figure 4.5.

FIGURE 4.5 REGIONAL WEATHERIZATION TARGETS

	2025	2035	2050
Total Residential Households	1,021	3,571	16,786
Percent of Regional Residential Households	4%	14%	57%
Total Commercial Establishments	284	392	823
Percent of Regional Commercial Establishments	24%	23%	64%

FIGURE 4.6 PROJECTED ENERGY NEEDS

Transportation energy projected to decrease by 58% by 2050.

Electricity and biodiesel are projected to provide 91% of total transportation energy needs by 2050.

Biodiesel will need to increase from 423,000 gallons in 2015 to 7.13 million gallons in 2050.

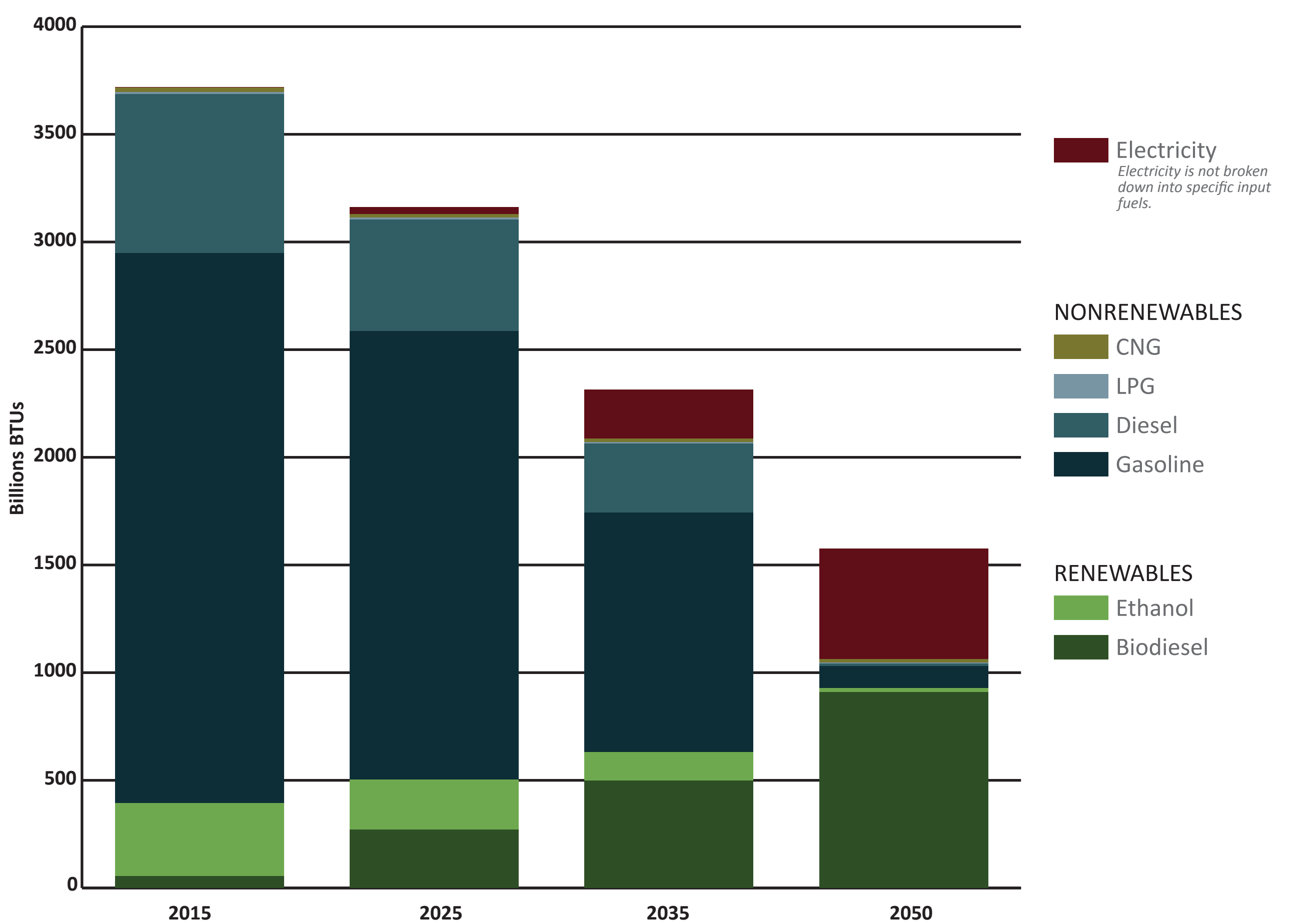
TRANSPORTATION

According to the LEAP model, transportation energy demand in the region falls significantly between 2015 and 2050. The demand decreases from approximately 3,719 billion BTUs to approximately 1,576 billion BTUs, a drop of about 58%. Gasoline, diesel, and ethanol demand equal 69%, 20%, and 9% of total transportation energy demand, respectively, in 2015. This demand decreases to 6%, <1%, and 1% of total transportation energy demand, respectively, in 2050. This is a drastic and ambitious shift in energy sources over time—arguably the biggest energy demand change in the model time frame. Per the model, the most considerable decreases in the use of gasoline and diesel energy sources occur between 2035 and 2050.

Electricity demand for transportation energy increases in a similarly dramatic fashion during the same time frame. In 2015, the model shows electricity demand at approximately 0.05% of transportation energy demand, increasing to approximately 33% by 2050.

Ethanol, compressed natural gas, and biodiesel are three other types of transportation energy sources that increase during the model time frame. Although the increases in demand for ethanol and compressed

FIGURE 4.7 LEAP PROJECTED REGIONAL TRANSPORTATION ENERGY DEMAND



natural gas are relatively modest, the growth in biodiesel demand is considerable (1.45% to 58% for transportation energy demand) and would mean an enormous increase in biodiesel gallons used in the region. This transition poses significant challenges, notably regarding the production and distribution (as well as the associated infrastructure) involved. These challenges are discussed in Section VI.

FIGURE 4.8 PERCENTAGE OF TOTAL TRANSPORTATION ENERGY DEMAND

	2015	2025	2035	2050
Electricity	0.05%	1.01%	9.81%	32.55%
Gasoline	68.65%	65.84%	48.06%	6.47%
Diesel	19.90%	16.38%	13.83%	0.76%
LPG	0.24%	0.25%	0.30%	0.32%
Ethanol	9.17%	7.37%	5.79%	1.14%
CNG	0.54%	0.57%	0.73%	1.02%
Biodiesel	1.45%	8.57%	21.48%	57.74%

The reasons for the shift in demand for transportation energy sources are briefly addressed in previous sections. The model accounts for level VMT despite a growing regional population. This—combined with the increased efficiency of gasoline vehicles and the anticipated electrification of the passenger vehicle fleet—results in increased electricity demand for transportation, yet decreased demand for gasoline (because electric vehicles use energy much more efficiently than gasoline vehicles). Meanwhile, heavy vehicles are anticipated to transition from diesel fuels to biodiesel during the model time frame. To meet regional transportation BTU targets, the region should support policies that would result in the following number of electric and biodiesel vehicles (Figure 4.9).

FIGURE 4.9 TRANSPORTATION FUEL SWITCHING TARGET - ELECTRIC AND BIODIESEL VEHICLES

	2025	2035	2050
Electric Vehicles	3,716	27,828	62,889
Biodiesel Vehicles	6,546	13,034	24,989

ELECTRICITY AND ELECTRICAL GENERATION

Electricity demand increases significantly in the region according to the LEAP model results. Electricity increases from 16% to 44% of total energy demand between 2010 and 2050. This is an increase from approximately 523 million kWh in 2010 to 1.06 billion kWh in 2050, which equates to approximately a doubling of electricity demand (Figure 4.10).

FIGURE 4.10 PROJECTED ENERGY CONSUMPTION

Total regional electricity consumption projected to increase by over 100% by 2050.

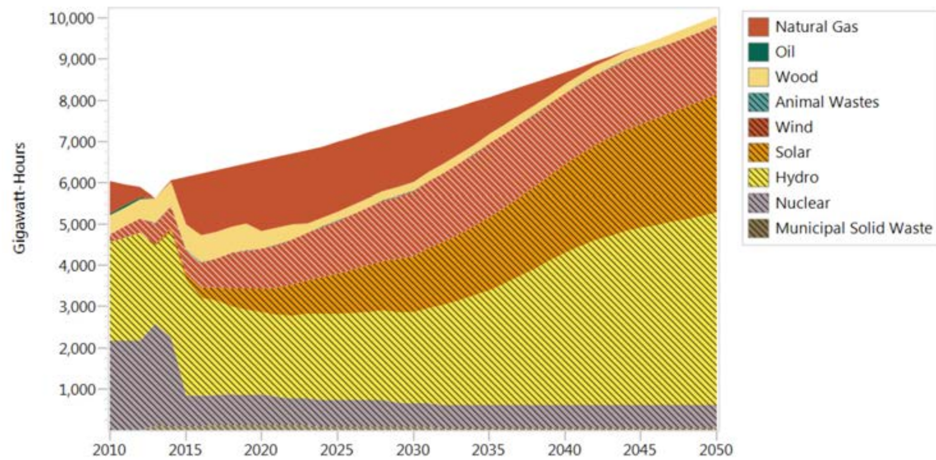
Figure 4.11 displays the projected sources of Vermont's electricity between 2010 and 2050 according to VEIC. Generation from renewable sources greatly expands during this time frame. Hydro generation continues to grow due to additional in-state generation. Hydro generation from Hydro-Québec used in both Vermont and the region stays relatively constant throughout the model time frame. Wind and solar generation also grow due to additional in-state generation. Nuclear electricity production shows the closure of the Vermont Yankee facility since 2010. The remaining nuclear electricity generation between 2010 and 2050 is from the Seabrook Station in New Hampshire. No new nuclear generation is anticipated. The use of fossil fuels for electricity consumed within Vermont is essentially zero by 2050.

REGIONAL GENERATION TARGETS

Based on the LEAP model and the Vermont Comprehensive Energy Plan, the Department of Public Service worked with regional planning commissions in Vermont to develop targets for new renewable generation. The solar and wind generation targets are based on the estimated needs to cover the region's energy use in 2050 within the context of the 90 x 50 goal. The hydro generation target is based on a study written by Community Hydro, a hydro advocacy organization. The study looks at generation potential at existing dam locations in the region that could be retrofitted to produce electricity.

Figure 4.12 displays the regional targets for renewable generation. The targets envision a low wind/high solar mix of renewable generation in the region. There is a 19 MW target for new wind generation and a 208.5 MW for new solar generation by 2050. The hydro generation target is 10 MW by 2050 based on the Community Hydro study findings. Interim targets for 2025 and 2035 have also been created by NRPC. These targets display a linear progression to the 2050 generation targets.

FIGURE 4.11 VERMONT PROJECTED ELECTRIC GENERATION SOURCES



The generation targets call for only the addition of renewable energy generation sources in the region and do not include using biomass as a source of electric generation. The reason biomass has been excluded is because the Vermont Comprehensive Energy Plan identifies limited opportunities for large-scale biomass electricity generation (such as McNeil generating plant in Burlington) in Vermont given the size, health, and composition of the state's forests.

FIGURE 4.12 GENERATION TARGETS

Year	New Wind (MW)	New Hydro (MW)	New Solar (MW)	Total New Generation (MWh)
2025	6.3	3.3	68.8	115,169.5
2035	12.5	6.6	137.6	230,338.9
2050	19.0	10.0	208.5	348,998.4

It is important to stress that the generation targets in Figure 4.12 represent only one possible way to derive 90% of total energy from renewable sources by 2050. The intent of the targets is to provide a sense of scale and a basis for discussion regarding the need for future electric generation, and about the siting of electric generation, in the region. Other electricity generation combinations may be possible. To guide the continuing conversation about the generation "mix," a regional MWh target has also been provided for each target year. This MWh target is based on the wind, solar, and hydro targets and each resources' capacity factor.

WIND GENERATION

The topic of wind generation within the region has become divisive within Vermont, and within the Northwest Region over the last several years. The NRPC remains committed to achieving the wind generation target of 19 MW of generation by 2050, but only through the construction of appropriately scaled wind generation facilities. Based upon the analysis in section V, NRPC generally does not have suitable locations for the construction of "industrial" or "commercial" wind facilities within the region and therefore finds this scale of development does not conform to this plan. For the purposes of this plan, NRPC will consider any wind facility with a tower height (excluding blades) in excess of 100 feet tall to be considered an "industrial" or "commercial" wind facility.

If a municipality through its local planning process identifies a preferred location(s) for an "industrial" or "commercial" wind facility within their boundaries, NRPC may consider amending this plan to account for this local preference. Coordination and consensus among neighboring municipalities will be a critical component of any process to amend the regional plan in this regard. Additionally, NRPC shall only consider such an amendment if the location, or locations, identified by the municipality do not include "known constraints" and mitigate impacts to "possible constraints" as identified in this plan.

REGIONAL MUNICIPAL ELECTRICITY GENERATION

The Department of Public Service "determination standards," or the standards required to achieve "enhanced energy planning," require that regional planning commissions develop targets for each municipality in the region. The NRPC has provided municipal renewable generation targets for solar generation, however wind targets have not been provided to municipalities and are instead considered a regional target. This is because of the limited amount of area in the region that is appropriate for wind generation per mapping completed by the NRPC (see Section V) and because of the NRPC's position regarding the construction of "industrial" and "commercial" wind facilities in the region.

Solar generation targets have been established based on municipal population and based on the availability of solar resources in the municipality established by the mapping completed by the NRPC. The municipal targets are not a mandate, but are a planning tool. They present one scenario in which NRPC and municipalities can achieve local, regional and state energy goals. A MWh target for each municipality has been provided to help each municipality have a conversation about the desired mix of renewable generation.

FIGURE 4.13 MUNICIPAL GENERATION TARGETS

Municipality	Solar Target 2025	Solar Target 2035	Solar Target 2050	MWh Target 2025	MWh Target 2035	MWh Target 2050
Northwest Region	68.8	137.6	208.5	115,169.5	230,338.9	348,998.4
Franklin County						
Bakersfield	2.7	5.3	8.1	4,262.5	8,525.0	12,916.6
Berkshire	6.4	12.8	19.4	8,806.2	17,612.4	26,685.4
Enosburgh	5.1	10.1	15.4	7,188.4	14,376.8	21,783.1
Fairfax	5.7	11.3	17.2	7,931.5	15,862.9	24,034.8
Fairfield	3.3	6.5	9.9	5,035.4	10,070.9	15,258.9
Fletcher	2.5	5.0	7.5	4,008.6	8,017.1	12,147.2
Franklin	4.5	9.0	13.6	6,507.4	13,014.8	19,719.4
Georgia	6.0	12.1	18.3	8,360.3	16,720.7	25,334.3
Highgate	3.9	7.8	11.8	5,746.5	11,493.0	17,413.6
Montgomery	1.7	3.4	5.2	3,073.3	6,146.5	9,312.9
Richford	2.7	5.4	8.2	4,276.2	8,552.3	12,958.1
Saint Albans City	1.7	3.3	5.0	2,984.8	5,969.5	9,044.7
Saint Albans Town	5.4	10.7	16.2	7,524.9	15,049.9	22,802.8
Sheldon	2.4	4.9	7.4	3,948.2	7,896.4	11,964.2
Swanton	5.9	11.8	17.9	9,408.3	18,816.7	28,510.1
Grand Isle County						
Alburgh	2.8	5.5	8.4	4,371.9	8,743.9	13,248.3
Grand Isle	2.2	4.4	6.6	3,650.3	7,300.7	11,061.6
Isle La Motte	0.8	1.6	2.5	1,969.0	3,938.0	5,966.6
North Hero	1.1	2.2	3.3	2,316.8	4,633.6	7,020.5
South Hero	2.2	4.3	6.5	3,606.1	7,212.1	10,927.4

RENEWABLE ENERGY CREDITS (REC)

The generation targets do not take into consideration renewable energy credits (RECs). RECs are legally created when a renewable energy generation facility is constructed. RECs can then either be "retired" by their owner or sold within the New England regional market. There is a contentious discussion in Vermont about the current REC system and whether or not the current system should continue to be used. This discussion is outside the scope of this plan. This is due, at least in part, to changes that are currently occurring in regards to the disposition of RECs, particularly for net-metering projects.

For the purposes of this plan, all new solar, wind, or hydro generation in the region shall be considered to be progress toward the regional generation targets. This is regardless of whether to RECs are retired in state or sold out of state.

FIGURE 4.14 CAPACITY FACTOR - NOT ALL GENERATION IS EQUAL

This section provides targets for new renewable generation from solar, wind, and hydro sources. However, there may be a preference for one kind of renewable energy generation vs. another type of renewable generation within the region. It is possible (but not simple) to "swap" one generation type for another (for example, the region could decrease the amount of solar in favor of more wind).

It is important to recognize the different types of renewable energy are not equal, and each have a different "capacity factor" (actual output over time). For example, a solar generation system with a capacity of 100 MW, in practice it won't produce energy at that level all the time because the sun is not available for 24 hours a day, 365 days a year. Solar in Vermont is generally considered to have a capacity factor of 14%. Wind generation in VT, on the other hand, has a capacity factor of roughly 35%, because winds are more consistent source of energy than the sun. This means that if a reigon or community was determined to reduce the number of wind generation needed to reach targeted by the LEAP model, significantly more solar would be needed to make up the lost capacity.

Capacity factors also exist for hydro (40%) and biomass generation facilities (47%).

SECTION V

V. STRATEGIES TO ACHIEVE REGIONAL TARGETS

V. STRATEGIES TO ACHIEVE REGIONAL TARGETS

The results of the LEAP model provide one scenario of future energy use in the Northwest region that ensures that state and regional energy goals are met. However, the LEAP model only provides targets for energy conservation and generation. It does not provide details about how the region may attain the targets set by the model.

Section V addresses how the LEAP targets will be attained by examining specific goals, strategies, and implementation steps that the region may use to progress toward the 90 x 50 goal and a more sustainable future.

This section is guided by the following statements of policy. The NRPC adopts these statements of policy to affirm it commitment to meeting state and regional energy goals and to satisfy the determination standards established by the Vermont Department of Public Service:

STATEMENTS OF POLICY

- NRPC supports conservation efforts and the efficient use of energy across all sectors.
- NRPC supports the reduction of in-region transportation energy demand, reduction of single-occupancy vehicle use, and the transition to renewable and lower-emission energy sources for transportation.
- NRPC supports patterns and densities of concentrated development that result in the conservation of energy.
- NRPC supports the development and siting of renewable energy resources in the Northwest region that are in conformance with the goals, strategies, and standards outlined in this plan.

Section V is separated into conservation and generation strategies. The conservation strategies look specifically at the topics of electricity conservation, weatherization, and transportation, while the generation strategies explore how and where generation may be developed in the region.

Only strategies and implementation steps that can be completed by the NRPC are included in this plan. Many other strategies and implementation steps could help the region attain its energy goals, but these strategies cannot be achieved by the NRPC and require the action of the state agencies, municipalities, public utilities, and private individuals. The goals, strategies, and implementation steps outlined in this section are meant to evolve over time to reflect continuing changes in the Northwest region.

A. CONSERVATION

ELECTRICITY CONSERVATION

Additional electric generation and conservation are both required to ensure that the region can attain the targets set in the LEAP model and in state statutes. The following goals focus on electricity conservation. Policy makers must find ways to further electricity conservation efforts while also increasing the overall use of electricity compared to other energy sources (especially for space heating and transportation). The failure of conservation efforts could severely hinder the region's ability to achieve the 90 x 50 goal.

FIGURE 5.1
RECAP: LEAP ELECTRICITY CONSERVATION TARGETS

To meet the 90 x 50 goal, LEAP establishes the following targets:

- Total regional electricity demand projected to increase by 100% by 2050.
- Regional electricity use for transportation projected to increase .05% in 2010 to 33% in 2050.
- Use of electric heat pumps to projected to account for 52% of single family home energy thermal energy demand by 2050.

Strategies used to address electric demand focus on supporting further development of energy storage systems (i.e., batteries), which can help address peak-demand issues associated with renewable generation, and on supporting existing programs that address the efficiency of appliances and lighting in Vermont. Smart rates, which use a rate structure that charges more for energy use during peak hours, can be used to reduce peak-hour electricity use.

1 GOAL

Use demand-side management to handle the expected doubling of electric energy demand in the Northwest region by 2050.

STRATEGIES

1. Encourage public utilities to move all customers to smart rates (i.e., charging higher rates during peak demand times), and encourage public utilities to mitigate any differential effects of smart rates on low-income customers.
2. Encourage legislature and/or public utilities to create programs that promote the use of energy storage systems. Using electric storage systems may reduce peak demand and provide emergency back-up power.
3. Support public utilities' efforts to increase customers' knowledge of their energy use. This may happen through increased outreach to and education of customers, but it may also occur through the use of new technology such as real-time monitoring of energy use.
4. Support the efforts of Efficiency Vermont to promote the selection and installation of devices, appliances, and equipment that will perform work using less energy (e.g., ENERGY STAR). This includes "load controllable equipment."
5. Encourage HVAC and weatherization providers to join the Building Performance Professionals Association of Vermont (BPPA-VT) to provide holistic energy advice to Vermonters.
6. Support and encourage school participation in Vermont Energy Education Program (VEEP) activities that foster an educational foundation geared toward energy savings.

IMPLEMENTATION

1. Work with GMP and regional partners to better promote the use of electricity conservation programs like the GMP eHome program and the Zero Energy Now program (in conjunction with GMP and BPPA-VT).
2. Support and provide outreach for EVT's customer engagement web portal and home energy reports.

THERMAL EFFICIENCY

Weatherizing structures to increase thermal efficiency is a very important part of reducing the region's energy demand by 2050. Outreach is one challenge that has limited building weatherization and the adoption of alternative heating systems in the region. An organization that can deliver both the message and the services doesn't exist. Businesses that deliver home heating oil, propane, and natural gas might be ideal for advocating weatherization efforts due to their connections to and frequent contact with business owners, homeowners, and landlords.

The amount of oil and gas being sold by most fuel dealers has declined in recent years, and further declines are expected. It may be in the interest of these companies—as well as the region—to begin transitioning their business

FIGURE 5.2
RECAP: LEAP THERMAL EFFICIENCY TARGETS

To meet the 90 x 50 goal, LEAP establishes the following targets:

- Total regional thermal energy needs for single family homes projected to drop by 9% by 2050.
- Use of cord wood to heat single family homes projected to decrease by only 20% by 2050.
- Use of electric heat pumps to projected to account for 52% of single family home energy thermal energy demand by 2050.
- Use of natural gas for single family home thermal energy expected to decrease by 68% by 2050.

models to become energy service providers (ESPs). Doing so will help them expand their current business model to include building audits, the sale of alternative heating systems, and other weatherization-related services. There may be value in working with regional partners to help orient area fuel dealers to this new market segment. Efficiency Vermont has created Efficiency Excellence Network, a program whereby contractors receive training in Efficiency Vermont–related efficiency programs and thus become eligible to be a "participating contractor," which offers benefits including receiving leads from Efficiency Vermont. However, more needs to be learned regarding this program to ensure that it is sufficient for both contractors and customers.

The availability of alternative, efficient heating sources is important to ensure greater thermal efficiency in the region. Heat pumps efficiently provide heat or supplement heat for residential and commercial buildings, particularly if the structure is airtight and well insulated. The NRPC will focus on coordinating with Efficiency Vermont and local public electric utilities to educate property owners about these heat pump systems and available incentives. At present, conversions to heat pump systems are not occurring at a high rate in the region. This may be due to high costs and inadequate incentives. The NRPC supports efforts to reduce the costs of converting to heat pump systems.

Other weatherization efforts can be completed by individual homeowners and businesses, or through several local organizations, both public and private, that provide weatherization services in the region. CVOEO provides full-service weatherization programs for low-income homeowners, from audits to financing to contracting. The organization has conducted hundreds of home energy audits and overseen many weatherization projects in the region, but it has not had a strong presence in the region compared to Chittenden County.

Efforts to weatherize existing structures should target the region's downtowns and village centers. These areas contain more residential and commercial units and include a very high percentage of rental housing, much of it in older houses that have been converted into multi-family units. Incentives for landlords to undertake energy efficiency improvements and install new alternative heating systems are limited, but the renters or landlords of these units could benefit from reduced heating expenses through such improvements. The region should also assess whether specific incentive programs should be created for older structures in rural areas, considering that many buildings in the region are located outside of existing downtowns and village centers.

The energy efficiency of newly constructed structures can be addressed through regulatory means. Efficiency Vermont recently adopted a "stretch" code for commercial and residential structures for use in Vermont. A stretch code has higher energy standards than the currently required Residential Building Energy Standards and the Commercial Building Energy Standards. The stretch code currently applies to all residential projects that are subject to Act 250 and can be used by commercial projects to demonstrate compliance with Act 250 Criteria 9(F). A stretch code can be adopted by municipalities to apply to new construction and rehabilitation of structures. Some municipalities may be interested in adopting a building code. Policy makers should remain aware that adoption of a stretch code or building code may increase up-front costs for new construction and renovations.

The potential of geothermal heating, also known as ground-source heat pumps, in the region is relatively unknown. However, the long-term economic benefits of utilizing such systems should be carefully considered by any multifamily residential, commercial, institutional, or industrial developers in the region and should be supported when such systems are feasible.

Several facilities in the region currently use biomass heating, but there aren't any district biomass heating facilities in the region (where a central biomass facility heats several structures). The use of biomass district heating at appropriate sites is critical to meeting thermal energy targets. The NRPC has developed a list of candidate sites in the region (see Figure 5.3. The list includes large institutions, industrial parks, and areas of dense development are prime candidates). NRPC will work with regional partners to investigate the feasibility of district heating and combined heat and power at the identified candidate sites and in the region at-large.

FIGURE 5.3 POTENTIAL DISTRICT HEATING SYTEM SITES

Municipality	Site Description: Potential District Heating System Sites
Alburgh	Town/Village Office/ surrounding village/industrial park
Bakersfield	Town Office/School and surrounding village
Berkshire	Town Office/School and surrounding village and East Bershire Village
Enosburgh	West Enosburgh Village
Fairfax	Village and School
Fairfield	Fairfield Village and East Fairfield Village
Fletcher	Binghamville Village and School
Franklin	Expand school sytem to village and East Franklin/East Berkshire
Grand Isle	Expand school sytem to village and Island Industrial Park
Highgate	Highgate Springs/Tyler Place and East Highgate Village
Isle La Motte	Village and School
Montgomery	Montgomery Village and Center Village
North Hero	Village
Richford	Village
St. Albans Town	St. Albans Bay Village
Sheldon	Sheldon Springs Village/School/Mill and Sheldon Village
South Hero	South Hero Village and Keeler Bay Village

2 GOAL

To reduce annual regional fuel needs and fuel bills for heating structures, to foster the transition from non-renewable fuel sources to renewable fuel sources, and meet regional targets for the weatherization of residential households and commercial establishments.

STRATEGIES

1. Support efforts to transfer residential and commercial sectors from heating oil and propane to biofuels, biomass, and electric heat pumps.
2. Support changes that create simplified financing for fuel switching that links bill payments, home equity, and public sector incentives.
3. Support the use of geothermal heating and cooling systems for new residential and commercial construction in the region.
4. Support programs that provide assistance to low-income households to weatherize their homes.
5. Endorse the use of Downtown and Village Tax Credit programs to complete weatherization projects in the region's designated areas.
6. Support the creation of additional sustainable forest industries and biomass-related industries in the region to supply local biomass users.
7. Support greater state enforcement of existing state energy codes (e.g., RBES and CBES) to ensure that all renovations of existing structures are energy efficient and meet current standards.

IMPLEMENTATION

1. In partnership with municipalities, utilities, and other regional stakeholders, educate owners of rental housing about weatherization and funding opportunities, particularly in village areas. This may include investigating the creation and implementation of a revolving loan program to fund weatherization improvements to rental properties in the region.
2. Study and assess the feasibility of biomass district heating and/or combined heat and power systems in the region, particularly in areas of the region with large institutions.
3. Work with the county forester and state wood utilization forester to implement strategies identified in the Northwest Region Forest Stewardship Plan to encourage the sustainable development of wood products industries in the region. This includes utilizing low-quality wood locally for pellet production.
4. Provide technical assistance to municipalities to revise their zoning regulations to allow and encourage the location of forestry- and biomass-related industries in appropriate locations.
5. Provide outreach to municipal officials and contractors regarding the use and enforcement of residential and commercial building energy standards for all new construction, including new stretch codes.
6. Strategize with CVOEO about ways to increase the use of the weatherization assistance programs in the Northwest region.
7. Work with Efficiency Vermont to assess the effectiveness of the Efficiency Excellence Network in order to ensure that the program is effectively serving both consumers and contractors, and working toward state energy goals. Work with local fuel dealers, and other regional stakeholders such as Franklin County Industrial Development Corporation (FCIDC) and Lake Champlain Island Economic Development Corporation (LCIEDC), to encourage fuel dealers to become energy service providers.

FIGURE 5.4
RECAP: LEAP TRANSPORTATION ENERGY TARGETS

To meet the 90 x 50 goal, LEAP establishes the following targets:

- Total regional transportation energy demand projected to decrease by 58% by 2050.
- Gasoline and diesel demand projected to drop from 89% of demand in 2015 to 7% of demand in 2050.
- Electricity, ethanol, and biodiesel projected to account for 91% of transportation energy demand in 2050.

TRANSPORTATION

Transportation is an area that the NRPC has long been actively involved in and one that will greatly influence the region's ability to meet the targets set by the LEAP model. The state statute (Title 24 Chapter 117) enables the NRPC to have a considerable influence on land use and transportation issues in the region, especially in the Act 250 process and through the implementation of the Transportation Planning Initiative (TPI), a program through which the Vermont Agency of Transportation coordinates policy development and planning with regional planning commissions.

The following three goals are focused on three different issues that pertain to transportation: compact development, rail use, and fuel type. The compact development goal is focused on issues that the NRPC is already actively involved in promoting through the implementation of the Northwest Regional Plan: additional regional development in or near existing growth centers and villages, increased bicycle and pedestrian infrastructure, and increased access to public transportation. Compact development located in or adjacent to existing growth centers has the potential to significantly decrease regional transportation energy demand and costs by reducing VMT and potentially increasing the use of public transportation. The increasing use of rail in the region, by both passengers and freight, will also decrease energy demand and costs. Finally, transitioning from fossil fuels to renewable, cleaner sources of energy equates to more efficient energy use, but it will require addressing infrastructural challenges that come with changing fuels.

3 GOAL

Hold VMT per capita to 2011 levels through reducing the share of single-occupancy vehicle (SOV) commute trips by 20%, doubling the share of pedestrian and bicycle commute trips, increasing public transit ridership by 110% by 2050, and focusing regional development in or near existing growth centers and villages.

STRATEGIES

1. New public and private transportation infrastructure shall be designed and built to interconnect with existing adjacent land development(s) and with adjacent lands that have the potential for future land development. This will ensure more efficient traffic patterns and bicycle/pedestrian movement within the region.
2. Support efforts to make regional transit authorities like Green Mountain Transit statutory parties to all Act 250 applications in the region.
3. Require a public transit stop for all residential and large commercial land developments subject to Act 250 if a stop is not currently available.
4. Support planning for municipal streetscape improvements and on-street parking in state-designated village areas. This may require some cooperation with the Vermont Agency of Transportation in some villages due to the existence of state roads.
5. Support municipal efforts to plan for future compact development that includes opportunities for walking, use of public transportation, and other forms of transportation that are an alternative to the SOV. Municipal efforts may include capital budgeting, streetscape plans, revitalization plans, or adoption of an "official map" (as outlined in 24 V.S.A. Chapter 117, to identify future municipal utility and facility improvements such as road or recreational path rights-of-way, parkland, utility rights-of-way, and other public improvements) by the municipality.
6. Support changes to public transportation funding in the state that alters how public transit routes are funded. Support efforts for state funding of public transportation routes that serve stops on federal and state highways (in a similar manner to the existing highway funding system) and require municipal funding primarily for public transportation routes that serve local roads.
7. Investigate "cash out" programs that enable large employers to allow employees to "cash out," or obtain cash in exchange for the ability to park at their job site. Work with large regional employers to determine if such a model is viable in the region.

IMPLEMENTATION

1. Utilize Complete Streets implementation policies, as outlined in the Transportation section of the regional plan, when reviewing Act 250 applications within the region to ensure greater connectivity of bike and pedestrian networks within the region's city, villages, regionally designated growth centers, and transitional areas. This includes working with municipalities to adopt Complete Streets policies.
2. Study current park-and-ride capacity and identify future park-and-ride sites within the region in cooperation with VTrans. Support efforts to triple the number of park-and-ride locations in the region by 2050 as outlined in the Vermont Comprehensive Energy Plan.
3. Continue active participation with the Green Mountain Transit Board of Commissioners and support increased levels of public transportation service to the Northwest region.
4. Work with regional municipalities to investigate and institute local zoning changes that allow for greater residential density within regional downtowns, growth centers, and villages.
5. Provide education and technical assistance regional municipalities to decrease parking requirements in

[6] Vermont State Rail Plan – 2015, p.80.

their zoning regulations and to allow on-street parking in villages.

6. Develop ways to incentivize capital budgeting, official maps, and other planning efforts by municipalities to focus on expanding public infrastructure (including water and wastewater infrastructure) for future compact development.
7. Investigate methods that discourage sprawl and other types of land development, including subdivision, that threaten the regional working landscape and potentially increase transportation energy use.

4 GOAL

Quadruple region-based passenger rail trips (3,592/year in 2013), and double rail freight tonnage in the region (about 1,000 tons in 2011) by 2050.[6]

STRATEGIES

1. Support the extension of Amtrak Ethan Allen Express rail service from Rutland to Burlington, and bring Vermonter service to Montreal.
2. Support increased rail freight service to the region.

IMPLEMENTATION

1. Be an active participant in anticipated VTrans feasibility studies concerning commuter rail service between St. Albans and Montpelier to Chittenden County.
2. Work with municipalities to identify future passenger station sites in the region.
3. Work with New England Central Railroad, regional development corporations, VTrans, the Chittenden County Regional Planning Commission (CCRPC), the City of Burlington, the City of St. Albans, and other regional partners to study regional constraints and opportunities for increased freight traffic within the Northwest region.

5 GOAL

Increase the share of renewable energy in transportation to 10% by 2025 and to 90% by 2050 by increasing the use of renewable and less carbon-intensive fuels, such as electricity, biofuels, and compressed natural gas.

STRATEGIES

1. Require all commercial, industrial, and multifamily developments subject to Act 250 to provide electric vehicle (EV) parking spots and infrastructure to supply electricity for charging.
2. Continue to support Vermont Agency of Commerce and Community Development (ACCD) grant opportunities for municipalities to install electric charging stations, infrastructure, and supply in designated areas.
3. Support financial incentives for those that develop direct current (DC) fast electric charging stations.
4. Support the development and creation of biofuels production and distribution infrastructure in the region.
5. Support the efforts of municipal fleet operators to replace inefficient vehicles with more efficient vehicles, including heavy-duty vehicles that operate on biofuels.

IMPLEMENTATION

1. Work with VEIC and municipalities to identify local zoning barriers to allow for electric vehicle charging stations.

2. Partner with Drive Electric Vermont, LCIEDC and FCIDC to develop ways to celebrate and showcase employer investments in EV-friendly workplaces and new, innovative transportation programs in the region.
3. Work with municipalities to acquire grant funding for the installation of DC fast charging infrastructure at locations strategically located along major travel corridors, in transit hubs such as park-and-ride lots, and in designated downtowns and villages.
4. Work with state and regional partners, including UVM Extension, to assess the viability of using switchgrass and other crops in the production of biodiesel fuels.

OTHER STRATEGIES

There are several other strategies that can be used by the region to accomplish the goals of this plan that don't fit into major categories. Creating more municipal energy committees in the region will provide the support of additional regional volunteers to work toward accomplishing state, regional, and local energy goals and provide direct contact with citizens in each municipality. Municipal energy committees can aid municipal planning commissions and selectboards in writing energy chapters of municipal plans and accomplishing implementable projects for the municipality that are identified in the municipal plans. The NRPC will also work with Energy Action Network (EAN) to promote the use of the Community Energy Dashboard, an online tool that, according to EAN, will "enable communities to understand their energy use and make clean energy choices and investments across all energy sectors: electric, thermal, and transportation."

Support for the burgeoning local foods movement can also aid the region in meeting the goals of the plan. Increased production and consumption of local foods reduces the costs associated with transporting food to and from the region.

6 GOAL

Increase the number of municipal energy committees in the Northwest region.

STRATEGIES

1. Support the creation of municipal energy committees in the Northwest region.

IMPLEMENTATION

1. Advocate for the creation of municipal energy committees in the region, and provide municipalities with technical support when creating such committees.
2. Work with Energy Action Network to promote use of the Community Energy Dashboard by municipal planning commissions and energy committees to aid municipal energy planning work.

7 GOAL

Increase local food production and consumption.

STRATEGIES

1. Support the efforts of the Healthy Roots Collaborative and other regional organizations focused on expanding the local food system.

IMPLEMENTATION

1. Implement the existing language in the Northwest Regional Plan that calls for limiting the loss of primary agricultural soils and active farmland. In addition, implement the existing language in the Northwest Regional Plan that calls for mitigating the impacts to primary agricultural soils and active farmland when these areas are to be developed, including the construction of renewable energy generation facilities.
2. Work with regional municipalities to institute local zoning changes that provide additional protections to productive agricultural land and primary agricultural soils.

B. GENERATION

As seen in the results of the LEAP model, achieving the state's energy goals will take more than improvements to energy efficiency and reductions in energy use. It will also require additional energy generation, particularly of electricity.

ELECTRICITY GENERATION

Electricity generation strategies focus on continued support of existing state programs that encourage renewable generation development such as net-metering programs and the Standard Offer Program. Strategies also focus on the creation of more accessible, internet-based information for electricity generation developers and for the general public regarding grid limitations and the Certificate of Public Good process. Implementation will primarily focus on the NRPC aiding municipal energy planning efforts, which includes working with municipalities to identify preferred locations for future generation development in municipal plans. It also includes working with municipalities to identify and develop effective policies to protect significant cultural, historical, scenic, or natural resources. The development of these policies can address many of the concerns that communities and citizens in the region have expressed with regard to solar and wind generation facilities. The NRPC will work with municipalities to ensure that municipal plans receive an affirmative "determination" from the Northwest Regional Planning Commission.

The NRPC would like to further investigate the public benefits provided to municipalities either directly from renewable energy generation developers or as a condition of a Certificate of Public Good. The NRPC is interested in determining whether the current system creates equitable outcomes or if it can be improved to provide greater equity to all municipalities impacted by a renewable energy generation facility, even if the facility is only located in one municipality. This is particularly relevant when discussing "industrial" or "commercial" wind generation facilities.

Lastly, the NRPC finds it to be essential that all decisions regarding new renewable energy generation facilities take into consideration concerns about health and safety. The noise, vibration, glare, or other impacts from generation facilities shall be mitigated by developers to ensure that such impacts do not have an undue adverse impact upon neighboring properties. This includes any impacts that pertain from electric or magnetic fields, or from construction activities associated with the facility.

FIGURE 5.5
RECAP: LEAP ELECTRIC GENERATION ENERGY TARGETS

To meet the 90 x 50 goal, LEAP establishes the following targets:

- Total regional electricity consumption expected to double between 2010 and 2050.
- Regional generation needs project to be met by development of 208.5 MW of new solar generation, 19 MW of new wind generation, and 10 MW of a new hydro generation.

8 GOAL

Increase the renewable energy generation capacity in the Northwest region to include an additional 208.5 MW of new solar generation capacity, 19 MW of new wind generation capacity, and 10 MW of new hydro generation capacity by 2050.

STRATEGIES

1. Support the development of individual home and community-based renewable energy projects in the region through the following programs: Vermont Small Scale Renewable Energy Incentive Program, Clean Energy Development Fund, and tax and regulatory incentives including net-metering.
2. Support changes to net-metering rules and other regulatory tools to provide financial incentives in order to encourage siting of renewable generation facilities on the built environment (such as parking structures and rooftops) and other disturbed lands (such as former landfills, brownfields, or gravel pits). Support changes to net-metering rules that disincentivize development on land identified in this plan as a location with known and possible constraints. Encourage multiple uses in conjunction with the development of renewable generation facilities, such as grazing of livestock, recreation, or parking.
3. Continue to support the Standard Offer Program (Figure 5.6) to foster deployment of diverse and cost-effective renewable energy resources, and support the evaluation of this program after 2022 to determine if the program should be extended or changed.
4. Support the creation of "solar maps," like the maps developed by Green Mountain Power, to make interconnection information available to the general public and accessible online. Local electric utilities could partner with the NRPC to create these maps.
5. Support efforts by local utilities and private individuals to maintain and upgrade existing renewable electric generation facilities in the Northwest region and the state.
6. Support the development of additional methane digesters on farms in the Northwest region, especially those that utilize manure from multiple farms and/or food waste.
7. Support the creation of incentives for locating new renewable energy generation facilities within a half-mile of three-phase distribution line or electric transmission line infrastructure. Ensure new transmission lines and three-phase power lines associated with renewable energy projects do not create forest fragmentation or have an undue adverse impact on necessary wildlife habitats, ecological systems, and water and/or air quality.

FIGURE 5.6 STANDARD OFFER PROGRAM

In 2009, the Vermont legislature created the Standard Offer Program, which is designed to encourage the development of renewable energy generation facilities by establishing prices for new renewable energy generation facilities based on the cost of developing a project plus a reasonable rate of return. Through the program, renewable energy developers can receive a long-term, fixed-price contract for renewables facilities up to 2.2 MW in size. The original program cap was 50 MW, which was amended to 127.5 MW in Act 170 of the 2011–2012 legislative session. Facilities to meet the program cap will be built over time through 2022. All facilities to be built through the program are required to receive a Certificate of Public Good from the Public Service Board.

IMPLEMENTATION

1. Apply to the Public Service Department to have the Northwest Regional Energy Plan receive an affirmative determination of energy compliance in order to ensure that the plan is given greater weight in the Certificate of Public Good process.
2. Provide assistance to municipalities to identify potential areas for development and siting of renewable energy generation facilities. Work with municipalities to identify areas, if any, that are unsuitable for siting renewable energy generation facilities or particular categories of renewable energy generation

facilities. Ensure that municipalities include this information in their municipal plans and work to ensure that municipal plans are given an affirmative regional determination of energy compliance by the NRPC so that municipalities may receive "substantial deference" in the Certificate of Public Good process.

3. Work with municipalities to specifically identify significant cultural, historical, or scenic resources in their communities. Work with municipalities to protect these resources through the development of a statement of policies on the preservation of rare and irreplaceable natural areas and resources as well as scenic and historic features and resources, as required by 24 V.S.A. 4382, and include such policies in municipal plans.
4. Identify, catalog, and map potential brownfield sites and other previously disturbed sites in the region that may be appropriate for future solar generation facilities.
5. Investigate public benefits provided to municipalities either directly from renewable energy generation developers or as a condition of a Certificate of Public Good. Assess if the current system is equitable to all municipalities impacted by a renewable generation facility, or if the current system can be improved to provide greater equity to all municipalities impacted by a renewable energy generation facility.

ENERGY RESOURCE MAPS AND THE PUBLIC SERVICE BOARD

The Vermont Public Service Board has jurisdiction over all energy generation facilities that are a part of the public electrical grid. The board provides its approval to an energy generation facility by issuing a Certificate of Public Good to that facility. A proposed energy generation facility must meet the criteria found in 30 V.S.A. §248 in order to receive a Certificate of Public Good. The role of regional planning commissions in the Certificate of Public Good process is outlined in 30 V.S.A. §248(b)(1), commonly referred to as Section 248:

> *With respect to an in-state facility, will not unduly interfere with the orderly development of the region with due consideration having been given to the recommendations of the municipal and regional planning commissions, the recommendations of the municipal legislative bodies, and the land conservation measures contained in the plan of any affected municipality.*

In addition, regions and municipalities may receive "substantial deference" instead of "due consideration" during a Certificate of Public Good proceeding if the region or municipality has received an affirmative determination of energy compliance. This potentially provides regional and municipal plans with greater weight before the Public Service Board.

In recent Certificate of Public Good proceedings, the Public Service Board has frequently found that municipalities and regional planning commissions have not had language, or maps, that have provided for "land conservation measures" that are specific and/or well-reasoned enough to have a real impact on the siting of renewable generation facilities through the Certificate of Public Good process. Through the creation of the following regional energy generation maps, the NRPC is planning for the development of additional renewable generation facilities in the region (using the LEAP model targets as a basis of conversation) and providing for clarity regarding regional land conservation measures and specific policies.

The NRPC has developed renewable energy generation maps for four renewable energy resources: solar, wind, hydro, and biomass. The following subsection provides a basic explanation of how the maps were created and how they are intended to be used and/or integrated into the Northwest Regional Plan. This is followed by subsections explaining the intent behind the maps of each renewable energy resource. Maps created while developing this project are provided in Appendix C.

ENERGY GENERATION MAPS METHODOLOGY

NRPC staff worked with other regional planning commissions, the Department of Public Servie and other project partners in the state to develop criteria that would inform and guide the siting of renewable energy generation facilities. The NRPC and the other RPCs each created maps that provide a macro-scale look at different factors that impact the siting of facilities.

Spatial data showing generation potential, which was originally compiled by the Vermont Sustainable Jobs Fund, formed the basis of the NRPC's mapping exercise. The NRPC then identified conservation resources in the region that were considered worthy of protection from development. These resources were selected through conversations with project partners, analysis of the current Northwest Regional Plan, and public input. Known and possible constraints were subsequently identified.

Known constraints are conservation resources that shall be protected from all future development of renewable generation facilities. Possible constraints are conservation resources that the NRPC intends to protect, to some extent, from the development of renewable generation facilities. The presence of possible constraints on a parcel does not necessarily preclude the siting of renewable generation facilities on a site. Siting in these locations could occur if impacts to the affected possible constraints are mitigated, preferably on-site.

When considering locations for future renewable energy generation facilities, the NRPC would like developers to target regional locations with generation potential that do not contain any known or possible constraints. These areas are shows as "prime" on the renewable energy generation maps in Appendix C. Further, if prime areas are located within a half-mile of existing transmission or three-phase distribution infrastructure, the NRPC finds that these areas should be given further preference by the Public Service Board. Areas with high generation potential but that also contain possible constraints are identified on the regional energy generation maps as "base" areas. These areas may be appropriate for the development of renewable energy generation facilities, but they should be given less preference than prime areas.

FIGURE 5.7 ROOFTOP SOLAR – POTENTIAL CAPACITY

NRPC has appoximated potential solar generation from both commercial/industrial and residential rooftops in region. The analysis estimates that 25% of all residential, commercial and industrial structures may be correctly side for solar generation and have actually installed solar panels. NRPC then estimated that a typical residential system would generate 4 kW of electricity and that a typical commercial or industrial system would generate 20 kW of electricity.

Based on these assumptions, the Northwest region could potentially generate 28.8 MW of electricity from rooftop solar generation. About 21.6 MW would come from residential rooftops and 7.2 MW would come from commerical and industrial rooftops.

Additional development of structures in the region would provide additional generation capacity. While these assumptions allow for only rough approximations, they do provide a sense that rooftop solar may be a viable way to meet at least a portion of the regional generation targets.

A full list of the known constraints and possible constraints identified by the NRPC for each type of generation (solar, wind, biomass, hydro), along with information about data sources, may be found in Appendix B.

It should be noted that the energy generation maps are based on the best available geographic data. They are macro-scale maps meant to guide the development of renewable generation facilities. The NRPC expects that some applicants or parties will be able to provide on-site information that is more accurate regarding the presence of known and/or possible constraints. This information will need to be taken into account by the NRPC and the Public Service Board when reviewing applications for renewable generation facilities to ensure that known constraints are not impacted and to ensure that impacts to possible constraint areas are mitigated. The energy generation maps are not intended to be used without the accompanying goals and policies of the NRPC contained in this plan.

NORTHWEST REGIONAL ENERGY GENERATION MAPS AND STANDARDS

Solar Generation Facilities - LEAP Generation Target 208.5 MW

The NRPC has determined that several types of locations in the region should be targeted for future solar generation. These locations are not shown on the solar generation maps, yet are considered "preferred locations" by the NRPC. In no particular order, these preferred locations include the following:

- Rooftops of structures
- Former landfill sites
- Brownfield sites and Superfund sites that are not located in a state or regionally designated downtown or village center
- Abandoned and active earth resource extraction sites (sand pits, gravel pits, rock quarries)
- Surface parking lots

FIGURE 5.8 SOLAR POTENTIAL DIAGRAM

The preferred locations are often a good fit for solar generation facilities (provided that site-specific standards are met). These sites are typically underutilized (e.g., former landfill sites, brownfield sites, and earth resource extraction sites) or are already heavily developed (e.g., rooftops and parking lots). Solar siting should be prioritized in these locations.

There currently is a lack of geographic data that accurately shows parking lots, former landfills, existing and abandoned quarries and potential brownfield locations in the region. NRPC is actively working to develop this data to help provide additional guidance for future development of solar facilities.

The targets developed by the Department of Public Service and the regional planning commissions indicate that approximately 208.5 MW of solar will be needed in the region by 2050 to meet the 90 x 50 goal. Although this amount seems considerable at first glance, upon analysis the target seems much more achievable for the region. Acreage data from the solar regional energy generation maps shows that there are approximately 24,184 acres of "prime" solar in the region after land with known and possible constraint areas are removed.

To generate 208.5 MW of solar generation, approximately 1,459.5 acres are required given today's technology (approximately 7 acres per 1 MW of generation). The 1,459.5 acres needed to meet the target constitute 5.31% of the total acreage of prime solar (with known and possible constraints removed) and 0.32% of the total land area of the entire Northwest region. Therefore, the NRPC finds that the solar target is attainable.

Many parts of the region are suited to solar development, but western Franklin County and Grand Isle County stand out. Western Franklin County is where the greatest regional electrical demand is located, so developing solar in this area is ideal in terms of electrical grid efficiency. Grand Isle County has less electrical demand and may also have some grid capacity restrictions based on comments made by the public electric utility serving the area, Vermont Electric Cooperative. Both areas also have a substantial amount of area that is prime solar yet also contains a possible constraint. In many of these locations, the possible constraint on the site is typically primary agricultural soils or protected lands.

Based on conversations with the Department of Public Service and other RPCs, it is the NRPC's understanding that it is generally less expensive to interconnect ground-mounted solar when it is close to existing transmission lines or three-phase distribution lines. The NRPC analyzed the amount of prime solar acres located within a half-mile of transmission lines and three-phase distribution lines. The NRPC's analysis found about 10,259 acres of prime solar (with known and possible constraints removed) within a half-mile of transmission or distribution infrastructure. It is in these areas that the NRPC would like to target future solar generation (if generation is not to be located in "preferred locations," as identified above).

There is more electric infrastructure in southern and western Franklin County than in other parts of the region. These same areas also are close to Chittenden County, a region that may have a difficult time meeting its generation targets due to its considerable electric demand and smaller land mass on which to site generation facilities. There is some concern that southern and western Franklin County may see more than its fair share of new solar generation facilities. However, the NRPC understands that siting facilities in these areas will provide landowners with financial benefits and that it may be necessary to provide electricity to meet state economic and energy needs.

Wind Generation Facilities - LEAP Generation Target 19 MW

The Department of Public Service sets a lower target for wind generation than solar generation in the region. The Northwest region is already home to half of the Georgia Mountain Community Wind project, which generates approximately 10 MW of electricity (the electricity generated is purchased by Burlington Electric). The generation targets call for an additional 19 MW of new wind generation in the Northwest region by 2050.

Prime wind generation data is available from the Vermont Sustainable Jobs Fund. Wind potential at wind "hub" heights of 50 meters (164 feet) and 70 meters (230 feet), as provided in the dataset, have been regionally mapped (See Appendix C).

Smaller, net-metering scale wind generation may be possible throughout most of the region at lower elevations. More information is needed regarding the viability and affordability of these systems, but generally the NRPC views these types of facilities favorably provided that impacts to known constraints are avoided, impacts to possible constraints are mitigated, and site-specific concerns are addressed. NRPC does not support the construction of "industrial" or "commercial" wind generation facilities within the region. For more information please see Section IV.

The regional wind generation maps in Appendix C do not show many wind generation areas with high generation potential. This is due to the existence of known constraints, most notably conservation habitat design blocks and source protection areas for public water supplies. This is consistent with existing language in the Northwest Regional Plan.

As stated earlier, known constraint areas have been removed from the map and are not suitable for renewable generation development. The remaining portion of the region with considerable wind generation potential constitutes a relatively small area that can effectively generate electricity from wind. Meeting the 19 MW target for new wind generation in areas without known or possible constraint areas may be a challenge.

To compensate for the challenge of meeting the wind generation target, the NRPC may need to plan for additional generation from other renewable sources—most likely, solar. Hydro, biomass, and even geothermal sources would probably be insufficient to produce the amount of electricity required to keep the region on track to meet the 90 x 50 goal.

There has been an ongoing call from concerned citizens and advocacy groups for site-specific standards for large-scale wind generation facilities in Vermont, especially regarding sound. Concerns have also been raised regarding aesthetics, surface water degradation, and the "flicker effect" (caused by moving turbine arms in front of the sun). The Public Service Board has been tasked with creating sound standards for wind generation facilities per Act 174. These standards shall be adopted by the board by July 1, 2017. The NRPC finds that the other potential concerns raised regarding wind generation facilities should continue to be studied by the Department of Public Service and the Public Service Board but are not addressed by this plan.

Hydro Generation Facilities - LEAP Generation Target 10 MW

The LEAP model results follow the guidance from a study commissioned by the Department of Public Service. The study found that 10 MW of new hydro generation is possible in the region. This generation would come from 16 existing dams in the region that are not currently producing electricity (see Figure 5.9) and from retrofits to existing dams to generate additional electricity at those sites. Existing dams that are not currently producing electricity could only account for approximately 1,019 kW (or about 1 MW) of generation capacity. According to the Department of Public Service, most dams need to provide at least 500 kW of generation capacity to be cost effective. Therefore, it seems unlikely that many of the smaller existing dams in the region would be refitted in the future to provide generation capacity. It also means that the majority of untapped hydro potential in the region is located at existing dam sites that are already producing electricity.

The growth of hydro generating capacity in the region is desirable because of the positive effect it may have on baseload electrical production (according to the Department of Public Service, most new in-state hydro

FIGURE 5.9 EXISTING HYDRO FACILITIES WITH GENERATION POTENTIAL

Name	Stream	Owner	Year Built	Hazard Classification	Potential kW
Georgia-3	Lamoille River-TR				5
Sheldon-2	Goodsell Brook				0
Webster (Lower)	Black Creek				46
Mud Creek	Mud Creek	State of VT - DFW	1957	Low	8
Johnsons Mill	Bogue Branch	Perry Cooper	1928	Low	5
Trout Brook Reservoir	Trout Brook	Town of Enosburg		Low	4
Bullis Pond	Rock River	Town of Franklin	1843	Low	9
Lynch	Abenaki Bay-TR	Karen Lynch	1969	Low	1
Browns Pond	The Branch	Jamie Rozzi	1920	Low	29
Fairfield Pond	Dead Creek-TR	Swanton Light & Power Department		Low	15
Lake Carmi	Pike River-TR	State of VT - DEC	1970	Low	14
Fairfield Swamp Pond	Dead Creek	State of VT- DFW	1967	Low	18
Swanton	Missisquoi River	Swanton Light & Power Department	1920	Low	850
St. Albans North Reservoir	Mill River	City of St. Albans	1895	High	6
St. Albans South Reservoir	Mill River	City of St. Albans	1910	Significant	6
Silver Lake	Beaver Meadow Brook-TR	City of St. Albans	1912	Significant	3
				Total Potential kW	**1,019**

can't be considered baseload power because the dams are required to operate as "run-of-river" and therefore aren't always a reliable source of generation in the summertime). Hydro generation is a more consistent and reliable source of renewable generation than both wind and solar generation. Investment in existing and new hydro sites should meet environmental standards established by the State of Vermont Agency of Natural Resources.

The NRPC supports continued import of hydro-generated electricity from the New York Power Authority projects in the St. Lawrence River Valley and from Hydro-Québec. However, the commission is concerned about the long-term price of electricity from these projects. In recent years, several projects have been proposed in Vermont and New York to construct privately owned DC transmission lines from the Canadian border to various points on the New England grid, including several locations in Vermont. These transmission lines will allow additional electricity to be transmitted to the United States from Canada, primarily from Hydro-Québec, which will subsequently be sold on the ISO New England grid. This potentially will mean that Vermont public utilities will be competing with public utilities from southern New England for electricity generated by Hydro-Québec. The NRPC is concerned that this increased competition with public utilities from outside the state may lead to higher wholesale electricity costs and higher electricity rates for Vermonters. Although the region and state may need to continue to rely on Hydro-Québec for some hydro generated electricity to ensure that the 90 x 50 goal is met, the NRPC finds additional in-state renewable generation to be preferable.

The NRPC generally supports hydro generation in the region—but due to the regulatory complexity of permitting dams, the cost of refurbishing existing dams, and the potential effects that dams may have on wildlife, it finds that meeting the LEAP target of 10 MW of new generation capacity by 2050 would be tremendously difficult. The NRPC is committed to planning for and exploring hydro generation at existing sites, but the commission believes that planning for additional generation from other renewable sources and advances in electricity storage may be needed to ensure that the 90 x 50 goal can be attained.

Biomass Generation Facilities

Biomass, in various forms, can be used to produce heat and electricity. For several reasons, the LEAP model does not provide a target for biomass electric generation or thermal generation (or at least for thermal generation from a "district heating facility"—a central facility that would provide heat to several structures).

Electrical generation from biomass is specifically not addressed by LEAP due to concerns about how additional large-scale biomass electric generation, from both wood and methane sources, may impact climate change and air quality in the region. There are also concerns about the efficiency of using biomass to generate electricity. However, in the event that a biomass heating facility is proposed in the region, it would certainly make sense to have the proposed facility operator assess whether the facility could also cost effectively provide electrical generation (i.e., a Combined Heat and Power [CHP] facility).

Some farms in the Northwest region currently use "cow power" biomass to generate electricity. "Cow power" utilizes methane released from cow manure to fuel an engine. The engine, in turn, creates electricity. There are five "cow power" facilities located on farms in Franklin County. A currently proposed facility in St. Albans Town is slated to use manure and food scraps from the solid waste district to generate electricity. Food scraps are another fuel source that may open up possibilities for additional generation. The NRPC supports using cow power to the greatest extent possible in the region given its renewable nature, the financial support it can provide to regional farmers, and additional water quality benefits.

Thermal generation is the more probable route for utilizing biomass, especially from forests (i.e., "woody biomass") in the region. The LEAP model also does not provide a target for thermal generation from a central biomass facility (i.e., district heating), but instead it provides some targets for distributed thermal generation that are addressed in Section VI and Appendix A. New district heating facilities that utilize woody biomass for thermal generation should be located in areas that have a relatively dense collection of possible system users. Downtowns and villages (and probably some hamlets) should be targeted as possible future sites of district heating facilities.

The development of a district heating facility entails high capital costs for both the “power plant” and the distribution network. Ensuring buy-in from prospective local users is necessary for economic viability and is certainly a challenge to facility development.

Developing future district heating facilities may be difficult, especially in the short term, because many ideal sites are served by relatively low-priced natural gas. Future district heating ideally would be located in eastern Franklin County, where biomass resources are most abundant. Grand Isle County may also be a potential location for a district heating facility due to a lack of competition with natural gas. However, Grand Isle County lacks local biomass resources and would most likely need to be supplied from other parts of the region, or from outside the region, making such a facility less economically viable.

When discussing the use of woody biomass, it is important to consider the long-term sustainability of the region’s forest. It takes time for forest regeneration to occur after logging. The region should not become overly reliant on biomass for electrical or thermal generation in order to ensure that the region’s forests are sustainable over the long term. That said, woody biomass will continue to be an important, affordable, and accessible fuel source for heating individual structures in rural locations in the region.

Biomass from agricultural crops can be used in the production of biofuels. Although the research in this field is evolving, using agricultural land to produce crops to be manufactured into biofuels in the region could provide an economic opportunity for regional farmers. Ideally, production facilities where agricultural products are manufactured into biofuels would be located on farms or in appropriate locations within the region’s villages.

SECTION VI

VI. FEASIBILITY, CHALLENGES AND CONCLUSIONS

A. FEASIBILITY

B. IMPLEMENTATION CHALLENGES

C. ONGOING COMMUNICATIONS AND COORDINATION

VI. FEASIBILITY, CHALLENGES AND CONCLUSIONS

A. FEASIBILITY

Combined with the LEAP model results, the analysis of existing energy demand and supply provides a framework for discussing the region's energy present and future. From that framework, the NRPC has developed goals, strategies, and implementation actions for both conservation and generation that will help the region achieve the 90 x 50 goal. Generally, the generation goals and strategies, guided by the LEAP generation targets, are feasible for the region to achieve in terms of both the amount of electricity needed to reach projected demand and the amount of land required to generate the electricity.

In the Northwest region, solar generation is the preferred method of renewable generation. Solar will have to meet generation levels higher than the targets set by the LEAP model to make up for the difficulty of developing hydro and wind generation facilities in the region. However, the generation targets remain feasible despite challenges posed by grid limitations and by site-specific siting issues that the NRPC is confident can be addressed at least partially and overcome through the implementation of this plan. The development of other types of renewable generation (e.g., wind, hydro, biomass) is also possible in the region, and the regional generation maps in Appendix C provide guidance on how those types of renewable energy generation facilities should be deployed in the region.

The identified conservation goals and strategies may be more difficult for the NRPC to implement. Electricity conservation goals will require changes by individual consumers in the region. The NRPC can facilitate and help organize the efforts of other organizations in the region (e.g., public utilities, Efficiency Vermont) but has little expertise or influence in this area. Thermal efficiency is similar. The NRPC can aid the efforts of other organizations to increase thermal efficiency in the region, but it cannot accomplish the plan's goals and strategies alone.

The third area of conservation—transportation—is different. One of the NRPC's core functions is to coordinate transportation planning for the region. Combined with the NRPC's experience in land use planning—a discipline inextricably linked to transportation planning—the commission is well suited to implement transportation goals and strategies. Progress on transportation implementation actions will be prioritized.

B. IMPLEMENTATION CHALLENGES

The NRPC faces several challenges in achieving the 90 x 50 goal. Many cannot be resolved by the NRPC alone and will require the cooperation and coordination of the federal government, state government, and private sector. Other challenges, such as those posed by Chittenden County's future electricity demand, will require the NRPC to make policy decisions that will have an impact on the achievement of state energy goals. Key implementation challenges include the following:

- **Baseload vs. intermittent electricity** – Solar and wind generation technologies create electricity intermittently: when the sun is shining and when the wind is blowing, respectively. Unfortunately, the times when these generation sources are operating do not always correspond to the times when electric demand is at its peak. "Baseload" electricity, or electricity that is available on demand, is needed to ensure that peak demand can be met at any time. At present, baseload electricity is typically generated by fossil fuel, nuclear, or hydro generation sources; this may change in the future. Research indicates that solar and wind generation often complement each other, and increased solar generation in the region has helped the region address peak loads. Still, reaching the 90 x 50 goal will require the development of alternative technologies—most likely, more efficient and large-scale batteries, which will enable renewable technologies to supply baseload electricity (and fossil fuel generation facilities transitioning to "peaking" plants).

- **Grid limitations** – Distributed solar generation can impact the function of the electrical grid. The Vermont electrical grid was developed to have a one-way flow of electricity. As with the rest of the United States, Vermont has historically depended on a small number of centralized power plants—the vast majority of which are now located outside of the state. When the Vermont Yankee nuclear facility was operating, the state had a relatively “balanced” grid.

  With growth in distributed solar generation, the way in which electricity is generated has changed. In some parts of the region, the grid may not be fully capable of allowing the placement of all scales of renewable energy generation facilities in every community. According to Green Mountain Power, its portion of the regional grid should be able to deal with additional solar generation, but there is less information available from VEC, the Village of Swanton, and the Village of Enosburg Falls. If the region and state are going to become more reliant on distributed solar generation, or even become a net exporter of renewable energy, Vermont public utilities and Vermont Electric Power Company (VELCO) will need to increase the pace of system-wide upgrades. This may be a difficult task to complete without directly impacting ratepayers and the cost of electricity in the state and the region.

- **Inclement weather** – Increased reliance on electricity for regional heating and transportation energy needs could be challenged by the region’s weather. Winter storms and high winds often threaten the region’s electrical distribution infrastructure. Downed power lines could impact the ability of some regional households to provide heat or to have a means of transportation if the household is solely reliant on electric heat pumps and/or electric vehicles. Although this challenge may be addressed through increasingly concentrated regional development and improved battery technology, households might still need to have a secondary means of heating their homes (and to carry the cost of maintaining a secondary heating source). Other means of overcoming the challenge of inclement weather include creating grid redundancy, creating microgrids (i.e., grids that can disconnect and operate when the main grid is not functioning), and developing more accurate weather prediction tools such as VELCO’s weather analytics tool.

- **Difficulty in developing new hydro** – As mentioned, it is difficult to develop new hydro power sources, even at existing dam sites. Achieving the LEAP target of hydro generation in the region may be difficult or even impossible. Due to the relatively high capacity factor associated with hydro generation, “replacing” the need for hydro with more solar generation will be difficult.

- **Biofuels, ethanol, renewable natural gas, and heat pumps** – The LEAP targets are very reliant upon biofuels and ethanol as an energy source for heavy vehicles. Current technology and economics would certainly make a transition from diesel to biodiesel and ethanol unlikely. Significant technological advances will be necessary to make the use of biofuels on such a large scale possible and truly renewable (currently, biofuels production requires considerable fossil fuel inputs).

  Manufacturing biodiesel fuels locally may be an economic opportunity for local farmers. UVM Extension has successfully worked with Borderview Farms in Alburgh to grow crops that are converted to biofuels. The farm currently cultivates sunflowers and switchgrass which are refined on site. The biofuels created are then used by machinery, including tractors, on farm. It remains to be seen if this success story can be replicated on other farm in the region or on a commercial scale.

  The NRPC also has concerns about producing and using ethanol given the high amount of fossil fuels needed for its production. There may also be major infrastructural challenges to creating a supply chain to distribute and sell biofuels in the region and the state.

  The LEAP analysis does not factor in the potential use of “renewable” natural gas by Vermont Gas in the future. According to Vermont Gas, it will begin to purchase renewable natural gas from a farm in Salisbury, VT in 2017. The gas will be produced by processing cow manure in an anaerobic digester to create natural gas. The economic viability of renewable natural gas, its impacts on climate change, and its classification as a "renewable" resource should be analyzed in future updates to this plan.

The LEAP analysis only factors in the energy use of heat pumps for heating. It does not factor in the use of heat pumps for cooling. Use of heat pumps for cooling may have a substantial effect on electricity demand in the summer, especially given the potential effects of climate change on the region. This issue should be addressed in future revisions to the LEAP analysis.

- **Proximity to Chittenden County** – Although the LEAP generation targets appear to be achievable in the Northwest region and for most of the state, it may be much more difficult for neighboring Chittenden County to attain its LEAP generation targets. Chittenden County's existing electricity demand is larger than that of the Northwest region, and the electric demand in Chittenden County is growing at a faster rate than in the rest of the state. There will likely be pressure on the regions surrounding Chittenden County to "help" it meet its generation targets. The NRPC specifically expects there to be pressure to develop additional solar in southern and western parts of the region due to these areas being adjacent to Chittenden County. This is especially true given grid limitations that exist in Addison County and Washington County. The NRPC will need to decide whether or not it is appropriate for the region to be an energy "exporter" to Chittenden County. The effects of additional generation in the region will need to be weighed against the potential monetary benefits that additional generation may have for some of the region's landowners, as well as the positive impacts that it may have both in helping the state achieve the 90 x 50 goal and on the overall state economy. Many regional residents rely on Chittenden County for employment.
- **Reliance on cord wood and biomass** – The LEAP model depends very heavily on cord wood use as a single-family home heating source (and for commercial and industrial heating, too). The NRPC has some questions about how this increased demand will be met regionally and about the potential environmental impacts of increased reliance on wood—particularly with regard to climate change. Although wood is a renewable resource that is currently available in the region, its use in the region should be monitored as this plan evolves to ensure that it continues to be harvested in a sustainable manner. The continued reliance on cord wood for heating and its impacts on greenhouse gas emissions in the region should be monitored. As the impacts of climate change on the Northwest region become clearer, the widespread use of cord wood should be reassessed to ensure that its use continues to be in the best interest of the region and the state. In addition, information from BERC indicates that the region has less low-grade wood that can be used for biomass heating than other regions of Vermont. This may limit efforts in the region to greatly expand the use of biomass for heat and electricity generation.
- **Lack of site-specific guidelines for solar and wind generation facilities** – The energy generation maps in the plan address which conservation resources should be protected from development of renewables and which conservation resources should be subject to mitigation if impacted by development of renewables. This plan does not provide site-specific guidelines for how solar or wind should be placed on a site if it is deemed appropriate for development. The issues of screening, stormwater management, fall distance, sound levels, and aesthetics have not been addressed in this plan. The NRPC did not address these issues directly in this plan primarily due to the unique challenges that each particular site poses to renewable development.

  The legislature has developed setback requirements for solar facilities and has enabled municipalities to develop solar facility screening ordinances, but concerns persist about whether enough has been done to protect the state's working landscape. Sentiment is even stronger in the state regarding the need for siting standards for wind generation facilities. Of particular concern to the NRPC are the possible economic inequities that can result through the siting of a wind generation facility in the region. The NRPC advocates for changes to the Section 248 process ensuring that the economic benefits provided by a developer are distributed equally to all municipalities that are impacted by a proposed facility.

- **Impacts on local energy companies** – The changing energy landscape may have negative impacts on local energy companies that cannot evolve their business model. In the short term, this may hinder regional citizens from accessing new, innovative heating technologies locally. In the long term, it may lead some local energy companies to disband, with lost jobs as a consequence.

- **Lack of RBES and CBES outreach and enforcement** – Although Efficiency Vermont has provided some outreach to local contractors and the general public regarding the requirements of RBES and CBES, there is still a lack of knowledge about the programs. The state also lacks the ability to enforce the code. Combined, this could slow regional and statewide weatherization efforts.

- **Limits of regional jurisdiction** – There are limits to how much the NRPC can do to ensure that the 90 x 50 goal is accomplished. The commission can influence state policy and implement projects that fall within an RPC's jurisdiction in state statutes, but many of the changes that will be required will need to happen on a macro scale (i.e., federal and state policy) and on a micro scale (i.e., the choices of individuals in the region). The NRPC will need to be cognizant of its limitations when implementing this plan.

Despite the challenges involved in implementation, it is important to remember the key issues this plan hopes to address: energy security, environmental protection, and economic need/opportunities. Without making significant changes to how the Northwest region generates and uses energy, our energy future will be less secure, our environment less healthy, and our economic situation potentially dire. The NRPC finds that any and all progress toward the goals of this plan is important. A lack of action at the state, regional, and local levels may have calamitous consequences.

C. ONGOING COMMUNICATION AND COORDINATION

The NRPC's efforts moving forward will focus on implementing the strategies identified in Section V. The NRPC will work with the Department of Public Service to integrate this plan into the regional plan in a manner that ensures that the latter may receive "certification" from the department. Once certification of the regional plan is complete, the NRPC will begin to work with interested regional municipalities to amend their municipal plans to ensure regional certification.

APPENDIX A

APPENDIX A - SUMMARY RESULTS AND METHODOLOGY

Summary Results and Methodology

Introduction

This document supplements the regional energy plans created by each Regional Planning Commission (RPC). It was developed by Vermont Energy Investment Corporation (VEIC) as documentation to modeling work performed for the RPCs. An award from the Department of Energy's SunShot Solar Market Pathways program funded the creation of a detailed statewide total energy supply and demand model. The VEIC team used the statewide energy model as a foundation for the region-specific modeling efforts. More detailed methodology is included at the end of this report.

Statewide Approach

Historic information was primarily drawn from the Public Service Department's Utility Facts 2013[1] and EIA data. Projections came from the Total Energy Study (TES)[2], the utilities' Committed Supply[3], and stakeholder input.

Demand Drivers

Each sector has a unit that is used to measure activity in the sector. That unit is the "demand driver" because in the model it is multiplied by the energy intensity of the activity to calculate energy demand.

The population change for each region is calculated from town data in *Vermont Population Projections 2010-2030*.[4] Growth rates are assumed constant through 2050.

RPC	Annual Growth
Addison	0.00%
Bennington	0.02%
Central VT	0.12%
Chittenden	0.48%
Lamoille	1.46%
Northwest	0.87%
NVDA	0.21%
Rutland	-0.27%
Southern Windsor	0.24%
Two Rivers	0.29%

[1] Vermont Public Service Department, *Utility Facts 2013*, http://publicservice.vermont.gov/sites/dps/files/documents/Pubs_Plans_Reports/Utility_Facts/Utility%20Facts%202013.pdf

[2] Vermont Public Service Department, *Total Energy Study: Final Report on a Total Energy Approach to Meeting the State's Greenhouse Gas and Renewable Energy Goals.* December 8, 2014. http://publicservice.vermont.gov/sites/psd/files/Pubs_Plans_Reports/TES/TES%20FINAL%20Report%2020141208.pdf.

[3] Vermont Public Service Department provided the data behind the graph on the bottom half of page E.7 in *Utility Facts 2013.* It is compiled from utility Integrated Resource Plans

[4] Jones, Ken, and Lilly Schwarz, *Vermont Population Projections-2010-2030*, August, 2013. http://dail.vermont.gov/dail-publications/publications-general-reports/vt-population-projections-2010-2030.

Windham	0.34%

People per house are assumed to decrease from 2.4 in 2010 to 2.17 in 2050. This gives the number of households, the basic unit and demand driver in the model for **residential energy** consumption.

Projected change in the **energy demand from the commercial sector** was based on commercial sector data in the TES. The demand driver for the commercial sector is commercial building square feet which grow almost 17% from 2010 to 2050.

The team entered total **industrial consumption** by fuel from the TES directly into the model. It grows from 1.1 TBtu in 2010 to 1.4 TBtu in 2050.

Transportation energy use is based on projections of vehicle miles traveled (VMT). VMT peaked in 2006 and has since declined slightly.[5] Given this, and Vermont's efforts to concentrate development and to support alternatives to single occupant vehicles, VMT per capita is assumed to remain flat at 12,000.

The regional models use two scenarios. The **reference scenario** assumes a continuation of today's energy use patterns, but does not reflect the Vermont's renewable portfolio standard or renewable energy or greenhouse gas emissions goals. The main changes over time in the reference scenario are more fuel efficient cars because of CAFE standards and the expansion of natural gas infrastructure. The **90% x 2050 $_{\mathbf{VEIC}}$ scenario** is designed to achieve the goal of meeting 90% of Vermont's total energy demand with renewable sources. It is adapted from the TES TREES Local scenarios. It is a hybrid of the high and low biofuel cost scenarios, with biodiesel or renewable diesel replacing petroleum diesel in heavy duty vehicles and electricity replacing gasoline in light duty vehicles. Despite a growing population and economy, energy use declines because of efficiency and electrification. Electrification of heating and transportation has a large effect on the total demand because the electric end uses are three to four times more efficient than the combustion versions they replace.

Regionalization Approach

The demand in the statewide model was broken into the state's planning regions. Residential demand was distributed according to housing units using data from the American Community Survey. Commercial and industrial demand was allocated to the regions by service-providing and goods-producing NAICS codes respectively. Fuel use in these sectors was allocated based on existing natural gas infrastructure. In the commercial sector, it was assumed that commercial fuel use per employee has the same average energy intensity across the state. All commercial natural gas use was allocated to the regions currently served by natural gas infrastructure, and the rest of the fuel was allocated to create equal consumption by employee.

[5] Jonathan Dowds et al., "Vermont Transportation Energy Profile," October 2015, http://vtrans.vermont.gov/sites/aot/files/planning/documents/planning/Vermont%20Transportation%20Energy%20Profile%202015.pdf.

The industrial sector was assumed to be more diverse in its energy consumption. In the industrial sector, natural gas was allocated among the regions currently served by natural gas based on the number of industrial employees in each region. Other non-electric fuels were distributed among regions without access to natural gas, as it was assumed that other non-electric fuels were primarily used for combustion purposes, and that purpose could likely be served more cheaply with gas. Transportation demand was primarily regionalized through population. The passenger rail sector of transportation demand was regionalized using Amtrak boarding and alighting data to create percentages of rail miles activity by region.[6] The freight rail sector of transportation was regionalized using the following approach: in regions with freight rail infrastructure, activity level was regionalized by share of employees in goods-producing NAICS code sectors. Regions without freight rail infrastructure were determined using a Vermont Rail System map and then assigned an activity level of zero.[7] A weighting factor was applied to regions with freight rail infrastructure to bring the total activity level back up to the calculated statewide total of freight rail short-ton miles in Vermont. Each region's share of state activity and energy use is held constant throughout the analysis period as a simplifying assumption.

Results

The numbers below show the results of the scenarios in "final units," sometimes referred to as "site" energy. This is the energy households and businesses see on their bills and pay for. Energy analysis is sometimes done at the "source" level, which accounts for inefficiency in power plants and losses from transmission and distribution power lines. The model accounts for those losses when calculating supply, but all results provided here are on the demand side, so do not show them.

The graphs below show the more efficient 90% x 2050 $_{\text{VEIC}}$ scenario, which is one path to reduce demand enough to make 90% renewable supply possible. This scenario makes use of wood energy, but there is more growth in electric heating and transportation to lower total energy demand. Where the graphs show "Avoided vs. Reference," that is the portion of energy that we do not need to provide because of the efficiency in this scenario compared to the less efficient Reference scenario.

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[6] National Association of Railroad Passengers, "Fact Sheet: Amtrak in Vermont," 2016, https://www.narprail.org/site/assets/files/1038/states_2015.pdf.
[7] Streamlined Design, "Green Mountain Railroad Map" (Vermont Rail System, 2014), http://www.vermontrailway.com/maps/regional_map.html.

Statewide Total Energy Consumption

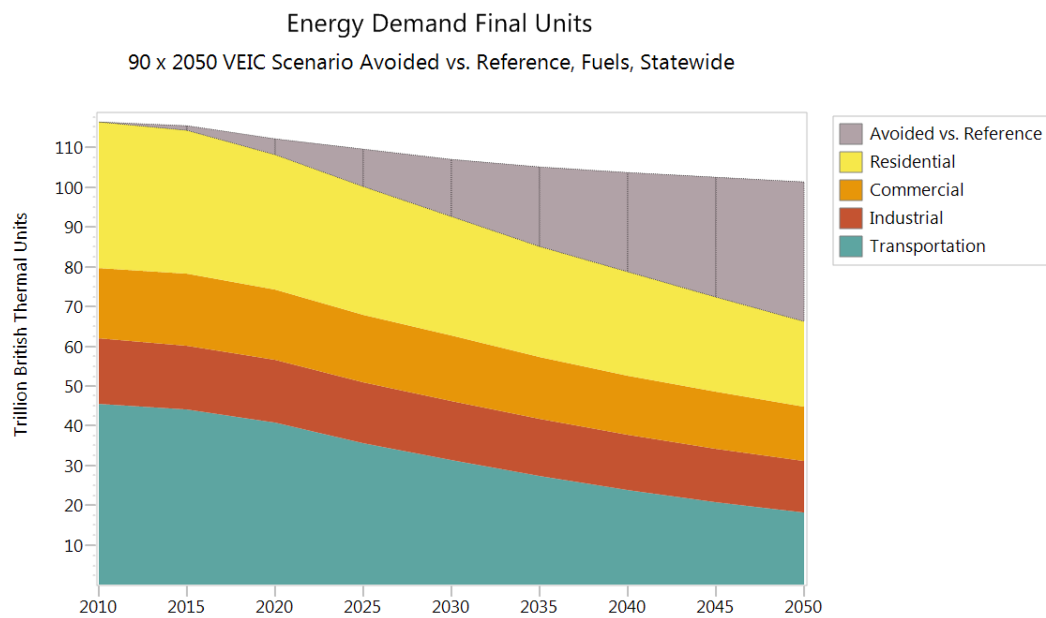

Figure 1 - Statewide energy consumption by sector, 90% x 2050 VEIC scenario compared to the reference scenario

Regional Total Energy Consumption

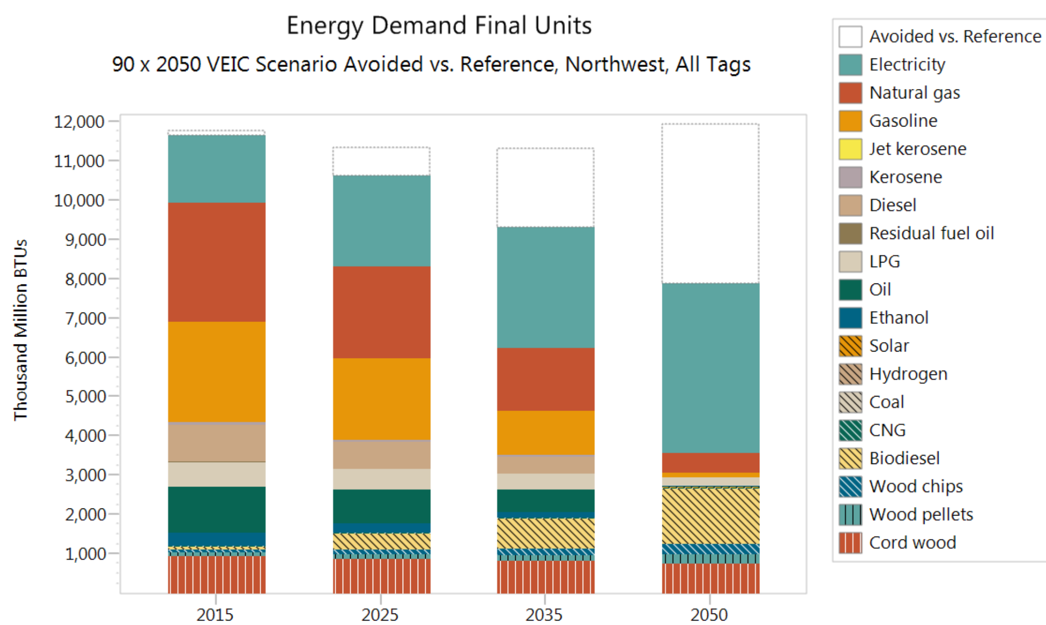

Figure 2: Regional energy consumption by fuel

Regional Energy Consumption by Sector

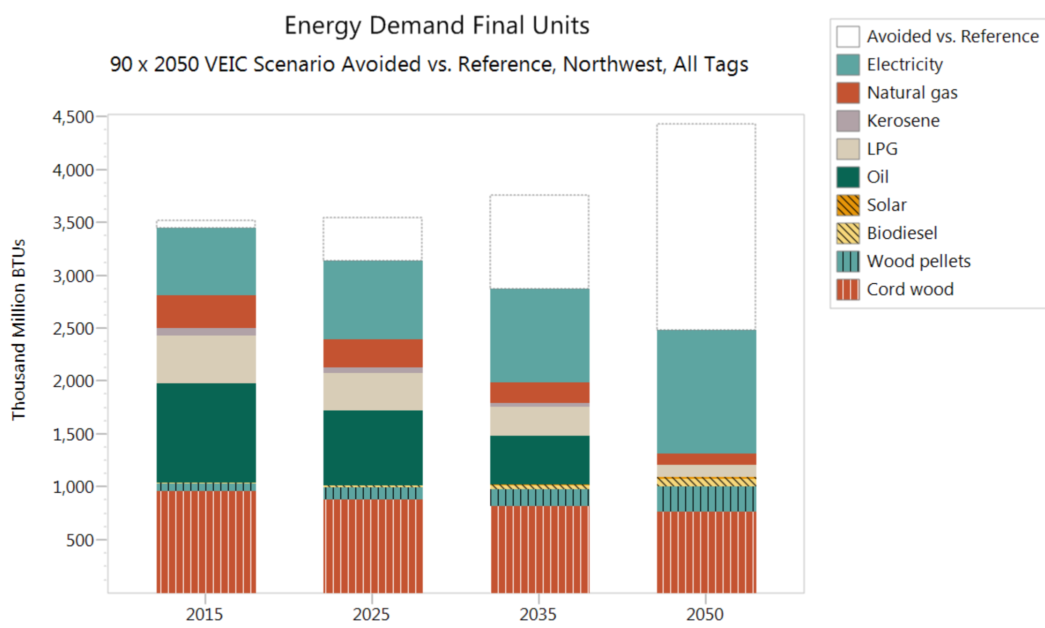

Figure 3: Regional residential energy consumption by fuel

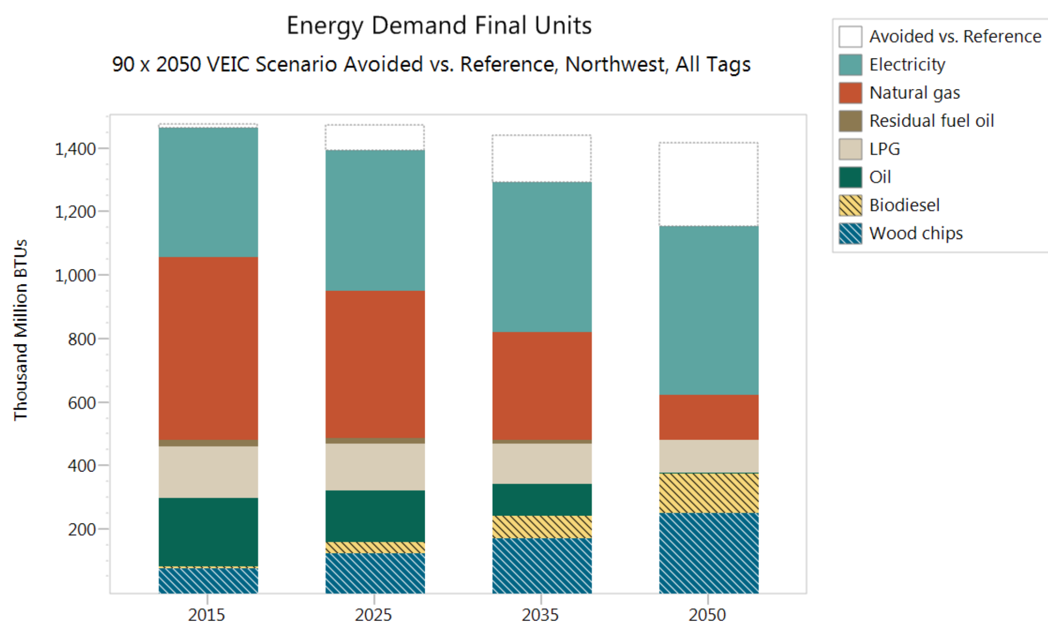

Figure 4: Regional commercial energy consumption by fuel

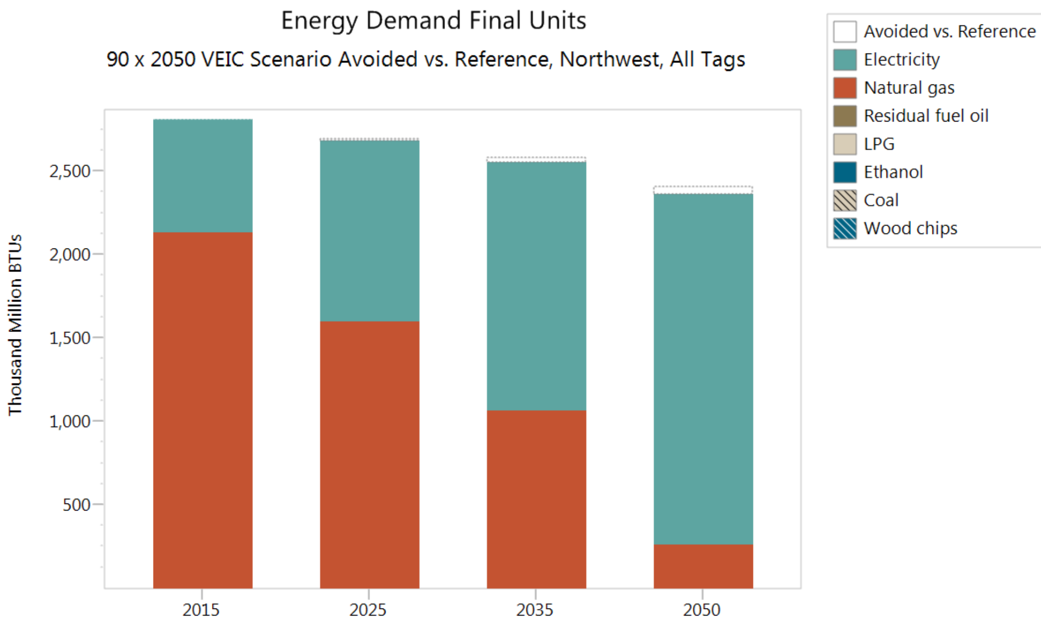

Figure 5: Regional industrial energy consumption by fuel

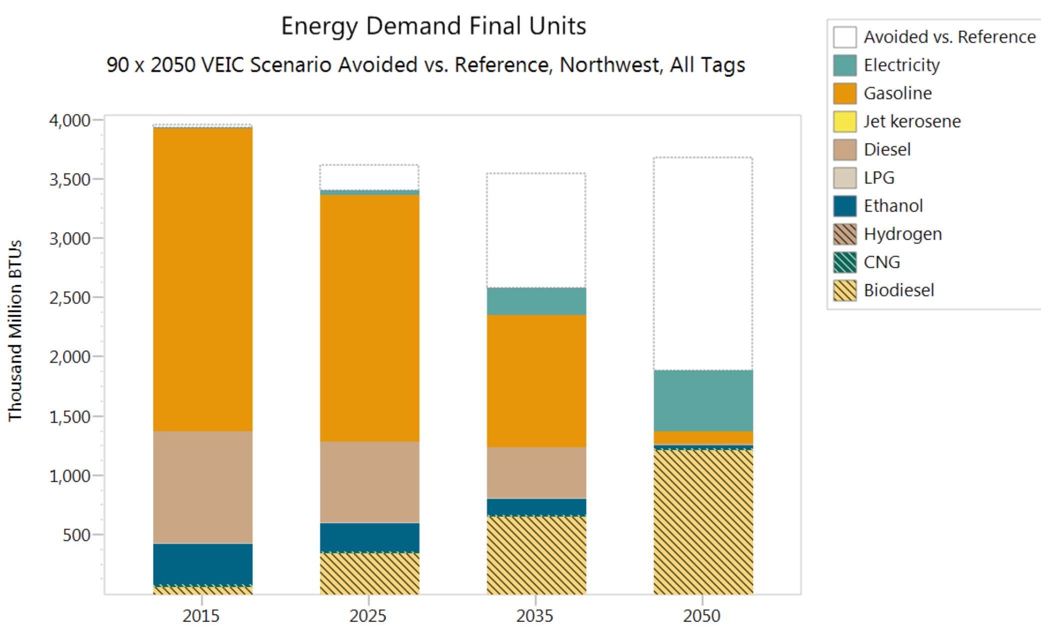

Figure 6: Regional transportation energy consumption by fuel

Detailed Sources and Assumptions

Residential

The TES provides total fuels used by sector. We used a combination of industry data and professional judgement to determine demand inputs at a sufficiently fine level of detail to allow for analysis at many levels, including end use (heating, water heating, appliances, etc.), device (boiler, furnace, heat pump) or home-type (single family, multi-family, seasonal, mobile). Assumptions for each are detailed below. All assumptions for residential demand are at a per-home level.

Space Heating

The team determined per home consumption by fuel type and home type. EIA data on Vermont home heating provides the percent share of homes using each type of fuel. 2009 Residential energy consumption survey (RECS) data provided information on heating fuels used by mobile homes. Current heat pumps consumption estimates were found in a 2013 report prepared for Green Mountain Power by Steve LeTendre entitled *Hyper Efficient Devices: Assessing the Fuel Displacement Potential in Vermont of Plug-In Vehicles and Heat Pump Technology*. Future projections of heat pump efficiency were provided by Efficiency Vermont Efficient Products and Heat Pump program experts.

Additional information came from the following data sources:

- 2010 Housing Needs Assessment[8]
- EIA Vermont State Energy Profile[9]
- 2007-2008 VT Residential Fuel Assessment[10]
- EIA Adjusted Distillate Fuel Oil and Kerosene Sales by End Use[11]

The analyst team made the following assumptions for each home type:

- Multi-family units use 60% of the heating fuel used by single family homes, on average, due to assumed reduced size of multi-family units compared to single-family units. Additionally, where natural gas is available, the team assumed a slightly higher percentage of multi-family homes use natural gas as compared to single family homes, given the high number of multi-family units located in the Burlington area, which is served by the natural gas pipeline. The team also assumed that few multi-family homes rely on cordwood as a primary heating source.

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[8] Vermont Housing and Finance Agency, "2010 Vermont Housing Needs Assessment," December 2009 http://www.vtaffordablehousing.org/documents/resources/623_1.8_Appendix_6_2010_Vermont_Housing_Needs_Assessment.pdf.
[9] U.S. Energy Information Administration, "Vermont Energy Consumption Estimates, 2004," https://www.eia.gov/state/print.cfm?sid=VT
[10] Frederick P. Vermont Residential Fuel Assessment: for the 2007-2008 heating season. Vermont Department of Forest, Parks and Recreation. 2011.
[11] U.S. Energy Information Administration, "Adjusted Distillate Fuel Oil and Kerosene Sales by End Use," December 2015, https://www.eia.gov/dnav/pet/pet_cons_821usea_dcu_nus_a.htm.

- Unoccupied/Seasonal Units: On average, seasonal or unoccupied homes were expected to use 10% of the heating fuel used by single family homes. For cord wood, we expected unoccupied or seasonal homes to use 5% of heating fuel, assuming any seasonal or unoccupied home dependent on cord wood are small in number and may typically be homes unoccupied for most of the winter months (deer camps, summer camps, etc.)
- Mobile homes—we had great mobile home data from 2009 RECS. As heat pumps were not widely deployed in mobile homes in 2009 and did not appear in the RECs data, we applied the ratio of oil consumed between single family homes and mobile homes to estimated single family heat pump use to estimate mobile home heat pump use.
- The reference scenario heating demand projections were developed in line with the TES reference scenario. This included the following: assumed an increase in the number of homes using natural gas, increase in the number of homes using heat pumps as a primary heating source (up to 37% in some home types), an increase in home heated with wood pellets, and drastic decline in homes heating with heating oil. Heating system efficiency and shell efficiency were modeled together and, together, were estimated to increase 5-10% depending on the fuel type. However, heat pumps are expected to continue to rapidly increase in efficiency (becoming 45% more efficient, when combined with shell upgrades, by 2050). We also reflect some trends increasing home sizes.
- In the 90% x 2050 $_{\text{VEIC}}$ scenario, scenario heating demand projections were developed in line with the TES TREES Local scenarios, a hybrid of the high and low biofuel cost scenarios. This included the following: assumed increase in the number of homes using heat pumps as a primary heating source (up to 70% in some home types), an increase in home heated with wood pellets, a drastic decline in homes heating with heating oil and propane, and moderate decline in home heating with natural gas. Heating system efficiency and shell efficiency were modeled together and were estimated to increase 10%-20% depending on the fuel type. However, heat pumps are expected to continue to rapidly increase in efficiency (becoming 50% more efficient, when combined with shell upgrades by 2050). We also reflect some trends increasing home sizes.

Lighting

Lighting efficiency predictions were estimated by Efficiency Vermont products experts.

Water Heating

Water heating estimates were derived from the Efficiency Vermont Technical Reference Manual.[12]

Appliances and Other Household Energy Use:

EnergyStar appliance estimates and the Efficiency Vermont Electric Usage Chart[13] provided estimates for appliance and other extraneous household energy uses.

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[12] Efficiency Vermont, "Technical Reference User Manual (TRM): Measure Savings Algorithms and Cost Assumptions, No. 2014-87," March 2015, http://psb.vermont.gov/sites/psb/files/docketsandprojects/electric/majorpendingproceedings/TRM%20User%20Manual%20No.%202015-87C.pdf.

Using the sources and assumptions listed above, the team created a model that aligned with the residential fuel consumption values in the TES.

Commercial

Commercial energy use estimates are entered in to the model as energy consumed per square foot of commercial space, on average. This was calculated using data from the TES.

Industrial

Industrial use was entered directly from the results of the TES data.

Transportation

The transportation branch focused on aligning with values from the Total Energy Study (TES) Framework for Analysis of Climate-Energy-Technology Systems (FACETS) data in the transportation sector in the Business as Usual (BAU) scenario. The VEIC 90% x 2050 scenario was predominantly aligned with a blend of the Total Renewable Energy and Efficiency Standard (TREES) Local High and Low Bio scenarios in the transportation sector of FACETS data. There were slight deviations from the FACETS data, which are discussed in further detail below.

Light Duty Vehicles

Light Duty Vehicle (LDV) efficiency is based on a number of assumptions: gasoline and ethanol efficiency were derived from the Vermont Transportation Energy Profile.[14] Diesel LDV efficiency was obtained from underlying transportation data used in the Business as Usual scenario for the Total Energy Study, which is referred to as TES Transportation Data below. Biodiesel LDV efficiency was assumed to be 10% less efficient than LDV diesel efficiency.[15] Electric vehicle (EV) efficiency was derived from an Excel worksheet from Drive Electric Vermont. The worksheet calculated EV efficiency using the number of registered EVs in Vermont, EV efficiency associated with each model type, percentage driven in electric mode by model type (if a plugin hybrid vehicle), and the Vermont average annual vehicle miles traveled. LDV electric vehicle efficiency was assumed to increase at a rate of .6%. This was a calculated weighted average of 100-mile electric vehicles, 200-mile electric vehicles, plug-in 10 gasoline hybrid and plug-in 40 gasoline hybrid vehicles from the Energy Information Administration Annual Energy Outlook.[16]

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[13] Efficiency Vermont, "Electric Usage Chart Tool," https://www.efficiencyvermont.com/tips-tools/tools/electric-usage-chart-tool.

[14] Jonathan Dowds et al., "Vermont Transportation Energy Profile," October 2015, http://vtrans.vermont.gov/sites/aot/files/planning/documents/planning/Vermont%20Transportation%20Energy%20Profile%202015.pdf.

[15] U.S. Environmental Protection Agency: Office of Transportation & Air Quality, "Biodiesel," *Www.fueleconomy.gov*, accessed August 19, 2016, https://www.fueleconomy.gov/feg/biodiesel.shtml.

[16] U.S. Energy Information Administration, "Light-Duty Vehicle Miles per Gallon by Technology Type," *Annual Energy Outlook 2015*, 2015, https://www.eia.gov/forecasts/aeo/data/browser/#/?id=50-AEO2016&cases=ref2016~ref_no_cpp&sourcekey=0.

Miles per LDV was calculated using the following assumptions: data from the Vermont Agency of Transportation provided values for statewide vehicles per capita and annual miles traveled.[17] The total number of LDVs in Vermont was sourced TES Transportation Data. The calculated LDV miles per capita was multiplied by the population of Vermont and divided by the number of LDVs to calculate miles per LDV.

The number of EVs were sourced directly from Drive Electric Vermont, which provided a worksheet of actual EV registrations by make and model. This worksheet was used to calculate an estimate of the number of electric vehicles using the percentage driven in electric mode by vehicle type to devalue the count of plug-in hybrid vehicles. Drive Electric Vermont also provided the number of EVs in the 90% x 2050 $_{\text{VEIC}}$ scenario.

Heavy Duty Vehicles

Similar to the LDV vehicle efficiency methods above, HDV efficiency values contained a variety of assumptions from different sources. A weighted average of HDV diesel efficiency was calculated using registration and fuel economy values from the Transportation Energy Data Book.[18] The vehicle efficiency values for diesel and compressed natural gas (CNG) were all assumed to be equal.[19] Diesel efficiency was reduced by 10% to represent biodiesel efficiency.[20] Propane efficiency was calculated using a weighted average from the Energy Information Administration Annual Energy Outlook table for Freight Transportation Energy Use.[21]

In the 90% x 2050 $_{\text{VEIC}}$ scenario, it was assumed HDVs will switch entirely from diesel to biodiesel or renewable diesel by 2050. This assumption is backed by recent advances with biofuel. Cities such as Oakland and San Francisco are integrating a relatively new product called renewable diesel into their municipal fleets that does not gel in colder temperatures and has a much lower overall emissions factor.[22] Historically, gelling in cold temperatures has prevented higher percentages of plant-based diesel replacement products.

Although there has been some progress toward electrifying HDVs, the VEIC 90% x 2050 scenario does not include electric HDVs. An electric transit bus toured the area and gave employees of BED, GMTA, and VEIC a nearly silent ride around Burlington. The bus is able to fast charge using an immense amount of power that few places on the grid can currently support. The California Air Resources Board indicated

[17] Jonathan Dowds et al., "Vermont Transportation Energy Profile."
[18] Ibid.
[19] "Natural Gas Fuel Basics," *Alternative Fuels Data Center*, accessed August 19, 2016, http://www.afdc.energy.gov/fuels/natural_gas_basics.html.
[20] U.S. Environmental Protection Agency: Office of Transportation & Air Quality, "Biodiesel."
[21] US Energy Information Administration (EIA), "Freight Transportation Energy Use, Reference Case," *Annual Energy Outlook 2015*, 2015, http://www.eia.gov/forecasts/aeo/data/browser/#/?id=58-AEO2015&region=0-0&cases=ref2015&start=2012&end=2040&f=A&linechart=ref2015-d021915a.6-58-AEO2015&sourcekey=0.
[22] Oregon Department of Transportation and U.S. Department of Transportation Federal Highway Administration, "Primer on Renewable Diesel," accessed August 29, 2016, http://altfueltoolkit.org/wp-content/uploads/2004/05/Renewable-Diesel-Fact-Sheet.pdf.

a very limited number of electric HDVs are in use within the state.[23] Anecdotally, Tesla communicated it is working on developing an electric semi-tractor that will reduce the costs of freight transport.[24]

The total number of HDVs was calculated using the difference between the total number of HDVs and LDVs in 2010 in the Vermont Transportation Energy Profile and the total number of LDVs from TES Transportation Data.[25] HDV miles per capita was calculated using the ratio of total HDV miles traveled from the 2012 Transportation Energy Data Book and the 2012 American Community Survey U.S. population estimate.[26,27] The total number of HDVs and HDV miles per capita were combined with the population assumptions outlined above to calculate miles per HDV.

Rail

The rail sector of the transportation branch consists of two types: freight and passenger. Currently in Vermont, freight and passenger rail use diesel fuel.[28,29] The energy intensity (Btu/short ton-mile) of freight rail was obtained from the U.S Department of Transportation Bureau of Transportation Statistics.[30] A 10-year average energy intensity of passenger rail (Btu/passenger mile) was also obtained from the U.S Department of Transportation Bureau of Transportation Statistics.[31] Passenger miles were calculated using two sets of information. First, distance between Vermont Amtrak stations and the appropriate Vermont border location were estimated using Google Maps data. Second, 2013 passenger data was obtained from the National Association of Railroad Passengers.[32] Combined, these two components created total Vermont passenger miles. We used a compound growth rate of 3% for forecast future passenger rail demand in the 90% x 2050 $_{\text{VEIC}}$ scenario, consistent with the historical growth rates of rail

[23] California Environmental Protection Agency Air Resources Board, "Draft Technology Assessment: Medium- and Heavy-Duty Battery Electric Trucks and Buses," October 2015, https://www.arb.ca.gov/msprog/tech/techreport/bev_tech_report.pdf.
[24] Elon Musk, "Master Plan, Part Deux," *Tesla*, July 20, 2016, https://www.tesla.com/blog/master-plan-part-deux.
[25] Jonathan Dowds et al., "Vermont Transportation Energy Profile."
[26] "Transportation Energy Data Book: Edition 33" (Oak Ridge National Laboratory, n.d.), accessed August 18, 2016.
[27] U. S. Census Bureau, "Total Population, Universe: Total Population, 2012 American Community Survey 1-Year Estimates," *American Fact Finder*, 2012, http://factfinder.census.gov/bkmk/table/1.0/en/ACS/12_1YR/B01003/0100000US.
[28] US Energy Information Administration (EIA), "Freight Transportation Energy Use, Reference Case."
[29] Vermont Agency of Transportation Operations Division - Rail Section, "Passenger Rail Equipment Options for the Amtrak Vermonter and Ethan Allen Express: A Report to the Vermont Legislature," January 2010, http://www.leg.state.vt.us/reports/2010ExternalReports/253921.pdf.
[30] U.S. Department of Transportation: Office of the Assistant Secretary for Research and Technology Bureau of Transportation Statistics, "Table 4-25: Energy Intensity of Class I Railroad Freight Service," accessed August 26, 2016, http://www.rita.dot.gov/bts/sites/rita.dot.gov.bts/files/publications/national_transportation_statistics/html/table_04_25.html.
[31] U.S. Department of Transportation: Office of the Assistant Secretary for Research and Technology Bureau of Transportation Statistics, "Table 4-26: Energy Intensity of Amtrak Services," accessed August 26, 2016, http://www.rita.dot.gov/bts/sites/rita.dot.gov.bts/files/publications/national_transportation_statistics/html/table_04_26.html.
[32] National Association of Railroad Passengers, "Fact Sheet: Amtrak in Vermont," 2016, https://www.narprail.org/site/assets/files/1038/states_2015.pdf.

passenger miles in Vermont.[33] Passenger rail is assumed to completely transform to electric locomotion. Freight rail is assumed to transform to biodiesel or renewable diesel.

Air

The total energy of air sector used appropriate FACETS data values directly. The air sector is expected to continue using Jet Fuel in both scenarios.

[33] Joseph Barr, AICP et al., “Vermont State Rail Plan: Regional Passenger Rail Forecasts.”

APPENDIX

B

APPENDIX B - ENERGY RESOURCE MAPPING

A. EXPLANATION OF CONSTRAINTS

B. SOLAR GENERATION MAPS

C. BIOMASS MAPS

D. WIND GENERATION MAPS

E. HYDRO GENERATION MAPS

F. EXPLANATION OF MUNICIPAL CONSERVATION LAND USE AREAS

APPENDIX B - ENERGY RESOURCE MAPPING

Version 13 – 5/30/2017

The following is a list of the known constraints and possible constraints that have been included on the regional energy generation map in Appendix C (solar, wind, woody biomass, and hydroelectric). The energy generation maps are not intended to be used without the accompanying goals and policies of the NRPC contained in this plan. For more information about how the energy generation maps shall be used, please see Section V of the plan (see: Energy Resources Maps and the Public Service Board, Energy Generation Maps Methodology, and Northwest Regional Energy Generation Maps and Standards).

A. EXPLANATION OF CONSTRAINTS

The following is an explanation of known and possible constraints used by the NRPC to create the regional energy generation maps. This list of constraints shall also be considered by the NPRC during the review of generation project applications (Section 248) in the Northwest Region:

KNOWN CONSTRAINTS

Known constraints are considered high-priority resources and for this reason energy generation facilities shall not be located in areas where known constraints exist. For this planning initiative, known constraints have been removed from the base layer of each applicable type of resource (solar, wind, biomass, hydro).

POSSIBLE CONSTRAINTS

Possible Constraints are lower-priority resources. These resources often impact the siting process for generation facilities. New generation facilities shall not have an undue adverse impact upon possible constraints. Often, site-specific mitigation solutions are possible when possible constraints exist on a parcel. Therefore, possible constraints have been included in the area designated as “base” on the regional energy generation maps (solar, wind, biomass, hydro).

B. SOLAR GENERATION MAPS

STATE KNOWN CONSTRAINTS

- **Confirmed and Unconfirmed Vernal Pools:** There is a 600-foot buffer around confirmed or unconfirmed vernal pools. (*Source: ANR*)
- **State Significant Natural Communities and Rare, Threatened, and Endangered Species:** Rankings S1 through S3 were used as constraints. These include all of the rare and uncommon rankings within the file. For more information on the specific rankings, explore the methodology for the shapefile. (*Source: VCGI*)
- **River Corridors:** Only mapped River Corridors were mapped. Does not include 50 foot buffer for streams with a drainage area less than 2 square miles. (*Source: VCGI*)
- **National Wilderness Areas:** (*Source: VCGI*)
- **FEMA Floodways:** (*Source: VCGI*)
- **Class 1 and Class 2 Wetlands:** (*Source: VCGI*)

REGIONALLY IDENTIFIED CRITICAL RESOURCES (REGIONAL KNOWN CONSTRAINTS)

- **Designated Downtowns, Designated Growth Centers, and Designated Village Centers:** These areas the center of dense, traditional development in the region. This constraint does not apply to roof-mounted solar within such designated areas. The inclusion of this resource as a regional constraint is consistent with goals and policies of the Northwest Regional Plan. (*Source: NRPC*)

- **FEMA Flood Insurance Rate Map (FIRM) Special Flood Hazard Areas:** Special flood hazard areas as digitized by the NRPC were used—just 100-year flood plain (500-year floodplain not mapped). The inclusion of this resource as a regional constraint is consistent with goals and policies of the Northwest Regional Plan. (*Source: NRPC*)
- **Ground and Surface Waters Drinking Protection Areas:** Buffered Source Protection Areas (SPAs) are designated by the Vermont Department of Environmental Conservation (DEC). SPA boundaries are approximate but are conservative enough to capture the areas most susceptible to contamination. The inclusion of this resource as a regional constraint is consistent with goals and policies of the Northwest Regional Plan. (*Source: Vermont Agency of Natural Resources [ANR]*)
- **Vermont Conservation Design Highest Priority Forest Blocks:** The lands and waters identified here are the areas of the state that are of highest priority for maintaining ecological integrity. Together, these lands comprise a connected landscape of large and intact forested habitat, healthy aquatic and riparian systems, and a full range of physical features (bedrock, soils, elevation, slope, and aspect) on which plant and animal natural communities depend. The inclusion of this resource as a regional constraint is consistent with goals and policies of the Northwest Regional Plan. (*Source: ANR*)
- **Public Water Sources:** A 200-foot buffer is used around public drinking water wellheads. The inclusion of this resource as a regional constraint is consistent with goals and policies of the Northwest Regional Plan. (*Source: ANR*)
- **National Natural Landmark – Chazy Fossil Reef:** The Chazy Fossil Reef in Isle La Motte has been designated a National Natural Landmark by the US Department of Interior. (*Source: NRPC*)
- **Municipal Conservation Land Use Areas:** Conservation Land Use Districts, as designated in municipal plans, that include strict language that strongly deters or prohibits development have been included as a regional known constraint. The inclusion of this resource as a regional constraint is consistent with the goals and policies of the Northwest Regional Plan. Specific municipal land use districts included are outlined in Section D.

STATE POSSIBLE CONSTRAINTS

- **Protected Lands:** This constraint includes public lands held by agencies with conservation or natural resource oriented missions, municipal natural resource holdings (ex. Town forests), public boating and fishing access areas, public and private educational institution holdings with natural resource uses and protections, publicly owned rights on private lands, parcels owned in fee by non profit organizations dedicated to conserving land or resources, and private parcels with conservation easements held by non profit organizations. (*Source: VCGI*)
- **Deer Wintering Areas:** Deer wintering habitat as identified by the Vermont Agency of Natural Resources. (*Source: VCGI*)
- **Hydric Soils:** Hydric soils as identified by the US Department of Agriculture. (*Source: VCGI*)
- **Agricultural Soils:** Local, statewide, and prime agricultural soils are considered. (*Source: VCGI*)
- **Act 250 Agricultural Soil Mitigation Areas:** Sites conserved as a condition of an Act 250 permit. (*Source: VCGI*)

REGIONALLY IDENTIFIED RESOURCES (REGIONAL POSSIBLE CONSTRAINTS)

- **Class 3 Wetlands:** Class 3 wetlands in the region have been identified have been included as a Regional Possible Constraint. The inclusion of this resource as a regional constraint is consistent with goals and policies of the Northwest Regional Plan (*Source: ANR*)
- **Municipal Conservation Land Use Areas:** Conservation Land Use Districts, as designated in municipal plans, that include strict language that deters, but does not prohibit development, have been included as a regional possible constraint. Specific municipal land use districts included are outlined in Section D.

OTHER MAP FEATURES

- **Three-Phase Distribution Lines:** All available utilities with service in any of the three regions (*Source: Green Mountain Power, Swanton Village Electric Department, Vermont Electric Coop, and Village of Enosburg Falls*) were mapped.
- **Transportation Infrastructure:** These were removed in the initial analysis performed by VCGI. Does not include parking lots. (*Source: VCGI*)
- **VELCO Transmission Lines and Substations:** (*Source: VCGI*)
- **Water Bodies:** Major water bodies (i.e., >1 square kilometer in surface area) are shown on maps as "Lakes/Ponds." (*Source: VCGI*)

C. BIOMASS MAPS

STATE KNOWN CONSTRAINTS

- **Confirmed and Unconfirmed Vernal Pools:** There is a 600-foot buffer around confirmed or unconfirmed vernal pools. (*Source: ANR*)
- **State Significant Natural Communities and Rare, Threatened, and Endangered Species:** Rankings S1 through S3 were used as constraints. These include all of the rare and uncommon rankings within the file. For more information on the specific rankings, explore the methodology for the shapefile. (*Source: VCGI*)
- **River Corridors:** Only mapped River Corridors were mapped. Does not include 50 foot buffer for streams with a drainage area less than 2 square miles. (*Source: VCGI*)
- **National Wilderness Areas:** (*Source: VCGI*)
- **FEMA Floodways:** (*Source: VCGI*)
- **Class 1 and Class 2 Wetlands:** (*Source: VCGI*)

REGIONALLY IDENTIFIED CRITICAL RESOURCES (REGIONAL KNOWN CONSTRAINTS)

- **Designated Downtowns, Designated Growth Centers, and Designated Village Centers:** These areas the center of dense, traditional development in the region. This constraint does not apply to roof-mounted solar within such designated areas. The inclusion of this resource as a regional constraint is consistent with goals and policies of the Northwest Regional Plan. (*Source: NRPC*)
- **FEMA Flood Insurance Rate Map (FIRM) Special Flood Hazard Areas:** Special flood hazard areas as digitized by the NRPC were used—just 100-year flood plain (500-year floodplain not mapped). The inclusion of this resource as a regional constraint is consistent with goals and policies of the Northwest Regional Plan. (*Source: NRPC*)
- **Ground and Surface Waters Drinking Protection Areas:** Buffered Source Protection Areas (SPAs) are designated by the Vermont Department of Environmental Conservation (DEC). SPA boundaries are approximate but are conservative enough to capture the areas most susceptible to contamination. The inclusion of this resource as a regional constraint is consistent with goals and policies of the Northwest Regional Plan. (*Source: Vermont Agency of Natural Resources [ANR]*)
- **Vermont Conservation Design Highest Priority Forest Blocks:** The lands and waters identified here are the areas of the state that are of highest priority for maintaining ecological integrity. Together, these lands comprise a connected landscape of large and intact forested habitat, healthy aquatic and riparian systems, and a full range of physical features (bedrock, soils, elevation, slope, and aspect) on which plant and animal natural communities depend. The inclusion of this resource as a regional constraint is consistent with goals and policies of the Northwest Regional Plan. (*Source: ANR*)
- **Public Water Sources:** A 200-foot buffer is used around public drinking water wellheads. The inclusion of this resource as a regional constraint is consistent with goals and policies of the Northwest Regional Plan. (*Source: ANR*)

- **National Natural Landmark – Chazy Fossil Reef:** The Chazy Fossil Reef in Isle La Motte has been designated a National Natural Landmark by the US Department of Interior. (*Source: NRPC*)
- **Municipal Conservation Land Use Areas:** Conservation Land Use Districts, as designated in municipal plans, that include strict language that strongly deters or prohibits development have been included as a regional known constraint. The inclusion of this resource as a regional constraint is consistent with the goals and policies of the Northwest Regional Plan. Specific municipal land use districts included are outlined in Section D.

STATE POSSIBLE CONSTRAINTS

- **Protected Lands:** This constraint includes public lands held by agencies with conservation or natural resource oriented missions, municipal natural resource holdings (ex. Town forests), public boating and fishing access areas, public and private educational institution holdings with natural resource uses and protections, publicly owned rights on private lands, parcels owned in fee by non profit organizations dedicated to conserving land or resources, and private parcels with conservation easements held by non profit organizations. (*Source: VCGI*)
- **Deer Wintering Areas:** Deer wintering habitat as identified by the Vermont Agency of Natural Resources. (*Source: VCGI*)
- **Hydric Soils:** Hydric soils as identified by the US Department of Agriculture. (*Source: VCGI*)
- **Agricultural Soils:** Local, statewide, and prime agricultural soils are considered. (*Source: VCGI*)
- **Act 250 Agricultural Soil Mitigation Areas:** Sites conserved as a condition of an Act 250 permit. (*Source: VCGI*)

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- **Three-Phase Distribution Lines:** All available utilities with service in any of the three regions (*Source: Green Mountain Power, Swanton Village Electric Department, Vermont Electric Coop, and Village of Enosburg Falls*) were mapped.
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- **VELCO Transmission Lines and Substations:** (*Source: VCGI*)
- **Water Bodies:** Major water bodies (i.e., >1 square kilometer in surface area) are shown on maps as "Lakes/Ponds." (*Source: VCGI*)

D. WIND GENERATION MAPS

STATE KNOWN CONSTRAINTS

- **Confirmed and Unconfirmed Vernal Pools:** There is a 600-foot buffer around confirmed or unconfirmed vernal pools. (*Source: ANR*)

- **State Significant Natural Communities and Rare, Threatened, and Endangered Species:** Rankings S1 through S3 were used as constraints. These include all of the rare and uncommon rankings within the file. For more information on the specific rankings, explore the methodology for the shapefile. (*Source: VCGI*)
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- **Vermont Conservation Design Highest Priority Forest Blocks:** The lands and waters identified here are the areas of the state that are of highest priority for maintaining ecological integrity. Together, these lands comprise a connected landscape of large and intact forested habitat, healthy aquatic and riparian systems, and a full range of physical features (bedrock, soils, elevation, slope, and aspect) on which plant and animal natural communities depend. The inclusion of this resource as a regional constraint is consistent with goals and policies of the Northwest Regional Plan. (*Source: ANR*)
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- **Deer Wintering Areas:** Deer wintering habitat as identified by the Vermont Agency of Natural Resources. (*Source: VCGI*)
- **Hydric Soils:** Hydric soils as identified by the US Department of Agriculture. (*Source: VCGI*)
- **Agricultural Soils:** Local, statewide, and prime agricultural soils are considered. (*Source: VCGI*)
- **Act 250 Agricultural Soil Mitigation Areas:** Sites conserved as a condition of an Act 250 permit. (*Source: VCGI*)

REGIONALLY IDENTIFIED RESOURCES (REGIONAL POSSIBLE CONSTRAINTS)

- **Class 3 Wetlands:** Class 3 wetlands in the region have been identified have been included as a Regional Possible Constraint. The inclusion of this resource as a regional constraint is consistent with goals and policies of the Northwest Regional Plan (*Source: ANR*)
- **Municipal Conservation Land Use Areas:** Conservation Land Use Districts, as designated in municipal plans, that include strict language that deters, but does not prohibit development, have been included as a regional possible constraint. Specific municipal land use districts included are outlined in Section D.

OTHER MAP FEATURES

- **Three-Phase Distribution Lines:** All available utilities with service in any of the three regions (*Source: Green Mountain Power, Swanton Village Electric Department, Vermont Electric Coop, and Village of Enosburg Falls*) were mapped.
- **Transportation Infrastructure:** These were removed in the initial analysis performed by VCGI. Does not include parking lots. (*Source: VCGI*)
- **VELCO Transmission Lines and Substations:** (*Source: VCGI*)
- **Water Bodies:** Major water bodies (i.e., >1 square kilometer in surface area) are shown on maps as "Lakes/Ponds." (*Source: VCGI*)

E. HYDRO GENERATION MAPS

KNOWN CONSTRAINTS

- None

REGIONALLY IDENTIFIED RESOURCES (REGIONAL POSSIBLE CONSTRAINTS)

- **National Scenic and Recreational Rivers:** Known constraint; Missisquoi and Trout Rivers. This constraint will only be incorporated into the Hydroelectric Resource Map. Dams occurring within an impacted area will be displayed as such on maps. (*Source: Digitized by the BCRC from Upper Missisquoi and Trout Rivers, Wild and Scenic Study Management Plan*)

POSSIBLE CONSTRAINTS

- **"303d" List of Stressed Waters:** Possible constraint. This constraint will only be incorporated into the Hydroelectric Resource Map. Dams occurring within an impacted area will be displayed as such on maps. (*Source: ANR*)
- **Impaired Water:** Possible constraint. This constraint will only be incorporated into the Hydroelectric Resource Map. Dams occurring within an impacted area will be displayed as such on maps. (*Source: ANR*)

- **State Significant Natural Communities and Rare, Threatened, and Endangered Species:** Rankings S1 through S3 were used as constraints. These include all of the rare and uncommon rankings within the file. For more information on the specific rankings, explore the methodology for the shapefile. (*Source: VCGI*)

OTHER MAP FEATURES

- **Three-Phase Distribution Lines:** All available utilities with service in any of the three regions (*Source: Green Mountain Power, Swanton Village Electric Department, Vermont Electric Coop, and Village of Enosburg Falls*) were mapped.
- **Transportation Infrastructure:** These were removed in the initial analysis performed by VCGI. Parking lots are not included. (*Source: VCGI*)
- **VELCO Transmission Lines and Substations:** (*Source: VCGI*)
- **Water Bodies:** Major water bodies (i.e., >1 square kilometer in surface area) are shown on maps as "Lakes/Ponds." (*Source: VCGI*)

F. EXPLANATION OF MUNICIPAL CONSERVATION LAND USE AREAS

The NRPC conducted an analysis of municipal conservation land use area. The analysis reviewed the written descriptions of conservation land use areas from each municipal plan in the region. The intent of the analysis was to see if the conservation land use areas contained language that restricted future development (including the development of renewables). After review, the conservation land use areas from each municipal plan were divided into the following categories:

STRONGLY DETERS

These conservation land uses areas use language that prohibits development or only permits limited, low-density residential development. These areas are included as Regional Known Constraints on the Regional Energy Generation maps. Municipal conservation land use areas that meet this description include:

- Alburgh Town & Village – Conservation Land A
- Enosburgh – Conservation District
- Enosburgh Falls – Conservation District
- Fletcher – Forest District
- Grand Isle – Conservation District
- Montgomery – Conservation District II
- North Hero – Conservation District
- Richford – Recreation/Conservation District and Water Supply District
- St. Albans Town – Conservation District

DETERS

Several conservation land use areas in the region are described in municipal plans as areas where land use shall be restricted to conservation, forestry, and agricultural uses and/or are described as land that is geographically unsuitable for development. These areas are included as Regional Possible Constraints on the Regional Energy Generation maps. Municipal conservation land use areas that meet this description include:

- Alburgh Town and Village – Conservation Land B
- Bakersfield – Conservation District
- Fairfax – Conservation District
- Fairfield – Conservation District
- Fletcher – Conservation District
- Highgate – Forest Reserve District

- Highgate – Protected District
- Montgomery – Conservation District I
- Richford - Forest/Conservation District
- Sheldon – Rural Lands II
- Swanton Town and Village – Conservation District

NEUTRAL

These conservation land use areas may be identified in municipal plans as being geographically or topologically unsuitable for development, yet contain language that allows for some types of development. These areas have not been included on the Regional Energy Generation maps. Municipal conservation land use areas that meet this description include:

- Berkshire – Conservation District
- Georgia – Natural Areas District
- Georgia – Recreation District
- South Hero – Conservation District

DEVELOPMENT MAY OCCUR

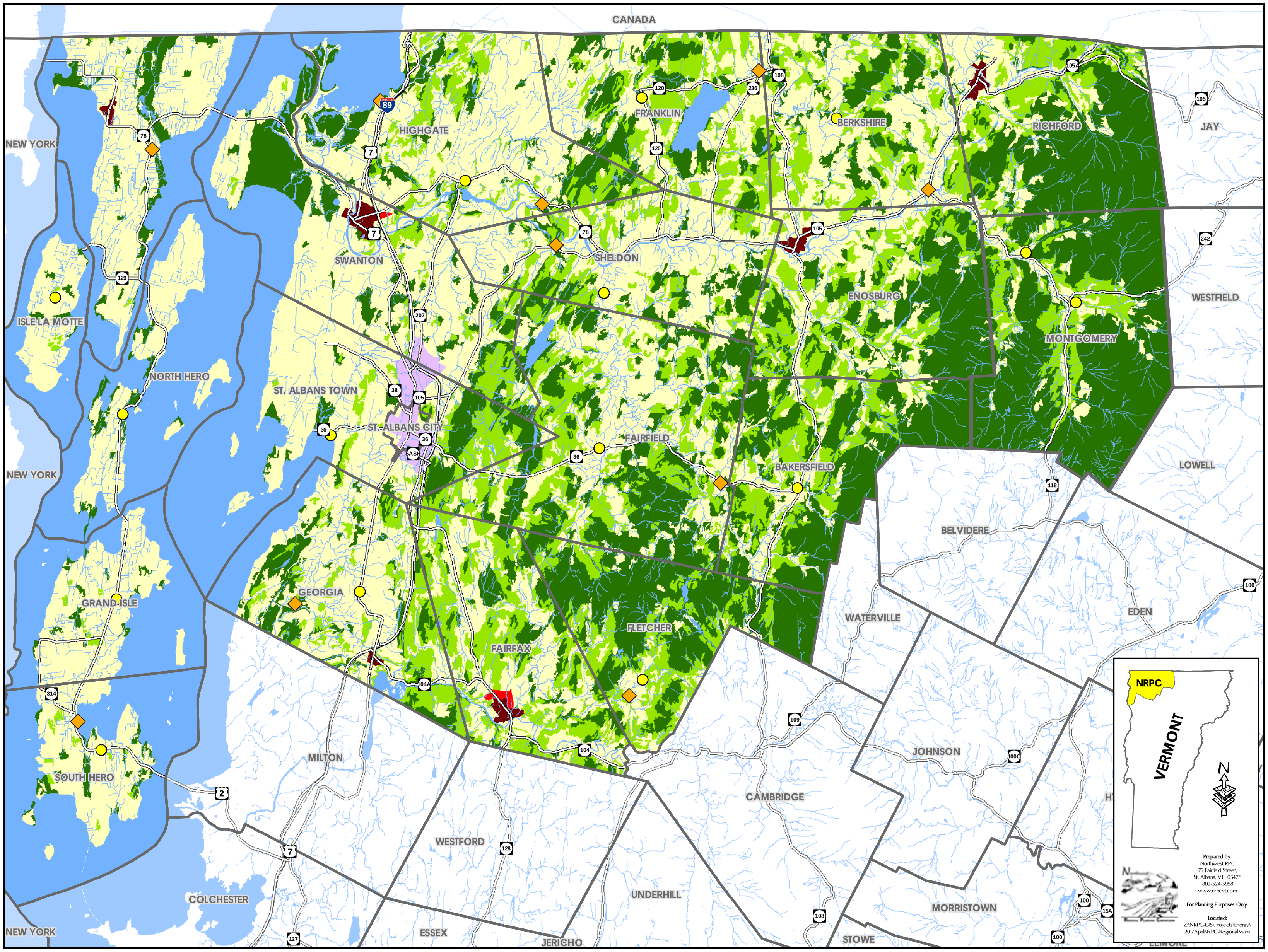
These conservation land use areas do not contain language that restricts development. These areas have not been included on the Regional Energy Generation maps. Municipal conservation land use areas that meet this description include:

- Franklin – Conservation District

APPENDIX

C

APPENDIX C - REGIONAL GENERATION MAPS



Proposed Land Use

Northwest Region, VT
Act 174
Energy Development Improvement Act of 2016

This map and the corresponding data is intended to be used to inform energy planning efforts by municipalities and regions. This may also be used for conceptual planning or initial site identification by those interested in developing renewable energy infrastructure. The maps do **NOT** take the place of site-specific investigation for a proposed facility and cannot be used of as "siting maps."

Legend

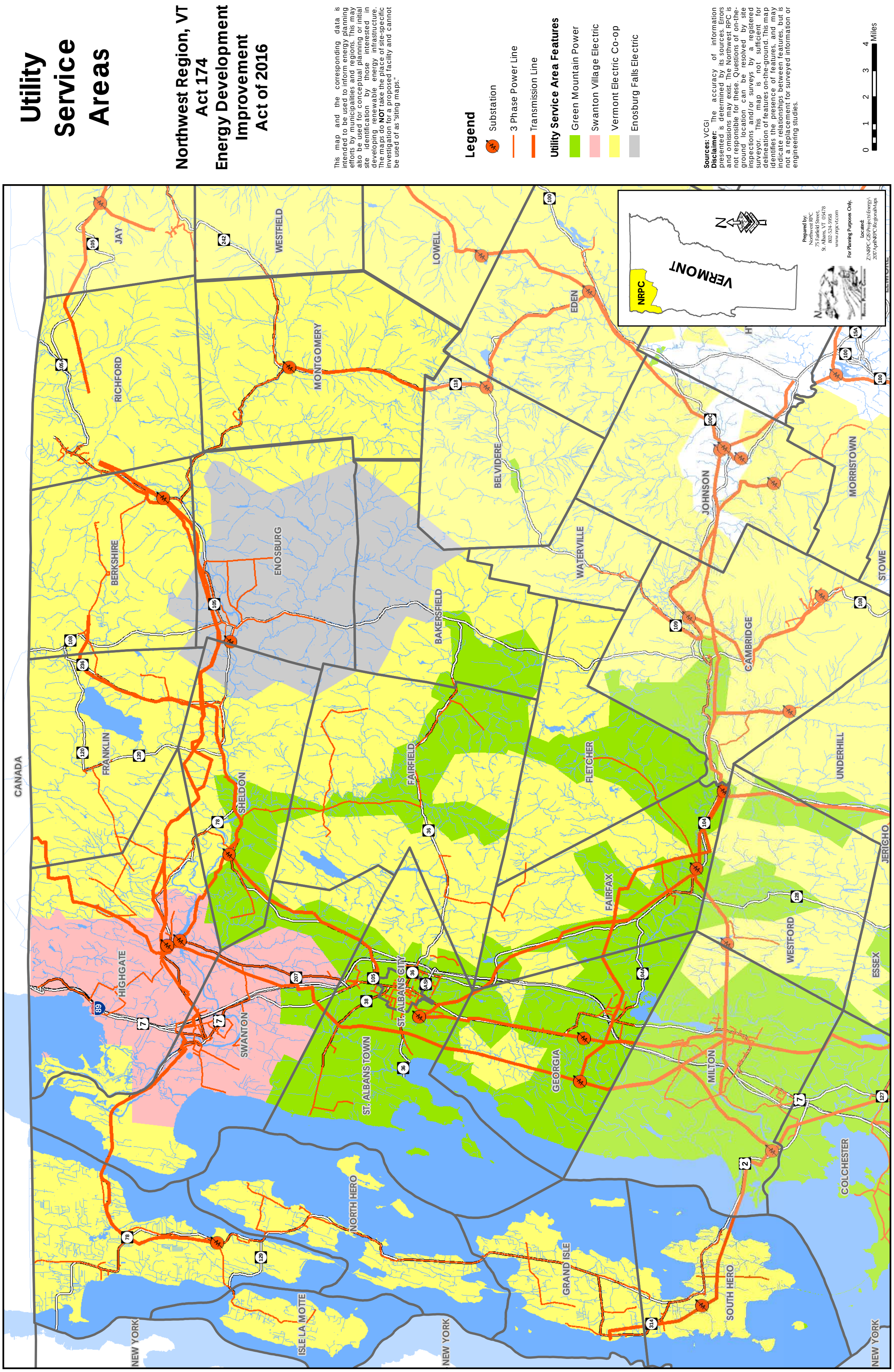
- Village
- Hamlet

Proposed Land Use Features

- Regional Growth Area
- Sub-Regional Growth Area
- Transitional Growth Area
- Agricultural Resource Planning Area
- Conservation & Forest Resource Planning Area
- Rural Planning Area

Sources: VCGI
Disclaimer: The accuracy of information presented is determined by its sources. Errors and omissions may exist. The Northwest RPC is not responsible for these. Questions of on-the-ground location can be resolved by site inspections and/or surveys by a registered surveyor. This map is not sufficient for delineation of features on-the-ground. This map identifies the presence of features, and may indicate relationships between features, but is not a replacement for surveyed information or engineering studies.

0 1 2 3 4 Miles


Utility Service Areas
Northwest Region, VT
Act 174
Energy Development Improvement Act of 2016
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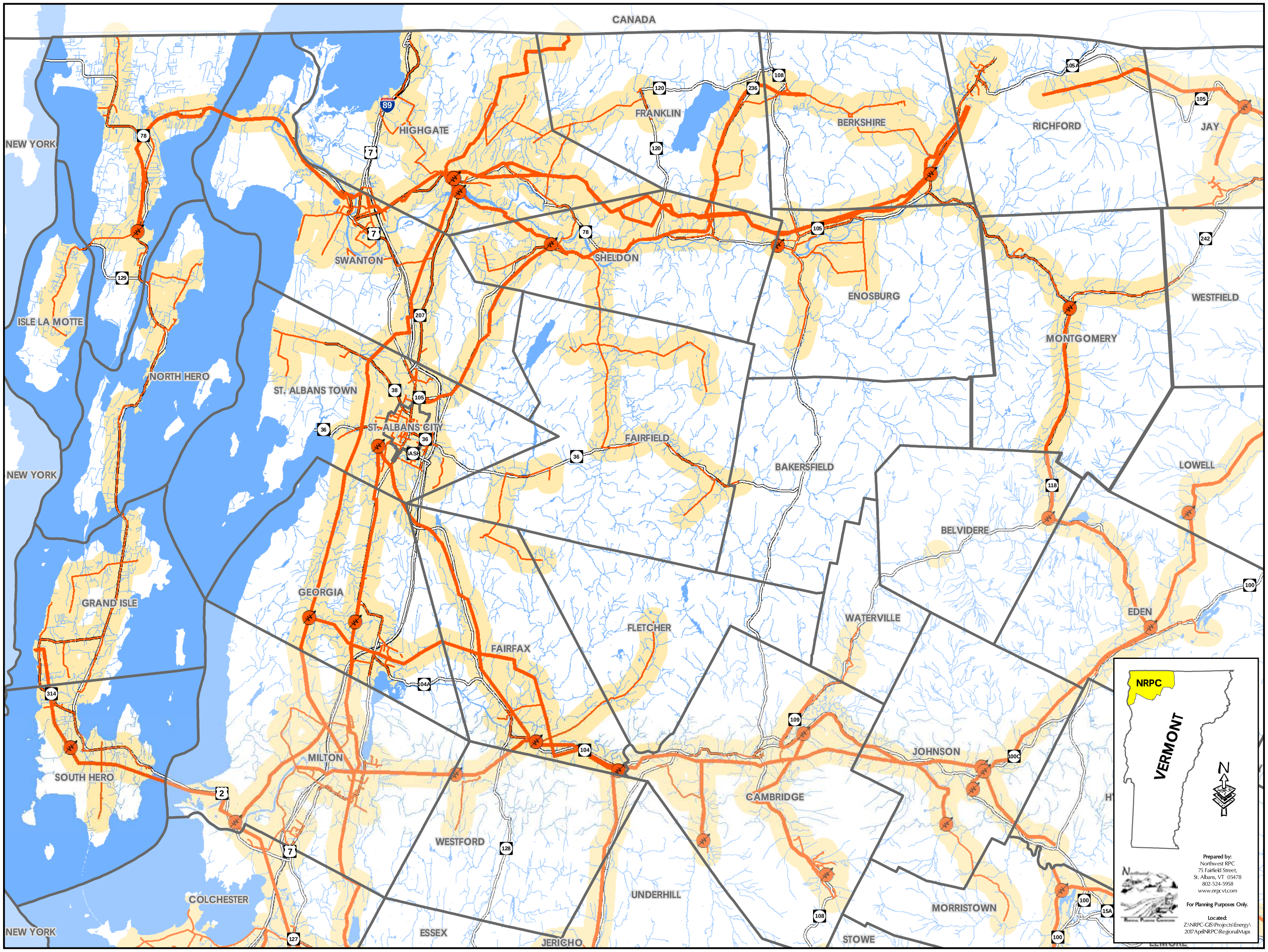
Legend
Substation
3 Phase Power Line
Transmission Line
Utility Service Area Features
Green Mountain Power
Swanton Village Electric
Vermont Electric Co-op
Enosburg Falls Electric
Sources: VCGI
Disclaimer: The accuracy of information presented is determined by its sources. Errors and omissions may exist. The Northwest RPC is not responsible for these. Questions of on-the-ground location can be resolved by site inspections and/or surveys by a registered surveyor. This map is not sufficient for delineation of features on-the-ground. This map identifies the presence of features, and may indicate relationships between features, but is not a replacement for surveyed information or engineering studies.
0 1 2 3 4 Miles
CANADA
NEW YORK
HIGHGATE
FRANKLIN
BERKSHIRE
RICHFORD
JAY
SWANTON
SHELDON
ENOSBURG
WESTFIELD
MONTGOMERY
ISLE LA MOTTE
NORTH HERO
ST. ALBANS TOWN
ST. ALBANS CITY
FAIRFIELD
BAKERSFIELD
LOWELL
BELVIDERE
GRAND ISLE
GEORGIA
FLETCHER
WATERVILLE
EDEN
FAIRFAX
SOUTH HERO
MILTON
JOHNSON
CAMBRIDGE
WESTFORD
COLCHESTER
UNDERHILL
MORRISTOWN
ESSEX
JERICHO
STOWE
NRPC
VERMONT
N
Prepared by:
Northwest RPC
75 Fairfield Street,
St. Albans, VT 05478
802-524-5958
www.nrpcvt.com
For Planning Purposes Only.
Located:
Z:\NRPC-GIS\Projects\Energy\2017April\NRPC\RegionalMaps

Transmission and 3 Phase Power Infrastructure

Northwest Region, VT Act 174 Energy Development Improvement Act of 2016



This map and the corresponding data is intended to be used to inform energy planning efforts by municipalities and regions. This may also be used for conceptual planning or initial site identification by those interested in developing renewable energy infrastructure. The maps do **NOT** take the place of site-specific investigation for a proposed facility and cannot be used of as "siting maps."

Legend

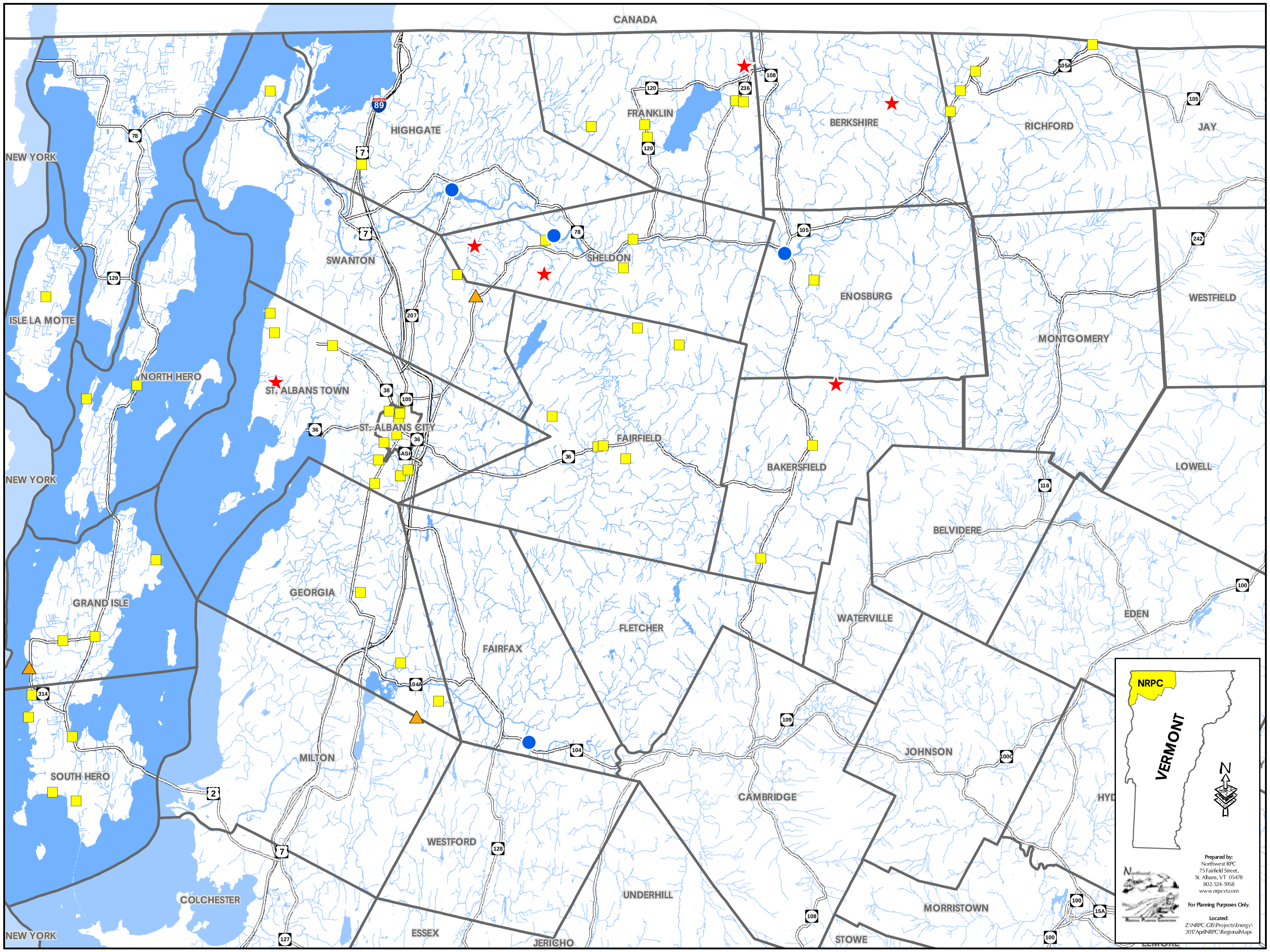
- Substation
- 3 Phase Power Line
- Transmission Line
- 1/2 Mile Buffer (3 Phase Power Line & Transmission Line)

Sources: VCGI
Disclaimer: The accuracy of information presented is determined by its sources. Errors and omissions may exist. The Northwest RPC is not responsible for these. Questions of on-the-ground location can be resolved by site inspections and/or surveys by a registered surveyor. This map is not sufficient for delineation of features on-the-ground. This map identifies the presence of features, and may indicate relationships between features, but is not a replacement for surveyed information or engineering studies.

0 1 2 3 4 Miles

Existing Generation Facilities

Northwest Region, VT Act 174 Energy Development Improvement Act of 2016



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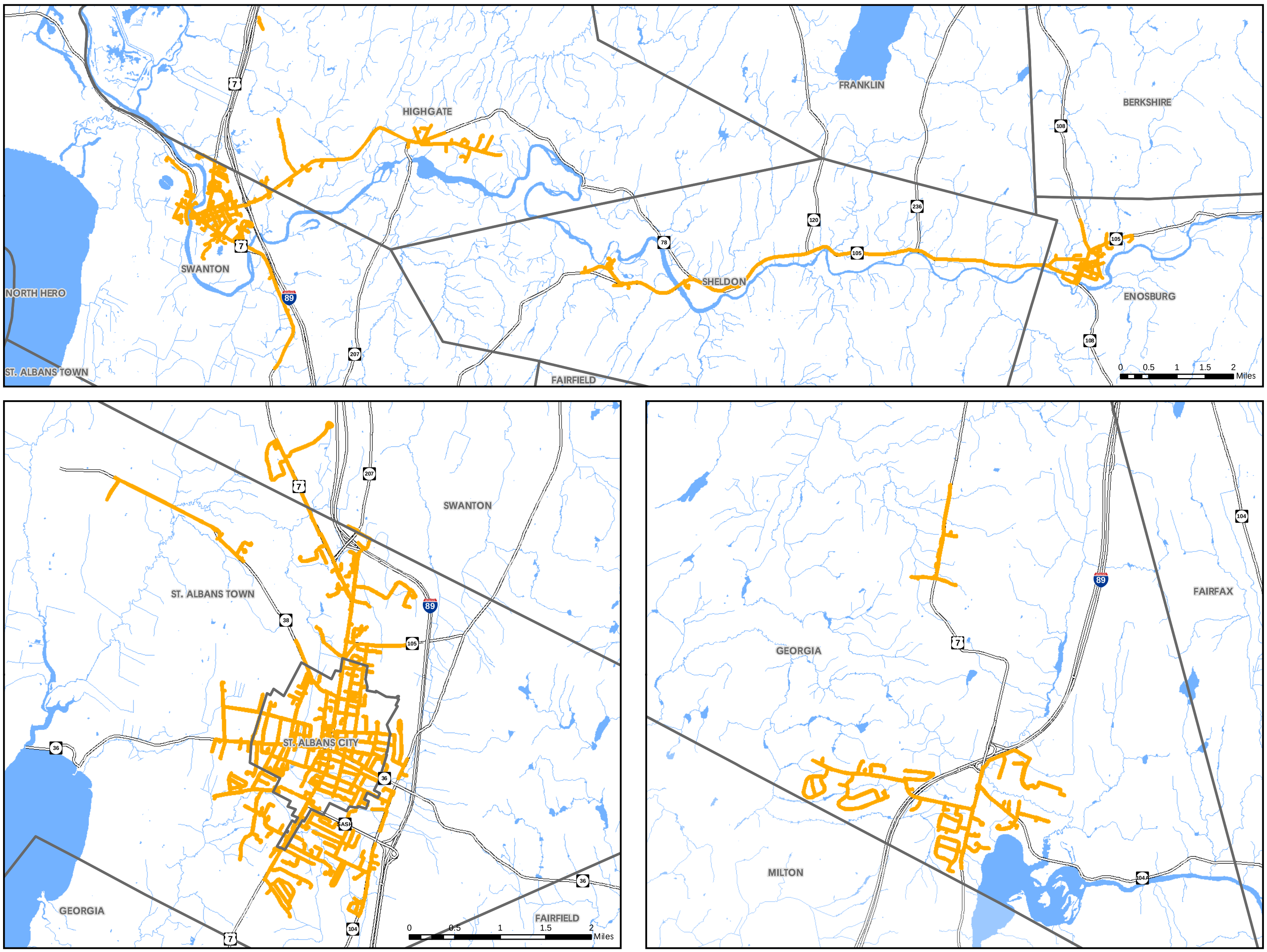
Legend

- Biomass Facility
- Hydro Facility
- Solar Facility
- Wind Facility

Note: Only generators 15kW are shown on the map. A full list of all generators is available.

Sources: VCGI
Disclaimer: The accuracy of information presented is determined by its sources. Errors and omissions may exist. The Northwest RPC is not responsible for these. Questions of on-the-ground location can be resolved by site inspections and/or surveys by a registered surveyor. This map is not sufficient for delineation of features on-the-ground. This map identifies the presence of features, and may indicate relationships between features, but is not a replacement for surveyed information or engineering studies.

0 1 2 3 4 Miles



Natural Gas Lines

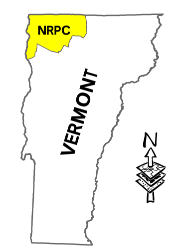
Northwest Region, VT Act 174 Energy Development Improvement Act of 2016

This map and the corresponding data is intended to be used to inform energy planning efforts by municipalities and regions. This may also be used for conceptual planning or initial site identification by those interested in developing renewable energy infrastructure. The maps do **NOT** take the place of site-specific investigation for a proposed facility and cannot be used of as "siting maps."

Legend

Natural Gas Line

Sources: VCGI
Disclaimer: The accuracy of information presented is determined by its sources. Errors and omissions may exist. The Northwest RPC is not responsible for these. Questions of on-the-ground location can be resolved by site inspections and/or surveys by a registered surveyor. This map is not sufficient for delineation of features on-the-ground. This map identifies the presence of features, and may indicate relationships between features, but is not a replacement for surveyed information or engineering studies.



Prepared by:
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St. Albans, VT 05478
802-524-5958
www.nrpcvt.com

For Planning Purposes Only.

Located:
Z:\NRPC-GIS\Projects\Energy\2017AprilNRPC\RegionalMaps


Hydro
Northwest Region, VT
Act 174
Energy Development
Improvement
Act of 2016
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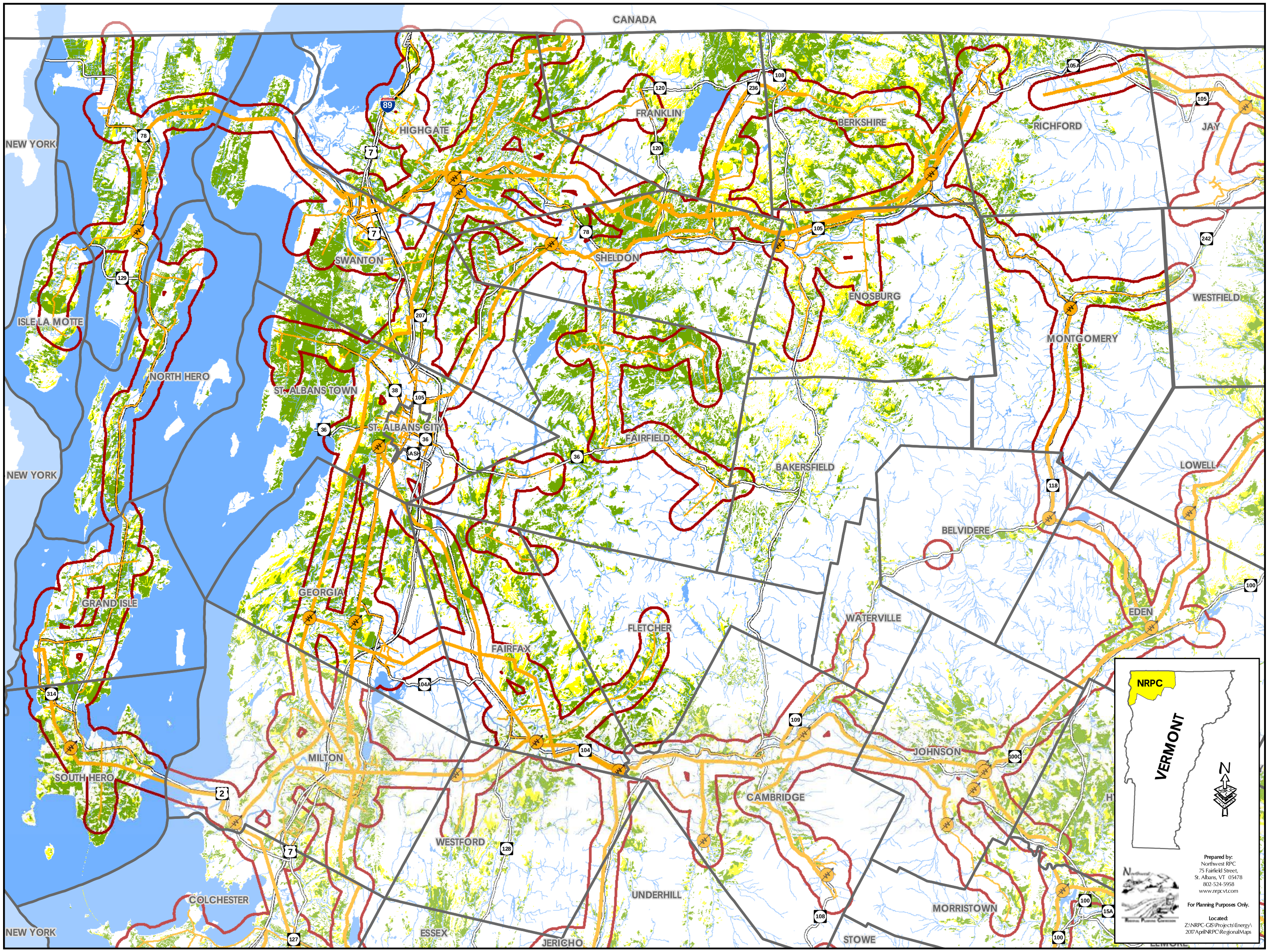
Legend
Substation
3 Phase Power Line
Transmission Line
Designated Outstanding Resource Water
Known Constraint - Designated National Wild & Scenic River
Possible Constraint - Stressed or Impaired Water
Possible Constraint - RINAs
Potential Hydroelectric Facility
< 50 kW Capacity
> 50 kW Capacity
High Hazard with < 50 kW Capacity
High Hazard with > 50 kW Capacity
Operating Hydroelectric Facility
Dam not on National Wild and Scenic River
Dam on National Wild and Scenic River
Sources: VCGI
Disclaimer: The accuracy of information presented is determined by its sources. Errors and omissions may exist. The Northwest RPC is not responsible for these. Questions of on-the-ground location can be resolved by site inspections and/or surveys by a registered surveyor. This map is not sufficient for delineation of features on-the-ground. This map identifies the presence of features, and may indicate relationships between features, but is not a replacement for surveyed information or engineering studies.
0 1 2 3 4 Miles
CANADA
NEW YORK
VERMONT
NRPC
For Planning Purposes Only.
JAY
WESTFIELD
LOWELL
RICHFORD
MONTGOMERY
EDEN
BELVIDERE
JOHNSON
MORRISTOWN
BERKSHIRE
ENOSBURG
WATERVILLE
STOWE
BAKERSFIELD
CAMBRIDGE
FRANKLIN
SHELDON
FAIRFIELD
FLETCHER
UNDERHILL
JERICHO
HIGHGATE
SWANTON
ST. ALBANS CITY
ST. ALBANS TOWN
FAIRFAX
WESTFORD
ESSEX
GEORGIA
MILTON
COLCHESTER
NORTH HERO
GRAND ISLE
SOUTH HERO
ISLE LA MOTTE

Solar

Northwest Region, VT Act 174 Energy Development Improvement Act of 2016



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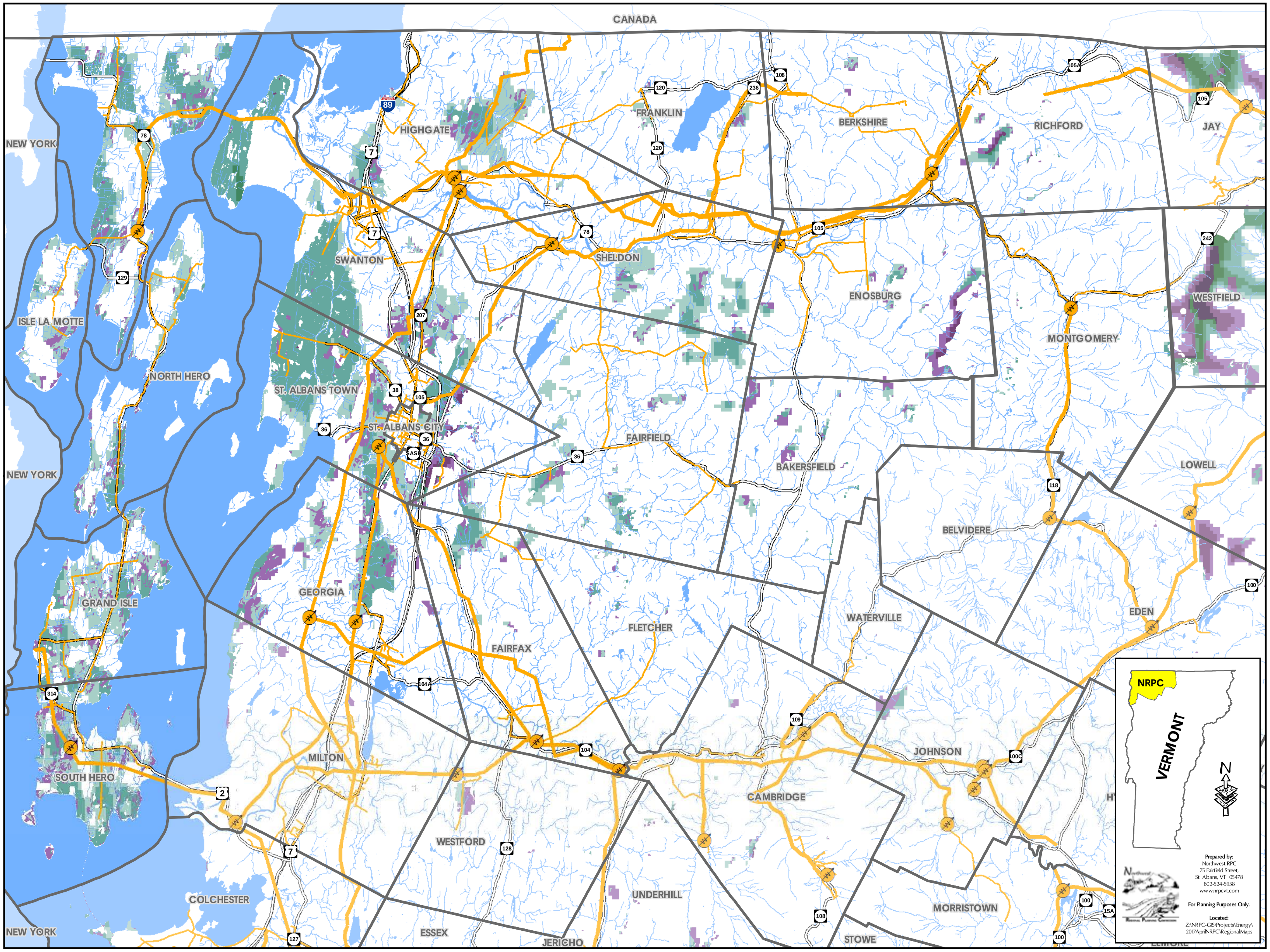
Legend

- Substation
- 3 Phase Power Line
- Transmission Line
- 1/2 Mile Buffer (3 Phase Power Line & Transmission Line)
- Prime Solar/No Known Constraints
- Base Solar/Possible Constraints

Sources: VCGI
Disclaimer: The accuracy of information presented is determined by its sources. Errors and omissions may exist. The Northwest RPC is not responsible for these. Questions of on-the-ground location can be resolved by site inspections and/or surveys by a registered surveyor. This map is not sufficient for delineation of features on-the-ground. This map identifies the presence of features, and may indicate relationships between features, but is not a replacement for surveyed information or engineering studies.

0 1 2 3 4 Miles



Wind

Northwest Region, VT Act 174 Energy Development Improvement Act of 2016

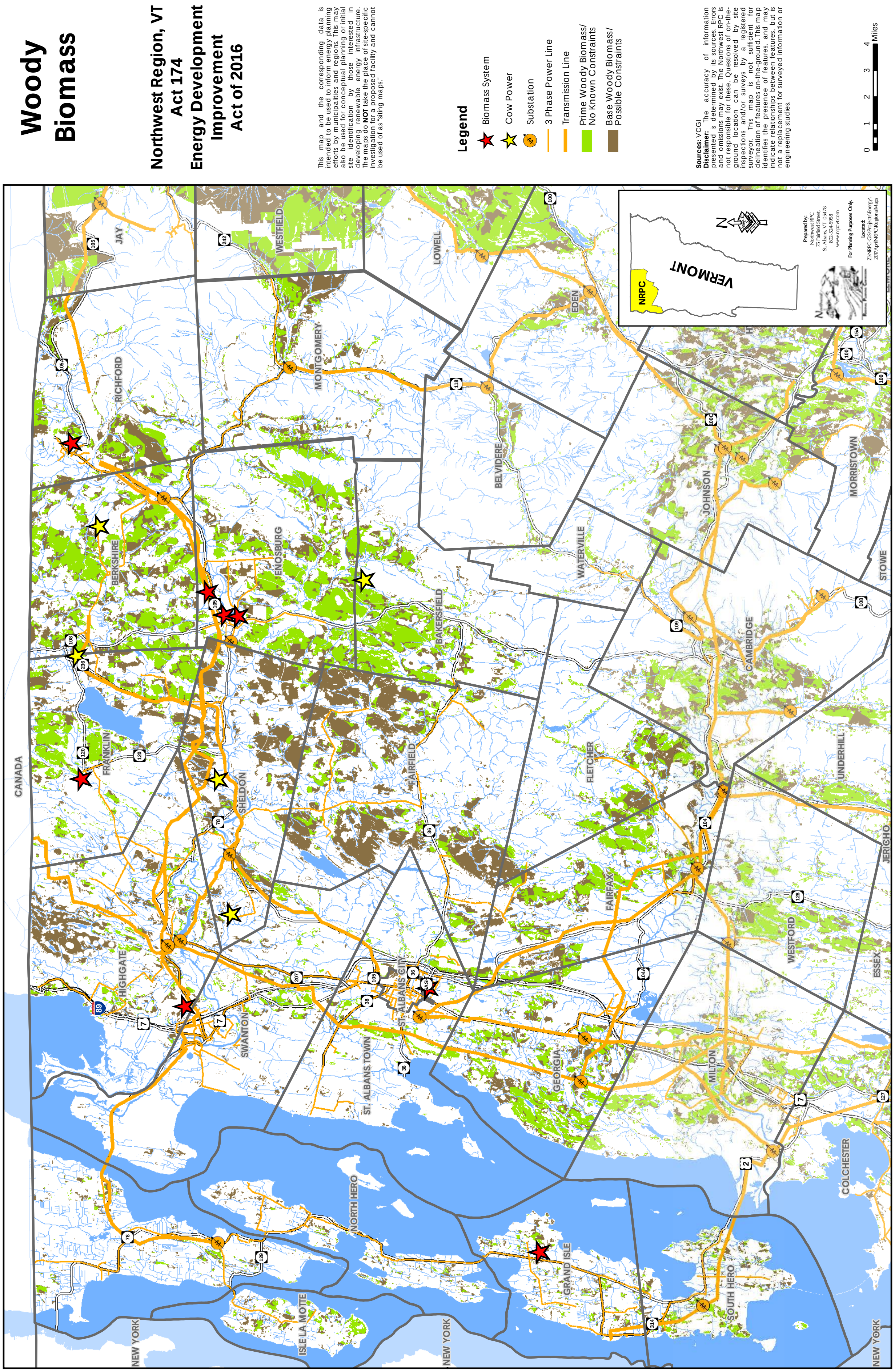
This map and the corresponding data is intended to be used to inform energy planning efforts by municipalities and regions. This may also be used for conceptual planning or initial site identification by those interested in developing renewable energy infrastructure. The maps do **NOT** take the place of site-specific investigation for a proposed facility and cannot be used of as "siting maps."

Legend

- Substation
- 3 Phase Power Line
- Transmission Line
- **Prime Wind**
  Areas of high wind potential and no known constraints.
  Darker areas have higher wind speeds.
- **Base Wind**
  Areas of high wind potential and a presence of possible constraints.
  Darker areas have higher wind speeds.

Sources: VCGI
Disclaimer: The accuracy of information presented is determined by its sources. Errors and omissions may exist. The Northwest RPC is not responsible for these. Questions of on-the-ground location can be resolved by site inspections and/or surveys by a registered surveyor. This map is not sufficient for delineation of features on-the-ground. This map identifies the presence of features, and may indicate relationships between features, but is not a replacement for surveyed information or engineering studies.

0 1 2 3 4 Miles


Woody Biomass
Northwest Region, VT
Act 174
Energy Development Improvement Act of 2016
This map and the corresponding data is intended to be used to inform energy planning efforts by municipalities and regions. This may also be used for conceptual planning or initial site identification by those interested in developing renewable energy infrastructure. The maps do NOT take the place of site-specific investigation for a proposed facility and cannot be used of as "siting maps."
Legend
Biomass System
Cow Power
Substation
3 Phase Power Line
Transmission Line
Prime Woody Biomass/ No Known Constraints
Base Woody Biomass/ Possible Constraints
Sources: VCGI
Disclaimer: The accuracy of information presented is determined by its sources. Errors and omissions may exist. The Northwest RPC is not responsible for these. Questions of on-the-ground location can be resolved by site inspections and/or surveys by a registered surveyor. This map is not sufficient for delineation of features on-the-ground. This map identifies the presence of features, and may indicate relationships between features, but is not a replacement for surveyed information or engineering studies.
0 1 2 3 4 Miles
CANADA
NEW YORK
VERMONT
NRPC
JAY
WESTFIELD
LOWELL
EDEN
RICHFORD
MONTGOMERY
BELVIDERE
JOHNSON
MORRISTOWN
BERKSHIRE
ENOSBURG
WATERVILLE
STOWE
BAKERSFIELD
CAMBRIDGE
FRANKLIN
SHELDON
FAIRFIELD
FLETCHER
UNDERHILL
HIGHGATE
JERICHO
FAIRFAX
WESTFORD
SWANTON
ST. ALBANS CITY
ST. ALBANS TOWN
GEORGIA
MILTON
ESSEX
COLCHESTER
NORTH HERO
ISLE LA MOTTE
GRAND ISLE
SOUTH HERO
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APPENDIX

D

APPENDIX D - SUMMARY OF PLANNING APPROACH AND PROCESS

APPENDIX D - SUMMARY OF PLANNING APPROACH AND PROCESS

This plan is the result of more than two years of work completed by NRPC staff, NRPC commissioners, and various stakeholders throughout the region and the state. This plan builds on previous energy planning efforts in the region and the efforts of the Public Service Department.

During the spring, summer, and fall of 2015, the NRPC worked with two other regional planning commissions—the Bennington County Regional Commission and the Two Rivers-Ottauquechee Regional Commission—to meet with stakeholders and discuss several issues. Meeting topics included the following: mapping and geographic information, thermal efficiency, transportation, and electricity conservation and efficiency. From these stakeholder meetings, many of the strategies in Section IV and Section V were formulated. The NRPC also worked to collect a large amount of the data used in the plan—much of which is cataloged in Section III—during this same time period.

Starting in the summer of 2015, the NRPC formed a Regional Energy Committee. Composed primarily of regional commissioners, the 12 members of the committee met monthly to discuss the development of the plan. Much of the committee's early work consisted of aiding staff in the development of the Regional Energy Generation Maps discussed in Section IV. The committee also provided direction for the development of this plan.

The NRPC held two public meetings in December 2015—one in North Hero and the other in Enosburg Falls—to inform the public about the project and to solicit public input regarding the Renewable Energy Generation Maps. This public input was then analyzed and assessed by the Regional Energy Committee and incorporated into this plan.

A first draft of the plan was reviewed by the NRPC Energy Committee and the Department of Public Service in the summer of 2016. Additional revisions were made, and a draft was released for public comment in October 2016. After releasing the draft plan, the NRPC collected comments from individuals, municipalities, public utilities, and other regional stakeholders. These comments influenced the content—including the strategies and energy generation maps—and the construction of the adopted Regional Energy Plan.

Additional revisions were made to the draft Regional Energy Plan after the release of the "Regional Determination Standards" by the Vermont Department of Public Service in November 2016. The plan then underwent hearings before the Board of Regional Commissioners in May 2017 and June 2017.

The following organizations were integral to the development of the plan through their involvement in the stakeholders process in 2015 or through direct feedback on drafts of the plan released by the NRPC 2016 and 2017:

- Champlain Valley Office of Economic Opportunity
- Chittenden County Regional Planning Commission
- Energy Action Network
- Green Mountain Power
- NeighborWorks of Western Vermont
- Renewable Energy Vermont
- VELCO
- Vermont Agency of Commerce and Community Development
- Vermont Agency of Transportation
- Vermont Center for Geographic Information
- Vermont Energy Investment Corporation and Efficiency Vermont
- Vermont Electric Cooperative
- Vermont Gas
- Vermont Natural Resources Council
- Vermont Public Power Supply Authority
- Vermont Public Transportation Association
- Vermont Public Service Department
- Vermont Sustainable Jobs Fund
- Village of Swanton Electric Department
- Village of Enosburg Falls Electric Department
- Vital Communities

APPENDIX

E

APPENDIX E - LISTS OF ACRONYMS

APPENDIX E - LISTS OF ACRONYMS

- ACCD – Vermont Agency of Commerce and Community Development
- ACS – American Community Survey
- ANR – Vermont Agency of Natural Resources
- BCRC – Bennington County Regional Commission
- BERC – Biomass Energy Resource Center
- BTU – British thermal unit
- CBES – Commercial Building Energy Standards
- CCRPC – Chittenden County Regional Planning Commission
- C.I.D.E.R. - Champlain Islanders Developing Essential Resources
- CNG – compressed natural gas
- CPG – Certificate of Public Good
- CVOEO – Champlain Valley Office of Economic Opportunity
- DC – direct current
- EAN – Energy Action Network
- EIA – Energy Information Administration
- ESP – energy service provider
- EV – electric vehicle
- EVT – Efficiency Vermont
- FCIDC – Franklin County Industrial Development Corporation
- GMP – Green Mountain Power
- GMT – Green Mountain Transit
- GT – green tons
- kW – kilowatts
- LEAP – Long-range Energy Alternatives Planning
- LP(G) – liquefied petroleum gas (propane)
- NAICS - North American Industry Classification System
- NALG – net available low-grade growth (wood)
- NRPC – Northwest Regional Planning Commission
- NYPA – New York Power Authority
- MW – megawatts
- PSB – Public Service Board
- RBES – Residential Building Energy Standards
- REC – Renewable Energy Credit
- RINAs – rare and irreplaceable natural resources
- RPC - regional planning commission
- TES – Total Energy Study
- TPI – Transportation Planning Initiative
- TRORC – Two Rivers-Ottauquechee Regional Commission
- VCGI – Vermont Center for Geographic Information
- VEC – Vermont Electric Cooperative
- VEIC – Vermont Energy Investment Corporation
- VELCO – Vermont Electric Power Company
- VMT – vehicle miles traveled
- VPPSA – Vermont Public Power Supply Authority
- VTrans – Vermont Agency of Transportation
- VY – Vermont Yankee

APPENDIX

F

APPENDIX F - NORTHWEST REGION - EXISTING RENEWABLE GENERATION FACILITY SUMMARY

APPENDIX F - NORTHWEST REGION - EXISTING RENEWABLE GENERATION FACILITY SUMMARY

The following is a summary of all existing renewable generation facilities in the Northwest Region organized by municipality. For maps showing the location of each renewable generation facility in the region, please visit the Energy Action Network's Community Energy Dashboard: http://www.vtenergydashboard.org/.

EXISTING REGIONAL GENERATION

Municipality	Solar Facilities	Solar Generation Capacity (MW)	Wind Facilities	Wind Generation Capacity (MW)	Hydro Facilities	Hydro Generation Capacity (MW)	Anaerobic Digester Sites	Anaerobic Digester Capacity (MW)
Alburgh	15	0.11	0	0.000	0	0	0	0.00
Bakersfield	21	0.14	2	0.012	0	0	1	0.40
Berkshire	8	0.07	1	0.010	0	0	1	0.60
Enosburgh	23	0.29	2	0.003	1	2	0	0.00
Fairfax	73	0.43	1	0.003	1	3.6	0	0.00
Fairfield	38	0.74	3	0.025	0	0	0	0.00
Fletcher	19	0.11	0	0.000	0	0	0	0.00
Franklin	17	0.2	1	0.003	0	0	1	0.18
Georgia	70	0.71	3	5.017	0	0	0	0.00
Grand Isle	34	0.27	5	0.132	0	0	0	0.00
Highgate	13	0.09	0	0.000	1	9.4	0	0.00
Isle La Motte	6	0.08	0	0.000	0	0	0	0.00
Montgomery	11	0.07	0	0.000	0	0	0	0.00
North Hero	13	0.1	0	0.000	0	0	0	0.00
Richford	8	0.13	1	0.010	0	0	0	0.00
St Albans City	44	0.93	0	0.000	0	0	0	0.00
St Albans Town	109	4.33	3		0	0	1	0.30
Sheldon	23	2.5	0	0.000	1	26.38	2	0.83
South Hero	51	0.39	2	0.005	0	0	0	0.00
Swanton	42	0.79	2	0.029	0	0	0	0.00

***Source:** EAN Community Energy Dashboard*

See Appendices for Appendices G & H.