Northfield Electric Department

2019 Integrated Resource Plan

Filed with the Public Utility Commission

VPPSA
Vermont Public Power Supply Authority

EXECUTIVE SUMMARY

Incorporated in 1894, the Northfield Electric Department (NED) serves approximately 2,200 customers in Northfield, Berlin, and Moretown. Northfield, with just over 6,200 residents, is located in central Vermont, ten miles south of the State's capital, Montpelier. `It is home to Norwich University, one of NED's largest customers and the oldest private military college in the United States. As a small municipal utility NED is careful to balance maintaining reliability and reasonable cost levels with the need to deliver innovative programs to customers that provide practical value.

NED's distribution system serves a mix of residential, small, and large commercial customers. Residential customers make up over 85% of the customer mix while accounting for about a third of NED's retail kWh sales. Thirteen large commercial customers (about 1%) make up about 50% of retail usage with the remaining retail sales going to small commercial and public authority customers

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

NED 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 NED'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 NED's largest customers is currently anticipated, the potential does exist. Norwich University represents about 30% of NED's retail load with an additional twelve large customers accounting for another 20%. NED monitors the plans of these large customers in order to anticipate necessary changes to the existing system infrastructure. In the case of a significant expansion by one or more customers detailed engineering studies may be needed to identify necessary system upgrades,

ELECTRICITY SUPPLY

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

When considering future electricity demand, NED seeks to supplement its existing resources with market contracts as well as new demand-side and supply resources. NED 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. NED anticipates regional availability of competitively priced renewable resources including

solar, wind, and hydro. In addition to being a factor in meeting future electricity requirements, this category of resource contributes to meeting Renewal Energy Standard goals. Gas fired generation may have a role to play in the future portfolio for reliability purposes. As battery storage technology matures and proves economically feasible NED 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, NED employs an integrated financial model that takes into account impacts on load and subsequent effects on revenue and power supply costs, as well effects on investment, financing and operating costs. Use of the integrated model allows for evaluation of uncertainty related to key variables, on the way to identifying anticipated rate impacts over time. While rate trajectory is the primary metric NED 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.

NED faces three major energy resource decisions over the 2020 – 2039 period covered by this Integrated Resource Plan (IRP). The first of these involves the need to cover the roughly 10% of NED's energy requirement that is currently unhedged by long term contracts over the 2020 to 2022 period. Options being evaluated by NED include leaving the position unhedged, purchasing a fixed-price market contract for energy, or purchasing a fixed-price contract for hydro energy including RECs. The main factors expected to impact this decision are volatility in gas prices, which are a driver of New England energy prices, and expected pricing for RECs needed to meet NED's obligations under Vermont's Renewable Energy Standard.

The second and third major resource decisions faced by NED occur in 2023 and 2032, respectively. Both decisions come about due to the scheduled termination of current long-term contracts. Similar to the first decision described above, the evaluation of options to replace these resources is expected to be primarily influenced by energy price and REC price considerations. NED notes that the latter decision, which will nearly coincide with the expiration of the current renewable energy standard, may be subject to uncertainty arising from changes in RES requirements.

Because NED holds entitlements in capacity resources that exceed expected requirements based on demand, no capacity related resource decisions are anticipated.

RENEWABLE ENERGY STANDARD

NED is subject to the Vermont Renewable Energy Standard which imposes an obligation for NED 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. NED' 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 NED's TIER III obligation involves energy transformation, or reduction of fossil fuel use within its territory. TIER 3 programs can consist of thermal efficiency measures, electrification of the transportation sector, and converting customers that rely on diesel generation to electric service, among other things. By providing incentive programs to encourage conversion of traditional fossil fuel applications such as space heating, water heating, or electric vehicles to electric power, NED receives credits toward its TIER III obligation. More detail regarding NED's plans to meet its TIER III obligation is available in Appendix B to this document.

ELECTRICITY TRANSMISSION AND DISTRIBUTION

NED has a compact service territory as a result of being a small, municipal-owned electric utility and has benefitted from several major system improvements over the past 15 years, including an upgrade of distribution system voltage to 12.47kV. NED's distribution system consists of 39 miles of distribution line divided into four (4) distribution feeders in a cross-shaped configuration running generally north-south, and east-west from the center of town out of the King Street Substation. Most of the Norwich University load is served by the Norwich University Substation located on campus and fed from the King Street Substation. The capacity of the sub-transmission line to the Norwich University Substation is currently more than adequate to supply the NU campus and is currently loaded to less than half its capacity.

In addition to upgrading and routinely maintaining the system to ensure efficiency and reliability, NED is looking at the need to modernize so as to support additional distributed generation on the system and to provide more customer oriented services including load management programs that reduce costs for both NED and it's customers. NED 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.

NED sees potential value to customers by utilizing rate design, direct load control or other incentive programs as tools to manage both system and customer peak loads in unison. Implementation of an AMI system is expected to enhance NED's ability to deliver these benefits and capture economic development/retention opportunities where possible.

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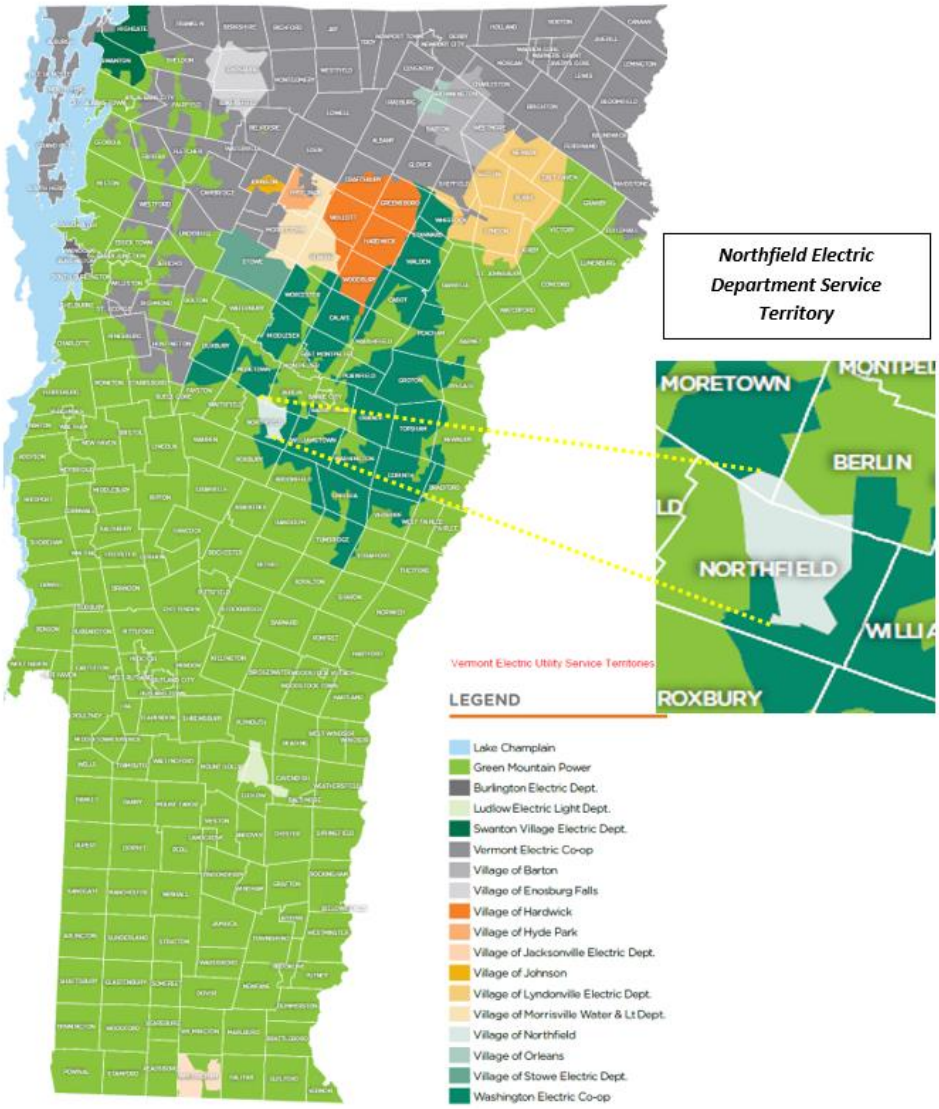
Glossary

CAGR	Compound Annual Growth Rate
CC	Combined Cycle (Power Plant)
CCHP	Cold Climate Heat Pump
DPS	Department of Public Service or "Department"
EIA	Energy Information Administration
ET	Energy Transformation (Tier III)
EV	Electric Vehicle
EVT	Efficiency Vermont
HPWH	Heat Pump Water Heater
IRP	Integrated Resource Plan
kVA	Kilovolt Amperes
MAPE	Mean Absolute Percent Error
MVA	Megavolt Ampere
MW	Megawatt
MWH	Megawatt-hour
NED	Northfield Electric Department
NYPA	New York Power Authority
PUC	Public Utility Commission
R^2	R-squared
RES	Renewable Energy Standard
RTLO	Real-Time Load Obligation
SCADA	Supervisory Control and Data Acquisition
TIER I	Total Renewable Energy (Tier I)
TIER II	Distributed Renewable Energy (Tier II)
TOU	Time-Of-Use (Rate)
VFD	Variable Frequency Drive
VSPC	Vermont System Planning Committee

INTRODUCTION

Chartered in 1781, Northfield is located in central Vermont, ten miles south of the State's capital, Montpelier. It is home to Norwich University, the oldest military college in the United States, and to just over 6,200 residents. Incorporated in 1894, the Northfield Electric Department (NED) serves approximately 2,200 customers in Northfield, Berlin, and Moretown.

Figure 1: NED'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.

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

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

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

SYSTEM OVERVIEW

NED's distribution system serves a mix of residential and commercial customers, the largest of which is Norwich University, which accounted for approximately 30% of Electric Department's retail sales in 2018. The following tables show NED's number of customers, retail sales and system peaks for the past five years.

Table 1: NED's Retail Customer Counts

Data Element	2014	2015	2016	2017	2018
Residential (440)	1,620	1,614	1,609	1,604	1,610
Norwich University	1	1	1	1	1
Small C&I (442) 1000 Kw or less	173	176	178	180	176
Large C&I (442) above 1,000 Kw	15	15	14	12	12
Street Lighting (444)	334	324	327	329	330
Public Authorities (445)	25	25	25	26	27
Interdepartmental Sales (448)	55	55	58	57	53
Total	**2,223**	**2,210**	**2,212**	**2,209**	**2,209**

Table 2: NED's Retail Sales (kWh)

Data Element	2014	2015	2016	2017	2018
Residential (440)	10,547,695	10,094,690	10,065,357	9,862,631	10,189,153
Norwich University	8,494,809	8,703,707	8,784,278	8,391,724	8,525,879
Small C&I (442) 1000 Kw or less	2,346,696	2,409,467	2,278,633	2,405,120	2,420,080
Large C&I (442) above 1,000 Kw	6,033,259	5,987,355	5,363,262	5,101,865	5,268,015
Street Lighting (444)	108,413	50,347	51,366	51,467	51,835
Public Authorities (445)	1,997,647	1,829,590	1,782,209	1,746,710	1,724,910
Interdepartmental Sales (448)	41,502	39,005	40,427	40,471	37,403
Total	**29,570,021**	**29,114,161**	**28,365,532**	**27,599,988**	**28,217,275**
YOY	1%	-2%	-3%	-3%	2%

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

Data Element	2014	2015	2016	2017	2018
Peak Demand kW	5,105	5,119	4,831	4,910	5,126
Peak Demand Date	01/22/14	09/08/15	01/19/16	09/27/17	09/05/18

Peak Demand Hour	18	20	18	20	20

Finally, NED does not own or operate any generation plants. Instead, it supplies electricity to its customers with contractual entitlements to power plants and wholesale market contracts throughout the region. NED's territory does contain a privately-owned hydro facility on the Dog River at Nantanna that produces about 675 MWh per year. NED is considering potential options for this hydro facility, such as a net-metering type of arrangement, upon the 2020 expiration of the private owner's contract. The facility is licensed by FERC (#6757). The facility is connected to feeder 54G2 at pole # 165205

STRUCTURE OF REPORT

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

ELECTRICITY DEMAND

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

ELECTRICITY SUPPLY

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

RESOURCE PLANS

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

ELECTRICITY TRANSMISSION AND DISTRIBUTION

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

FINANCIAL ANALYSIS

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

ACTION PLAN

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

APPENDIX

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

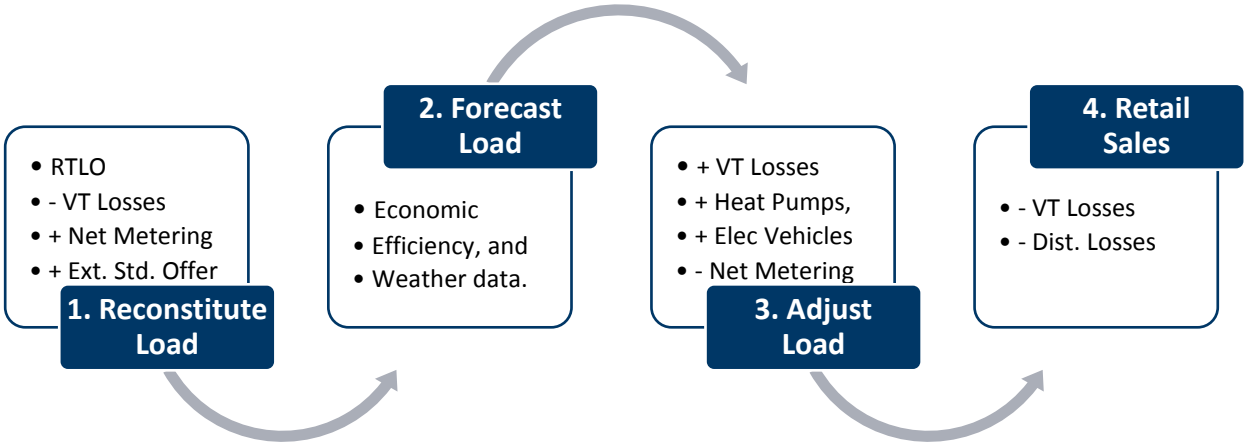
ELECTRICITY DEMAND

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 NED'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 NED'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 tiepoints (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 3: 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	

[1] Vermont Electric Power Company

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 4.

Table 4: 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 electricity 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 very good. Based on monthly data, it has an R-squared of 92%, and a Mean Absolute Percent Error (MAPE) of 1.27%.

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 Northfield. 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

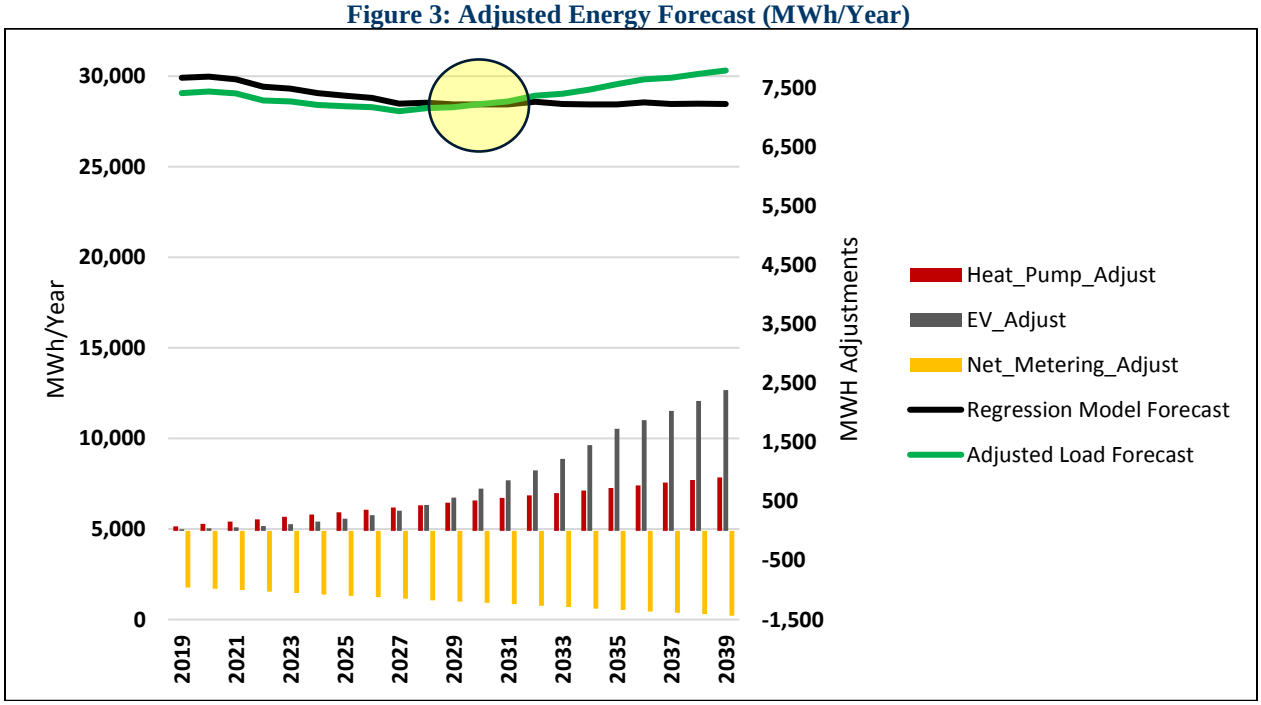
Table 5 shows the results of the Regression Forecast for energy, as well as the adjustments that are made to arrive at the Adjusted Forecast. The Compound Annual Growth Rates (CAGR) at the bottom of the table illustrate the trends in each of the columns. Notice that the Regression Forecast itself is declining by 0.2% per year. After making adjustments for CCHPs, EVs, and net metering, the Adjusted Forecast actually increases by 0.2% per year.

Table 5: 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	29,975	117	41	-982	29,151
2025	6	28,916	316	207	-1,099	28,340
2030	11	28,441	516	717	-1,218	28,456
2035	16	28,441	728	1,729	-1,338	29,560
2039	20	28,458	905	2,384	-1,433	30,313
CAGR		**-0.2%**	**12.3%**	**24.0%**	**1.9%**	**0.2%**

The Adjusted Forecast is the result of high CAGRs for CCHPs (12.3%) and EVs (24%). But during the first ten 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 1.9% per year. By year eleven, the impact of CCHPs and EVs is greater than the impact of net metering, and the cross-over point can be seen in the yellow-highlighted circle in Figure 3.

Figure 3: Adjusted Energy Forecast (MWh/Year)



All of the trends in these adjustments are highly uncertain. However, they do offset each other, and their collective impact on the forecast is small. Specifically, their individual and collective impact represents fractions of 1%, which falls well within the forecast error (1.27%).

ENERGY FORECAST – HIGH & LOW CASES

To form a high case, we assumed that the CAGRs for CCHPs doubles to 25%, and the growth rate for EVs rises to 35%. Simultaneously, we assume that net metering penetration stops at today's levels. At these growth rates, the market penetration for CCHPs and EVs reaches approximately 100% (all 2,200 customers) in 2039. This is admittedly a rough underestimate because most households and buildings will have more than one CCHP and more than one car. Nevertheless, it gives a reasonable indication of the kind of growth in energy use that is possible: 2.7% per year. This growth rate results in a 70% increase over 2020 electricity use.

Table 6: Energy Forecast – High Case

Year	Year #	Regression Fcst. (MWh)	CCHP Adjustment (MWh)	EV Adjustment (MWh)	Net Metering Adjustment (MWh)	Adjusted Fcst. (MWh)
2020	1	29,975	117	41	-982	29,151
2025	6	28,916	379	184	-982	28,497
2030	11	28,441	1,228	824	-982	29,511
2035	16	28,441	3,977	3,696	-982	35,132
2039	20	28,458	10,184	12,278	-982	49,938
CAGR		**-0.2%**	**25.0%**	**33.0%**	**0.0%**	**2.7%**

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 more than doubles. This combination of trends is a plausible worst-case scenario, and results in a forecast that *decreases* by 0.4% per year. Like the base case, this rate of change is well within the forecast error.

Table 7: Energy Forecast - Low Case

Year	Year #	Regression Fcst. (MWh)	CCHP Adjustment (MWh)	EV Adjustment (MWh)	Net Metering Adjustment (MWh)	Adjusted Fcst. (MWh)
2020	1	29,975	117	41	-982	29,151
2025	6	28,916	151	68	-1206	27,929
2030	11	28,441	196	112	-1482	27,268
2035	16	28,441	254	186	-1820	27,060
2039	20	28,458	312	278	-2146	26,902
CAGR		**-0.2%**	**5.0%**	**10.0%**	**4.0%**	**-0.4%**

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 extremes weather conditions, in reality extreme weather *is* normal.

The accuracy of the peak forecast regression model is good. Based on daily data, it has an R-squared of 80%, and a MAPE of 4.25%.

PEAK FORECAST RESULTS

Table 8 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 declining by 0.4% per year. After making adjustments for CCHPs, EVs, and net metering, the Adjusted Forecast actually increases by 0.1% per year. Finally, the table shows that the timing of NED's peak load is forecast to stay in the winter months, at hour 1800 (6:00 PM).

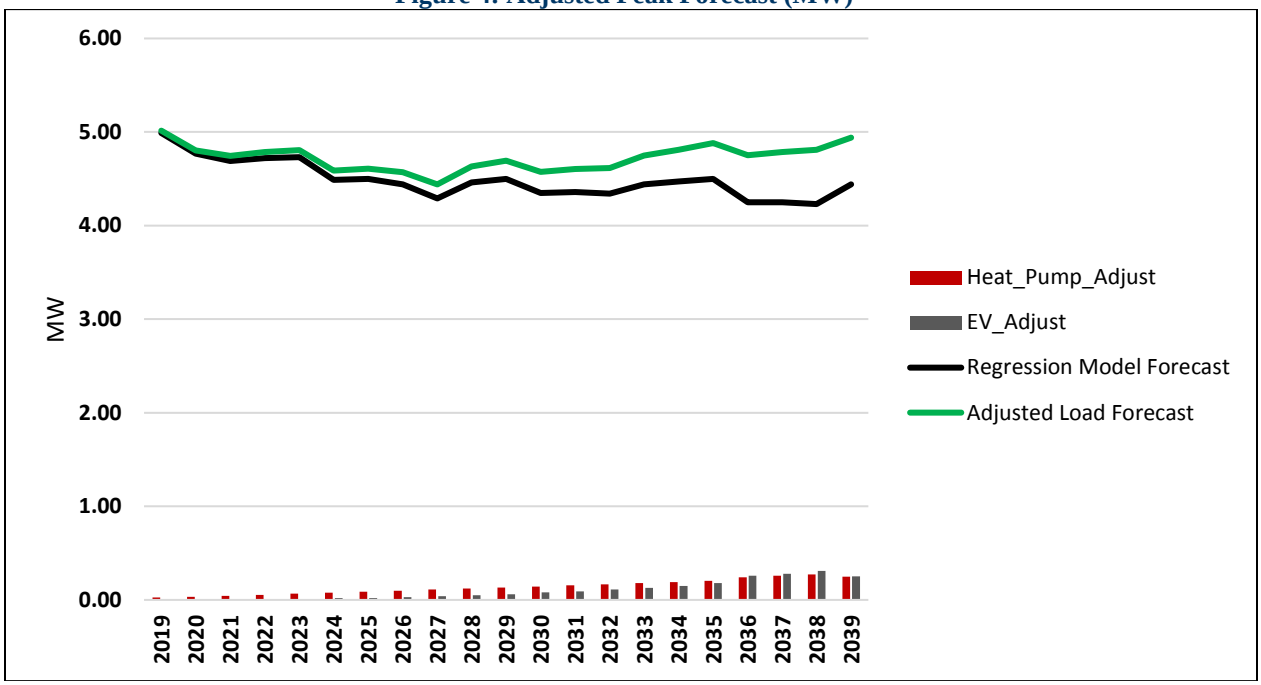
Table 8: Peak Forecast (MW)

MMM-YY	Day	Peak Hour	Regression Forecast	EV Adjustment	CCHP Adjustment	Net Metering Adjustment	Adjusted Forecast
Dec-20	17	18	4.8	0.00	0.03	0	4.8
Dec-25	18	18	4.5	0.02	0.09	0	4.6
Dec-30	18	18	4.4	0.08	0.14	0	4.6
Dec-35	18	18	4.5	0.18	0.20	0	4.9
Dec-39	19	18	4.4	0.25	0.25	0	4.9
CAGR			**-0.4%**	**18.3%**	**10.8%**	**0%**	**0.1%**

The Adjusted Forecast exceeds the Regression Forecast starting in 2025 due to high CAGRs for CCHPs (13.8%) and EVs (20.5%). Unlike the energy forecast, the net metering program does not offset the impacts of EVs and CCHPs because solar panels are not producing energy at the peak month and hour in this forecast. Notice that the size of the adjustments is small (measured in tenths of a MW), and that the peak load forecast starts and ends near five MW. This can be seen in Figure 4, which shows the peak forecast net of adjustments.

[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

Figure 4: Adjusted Peak Forecast (MW)[4]



PEAK FORECAST – HIGH & LOW CASES

To form a high-case, we assume that neither load controls nor Time-of-Use (TOU) rates are implemented, and then we adopt the same 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 steep change in consumer adoption of CCHPs and EVs, electrification is not likely to produce any peak load growth for the next ten years. However, we will continue to monitor these trends annually during our budget forecasting process.

Table 9: Peak Forecast – High Case

MMM-YY	Day	Peak Hour	Regression Forecast	CCHP Adjustment (MW)	EV Adjustment (MW)	Net Metering Adjustment (MW)	Adjusted Fcst. (MW)
Dec-20	17	18	4.8	0.03	0.00	0	4.8
Dec-25	18	18	4.5	0.09	0.00	0	4.6
Dec-30	18	18	4.4	0.29	0.02	0	4.7
Dec-35	18	18	4.5	0.96	0.09	0	5.6
Dec-39	19	18	4.4	2.50	0.30	0	7.2
CAGR			**-0.4%**	**24.2%**	**33.0%**	**0.0%**	**2.1%**

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.

[4] A close inspection of this Figure shows that between 2036-2038, the impact of heat pumps and EVs spikes and then returns to the long-term Tier Ind line in 2039. This is a result of the peak month shifting from December to January and back to December during those years of the forecast.

FORECAST UNCERTAINTIES & CONSIDERATIONS

Despite strong growth in CCHPs and EVs, NED's electricity demand is expected to be quite flat over the forecast period. However, several uncertainties do exist.

NED presently has about three dozen net metered customers. However, as solar net metering costs continue to decline, the cost of net metered solar could reach parity with the price of grid power. If state policy continues to be supportive of net metering in this event, it could lead to a step change in the adoption rate of net metering, and a quicker erosion of retail sales and revenues for the utility. However, sensitivity analysis indicates that the adoption rate for net metering would have to increase threefold (from 1.9% per year to over 6.0% per year) before it would negate the sales-increasing impact of CCHPs and EVs. This outcome is not likely in the near-term, and can be addressed in subsequent Integrated Resource Plans.

A more realistic possibility is that a series of large net metered projects are built. For example, the Cabot Hosiery and the Armory are both considering 100 kW systems. Neither of these systems are assumed in this forecast, but their impact can be estimated. For example, two 100 kW net metered solar projects built in 2020 would increase the base of installed, net metered capacity on the system (which was 600 kW as of 2019) by 30% and would increase net metered generation by a similar percentage. In this event, the impact would be captured in interconnection and annual power budgeting processes, and managed accordingly.

As NED's largest customer, Norwich University represents an uncertainty to the load forecast. A major increase or decrease in enrollment or a change in physical infrastructure could impact the utility. For example, Norwich is presently enrolling students in a summer semester that could increase building energy use. However, no air conditioning equipment is installed, and the existing dehumidification equipment is already in operation. As a result, a substantial increase in load is not anticipated. In terms of physical infrastructure, the university has a 200 kW, wood-fired combined heat and power system.

Two other consideration are worthy of note. The first is the town's water plant. It is already monitored by NED's Supervisory Control and Data Acquisition (SCADA) system, is operating Variable Frequency Drive (VFD) pumps, and is operating primarily at night. As a result, there is little impact on the load forecast, and no real demand response potential in the facility.

The final consideration is the possible expansion of the Cabot Hosiery, the maker of Darn Tough Socks. The manufacturer has engaged NED in preliminary discussions about an expansion that could add three megawatts to the electric system. However, these discussions are several years old, and the customer appears to be managing the demand for their product with a third shift instead of a day-time expansion. In the event that the expansion plans are revived, detailed engineering studies would be required to assess the distribution system investments that could be required. Until the discussions advance to the point of an engineering study, there is no data on which to base a load forecast. As a result, NED will continue to monitor the status of this customer and their expansion plans for future Integrated Resource Plans.

ELECTRICITY SUPPLY

II. ELECTRICITY SUPPLY

NED's power supply portfolio is made up of generation resources, long-term contracts, and short-term contracts. The portfolio acts as a diversified, financial hedge that buffers NED and its customers from the cost and volatility of buying electricity from ISO New England on the spot market at the Vermont Zone. The following sections describe each of the 14 power supply resources in NED's portfolio.

EXISTING POWER SUPPLY RESOURCES

1. **Chester Solar**
   NED holds a 10.7% (514 kW) entitlement in a 4.8 MW solar facility in Chester, Massachusetts. The facility began commercial operation in June 2014, and the Purchased Power Agreement (PPA) includes energy and capacity on a unit contingent basis for a period of 25 years. Renewable energy credits are not included.

2. **Fitchburg Landfill**
   NED holds a 10.2% entitlement of a landfill gas-fired generator at the Fitchburg Landfill in Westminster, MA. Beginning in 2012, the 15-year PPA provided nine participating VPPSA members with 3 MW of firm energy, capacity and renewable attributes for five years. Between 2017 and 2021, the contract supplies 3 MW of firm energy, capacity and renewable attributes plus 1.5 MW of unit contingent energy, capacity and renewable attributes. From 2022 to 2026, the participants will receive 4.5 MW of unit contingent energy, capacity and renewable attributes. The contract includes an option to extend deliveries for an additional five years (2027-2031).

3. **Hydro Quebec US (HQUS)**
   In 2010, a long-term, statewide Purchased Power Agreement (PPA) with Hydro Quebec was signed. NED's entitlement under the contract is presently 0.121% (257 kW) and the kW entitlement will change in future years as shown in the following table. HQ-US energy will, based on an annual attestation, largely qualify for Vermont RES Tier 1 compliance, though the resource does not generate marketable RECs at this time.

Table 10 HQ Contract Entitlements

Time Period	NED Entitlement
Nov 1, 2016 – Oct 31, 2020	257 kW
Nov 1, 2020 – Oct 31, 2030	256 kW
Nov 1, 2030 – Oct 31, 2035	264 kW
Nov 1, 2035 – Oct 31, 2038	65 kW

4. **Kruger Hydroelectric Facilities**
   The Kruger Hydroelectric Facilities consist of six small facilities in Maine and Rhode Island; Barker Lower, Barker Upper, Blackstone, Brown's Mill, Gardiner and Pittsfield. Their output (excluding renewable attributes) was purchased by VPPSA under three long-term purchased power agreements signed in February 2017. NED has an agreement with VPPSA to purchase 12.0826% of their collective output. Finally, these contracts do not include entitlement to the renewable attributes of these facilities.

5. **McNeil**
   VPPSA is a joint owner of McNeil, a 54 MW (summer claimed capability rating) wood-fired generator in Burlington, VT. NED is entitled to a 1.982% share of both the costs and output of the facility. We assume that McNeil is available throughout the forecast period. Finally, McNeil is qualified under a number of state Renewable Portfolio Standards.

6. **New York Power Authority (NYPA) – Niagara**

NYPA provides power to utilities in Vermont under two contracts: Niagara and St. Lawrence. NED's share of the Niagara facility is 1.81% (146 kW), and ends on September 1, 2025. We assume that the contract is renewed through 2039. Finally, the Niagara contract energy qualifies as a Vermont RES Tier 1 resource though the resource does not generate marketable RECs at this time.

7. **New York Power Authority (NYPA) – St. Lawrence**
   NED's share of the St. Lawrence facility is 0.6984% (12 kW). The contract ends on April 30, 2032 but we assume that the contract is renewed through the rest of the forecast period.

8. **NextEra 2018-2022**
   NED has a PPA with VPPSA to purchase firm, fixed price energy with NextEra, which provides energy from Seabrook Station, a nuclear facility in Seabrook, New Hampshire. NED has an 8.8% (1.5 MW) share of the on-peak energy and a 8.3% (1 MW) share of the off-peak energy, which expires on December 31, 2022. While this resource is not qualified under any state RPS, it is tracked separately due to its carbon-free emission profile.

9. **Project 10**
   NED has an agreement with VPPSA to purchase a portion of the power produced by Project 10, an oil-fired peaking generator located in Swanton, VT. NED's share of Project 10's benefits and costs is 12%, and we assume that Project 10 is available throughout the forecast period.

10. **Public Utilities Commission (PUC) Rule 4.100**
    NED is required to purchase power from small power producers through Vermont Electric Power Producers, Inc. (VEPP Inc.), in accordance with PUC Rule 4.100. NED's share of VEPPI power in 2018 was 0.5096%, and the current contracts between VEPP Inc. and its power producers will expire in 2020. We assume that there are no new participants in the 4.100 program for the rest of the forecast period. This is consistent with the relatively recent changes to Rule 4.100 that returned PURPA purchasing obligations to the host utility.

11. **Public Utilities Commission (PUC) Rule 4.300**
    NED is required to purchase power from small power producers through the Vermont Standard Offer Program, in accordance with PUC Rule 4.300. Some of the Standard Offer resources are configured as load-reducers and are not settled in the wholesale markets, resulting in lower reported loads. NED's share of Standard Offer power in 2018 was 0.5562%.

12. **Ryegate Facility**
    NED receives power from the Ryegate biomass facility, a 20.5 MW generator in East Ryegate, Vermont. In 2018 Northfield received 0.5429% of the energy from the plant. Under Vermont statutes, Ryegate is the only plant eligible to meet 30 V.S.A. § 8009, and at this time, we have assumed that there may be a renewal of the current contract upon expiration. As a result, we assume that the generator is available throughout the forecast period. Currently NED is entitled to a portion of the RECs produced by the facility.

13. **Seabrook Station**
    VPPSA entered into a long-term PPA with NextEra Energy Resources for energy, capacity, and associated carbon-free emissions attributes from the Seabrook Nuclear power plant in Seabrook, NH. The 20-year contract began in 2014 and expires on December 31st, 2034. It includes varying amounts of energy and capacity over the life of the contract, and employs a known price-escalating mechanism. As a result, it provides baseload energy at predictable prices, helping to reduce exposure to market volatility. NEDs entitlement to the PPA is 33% (0.2 MW).

14. **Market Contracts**

NED meets the remainder of its load obligations through ISO New England's day-ahead and real-time energy markets, and through contracts (physical and financial) that are less than five years in duration. Market purchases range in size, duration, and counterparty, and are designed to balance NED's supply resources with its load obligations in ISO New England's markets.

Table 11 summarizes the resources in the portfolio based on a series of important attributes. First the megawatt hours (MWH) and megawatts (MW) are shown to 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

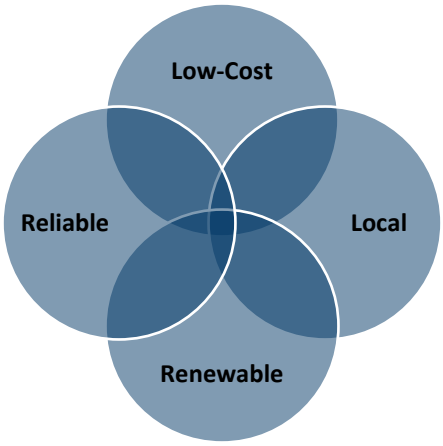
RESOURCE	2020 MWH	% of MWH	2020 MW	Delivery Pattern	Price Pattern	RECs	Expiration Date	Renewal to 2039
1. Chester Solar	714	2.5%	0.204	Intermittent	Fixed		6/30/39	No
2. Fitchburg Landfill	3,440	11.9%	0.341	Firm	Fixed	✓	12/31/31	No
3. HQUS	1,502	5.2%	0.000	Firm	Indexed	✓	10/31/38	No
4. Kruger Hydro	3,060	10.6%	0.191	Intermittent	Fixed		12/31/37	No
5. McNeil Facility	5,440	18.9%	1.031	Dispatchable	Variable	✓	Life of unit.	Yes
6. NYPA – Niagara	1,501	5.2%	0.254	Baseload	Fixed	✓	09/01/2025	Yes
7. NYPA – St. Lawrence	149	0.5%	0.009	Baseload	Fixed		04/30/2032	Yes
8. NextEra 2018-2022	6,152	21.4%	0.000	Firm	Fixed	✓	12/31/2022	No
9. Project 10	70	0.2%	4.638	Dispatchable	Variable		Life of unit.	Yes
10. PUC Rule 4.100	146	0.5%	0.000	Intermittent	Fixed		2020	No
11. PUC Rule 4.300	832	2.9%	0.007	Intermittent	Fixed	✓	Varies	No
12. Ryegate Facility	885	3.1%	0.103	Baseload	Fixed	✓	10/31/2021	Yes
13. Seabrook Station	1,757	6.1%	0.200	Baseload	Fixed	✓	12/31/2034	No
14. Market Contracts	3,143	10.9%	0.000	Firm	Fixed		< 5 years.	N/A
Total MWH	**28,790**	**100%**	**7.155**					

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

FUTURE RESOURCES

NED 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.

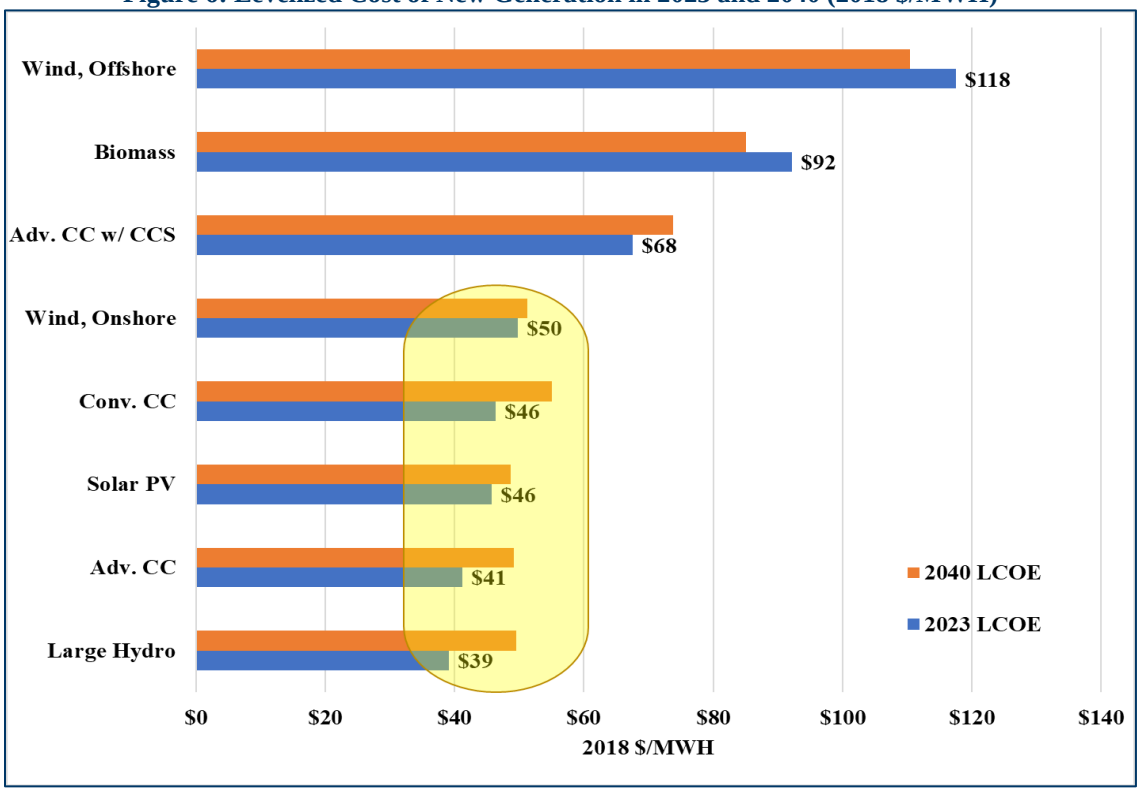
✓ **Local** resources are located within Northfield's Regional Planning Commission area or within Vermont.

✓ **Renewable** resources meet or exceed RES requirements.

✓ **Reliable** resources not only provide operational reliability, but are also owned and operated by financially strong and experienced companies.

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

Figure 6: Levelized Cost of New Generation in 2023 and 2040 (2018 $/MWH)[6][7]



While these cost estimates represent national averages, they do illustrate the competitive range of new generation technologies in and around the New England region. For example, ISO New England continues to get interconnection requests from all five of the lowest-cost technologies in Figure 6 (highlighted in yellow). In addition, NED would also evaluate new off-shore wind and biomass projects, which continue to attract development in the region.

CATEGORY 1: EXTENSIONS OF EXISTING RESOURCES

This plan assumes that four existing resources are extended past their current expiration date. These include McNeil, Ryegate, Project 10, and NYPA. Depending on how contract negotiations align with the Resource Criteria, other existing resources may be extended including the Fitchburg Landfill Gas, NextEra 2018-2022, and Kruger Hydro resources. Where resource needs remain, market contracts will be used to supply them.

1.1 MARKET CONTRACTS

Market contracts are expected to be the most readily available source of electric supply for energy, capacity, ancillary services and renewable attributes (RECs). By conducting competitive solicitations through VPPSA, Northfield 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 Northfield 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.

[6] Source: US Energy Information Administration, https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

[7] CC, shown in Figure 6, means combined cycle generation

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, NED will continue to welcome the work of the Efficiency Vermont (EVT) and Capstone Community Action in its service territory. NED 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 NED 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, NED 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, NED 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, NED 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 continue 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 NED will continue to investigate solar developments both within its service territory and outside of it.

3.3.1 NET METERING

While net metering participation rates are presently modest and are forecast to grow modestly, NED 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[8]. 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

[8] 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

prevailing market prices. As a result, existing hydro generation could be both low-cost (or at least at market) and renewable.

BATTERY STORAGE

Any discussion of future resources would be remiss 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[9], 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 NED 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, NED 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.

REGIONAL ENERGY PLANNING (ACT 174)

As part of the Central Vermont Regional Planning Commissions (CVRPC), Northfield is part of a Regional Energy Plan that was approved by the CVRPC Board of Commissioners in May 2018. The purpose of the plan is to give the CVRPC greater input into local energy permitting decisions before the PUC, as explained in the Executive Summary:

> "The 2016 State Comprehensive Energy Plan identified a goal to have 90% of the state's energy needs derived from renewable sources by 2050. As part of this goal, the Vermont State Legislature passed Act 174 in 2016. Act 174 provides an avenue for regions and municipalities to have increased input in PUC determinations for Certificates of Public Good regarding renewable energy generation facilities. As such, Act 174 identified standards that need to be met in support of the state's goal of 90% renewable energy by 2050 in order to have a plan receive a DOEC [Determination of Energy Compliance] and have "substantial deference". Otherwise, a plan will receive "due consideration" in the Section 248 review process. Act 174 is categorized as enhanced energy planning and goes beyond what is outlined in 24 VSA 117 Section §4348a and §4382 respectively."

This plan is presently before the PUC, and is expected to result in a DOEC, "…that will give the CVRPC 'substantial deference' before PUC for applications that seek a Certificate of Public Good (CPG)." The

[9] 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/

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

RESOURCE PLAN

III. RESOURCE PLANS

DECISION FRAMEWORK

NED will generally evaluate major policy decisions, such as resource acquisitions, using the integrated financial model developed in this IRP. The primary quantitative evaluation metric will be the impact that a decision has on NED's retail cost of service per kWh over time. (i.e. the effect on the rate trajectory)

When evaluating significant decisions, NED will identify the key variables whose potential range of possible outcomes (due to uncertainty) has the largest impact on the retail costs of service per kWh. NED will consider the impacts on potential decisions of changes from the base case assumptions to assist in evaluating the risks associated with the decision. This analysis could include evaluating ranges of potential values for the key variables either via simple replacement of the base assumptions in either the power supply or the integrated financial model as appropriate. Another potential (and similar) evaluation would be to review the decision under extreme (but improbable values) to consider how sensitive the decision is to unexpected outcomes.

Some decisions, such a simple or short-term resource acquisitions, may not have integrated effects. In such cases, the impact of the resource decision on power costs may be used as a proxy for the relative impact on overall retail costs per kWh.

For example, a simple choice between two resources could be evaluated in this streamlined manner. (Assuming that the resources do not impact non-power supply costs, retail sales volumes, or are not needed under all load forecast cases.) Decisions with small relative impacts may not warrant detailed evaluation at all. It is important to scale the effort spent evaluating a decision, to its potential impact on the utility. Larger decisions that impact power supply costs, as well as non-power-supply costs and/or sales volumes would generally require the use of the full financial model to evaluate.

Any quantified potential impact on rates, determined either through the power supply or integrated financial model, will be considered in conjunction with other metrics that are less easily converted to numerical values in the final decision-making process. Such factors might include resource diversity, risk of fundamental changes in market rules, and other factors.

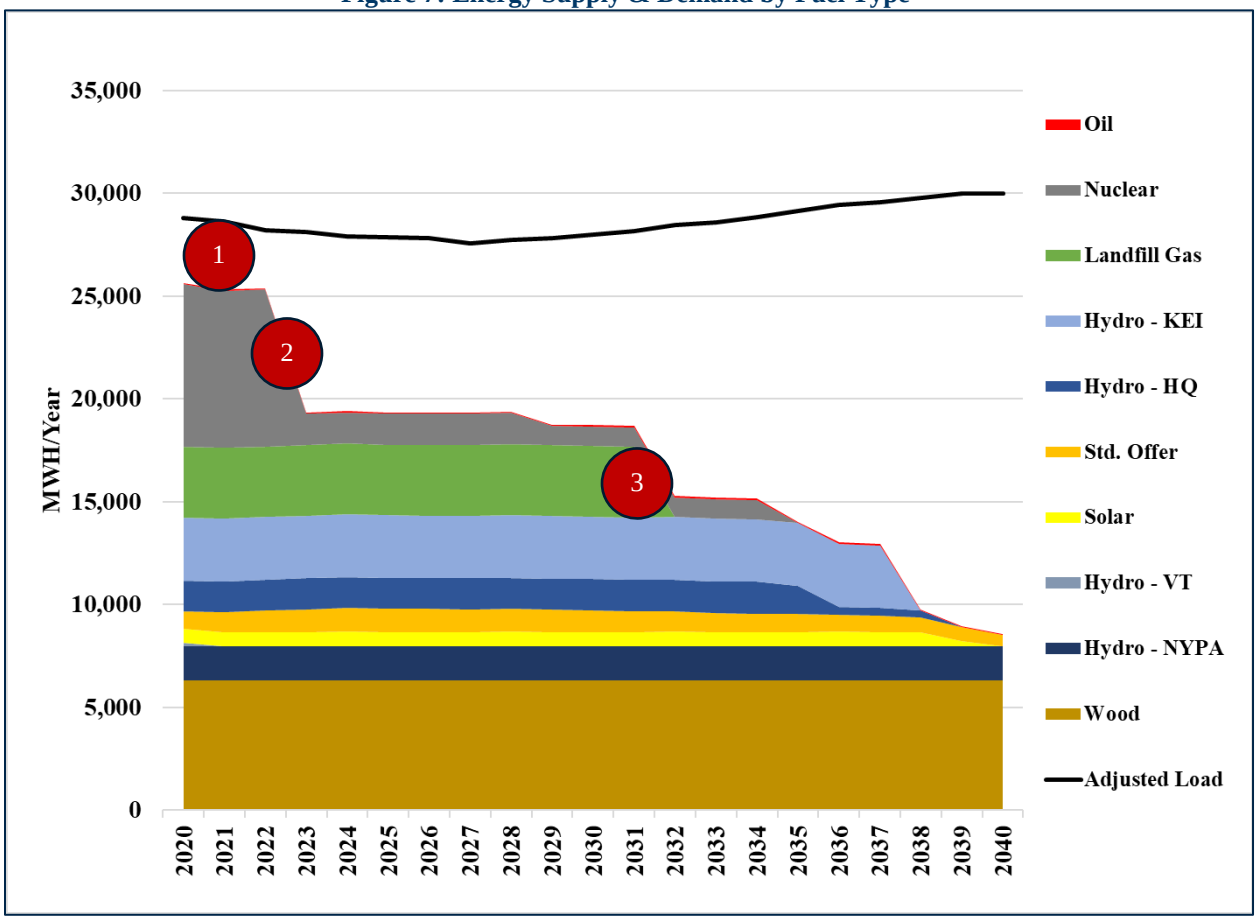
ENERGY RESOURCE PLAN

Figure 7 compares NED's energy supply resources to its adjusted load. There are three major resource decisions that, in total, will affect about 50% of NED's energy supply between 2020 and 2031. Importantly, the first two decisions occur during the first three years of the forecast period (2020-2022), and these two decisions will affect about 30% of NEDs energy supply.

DECISION 1: 2020-2022

First, notice that about 90% of NED's energy requirements are hedged by long-term resources between 2020 and 2022. The remaining 10% will be hedged before the start of each calendar year by purchasing fixed-price market contracts. The cost and rate impact of this short-term purchase is quantified in the Financial Analysis section, and is expected to be minimal.

Figure 7: Energy Supply & Demand by Fuel Type



DECISION 2: 2023+

The second resource decision occurs at the end of 2022 when the NextEra 2018-2022 Contract expires. This can be seen in Figure 7 by the decrease in the gray-shaded "Nuclear" area. This contract supplies about 20% of NED's energy, and represents a significant energy resource decision. (Because this is an energy-only resource, it is not a significant capacity resource decision.) Because the pricing in the NextEra 2018-2022 Contract is very similar to the forecast of market prices, cost and rate impacts are expected to be neutral.

As indicated in the Electricity Supply chapter, NED may elect to negotiate a new or extended contract with NextEra. However, the timing of the contract's expiration coincides with a 4% increase in the Total Renewable Energy (TIER I) requirements (from 59% to 63%) under RES. As a result, NED may consider an energy resource that includes low-cost renewable energy credits such as an existing hydro facility. In any event, the resource decision will be made with NED's Resource Criteria (Figure 5) in mind, and the term of the new resource will be negotiated so that it does not expire at the same time as the other major resources in the portfolio, namely the Fitchburg Landfill Gas Facility which expires at the end of 2031.

DECISION 3: 2032+

The third major resource decision will coincide with the expiration of the Fitchburg Landfill Gas contract. This resource will represent about 12% of NED's energy requirements in 2031, and because it produces premium RECs that are being sold out-of-state to reduce the overall cost of the portfolio, it does not impact RES compliance. However, its expiration will be just one year before the culmination

of RES. As a result, the decision to extend this contract or replace it with another resource will be influenced by RES requirements and any subsequent energy policies that are being considered at that time. Finally, the market value of this resource is presently forecast to be about the same as its costs, and if this turns out to be the case, then the cost and rate impacts of this resource decision may be neutral. Table 12 summarizes the energy resources decisions NED faces in the coming twelve years.

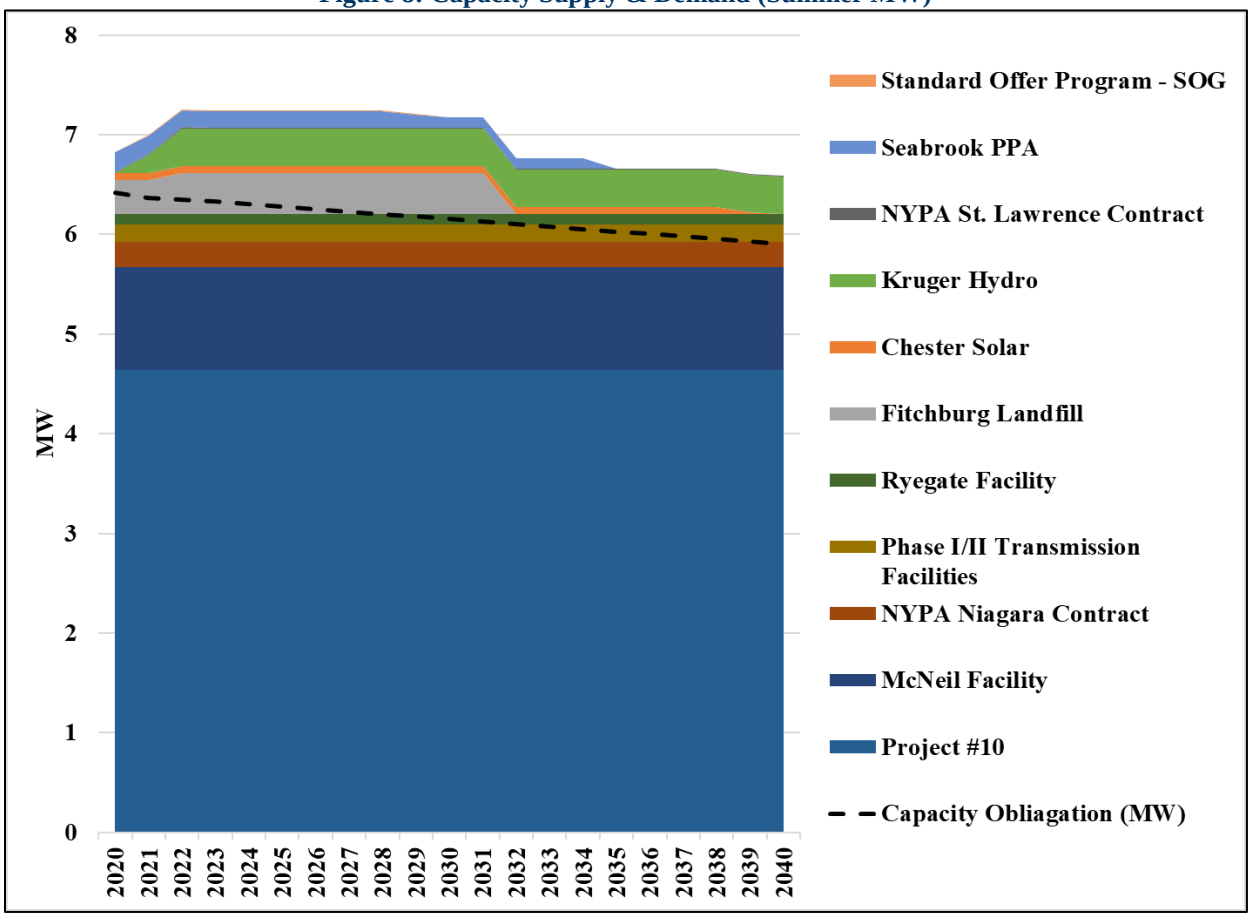
Table 12: Energy Resource Decision Summary

Resource	Years Impacted	% of MWH	Rate Impact	RES Impact
1. Short-Term Market Purchases	2020-2022+	10%	Neutral	None
2. NextEra 2018-2022	2023+	20%	Neutral	Possible
3. Fitchburg Landfill Gas	2032+	12%	Neutral	Possible

CAPACITY RESOURCE PLAN

Figure 8 compares NED's capacity supply to its capacity supply obligation (CSO). The CSO is equal to NED's coincident peak demand with ISO New England plus a reserve margin. As a result, the CSO is higher than the Adjusted Peak Load Forecast, which is not coincident with ISO New England and does not include a reserve margin. In any event, two resources provide about 90% of NED's capacity. In 2020, Project 10 provides about 72% and McNeil provides another 16%.

Figure 8: Capacity Supply & Demand (Summer MW)



Because the supply of capacity is about 10% higher than the demand, no resource decisions are necessary unless the reliability of McNeil or Project 10 drops for an extended period of time. As a result, the reliability of these two resources will be the key to minimizing NED's capacity costs, as explained in the next section.

ISO NEW ENGLAND'S PAY FOR PERFORMANCE PROGRAM

Because NED 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 or McNeil are not available, NED 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 NED's 12% 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, NED could receive up to a $6,000 payment or pay up to a $7,000 penalty during a one-hour scarcity event. This represents a range of plus or minus sixteen to 18% of NED's monthly capacity budget. However, such events are not expected to occur more than a few times a year (if at all), and frequently 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	-$3,000	$2,000	$6,000
15,000	$2,000/MWH	-$4,000	$0	$5,000
20,000	$2,000/MWH	-$6,000	-$1,000	$4,000
25,000	$2,000/MWH	-$7,000	-$2,000	$2,000

[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

NED's obligations under the Renewable Energy Standard[12] (RES) are shown in Table 14. Under RES, NED 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 9.4% in 2032. Note that this plan assumes that both the Tier I and Tier II requirements are maintained at their 2032 levels throughout the rest of the study period.

Under RES, the Tier II requirements are a subset of the Tier I requirements. As a result, we subtract the Tier II percentage from the Tier I percentage to get the Net Tier I requirement in the fourth column. Notice that the net Tier I requirement declines every second and third year until the Tier I requirement increases. When these percentages are multiplied by the forecast of retail sales (which decline during the 2020-2030 period), the result is a seesaw effect where the Net Tier I requirement declines every second and third year. This effect can be seen more clearly in Figure 9 in the next section.

Table 14: RES Requirements (% of Retail Sales)

Year	Tier I: Total Renewable Energy (A)	Tier II: Distributed Renewable Energy (B)	Net Tier I: Net Total Renewable Energy (A) - (B)	Tier III: Energy Transformation
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%	0.00%

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 and Tier II requirements…which count only electricity that is produced and consumed in an individual year[14]…Tier III programs account for the "lifetime" of the fossil fuel savings. For example, if a Tier III program installs a CCHP in 2020, the fossil fuel savings from that

[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.

CCHP are counted such that the full ten-years of the CCHP's expected useful life accrue to the 2020 Tier III requirement. For this reason, we do not carry the 2032 requirement into the 2033-2039 period.

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

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

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

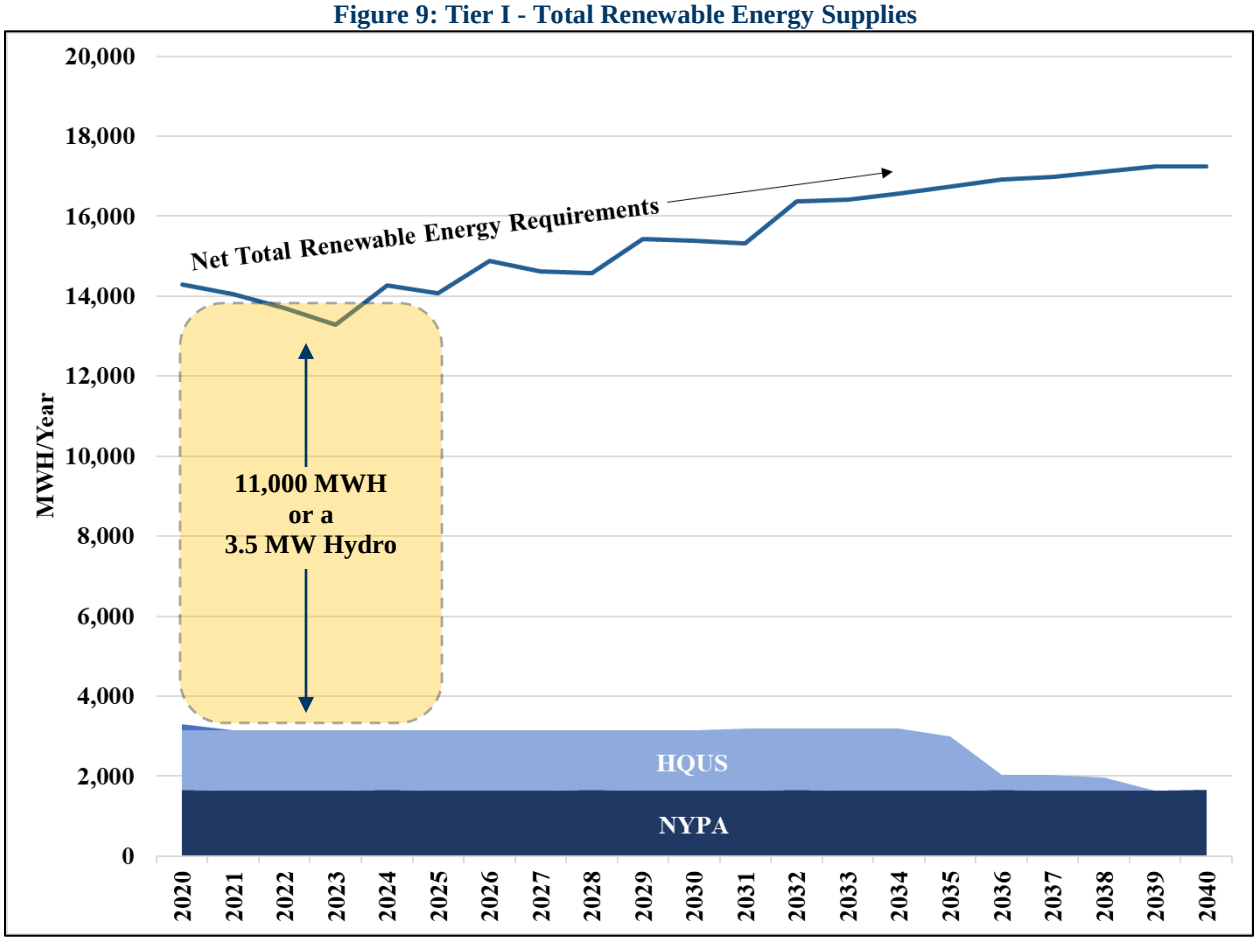
Year	TIER I	TIER II & III
2020	$10.00	$60.00
2021	$10.22	$61.32
2022	$10.44	$62.67
2023	$10.67	$64.05
2024	$10.91	$65.46
2025	$11.15	$66.90
2026	$11.39	$68.37
2027	$11.65	$69.87
2028	$11.90	$71.41
2029	$12.16	$72.98
2030	$12.43	$74.59
2031	$12.70	$76.23
2032	$12.98	$77.90

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

TIER I - TOTAL RENEWABLE ENERGY PLAN

Between 2020 and 2025, NED's Net Tier I requirement is about 14,000 MWH per year. There are three hydroelectric resources that contribute to meeting the Net Tier I requirement; NYPA, HQUS, and the (miniscule) remainder of PUC's 4.100 program. These resources add up to about 3,000 MWH per year or 22% of NED's Net Tier I requirement. Through 2025, the remaining Net Tier I requirement (deficit) is about 11,000 MWH.

Figure 9: Tier I - Total Renewable Energy Supplies



In the early years of the 2020s, NED 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 $1.00 to a high of $2.50 per MWH over the past four years. At the current price of $1/MWH, the cost of complying with Net Tier I in 2020 to 2025 period with ME II RECs would be about $11,000 per year.

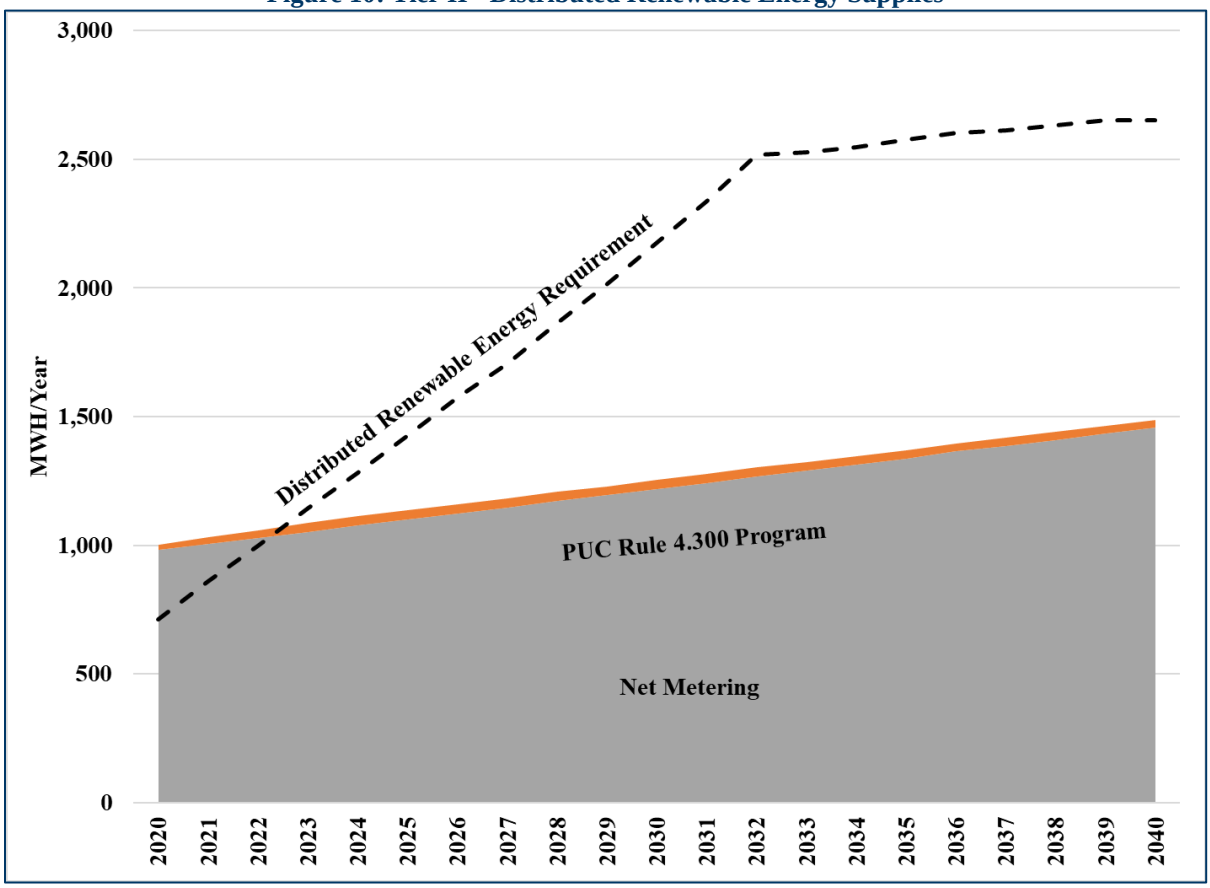
As mentioned in the Energy Resource Plan, the expiration of the NextEra 2018-2022 PPA creates an opportunity to purchase a resource that provides both energy and RECs. The 11,000 MWH per year deficit is equivalent to a 3.5 MW hydro facility[16], and if the output from a hydro resource of this size and capacity factor was purchased (including RECs), the Net Tier I deficit between 2023 and 2025 would be erased. To fulfill the entire Net Tier I requirement through 2032, a 4 MW hydro facility (12,000 MWH per year) would be necessary, and after 2032, a 5 MW hydro facility (15,000 MWH per year) would be necessary to maintain 65% Net Tier I.

[16] We have assumed a thirty-five percent capacity factor, which results in about 11,000 MWH per year.

TIER II - DISTRIBUTED RENEWABLE ENERGY PLAN

The dashed line in Figure 10 shows NED's Distributed Renewable Energy[17] (Tier II) requirement, which rises steadily from 700 MWH in 2020 to 2,500 MWH in 2032. Between 2020 and 2023, the net metering program (plus a small contribution from PUC's 4.300 Program) is expected to fulfill the Tier II requirement. After 2023, another Vermont-based renewable resource(s) will be required[18].

Figure 10: Tier II - Distributed Renewable Energy Supplies



NED is presently working to develop a 1.25 MW AC solar facility within its service territory to meet this need. Known as the Bone Hill Solar Project, it being developed through a partnership between VPPSA and Encore Renewable Energy[19], who have successfully completed a number of solar projects since 2016. In the event that this project is built, NED will have enough RECs to fulfill its Tier II requirement, plus a surplus that can be used toward its Energy Transformation requirement.

In the event that the project is not built, then NED will most likely work with other VPPSA members to develop a solar project elsewhere in Vermont because suitable solar sites within its service territory are limited. In any years where there is a deficit, NED plans to purchase qualifying RECs to meet its Tier II requirement. In recent years, the cost of these RECs has been 60% to 90% lower than the ACP.

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

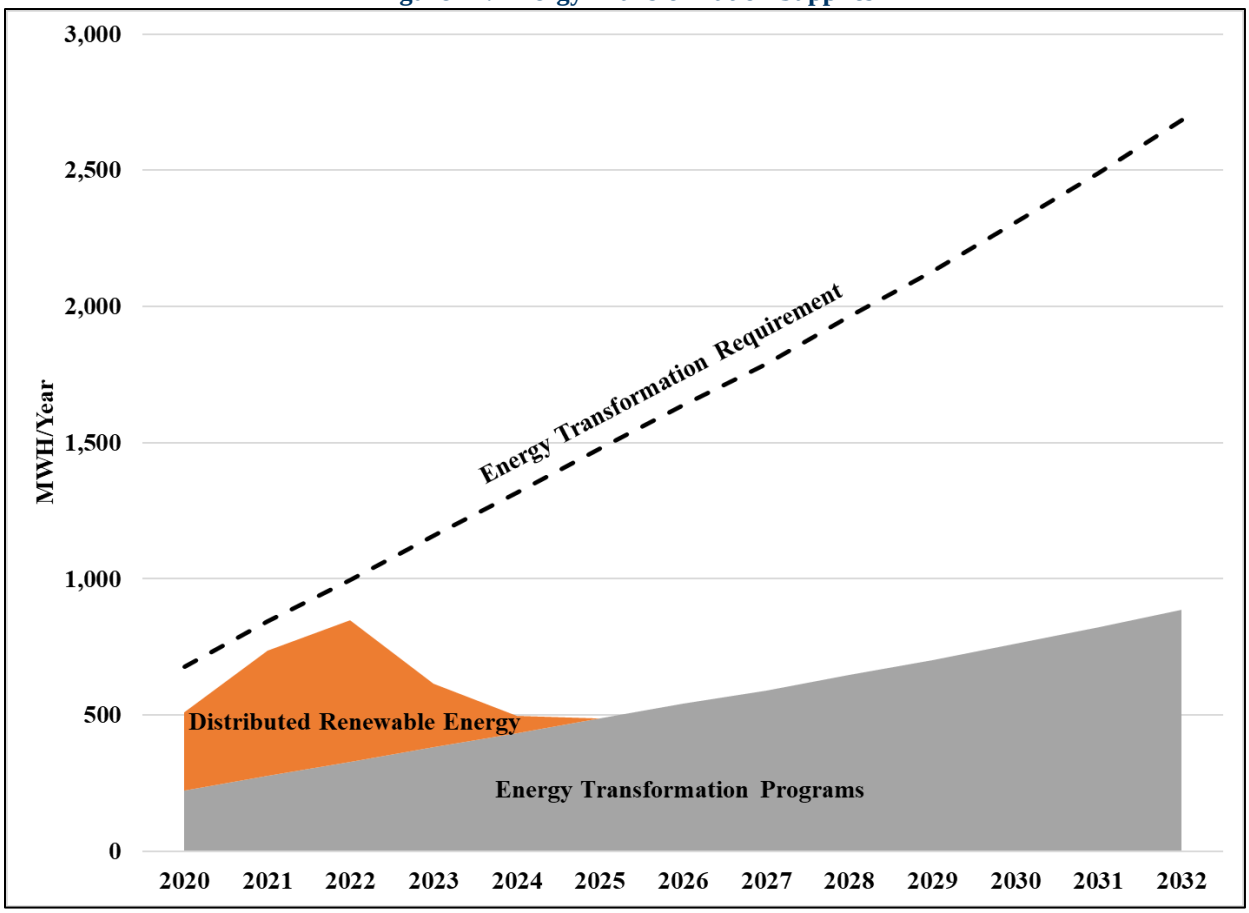
[18] We assume that the surplus MWH in 2020-2022 are not banked, and are instead applied to Northfield's Energy Transformation requirement.

[19] https://encorerenewableenergy.com/vermont-public-power-supply-authority-and-encore-renewable-energy-partner-to-increase-solar-generation-for-member-communities/

TIER III - ENERGY TRANSFORMATION PLAN

The dashed line in Figure 11 shows NED's Energy Transformation[20] (Tier III) requirements, which rise from almost 700 MWH in 2020 to almost 2,700 MWH in 2032. Energy Transformation programs are presently budgeted to fulfill about a third of the requirement, and are shown in the gray-shaded area of Figure 11. These programs cover a range of qualifying technologies including EVs, CCHPs, and HPWHs. More detail on these programs can be found in Appendix B (VPPSA's 2019 Tier 3 Annual Plan) and on VPPSA's website.

Figure 11: Energy Transformation Supplies



Between 2020 and 2024, net metered solar projects are expected to create a Tier II surplus that can almost fulfill the Tier III requirements. This leaves a small and manageable deficit that can be fulfilled by purchasing more qualifying RECs under the Tier II requirements. Starting in 2021 and particularly after 2024, the remaining Tier III requirements are likely to be fulfilled by the Bone Hill solar project. However, without Bone Hill, NED is expected to have a substantial deficit which is illustrated in Figure 11. This could be fulfilled by a different solar project, a large custom Tier III project as contemplated in the Tier 3 Annual Plan, or by purchasing qualifying RECs under the Tier II requirement. In any event, NED's will follow a four-part strategy to fulfill its Tier III requirements.

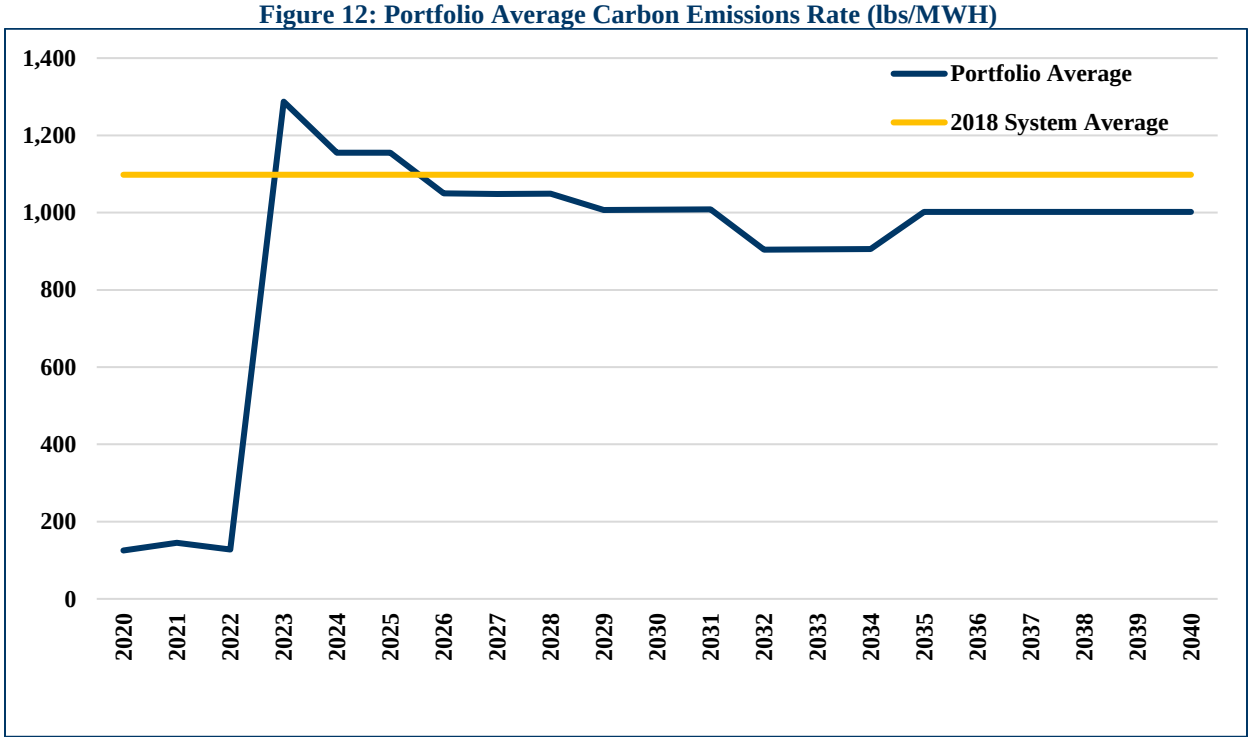
1. Identify and deliver *prescriptive* Energy Transformation ("Base Program") programs, and/or
2. Identify and deliver *custom* Energy Transformation ("Custom Program") programs, and/or
3. Develop and complete the Bone Hill Solar or a comparable, Vermont-based solar project, and/or
4. Purchase Tier II-qualifying renewable energy credits.

[20] The Energy Transformation requirements are also known as "Tier 3" requirements.

CARBON EMISSIONS RATE

Figure 12 shows an estimate of NED's carbon emissions compared to the 2018 system average emissions in the New England region[21]. The emissions rate between 2020 and 2022 is below 200 lbs/MWH because of the NextEra 2018-2022 contract, which includes the carbon-free emissions attributes of Seabrook Station, a nuclear generator in Seabrook NH. After this contract expires, carbon emissions increase to 1,287 lbs/MWH because the same MWHs are being supplied by fossil fuels. 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.[22]

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



The carbon emissions rate starts to decline in 2024 as a result of increasing RES requirements and drops below the system average by 2026. This decline continues until 2032, when the RES requirements end. The emissions rate remains stable through 2034 and then increases in 2035 when the Seabrook PPA expires. Thereafter, the emissions rate is stable because this plan assumes that the RES requirements will be maintained.

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

[22] For the current value of the NEPOOL Residual Mix, please visit https://www.nepoolgis.com/public-reports/.

TRANSMISSION & DISTRIBUTION

IV. ELECTRICITY TRANSMISSION & DISTRIBUTION

TRANSMISSION AND DISTRIBUTION SYSTEM:

The distribution system consists of 39 miles of distribution line divided into four (4) distribution feeders in a cross-shaped configuration running generally north-south, and east-west from the center of town out of the King Street Substation. The two longest feeders, north and south from the substation, contain pole-mounted reclosers located at approximately their midpoint for sectionalizing those feeders. Most of the Norwich University load is served by the Norwich University Substation located on campus that is fed by a 34.5kV sub-transmission line, wholly located within its service territory, from the King Street Substation.

NED converted the majority of the system to 12.47kV in 1999, and only a small section of 4.16kV distribution remains west of the Northfield Commons fed from a step-down transformer at the bottom of Terry Hill. At this time, NED does not plan to upgrade this small section of line as the cost-benefit analysis has shown that the upgrade would not be economical. Conversion to 12.47kV has reduced line losses and improved overall service quality for NED customers. Power factor correction capacitors have been installed on each of the four King Street Substation distribution feeders.

TRANSMISSION SYSTEM DESCRIPTION

The capacity of the sub-transmission line to the Norwich University Substation is currently adequate to supply the NU campus. The system is currently loaded to less than half its capacity. The sub-transmission circuit is the 34.5kV feeder from the King Street Substation to the Norwich University Substation. The load at the Norwich University Substation carries the majority of the load of the university. The peak load is currently about 1.5MW. The circuit capacity is about 500A (capacity of about 30MVA). NU has recently completed renovations to their campus with an estimated additional load of less than 500kVA with no anticipated additional load growth. NU's recent renovations did not have a significant impact on the substation or sub-transmission.

DISTRIBUTION SYSTEM DESCRIPTION

NED has a compact service territory as a result of being a small, municipal-owned electric utility, and has benefitted from several major system improvements over the past 15 years. NED evaluates T&D circuits when significant increases in customer loads are proposed that would affect the power quality. GMP performs load studies for NED to support analysis for responding to Ability To Serve requests. In most cases, the system capacity is capable of supporting modest load growth within the service territory. When load studies indicate that a load increase will have an adverse effect on power quality, several options for modifications to the existing circuit are proposed. The proposed solutions are evaluated for technical feasibility, cost, reliability, and safety, and the optimum solution is selected for implementation.
NED collects data from a variety of sources for use in prioritizing system improvements. These sources include:

- Observations of GMP employees in the course of their contract work on the NED system;
- Load data provided by GMP from its SCADA equipment in the King Street Substation;
- Observations of NED employees when reading meters;
- Act 250 requests; and
- System reliability data.

The distribution circuit that had the greatest number of outages in 2018 was the 54G4. It's also the longest of NED's circuits. There were various causes for the twelve outages on that circuit. Four were caused by weather. Two were caused by equipment failures. Two were caused by trees. Three outages had unknown causes. One was caused by an animal.

The data reported in the Public Utility Commission Rule 4.900 - Overall Assessment of System Reliability - report is analyzed on an annual basis to assess critical reliability issues. A project weighting spreadsheet from GMP is used to inform decisions for system improvements.

EFFICIENCY

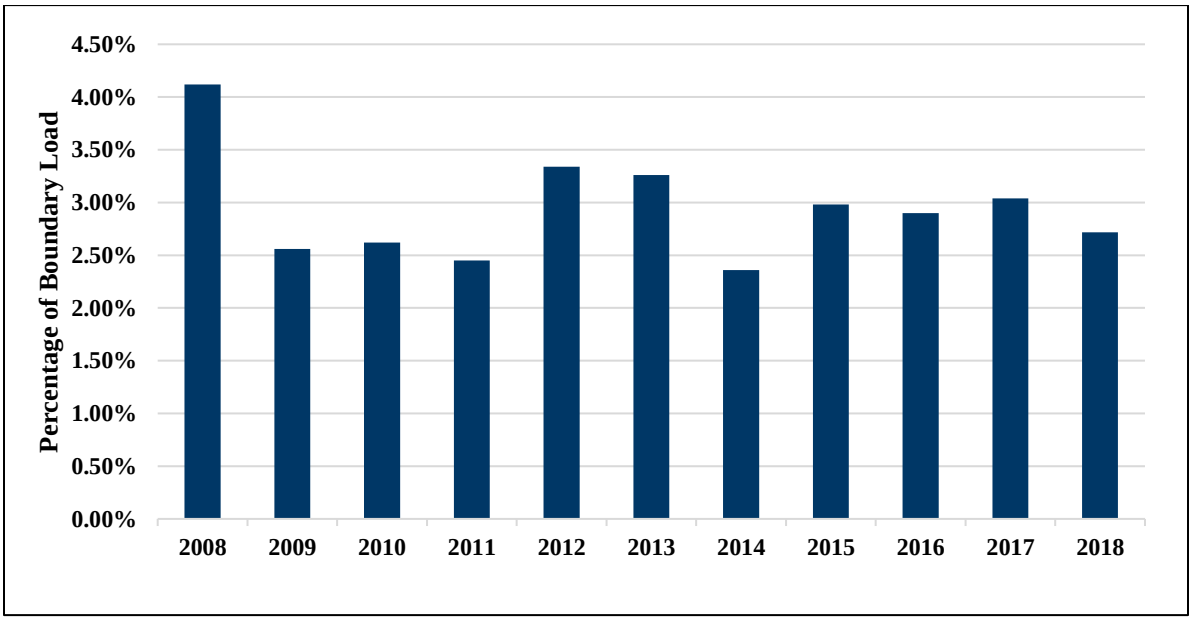
NED is committed to providing efficient electric service to its customers. NED's strategy for improving system efficiency involves monitoring actual system losses and implementing system improvements to reduce system losses. These strategies are discussed briefly below.

ACTUAL SYSTEM LOSSES

NED calculates distribution system losses as the difference between the metered system boundary load at its interconnections to GMP and system retail sales. The calculation is done on an annual basis to minimize the impact of unbilled energy resulting from meter reading cycles not corresponding with the system boundary load measurements. NED's average distribution losses were calculated as 2.72% of the metered system boundary load in 2018.

System losses in 1998 were over 8%. The plot of system losses versus year (below) shows that the reconductoring and voltage upgrade in 1999 significantly reduced system losses which have stabilized at about 3%. The substation transformers at King Street Substation and Norwich University Substation were replaced with larger units in 2008. Capacitor banks were added to the system in 2009 for power factor correction and voltage support.

Table 16 Historic Distribution Losses



LINE LOSS REDUCTION

The principal strategies for reducing line losses are system voltage upgrade and power factor correction, both of which have been implemented.

SYSTEM VOLTAGE CONVERSION

In 1999, the distribution system voltage was upgraded to 12.47kV. There is only a small section of 4.16kV distribution remaining within the service territory at Terry Hill and Dole Hill that is routed through the woods. NED does not plan to upgrade this small section of line as the cost-benefit analysis has shown that the upgrade would not be economical.

LED STREETLIGHTING

In the summer of 2014, NED replaced all of the existing HPS streetlight fixtures with LED fixtures at the request of the Northfield Selectboard in an effort to reduce streetlighting costs. The town highway department reimbursed NED for the stranded investment of the existing fixtures. Customer yard lights were not replaced at that time.

OTHER EFFICIENCY ITEMS

Efficiency improvements have been made at the Town water and sewer plants. Both of the plants are SCADA controlled and the water plant pumps water at night, when demand is low, and lower cost off peak energy is available.

The Town sewer plant implemented variable speed drive pumps to reduce losses in the plant.
NU has a combined heat and power wood chip system on their premises that they own and operate. This renewable source provides most of the heat (some back-up heat provided by oil) for their buildings and also provides about 250kW of power.

Currently, VPPSA and Efficiency Vermont (EVT) are engaged in a targeted community effort in Northfield that will continue through early 2019. This initiative involves enhanced outreach to customers regarding VPPSA and EVT incentives, in-person communication with small businesses, and educational workshops on a series of energy efficiency topics. VPPSA and EVT will evaluate whether such joint targeted efforts have the potential to generate greater savings and/or better align with a community's specific energy efficiency needs. If successful, this model may be adapted and deployed in other VPPSA municipalities.

T&D SYSTEM EVALUATION

POWER FACTOR MEASUREMENT AND CORRECTION

Capacitor banks were installed on each of the 12.47kV distribution feeders from the King Street Substation in 2009. GMP Distribution Engineering determined the capacitance and optimum placement for each feeder based on load data.

The average power factor for the distribution circuits from the King Street Substation was calculated using half-hour load data of feeders 54G1 through 54G4, and 55 (Norwich University Substation sub-transmission). The data for 54G2 was adjusted to add in the 675MWh generated by the Nantanna hydro. The average power factor is 0.99 leading.

DISTRIBUTION CIRCUIT CONFIGURATION

VOLTAGE UPGRADES

In 1999, the distribution system voltage was upgraded to 12.47kV. There is only a small section of 4.16kV distribution remaining within the service territory at Water Street Extension that is routed through the woods. NED does not plan to upgrade this small section of line as the cost-benefit analysis has shown that the upgrade would not be economical.

PHASE BALANCING

NED's loads are stable and do not generally require reconfiguration to balance the load. Load data for each phase of each feeder is reviewed periodically in order to check balance. Phase currents that are generally within 5% of each other are considered balanced.

FEEDER BACK-UPS

Due to the cross-shaped pattern of the four (4) distribution feeders and the terrain of Northfield, there are limited options for feeder back-ups. NED continues to consider options for feeder back-up designs in proximity of the King Street Substation, as well as potential designs that would provide back-up capability from the Norwich University Substation.

SYSTEM PROTECTION PRACTICES AND METHODOLOGIES;

PROTECTION PHILOSOPHY

The NED system is small and compact consisting of two distribution substations and a total of four (4) distribution feeders. Equipment protection is achieved through the use of fuses and reclosers. The substation transformers are protected by fuses on the 34.5kV primary side. Reclosers provide protection on the four distribution feeders, as well as the 34.5kV line to the Norwich University Substation. The remaining McGraw-Edison 15kV-class reclosers in the King Street Substation were replaced in 2012 with Cooper VWE reclosers, and all reclosers have Form 6 controls that also provide the capability for under-frequency load shedding. There are two NU-owned feeders supplied by the Norwich University Substation. The campus feeder is protected by a Cooper VWE recloser with Form 6 control, and the transformer of the VT National Guard Training Center on the NU campus is protected with SMD-20 fuses.

Distribution feeder taps are fused, as are the distribution transformers. In 2009, GMP completed a fuse coordination study based on current loads to provide information relative to the appropriate size of distribution fuses. It is possible that fuses exist on the system that may not have been changed since the system voltage upgrade in 1999. Fuses sized for the old 4.16kV system will be of a higher current rating than required at 12.47kV and may lead to a protection coordination problem. Fuse information provided by the study is used to guide line crews to check installed fuses, and replace as necessary, during regular outage and maintenance work.

Fuses are not systematically checked due to the labor expense and resulting outages related to opening the fuse to check the element size. System events have not indicated issues with fuse sizes; accordingly, NED has instructed GMP to check fuses during outages, and replace with appropriately sized fuses in the event that the wrong fuse is installed. Fuse information is provided by the line crew to the distribution field engineer who records the information in the GIS system for NED. NED will coordinate with GMP to update NED's fuse information in the GIS data.

SMART GRID INITIATIVES

EXISTING SMART GRID

GMP currently monitors the loads and controls the reclosers and regulators at the King Street Substation through its SCADA system. A SCADA remote terminal unit ("RTU") was installed at the Norwich University Substation in 2013 through the Smart Grid Investment Grant ("SGIG"). A VELCO fiber build-out project connects the Norwich University Substation and King Street Substation with a fiber-optic link. Other SGIG-supported projects included replacing the SCADA battery backup bank and replacing the remaining three Type RE reclosers at the King Street Substation. The new VWE reclosers that replace the Type RE devices also

have Form 6 controls that provide additional control and monitoring capabilities including the capability to detect and respond to under-frequency load shedding incidents.

Pole-mounted reclosers with SCADA capabilities were installed on feeders 54G1 and 54G4 to improve system reliability. These two feeders run north and south, respectively, from the King Street Substation, and are the longest of the feeders. The pole-mounted reclosers coordinate with the substation reclosers, and sectionalize the long feeders. Due to the compact nature of the NED system, fault indicators may provide limited benefits to customers.

PLANNED SMART GRID

Beginning in 2018, NED 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 NED 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 2019, NED will decide whether to proceed to the RFP phase of the process.

NED 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.

NED 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, NED 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, NED stays abreast of these developments and the strategies needed to maintain a safe, reliable, and economically viable distribution system.

NED is also mindful of the increasing importance of cybersecurity concerns, and the relationship of those concerns to technology selection and protection. While NED is not presently required to undertake NERC or NPCC registration, VPPSA is a registered entity, and NED's membership in VPPSA provides NED with knowledge and insight regarding ongoing cybersecurity developments and risks. On a more local level, NED 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. NED 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;

RE-CONDUCTORING FOR LOSS REDUCTION

NED replaced most of the overhead conductors with 1/0 AAC during the system upgrade in 1999. A small section of 4.16kV distribution remains within the service territory; NED does not plan to upgrade this small section of line as the cost-benefit analysis has shown that the upgrade is not economical.

TRANSFORMER ACQUISITION

Transformer failures create the primary need to purchase and install new transformers. GMP provides equipment and supplies for system restoration and maintenance. GMP reports that it uses a spreadsheet-based tool, developed in collaboration with the Public Service Department, to select lowest life-cycle cost equipment.

CONSERVATION VOLTAGE REGULATION

GMP monitors and controls the King Street Substation through its SCADA system. NED does not currently implement conservation voltage regulation at its substations, nor does it foresee doing so until AMI is implemented. Implementation of AMI will provide timely load voltage information from customers at the end of the feeders.

DISTRIBUTION TRANSFORMER LOAD MANAGEMENT (DTLM)

NED will collaborate with GMP to implement a DTLM program that is appropriate for its service territory subsequent to implementation of AMI.

SUBSTATIONS WITHIN THE 100 AND 500 YEAR FLOOD PLAINS

Both the King Street Substation and Norwich University Substation are located outside of the 500-year flood plain. Neither substation was affected by the floods of Tropical Storm Irene.

THE UTILITY UNDERGROUND DAMAGE PREVENTION PLAN (DPP)

NED has an underground Damage Prevention Plan in place. It was filed with the Department of Public Service in November 2016.

SELECTING TRANSMISSION AND DISTRIBUTION EQUIPMENT

GMP generally does the design for new or upgrade projects and uses its selection process for equipment.

MAINTAINING OPTIMAL T&D EFFICIENCY

RELIABILITY

System reliability is important to our customers and NED has a number of initiatives underway to improve reliability. Each of these initiatives is described below.

ANIMAL GUARDS

NED experiences a few animal contact events each year so a strategy of installing animal guards on all new construction and line rebuilds has been implemented. NED believes that animal guards are a cost-effective means of reducing animal contact and the associated service interruptions. GMP has been instructed to install animal guards where needed in conjunction with other maintenance at that location.

FAULT INDICATORS

NED does not currently use fault indicators since NED's circuits are relatively short and accessible.

POLE INSPECTION

NED has numbered and tagged all poles in the system with a unique identifier that was generated by GMP. Pole condition observations were recorded when the pole was tagged, and that information will be used to develop pole inspection lists. Approximately 40% of the poles have been inspected by Osmose within the last four years. All poles that have been inspected are recorded in a spreadsheet and NED is currently developing a plan for inspecting the remaining poles so that overall, all poles are inspected on a 10-year cycle, with tracking taking place in a spreadsheet. NED does not use the NJUNS database since neither Trans-video nor TDS Telecom use the database.

EQUIPMENT

NED contracts GMP to conduct all maintenance on substation transformers, reclosers, switches, cutouts, and protective relays. The substation transformer in the King Street substation was new in 2008, and the substation transformer in the Norwich University Substation, which was formerly in service at King Street Substation, was refurbished in 2008 prior to being placed in service after the substation rebuild. All four 15kV reclosers at the King Street Substation have been replaced with Cooper VWE reclosers with Form 6 control. The 35kV recloser was replaced in 2010. The King Street Substation back-up battery bank was replaced in 2011.

NED will investigate installation of appropriate surveillance equipment for substation assets for safety and security purposes.

SYSTEM MAINTENANCE

NED contracts with GMP to provide system construction, maintenance, and service restoration following outages. Much of the system hardware and equipment has been replaced through system upgrades over the past 20 years.

TRACKING TRANSFER OF UTILITIES AND DUAL POLE REMOVAL(NJUNS)

NED does not use the NJUNS database because neither TDS Telecom (telephone) nor Trans-video (cable TV) use the database. NED, TDS, and Trans-video are all local utilities and can easily reach each other via a phone call when necessary. This system has not proved to be problematic.

RELOCATING CROSS-COUNTRY LINES TO ROAD-SIDE?

NED 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.

DISTRIBUTED GENERATION IMPACT:

Currently, NED has 30 residential solar net metering customers, with a combined total residential installed capacity of 152 kW. This number has been growing slowly at about 1 to 2 customers per year. Also, in NED's service territory is a large, 500 kW, commercial solar installation, called Bull Run.

NED is investigating installing a 1.5 MW solar project on Bone Hill. If the project does come to fruition, it would likely need to be paired with storage, due to system limitations. NED also evaluated installing a 1MW solar project at Cheney Farm, but strong community resistance related to aesthetics led to the determination that this was not a viable site.

INTERCONNECTION OF DISTRIBUTED GENERATION

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

At this time, reliability evaluations are underway for two pending 100kW projects and NED is planning to evaluate individual feeders to determine safe levels of solar that can be added to the system without causing reliability issues.

VEGETATIVE MANAGEMENT/TREE TRIMMING

NED has about 40 miles of total distribution and sub-transmission lines. NED estimates about 5% of the lines run through fields that do not require tree trimming. The remaining 95% of the lines require tree trimming. NED trims to 10 feet on either side of the line and 20 feet above the line. NED trims to the edge of the right-of-way. The following tables summarize the amount of line trimmed and the cost of the trimming over the past few years.

Table 17 Northfield Vegetation Trimming Cycles

	Total Miles	Miles Needing Trimming	Trimming Cycle
Sub-Transmission	0.9 miles	0.5	7 years
Distribution	39 miles	37	7 years

Table 18 Northfield Vegetation Management Costs

	2016	2017	2018	2019	2020	2021
Amount Budgeted	$25,000	$25,000	$35,000	$45,000	$45,000	$45,000
Amount Spent (FY)	$23,443	$24,203	$44,838	x	x	x
Miles Trimmed	2.7	1.7	5.9	5.3	5.3	5.3

Significant tree trimming accompanied the voltage upgrade project in 1999, and there was subsequently no formal trimming plan. In 2009 through 2011, 33.9 miles of distribution circuits were trimmed in an aggressive trimming program to address increased system outages resulting from a lack of systematic trimming. Trimming in the past 4 years has been to address hot spots and hazard trees.

Trimming progress is tracked by marking up a system map using billing descriptions from Davey. NED has implemented a 7-year cycle program of 5.3 miles of distribution line trimming per year and trimming hot spots as necessary. Within a 7-year period, the entire distribution and sub-transmission system will be trimmed as appropriate for aesthetics and system reliability. Some of the reported lengths of trimmed line have been those that required trimming and do not include lengths of contiguous circuit distances that are void of undergrowth. A more consistent reporting and tracking system will be initiated to track trimming progress and costs per mile.

On an average basis, NED budgets approximately 5 distribution circuit miles of tree-trimming per year. These are not necessarily contiguous circuit miles. NED budgets $45,000 per year for tree-trimming. NED surveys at least 5 miles per year. In historical years, where the miles trimmed were fewer than 5 miles, at least 5 miles were surveyed but only those miles actually requiring trimming show in the table (above).

Danger trees are identified by our utility personnel while patrolling the lines, reading meters, or inspecting the system. Once a danger tree is identified, it is promptly removed if it is within NED's right-of-way. For danger trees outside of the right-of-way, NED contacts the property owner, explains the hazard, and with the owner's permission removes them. Where permission is not granted, NED 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 NED's territory. NED 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 NED's territory, affected trees will be cut down, chipped and properly disposed of.

OUTAGE STATISTICS

NED tracks all outage statistics as part of its Service Quality Reliability Plan (SQRP). These outage statistics allow us to examine causes by circuit and develop plans for the most cost-effective reliability improvements. The following table summarizes SAIFI and CAIDI results for the past 5 years. NED's Vermont Public Utility Commission Rule 4.900 Electricity Outage Reports, reflecting the last five years (2014-2018) in their entirety, can be found at the end of this document.

Table 19 Northfield Outage Statistics

	Goals	2014	2015	2016	2017	2018
SAIFI[23]	**1.00**	0.92	**0.21**	**1.27**	**1.85**	**0.41**
CAIDI[24]	**2.40**	1.77	**1.89**	**0.77**	**1.60**	**3.99**

Analysis of the Outage Reports for the past three years indicate that tree-related outages and cutout failures continue to require attention. We have implemented a robust tree-trimming strategy and a cost-effective cutout replacement plan to address these two areas. A major outage that significantly contributed to the increased SAIFI metric in 2014 was the failure of a regulator in the King Street Substation. The October 16, 2018 tree-related outage, resulting in 149 customers without power for 8 hours, was a major contributor to the increased CAIDI value for that year. Out of all the 2018 outages,

[23] System Average Interruption Frequency Index

[24] Customer Average Interruption Duration Index

this outage resulted in the greatest number of customers out in one single day and accounted for almost half of the total customer hours out for the year.

NED installed directional relays in the King Street Substation through the SGIG in early 2013 that work with the motor-operated interconnect switches to sectionalize the sub-transmission circuit in collaboration with similar equipment installed by GMP on its substations on that circuit. This equipment has significantly improved system reliability and the SAIFI metric since 2013.

GMP performs service restoration work following outages for NED and outages are reported by GMP to www.vtoutages.com. NED notifies customers of planned outages either through a visit to the customer's premises or via a telephone call.

TREE-RELATED OUTAGES

Table 20 Northfield Tree Related Outages

	2014	2015	2016	2017	2018
Tree Related Outages	5	5	11	5	5
Total Outages	25	13	35	20	29
Tree-related outages as % of total outages	20%	38%	31%	25%	17%

STORM/EMERGENCY PROCEDURES

Unlike most other Vermont municipal electric utilities, NED does not have any line crews. NED contracts with GMP for maintenance and outage restoration. NED does not actively participate in the Northeast Public Power Association ("NEPPA") mutual aid system, since it does not have any line crew to participate in mutual aid and depends solely on GMP for restoration. NED outages are entered into GMP's Outage Management System, which in turn feeds www.vtoutages.com. NED believes it is beneficial to inform the Public Service Department if it is experiencing these types of outages.

PREVIOUS AND PLANNED T&D STUDIES

NED commissioned a Distribution System Analysis, completed in 1994, by Booth & Associates, Inc. of Raleigh, NC to evaluate the performance of the distribution system and to propose system improvements. At the time of the study, the system consisted of three (3) distribution substations and seven (7) distribution feeders rated at 4.16kV. The Norwich and Center Village substations were connected to the King Street Substation with 34.5kV sub-transmission lines. The primary supply to NED was, and continues to be, from GMP's 34.5kV sub-transmission system interconnection at the King Street Substation.

The recommendations resulting from the analysis were to:

- Convert the system from 4kV to 12kV.
- Replace the King Street Substation.
- Reduce the number of circuits from seven (7) to four (4).
- Perform a sectionalizing study for operation of the 12kV system.
- Perform a capacitor placement and optimization study.

NED has implemented all of the recommendations of that report. The system conversion to 12.47kV, reduction of the number of distribution feeders, and rebuild of the King Street Substation were completed in 1999. GMP provides engineering services for determining the recloser settings in the substations. In 2008, a larger substation transformer was purchased and installed at the King Street Substation, and the Norwich University Substation was completely rebuilt using the refurbished transformer from the King Street Substation. GMP engineers determined the power factor correction capacitor placements, and capacitors were installed and placed in service on each of the four distribution circuits in 2009.

During the conversion, non-PCB distribution transformers were installed throughout the system. In addition, substation equipment has been upgraded, and non-PCB power factor correction capacitors have been installed. Only one small section of the old 4.16kV system remains in service with possibly 10 transformers and its PCB-status should be verified. Testing requires de-energizing and lifting the lid of older model transformers to take an oil sample. It is located in a right-of-way through the woods to serve a small number of customers. The step-down transformer feeding this section from the 12.47kV system was recently replaced after a failure and NED does not plan to upgrade nor relocate this section.

Most of the current Norwich University (NU) load, as well as new load resulting from campus additions, is supplied by the Norwich University Substation. The entire campus load was supplied by the 54G4 feeder in 2008 during the complete rebuild of the Norwich University Substation. The Norwich University system has an additional interconnect to the 54G4 line to permit the entire campus to be fed from that feeder in the event that there is an extended outage of the Norwich University Substation.

FUSE COORDINATION STUDY

GMP performed a fuse coordination study in 2009 based on current loads to provide information relative to the appropriate size of distribution fuses. It is possible that there exist fuses on the system that may not have been changed since the system voltage upgrade in 1999. Fuses sized for the old 4.16kV system will be of a higher current rating than required at 12.47kV and would lead to a protection coordination problem. Fuse information provided by the study is used by line crews to guide checking and replacement when necessary or during ongoing outage and maintenance work that necessitates disturbing the fuse. Recent experience has confirmed that this approach is not resulting in an undue number of trips or problematic conditions. NED believes this information to still be valid due to lack of load growth.

NED is considering future system studies. In 2008, both substations in Northfield were upgraded. There is capacity available at the Norwich University Substation as a result of refurbishing and redeploying the station transformer from the King Street Substation. Anticipated future systems studies will likely include evaluation of design options to use the Norwich University Substation in a feeder backup scheme, and an analysis of the ability of circuit 54G4 to supply the Norwich University load in the event of an outage at the Norwich University Substation.

CAPITAL SPENDING

CONSTRUCTION COST 2016-2018

Table 21 Northfield Historic Construction Costs

Town of Northfield Electric Department		**Historic Construction**		
Historic Construction		**2016**	**2017**	**2018**
Pole Replacements	Dist	**61,874**		
Customer requested Jobs (4)	Dist	**22,814**		
Misc Plant	Dist	**14,533**		
Computer Upgrades	General	**9,458**		
Bull Run Solar (interconnection)	Dist		**5,974**	
Underground & 75 kva transformer on King St.	Dist		**41,351**	
Pole replacements	Dist		**14,548**	
Customer requested Jobs (4)	Dist		**25,002**	
Misc Plant	Dist		**14,574**	
Pole Replacements	Dist			**49,980**
Customer requested Jobs (4)	Dist			**20,957**
King St Sub Airbreak & Recloser	Dist			**17,587**
Bull Run Interconnection	Dist			**76,681**
Misc Plant	Dist			**15,193**
Computer Upgrades	General			**1,290**
Total Construction		**$ 108,679**	**$ 101,449**	**$ 181,688**
Functional Summary:				
Prod		-	-	-
General		9,458		1,290
Distribution		99,221	101,449	180,398
Transmission		-	-	-
Total Construction		108,679	101,449	181,688

PROJECTED CONSTRUCTION COSTS (2020-2022):

Table 22 Northfield Projected Construction Costs 2020-2022

Town of Northfield Electric Department		Projected Construction		
Projected Construction		**2020**	**2021**	**2022**
Relocate sub-transmission line	trans	**150,000**		
Pole Replacements	Dist	**45,000**		
Misc Plant	Dist			
	General			
Pole Replacements	Dist		**45,000**	
Misc Plant	Dist		**75,000**	
	Dist			
Pole Replacements	Dist			**45,000**
Misc Plant	Dist			**30,000**
	General			
Total Construction		**$ 195,000**	**$ 120,000**	**$ 75,000**
Functional Summary:				
Prod		-		
General		-		-
Distribution		45,000	120,000	75,000
Transmission		150,000	-	-
Total Construction		195,000	120,000	75,000

V. FINANCIAL ANALYSIS

The most immediate question facing NED is how to fulfill unhedged energy requirements between 2020 and 2025. The solution to the first three years of this timeframe is outlined in the Resource Plan section under Energy Resource Plan Decision 1. We have elected to evaluate the first five years of the open position to illustrate the decision-making process between two prototypical market contracts. The leading resource options are summarized in Table 23. Notice that volume and term remain consistent while the product and all-in-price vary.

Table 23: Energy Resource Options & Characteristics

Resource Option	Price Structure	Volume	Product	Term	All-In Price
Status Quo	Variable at market prices.	3,000 MWH	7x24 Energy	5 Years, 2020-24	$51.93
Market Contract	Fixed at levelized market prices.	3,000 MWH	7x24 Energy	5 Years, 2020-24	$48.96
Hydro + Tier I RECs	Fixed at levelized market prices.	3,000 MWH	7x24 Energy + RECs	5 Years, 2020-24	$51.56

The status quo option is to leave energy requirements unhedged. These requirements would be fulfilled by ISO New England's energy markets at the Locational Marginal Price (LMP) at the Vermont Zone. As a result, the price structure in Table 23 is variable at market prices. The status quo option is only listed in this table for comparison purposes. In practice, VPPSA would not leave energy requirements unhedged.

The remaining two resource options are to purchase a fixed-price market contract for energy or to purchase a fixed-price contract for existing hydroelectric energy plus RECs. The resource need is short-term by nature, thus new long-term resources like solar or wind are not considered. Similarly, new demand-side resources are not considered as they have already been captured by the load forecast.

To evaluate these options, we calculated the fixed all-in price of each of the two options by levelizing the forecast of annual energy and REC prices in our budget models. This enables us to evaluate how the resources would perform under different market conditions, summarized in Table 24.

Table 24: Range of Market Conditions

Market Price Condition	Natural Gas Price Range	Tier I REC Price Range
Low	-50%	$1.00
Base	100%	$2.50
High	150%	$10

Natural gas prices are the primarily determinant of electricity prices in New England. REC prices are an increasing risk because of the need to fulfill RES requirements. We chose to test the resource options against changes in these two markets. Historical data indicates that natural gas prices have changed by +/- 50% over time. Tier I REC prices have seen a low of about $1. The ACP sets the upper bound of $10 for Tier I RECs.

Because NED is short on both energy and Tier I RECs, the lowest-cost outcomes would occur when market prices decrease. Conversely, the highest-cost outcomes would occur when market prices increase. This reduces the number of scenarios we need to analyze to nine.

VPPSA's fully integrated financial model incorporates power supply, capital, financing, and other operating costs. Northfield's transmission and distribution system was largely rebuilt or upgraded in the past fifteen to twenty years; as a result, ongoing construction costs are not anticipated to be a significant

cost driver for the foreseeable future. Coupled with a projection of relatively stable loads, power supply costs are expected to be the primary driver of NED's modest rate trajectory. Overall revenue requirements are estimated to grow at a 2.4% compound annual growth rate over the 2020-2039 period. The financial model is summarized in Appendix F. Using the financial model, we estimated NED's revenue requirements under each market condition. The results of each scenario are shown in the following table.

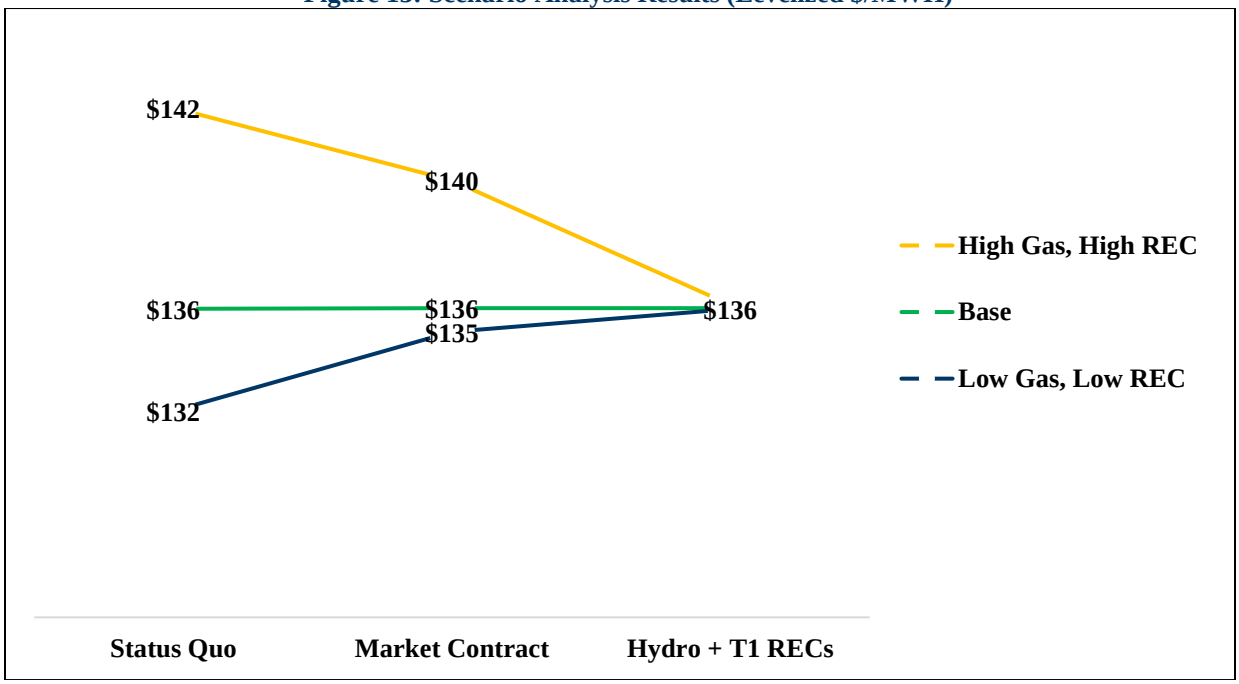
Table 25: Scenario Analysis Results (Levelized $/MWH)

Decision Option	Low Gas, Low REC	Base Case	High Gas, High REC
Status Quo	$132	$136	$142
Market Contract	$135	$136	$140
Hydro + T1 RECs	$136	$136	$136

The lowest and highest cost scenarios are both the result of the status quo decision option. This makes sense because this option leaves the energy and REC requirements unhedged and exposed to the full range of potential to spot market prices. If prices decrease, NED's cost also decreases. But if prices increase, NED's cost increases.

The range of cost outcomes narrows under the market contract option because the energy market risk has been hedged. The narrowest range of outcomes occurs under the Hydro + Tier I REC option because the energy and the REC price risk has been hedged. Notice that the cost outcomes of this option match the base case. This result is not surprising, and simply means that NED's costs were "locked in" at today's market prices. In any event, the benefits of hedging energy and REC risk is more vividly illustrated in the following figure.

Figure 13: Scenario Analysis Results (Levelized $/MWH)



Looking from left to right, the lines in Figure 13: Scenario Analysis Results (Levelized $/MWH)converge to $136/MWH. This illustrates the risk-reducing nature of buying resources at fixed prices. In this example, the lowest risk resource is Hydro + T1 RECs because changes in market prices no longer impact the financial outcome. While some policy makers may prefer this scenario, others may prefer to carry more (variable) price risk in the hopes that a lower cost outcome can be realized. Using decision analysis, the final step in the process is to have policy makers choose the probability of each market condition occurring (Table 24). The final resource decision becomes a probability-weighted average of the decision-making body's collective market view.

ACTION PLAN

VI. ACTION PLAN

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

1. **Automated Metering Infrastructure (AMI)**
    - NED has great interest in implementing AMI and anticipates beginning implementation during 2020, subject to careful completion of the evaluation process discussed above. NED 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. NED 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. NED also notes that unanticipated initiatives may emerge over time that positively impact the perceived value of having an AMI system in place. Given current expectations, the potential for unexpected demands, and related uncertainties, NED will likely elect to implement AMI, absent the RFP process resulting in a prohibitively high cost estimate.

2. **Energy Resource Actions**
    - Manage year to year energy market requirements using fixed-price, market contracts that are less than five years in duration.
    - Consider replacing the NextEra 2018-2022 Contract with a 3.5 to 5 MW hydro entitlement that includes bundled energy and renewable energy credits.
    - Replace the Fitchburg Landfill Gas resource with the end of RES in mind.

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

4. **Tier I Requirements**
    - Consider replacing the NextEra 2018-2022 Contract with a 3.5 to 5 MW hydro plant that includes bundled energy and renewable energy credits.
    - Make forward purchases of qualifying RECs on the regional market to manage REC price and ACP risk.

5. **Tier II Requirements**
    - Develop and complete the Bone Hill Solar or a comparable, Vermont-based solar project.
    - Make forward purchases of qualifying RECs on the Vermont market to manage REC price and ACP risk.

6. **Tier III Requirements**
    - Identify and deliver prescriptive and/or custom Energy Transformation programs, and/or
    - Develop and complete the Bone Hill Solar or a comparable, Vermont-based solar project, and/or
    - Purchase Tier II-qualifying renewable energy credits.

7. **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.

8. 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.

9. Pole Inspection Tracking Process

- Develop a tracking and reporting process for pole inspections.

10. **Surveillance of Substation Assets**

- Install appropriate security surveillance equipment in NED's substations.

11. **Norwich University Load Study**

- Evaluate the adequacy of the alternative feed for the Norwich University campus.

12. 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.

13. 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: CVRPC REGIONAL ENERGY PLAN

This appendix is provided separately in a file named:

Appendix A - 05.08.2018-Approved-Regional-Energy-Plan-Reduced.pdf

APPENDIX B: 2019 TIER 3 ANNUAL PLAN

This appendix is provided separately in a file named:

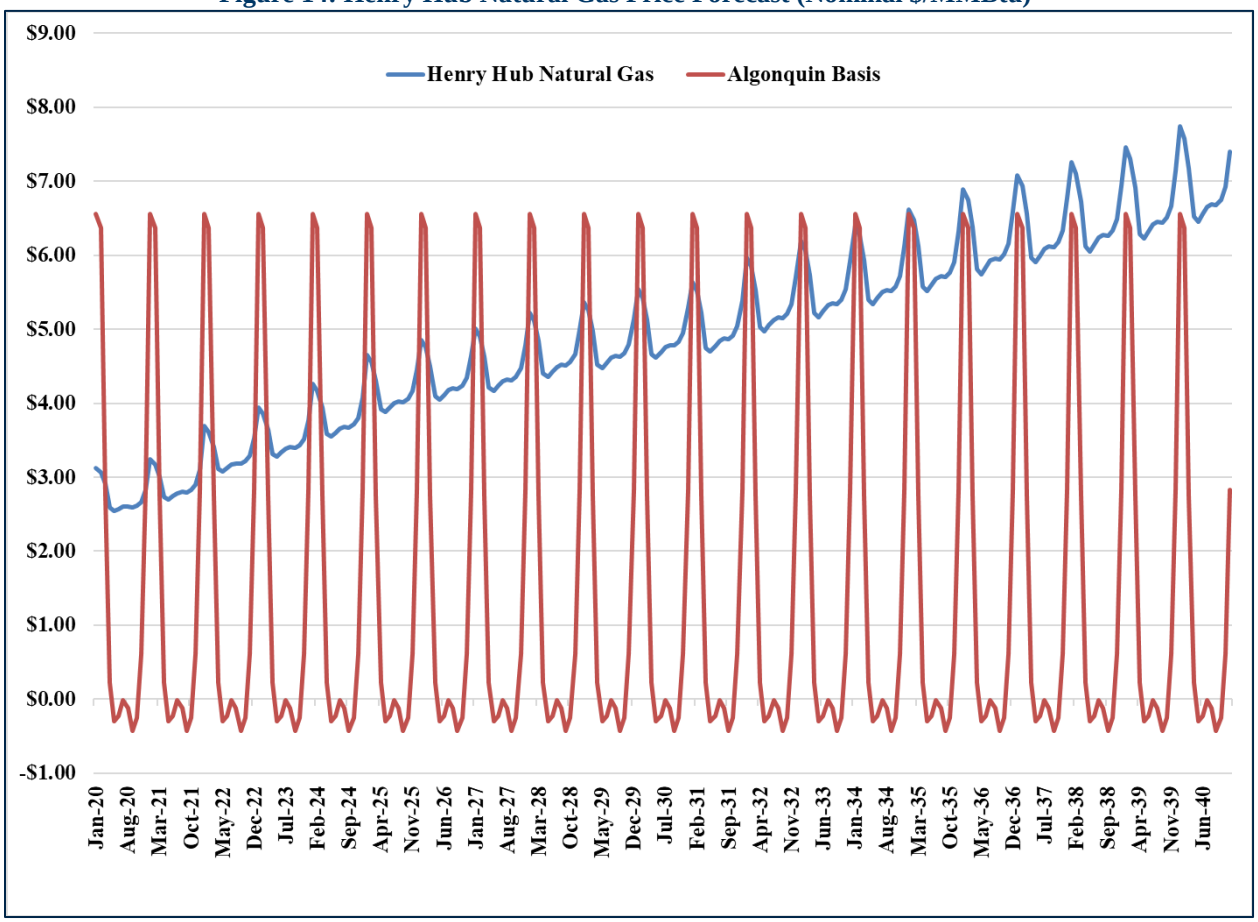
Appendix B - VPPSA Tier 3 2019 Annual Plan.pdf

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 14.

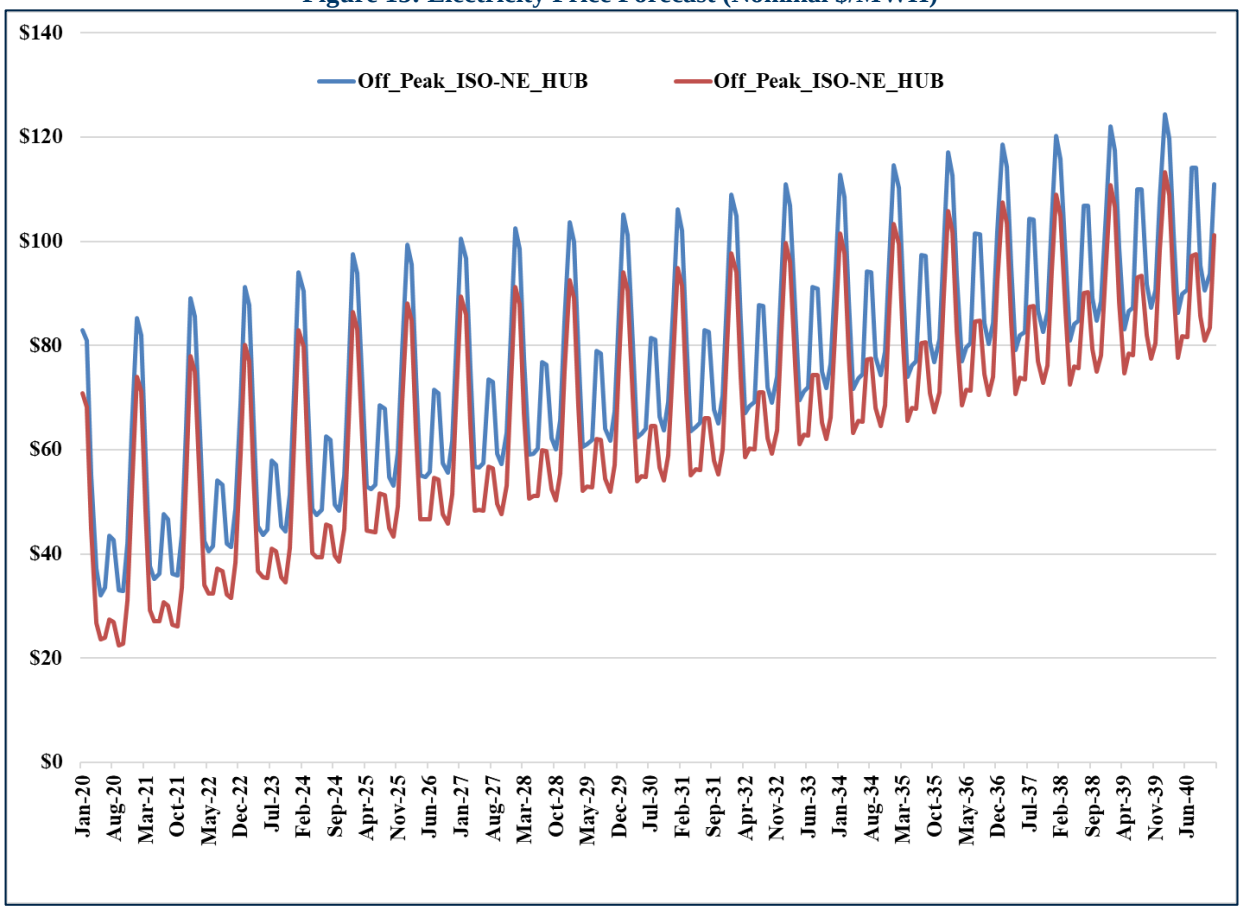
Figure 14: Henry Hub Natural Gas Price Forecast (Nominal $/MMBtu)



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 15.

Figure 15: Electricity Price Forecast (Nominal $/MWH)

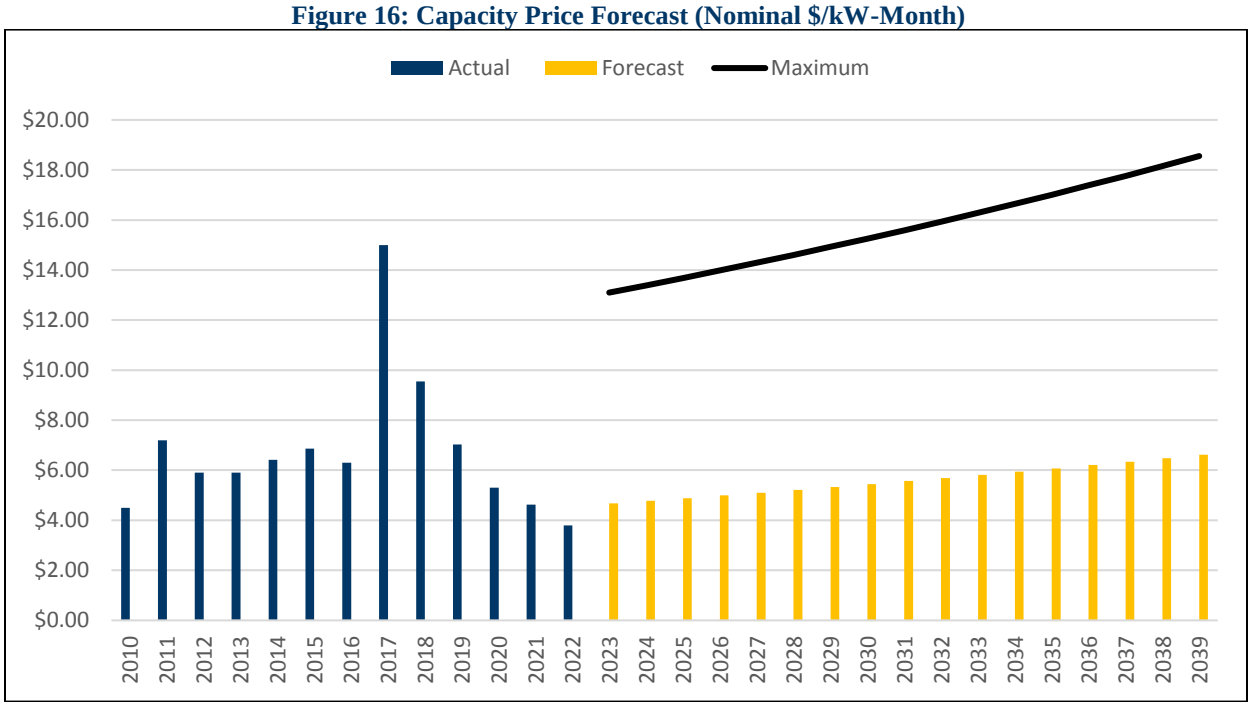


In keeping with the function of ISO-NE's Standard Market Design, we use a five-year average basis between Locational Marginal Price (LMP) nodes to adjust the price forecast at the MA Hub to the location of NED's load and resources.

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 16. This line represents the Forward Capacity Auction Starting Price plus inflation.

Figure 16: Capacity Price Forecast (Nominal $/kW-Month)



APPENDIX D: PUC RULE 4.900 OUTAGE REPORTS

Northfield Electric Department

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	Northfield Electric Department
Calendar year report covers	**2014**
Contact person	Patrick Demasi
Phone number	802-485-7355
Number of customers	1,834

System average interruption frequency index (SAIFI) = 0.92
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 1.77
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out	Total customers interrupted	c codes	Sum	non c customer hours out	c code customer hours out
1	**Trees**	5	28	12	0	12	28	0
2	**Weather**	7	640	47	0	47	640	0
3	**Company initiated outage**	0	0	0	0	0	0	0
4	**Equipment failure**	9	2,277	1,599	0	1,599	2,277	0
5	**Operator error**	0	0	0	0	0	0	0
6	**Accidents**	0	0	0	0	0	0	0
7	**Animals**	3	26	20	0	20	26	0
8	**Power supplier**	0	0	0	0	0	0	0
9	**Non-utility power supplier**	0	0	0	0	0	0	0
10	**Other**	1	3	1	0	1	3	0
11	**Unknown**	0	0	0	0	0	0	0
	Total	25	2,974	1,679		1,679		

Northfield Electric Department

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	Northfield Electric Department
Calendar year report covers	**2015**
Contact person	Patrick Demasi
Phone number	802-485-7355
Number of customers	1,831

System average interruption frequency index (SAIFI) = 0.21
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 1.89
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out	Total customers interrupted	c codes	Sum	non c customer hours out	c code customer hours out
1	**Trees**	5	400	249	0	249	400	0
2	**Weather**	0	0	0	0	0	0	0
3	**Company initiated outage**	1	148	37	0	37	148	0
4	**Equipment failure**	2	25	19	0	19	25	0
5	**Operator error**	0	0	0	0	0	0	0
6	**Accidents**	0	0	0	0	0	0	0
7	**Animals**	3	93	53	0	53	93	0
8	**Power supplier**	0	0	0	0	0	0	0
9	**Non-utility power supplier**	0	0	0	0	0	0	0
10	**Other**	2	45	18	0	18	45	0
11	**Unknown**	0	0	0	0	0	0	0
	Total	13	711	376		376		

Northfield Electric Department

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	Northfield Electric Department
Calendar year report covers	**2016**
Contact person	Patrick Demasi
Phone number	802-485-7355
Number of customers	1,837

System average interruption frequency index (SAIFI) = 1.27
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 0.77
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out	Total customers interrupted	c codes	Sum	non c customer hours out	c code customer hours out
1	**Trees**	11	449	177	0	177	449	0
2	**Weather**	10	970	135	0	135	970	0
3	**Company initiated outage**	0	0	0	0	0	0	0
4	**Equipment failure**	5	146	129	0	129	146	0
5	**Operator error**	0	0	0	0	0	0	0
6	**Accidents**	0	0	0	0	0	0	0
7	**Animals**	3	28	14	0	14	28	0
8	**Power supplier**	1	153	1,830	0	1,830	153	0
9	**Non-utility power supplier**	0	0	0	0	0	0	0
10	**Other**	3	34	27	0	27	34	0
11	**Unknown**	2	9	2	0	2	9	0
	Total	35	1,788	2,314		2,314		

Northfield Electric Department

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	Northfield Electric Department
Calendar year report covers	**2017**
Contact person	Patrick Demasi
Phone number	802-485-7355
Number of customers	1,823

System average interruption frequency index (SAIFI) = 1.85
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 1.60
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out	Total customers interrupted	c codes	Sum	non c customer hours out	c code customer hours out
1	**Trees**	5	144	52	0	52	144	0
2	**Weather**	4	1,194	103	0	103	1,194	0
3	**Company initiated outage**	0	0	0	0	0	0	0
4	**Equipment failure**	7	1,862	746	0	746	1,862	0
5	**Operator error**	0	0	0	0	0	0	0
6	**Accidents**	1	1	1	0	1	1	0
7	**Animals**	0	0	0	0	0	0	0
8	**Power supplier**	3	2,206	2,477	0	2,477	2,206	0
9	**Non-utility power supplier**	0	0	0	0	0	0	0
10	**Other**	0	0	0	0	0	0	0
11	**Unknown**	0	0	0	0	0	0	0
	Total	20	5,408	3,379		3,379		

Northfield Electric Department

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	Northfield Electric Department
Calendar year report covers	**2018**
Contact person	Patrick Demasi
Phone number	802-485-7355
Number of customers	1,826

System average interruption frequency index (SAIFI) = 0.41
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 3.99
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out	Total customers interrupted	c codes	Sum	non c customer hours out	c code customer hours out
1	**Trees**	5	1,532	271	0	271	1,532	0
2	**Weather**	8	579	79	0	79	579	0
3	**Company initiated outage**	0	0	0	0	0	0	0
4	**Equipment failure**	7	226	70	0	70	226	0
5	**Operator error**	0	0	0	0	0	0	0
6	**Accidents**	0	0	0	0	0	0	0
7	**Animals**	3	29	25	0	25	29	0
8	**Power supplier**	0	0	0	0	0	0	0
9	**Non-utility power supplier**	0	0	0	0	0	0	0
10	**Other**	1	155	33	0	33	155	0
11	**Unknown**	4	448	266	0	266	448	0
	Total	28	2,970	744		744		

APPENDIX E: INVERTER SOURCE REQUIREMENTS

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

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

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

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

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

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

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

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

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

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

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

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

   The following additional performance requirements shall apply for all inverters:

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

1
7.3 as a proxy, subject to minor
editorial changes.

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

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

4. Other grid support utility interactive inverter functions statuses

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

5. Definitions

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

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

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

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

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

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

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

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

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

Table II: Inverters' Frequency Trip Settings

Shall Trip Function	Required Settings		Comparison to IEEE Std 1547-2018 (2nd ed.) default settings and ranges of allowable settings for Category I, Category II, and		
	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 (2nd ed.)
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.

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.) for Category II
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 or	OFF
SS, Soft-Start Ramp Rate	ON Default value: 2% of maximum current output
FW, Freq-Watt Function OFF	OFF

2
with unity PF.

APPENDIX F: FINANCIAL MODEL SUMMARY

Figure 17: Financial Model Summary

Northfield Electric Department								
Base Case Projected Revenue Requirement 2020-2039								
	2020	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**	**2039**
Revenue Requirement Increase %		1.69%	0.41%	1.90%	2.38%	2.60%	3.23%	3.02%
Retail Load MWH	27,456	27,351	26,999	26,946	26,761	26,641	27,562	28,551
Retail Load Growth		-0.4%	-1.3%	-0.2%	-0.7%	0.2%	0.8%	0.6%
Retail Revenue Requirements								
Production O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Purchased Power &TBO	3,162,027	3,209,630	3,213,008	3,270,355	3,345,032	3,810,833	4,443,198	5,232,829
Other O&M	137,130	140,147	143,231	146,382	149,602	166,798	185,972	207,349
A&G	330,220	337,485	344,910	352,498	360,253	401,663	447,833	499,311
Depreciation	145,116	150,634	153,232	155,232	157,069	167,955	181,337	194,825
Taxes	77,893	77,087	78,358	79,247	80,549	89,984	101,118	115,114
Total Operating Expenses	$3,852,386	$3,914,984	$3,932,739	$4,003,713	$4,092,505	$ 4,637,234	$ 5,359,458	$ 6,249,428
Other Income & Expense								
Misc. Electric Revenue	13,084	13,372	13,666	13,967	14,274	15,915	17,744	19,784
Other Income	367,789	367,074	368,467	370,092	370,744	375,435	381,255	387,605
Interest Expense	17,067	13,017	11,492	9,967	8,442	67	69	69
Net Income	$ 122,100	$ 124,164	$ 124,673	$ 127,037	$ 130,058	$ 148,608	$ 173,618	$ 204,474
Total Revenue Requirement	$3,610,681	$3,671,720	$3,686,772	$3,756,658	$3,845,986	$ 4,394,559	$ 5,134,146	$ 6,046,582
Average Retail Rate $/MWH	$ 131.5	$ 134.2	$ 136.6	$ 139.4	$ 143.7	$ 165.0	$ 186.3	$ 211.8
YOY rate change		2.1%	1.7%	2.1%	3.1%	2.4%	2.4%	2.4%
Average Rates - CAGR	2.4%							
Key Cash Related Items								
Cash provided by operations	$ 157,471	$ 165,053	$ 168,160	$ 172,523	$ 177,381	$ 316,563	$ 354,955	$ 399,299
Bonds Issued	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Construction expenditure	$ (250,000)	$ (116,650)	$ (93,336)	$ (106,746)	$ (81,821)	$ (160,658)	$ (101,712)	$ (148,404)
Long Term Debt Principal Payment	$ (35,000)	$ (35,000)	$ (35,000)	$ (35,000)	$ (35,000)	$ (5,000)	$ -	$ -
Operating reserve Balance	$ 297,471	$ 310,874	$ 350,698	$ 381,476	$ 342,036	$ 387,599	$ 467,392	$ 493,482
TIER (EBIT/INT)	**1.7**	**2.1**	**2.3**	**2.7**	**3.4**			
Debt Service Coverage (EBITDA/(P&I))	**5.5**	**6.0**	**6.2**	**6.5**	**6.8**			

CENTRAL VERMONT
REGIONAL PLANNING COMMISSION

REGIONAL ENERGY PLAN

Approved by the
CVRPC Board of Commissioners
May 8, 2018

Central Vermont Regional Planning Commission
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802.229.0389
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ACKNOWLEDGEMENTS

The development of this plan would not have been possible without the assistance of the dedicated individuals that volunteered their time to participate on the Regional Energy Committee. This committee was established by the CVRPC Board of Commissioners to provide recommendations regarding energy planning and lead to action by the full Commission. The committee represented a diverse cross section of the region and interests to provide multiple perspectives that were critical to the development of this plan. The members that served on this committee include:

Steve Fitzhugh, Chair, Town of Northfield Planning Commission
Bram Towbin, Vice-Chair, Town of Plainfield Selectboard
Alex Bravakis, Novus Energy Development
Jackie Cassino, Vermont Agency of Transportation
Barbara Conrey, Montpelier Energy Committee
Robert Dostis, Green Mountain Power
Brian Fitzgerald, CVRPC (Town of Duxbury)
Karen Horn, Vermont League of Cities & Towns
Ron Krauth, CVRPC (Town of Middlesex)
Don La Haye, CVRPC (Town of Waitsfield)
Karin McNeill, Vermont Agency of Natural Resources
Julie Potter, CVRPC (Town of East Montpelier)
Patty Richards, Washington Electric Cooperative
Janet Shatney, CVRPC (Barre City)
Mark Sousa, Green Mountain Transit
Jamie Stewart, Central Vermont Economic Development Corporation
Paul Zabriskie, Capstone Community Action

How This Plan Will Be Used

The Central Vermont Regional Energy Plan will establish the policies that will help the Regional Planning Commission achieve its share of the state's goal of 90% of the state's energy coming from renewable sources by 2050, as outlined in the 2016 State Comprehensive Energy Plan. In order for this document to have standing, it will need to receive a Determination of Energy Compliance (DOEC) from the Vermont Public Utility Commission (PUC). This determination will give the Central Vermont Regional Plan "substantial deference" before the PUC during their review of applications for Certificates of Public Good related to renewable energy generation facilities.

Once a DOEC has been issued, the Central Vermont Regional Plan will be used to establish a position in proceedings before the PUC if warranted Additionally, where applicable, the plan will be used during Act 250 proceedings before the District 5 Environmental Commission. Finally, once a DOEC has been issued to the region, municipal plans will be reviewed against the Regional Energy Plan and against the standards of Act 174 for municipal planning. If all the requirements for municipal planning are successfully met, the Region will issue a DOEC for the municipal plan. This determination will provide the municipal plan with "substantial deference" before the PUC as applicable.

Additional Energy Generation Technology

The general premise of the Central Vermont Regional Energy Plan is based on the idea that generation of energy will be achieved using more renewable sources and less fossil fuel based resources. To this end, the focus for generation of energy is primarily based on existing technologies such as solar, wind, and hydroelectric. Additionally, the plan notes woody biomass and biogas as renewable forms of energy generation when developed in a sustainable manner. This direction is taken from the State's Comprehensive Energy Plan which focuses on electrification of the grid in order to meet their goals of 90% of the state's energy use coming from renewable sources by 2050.

The sources of renewable energy generation that are identified in this plan include current technologies that are known and supported in Vermont. Advances in the development of renewable energy technologies may result in generation measures or techniques that are not currently considered in this plan but may be more efficient or effective. As such, this plan will consider renewable generation technologies that do not have an adverse impact on the region, its municipalities, or the policies that guide the Regional Planning Commission and not be limited exclusively to the generation techniques and technologies noted herein.

EXECUTIVE SUMMARY & INTRODUCTION

The 2017 Central Vermont Regional Energy Plan represents the efforts of the Central Vermont Regional Planning Commission, through it's Regional Energy Committee to develop a plan that will receive a Determination of Energy Compliance (DOEC) through the Vermont Public Utilities Commission (PUC). A DOEC will give the Central Vermont Regional Plan "substantial deference" before the PUC for applications that seek to receive a Certificate of Public Good.

The 2016 State Comprehensive Energy Plan identified a goal to have 90% of the state's energy needs derived from renewable sources by 2050. As part of this goal, the Vermont State Legislature passed Act 174 in 2016. Act 174 provides an avenue for regions and municipalities to have increased input in PUC determinations for Certificates of Public Good regarding renewable energy generation facilities. As such, Act 174 identified standards that need to be met in support of the state's goal of 90% renewable energy by 2050 in order to have a plan receive a DOEC and have "substantial deference". Otherwise, a plan will receive "due consideration" in the Section 248 review process. Act 174 is categorized as enhanced energy planning and goes beyond what is outlined in 24 VSA 117 Section §4348a and §4382 respectively.

Through Act 174, three primary planning areas are identified and need to be met satisfactorily in order for successful compliance. These sections include Analysis & Targets; Pathways & Implementation Actions; and Mapping. All three sections include an evaluation of energy sectors that include thermal (heating), electrical, and transportation.

Section I: Analysis & Targets

This section provides a baseline of information for where a region or municipality currently stand in terms of energy and identifies the trajectories and pace of change needed to meet targeted reductions and conservation of energy. It incudes information on current electricity use for residential and non-residential uses; existing

and potential renewable resource generation; and current transportation energy use information. Additionally, targets are established to provide milestones for thermal efficiency, renewable energy use, and conversion of thermal and transportation energy from fossil fuels to renewable resources. These milestones are intended to help the region measure progress towards the overall goals and are not identified as requirements. Targets are established for the years 2025, 2035, and 2050 which coincide with the State Comprehensive Energy Plan.

Specific information in this section notes the region currently uses approximately 600,000 megawatt hours of electricity on an annual basis across the identified sectors. By comparison, the regional share of new renewable energy generation needed to meet the state's goal is approximately 420,000 megawatt hours. Based on the mapping and resource data (Section III), the region has resources available to generate approximately 90,000,000 megawatt hours of energy.

Other analysis includes 2050 targets for fuel switching of vehicles from fossil based to alternative power, and conversion or installation of high efficiency heating systems for residential and commercial structures. Specific targets for Central Vermont include approximately 75,000 alternative powered vehicles and approximately 14,500 heating systems. These targets may be ambitious for Central Vermont based on the number of existing vehicles and structures which are listed at approximately 45,500 and 30,000 respectively. Also, specific implementation actions in this plan call for increased transit use which could reduce the overall need for vehicles region-wide. The specific 2050 targets for transportation and heating renewable use in Central Vermont are 90.2% and 92.5% respectively.

Section II: Pathways & Implementation Actions

Section II provides the basis for how the region will meet their target year goals as noted in Section I. The implementation actions are categorized by:

1. Conservation & efficient use of energy
2. Reducing transportation demand and single occupancy vehicles trips, and encouraging the use of renewable sources for transportation
3. Patterns and densities of land use likely to result in conservation of energy
4. The siting of renewable energy generation

The implementation actions that are identified in this section focus primarily in areas where the Central Vermont Regional Planning Commission is already working to support its member municipalities through local land use, transportation, and environmental planning activities.

To this end, the 2016 Central Vermont Regional Plan was first reviewed and implementation actions that pertained to any of the above mentioned sections were noted. These implementation items were carried forward for inclusion in the Regional Energy Plan to establish consistency with the two documents. To ensure all the categories for implementation as noted above were adequately addressed, guidance from the Department of Public Service related to implementation was utilized.

The implementation actions identify who will be responsible for completing each action, the timeframe for when it should be completed, and an anticipated outcome that will help provide a measure of success. This section will serve as the basis for how energy planning will be incorporated into regional activities. The implementation actions that were included are based on the CVRPC's ability to lead the action. This will

create consistency with regard to implementation and put the responsibility for action on the CVRPC. Other partners are listed when appropriate to indicate which groups will be engaged support the successful completion of the identified actions.

Section III: Mapping

The mapping section allows the region to visually identify where renewable energy generation is most suitable. This section combines resource information with specific known and possible constraints to the development of renewable energy generation. The mapping section also allows the opportunity to identify preferred locations for renewable energy development and areas that are unsuitable for development of any kind. In addition, the maps identify existing infrastructure to support renewable energy development.

In general, the mapping information looks at state-level data and breaks it down to a regional perspective. From there, an analysis was done (as noted in Section I) regarding the potential renewable energy generation that might be possible based on resource areas and constraints. This information is useful to visualize what geographies throughout Central Vermont are most ideally suited or best to avoid regarding renewable energy siting.

This section also contains specific policy information regarding the development and siting of renewable energy resources that are reflected on the maps. It was determined that no specific locations would be identified at a regional level as being preferred or prohibited areas for the development of renewable energy generation. This was done to allow the municipalities to decide if it was appropriate to identify these areas locally, rather then have this information dictated by the region. The Regional Planning Commission did, however, identify additional possible constraints to be considered. These include elevations above 2,500 feet, slopes greater than 25%, municipally owned lands, and lakeshore protection buffer areas of 250 feet. The decision was made to include these resources as possible constraints to allow for further analysis by the region or the municipalities to determine if development of renewable energy generation facilities may be appropriate based on specific conditions.

Appendices

There are three appendices included with this plan. Appendix A provides definitions for the known, possible, and regional constraints that are included on the maps and discussed in Section III. These definitions include source information and in several instances provide insight as to why the particular resource is listed as a known, possible, or regional constraint. Appendix B includes the specific regional resource and constraint maps. Included in the resource mapping is data specific to wind, solar, hydrological, and woody biomass. All of these maps also include information regarding three-phase power and transmission lines; roads; and other relevant data used to assist with siting of renewable energy development. Finally, Appendix C includes information related to Long-Range Energy Alternatives Planning (LEAP) modeling. The LEAP model is what established the baseline information for the entire state regarding current energy use and necessary reductions in energy use in order to achieve the state's goals of 90% renewable energy use by 2050. This information serves as the primary data source for the information in Section I. The methodology for how the modeling was conducted is also included in Appendix C.

CONFLICT RESOLUTION

The following information is being provided to help guide the process and ensure conflicts that may arise through regional or local energy planning are identified and addressed as early in the process as possible. Municipalities are encouraged to work with the Regional Planning Commission and their neighbors when developing an energy plan to identify any potential conflicts. Early discussions during the planning process may help alleviate the need to engage in the conflict resolution process as noted below.

Three conflict types are identified. These include:

1. Conflicts between a municipal energy plan and the regional energy plan
2. Conflicts between two municipal energy plans
3. Conflicts between the regional energy plan and the Central Vermont Regional Plan.

<u>Conflicts between a municipal energy plan and the regional energy plan</u>

The regional energy plan has been purposefully written to limit the region from dictating how the municipalities need to address renewable energy development and the standards of Act 174. The regional plan focuses on impacts at the regional scale and provides general guidance to municipalities regarding siting, renewable energy generation technology, and specific implementation actions. This was done to allow municipal energy plans to include specific detail related to these aspects while limiting conflicts with the regional energy plan.

If a municipal energy plan is in conflict with the regional energy plan regarding siting, the type of renewable energy generation, or implementation actions that will only impact the host municipality, the municipal energy plan will take precedent. If, however, the municipality proposes an action that will adversely impact a regionally significant resource (such as critical habitat) that is specifically identified in the Central Vermont Regional Plan, then the regional energy plan would take precedent and provide guidance to the Public Utility Commission or the District 5 Environmental Commission. Consistency with the Central Vermont Regional Plan and regional energy plan is necessary for municipalities requesting regional approval of their municipal development plan or municipal energy plan.

<u>Conflicts between municipal energy plans</u>

Requirements for a municipal development plan are outlined in statute. Specifically, 24 VSA 117 §4382(a)(8) requires, "A statement indicating how the plan relates to development trends and plans for adjacent municipalities, areas and the region developed under this title." To this end, municipalities are required to consider the development trends and plans in adjacent municipalities during the drafting of their municipal development plans. As such, the following process will be considered to assist in the resolution of potential conflicts between municipalities during the development of municipal energy plans.

This process only applies to the development of municipal energy plans. Notifications for specific projects seeking a Certificate of Public Good from the Public Utility Commission will follow the process outlined in 30 VSA 5 §248 for notification of municipal planning commissions, regional planning commissions, and interested parties.

1. If the policy or action being proposed by the host municipality will adversely impact a resource within the adjacent municipality (or municipalities) that has been identified in a municipal development plan, the host municipality must provide justification in writing as to why the policy or action is necessary. This notice must be sent to all effected adjacent municipalities and the Regional Planning Commission. If the adjacent municipality is outside of the Central Vermont RPC's jurisdiction, the adjacent municipality's RPC will also be notified.

2. If the adjacent municipality or regional planning commission objects to the justification as presented, a written response will be provided to the host municipality citing any studies or empirical data to support their objection. If the host municipality is not persuaded by any objections to change its position, the statement addressing 24 VSA 117 §4382(a)(8) will include information noting the inconsistency with the adjacent municipality. This notation may impact a municipality's ability to receive regional approval of a municipal plan.

An affected municipality may request assistance in mediating the conflict from the Regional Planning Commission. The Regional Planning Commission will consider the impacts on available resources when evaluating these requests.

Conflicts between the regional energy plan and the regional development plan

The Central Vermont Regional Energy Plan is intended to be a complimentary document and to inform land use decisions of the region related to energy. While efforts have been taken to ensure consistency with the regional energy plan and the rest of the Central Vermont Regional Plan, conflicts may exist. In the instance a conflict exists between policies or actions of the Central Vermont Regional Plan and the Central Vermont Regional Energy Plan, the more restrictive interpretation will be used to evaluate a proposal of regional significance. Additionally, the inconsistency will be noted and discussed by the Regional Plan Committee who will provide a recommendation to the full Commission on how to rectify the inconsistency.

PUBLIC PROCESS

The Regional Energy Committee held public meetings each month from December through May to develop a draft regional energy plan that could be reviewed against the specific standards outlined in Act 174. This draft was presented to the Regional Commission for consideration at their regular meeting on June 13, 2017. At that meeting, the three primary sections of the plan were presented for consideration. Several minor comments were discussed and changes were made as appropriate. On June 19, 2017, the Draft Central Vermont Regional Energy Plan was submitted to the Department of Public Service for review and comments against the standards of Act 174.

On October 30, 2017, the Department of Public Service returned comments on the Draft Central Vermont Regional Energy Plan. In the same transmittal, comments from the Agency of Natural Resources and the Agency of Agriculture, Food, & Markets were provided. Comments were also received from the public and staff at the Agency of Transportation who participated as members of the Regional Energy Committee. All of these comments were evaluated and incorporated as appropriate. On November 29, 2017 and December 7, 2017, the Central Vermont Regional Energy Committee met to discuss the updates to the draft regional energy

plan and recommend additional changes based on the comments received. At the meeting on December 7th, the Regional Energy Committee made a recommendation to the Central Vermont Regional Planning Commission's Board of Commissioners regarding approval of the draft.

In addition to the regular public meetings of the Regional Energy Committee, The CVRPC engaged in a robust public outreach effort to solicit feedback on the Draft Central Vermont Regional Energy Plan. This included:

- Tabling at the Waterbury LEAP Energy Fair
- Informational handouts distributed at 2017 Town Meeting Day
- Addition of a section of the CVRPC webpage dedicated to energy
- Presentations to the Barre Area Development Corporation on 12/12/2016 & 11/13/2017
- Open public comment period on the draft plan from 09/22/2017 through 10/31/2017
- Presentation to the Barre City Energy Committee on 10/23/2017
- Memo and discussion with the Central Vermont Transportation Advisory Committee on 10/24/2017
- Presentation to Downstreet Housing & Community Development on 11/15/2017
- Presentation to the Montpelier Energy Advisory Committee on 11/21/2017
- Two training sessions on Act 174 requirements and standards throughout the region
- Development of analysis & targets and mapping data for each CVRPC municipality

Additionally, the CVRPC will continue to evaluate and update the Central Vermont Regional Energy Plan as needed to ensure actions and information remains current and consistent with statewide planning goals.

ANALYSIS & TARGETS

In order to adequately determine if the Central Vermont Region is on the right path to meeting it's share of the state's goal of 90% of the energy used being produced by renewable sources, an identification and analysis of current energy use is necessary. To this end, the following questions have been identified to help determine current energy use and targets for moving forward.

I. *Does the plan estimate current energy use across transportation, heating, and electric sectors?*

II. *Does the plan establish 2025, 2035, and 2050 targets for thermal and electric efficiency improvements, and use of renewable energy for transportation, heating, and electricity?*

III. *Does the plan evaluate the amount of thermal-sector conservation, efficiency, and conversion to alternative heating fuels needed to achieve these targets?*

IV. *Does the plan evaluate transportation system changes and land use strategies needed to achieve these targets?*

V. *Does the plan evaluate electric-sector conservation and efficiency needed to achieve these targets?*

These five questions and their respective responses serve as the basis for identifying where the region is now, where the region needs to go, and how it will get there in terms of its energy future.

The information needed to answer the five questions listed above was procured from various sources. This includes information from the American Community Survey (as part of the U.S. Census), The Vermont Agency of Transportation, the Vermont Department of Labor, the Vermont Department of Public Service, Efficiency Vermont, the Vermont Energy Investment Corporation (VEIC), and the Central Vermont Regional Planning Commission. A significant portion of the data related to targets was provided by the VEIC through a process known as Long-Range Energy Alternatives Planning or LEAP. This modeling factors in a significant number of data points and has been used extensively throughout the world for energy planning such as this.

The majority of the data in this section was developed with a "bottom up" approach. That is to say, the data was developed at a municipal scale to complete the requirements of Standard 5 of the Energy Planning Standards for Regional Plans. The municipal data was then aggregated to establish a regional total. The one primary exception to that is the LEAP data, which was modeled at a regional scale. The LEAP data serves as the basis for the conservation and efficiency targets that are included in this plan. To that end, it is important to note that the data provided herein is only a starting point and should be used to establish a general direction, not a required outcome. This data is presented as a way to gauge the region's overall progress towards achieving 90% of its regional energy used produced from renewable sources. As new or better data is provided or developed, these tables will be updated to reflect the changes.

I. Estimates of current energy use across transportation, heating, and electric sectors

In order to determine where we need to go with our energy future, it is important to know where we currently are. Included in this is an identification of the existing sources of energy generation. In general, energy can be divided into four basic categories where discussions can be focused. These include resource type, land use, transportation, and siting. While all four are related and interconnected, they all serve separate components that need to be addressed individually as well as collectively.

Resource Type

The 2016 State Comprehensive Energy Plan notes four primary resource types for energy that are used throughout the state. These include non-combustion based renewables (including wind, hydroelectric, and solar), combustion based renewables (including biomass), nuclear energy, and fossil fuels. Fossil fuels account for a majority of the energy used in the state with natural gas and petroleum products accounting for 62% of Vermont's total energy use[1].

Non-Combustion Based Renewables

Non-combustion based renewables includes all the typical sources of energy generation such as wind, solar, and hydroelectric. Based on information from the Vermont Department of Public Service and the Energy Action Network's Community Energy Dashboard, there are approximately 1,300 sites in Central Vermont that are producing renewable energy across the three resource types. This accounts for approximately 130,000 megawatt hours of energy produced annually within Central Vermont. This amounts to approximately 3.5% of the annual energy consumption in Central Vermont.

Combustion Based Renewables

A second category of renewable energy generation is combustion based. Combustion based renewables include methane gas, anaerobic digesters, biodiesel, combined heat and power, compost heat, and woody biomass. Combustion based renewables are used for both electricity generation and thermal heating.

When looking at combustion based renewables for thermal heating, woody biomass is the most common form in Central Vermont. Wood products or byproducts such as wood pellets or wood chips are the most popular form of biomass heating. According to data from the U.S. Energy Information Administration, in 2015 one in six Vermont households used some form of biomass as their primary home heating source.

Currently, the primary electricity generator of combustion based renewables is methane gas. In Central Vermont, the Moretown Landfill provides the primary source of electrical generation from biomass in the form of methane gas. According to the 2014 Green Mountain Power (GMP) Integrated Resource Plan, GMP has an agreement with Moretown Landfill to purchase 100% of their energy generation capacity totaling approximately three megawatts, through 2023. Additionally, the Washington Electric Cooperative receives a majority of its energy generation from the Coventry Landfill in Coventry, Vermont. According to the Washington Electric Cooperative's data, in 2014 over 53% of their power came from the Coventry facility. Table One indicates the existing renewable electricity generation for the Central Vermont region.

1. 2016 Comprehensive Energy Plan – p.389.

TABLE ONE EXISTING REGIONAL RENEWABLE ELECTRICITY GENERATION		
RESOURCE TYPE	**MEGAWATTS**	**MEGAWATT HOURS**
Solar	24	29,919
Wind	.14	486
Hydroelectric	25	88,467
Biomass (including wood, methane, and farm biogas)	3	13,091
Other	0	0
Total Existing Regional Renewable Electricity Generation	52.14	131,963

Notes:
1. Information provided by the Department of Public Service, 2015
2. Regional totals were aggregated from each municipal total therefore not all calculations will be consistent.
3. Municipal data can be found at http://centralvtplanning.org/programs/energy/municipal-energy-planning/

Nuclear Energy

The Central Vermont Region's energy portfolio has been significantly impacted by the decommissioning of the Vermont Yankee Nuclear Facility in Vernon, Vermont. This facility, which was shut down at the end of 2014, provided approximately 55% of the electrical generation capacity for the State of Vermont. To make up for the loss of generation from Vermont Yankee, utility companies throughout the state have filled this gap through a variety of ways and established long-term contracts with other market power providers. Sources for this electricity generator consist of both renewable and non-renewable sources including wind, solar, hydroelectric, natural gas or other in-state utility owned renewable generation contracts.

Based on data from the Vermont Public Service Department, in 2011 the majority of energy being provided to Central Vermont from Green Mountain Power, Hardwick Electric Department, Northfield Electric Department, and Washington Electric Cooperative was from hydroelectric sources including Hydro Quebec. In fact nuclear energy as a source accounted for only about 10% of the energy generation for the service providers in Central Vermont.

Fossil Fuels

Fossil fuels are all non-renewable sources of energy that are generally carbon based and formed over millions of years from organic matter (including plants and animals) that were gradually buried under layers of rock. These fuels include natural gas, coal, and oil. Fossil fuels are typically refined for use as gasoline or other distillate fuels such as diesel fuel; home heating oil; or transported as natural gas.

In general, the majority of fossil fuel usage is attributed to home heating (including water) in the form of natural gas or home heating oil, or for transportation to fuel vehicles. According to information from the U.S. Energy Information Administration, natural gas fired power plants are providing energy to Vermonters, however these plants are generally located outside of the state. Additional information regarding fossil fuels will be included in the discussion on transportation later in this document.

In order to further refine the existing energy picture within Central Vermont, the CVRPC calculated its current energy consumption for transportation, heating, and electric use. This included both commercial and residential heating information. This information is listed in Tables Two through Six.

TABLE TWO CURRENT REGIONAL TRANSPORTATION ENERGY USE	
DATA CATEGORY	**INFORMATION**
Total number of vehicles	45,584 vehicles
Average miles traveled per vehicle	12,500 miles
Total regional miles traveled	567,650,000 miles
Average gallons of fuel used per vehicle per year	576 gallons
Total regional gallons of fuel used per year	30,518,817
Transportation energy used per year (in Billions)	3,396 BTUs
Average regional cost per gallon of fuel	$2.31
Regional fuel costs per year	$70,488,465.00

Notes:
1. Regional totals were aggregated from each municipal total therefore not all calculations will be consistent.
2. Total vehicles provided by the American Community Survey.
3. Average miles traveled & Average gallons of fuel used per vehicle provided by VTrans.
4. Average cost per gallon of fuel provided by the CVRPC.
5. Information related to public transit is not included in this table.

TABLE THREE CURRENT REGIONAL RESIDENTIAL HEATING ENERGY USE BY FUEL SOURCE				
FUEL SOURCE	**NUMBER OF HOUSEHOLDS**	**PERCENT OF HOUSEHOLDS**	**REGIONAL HEATED SQUARE FOOTAGE**	**REGIONAL BTUs (in Billions)**
Natural Gas & Propane	5,983	22.2%	9,632,438	578
Electricity	1,206	4.5%	1,494,263	90
Fuel Oil	14,238	52.9%	24,431,228	1,466
Coal	66	.2%	132,664	8
Wood	5,031	18.7%	9,493,439	570
Other (includes solar)	392	1.5%	696,536	42
No Fuel	22	.1%	42,680	3
TOTAL	**26,938**	**100%**	**45,923,248**	**2,755**

Notes:
1. Regional totals were aggregated from each municipal total therefore not all calculations will be consistent.
2. Data provided by the American Community Survey.

TABLE FOUR CURRENT REGIONAL COMMERCIAL THERMAL (HEATING) ENERGY USE		
COMMERCIAL ESTABLISHMENTS	**AVERAGE THERMAL ENERGY USED PER ESTABLISHMENT**	**COMMERCIAL THERMAL ENERGY USED REGIONALLY**
2,647	699	1,847,355

Notes:
1. Regional totals were aggregated from each municipal total therefore not all calculations will be consistent.
2. Thermal energy use is expressed in Millions of BTUs.
3. Information provided by the Vermont Department of Labor and the Department of Public Service.

While Table Four identifies the amount of energy used regionally for commercial thermal (heating) purposes, Table Five provides a list of the sources of fuel being used by the commercial establishments in the region for thermal purposes. Even though a large percent of commercial establishments currently use electricity for their heating needs, non-renewable fuels such as propane and fuel oils are almost as common.

TABLE FIVE CURRENT REGIONAL COMMERCIAL HEATING USE BY FUEL SOURCE		
FUEL SOURCE	**NUMBER OF ESTABLISHMENTS**	**PERCENT OF ESTABLISHMENTS**
Biofuel	0	0.0%
Distillate Fuel Oil	505	19.1%
Electric Use	922	34.8%
LPG	381	14.4%
Natural Gas	0	0.0%
Residual Fuel Oil	51	2.0%
Wood & Wood Waste	165	6.2%
Other	623	23.5%
Total Commercial Establishments	**2,647**	**100%**

Notes:
1. Information derived from VEIC LEAP Modeling.
2. Data based on 2015 information

TABLE SIX CURRENT REGIONAL ELECTRICITY USE	
USE SECTOR	**CURRENT ELECTRICITY USE**
Residential	241,268 megawatt hours
Commercial & Industrial	353,117 megawatt hours
TOTAL	**594,385 megawatt hours**

Notes:
1. Regional totals were aggregated from each municipal total therefore not all calculations will be consistent.
2. Information provided by Efficiency Vermont.

II. 2025, 2035, and 2050 targets for thermal and electric efficiency improvements, and use of renewable energy for transportation, heating, and electricity

With the baseline information established for the region, the next step is to identify what targets need to be met in order for the region to achieve its share of the state's renewable energy goals. The 2016 State Comprehensive Energy Plan identifies target years of 2025, 2035, and 2050 as specific points to help measure progress. Using these same target years, the Central Vermont RPC has identified percentage targets for efficiency improvements regarding transportation, heating, and electricity.

The targets indicated in Tables Seven, Eight, and Nine are cumulative totals and account for the previous target year's percentages. For example, the residential thermal efficiency target for 2035 in Table Seven indicates that 42% of the residential units should be weatherized and efficient. This could be done through a combination of new construction or weatherization of existing structures. These are targets for the region to try and achieve and not a mandate on what they must accommodate.

The information in Tables Seven, Eight, and Nine were developed using the Long-Range Energy Alternatives Planning (LEAP) Model as provided by the Vermont Energy Investment Corporation (VEIC). VEIC was contracted to provide modeling support for this project and developed the LEAP model for each Regional Planning Commission to reflect their share of the state totals. The percentages are weighted heavier in the later years which assumes increases in efficiencies and technological improvements that will establish these targets.

TABLE SEVEN
REGIONAL TARGETS FOR THERMAL EFFICIENCY IMPROVEMENTS OF EXISTING STRUCTURES

SECTOR TYPE	2025	2035	2050
Residential Thermal Efficiency	20%	42%	92%
Commercial Thermal Efficiency	22%	33%	61%

Notes:
1. Information derived from VEIC LEAP Modeling.
2. Assumes a base year of 2015.
3. Percentages are cumulative for each target year.

Table Seven identifies the percentage of existing residential and commercial structures in Central Vermont that would need to be weatherized in each of the target years to meet the State's energy goals. These targets also assume that new structures will be built based on existing state energy codes and therefore meet or exceed the needed efficiency standards.

In addition to the thermal efficiency improvements of existing buildings outlined in Table Seven, Table Eight identifies the electric efficiency improvements needed for each target year to meet the renewable energy goals in the State's Comprehensive Energy Plan. The electric efficiency is an indication of how much efficiency is needed across all sectors. It is a comparison between anticipated electricity use for each target year versus the electricity use in the base year, which in this case, is 2010.

TABLE EIGHT REGIONAL TARGETS FOR ELECTRIC EFFICIENCY IMPROVEMENTS ACROSS ALL SECTORS			
SECTOR TYPE	**2025**	**2035**	**2050**
Electric Efficiency	1.5%	7.3%	15.2%

Notes:
1. Information derived from VEIC LEAP Modeling.
2. Assumes a base year of 2015.
3. Percentages are cumulative for each target year.

Table Eight outlines the electric efficiency improvements needed for each of the three target years. These targets would cover all sectors including electric, thermal (heating), and transportation. Many of these efficiencies will be met through technological changes and improvements that will occur over time, however conversions to more efficient technologies will need to be supported. Specific policies and actions to encourage conversions for efficiencies are outlined in the Pathways & Implementation Actions section.

Similar to Tables Seven and Eight, Table Nine identifies the percent of energy use to be derived from renewable sources for energy related to transportation and thermal needs. While energy needs for transportation and thermal uses are different, Table Nine is intended to identify percentage of renewable energy use for these two sectors and not intended to provide a parallel association between these two sectors.

TABLE NINE REGIONAL TARGETS FOR RENEWABLE ENERGY USE BY SECTOR			
SECTOR TYPE	**2025**	**2035**	**2050**
Transportation Use	9.6%	31.3%	90.2%
Thermal Use	52.3%	66.6%	92.5%

Notes:
1. Information derived from VEIC LEAP Modeling.
2. Assumes a base year of 2015.
3. Percentages are cumulative for each target year.

A major factor that will impact these targets are market forces which are beyond the control of an individual municipality or region. With that in mind, the region (and therefore the municipalities) should work to ensure barriers don't exist that would adversely impact the ability to reach these targets. The Pathways & Implementation Actions identified in this plan will discuss this in more detail.

TABLE TEN REGIONAL TARGETS FOR NEW RENEWABLE ELECTRIC ENERGY GENERATION			
SECTOR TYPE	**2025**	**2035**	**2050**
New Renewable Electric Energy Generation	104,620	167,404	418,531

Notes:
1. Information provided by The Department of Public Service.
2. Values are in megawatt hours.
3. Assumes a base year of 2015.

Table Ten notes the renewable electricity generation for each of the target years and is expressed in megawatt hours. The identification of these targets by megawatt hour is a significant factor because it represents energy (megawatt hours) as opposed to power (megawatt). In this case, the megawatt hours identified denote the amount of renewable energy that should be consumed as part of the total energy being consumed by the target years. This information was generated base on data provided by the Department of Public Service and information developed by the Regional Planning Commission.

III. Evaluation of the amount of thermal-sector conservation, efficiency, and conversion to alternative heating fuels needed to achieve these targets

One important way for each region to support and work collectively to achieve the state's goal of 90% renewable energy generation by 2050 is through conversion and development of alternative fuels. Conversions to more efficient technologies such as cold climate heat pumps for residential heating or switching to electric vehicles will mean that less energy needs to be generated as efficiencies in technologies increase. If less energy needs to be generated, the energy being generated from renewable sources will provide more of the demand over time.

Table Eleven outlines the thermal sector conversions to wood heat and heat pumps. For these tables residential and commercial uses are combined to indicate the total fuel switching needed.

TABLE ELEVEN
REGIONAL THERMAL SECTOR CONVERSIONS
(RESIDENTIAL & COMMERCIAL)

SYSTEM TYPE	2025	2035	2050
New Efficient Wood Heat Systems	117	108	966
New Heat Pumps	2,792	7,198	13,630

Notes:
1. Regional totals were aggregated from each municipal total therefore not all calculations will be consistent.
2. Information derived from VEIC LEAP Modeling.
3. Heat pumps includes both space heating and hot water heating.

The information in Table Eleven is derived from calculations based on information provided in the LEAP modeling data. As with other targets, the numbers identified for each target year represent the number of new systems needed to achieve the overall efficiency goals. It should be noted that Table Eleven only highlights efficient wood burning systems and heat pumps. This is an indication that using these two technologies could account for all the changes needed in Central Vermont regarding conversions from fossil fuel based heating systems such as fuel oil or natural gas.

Other options for conversion of residential and commercial heating systems may be available that would satisfy the goals of the state's comprehensive energy plan. Wood systems are being highlighted due to their renewable fuel. Heat pumps are being highlighted because the 2016 State Comprehensive Energy Plan focuses on electrification. Therefore a high efficiency electric heat pump would address the efficiency goals while the electricity to power the system being generated from renewable sources.

Another system type that should be encouraged is geothermal heating and cooling. Geothermal systems use the consistent temperature of the earth to either provide heat or cooling to homes and businesses. Geothermal systems generally require an electric fan to force air through the system, however like with other systems, the increase in efficiency through technology and the electrification of the grid make systems like this a viable option to address conservation and conversion of systems.

One challenge that will need to be addressed regarding conversions and conservation efforts will be the tracking and monitoring of system upgrades or improvements that address efficiency to increase weatherization of residential and commercial properties. While specific programs are set up to help track and score these changes, many homeowners and business owners make changes and upgrades as part of the normal lifecycle of a property. These systems are often upgraded without any formal acknowledgement of the possible efficiency improvements being made. In order to measure how the targets in Table Eleven are being met (or not being met), a methodology should be developed to ensure the necessary information is gathered when changes occur. This will be addressed in the Pathways and Implementation Actions section.

IV. Evaluation of transportation system changes and land use strategies needed to achieve these targets

Transportation

As noted in Table Two, the average vehicle miles traveled for residents in Central Vermont is approximately 12,500 miles per year. At an average cost of approximately $2.31 per gallon of fuel and an efficiency factor of approximately 22 miles per gallon of fuel, the average person living in Central Vermont is spending approximately $1,300 dollars on fuel each year. According to information from the American Automobile Association, the average cost of owning a vehicle can range from approximately $6,500 for a small sedan to $10,400 for an SUV[2]. By creating development patterns whereby uses are in closer proximity to where people live, work, or recreate, trips can be combined or alternative modes of transportation can be employed. This will reduce the vehicle miles traveled and therefore reduce the transportation costs to individuals.

Another option to consider when evaluating system changes is the conversion to electric or alternative fuel vehicles. Vehicles that are powered by renewable energy sources increase efficiency, reduce greenhouse gas emissions, and can reduce the need for fossil fuels. While switching to alternative fuel vehicles does not reduce the vehicle miles traveled, it does reduce the dependence on fossil fuels. These changes also require improvements to infrastructure such as grid capacity to transmit the electricity as well as an increase in the volume of charging stations to provide additional opportunities and locations for vehicle charging thus increasing the range of electric vehicles.

An evaluation of LEAP data and information from the American Community Survey identifies the number of vehicles needed to be switched from fossil fuels to renewable fuels. Specifically, conversion to electric vehicles and biodiesel vehicles was noted in the LEAP analysis in order to meet the needed reductions in energy related to transportation. Table Twelve identifies the number of electric and biodiesel vehicles needed for each of the three target years in order to meet the energy reduction goals related to transportation as identified in the LEAP analysis.

2. 2016 article from the American Automobile Association (AAA) http://newsroom.aaa.com/auto/your-driving-costs/. Costs include fuel, insurance, maintenance, registration, depreciation, and similar expenses associated with owning a vehicle and is based on driving 15,000 miles per year.

TABLE TWELVE REGIONAL TRANSPORTATION FUEL SWITCHING TARGETS			
FUEL TYPE	**2025**	**2035**	**2050**
Electric Vehicles	3,902	26,954	53,809
Biodiesel Vehicles	6,801	12,603	20,438

Notes:
1. Information derived from VEIC LEAP Modeling.
2. Assumes the replacement of existing vehicles with new alternative fuel vehicles.

It is important to note that Table Twelve indicates the number of fossil fuel based vehicles that would need to be replaced with alternative fuel vehicles to meet the reduction goals for transportation energy by each target year. That is to say that of all the new vehicles on the road in 2025, approximately 10,700 of those vehicles would need to use alternative fuels as the primary fuel type. For reference, electric vehicles would be similar to a standard passenger vehicle currently using gasoline and biodiesel vehicles would be consistent with light or heavy duty trucks that currently run on standard diesel fuels.

In addition to the information regarding transportation that is noted in this plan, the Central Vermont Regional Planning Commission maintains a regional transportation plan. Under the direction of a Transportation Advisory Committee (TAC), the CVRPC identifies annual transportation priorities to be considered by the Agency of Transportation. These priorities will help determine not only the direction of future transportation projects within the region, but may also impact land use decisions a the regional or local level. This underscores the importance to coordinate transportation objectives with land use priorities to ensure a coordinated approach to land development is pursued. The confluence of land use and transportation will impact future needs and impacts to energy use including conservation, conversions, infrastructure needs, and siting. The Regional Transportation Plan provides more significant detail on specific projects that may impact the Region's energy planning future and should be considered part of the Region's energy planning priorities.

Land Use

One key factor that impacts the amount of energy being used is land use. Land use directly impacts and influences our choices, especially as they relate to transportation. When land use patterns focus on density, compact development, or mixing of uses, the result can be an area that is walkable, bicycle friendly, or promote public transit use.

Land use planning and management can have a direct impact on how much energy is used and consumed in regard to transportation. As development density decreases (creating fewer lots or uses per acre), the impacts associated with that decrease in density will rise. This includes both costs and consumption of resources including energy to move people from place to place. As land uses are spread further from one another, more resources are required to link those uses together. This includes infrastructure such as roads or utilities; needs for emergency services such as police, fire, and ambulance, and increases in municipal service needs such as road maintenance.

In order to reduce the costs and needs for energy related to transportation and land uses, changes in land development will need to occur. One significant way that this can be addressed is through amendments to land development regulations such as zoning or subdivision. Changes to land development regulations that require

pedestrian facilities such as sidewalks or multi-use paths to connect uses or activity centers is one technique that can be used to help create alternative transportation options in a community. Additionally, smaller changes could be implemented that can have larger impacts. Examples of this include reducing lot sizes, reducing parking requirements, adjusting setbacks, implementing traffic calming measures, or increasing building heights are all ways to maximize development potential within the framework of existing land development regulations.

If a municipality does not have land development regulations, there are still avenues that can be explored from the non-regulatory side that would impact land development practices. For example, developing a capital plan for public utilities and services that is consistent with a municipal plan can identify and prioritize where public funds should be spent. This could include sidewalk connections, park & ride facilities, or water and wastewater services. Expansions to emergency services or road maintenance equipment can also be a way to signal intended growth. Receiving a state designation for a Downtown, Village Center, Growth Center, New Town Center, or New Neighborhood Development Area can provide the basis for non-regulatory growth management and the tools necessary to regulate development without a formally adopted set of regulations. Finally, having clear goals, policies, and action items identified in municipal plans will impact how a community grows and therefore how the connection between land use and transportation is addressed on a municipal basis.

Currently, 19 of the 23 municipalities in the Central Vermont Region have some form of development regulation. Six of the 19 only have zoning regulations in place while the other 13 have zoning and subdivision regulations. Additionally, 12 of the municipalities have an active state designation and several municipalities have multiple designations. For example, the City of Montpelier has both a Downtown and a Growth Center designation, while the Town of Calais has three village centers that are designated including Adamant, East Calais, and Maple Corners.

While the techniques noted herein can help provide avenues for changes to support development density and create compact development patterns, a primary factor that will influence development density is adequate infrastructure to accommodate water and wastewater. Water and wastewater infrastructure is critical to provide a development pattern that includes density, mixed uses, and alternative transportation options. This is done by moving the supply and treatment of water and wastewater off-site therefore, reducing the need for land to accommodate these facilities on-site. Doing so creates opportunities for smaller lots, denser development, increased building heights, and mixed uses. All of these are positive steps to reducing the need for infrastructure to accommodate single-occupancy vehicles such as parking areas, but also begin to support the critical mass that is necessary to support public transit.

As noted previously, regulatory and non-regulatory approaches can have an impact on energy use due to the future development patterns in a community. While there isn't a single approach that will address all of the Region's energy needs, municipalities are encouraged to identify what programs or actions will work best to implement their community's future transportation and land use planning. Specific actions from the Region that can assist with municipal transportation and land use priorities can be found in the next section of this plan regarding Pathways & Implementation Actions. Ultimately, positioning the municipalities to take control of their energy futures while working collectively as a region could be a successful outcome for all.

V. Evaluate electric-sector conservation and efficiency needed to achieve these targets

Conservation and efficiency of electricity is a key component to achieving the state's comprehensive energy planning goals. Over time, advancements in technology will provide a degree of the needed efficiency and conservation measures to achieve these goals, but also, efforts can be taken now to ensure that Central Vermont is on track to meet their conservation and efficiency targets. Targets for electric efficiency improvements for Central Vermont were previously noted in Table Eight. Information related to renewable energy generation, which is a necessary component in achieving these targets, is noted below.

Siting

A discussion of electric sector conversions and efficiencies should include information related to the ability to generate electricity through renewable means, but also to have a grid that can support the distribution of that electricity. An analysis of existing land and renewable resource potential will help determine what the capacity of the region is to generate and distribute local renewable energy. As noted previously, Table One identifies the current renewable generation for the region, while Table Thirteen identifies the potential generation for the region.

TABLE THIRTEEN
EXISTING POTENTIAL NEW REGIONAL RENEWABLE ELECTRIC ENERGY GENERATION

RESOURCE TYPE	MEGAWATTS	MEGAWATT HOURS
Rooftop Solar	40	49,268
Ground-mounted Solar	15,622	19,160,098
Wind	23,050	70,671,678
Hydroelectric	.01	28
Biomass & Methane[3]	Unknown	Unknown
Other	0	0
Total Potential Regional Renewable Energy Generation	38,713	89,881,072

Notes:
1. Regional totals were aggregated from each municipal total therefore not all calculations will be consistent.
2. Information calculated by the CVRPC based on data provided by the Vermont Center for Geographic Information and efficiency factors provided by the Department of Public Service.
3. Municipal data can be found at http://centralvtplanning.org/programs/energy/municipal-energy-planning/

Based on the information included in Table Thirteen, the municipalities in Central Vermont have enough potential resource area (both prime and secondary) that is not impacted by known or possible constraints (as defined in Appendix A) to sufficiently accommodate the megawatt hour allocation and meet their share of the state's renewable energy goal as noted previously in Table Ten. This means that the municipalities can reasonably identify additional constraints or preferred locations to align with their own land use planning goals if they so choose.

3. Biomass and methane are not restricted by resource locations and should be sited accordingly to provide maximum benefit to the greatest number of end users or to meet municipal needs. Siting will be more dependent on local regulatory controls and should be planned for accordingly.

To better understand the relationship between megawatts and megawatt hours, the following conversions are used. It should be noted that some renewable generation types are more efficient at producing energy when they are actively in production. For example, the wind does not always blow and the sun is not always shining, therefore a constant production of these resources may not be possible. On the other hand, methane generated from a landfill will be producing consistently for a finite number of years therefore, its efficiency factor will be greater for the useful life of the facility. Table Fourteen outlines the various renewable technologies including their capacity factor and annual megawatt hour output per installed megawatt of capacity.

Table Fourteen reinforces the fact that multiple options of renewable energy generation exist and can be utilized at a regional and municipal level. For all of these generation types, understanding where the resources that support these sources are the best or preferred is critical. This information will be further discussed in the mapping section, however planning for the siting of renewable energy generation will ensure that, like any other land use, a municipality has made a concerted effort to ensure compatibility with other uses while accounting for possible future needs.

TABLE FOURTEEN
RENEWABLE ENERGY GENERATION OUTPUTS & CAPACITY FACTORS

RESOURCE TYPE	CAPACITY FACTOR	ANNUAL MEGAWATT HOUR OUTPUT PER INSTALLED MEGAWATT
Solar	14% - 16%	1,300
Small Wind	20% - 25%	2,000
Utility Scale Wind	25% - 35%	2,600
Methane	60% - 90%	6,600
Biomass	60% - 80%	6,100
Small Hydroelectric	40% - 60%	4,400

Notes:
1. Information provided by the Vermont Department of Public Service.
2. "Capacity Factor" indicates the percent of time an identified resource is actively producing electricity.

As Table Fourteen indicates, solar installations have the lowest capacity factor, however the costs associated with installation of solar generation facilities are also low compared to other resource types. The economics of using a given resource may prove to be more of a consideration than the actual energy output. As such, measures may need to be considered to off-set the costs associated with higher capacity resource generators if they are to be viable throughout the region.

It should be noted that while biomass has a high level of annual output per installed megawatt, the source of the biomass should be taken into consideration. When possible, locally sourced biomass will have the greatest benefit to the community. In order to limit the secondary impacts associated with biomass, the origin of the fuel source should be considered. Transporting biomass from out of region or out of state will have increased costs and the impacts from transportation will off-set a portion of the efficiencies. Also, invasive species that impact woody biomass need to be considered.

Currently, there are two Federal quarantine regulations that are relevant to the movement of woody biomass (including chips, cordwood, and logs) from New York and Massachusetts. These include the emerald ash borer and the Asian longhorned beetle. Additionally, the State of Vermont has quarantines for external firewood and the hemlock woody adelgid. All of these factors need to be considered to ensure a sustainable supply of woody biomass can be sourced as locally as possible to limit the spread of these invasive species that could adversely impact the forest cover.

Central Vermont enjoys rich natural and scenic resources. This is represented by the peaks of the Worcester and Green Mountain ranges (including Camel's Hump State Park), which are characteristic of many Vermont communities. These areas are important to Central Vermont not only for their natural, scenic, and recreational value, but also for the predominance of critical plant and animal habitat that exists in the undisturbed forest blocks. In support of the protection of these areas, the 2016 Central Vermont Regional Plan identifies critical resources areas including wildlife habitat, steep slopes, and lands above 2,500 feet in elevation. These areas are specifically identified for their value as a regional resource.

With this in mind, the Central Vermont Regional Planning Commission has determined that industrial-scale wind development is not compatible with the future land use patterns of Central Vermont. For the purposes of this plan, industrial-scale wind development will include any wind turbine with a hub height greater than 125 feet (excluding the blades). Additionally, wind energy development will be restricted above 2,500 feet in elevation consistent with the 2016 Central Vermont Regional Plan's future land use plan.

For the purposes of this energy plan, a 125 foot hub height is expected to accommodate both residential and commercial wind generation. Hub heights above 125 feet will be considered industrial in scale and not fitting for Central Vermont. This height restriction is intended to reduce the visual impact of wind generation facilities while still permitting commercial and residential land uses to incorporate wind generation as appropriate. Additionally, the height restriction will limit the amount of land needed to accommodate wind generation and help maintain the sensitive natural resources throughout the region where industrial-scale wind resources have been identified.

To further support this limitation on industrial-scale wind generation, the 2016 Central Vermont Regional Plan identifies two distinct planning areas that encompass a significant portion of the region and includes almost all of the resource areas identified for wind generation. These planning areas are Rural and Resource and are delineated on the Future Land Use Map in Appendix A of the 2016 Central Vermont Regional Plan. These planning areas are described as:

Rural – These areas encompass much of the Region's large forest blocks, sand/gravel/mineral deposits, and prime agricultural soils that, when in productive use, contribute to the working landscape and have significant economic value. Rural areas also include residential, small-scale commercial and industrial, and recreational uses.

Resource – These areas are dominated by lands requiring special protection or consideration due to their uniqueness, irreplaceable or fragile nature, or important ecological function. These include, protected lands; elevations above 2,500 feet (elevations above 1,700 feet in Waitsfield, as regulated); slopes of 25% or more; rare, threatened or endangered species and significant natural communities; wetlands; special flood hazard areas; and shoreline protection areas. As a subcategory of Resource lands, this plan recognizes critical resource areas as key sites that are particularly sensitive and should be given maximum protection.

Based on the mapping analysis completed by the CVRPC, there are approximately 250,000 acres of wind resource area within Central Vermont that has no known constraints (but does include possible constraints). Of that land, approximately 27,000 acres of wind resource area is specifically classified for industrial-scale wind generation. Of those 27,000 acres, all but approximately 15 acres of wind resource area is located within land that is designated as Rural or Resource on the Future Land Use map included in Appendix A of the 2016 Central Vermont Regional Plan.

These 15 acres of land are located in the Industrial future land use designation. The regional plan identifies industrial areas to support economic development in the region including expansion, development, or redevelopment of existing industrial uses. These 15 acres of land are located on property that is an active quarrying operation which has been in existence for over 100 years. This use is expected to continue for the life of this plan and well into the future as an on-going economic force in the region that is supported by the regional plan therefore a change of use is not expected. With this in mind, there is currently no suitable land available where industrial/utility-scale wind generation could be developed.

The restriction on industrial-scale wind generation is also consistent with other policies outlined in the Regional Plan's Land Use element. Policies in the Rural designation support clustered development in order to protect important resources such as agricultural soils or forest blocks. The policies also support the development of small-scale business opportunities that do not adversely impact the forestry or agricultural uses or diminish the rural character of these areas. The plan notes that these uses should be established in conjunction with existing rural developments where appropriate, and not be a dominant feature.

Land use policies associated with the Resource designation propose the avoidance of development on steep slopes; fragmentation of habitat connectors and forest blocks; wetlands; and ridgelines. The Resource district also discourages the extension of permanent roads, energy transmission facilities, and utilities. The policies further state that development should be subject to extensive planning, review, and conditions to protect these areas, but does not outright prohibit development. Additional policies that support smaller scale development in the Rural or Resource areas of the region are included in the land use element and consistent with the limitation on industrial-scale wind development.

The following is an excerpt of policies related to the Rural and Resource Land Uses. A complete list of the Future Land Use Policies identified herein can be found beginning on page 2-18 of the Regional Plan.

Rural Land Use Policies:

6. Wildlife connectivity areas should be protected from fragmentation and uses that reduce their viability for movement of wildlife, particularly where they connect forest blocks.

7. Non-residential uses, including small service businesses, small professional offices and inns are acceptable land uses for Rural Areas provided that such uses are planned as relatively small in size or scale, are not primary or dominant uses in an area, do not unduly conflict with existing or planned residential, forestry or agricultural uses, and do not unduly affect rural character. Towns should limit the number and size of such establishments to prevent a proliferation of scattered commercial development that does not serve the needs of the community.

8. Occupations that are customarily practiced in residential areas, and which do not affect the character of those areas, are another form of small-scale commercial use common in and appropriate for rural areas. Small professional offices, antique shops, and craft studios are examples of such "customary home occupations."

9. Cross country ski centers, mountain biking facilities and other outdoor recreational areas represent an economically viable means of maintaining rural open spaces with little secondary development; both expansion and development of new facilities are consistent with this Plan.

Resource Land Use Policies:

1. Conservation of the natural landscape and careful management of lands is sought for these areas. Development in these areas should be subject to extensive planning, review and conditions that ensure its protection.

2. Any development proposed within critical resource areas shall provide evidence as to why the development cannot be avoided, and shall provide mitigation for natural resources impacted by the development.

3. The extension of permanent roads, energy transmission facilities, and utilities into Resource areas is discouraged.

4. Development on wetlands, steep slopes of 25% or more, and ridge lines should be avoided.

5. Avoid or limit development and investment in identified flood hazard areas, where feasible.

6. Avoid development that fragments forest blocks and habitat connectors.

Finally, the land use element notes that smaller scale or clustered development is appropriate in certain locations. Policies 1 and 2 under Resort Centers discusses support for expansion of the existing commercial ski areas including Sugarbush and Mad River Glen (in Warren and Fayston) instead of resort development at new locations. Both of these ski areas include limited development that extends above 2,500 feet in elevation. Aside from these uses, few structures exist above 2,500 feet in elevation throughout the Region further supporting the restriction on development in the area designated as Resource on the Future Land Use map.

If, through the development of a local energy plan consistent with Act 174, a municipality identifies industrial-scale wind generation as a community supported resource, the CVRPC may revise or amend this plan to consider the location(s) that has been identified. Prior to any amendments, the CVRPC will consider regional planning goals, mitigation of any identified constraints, and compatibility with the plans of adjacent municipalities.

Energy Storage

Finally, a discussion of electrical conservation and conversions would not be complete without acknowledging the potential limitations. Electricity as the primary power source for future needs will have to also consider the infrastructure and demand. If homes and vehicles are converted to electric power, there will be an increased demand for these resources in locations that may not currently be suited to provide that demand. Additionally, limitations on renewable resource technology will impact peak needs which may create a demand for storage of electrical power.

These factors will need to be considered in all our future decisions if a 90% renewable energy system is to become a reality. This may require potential changes to land use regulations that will accommodate battery or other storage options. Incentives to establish or upgrade infrastructure may be necessary and new construction may be required to include enhanced mechanical systems to handle increased electrical loads or design contingencies for fuel storage. While these challenges are not insurmountable, they will require an additional level of planning and consideration to ensure unforeseen issues are limited. More specific details regarding possible implementation actions to address these needs are included in the Pathways & Implementation Actions section of this plan.

Conclusion

As noted throughout this section, the Central Vermont Region faces challenges similar to the rest of the state regarding its energy future including the need for conservation, renewable energy development, and changing habits and attitudes towards renewable technology and land use choices. All of these components need to work together in order to ensure a collective and comprehensive approach to energy planning is initiated.

The information provided in this section has shown that Central Vermont has the ability to shape its energy future within the spectrum of the avenues that it can control. The unknown component is whether or not the changes and development will occur and when. The State Comprehensive Energy Plan has set a goal of 90% renewable energy by the year 2050. This goal is achievable if all stakeholders including the state, the region, municipalities, energy developers, private land owners, special interest groups, and interested citizens come together to discuss the issues and work collectively to identify the outcomes that satisfy the needs of the whole to the best of their ability.

This plan primarily explores renewable energy related to the production of electricity and electrification of the grid. In addition to the resources noted herein, it's important to consider other forms or technologies that could contribute to our renewable energy future. With advancements in safety, efficiency, and technology, the Region's energy future could look vastly different in the next five or ten years. This will not only impact the generation of energy, but the delivery and infrastructure to support distribution of energy.

PATHWAYS & IMPLEMENTATION ACTIONS

The following policies, pathways, and implementation actions outline the specific strategies for the region to consider in order to effectively support the State of Vermont's goals that are outlined in the 2016 Comprehensive Energy Plan. These actions are intended to cover a variety of pathways that address land use and siting of developments (including renewable energy generation); efficiency of building construction and weatherization; and fuel switching from fossil based fuels to more sustainable and renewable options.

The specific actions identified herein include a list of the responsible parties, the timeframe for the action, and a measure to determine success or to gauge progress towards a specific action. A key factor that will influence the success or progress on these actions will be available resources. This includes funding, personnel, and other work plan priorities. The specific resources available may impact which actions are prioritized for completion. When possible, actions outlined below may be combined with other work plan tasks to limit the duplication of resources and to expedite their completion.

This implementation program reflects actions that will be the primary responsibility of the Central Vermont Regional Planning Commission. When appropriate, other organizations are listed under the heading of "Responsibility" with the expectation that their guidance, insights, or expertise will be sought to support the Regional Planning Commission's efforts. In some cases, the term "regional partners" is used. This general term is intended to be a catch-all to limit the need for an exhaustive list of possible organizations that could assist in completing the identified action as all the partners may not initially be known.

Additionally, groups could be added or removed as an action progresses based on the specific needs identified to complete each task. The groups listed in this column are intended to provide a general sense of who may be involved in a specific action and not intended to be a list of required organizations. The list of responsible parties will provide guidance to the CVRPC to help establish project priorities and how actions may relate to one another.

Finally, the pathways and implementation actions included below outline actions that the Central Vermont Regional Planning Commission will engage in to support the 2016 State Comprehensive Energy Plan's goal of 90 percent renewable energy generation by 2050. As the comprehensive energy plan is updated, priorities may change which could impact the specific actions that will be necessary to meet the state's overall goals. As such, actions may change, be amended, or removed as appropriate to reflect changing trends or priorities.

A. Conservation and Efficiency

Policy A-1: Increase conservation of energy by individuals and organizations.

Conservation of energy is a key component to achieving the State's goals of 90% energy derived from renewable sources by 2050. Conservation of energy in-turn will reduce the amount of energy needed to support the existing and future systems thus allowing small increases in generation to support more uses overall.

	IMPLEMENTATION ACTION	RESPONSIBILITY	PRIORITY/ TIMELINE	MEASURE OF SUCCESS
1	Identify and maintain a directory of regional organizations that offer assistance in weatherization and make this information available to the Region's municipalities, including residents, businesses, and other interested parties on a quarterly basis.	CVRPC, Regional Partners, other RPCs	High On-going	Directory is established and available
2	Identify existing information regarding energy efficiency, conservation, weatherization, and their benefits related to cost savings that can be distributed through multiple media formats. a. Work with regional partners to develop this information and update as appropriate. b. Distribute this information to municipalities for display or dissemination at a municipal level.	CVRPC, Regional Partners, Utility Providers, other RPCs	High On-going	Information is identified and available
3	Identify underserved populations such as low-income households and work with regional partners to encourage participation in programs such as the state Weatherization Assistance Program or similar initiatives.	CVRPC, Regional Partners	High 1 to 3 years	Population segments identified and contacts established
4	Work with interested municipalities to form municipally supported Energy or Climate Action Committees to address local energy concerns and provide support as appropriate.	CVRPC, Regional Partners	Medium On-going	Committees formed
5	Continue to provide technical assistance to municipalities and encourage municipal bylaws that promote energy conservation and the development of renewable energy resources.	CVRPC, Regional Partners	High On-going	Regulations updated to reflect energy specific requirements

Policy A-2: Promote energy efficiency in the design, construction, renovation, operation, and retrofitting of systems for buildings and structures.

Energy efficient building designs provide benefits to the owners and occupants by reducing the amount of energy needed to heat, cool, and maintain the mechanical systems within the building. Establishing and promoting energy efficiency in design, construction, retrofits, and renovations will ensure new buildings and building practices will be more efficient into the future. These efficiencies can also lead to conservation of energy which can promote cost savings and affordability for owners and renters.

	IMPLEMENTATION ACTION	RESPONSIBILITY	PRIORITY/ TIMELINE	MEASURE OF SUCCESS
1	Partner with existing organizations to provide education and support to interested municipalities to establish "stretch codes"[4] for residential and commercial building standards.	CVRPC, State Agencies, Regional Partners	High 1 to 3 years	Codes established and adopted
2	Work with municipalities to develop local energy codes requiring or promoting energy efficient site design and renewable fuel use in new construction projects that require an Act 250 permit.	CVRPC	High 1 to 3 years	New regulations established as appropriate
3	Identify existing educational materials related to net-zero ready buildings[5] to be utilized by municipalities to inform their citizens about the efficiency of this design technique.	CVRPC, Regional Partners	Medium 3 to 5 years	Materials developed and available
4	Work with community organizations or existing businesses to identify available information regarding the use of landscaping for energy efficiency including the importance of tree canopies, pervious surfaces, and similar design practices.	CVRPC, Regional Partners	Low 5 to 10 years	Information identified and available
5	Identify existing information that promotes the use of Vermont's residential building energy label/score to inform the community of the importance of energy efficiency in building design and construction including cost savings and affordability.	CVRPC, Regional Partners	Low 5 to 10 years	Materials identified and available

4. Vermont has Residential Building Energy Standards (RBES) and Commercial Building Energy Standards (CBES). Stretch energy codes are those that achieve greater energy savings than the base RBES and CBES by including more stringent requirements for design and evaluation of energy efficiency.

5. A net-zero ready building is generally defined as a building whereby an equal or greater amount of energy used by a building is produced on site.

Policy A-3: Identify ways to decrease the use of fossil fuels for heating.

Reliance on fossil fuels such as oil, kerosene, or propane for heating is an unsustainable practice. Fossil fuels are non-renewable therefore they will eventually be depleted to a point where they are too expensive or too rare to be viable. Establishing alternative sources of renewable fuels for heating or conversions to heating from electric sources (which can be generated through renewable methods) will promote a more sustainable thermal energy future.

	IMPLEMENTATION ACTION	RESPONSIBILITY	PRIORITY/ TIMELINE	MEASURE OF SUCCESS
1	Identify existing funding programs or partners that can assist with conversion of heating sources from fossil fuels to renewable based systems for homes and businesses.	CVRPC, Regional Partners, State Agencies	High 1 to 3 years	List of existing funding sources identified
2	Identify innovative products such as solar shingles, solar panels, cold climate heat pumps, ground source heat pumps, district heating[6], or high efficiency combustion wood stoves that would be suitable for home and business conversions and educate users on their advantages.	CVRPC, Industry Experts, Regional Partners	High 1 to 3 years	Information sessions conducted bi-annually
3	Identify potential locations throughout the region that could benefit from district heating projects based on building density, proximity to resources such as biomass, or status as a use by right where applicable.	CVRPC, Municipalities	Low 5 to 10 years	Locations identified and mapped
4	Work with interested municipalities to evaluate and amend as necessary local regulations to ensure district heating or similar centralized renewable generation facilities such as biogas or bio-digesters are permitted in appropriate locations.	CVRPC, Municipalities	High 1 to 3 years	Local regulations updated as needed
5	Identify sources of renewable materials such as biomass, farm waste, or food waste (such as schools, restaurants, or food processors) to determine supply of alternative fuels that may be available for district heating or other heating alternatives for homes or businesses.	CVRPC, Municipalities, Business Community	Medium 3 to 5 years	Locations identified and mapped

6. District heating is a system for distributing heat generated in a centralized location for two or more homes and/or buildings' heating requirements.

	IMPLEMENTATION ACTION	RESPONSIBILITY	PRIORITY/ TIMELINE	MEASURE OF SUCCESS
6	Work with state agencies to identify and inventory known sources and supplies of woody biomass that do not contribute to the spread of Federal or state identified invasive species and make this information available to the public as appropriate.	CVRPC, State Agencies	Medium 3 to 5 years	Sources are identified, mapped, and publicized
7	Identify energy storage technologies such as batteries to support off-grid systems or emergency pack-up power and educate the community on the costs, benefits, or challenges associated with these technologies.	CVRPC, Industry Experts, Utility Providers	High 1 to 3 years	Information is collected and disseminated as appropriate
8	Due to the rural nature of Central Vermont, identify and map large farm operations that may provide a sustained source of materials that could be used for bio-digesters.	CVRPC, Agency of Agriculture, Food, & Markets, Municipalities	Medium 3 to 5 years	Locations are identified and mapped

B. Reducing Transportation Energy Demand, Single-Occupancy Vehicle Use, and Encouraging Renewable or Lower-Emission Energy Sources for Transportation

Policy B-1: Encourage increased use of transit as a primary method to complete daily trips and reduce demands on existing infrastructure such as roads and parking.

Public transit offers communities the ability to move multiple persons utilizing existing roadway or railway infrastructure. Convenient, reliable and efficient public transit provides an alternative mode for individuals that might otherwise choose to drive alone. Public transit has the ability to reduce the need for parking in certain locations, provide more walkability in communities, and reduce congestion on local roads.

IMPLEMENTATION ACTION		RESPONSIBILITY	PRIORITY/ TIMELINE	MEASURE OF SUCCESS
1	Assist municipalities and regional partners including state agencies and the development community to identify incentives that encourage the inclusion of public transit in land development plans such as reductions in parking requirements, reduced local permit fees, or similar incentives.	CVRPC, Development Community, Regional Partners, State Agencies	High 1 to 3 years	Incentives identified and regulations updated as necessary
2	Work with regional partners including state agencies and the business community to identify incentives that encourage employers to support the use of public transit by their employees such as discounted transit fares, flexibility in work hours, or similar incentives.	CVRPC, Business Community, Regional Partners, State Agencies	High 1 to 3 years	Incentives identified and presented as necessary
3	Work with VTrans and Green Mountain Transit to identify future growth areas or development centers to ensure public transit will be accommodated in these locations including access to park & ride locations when appropriate.	CVRPC, Vtrans, Municipalities, GMT	High 1 to 3 years	Areas identified and prioritized as appropriate
4	Work with public transit providers and other partners to identify underserved communities such as rural areas or low-income neighborhoods to identify transit opportunities in these locations.	CVRPC, VTrans, Regional Partners, GMT	High 1 to 3 years	Service options identified for designated locations
5	Ensure the Central Vermont Regional Plan includes clear policy language that requires large scale developments to consult with transit providers regarding the need to include transit or multi-modal infrastructure with development proposals.	CVRPC	High 1 to 3 years	The Central Vermont Regional Plan is updated as appropriate

	IMPLEMENTATION ACTION	RESPONSIBILITY	PRIORITY/ TIMELINE	MEASURE OF SUCCESS
6	Work with regional partners and municipalities to establish a comprehensive transportation plan that incorporates policies and implementation regarding the expansion of public transit that considers locations of park & ride facilities; public facilities such as schools and government buildings; or other activity centers and uses throughout the Region and identifies possible funding sources to support implementation and the Region's future land use planning efforts.	CVRPC, VTrans, GMT, Regional Partners	High 1 to 3 years	Plan developed, areas prioritized, and funding options identified
7	Ensure the continued support of inter-municipal or inter-regional public transit options are maintained, such as bus or rail service.	CVRPC, VTrans, GMT	On-going	Services are maintained
8	Work with municipalities to evaluate and determine the feasibility of intermodal transit facilities in appropriate regional locations that can be supported by infrastructure, population, and resources.	CVRPC, Municipalities, VTrans, GMT	High 1 to 3 years	Locations are identified and mapped
9	Provide technical assistance to transit providers as appropriate regarding land use, infrastructure, and future planning considerations to help plan for service needs.	CVRPC, VTrans, GMT	On-going	Technical assistance is provided as requested

Policy B-2: Promote the shift away from single-occupancy vehicle trips to reduce congestion, impacts to local facilities, and support alternative options for transportation needs.

Due to the rural nature of Central Vermont, single-occupancy vehicle trips are a common occurrence. While many people rely on their vehicle to perform general day-to-day tasks, reducing the rate of these trips can reduce congestion on local roads; reduce conflicts with vehicles and pedestrians; and provide more support for ride shares, public transit, or similar multi-occupancy trips.

IMPLEMENTATION ACTION		RESPONSIBILITY	PRIORITY/ TIMELINE	MEASURE OF SUCCESS
1	Promote the use of ride share programs within the region such as GoVermont, and maintain an active list of available services that can be distributed to the municipalities.	CVRPC, VTrans	Medium On-going	List of providers developed and maintained
2	Work with regional partners such as VTrans to ensure inventories of park & ride locations and conditions are up-to-date and are consistent with the State Park & Ride Plan. This may include occupancy studies or user surveys to assess specific needs.	CVRPC, VTrans	Medium On-going	Inventories completed and prioritized
3	Identify park & ride facilities that are near or over capacity to ensure future planning will accommodate expansions, upgrades, modifications, or alternative locations are identified as appropriate.	CVRPC, VTrans	High On-going	Facility upgrades/ improvements are identified for priority locations
4	Work with utility companies and municipalities to inventory and map infrastructure such as fiber optic cable to identify gaps that may prohibit information accessibility or telecommuting options.	CVRPC, Utility Providers	High On-going	Identify gaps and prioritize needs

Policy B-3: Promote the shift away from gas/diesel vehicles to electric or non-fossil fuel transportation options to reduce dependency on non-renewable fuel sources for transportation.

Reducing the dependency on fossil fuels and other non-renewable fuels is a key pathway to achieving the state's energy planning goals. Switching to electric or non-fossil fuel based vehicles will help reduce greenhouse gas emissions and promote cleaner fuel alternatives.

IMPLEMENTATION ACTION		RESPONSIBILITY	PRIORITY/ TIMELINE	MEASURE OF SUCCESS
1	Work with municipalities to ensure land use regulations do not prohibit the installation of electric vehicle charging stations or similar alternative fuel technologies (such as bio-diesel) and identify model language that can be considered by municipalities to support these uses.	CVRPC, Municipalities	Medium 3 to 5 years	Model regulations developed and approved by municipalities
2	Identify businesses and municipalities in the region that operate large fleets of vehicles to provide assistance evaluating the possibility of integrating electric or non-fossil fuel based vehicles into their fleets.	CVRPC	Medium 3 to 5 years	Businesses inventoried and contacts established
3	Inventory existing locations of electric vehicle charging stations to identify where infrastructure gaps may exist or where needs could be met to provide greater access for electric vehicle owners.	CVRPC, Drive Electric Vermont	Medium On-going	Inventory of locations mapped to identify potential gaps
4	Work with industry advocates and municipalities to ensure open communications exist to disseminate information about alternative fuel vehicles (including financial, environmental, and sustainability benefits) on a routine basis. This may be done through regular meetings, special events, or other avenues as deemed appropriate.	CVRPC, Industry Representatives, Lending Institutions, State Agencies	Low On-going	Contacts established and regularly engaged
5	Consult with the Vermont Energy Investment Corporation's Drive Electric Vermont program to ensure the CVRPC staff is up-to date on current technology trends related to electric vehicles in order to provide guidance to municipalities.	CVRPC, VEIC	On-going	Regular updates are provided as necessary
6	Consider regulations that would require electric vehicle charging stations or infrastructure to be included in large scale developments as appropriate.	CVRPC, municipalities	Low 5 to 10 years	Regulations developed and implemented where appropriate

Policy B-4: Facilitate the development of walking and biking infrastructure to provide alternative transportation options for the community.

Walking and biking provide valuable alternatives to motorized vehicle travel. Ensuring a safe, efficient, and convenient infrastructure exists to promote walking and biking is essential to the future growth and sustainability of the Region's municipalities.

IMPLEMENTATION ACTION		RESPONSIBILITY	PRIORITY/ TIMELINE	MEASURE OF SUCCESS
1	Evaluate local regulations and recommend changes as necessary to support state complete streets legislation as noted in 19 V.S.A §309d, which would include walking, biking, or transit infrastructure to be considered in the land development process.	CVRPC, municipalities	Medium On-going	Regulations evaluated and recommendations made
2	Develop model regulations to be evaluated by municipalities that require walking and biking infrastructure in downtowns, village centers, growth areas, or locations that propose high density development patterns.	CVRPC, municipalities	Medium 3 to 5 years	Model regulations developed
3	Provide regular updates and training to municipalities that discuss complete streets concepts and to effectively implement these facilities including sample language to be evaluated for inclusion in local regulations.	CVRPC, VTrans	Medium On-going	Regular reports to VTrans regarding trainings held
4	Work with its municipalities and regional partners to develop a walking and biking master plan that identifies priority projects, gaps in the infrastructure, and implementation strategies for incorporating facilities where appropriate.	CVRPC, municipalities, regional partners, state agencies, business community	Low 5 to 10 years	Plan developed and priority projects identified
5	Evaluate land use patterns to ensure walking and biking connections exist or are possible between key land uses such as schools, parks/greenways, commercial areas, or neighborhoods to help create walkable communities.	CVRPC	Low 5 to 10 years	Connections evaluated or established

C. Patterns and Densities of Land Use Likely to Result in Conservation of Energy

Policy C-1: Central Vermont is committed to reducing sprawl and minimizing low-density development by encouraging density in areas where infrastructure exists or is planned to support growth.

Land use policies that work to limit the proliferation of large lot development in favor of small lots in a compact area help communities address conditions that create sprawl, or the outward pattern of development that is characterized by auto-centric uses in an expanded geography. By limiting conditions that lead to sprawling development patterns, the Region can more effectively support energy independence.

	IMPLEMENTATION ACTION	RESPONSIBILITY	PRIORITY/ TIMELINE	MEASURE OF SUCCESS
1	Evaluate municipal regulations to ensure higher density development patterns are located in regional and town centers to maintain existing settlement patterns and do not inadvertently promote sprawling development.	CVRPC, Municipalities	Medium On-going	Regulations are evaluated as needed and recommendations are included
2	Assist municipalities to identify future growth areas that can accommodate development needs while meeting smart growth principles and respecting historic settlement patterns of compact villages, neighborhoods, and urban centers as appropriate.	CVRPC, Municipalities	Medium On-going	Assistance provided and areas identified
3	Assist municipalities in preparing information necessary to acquire or maintain state designations including statutory requirements.	CVRPC, Municipalities, ACCD	Low On-going	State designations are maintained or acquired
4	Work with municipalities and regional partners to inventory and map existing infrastructure such as water and wastewater to evaluate capacity and development potential.	CVRPC, Municipalities	Medium 3 to 5 years	Infrastructure mapped and updated as needed
5	Work with communities to evaluate their land development regulations to ensure these regulations (including scale, massing, building height, and minimum lot size) are suitable to support density in appropriate locations and in proximity to needed infrastructure that is consistent with community character.	CVRPC	Low 5 to 10 years	Regulations evaluated and updated as appropriate
6	Develop or make available model ordinances related to Planned Unit Developments, for review and consideration by municipalities as a way to establish compact development patterns outside of existing growth areas.	CVRPC	Low 5 to 10 years	Model regulations developed

	IMPLEMENTATION ACTION	RESPONSIBILITY	PRIORITY/ TIMELINE	MEASURE OF SUCCESS
7	Provide information related to available funding opportunities (including sources and programs) for municipal infrastructure projects or improvements that will promote or support development density or compact development patterns.	CVRPC, State Agencies	High 1 to 3 years	Information on funding collected and available
8	Work with interested municipalities to create policies that incentivize development in designated growth areas with opportunities that could expedite land development reviews, permitting, or other regulatory processes as appropriate.	CVRPC, Municipalities, State Agencies	High 1 to 3 years	Regulations & processes updated as appropriate
9	Assist interested municipalities to review regulations and develop updates as appropriate that would support the development of community scale infrastructure for renewable energy generation and conservation.	CVRPC, Municipalities	Medium 3 to 5 years	Regulations updated as appropriate
10	Work with interested municipalities to ensure adequate land exists for agricultural uses as a way to encourage local food production.	CVRPC, Municipalities	Medium 3 to 5 years	Regulations updated as appropriate
11	Work with municipalities and the Agency of Agriculture, Food & Markets to ensure prime farmland inventories are up-to-date and mapped.	CVRPC, Agency of Agriculture, Food, & Markets, municipalities	On-going	Prime agricultural land inventories are updated and mapped
12	Support amendments to local regulations that encourage local food production through regulatory and non-regulatory approaches that focus development and preserve agricultural opportunities.	CVRPC, Municipalities, Agency of Agriculture, Food, & Markets	Medium 3 to 5 years	Regulations are updated as appropriate

Policy C-2: Strongly prioritize development in compact, mixed-use centers when feasible and appropriate; and identify ways to make compact development more feasible throughout Central Vermont.

Compact development patterns create opportunities whereby land uses that support where people live, work, and recreate, are all within close proximity. This not only creates a greater sense of place but it provides opportunities to walk, bike, or utilize public transit as the primary mode of transportation. Additionally, compact development patterns can promote conservation of energy through the redevelopment of underutilized spaces therefore including more energy efficient building designs.

	IMPLEMENTATION ACTION	RESPONSIBILITY	PRIORITY/ TIMELINE	MEASURE OF SUCCESS
1	Provide information to municipalities regarding alternative land use regulations such as form-based codes and identify communities where similar regulations have been successfully implemented including rural or non-urban scale regulations.	CVRPC	Low 5 to 10 years	Workshops or other informational sessions conducted
2	Evaluate municipal regulations and recommend amendments that will support and encourage infill development, redevelopment, adaptive reuse of existing buildings such as historic structures, and reuse of "brownfield" sites	CVRPC, Municipalities, Regional Partners	High 1 to 3 years	Regulations evaluated and recommendations made as appropriate
3	Provide information to municipalities on capital planning, public investment strategies, or state and federal programs that support infill development within core community areas.	CVRPC, State Partners	High 1 to 3 years	Workshops or other informational sessions conducted
4	Evaluate roadways in existing villages, downtowns, or municipal activity centers to identify conflict points between motorized and non-motorized modes of travel and recommend options to promote walkable and bike friendly centers that encourage alternative transportation choices	CVRPC, VTrans, Municipalities	Medium 3 to 5 years	Evaluations completed as needed and recommendations provided
5	Work with municipalities to identify priority development zones, growth areas, or locations where high demand for electric loads exist or are planned (such as industrial parks) to ensure current planning acknowledges future needs.	CVRPC, Municipalities, State Partners	High 1 to 3 years	Locations are identified and incentives established as appropriate

D. Development and Siting of Renewable Energy Resources

Policy D-1: Evaluate generation from existing renewable energy generation by municipality including the identification of constraints, resource areas, and existing infrastructure by energy type.

Identifying and mapping existing renewable energy generation facilities throughout the region will provide a baseline to determine the generation that currently exists. This information can provide a better understanding for where developments are currently being established and can help prioritize assistance that may be needed at the municipal level. Additionally, mapping existing constraints will provide municipalities with a better understanding of resources that are available within their community.

IMPLEMENTATION ACTION		RESPONSIBILITY	PRIORITY/ TIMELINE	MEASURE OF SUCCESS
1	Provide regular mapping updates to municipalities regarding existing generation facilities to maintain an up-to-date inventory of locations.	CVRPC, Department of Public Service	On-going	Updated maps provided as requested
2	Provide regular mapping updates to municipalities regarding known and possible constraints to ensure consistency with state guidelines on renewable energy siting.	CVRPC, State Agencies	On-going	Updated maps provided as necessary
3	Update regional maps to reflect changes at the municipal level regarding preferred or unsuitable locations for renewable energy generation.	CVRPC, Municipalities	On-going	Maps and information updated as necessary
4	Work with state agencies to map locations of woody biomass or methane generation for possible fuel sources.	CVRPC, State Agencies	On-going	Specific locations are identified and mapped

Policy D-2: Evaluate generation from potential renewable energy generation by municipality including the identification of constraints, resource areas, and existing infrastructure by energy type.

Identifying and mapping potential renewable energy generation throughout the region will provide municipalities with information regarding available land area where renewable energy generation could be located. This information can be used to help municipalities prioritize and evaluate where future renewable generation could or should occur based on municipal land use policies and constraints. Additionally, information on potential renewable energy generation will ensure municipalities are working to support the state's renewable energy generation goals of 90% of the state's energy needs coming from renewable sources by 2050.

IMPLEMENTATION ACTION		RESPONSIBILITY	PRIORITY/ TIMELINE	MEASURE OF SUCCESS
1	Evaluate known, possible, and regionally identified constraints to ensure up-to-date information is available for future planning purposes.	CVRPC, State Agencies	On-going	Constraints will be evaluated and mapped as necessary
2	Update information on utility infrastructure including existing and proposed transmission facilities to ensure accurate data exists.	CVRPC, Utility Providers	On-going	Utility information is updated and mapped as necessary
3	Evaluate and update preferred and unsuitable locations for future renewable energy generation siting as needed based on state, regional, and municipal policies and plans.	CVRPC, Municipalities, State Agencies	On-going	Preferred and prohibited locations are evaluated and mapped as necessary
4	Update generation potential based on future land developments, changes to land uses, or updates to priority areas as identified by state, regional, or municipal actions.	CVRPC, Municipalities, State Agencies	On-going	Generation potential is updated as necessary
5	Work with municipalities, as requested, to evaluate and prioritize future renewable energy generation technologies and locations to best suit municipal needs and policies.	CVRPC, Municipalities	On-going	Locations and technologies will be evaluated and prioritized

MAPPING

As noted in the Pathways & Implementation Actions section, specific policies have been identified related to mapping. These policies include evaluation of existing renewable energy generation and future renewable energy generation potential. The following information provides additional detail related to mapping including infrastructure, constraints, and specific locational preferences. In addition to the information in this section, Appendix B includes regional maps to support the discussion in this section.

The siting and generation of renewable resources is a critical part to identifying whether or not the region can meet its share of the state's renewable energy goals by 2050. Furthermore, this analysis is important to determine where resources are available throughout the region to ensure no one municipality is unduly burdened with supporting more than should be reasonably anticipated. Finally, this information will better position the region and its municipalities to evaluate the renewable energy generation options that are available to meet these goals.

To this end, maps were created for Central Vermont at a regional and municipal level that identify resources related to solar, wind, hydroelectric, and woody biomass. Maps were also created to identify constraints that may limit the overall area of possible resource development within Central Vermont. The following information will address the evaluation of current and future generation potential within the region.

Existing Renewable Energy Generation

As noted in the Analysis & Targets section, Table One identifies the existing renewable generation for Central Vermont. Information on existing generation is a representation of all projects that were issued a Certificate of Public Good by the Public Service Board through the end of 2014. Projects that are currently under review are not included in these numbers therefore additional renewable energy generation may be developed that will not be included in the total generation represented in Table One.

One resource that provides data on existing generation is the Vermont Energy Action Network's Energy Dashboard. This resource incorporates data from the Department of Public Service relative to projects that have received a Certificate of Public Good, but also includes information from the community on self-reported actions. These include activities such as weatherization of buildings, switching of lightbulbs to high efficiency LED technologies, conversions to high efficiency appliances, or replacement of fossil fueled vehicles with alternative fuel technologies. The Energy Dashboard can be accessed by visiting http://www.vtenergydashboard.org/energy-atlas.

Appendix B includes maps with existing solar generation greater than 15 kW and all wind and woody biomass generation sites. Solar projects are the predominant form of generation in Central Vermont. In addition to the mapped locations for solar generation, the Energy Dashboard identifies approximately 1,000 additional solar sites in the region that are less than 15 kW. These are primarily individual homes with solar installations to supplement conventional electrical service. Also, approximately 250 solar hot water installations existing within the region bringing the total number of solar generation facilities in the region to just over 1,300 installations.

Potential Renewable Energy Generation

Table Thirteen in the Analysis & Targets section identifies potential generation of renewable energy for Central Vermont. This information is based on mapping data provided by the Vermont Center for Geographic Information (VCGI) and the Department of Public Service. This information includes specific data related to prime resource areas for solar and wind development which is an indication of where the conditions are most ideal for generation of the specific resource. Also included with this data is information regarding constraints to be considered when evaluating areas for renewable energy development. Additional detail regarding known and possible constraints is discussed below.

Constraints[7]

As part of this effort, the CVRPC has identified information related to renewable energy generation that includes an analysis and evaluation of resource areas within the region and how those resource areas are impacted by statewide and regionally identified constraints. In order to determine the impacts, an understanding of the constraints needs to be discussed.

For the purpose of this plan, constraints are separated into two main categories; known and possible. Known constraints are those areas where development of a renewable resources are very limited and therefore not likely to occur. Known constraints that have been identified include:

- Vernal Pools (confirmed or unconfirmed)
- River Corridors as identified by the Vermont Department of Environmental Conservation
- Federal Emergency Management Agency Identified Floodways
- State-significant Natural Communities and Rare, Threatened, and Endangered Species
- National Wilderness Areas
- Class 1 and Class 2 Wetlands (as noted in the Vermont State Wetlands Inventory or Advisory Layers
- Regionally or Locally Identified Critical Resources

Similarly, the state has identified a list of possible constraints to be considered. Possible constraints identify areas where additional analysis will need to occur in order to determine if development of renewable energy resources is appropriate. In some cases, conditions may be prohibitive, but in others the conditions may be suitable for renewable energy development. The possible constraints include:

- Agricultural Soils
- Federal Emergency Management Agency Special Flood Hazard Areas
- Protected Lands (State fee lands and private conservation lands)
- Act 250 Agricultural Soil Mitigation Areas
- Deer Wintering Areas
- Vermont Agency of Natural Resources Conservation Design Highest Priority Forest Blocks
- Hydric Soils
- Regionally or Locally Identified Resources

7. Appendix A provides specific definitions for the known and possible constraints.

In addition to the items listed above, the Regional Planning Commission, through its Regional Energy Committee, has identified additional constraints to be included. For the purposes of this mapping exercise, all of the regional constraints are considered possible constraints. This is due to the fact that the Regional Energy Committee determined that, like the statewide possible constraints, conditions could be such that developing renewable energy resources in these locations could occur but should be studied further to determine if the specific conditions regarding these locations are suitable. The possible regional constraints that were identified include:

- Elevations above 2,500 feet
- Slopes greater than 25%
- Municipally Owned Lands
- Lakeshore Protection Buffer Areas of 250 feet

It should be noted that the regionally identified constraints are intended to be a starting point. Future updates to the Regional Energy Plan may include additional analysis of regional constraints. Changes to regional priorities may impact specific constraints that should be considered. This could include factors such as contiguous blocks of farmland, parcel sizes, or other factors that are identified as regional priorities.

Methodology

With all the known and possible constraints identified, this information was overlaid on the resources maps for solar and wind resources. Where known constraints existed, the resource areas were deleted. Where possible constraints existed, the resource areas were shaded. The resulting areas included those lands where prime resources exist without any constraints and prime resources with possible constraints. The total area within these two categories served as the basis to determine the amount of resource that is available for potential development within Central Vermont.

As noted in Table Thirteen of the Analysis & Targets section, based on the solar, wind, and hydroelectric potential within Central Vermont, approximately 90,000,000 megawatt hours of energy could be produced, well above the region's allocation of 418,531 megawatt hours by 2050. The potential energy generation for Central Vermont increases when other sources of renewable energy generation such as biomass, biogas, and methane are included. No specific generation numbers are listed in Table Thirteen for these types of energy generation as their siting is not specifically tied to the availability of a resource, therefore calculating a potential for generation would be difficult.

Finally, the constraints outlined above have been evaluated to ensure sufficient resource area will exist to meet the region's share of the state's renewable energy targets. As noted, the regional constraints are included as "possible" therefore development of renewable resources could occur in these locations after an analysis of the specific site has been concluded. Additionally, multiple technologies could be used to meet the region's target. This means that some technologies, such as wind or hydroelectric, could be replaced by biomass or biogas to meet the region's target.

Transmission Infrastructure

In addition to identifying and calculating possible generation of renewable energy based on resources and constraints, the mapping included in this plan also incorporates the existing three phase power infrastructure throughout the region. This is important to include because large-scale renewable energy generation typically needs three phase power to provide energy generation back to the grid. Smaller generation facilities (such as residential scale) can typically be accommodated by single phase transmission even when not located close to the load, therefore three phase power may not be a limiting factor in renewable energy development.

Similar to limits on three phase power are potential limitations on existing transmission infrastructure and the ability to transmit energy from its point of generation to the possible users. As noted previously, the mapping includes three phase power, but it also includes information on current transmission infrastructure. This is another component to consider when identifying where specific generation types should be located to ensure the transmission capacity exists within the grid or to identify areas where upgrades may be needed before development of renewable energy generation can occur.

Based on the factors noted above, it may be appropriate for mapping to identify areas where significant energy loads are currently occurring or anticipated based on future land use and zoning. Locations of high energy use were not included on the current mapping and this information should first be considered at a municipal level before being identified regionally. This process would be consistent with others herein that support municipal identification of energy planning needs to ensure consistency with local regulations and planning efforts.

In the future, it may be appropriate to evaluate the entire transmission and distribution network to determine not only where there may be limitations to grid capacity, but also to identify where there may be surplus capacity. Identifying where limits and excesses exist throughout the electrical grid will be valuable information to inform future planning decisions related to both the siting of future renewable energy generation, but also when considering future land uses or development patterns. These evaluations could also identify locations that may be suitable for microgrids to address critical facilities or similar needs to ensure continuous power supplies are available.

Preferred & Unsuitable Siting Locations

Similar to the discussion regarding the identification of constraints at a regional scale, the Regional Energy Committee recommended that preferred and unsuitable areas would not be included on the mapping with the exception of statewide preferred locations that may exist within the region. The statewide preferred locations include:

- Parking lots
- Gravel pits
- Brownfield sites as defined in 10 V.S.A. §6642[8]
- Sanitary Landfills as defined in 10 V.S.A. §6602
- Rooftop installations

8. The State of Vermont is developing specific guidance to ensure brownfield sites have been properly evaluated to include the identification and the extent of the possible contamination. Based on this guidance, a Phase I and/or Phase II analysis may be required prior to the site being formally designated as a brownfield. This may impact the eligibility of a specific site to meet this designation and be considered a preferred site for renewable energy development.

The Regional Energy Committee further concluded that the final determination and identification of suitable sites would be left to the individual municipalities as they develop and evaluate their needs, development patterns, and future land use goals. Similarly, unsuitable areas for development of renewable energy generation were not included on the regional maps and no specific examples beyond the constraint layers are noted. This will allow the municipalities to use local insight and knowledge to evaluate and establish the criteria for identifying locally preferred or unsuitable locations. Regional maps may be updated to include locally identified preferred or unsuitable sites as municipalities work to identify these locations through local energy planning processes. This could include siting for all resource technologies including biogas, biosolids, wind, solar, and woody biomass.

The CVRPC will also evaluate and consider preferred locations as identified by the Public Utility Commission's net metering rules. This will ensure consistency between state, regional, and locally preferred locations for renewable energy siting. In addition to the actions outlined in the Pathways & Implementation Actions section, a map identifying existing locations of statewide preferred locations as noted previously can be found in Appendix B.

Finally, the Central Vermont Regional Energy Plan supports the development of renewable energy generation technology that will not result in an undue adverse impact on the built or natural environment or conflict with identified regional policies. Similar to constraint mapping, it was decided that the region should not limit the extent to which municipalities can plan for their energy future. Due to the diverse nature of Central Vermont, including urban and rural areas, there was no way to develop a consistent regional policy that would be equitable to all the municipalities, therefore all renewable energy generation types (both current and developed through future advances in technology or innovations in the industry) may be considered for application in Central Vermont.

Municipal Information

As part of this effort, the Central Vermont Regional Planning Commission developed information for all 23 municipalities within the region related to Analysis & Targets and Mapping, using best available information. This information was completed and distributed on April 28, 2017. The CVRPC website was the mechanism for this information to be disseminated and including guidance and other resources for how to best use the information. This information is available at http://centralvtplanning.org/programs/energy/municipal-energy-planning/

Regional Mapping

To provide a more specific visual representation of resources and constraints, mapping was developed that includes:

- Solar Resource Areas
- Wind Resource Areas
- Hydroelectric Resource Areas
- Known Constraints
- Possible Constraints
- Woody Biomass Resource Area

These maps should be used as a starting point to determine what areas may exhibit characteristics consistent with conditions that would support renewable energy development. More detailed review and analysis should be conducted to determine specific boundaries for resource areas or constraints. These maps can be found in Appendix B.

APPENDIX A

KNOWN & POSSIBLE CONSTRAINT DEFINITIONS & DESCRIPTIONS

The following is a list of the known, possible, and regional constraints that were used and referenced in the mapping section of this document. A definition of the constraint including source of the data is provided.

Known Constraints

Vernal Pools (confirmed and unconfirmed layers) –
Source: Vermont Fish and Wildlife, 2009 - present

Vernal pools are temporary pools of water that provide habitat for distinctive plants and animals. Data was collected remotely using color infrared aerial photo interpretation. "Potential" vernal pools were mapped and available for the purpose of confirming whether vernal pool habitat was present through site visits. This layer represents both those site which have not yet been field-visited or verified as vernal pools, and those that have.

Department of Environmental Conservation (DEC) River Corridors –
Source: DEC Watershed Management District Rivers Program, January 2015

River corridors are delineated to provide for the least erosive meandering and floodplain geometry toward which a river will evolve over time. River corridor maps guide State actions to protect, restore and maintain naturally stable meanders and riparian areas to minimize erosion hazards. Land within and immediately abutting a river corridor may be at higher risk to fluvial erosion during floods.

River corridors encompass an area around and adjacent to the present channel where fluvial erosion, channel evolution and down-valley meander migration are most likely to occur. River corridor widths are calculated to represent the narrowest band of valley bottom and riparian land necessary to accommodate the least erosive channel and floodplain geometry that would be created and maintained naturally within a given valley setting.

Federal Emergency Management Agency (FEMA) Floodways –
Source: FEMA Floodway included in Zones AE – FEMA Map Service Center

These are areas subject to inundation by the 1-percent-annual-chance flood event determined by detailed methods. A "Regulatory Floodway" means the channel of a river or other watercourse and the adjacent land areas that must be reserved in order to discharge the base flood without cumulatively increasing the water surface elevation more than a designated height.

State-significant Natural Communities and Rare, Threatened, and Endangered Species –
Source: Vermont Fish and Wildlife, National Heritage Inventory

The Vermont Fish and Wildlife Department's Natural Heritage Inventory (NHI) maintains a database of rare, threatened and endangered species and natural (plant) communities in Vermont. The Element Occurrence (EO) records that form the core of the Natural Heritage Inventory database include information on the location, status, characteristics, numbers, condition, and distribution of elements of biological diversity using established Natural Heritage Methodology developed by NatureServe and The Nature Conservancy.

An Element Occurrence (EO) is an area of land and/or water in which a species or natural community is, or was, present. An EO should have practical conservation value for the Element as evidenced by potential

continued (or historical) presence and/or regular recurrence at a given location. For species Elements, the EO often corresponds with the local population, but when appropriate may be a portion of a population or a group of nearby populations (e.g., metapopulation).

National Wilderness Areas –
Source: United States Department of Agriculture Forest Service

A parcel of Forest Service land congressionally designated as wilderness.

Class 1 and Class 2 Wetlands –
Source: Vermont Significant Wetland Inventory (VSWI) and advisory layers

The State of Vermont protects wetlands which provide significant functions and values and also protects a buffer zone directly adjacent to significant wetlands. Wetlands in Vermont are classified as Class I, II, or III based on the significance of the functions and values they provide. Class I and Class II wetlands provide significant functions and values and are protected by the Vermont Wetland Rules. Any activity within a Class I or II wetland or buffer zone which is not exempt or considered an "allowed use" under the Vermont Wetland Rules requires a permit.

Class I wetlands have been determined to be, based on their functions and values, exceptional or irreplaceable in its contribution to Vermont's natural heritage and, therefore, merits the highest level of protection. All wetlands contiguous to wetlands shown on the VSWI maps are presumed to be Class II wetlands, unless identified as Class I or III wetlands, or unless determined otherwise by the Secretary or Panel pursuant to Section 8 of the Vermont Wetland Rules.

Possible Constraints

Agricultural Soils –
Source: Natural Resources Conservation Service (NRCS)

Primary agricultural soils" are defined as "soil map units with the best combination of physical and chemical characteristics that have a potential for growing food, feed, and forage crops, have sufficient moisture and drainage, plant nutrients or responsiveness to fertilizers, few limitations for cultivation or limitations which may be easily overcome, and an average slope that does not exceed 15 percent. Present uses may be cropland, pasture, regenerating forests, forestland, or other agricultural or silvicultural uses.

The soils must be of a size and location, relative to adjoining land uses, so that those soils will be capable, following removal of any identified limitations, of supporting or contributing to an economic or commercial agricultural operation. Unless contradicted by the qualifications stated above, primary agricultural soils include important farmland soils map units with a rating of prime, statewide, or local importance as defined by the Natural Resources Conservation Service of the United States Department of Agriculture.

FEMA Special Flood Hazard Areas -

The land area covered by the floodwaters of the base flood is the Special Flood Hazard Area (SFHA) on NFIP maps. The SFHA is the area where the National Flood Insurance Program's (NFIP's) floodplain management regulations must be enforced and the area where the mandatory purchase of flood insurance applies.

Protected Lands –

State fee land and private conservation lands are considered protected lands. Other state level, non-profit and regional entities also contribute to this dataset. The Vermont Protected Lands Database is based on an updated version of the original Protected Lands Coding Scheme reflecting decisions made by the Protected Lands Database Work Group to plan for a sustainable update process for this important geospatial data layer.

Act 250 Ag Mitigation Parcels –
Source: Vermont Department of Agriculture

All projects reducing the potential of primary agricultural soils on a project tract are required to provide "suitable mitigation," either "onsite or offsite," which is dependent on the location of the project. This constraint layer includes all parcels in the Act 250 Ag Mitigation Program as of 2006.

Deer Wintering Areas (DWA) –
Source: Vermont Department of Fish and Wildlife

Deer winter habitat is critical to the long term survival of white-tailed deer (Odocoileus virginianus) in Vermont. Being near the northern extreme of the white-tailed deer's range, functional winter habitats are essential to maintain stable populations of deer in many years when and where yarding conditions occur. Consequently, deer wintering areas are considered under Act 250 and other local, state, and federal regulations that require the protection of important wildlife habitats. DWAs are generally characterized by rather dense softwood (conifer) cover, such as hemlock, balsam fir, red spruce, or white pine. Occasionally DWAs are found in mixed forest with a strong softwood component or even on found west facing hardwood slopes in conjunction with softwood cover. The DWA were mapped on mylar overlays on topographic maps and based on small scale aerial photos.

Vermont Conservation Design include the following Highest Priority Forest Blocks: Connectivity, Interior, and Physical Landscape Diversity –
Source: Vermont Department of Fish and Wildlife

The lands and waters identified in this constraint 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.

Hydric Soils –
Source: Natural Resources Conservation Service

A hydric soil is a soil that formed under conditions of saturation, flooding or ponding long enough during the growing season to develop anaerobic conditions in the upper part. This constraint layer includes soils that have hydric named components in the map unit.

Regional Constraints

Elevations above 2500 feet –

This constraint uses USGS contours over 2500 feet.

250 Foot Lake Shore Protection Buffers –

For this constraint, CVRPC selected Vermont Hydrologic Dataset lakes and ponds greater than 10 acres and then buffered those by 250 feet.

Slopes Greater Than 25% –

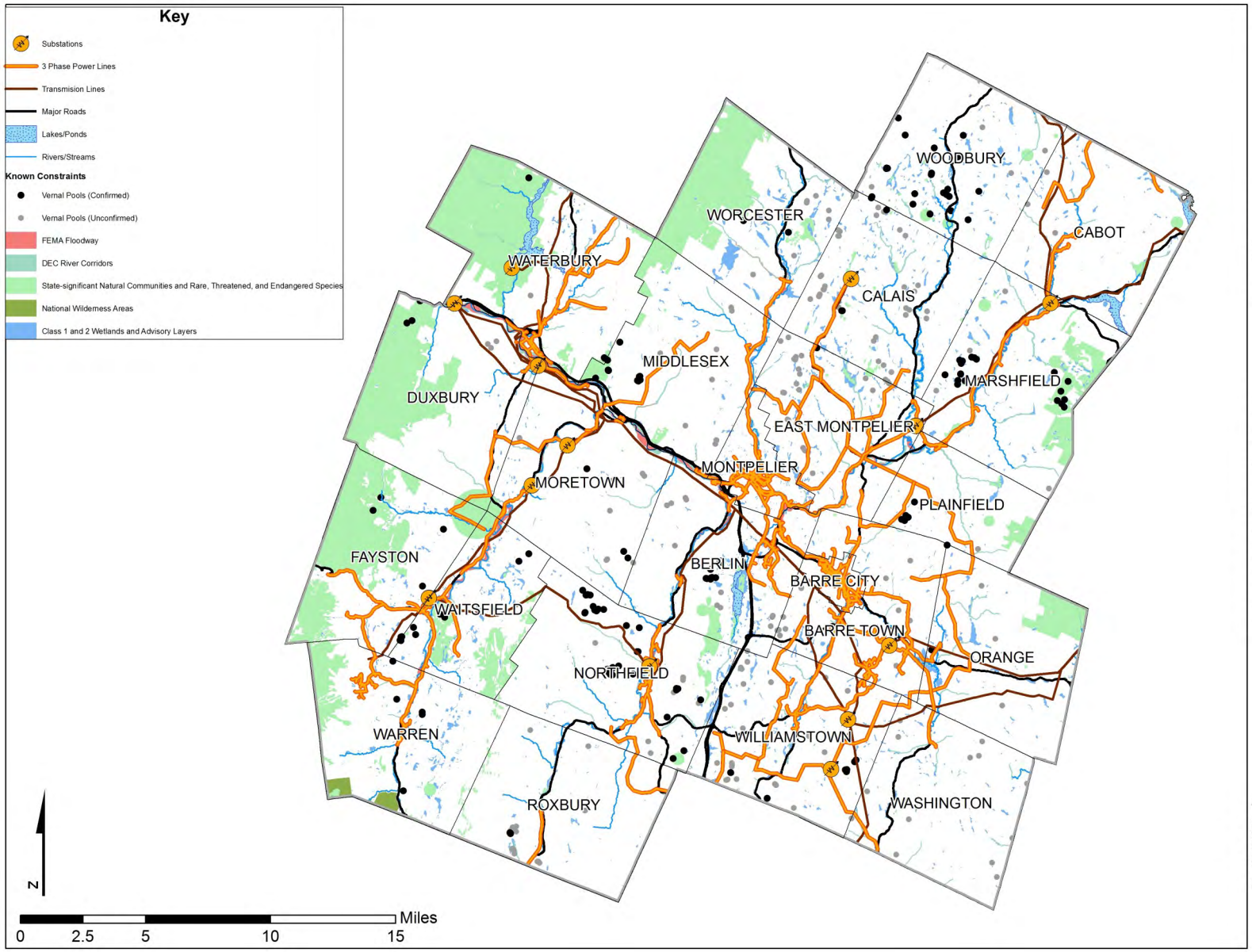
For this constraint, CVRPC performed a slope analysis using a 10 meter Digital Elevation Model.

Municipal Lands –

For this constraint, CVRPC used the Vermont Center for Geographic Information's Protected Lands Database.

APPENDIX B

REGIONAL RESOURCE MAPS



Known Constraints Map

Known Constraints

These constraints signal likely, though not absolute, unsuitability for development based on statewide or local regulation or designated critical resources.

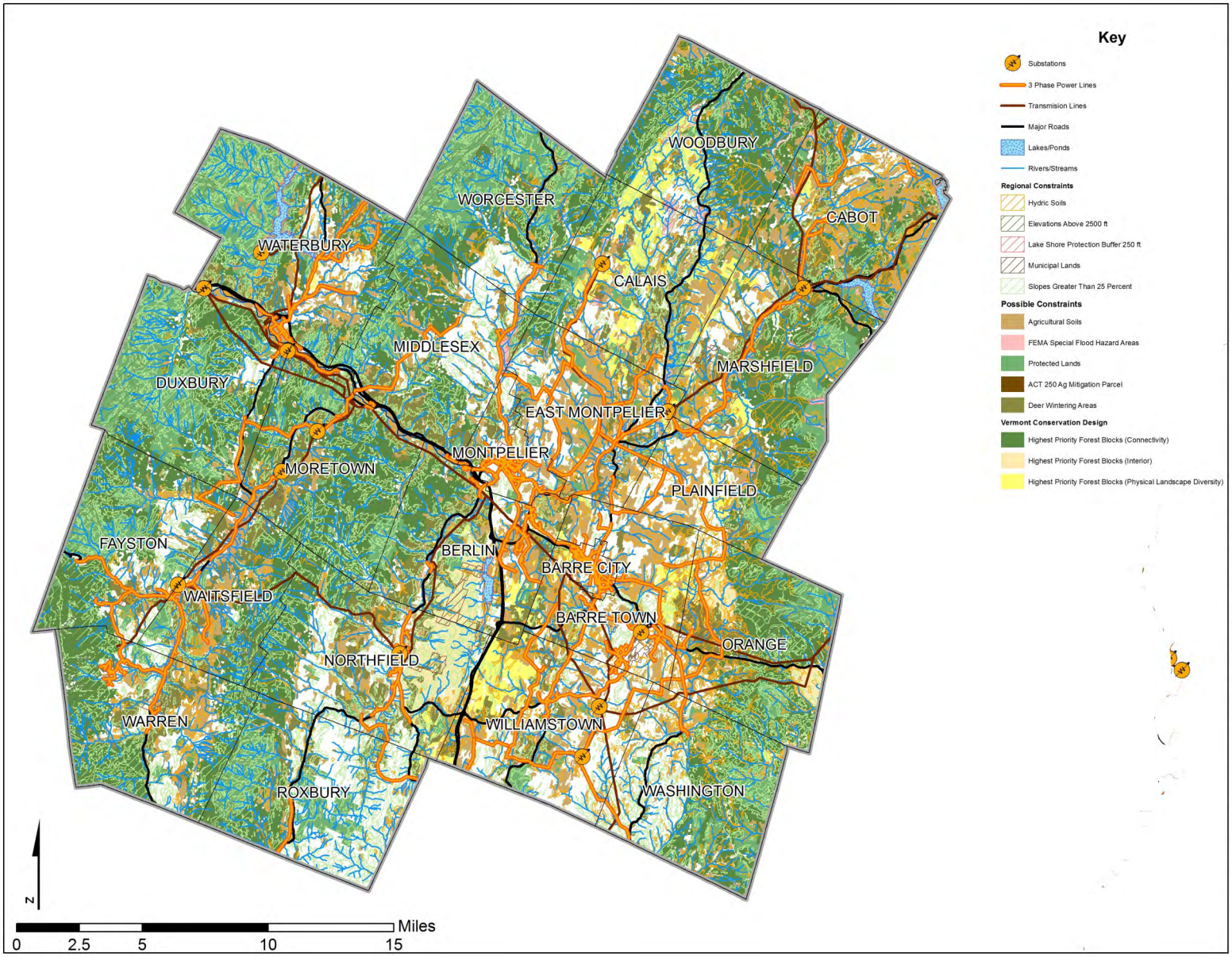
Link to Data -
http://vcgi.vermont.gov/opendata/act174

Known Constraints
Vernal Pools incuding confirmed and unconfirmed -
Vermont Fish and Wildlife
DEC River Corridors -
DEC WSMD Rivers Program 1/2/15
FEMA Floodway included in Zones AE -
FEMA Map Service Center
State-significant Natural Communities and Rare, Threatened, and Endangered Species -
Vermont Fish and Wildlife, Natural Heritage Inventory
National Wilderness Areas -
USDA Forest Service
Class 1 and Class 2 Wetlands (VSWI) and Advisory Layers - VT Watershed Management Division

This map was created as part of a Regional Energy Planning Initiative being conducted by the Bennington County Regional Commission, and the Vermont Public Service Department.

Created: December 2016 by CVRPC GIS.

CVRPC



Key

- Substations
- 3 Phase Power Lines
- Transmision Lines
- Major Roads
- Lakes/Ponds
- Rivers/Streams

Regional Constraints

- Hydric Soils
- Elevations Above 2500 ft
- Lake Shore Protection Buffer 250 ft
- Municipal Lands
- Slopes Greater Than 25 Percent

Possible Constraints

- Agricultural Soils
- FEMA Special Flood Hazard Areas
- Protected Lands
- ACT 250 Ag Mitigation Parcel
- Deer Wintering Areas

Vermont Conservation Design

- Highest Priority Forest Blocks (Connectivity)
- Highest Priority Forest Blocks (Interior)
- Highest Priority Forest Blocks (Physical Landscape Diversity)

Possible Constraints Map

Possible Constraints

These constraints signals conditions that would likely require mitigation, and which may prove a site unsuitable after site-specific study, based on statewide or regional/ local policies that are currently adopted or in effect.

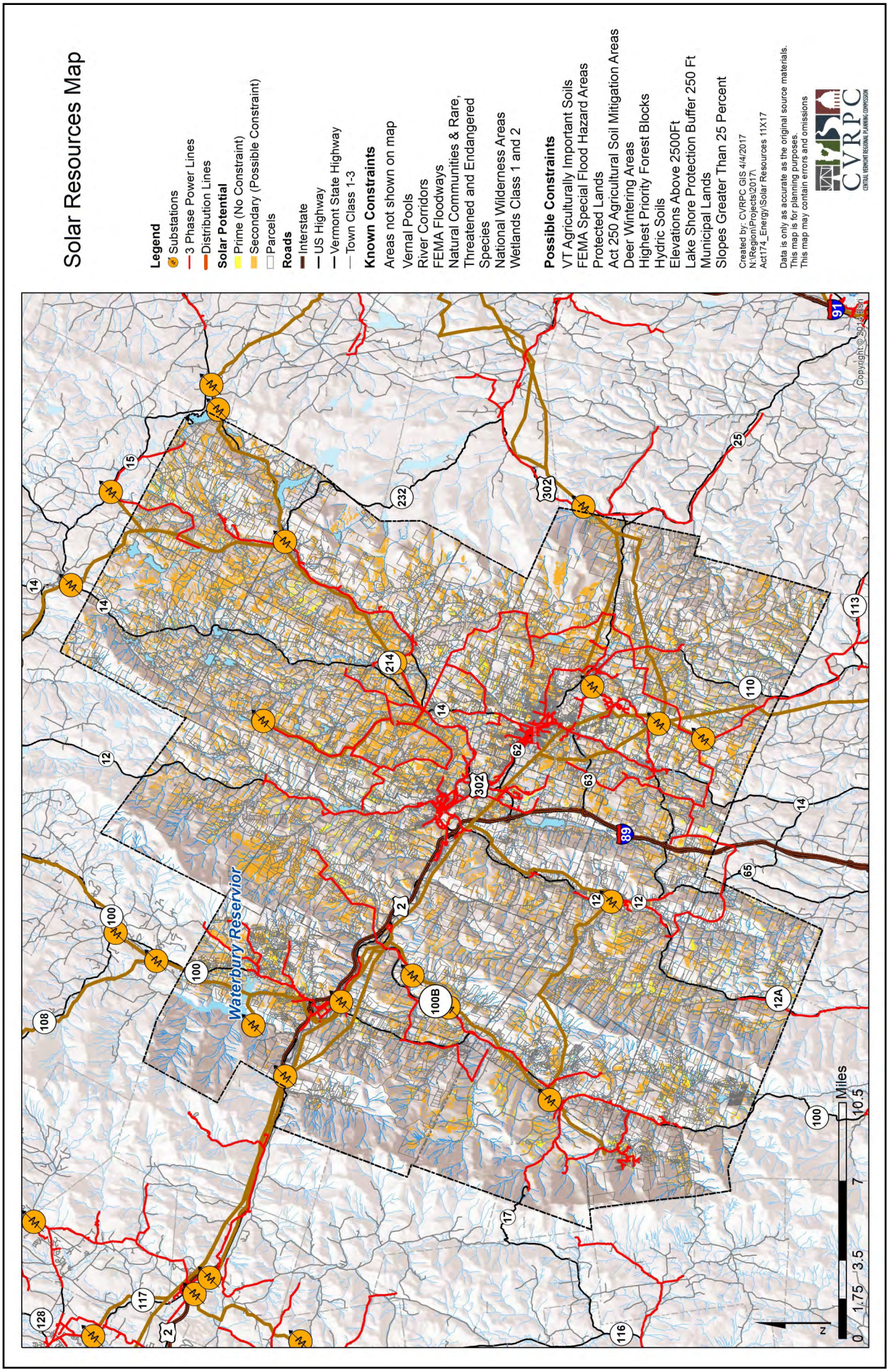
Link to Data - http://vcgi.vermont.gov /opendata/act174

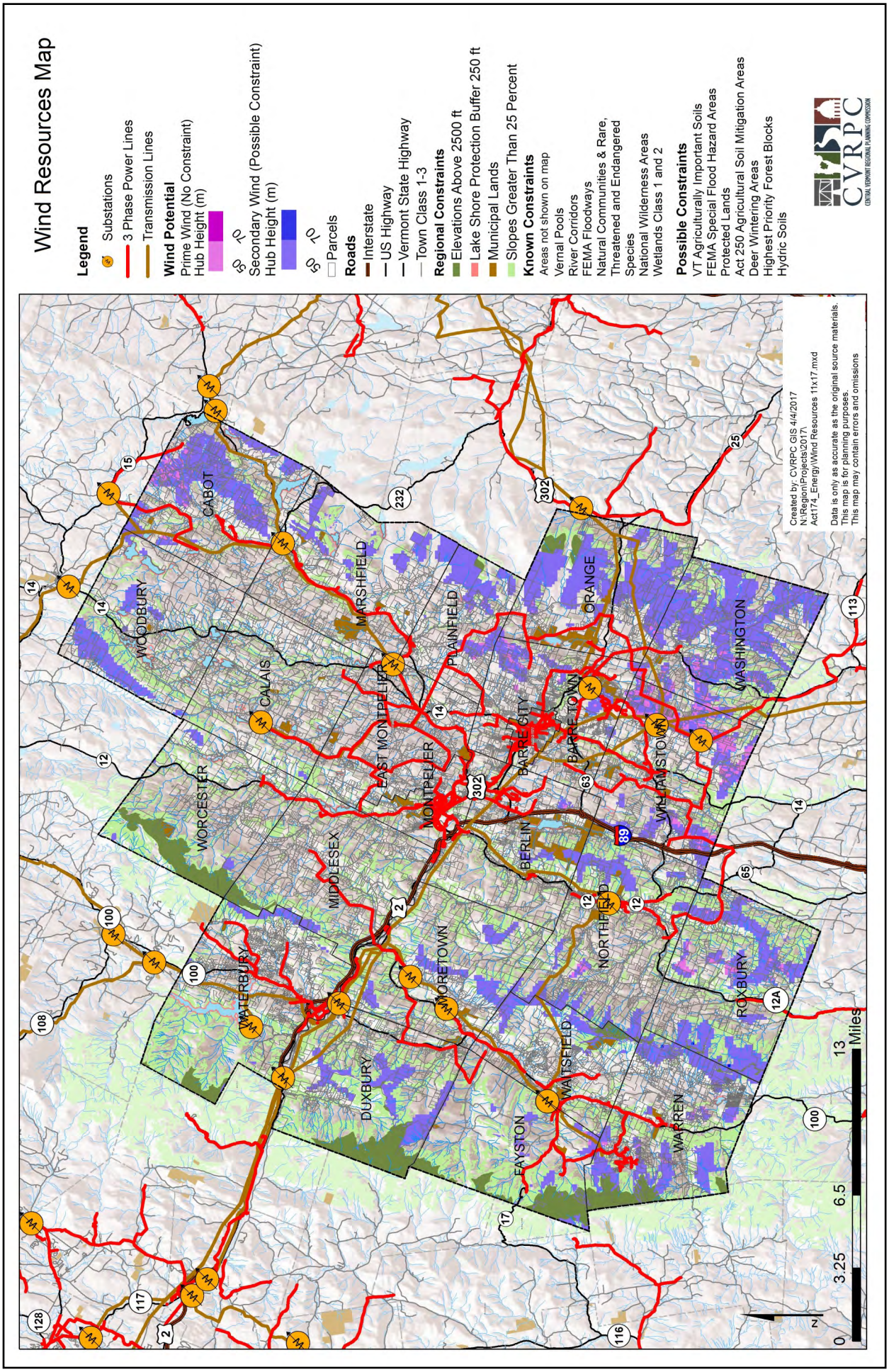
Possible Constraints Data Sources
Agricultural Soils include local, prime and statewide classifications - NRCS
FEMA Special Flood Hazard Areas include Zones A and AE - FEMA Map Service Center
Protected Lands - Include State fee lands and private conservation lands - VCGI
Act 250 Ag Mitigation Parcels include parcel as of 2006 - VT Dept. of Ag
Deer Wintering Areas - VT Fish and Wildlife
Vermont Conservation Design include the following Highest Priority Forest Blocks: Connectivity, Interior, and Physical Landscape Diversity) - VT Fish and Wildlife
Hydric Soils include soils that have hydric named components in the map unit - NRCS

This map was created as part of a Regional Energy Planning Initiative being conducted by the Bennington County Regional Commission, and the Vermont Public Service Department.

Created: December 2016 by CVRPC GIS.

CVRPC


Solar Resources Map
Legend
Substations
3 Phase Power Lines
Distribution Lines
Solar Potential
Prime (No Constraint)
Secondary (Possible Constraint)
Parcels
Roads
Interstate
US Highway
Vermont State Highway
Town Class 1-3
Known Constraints
Areas not shown on map
Vernal Pools
River Corridors
FEMA Floodways
Natural Communities & Rare, Threatened and Endangered Species
National Wilderness Areas
Wetlands Class 1 and 2
Possible Constraints
VT Agriculturally Important Soils
FEMA Special Flood Hazard Areas
Protected Lands
Act 250 Agricultural Soil Mitigation Areas
Deer Wintering Areas
Highest Priority Forest Blocks
Hydric Soils
Elevations Above 2500Ft
Lake Shore Protection Buffer 250 Ft
Municipal Lands
Slopes Greater Than 25 Percent
Created by: CVRPC GIS 4/4/2017
N:\Region\Projects\2017\
Act174_Energy\Solar Resources 11X17
Data is only as accurate as the original source materials.
This map is for planning purposes.
This map may contain errors and omissions
CVRPC
CENTRAL VERMONT REGIONAL PLANNING COMMISSION
Waterbury Reservior
Miles
0 1.75 3.5 7 10.5
N
Copyright © 2014 Esri


Wind Resources Map
Legend
Substations
3 Phase Power Lines
Transmission Lines
Wind Potential
Prime Wind (No Constraint)
Hub Height (m)
0 - 50
Secondary Wind (Possible Constraint)
Hub Height (m)
0 - 50
Parcels
Roads
Interstate
US Highway
Vermont State Highway
Town Class 1-3
Regional Constraints
Elevations Above 2500 ft
Lake Shore Protection Buffer 250 ft
Municipal Lands
Slopes Greater Than 25 Percent
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VT Agriculturally Important Soils
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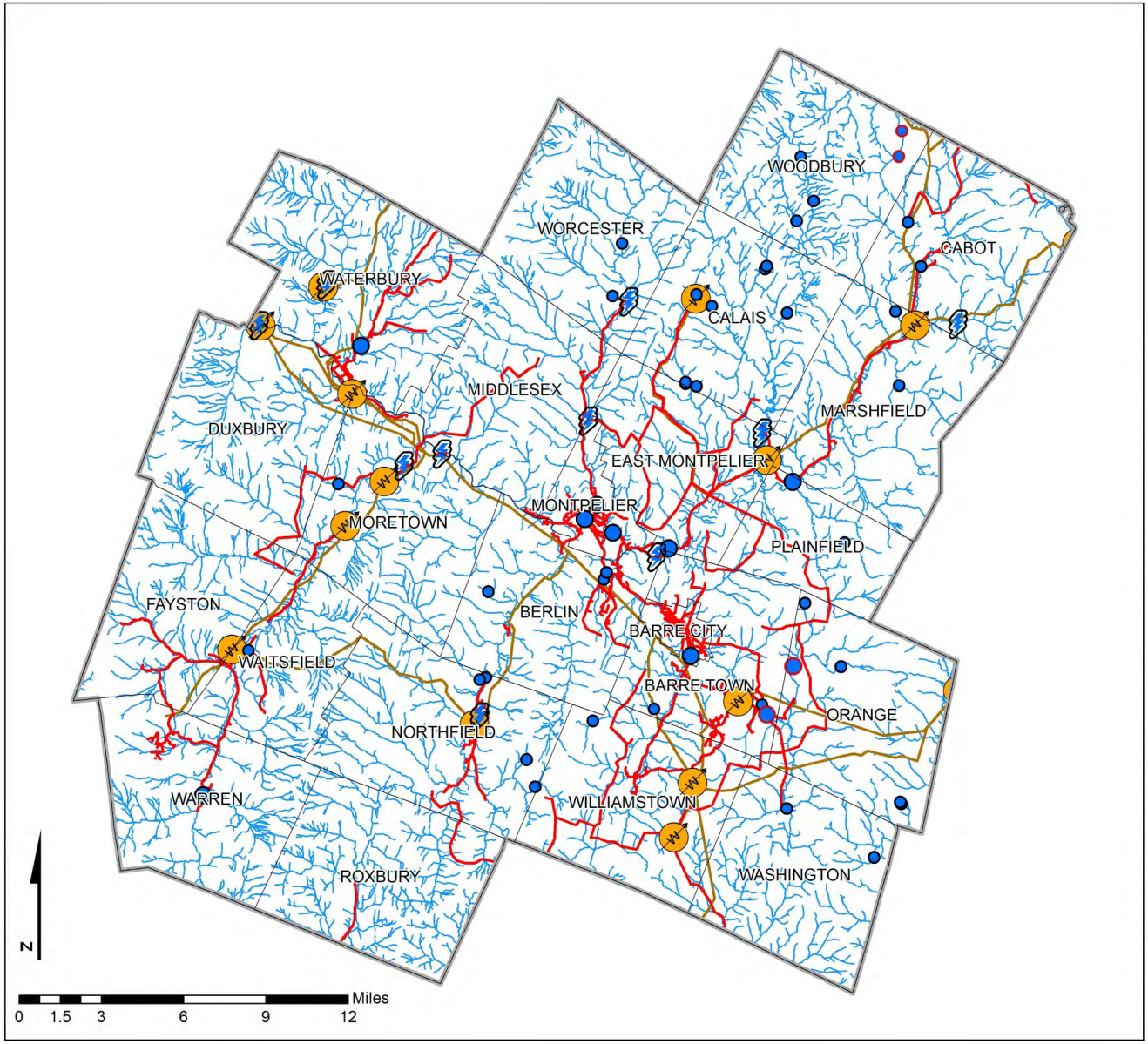
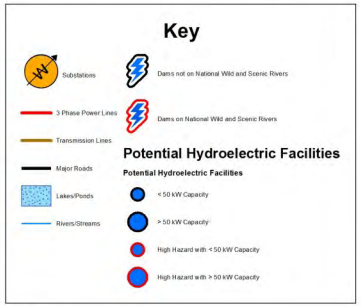
Act 250 Agricultural Soil Mitigation Areas
Deer Wintering Areas
Highest Priority Forest Blocks
Hydric Soils
CVRPC
CENTRAL VERMONT REGIONAL PLANNING COMMISSION
WOODBURY
CABOT
CALAIS
MARSHFIELD
WORCESTER
EAST MONTPELIER
PLAINFIELD
MONTPELIER
BERLIN
BARRE CITY
BARRE TOWN
ORANGE
WILLIAMSTOWN
WASHINGTON
MIDDLESEX
WATERBURY
MORETOWN
DUXBURY
NORTHFIELD
WAITSFIELD
FAYSTON
WARREN
ROXBURY
Created by: CVRPC GIS 4/4/2017
N:\Region\Projects\2017\
Act174_Energy\Wind Resources 11x17.mxd
Data is only as accurate as the original source materials.
This map is for planning purposes.
This map may contain errors and omissions
0
3.25
6.5
13
Miles
N



Hydroelectric Resources Map



Methodology

This map shows areas of resource potential for renewable energy generation from hydroelectric , i.e., dams that could be converted in to hydroelectric facilities as well as active hydroelectric sites. Existing hydroelectric dam information was extracted from the Vermont Dam Inventory, while potential hydroelectric sites were derived from a study conducted by Community Hydro in 2007.1 Based on estimates conducted within the report, this map categorizes dams based on their potential hydroelectric generation capacity, and the downstream hazard risk that would be involved in hydroelectric production at each site.

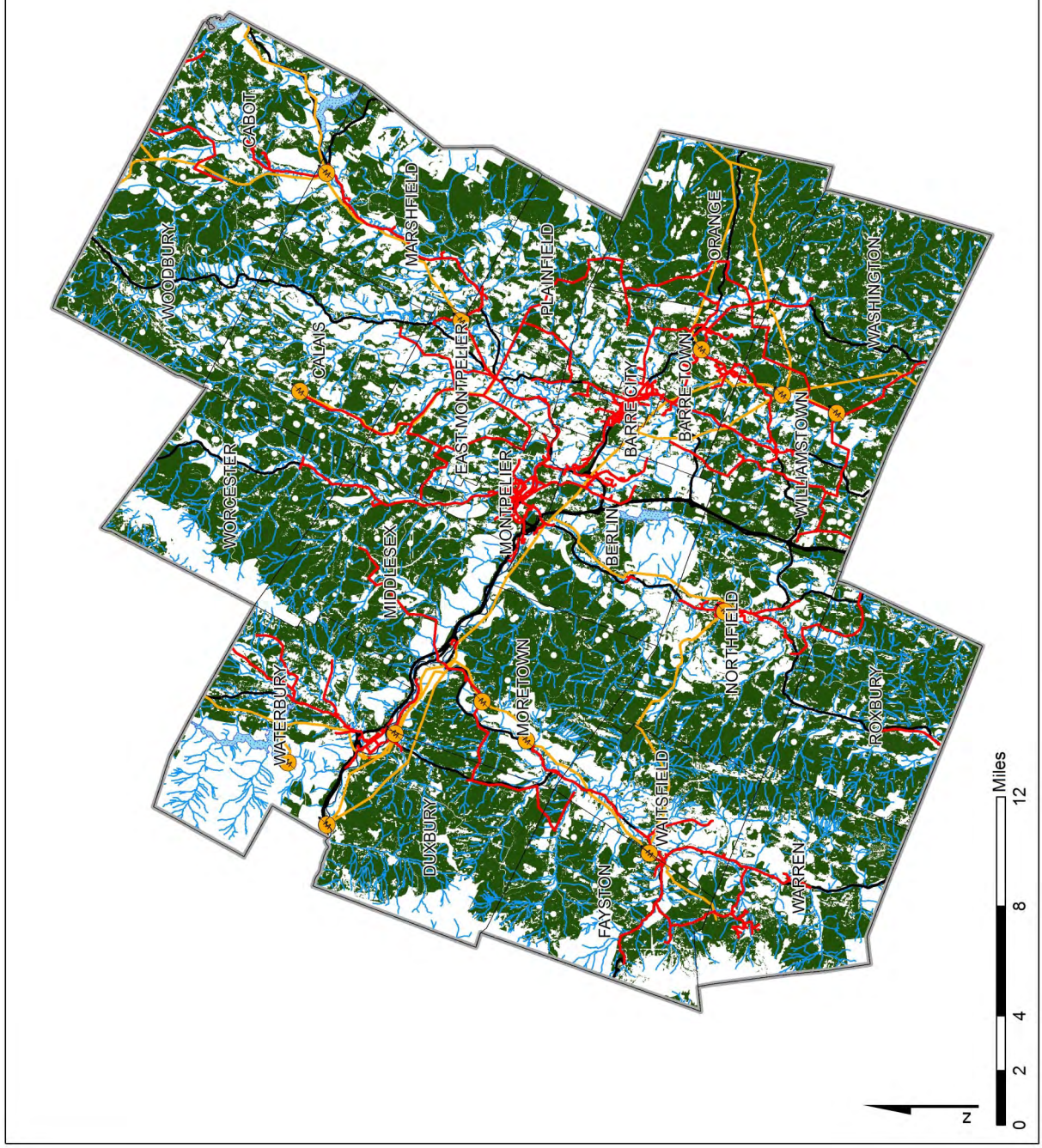
High hazard potential dams are those where failure or mis-operation will probably cause loss of human life. The other rankings were grouped together and their failure or mis-operation results in no probable loss of human life, but could cause economic loss, environmental damage, disruption of lifeline facilities, or impact other concerns. These dams are often located in predominately rural or agricultural areas, but could be located in areas withpopulation and significant infrastructure.

This map was created as part of a Regional Energy Planning Initiative being conducted by the Bennington County Regional Commission, and the Vermont Public Service Department.

Created: December 2016 by CVRPC GIS.
N:\Region\Projects\2017\Act174_Energy\
Hydroelectric Resources 11x17.mxd

CVRPC
CENTRAL VERMONT REGIONAL PLANNING COMMISSION

Woody Biomass Resources Map



Key

- Substations
- 3 Phase Power Lines
- Transmission Lines
- Major Roads
- Lakes/Ponds
- Rivers/Streams
- Woody Biomass

Methodology

This map shows areas of resource potential for woody biomass, i.e., locations where forested areas are. This map also considers various other conditions, such as ecological zones, that may impact the feasibility of renewable energy/alternative heating source. These conditions are referred to as constraints. This map does not include areas where other types of biomass, such as biomass from agricultural residue, could be grown/harvested.

This map was created as part of a Regional Energy Planning Initiative being conducted by the Bennington County Regional Commission, and the Vermont Public Service Department.

Created: December 2016 by CVRPC GIS.

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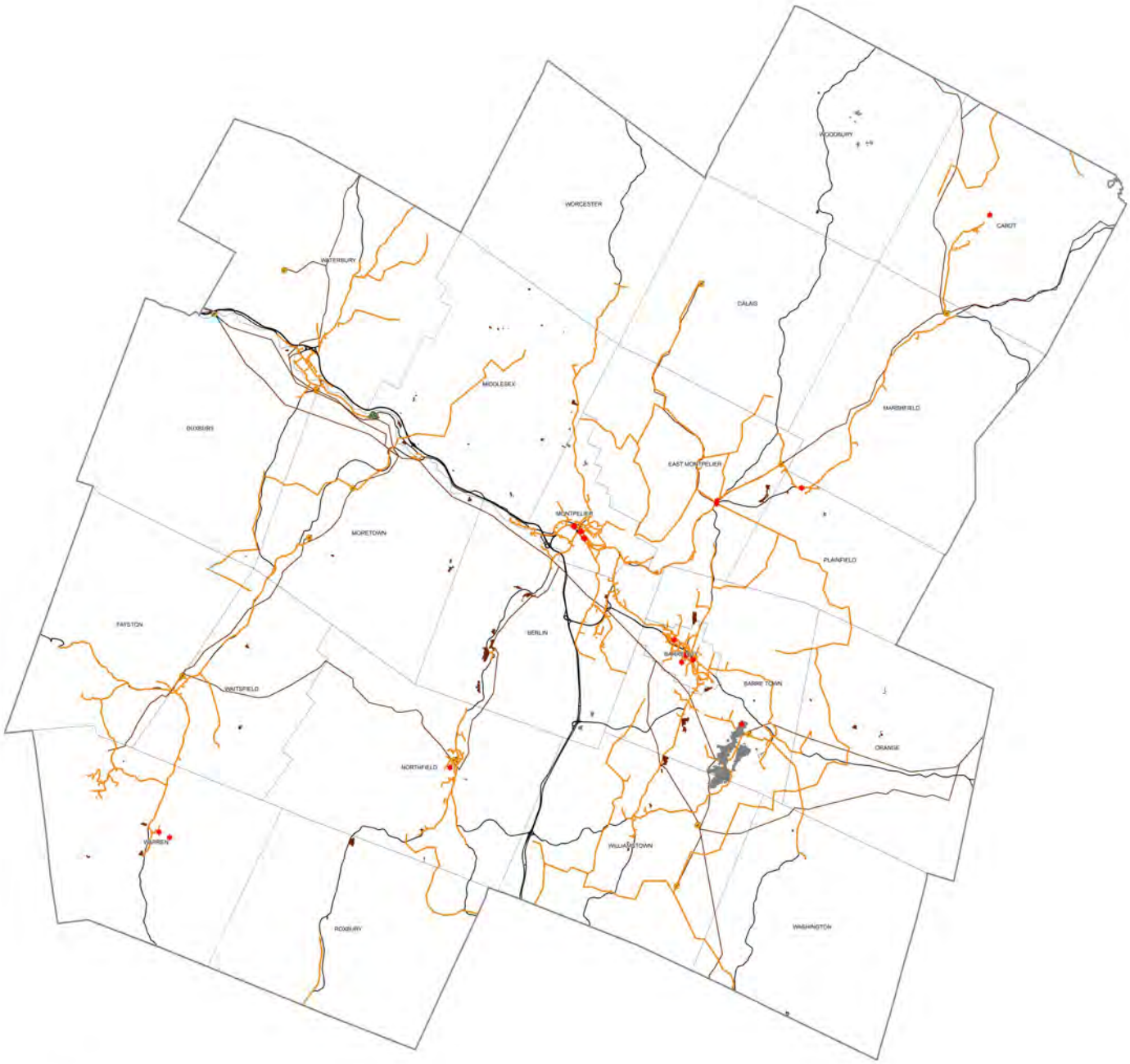
Central Vermont Regional Planning Commission
Energy Planning Statewide Preferred Sites



Key

- Brownfields Sites
- Moretown Landfill
- Sand and Gravel Pits
- Quarries
- Substations
- 3 Phase Power Lines
- Transmision Lines
- Major Roads

N

0 2.25 4.5 9 Miles

CVRPC
CENTRAL VERMONT REGIONAL PLANNING COMMISSION

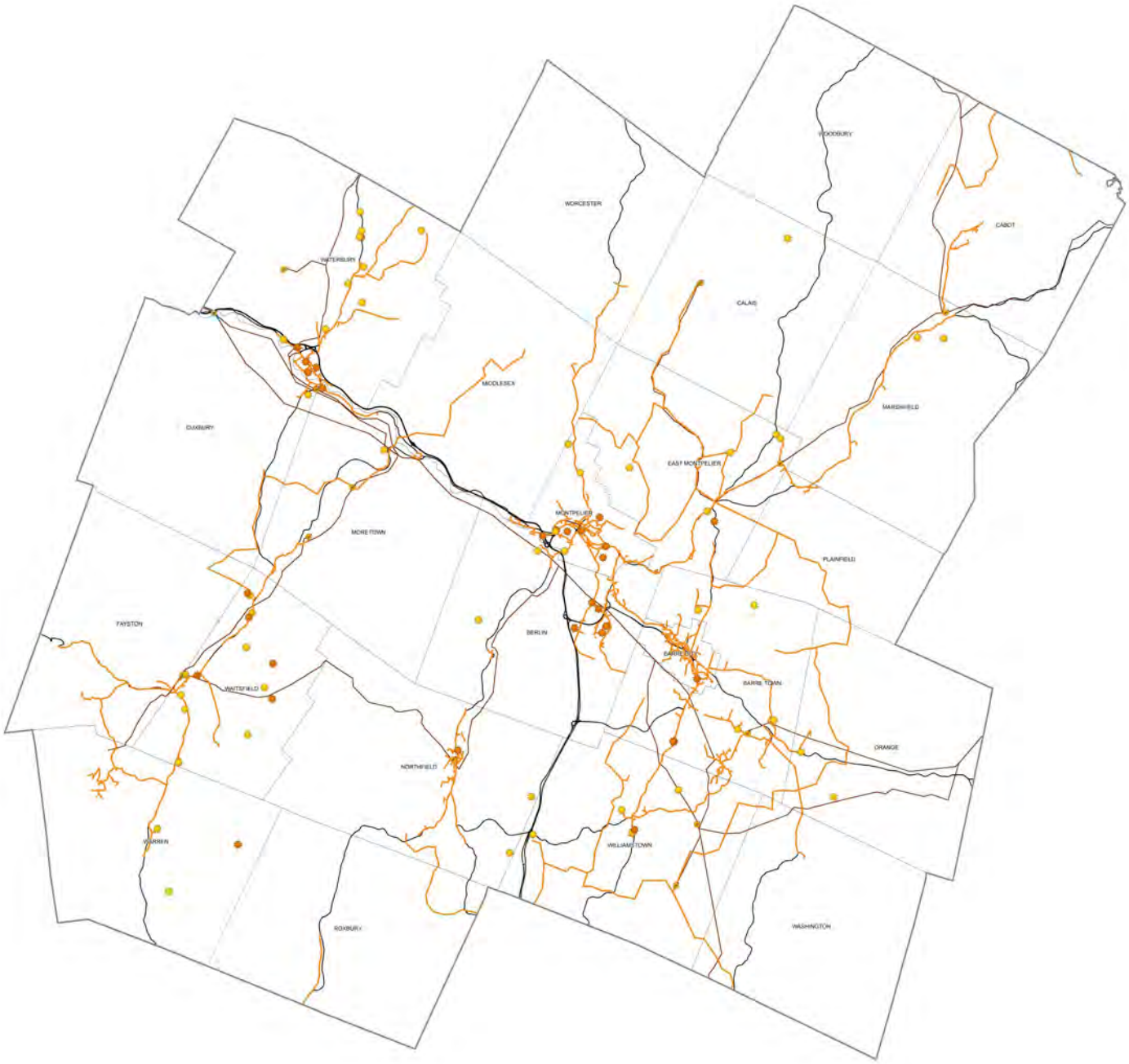
Data:

Brownfields: VT ANR, VCGI.
Sand and Gravel Pits, Quarries: CVRPC, 2013 disgitized from 1998 imagery

This map was created as part of a Regional Energy Planning Initiative being conducted by the Bennington County Regional Commission, and the Vermont Public Service Department.

Created: November 2017 by CVRPC GIS.

Central Vermont Regional Planning Commission
Current Solar Energy Generation Sites > 15 KW



Key

Solar Sites - Current Generation > 15 KW

- Ground-mounted PV
- Roof-Mounted PV
- Substations
- 3 Phase Power Lines
- Transmision Lines
- Major Roads

N

0 2.25 4.5 9 Miles

CVRPC
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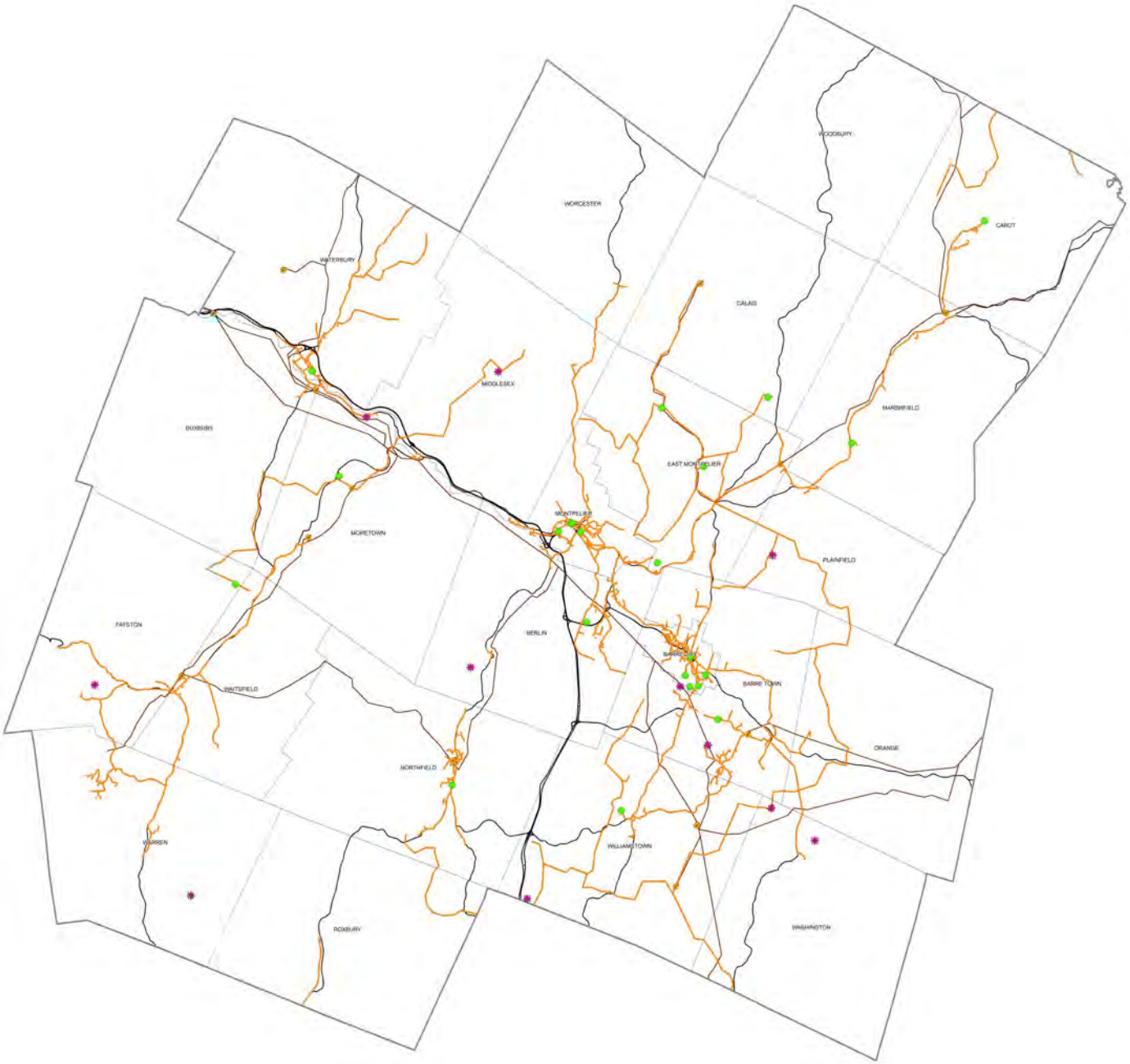
Data:

Solar Sites: VT Energy Dashboard

This map was created as part of a Regional Energy Planning Initiative being conducted by the Bennington County Regional Commission, and the Vermont Public Service Department.

Created: November 2017 by CVRPC GIS.

Central Vermont Regional Planning Commission
Current Wind and Biomass for Heat Sites



Key

- Biomass for Heat - Current Sites
- Wind Generation - Current Sites
- Substations
- 3 Phase Power Lines
- Transmision Lines
- Major Roads

N

0 2.25 4.5 9 Miles

CVRPC
CENTRAL VERMONT REGIONAL PLANNING COMMISSION

Data:

Wind and Biomass generation: VT Energy Dashboard

This map was created as part of a Regional Energy Planning Initiative being conducted by the Bennington County Regional Commission, and the Vermont Public Service Department.

Created: November 2017 by CVRPC GIS.

APPENDIX C

LONG-RANGE ENERGY ALTERNATIVES PLANNING DATA & INFORMATION

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%
Windham	0.34%

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.

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 $_{\text{VEIC}}$ 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.

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

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.

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

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

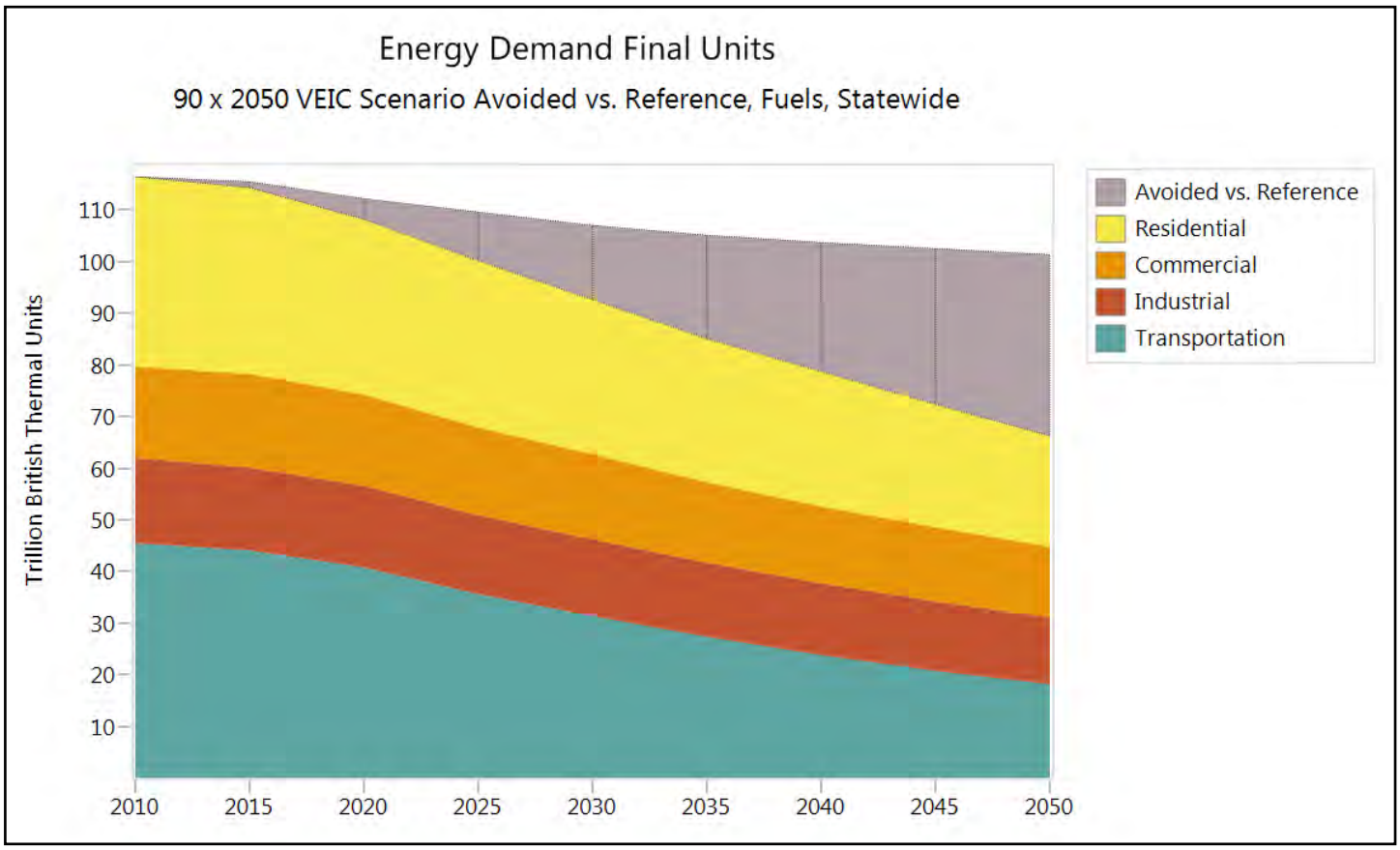


Figure 1 - Statewide energy consumption by sector, 90% x 2050 $_{\text{VEIC}}$ scenario compared to the reference scenario

Regional Total Energy Consumption

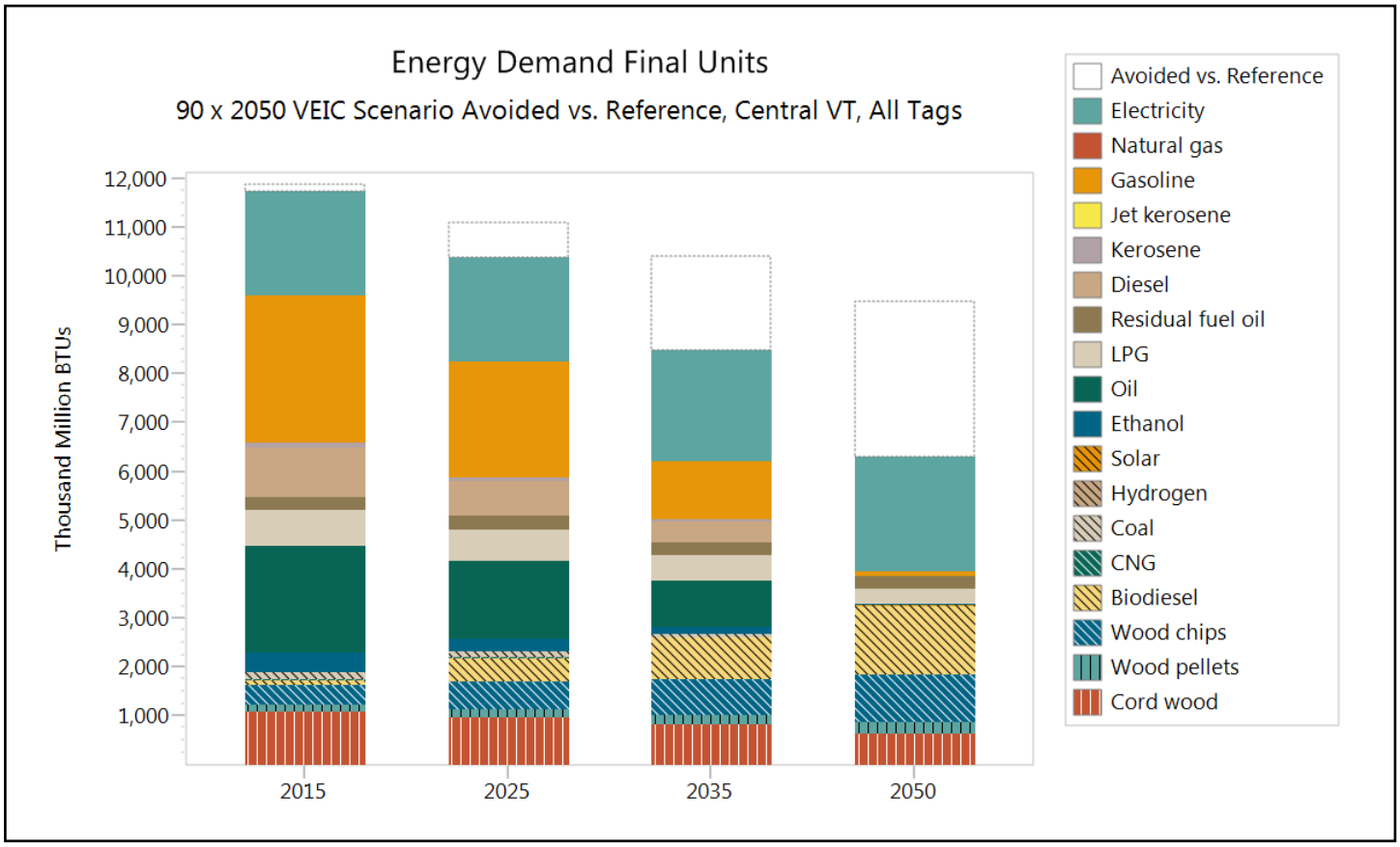


Figure 2: Regional energy consumption by fuel

Regional Energy Consumption by Sector

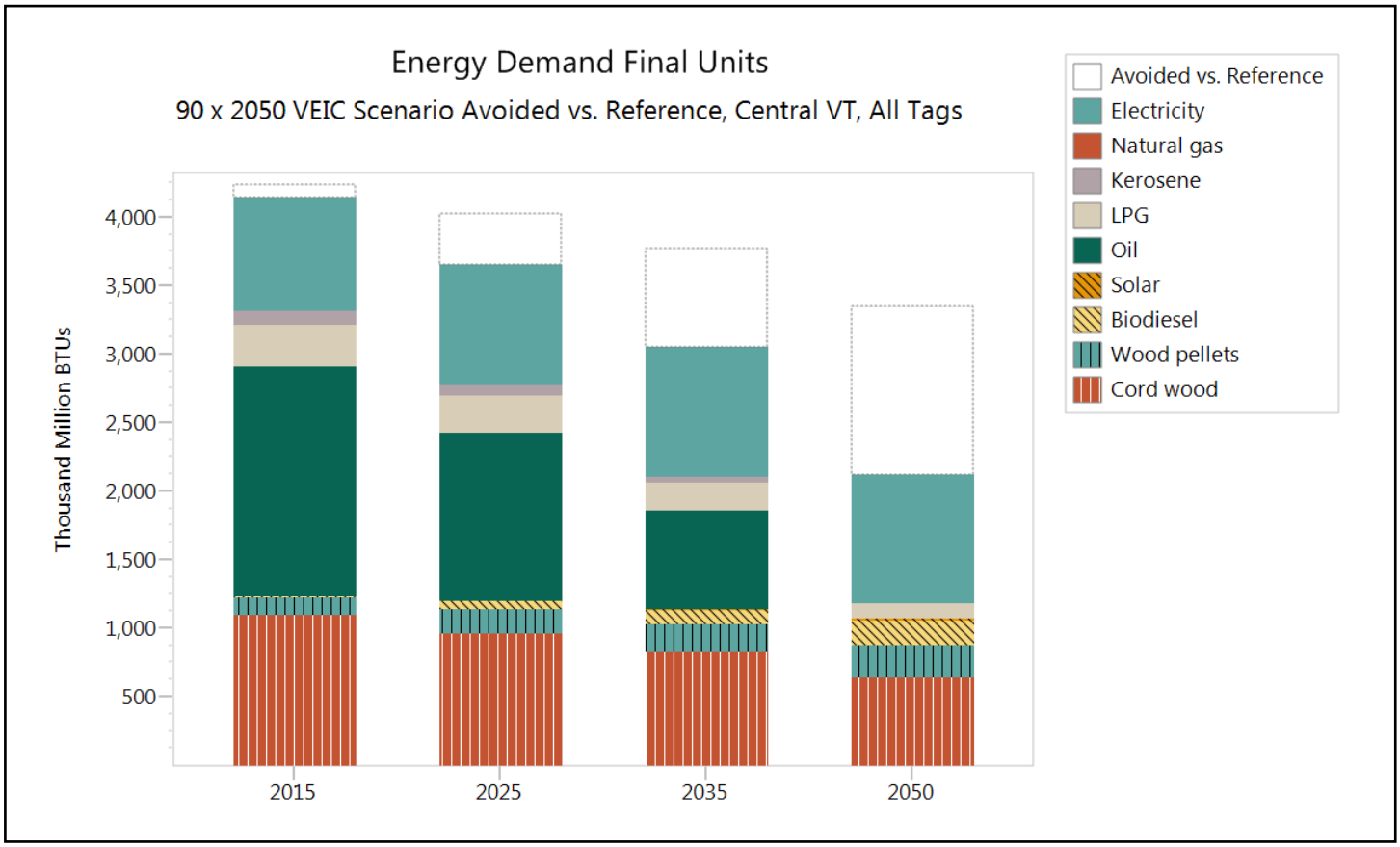


Figure 3: Regional residential energy consumption by fuel

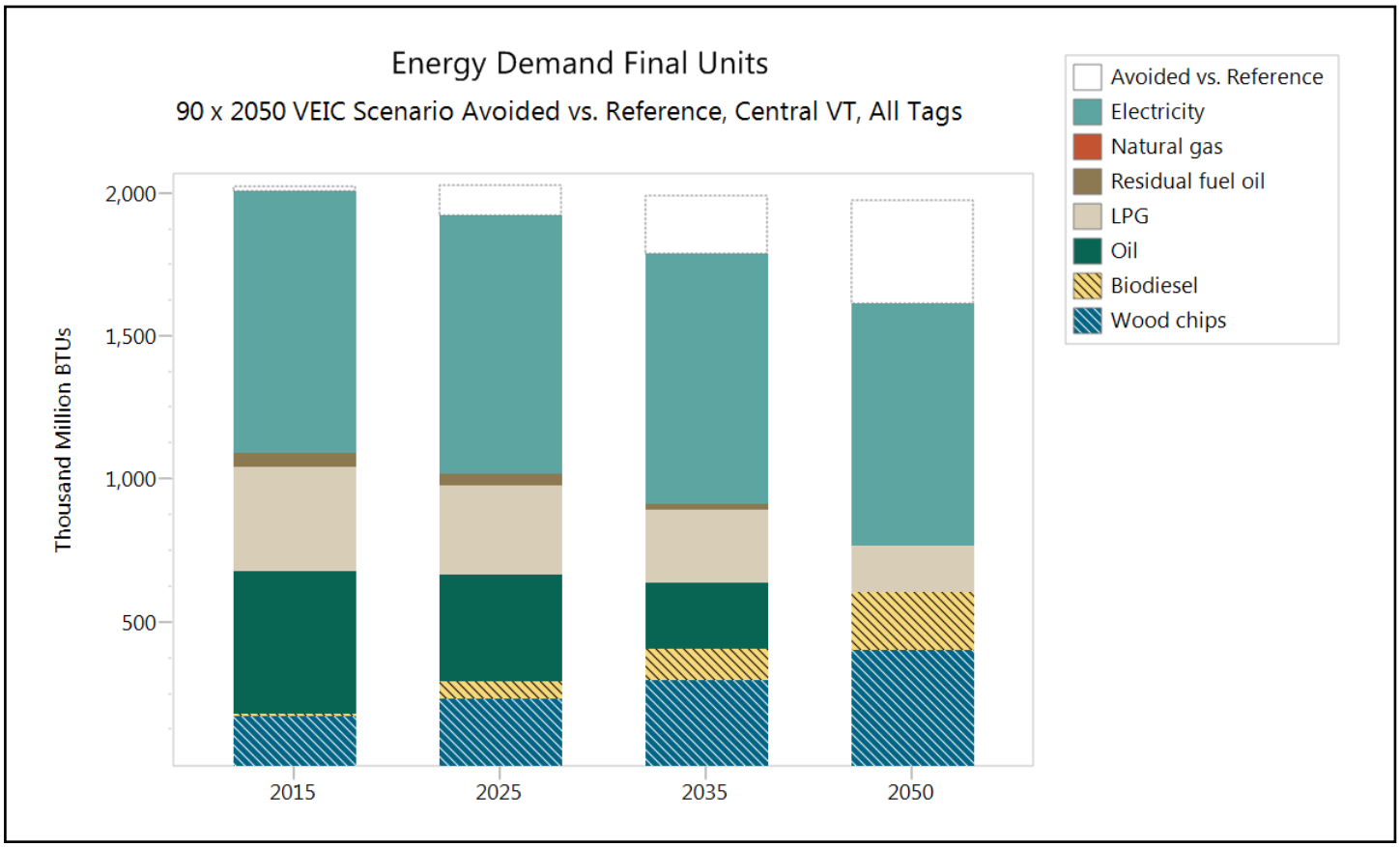


Figure 4: Regional commercial energy consumption by fuel

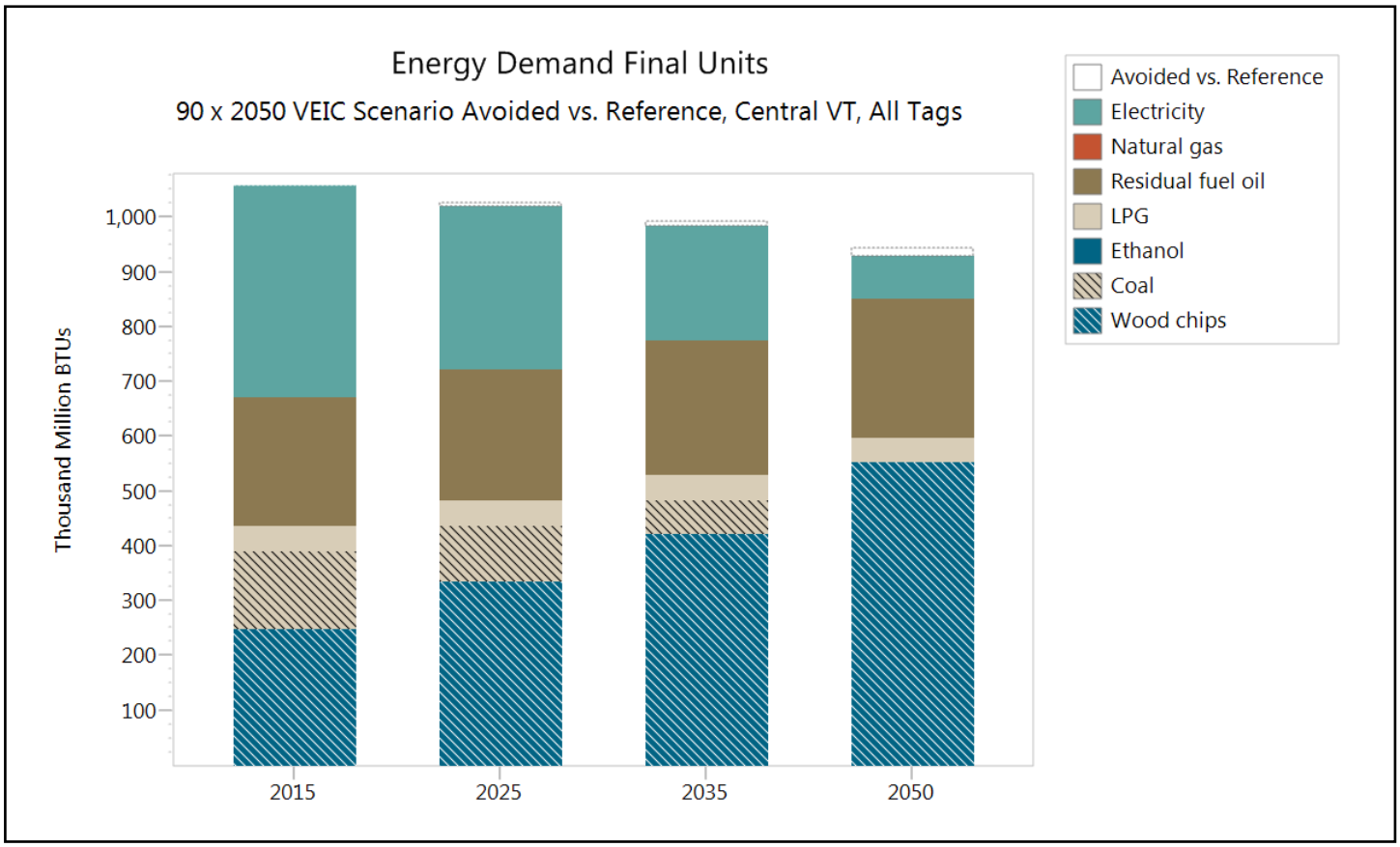


Figure 5: Regional industrial energy consumption by fuel

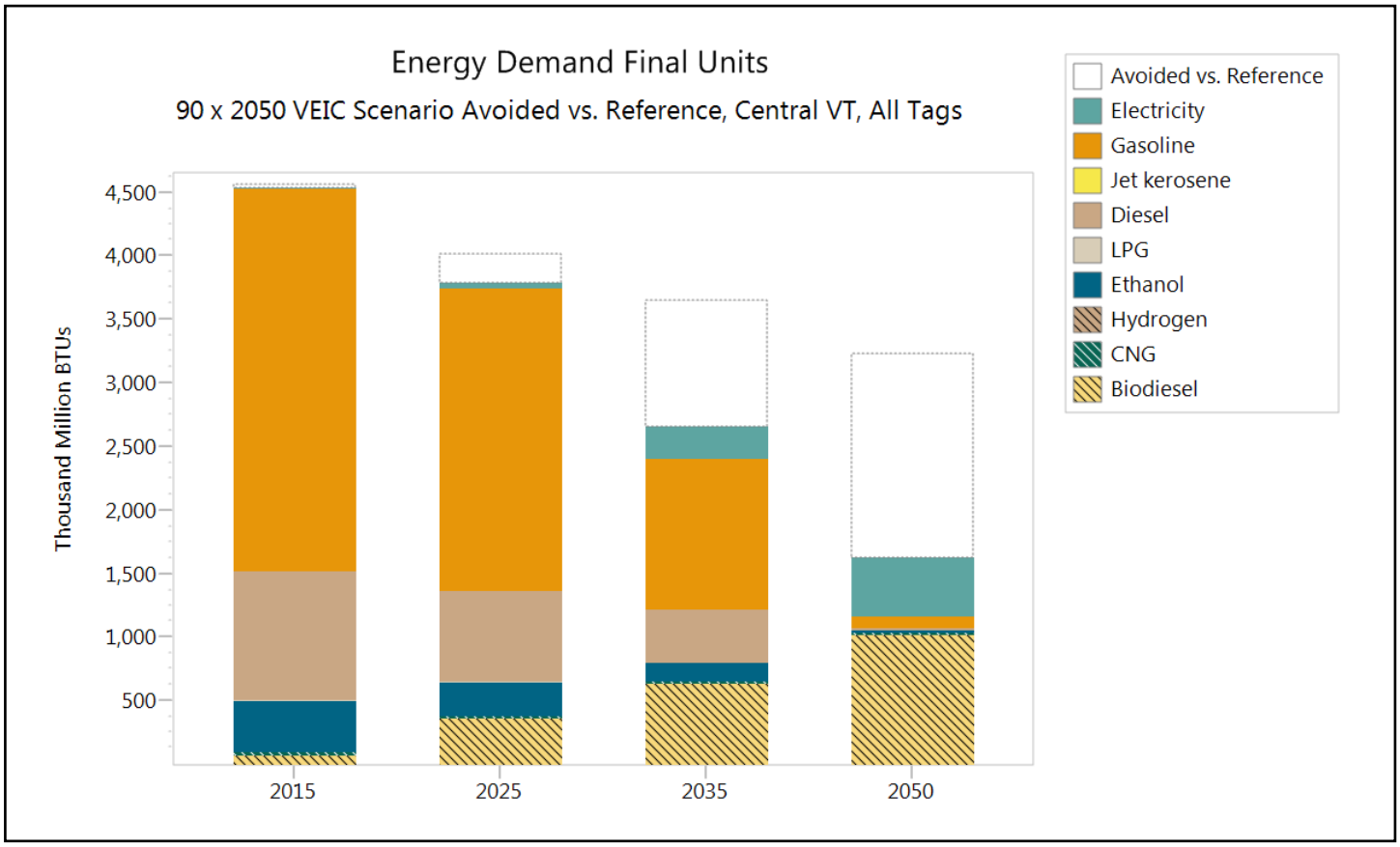


Figure 6: Regional transportation energy consumption by fuel

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.

- 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

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.

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.

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

13. Efficiency Vermont, "Electric Usage Chart Tool," https://www.efficiencyvermont.com/tips-tools/tools/electric-usage-chart-tool. www.eia.gov/dnav/pet/pet_cons_821usea_dcu_nus_a.htm.

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].

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.

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.

17. Jonathan Dowds et al., "Vermont Transportation Energy Profile."

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 $_{VEIC}$ 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 $_{VEIC}$ 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 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

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.

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."

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 VEIC scenario, consistent with the historical growth rates of rail 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.

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.

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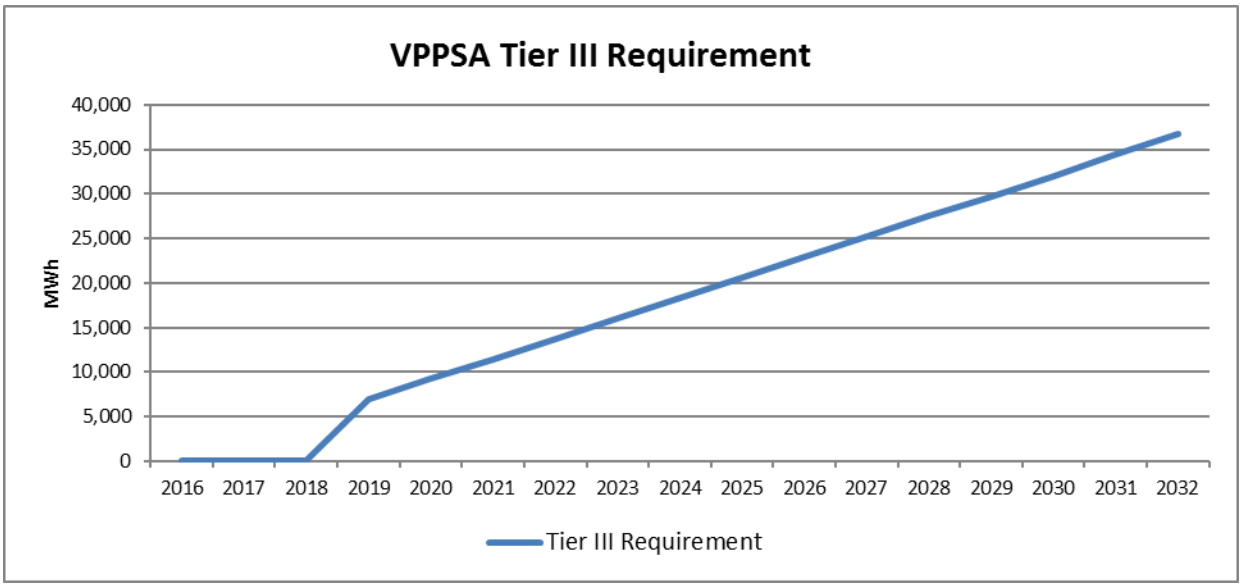
Vermont Public Power Supply Authority 2019 Tier 3 Annual Plan

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 2019 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 projects or purchase additional Renewable Energy Credits from small, distributed renewable generators ("Tier 2"). Utilities' Energy Transformation ("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]" The 12 municipal Members of VPPSA are each eligible to have their obligation begin in 2019 under this provision. In addition, 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 VPPSA Member utilities plan to meet Tier 3 requirements in aggregate in 2019.

VPPSA Tier 3 Obligation

In 2019, VPPSA's aggregate requirement is estimated to be 6,917 MWh or MWh equivalent in savings. Obligations increase rapidly, doubling within three years.



[1] 30 V.S.A. § 8005(a)(3)(B)

Prescriptive Programs

VPPSA plans to meet these challenging requirements through a mix of programs and measures that meet each statutory goal for Tier 3 while mitigating costs that could put upward pressure on rates.

VPPSA Electric Vehicle Program

Despite lower operating and maintenance costs associated with Electric Vehicle ("EV") 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 844 vehicles, or 48%, over the past year and these vehicles comprised 3.4% of new passenger vehicle registrations over the past quarter. Nonetheless, there were only 2,612 plug-in vehicles registered in Vermont as of July 2018. VPPSA and other utilities are 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. The customer incentive for purchasing or leasing an electric vehicle will be $800 and the customer incentive for purchasing or leasing a plug-in hybrid electric vehicle will be $400. Low-income customers[2] will receive an additional $200 towards the purchase or lease of an EV or PHEV.

The VPPSA utilities offered an EV Pilot Program on a voluntary basis in 2018. The Pilot enabled VPPSA to develop the necessary infrastructure to implement programs across utility service territories and determine how its Members can best benefit from Tier 3 aggregation. The structure put in place to track Tier 3 costs and benefits under the EV Pilot Program will be replicated as 2019 Tier 3 programs are rolled out. Savings accrued during the 2018 Pilot Program will be banked for use to meet 2019 or future compliance obligations, consistent with 30 V.S.A. § 8005(a)(3)(F)(iv).[3]

VPPSA Cold Climate Heat Pump Program

In 2019, VPPSA will offer customer rebates for the purchase of cold climate heat pumps ("CCHP") in the amount of $300. For customers that can demonstrate a defined level of building performance, the CCHP rebate will be increased to $400. The additional incentive, even if it isn't utilized, serves to highlight the importance of overall building performance. Because heat pumps in high-performing buildings will have less impact on peaks, this also serves to assist in

[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.

[3] Act 56 requires the Public Utility Commission to adopt rules: "… (iv) To allow a provider who has met its required amount under this subdivision (3) in a given year to apply excess net reduction in fossil fuel consumption, expressed as a MWH equivalent, from its energy transformation project or projects during that year toward the provider's required amount in a future year."

managing demand during those high cost times. 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 Technical Advisory Group ("TAG").

VPPSA Heat Pump Water Heater Program

VPPSA intends to provide rebates to customers that install heat pump water heaters ("HPWH") to replace fossil-fuel fired water heaters. These incentives will be provided in conjunction with Efficiency Vermont ("EVT") HPWH rebates. VPPSA and EVT are currently negotiating a Memorandum of Understanding ("MOU") to implement this joint program and define the "savings split" between the VPPSA utilities and EVT.

Savings from Heat Pump Water Heaters, Cold Climate Heat Pumps, and Plug-in and Electric Vehicles will be estimated using measure characterizations created by the Tier 3 TAG. VPPSA's budget and estimated savings for prescriptive Tier 3 Programs is summarized below.

VPPSA Tier 3 Prescriptive Program Expected Costs and Savings

Measure	*Savings/unit (MWH)*	*Incentive Amount*	*Admin Cost*	*Total Cost*	*Volume*	*Cost/MWH*	*Total Credit (MWH)*	*Budget*
EV	24.6	$800	$148	$948	15	$38.52	369	$14,215
PHEV	13.7	$400	$148	$548	30	$39.98	411	$16,431
CCHP	12.8	$300	$148	$448	80	$35.09	1021	$35,815
CCHP (wz)	15.8	$400	$148	$548	20	$34.75	315	$10,954
HPWH*	5.69	$300	$148	$448	5	$78.68	28	$2,238
TOTAL					150	**$37.14**	**2144**	$79,653

**reflects expected savings split with EVT*

Other Tier 3 Measures

Incentives for Electric Vehicle Supply Equipment

Several VPPSA members have identified possible locations for the installation of electric vehicle charging stations within their territories. These utilities are working with potential charging station hosts to apply for funding from the Volkswagen Mitigation Trust Fund for public EV chargers. Should these installations move forward, VPPSA members may provide financial contributions and/or technical assistance in addition to that already provided in support of the application to facilitate the installation of electric vehicle charging infrastructure.

Fork Lifts and Golf Carts

In addition to the prescriptive rebate programs described above, VPPSA is actively seeking out opportunities for fuel switching golf carts and fork lifts to electricity. Both of these measures were recently characterized by the TAG and together provide substantial potential for fossil fuel savings. VPPSA anticipates working with businesses that may wish to replace fossil fuel equipment with electric-powered equipment and is exploring what level of incentive would be needed for these conversions.

Commercial and Industrial Customers

Commercial and industrial ("C&I") customers will be served on an individual, custom basis in 2019. 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 a ski resort, a furniture maker, a quarry, and a candy manufacturer. VPPSA has and will continue to work with the Department on custom projects to ensure savings claims are valid and able to be evaluated.

Equitable Opportunity

The Tier 3 incentives offered by VPPSA will be available to all of the VPPSA Members' customers. Discussions with vehicle dealerships around the electric vehicle rebate program indicated that many low- to moderate-income customers take advantage of PHEV leases. By providing additional incentives for income-eligible customers, as well as by making the incentives available for both vehicle leases and vehicle purchases, VPPSA's EV rebate program is designed to be accessible to low-income 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. All of a host utility's customers have the potential to benefit from the increased electric sales that accompany electrification programs such as VPPSA's electric vehicle, heat pump, and heat pump water heater programs. 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.

Collaboration/Exclusive Delivery

Strategic electrification of the transportation and heating sectors is an appropriate responsibility of the Vermont's distribution utilities, who are charged with procuring electric supply and managing the distribution grids across the state. Strategic electrification is outside of the purview of the state's energy efficiency utilities, whose mandate is to achieve cost-effective electric and thermal efficiency savings (where the presumption is that reductions in load do not have the possibility for adverse distribution/transmission system impacts/costs). Distribution utilities are uniquely positioned to promote heating and transportation electrification while assessing and mitigating grid impacts. If electrification is going to deliver its potential climate and economic benefits to Vermonters, it must be carried out in a way that does not disproportionately increase utility costs.

VPPSA and Efficiency Vermont are working together to define how the two entities can provide holistic efficiency services to residential, commercial, and industrial customers. A Memorandum of Understanding to govern this engagement and interaction is under development. In many cases, this partnership will involve VPPSA providing incentives for electrification measures, which can provide benefits to all utility ratepayers, while EVT provides incentives for thermal and electric efficiency measures.

Currently, VPPSA and EVT are engaged in a targeted community effort in Northfield that will continue through early 2019. This initiative involves enhanced outreach to customers regarding VPPSA and EVT incentives, in-person communication with small businesses, and educational workshops on a series of energy efficiency topics. VPPSA and EVT will evaluate whether such joint targeted efforts have the potential to generate greater savings and/or better align with a community's specific energy efficiency needs. If successful, this model may be adapted and deployed in other VPPSA municipalities.

VPPSA has also been working with NeighborWorks of Western Vermont, a comprehensive weatherization service provider that recently expanded its service territory to include the Northeast Kingdom. VPPSA has provided marketing support in the form of utility bill stuffers to NeighorWorks to promote awareness of this new service offering. NeighborWorks, in turn, will be making customers aware of VPPSA's incentives. The collaboration with NeighborWorks is ongoing, and VPPSA sees the thermal efficiency services offered by NeighborWorks as complementary to the electrification measures promoted by VPPSA.

Regarding VPPSA's EV program, the natural partners are vehicle dealers located throughout the VPPSA Members' service territories. VPPSA has done direct outreach to local dealers that sell EVs to ensure they are aware of the VPPSA rebate program. VPPSA is not aware of other energy service providers currently offering electric vehicle incentives in the VPPSA utilities' service territories, as transportation electrification is outside of the purview of Efficiency Vermont. Another partner in VPPSA's EV program is Drive Electric Vermont, who has been consulted regarding program design considerations and also engaged in helping develop customer educational materials.

Best Practices and Minimum Standards

Over the long-term, electric vehicles and heat pumps 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. According to the load forecast developed by VELCO and the Vermont System Planning Committee in conjunction with VELCO's Long-Range Transmission Plan, load growth associated with strategic electrification is not expected to impact the transmission grid for the next eight to ten years. In the short-term, VPPSA's strategy for managing increased load will rely largely on customer education. The VPPSA member utilities will continue to monitor load impacts of the electrification of home heating, water heating, and EV charging to determine when more active load management will be necessary.

With regards to EVs, it is expected that the majority of home charging will occur during overnight, off-peak hours. Through VPPSA's EV Pilot Program, informational materials about the ideal time to charge vehicles will be provided to customers that receive rebates.

Under VPPSA's heat pump program, customers that can demonstrate that their homes have been weatherized will receive a higher incentive for the installation of a heat pump. This increased incentive will encourage customers to improve the thermal performance of their homes, thus allowing heat pumps to operate more effectively. Customers will be informed of the benefits of weatherization and provided with resources for increasing the performance of their homes. Heat pumps installed in well-insulated homes have the potential to mitigate the grid impacts of heating electrification as compared with heat pumps installed in poorly insulated buildings.

Ultimately, in the long term VPPSA expects that active load control will be necessary to manage EV charging and, to some extent, heat pump usage. Managing when the increased load from strategic electrification occurs will enable utilities to collect added revenue from increased electric sales without significant increases in the costs associated with higher peak loads. Effective load control requires a combination of rate offerings and technology that either provide active control or verify customer adherence to desired goals. These technologies have historically been challenging to implement in rural areas of Vermont where communication systems are lacking and the cost of the required back-office systems is often prohibitive. Some form of interval metering is needed for most types of load control rate offerings. The VPPSA Members are currently exploring the viability of installing advanced metering ("AMI") technology within their territories and expect to have consultant recommendations on whether to move forward with AMI deployment by early 2019. In addition, VPPSA is in discussions with VELCO about the viability of extending VELCO's fiber optic network into VPPSA member distribution systems to both facilitate AMI technology and provide a platform for expanded broadband coverage in areas of the state that do not currently have access. AMI and/or broadband technology will facilitate the implementation of demand response and load control programs that will allow utilities to manage increased electrification load in the most cost-effective manner.

VPPSA Tier 3 Strategy

VPPSA intends to deploy Energy Transformation programs, with a focus on electrification measures, to residential and commercial and industrial customers to satisfy the VPPSA Members' Tier 3 obligations. VPPSA is ramping up Tier 3 programs at an aggressive yet considered pace in its first Tier 3 compliance year. To the extent that there is a shortfall in savings from Energy Transformation programs, VPPSA will employ alternative strategies for meeting Tier 3 requirements in a cost-effective manner. One component of VPPSA's Tier 3 strategy is to 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. In addition, for VPPSA members that own Tier 2 eligible generating resources, Tier 2 RECs may be the primary strategy for Tier 3 compliance. VPPSA's Tier 3 strategy may also include providing incremental support to the state's Weatherization Assistance Program. Since the RES was enacted, VPPSA has explored developing a Tier 3 program focusing on weatherization but found that program to be cost-prohibitive. Given the PUC's August 24, 2018 Order in Case 17-4632 regarding Washington Electric Cooperative's Tier 3 savings claim for weatherization work, it may be prudent for VPPSA to implement the same type of Tier 3 program at a cost significantly lower that the Tier 3 Alternative Compliance Payment.