Northfield Electric Department

2019 Integrated Resource Plan

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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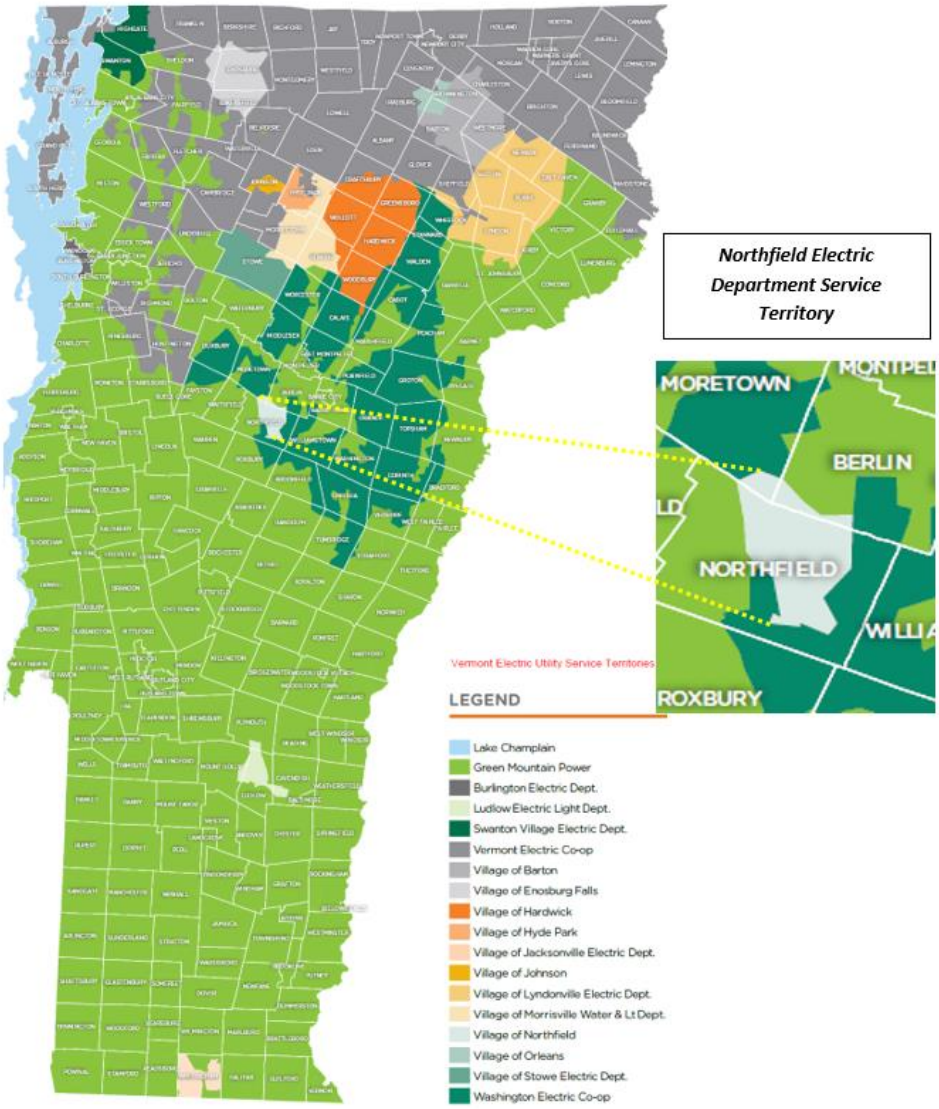
Glossary

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.

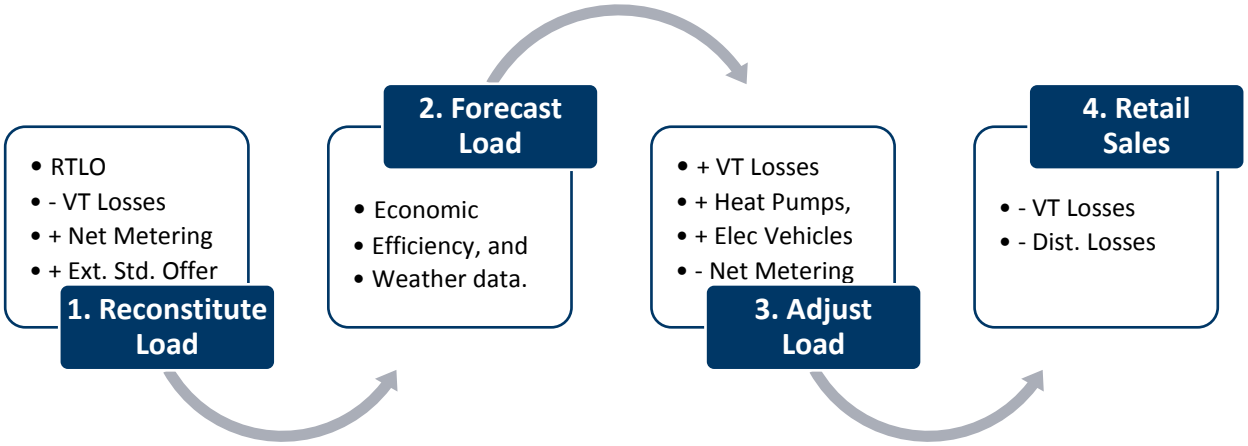
ELECTRICITY DEMAND

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

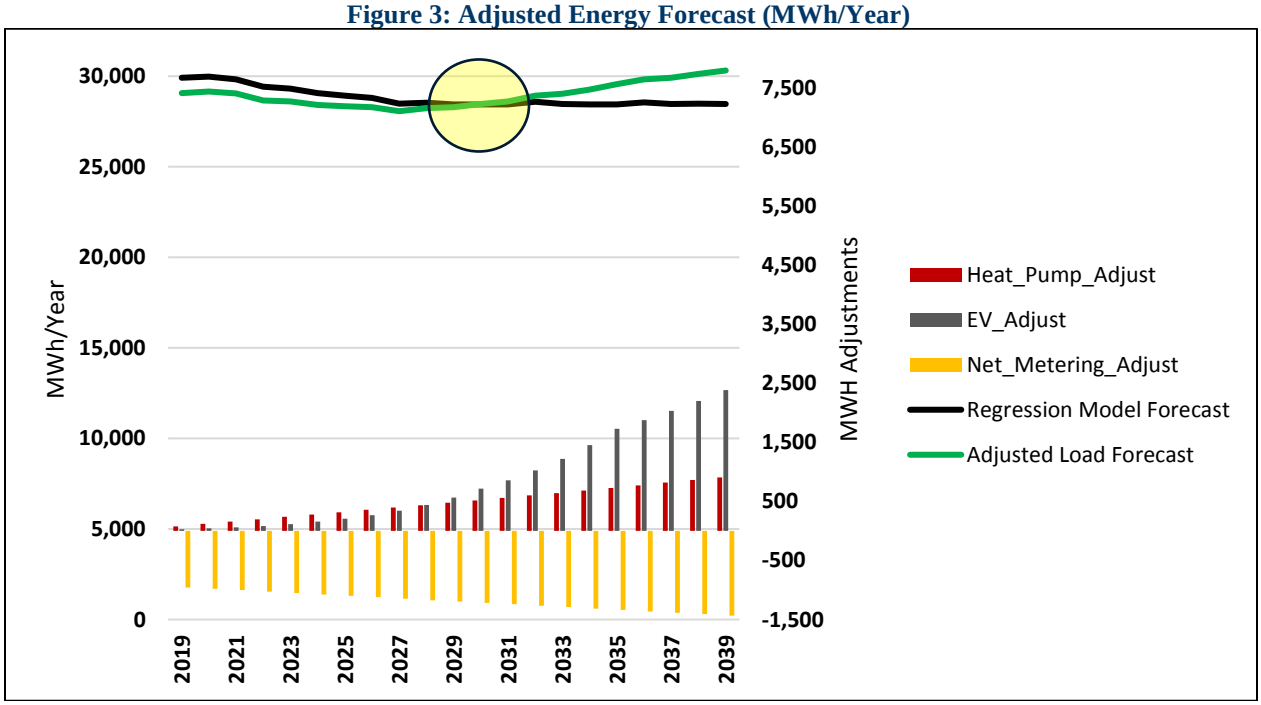
Table 5 shows the results of the Regression Forecast for energy, as well as the adjustments that are made to arrive at the Adjusted Forecast. The Compound Annual Growth Rates (CAGR) at the bottom of the table illustrate the trends in each of the columns. Notice that the Regression Forecast itself is 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).

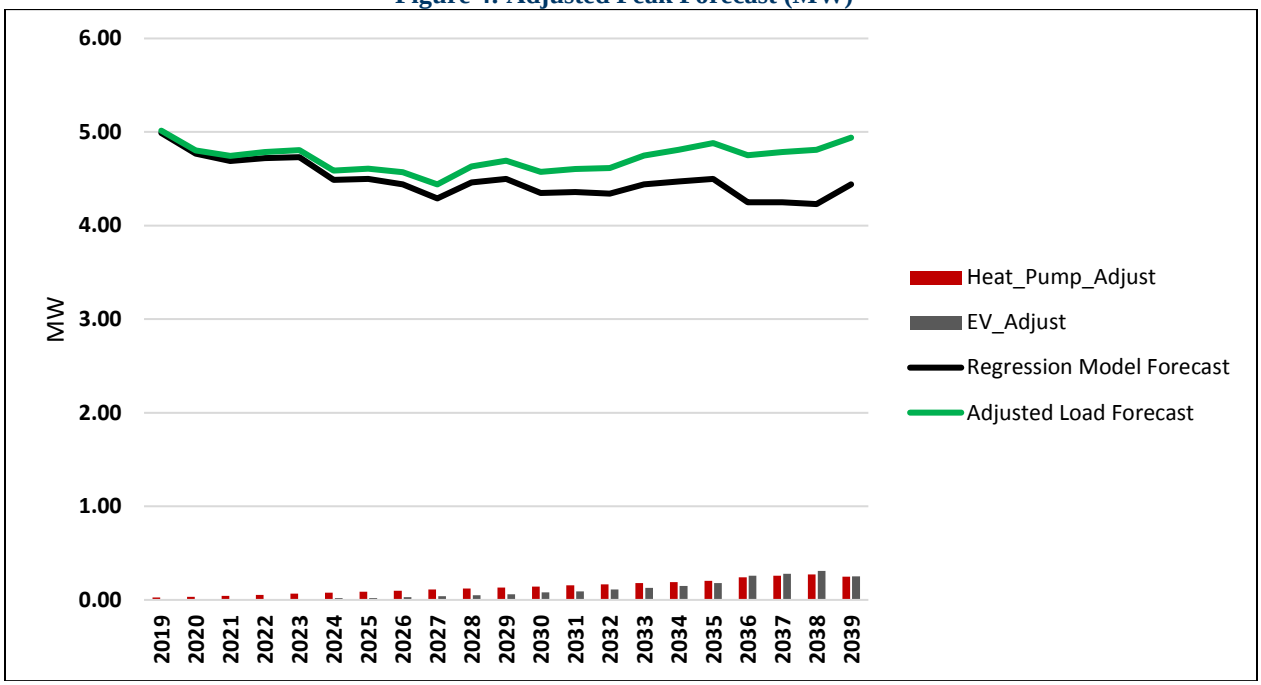
Table 8: Peak Forecast (MW)

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

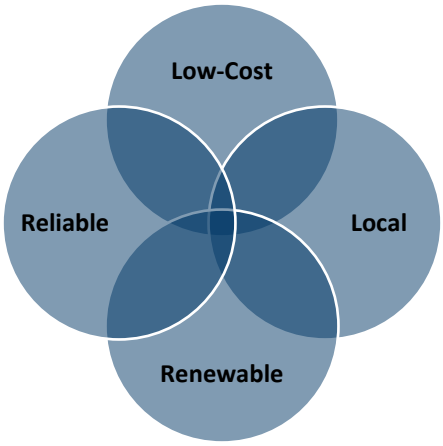
RESOURCE	2020 MWH	% of MWH	2020 MW	Delivery Pattern	Price Pattern	RECs	Expiration Date	Renewal to 2039
1. Chester Solar	714	2.5%	0.204	Intermittent	Fixed		6/30/39	No
2. Fitchburg Landfill	3,440	11.9%	0.341	Firm	Fixed	✓	12/31/31	No
3. HQUS	1,502	5.2%	0.000	Firm	Indexed	✓	10/31/38	No
4. Kruger Hydro	3,060	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.

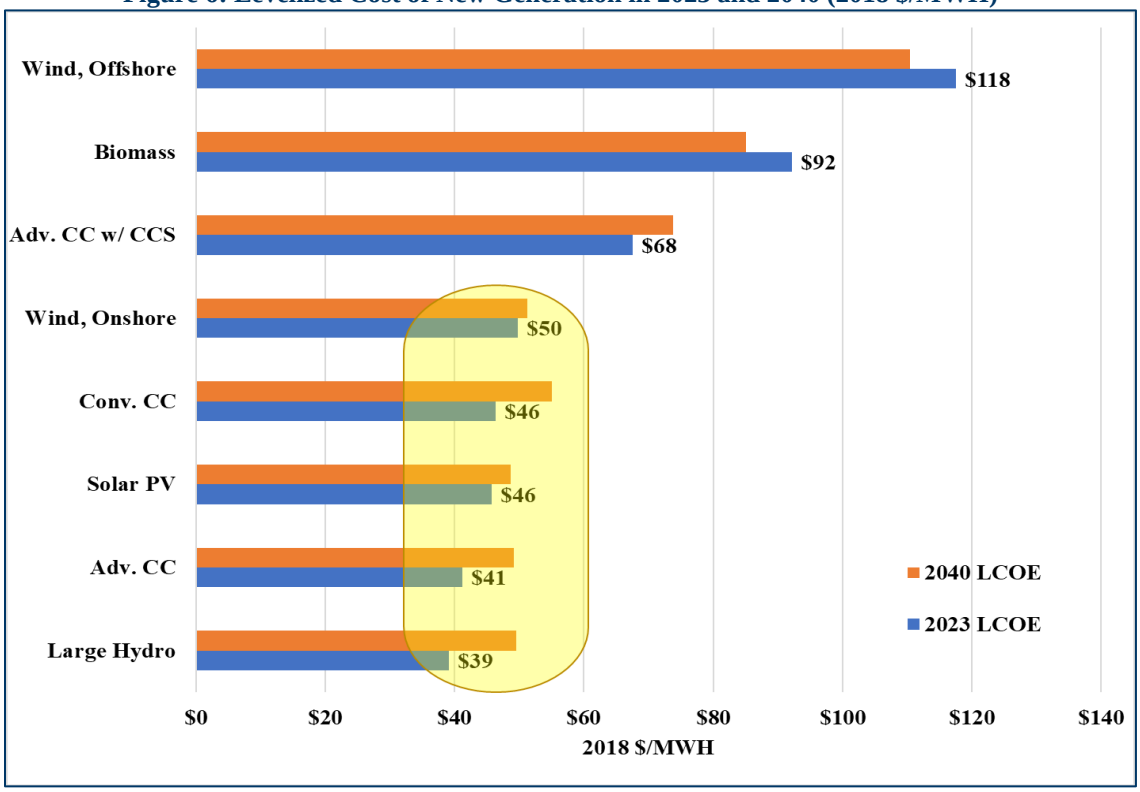
✓ **Local** resources are located within Northfield's Regional Planning Commission area or within Vermont.

✓ **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.

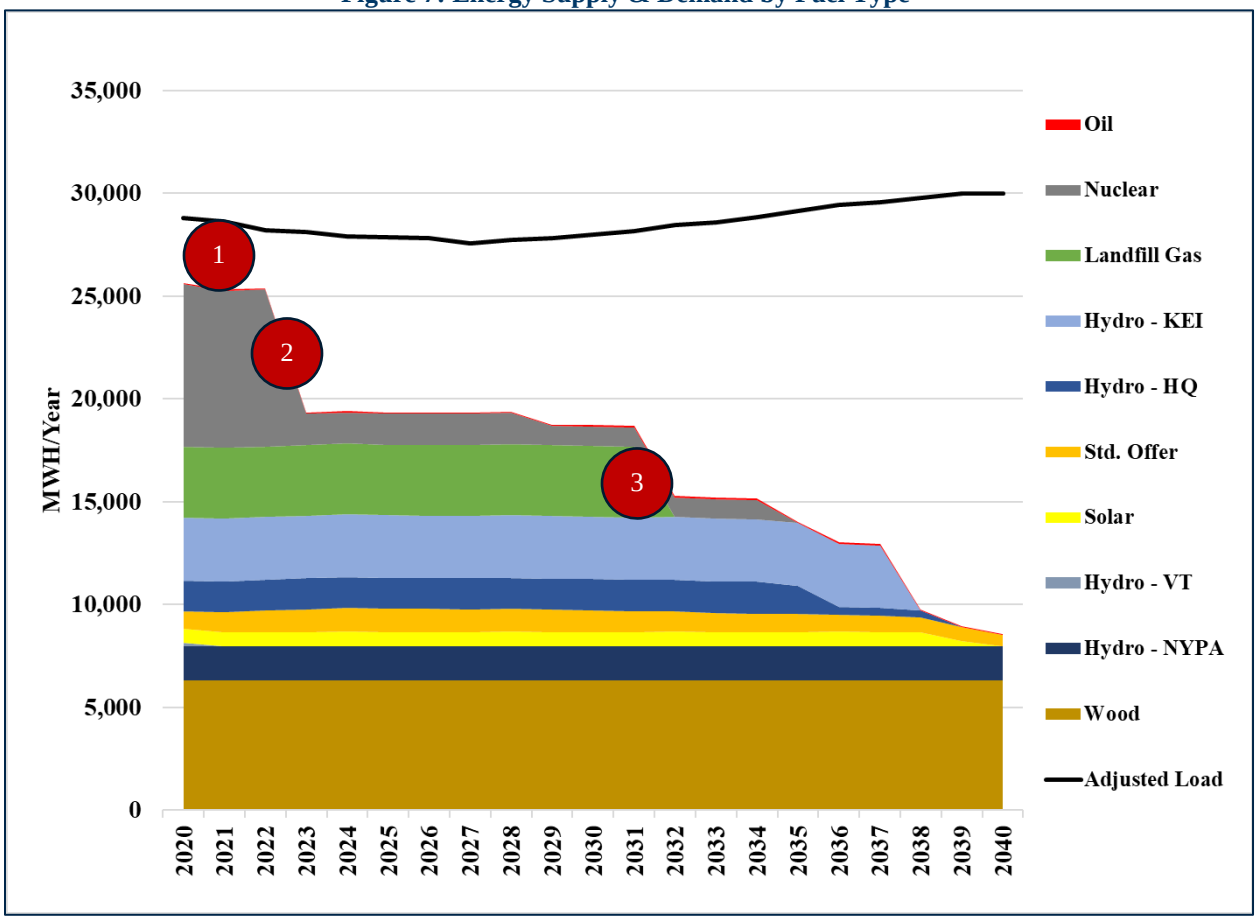
ENERGY RESOURCE PLAN

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.

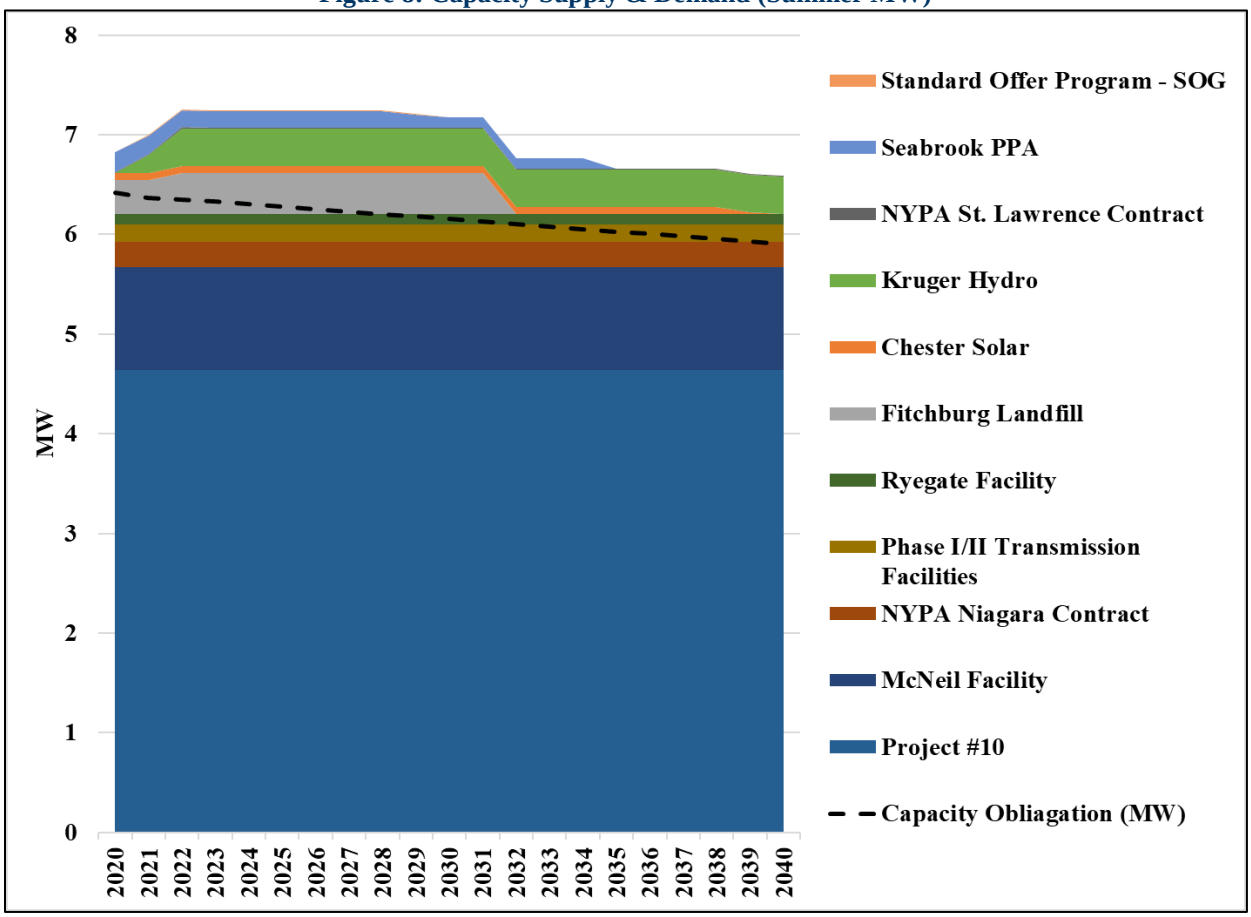
Table 12: Energy Resource Decision Summary

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)

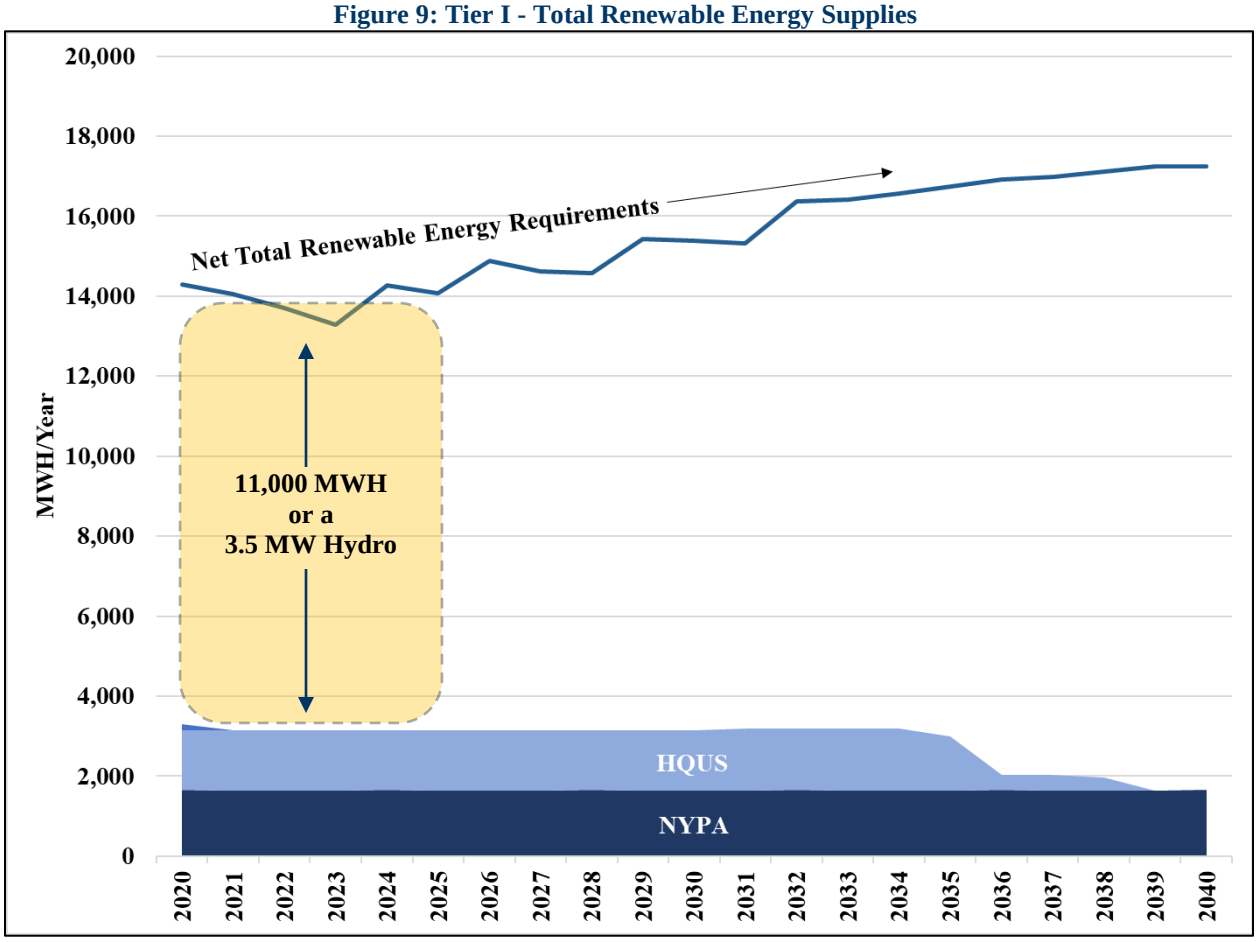
Year	TIER I	TIER II & III
2020	$10.00	$60.00
2021	$10.22	$61.32
2022	$10.44	$62.67
2023	$10.67	$64.05
2024	$10.91	$65.46
2025	$11.15	$66.90
2026	$11.39	$68.37
2027	$11.65	$69.87
2028	$11.90	$71.41
2029	$12.16	$72.98
2030	$12.43	$74.59
2031	$12.70	$76.23
2032	$12.98	$77.90

[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.

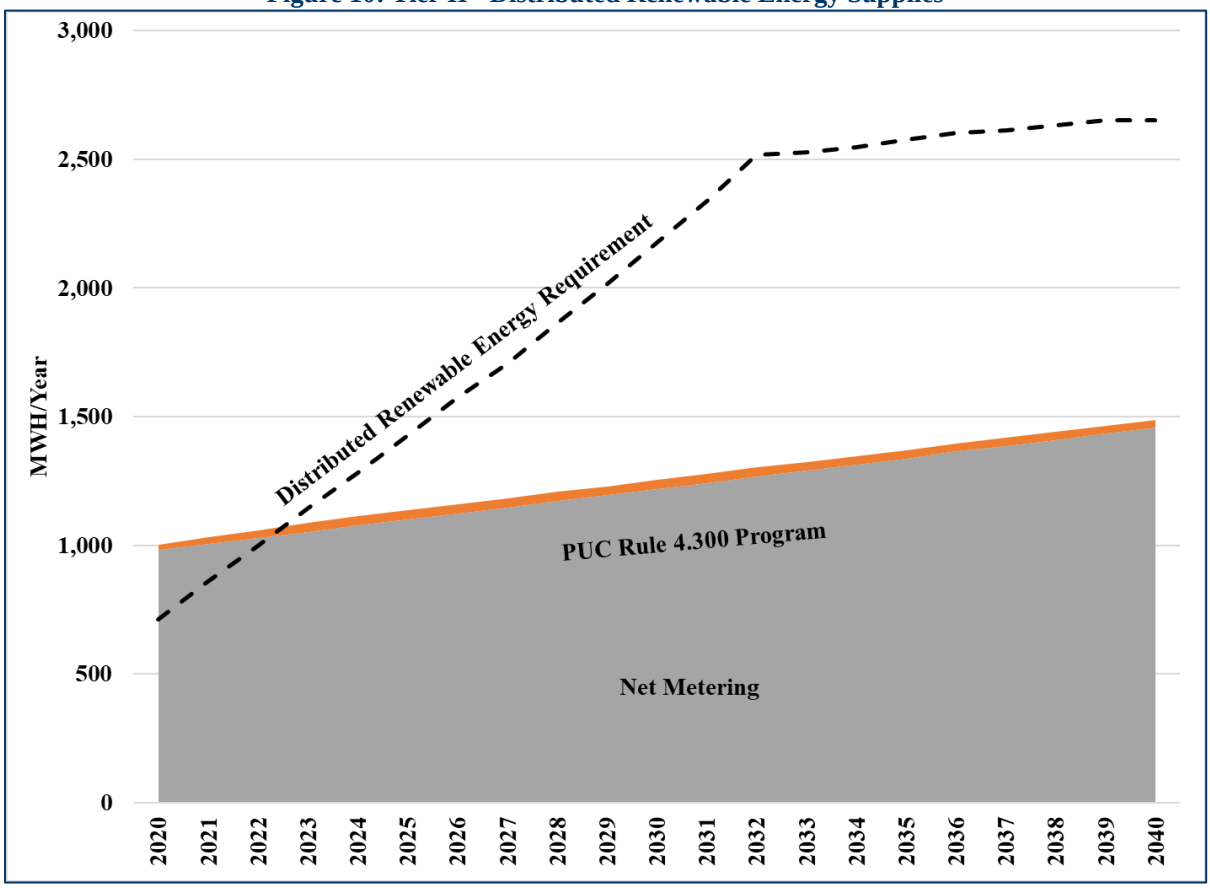
As mentioned in the Energy Resource Plan, the expiration of the NextEra 2018-2022 PPA creates an opportunity to purchase a resource that provides both energy and RECs. The 11,000 MWH per year deficit is equivalent to a 3.5 MW hydro facility[16], and if the output from a hydro resource of this size and 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".

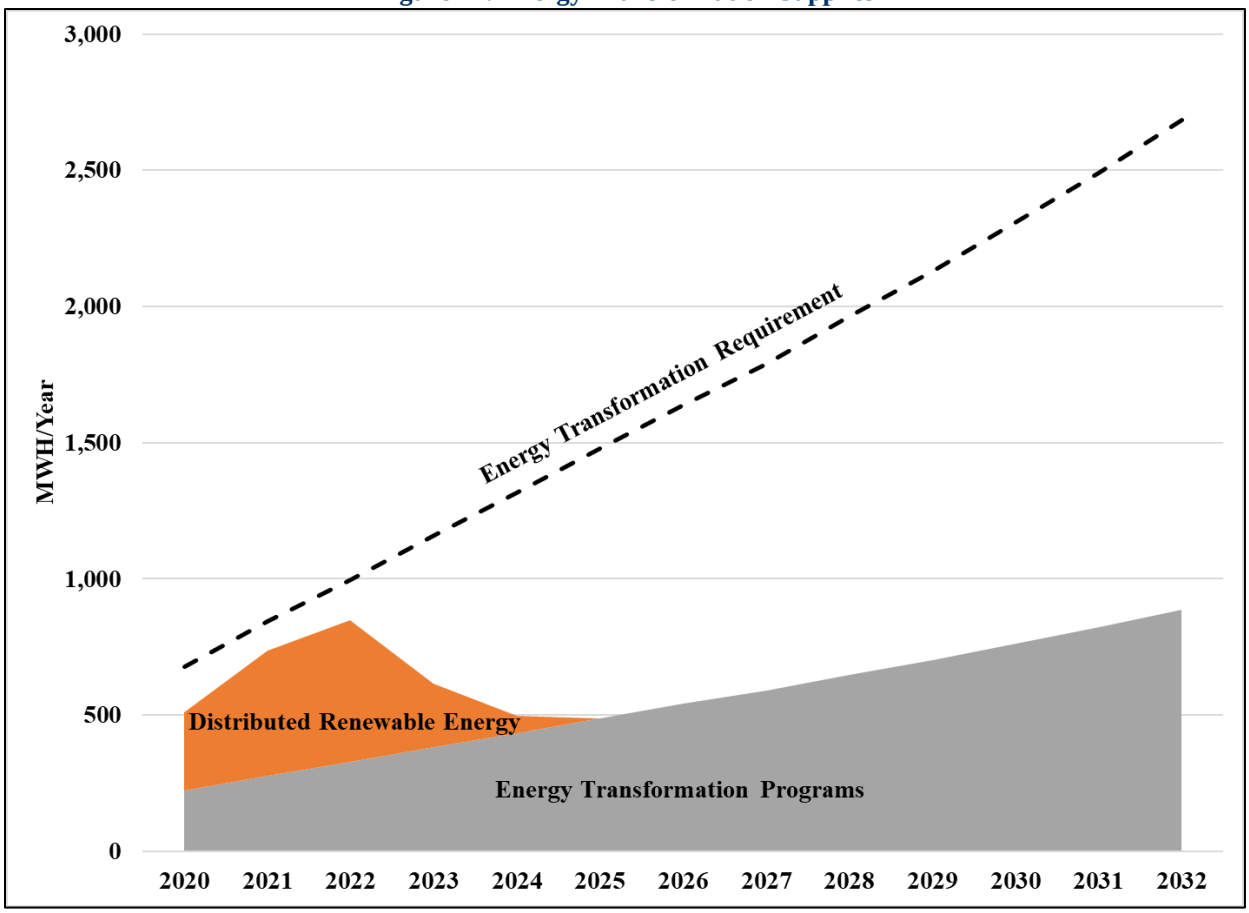
[18] We assume that the surplus MWH in 2020-2022 are not banked, and are instead applied to Northfield's Energy Transformation requirement.

[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.

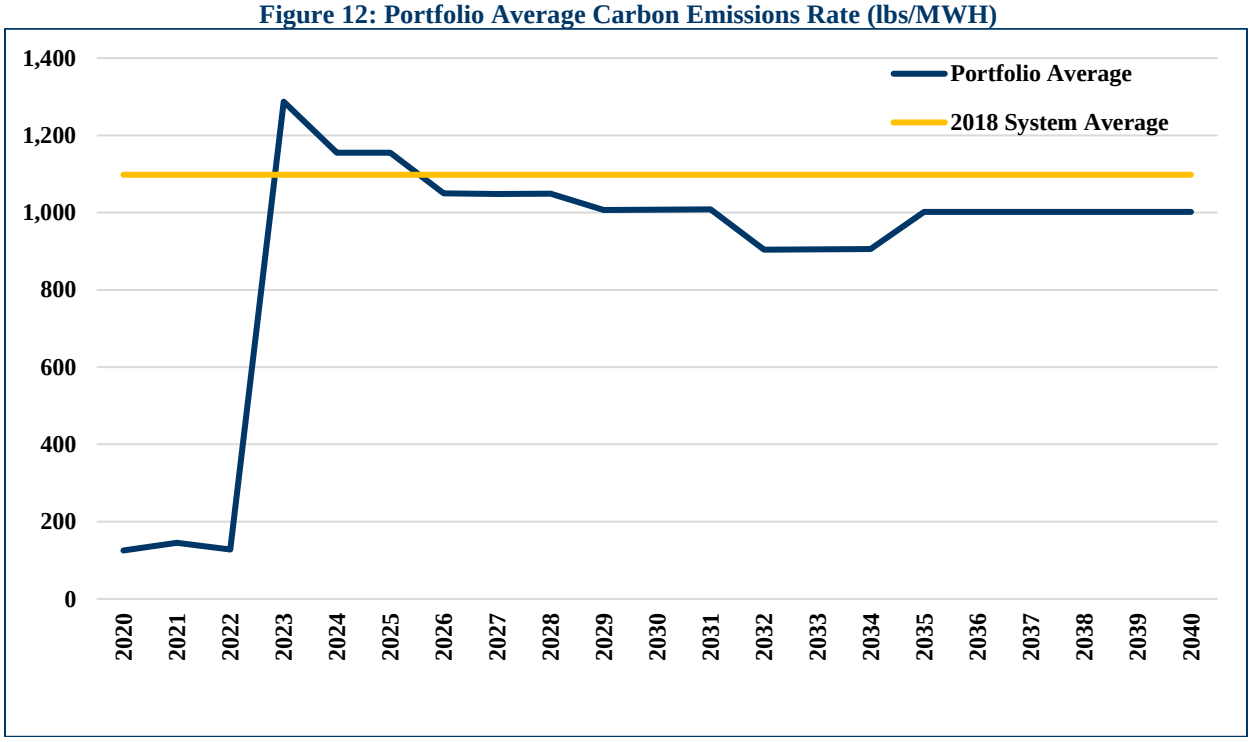
1. Identify and deliver *prescriptive* Energy Transformation ("Base Program") programs, and/or
2. Identify and deliver *custom* Energy Transformation ("Custom Program") programs, and/or
3. Develop and complete the Bone Hill Solar or a comparable, Vermont-based solar project, and/or
4. Purchase Tier II-qualifying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

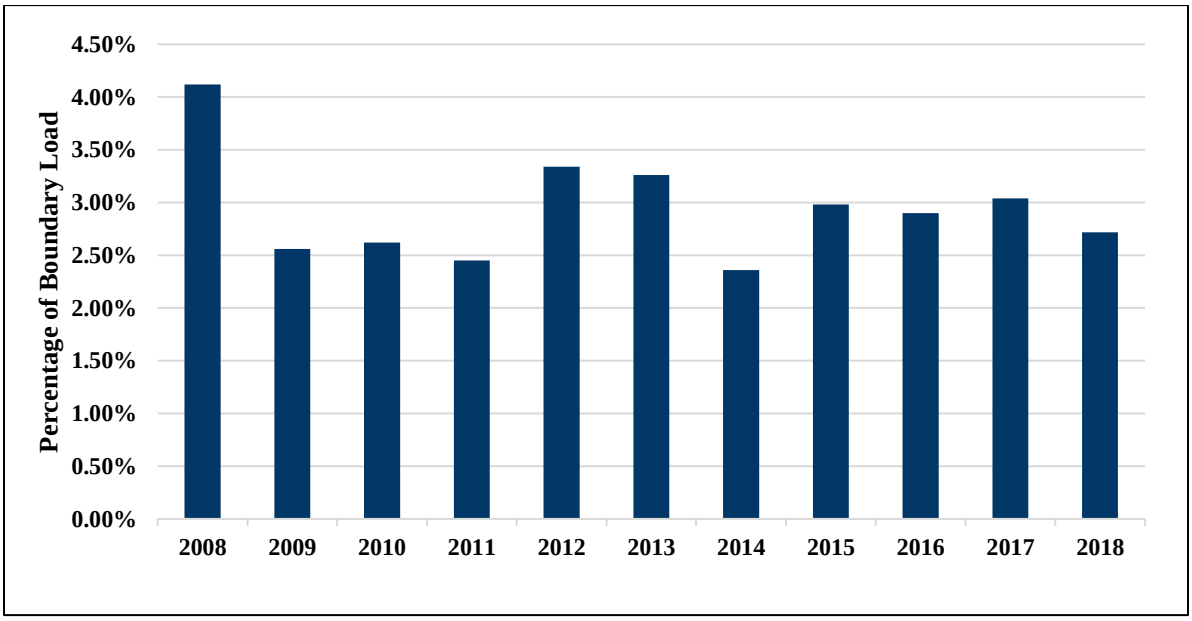
NED is committed to providing efficient electric service to its customers. NED's strategy for improving system efficiency involves monitoring actual system losses and implementing system improvements to reduce system losses. These strategies are discussed briefly below.

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.

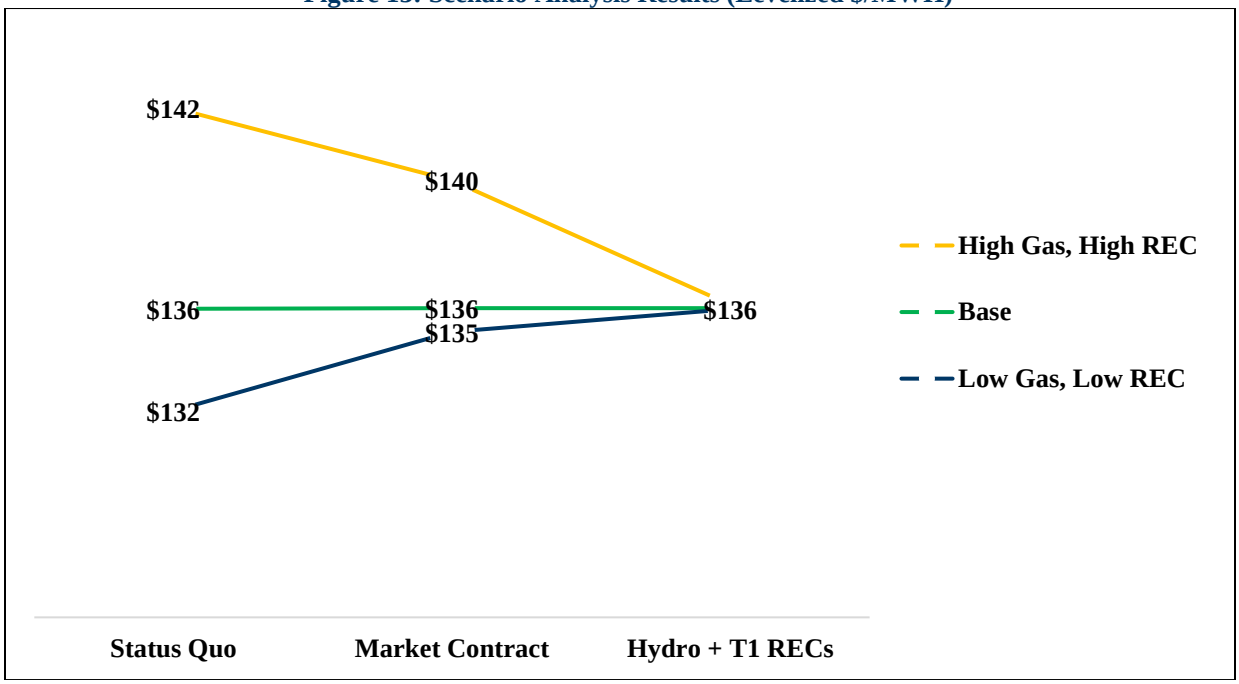
Table 25: Scenario Analysis Results (Levelized $/MWH)

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:

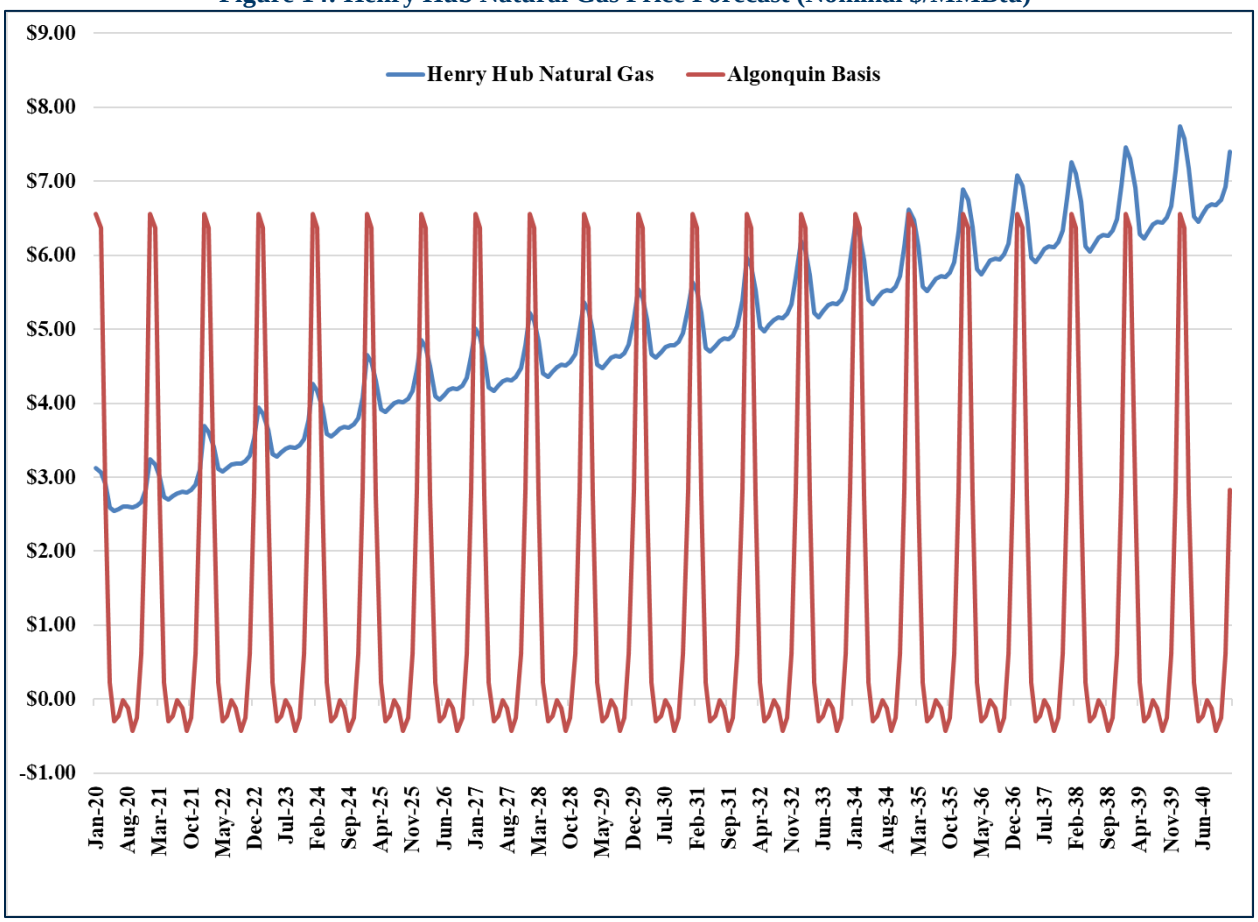
Appendix B - VPPSA Tier 3 2019 Annual Plan.pdf

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.

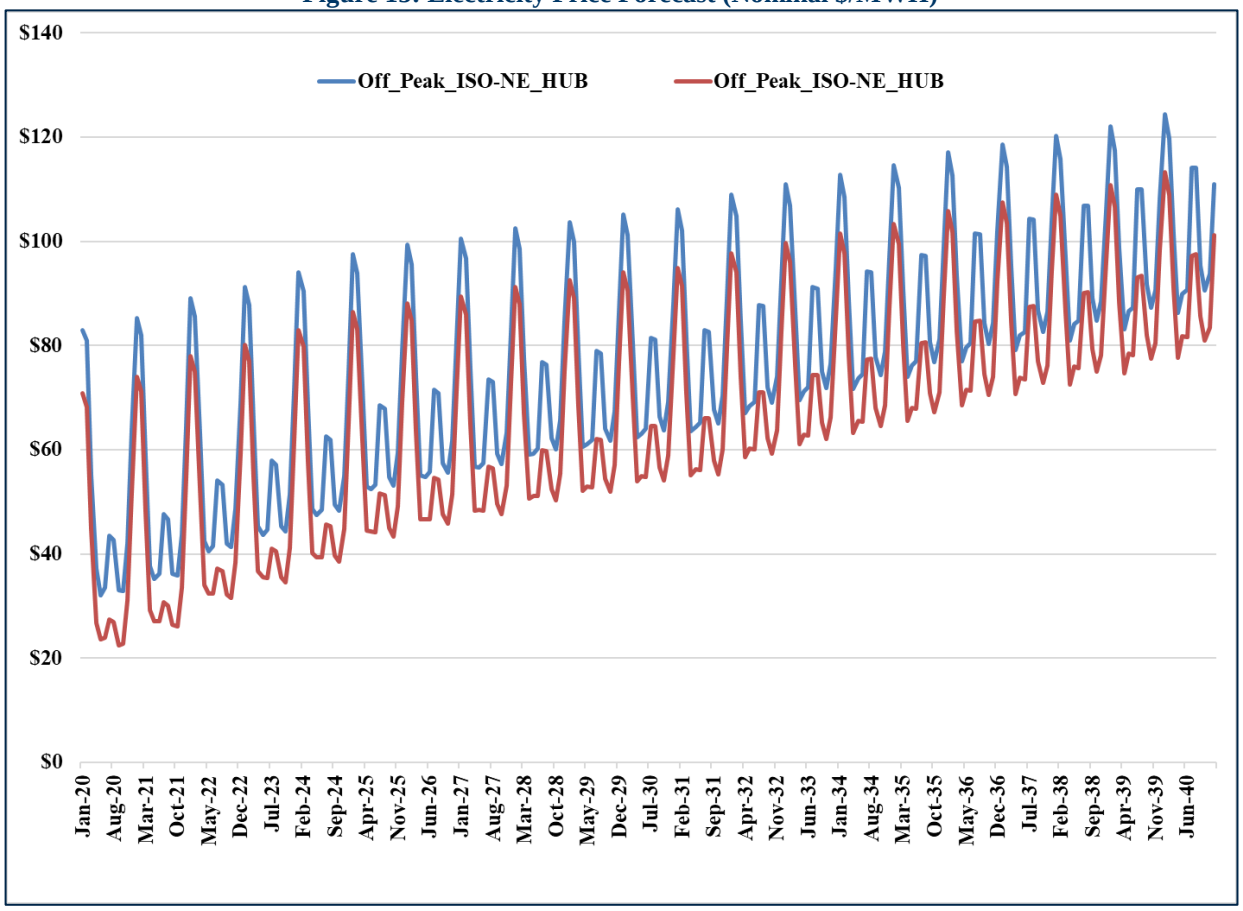
Figure 14: Henry Hub Natural Gas Price Forecast (Nominal $/MMBtu)



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)

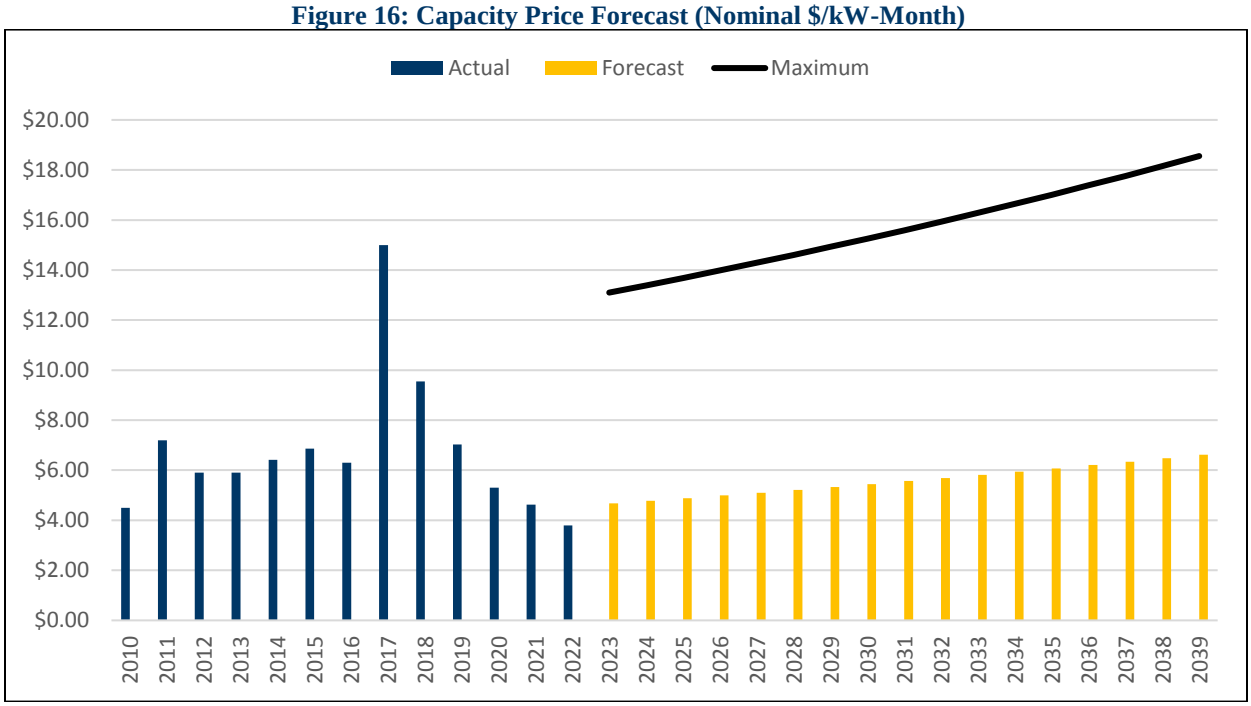


In keeping with the function of ISO-NE's Standard Market Design, we use a five-year average basis between Locational Marginal Price (LMP) nodes to adjust the price forecast at the MA Hub to the location of NED's load and resources.

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**			