Northfield Electric Department

2022 Integrated Resource Plan

Vermont Public Power Supply Authority

Filed with the Public Utility Commission

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 about 75% of the customer mix while accounting for about a third of NED's retail kWh sales. Fourteen 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 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. Forecast increases in the adoption of cold climate heat pumps, other appliances, and electric vehicles is expected to overtake demand reductions associated with solar net metering in the next 5 to 10 years, resulting in modest projected load growth in the longer term.

While no significant change in the demand associated with NED's largest customers is currently anticipated, the potential does exist. Norwich University represents about 30% of NED's retail load with an additional thirteen large customers accounting for another 20%. NED monitors the plans of these large customers 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 market prices, the portfolio is heavily weighted toward hydro, solar and other renewable resources.

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, including offshore wind as it becomes competitively priced, and hydro. In addition to being a factor in meeting future electricity requirements, this category of resources contribute to meeting Renewal Energy Standard goals. Gas fired generation may have a role to play in the future portfolio for reliability purposes. As battery storage technology matures and proves economically feasible, NED sees potential for storage to play an important load management role and to enhance the local impact of distributed generation. NED is currently working with development partners to explore the siting of a significant storage facility adjacent to its King Street Substation.

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.

There are three major resource decisions that, in total, will affect about 40% of NED's energy supply between 2022 and 2031. Importantly, the first two decisions occur during the first five years of the forecast period (2023-2027), and these two decisions will affect about 20% of NEDs energy supply. Options being evaluated include annual market purchases, purchasing a longer term fixed-price contract for bundled hydro energy including Tier I RECs, and offshore wind.

The second group of major resource decisions faced by NED occur in 2025 and 2027, respectively. The first of these two decisions involves whether to elect a five-year extension of the Fitchburg Landfill PPA in 2025. The second of these decisions relates to the replacement of the Brookfield Hydro contract, which expires in 2027. The evaluation of these options is expected to be primarily influenced by market energy prices, REC price considerations, and the availability of other competitively priced renewable resources such as on or offshore wind. NED notes both of these decisions are subject to uncertainty arising from potential changes in RES requirements.

The third major resource decision coincides with the 2031 expiration of the Fitchburg Landfill Gas contract which represents about 12% of NED's energy requirements. Because this contract provides Class I RECs, the decision to replace or extend this contract will be sensitive to changes in existing energy policy and subsequent changes in RES compliance requirements.

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

RENEWABLE ENERGY STANDARD

NED is subject to the Vermont Renewable Energy Standard (RES) 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 III programs can consist of thermal efficiency measures, electrification of the transportation sector, and converting customers that rely on diesel generation to electric service, among other things. By providing incentive programs to encourage conversion of traditional fossil fuel applications such as space heating, water heating, or 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 A 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 regular 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 update its system to support additional distributed generation and beneficial electrification on the system and to provide customers with targeted services including load management supported by more innovative programs and rate designs that reduce costs for both NED and its customers. NED is currently engaged, with VPPSA, in the final stages of a multi-phased process that is expected to result in implementation of an AMI system beginning in late 2022. 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.

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

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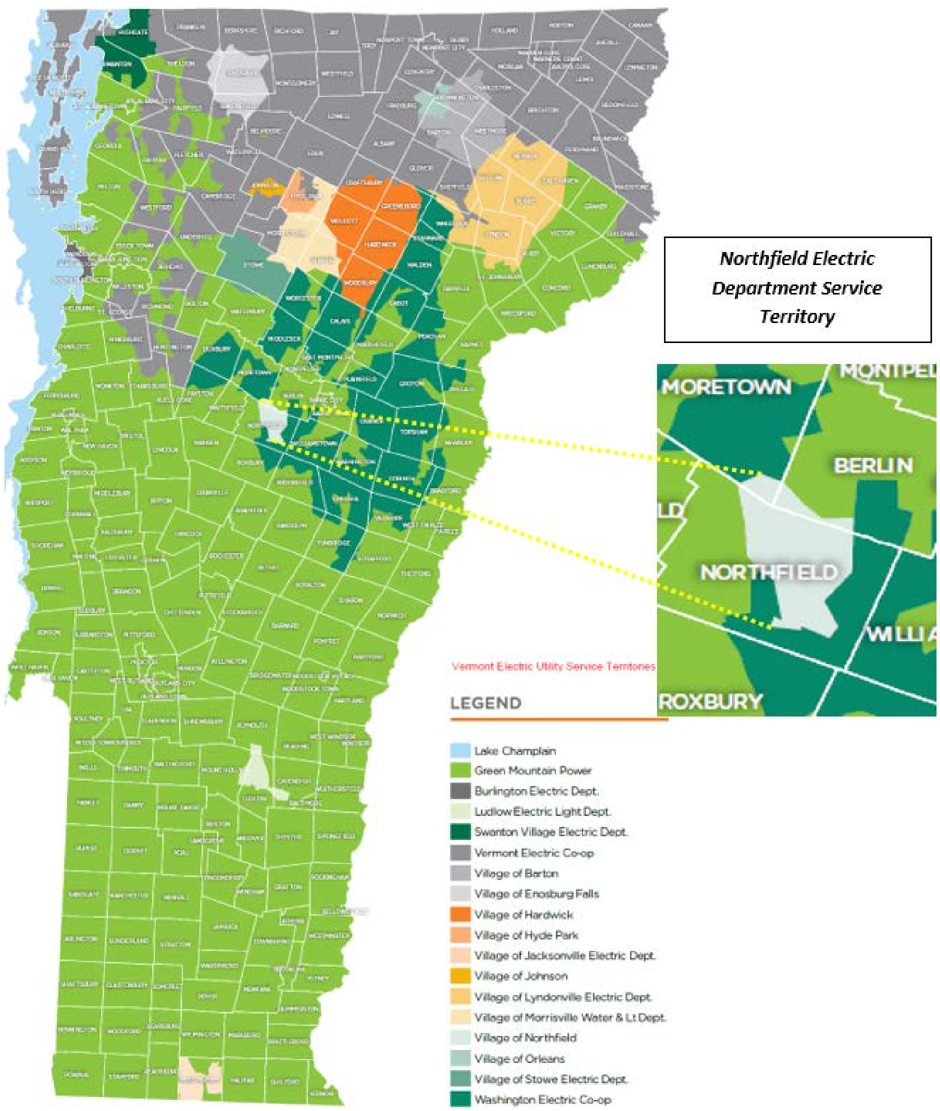
INTRODUCTION

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

- Northfield Electric Department,
- Barton Village Inc.,
- Village of Enosburg Falls Electric Light Department,
- Hardwick Electric Department,
- Village of Jacksonville Electric Company,
- Village of Johnson Electric Department,
- Ludlow Electric Light Department,
- Lyndonville Electric Department,
- Morrisville Water & Light Department,
- 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 2021. 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	2017	2018	2019	2020	2021
Residential (440)	1,604	1,610	1,620	1,620	1,622
Norwich University	1	1	1	1	1
Small C&I (442) 1000 Kw or less	180	176	168	167	168
Large C&I (442) above 1,000 Kw	12	12	12	12	13
Street Lighting (444)	329	330	324	330	330
Public Authorities (445)	26	27	29	29	29
Interdepartmental Sales (448)	57	53	54	54	54
Total	**2,209**	**2,209**	**2,209**	**2,213**	**2,216**

Table 2: NED's Retail Sales (kWh)

Data Element	2017	2018	2019	2020	2021
Residential (440)	9,862,631	10,189,153	10,186,640	10,696,038	10,594,021
Norwich University	8,391,724	8,525,879	8,849,076	7,241,326	7,896,119
Small C&I (442) 1000 Kw or less	2,405,120	2,420,080	2,384,371	2,429,502	2,309,516
Large C&I (442) above 1,000 Kw	5,101,865	5,268,015	5,626,651	5,014,309	5,818,330
Street Lighting (444)	51,467	51,835	51,696	51,557	51,740
Public Authorities (445)	1,746,710	1,724,910	1,687,783	1,459,443	1,656,386
Interdepartmental Sales (448)	40,471	37,403	37,757	36,714	36,407
Total	**27,599,988**	**28,217,275**	**28,823,974**	**26,928,889**	**28,362,519**
YOY	-3%	2%	2%	-7%	5%

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

Data Element	2017	2018	2019	2020	2021
Peak Demand kW	4,910	5,126	4,967	5,248	5,420
Peak Demand Date	09/27/17	09/05/18	12/03/19	11/03/20	01/25/21
Peak Demand Hour	20	20	18	18	18

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.

[1] Noncoincident Peak (NCP)

[2] Total load excluding losses (TLEL)

STRUCTURE OF REPORT

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

ELECTRICITY DEMAND

This chapter describes how 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 IRP.

APPENDIX

The appendix includes a series of supporting documents and reports.

GLOSSARY

ELECTRICITY DEMAND

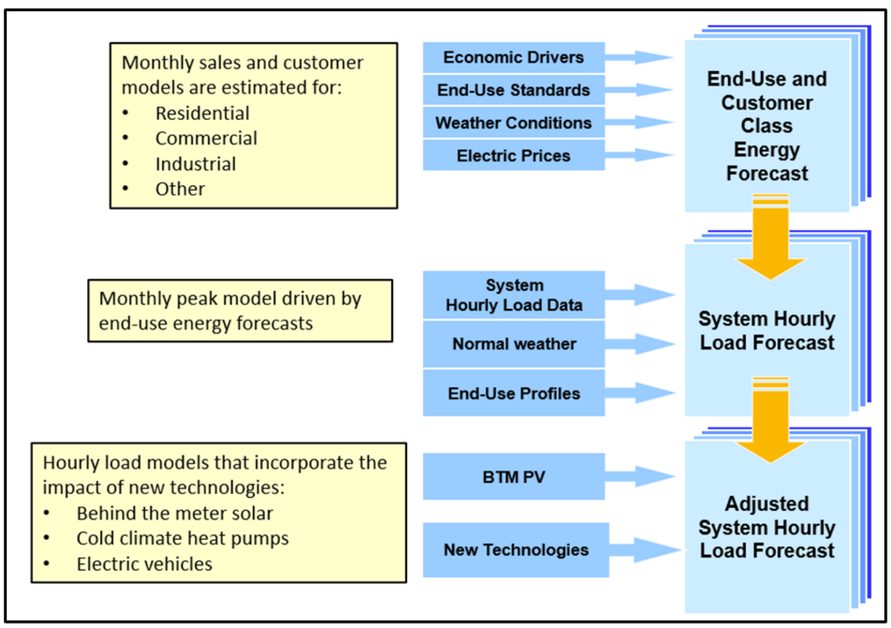
I. ELECTRICITY DEMAND

ENERGY FORECAST: STATISTICALLY ADJUSTED END USE METHODOLOGY

VPPSA retained Itron to forecast NED's peak and energy requirements. Using the SAE (Statistically Adjusted End Use) methodology, the Itron team used the same electrification inputs and assumptions that were approved by the Vermont System Planning Committee during VELCO's 2021 Long-Range Transmission Plan (LRTP). Specifically, the adoption rates for heat pumps and electric vehicles (also known as "electrification") are shared with the LRTP.

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

Figure 2: Forecasting Process



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

ENERGY FORECAST RESULTS

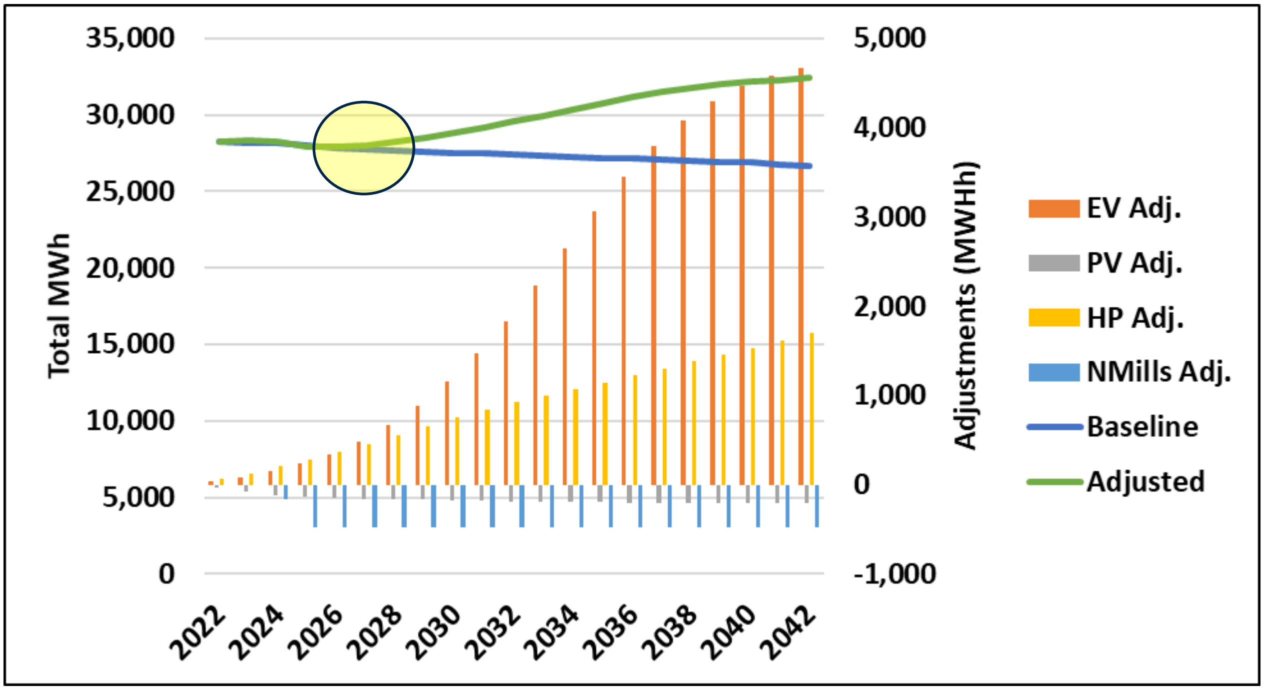
Table 3 shows the results of the Baseline Forecast for energy, as well as the adjustments that are made to arrive at the Adjusted Forecast. The Compound Annual Growth Rates (CAGR) at the bottom of the table illustrate the trends in each of the columns. Notice that the Baseline Forecast itself is declining by 0.3% per year. After making adjustments for electric vehicles (EV), net metered solar (NM PV), heat pumps (HP), and Nantanna Mills (NMills), the Adjusted Forecast actually increases by 0.7% per year.

Table 3: Adjusted Energy Forecast (MWh/Year)

Year	Yr #	Baseline Forecast (MWh)	EV Adj. (MWh)	NM PV Adj. (MWh)	HP Adj (MWh)	NMills Adj. (MWh)	Adj. Forecast (MWh)
2022	1	28,269	37	-33	63	0	28,336
2027	5	27,768	485	-160	460	-471	28,083
2032	10	27,500	1,834	-188	921	-472	29,594
2037	15	27,142	3,789	-199	1,301	-472	31,562
2042	20	26,739	4,673	-210	1,704	-473	32,433
CAGR		-0.3%	27.3%	9.7%	17.9%		0.7%

The Adjusted Forecast is the result of high CAGRs for HPs (17.9%) and EVs (27.3%). But during the first five years of the forecast, these two trends are offset by the net metering program, which grows by 9.7% per year. By year six, the impact of CCHPs and EVs is greater than the impact of net metering. The cross-over point can be seen in the yellow circle in Figure 3.

Figure 3: Adjusted Energy Forecast (MWh/Year)



ENERGY FORECAST – HIGH & LOW CASES

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

At these growth rates, the market penetration for CCHPs and EVs reaches approximately 100% (all 2,200 customers) in 2042. This rough estimate assumes that most households and buildings will have more than one CCHP and more than one car. Nevertheless, it gives a reasonable indication of the kind of growth in energy use that is possible: 1.6% per year. This growth rate results in a 38% increase over 2022 electricity use.

Table 4: Energy Forecast – High Case (MWH)

Year	Yr #	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	NMills Adj.	Adj. Forecast
2022	1	28,222	74	-33	126	0	28,436
2027	5	28,189	970	-160	920	-471	29,028
2032	10	28,144	3,668	-188	1,842	-472	32,349
2037	15	27,970	7,579	-199	2,603	-472	36,652
2042	20	27,852	9,346	-210	3,409	-473	38,811
CAGR		-0.3%	27.3%	9.7%	17.9%		1.6%

To form a low case, we assumed that the penetration for CCHPs and EVs is half of the base case, and we kept the net-metered PV penetration rate the same as the base case. This results in a forecast that increases by 0.2% per year. Like the base case, this rate of change is well within the forecast error.

Table 5: Energy Forecast - Low Case (MWH

Year	Yr #	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	NMills Adj.	Adj. Forecast
2022	1	28,222	37	-33	63	0	28,336
2027	5	28,189	243	-160	230	-471	27,610
2032	10	28,144	917	-188	460	-472	28,217
2037	15	27,970	1,895	-199	651	-472	29,017
2042	20	27,852	2,337	-210	852	-473	29,245
CAGR		-0.3%	23.0%	9.7%	13.9%		0.2%

PEAK FORECAST RESULTS

Table 6 and Table 7 shows the results of the Baseline Forecast of peak loads, as well as the adjustments that are made to arrive at the Adjusted Forecast. The CAGR at the bottom of the table illustrate the trends in each of the columns. Notice that the Baseline Forecast itself is declining but nearly flat. After making adjustments for CCHPs, EVs, and net metering, the Adjusted Forecast actually increases by 0.9-1.7% per year. Although the summer and winter peaks are presently equal, the winter peak is expected to predominate over time, and the timing of the peak hour is expected to be stable in the early evening hours.

Table 6: Summer Peak Forecast (MW)

Year	Yr #	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	NMills Adj.	Adj. Forecast
2022	1	4.7	0.0	0.0	0.0	0.0	4.7
2027	5	4.6	0.1	0.0	0.1	0.0	4.7
2032	10	4.6	0.3	0.0	0.1	0.0	5.0
2037	15	4.6	0.7	0.0	0.2	0.0	5.4
2042	20	4.6	0.8	0.0	0.2	0.0	5.6
CAGR		0.0%	27.0%	11.6%	17.7%		0.9%

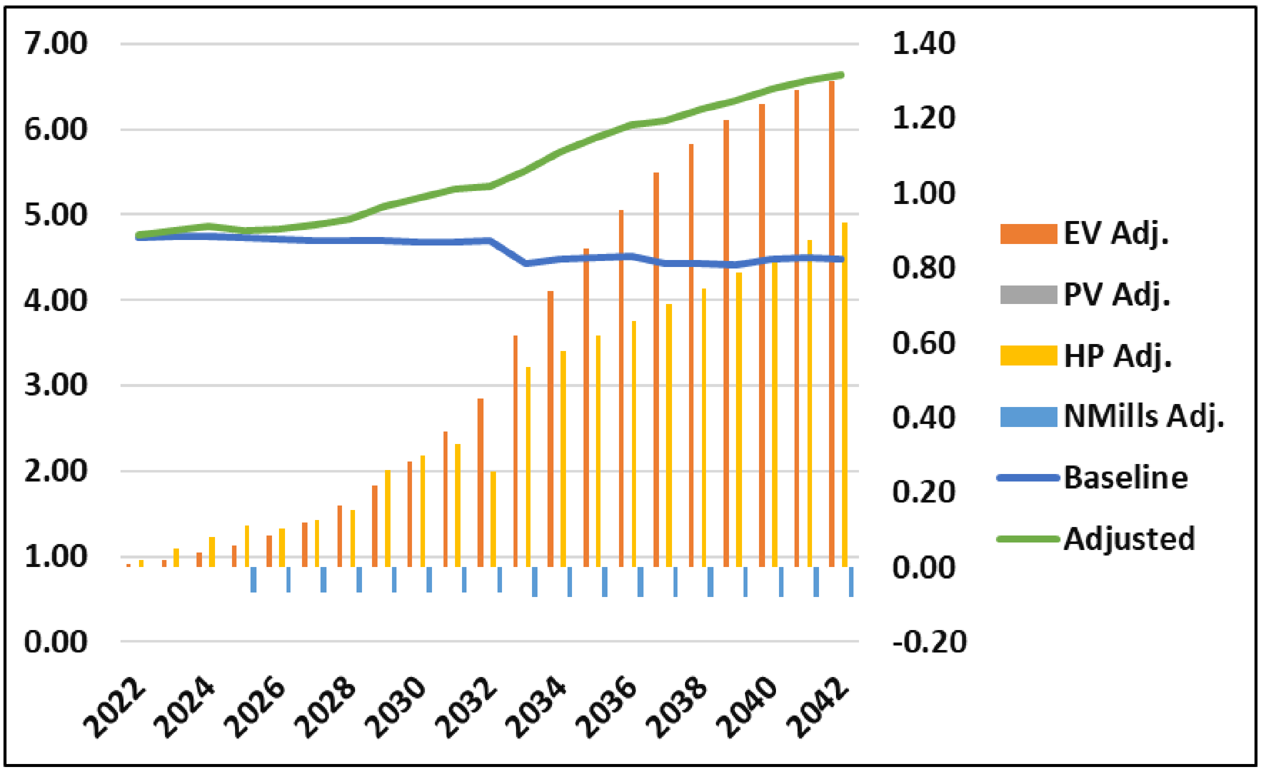
Table 7: Winter Peak Forecast (MW)

Year	Yr #	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	NMills Adj.	Adj. Forecast
2022	1	4.7	0.0	0.0	0.0	0.0	4.8
2027	5	4.7	0.1	0.0	0.1	-0.1	4.9
2032	10	4.7	0.5	0.0	0.3	-0.1	5.3
2037	15	4.4	1.1	0.0	0.7	-0.1	6.1
2042	20	4.5	1.3	0.0	0.9	-0.1	6.6
CAGR		-0.3%	28.2%		21.7%		1.7%

The size of the adjustments can be seen in Figure 4, which shows the winter peak forecast net of adjustments. The transformer at the King St. substation is rated up to 10.5 MVA, which is more than large enough to accommodate this peak load forecast.

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

Figure 4: Adjusted Peak Forecast (MW)



PEAK FORECAST – HIGH & LOW CASES

To form a high-case, we assume that neither load controls nor Time-of-Use (TOU) rates are implemented, and then we adopt the same assumptions from the high case as in the energy forecast. Under these assumptions, peak load growth starts to impact the system after 2030, and by 2042, the peak reaches 8.9 MW, which is 15% lower than the transformer rating.

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

Year	Peak Hour	Baseline Forecast	EV Adj.	NM PV Adj.	HP Adj	NMills Adj.	Adj. Forecast
2022	18	4.7	0.0	0.0	0.0	0.0	4.8
2027	18	4.7	0.2	0.0	0.3	-0.1	5.1
2032	18	4.7	0.9	0.0	0.5	-0.1	6.0
2037	18	4.4	2.1	0.0	1.4	-0.1	7.8
2042	18	4.5	2.6	0.0	1.8	-0.1	8.9
CAGR		-0.3%					3.1%

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 Baseline Forecast without any adjustments.

TIER III IMPACTS ON THE FORECAST

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

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

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

Table 9 shows the budgeted measures from VPPSA's 2022 Tier III budget, and the increased electric loads that are anticipated. These loads are based on averages as published in the Tier III Planning Tool. Ninety-five percent of the new electric loads are expected to come from only two technologies: heat pumps and electric vehicles, and the 117 MWH/Year of new electric loads is in alignment with the heat pump and electric vehicle adjustments in Table 5, which shows a 100 MWH increase in electric loads in 2022 due to these technologies.

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

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

Measure	# Measures	Added MWH/Unit/Yr	Total New MWH/Yr
Electric Vehicle - New	2	2.8	5.5
Electric Vehicle - New, Income Qualifying	1	2.8	2.8
PHEV- New, Income Qualifying	1	1.7	1.7
Heat Pump - ductless	25	3.4	84.2
Heat Pump - ductless, Weatherized	1	3.4	3.4
Heat Pump - ductless, Income Qualified	1	3.4	3.4
Integrated Controls (with Heat Pump)	1	3.4	3.4
WBHP - Ducted	2	4.2	8.4
Electric Bicycle	2	0.030	0.06
Heat Pump Water Heater	2	1.0	1.9
Golf Carts	3	0.8	2.3
Residential Lawn Mower	2	0.009	0.02
Total	43		117

TIER III LOAD CONTROL

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

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

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

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

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

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

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

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

FORECAST UNCERTAINTIES & CONSIDERATIONS

Despite strong growth in CCHPs and EVs, NED's electricity demand is expected to be flat over the next five years. Thereafter, the forecasted demand growth depends heavily on the electrification trends for EVs and HPs, which are uncertain. Other uncertainties do exist, however.

NED presently has about forty-three 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.

This is a real possibility if a series of large net metered projects are built. For example, the Armory has already built a 100 kW system, and two other large systems have been proposed, one at the hosiery and one at the Tucker pit. Only installed systems are included in this forecast, and the impacts of the proposed systems are estimated. For example, two 100 kW net metered solar projects built in 2023 would increase the base of installed, net metered capacity on the system (which was 862 kW as of March 2022) by 23% 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.

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 power supply resources in NED's portfolio.

EXISTING POWER SUPPLY RESOURCES

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

2. Chester Solar
   - Size: 4.8 MW
   - Fuel: Solar
   - Location: Chester, MA
   - Entitlement: 10.7%, PPA
   - Products: 7x16 energy, capacity
   - End Date: 6/30/39
   - Notes: The PPA does not include RECs.

3. Fitchburg Landfill
   - Size: 4.5 MW
   - Fuel: Landfill Gas
   - Location: Westminster, MA
   - Entitlement: 10.2%, PPA
   - Products: Baseload energy, capacity, and RECs (MA Class I)
   - End Date: 12/31/31

4. Kruger Hydroelectric Facilities
   - Size: 6.7 MW
   - Fuel: Hydro
   - Location: Maine and Rhode Island
   - Entitlement: 12.08%, 0.391 MW, PPA
   - Products: Run of river energy, capacity
   - End Date: 12/31/37
   - Notes: NED has an agreement with VPPSA to purchase unit contingent energy and capacity from six hydroelectric generators. It does not include RECs.

5. Hydro Quebec US (HQUS)
   - Size: 212 MW
   - Fuel: Hydro
   - Location: Quebec
   - Entitlement: 0.121% (0.257) MW, PPA
   - Products: 7x16 energy, RECs (Quebec system mix)
   - End Date: 10/31/38

6. Market Contracts
    - Size: Varies
    - Fuel: New England System Mix
    - Location: New England
    - Entitlement: Varies (PPA)
    - Products: Energy, renewable energy credits
    - End Date: Varies, less than 5 years.
    - Notes: In addition to the above resources, NED purchases system power from various other entities under short-term (5 years or less) agreements.

7. McNeil
    - Size: 54 MW
    - Fuel: Wood
    - Location: Burlington, Vermont
    - Entitlement: 1.98%, joint-owned through VPPSA
    - Products: 7x16 energy, capacity, RECs (CT Class I)
    - End Date: Life of Unit
    - Notes: As the joint-owner, VPPSA has agreements with NED to purchase 1.98% of the unit's output.

8. New York Power Authority (NYPA)
    - Size: 2,675 MW (Niagara), 1,957 MW (St. Lawrence)
    - Fuel: Hydro
    - Location: New York State
    - Entitlement: 0.146 MW (Niagara PPA), 0.012 MW (St. Lawrence PPA)
    - Products: Energy, capacity, RECs (NY System Mix)
    - End Date: 9/1/25 (Niagara), 4/30/2032 (St. Lawrence)
    - Notes: NYPA provides hydro power to NED under two contracts, which will be extended at the end of their term.

9. **Project 10**

- Size: 40 MW
- Fuel: Oil
- Location: Swanton, VT
- Entitlement: 12%, joint-owned through VPPSA
- Products: Energy, capacity, reserves
- End Date: Life of unit
- Notes: As the joint-owner, VPPSA has agreements with NED to pay for and purchase 2% of the unit's output.

10. **Ryegate Facility**

- Size: 20.5 MW
- Fuel: Wood
- Location: East Ryegate, VT
- Entitlement: 0.5429% (0.232 MW), PPA
- Products: Baseload energy, capacity, RECs (CT Class I)
- End Date: 10/31/2026

11. **Seabrook 2018-2022 (NextEra)**

- Size: 1,250 MW
- Fuel: Nuclear
- Location: Seabrook, NH
- Entitlement: 1.5 MW On-Peak, 1.0 MW Off-Peak (PPA)
- Products: Baseload energy, capacity, RECs (Carbon-free nuclear)
- End Date: 12/31/2022

12. Seabrook PPA

- Size: 0.6 MW
- Fuel: Nuclear
- Location: Seabrook, NH
- Entitlement: 33%, PPA
- Products: Baseload energy, capacity, RECs (carbon-free nuclear)
- End Date: 12/31/2034

13. Standard Offer Program (PUC Rule 4.300)

- Size: Small renewables, primarily solar < 2.2 MW
- Fuel: Mostly solar, but also some wind, biogas & micro-hydro
- Location: Vermont
- Entitlement: 0.5537% (Statutory)
- Products: Energy, capacity, RECs
- End Date: Varies
- Notes: NED is required to purchase power from small power producers through the Vermont Standard Offer Program, in accordance with PUC Rule 4.300. The entitlement percentage fluctuates slightly each year with NED's pro rata share of Vermont's retail energy sales.

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

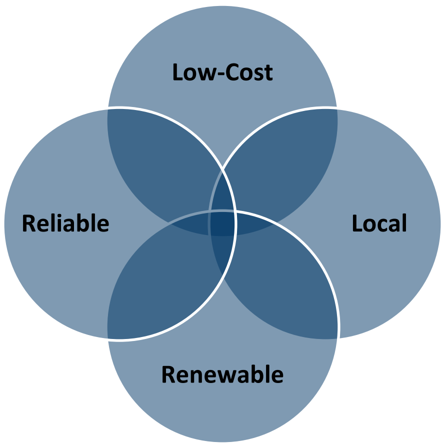
Table 11: Existing Power Supply Resources

RESOURCE	2021 MWH	% of MWH	2021 MW	Delivery Pattern	Price Pattern	REC	Expiration Date	Renewal to 2042
Brookfield Hydro 2023-2027	0	0%	0	Firm	Fixed	✓	12/31/27	No
Chester Solar	727	2.5%	0.204	Intermittent	Fixed		6/30/39	No
Fitchburg Landfill	3,708	12.5%	0.447	Unit Contingent	Fixed	✓	12/31/31	No
HQUS Contract	1,495	5.0%	0.000	Firm	Indexed	✓	10/31/38	No
Kruger Hydro	2,569	8.7%	0.178	Intermittent	Fixed		12/31/37	No
Market Contracts	-98	-0.3%		Firm, Varies	Variable		12/21/19	No
McNeil Facility	5,418	18.3%		7x16, Unit Contingent	Variable	✓	Life of Unit	Yes
NYPA Niagara Contract	2,059	6.9%	0.26	Baseload & Peaking	Fixed	✓	9/1/25	Yes
NYPA St. Lawrence Contract	51	0.2%	0.009	Baseload & Peaking	Fixed	✓	4/30/32	Yes
Project #10	47	0.2%	4.638	Dispatchable	Variable		Life of Unit	Yes
Ryegate Facility	909	3.1%	0.111	Baseload, Unit Contingent	Fixed	✓	10/31/26	No
Seabrook 2018-22 Purchase	10,773	36.3%	0.0	Baseload, Firm	Fixed		12/31/22	No
Seabrook PPA	1,374	4.6%	0.173	Baseload, Unit Contingent	Fixed + Inflation		12/31/34	No
Standard Offer Program	629	2.1%	0.000	Intermittent	Fixed	✓	Varies	N/A
Total MWH	29,661	100%	7.02					

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 or stabilize electric rates.
- ✓ **Local** resources are located within NED'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 that meet the criteria in Figure 5.

CATEGORY 1: EXTENSIONS OF EXISTING RESOURCES

This plan assumes that three existing resources are extended past their current expiration date. These include McNeil, 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 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, NED 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 NED's incremental electric demands by month, season and year. In many cases, the delivery point for market contracts can be set to the Vermont Zone reducing potential price differential risks between loads and resources. Finally, the financial strength of the suppliers in the solicitation can be predetermined. The combination of these attributes makes market contracts a good fit for procuring future resources.

CATEGORY 2: DEMAND-SIDE RESOURCES

The lowest cost, most local source of energy is often energy that is conserved or never consumed. As a result, 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.

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

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

CATEGORY 3: NEW RESOURCES

VPPSA regularly meets with developers throughout New England, and through VPPSA staff, 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, and the costs are becoming competitive. As a result, NED will consider both on and off-shore wind PPA's as those opportunities arise.

3.2 GAS-FIRED GENERATION

Project 10 is undergoing a major overhaul in 2022, and the expected life of the unit spans the planning period. As a result, no new sources of gas-fired generation are being planned for in this IRP.

3.3 SOLAR GENERATION

Solar is the primary technology that is being employed to meet NED's Distributed Renewable Energy (TIER II) requirements under RES. If the RES Tier II requirements increase, solar is likely to be a leading resource option. As a result, NED will continue to investigate solar developments both within and outside its service territory.

3.3.1 NET METERING

NED has 43 net-metered customers and an installed base of solar capacity of 862 kW. Three quarters of this capacity is from two large arrays, and another large array (350 kW) has been proposed. As a result, the growth in net-metered capacity is dominated by a few large systems.

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[5]. As a result, net metered solar is an inferior option when compared to lower-cost and utility scale solar projects.

3.4 HYDROELECTRIC GENERATION

Hydroelectric generation is widely available in the New England region, and can be purchased within the region or imported from New York and Quebec. Furthermore, it can be sourced from either small or large facilities. Like all existing resources, price negotiations begin at or near prevailing market prices. As a result, existing hydro generation could be both low-cost (or at least at market) and renewable.

3.5 BATTERY STORAGE

VPPSA conducted a Request for Information (RFI) process in 2020 to better understand the business case for storage. Nine companies responded, including four that were based in Vermont and two that are among the largest developers in the US. The pricing that was received was used to develop a net-present value positive business case for peak shaving that is congruent with other storage projects that have already been built in Vermont. Based on a peak shaving business case and the strength of the responses to the RFI, VPPSA conducted a

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[5] 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

Request for Proposals (RFP) process in 2021, and selected a development partner, Delorean Power.

Delorean is presently developing a series of storage sites, including one that is adjacent to Northfield's King Street substation. The size of the project is approximately 3 MW and 9 MWH, and it is presently undergoing an interconnection study. If the results of that study are supportive, we expect that the 248 permitting process could begin later this year.

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 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

ENERGY PROCUREMENT PROCESSES

MONTHLY PROCESS

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

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

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

ANNUAL PROCESS

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

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

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

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

LONG-TERM PROCESS

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

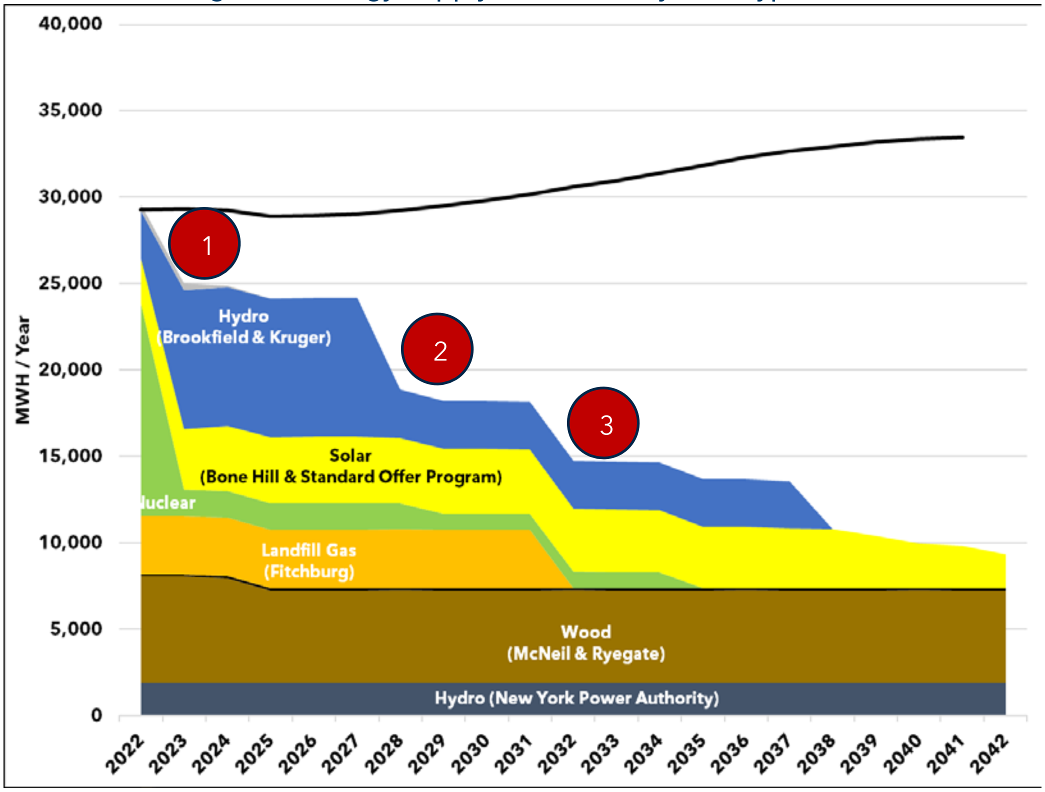
ENERGY RESOURCE PLAN

Figure 6 compares NED's energy supply resources to its adjusted load. There are three major resource decisions that, in total, will affect about 40% of NED's energy supply between 2022 and 2031. Importantly, the first two decisions occur during the first five years of the forecast period (2023-2027), and these two decisions will affect about 20% of NEDs energy supply.

DECISION 1: 2023

First, notice that 100% of NED's energy requirements are presently hedged by multi-year resources. When the NextEra 2018-2022 contract expires later this year, a 10% deficit forms starting in 2023. This deficit may be hedged before the start of each calendar year using the annual hedging process. The most likely resource to replace the NextEra contract is a bundled energy and Tier I REC PPA like the one that was already purchased from Brookfield. Because the cost of market energy is higher than the cost of the NextEra 2018-2022 PPA, replacing this resource now would result in upward rate pressure.

Figure 6: Energy Supply & Demand by Fuel Type



DECISION 2: 2026-2027

There is a two-part resource decision leading up to the 2026-2027 period. The first decision is whether to elect a five-year extension of the Fitchburg Landfill PPA. This contract has had this option since it was signed, and it must be triggered one year in advance of 12/31/26. The option is priced at a fixed and levelized $95/MWH for the 2027-2031 period. VPPSA maintains a Monte Carlo analysis of this PPA that it will use to make this decision in the summer of 2025. Because this PPA is currently in the money, we have already assumed that the extension is triggered in

Figure 6. However, if market conditions change and prices drop, we may elect to let this resource expire in favor of something more cost effective.

The second resource decision occurs at the end of 2027 when the Brookfield 2023-2027 contract expires. This can be seen in

Figure 6 by the decrease in the blue-shaded "Hydro" area. This contract supplies about 18% of NED's energy. Because the cost of market energy and Tier I RECs is higher than the cost of the Brookfield 2023-2027 PPA, replacing this resource now would result in upward rate pressure. The cost and rate impact of this decision is quantified in the Financial Analysis section.

NED may elect to negotiate a new or extended contract with Brookfield or with another supplier of energy and Tier I RECs. It may also purchase a wind resource, either on or offshore. 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.

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.

Table 12 summarizes the energy resources decisions NED faces in the coming ten years.

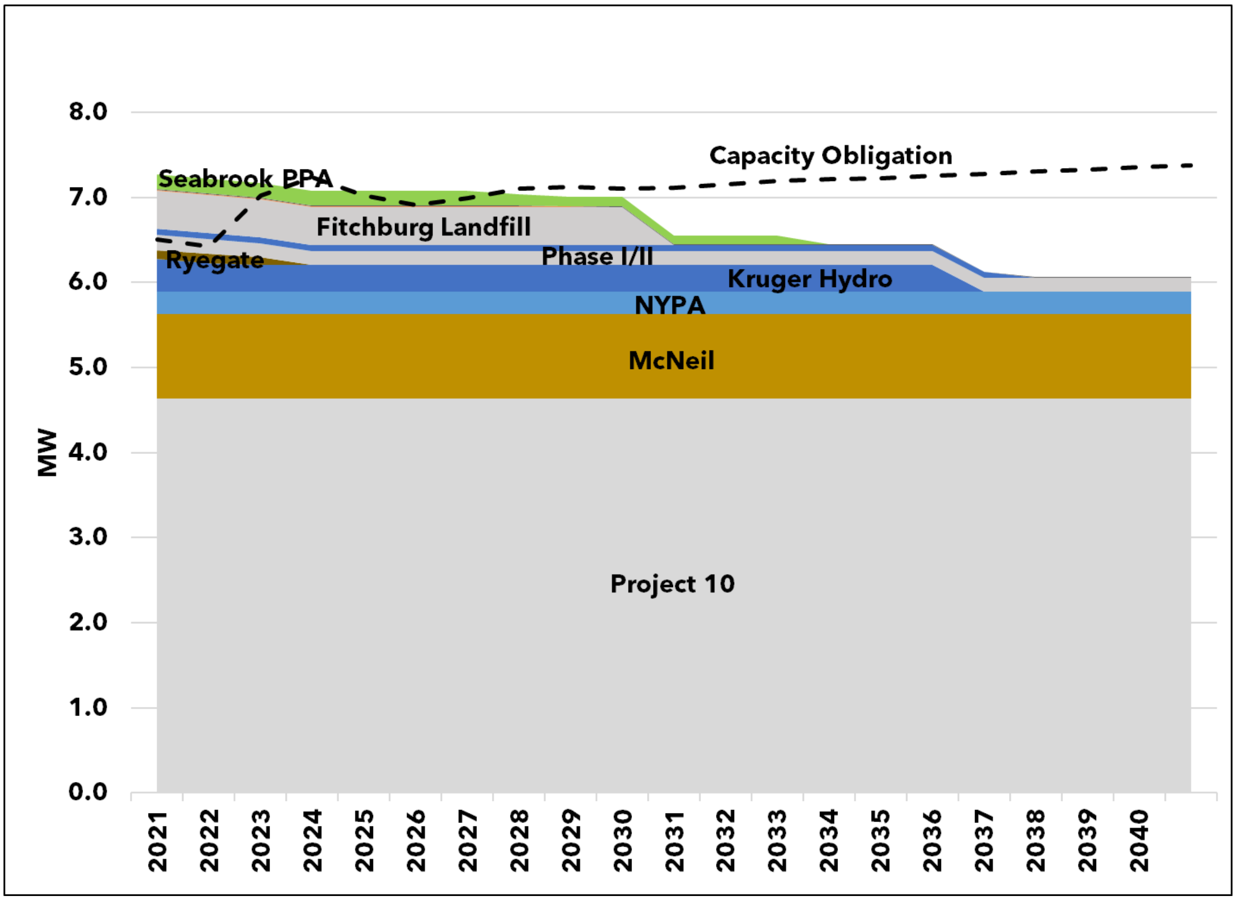
Table 12: Energy Resource Decision Summary

Resource	Years Impacted	% of MWH	Rate Impact	RES Impact
NextEra 2018-2022	2023+	10%	Increase	None
Fitchburg Landfill Gas	2026 & 2031	12%	Neutral	Possible
Brookfield Hydro	2028+	18%	Increase	Yes

CAPACITY RESOURCE PLAN

Figure 7 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. In any event, two resources provide about 80% of NED's capacity. In 2023, Project 10 provides about 66% and McNeil provides another 14%.

Figure 7: Capacity Supply & Demand (Summer MW)



Because the supply of capacity is about equal to 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[6] (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 $17,000 payment or pay up to a $19,000 penalty during a one-hour scarcity event. This represents a range of plus or minus sixteen to 30% of NED's 2022 monthly capacity budget. However, such events occur infrequently (only once since 2018), and they frequently last less than one hour.

Table 13: Pay for Performance Ranges for One Hour of Project 10 Operation[7]

ISO-NE Load	Performance Payment Rate	0% Performance	50% Performance	100% Performance
10,000	$5,500/MWH	-$8,400	$4,400	$17,100
15,000	$5,500/MWH	-$12,000	$700	$13,500
20,000	$5,500/MWH	-$15,700	-$2,900	$9,800
25,000	$5,500/MWH	-$19,300	-$6,600	$6,200

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

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

RENEWABLE ENERGY STANDARD (RES 1.0) REQUIREMENTS

NED's obligations under the Renewable Energy Standard (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 2022 to 75% in 2032, and the Distributed Renewable Energy (Tier II) requirement rises from 4.0% in 2022 to 9.4% in 2032. Note that this plan assumes that both the Tier I and Tier II requirements are maintained at their 2032 levels throughout the rest of the study period.

Under RES, the Tier II requirements are a subset of the Tier I requirements. As a result, we subtract the Tier II percentage from the Tier I percentage to get the Net Tier I requirement in the fourth column. Notice that the net Tier I requirement declines every second and third year until the Tier I requirement increases. When these percentages are multiplied by the forecast of retail sales, the result is a seesaw effect where the Net Tier I requirement declines every second and third year. This effect can be seen more clearly in Figure 8 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
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%
2033-42	75%	10.00%	65.00%	0.00%

The final column shows the Energy Transformation (Tier III) requirement. Note that the Tier III requirement is zero in the 2033 to 2042 period. This is due to the fact that the RES statute does not define an obligation during these years. We assume that the 10.67% requirement holds steady through these years.

Because it is designed to reduce fossil fuel use, the Tier III requirement is fundamentally different from Tier I and Tier II requirements. Unlike the Tier I and Tier II requirements…which count only electricity that is produced and consumed in an individual year[8]…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 CCHP are counted such that the full ten-years of the CCHP's expected useful life accrue to the 2022 Tier III requirement.

Table 15: ACP Prices[9] ($/MWH)

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

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

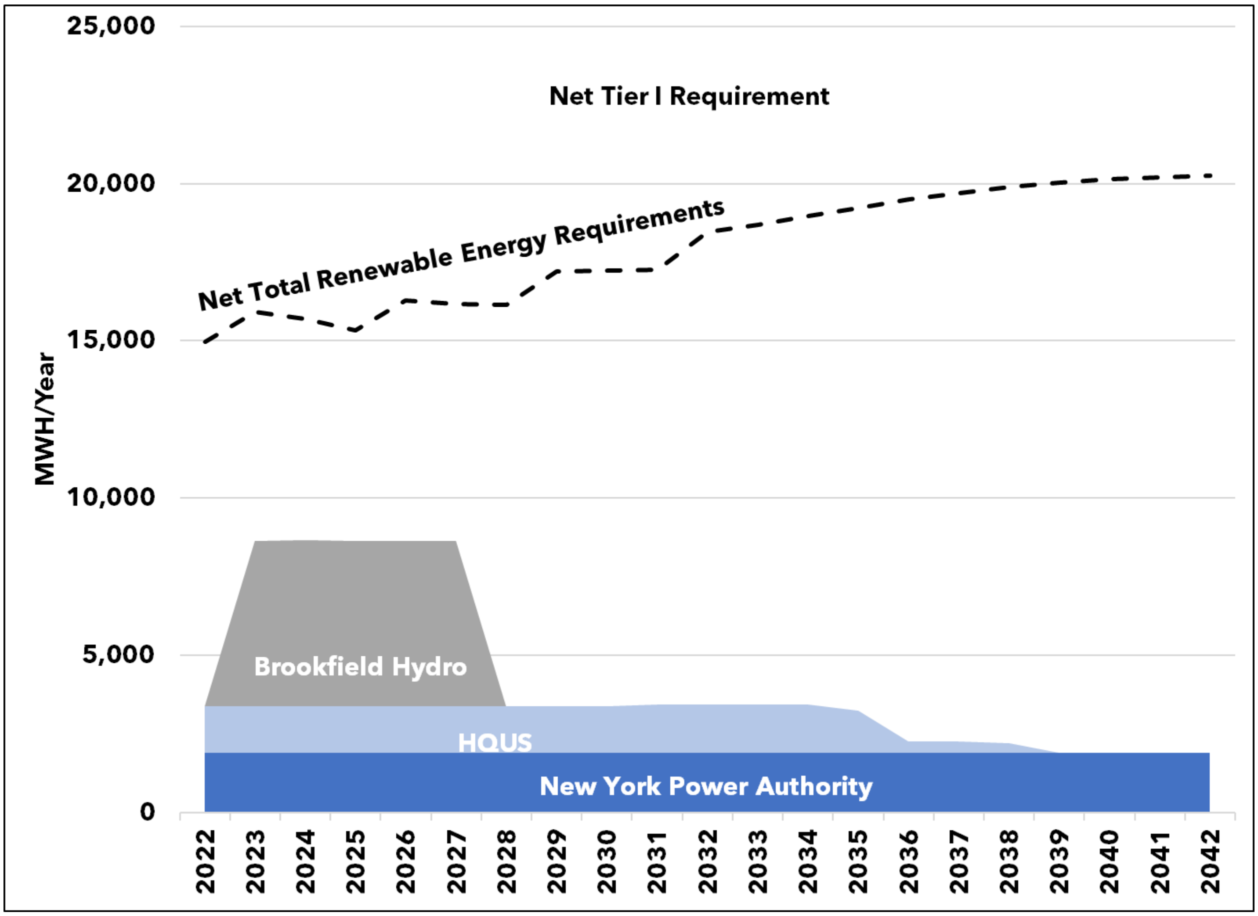
[8] For simplicity, we assume that no banking occurs in this example. In practice, banking excess TIER I and TIER II credits for use in future years is permitted under RES.

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

TIER I - TOTAL RENEWABLE ENERGY PLAN

Between 2023 and 2027, NED's Net Tier I requirement is about 16,000 MWH per year. There are three hydroelectric resources that contribute to meeting the Net Tier I requirement; NYPA, HQUS, and the Brookfield Hydro PPA. These resources add up to about 8,600 MWH per year or 55% of NED's Net Tier I requirement. Through 2027, the remaining Net Tier I requirement (deficit) is about 7,000 MWH.

Figure 8: Tier I - Total Renewable Energy Supplies

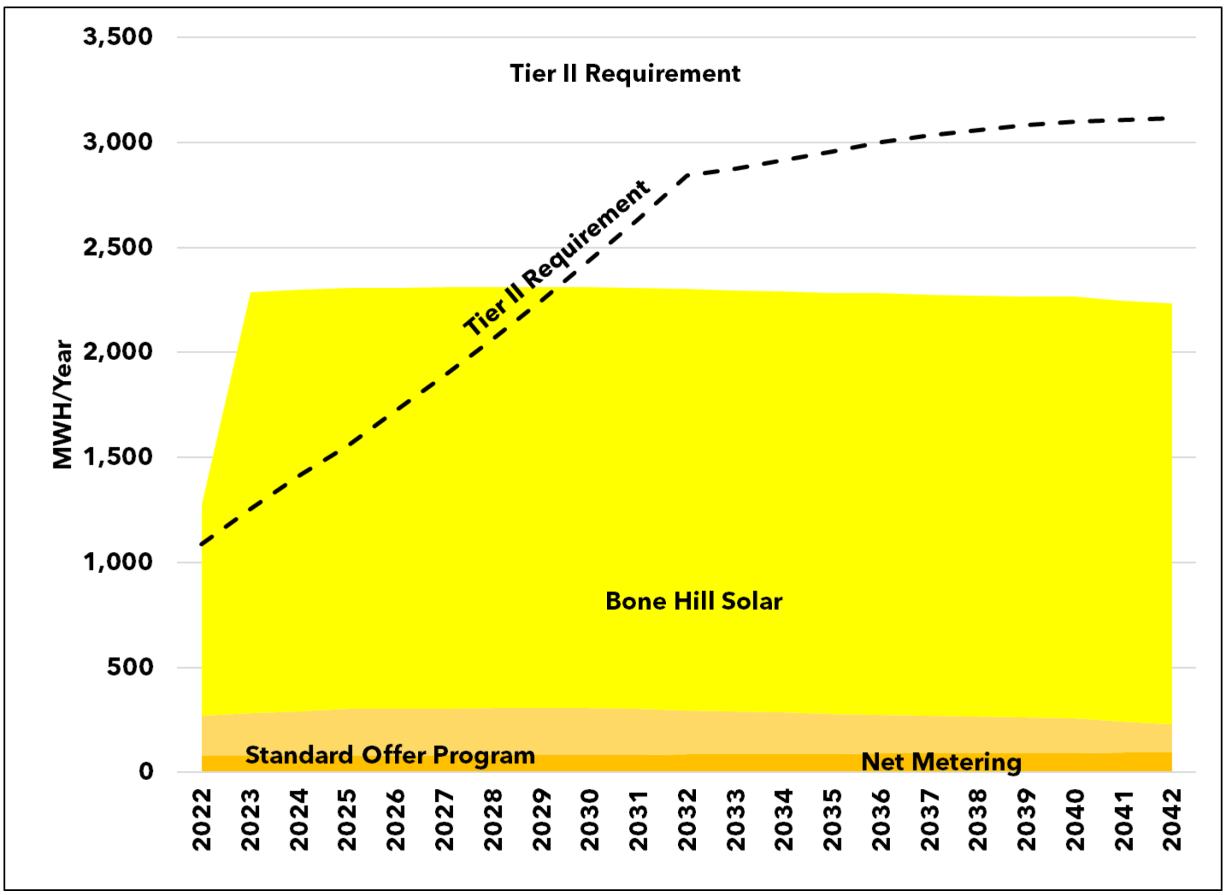


NED is likely to meet its Net Tier I requirements by purchasing Maine Class II (ME II) Renewable Energy Credits (RECs). These are presently the lowest cost source of Tier I-compliant RECs in the region, and their price has ranged from a low of $1.00 to a high of $10.00 per MWH over the past five years. At the current price of $10/MWH, the cost of complying with Net Tier I between 2023 and 2027 with ME II RECs would be about $77,000 per year.

TIER II - DISTRIBUTED RENEWABLE ENERGY PLAN

The dashed line in Figure 9 shows NED's Distributed Renewable Energy (Tier II) requirement, which rises steadily from 1,250 MWH in 2023 to 2,800 MWH in 2032. NED is presently working to commission a 1.25 MW AC solar facility within its service territory to meet this need. The Bone Hill Solar Project was developed through a partnership between VPPSA and Encore Renewable Energy[10], and it will soon provide enough RECs to fulfill NED's Tier II requirement through 2030, plus a surplus that can be used toward its Energy Transformation requirement.

Figure 9: Tier II - Distributed Renewable Energy Supplies

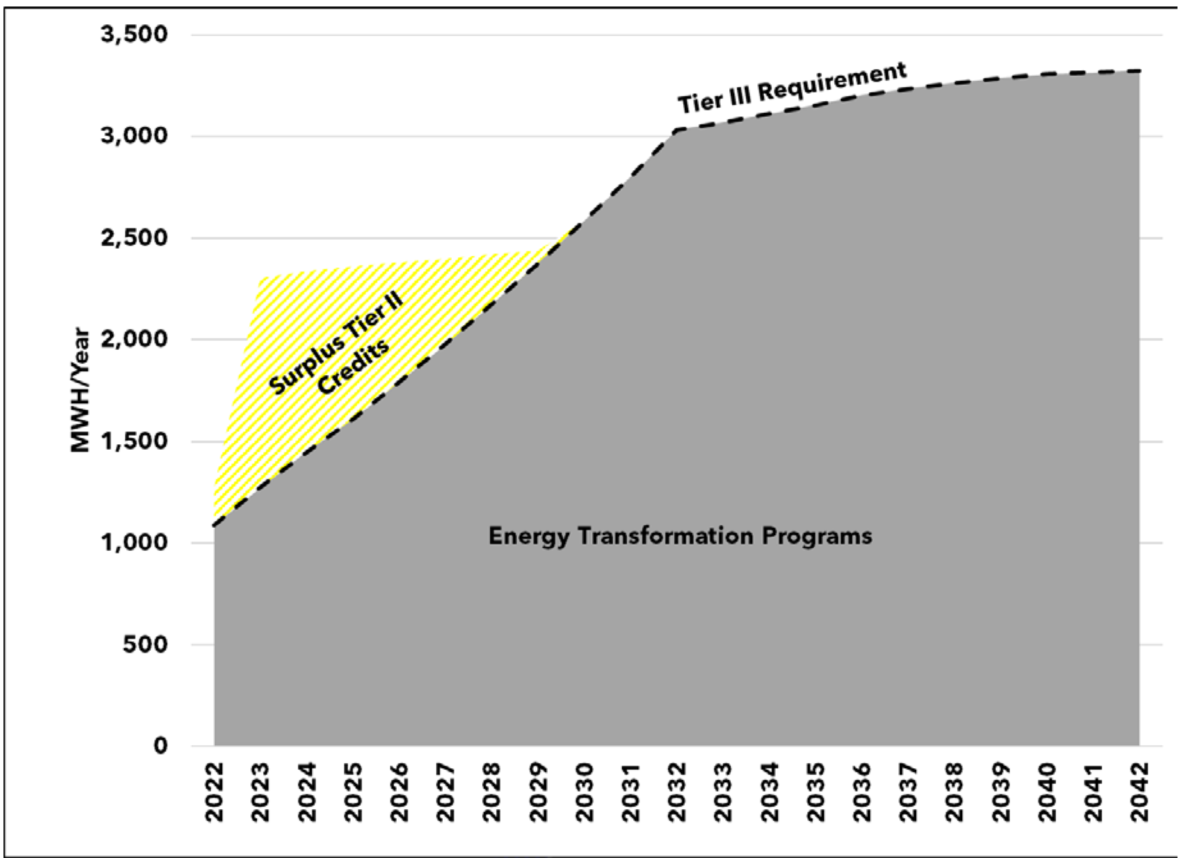


[10] https://encorerenewableenergy.com/vermont-public-power-supply-authority-and-encore-renewable-energy-partner-to-increase-solar-generation-for-member-communities/

TIER III - ENERGY TRANSFORMATION PLAN

The dashed line in Figure 10 shows NED's Energy Transformation (Tier III) requirements, which rise from about 1,000 MWH in 2022 to 3,000 MWH in 2032. Prescriptive programs are presently budgeted to fulfill the entire requirement, and are shown in the gray-shaded area of Figure 10. These programs cover a range of qualifying technologies including EVs, CCHPs, and HPWHs. More detail on these programs can be found in Appendix A (VPPSA's 2022 Tier 3 Annual Plan) and in the following section.

Figure 10: Energy Transformation Supplies



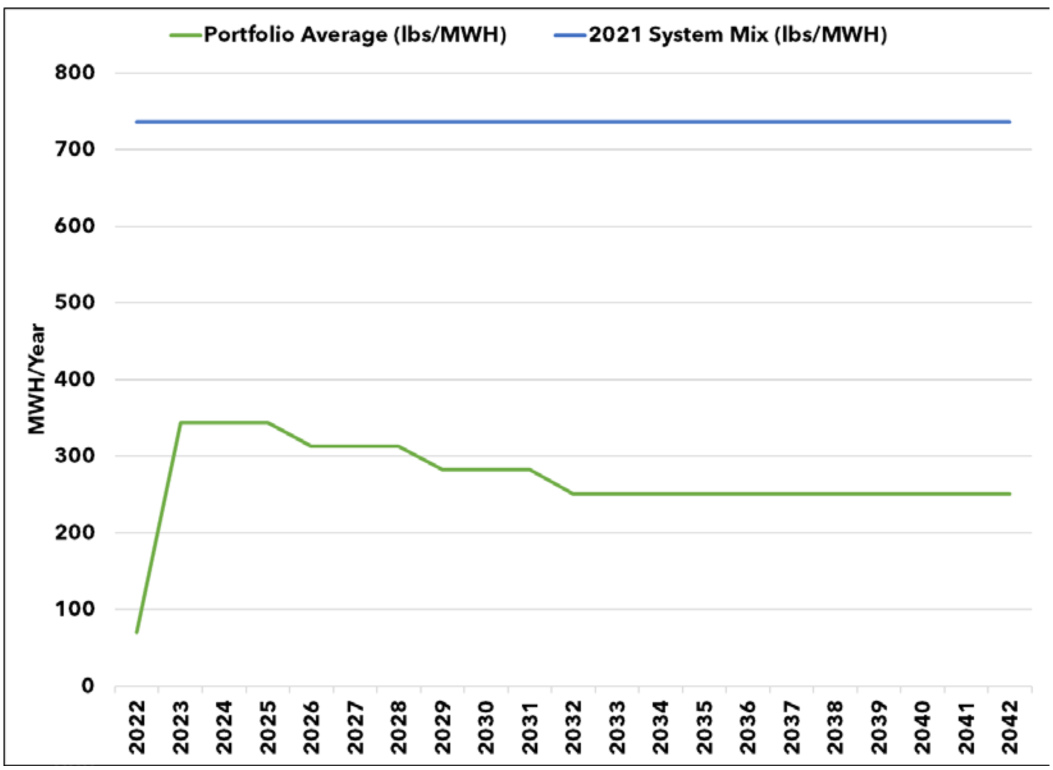
Between 2022 and 2029, the Bone Hill solar project is expected to create a Tier II surplus that could be applied toward the Tier III requirements. However, those credits are likely to be more valuable if they are sold as Tier II to other utilities. If prescriptive programs do not fulfill the entire requirement, custom Tier III projects may fill the gap as contemplated in the Tier 3 Annual Plan. NED will follow a three-part strategy to fulfill its Tier III requirements.

1. Identify and deliver *prescriptive* Energy Transformation ("Base Program") programs, and/or
2. Identify and deliver *custom* Energy Transformation ("Custom Program") programs, and/or
3. Manage Tier II credits to maximize value across both Tier II and Tier III requirements.

CARBON EMISSIONS AND COSTS

Figure 11 shows an estimate of NED's carbon emissions rate compared to the 2021 system average emissions rate in New England[11]. The emissions rate in 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 about 350 lbs/MWH because the NextEra contract has been partially replaced with the Brookfield Hydro PPA and some market-base (natural-gas fired) supply. We assume that the carbon emissions rate of these MWH will be equal to the 2021 NEPOOL Residual Mix which is a proxy for the fossil fuel emissions rate in the region.[12]

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



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

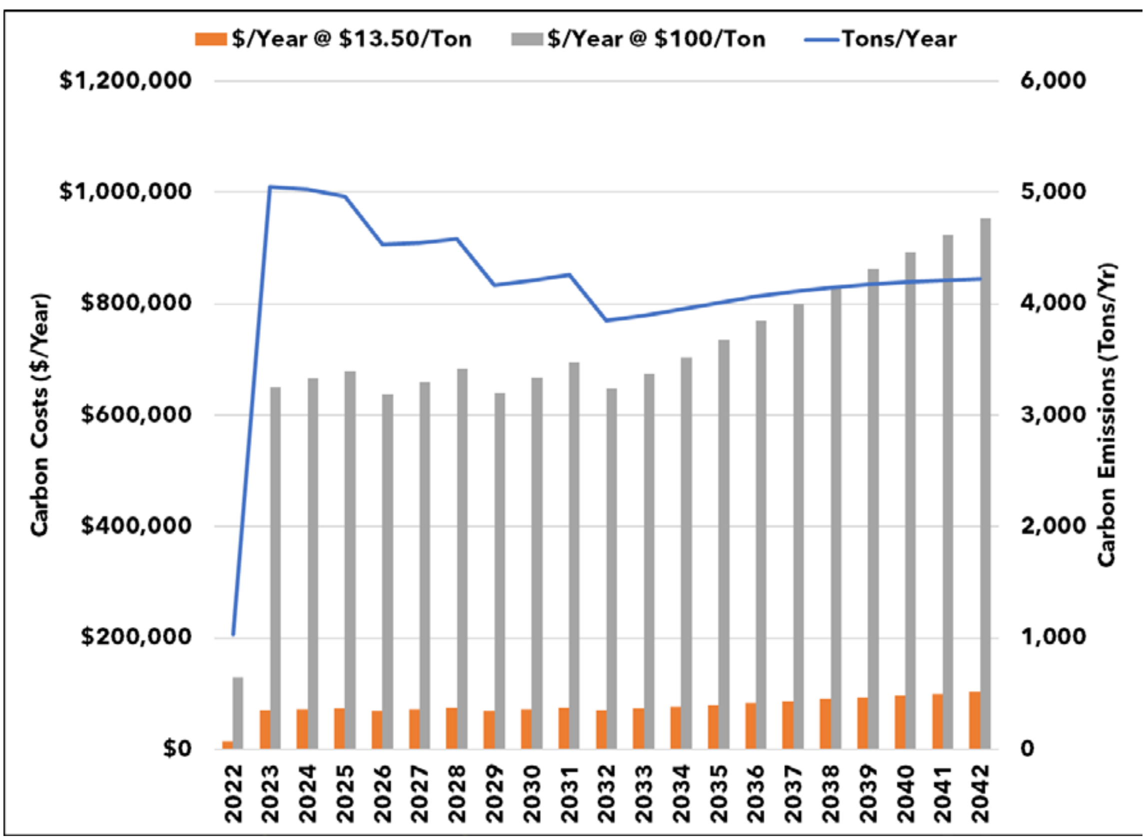
[12] For the current value of the NEPOOL Residual Mix, please visit https://www.nepoolgis.com/public-reports/.

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

These emissions rates were multiplied by the load forecast from Section I. Electricity Demand to arrive at an estimate of carbon emissions in tons per year. The following figure shows that carbon emissions range from about 1,000 tons/year in 2022 up to 5,000 tons/year in 2023, and then decline as the RES requirement increase over time.

The costs of these emissions were calculated using two sources, the 2021 Regional Greenhouse Gas Initiative Auction (RGGI) results ($13.50/ton) and the 2021 Avoided Cost of Energy Supply (AESC) study ($125/ton). Using RGGI prices (plus inflation), the cost of carbon emissions in 2022 is $14,000/year and about $70,000/year in 2032. Using AESC prices, the range is $130,000/year in 2022 up to almost $650,000 per year in 2032.

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



RES 2.0 REQUIREMENTS

Because there is discussion in the Vermont legislature to increase the RES requirements, we have analyzed the impact of a 100% by 2030 Tier I requirement and a doubling of the Tier II requirement. In addition, we assume that the Tier III requirements stays the same through 2032, and that they continue to increase by 0.67% per year through the forecast period. This would result in a Tier III requirement of 17.34% in 2042. Figure 13 shows the year by year trajectory of these changes to the RES.

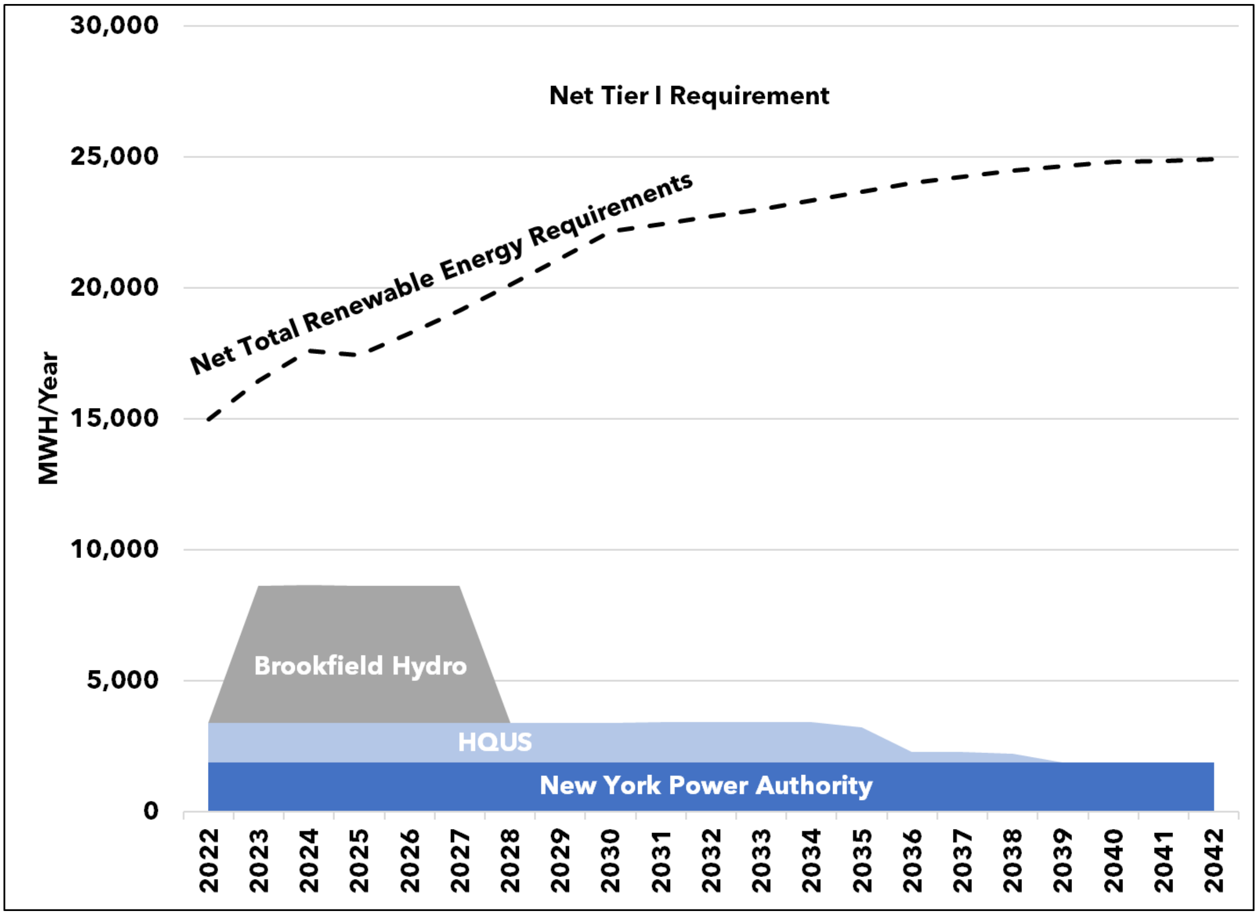
Figure 13: RES 2.0 Requirements

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

TIER I - TOTAL RENEWABLE ENERGY PLAN

Under a 100% by 2030 Tier I requirement, NED would need 80% of its supply to come from Tier I resources. This may seem counterintuitive, but it is a basic feature of the RES. The Tier II requirement would be 20% by 2030, and Tier I's requirement is net of Tier II. In any case, NED's requirement would rise from 9,000 MWH per year in the mid 2020s to 19,000 per year in 2030.

Figure 14: Tier I Requirements Under RES 2.0



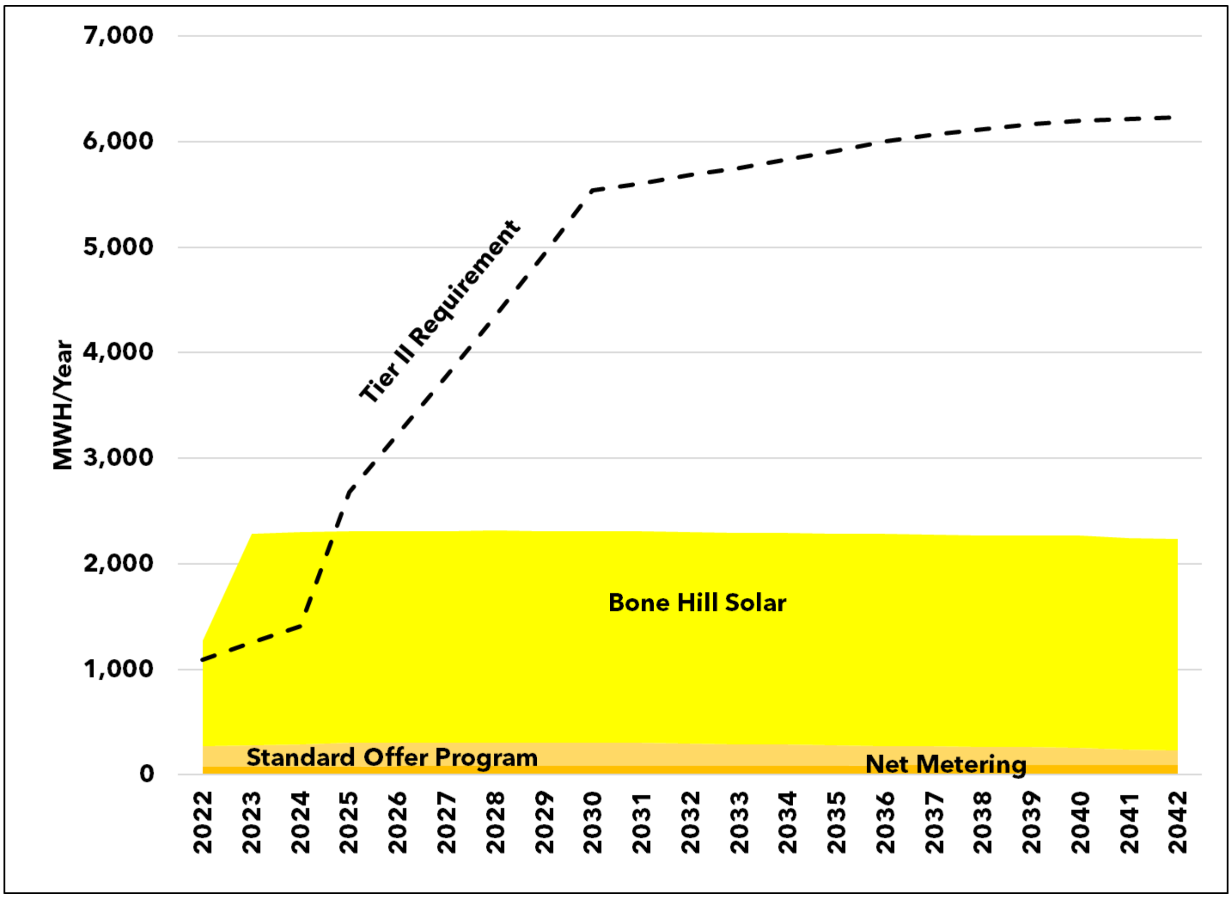
NED could meet this requirement by purchasing any number of hydro resources in New England, but it could also purchase a wind resource, whose Class I RECs could be resold and act as a hedge against the cost of Tier I RECs. The financial impact of this strategy will be measured in the Financial Analysis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

TIER II - DISTRIBUTED RENEWABLE ENERGY PLAN

The impact of a 20% by 2030 Tier II requirement is shown in Figure 15. In 2030, the requirement rises to 5,500 MWH per year, and as a result, a new 2 MW resource would be needed to fulfill and maintain Tier II requirements through the 2030s. The cost of this resource will be measured in the Financial Analysis section.

Based on forecasted load, we are seeing that raising Tier II requirements raises a question of whether we will have sufficient load to absorb the additional solar and operate the distribution system safely at these levels.

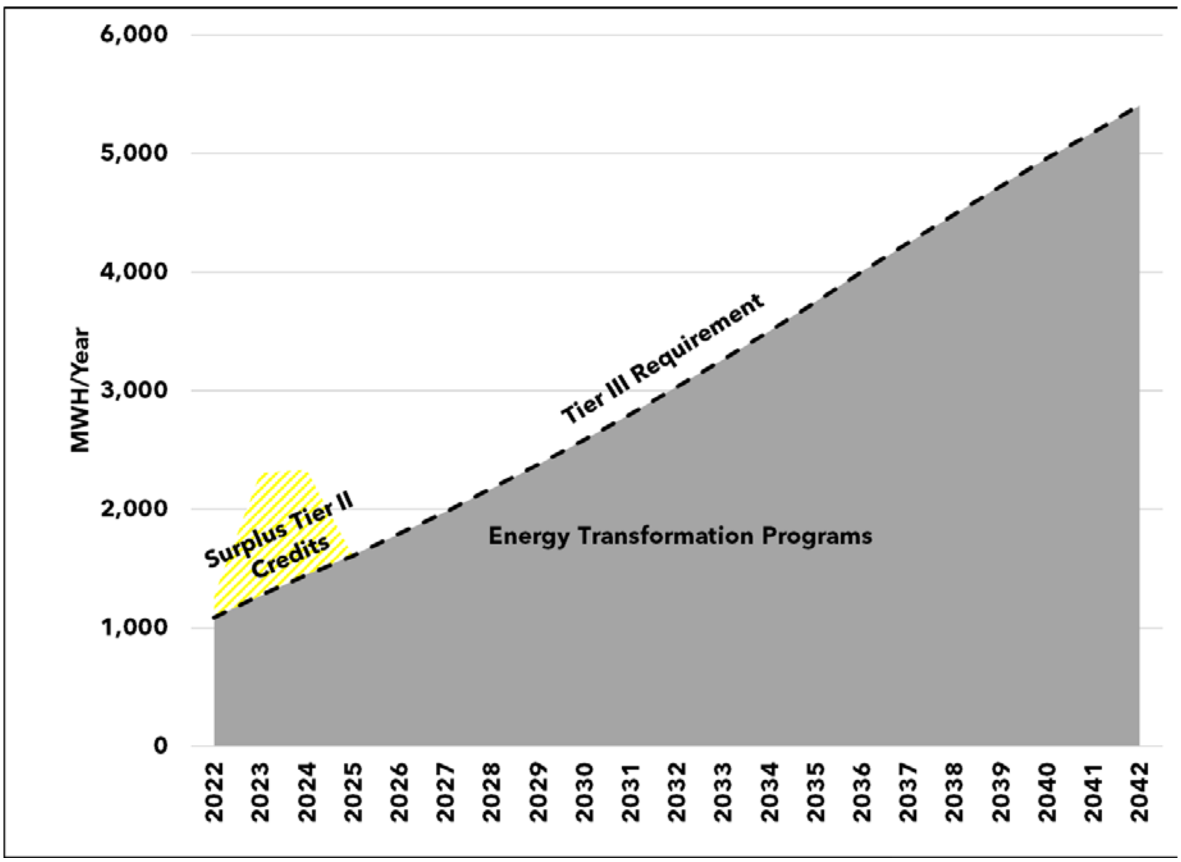
Figure 15: Tier II Requirements Under RES 2.0



TIER III - ENERGY TRANSFORMATION PLAN

The dashed line in Figure 16 shows NED's Energy Transformation (Tier III) requirements, which rise from about 1,000 MWH in 2022 to 5,500 MWH in 2042. This level of market support may be necessary to support high penetrations of electrification technologies. In keeping with the current RES assumptions, prescriptive programs are assumed to fulfill the entire requirement, and are shown in the gray-shaded area. The cost of running these programs will be measured in the Financial Analysis section.

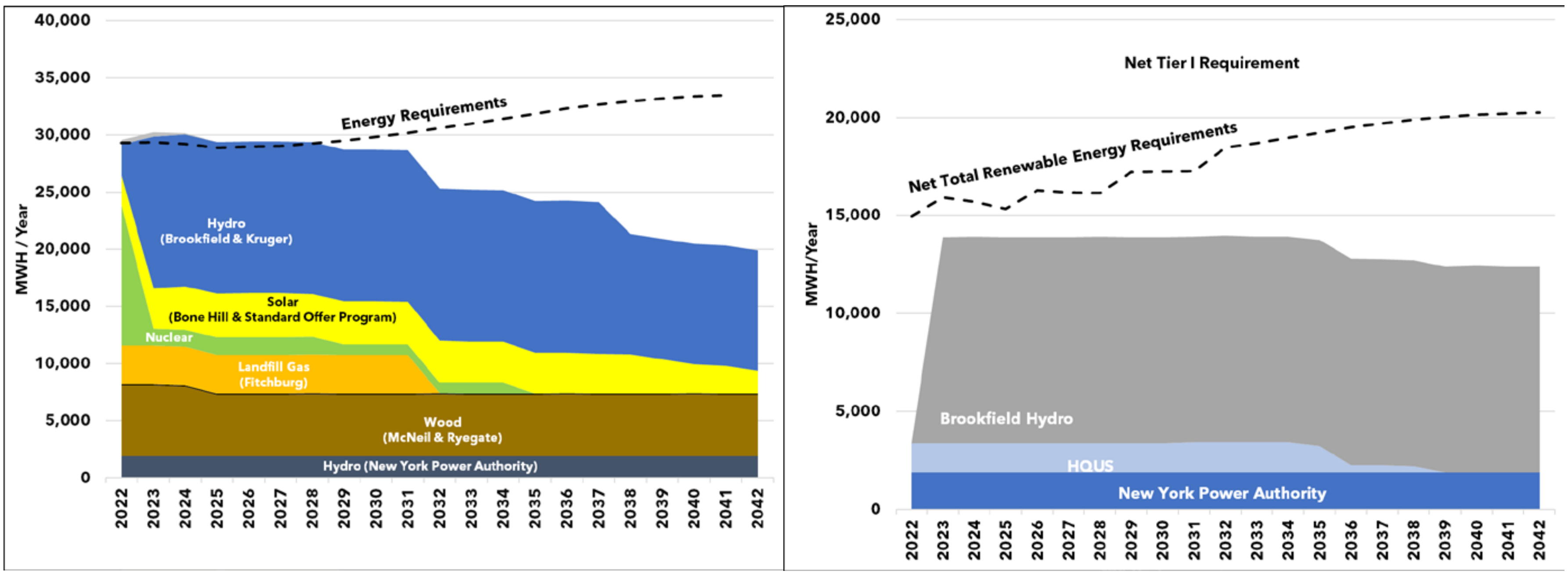
Figure 16: Tier III Requirements Under RES 2.0



PROCUREMENT PLAN FOR RES 1.0

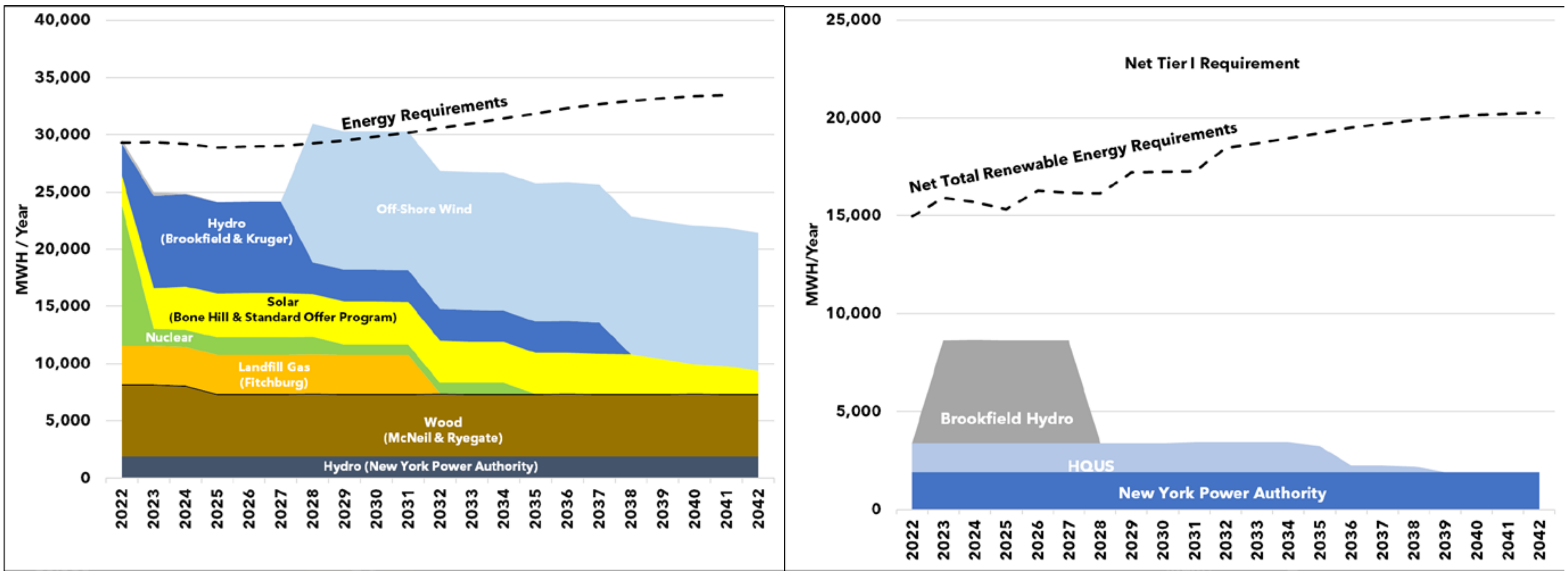
Under RES 1.0 requirements, NED has two primary options to procure the energy and Tier I RECs that it requires. First, it can purchase more hydro energy that is bundled with Tier I RECs. A doubling of the existing Brookfield contract, from 0.6 MW to 1.2 MW 7x24, would fulfill NED's energy requirements through 2030. However, it would leave NED 15-20% short of the Tier I RECs that it needs. However, this is a manageable level of REC market exposure, and multi-year REC contracts are beginning to become available if NED wishes to hedge the remaining risk.

Figure 17: RES 1.0 Option 1 – Hydro Energy & Tier I RECs Compared to Requirements



The other option to fulfill RES 1.0 is to purchase 3 MW of offshore wind energy and Class I RECs. The disadvantage of this approach is that the resource wouldn't be available until later this decade, it would be intermittent, and it would provide RECs that are not required under the RES. However, the seasonal shape of the resource is beneficial because it peaks in the winter, and the Class I RECs would be an effective hedge against the price of buying Tier I RECs for compliance.

Figure 18: RES 1.0 Option 2 – Off-Shore Wind Energy & Class I RECs Compared to Requirements



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

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

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

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

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

Table 17: Bundled Hydro Vs. Offshore Wind Costs (Levelized $/MWH, 2028-2042)

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

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

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

PROCUREMENT PLAN FOR RES 2.0

The procurement plan for meeting RES 2.0 involves a mix of three resources. First, the Brookfield Hydro PPA would need to be doubled from 2023-2027. This step meets NED's energy requirements, but also leaves NED in a deficit position on Tier I RECs. Second, the offshore wind resource is procured in 2028, but only 2 MW is required. This leaves room for the third resource, 2.1 MW of new solar, that would be required to meet a 20% by 2030 requirement under Tier II.

Figure 19: RES 2.0 Energy Resources Compared to Requirements

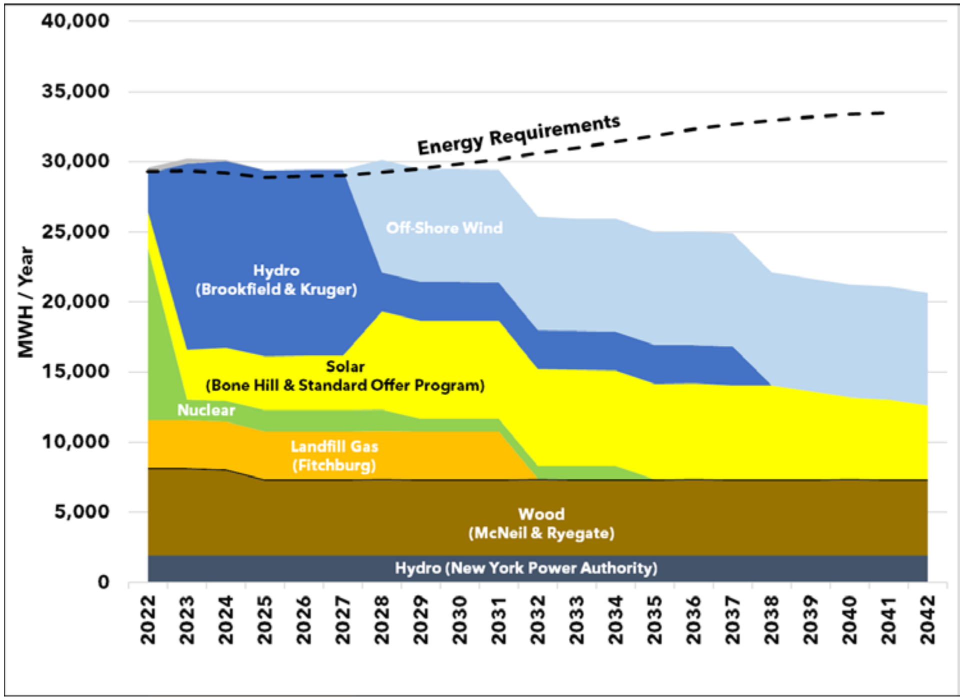
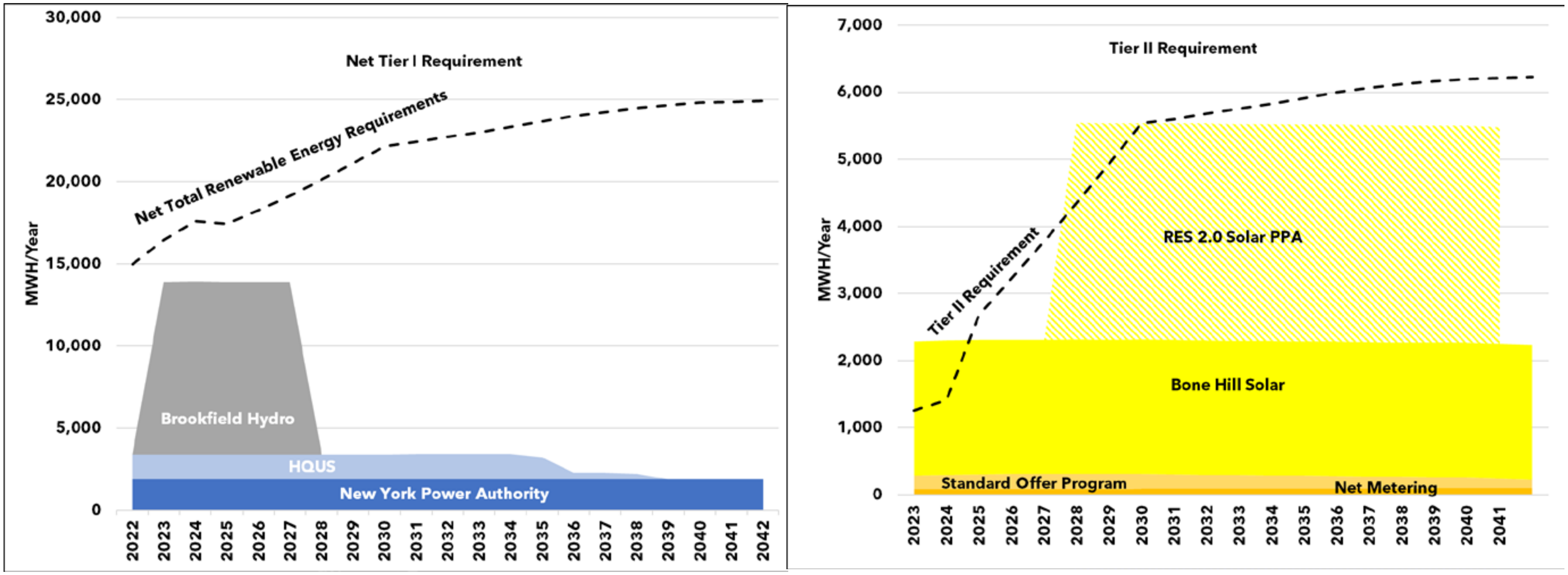


Figure 20: RES 2.0 Tier I and Tier II Resources Compared to Requirements



The timing and magnitude of the hydro and offshore wind resource procurements can change, and economics and resource availability will ultimately determine which resource is procured.

RESOURCE PLAN OBSERVATIONS

A number of observations can be drawn from these resource plans. First, although meeting additional Tier I and Tier II requirements by 2030 is feasible, there are some limits and some trade offs. For example, NED's ability to meet a 100% Tier I requirement by 2030 is limited by the amount of bundled energy and Tier I RECs that it can procure between 2023 and 2030. Why? NED's energy requirements are fulfilled before its Tier I requirements are fulfilled. As a result, a 100% Tier I requirement would force NED to procure an unbundled Tier I REC contract. This is commercially feasible in the 1-3 year time frame, but is untested in the 5-20 year time frame. As a result, RES 2.0 requirements would add both additional cost and Tier I REC price risk.

Similarly, there is a limit to the amount of Tier II resources that NED's can reasonably develop and use. NED's service territory is limited in both area and in suitable terrain. Furthermore, NED already has sufficient volumes of existing daytime resources, namely the Chester Solar, Bone Hill Solar, HQUS, McNeil and Standard Offer Resources. As a result, any additional daytime resources (solar) will often be exported. This energy has financial value because there is a market (ISO New England) in which to liquidate it. However, it has limited value as a physical resource when there is insufficient load, and absent a large and cost-effective storage resource, it has no value during the night-time hours, when the major electrification technologies (EVs and heat pumps) are expected to be charging or operating.

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

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. 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. Green Mountain Power (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 while reading meters;
- Act 250 requests; and
- System reliability data.

The distribution circuits that had the greatest number of outages in 2021 were the 54G1 and 54G3, where both circuits had five outages each. There were various causes for the five outages on each of those circuits, but they were the same reasons for the same number of outages on both circuits. Two were caused by trees. Two were caused by equipment failures. One was caused by weather. In addition to the outages discussed above, there was also a system-wide power supplier outage and a system-wide outage caused by an animal in 2021. On one of the feeders, there were many outages due to lines coming down. The cause was attributed to dissimilar metals causing connections to fail. To decrease the number of outages and improve reliability, GMP has replaced all of those connections.

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 1.3% for 2021.

System losses in 1998 were over 8%. Reconductoring and voltage upgrade in 1999 significantly reduced system losses. 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.

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.

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 essentially unity.

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. A tie switch was recently installed between two of the King Street feeders outside of the substation. The other two feeders had a tie switch previously installed.

SYSTEM PROTECTION PRACTICES AND METHODOLOGIES.

PROTECTION PHILOSOPHY

The NED system is small and compact consisting of two distribution substations and a total of four 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 AMI

Beginning in 2018, NED began participating in a multi-phased, VPPSA joint-action project intended to assess individual member readiness for AMI, guide participating members through an RFP process culminating in vendor and equipment selection and implementation.

Vermont Public Power Supply Authority (VPPSA) contracted with Lemmerhirt Consulting to evaluate its member utilities readiness for an Automated Meter Infrastructure (AMI) in its territory. This effort was to provide a current assessment of business processes, systems, and equipment in place that would be impacted by AMI and evaluate the suitability, uses, challenges, and benefits for AMI at NED. Since the Town of Northfield provides both electric and water services, this evaluation covered an AMI implementation for both services. AMI is a major technical and business transition for any utility and provides a platform to improve operational efficiency, reliability and customer service, including new functionality such as time-of-use or dynamic rate plans for customers, demand response programs, grid management improvements, and greater customer engagement.

Lemmerhirt Consulting visited and interviewed each member utility, gathering data from utility staff and driving around the service territory to assess challenging geographic areas for AMI suitability. The Readiness Assessment addressed ten functional areas in some detail, rating the member system's readiness for each functional area according to the following criteria:

Table 18: AMI Readiness Assessment Criteria

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

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

For a successful AMI project, the utility team and staff must be interested and receptive to adopting new technology and new ways of doing business. NED recognizes emerging requirements and value for AMI in offering more customer services such as time-of-use rates and self-service options; measuring and monitoring new technology - electric vehicles, distributed generation; distribution grid improvements by adopting programs like Conservation Voltage Reduction or Volt/Var Reduction. Since the Town of Northfield provides water service, there is the benefit of adding water metering to the solution, ultimately strengthening an AMI business case. The Readiness Evaluation is summarized in the table below:

Table 19: AMI Readiness Evaluation

Overall AMI Readiness	Rating
Electric Meter Readiness	**Fair**
Water Meter Readiness	**Fair**
Meter Reading Readiness	**Fair**
Billing and IT Readiness	**Fair**
Customer Engagement Readiness	**Fair**
Electric Distribution Readiness	**Fair**
Outage Management Readiness	**Fair**
Water Distribution System Readiness	**Good**
Telecommunications Readiness	**Good**
Asset Data Readiness	**Fair**
Overall	**Fair**

Following the Readiness Assessment, an RFI was developed and issued to multiple vendors with an eye toward learning more about potential available solutions and identifying well qualified partners. The Respondents to the RFI were required to describe the general AMI solution(s) being proposed, the respondent's experience with AMI systems and whether their proposed solution(s) included functionality for water system operation and could be shared by all VPPSA members and centrally operated. Further detail regarding the respondent's experience, contract negotiation process, product roadmap and project management/professional services capability was also requested.

In broad terms the "must have" features for proposed solutions included the following features:

- Support both Electric & Water meter operations,
- Support multiple meter manufacturers,
- Multiple communication options to address hard to reach areas,

- Service level agreement,
- Hosted software solution for required Head End, Meter Data Management System (MDM) etc.,
- Multi-tenant software – segregate multiple members data in central database
- Support distribution automation/management capabilities

In support of these goals respondents were asked to respond to a series of detailed technical questions (See Appendix D – AMI RFI Technical Requirements) with respect to:

- Electric & Water Meters
- The AMI network/communication
- Head end software, MDM capabilities and other system tools
- Water system functionality and
- Project Plan & pricing

VPPSA received responses from 7 vendors which were evaluated by a team made up of a mix of about 20 VPPSA /Member management, staff, and consulting personnel. Members of the evaluation team reviewed the RFI responses to the detailed technical questions for completeness and "fit" and assigned a numerical ranking to each. Ultimately, the rankings were aggregated, and the three highest scoring vendors were selected to participate in the subsequent RFP.

Subsequent to evaluation of the responses to its RFI, VPPSA issued an RFP to three chosen vendors; Aclara Technologies (Aclara),, Hometown Connections Inc, and Landis & Gyr. Respondents were asked to "…fully address the requirements of this solicitation related to performing all required work, including site assessment, drawings and document submittals, manufacturing, testing, delivery and technical support during and after installation. This general statement of scope aligned with the RFP's stated selection criteria:

Proposals will be reviewed, evaluated, and ranked utilizing the following criteria:

- Price (20%)

- Experience Qualifications (15%)
- Technical and Non-Technical Requirements (30%)
- Project Delivery (15%)
- Ongoing Support (20%)

VPPSA reserved the right to award this contract to the Proposer providing the best overall match to the RFP requirements and which best serves the interest of VPPSA and its members.

Key requirements for the RFP were similar to those mentioned above for the prior RFI with emphasis on a hosted software solution that included functionality for both electric and water meters to be centrally purchased and share the same network with no collector device being a single point of failure, have one set of software licenses and have all data in a common, multi-tenant database with the ability to view individual member data and also access data as a group. In addition, the AMI solution was required to deliver data to each member's CIS. The detailed technical requirements are provided for reference in Appendix E (AMI – RFP Technical Requirements).

During the evaluation phase the three vendor responses were reviewed, discussed and scored by a group of about 20 staff and management personnel drawn from both VPPSA and individual VPPSA members. Early in that process the proposal From Landis & Gyr was eliminated from further consideration because it did not include the required MDM feature. Ultimately the Aclara proposal was selected for final contract negotiation; key factors in the Aclara proposal's favor included its fully integrated, single vendor aspect and its ability to meet several key requirements including:

- Single License (not separate licenses for individual VPPSA members)
- A hosted multi-tenant head end and MDM
- Inclusion of propagation study – confidence around cost estimates
- Licensed RF communication system; better penetration
- Reporting flexibility
- Customer support

The proposed Aclara system relies on a two-way, fixed base RF network that provides its meter-reading solutions through a secure, long-range wireless network using private licensed radio channels in the 450 - 470 MHz band. Built-in redundancy through multiple collection and processing paths without the use of repeaters prevents single-point failures from disrupting normal operation of the entire network. A failure of one DCU network device does not affect the entire network. The Aclara RF network uses conservative design, built-in redundancy, and continuous operation of multiple communication routes to prevent single-point failures from disrupting normal operation. The Aclara ONE headend and meter data management (MDM) system is hosted, multi-tenant software that will allow VPPSA members to see only their own data while providing VPPSA with an overview of the entire network and total distribution of electric and water across all members.

Northfield expects to benefit from AMI implementation in a number of ways:

- Collection of interval data to support cost of service and innovative rate design
- Offer energy programs for customers to promote beneficial load management
- Increase customer engagement in their use of electricity and water resources,
- Planning of future capital/T&D system investment strategies
- Comply with future regulatory and legislative requirements
- Reduction of overall meter reading impacts on staff and time
- Improve re-read needs and billing errors
- Reduce cost of non-pay disconnect/reconnect, move-in/out (off-cycle reads)
- Improve billing and customer care services
- Identify and reduce theft of service
- Improve accuracy of electric and water metering
- Optimize electric metering benefits such as transformer right-sizing
- Improved system planning capabilities and water resource management
- Improved water distribution system asset performance
- Reduced carbon footprint

In terms of business case, a cost benefit assessment, looking at about 20 areas of potential benefit, spanning field operations, metering and meter operations, billing, and customer and related rate programs was performed. This assessment indicates a positive NPV benefit in excess of $1 million, with a positive cost-benefit ratio of 2.08 and a 4.8-year payback, providing Northfield with reassurance that proceeding to the implementation phase is the correct decision. Note that the figures shown in this assessment are exclusive of any anticipated, but unconfirmed, state funding opportunity. While negotiation of a final contract with Aclara is ongoing at this time, Northfield is optimistic that it will begin implementation of a new AMI system during the second half of 2022, to be completed during 2023.

GEOGRAPHIC INFORMATION SYSTEM

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

CYBER SECURITY

2020 was a cybersecurity turning point for many industries around the globe as nefarious digital attacks threatened to hold organizations hostage and utility regulators at the state and federal level increased focus on cybersecurity. NED is 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.

VPPSA has initiated a cyber program that all members have access to and is working with each member individually to determine what the best approach is given individual member resources. VPPSA's Technology and Security Services team continues to work with its vendor consultants, developing cybersecurity hygiene and best practices to protect VPPSA and those of its members who choose to take advantage of it.

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

OTHER SYSTEM MAINTENANCE AND OPERATION

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.

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 & DUAL POLE REPLACEMENT (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:

NED currently has 43 net-metered customers and an installed base of solar capacity of 862 kW. Three quarters of this capacity is from two large arrays, and another large array (350 kW) has been proposed. As a result, the growth in net-metered capacity is dominated by a few large systems.

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. 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.

DISTRIBUTION-LEVEL IMPACT OF ELECTRIFICATION

NED recognizes that developing and maintaining a distribution system capable of integrating both distributed generation and developing load concentrations resulting from beneficial electrification is a coming challenge. As electric vehicles, heat pumps, heat pump water heaters, electric mowers and other measures become more common, the need to upgrade or proactively manage portions of the distribution system is likely to increase. NED is beginning to focus on the challenge of identifying and tracking "hot spots" on the system as they develop, with an eye toward formulating timely responses, whether those be load management efforts, equipment upgrades, or addition of generation/storage at key locations.

At the present time NED is able to identify the location of distributed generation by circuit and has some limited location information with respect to individual customer adoption of electrification measures; tracking through incentive programs yields only partial information regarding the true adoption rate and location of various incentive measures. NED believes that the planned implementation of AMI will play a key role in providing appropriate tracking and analytics, enabling NED to develop timely distribution system management responses to locational trends and developing load concentrations.

The NED distribution system currently has sufficient capacity for the immediate foreseeable future. As Table 20 indicates, NED has two large solar projects and a handful of smaller net-metering units scattered across its system. NED is aware of other scattered electrification measures in place, but information on this front is incomplete. Maximum 15-minute loading on the King Street substation transformer is about 73% of it's nameplate capacity and about 47% on average. The Norwich Substation transformer sees maximum usage of about 25% of nameplate capacity; average loading is about 14% of nameplate.

Table 20: NED Distribution-Level Impact of Electrification

SUBSTATION	# of Transformers	Transformer Capacity	Peak % of Nameplate	Energy % of Nameplate (1)	CIRCUIT/ FEEDER	Circuit Voltage Kv	Solar/Hydro Dist. Generation # of Units	Solar/Hydro Dist. Generation kW	Storage kW	Large Load kW	Large Load kWh
King Street 54	1	7.5 MVA	73.3%	47.0%	54G1	12.47	20	470	-	1,037	4,371,640
King Street 54					54G2	12.47	2	205	-	138	419,440
King Street 54					54G3	12.47	9	64	-	106	408,080
King Street 54					54G4	12.47	19	1,882	-	100	238,200
3357 Feeder					3357	34.5	1	100		1,790	8,577,765
Norwich 55	1	5.0 MVA	25.1%	14.0%							
*(1) Annual kWh / (transformer capacity * 8760)*											
Prescriptive (HP,HPWH,etc) TIER 3 has limited availability											

Based on available information, NED's distribution system is adequate for the near future. Electrification impacts have yet to become an issue. As the anticipated AMI and GIS implementations reach maturity NED will be in position to continuously analyze load trends on a locational basis and respond in a timely fashion with appropriate load management and distribution upgrade programs.

VEGETATION 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 21 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 22 Northfield Vegetation Management Costs

	2019	2020	2021	2023	2024	2025
Amount Budgeted	$45,000	$45,000	$45,000	$45,000	$45,000	$45,000
Amount Spent (FY)	$49,321	$57,363	$25,047	x	x	x
Miles Trimmed	2.3	1.6	2.0	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 four 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.

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 are shown 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 Performance, Monitoring & Reporting 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 five years. NED's Vermont Public Utility Commission Rule 4.900 Electricity Outage Reports, reflecting the last five years in their entirety, can be found in the Appendices.

Table 23 Northfield Outage Statistics

	Goals	2017	2018	2019	2020	2021
SAIFI[13]	1.00	1.85	0.41	0.47	0.03	[14]4.44
CAIDI[15]	2.40	1.60	3.99	2.35	2.21	[16]2.83

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

[13] System Average Interruption Frequency Index

[14] SAIFI of 4.44 with major storms, SAIFI of 4.32 without major storms

[15] Customer Average Interruption Duration Index

[16] CAIDI of 2.83 with major storms, CAIDI of 2.62 without major storms

robust tree-trimming strategy and a cost-effective cutout replacement plan to address these two areas.

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, 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.

An animal contact at one of the substations, on June 28, 2021, was a major contributor to the increased SAIFI and CAIDI values for 2021. That event resulted in a system-wide outage that lasted over three hours. One power supplier outage (system-wide), in November, lasting forty-five minutes, and a major storm outage in January, were additional contributors to the elevated SAIFI and CAIDI values in 2021.

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.

NED notifies customers of planned outages either through a visit to the customer's premises or via a telephone call.

TREE-RELATED OUTAGES

Table 24 Northfield Tree Related Outages

	2017	2018	2019	2020	2021
Tree Related Outages	5	5	7	2	7
Total Outages	20	28	15	12	20
Tree-related outages as % of total outages	25%	18%	47%	17%	35%

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

HISTORICAL CONSTRUCTION COST 2019-2021

Table 25 Northfield Historic Construction Costs 2019-2021

Town of Northfield Electric Department		Historic Construction		
Historic Construction		2019	2020	2021
Pole Replacements	Dist	34,426		
Station Equipment	Dist	17,588		
Overhead Construction	Dist	35,894		
Transformers	Dist	29,757		
Services	Dist	6,557		
Metering	Dist	519		
Street Lighting- LED	Dist	875		
Bull Run Solar Project	Dist	70,707		
Mapping	General	6,689		
Computer Upgrades	General	1,286		
Pole Replacements	Dist		12,030	
Overhead Construction	Dist		13,953	
Transformers	Dist		23,648	
Services	Dist		6,936	
Solar Make Ready	Dist		3,847	
Computer Upgrades	General		3,178	
Substation- Battery Bank	Dist			42,555
Poles	Dist			17,008
Overhead Construction	Dist			22,525
Transformers	Dist			40,079
Services	Dist			1,544
Metering	Dist			2,661
Street/Yard Lighting- LED	Dist			651
Computers/Software	Dist			220
Solar Make Ready	Dist			26,559
Total Construction		$ 204,297	$ 63,593	$ 153,802
Functional Summary:				
Prod		$ -	$ -	$ -
General		$ 7,975	$ 3,178	$ -
Distribution		$ 196,322	$ 60,414	$ 153,802
Transmission		$ -	$ -	$ -
Total Construction		$ 204,297	$ 63,593	$ 153,802

PROJECTED CONSTRUCTION COSTS 2023-2025

Table 26 Northfield Projected Construction Costs 2023-2025

Town of Northfield Electric Department		**Projected Construction**		
Projected Construction		**2023**	**2024**	**2025**
	Trans			
Pole Replacements	Dist			
AMI / GIS	Dist	50,000		
Misc Plant	Dist	81,250		
	General	39,190		
Pole Replacements	Dist			
AMI / GIS	Dist		25,000	
Misc Plant	Dist		83,038	
Misc Plant	General		40,052	
Pole Replacements	Dist			
Misc Plant	Dist			84,864
Pickup Truck	General			45,000
	General			40,934
Total Construction		$ 170,440	$ 148,090	$ 170,798
Functional Summary:				
Prod		-		
General		39,190	40,052	85,934
Distribution		131,250	108,038	84,864
Transmission		-	-	-
Total Construction		170,440	148,090	170,798

V. FINANCIAL ANALYSIS

This section quantifies the costs of a Reference Case and a series of procurement scenarios that would fulfill RES 1.0 and RES 2.0 requirements as discussed in the Resource Plans chapter. It also includes a storage-only procurement to illustrate the cost saving potential of a MW-scale, peak-shaving battery. The characteristics of these scenarios are summarized in Table 27.

Table 27: Scenarios

#	Resource Scenario	Size	Term	Price
0	Reference Case	N/A	N/A	Monthly DALMP
1	RES 1.0 - Tier I with Hydro	1.2 MW	2023-2042	$66/MWH Levelized
1.1	RES 1.0 - Tier I with Offshore Wind	3 MW	2028-2042	$95/MWH Levelized
2	RES 2.0 Requirements	N/A	2023-2042	Monthly DALMP
2.1	RES 2.0 - Tier I with Hydro	1.2 MW	2023-2042	$66/MWH Levelized
2.2	RES 2.0 - Tier I with Offshore Wind	2 MW	2028-2042	$95/MWH Levelized
2.3	RES 2.0 - Tier II Solar PPA	2.1 MW AC	2028-2042	$90/MWH Levelized
2.4	RES 2.0 - Hydro + Wind + Solar		2023-2042	
3	Storage	3 MW, 9 MWH	2024-2042	$20/kW-Month Levelized

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

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

Offshore wind pricing is based on recent market intelligence, and the solar PPA is priced at $90/MWH, which is in alignment with VPPSA's recent solar PPA's. Finally, storage is priced at $20/kW-month. Although VPPSA's storage RFP process resulted in prices that were roughly half this rate, the current price of raw materials and the state of the supply chain indicates that pricing may double by the time the interconnection study and permitting are complete. As a result, we view this as a conservative assumption. Storage pricing could be lower.

REFERENCE CASE

The results of the reference case reflect the underlying trends in the price and volume of serving load. The Net Resource and Load Charges and Credits are growing at about inflation, which is in alignment with the underlying assumptions for energy and capacity prices. Transmission charges are growing more quickly, however, because this has been the trend over the past decade. Administrative costs grow more slowly, and the load itself grows at 0.7% per year after accounting for electrification trends. Finally, the coverage ratio drops over time as contracts expire.

Table 28: Reference Case Financial, Load and Coverage Ratio Outcomes ($ Million)

Cost Item	2022	2027	2032	2037	2042	CAGR
Net Resource and Load Charges & Credits	$1.9	$2.5	$2.7	$3.2	$3.6	3.1%
Transmission Charges	$0.9	$1.1	$1.5	$2.0	$2.7	5.5%
Administrative and Other Charges & Credits	$0.075	$0.083	$0.093	$0.104	$0.116	2.1%
Total Charges	**$2.8**	**$3.8**	**$4.3**	**$5.3**	**$6.4**	**3.9%**
Total Load - Including Losses (MWH)	29,362	29,274	30,983	32,954	33,662	0.7%
Coverage Ratio	106%	88%	53%	42%	28%	

There are two primary strategies available to reduce the trend in these costs. To stabilize net resource costs, long-term, fixed price contracts can be entered at or below the embedded cost of the existing (or expiring) resource. Accomplishing this outcome requires ongoing monitoring of both market prices and embedded costs, and then procuring resources during those times when it is cost-minimizing to do so. To stabilize transmission costs, a fixed-price peak-shaving storage resource is being studied. The system is presently sized at 3 MW and 9 MWH, and the contract is structured to guarantee a 90% or greater peak shaving accuracy. At these levels of accuracy, there is an opportunity to stabilize transmission costs by managing peak loads with storage.

The next section quantifies the relative cost of each procurement scenario.

PROCUREMENT SCENARIOS

Table 29 shows the present value of the 20-year revenue requirement (PVRR) for the Reference Case and for the RES 2.0 scenario. Notice that the PVRR increases by about two million dollars or 2.8% under the RES 2.0 requirements. This is due to the increased cost of procuring Tier I and Tier II RECs. It is also influenced by increasing Tier III requirements, which are assumed to rise to support the electrification trends that are built into the load forecast.

Table 29: Financial Outcomes of each Procurement Scenario ($ Million)

#	Procurement Scenario	NPV	Unit	% Change
0	Reference Case	$67.5	PVRR	
1	RES 1.0 - Tier I with Hydro	($1.1)	Chg. from Ref. Case	-1.6%
1.1	RES 1.0 - Tier I with Offshore Wind	($1.5)	Chg. from Ref. Case	-2.2%
2	RES 2.0 Requirements	$69.3	PVRR	2.8%
2.1	RES 2.0 - Tier I with Hydro	$0.270	Chg. from RES 2.0 Req.	0.4%
2.2	RES 2.0 - Tier I with Offshore Wind	($0.967)	Chg. from RES 2.0 Req.	-1.4%
2.3	RES 2.0 - Tier II Solar PPA	($0.068)	Chg. from RES 2.0 Req.	-0.1%
2.4	RES 2.0 – Hydro + Wind + Solar	($0.766)	Chg. from RES 2.0 Req.	-1.1%
3	Storage	($2.3)	Chg. from Ref. Case	-3.0%

Under RES 1.0 requirements, purchasing offshore wind appears to be the least-cost strategy. However, this outcome is dependent on market prices when the Request for Proposals (RFP) is issued. As a result, including bundled hydro energy and Tier I RECs in the procurement process makes sense, despite the apparent difference in cost during the planning stage.

For RES 2.0, we examine how much each resource decision contributes to the cost of the total procurement plan. Notice that the hydro and Tier I REC purchase actually increases cost slightly. This is due to a small misalignment between levelized and inflationary pricing in the Brookfield contract. Said simply, the pricing isn't in perfect alignment with market prices. The net savings from the offshore wind is lower than in the RES 1.0 scenario because only 2 MW of the resource is needed in the context of the doubling of the Tier II requirement. Finally, note that the cost of meeting Tier II requirements is nearly PVRR neutral. This is coincidental. The prices of energy and RECs in the IRP models happen to be almost the same as the assumed cost of solar.

STORAGE

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

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

Inflation and supply chain challenges have undoubtedly increased the cost of storage since the RFP was conducted. If NED were to sign a Battery Energy Storage Service Agreement (BESS) at the following prices, the cost to NED would be between $540,000 and $900,000 per year.

Figure 21: Annual Cost of a 3 MW AC Battery ($/Year)

($/kW-mo)	3 MW AC
$15.00	$540,000
$20.00	$720,000
$25.00	$900,000

To determine the value of a peak shaving battery, VPPSA modeled the avoided cost of capacity, GMP transmission, and ISO transmission. Because our storage partner is offering a performance guarantee that ensures 90% accuracy of operating the battery during peak hours, we assumed a 90% success rate for shaving the monthly and annual peaks. Based on a Monte Carlo analysis of 1,000 different randomly generated results, the value of a peak shaving battery averaged $25/kW-month (levelized) between 2023 and 2042. As a result, any BESS agreement that is priced less than this should generate net present value and reduce costs over the life of the agreement. Specifically, a BESS agreement for $20/kW-month would be expected to reduce PVRR by $2,307,000.

CONCLUSIONS

The financial analysis can be summarized by two primary points. First, minimizing Tier I RES compliance costs is a close call between hydro and wind resources. As a result, these resources should be procured in a head-to-head, competitive process. The cost-minimizing resource(s) will be sensitive to energy, REC, and capacity market prices at the time of their procurement.

Second, RES 2.0 requirements will increase costs by about 2.8% as measured by the PVRR. As importantly, REC price risks would likely increase because of the procurement limits and trade offs between Tier I and Tier II resources that were discussed in the Resource Plans section.

Finally, peak shaving storage represents an opportunity to reduce costs by mitigating the increasing cost of transmission. Once the interconnection study is complete, NED expects to decide whether to pursue an Act 248 permit for the project at its King Street substation.

ACTION PLAN

VI. ACTION PLAN

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

- Automated Metering Infrastructure (AMI)
    - Pursue implementation of an AMI system as reflected in the recent RFP within the 2022-2023 time frame

- Energy Resource Actions
    - Manage year to year energy market requirements using fixed-price, market contracts that are less than five years in duration.
    - Continue to evaluate the costs and benefits of the Fitchburg Landfill Gas contract, and elect the 2027-2031 extension option as appropriate.
    - Solicit both a hydro PPA bundled with Tier I RECs and/or an offshore-wind PPA to fulfill RES requirements and hedge energy and REC price risk.

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

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

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

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

- Storage
  - Complete the interconnection study and finalize the pricing for the proposed 3 MW/9 MWH storage proposal at the King St. Substation.
  - Initiate the permitting process.

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

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

- 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.

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

APPENDIX

APPENDIX A: 2022 TIER 3 ANNUAL PLAN

This appendix is provided separately in a file named:

Appendix A - VPPSA Tier 3 2022 Annual Plan.pdf

APPENDIX B: PRICING METHODOLOGY

This appendix is provided separately in a file named:

Appendix B – NED Energy & Capacity Pricing Methodolgy.pdf

APPENDIX C: PUC RULE 4.900 OUTAGE REPORTS

This appendix is provided separately in a file named:

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

APPENDIX D: AMI RFI TECHNICAL REQUIREMENTS

This appendix is provided separately in a file named:

Appendix D – AMI_RFI_Technical_Requirements.pdf

APPENDIX E: AMI RFP TECHNICAL REQUIREMENTS

This appendix is provided separately in a file named:

Appendix E – AMI_RFP_Technical_Requirements.pdf

APPENDIX F: ITRON'S LOAD FORECAST REPORT

This appendix is provided separately in a file named:

Appendix F – Northfield IRP22 Demand Report.pdf

APPENDIX G: TIER III LIFE-CYCLE COST ANALYSIS

This appendix is provided separately in a file named:

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

APPENDIX H: CVRPC REGIONAL ENERGY PLAN

Appendix H - https://publicservice.vermont.gov/content/central-vermont-regional-planning-commission

GLOSSARY

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

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

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

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
1	**Trees**	5	144
2	**Weather**	4	1,194
3	**Company initiated outage**	0	0
4	**Equipment failure**	7	1,862
5	**Operator error**	0	0
6	**Accidents**	1	1
7	**Animals**	0	0
8	**Power supplier**	3	2,206
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	0	0
	Total	20	5,408

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
1	**Trees**	5	1,532
2	**Weather**	8	579
3	**Company initiated outage**	0	0
4	**Equipment failure**	7	226
5	**Operator error**	0	0
6	**Accidents**	0	0
7	**Animals**	3	29
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	1	155
11	**Unknown**	4	448
	Total	28	2,970

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	2019
Contact person	Patrick Demasi
Phone number	802-485-7355
Number of customers	1,831

System average interruption frequency index (SAIFI) =	**0.47**
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	**2.35**
Customer Hours Out / Customers Out	

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	7	466
2	**Weather**	3	430
3	**Company initiated outage**	1	1,050
4	**Equipment failure**	3	58
5	**Operator error**	0	0
6	**Accidents**	0	0
7	**Animals**	1	1
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	0	0
	Total	15	2,005

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	2020
Contact person	Patrick Demasi
Phone number	802-485-7355
Number of customers	1,826

System average interruption frequency index (SAIFI) =	**0.03**
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	**2.21**
Customer Hours Out / Customers Out	

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	2	90
2	**Weather**	0	0
3	**Company initiated outage**	0	0
4	**Equipment failure**	8	37
5	**Operator error**	0	0
6	**Accidents**	0	0
7	**Animals**	2	4
8	**Power supplier**	0	0
9	**Non-utility power supplier**	0	0
10	**Other**	0	0
11	**Unknown**	0	0
	Total	12	130

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	2021
Contact person	Patrick Demasi
Phone number	802-485-7355
Number of customers	1,837

System average interruption frequency index (SAIFI) = 4.44
Customers Out / Customers Served

Customer average interruption duration index (CAIDI) = 2.83
Customer Hours Out / Customers Out

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	7	7,544
2	**Weather**	3	2,287
3	**Company initiated outage**	0	0
4	**Equipment failure**	6	5,189
5	**Operator error**	0	0
6	**Accidents**	0	0
7	**Animals**	2	7,195
8	**Power supplier**	1	822
9	**Non-utility power supplier**	0	0
10	**Other**	1	11
11	**Unknown**	0	0
	Total	20	23,048

Northfield Electric Department

Without Major Storm Outages

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	2021
Contact person	Patrick Demasi
Phone number	802-485-7355
Number of customers	1,837

System average interruption frequency index (SAIFI) =	**4.32**
Customers Out / Customers Served	
Customer average interruption duration index (CAIDI) =	**2.62**
Customer Hours Out / Customers Out	

	Outage cause	Number of Outages	Total customer hours out
1	**Trees**	7	7,544
2	**Weather**	0	0
3	**Company initiated outage**	0	0
4	**Equipment failure**	6	5,189
5	**Operator error**	0	0
6	**Accidents**	0	0
7	**Animals**	2	7,195
8	**Power supplier**	1	822
9	**Non-utility power supplier**	0	0
10	**Other**	1	11
11	**Unknown**	0	0
	Total	17	20,761

1. TECHNICAL REQUIREMENTS

Please answer all questions and provide detail on any specific capabilities of your AMI technology in your response.

1.1 Electric Metering

The purpose of this section is to understand capabilities of the electric meters that work with the AMI solution.

1. Provide details of meters available with your AMI solution, e.g. meter type, manufacturer, etc.
2. List all the meters and manufacturers that your AMI solution will support.
3. Does your AMI solution support meters from more than one manufacturer in a single AMI implementation?
4. What compliance standards do your meters meet, e.g. ANSI, UL, IEC, etc.?
5. Meters will be installed in Vermont and be subject to a wide range of weather (ice, heat, snow, temperature) and environment considerations. Please provide details on the performance of meters given these details. This includes compliance with an outdoor installation. This includes UV resistance.
6. Describe the service life of the electric endpoint, including internal batteries, given weather/environment considerations.
7. Provide details regarding the failure rate of the electric meter and communications technology in a Pareto analysis format.
8. Provide details of the alerts, alarms, and configurations, i.e. tamper, temperature, reverse energy, voltage etc.
9. Describe the electric meter disconnect capability including support for remote disconnect, load limiting, disconnect security, etc.
10. Provide meter identification details including barcode, labeling and meter security keys. Describe how meter identification is handled if a single central AMI system is used across all Members.

11. Describe the measurement parameters available on all meter types, e.g. energy, demand, voltage, power factor, including interval data measurements.

12. Describe data storage capacity within the meter.

13. Provide details regarding the meter's ability to support Time-of-Use, Critical Peak Pricing and other rate designs.

14. Describe the meter display and any visual indicators, e.g. disconnect indicator.

15. Describe the meter's ability to support net energy metering installations.

16. Provide details regarding the meter data security, along with associated hardware considerations from field to back-office systems, including encryption/decryption.

17. Explain how security keys are managed. Include scenarios for a centralized implementation as well as individual Member deployment considerations.

18. Describe the processes available to access data from the meter (over-the-air, drive-by, manual, Wi-Fi, etc.).

19. Describe the process for meter firmware upgrades or configuration changes.

20. Describe any other functionality available in the meter.

1.2 Water Meters and Endpoints

The purpose of this section is to understand capabilities of a water AMI solution including water meter capabilities and/or the integration of an AMI water endpoint with existing water meters.

1. Describe features of the proposed system relating to water meters:

    a) Meter interface unit connection & mounting options. Address solutions for existing 6-digit touch read meters located in the basement with touchpad on the outside wall. There are a few meters in pits with a touchpad through the lid.

    b) Alarm and tamper alert features, e.g. reverse flow, tamper, battery life, etc.

    c) Read data and interval operations; describe the measurements available for each type of meter.

2. Provide a list of water meters and registers compatible with the AMI solution.

3. Explain power output and two-way communication functionality. Does the meter interface unit (MIU) have the ability to "hop" information to/from the electric meters or other water meters?

4. Explain the process of installation and commissioning of the meter and interface unit. Include any issues or concerns associated with communication devices. Address any issues of access to indoor meters. Most will be replacement of touchpad that is mounted on outside wall of the structure.

5. What industry compliance standards do your meter interface units meet, e.g. ANSI, UL, IEC, etc.?

6. What is the service life of the meter interface unit, including internal batteries, given weather/environment considerations?

7. Provide details regarding the failure rate of the water meter and meter interface unit in a Pareto analysis format.

8. Describe the capability of the system, meter interface unit and meter to support for remote disconnect, disconnect security, etc.

9. Provide details of meter identification including barcode, labeling, meter security keys. Describe implementation of meter identification/discretion if one central AMI system is used for several Member utilities.

10. Describe the meter data storage capacity within the meter interface unit.

11. Provide details regarding security of meter, interface unit and associated hardware considerations for back-office systems including encryption/decryption.

12. Explain how security keys are managed. Include scenarios for a centralized implementation as well as individual Member deployment considerations.

13. Describe the processes available to access data from the meter (over-the-air, drive-by, manual, Wi-Fi).

14. Describe the process for MIU firmware upgrades or configuration changes.

15. Describe any other functionality available in the meter.

16. Provide description of clock/calendar in the MIU including drift limits and synchronization intervals.

1.3 AMI Network

The purpose of this section is to understand the AMI network capabilities and operation as well as the equipment used for the network.

1. Describe the types of communications available with your AMI solution, e.g. RF, PLC. Include options for a mixed communication AMI solution.

2. Provide details regarding the metering communication network including types of equipment and backhaul options. Explain the alternative network backhaul options if cellular service is unavailable.

3. Explain the latency of your system for each communication and backhaul option used in your solution.

4. Explain the installation requirements for each type of network equipment, e.g. locations, mounting, height, power, protection from surges/lightning.

5. Describe the network architecture. Include the option of a shared AMI system for all Members. Does the configuration support common collection devices across Members, e.g. neighboring Members?

6. Describe the capacity of your AMI network, e.g. bandwidth, collector/repeater capacity (meters per network device), etc.

7. Describe the network security e.g. encryption, breach identification.

8. Provide an overview of how meters communicate with each type of collection device.

9. Describe how electric and water meters can be read concurrently through the network.

10. Describe how the network solution reaches hard-to-read meters (encumbered by terrain, foliage, etc.) or geographically dispersed meters.

11. Describe how the proposed system is managed over time, e.g. resource skill, training, remote management and maintenance, replacement process.

12. What service level agreement is supported by your solution and capabilities? Can the solution provide 99% of daily reads every day?

13. What is the success rate of last gasp messages for outages?

14. What is the success rate of on-demand meter interrogations or pings?

15. Provide a preliminary outline describing network solutions for VPPSA Members as a group and then also having each Member as an individual network.

16. Describe the procedure for AMI network component firmware upgrades.

17. Explain network disaster recovery processes specific to each proposed solution. Provide details regarding redundancy and failover of collection devices.

1.4 Software

In this section, provide a description of the AMI head end software, tools and software to operate the network and meter data management (MDM) capabilities. In addition, provide the options for implementation of the software and delivery of the solution.

1. Describe the software required to operate the AMI system. Provide product names of all software required for the solution. Include a MDM in your solution; third party solutions are acceptable.

2. Provide an architectural overview of the software solution provided with the AMI system.

3. Identify the software required to operate and troubleshoot the network.

4. Identify the software required to retrieve and manage all meter data.

5. What tools or software are available for field programming, data download and troubleshooting?

6. Does your company offer Meter Data Management (MDM) software?

7. Describe the following functionality and identify the software product performing the function:

    a) Meter Data Interrogation

    b) Meter Disconnect/Connect, Pinging

    c) Meter Data Validation, Estimation and Editing

    d) Reports

    e) Analytics

8. Describe how meter reads can be transferred to billing systems, include manual and automated processes.

9. Describe the options for software delivery including on-premise, hosted, managed services or others.

10. Can one central system serve all Members but have the data segregated and accessed by the Member owning the data, i.e. multi-tenant database

11. Can each VPPSA Member have their own separate system?

12. Describe the advantages and disadvantages of a single central system versus separate systems for each Member.

13. Has your system been integrated to the following systems and describe the type of integration, e.g. standard API, Multispeak, manual entry:

    a) SEDC

    b) NEMRC

    c) Harris Northstar

    d) Harris Spectrum

    e) Harris Select

    f) MUNIS

    g) Cogsdale

    h) Creative Technologies

    i) mPower

14. Does your company offer software for customer engagement such as a web portal? If not, what are your recommendations for a customer portal solution?

15. Does your company offer software for data analytics?

16. Does your software provide any mapping or GIS functionality? If so, describe any 3rd party products.

17. Provide al list of 3rd party products used in your AMI solution. Identify any product that requires a separate license.

1.5 Other Electric Capabilities

The purpose of this section is to understand the additional capabilities supported by the electric AMI solution beyond meter reading. If the solution has capabilities not captured in the questions below, please provide any additional material on those capabilities. Include any third-party solutions or partners that work with the AMI solution or network.

1. Describe your company's offerings for Demand Side Management (DSM).
2. Describe the AMI solution's capability to support Demand Response Programs.
3. Describe your AMI solution support for Home Area Networks (HAN).
4. What protocols are available to support DSM or HAN technologies, e.g. OpenADR, Zigbee, Multispeak?
5. What support does your AMI solution offer for outage management?
6. Describe the AMI solution's support for voltage reduction programs, e.g. CVR, VVR.
7. What support does your AMI solution offer for transformer sizing or transformer load management?
8. Describe the AMI solution's ability to support Distribution Automation.
9. Describe the AMI solution's support for net metering.
10. How does the AMI solution support new customer electric technologies, e.g. electric vehicles, power walls, etc.?
11. Describe methods of exporting data from your system.
12. Are there other functions available and supported by your AMI network e.g. streetlight control, security cameras, active shooter, propane tank monitoring?
13. Is there a customer pre-pay solution integrated with the AMI solution?

1.6 Water System Functionality and Leak Detection

The purpose of this section is to understand the additional capabilities of the water AMI solution beyond meter reading. If the solution has capabilities not captured in the questions below, please provide any additional material on those

capabilities. Include any third-party solutions or partners that work with the water AMI solution or network.

1. Describe leak detection features of the meter interface unit using existing meters

2. Describe distribution leak detection device, capabilities, and requirements.

3. Describe system capabilities for district (zone) metering

4. Describe other features available for use with the proposed AMI system such as:

    a) Pressure loggers

    b) Water quality monitoring

    c) Other water system monitoring features